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Arizona Public Service Company
Fuel Hedging Program
Benchmarking Assessment

November 1, 2006

R·W·BECK

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Arizona Public Service Company
Fuel Hedging Program
Benchmarking Assessment

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This report has been prepared for the use of the client for the specific purposes identified in the report. The conclusions, observations and recommendations contained herein attributed to R. W. Beck, Inc. (R. W. Beck) constitute the opinions of R. W. Beck. To the extent that statements, information and opinions provided by the client or others have been used in the preparation of this report, R. W. Beck has relied upon the same to be accurate, and for which no assurances are intended and no representations or warranties are made. R. W. Beck makes no certification and gives no assurances except as explicitly set forth in this report.

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Section 1
EXECUTIVE SUMMARY

This Executive Summary is intended to provide the reader with an overview of the nature of this project and the primary findings. Further detail is provided in the body of the report and the appendices.

1.1 Project Overview

Throughout the course of the hearings for the Arizona Public Service ("APS) Emergency Rate Case (ACC Docket E-01345A-0009), the matter of the issue of requiring APS to conduct a benchmarking study on the effectiveness of its natural gas purchasing practices was addressed by the parties. As a result of Decision 68685 from this case, APS was ordered to engage in a benchmarking study of their fuel costs and hedging practices. The ACC directed APS to work with ACC Staff to file within 180 days of the effective date of this decision (May 5, 2006) as a compliance item in this docket.

In keeping with the above, the purpose of this study is to conduct an independent benchmarking assessment of Arizona Public Service Company's fuel hedging program, with specific focus on natural gas. The review covers the overall design and process aspects of the hedging program, an assessment of the quality of the hedging program and associated transactions in light of common industry practices, and an assessment of the resultant net fuel costs. The central element of the project was a benchmarking study of other leading utilities, which is intended to provide a basis for comparing the process aspects and performance of APS' hedging program.

Primary sources of information which form the basis for assessing APS' program include 1) a survey of utilities developed and implemented for this study, 2) R. W. Beck's experience working with a wide range of other clients on energy risk management and hedging issues, and 3) supplemental information made available to R. W. Beck from an ongoing study of energy risk management practices by the Electric Power Research Institute.

1.2 Information Supporting Study

As further described in Section 4, a key part of this study was to conduct primary research through the design and implementation of a survey instrument focused on energy risk management and fuel hedging practices. These data points provide current indications of how the survey respondents approach fuel hedging and broader energy risk management issues compared to APS.

In addition, R. W. Beck has extensive experience assisting a broad range of utility clients with the development of energy risk management and hedging programs. By conducting interviews and extensive document reviews to develop a clear understanding of the design and implementation of APS' program, R. W. Beck is able to make comparisons of APS' program against those of the other clients with whom R. W. Beck has worked.

During 2006, the Electric Power Research Institute (EPRI) has been conducting a study of practices and techniques in portfolio and risk management. R. W. Beck has had the privilege of working with EPRI for several years, and was involved in the initial design of the EPRI study. R. W. Beck has reviewed EPRI's initial results and is able to rely on (and reference) them as supplemental support for this study.

1.3 Hedging Concepts

An important goal of this project is to provide foundational information regarding leading concepts in energy risk management and hedging.

The fundamental purpose of energy risk management and hedging is to reduce the uncertainty of meeting performance goals. The intended benefits of properly-applied hedging are:

- Reducing undesirable fluctuations in net costs and/or revenues so that customer prices and company cash flows become more stable
- Reducing the impact of stress conditions caused by extreme movements in energy market prices
- Creating greater financial performance stability, which is typically supported by customers, regulators, and lenders thereby helping to reduce the cost of capital
- Reducing the amount of cash and short-term credit needed to fund periodic shortfalls in cash flow caused by the impact of market price volatility

It is important to recognize that hedging is not intended to directly reduce costs through the hedging transactions themselves. Hedging can (on average) lead to slightly increased net fuel costs because the hedge transactions may include some level of risk premium. However, overall savings can accrue by creating greater certainty for customers, lenders and investors (thereby leading to lower relative cost of capital) and reducing the amount of cash and short-term credit needed to fund otherwise volatile cash flows that would occur in the absence of hedging.

To achieve the above benefits on a consistent basis, hedging activity must be done in a highly controlled manner through a well-designed and executed risk management program. For a risk management (or hedging) program to be complete and effective, it must be built around a framework that addresses the following elements: Organizational Objectives, Risk Tolerance, Risk Inventory, Portfolio Management, and Risk Control Infrastructure. These elements are described further in Section 3.

1.4 Project Tasks

As detailed further in Section 4, R. W. Beck completed a number of primary tasks in conducting this study. These are:

- Task 1: Review Project Plan and Collect Initial Information
- Task 2: Review Hedging Program Processes and Execution
- Task 3: Conduct Benchmarking Study of Comparable Utilities
- Task 4: Assess Hedging Program Design and Effectiveness
- Task 5: Prepare Written Report

1.5 Survey Process

A central element of this study was to conduct primary research on current energy risk management and fuel hedging practices. R. W. Beck is experienced in conducting benchmarking studies of electric utility operations and management. The R. W. Beck project team, which included persons with extensive experience in energy risk management and persons involved in prior benchmarking studies, independently developed the survey instrument with APS' input. It is important to note that the survey was intentionally designed to address not just natural gas hedging, but energy risk management practices in general. This was done in order to make the study more attractive for participation.

The project team and APS developed an initial list of approximately thirty-five companies that was provided to ACC Staff for their concurrence. The group of companies reflected a combination of West/Southwest utilities in general, plus utilities from other regions with which R. W. Beck has a relationship. The overall group included companies across the U.S. and Canada, and reflected various types of utilities (e.g. investor-owned, municipal, etc.) This was intentionally done to maximize the likelihood of a sufficient number of responses, and to provide for a more comprehensive study.

In general, the response rate was low in relation to the number of companies which initially either agreed or tentatively agreed to participate. **Energy risk management and hedging information is considered highly proprietary, and it is not surprising that many companies did not return a survey.** A total of twelve surveys were completed and returned. R. W. Beck made attempts to contact the companies who agreed to participate but did not return a survey. In some cases, multiple attempts were made. For the Arizona companies, Salt River Project tentatively agreed to participate, but later indicated that they felt the survey asked for too much proprietary data and that they were unlikely to return a survey. Tucson Electric agreed to complete and return a survey, but never did.

While the number of respondents is low compared to original participation targets, the survey results are very consistent with R. W. Beck's experience working with a wide range of clients on risk management issues. Further, while respondents include

municipal, district, and consumer-owned (i.e. cooperative) utilities as opposed to only IOU's, R. W. Beck's experience is that the size and type of utility is not a strong indicator of the existence and quality of an energy risk management program. In other words, we have seen excellent programs at small utilities and weak programs at large utilities (and vice versa). **R. W. Beck considers the survey results to be sufficiently representative to draw the conclusions contained in this report.**

1.6 Summary of Findings

R. W. Beck's overall conclusion from the survey results is that APS has a high-quality energy risk management and hedging program consistent with or superior to its utility peer group. No significant areas exist where APS would be considered deficient in its hedging program as it relates to standard industry practices, or hedging programs of like utilities. In addition, R. W. Beck's review of the initial results of EPRI's portfolio and risk management practices study also indicates that APS' program is consistent with leading industry practices.

Based on R. W. Beck's experience in energy risk management, the programmatic aspects of APS program are of high quality and consistent with those of other leading programs. All aspects of a high quality risk management framework (please refer to Section 3) are in place and appear to be operating effectively. There are no material areas in which APS' program was found to be substandard. In some areas, APS has arguably a superior program compared to other utilities.

APS has an appropriate mindset regarding hedging which is consistent with best industry practices:

- The purpose of hedging is to reduce volatility in costs by effective forward hedging of commodity prices.
- Seventy eight percent (78%) of the survey respondents forward hedge natural gas more than two years forward, and one third (33%) hedge more than three years forward. APS forward hedges its natural gas and purchased power requirements three years in advance
- The purpose of hedging is not to create financial gains by timing the market. Eighty percent (80%) of utilities surveyed indicated reduced price volatility or protection against unexpected future cost increases as their most important goal in their hedge program.

It is also important to note that APS' hedging activities and energy risk management program elements are consistent with rating agency views which are placing greater importance on energy risk management.

APS' approach to risk analytics and limits is consistent with standard industry practices. APS has implemented hedging parameters and limits based on volumetric parameters, which is consistent with industry standards. The interplay (correlation) between natural gas prices and power prices is considered as part of the volumetric analysis, which is a positive attribute. In R. W. Beck's opinion, APS hedges an

appropriate amount of natural gas given the goals of their hedging program, their financial condition, and their level of exposure to natural gas prices.

During recent years of generally rising and historically high natural gas prices, APS' hedging activities appear to have provided significant protection to customers from even higher fuel-related net costs that would have occurred in the absence of hedging. This conclusion is supported by reviews of data and reports provided to R. W. Beck by APS, fuel cost information obtained during the survey process, and analysis of fuel cost data from the Energy Velocity® database. Energy Velocity® is one of the leading industry data services providing comprehensive utility data and information which is collected and validated from numerous publicly-available sources.

Section 2
INTRODUCTION TO STUDY

2.1 Purpose of Study

The nations' second fastest growing utility, APS is an investor-owned utility serving more than one million customers in Arizona. With a large nuclear generating capacity, APS has traditionally been able to offer their customers low cost power, with rates decreasing several times between the years 1992 and 2004. Rapid growth and a corresponding need for additional resources in recent years have resulted in natural gas power plants comprising a greater percentage of APS' generation mix. This increased reliance on natural gas, coupled with upward price spikes over the past few years, have led to higher generation costs and financial burdens for APS, culminating in a downgrade of the corporate credit rating. In response to these events, APS filed for, and was granted, an emergency rate increase that took effect in May 2006. As part of the rate increase approval process, the ACC's Order required an independent assessment of APS' hedging program.

In keeping with the above, the purpose of this study is to conduct an independent benchmarking assessment of Arizona Public Service Company's fuel hedging program, with specific focus on natural gas. The review covers the overall design and process aspects of the hedging program, its execution in coordination with the energy risk management program and the overarching corporate business strategy, an assessment of the quality of the hedging program and transactions in light of common industry practices, and an assessment of the resultant net fuel costs. The benchmarking aspect of the project consists of comparing qualitative and quantitative aspects of APS' program against programs of other utilities though the results of a customized survey created for this project, subject matter expertise of R. W. Beck gained from a large number of prior risk management and fuel hedging-related consulting assignments, and incremental research. In essence, the questions being investigated are 1) What is the overall quality of the design and execution of APS' energy risk management and fuel hedging program, 2) How does APS' program compare to other utilities, and 3) What has been the impact of hedging on APS' net natural gas costs? These questions have been investigated in the context of assessing the prudence of APS' current hedging strategy, and the robustness of the design, overall philosophy, and execution of the program. The main focus of this assessment is a benchmarking study of comparable utilities, which is intended to provide a basis for comparing the process aspects and performance of APS' hedging program.

2.2 Primary Sources of Information

Three primary sources of information were used as the basis for this study. These are described below.

2.2.1 Benchmarking Survey Data

As further described in Section 4, a key part of this study was to conduct primary research through the design and implementation of a survey instrument focused on energy risk management and fuel hedging practices. These data points provide current indications of how the survey respondents approach fuel hedging and broader energy risk management issues compared to APS.

2.2.2 R. W. Beck Consulting Experience

R. W. Beck has extensive experience assisting a broad range of utility clients with the development of energy risk management and hedging programs. By conducting interviews and extensive document reviews to develop a clear understanding of the design and implementation of APS' program, R. W. Beck is able to make comparisons of APS' program against those of the other clients with whom R. W. Beck has worked.

2.2.3 Study by Electric Power Research Institute

During 2006, the Electric Power Research Institute (EPRI) has been conducting a study of practices and techniques in portfolio and risk management. R. W. Beck has had the privilege of working with EPRI for several years, and was involved in the initial design of the EPRI study. Due to the similar nature of the EPRI study and this study performed for APS, R. W. Beck made arrangements with EPRI to gain access to EPRI's study results. In exchange, R. W. Beck will be assisting EPRI with final review and editing of their report prior to publishing in late 2006 or early 2007. EPRI's study addresses many of the key aspects of risk management program design which are relevant and provide supplementation information against with APS' program can be compared. R. W. Beck has reviewed EPRI's initial results[1] and is able to rely on (and reference) this information as part of this study.

The EPRI study addresses both qualitative and quantitative risk management program issues. Rather than a survey approach, EPRI held in-depth discussions with a small number of companies to explore program structure and analytic issues. Similar to the survey instrument used for this project, EPRI's pre-meeting questionnaire covered such topics as type of utility, staffing levels, aggregate years of risk management experience, types and magnitudes of energy risk exposures, risk limits, and a variety of issues connected with analytics and systems.

[1] Survey of Practices and Techniques in Portfolio and Risk Management, Electric Power Research Institute, presented by Remi Audouin, Knoxville TN, September 2006.

Section 3
ENERGY RISK MANAGEMENT & HEDGING CONCEPTS

3.1 Hedging Concepts

An important goal of this project is to provide foundational information regarding leading concepts in energy risk management and hedging. This purpose of this is to provide a common understanding of these principles for those reading this report, and to provide greater context for R. W. Beck's conclusions.

The fundamental purpose of energy risk management and hedging is to reduce the uncertainty of meeting performance goals. An influential study conducted by the Energy Information Administration[2] (and one which provides an excellent introduction to risk management concepts) investigates the benefits of hedging activity through the use of derivatives. These concepts apply to hedging in general, regardless of whether the instruments used are derivatives or conventional physical energy contracting strategies. In essence, these benefits can be summarized as:

- Reducing undesirable fluctuations in net costs and/or revenues so that customer prices and company cash flows become more stable
- Reducing the impact of stress conditions caused by extreme movements in energy market prices
- Creating greater financial performance stability, which is typically supported by customers, regulators, and lenders, thereby helping to reduce the cost of capital
- Reducing the amount of cash and short-term credit needed to fund periodic shortfalls in cash flow caused by market price volatility

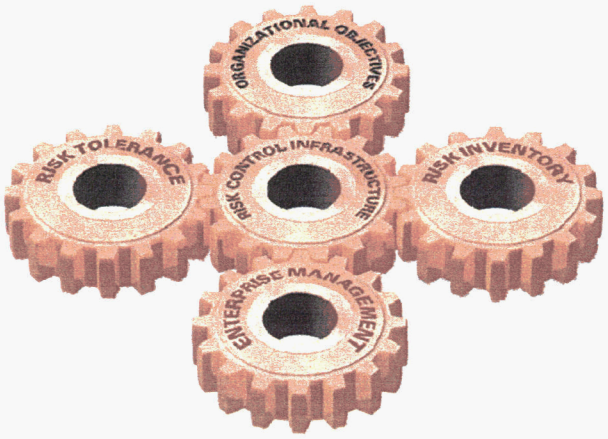
It is very important to recognize that hedging is not intended to directly reduce costs through the hedging transactions themselves. In reality, hedging can (on average) create a slight increase in net fuel costs because the hedge transactions may include some level of risk premium. However, as stated above, effective hedging creates greater performance certainty which, in addition to the benefits of greater price stability, can indirectly create lower costs. This occurs by creating greater certainty for customers, lenders and investors (thereby leading to lower relative cost of capital) and reduced cash and short-term credit needed to fund otherwise volatile cash flows that would occur in the absence of hedging.

[2] Derivatives and Risk Management in the Petroleum, Natural Gas, and Electricity Industries, U.S. Energy Information Administration, October 2002

3.2 Program Design & Execution

To achieve the above benefits, hedging activity must be done in a highly controlled manner through a well-designed and executed risk management program. Through the experience of its staff, as well as ongoing training and education on both financial standards and best practices among utilities, R. W. Beck has developed a clear view of how the components and execution of "best practices" can be most successfully integrated for risk management in utilities and energy companies.

R. W. Beck's working definition of risk is "any event or condition that could cause adverse financial performance compared to expectations." This definition is intentionally broad so as not to exclude potential risk sources that may be deserving of management attention. The key to successful risk management is to be able to understand and manage the sources of risk that most impact the achievement of core goals. R. W. Beck's view is that, for a risk management (or hedging) program to be complete, it must be built around a framework that addresses the following five elements: Organizational Objectives, Risk Tolerance, Risk Inventory, Portfolio Management, and Risk Control Infrastructure. APS has generally incorporated all of these elements into their program in a high-quality fashion.



3.2.1 Organizational Objectives

It is critical to articulate goals, strategies, and objectives that provide guideposts that define the appropriate hedging, trading, and portfolio management activities to be undertaken by the organization, as well as those activities that are inappropriate.

3.2.2 Risk Tolerance

Through risk tolerance definition, the organization should specify the amount of uncertainty that the organization is willing to accept in its costs and financial performance, with particular emphasis on the organization's tolerance for falling short of financial expectations.

3.2.3 Risk Inventory

Through the risk management program, the organization should characterize the types and magnitudes of risks to which the organization is exposed and which contribute to the potential for adverse financial performance.

3.2.4 Portfolio Management

Management and staff must engage in strategic (longer term) and tactical (shorter term) transaction strategies in order to help maintain risk exposures within the organization's risk tolerance and reduce the probability of falling short of performance expectations. Hedging activities should be driven by a high-quality risk control infrastructure to maximize effectiveness and efficiency, and to minimize the chance of inappropriate transactions.

3.2.5 Risk Control Infrastructure

Best practices dictate that a collection of internal controls, systems, and operating practices are necessary for the organization to maximize risk mitigation effectiveness and achieve the overall objectives of its risk management program. The Risk Control Infrastructure includes:

- Policies and Procedures
- Organization Structure and Responsibilities with clear separation of duties
- Limits for Risk Exposures and Transactions
- Position Tracking
- Risk Measurement
- Performance Measurement
- Management Reporting

By assembling these elements into an integrated system, changes in market environment or other factors can be properly translated into modified corporate policies, transaction strategies, etc. For example, if the risk tolerance of the company (or its customers) changes, this change can be addressed through the processes and controls in the risk control infrastructure, ultimately leading to appropriate adjustments in portfolio management (i.e. hedging) activities.

Section 4
STUDY PROCESS

This section provides an overview of the primary tasks which comprise the agreed-upon project scope, along with a summary of R. W. Beck's efforts in conducting the survey and the level of survey responses received.

4.1 Project Tasks

4.1.1 Task 1: Review Project Plan and Collect Initial Information

The purpose of this Task was to review the project plan and agree on a common understanding of the project scope, deliverables, schedule, and reporting protocols. This Task also served to facilitate the initial collection of information, through a request of various documents, and through on-site interviews with key personnel associated with various aspects of APS' hedging and risk management program. Specific activities completed under this task are listed below.

- Kick-off call
- Develop revised project schedule
- Submit initial data request
- Schedule and conduct on-site interviews

4.1.2 Task 2: Review Hedging Program Processes and Execution

The purpose of this Task was to understand the current hedging program, in terms of the various processes that comprise the program, how the program aligns with the overarching organizational goals/objectives and risk tolerance, and how the program is being executed. This Task probed more deeply into information obtained from Task 1, with a review of specific documents and follow-up interviews. Activities completed under this task are listed below.

- Conduct follow-up interviews
- Collect and review information
- Review current strategic and business plans
- Clarify business objectives and risk tolerance

- Review hedging program design and philosophy
- Review specific process aspects of hedging program
- Review hedging program execution, including sample transactions

4.1.3 Task 3: Conduct Benchmarking Study of Comparable Utilities

The purpose of this Task was to design and conduct a benchmarking study of the hedging programs for comparable utilities. This benchmarking study, which is the focal point of the project, consisted of primary research conducted by R. W. Beck, and investigated such measures as net natural gas costs, types of transactions, and process aspects of utility hedging programs. It was anticipated that the study would include up to fifteen peer utilities (twelve surveys were actually completed and returned to R. W. Beck). The intent of this analysis was to compare APS' hedging program against other utilities. Specific activities completed under this task are listed below.

- Develop benchmarking and research objectives
- Define fuel cost and hedging measures and data requirements
- Identify potential participants
- Prepare data collection mechanisms
- Contact and finalize participants
- Participant response time
- Analysis and refinement of results

4.1.4 Task 4: Assess Hedging Program Design and Effectiveness

Utilizing information gleaned from Tasks 1 through 3, the purpose of this Task was to assess the quality of APS' hedging program, both in terms of process aspects and financial performance (fuel costs). R. W. Beck assessed the quality with which APS' program is being executed, identified key differences in program design and execution compared to other utilities' programs, and identified potential improvement opportunities. Specific activities completed under this task are listed below.

- Conduct follow-up interviews
- Collect and review information
- Assess APS hedging program design and process aspects
- Assess APS hedging program execution
- Compare program to benchmarking study findings
- Assess overall program quality and identify key differences

4.1.5 Task 5: Prepare Written Report

The purpose of this Task was to communicate key findings from the assessment of APS' hedging program. These findings, which address both the overall focus and quality of the program, are being communicated in both written and verbal form. R. W. Beck produced a draft written letter report, to be reviewed by APS and the Commission Staff for content and compliance with the Order.

4.2 Survey Process

As stated previously, a central element of this study was to conduct primary research on current energy risk management and fuel hedging practices. Because of the importance of this portion of the project, provided below is additional information regarding the specific activities conducted, and the level of success (in this case, the lack thereof) in receiving survey responses.

4.2.1 Survey Design

R. W. Beck is experienced in conducting benchmarking studies of electric utility operations and management. The R. W. Beck project team, which included persons with extensive experience in energy risk management and persons involved in prior benchmarking studies, worked with APS to design the survey instrument. R. W. Beck developed an initial draft, which APS subsequently reviewed. Some of APS' comments were incorporated. Others were not, reflecting R. W. Beck's position as a fully independent consultant. After several rounds of review and comments, the survey instrument was finalized.

It is important to note that the survey was intentionally designed to address not just natural gas hedging, but energy risk management practices in general. This was done in order to make the study more attractive for participation. For example, some companies do not hedge natural gas (because they do not utilize natural gas), but have broader energy risk management issues connected with other fuels and/or hydroelectric generation. R. W. Beck felt it was important to include such companies to strengthen the number of possible respondents, and to gain greater information on general industry practices in risk management which are relevant regardless of fuel sources. Issues such as governance, segregation of duties, instrument types, etc. are examples of this.

4.2.2 Companies Contacted

The project team and APS developed an initial list of approximately thirty-five companies that was provided to ACC Staff for their concurrence. The group of companies reflected a combination of West/Southwest utilities in general, plus utilities from other regions with which R. W. Beck has a relationship (thereby creating initial optimism that a large number of responses would be achieved). The overall group included companies across the U.S. and in Canada, and also included various types of utilities (e.g. investor-owned, municipal, etc.) This was intentionally done to

maximize the likelihood of a sufficient number of responses and to provide for a more comprehensive study.

4.2.3 Responses and Follow-Up Activities

Appendix B provides a list of the companies contacted, and whether or not a survey was returned. In general, the response rate was low in relation to the number of companies which initially either agreed or tentatively agreed to participate. **Energy risk management and hedging information is considered highly proprietary, and it is not surprising that many companies did not return a survey.** Twelve surveys were completed and returned, one of which only applied to the gas LDC potion of the utility and which was subsequently excluded. All of these were either fully or mostly complete. **Some companies elected to not respond to certain questions which they either thought were particularly sensitive or where they did not have immediate access to the information requested.** R. W. Beck made attempts to contact the companies that had agreed to participate but that did not return a survey. In some cases, multiple attempts were made. For the Arizona companies, Salt River Project tentatively agreed to participate, but later indicated that they felt the survey asked for too much proprietary data and that they were unlikely to return a survey. Tucson Electric agreed to complete and return a survey, but never did.

While the number of respondents is low compared to original participation targets, the survey results are very consistent with R. W. Beck's experience working with a wide range of clients on risk management issues. Further, while respondents include municipal, district, and consumer-owned (i.e. cooperative) utilities as opposed to only IOU's, R. W. Beck's experience is that the size and type of utility is not a strong indicator of the existence and quality of an energy risk management program. In other words, we have seen excellent programs at small utilities and weak programs at large utilities (and vice versa). **R. W. Beck considers the survey results to be sufficiently representative to draw the conclusions contained in this report.**

Section 5
FINDINGS & CONCLUSIONS

5.1 Observations from Survey

The observations and findings below are based on comparisons of the survey responses to R. W. Beck's understanding of APS' risk management and hedging program gained through interviews, document reviews, and APS' survey responses.

R. W. Beck's overall conclusion from the survey results is that APS has a high-quality energy risk management and hedging program. No significant areas exist where APS would be considered an "outlier." While a few areas exist where APS could be viewed as unique in their approach (Front Office compensation, for example), R. W. Beck is aware of other companies which handle such areas similarly.

R. W. Beck's review of the initial results of EPRI's portfolio and risk management practices study also indicates that APS' program is consistent with leading industry practices. All aspects of APS' program are within the norms implied by EPRI's results.

Provided below are highlights from the survey data which R. W. Beck considers to be particularly noteworthy.

- Most utilities (eighty five percent (85%) of the survey respondents) either have a formal energy risk management program or most elements thereof. The survey responses did not indicate any clear trend based on region, type of company, or size.
- Nearly three of four utilities surveyed (73%) had S&P credit ratings of AA or A, as opposed to APS which has a credit rating of BBB-. It appears companies with weaker ratings (such as APS) tend to hedge because they have relatively more at stake if unusual fuel cost-related events occur (in other words, they have less financial capacity to absorb cost shocks). Companies with strong ratings tend to hedge to maintain their strong position and because they can afford it.
- A significant potion (forty five percent (45%) of companies surveyed) indicated their ability to hedge is impacted by the credit rating of potential counterparties. APS is consistent with this.
- Diversity of fuel sources does not seem to lead to a difference in whether or not a utility has an energy risk management program, or the amount of fuel that is hedged. Ninety one percent (91%) of respondents have an energy risk management program despite several utilities indicating a vast majority of fuel sourced from either hydro or fixed price coal.

- There does not seem to be a correlation between a company's preference to hedge fuel costs and their fuel cost recovery mechanism. Companies with limited ability to pass-on fuel costs to customers hedge to protect net income and/or earnings. Companies with the ability to pass-on fuel costs generally hedge to help protect customers from fuel cost volatility. APS falls in the latter category.
- Most utilities hedge their fuel costs by locking in fixed prices for some portion of their needs. **Over one third (33%) of utilities surveyed hedge more than three years forward. APS, which forward hedges up to thirty months forward, was more of the norm.** Some companies hedge less and some companies hedge more.
- **Nearly one-half (45%) of utilities researched hedged over eighty percent (80%) of their expected natural gas usage one year in advance. In addition, two of three (67%) hedged at least sixty one percent (61%) of their forward one year gas requirements. APS is typical amongst its peers as it hedges eighty five percent (85%) of its natural gas needs one year in advance.**
- Only twenty seven percent (27%) of the respondent utilities indicated that their Commission and/or external stakeholders participated in the design of its hedging program. This trend appears to be a standard observation in many jurisdictions.
- Only one utility responding had more experience with energy risk management and fuel hedging functions than APS. APS' program has been in place longer than most.
- APS is the only respondent having Front Office compensation partly tied to transaction-related performance. Depending on the design of the compensation program, this can benefit APS customers by creating incentives for transactions which can lead to net cost savings.
- The risk management committee of a slight majority of the respondents deals with enterprise-wide risk issues in addition to energy commodity risks. APS' committee primarily focuses on energy commodity risks.
- APS' hedging program appears more disciplined than most. Hedging quantity deadlines are enforced and cannot be modified. The Middle Office independently monitors the placement of hedges to ensure that they are in accordance with APS' hedging plan. This is a positive attribute.

5.2 Additional Findings

The findings below are based on R. W. Beck's experience in energy risk management, coupled with the information collected during the interviews and document reviews. Please refer to Section 3 for an overview of some of the key principles which R. W. Beck uses as the basis for assessing the quality of energy risk management and hedging programs.

5.2.1 Qualitative Program Elements

Qualitative program elements include the general set of governance, communication, policy, and procedural elements of the program.

- APS has an appropriate mindset regarding hedging which is consistent with best industry practices:
  - The primary purpose of hedging is to reduce volatility in costs.
  - A secondary purpose is to help reduce cost of capital by creating greater customer, regulatory, and investor/lender confidence.
  - The purpose of hedging is not to create financial gains by timing the market.
- The programmatic aspects of APS program are of high quality and consistent with those of other leading programs. All aspects of a high quality risk management framework (please refer to Section 3) are in place and appear to be operating effectively. There are no material areas in which APS' program was found to be substandard. In some areas, APS has arguably a superior program compared to other utilities.
- APS' hedging activities and energy risk management program elements are consistent with rating agency views which are placing greater importance on energy risk management.

5.2.2 Quantitative Program Elements

Quantitative program elements primarily consist of the limits, risk metrics, and the forms of analytics (i.e. models and information systems) employed in the risk management and hedging program.

- APS' approach to risk analytics and risk limits is consistent with standard industry practices.
- APS hedges an appropriate amount of natural gas given the goals of their hedging program, their financial condition, and their level of exposure to natural gas prices.
- APS has implemented hedging parameters and limits based on volumetric parameters, which is consistent with industry standards. The interplay (correlation) between natural gas prices and power prices is considered as part of the volumetric analysis, which is a positive attribute.

5.2.3 Impact of Fuel Hedging on Net Fuel Costs

As discussed in Section 3, fuel hedging activities are intended, first and foremost, to reduce volatility in fuel costs. On average, hedging can tend to create a slight increase in average fuel costs over the long-term. However, most companies generally consider it desirable (and prudent) to incur this cost in order to reduce volatility and the possibility of drastic cost increases which can occur in extreme market conditions. While hedging activity is not, in general, intended to reduce fuel

costs on average, cost savings can occur during periods of rising prices if the hedging activity occurred prior to or during the beginning of the period of price escalation. Over the last few years the industry has experienced a significant increase in natural gas prices, rising from the $4-$6 range per MMBTU to in excess of $12 for forward gas contracts. While prices have retreated in recent months, the last few years have clearly been characterized by much higher natural gas prices than historical averages.

During this period, APS' hedging activities appear to have provided significant protection to customers from even higher fuel-related net costs that would have occurred in the absence of hedging. This conclusion is supported by reviews of data and reports provided to R. W. Beck by APS, fuel cost information obtained during the survey process, and analysis of fuel cost data from the Energy Velocity® database.

Section 6
PRINCIPAL CONSIDERATIONS & ASSUMPTIONS

The performance of this review was based on a variety of considerations and assumptions, which are listed below:

- The review is primarily qualitative in nature and does not include rigorous quantification of risk levels or hedging effectiveness. Any numeric estimates contained in this document not related directly to the study itself are general in nature based on professional judgment and preliminary analysis, and would require further analysis to reach firm conclusions.
- The review included onsite interviews of APS' personnel and document reviews. All meetings at APS' facilities have been for the purpose of meeting with APS' personnel. No direct review of the condition of facilities or systems has been conducted.
- All conclusions and recommendations are based on information provided to R. W. Beck. R. W. Beck has not performed comprehensive "due diligence" confirmation of the quality and accuracy of the information provided.
- The adoption of any conclusions contained in this report, or any actions taken in connection with these conclusions may not, by themselves, fully protect APS against the impact of any or all of the risk sources to which the organization is exposed.
- The outcome of any risk mitigation strategies implemented by APS is highly dependent upon the quality of strategy implementation and the actual business conditions that occur. Extreme conditions are always possible that could result in impacts to APS beyond the potential impacts that may be estimated by APS or other parties, including the assessments of this report.

Appendix A
LIST OF PERSONS INTERVIEWED

Director of Enterprise Risk

Associate General Counsel

Portfolio Manager- Regulated

Electricity Trader

Risk Manager

Vice President/Treasuer

Vice President, APS Marketing and Trading

Back Office Manager

Senior Gas Trader

Portfolio Manager - Unregulated

Director of Trading Floor Operations

Vice President of Planning

Credit Risk Manager

Director of Risk Management, APS Marketing and Trading

Commodity Consultant

Appendix B
COMPANIES CONTACTED FOR SURVEY

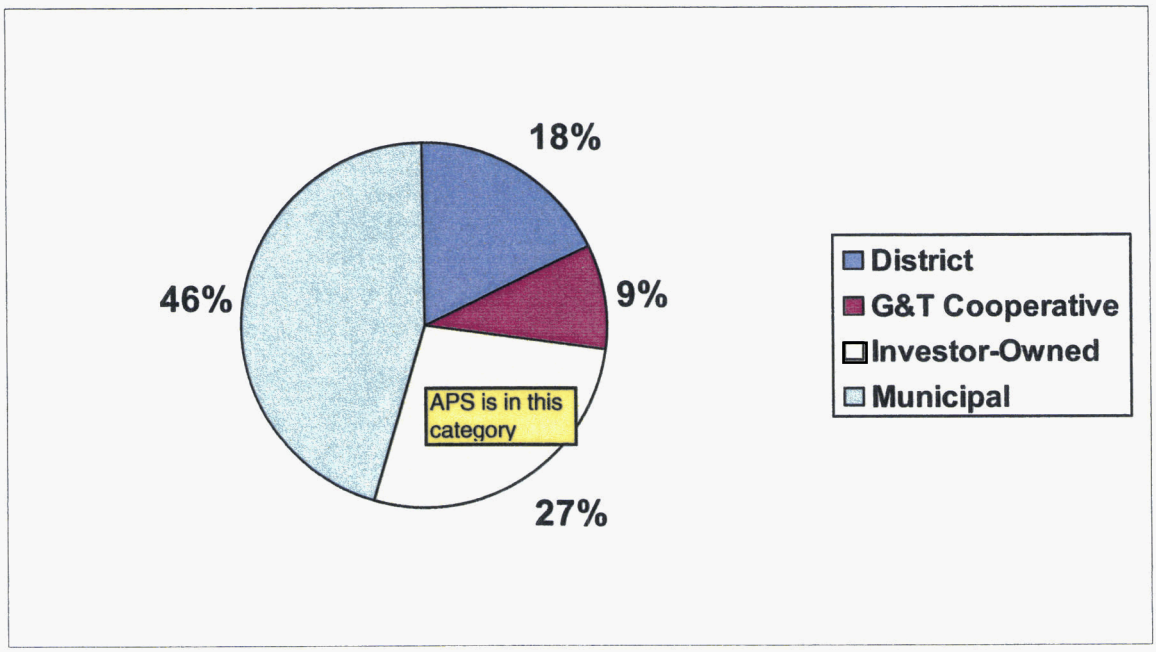
Company	State	Contacted?	Agreed?	Sent?	Returned?	Comments
Arizona Public Service	AZ	y	y	y	y	Contacted. Survey completed and returned.
Salt River Project	AZ	y	tent	y	n	Contacted. Tentatively agreed to participate. Survey sent. Survey not returned. Followed-up but no response.
PNM Resources	NM	y	y	y	n	Contacted. Agreed to participate. Survey sent. Survey not returned. Followed-up but no response.
TXU	TX	n		y	n	Unsuccessful contacting.
Southern California Edison	CA	y		y	n	Contacted. Survey sent. Survey not returned. Followed-up but no response.
San Diego Gas & Electric	CA	y		y	n	Contacted. Survey sent. Survey not returned. Followed-up but no response.
Tucson Electric	AZ	y	y	y	n	Contacted. Agreed to participate. Survey sent. Survey not returned. Followed-up but no response.
Lower Colorado River Authority	TX	y	tent	y	n	Contacted. Tentatively agreed to participate. Survey sent. Survey not returned. Followed-up but no response.
Austin Energy	TX	y	y	y	y	Contacted. Survey completed and returned.
City Public Service (San Antonio)	TX	y	y	y	n	Contacted. Agreed to participate. Survey sent. Survey not returned. Followed-up but no response.
Colorado Springs Utilities	CO	y	y	y	y	Contacted. Survey completed and returned.
Tri-State Generation & Transmission	CO	y	y	y	y	Contacted. Survey completed and returned.
Xcel	CO, TX, MN	y	n	n	n	Contacted. Declined to participate.
Los Angeles Dept of Water & Power	CA	y	tent	y	n	Contacted. Tentatively agreed to participate. Survey sent. Survey not returned. Followed-up but no response.
Oklahoma Gas & Electric	OK	y		y	n	Contacted. Survey sent. Survey not returned. Followed-up but no response.
Ameren	MO, IL	y	tent	y	n	Contacted. Tentatively agreed to participate. Survey sent. Survey not returned. Followed-up but no response.
Entergy	TX, AK, LA, MS	y	y	y	y	Contacted. Survey completed and returned.

Company	State	Contacted?	Agreed?	Sent?	Returned?	Comments
Kansas City Power & Light	MO, KS	y	y	y	n	Contacted. Agreed to participate. Survey sent. Survey not returned. Followed-up but no response.
First Energy	OH, NJ, PA	y	y	y	n	Contacted. Agreed to participate. Survey sent. Survey not returned. Followed-up but no response.
PSEG	NJ	y		y	n	Contacted. Survey sent. Survey not returned. Followed-up but no response.
Florida Power & Light	FL	y	y	y	n	Contacted. Agreed to participate. Survey sent. Survey not returned. Followed-up but no response.
Progress Energy	NC, FL	n		n	n	Unsuccessful contacting.
SaskPower	Canada	y	y	y	y	Contacted. Survey completed and returned.
Louisville Gas & Electric	KY	y		y	n	Contacted. Survey sent. Survey not returned. Followed-up but no response.
Sacramento Municipal Utility District	CA	y	y	y	y	Contacted. Survey completed and returned.
Enmax	CA	y	y	y	y	Contacted. Survey completed and returned.
El Paso Electric	TX	y		y	n	Contacted. Survey sent. Survey not returned. Followed-up but no response.
Idaho Power	ID	y		n	n	Unsuccessful contacting.
Puget Sound Energy	WA	y	y	y	n	Contacted. Agreed to participate. Survey sent. Survey not returned. Followed-up but no response.
Pacificorp	WA, OR, CA, UT, WY, ID	n		n	n	Unsuccessful contacting.
Portland General Electric	OR	y	tent	y	n	Contacted. Tentatively agreed to participate. Survey sent. Survey not returned. Followed-up but no response.
Seattle City Light	WA	y	n	n	n	Contacted. Declined to participate.
Pacific Gas & Electric	CA	y		y	n	Contacted. Survey sent. Survey not returned. Followed-up but no response.
Nevada Power	NV	y	n	n	n	Contacted. Declined to participate.
Siera Pacific	NV	y	n	n	n	Contacted. Declined to participate.
Manitoba Hydro	Canada	y	y	y	n	Contacted. Survey completed and returned.

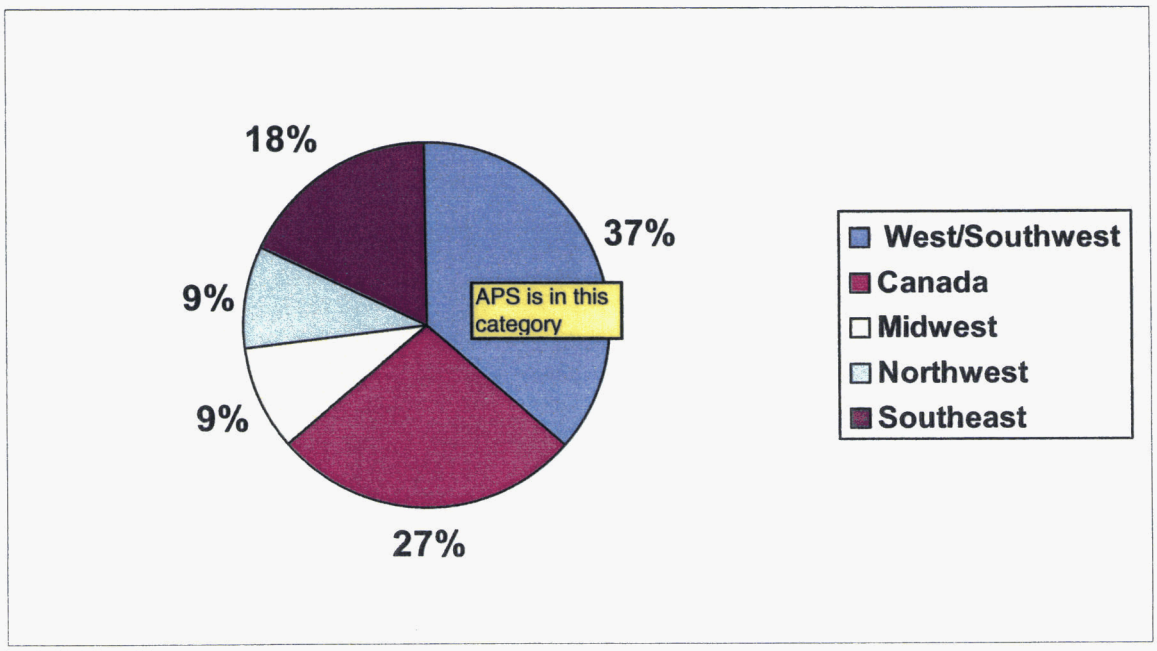
Company	State	Contacted?	Agreed?	Sent?	Returned?	Comments
EPCOR	Canada	y	y	y	n	Contacted. Agreed to participate. Survey sent. Survey not returned. Followed-up but no response.
Omaha Public Power District	NE	y	y	y	y	Contacted. Survey completed and returned.
Chelan Public Utility District	WA	y	y	y	y	Contacted. Survey completed and returned.
ATCO Power	Canada	y	y	y	y	Contacted. Survey completed and returned.
City of Pasadena	CA	y	y	y	y	Contacted. Survey completed and returned.
Missouri River Energy Services	SD	y		y	n	Contacted. Survey sent. Survey not returned. Followed-up but no response.

Appendix C
SURVEY RESULTS

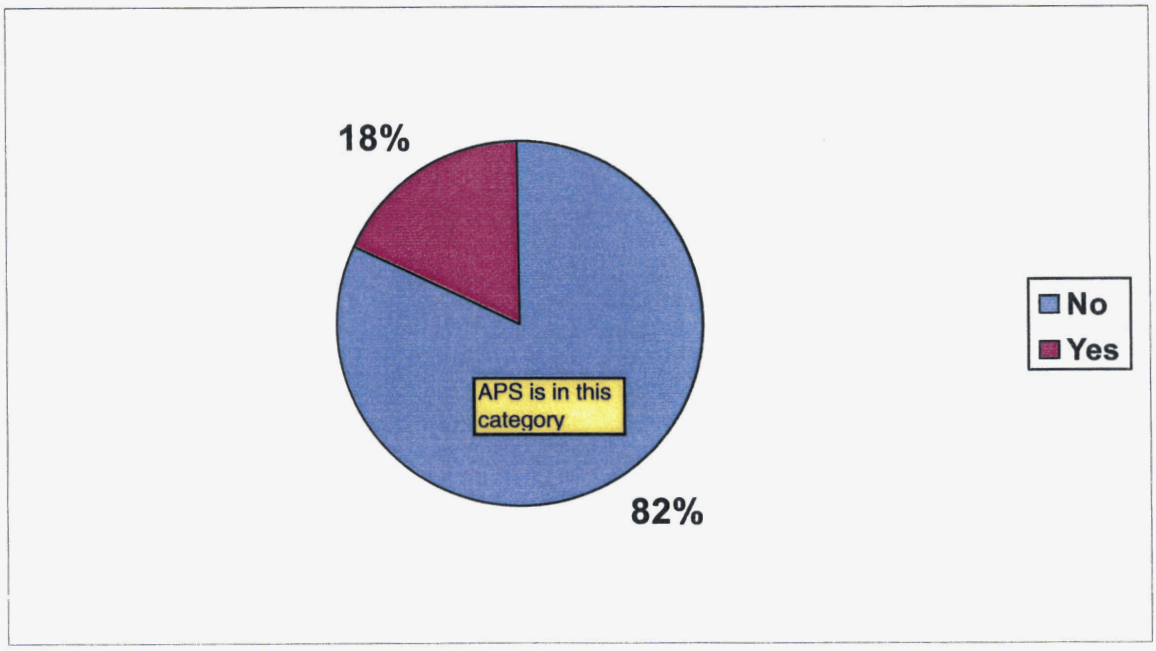
What type of utility is your company?



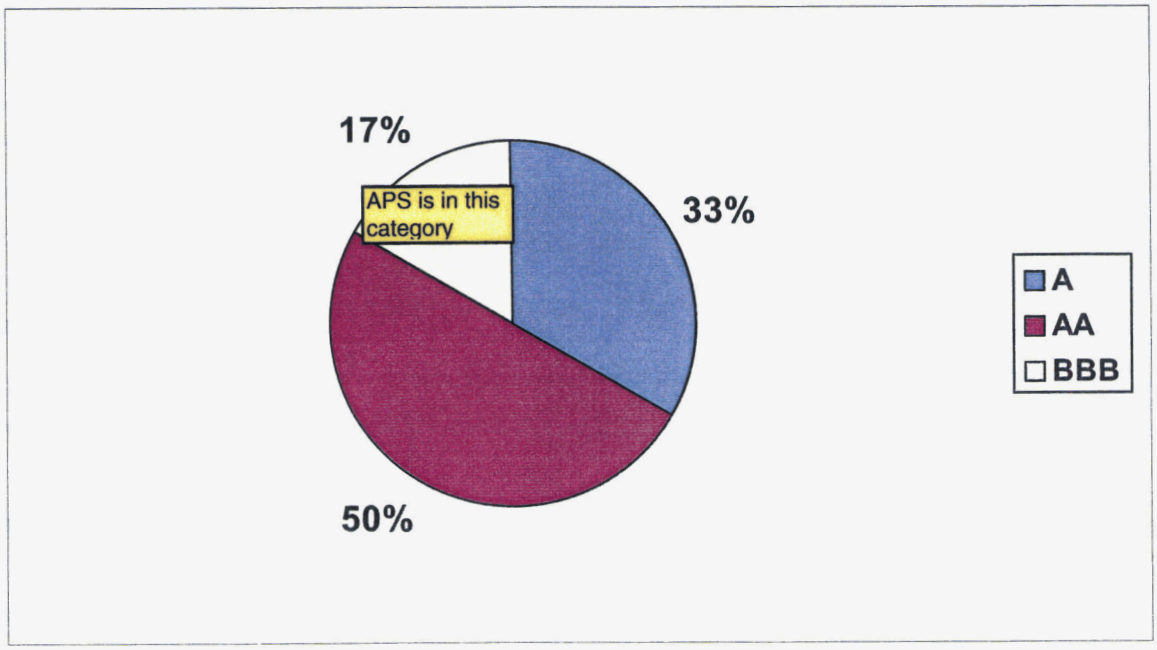
What is the primary geographic region your company operates within?



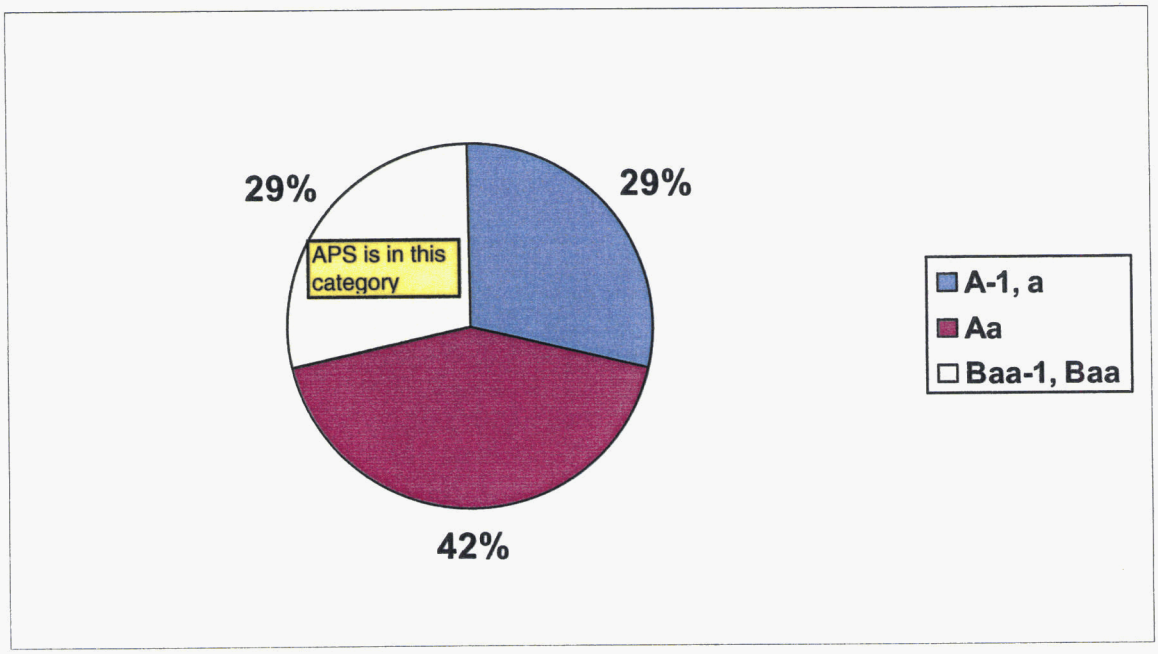
Are you in an Independent System Operator (ISO)?



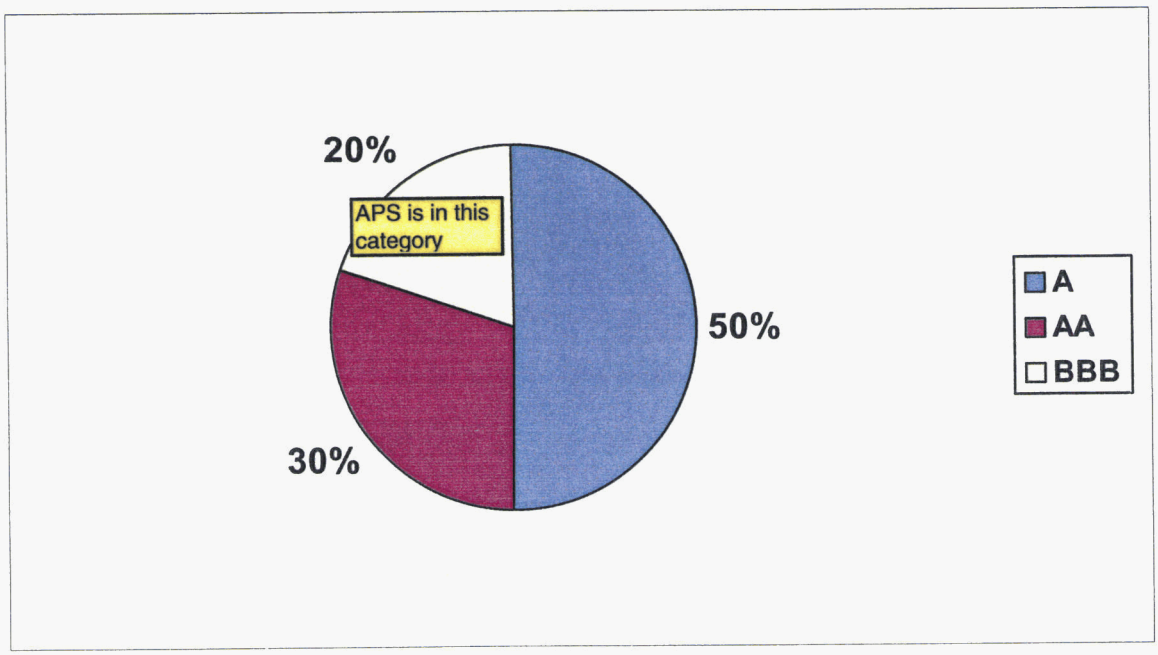
What is your Fitch rating?



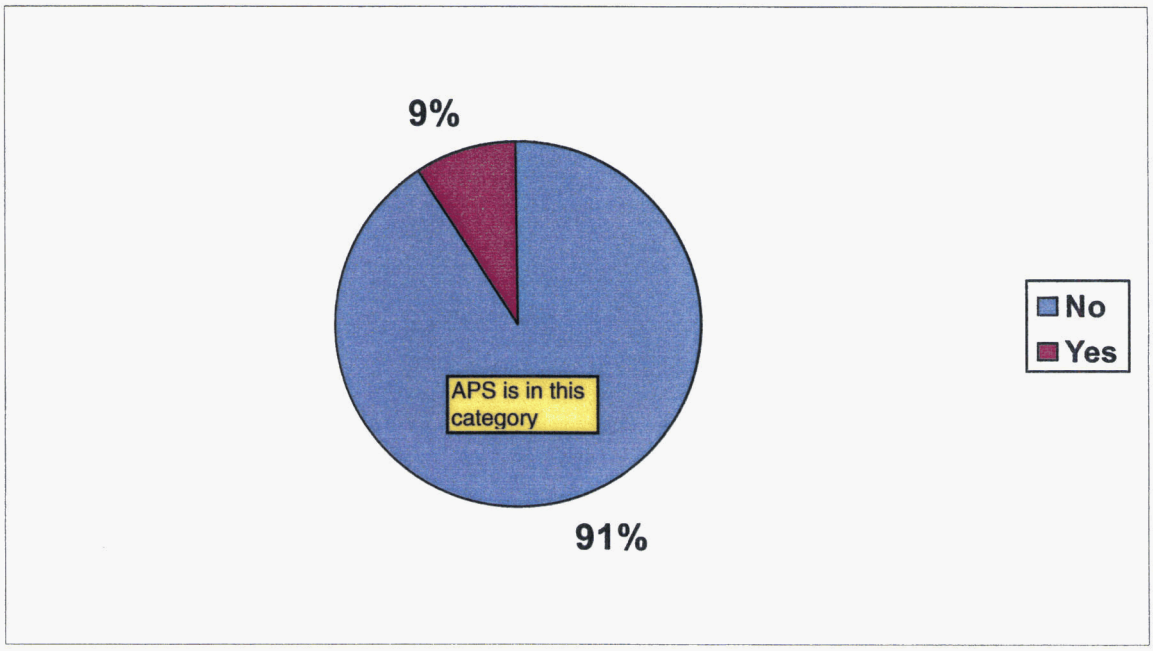
What is your Moody's rating?



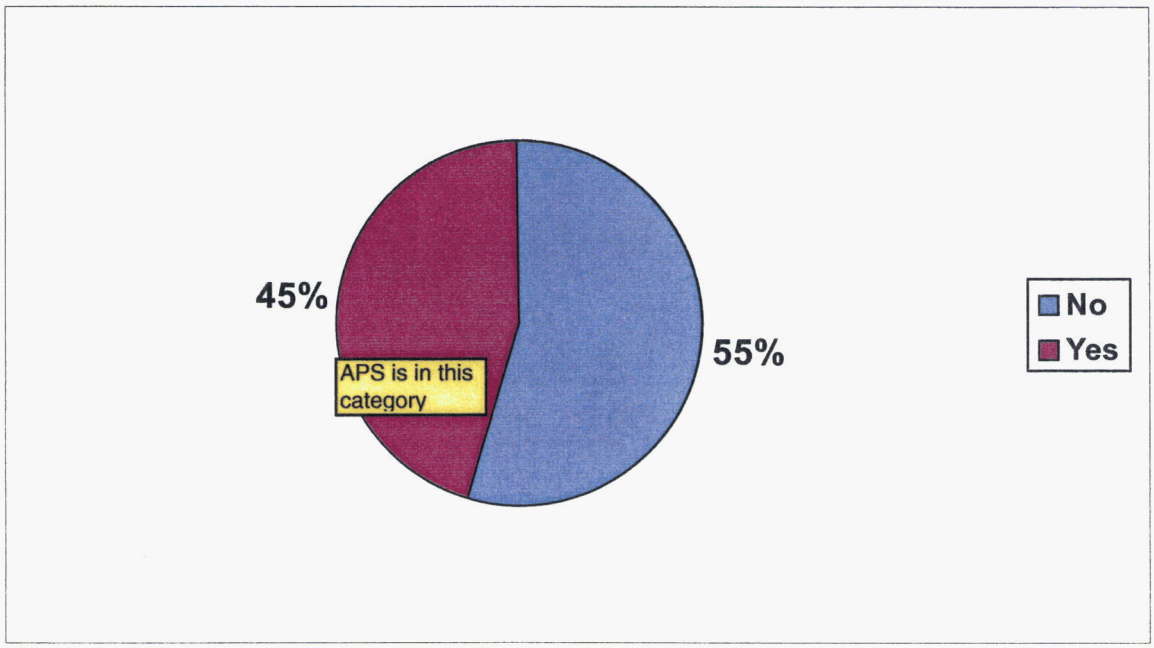
What is your S&P rating?



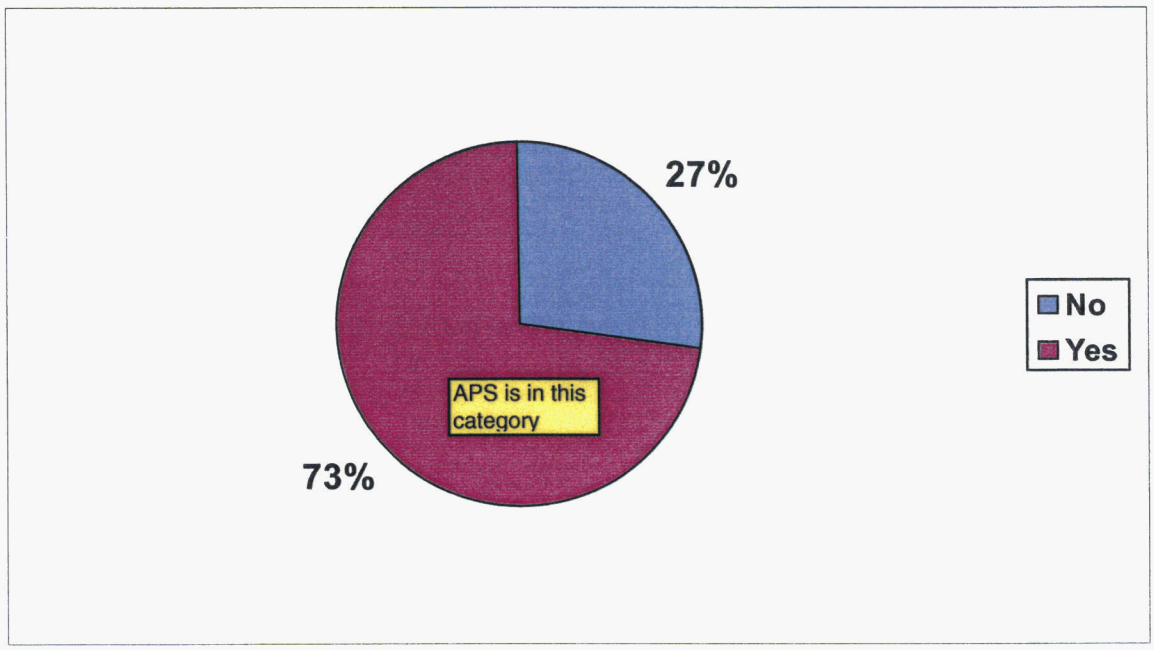
Does your corporate credit rating (or lack thereof) reduce your ability to effectively forward hedge?



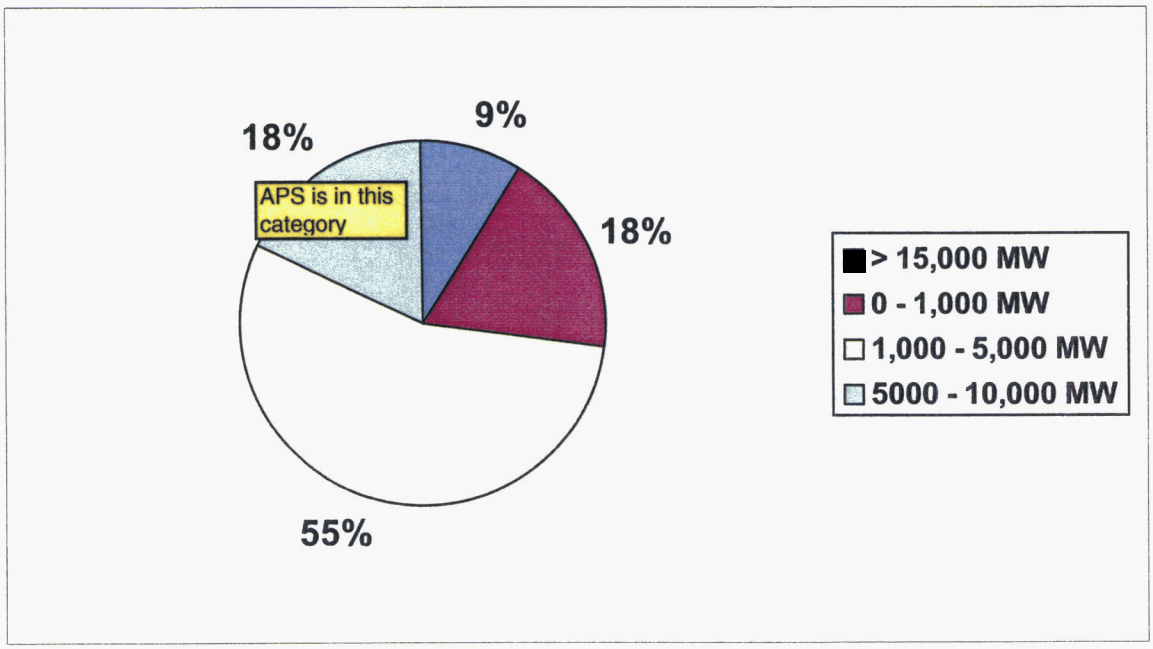
Do counterparty credit ratings of other potential trading partners reduce your ability to effectively forward hedge?



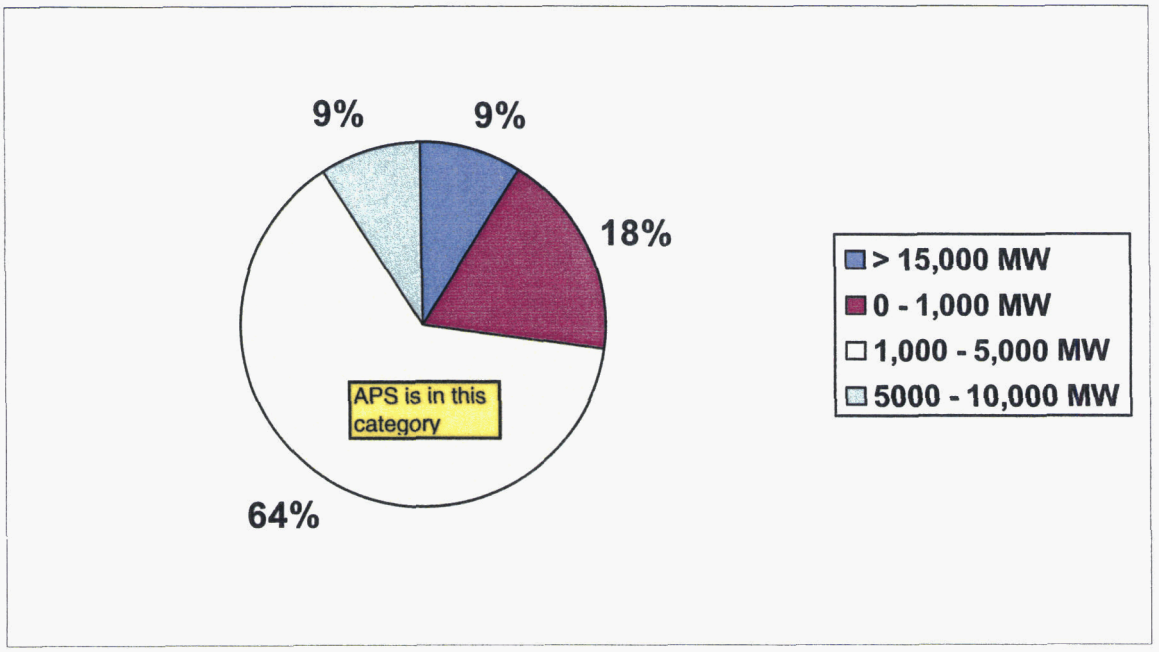
Do you have nearby access to an actively-traded natural gas hub?



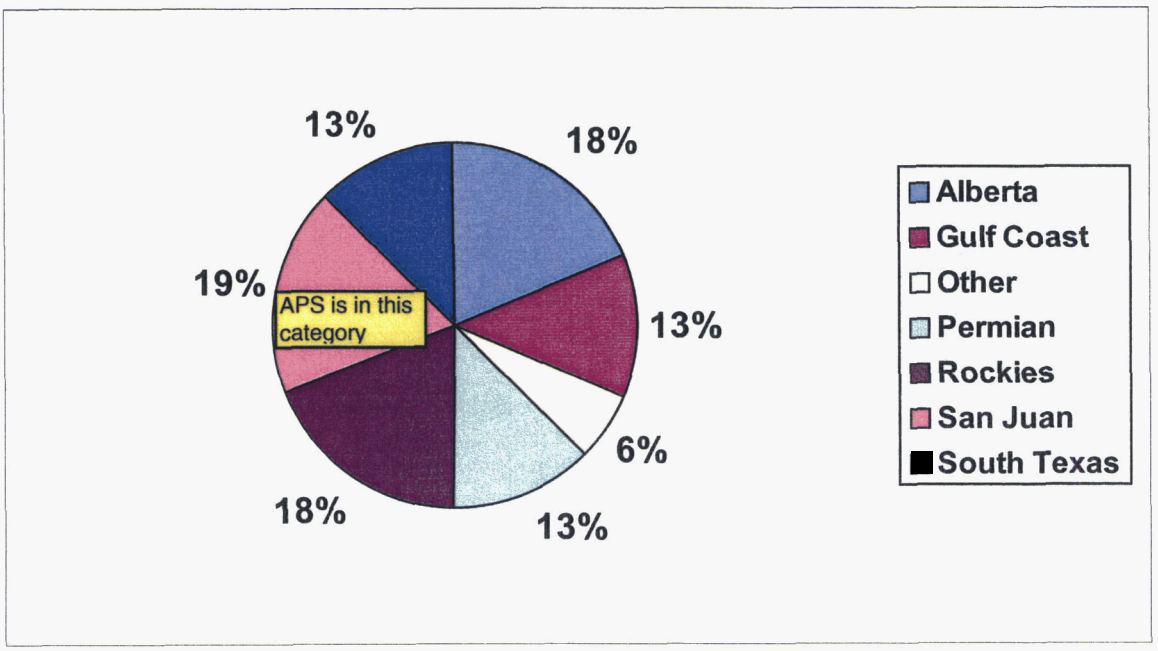
What is your summer peak load (MW) ?



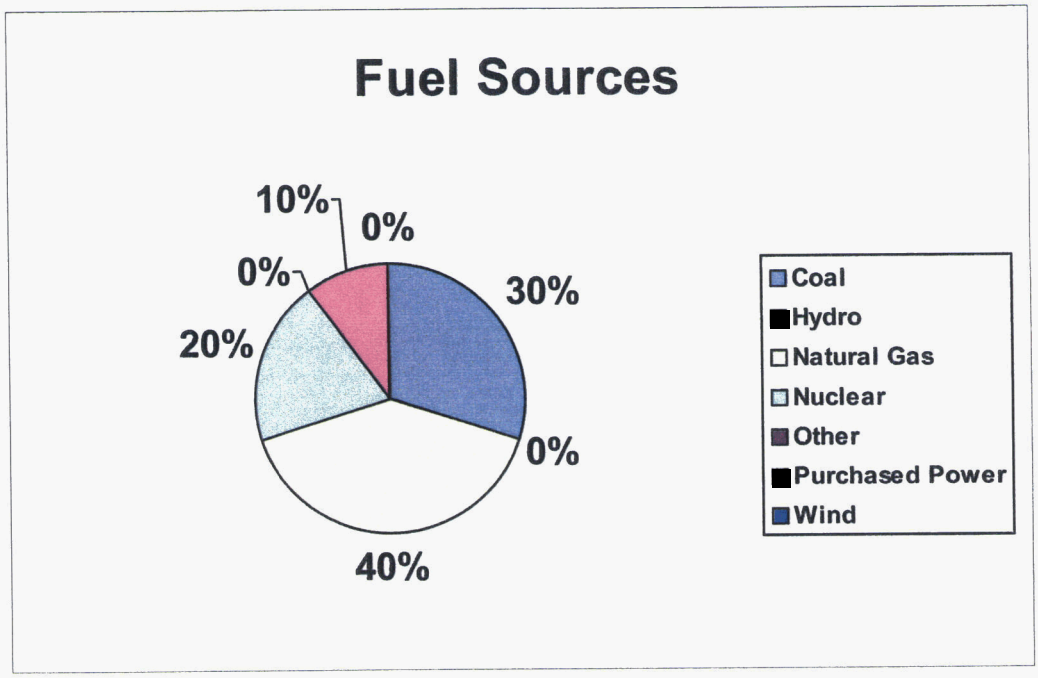
What is your winter peak load (MW) ?



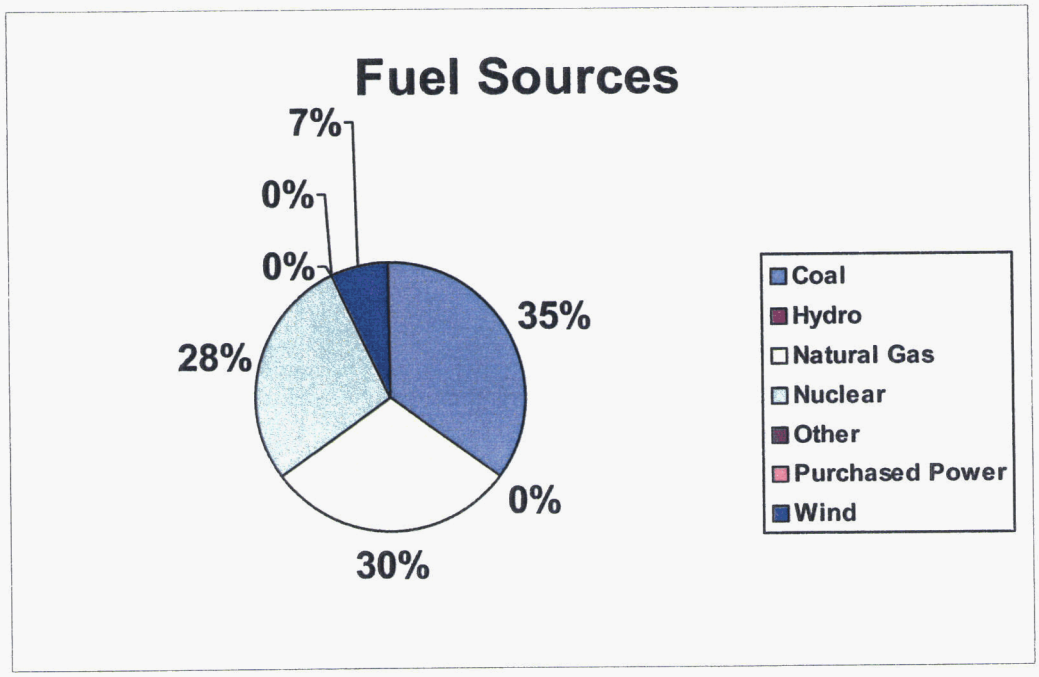
What regional basins is your natural gas delivered from?



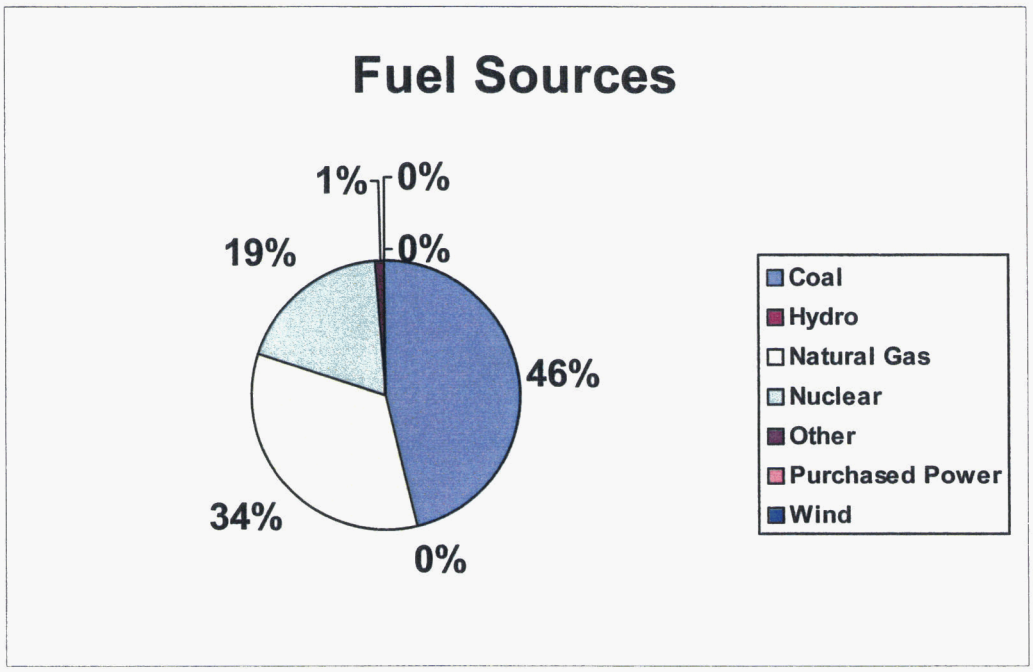
Company A



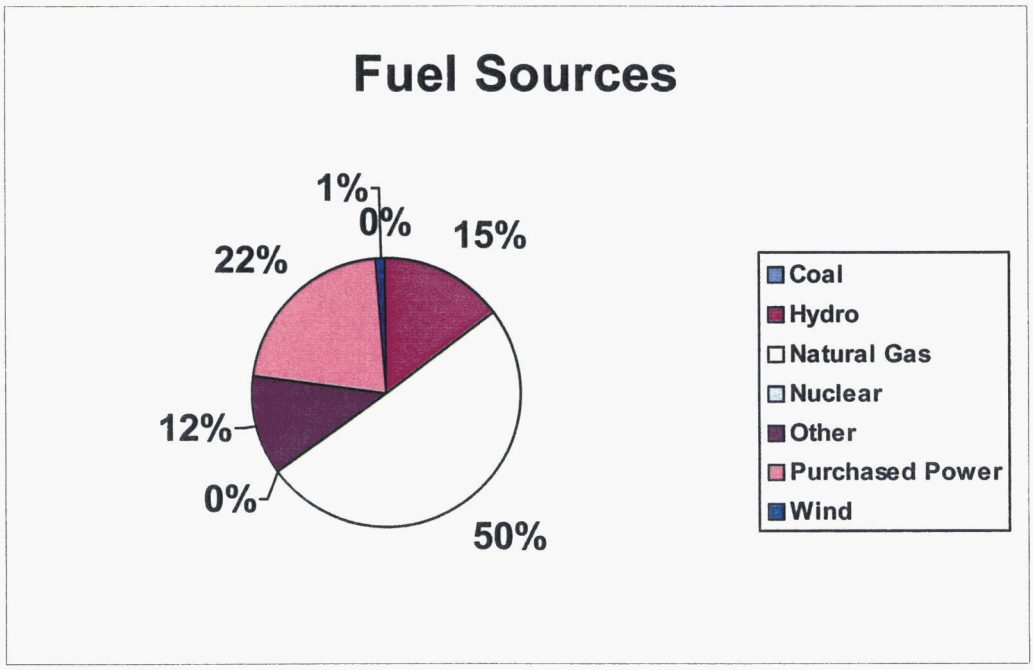
Company B



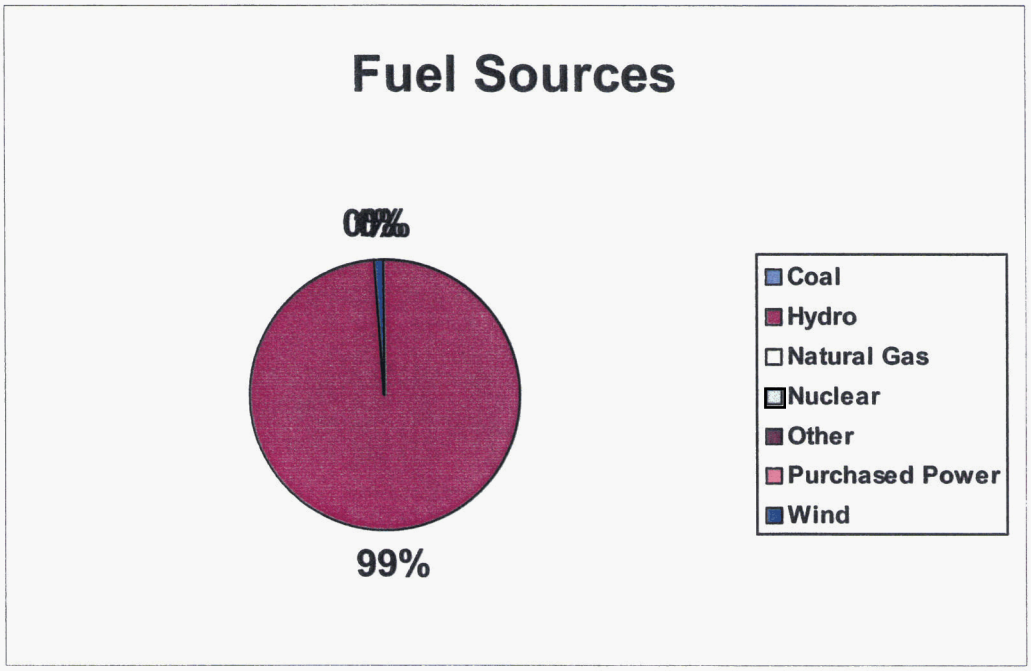
Company C



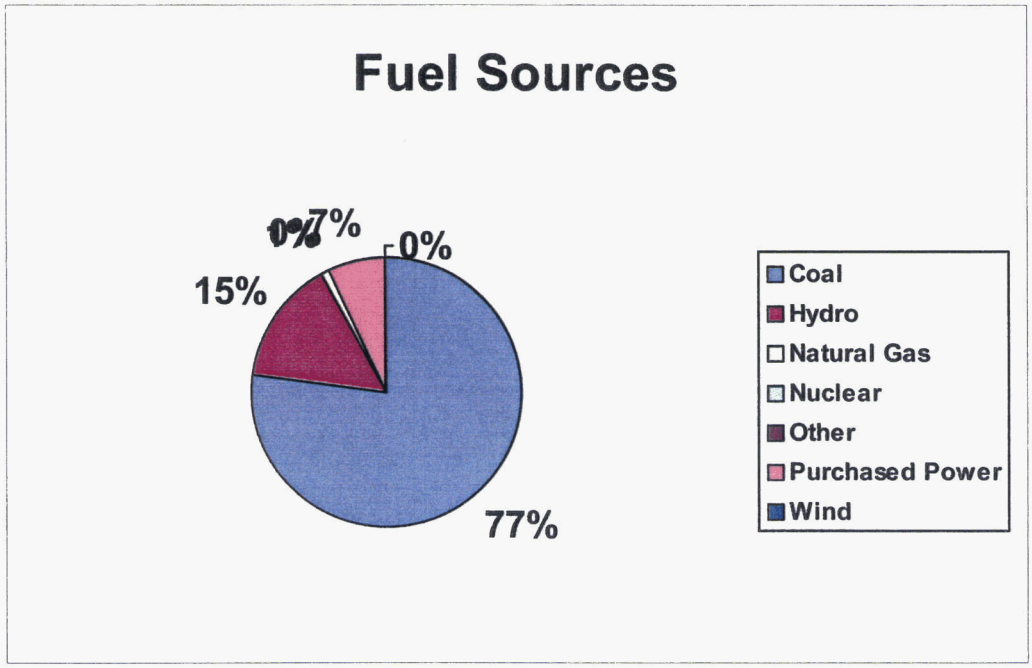
Company D



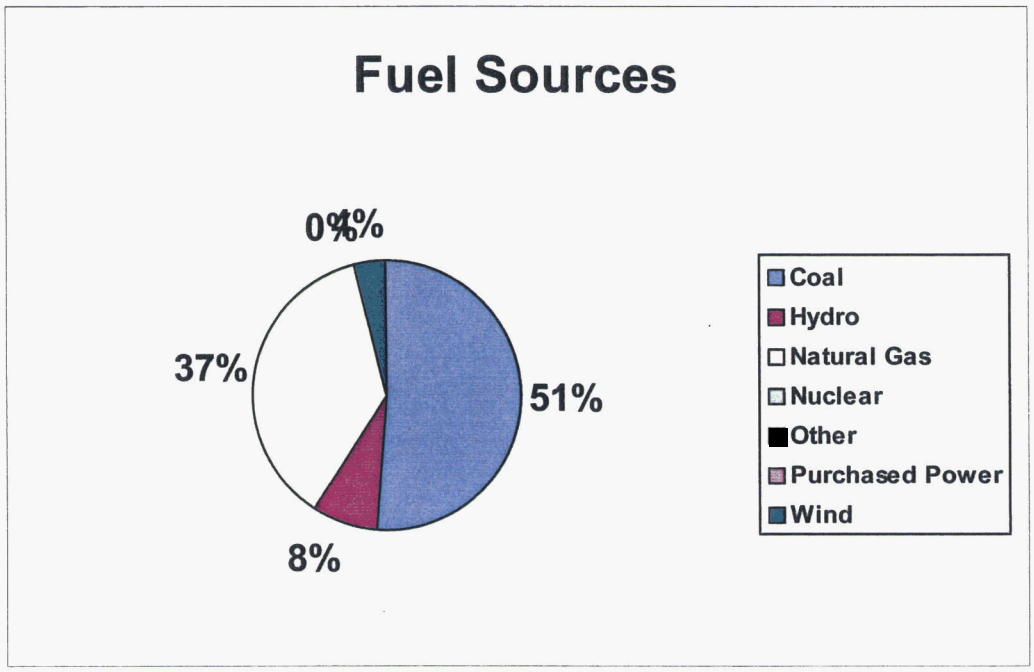
Company E



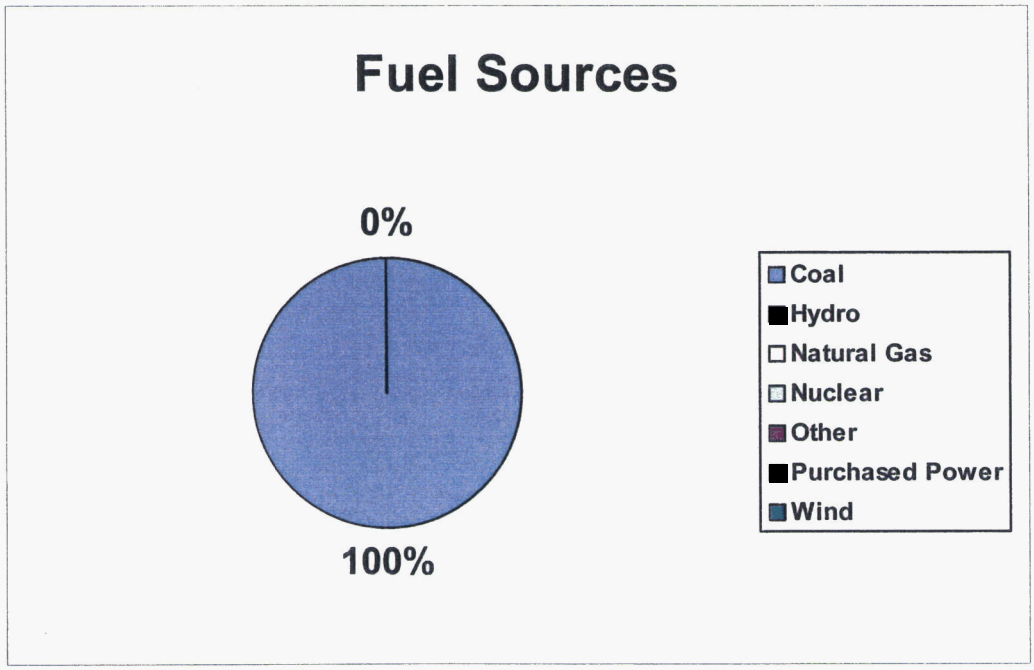
Company F



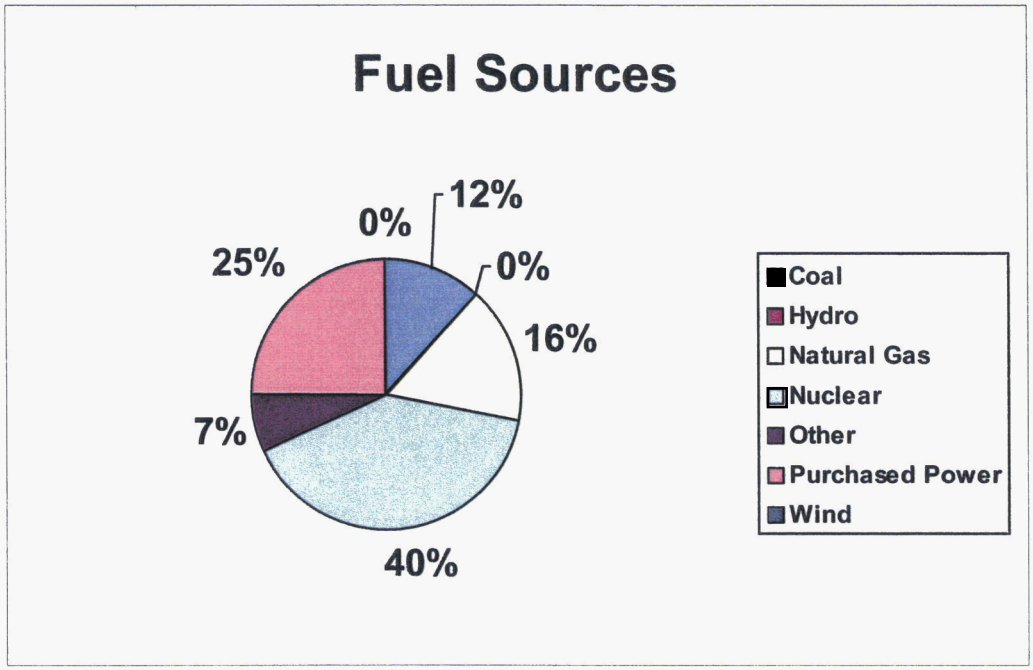
Company G



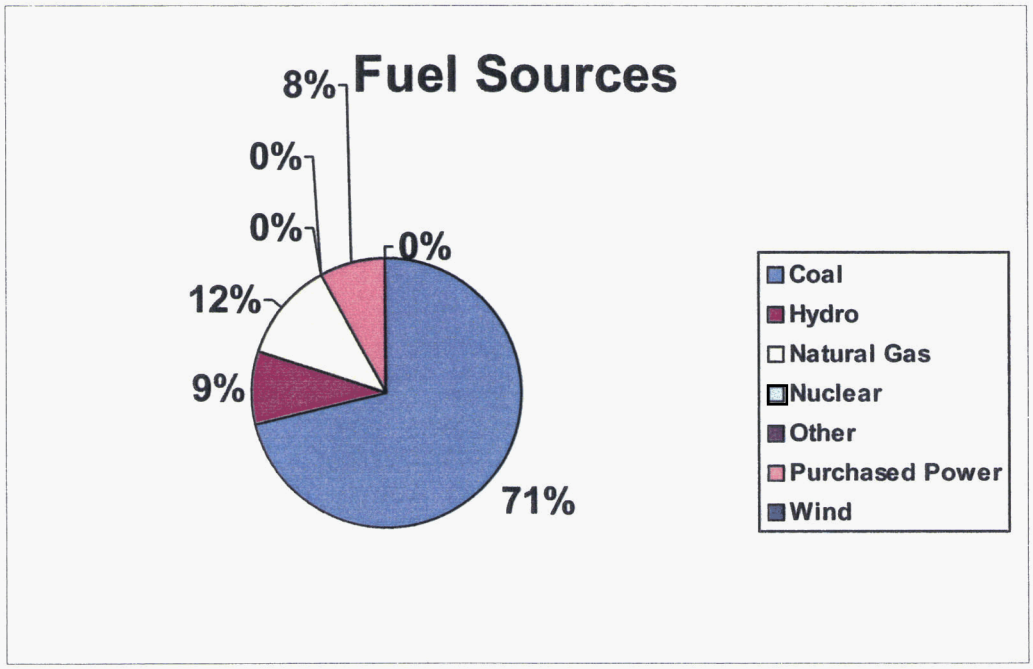
Company H



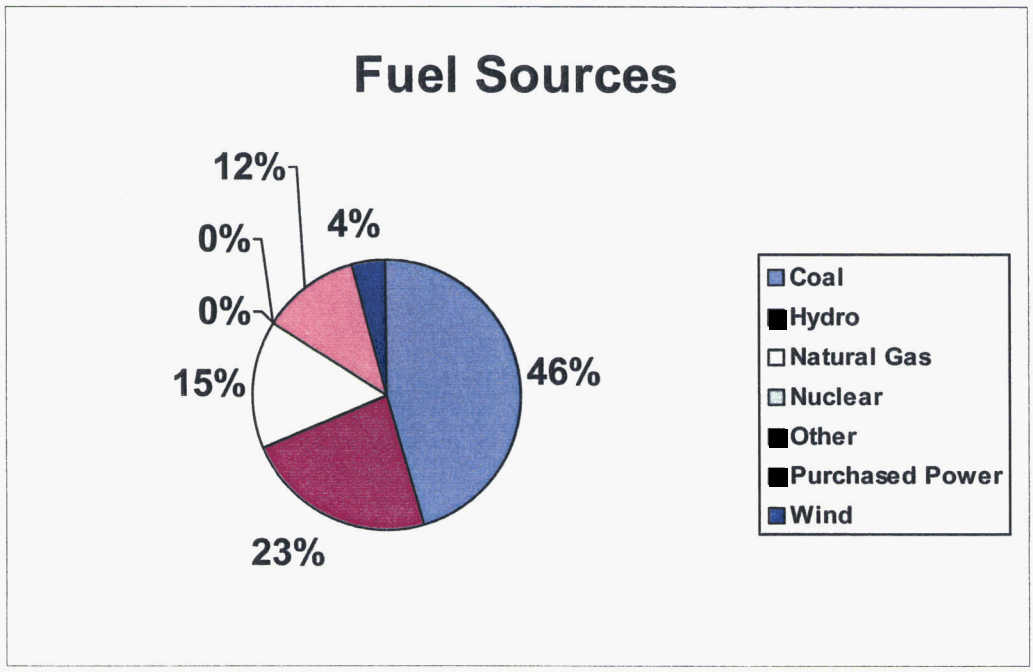
Company I



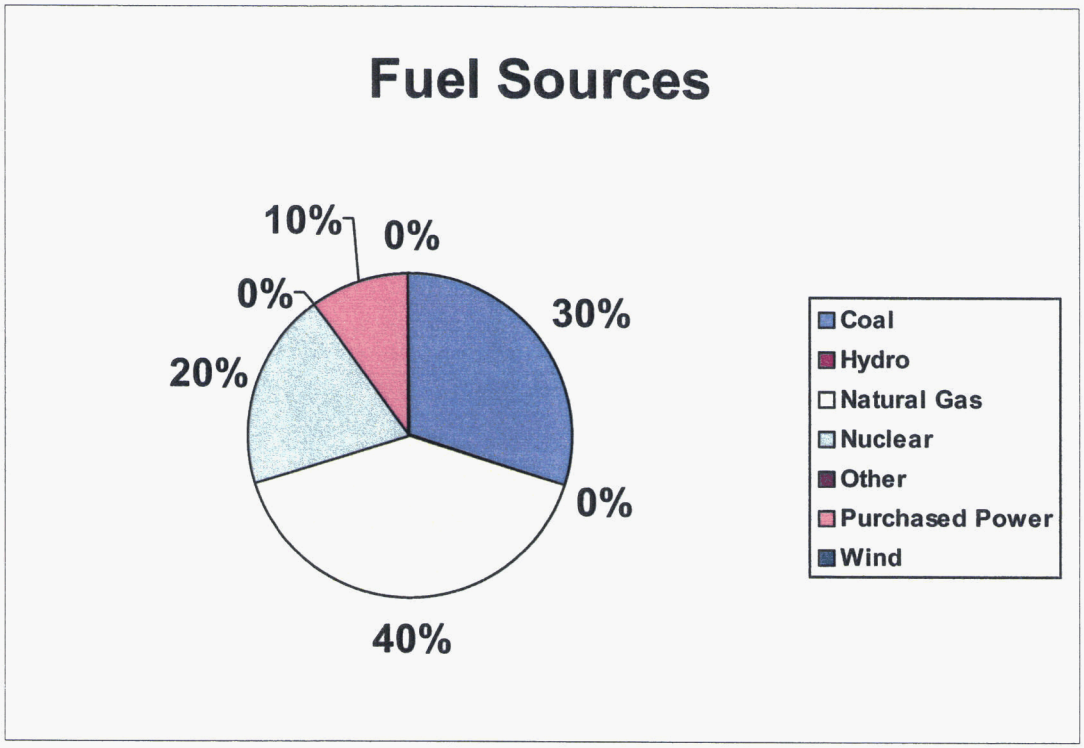
Company J



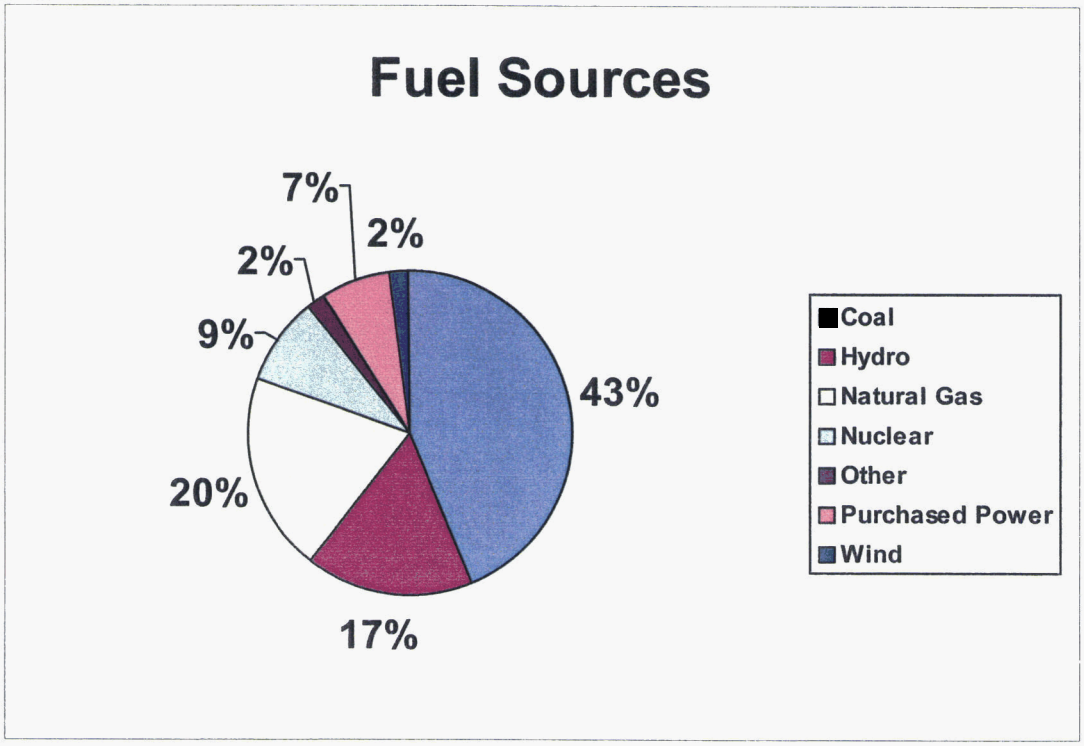
Company K


Fuel Sources
12%
4%
0%
0%
15%
46%
23%
Coal
Hydro
Natural Gas
Nuclear
Other
Purchased Power
Wind

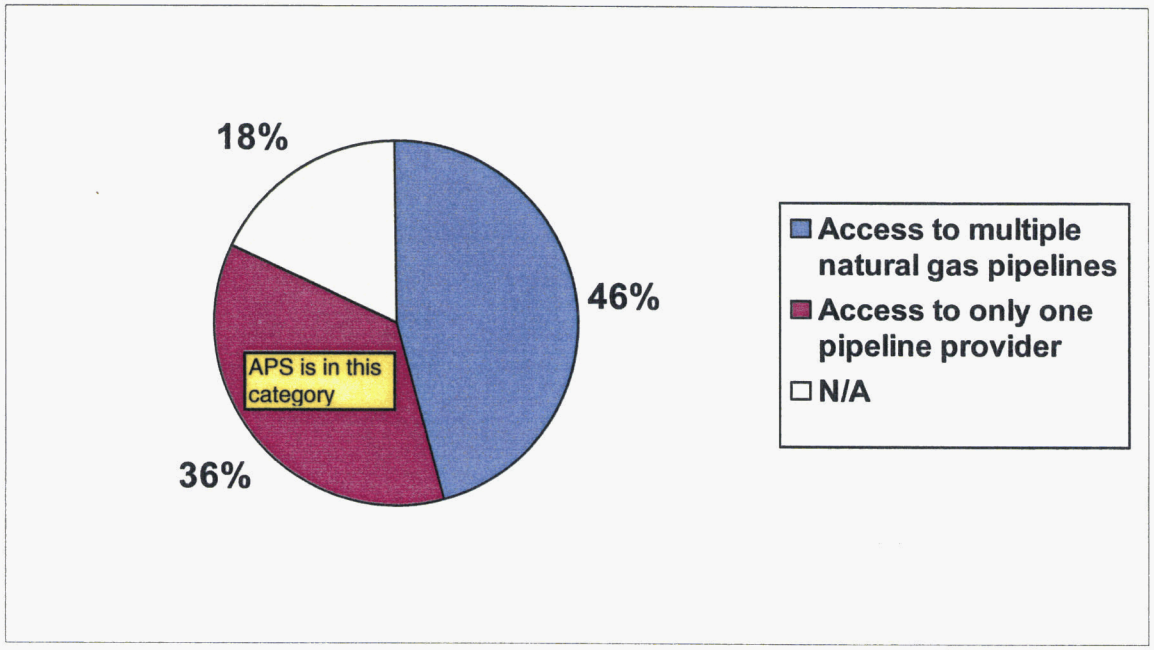
Company A



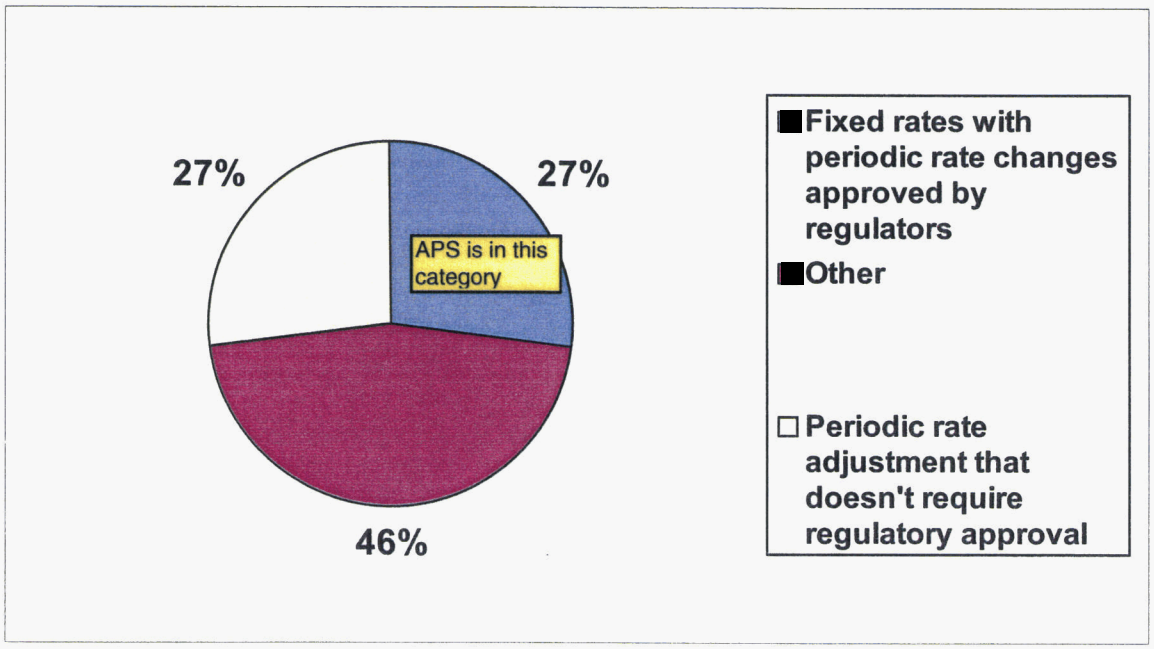
Others



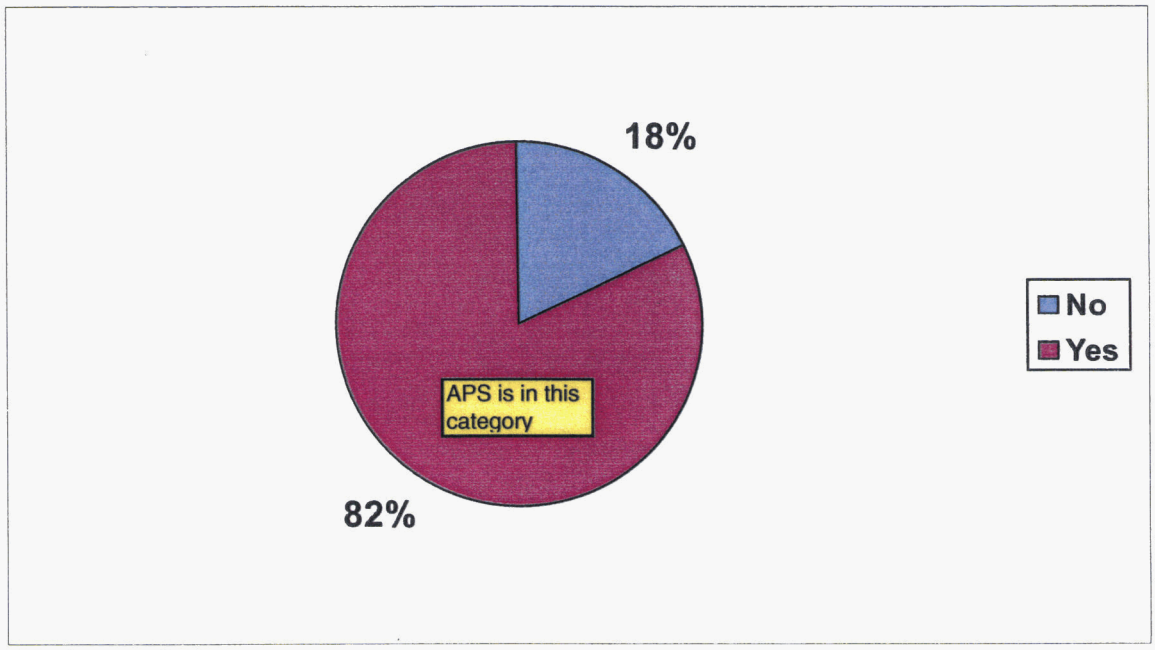
If you use natural gas to serve load, do you have access to multiple natural gas pipelines or are you captive to one pipeline provider?



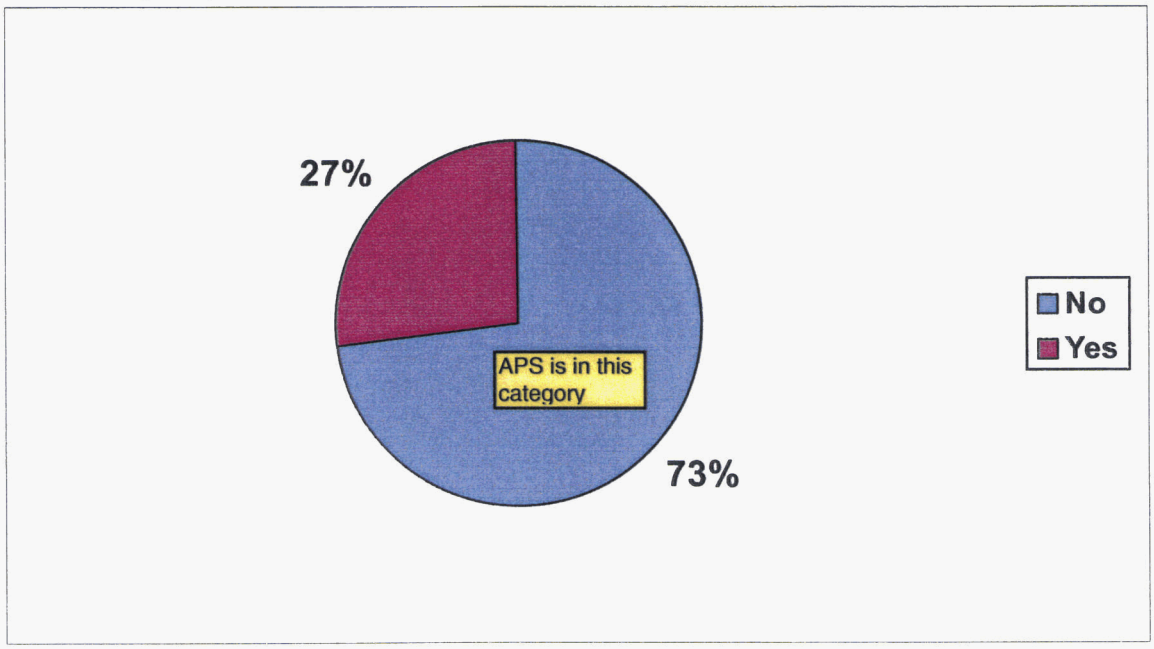
How do you recover fuel costs?



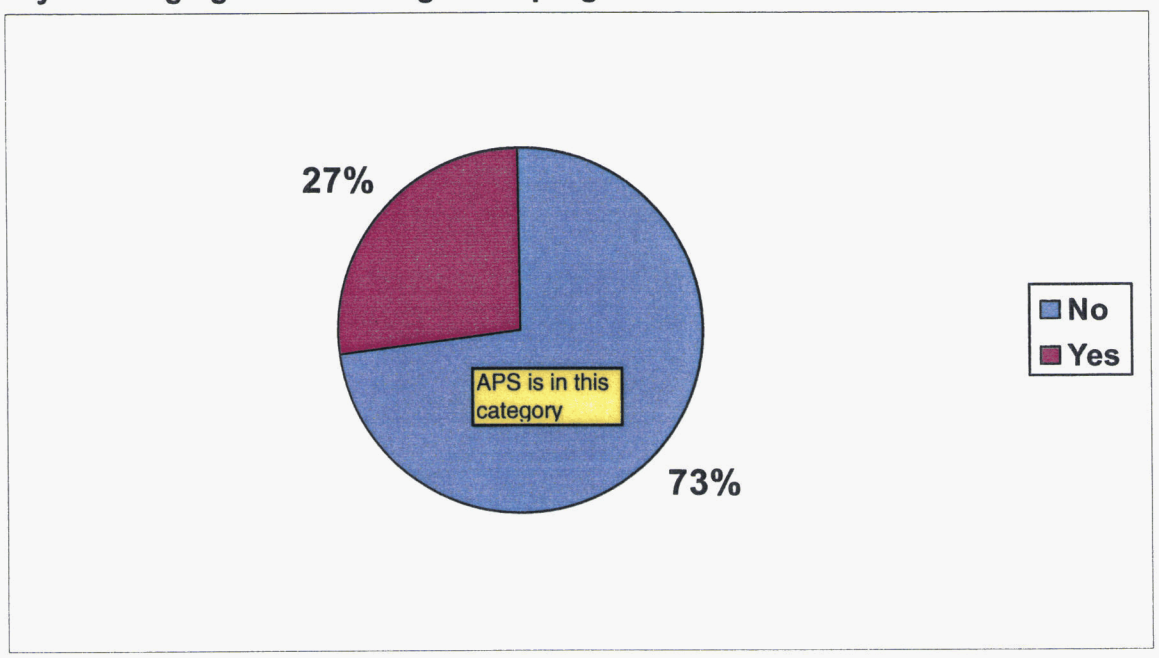
Does your Commission (or other body that regulates your company) allow hedging of fuel costs?



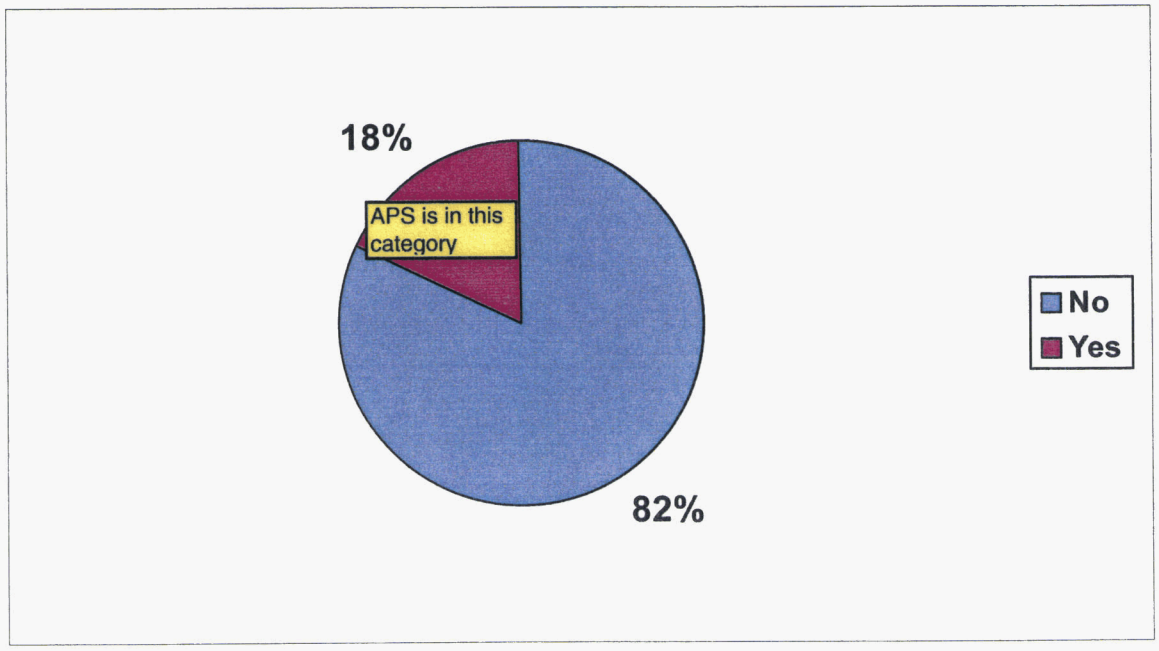
Do you face Commission or other mandated energy or fuel procurement sufficiency requirements?



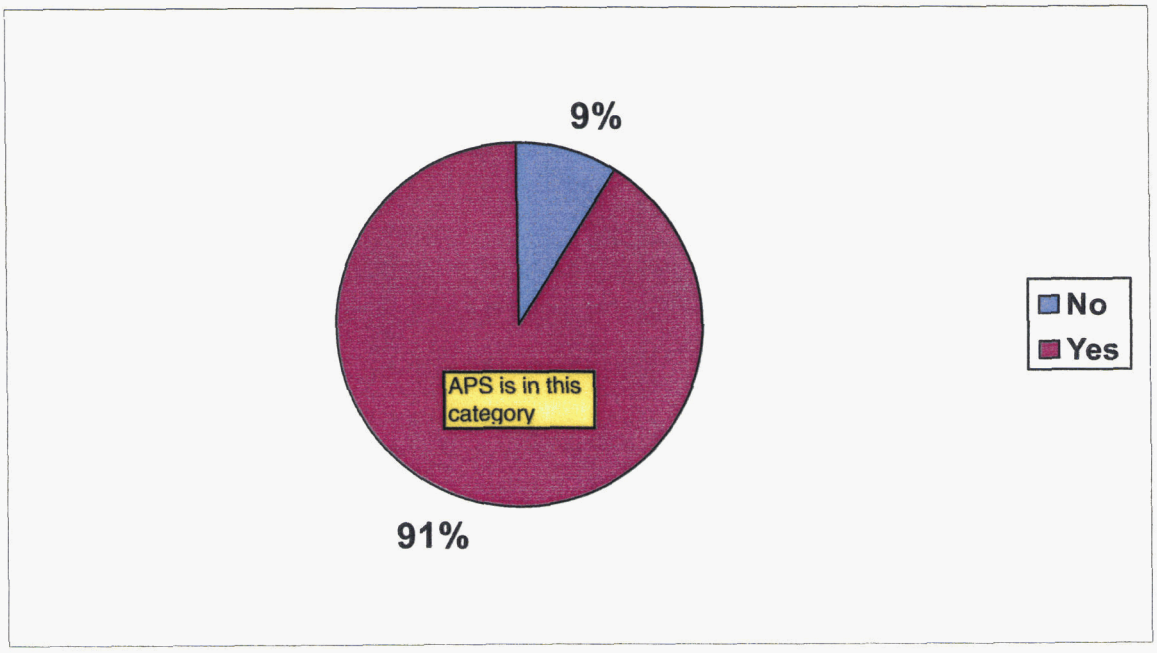
Has your Commission or other external stakeholders participated in the design of your hedging or risk management program?



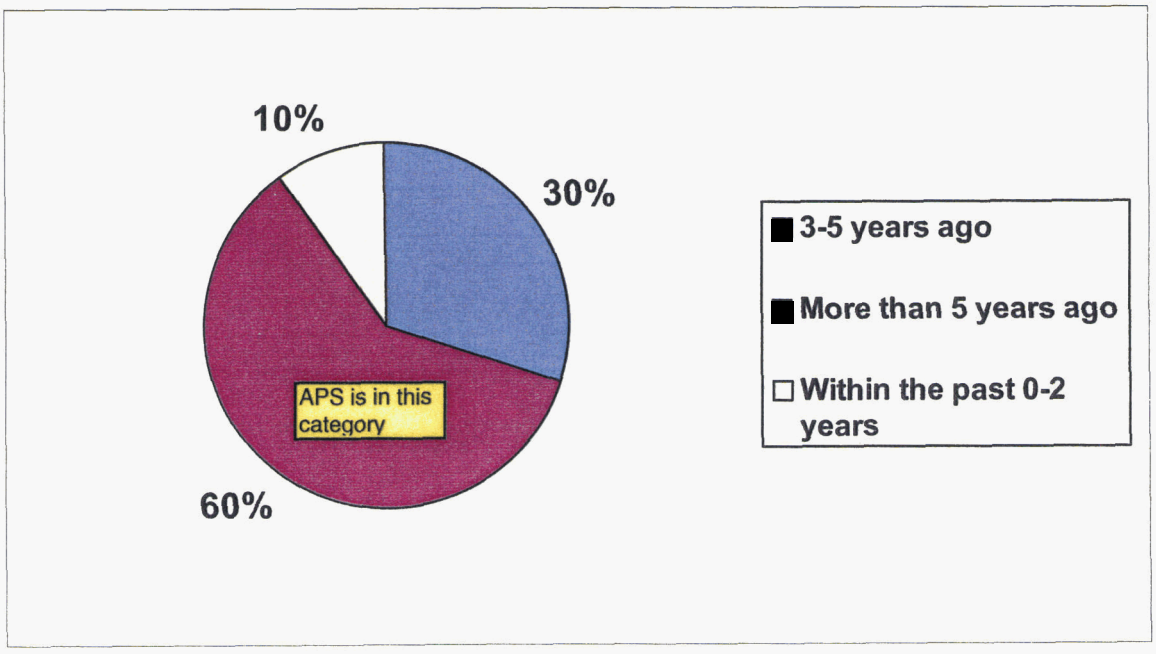
Is Front Office personnel compensation tied to trading related performance?



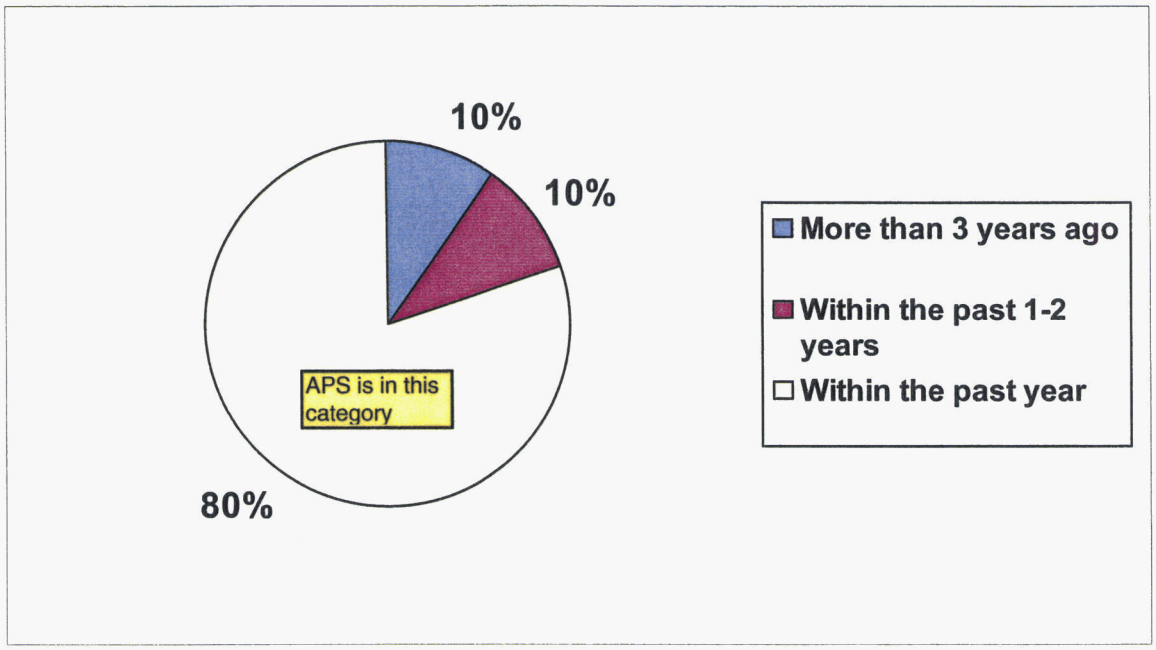
Do you have a formal energy risk management policy?



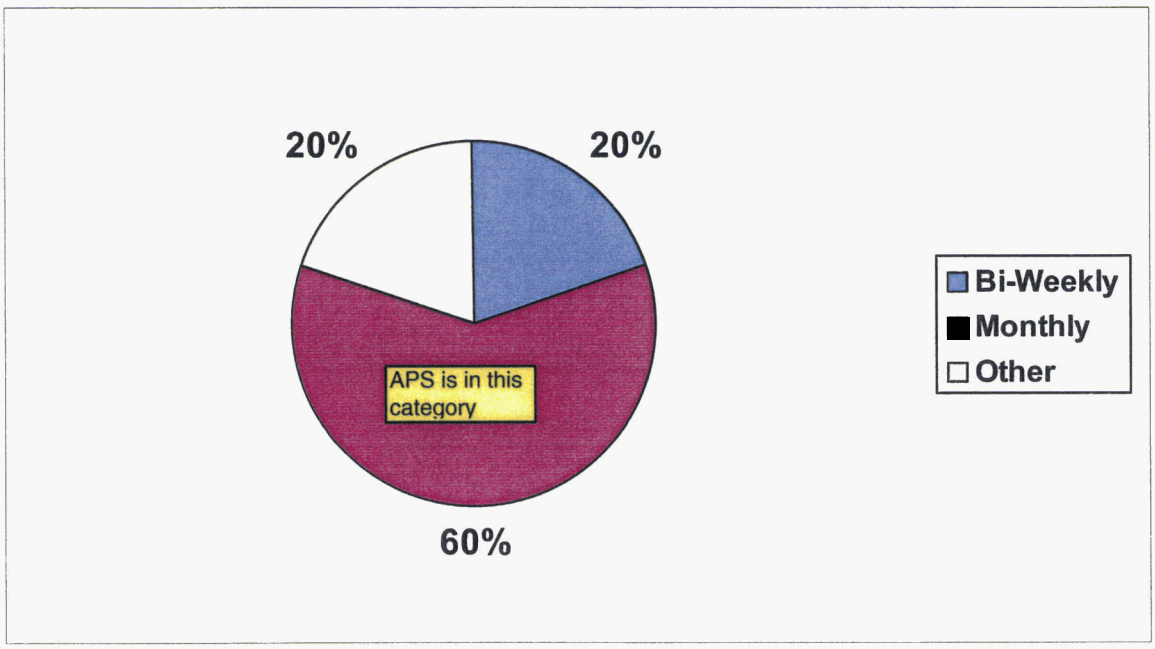
When was your risk policy first developed?



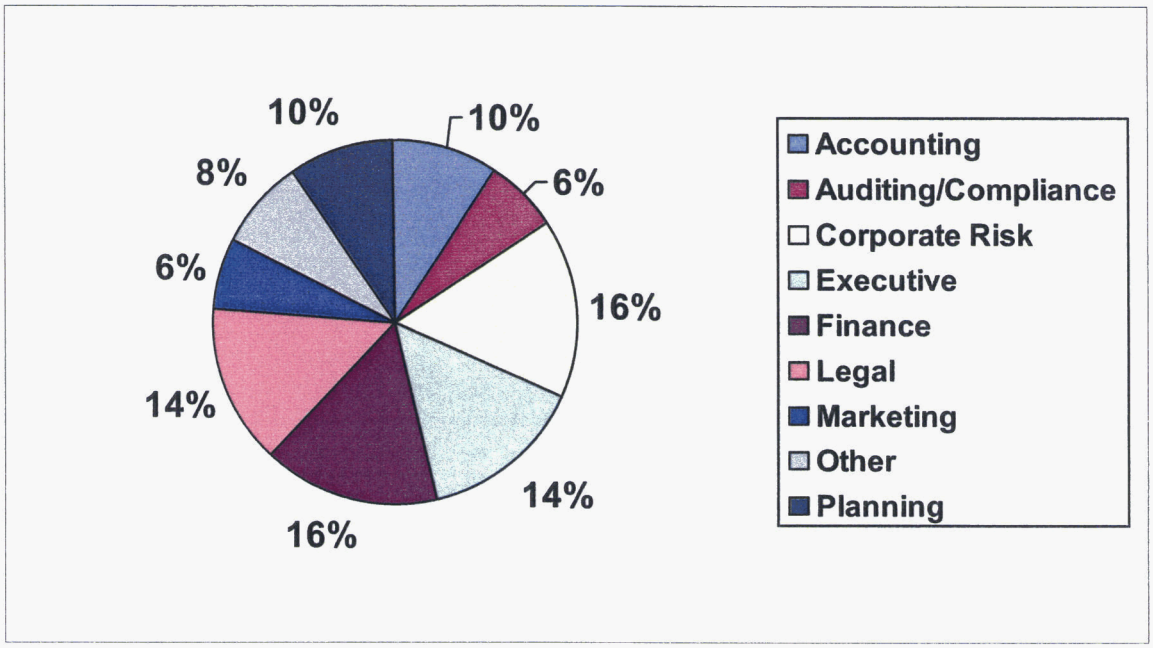
When was your risk management program last independently reviewed?



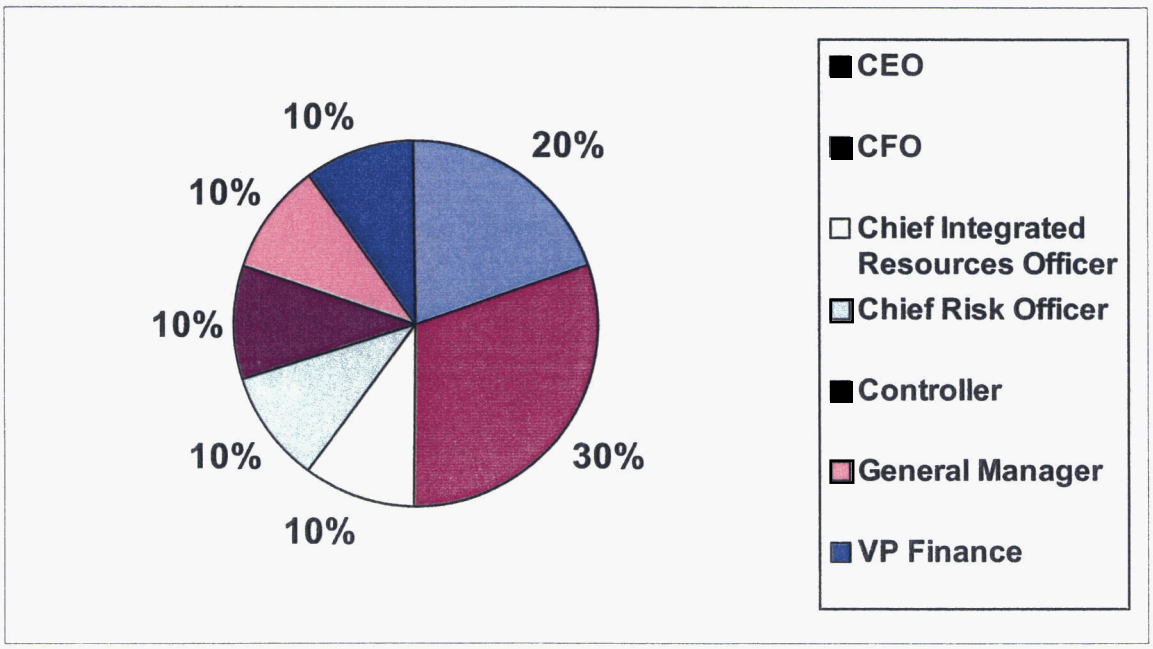
How often does your energy risk committee meet?



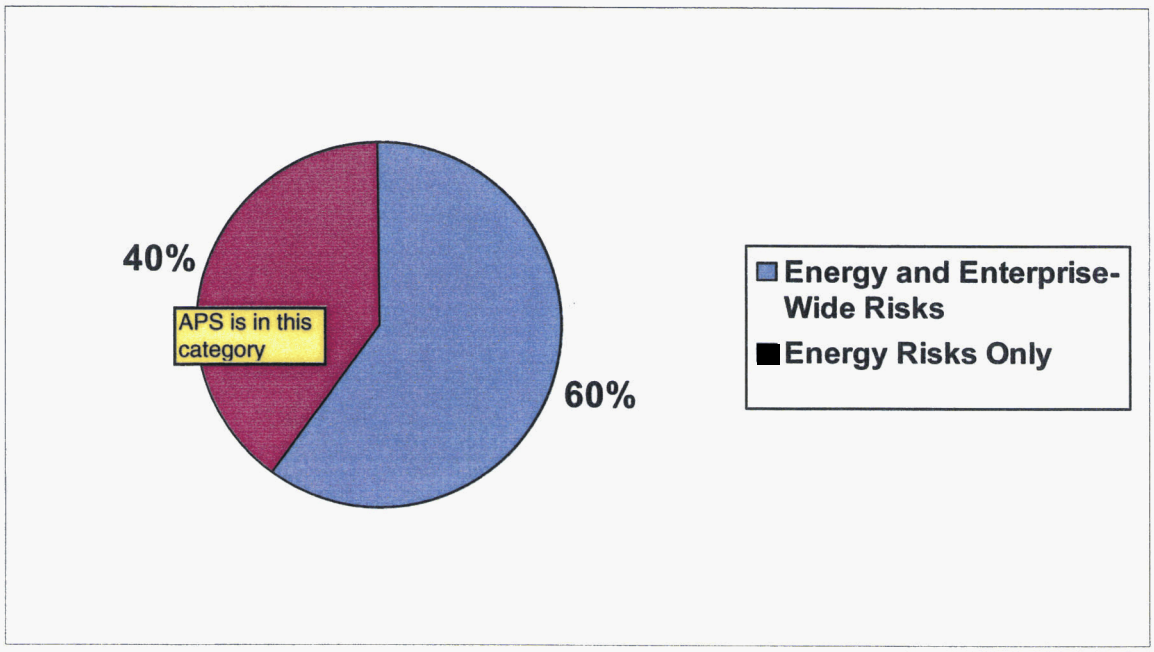
What departments are represented on your energy risk management committee?



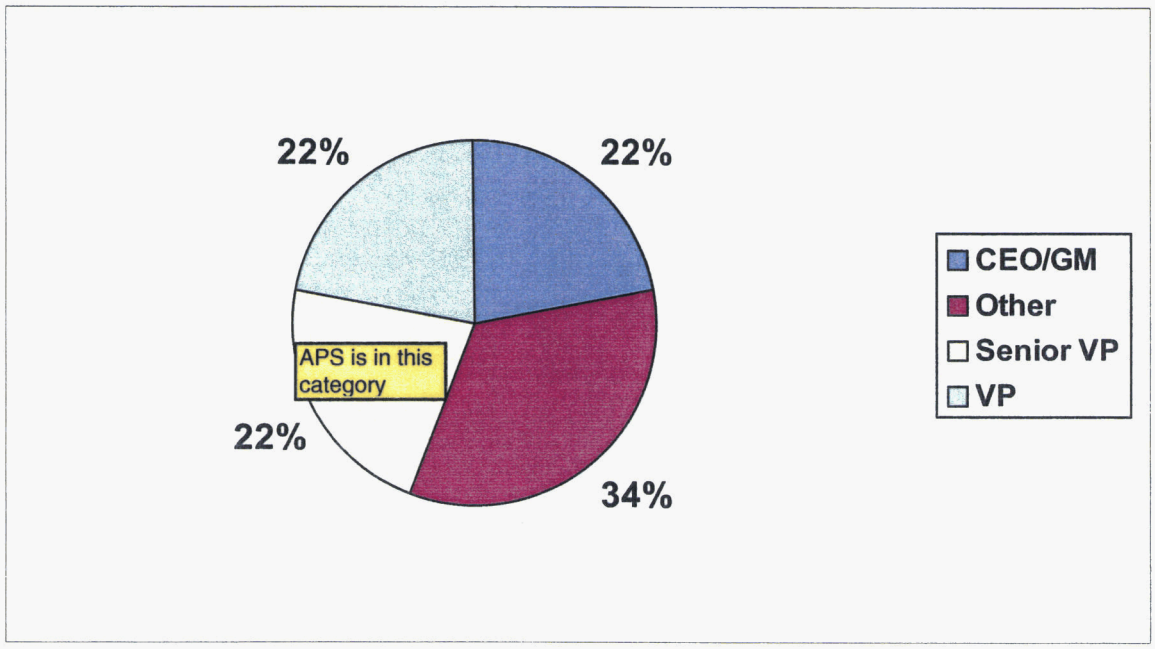
Who serves as Chairperson of your risk management committee?



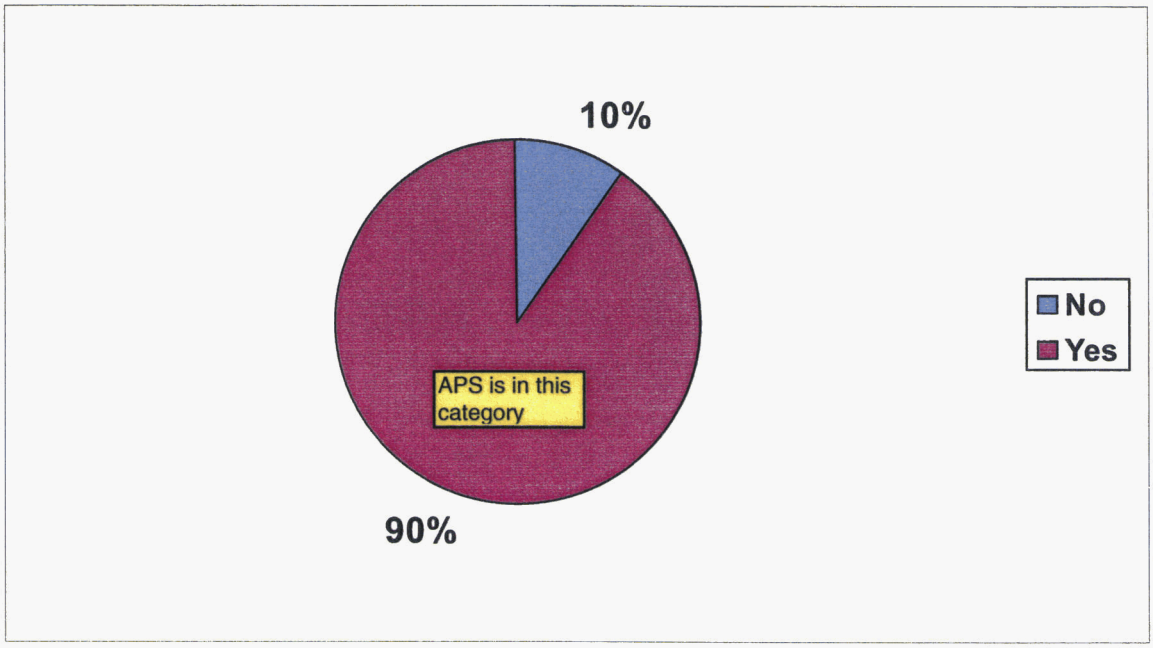
Does the committee deal with energy risks only, or also enterprise-wide risk issues?



What is the highest level person on your risk management committee?



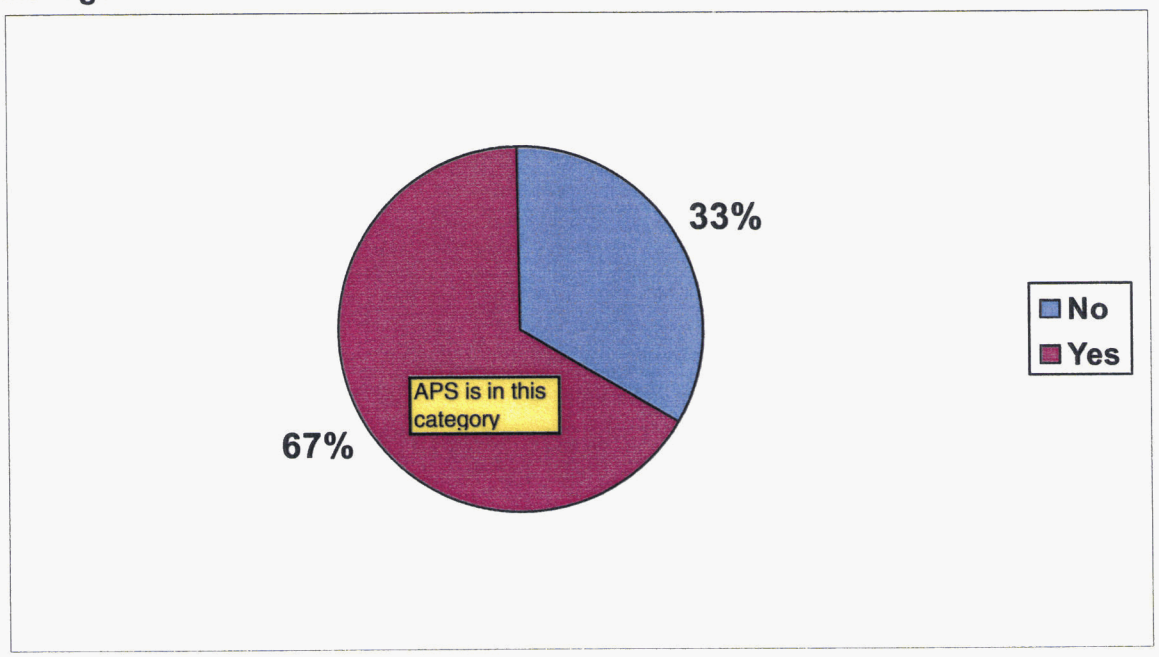
Do you have a formalized Middle Office function which provides for independent oversight?



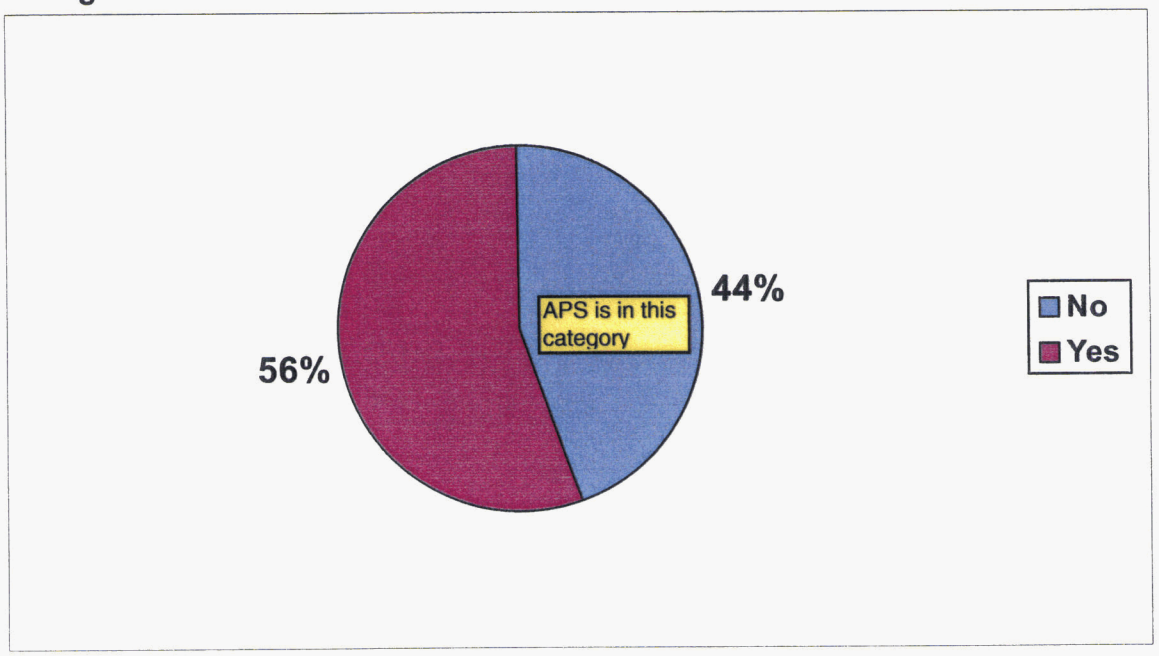
What is the title of the person who heads the Middle Office?

Company A	Director of Risk Management
Company B	Manager, Risk Control
Company C	Manager - Treasury & Risk Management
Company D	CFO
Company E	Controller
Company G	Mid-Office Risk Manager
Company I	Chief Risk Officer
Company J	Enterprise Risk Manager
Company K	Director, Energy & Risk Management

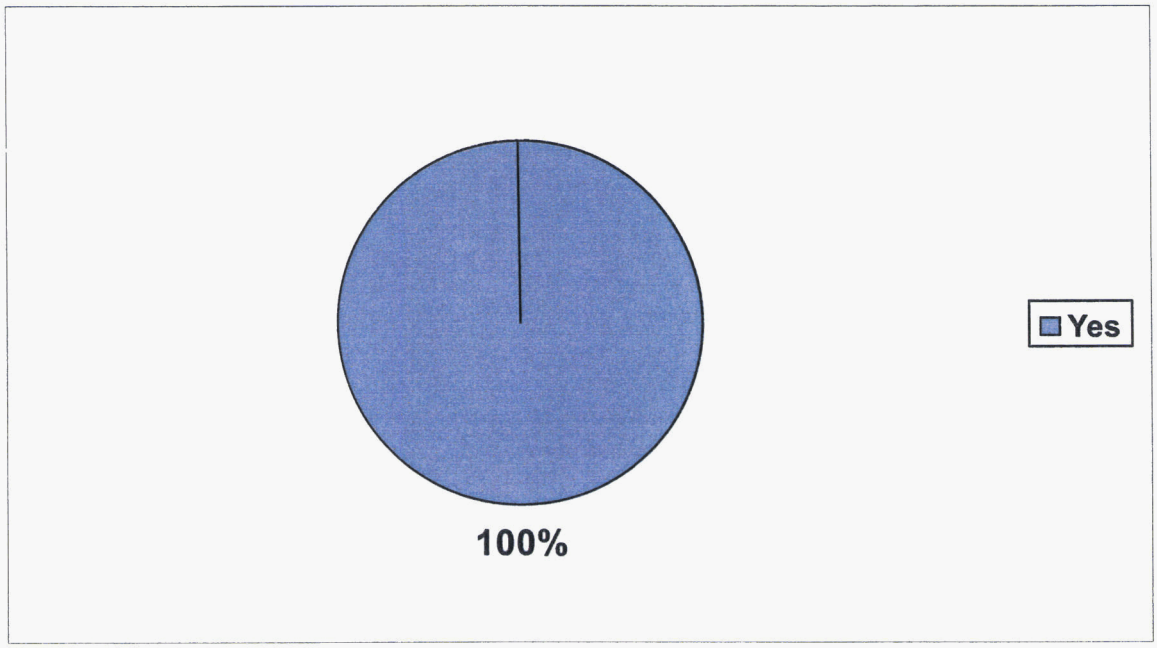
Is the person who heads the Middle Office an official member of the risk management committee?



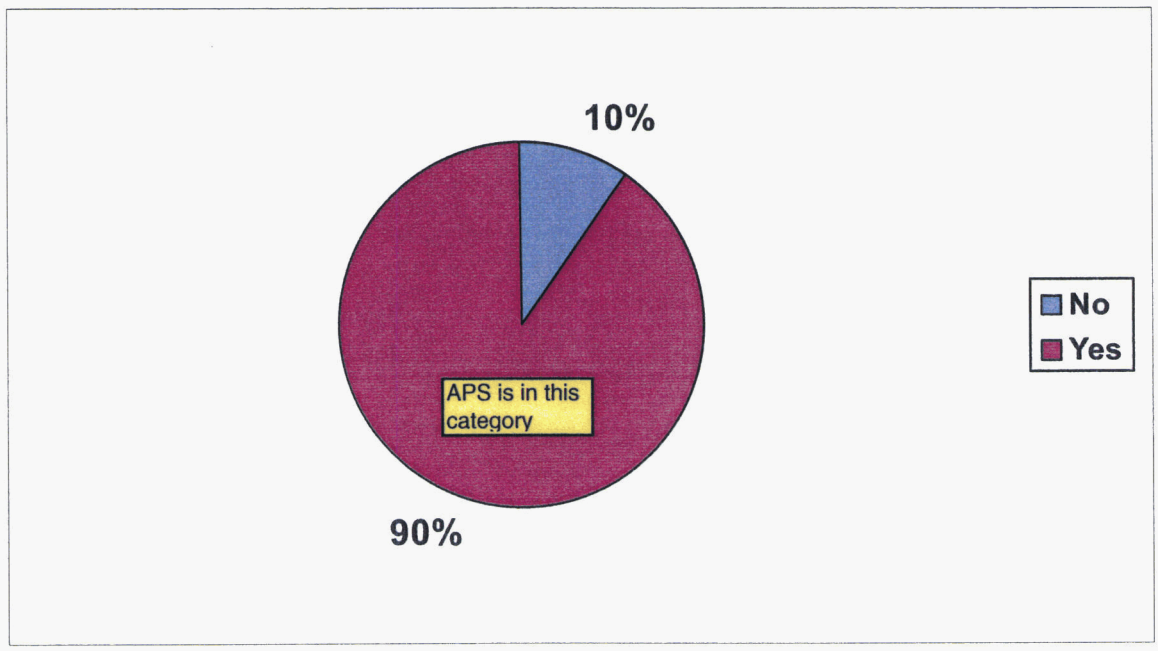
Is the head of power supply and/or trading an official member of the risk management committee?



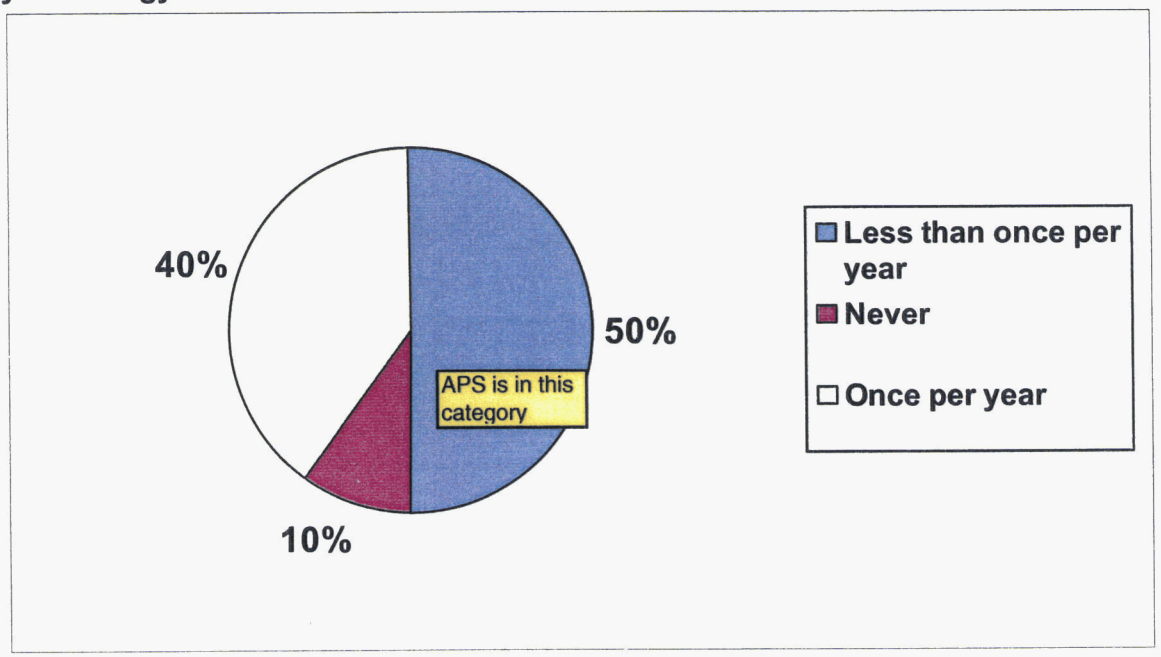
Is your Middle Office fully independent and separate of Front Office transactional activities?



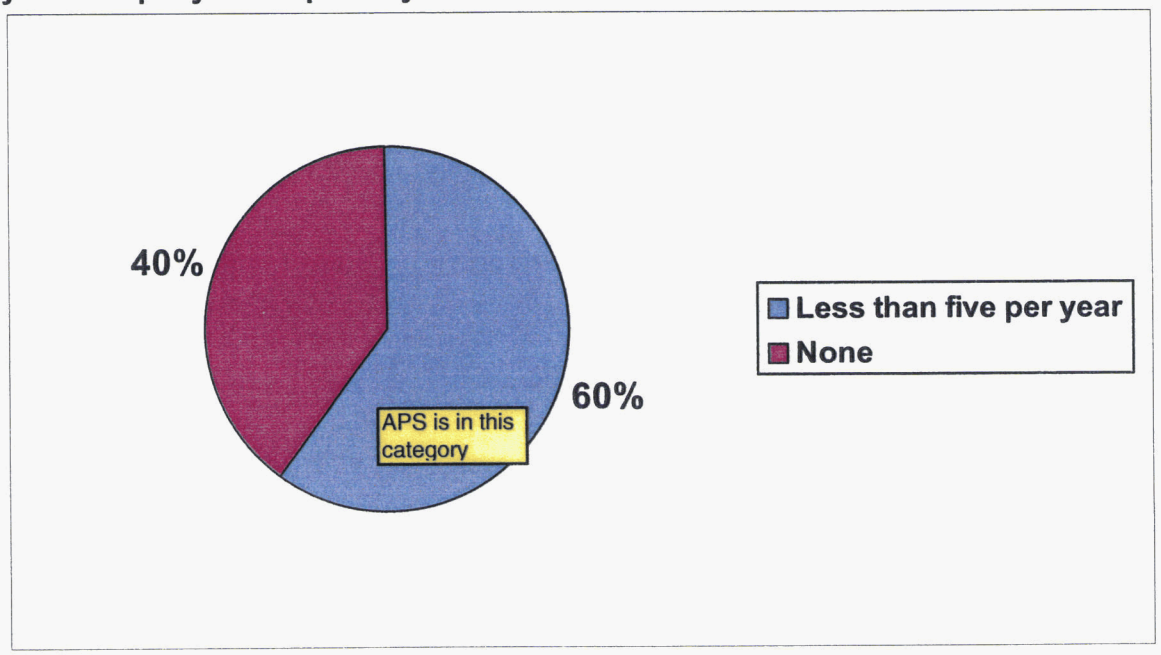
Is your Back Office fully independent and separate of Front Office transactional activities?



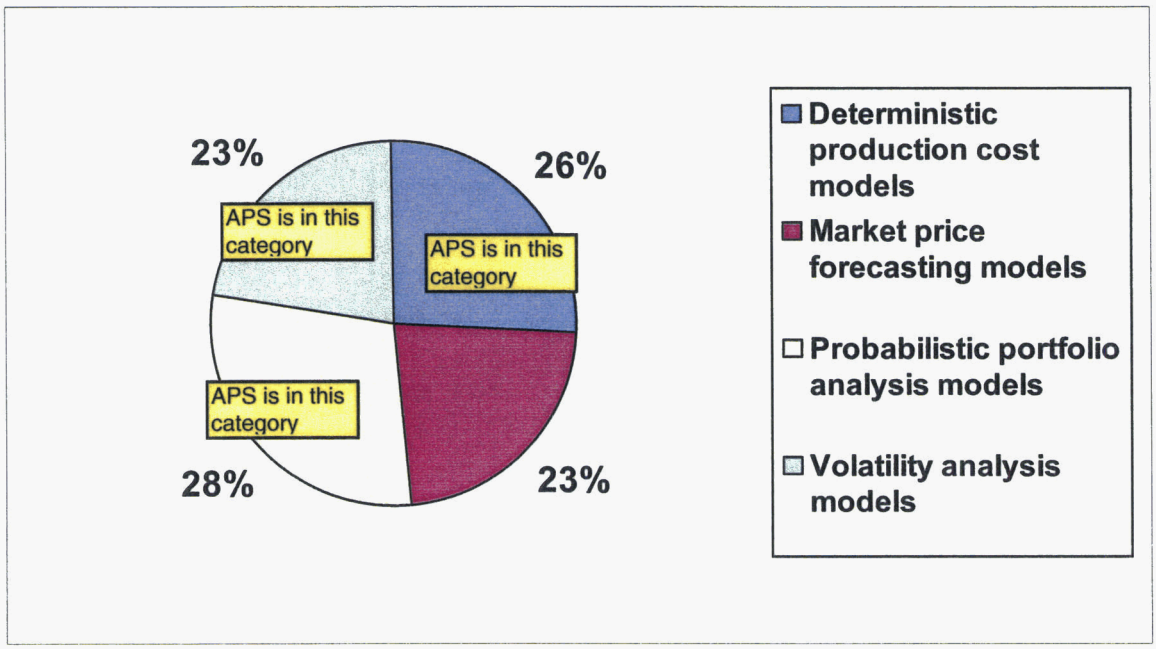
How frequently does your organization have independent audits performed of your energy risk control functions?



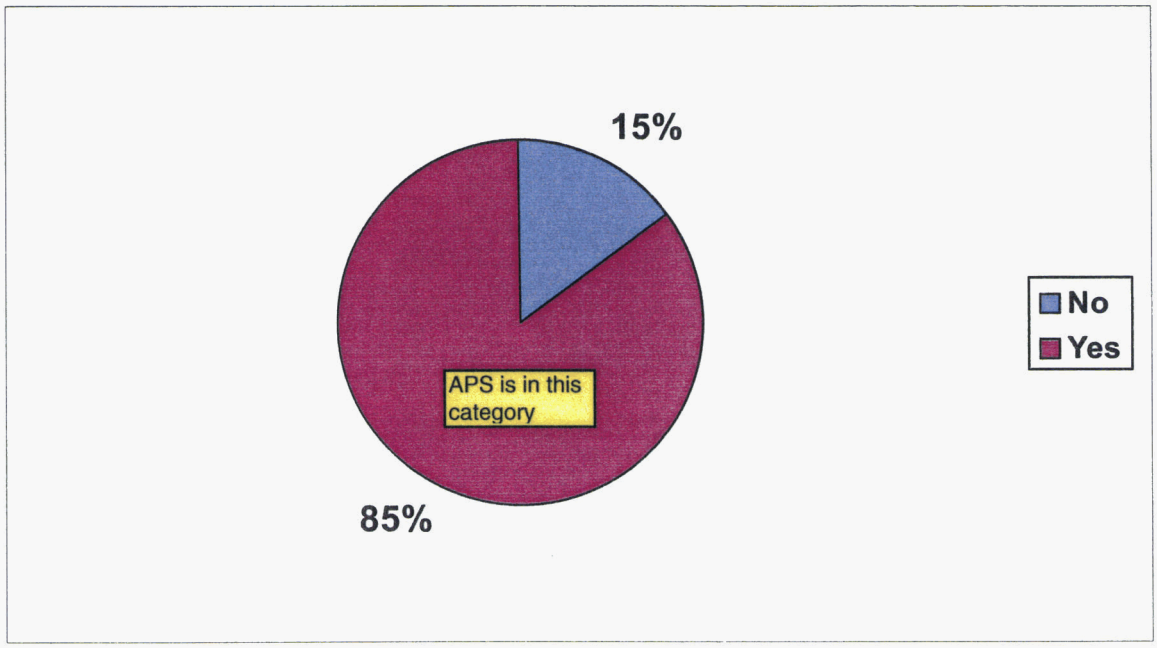
Approximately how many risk limit violations have occurred, on average, in your company in the past 5 years?



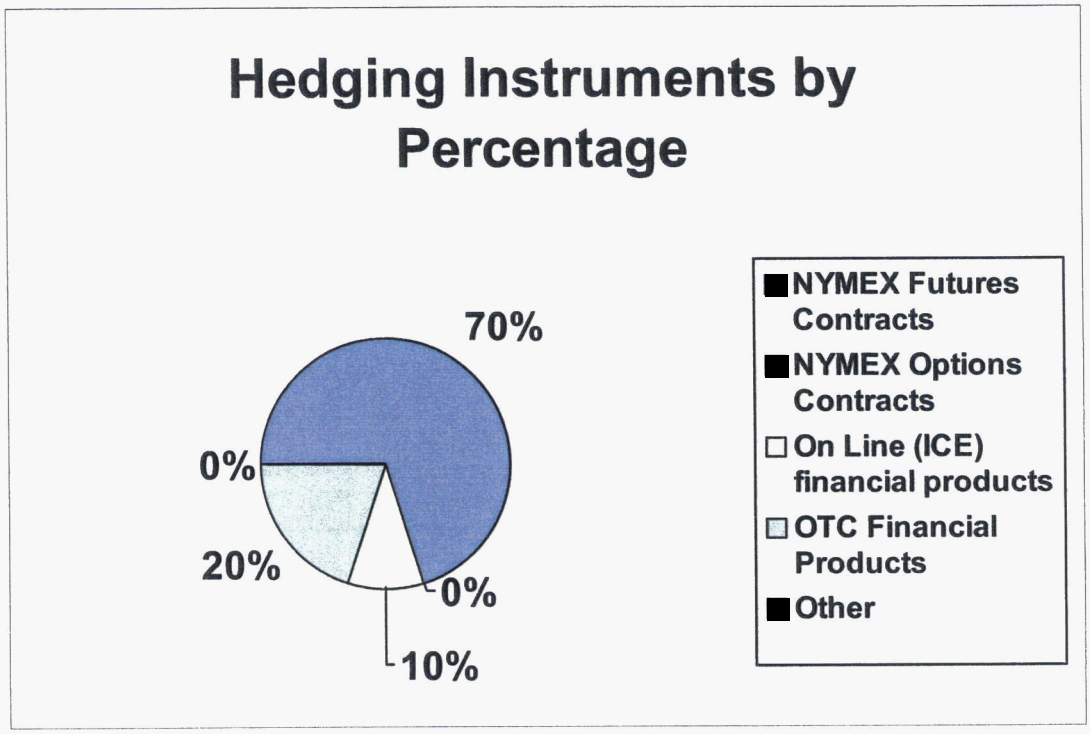
What types of models do you apply in your hedging program?



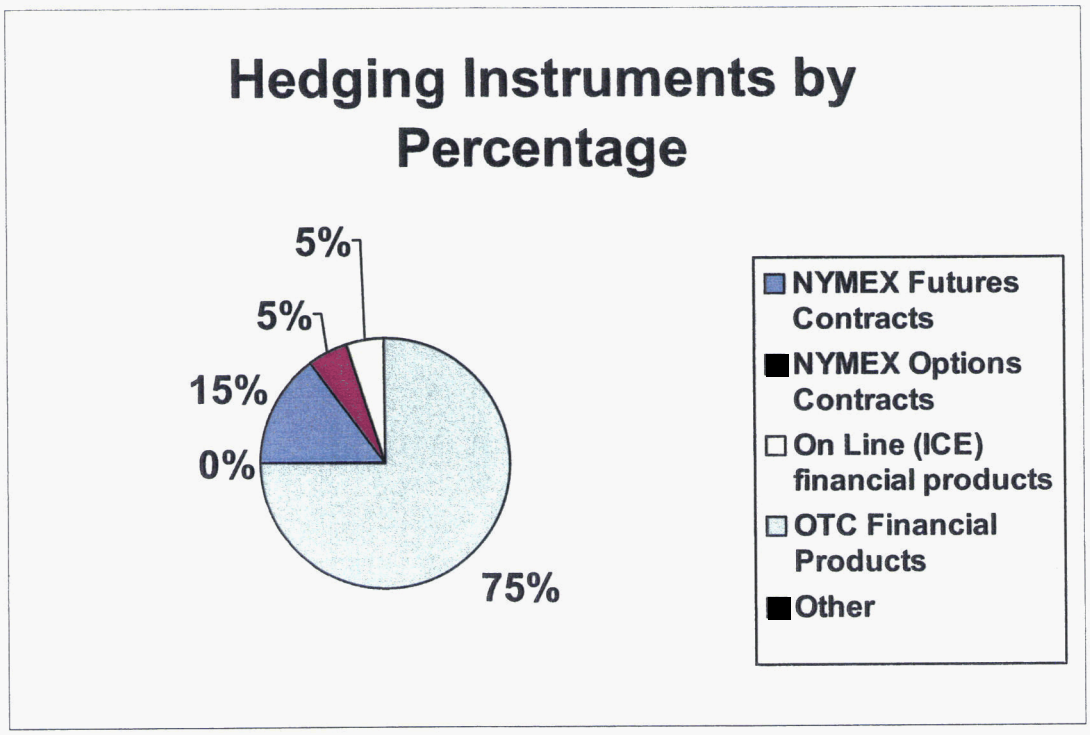
Does your company hedge or "lock-in" a portion of its natural gas requirements using either fixed price physical contracts or financial instruments?



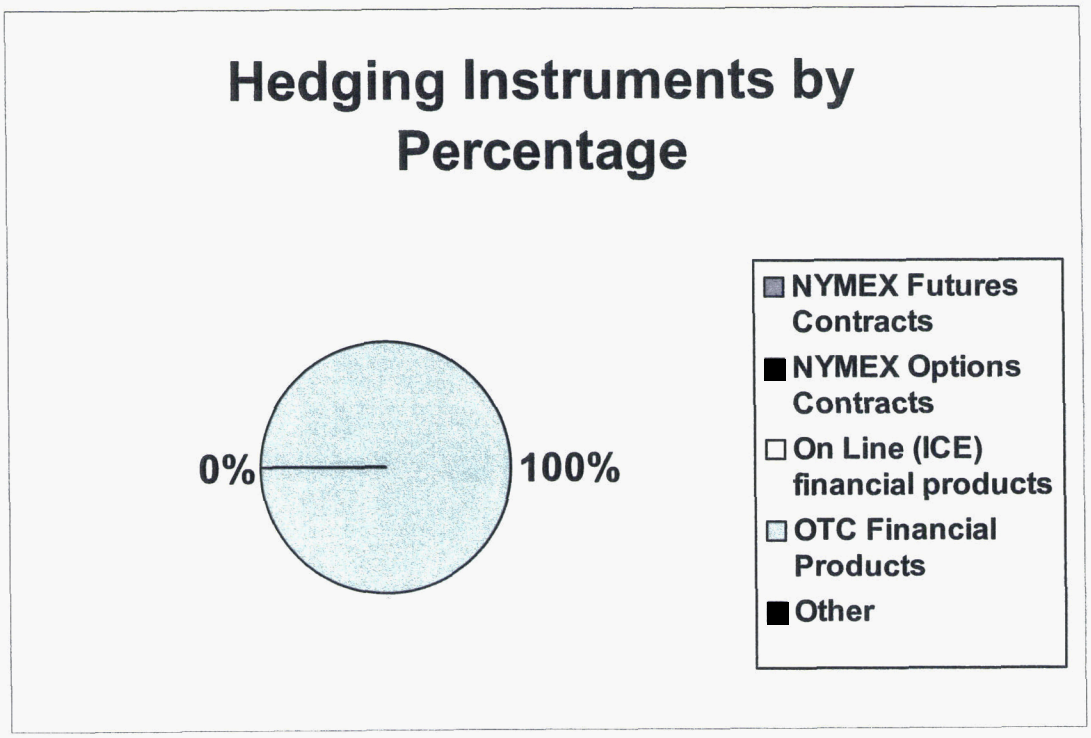
Company A



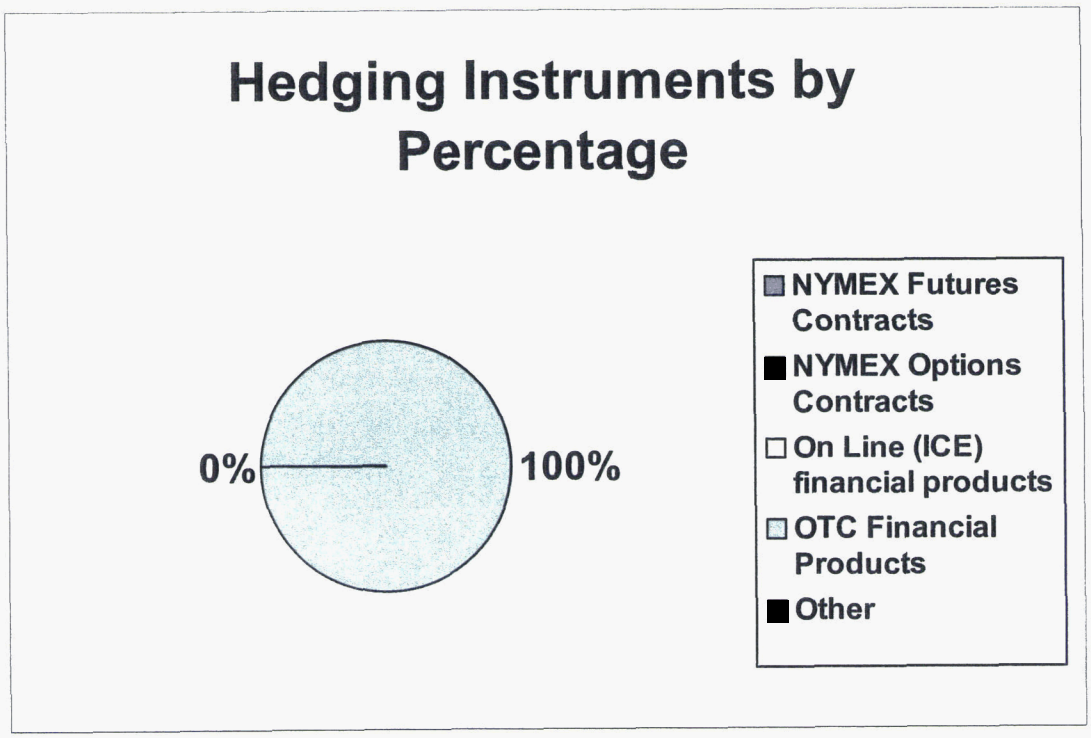
Company B



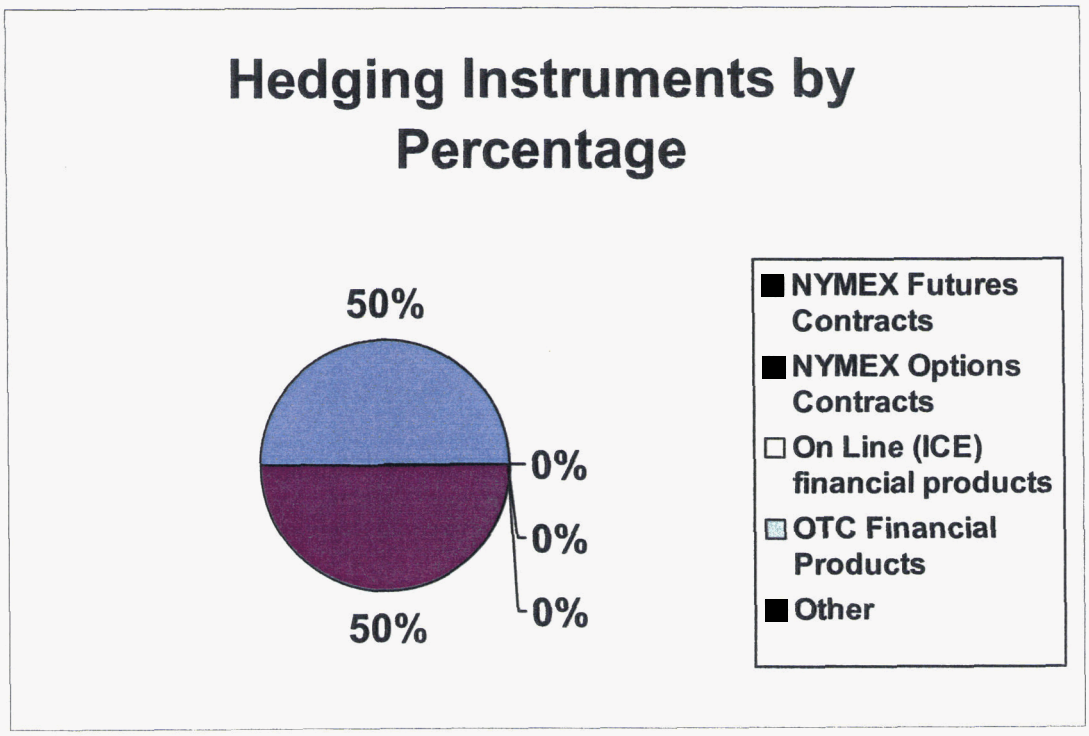
Company D



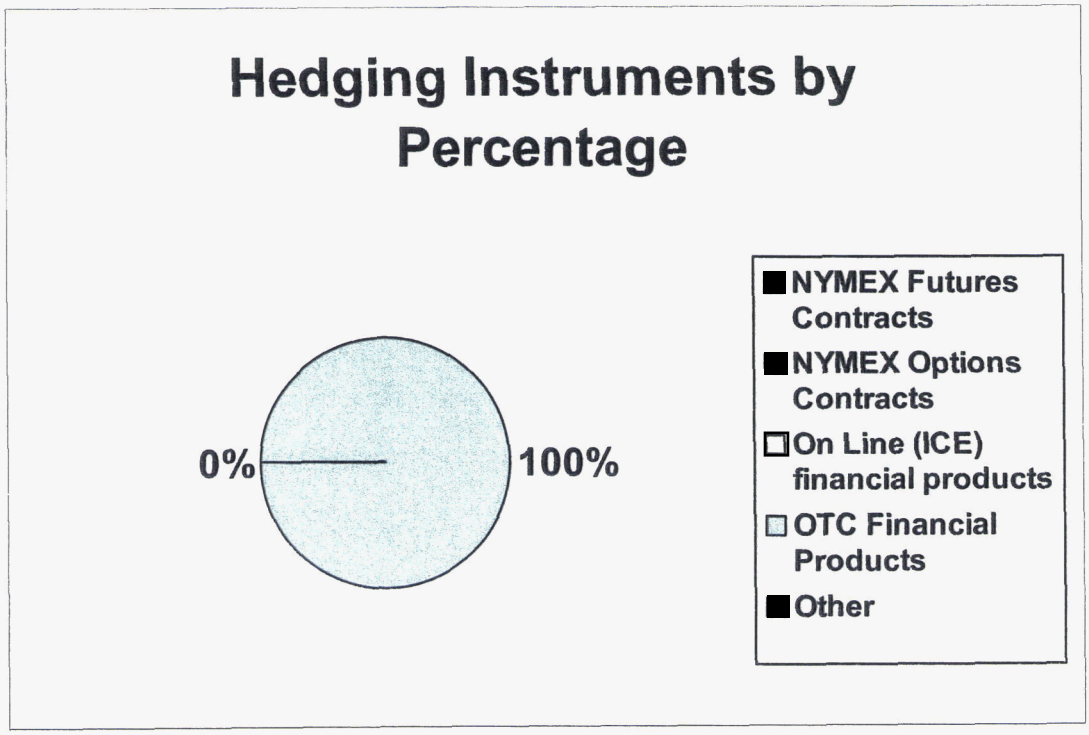
Company G



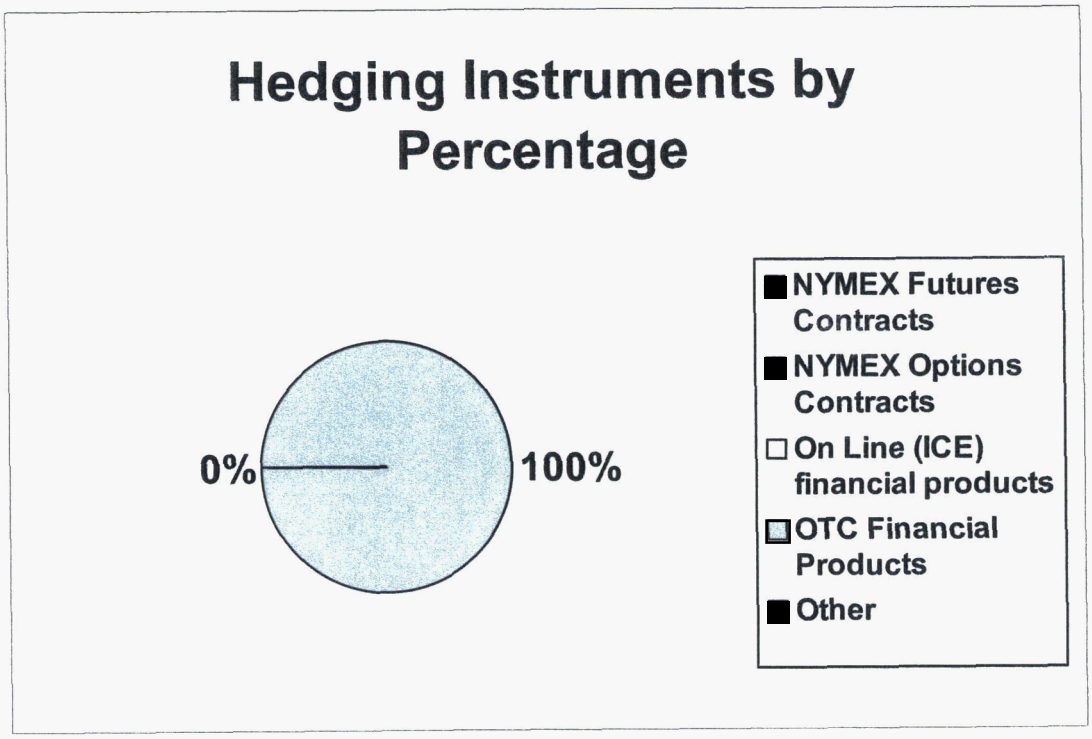
Company H



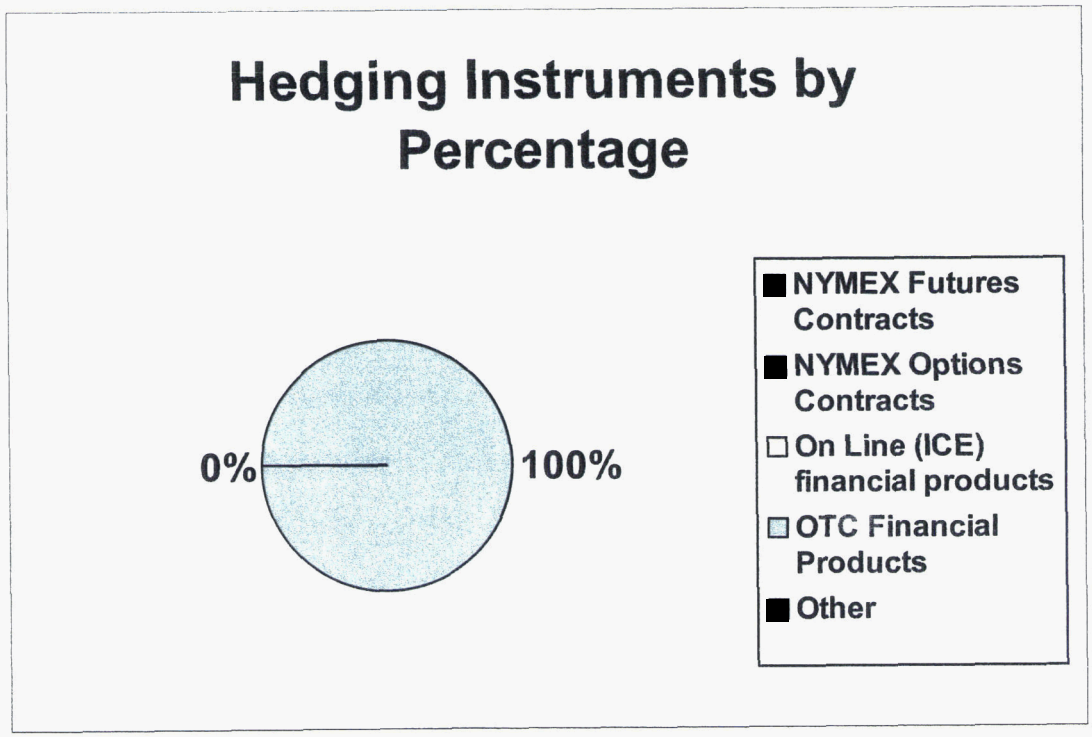
Company I



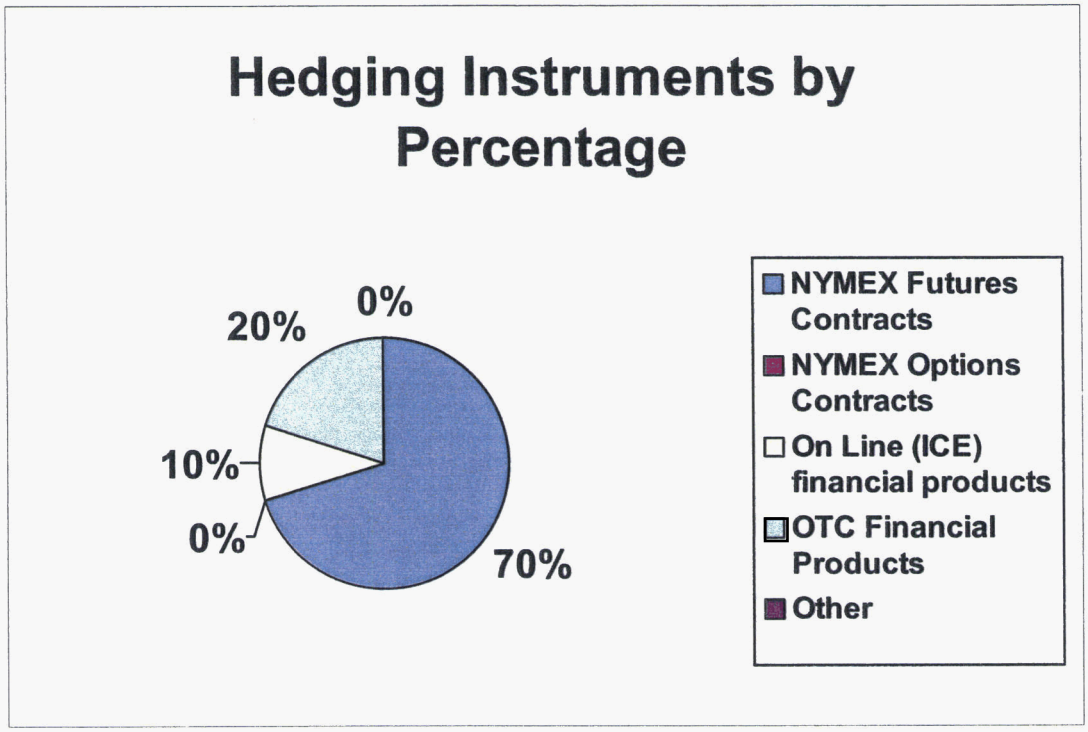
Company J



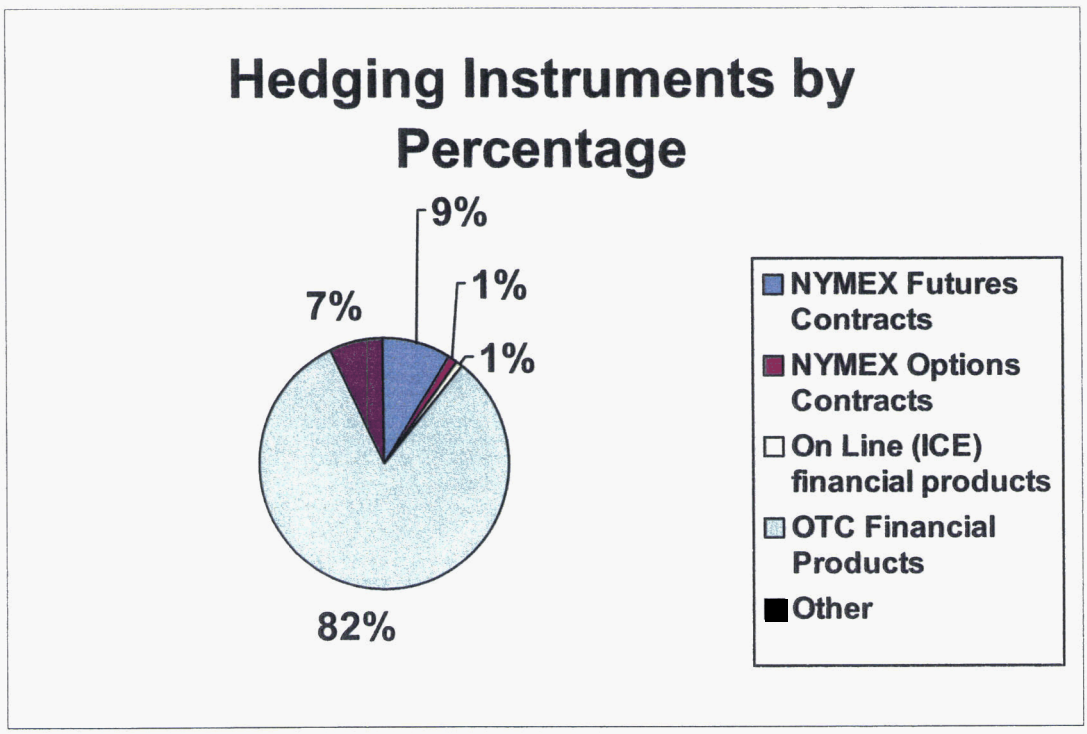
Company K



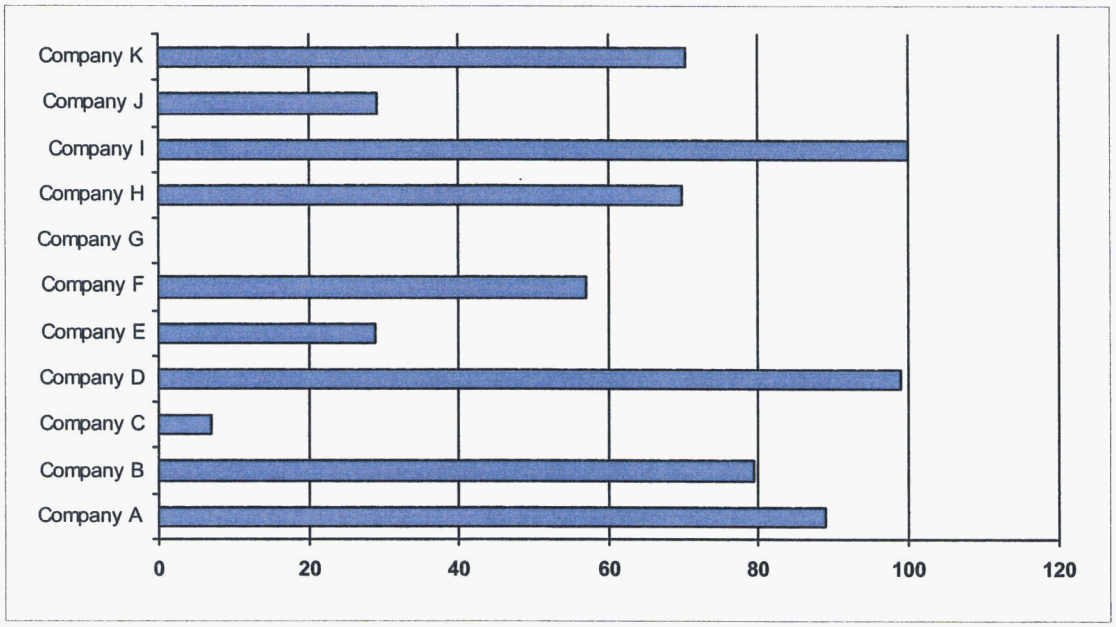
Company A



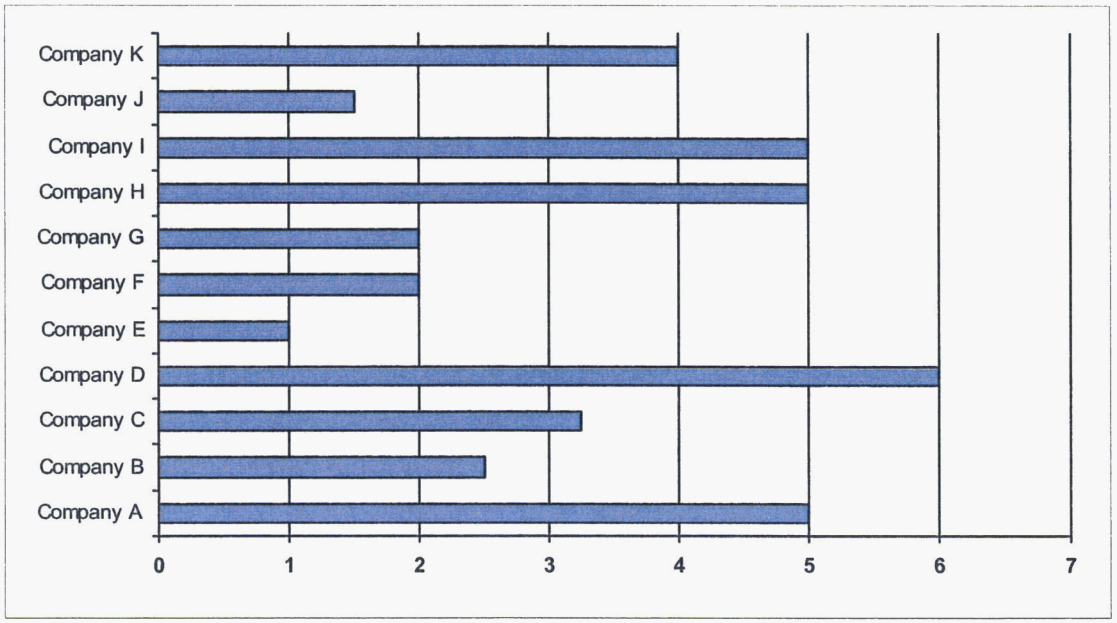
Others



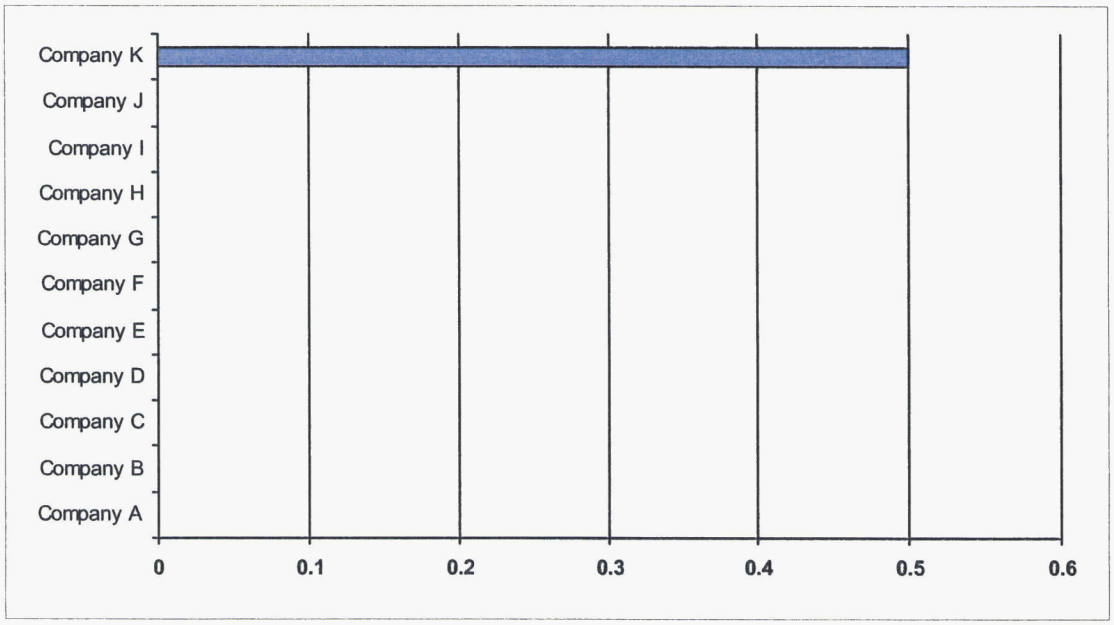
What is your average delivered energy price ($/MWh) to your customers?



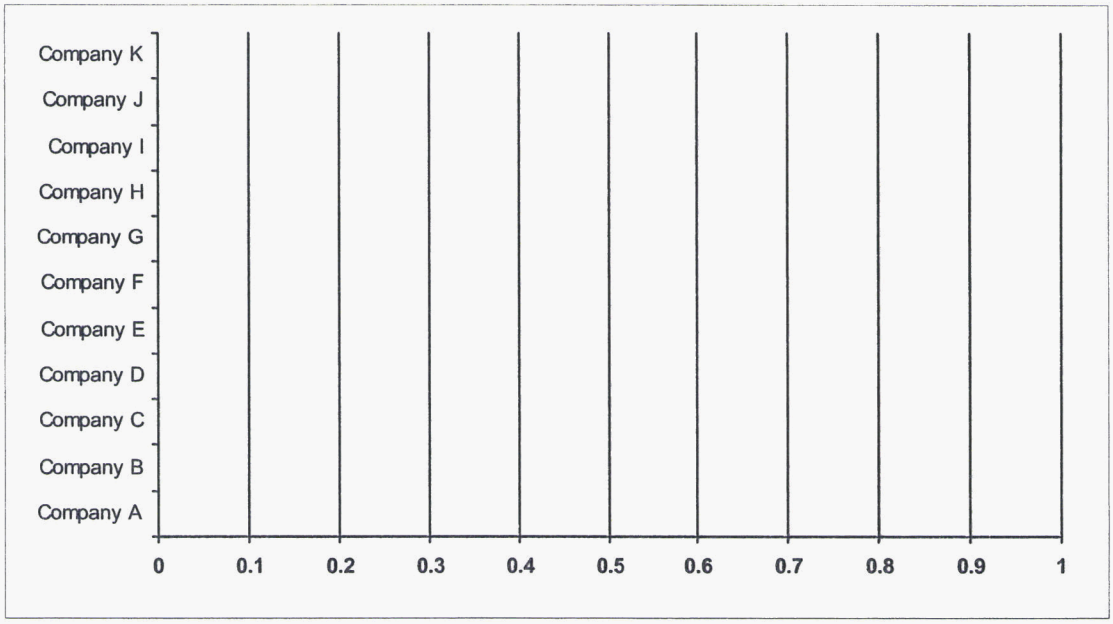
Number of Full-time-equivalent employees in your energy risk management function



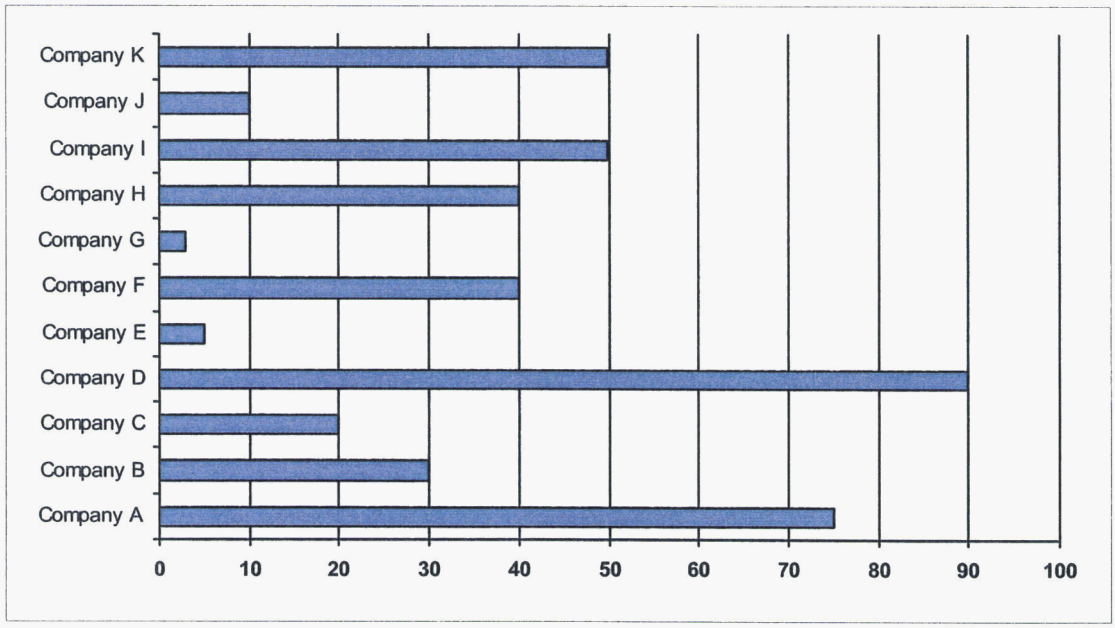
Number of Part-time employees in your energy risk management function, expressed in terms of Full-time-equivalent employees



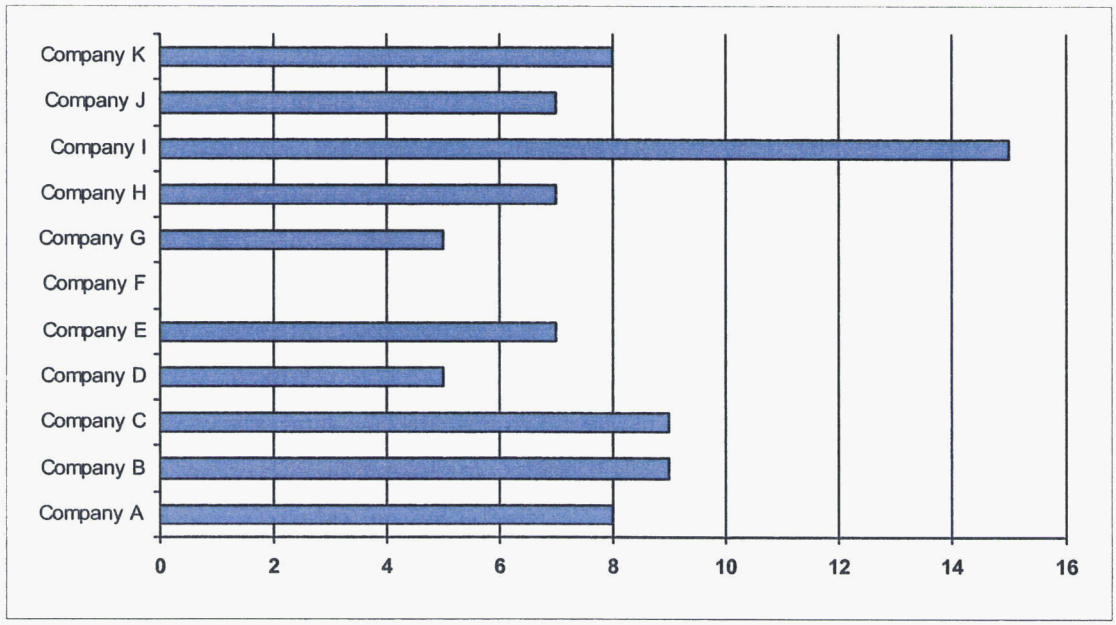
Number of Outsourced employees in your energy risk management function, expressed in terms of Full-time-equivalent employees



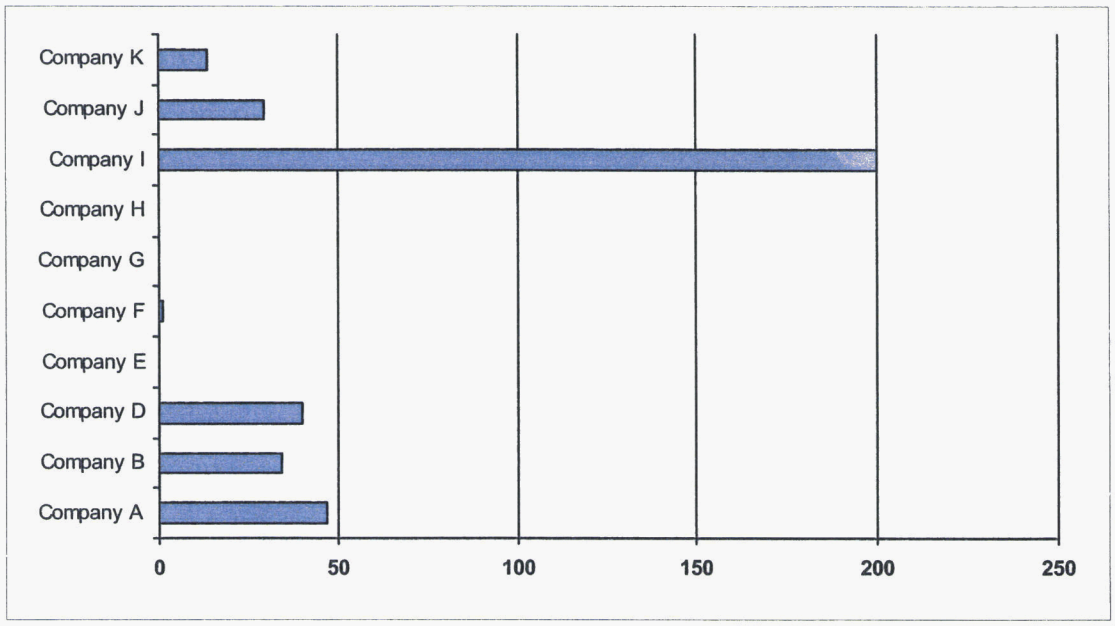
Number of approximate years of cumulative experience for all employees in energy risk management function



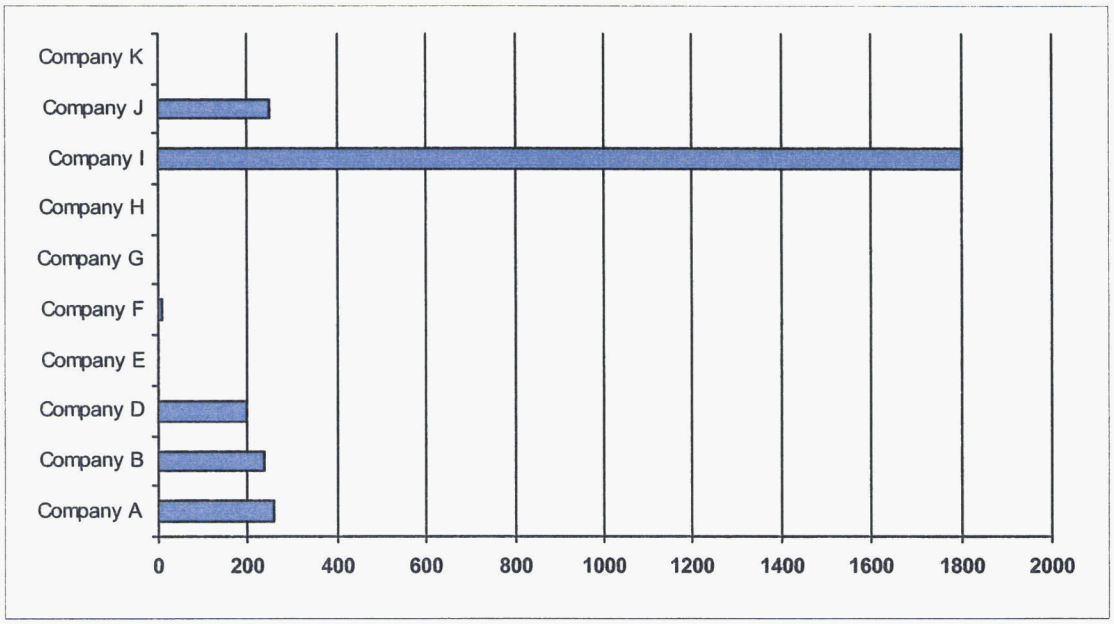
How many persons are official members of your risk management committee?



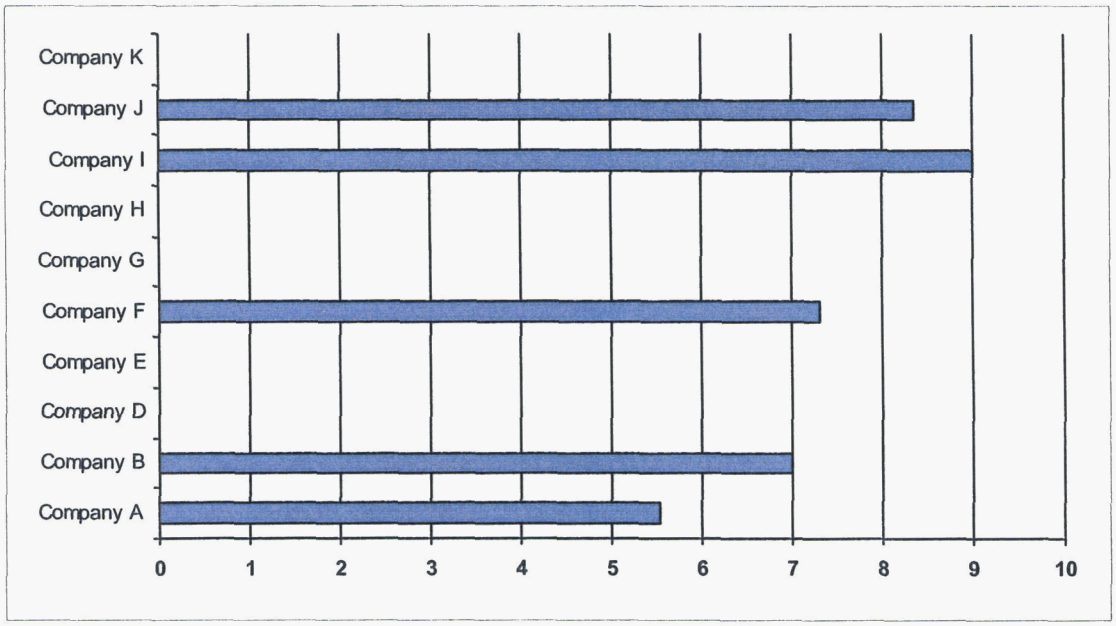
How much natural gas did you buy last year (in millions of MMBTU) ?



What was your total expenditure on natural gas last fiscal year (in millions of dollars) ?



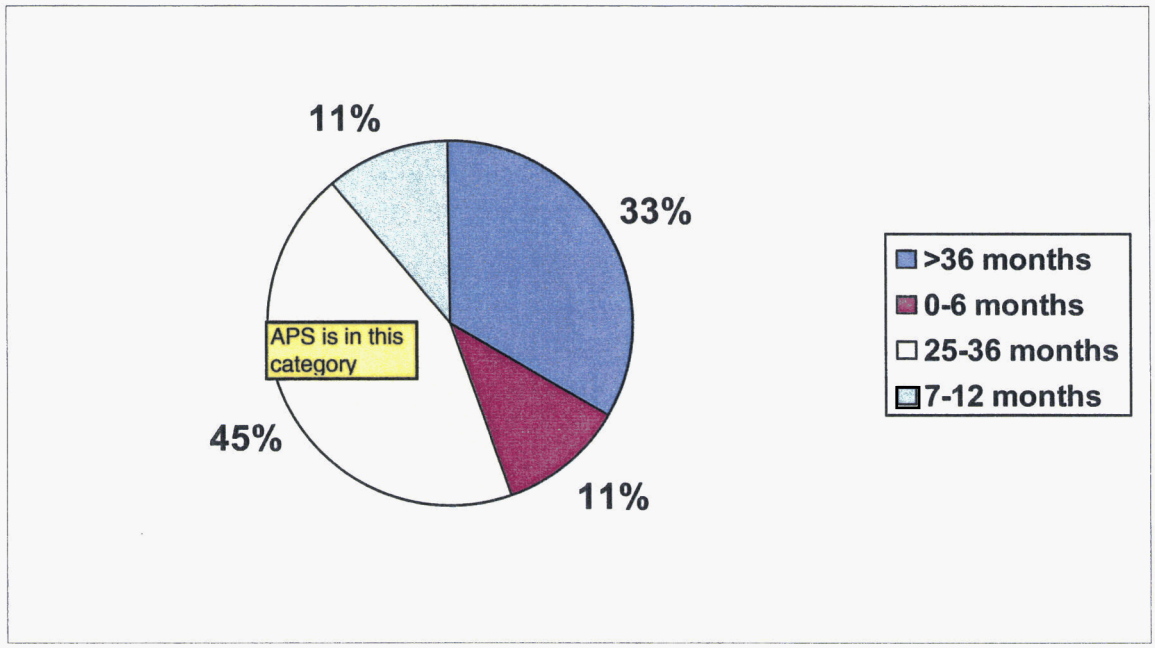
What was the average delivered commodity cost ($/MMBTU) of that gas?



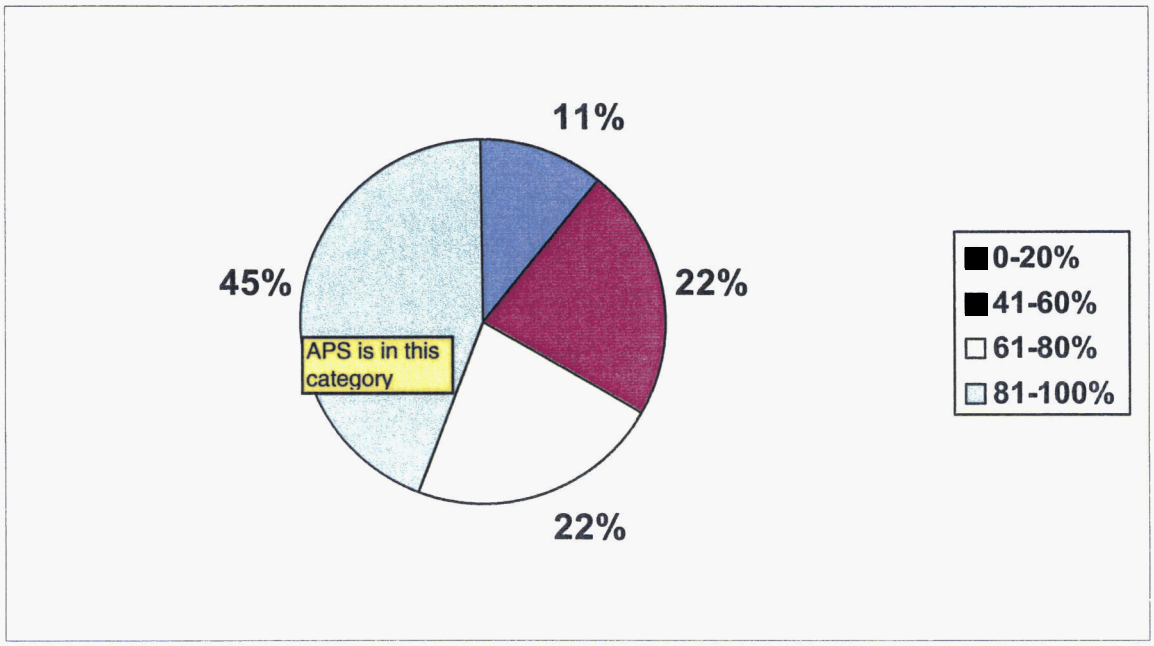
What circumstances led to development and implementation of the hedge plan?

Company A	Price volatilty in late 1990's
Company B	1) Desire to have written guidelines approved by ROC to guide transactions, provide auditbility to strategies
Company C	Volatility in natural gas prices
Company D	California Energy Crisis
Company G	Asset Optimization
Company H	Acquisition of additional supply led to development of hedging plan.
Company I	Desire to stablize end user costs.
Company K	Increased volatility in natural gas prices.

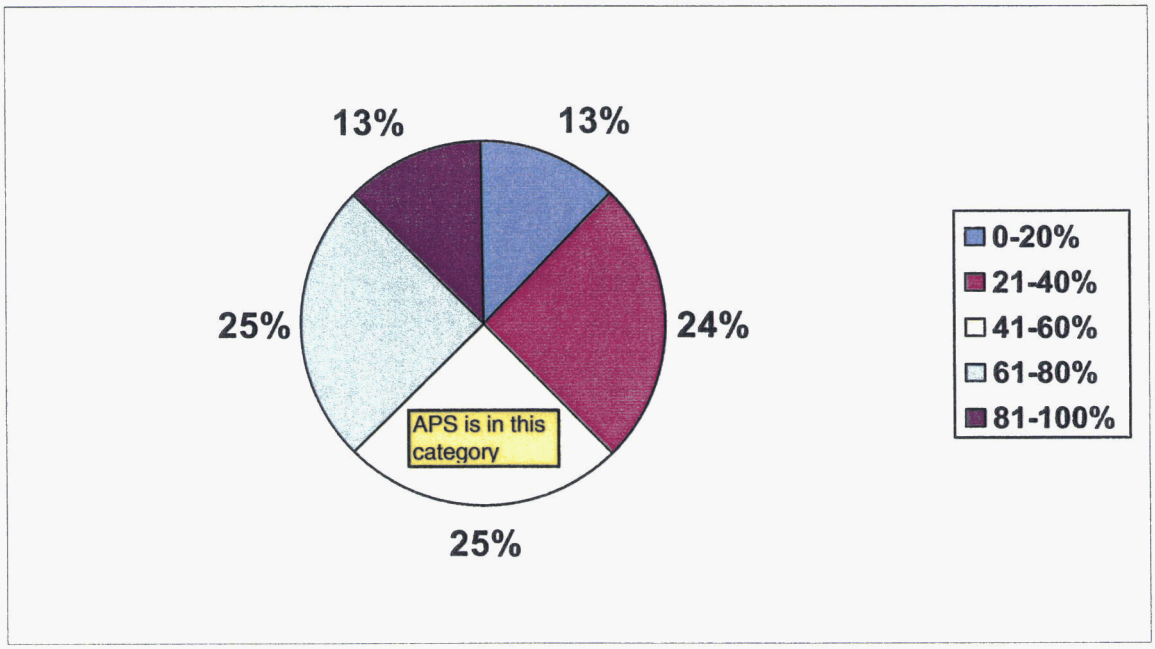
How far out do you typically hedge your natural gas requirements?



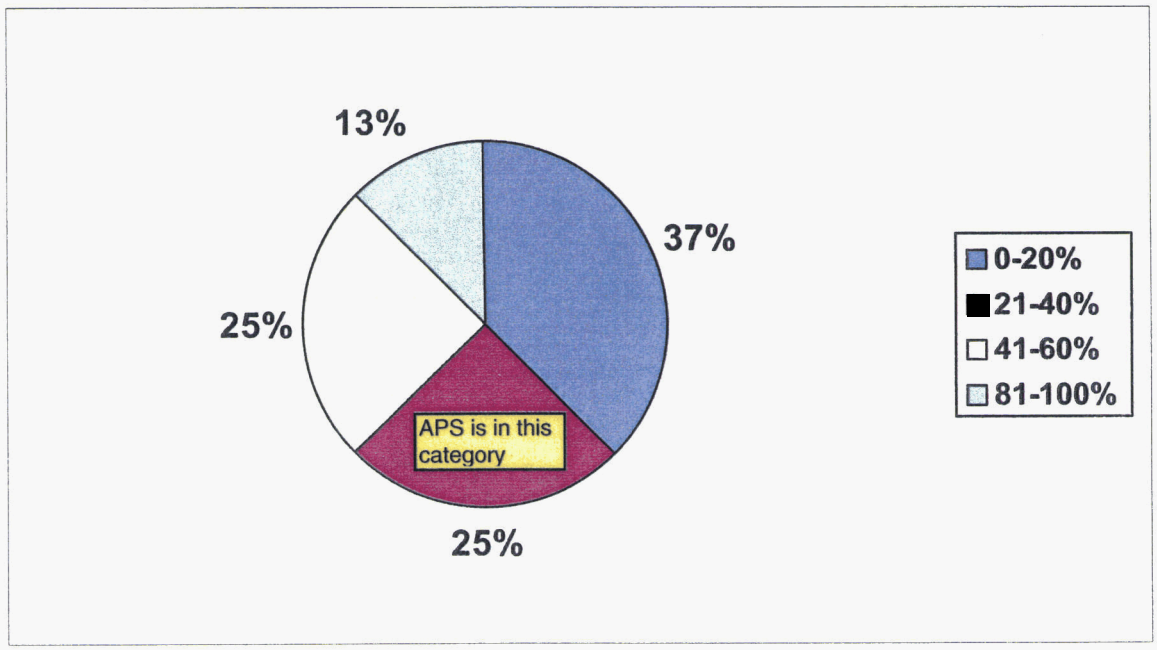
For the period of 0-12 months, what percentage of your expected natural gas usage do you hedge?



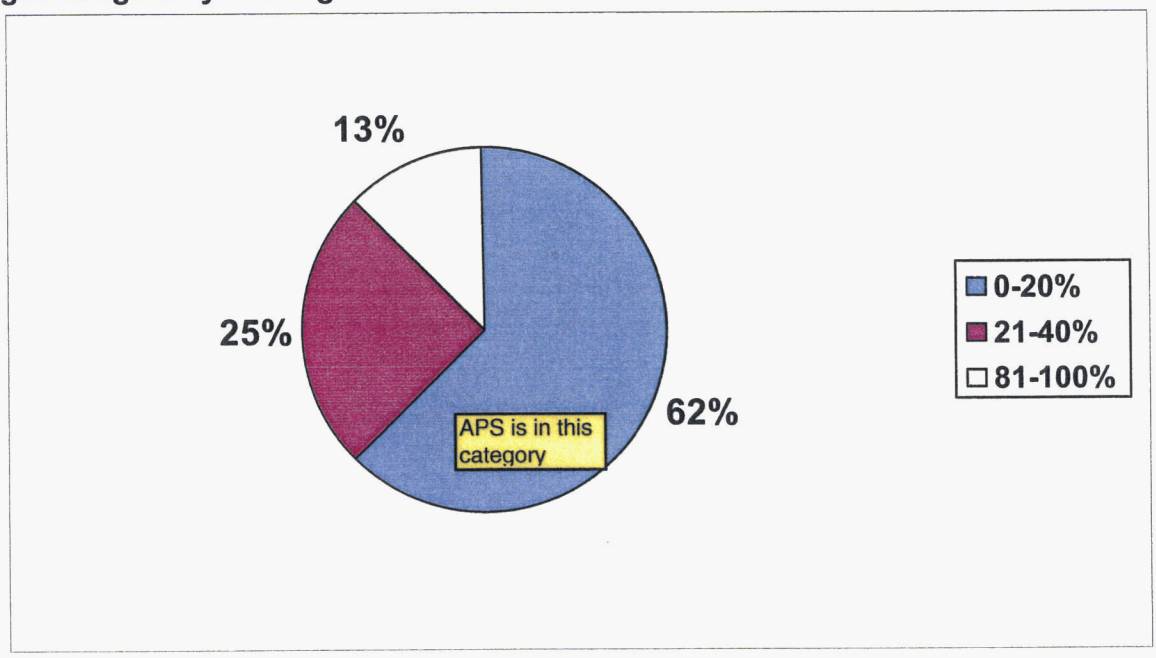
For the period of 12-24 months, what percentage of your expected natural gas usage do you hedge?



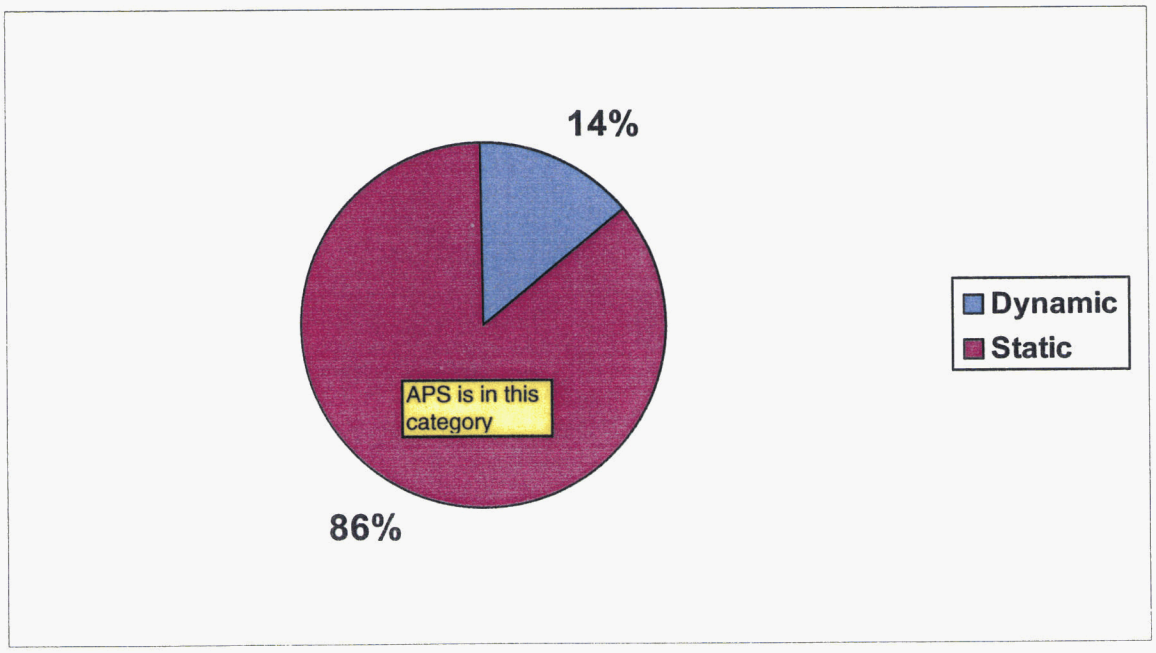
For the period of 24-36 months, what percentage of your expected natural gas usage do you hedge?



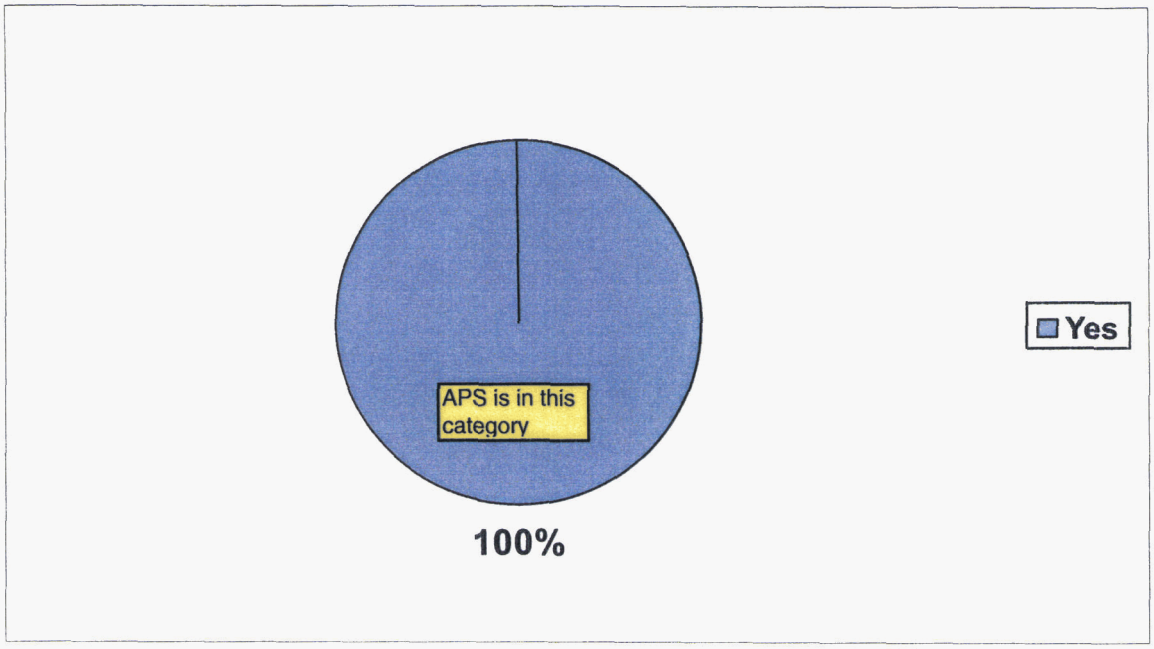
For the period beyond 36 months, what percentage of your expected natural gas usage do you hedge?



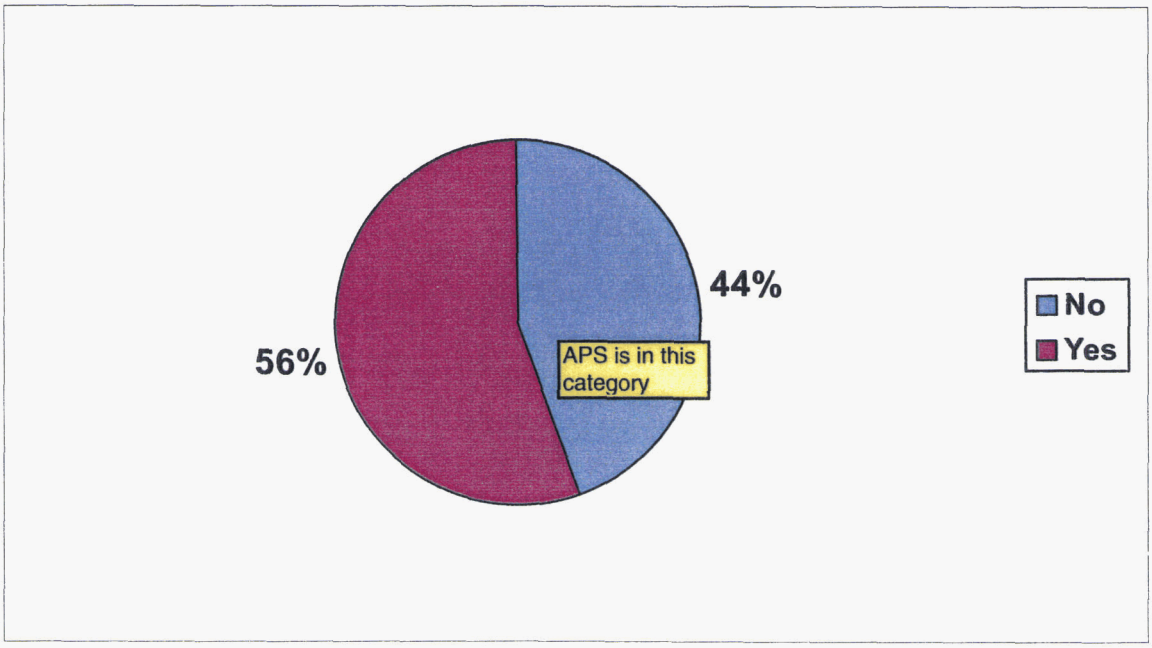
If you hedge fuel, are the hedges primarily static or are they dynamic?



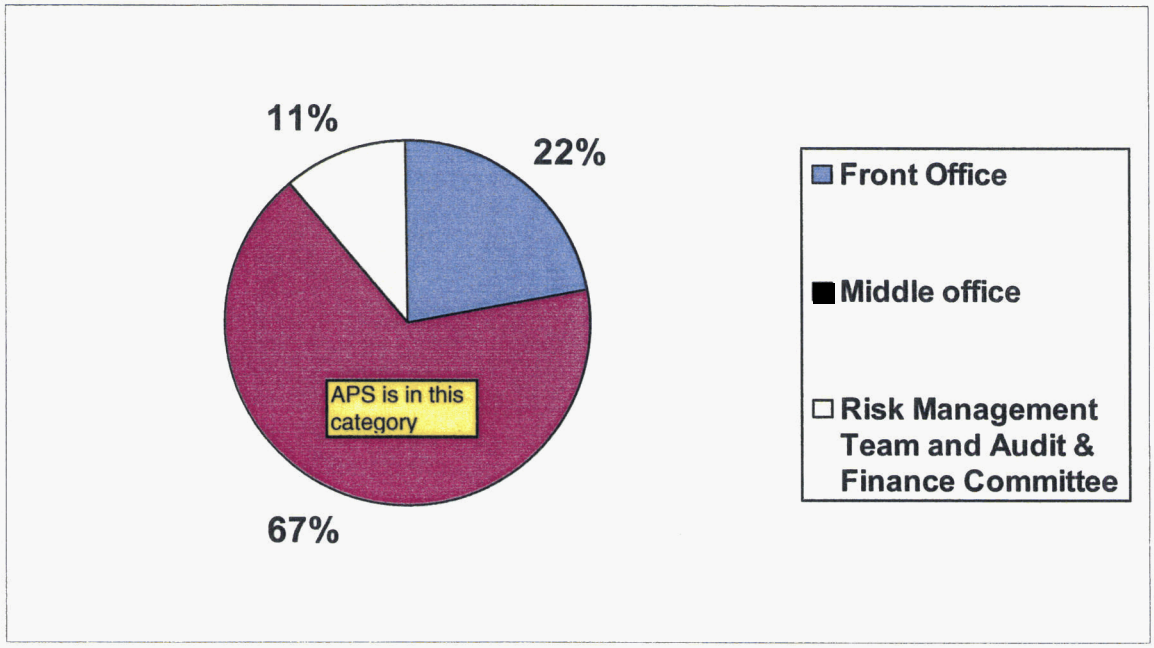
Does your hedge program include target deadlines to reach planned hedge percentage?



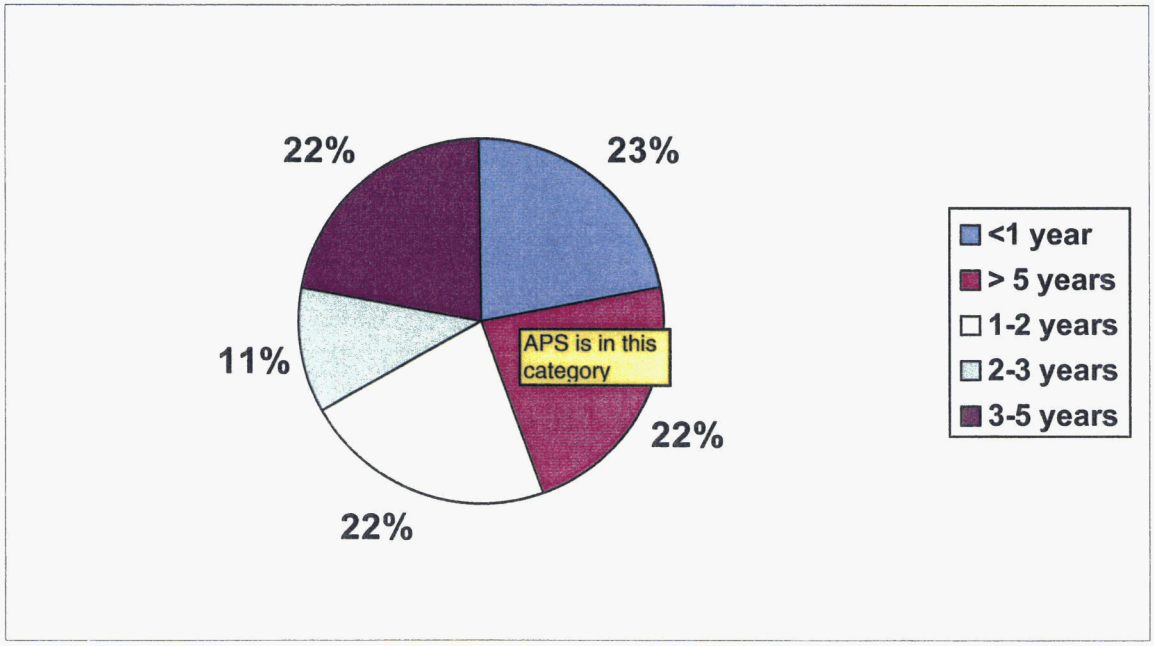
Can the target deadlines be adjusted?



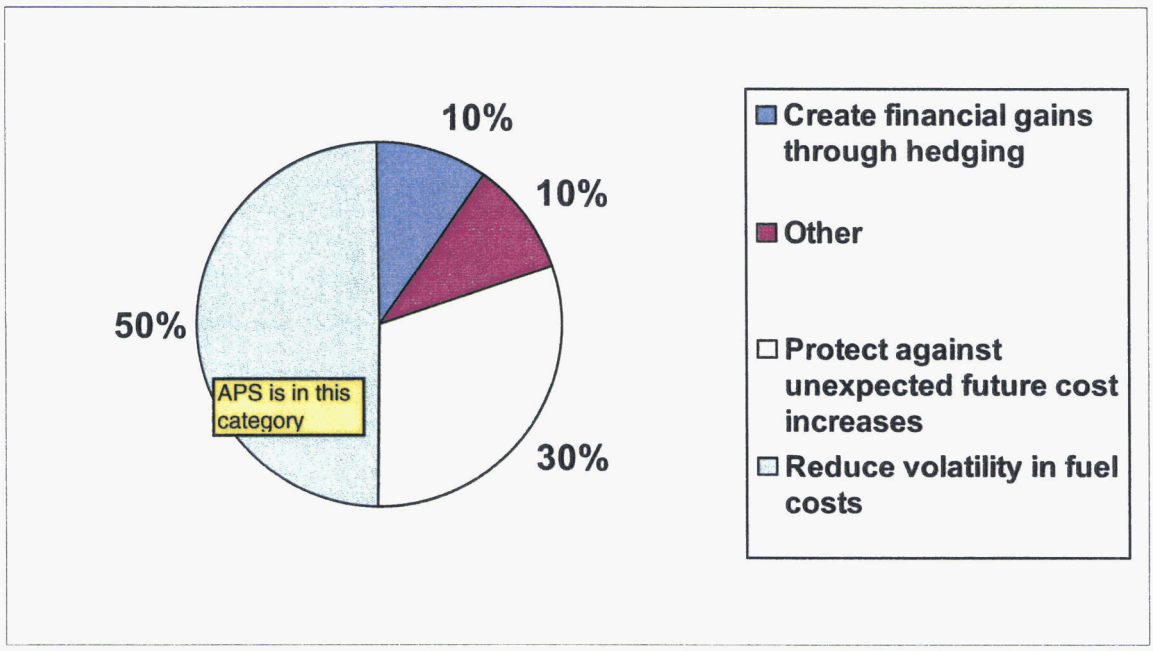
If your hedge program has target deadlines, what individuals/departments ensure they are complied with?



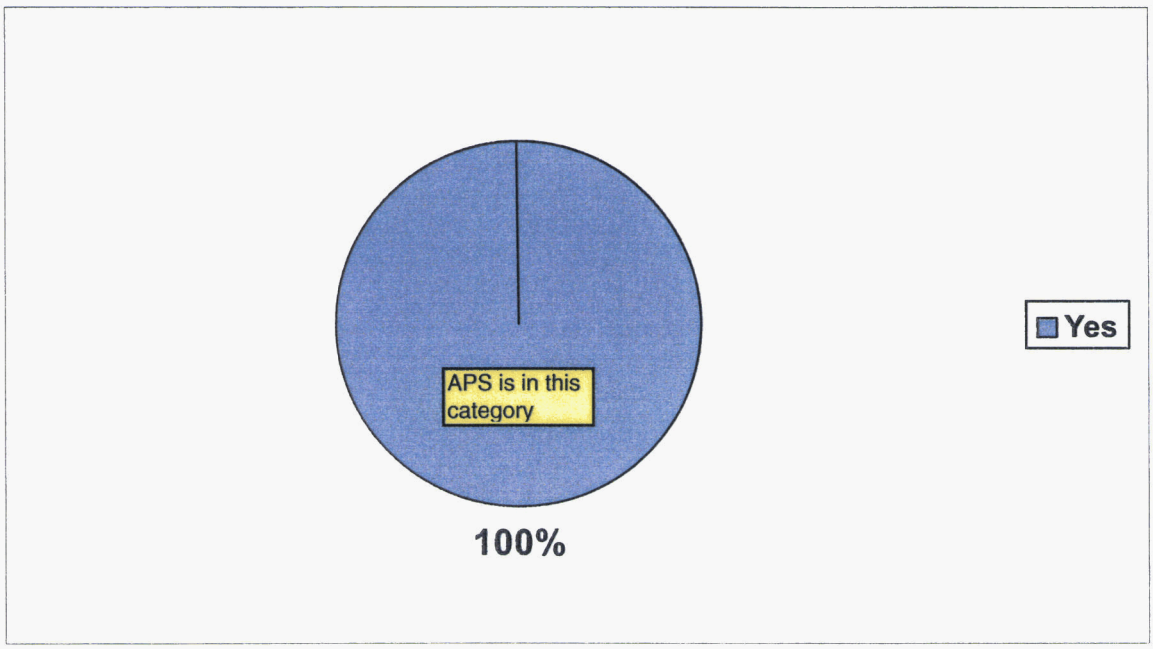
How long has the hedge plan been in place?



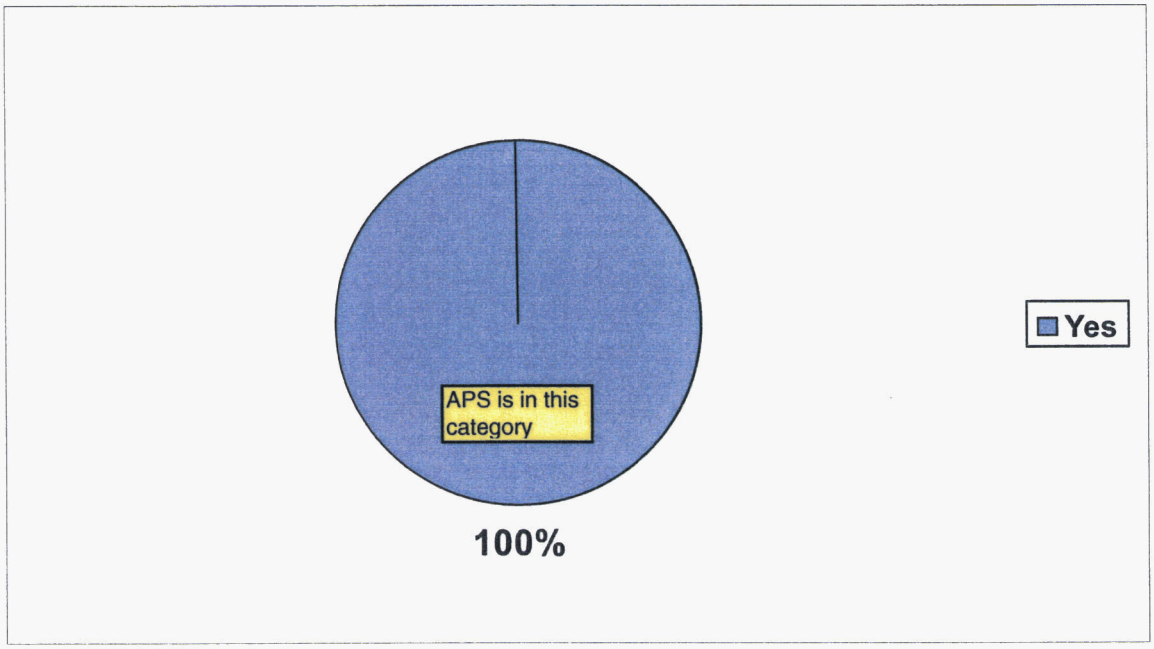
What is the most important goal of your energy hedging program?



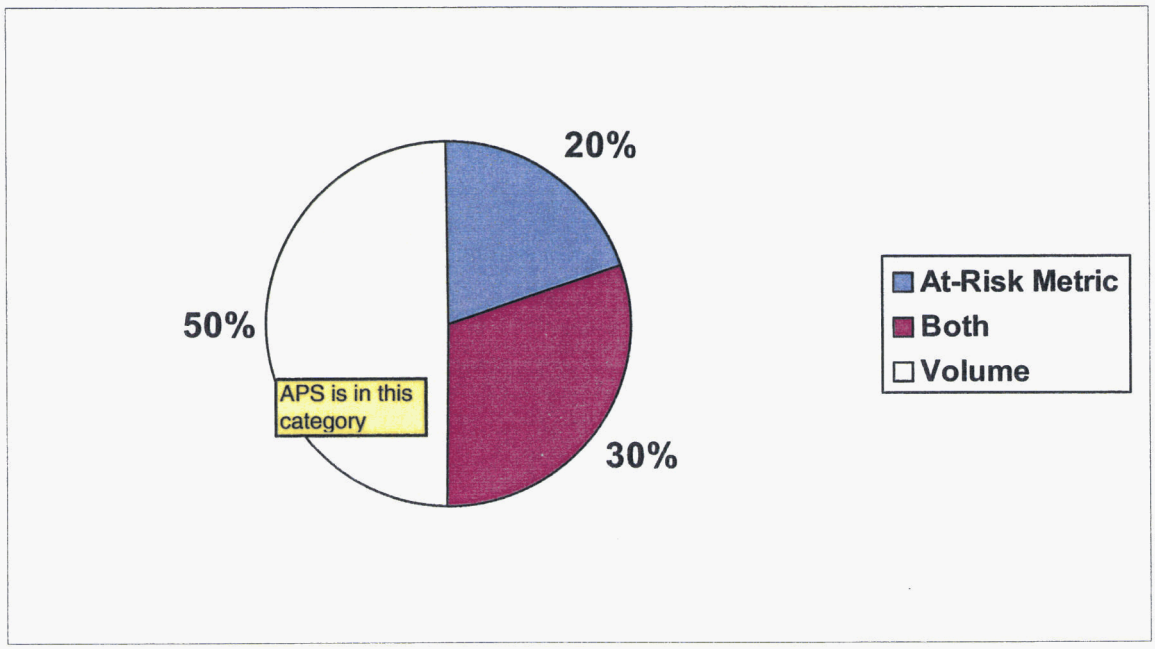
Have your hedges been effective in achieving this goal?



Do you regularly calculate and update the mark-to-market value of your hedges?



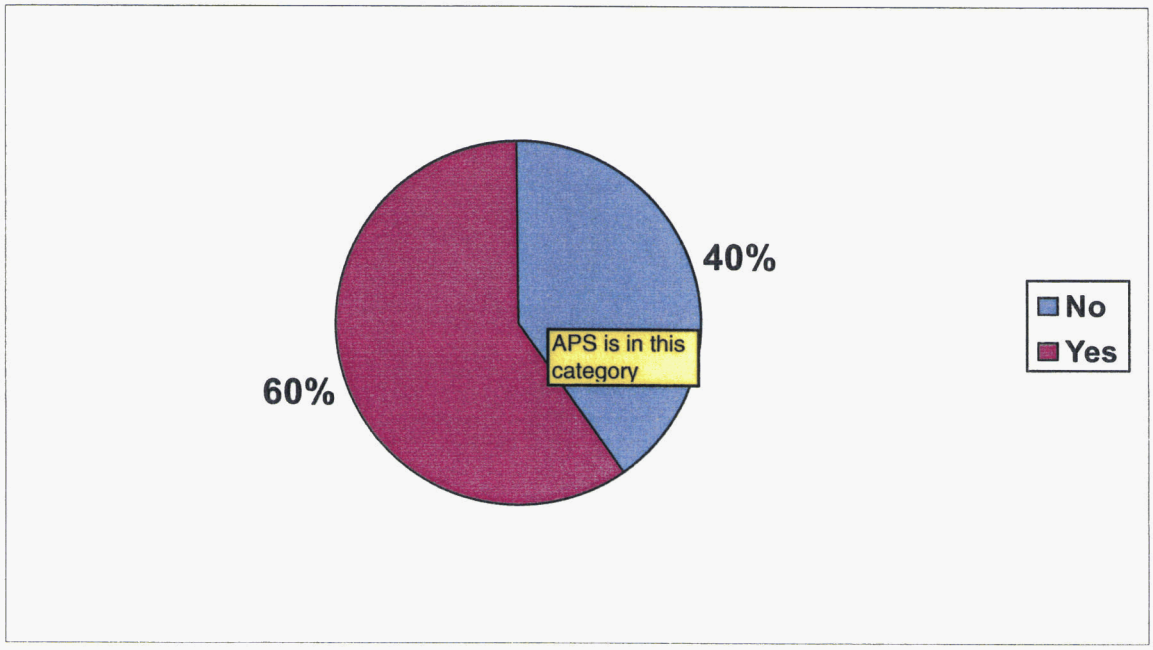
Is your hedging program primarily tied to an at-risk metric (e.g. VaR, CFaR, etc.) or to volume?



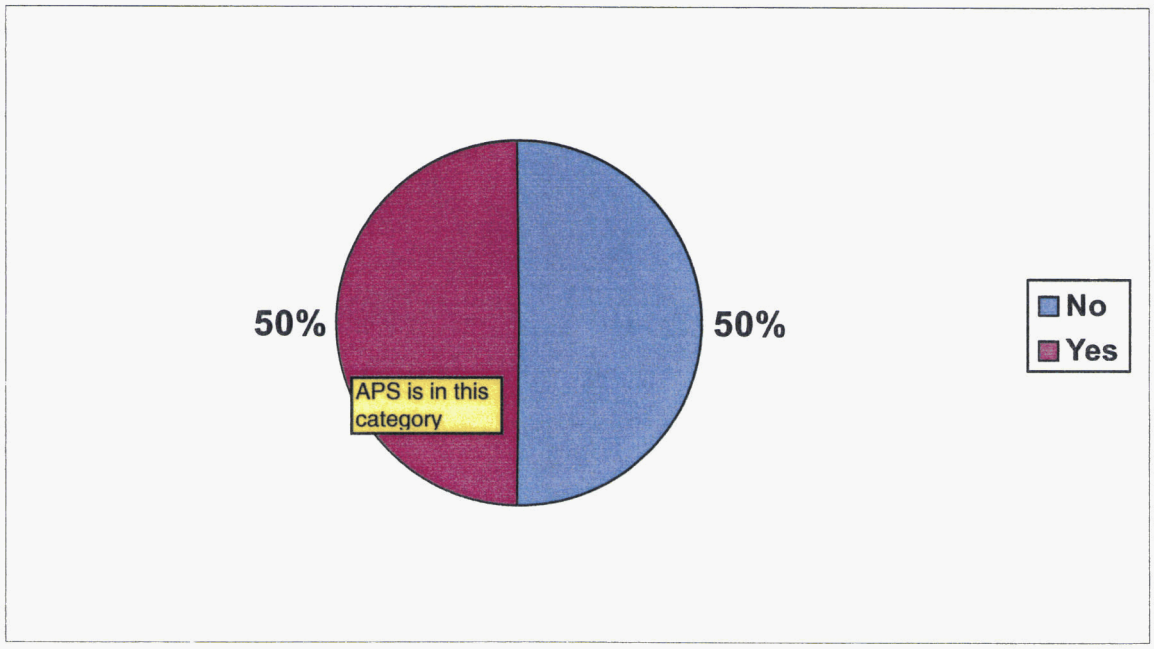
How do you analyze and document hedge effectiveness? Please describe.

Company A	We primarily look at changes in stress test levels, and MTM value of hedge.
Company B	Ongoing analysis of overall P&L, and instrument P&L, forecast hedge levels vs. actual (forecast error), annual external review to include strategy elements
Company C	Results are reviewed. Hedging is for price certainity, not speculation.
Company E	Don't currently
Company G	Mark to market
Company H	performance within limits, expected versus actuals
Company J	We do not have an established method for analyzing and documenting hedge effectiveness. We do not use "hedge accounting" under FAS 133
Company K	Prepare an annual report on strategy compliance and effectiveness.

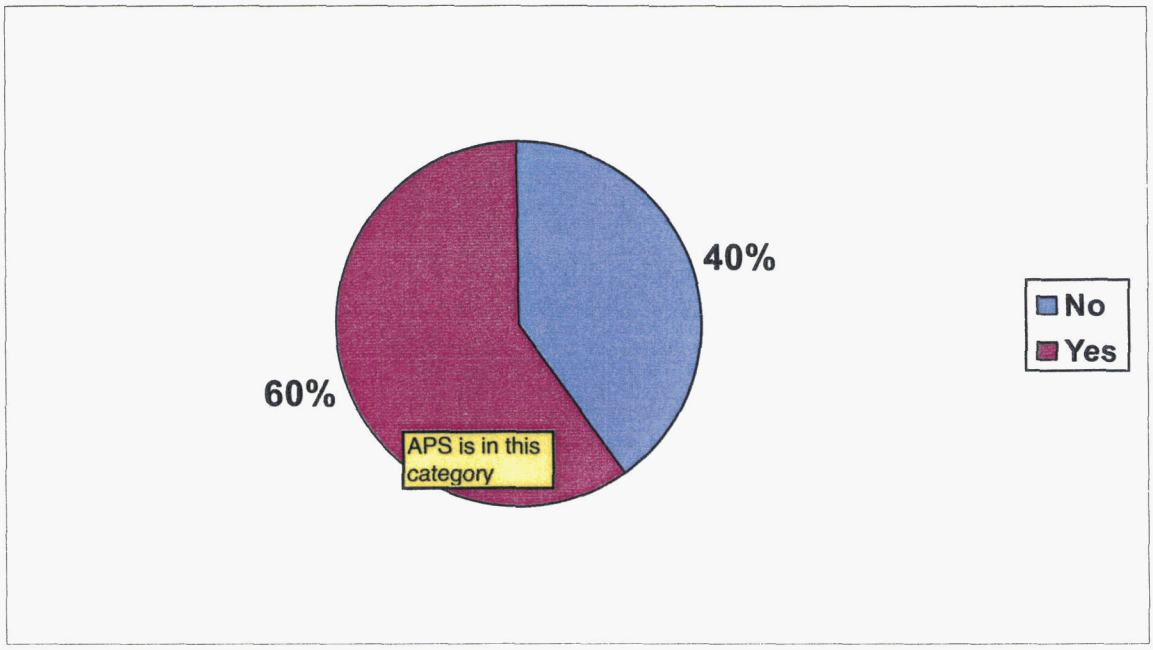
Is your Front Office allowed to execute discretion regarding the quantity and timing of hedge transactions?



After a hedging transaction has been placed, does the Front Office have the authority to liquidate the position?



Does your hedge program allow you to optimize your fuel mix in order to reduce costs?



What level of trader discretion is allowed when optimizing fuel mix to reduce fuel costs?

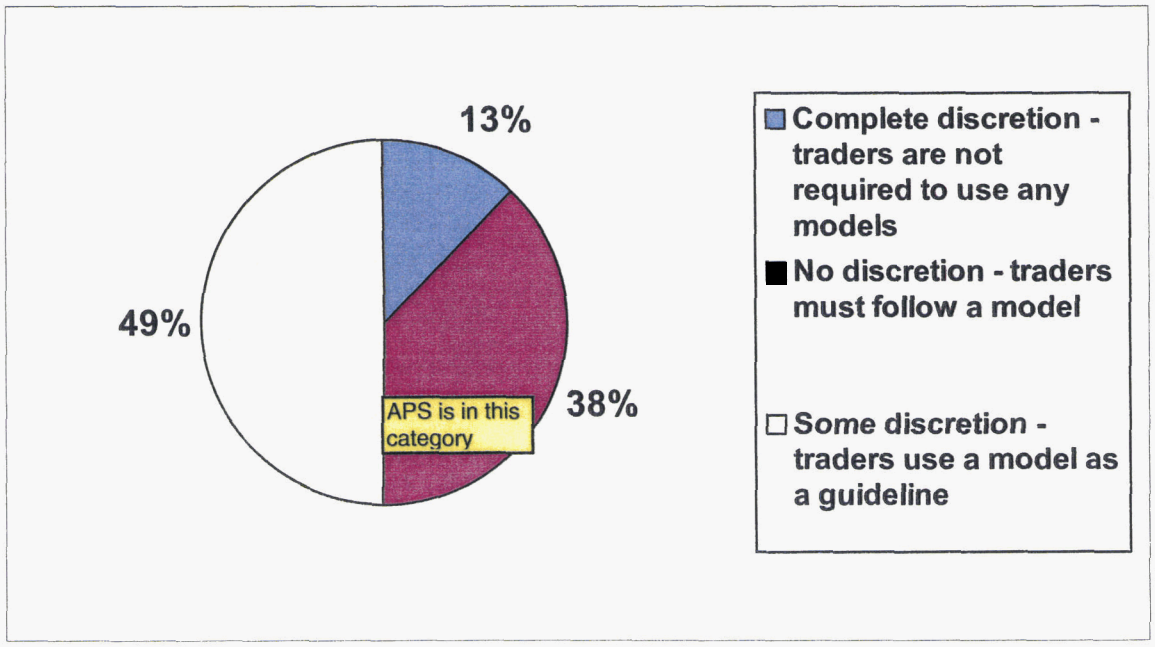


EXHIBIT
APS-73
admitted

ARIZONA PUBLIC SERVICE COMPANY
RES Surcharge Calculations for Impacts of Uncollected Fixed Costs under Net Metering
Prepared in Response to Commissioner Mayes request 10/30/06

Year	Retail Sales (GWh)	Estimated Dist. Gen. Requirement (GWh) [1,2]	Total Uncollected Fixed Costs at $0.04/kWh [3]	Uncollected Fixed Costs Recovered From RES [4]	Uncollected Fixed Costs Recovered From Base Rates [4]	Estimated Total RES Revenue [5]	RES Funds Available After Uncollected Fixed Costs
2007	28,740	22	$ 880,000	$ 880,000	$ -	$ 29,123,924	$ 28,243,924
2008	29,602	52	$ 2,080,000	$ 2,080,000	$ -	$ 30,279,676	$ 28,199,676
2009	30,490	91	$ 3,640,000	$ -	$ 3,640,000	$ 31,413,319	$ 31,413,319
2010	31,405	157	$ 6,280,000	$ 2,640,000	$ 3,640,000	$ 32,513,221	$ 29,873,221
2011	32,347	243	$ 9,720,000	$ 6,080,000	$ 3,640,000	$ 33,586,356	$ 27,506,356
2012	33,317	350	$ 14,000,000	$ -	$ 14,000,000	$ 34,571,720	$ 34,571,720
2013	34,317	412	$ 16,480,000	$ 2,480,000	$ 14,000,000	$ 35,533,433	$ 33,053,433
2014	35,346	477	$ 19,080,000	$ 5,080,000	$ 14,000,000	$ 36,486,687	$ 31,406,687
2015	36,407	546	$ 21,840,000	$ -	$ 21,840,000	$ 37,428,809	$ 37,428,809
2016	37,499	675	$ 27,000,000	$ 5,160,000	$ 21,840,000	$ 38,386,702	$ 33,226,702
2017	38,624	811	$ 32,440,000	$ 10,600,000	$ 21,840,000	$ 39,329,965	$ 28,729,965
2018	39,782	955	$ 38,200,000	$ -	$ 38,200,000	$ 40,250,898	$ 40,250,898
2019	40,976	1,106	$ 44,240,000	$ 6,040,000	$ 38,200,000	$ 41,181,516	$ 35,141,516
2020	42,205	1,266	$ 50,640,000	$ 12,440,000	$ 38,200,000	$ 42,105,040	$ 29,665,040
2021	43,471	1,435	$ 57,400,000	$ -	$ 57,400,000	$ 43,009,234	$ 43,009,234
2022	44,776	1,612	$ 64,480,000	$ 7,080,000	$ 57,400,000	$ 43,886,605	$ 36,806,605
2023	46,119	1,799	$ 71,960,000	$ 14,560,000	$ 57,400,000	$ 44,737,188	$ 30,177,188
2024	47,502	1,995	$ 79,800,000	$ -	$ 79,800,000	$ 45,603,445	$ 45,603,445
2025	48,927	2,202	$ 88,080,000	$ 8,280,000	$ 79,800,000	$ 46,439,706	$ 38,159,706

Notes:

1: Assumes RES Target DG requirement kWh attained entirely from net metered customers.
2: Assumes growth in sales as provided within the RES DG requirement.
3: Assumes fixed costs do not increase on a kWh basis over the period.
4: Assumes general rate case every third year, Uncollected Fixed Costs from RES reset to zero, and previous years Uncollected Fixed Costs rolled into Base Rates for recovery.
5: Assumes the following Caps and Charges based on APS version of the Sample Tariff:

	Cap	Rate per kWh
Residential	$ 1.33	$ 0.003325
C&I <3MW	$ 49.40	$ 0.003325
C&I >3MW	$ 148.20	$ 0.003325

ARIZONA PUBLIC SERVICE COMPANY
RES Surcharge Calculations for Impacts of Uncollected Fixed Costs under Net Metering
Prepared in Response to Commissioner Mayes request 10/30/06

2018 Incremental Increase to RES Caps and Surcharges for Uncollected Fixed Costs:

	APS Sample Rate Schedule		Projected Rate Schedule**		Increase	
	Cap	Rate per kWh	Cap	Rate per kWh	Cap	Rate per kWh
Residential	$ 1.33	$ 0.003325	$ 2.59	$ 0.006480	$ 1.26	$ 0.003155
C&I <3MW	$ 49.40	$ 0.003325	$ 96.28	$ 0.006480	$ 46.88	$ 0.003155
C&I >3MW	$ 148.20	$ 0.003325	$ 288.84	$ 0.006480	$ 140.64	$ 0.003155

** Projected Caps and Charges only include increases for Uncollected Fixed Costs. Increases in actual RES Program Costs are not included. Uncollected Fixed Costs are not included in Base Rates during General Rate Increases.

EXHIBIT
APS-74
admitted

APS Exhibit 74
Submitted 12/1/06

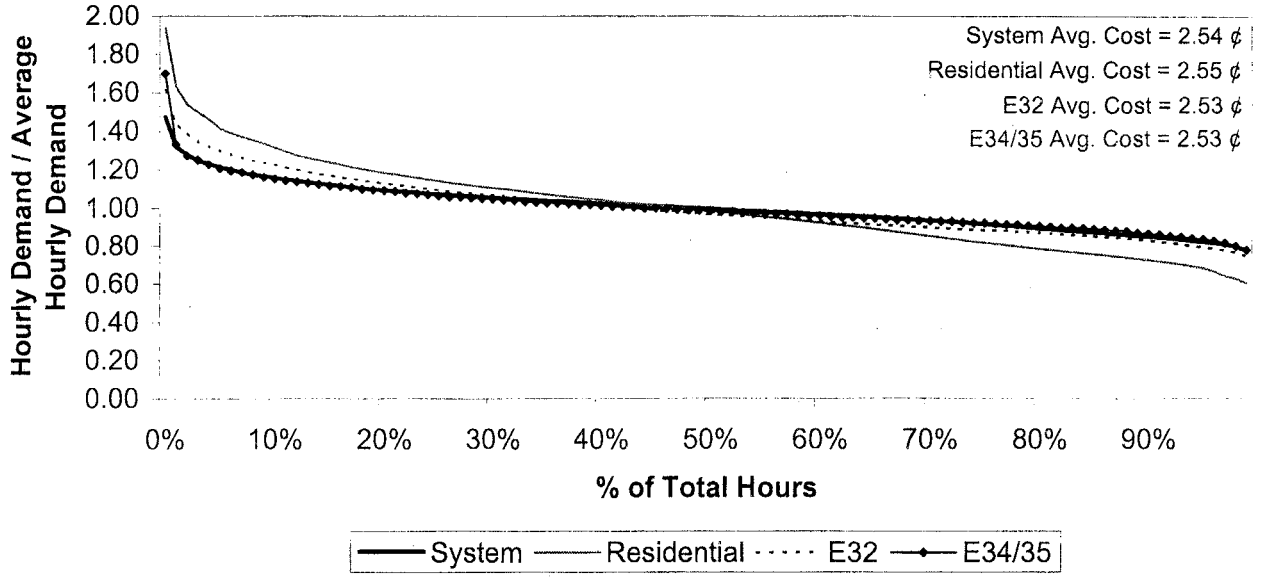
The attached graphs are being provided pursuant to a request by Commission Gleason:

Tables 1a and 2a are load duration curves by major load class, by rate season. Additionally, they indicate the volume-weighted average variable fuel cost by major load class, by rate season, which results from the application of each class's load shape to the system average variable fuel costs described below. The load shapes are from the TYE 9/30/05, and are scaled to fit energy amounts in the adjusted fuel expense estimate. The load shapes are normalized so that each class's average load = 1.0.

Tables 1b and 2b are system average variable fuel cost duration curves by rate season. The average cost duration curves portray hourly production costs with credits for hourly off system sales. Average hourly fuel costs are those provided in Response to Data Request AECC 2-4. Fixed fuel expenses that do not vary with production are not included.

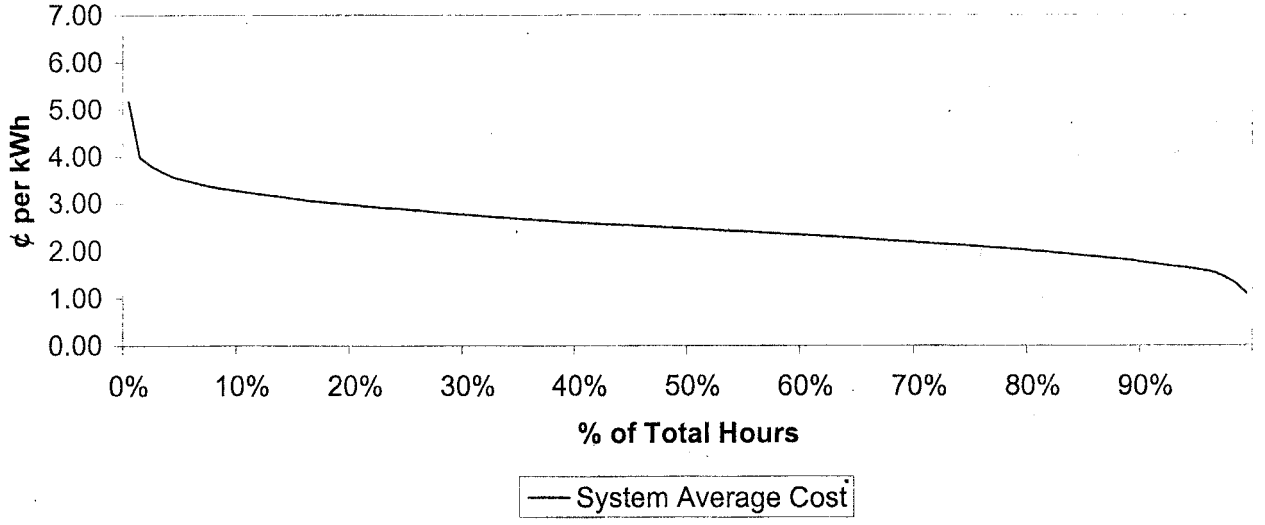
Load Duration Curves for Winter Hourly Demand

Table 2a



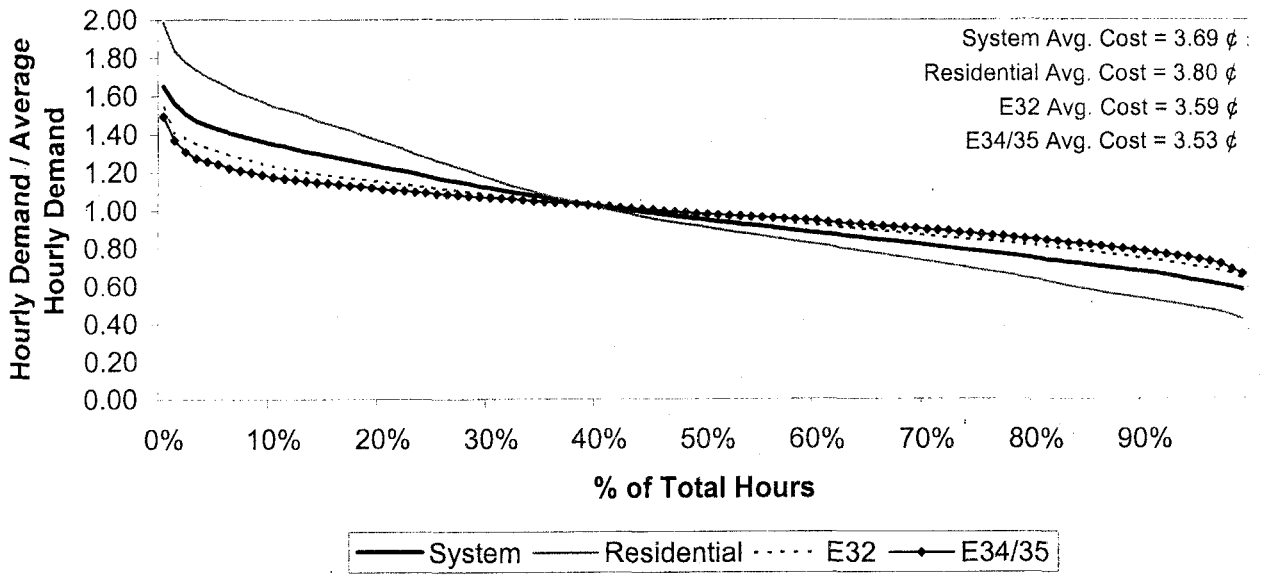
System Average Cost Duration Curve Winter

Table 2b



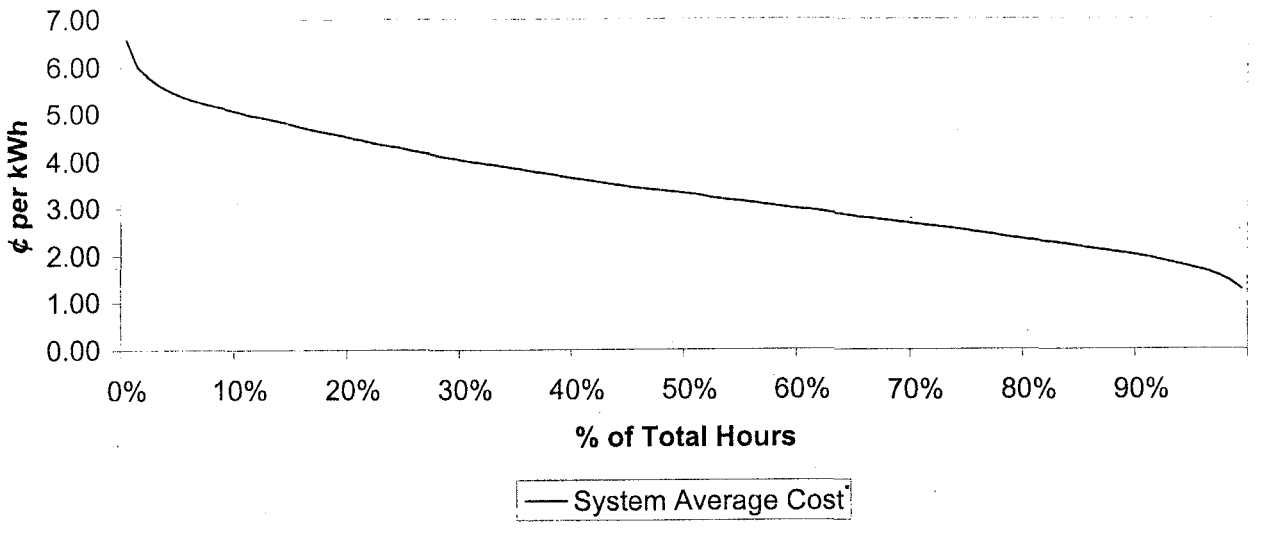
Load Duration Curves for Summer Hourly Demand

Table 1a



System Average Cost Duration Curve Summer

Table 1b



Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
PENSION EXPENSE ADJUSTMENT
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LLR_WP12RB

LINE NO.	DESCRIPTION	REFERENCE		AMOUNT (000s)	
	(A)	(B)		(C)	
1	Reversal of APS' Proposed Total Company	APS Exhibits			Revised
2	Adjustment to Amortize the Unfunded Projected	Sch. C-2, page 7			
3	Benefit Obligation Over a Five Year Period	Adj't No. 21	$	(43,695)	
4	Total Company Monthly Accrual for Pension				
5	Expense in 2006	UTI-7-258		2,784	—
6	Annualized 2006 Total Company Pension Expense	Line 5 * 12	WP1 a)	33,408	26,548
7	Test Year Actual Recorded Pension Expense	UTI-7-258		(23,484)	(23,484)
8	Pension Expense Adjustment Included Within APS'	LLR_WP21,			
9	Payroll Annualization Adjustment 2005 Adj ONLY	page 34	*	(1,769)	(815)
10	Subtotal:	Sum Lines 6 - 9		8,155	2,249
11	Net Total Company Adjustment to APS' Proposed				
12	Level of Pension Expense	Line 3 + Line 10		(35,540)	(41,446)
13	Composite ACC Jurisdictional Wages				
14	and Salaries Allocator			94.212%	—
15	ACC Jurisdictional Adjustment to APS' Proposed				
16	ACC Jurisdictional Pension Expense	Line 12 * Line 14	$	(33,483)	(39,047)

UPDATE TO DITTMER = (912) in PENSION / OPEB.

* 1,769 WP6 a)
× 46.07% APS % to ACC WP4 a)
815

• UPDATED 2006 WITH CURRENT INFO
(*) DITTMER [illegible] PENSION/OPEB.
SIB - JUST SAM

EXHIBIT
APS-75
admitted

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
POST RETIREMENT MEDICAL BENEFITS ADJUSTMENT
FOR THE TEST YEAR ENDED SEPTEMBER 2005

Schedule C-7
Page 1 of 1

LLR_WP13RB

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT (000s)	
	(A)	(B)	(C)	
				Revised
1	Monthly Post Retirement Medical Benefits			
2	Expense Being Accrued in 2006	UTI-7-259	$ 1,423	—
3	Annualized 2006 PRMB Expense	Line 2 • 12	17,076	11,298
4	Less: Test Year Actual PRMB Expense	UTI-7-259	(14,020)	<14,020>
5	APS PRMB Expense Annualization			
6	Adjustment Included as Part of the	LLR_WP21,		
7	Payroll Expense Annualization	page 34	(1,018)	(469)
8	Net Total Company PRMB Adjustment to Annualize			
9	Expenses for 2006 Actuarial Estimates	Sum Lines 3 - 7	2,038	<3,191>
10	Composite ACC Jurisdictional Wages			
11	and Salaries Allocator		94.212%	—
12	ACC Jurisdictional Adjustment to APS' Proposed			
13	ACC Jurisdictional Pension Expense	Line 9 • Line 11	$ 1,920	<3,006>

1,018 WPL b)
× 46.07% APS % to OCM WP4 a)
469

EXHIBIT
APS-76
admitted

EXHIBIT
APS-77
admitted

PINNACLE WEST
CAPITAL CORPORATION
LAW DEPARTMENT

Thomas L. Mumaw
Senior Attorney
(602) 250-2052
Direct Line

November 28, 2006

Jeff Hatch-Miller, Chairman
ARIZONA CORPORATION COMMISSION
1200 West Washington
Phoenix, Arizona 85007-2996

Re: Arizona Public Service Company General Rate Case
Docket Nos. E-01345A-05-0816, E-01345A-05-0826, E-01345A-05-0827

Dear Chairman Hatch-Miller:

This is in response to your letter dated October 24, 2006, wherein you requested that APS address several inquiries, most of which aim at exploring how the Company will meet its obligations to serve its rapidly growing customer base in a fiscally prudent and economically sound manner. As your letter indicates, APS faces a host of arduous challenges over the next several years. Your concerns about:

1. system reliability,
2. power supply adequacy,
3. the ability to meet load growth,
4. the maintenance of or improvement of credit ratings, and
5. APS' ability to earn its allowed return on equity,

highlight the serious issues that confront APS.

RESOURCE PLANNING AND ACQUISITION ISSUES

Without a doubt, APS' service territory continues to experience robust growth in energy needs. By 2020, APS projects customer load requirements will increase by 4,000 MWs over the 2006 peak load. After accounting for system reserve requirements and the expiration of existing Power Purchase Agreements (PPAs), APS will need approximately 5,500 MWs of new resources to meet these projected demands.

Law Department, 400 North Fifth Street, Mail Station 8695, Phoenix, AZ 85004-3992
Phone: (602) 250-2052 · Facsimile (602) 250-3393
E-mail: Thomas.Mumaw@pinnaclewest.com

APS expects to meet this large resource need through a diverse set of future resource additions including Demand Side Management programs, renewable energy resources, PPAs with merchant generators and, if appropriate, new peaking and base load generation. As part of the resource acquisition process, APS is currently in the process of evaluating bids from a base load RFP which was issued in January, 2006. A decision on the final selection is expected in the first or second quarter of 2007. Additionally, APS has a request before the Commission to allow for self-build of peaking capacity in Yuma with an in-service date prior to the summer of 2008.

Your letter raises another important issue that the affected parties had attempted to resolve in past proceedings: the limited self-build moratorium. The Company believes that the intent of the moratorium, which is predominantly to ensure that APS engages the competitive wholesale market in its resource acquisition efforts, is constructive, and APS wholeheartedly embraces that objective. APS has seen this provision work effectively for the Company's customers in the past year with the procurement of approximately 1,300 MW of long-term resources through the Renewable and Reliability RFPs. However, there may be circumstances where the most beneficial, perhaps even the only, procurement falls into the category of "self-build." "Self-build" necessitates that APS seek approval from the Commission prior to making any resource commitments either on the Company's own behalf or in furtherance of a merchant turn-key project. To assure continued reliable service, in these instances the Commission must strive to make this approval process as timely as possible.

Investment in transmission assets will accompany many of these future resource additions. Moreover, because APS cannot locate many of these resources close to the Phoenix metropolitan area, we will make substantial new investments in transmission facilities to move the remotely-generated power to the load consuming areas. APS' filed 10-year Transmission Plan describes the currently scheduled in-state transmission lines, and this plan will be updated annually as new projects are identified. In addition, the Company has previously advised the Commission of its involvement in the development of the TransWest Express Project, a Wyoming to Arizona line that could bring power from coal and renewable resources to the Southwest.

APS' Vice President of Planning, Mr. Don Robinson will be available to testify about resource planning issues during the latter part of the week of December 4th should the Commissioners or any of the parties have resource planning related questions.

FINANCIAL ISSUES

Underlying, and intertwined with all of these issues, remains the inescapable fact that APS must invest heavily in critical infrastructure over the next 10-year period. APS must budget $14.7 billion in capital expenditures over the 2007 through 2016 timeframe alone, including $4.4 billion over just the next five years. These capital expenditure amounts reflect the additional generation resources that APS customers will require, for which APS must have the financial strength to shoulder the burden of $6 billion, whether by direct APS investment or investment by merchant power generators on behalf of

Law Department, 400 North Fifth Street, Mail Station 8695, Phoenix, AZ 85004-3992
Phone: (602) 250-2052 · Facsimile (602) 250-3393 · E-mail: Thomas.Mumaw@pinnaclewest.com

APS (for which the credit rating agencies impute a debt obligation). Already planned Arizona-based transmission assets, excluding any TransWest Express commitments (which alone could total between $1 billion and $2 billion), will surpass $2 billion over those 10 years. Financings in the capital markets of up to $8 billion will only add to these increasing financial pressures. Of necessity, APS' capital expenditure program, and its ability to finance the program in the capital markets is highly dependent on the adequacy of rate levels

In order for APS to meet its service obligations and to serve its customer base efficiently, the Company must work together with the Commission and other affected parties to improve APS' creditworthiness. As APS has stated consistently throughout the last several regulatory proceedings, the credit rating agencies (Standard & Poor's and Moody's), examine our financial ratios, business results and regulatory environment before assigning a rating to APS debt. Access to capital markets and our interest costs, a significant component of the cost of service, depend on these ratings. The lower the ratings, the higher costs and the greater the constraints on the Company's ability to serve its customers, and conversely, improved ratings would both reduce the ultimate cost of service to APS customers and allow for greater flexibility in financing the capital additions and improvements necessary to provide that service.

APS will now more specifically respond to the financial issues raised in your letter:

1. Sufficient operational cash flow, as you have termed it in your letter, has a direct effect on the important FFO to Total Debt credit metric. At the end of the day, we have to generate enough cash from our business to pay the costs of capital and construction, and provide the necessary security to the Company's lenders. APS' proposal for the Commission to consider accelerated depreciation would increase cash flow by $50 million per year and correspondingly improve the Company's credit metrics while having no effect on earnings. It would also reduce future customer revenue requirements by providing a dollar-for-dollar reduction of the Company's future rate base for which customers would have to provide a return on and a return of capital.

2. Construction Work In Progress (CWIP) in rate base could constitute another element in a sound regulatory foundation. Should the Commission allow the inclusion of CWIP in rate base, APS would benefit from additional cash flow which, in turn, would help to finance the Company's massive construction program. This, too, would have no material effect on earnings because APS would reduce by a similar amount its allowance for funds used during construction ("AFUDC"). Similar to accelerated depreciation, and for the same reasons, inclusion of CWIP reduces future customer revenue requirements.

Law Department, 400 North Fifth Street, Mail Station 8695, Phoenix, AZ 85004-3992
Phone: (602) 250-2052 · Facsimile (602) 250-3393 · E-mail: Thomas.Mumaw@pinnaclewest.com

3. Granting APS an attrition adjustment designed to mitigate the earnings erosion due to the lag in recovering capital expenditures in a period of higher per customer costs would benefit the Company and its customers in a number of ways:

   a. Initially, it would signal to the rating agencies a supportive regulatory environment.

   b. Secondly, APS would have a reasonable opportunity (still far from a guarantee) to earn its allowed return on equity.

   c. Thirdly, potential equity investors would recognize the improvement in our ROE status and demonstrate a greater willingness to purchase our offerings of equity on reasonable terms.

In light of the magnitude of the Company's construction program, we must have cost-effective access to the equity markets to maintain a reasonably balanced capital structure. If not, the rating agencies will use that fact alone to plunge APS into junk territory. Equity investors always examine a Company's ROE and gain comfort from the higher interest coverage ratios that flow from a higher ROE. By the same token, equity investors know of a regulated utility's recent history of under-earning its allowed ROE, and, as Mr. Brandt explained in his testimony several weeks ago, APS has substantially under-earned its current allowed ROE over the last several years. The amount of under-earnings was shown in Mr. Brandt's rebuttal testimony, Attachment DEB-10RB, page 4. This arises from the earnings attrition resulting from the Company's significant capital expenditure obligations, which attrition occurs despite additional sales growth. As demonstrated in APS Exhibit 59, submitted on November 3, 2006, the required investment per customer in the 2007-2008 timeframe is nearly double the amount currently reflected in the test year.

You inquired in your letter if APS would be able to attain its authorized ROE, excluding cost recovery for fuel and purchased power. The answer is no. Even with timely recovery of fuel and purchased power costs though the PSA, the cost of new construction exceeds the annual revenue from customer growth. Attachment 1 to this letter, which was prepared in response to an earlier request from Commissioner Gleason, shows that the annual non-fuel related revenue from growth is some $86 million <u>short</u> of the annual increase in revenue requirement needed to meet that customer demand.

Regulatory lag compounded by the magnitude of our construction program has in the past, as it will in the future, virtually guarantee that APS will be unable to earn its allowed ROE. An attrition adjustment would help remedy the serious issues that flow from a massive construction program attributable to a relentlessly growing service territory.

None of these proposals, previously discussed in the Company's response to your July 2006 letter and in consideration of the revenue requirement recommendations of Staff and RUCO (which call for a

Law Department, 400 North Fifth Street, Mail Station 8695, Phoenix, AZ 85004-3992
Phone: (602) 250-2052 · Facsimile (602) 250-3393 · E-mail: Thomas.Mumaw@pinnaclewest.com

reduction in rates exclusive of fuel), is unique either to regulation in general or to Arizona regulation in particular. The Commission has allowed both CWIP and attrition allowances in prior APS rate decisions. Accelerated amortization of some $1.3 billion in regulatory assets (very analogous to our suggestion for accelerated depreciation of tangible assets, albeit on a larger scale) was a cornerstone of the 1996 settlement agreement approved by Decision No. 59601 (April 24, 1996). Even an adjustment to "fair value" rate base is solidly grounded in Arizona precedent, which clearly indicates that there is no specific formula required in the determination of "fair value" and that the cost of capital as applied to original cost is a floor for the required return on "fair value," not a ceiling.

As you note in your letter, even with the benefit of these regulatory and financial tools, we may not satisfy the rating agencies should the Company not have the ability to recover our fuel and purchased power costs in a timely manner. The rating agencies, unfortunately, look very closely at overall financial performance, and give little leeway to companies that rapidly accrue large amounts of costs which require expensive financing prior to recovery.

APS' Executive Vice President and Chief Financial Officer, Mr. Brandt, will testify during the latter part of the week of December 4th and will be available to respond to any of the above financial matters.

Sincerely,

Thomas L. Mumaw

TLM/na
Enclosure
cc: William A. Mundell, Commissioner
Mike Gleason, Commissioner
Kristin K. Mayes, Commissioner
Barry Wong, Commissioner
Parties of Record

Law Department, 400 North Fifth Street, Mail Station 8695, Phoenix, AZ 85004-3992
Phone: (602) 250-2052 · Facsimile (602) 250-3393 · E-mail: Thomas.Mumaw@pinnaclewest.com

ARIZONA PUBLIC SERVICE COMPANY
Revenue Growth Vs. Growth in Capital Related Costs

Exhibit Description: This exhibit is APS' analysis of how annual non-fuel revenue from customer growth under the current Staff proposal compares to the annual non-fuel revenue requirement due to forecast construction expenditures. This analysis shows that the total annual non-fuel revenue requirement due to forecast construction of $150 million is significantly greater than the total annual non-fuel revenue from customer growth of $64 million resulting in an annual non-fuel revenue shortfall of $86 million. In summary, revenue growth fails to meet the additional revenue requirement.

	Forecast Avg. Annual Number of New Customers 2007 - 2008		Annual Rev. [1] Per Cust. from Staff's Proposed Rates Net of Fuel		Est. Annual Rev. from Cust. Growth (Millions)	Est. Annual Rev. [2] from Cust. Growth Per Avg. Ann. MW Growth (Dollars per MW)
Annual Non-Fuel Revenue from Customer Growth						
Residential	39,864	x	$ 948	=	$ 38	
General Service	4,346	x	$ 5,967	=	$ 26	
Total Annual Revenue from Customer Growth					$ 64	$ 261,224

	Forecast Avg. Annual Construction 2007 - 2008 (Millions)		Revenue Requirement Factors		Annual Rev. Req. of Construction with Staff's Cost of Cap. (Millions)	Annual Rev. Req. of [2] Construction with Staff's Cost of Cap. Per Avg. Ann. MW Growth (Dollars per MW)
Annual Non-Fuel Rev. Req. Due to Forecast Construction [3]						
Property Tax	$ 910	x	1.14% [4]	=	$ 10	
Depreciation	$ 910	x	2.80% [5]	=	$ 25	
Interest	$ 910	x	3.41% [6]	=	$ 31	
Staff's Weighted Cost of Equity	$ 910	x	5.59% [7]	=	$ 51	
Income Tax Gross Up on Equity	$ 910	x	3.58% [7]	=	$ 33	
Total Annual Rev. Req. due to Forecast Construction					$ 150	$ 612,245
Revenue Shortfall [8]					$ (86)	$ (351,020)

[1] The annual non-fuel revenue per customer was derived by subtracting Staff's proposed base fuel amount of $0.027975/kWh from the average non-fuel revenue per kWh for the residential class ($0.09606/kWh) and the E-32 rate for the general service class ($0.08455/kWh) based on the proposed revenue increase of 9.0% shown on Staff Witness Dittmer's Surrebuttal Testimony, Pg. 23. E-32 was used because most of the Company's new general service customers will be on this rate. The energy consumption used in this analysis is the test year residential consumption of 12,362,652 MWhs (13,946 annual kWh per customer) and general service consumption of 10,879,043 MWhs (105,385 annual kWh per customer) per APS S.F.R. Schedule H-2.

[2] Calculation is based on the 2007 - 2008 average annual weather normalized peak demand growth of 245 MWs.

[3] O&M was not included.

[4] Estimated Property Taxes for 2007 divided by Total Utility Plant from 2005 FERC Form 1.

[5] The depreciation rate shown is a weighted average rate. The rate was derived by applying the Foster & Associates 2005 Technical Update depreciation rates that were included in APS witness Dr. Ronald White's Direct Testimony (Attachment REW-1, Pg. 3, Present Accrual Rates) to the 2007 - 2008 forecast construction costs.

[6] Based on 7.5% marginal cost of debt and a 45.5% debt and 54.5% equity capital structure.

[7] Based on Staff's proposed 10.25% cost of equity and a 45.5% debt and 54.5% equity capital structure.

[8] $26 million of the $86 million revenue shortfall is associated with Transmission Plant.

EXHIBIT
APS-78
admitted

U.S. Treasury Securities Interest Rates

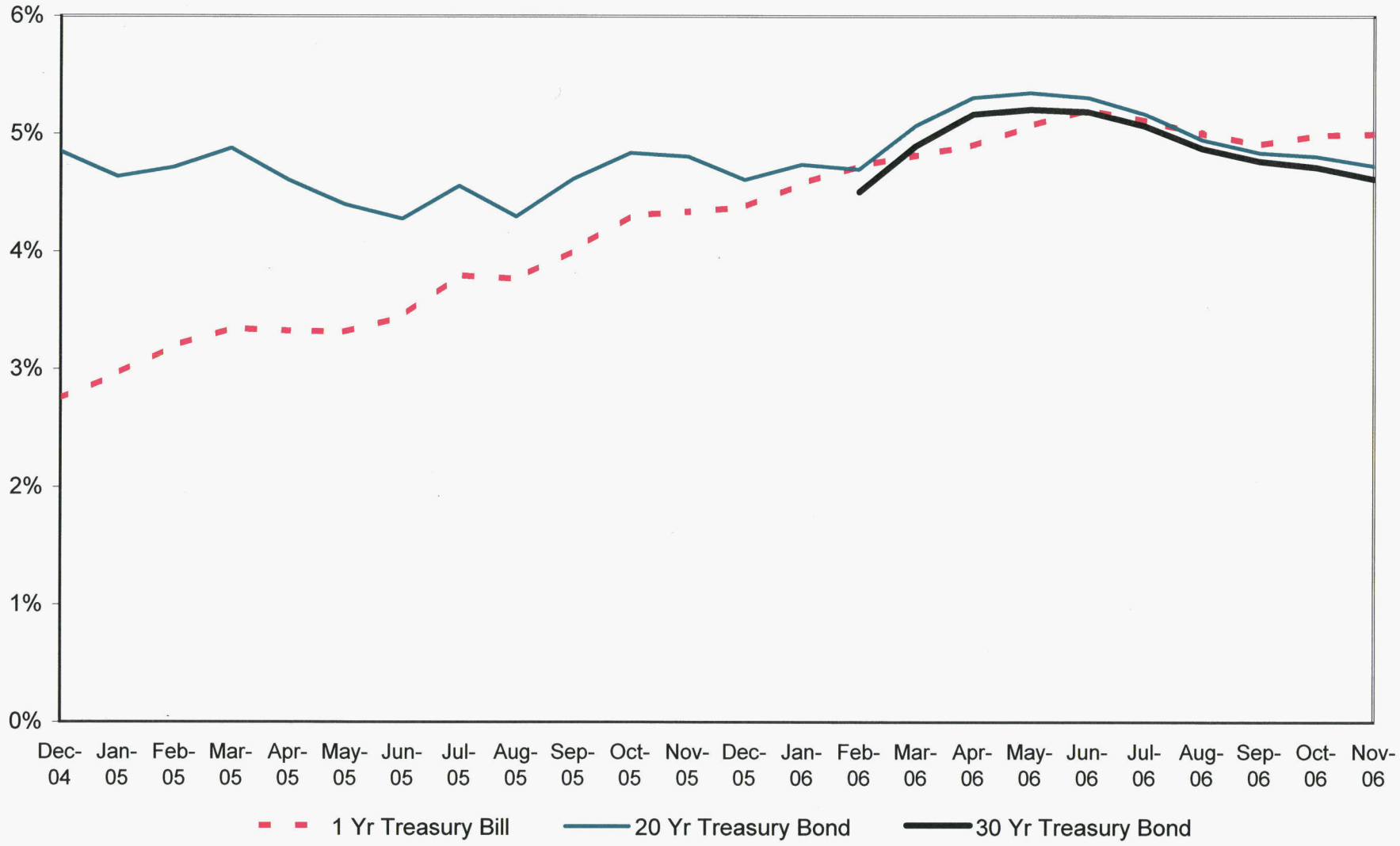
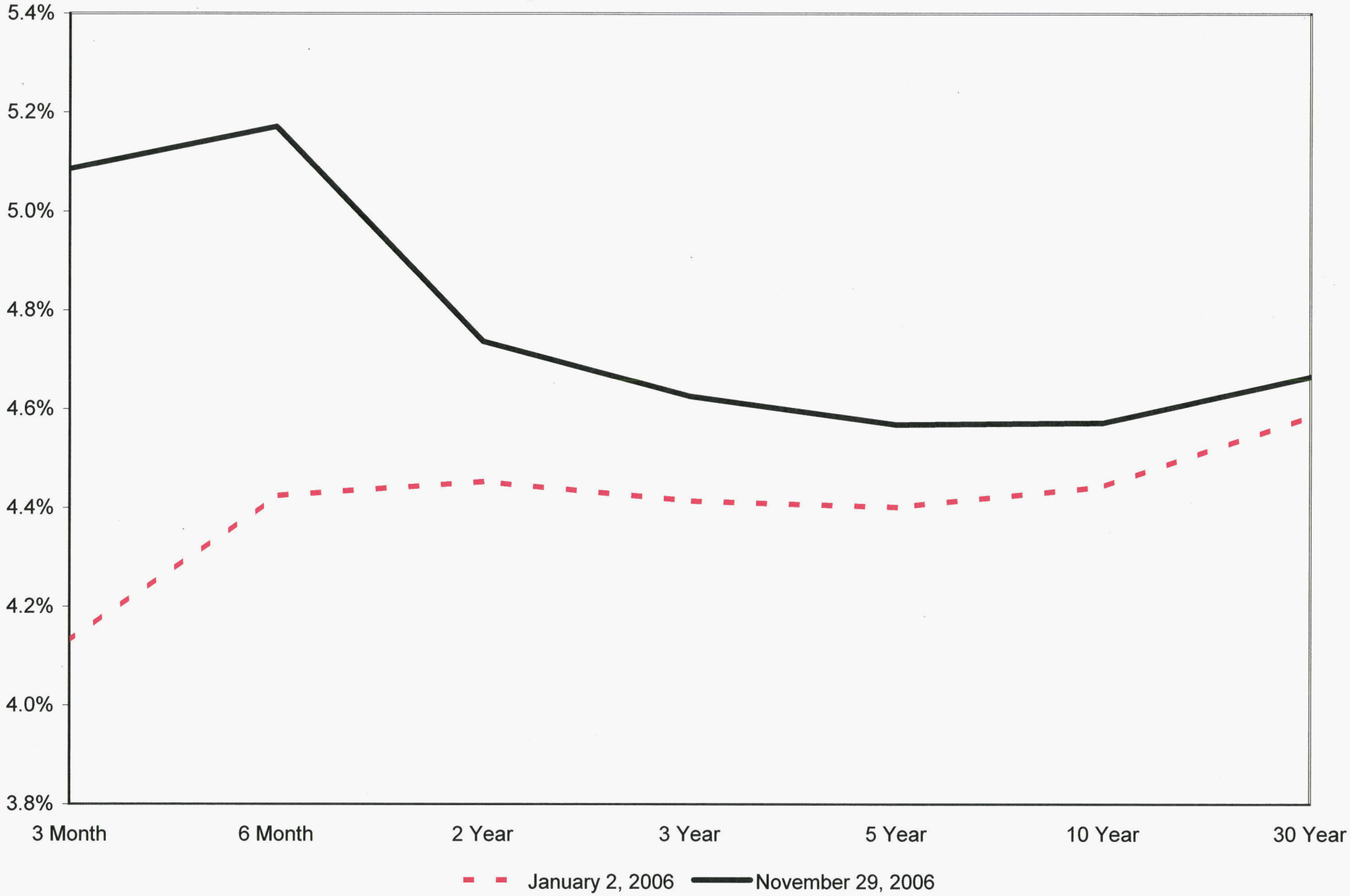


EXHIBIT
APS-29
admitted

U.S. Treasury Securities Interest Rate Yield Curve



9/30/05 Adjusted Test Year ACC Revenue Requirements from APS Rejoinder ($ in millions)

EXHIBIT
APS-80
admitted

								ACC Revenue Requirements	% Of Total ACC Revenue Requirements
Operating expenses:									
Fuel and purchased power (adjusted for revenue credits)								$ 826	32%
O&M								746	29%
Depreciation and amortization								307	12%
APS accelerated depreciation adjustment								0 to 50	
Property and other taxes								120	5%
Total operating expenses								1,999	78%
Return on rate base:									
	Cost Rate		Capitalization Ratio		Weighted Cost		ACC Rate Base		
Interest	5.41%	x	45.50%	=	2.46%	x	4,457 =	110	4%
Equity return	11.50%	x	54.50%	=	6.27%	x	4,457 =	279	11%
					8.73%				
Revenue conversion factor minus 1								x (1.6407-1)	
Income tax gross-up on equity return								174	7%
Total equity return with income tax gross-up								453	18%
Total return on rate base								563	22%
APS CWIP in rate base adjustment ($261m CWIP x 8.73% + income tax gross-up)								0 to 33	
APS attrition adjustment (0% to 4.1%)								0 to 163	
Total revenue requirements:								$ 2,562	100%

EXHIBIT
APS-81
admitted

Stock Price Comparison
24 Months Ended December 4, 2006

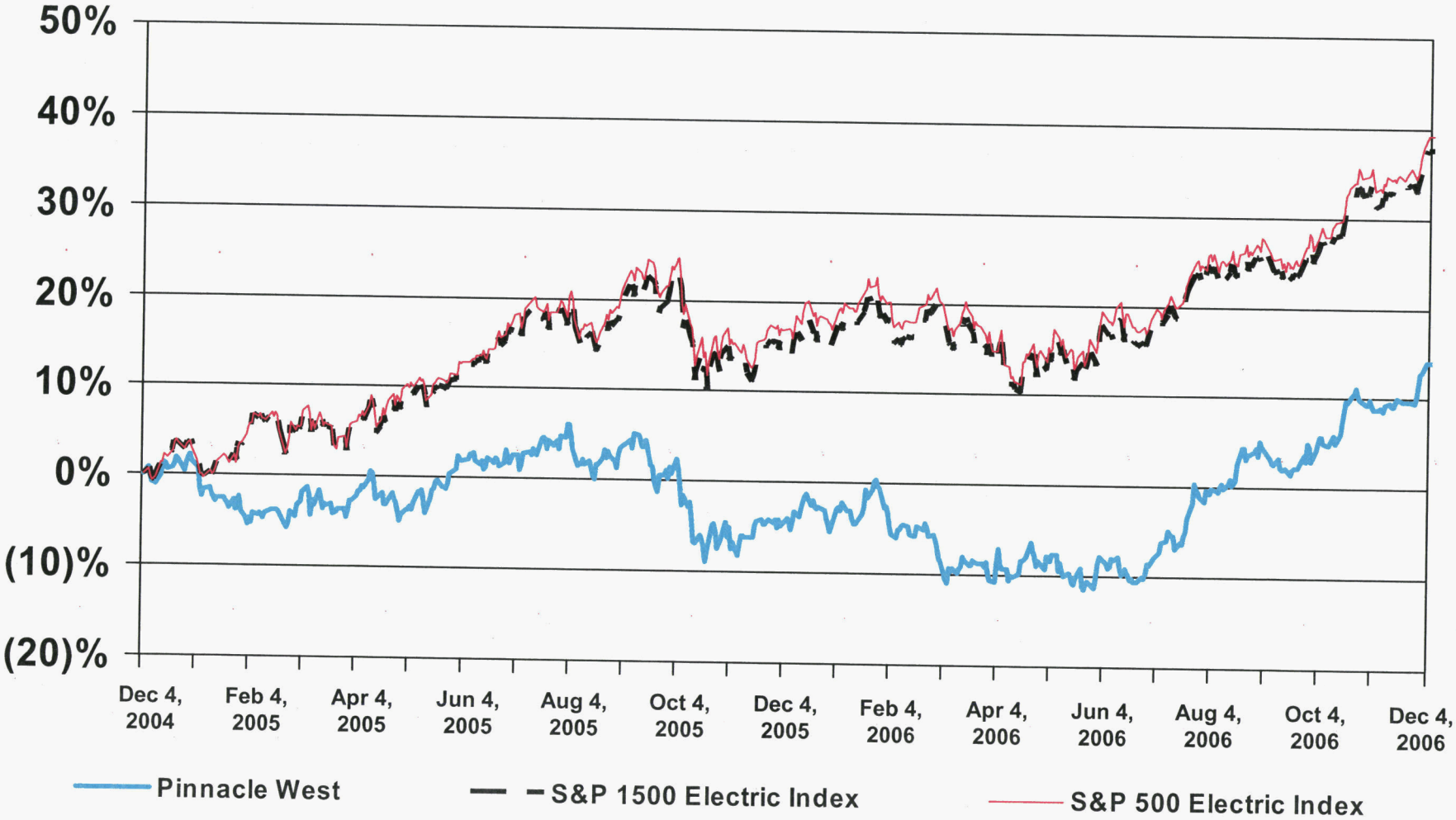
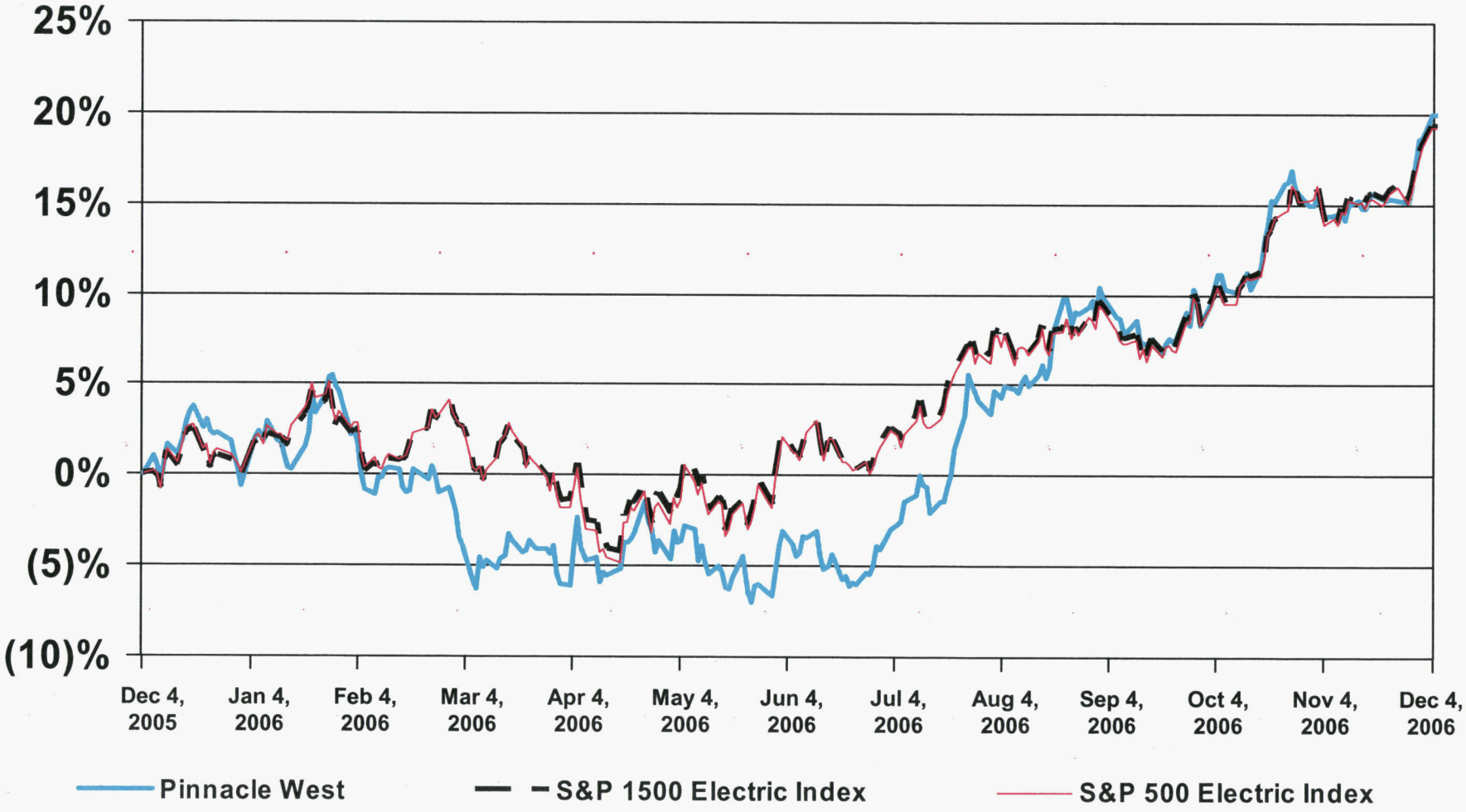


EXHIBIT
APS-82
admitted

Stock Price Comparison
12 Months Ended December 4, 2006



Return to the referring page.

Las Vegas SUN

December 17, 2005

EXHIBIT
APS-83
admitted

Bright future expected for solar project

By Kevin Rademacher <kevin.rademacher@lasvegassun.com>
Las Vegas Sun

A project that would be the largest solar power plant built anywhere in the world in the last 15 years is set to get under way next month in Boulder City.

The plant would take advantage of Southern Nevada's abundant sunlight and bring the state's largest electric utility into compliance with the solar power component of the state's aggressive renewable energy mandate through 2009.

North Carolina-based Solargenix Energy said this week that it will break ground in January on its 64-megawatt solar power plant, dubbed Nevada Solar One.

"It's moving forward very well," said John Myles, president and chief executive of Solargenix, which was still operating as Duke Solar when the project was first proposed in 2001.

Myles said construction would take 12 to 14 months. One megawatt is estimated to be enough power to serve about 750 homes. The plant is expected to cost more than $100 million.

In July the Nevada Commission on Economic Development approved more than $15 million in incentives for the project. The state deal includes about $6 million in sales and use tax abatement incentives for the $106 million in equipment needed to build the 350-acre project. Solargenix also received $9 million in property tax abatement through a program created by the 2003 Legislature to promote renewable energy development.

The company secured a lease with Boulder City in 2003 to build the plant in the Eldorado Valley.

Solargenix plans to use parabolic trough technology. In the system, mirrors will heat a fluid in order to generate steam that will power turbines used to generate power. Similar technology was used for nine power plants built in California between 1984 and 1990, said Hank Price, a senior engineer and solar trough project leader with the National Renewable Energy Laboratory in Golden, Colo.

The company that built the California plants, LUZ International, fell into bankruptcy when traditional energy prices dropped to a level below the cost of solar generation. The plants are located in Kramer Junction in the Mojave Desert and are expected to remain in operation for 15 years.

Price said the cost of energy remains an issue with solar development today, but energy prices are currently rising because of record high prices for natural gas, which is used not only for winter heating but also to fuel power plants that generate electricity for summer air-conditioning use.

"If energy prices stayed at this current level, this technology would make a lot of sense," said Price, who

has worked with Solargenix in refining some solar collection technologies. "The problem is that because of the uncertainty, it's difficult to get investment."

Price said he had little doubt that the Boulder City project would be built.

"I don't see any reason why it's not going to happen," he said. "I have no doubts that they are serious about it, and they have a lot of knowledge."

The success of the Boulder City project, he added, could be a key factor in future developments.

"This is important in terms of how people perceive this type of project in the future," Price said.

The Solargenix project also has significant ramifications for Nevada Power Co. of Las Vegas. State laws mandate that Nevada's largest electric utilities generate an increasing percentage of their power from renewable resources, peaking at 20 percent by 2015. Nevada Power and its sister utility, Sierra Pacific Power of Reno, have failed to meet the initial standards established by the Legislature.

At least one-fourth of the renewables mandated by the Legislature must come from solar power, and the Solargenix plant would bring Nevada Power into compliance with the solar piece of the mandate through 2009.

While Nevada Power has entered into contracts with developers -- including Solargenix -- to buy renewable power generated by new projects, to date none of the planned plants have been built in Southern Nevada. A major stumbling block has been financing. Developers have complained that investors are hesitant to put up capital for a plant that will sell power to a utility -- Nevada Power -- with less than perfect credit. Nevada Power had its credit rating cut to junk status amid the fallout of the Western energy crisis and the subsequent battles over hundreds of millions of dollars with the likes of Enron Corp.

Nevada Power's financial strength, however, is improving, and utility executives and developers agree that if the Solargenix project succeeds it could open the door for further activity.

"It's a very important project," said Roberto Denis, senior vice president for generation and energy supply for Sierra Pacific Resources, parent company of Nevada Power and Sierra Pacific Power.

"It's important because of the experience to be gained by putting it in service so further projects can, in fact, be successful," he added. "It will prove to other developers and financial institutions that from a business standpoint it works here."

Rebecca Wagner, energy adviser to Gov. Kenny Guinn, agreed that Solargenix could set the stage for future renewable development.

"Everyone is quick to point fingers on why projects are not happening," she said. "We need to get the project in the ground. ... I think this has the potential to get momentum going."

Gary Bailey, Southwest region managing director for Solargenix, said the company is well aware that the eyes of the industry are on its Nevada project.

"That's good," he said. "We're excited, and we're going to move forward."

Success with the project also could serve to silence the critics of renewable power projects, Bailey said.

"It proves wrong all the things people have said negatively about renewables, especially solar, for years," he said.

Local economic development officials also are keeping a close eye on Solargenix. In giving the company tax incentives to locate their project in Southern Nevada, the state Commission on Economic Development hailed the project as the beginning of a new economic engine for Nevada.

The potential for economic impact also was noticed by former President Bill Clinton, who in October challenged local business leaders to embrace the renewable industry.

"If I were the economic development czar for America today or if I were in charge of economic planning for Las Vegas and Nevada today, I would start by making a complete and total commitment to a clean energy future because I think you can create more jobs there than anywhere else," Clinton said at the Nevada Development Authority's annual meeting.

Bailey agreed that the emergence of the project could have significant implications for the state's future.

"I don't think people locally recognize how important it is," he said.

Kevin Rademacher can be reached at 259-4069 or at kevinr@lasvegassun.com.

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REBUTTAL TESTIMONY OF ROGER J. MATTSON, PH.D.

On Behalf of Arizona Public Service Company

DOCKET NO. E-01345A-05-0816

September 15, 2006

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1. QUALIFICATIONS OF ROGER MATTSON

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

A. My name is Roger J. Mattson and my business address is 2511 Fossil Trace Court, Golden, CO 80401. I am self-employed.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING AND WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am appearing on behalf of Arizona Public Service Company (APS). (A list of Acronyms is provided in Attachment RJM-1RB.) I was asked by APS to perform an independent assessment of the safety regulatory aspects of its operation of Palo Verde Nuclear Generating Station (Palo Verde) in 2005 and to describe the Nuclear Regulatory Commission's (NRC's) process for such regulation in comparison to state economic regulatory processes. APS also requested that I review its actions in connection with outages that occurred at Palo Verde during 2005 and to consider whether those actions were prudent. In particular, I have reviewed the outage of Units 2 and 3 between October 11 and 20, 2005 to address a question raised by an NRC inspector regarding the potential for air entrainment in suction piping from the refueling water tank. I have also been asked to address some of the analysis, conclusions and recommendations contained in the August 17, 2006 report of GDS Associates, Inc. (GDS), consultant to the staff of the Arizona Corporation Commission (ACC) in this proceeding.

Q. PLEASE SUMMARIZE YOUR EDUCATION, EXPERIENCE AND QUALIFICATIONS.

A. My qualifications are described in detail in a resume in Attachment RJM-2RB and summarized here. I am a mechanical engineer. I received a Ph.D. in mechanical engineering from the University of Michigan in 1972. My Bachelors and Masters Degrees are also in mechanical engineering, from the Universities of Nebraska and New Mexico, respectively. After my first job, a three year stint designing test reactors and irradiation experiments at Sandia National Laboratory in

Albuquerque, New Mexico, I served with the headquarters staff of the federal government agencies responsible for regulating the safety of nuclear power plants, the Atomic Energy Commission (AEC) and its successor, the Nuclear Regulatory Commission for most of the period from 1967 through early 1984. For a brief period in 1980 and 1981, I managed radiation protection and emergency preparedness activities in the Environmental Protection Agency (EPA). Hereinafter, the AEC and the Nuclear Regulatory Commission will be referred to as NRC.

My last seven years at the NRC were spent as Director, in succession, of three Divisions: Systems Safety, Safety Technology, and Systems Integration, in the Office of Nuclear Reactor Regulation. In those positions, I was responsible for much of the technical review of applications for construction permits, operating licenses, and license amendments for nuclear power plants. People under my supervision reviewed applications for those licensing actions in the following technical areas: reactor systems, containment systems, reactor core performance, fuel design, instrumentation and control systems, power systems, balance of plant systems, spent fuel storage, accident analysis, radiation protection, emergency preparedness, and a variety of engineering disciplines, depending on the time period, including structural design, codes and standards, seismic analysis, fire protection, and equipment qualification. I had signature authority for the technical content of safety evaluations in all of these disciplines for all plants under construction or in operation.

In various capacities, I managed development and implementation of the NRC's regulatory requirements for most of the period from 1974 to 1984. I have or persons reporting to me have performed safety reviews of all the nuclear power plants now operating in the United States, including Palo Verde.

I have continued to be involved in assuring the safety of nuclear power plant

construction, operation and decommissioning subsequent to my NRC experience. From 1984 to 1987, I worked for International Energy Associates Limited (IEAL). It was a technical services company specializing in nuclear technology with utility and government clients in the United States, Western Europe and Asia. I joined SCIENTECH, Inc. in 1987. SCIENTECH provided services in environmental protection; nuclear power plant design, operations, reliability, and maintenance; replacement of obsolete instrumentation and controls for nuclear power plants; reliability of aircraft; information systems; interactive networks; and security systems. I served as the Chief Operating Officer of both IEAL and SCIENTECH. I retired from SCIENTECH in 2002 and have worked as an independent consultant since that time.

Some of the projects in which I have been personally involved since leaving employment with the NRC are as follows:

- Co-chair of a panel to develop the International Atomic Energy Agency's Safety Principles for nuclear power plants (INSAG-3) after the accident at Chernobyl in the former Soviet Union;
- Reviews of advanced reactors for the Department of Energy (DOE), including advanced light water reactors being developed by Westinghouse and General Electric Companies, the gas-cooled Next Generation Nuclear Plant, the New Production Reactor and the fast burner reactors recently proposed for the President's Global Nuclear Energy Project;
- Reviews of combined operating license applications for advanced nuclear power plants co-funded by DOE;
- Assistance in developing nuclear plant life extension and advanced reactor licensing approaches for NRC;
- Studies of safety, cost and schedule effects of NRC regulation on about 20 nuclear construction projects and about 20 operating plants;
- Chair of operational readiness reviews for Limerick 2 nuclear power plant and DOE's Savannah River K Reactor and Rocky Flats plutonium facility;

- Studies of environmental, safety, and health vulnerabilities of production reactors, uranium facilities and plutonium facilities at Savannah River, Rocky Flats, Livermore, Los Alamos, Hanford and Pantex facilities;
- Member of Nuclear Safety Review Boards for Limerick and Peach Bottom nuclear power stations and for DOE's N-Reactor;
- Vice-chair of Nuclear Safety Review Board for the Rocky Flats Site;
- Vice-chair of Nuclear Safety Review Panel for a project in the Dynamic Experiments Division at Los Alamos National Laboratory;
- Studies of regulatory implications of claims of radiation injury at six nuclear facilities; and
- Safety and management consultant on decommissioning of Maine Yankee and Connecticut Yankee nuclear power plants.

Also, I have consulted on nuclear safety matters in England, Spain, France, Germany, Ukraine, Russia, Kazakhstan, Egypt, China, Japan, Taiwan, and Korea.

I have testified as an expert witness or Federal agency representative before committees of the U.S. House of Representatives and Senate, DOE, EPA, NRC, NRC's Advisory Committee on Reactor Safeguards, Defense Nuclear Facilities Safety Board, DOE's Advisory Committee on Nuclear Facility Safety, President's Commission on Three Mile Island, President's Nuclear Safety Oversight Board, licensing and rule-making hearing boards, regional planning commissions, state public service commissions, courts, and international organizations.

2. SUMMARY OF TESTIMONY

Q. WHAT DID YOU DO IN PREPARING YOUR TESTIMONY?

A. I reviewed correspondence from NRC to APS from January 1, 2004 to July 24, 2006. I also interviewed a number of employees and senior managers of APS to understand the context of the various NRC and APS documents. I also reviewed a

number of CRDRs (Condition Report/Disposition Requests) and reports of assessments performed by or for APS. I found these latter reports to be very helpful in understanding both sides of the matters described in NRC correspondence.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. In brief, my testimony will demonstrate the following:

- The safety standards that the NRC applies and those applicable to prudence cases such as this are markedly different. The NRC consistently uses hindsight in its safety analyses, and it is indisputably inappropriate to do so in a prudence determination. The NRC has also issued a Policy Statement on the content of economic performance standards set by State public utility commissions.
- Palo Verde's performance has been within industry norms over the decade from 1995 to 2005. Although it has experienced a decline recently, as most plants do at some point, APS is addressing this decline through its Performance Improvement Program. Self-critical reports and assessments are always a part of such improvement efforts and are not an indicia of imprudence.
- The October 2005 outages at Units 2 and 3 were not the result of APS imprudence. Palo Verde personnel responded reasonably to a new question the NRC raised – a question which the company should not have anticipated. Once APS answered the NRC's new question, the units restarted without any change to the equipment, training or procedures related to the systems in question.

In the sections of this testimony that follow, I will first explain, in Section 3, the NRC's regulatory process for oversight of nuclear power plants. I will describe the differences between the standards the NRC employs and the standards applicable to a prudence determination. Of course the NRC's first and foremost requirement is that nuclear plants operate safely, and there is no dispute that Palo Verde has done so, as both the NRC's Regional Administrator Bruce Mallett and ACC staff consultant GDS have told this Commission.

Unlike economic regulatory bodies, such as the ACC, the NRC does not consider whether utility management's actions were reasonable at the time such actions were taken. Rather, the NRC uses hindsight to continually improve safety performance and has done so successfully over the years. As a result, average performance today is much better than good performance was in the past.

The NRC focuses on results. In contrast, there is a focus on process in an ACC review of whether there has been adherence to a prudence standard. An understanding of the different standards applied by the NRC is critical to evaluating NRC actions and documents that may be offered as evidence in a prudence proceeding. In sum, NRC actions and documents generally can be relevant only to the prudence of utility management actions taken after learning of the NRC action or receiving the NRC document in question. This is an important issue in this case because GDS has said that it adheres to a prudence standard while in its report it makes no attempt to account for the hindsight typically found in NRC reports.

In Section 4, I describe the manner and extent to which NRC actions and documents may be relevant to prudence proceedings. I provide some background on the history and development of the NRC's assessment processes and demonstrate that the NRC has rejected some of its past efforts, such as the Watch List, as being unduly subjective and lacking in guidance to licensees. I point out that, unlike the majority of commercial nuclear power plants, Palo Verde was never on the NRC Watch List and never received a Trending Letter. I also describe the current Reactor Oversight Process and note that although it is generally recognized as a considerable improvement over the past, the NRC and the stakeholders in the process have recognized that it has weak areas, including areas that bear on recent NRC assessments of Palo Verde, e.g., NRC inspector acceptance of the original design basis of a plant and the role of NRC's

identification of cross cutting issues. Understanding these aspects of NRC's regulatory practices is important because GDS has either not addressed them, as in the case of the original design basis, or interpreted them incorrectly, as in the case of cross-cutting issues.

It is my understanding that the ACC has previously pointed out that, in examining the operating performance of power plants, one must look at both a plant's "successes" and "failures" in order to perform a fair review. This is not what GDS did in its report, choosing instead to concentrate on Palo Verde's performance in 2004 and 2005. I have chosen a longer time period to review Palo Verde's performance, 1995 through 2005, so that both successes and failures are brought to light. NRC data can be helpful in such a review.

Accordingly, I have set forth in detail in Section 5 and Attachment RJM-3RB of this testimony a comparison of how Palo Verde has performed relative to other nuclear power plants, over time, in a large number of categories. The categories are ones NRC uses to compare the performance of similar plants. These comparisons show Palo Verde's performance to be superior when viewed over the period since 1995. These data are consistent with the fact that Palo Verde represents the culmination of a significant design effort that extended over many years and many earlier plants by the Combustion Engineering Corporation (CE), now owned by Westinghouse. I think of it as the flagship of the CE product line. In significant measure it is among the best plants in the country and many of its design features will carry over into the advanced designs of light water reactors now being prepared for deployment in the U.S. The peer group that NRC has defined for Palo Verde performs better on the average than other pressurized water reactors in the U.S., and Palo Verde often performs better than its peers.

In Section 5, I also assess the recent regulatory performance of Palo Verde. Factoring into this assessment are citations by NRC in early 2005 of two violations

connected with voiding that was found in the lines leading from the containment sump to the ECCS pumps. These are the violations that led NRC to declare that Palo Verde has a degraded (yellow) cornerstone in the area of mitigating systems. The voids in the lines stemmed from the original design of the plants, and the missed opportunity for detecting the problem occurred in 1992. Thus, the two violations have no bearing on the current condition of the plant or capability of the APS staff.

The new reactor oversight process that NRC implemented in 2000 provides four levels of increasing scrutiny of licensees above the normal level of NRC oversight. Palo Verde is now at the second level of increased oversight (yellow cornerstone), and there are indications that it will successfully return to the lowest level of NRC scrutiny. In the meantime, NRC has not interfered with its continued operations.

NRC has raised concerns with cross-cutting aspects of Palo Verde operations (human performance and problem identification and resolution). These issues did not cause the yellow cornerstone or the outages experienced in 2005, and they have been controversial within the industry. In response to general industry criticism of the cross-cutting issues, NRC has recently acknowledged it has its own difficulty in understanding and dealing with cross-cutting findings and in early 2006 proposed new ways of dealing with them. The Government Accountability Office (GAO) recently told the U.S. House of Representatives that three-quarters of the country's 103 operating plants have been subjected to oversight beyond the baseline inspections for varying amounts of time, so Palo Verde is not unusual in receiving the increased NRC attention that it did in 2004 and 2005. GAO also told Congress that cross-cutting issues identified by NRC have increased dramatically across the industry so Palo Verde is not alone in its experience with these issues, either.

In response to the increased NRC oversight arising from the yellow cornerstone,

APS has implemented a Performance Improvement Program or PIP. It has been underway at Palo Verde since October 2005 and is beyond NRC's expectations for a station at Palo Verde's current level of performance. That is, the PIP is typical of improvement programs that have been implemented at many operating plants, but usually when they were experiencing worse performance problems than Palo Verde. Such programs involve self-assessments that use hindsight to identify opportunities for improvement, and they often do so in harsh terms that are expected by NRC and are the industry norm. Although I agree with the GDS report at pages 2 and 11 that the PIP should be successful in improving performance at Palo Verde, I strongly disagree with the manner in which GDS has taken out of context the harsh self criticism of the APS analyses connected with the PIP and incorrectly portrayed them as self condemnation. In fact, neither APS nor NRC has said that operations of Palo Verde are or have been imprudent or unsafe in light of recent performance, nor do I believe the performance to be indicative of imprudence.

At the end of Section 5, I discuss statements by the NRC about the features of an economic performance standard such as that recommended by GDS for Palo Verde. These NRC statements demonstrate that NRC is concerned that such economic incentives not create disincentives to safety. The GDS recommendation is not consistent with the NRC advice on this matter. I conclude that an economic performance standard is not needed for Palo Verde at this time based on its long-term record of superior performance and the Performance Improvement Program now underway to ensure such performance in the future.

Finally, in Section 6 of this testimony I address the prudence of outages of Units 2 and 3 in October 2005 connected with the possibility of air entrainment in the suction piping leading to the emergency core cooling system from the refueling water tank (RWT). In my review of the RWT outages, I could find no connection with the NRC and APS concerns with cross-cutting issues and the yellow

cornerstone, unlike the conclusions reached by GDS. I conclude that APS was prudent in its handling of the RWT air entrainment issue because it could not reasonably have anticipated the emergence of the new requirement that NRC levied, and, once the issue emerged, APS followed its only available line of response. My conclusion is similar to the conclusions reached by GDS for several of the other outages in 2005, i.e., APS could not reasonably have foreseen the reason for the outage. My conclusion also is consistent with that of NRC Region IV Administrator Bruce Mallett as evidenced by what he told the ACC on January 26, 2006, namely, the issue was a new question, one that NRC and APS had not come across before, APS did what NRC expected, and NRC did not determine that APS should have found the issue beforehand.

The new question dealt with adequacy of the design basis while the 2004 question involved implementation of the design basis. When APS responded to the new question in October 2005 by showing how air entrainment had been handled in the original operating license review by NRC and how the conditions flowing from that review had been factored into Palo Verde's design, the answer was deemed by the contract inspector to be insufficient. Because the additional question the inspector asked went beyond the original licensing basis of the plant, it could not be answered readily by APS. Accordingly, the safety systems in question were declared inoperable, and the two operating units (Units 2 and 3) were shut down on October 11 in accordance with their Technical Specifications.

The NRC's new, surprise question was resolved sufficiently to support a system operability declaration for Units 2 and 3, and they were restarted on October 20 without any changes in the procedures, hardware or training associated with the systems in question, a condition that remains the same on the three units as they operate today. The outage served to provide NRC inspectors greater assurance of safety, but the safety of the plant and the licensing basis of the plant are the same

today as they were before the new question was asked. APS was prudent in the manner in which it dealt with this issue before and after the issue was raised by the NRC.

In seeking to bolster its conclusion that the cause of the RWT outage could have been found beforehand, GDS says that the NRC senior resident inspector for Palo Verde told GDS that the RWT outages could have been avoided. First, it should be noted that this inspector did not participate in the inspection or in writing the inspection report. Second, I do not believe the senior resident inspector intended to make a prudence statement by such a remark. Nor do I believe he would have contradicted the NRC Regional Administrator who said the opposite to the ACC on January 26, 2006. Also, the inspection report of January 27, 2006 that addresses these matters did not contain a finding or violation for a failure to do an adequate evaluation of the extent of condition of air entrainment in the ECCS. Finally, since NRC does not examine the prudence of its licensees' actions and does not make prudence determinations, it is likely that the senior resident inspector was using the typical NRC retrospective viewpoint in opining on what might have been avoided with the benefit of hindsight. I also note that the scope of the proposed interview of the senior resident inspector approved by the NRC in a letter dated March 15, 2006, did not include solicitation of his opinion on the reasonableness of APS actions in connection with the outages in 2005. In any event, the senior resident inspector's view does not alter my conclusion that APS was prudent in not anticipating the RWT.

It is instructive to note that a situation similar to the one here occurred in another jurisdiction involving some of the same individuals, including GDS, and resulted in a finding by the cognizant public service commission that the utility involved had dealt with the issue prudently. I have learned in preparing this testimony that on January 27, 2005, the same NRC contract inspector, Craig Baron, raised the issue of air entrainment during a special NRC "pilot inspection" at the Kewaunee

nuclear power plant in Wisconsin. Baron asked if air entrainment had been considered in the design of the auxiliary feedwater (AFW) system at Kewaunee. After several days of analysis by the licensee, the unit was shut down because a way to get air into the AFW pumps was discovered that had not been considered in the original design. On December 22, 2005, the Wisconsin Public Service Commission found "that the costs associated with this outage were not imprudently incurred because the record does not support the allegations [by witness William R. Jacobs, Jr. of GDS Associates, Inc.] that revisions to the AFW system should have been made in the past in order to avoid the issues resulting in the outage."

3. DIFFERENCES BETWEEN SAFETY STANDARDS AND PRUDENCE STANDARDS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. This section addresses the question of whether and to what extent actions taken by the NRC in the safety regulation of its licensees can be used to answer the economic regulatory question of whether management's operation of a nuclear plant has been prudent. I address these matters because the GDS report relies heavily on NRC documents and does so heedless of NRC's intentional use of hindsight in its inspection reports.

Q. DO THE NRC'S SAFETY STANDARDS DIFFER FROM THE STANDARDS AGAINST WHICH PRUDENCE IS GENERALLY DETERMINED?

A. Yes. As I will explain below, the bedrock of the NRC's standards is adequate protection of public health and safety, not reasonableness. Prudence, on the other hand, as commonly stated, is determined against a standard of reasonableness. Because utility management decisions must be made before their outcome can be known, an evaluation of their reasonableness must occur within the context of the information that was available to the decision makers at the time decisions were

made. For these reasons, the definition of prudence or good utility practice used by economic regulators to evaluate whether utility management has been prudent is generally some variation of the following definition used by the Federal Energy Regulatory Commission:

> [W]e reiterate that managers of a utility have broad discretion in conducting their business affairs and in incurring costs necessary to provide services to their customers. 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 (or that of another jurisdictional entity) would have made, in good faith, under the same circumstances, and at the relevant point in time. We note that while in hindsight it may be clear that a management decision was wrong, our task is to review the prudence of the utility's actions and the costs resulting therefrom based on the particular circumstances existing either at the time the challenged costs were actually incurred, or the time the utility became committed to incur those expenses. (Federal Energy Regulatory Commission, *New England Power Co.*, Opinion No. 49, 31 FERC § 61,047 at 61,048 (1985))

The regulations of the Department of Agriculture provide another example that applies to loans made by the Rural Electrification Association. It reads as follows:

> *Prudent Utility Practice* shall mean any of the practices, methods and acts which, in the exercise of reasonable judgment, in light of the facts, including, but not limited to, the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry prior thereto, known at the time the decision was made, would have been expected to accomplish the desired result consistent with cost-effectiveness, reliability, safety and expedition. It is recognized the Prudent Utility Practice is not intended to be limited to optimum practice, method or act, to the exclusion of all others, but rather is a spectrum of possible practices, methods or acts which could have been expected to accomplish the desired result at the lowest reasonable cost consistent with cost-effectiveness, reliability, safety and expedition. (7 CFR Part 1718, Subpart B, Appendix A, Article 1.01 Definitions)

In Arizona, the standard is similar. It is my understanding that the Arizona Administrative Code contains the following provision regarding investments by utilities:

> "Prudently invested" – Investments which under ordinary circumstances would be deemed reasonable and not dishonest or obviously wasteful. All investments shall be presumed to have been prudently made, and such presumptions may be set aside only by clear and convincing evidence that such investments were imprudent, when viewed in the light of all relevant conditions known or which in the exercise of reasonable judgment should have been known, at the time such investments. (Arizona Administrative Code § R14-2-103 (A)(l))

It is also my understanding that the ACC in a previous decision (Decision No. 55118, page 20) has stated that "a realistic analysis of operating performance must look at both the 'successes' and the 'failures' if it is to avoid setting unobtainable goals of absolute perfection." As I discuss below, this is one of the reasons why my analysis examines whether Palo Verde has been operating within industry norms over the past decade, a period over which any company could be expected to have some "successes" and "failures."

Q. DID GDS ARTICULATE AND APPLY A PRUDENCE STANDARD?

A. At page 19 of its report, GDS articulated a standard that is generally consistent with these various prudence standards. Unfortunately, in its analysis, GDS did not apply the standard it articulated, choosing instead to use NRC and APS documents written with the benefit of hindsight to judge the prudence of actions that were taken without such benefit.

Q. DOES THE STANDARD AGAINST WHICH PRUDENCE IS JUDGED ALLOW FOR A RANGE OF REASONABLE UTILITY MANAGEMENT ACTIONS?

A. Yes. The prudence standard acknowledges that there is a range of options available to utility management, and it accepts that different utility managers might choose different alternatives from among a set of reasonable options. Also, a negative outcome is not necessarily indicative of an imprudent decision – sometimes the best we can do with the information we have is to make a wrong choice.

Q. DOES THE NRC EVALUATE THE PERFORMANCE OF PLANTS BASED

ON THE INFORMATION THAT WAS KNOWN OR REASONABLY AVAILABLE TO LICENSEE MANAGEMENT?

A. No. The NRC evaluates the results of plant management decisions primarily based on hindsight. The NRC has a policy of continuing to learn from operating experience, and it requires the same from its licensees. The NRC might describe an event as "avoidable", but in doing so, it would take full advantage of knowledge that was gained after the fact. Thus, significant events are studied (including root cause and extent of condition assessments) to identify lessons learned to help avoid that type of event or more serious events in the future. NRC uses this approach to assure that the safety of nuclear power plants is continually rising, always striving to make plants safer tomorrow than they are today. However, it is not an approach that is appropriate under a prudence standard.

4. NRC'S REGULATORY PROCESS AND ITS RELEVANCE TO PRUDENCE DETERMINATIONS

Q. **WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?**

A. I will describe in more detail the various actions and processes used by the NRC to oversee safe operation of its licensees and how they may be relevant to a prudence examination. This information is intended to provide background for understanding the testimony in Sections 4 and 5, dealing with Palo Verde.

Q. **HOW DOES THE NRC IMPLEMENT ITS POLICY OF CONTINUOUS IMPROVEMENT?**

A. When a significant event happens at a nuclear power plant, the NRC and the licensee typically analyze the event and draw conclusions with the benefit of hindsight. For example, the NRC could conclude that a component failed because it was inadequately maintained or because the procedures for its use were unsatisfactory, even if the NRC had previously inspected and approved the maintenance program for that component or the procedures for its use. These

inspections focus on the state of knowledge at the time the NRC is performing its inspection. The NRC intentionally seeks to benefit from analysis that can be undertaken only with the benefit of hindsight and knowledge of the outcome.

Q. ON WHAT BASIS DOES THE NRC EVALUATE THE PERFORMANCE OF NUCLEAR POWER PLANT OPERATIONS?

A. The Atomic Energy Act of 1954, as amended, requires the NRC to provide "reasonable assurance of adequate protection of public health and safety" (Sections 182 and 189) during nuclear power plant operation. The NRC takes a variety of actions to ensure protection of the public health and safety, such as issuing an operating license that contains restrictions on how a nuclear power plant is to be operated; conducting regular and special inspections to see that the license and applicable regulations are implemented; issuing inspection reports, notices of violation, and civil penalties; on occasion requiring certain actions to be taken before a plant can resume operation after an outage; and issuing confirmatory action letters (CALs) or orders that specify any special measures that may be needed, in NRC's judgment, to provide adequate protection.

The safety of nuclear power plants is required, as a matter of national policy, to be maintained at very high levels established by the NRC. The NRC has promulgated regulations and other guidance to licensees to define its requirements for assuring adequate protection. Although the NRC's regulations change only occasionally, its safety performance expectations are continually rising through changes in the interpretation of its regulations.

For example, in 2000 the NRC implemented a new Reactor Oversight Process (ROP). The ROP is based on four decades of nuclear power plant operating experience and is designed to take advantage of the maturity of the nuclear industry. It uses insights to safety significance based on risk assessment techniques that were pioneered by the NRC in the mid 1970s and are now widely used in the

industry. The NRC implemented the ROP without changing its regulations.

Q. BRIEFLY, WHAT IS AN OPERATING LICENSE?

A. An operating license is the authorization issued by the NRC to a licensee, such as APS, to operate a nuclear power station, such as Palo Verde, in conformance with the regulations of the NRC and the conditions of the license. It is based on an extensive safety analysis performed by the license applicant and reviewed by the NRC, a review that spans several years, involves many man-years of engineering and analysis effort on both sides, and is documented in a Final Safety Analysis Report (FSAR) that fills several book shelves. When I was working at the NRC in the late 1970s and early 1980s, the FSAR for Palo Verde was being reviewed and approved by the staff reporting to me. It is important to appreciate that a detailed technical review is performed by the NRC at the time the operating license is issued for every nuclear power plant because the outages connected with the refueling water tanks at Palo Verde in October 2005 involved an *ad hoc* rejection by NRC inspectors of conclusions reached in the operating license review by NRC headquarters staff for Palo Verde more than 20 years before.

Q. WHAT ARE TECHNICAL SPECIFICATIONS?

A. Technical Specifications are contained within the Operating License. The Tech Specs, as they are sometimes called, list the safety equipment that is required to be operable for the various modes of operation of the nuclear reactor, from full power operations to cold shutdown. The Technical Specifications also describe what must be done to demonstrate operability and the time required for such demonstration whenever there is uncertainty about the capability of safety equipment to perform its function. For example, Technical Specification 3.5.5 in the Palo Verde license requires that if a refueling water tank is inoperable for one hour, the affected Unit must be shut down and be in mode 3 (hot standby – no power generation and temperature greater than 350 F) within 6 hours and mode 5 (cold shutdown – no power generation and temperature less than 210 F) in 36 hours. This is what happened with Palo Verde Units 2 and 3 in October 2005.

Q. WHAT IS AN OPERABILITY DECLARATION?

A. An operability declaration (or determination, as some plants call it) occurs whenever the operability of safety equipment is placed in doubt (e.g., because of a failed component, a new analysis, or a new question about safety). In such a case, a decision must be made by a licensed senior reactor operator (SRO) on the shift crew operating a nuclear power plant as to whether there is reasonable assurance that the equipment can perform its specified safety function. The SRO cannot take into account the low probability of the demand for the safety function – he or she must decide only whether the equipment will perform or not. In making a declaration that certain equipment is operable, the SRO also must have assurance that the attendant instrumentation, controls, electrical power, cooling water, lubrication and other auxiliary equipment are capable of performing their related support functions. The Technical Specifications also set time limits on such determinations.

The GDS report at page 34 quotes the NRC Inspection Report of January 27, 2006 in criticizing the manner in which operability decisions were reached for the refueling water tanks leading up to the October 2005 outages in Units 2 and 3. Such criticism by NRC had nothing to do with the need for or duration of the outages and is not germane to the prudence determination sought in this proceeding. Rather, the criticism by NRC only had to do with how APS reached the decision to shut down and answer the question raised by the contract inspector, not with the correctness of the decision. Also, NRC requirements on operability determinations have recently changed so it is not unexpected that any operability decision in any operating nuclear power plant would attract some helpful NRC criticism at this time.

Q. YOU ALSO SAID EARLIER THAT NRC STANDARDS CHANGE WITH TIME. DOES THE NRC COMMUNICATE SUCH CHANGES TO ITS LICENSEES?

A. Yes. The NRC uses several methods to communicate changes in its requirements to licensees. In addition to generic information (i.e., information applying to more than one licensee) communicated through rulemaking, regulatory guidelines, Generic Letters, and Information Notices, the NRC uses licensee-specific means. Examples of the latter include reports of inspections, notices of violations, identification of cross-cutting issues, identification of degraded cornerstones of safety having risk significance, and civil penalties.

Q. DO THESE FORMS OF COMMUNICATION ENABLE LICENSEES TO PREDICT NRC REGULATORY EXPECTATIONS?

A. The NRC processes for issuing new or revised regulations and Regulatory Guides provide for public comment periods, so it is possible to predict what is expected in those instances. For the other forms of communication, it is only possible to tell what is expected after the fact, i.e., after the new requirement is issued.

Rising expectations conveyed through the inspection process are the most difficult to predict. Such new requirements are revealed and their meaning is defined for each plant after-the-fact, on an *ad hoc* basis, in meetings, inspection reports, violations, periodic assessments, identification of cross cutting issues and degraded cornerstones, and other forms of communication that often lack direct linkage to the formal requirements of NRC, i.e., those contained in its regulations. Through these less formal devices, NRC urges further performance improvement even where there is full compliance with formal regulatory requirements. Also, the communications of these rising standards are inherently negative in tone, seldom, if ever, providing recognition for good performance.

As I will describe later in this testimony, the outages of Units 2 and 3 connected with the refueling water tanks at Palo Verde in October 2005 were the result of a new, informal safety requirement communicated to APS through the inspection process in a way the company could not predict. The GDS report completely

1 misses this point, and it is the crux of whether these outages were prudent or not.

2 **Q. WHAT IS THE END RESULT OF NRC'S ESCALATING SAFETY**
3 **STANDARDS?**
4
5 A. The potential hazards of nuclear power are significant so the nuclear industry is a
6 highly regulated industry; it is probably the most closely regulated industry in the
7 United States. Due to the intense scrutiny and high standards of safety performance
8 demanded of licensees, the levels of performance achieved by nuclear power
9 plants are very high. Average performance in the nuclear industry is always rising,
10 so much so that average performance in years past is low performance today.

11 **Q. ARE THE ACTIONS AND DOCUMENTS OF THE NRC IRRELEVANT**
12 **TO PRUDENCE DETERMINATIONS?**
13
14 A. No. As stated above, because the NRC uses hindsight, its actions and documents
15 generally are not relevant to determinations of the prudence of utility management
16 conduct prior to issuance of the documents or prior to the actions of NRC officials.
17 However, NRC actions and documents can be relevant to assessments of the
18 prudence of subsequent actions taken by utility management.

19 **Q. CAN YOU GIVE SOME EXAMPLES OF HOW NRC DOCUMENTS AND**
20 **ACTIONS CAN BE RELEVANT TO PRUDENCE DETERMINATIONS?**
21
22 A. Yes. First, the performance indicator data accumulated by the NRC provide a way
23 to judge whether a particular licensee is keeping up with the long-term
24 performance improvements of the nuclear power industry that result from the NRC
25 policy of continuous improvement. Performance improvements occur over time
26 and licensees may have good years and bad years in achieving improvements, but
27 a long term failure to keep pace would provide a basis for inquiring into what
28 management was doing or had done to address why this was occurring. I show by
29 analyses described in Section 5 and Attachment RJM-3RB of this report that Palo
30 Verde has been a superior performer when viewed over the long term using
31 performance indicator data. Thus, I disagree with the manner in which the GDS
32 has portrayed Palo Verde as one of the worst performers in the industry by looking

only at data for a short period of time where the plant admittedly had a decline in performance. (GDS report page 9)

Second, NRC often issues correspondence (e.g., Generic Letters and Information Notices) to the entire industry about undesirable circumstances arising at a particular plant or group of plants, including reactions to operating experience and possible changes in design. The intent of such correspondence is to give all licensees the opportunity to take corrective action appropriate to their plant design to avoid those circumstances. These issuances of NRC can be helpful in determining whether subsequent actions by utility management to avoid undesirable circumstances have been prudent. Conversely, if NRC does not issue generic guidance arising from regulatory experience at a particular plant, this fact may have implications for prudence determinations for NRC licensees, as it does in connection with Palo Verde Unit 2 and 3 outages associated with the refueling water tanks that occurred in October 2005, as I explain in Section 6.

Q. CAN PLANT-SPECIFIC COMMUNICATIONS FROM THE NRC BE HELPFUL IN A PRUDENCE DETERMINATION?

A. Yes, if one is mindful that plant-specific communications, e.g., inspection reports, are almost always critical and based on hindsight. They serve to show what was known by a utility about the acceptability of its performance as of the date of the communication. Like many other NRC communications, they can be relevant to a prudence determination only in evaluating whether the licensee's response to such a communication is reasonable.

From 1980 to 1998, the NRC periodically (approximately every 18 months) summarized how its correspondence to a particular utility should be viewed. It was called the Systematic Assessment of Licensee Performance or SALP program. It provided a retrospective view of the overall strengths and weaknesses of a licensee's performance and identified common themes or symptoms that could be

derived from NRC correspondence to the licensee during the evaluation period. Additionally, the NRC used SALP ratings to assist in determining how to allocate its inspection resources in the coming months. From January 1995 through April 1998, when the station received its last SALP ratings, Palo Verde received SALP scores that averaged 1.5, that is, midway between superior and good performance.

Beginning in 2000 the SALP reports were replaced by continuous assessments of licensee performance made by NRC under its new Reactor Oversight Process. According to NRC's Inspection Manual Chapter 0305, its Regional Offices are to conduct quarterly, semi-annual and annual reviews of NRC's inspection results, and performance indicator data. The annual reviews roll up the results of the quarterly and semi-annual reviews. An annual assessment report is issued to the licensee to forecast NRC's planned inspection activities at the subject plant for the next 18 months and to address any substantive cross-cutting issues observed during the evaluation period. The periodic reviews for Palo Verde were routine until those issued for 2004 through mid 2006 wherein corrective actions associated with the yellow cornerstone and two substantive cross-cutting issues have been prominent.

Q. WHAT IS A SUBSTANTIVE CROSS-CUTTING ISSUE?

A. In its current reactor oversight process, NRC has identified three aspects of licensee performance that are common to all seven cornerstones of safety (initiating events, mitigating systems, barrier integrity, emergency preparedness, occupational radiation safety, public radiation safety, physical protection) and important to maintaining safe operations. NRC refers to these three performance aspects as cross-cutting areas. They are human performance, problem identification and resolution, and safety conscious work environment. If NRC finds multiple examples of cross-cutting aspects in a 12-month inspection period, as it has at Palo Verde for the first two of these areas, NRC may identify a "substantive" cross-cutting issue in its correspondence to that licensee. Doing so serves as a notice that NRC sees opportunities for improvement in the cross-

cutting area and will concentrate its inspection efforts there.

From pages 12 to 15 of its report, GDS discusses the NRC's identification of substantive cross-cutting issues at Palo Verde (GDS cites three such issues but the NRC has identified only two) and quotes liberally from the subsequent self assessments performed by APS in seeking opportunities to improve performance in these two areas. GDS makes no mention that such self assessments are possible only with the use of hindsight. It is not clear what use GDS would have the ACC make of these quotations since the NRC has made no connection between the quotations and the four outages in 2005 that GDS finds to be imprudent. One thing is clear, however; GDS lifts these quotes from critical self assessments out of context, without recognition of their retrospective nature, in an attempt to blame APS management and thereby hinder these and future uses of the NRC-mandated process to help improve performance at Palo Verde. Furthermore, these self assessments are at the heart of the Performance Improvement Program that GDS says will probably succeed. Unlike GDS, I find these self assessments to be prudent management behavior and consistent with what other licensees have done to recover excellent performance. That is, prudent managers continually seek ways to improve their performance and to do so openly, honestly and frankly. Their effort lies at the heart of the industry's efforts to implement the national policy of continuous improvement in the operation of nuclear power plants.

Q. IS IT APPROPRIATE TO RELY ON NRC STAFF OPINIONS IN DETERMINING THE PRUDENCE OF A PLANT'S MANAGEMENT ACTIONS?

A. Not in my opinion, having worked for the NRC, and not in the opinion of other managers from NRC. As a senior manager from the NRC has said, regarding Consolidated Edison Company of New York, which at the time operated the Indian Point 2 Nuclear Power Plant, a Notice of Violation does not prove imprudence because the NRC does not have the "role to review or judge that [prudence], nor do I endeavor to have the expertise to decide such matters; NRC inspections are

not designed to obtain the necessary information or perspectives to judge such matters." (A. Randolph Blough, NRC Region I Division Director, July 26, 2000 E-mail to Region I staff. –RJM_WP1RB)

At page 32 of the GDS report, it is claimed that the NRC's Senior Resident Inspector at Palo Verde stated that the RWT outages could have been avoided. The implication apparently intended by GDS is that the inspector had the necessary perspective and information to make a judgment about the prudence of APS in not avoiding these outages. I doubt this is true for six reasons, namely

- The senior resident inspector in question was not a member of the inspection team that dealt with the RWT issue nor did he write the January 27, 2006 report of that inspection (Attachment 3 to GDS report),
- As noted above, NRC inspectors are not trained or qualified to make such judgments,
- Region IV Administrator Mallett told the ACC on January 26, 2006 that NRC did not determine that APS should have found the new question beforehand,
- The inspection report of January 27, 2006 that dealt with this matter did not contain an NRC finding or a violation for APS's failure to find the new question beforehand,
- The NRC's approval of the GDS interview of the senior resident inspector was approved by the NRC in a letter dated March 15, 2006 from Troy W. Pruett of NRC to Janet Wagner of APS (RJM_WP2RB) and did not include solicitation of the inspector's opinion on the reasonableness of APS actions in connection with the outages in 2005, and
- There is an alternate interpretation of the senior resident's statement, i.e., he was speaking from his NRC perspective of continuous improvement using hindsight, not from the ACC perspective of judging prudent

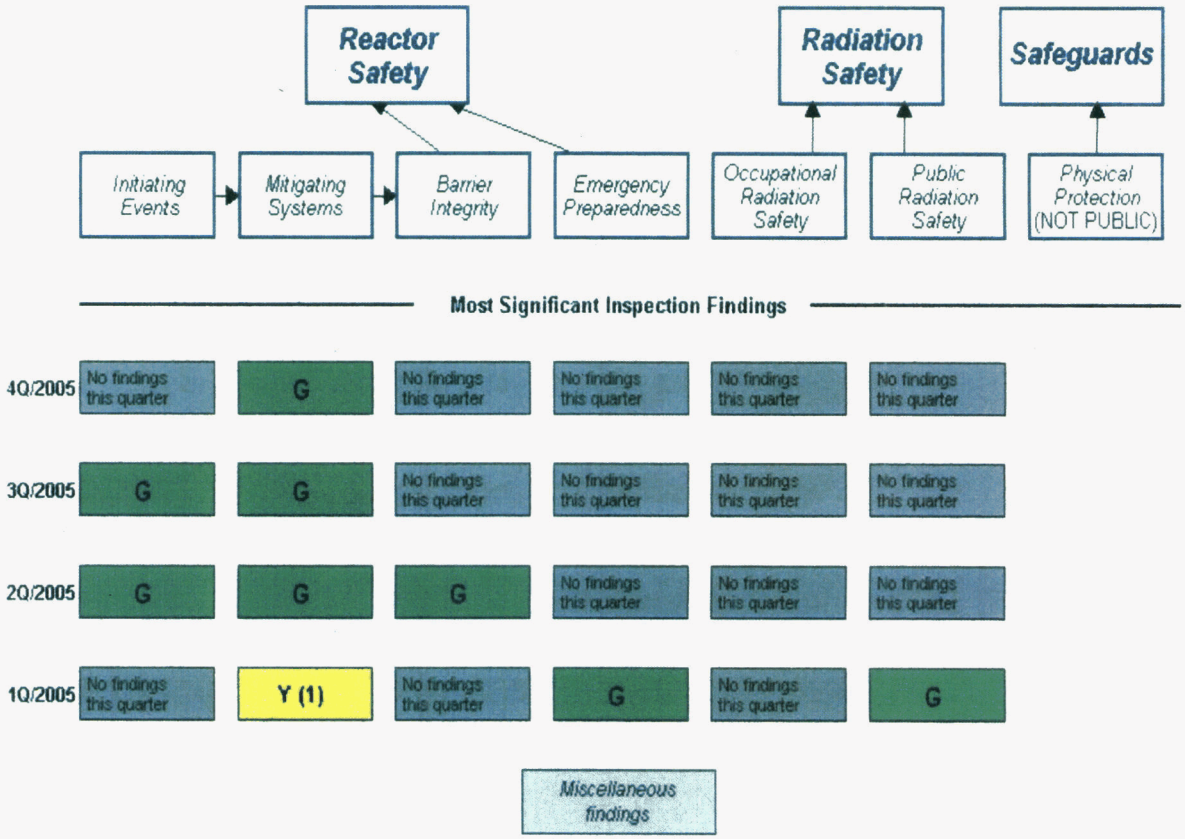
performance according to information reasonably available at the time.

Q. YOU MENTIONED THAT THE NRC ALSO INSPECTS EACH PLANT FOLLOWING ISSUANCE OF ITS OPERATING LICENSE. WHAT IS THE ROLE OF THE NRC'S INSPECTION PROCESS FOR AN OPERATING NUCLEAR POWER PLANT?

A. The primary purpose of the inspection program for operating power plants is to determine whether there is reasonable assurance that they are being operated safely and in accordance with NRC requirements. Most inspections are designed to identify situations that could be forerunners of future safety events. That is, inspections are intended to identify opportunities to improve plant safety.

Q. CAN YOU DESCRIBE HOW NRC USES THE FINDINGS IN ITS INSPECTION REPORTS?

A. Yes. Under the Reactor Oversight Process, NRC arranges its inspection findings in an Action Matrix just like the one it uses for current performance indicators, i.e., according to the seven cornerstones of safety. The Inspection Findings Action Matrix for Palo Verde Unit 1 for the last quarter of 2005 is shown on the following page.



The green blocks (boxes labeled G) in this figure represent areas in which there were NRC findings or violations of minor safety significance. The grey (shaded) blocks indicate areas that received no NRC findings or violations. The 2004 discovery that voided suction piping had existed between the containment sump and the ECCS since the plant first began operations is the source of the one yellow finding shown in this figure for the first quarter of 2005 under the Mitigating Systems cornerstone. It is discussed further in Section 5.

Q. ARE THERE ANY SPECIAL INSPECTIONS THAT ARE CONDUCTED UNDER NRC'S NEW REACTOR OVERSIGHT PROCESS?

A. Yes. Under the Reactor Oversight Process, there are three types of team inspections that are used in connection with recovery from degraded cornerstones. These team inspections are intended to assure that licensees have adequately assessed and understood the root causes of their degraded cornerstones, that the

generic implications of the root causes (extent of condition) are identified, and that the licensee's planned corrective actions are sufficient to address the root causes and generic implications and to prevent recurrence. These three types of team inspections are defined in accordance with the significance of the deficiencies identified by NRC. NRC Inspection Manual Chapter 0305 prescribes who in the NRC management hierarchy is empowered to take action on the basis of the results of these team inspections, as follows:

- Inspections conducted under Procedure 95001 "Supplemental Inspection for One or Two White inputs in a Strategic Performance Area" lead to action at the level of a branch chief or division director in the regional office;
- Inspections conducted under Procedure 95002 "Supplemental Inspection for One Degraded Cornerstone or any Three White Inputs in a Strategic Performance Area" lead to action at the level of a division director in a regional office or the regional administrator; and
- Inspections conducted under Procedure 95003 "Inspection for Repetitive Degraded Cornerstones, Multiple Degraded Cornerstones, Multiple Yellow Inputs, or One Red Input" lead to action at the level of the Executive Director for Operations in conjunction with the Director of the Office of Nuclear Reactor Regulation in NRC headquarters and the Regional Administrator.

The NRC's supplemental inspection at Palo Verde in the fall of 2005 using Inspection Procedure 95002 is discussed in Section 6, below.

Q. YOU MENTIONED EARLIER THE NRC WATCH LIST. WHAT WAS THE NRC WATCH LIST?

A. The Watch List was a means for NRC senior managers to identify plants that warranted additional NRC attention, such as increased NRC inspections or inspections with greater headquarters involvement, or more frequent meetings

between NRC and licensee management. Twice each year, the senior staff of the NRC conducted a Senior Management Meeting to determine which plants required placement on the Watch List.

Q. HOW MANY PLANTS WERE PLACED ON THE WATCH LIST?

A. The first group of plants to be placed on the Watch List was announced in May 1986. At that time, 13 units were placed on the list. From 1986 until its discontinuation in 1998, a total of 42 units were placed on the list. This number equates to about 40% of the total nuclear units that operated during that period. In June 1993, NRC's senior managers initiated a program whereby a Declining Trend Letter could be sent instead of placing a plant directly on the Watch List. A total of 14 nuclear units received a declining Trend Letter up to the time the program ended. Thus, more than half of all nuclear power units that operated during the period that the Watch List existed were either placed on the list or received a declining Trend Letter. Palo Verde was never on the Watch List and never received a Trending Letter.

Q. YOU HAVE SAID THAT BOTH THE WATCH LIST AND THE SALP PROGRAM WERE ELIMINATED IN 2000 WITH THE CREATION OF THE NEW REACTOR OVERSIGHT PROCESS. CAN YOU SAY WHY THE NRC DECIDED ON THIS APPROACH?

A. Yes. The NRC decided to eliminate the Watch List and the SALP Program because years of implementation of these programs demonstrated that they were too subjective. As NRC Chairman Shirley Jackson described in a written statement to the U.S. Senate Subcommittee on Air, Wetlands, Private Property, and Nuclear Safety on July 30, 1998, at the time the new ROP was being developed to replace the Watch List and the SALP programs,

> A major area of criticism focused on NRC processes that result in expending undue NRC and licensee resources to address NRC requirements that are of relatively low safety significance....In the area of reactor performance assessment, the strongest overall criticism has centered around the subjectivity and lack of scrutability of our assessment process....The NRC agrees with the thrust of these criticisms.

Q. AFTER THE ELIMINATION OF THE SALP PROGRAM AND THE WATCH LIST IN 2000, DID THE NRC USE A DIFFERENT SYSTEM TO CHARACTERIZE THE ATTENTION THAT IT WOULD GIVE A PLANT?

A. Yes. As currently implemented, the Reactor Oversight Process has four levels of NRC response to non-Green inspection findings or performance indicators. Two of the four levels are administered at the Regional Level and two of them are administered at the Agency Level (i.e., at NRC Headquarters in Rockville, MD).

Q. HAS NRC PLACED PALO VERDE IN ONE OF THESE CATEGORIES?

A. Yes. Palo Verde is in the second Regional Response category because it was identified as having a yellow degraded cornerstone for mitigating systems. This level of heightened attention is lower than the two levels of attention associated with the Agency Response level. The Agency Response Levels are similar to the previous Trending Letter and Watch List identifications. Although APS was not expected to implement a Performance Improvement Program at this level of increased regulatory scrutiny, it has voluntarily done so as discussed further in Section 5, below.

Q. IS IT UNCOMMON FOR NRC TO APPLY EXTRA SCRUTINY TO ITS LICENSEES?

A. No, NRC frequently applies extra resources to its oversight of individual licensees. The application of extra resources is a key part of NRC and licensee efforts to detect declining trends in performance before they turn into safety problems. In June 19, 2006 testimony before the Subcommittee on Oversight and Investigations, Committee on Energy and Commerce, U.S. House of Representatives, John Wells, Director of Natural Resources and Environment for the GAO, noted "On the basis of its findings and the performance indicators, NRC has subjected more than three-quarters of the 103 operating plants to oversight beyond the baseline inspections for varying amounts of time." (RJM_WP3RB)

Q. IS THE ROP ACHIEVING WHAT IT WAS INTENDED TO ACCOMPLISH?

A. In some ways it is. The process provides assessments of utility performance that are more standardized, understandable, and predictable than the assessments conducted under the previous programs. The process is risk-informed so it helps to focus NRC and utility resources on those issues that have the greatest safety and risk significance. However, some of the outputs of the ROP are still subjective and unpredictable, subject to variations in the judgment of individual inspectors and inspection teams. The process is still a work in progress and subject to continued refinement.

Q. HOW IS NRC SEEKING TO IMPROVE THE ROP?

A. Beginning in 2003, the NRC staff sought stakeholder feedback on the ROP. It issued a survey that contained 20 questions and was designed by Brookhaven National Laboratory (BNL) under contract to the NRC. The results of this survey are reported in "Final Results – USNRC Office of Nuclear Reactor Regulation Regulatory Impact Survey, " August 3, 2004. (RJM_WP4RB)

Q. WHAT DID THE STAKEHOLDERS TELL BNL AND NRC ABOUT THE ROP?

A. Most of the responses expressed satisfaction with the way the ROP works. However, there were criticisms voiced about two aspects of the ROP that have relevance to this proceeding and to the GDS report.

First, there were comments pertaining to the staff's unpredictable pursuit of generic issues on a case-by-case basis. This practice was evidenced at Palo Verde in the refueling water tank outages of Units 2 and 3 in October 2005, outages owing to an unanticipated backfit of the design basis for Palo Verde that was imposed by NRC inspectors instead of pursuing a generic issue under NRC procedures. The applicable comments in the 2004 BNL Report were as follows:

- NRC is failing to address generic issues in a generic manner…[it] is addressing too many such issues on a docket by docket basis; and
- [There is] disappointment at NRR's [NRC's Office of Nuclear Reactor

Regulation] failure to pick up and pursue an issue that clearly had generic implications.

Second, BNL conveyed industry comments pertaining to the NRC staff's reluctance to accept the original licensing basis of a plant, insisting instead that a licensee backfit the design to a more modern approach without going through the required backfit process. (The term "backfit" (a.k.a. ratchet) is defined in 10 CFR 50.109 as the modification of equipment, approvals or procedures at a plant required by a change in NRC requirements or in NRC staff interpretations of NRC requirements, imposed after a plant was originally constructed.) The backfit process at NRC is designed to prevent an individual or small group in the staff from imposing new requirements on a licensee or a group of licensees without adequate analysis and management approval. The costs (monetary and otherwise) and benefits of new requirements are intended to be assessed under NRC's backfit process. The NRC inspectors imposed such a backfit at Palo Verde without going through the backfit process in October 2005 in the case of the refueling water tank suction piping issue, as described more fully in Section 6, below. The comments in the 2004 BNL report that reflect similar backfitting occurring at other operating plants were as follows:

- Better understanding [is needed by NRC inspectors] of the licensing bases that older plants used and the analyses [sic] techniques which provided margins to address issues. Current codes and techniques were not available to early licensees, but this shouldn't be a ratchet for re-analyses;
- In the inspection arena issues arise that are not based in regulation.... It appears nothing prior to 2000 has any meaning;
- The NRC is not effectively utilizing precedents when reviewing licensing submittals;
- Regulatory requirements were at one stage being written through inspection and ...there was poor consistency between what was acceptable in the past and present;

- Inspectors appear to be making new regulatory requirements through inspection and enforcement; and
- Staff positions change without backfit considerations.

Q. WAS THERE ANOTHER SURVEY IN 2004?

A. Yes. It is reported in a paper from the Executive Director for Operations to the NRC Commissioners entitled "Reactor Oversight Process Self-Assessment for Calendar Year 2004," SECY-05-0070, April 25, 2005, without attachments. (RJM_WP5RB)

Q. WHAT DID IT HAVE TO SAY ABOUT HOW THE REACTOR OVERSIGHT PROCESS IS WORKING?

A. This report did not have the direct quotes of the external stakeholders that were provided in the 2004 BNL report. Instead, the NRC staff summarized the responses received in the annual survey, saying that most people thought the ROP was an improvement over the past. The report noted that the responses were generally in line with responses to earlier surveys. The staff said that it "continues to experience significant challenges in certain ROP areas and recognizes the need for further improvement." One of the areas listed as requiring focus in 2005 was "further improving guidance related to cross-cutting issues." This area relates to statements made in the GDS report and to NRC's recent inspection reports for Palo Verde, as discussed more fully in Section 5, below.

Q. HAS NRC MADE PROGRESS IN DEALING WITH THE CROSS-CUTTING ISSUES?

A. Yes. In a June 19, 2006 statement on behalf of the NRC Commissioners to the Subcommittee on Oversight and Investigations, Committee on Energy and Commerce, U.S. House of Representatives, Commissioner Edward McGaffigan, Jr. noted "The NRC has made numerous improvements to the ROP since its initial implementation, many as a result of independent program evaluations and feedback from internal and external stakeholders…The plant assessment process has been modified to improve its predictability, particularly in the treatment of

cross-cutting issues...." The improvements concerning cross-cutting issues to which the Commissioner referred were described in a May 24, 2006 NRC Policy Paper wherein NRC developed new definitions for each of its cross-cutting issues and provided additional guidance on their treatment once they are identified. (SECY-06-0122, "Safety Culture Initiative Activities to Enhance the Reactor Oversight Process and Outcomes of the Initiatives") Specific procedures were also provided for dealing with substantive cross-cutting issues. The relevance of this latest information on cross-cutting issues to this case is that even NRC did not have a good understanding of the role of such issues in the regulatory process until only recently, certainly well after a number of them had been identified at Palo Verde during the time period of interest here.

GAO, in the June 19, 2006 testimony to the House Subcommittee noted above, reported that between 2001 and 2005 cross-cutting issues had grown from 23% to 68% of all NRC inspection findings. The bearing of cross-cutting issues on Palo Verde is also discussed further in the next section of this testimony.

5. PALO VERDE PERFORMANCE

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. This section of my testimony discusses the performance of the three Palo Verde units. It contains data reflecting both the operational performance and the regulatory performance of Palo Verde. By operational performance I mean the performance of the people and equipment involved in generating electric power and assuring safety. By regulatory performance I mean the performance of APS in meeting the rules, regulations, and other expectations of the NRC. Finally, this section addresses the suggestion by GDS that the ACC adopt economic performance standards for Palo Verde.

Q. IS THE INFORMATION THAT THE NRC GATHERS ON NUCLEAR

POWER PLANT PERFORMANCE COMMUNICATED TO LICENSEES?

A. Yes. The NRC has always published its Performance Indicator data. The data were originally published and distributed quarterly, but in September 1995, the NRC changed to an annual publication consistent with the Federal government's fiscal year. Since implementation of the new ROP in 2000, the Performance Indicator data for each plant are updated quarterly on the NRC website.

The NRC's first Performance Indicator program ended in 1999. Thereafter, the NRC compiled performance data for its Industry Trend Program and for the ROP. I used data from these programs for this review of APS performance. To accomplish this task I designed and oversaw a project by SCIENTECH LLC in Clearwater, Florida that compiled a variety of performance indicator data for Palo Verde and the industry, using the Monthly Operating Reports that licensees were required to file with the NRC through 2004.

Q. HAS THE NRC ENDORSED THE USE OF COMPARISONS OF PERFORMANCE DATA WITHIN PEER GROUPS AND ACROSS THE INDUSTRY?

A. Yes. The NRC makes such comparisons itself. For making such comparisons the NRC assigned all nuclear power plants to their respective peer groups based upon similarity of design and vintage. Comparison of peer plants allows for evaluation of overall performance relative to similar plants constructed in a similar regulatory environment. Each peer group defined by NRC is based on nuclear steam system supplier, plant vintage, generating capacity, and licensing date.

Comparison of individual plant performance to peer group averages over time provides a relative measure of a plant's performance trend. NRC and licensees have used such comparisons to see whether special action was required to address problem areas or warrant closer NRC oversight at a particular plant. The NRC developed this program to provide itself and licensee management with early

warning of declining trends in performance that warranted special attention.

Q. OF WHICH PEER GROUP IS PALO VERDE A MEMBER?

A. Palo Verde belongs to the group of later Combustion Engineering plants (NRC calls this peer group 2) consisting of Arkansas Nuclear Unit 2, Waterford, San Onofre Units 2 and 3 and Palo Verde Units 1, 2 and 3. The Palo Verde units were the last of these plants to be placed in service and are the only ones that incorporate the System 80 Standard Plant Design of Combustion Engineering.

Q. WHAT PERFORMANCE INDICATOR DATA ARE YOU PRESENTING AND HOW ARE THE INDICATORS DEFINED?

A. I have compared Palo Verde's performance to its peers, other PWRs, the nuclear power industry, and, in one case, Region IV plants. I provide the comparisons for several parameters encompassing two time periods, before and after 2000 when the new ROP was implemented and the NRC performance indicators were changed. In addition to comparisons with its peer group of plants, I compared Palo Verde's performance to the entire industry for performance indicators that are independent of reactor design and to other PWRs for performance indicators that are not independent of reactor design. I made a Region IV comparison where the parameter was subject to variation among the four NRC Regions.

Some data under the old Performance Indicator Program have been compiled by SCIENTECH through 2001, even though NRC implemented the new ROP in 2000 and ceased to publish the old indicators at that time. I have included those SCIENTECH data where available. The data provided In Attachment RJM-3RB reflect the performance of Palo Verde during the period 1995 through 2004. I have included data for 2005 where available. I chose the 10-year period because it is long enough to show trends in performance. I chose the indicators as being the ones that best describe the safety and productivity of the station.

Q. WHAT DO THE NRC QUANTITATIVE PERFORMANCE INDICATORS GENERALLY REVEAL ABOUT THE PERFORMANCE OF PALO

VERDE?

A. The Performance Indicator data shown in Attachment RJM-3RB reveal that Palo Verde has performed well within industry norms when compared to its peer group, other PWRs and the nuclear industry.

Q. SHOULD THE PERFORMANCE OF NUCLEAR PLANTS BE EVALUATED ON THE SHORT-TERM OR THE LONG-TERM?

A. The performance of nuclear power plants should be evaluated over the long-term. As seen in the data of Attachment RJM-3RB, some of the events measured by Performance Indicators occur quite infrequently. Thus, the occurrence of one or two in a short period of time may or may not be statistically significant. Also, some indicators, such as worker radiation exposure, are keyed to long-term cycles in plant operation that can extend over several years. For example, the Palo Verde plants have nominal 18-month fuel cycles, and radiation exposures are highest during refueling outages when most of the maintenance of radioactive equipment is accomplished. Therefore, cumulative radiation exposures tend to spike every 18 months on each unit.

Q. PLEASE IDENTIFY THE PERFORMANCE INDICATORS THAT YOU CHOSE AND TELL US HOW YOU INTERPRET THEM.

A. The charts provided in Attachment RJM-3RB graphically depict Palo Verde's performance for each of the performance indicators that I chose. I chose indicators that bear on the reliability and safety of operations. I left out those relating to barrier integrity, emergency preparedness, public radiation safety and security because they do not bear on plant safety and reliability and involve issues that are not germane to this proceeding. I have provided a definition and a chart for each of the indicators that I chose. Each chart shows by year the average performance of the Palo Verde units and the performance of other units appropriate for comparisons for that indicator.

In sum, there are 18 indicators, some treating similar variables over the two

periods, 1995 to 1999 and 2000 to 2005. The average performance of the Palo Verde units meets or exceeds the average performance of the PWRs or all nuclear power plants for 16 of these 18 indicators. The average performance of Palo Verde is better than its peer group for 15 of the 18 indicators. I made these comparisons on a year-by-year basis, not accounting for how much the Palo Verde performance was under or over the comparison groups in any one year.

Based on these data, Palo Verde is a high performing station.

Q. DID YOU FORM ANY CONCLUSIONS REGARDING THE SAFETY OF THE PALO VERDE UNITS DURING THIS TIME PERIOD?

A. Yes, I concluded that there is no indication in the Performance Indicators, the NRC and APS documents, or the results of my interviews that the Palo Verde units were operated unsafely at any point in this time period.

Q. DOES NRC AGREE WITH THAT CONCLUSION?

A. Yes, on January 26, 2006, Bruce Mallett, Administrator of NRC Region IV, addressed the ACC and stated the same conclusion. Specifically for the years 2004 and 2005 Mallett said (Transcript page 18),

> First and foremost, the licensee, Arizona Public Service, has operated the Palo Verde nuclear plant in a safe and secure condition. They have ensured the protection of the public health and safety. And they have ensured the protection of the environment. They have also responded to emergent plant conditions and emergency events with safety as a primary focus.
>
> There have been problems, though, some identified by the licensee and some identified by the NRC, that have challenged the plant safety systems. If you remember in the first comments I made, those systems consist of people, facilities and procedures. This means that their performance is degraded in certain areas and that they and the NRC are taking actions to ensure improvements in these areas. This does not mean, however, that their operation is unsafe.

Q. YOU HAVE MENTIONED THE DISCOVERY IN 2004 OF VOIDED PIPING IN THE SUCTION LINES LEADING FROM THE

CONTAINMENT SUMP TO THE ECCS. WHY WAS THIS IMPORTANT?

A. In August 2004 NRC conducted a special inspection at Palo Verde following a finding by APS that some sections of the suction piping from the containment sump to the HPSI and containment spray systems were voided (i.e., did not contain water) in all three units. Initially, the voiding was a result of draining of the lines during ECCS testing conducted quarterly since the start of operations. This condition could affect the ability of these systems to perform their safety function in a loss of coolant accident. The inspection resulted in two potentially greater than green findings even though the condition had existed throughout the life of the plant. The two most significant findings of the inspection were

- Failure to maintain safety injection sump suction piping full of water in accord with UFSAR (Updated Final Safety Analysis Report), and
- Failure in 1992 to perform a written safety evaluation, in accord with 10 CFR 50.59, when the practice of intentionally draining the lines on plant restart was first implemented.

There were professional differences of opinion on whether the UFSAR specifically required that the lines be filled with water and on whether the ECCS pumps in question would be damaged by the air in the voided lines.

These differences were aired over several months at both the regional and headquarters levels of NRC, and, in the end, the NRC staff prevailed, viz. the risk significance of the finding was judged, by a narrow margin, to be sufficient to justify a yellow cornerstone under the ROP. The Inspection Report on this matter was issued on January 5, 2005, and the yellow cornerstone was issued on April 8, 2005.

As I write this testimony, the yellow cornerstone still exists, although most of the associated corrective actions have been accepted by the NRC. GDS says, at page 11 of its report, "While APS officials attempt to minimize this [yellow] rating,

stating that Palo Verde is in the 3rd column only because of the yellow finding,...the Action Matrix Summary reflects overall plant performance and is updated regularly..." That is not a correct interpretation of the yellow cornerstone. Rather, as Region IV Administrator Mallett told the ACC on January 26, 2006, (transcript page 24),

> They are in what we call the third column or yellow column [i.e., the second column of increased oversight] of our action matrix because they had a finding with this voiding issue in their emergency core cooling pipe system late 2004 that was risk significant. And we felt that needed to be corrected. So that's what put them into that column. Once they correct [accomplish] the actions they need to take for that specific issue and complete it, they will go back to the first column, or green column of performance where we don't have increased oversight of them.
>
> In addition to that action matrix, however, these other problems I listed, we issued them based on their performance, these two cross-cutting issues [of] problem identification and resolution and human performance. These have to be corrected by them[APS]. They have to address those issues. But they will still be in the green column with those issues.
>
> The reason we identified them [cross-cutting issues] is those are indicators that we believe lead you to getting into one of the columns to the right of the matrix... the yellow or red column. So we identify those issues early and hope to turn them around so...their performance doesn't get worse.

Q. RELYING ON THE COMPANY'S OWN SELF-CRITICAL DOCUMENTS, GDS CONTENDS THAT REGULATORY PERFORMANCE AT PALO VERDE HAD BEEN DECLINING FOR SEVERAL YEARS. IS THERE ANY CONTEMPORANEOUS EVIDENCE TO THE CONTRARY?

A. Yes. On August 16, 2004 NRC issued a report describing a May to July inspection of the APS program for Problem Identification and Resolution (PI&R), i.e., the corrective action program. (RJM_WP6RB) The report stands in stark contrast to the conclusions of the NRC in the January 5, 2005 inspection report relative to the voided sump suction piping. The PI&R inspection report stated that the "team determined that in general the corrective action program was appropriately

implemented; thresholds for identifying issues remained appropriately low and corrective actions were adequate to address conditions adverse to quality." A few examples were noted where problems were not properly identified, evaluated or corrected and operating experience reviews and actions were often extended. The inspectors also concluded "a positive safety conscious work environment exists at PVNGS."

Q. HAD THERE BEEN ANY INDICATION FROM NRC PRIOR TO THE JANUARY 5, 2005 INSPECTION REPORT THAT IT HAD DOUBTS ABOUT THE IMPLEMENTATION OF THE DESIGN AT PALO VERDE OR THE ADEQUACY OF 10 CFR 50.59 REVIEWS?

A. No, in fact there was contemporary evidence to the contrary. On August 27, 2004, NRC issued a report on a Safety System Design and Performance Capability Inspection. (RJM_WP7RB) This report described a 2-week, 5-person, on-site inspection in June and July "to verify that the licensee adequately preserved the facility safety system design and performance capability and that the licensee preserved the initial design requirements in subsequent modifications of the systems selected for review." The outcome of this inspection was excellent and contrary to the two most significant findings of the sump suction piping inspection that began only one month later.

Q. YOU HAVE CITED TWO EXAMPLES WHERE NRC INSPECTED SOME PALO VERDE PROGRAMS AND FOUND THEM SATISFACTORY, IF NOT SUPERIOR, AND THEN A SHORT TIME LATER FOUND SOMETHING QUITE DIFFERENT. HOW DO YOU EXPLAIN THESE DRAMATIC DIVERGENCES IN SUCH A SHORT TIME?

A. These two instances involving design implementation and problem identification and resolution demonstrate that, when dealing with an industry that has very high performance, extraordinary measures are applied by NRC to monitor performance so that early detection of a decline in performance is assured. They also indicate that the decline that has occurred at Palo Verde probably is relatively small. Finally, they indicate the high degree of subjectivity that remains in the NRC's reactor oversight process, as others have told NRC in the annual feedback on the

ROP that I described in Section 4, above. It is for this reason that I believe GDS overstates the case in the portion of its report (pages 11 to 15) addressing APS's regulatory performance.

Q. AT PAGES 2, 10 AND 11 OF ITS REPORT, GDS DISCUSSES THE PERFORMANCE IMPROVEMENT PLAN THAT APS ADOPTED IN OCTOBER 2005 AND CONCLUDES "BASED ON OUR EXPERIENCE WITH SIMILAR PLANS AT OTHER NUCLEAR PLANTS, GDS IS OPTIMISTIC THAT APS WILL BE SUCCESSFUL IN ACHIEVING IMPROVED PERFORMANCE AT PALO VERDE." DO YOU AGREE?

A. Yes. The PIP (Attachment 1 to GDS report) directs the activities that APS management has decided to undertake to reverse declining performance at Palo Verde. Within the Plan are specific action plans related to root causes identified by APS for the performance decline. NRC will review the effectiveness of the actions in the PIP in determining, among other things, whether the substantive cross-cutting aspects its inspectors identified have been suitably addressed. Successful completion of the actions in the PIP to improve the corrective action program and its utilization at the station will be instrumental in demonstrating that the needed improvements noted earlier by NRC have been made.

Q. WHAT CONCLUSIONS HAVE YOU FORMED ABOUT APS'S REGULATORY PERFORMANCE?

A. The new reactor oversight process that NRC implemented in 2000 provides four levels of increasing scrutiny of licensees above the normal level of NRC oversight. Palo Verde is now at the second level of increased oversight because of an error that was made in 1992 and found in 2004. There are recent indications that the station will be successfully returned to the lowest level of NRC scrutiny. For example, Mallett's statements to the ACC on January 26, 2006, (Transcript pages 24-25) about the corrective actions for the yellow column being separate from the substantive cross-cutting issues, as quoted above.

The cross-cutting issues did not cause the yellow cornerstone or the outages experienced in 2005. The NRC findings that contained these cross-cutting issues

were all green findings (low safety significance). NRC has acknowledged difficulty in understanding the significance of the cross-cutting findings. NRC has recently issued new guidance on identifying and resolving cross-cutting issues, guidance that was not available to assist either the NRC inspectors or APS in the period in which large numbers of these issues were identified for Palo Verde.

The only 2005 outage experienced at Palo Verde that involved actions by the NRC staff was the one in October concerning reexamination of the design basis for air entrainment in the suction line from the refueling water storage tank. My conclusions about APS's prudent handling of this unforeseeable backfit by the NRC staff are summarized below. Also, Region IV Administrator Mallett in his January 26, 2006 discussion with the ACC gave this event as an example of APS actions that "have been in compliance with our requirements and timely and thorough in response to events and emergent issues." (Transcript pages 19 – 20) These views are in marked contrast to those expressed about this outage at pages 31 to 35 and 39 to 40 in the report of GDS.

The NRC has described increased inspection efforts at Palo Verde owing to the yellow cornerstone. Mindful of these various statements, I conclude that there has been a decline in regulatory performance at Palo Verde from the previous level of excellence, and that APS and NRC are applying extra effort to reverse the trend. Neither APS nor NRC has said that performance at Palo Verde is imprudent or unsafe.

The Performance Improvement Process underway at Palo Verde is beyond NRC's requirements and expectations for a station at its level of performance and typical of such programs that have been implemented at many operating plants in the country, often more than once. Such processes always involve self-assessments that are expected by NRC and the industry generally to use hindsight and to identify opportunities for improvement in open, frank and often harsh terms.

Q. EARLIER IN THIS SECTION, YOU HAVE DISCUSSED THE PAST OPERATIONAL AND REGULATORY PERFORMANCE OF PALO VERDE. AT PAGE 52 OF ITS REPORT GDS RECOMMENDS THAT THE ACC ESTABLISH A MINIMUM STANDARD FOR FUTURE PERFORMANCE AT PALO VERDE, INCLUDING PENALTIES IF THE PLANT FAILS TO MEET THIS STANDARD. WHAT HAS THE NRC SAID ABOUT SUCH STANDARDS?

A. On July 24, 1991, the NRC published in the Federal Register a Final Policy Statement on "Possible Safety Impacts of Economic Performance Incentives". (RJM_WP8RB) The Policy Statement reflects the NRC's concern "that certain forms of economic performance incentive (EPI) regulation may adversely affect the operation of nuclear plants and the public health and safety." In the Policy Statement, the NRC identified four types of incentives for which it had particular concern because they "could directly or indirectly encourage the utility to maximize measured performance in the short term at the expense of plant safety (public health and safety)."

The NRC also said that it was concerned

> "...about any State public utility commission's undue reliance on a utility's corrective actions following an incident to justify the disallowance of costs related to the incident.... For example, where a State public utility commission observes that a utility has modified its procedures following an incident, infers from the utility's actions that the original procedures must have been inadequate, and then disallows certain costs on the basis of such assume inadequacies, the utility will have a strong disincentive voluntarily to enhance or improve its operations and procedures in the future. Such State public utility commission action can discourage utilities from making needed improvements in procedures and operations and, thus, can be detrimental to the long-term safety of operation."

The NRC went on to identify four features that it had reviewed

> "...and believes State Public Utility Commissions (PUCs) may want to consider... in establishing programs that prompt licensees to both economically and safely operate nuclear power plants. These features include

> (1) capacity factor targets based upon industry's average performance to account for problems throughout the industry,
> (2) equal opportunities for rewards and penalties,
> (3) the 'banking' of superior performance to offset lower performance, and
> (4) using performance measures of the entire system instead of those for a specific unit."

NRC also noted in the Policy Statement that it requires its licensees to inform it whenever a State PUC develops or substantially revises EPIs.

I note that the recommendation by GDS does not include three of the four features that NRC offered in its Policy Statement for consideration by State public utility commissions.

On June 26, 2001, Joseph R. Gray, NRC's Associate General Counsel for Licensing and Regulation, presented testimony on behalf of the NRC to the U.S. Senate Committee on Energy and Natural Resources concerning "Price-Anderson Act Renewal and Nuclear Energy Production and Efficiency Incentives". (RJM_WP9RB) With regard to incentive provisions such as one then being considered by the Senate, Gray said

> "The [NRC] has previously elaborated upon the potential impacts of performance incentives in a 1991 policy statement 'Possible Safety Impacts of Economic Performance Incentives: Final Policy Statement,' published in the Federal Register on July 24, 1991 (56 FR 33945). The Commission stated a concern with incentive plans such as the one proposed here, that, in the interest of real or perceived short-term economic benefit, the utility might hurry work, take short cuts, or delay shutdown for maintenance in order to meet a deadline, a cost limitation, or other incentive plan factor. Therefore, such an incentive program could directly or indirectly encourage the utility to maximize measured performance in the short term at the expense of plant safety and public health and safety.... A primary problem with the proposed production incentive is the short-term interval for measuring performance. Performance measurements for short-term intervals would encourage the licensee to focus on the short-term target, potentially diverting attention from long-term goals of reliability and

operational safety."

Q. HAVE YOU FORMED AN OPINION ABOUT THE NEED FOR AN ECONOMIC PERFORMANCE STANDARD FOR PALO VERDE?

A. Yes. In my opinion an economic performance standard is not needed for Palo Verde at this time based on its long-term record of superior performance and the Performance Improvement Program now underway to ensure such performance in the future.

6. PRUDENCE ASSESSMENT OF REFUELING WATER TANK OUTAGES

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section I will show that the Outages of Units 2 and 3 in October 2005 were not the result of imprudence, as claimed by GDS. Rather, these outages resulted from a new question that NRC inspectors raised, one that they and APS had not come across before, and one that APS could not have known beforehand. In other words, the inspectors imposed a backfit on Palo Verde in a way that APS could not reasonably anticipate, and the backfit led to the outages. Thus, APS was prudent in its dealings with this issue both before and after it was raised by the NRC.

Q. PLEASE DESCRIBE THE OUTAGES CONNECTED WITH THE SUCTION HEADER ON THE REFUELING WATER TANK (RWT).

A. The RWT issue arose during an NRC inspection pursuant to its Inspection Procedure 95002 "Inspection for One Degraded Cornerstone or Any Three White Inputs in a Strategic Performance Area." The inspection was a standard NRC follow-on to the problem with voided piping from the containment sump identified by APS in 2004 as having occurred in 1992, i.e., the issue that led to NRC's conclusion that Palo Verde had a degraded (yellow) cornerstone for Mitigating Systems, as discussed more fully in Section 5, above. The inspection occurred over

the period September 12 to December 12, 2005. Four NRC inspectors and one inspector intern from Region IV, one inspector from Region III, one NRC headquarters subject matter expert, and one NRC contractor conducted the inspection. During the inspection one of the NRC contractors raised a question about the design of the suction header serving several safety systems in each Unit.

As NRC Region IV Administrator Bruce Mallett later told the Arizona Corporation Commission on January 26, 2006 (Transcript pages 42-44),

> In the October [2005] time frame, when we raised this issue about the design flaw, it was a new question, okay, one that we hadn't come across before, nor had they [APS] to the best of my recollection. And so they did what we expected. They searched that out and said we can't answer the question – I am over simplifying – so that would put us in a condition we don't believe is within our design. If you can't answer [the] NRC, and we [APS] can't answer it within this certain time frame, we have to shut the plant down by our technical specifications until we get it resolved. And that's what they did....All I can say in this case is that it was a question we raised and they did the right thing when they couldn't answer the question...***In this instance we didn't determine that they should have found it beforehand....*** But the issue, I think, was it was a new question that was asked. If they were investigating and looking at that system, you would expect them to find out, but I am not sure we would expect them to go in and look at that system at the time we were looking at it....We have an inspection we are conducting at the time and we have a report that is coming out....we will probably issue it tomorrow....And that report will make our conclusions final in that instance that we looked at. [emphasis added]

As Mallett acknowledged, the question was a new one. It went beyond the questions about air entrainment in these lines that had been addressed in NRC's original licensing review of the plant. It went to the adequacy of the original licensing basis, and thus was outside the scope of an extent of condition review for the problem found in 2004 with voiding in the sump suction lines, which was a design basis implementation issue; i.e., the question went to whether the design the NRC had approved back before the plant operated was adequate rather than

whether APS had properly implemented the NRC-approved design.

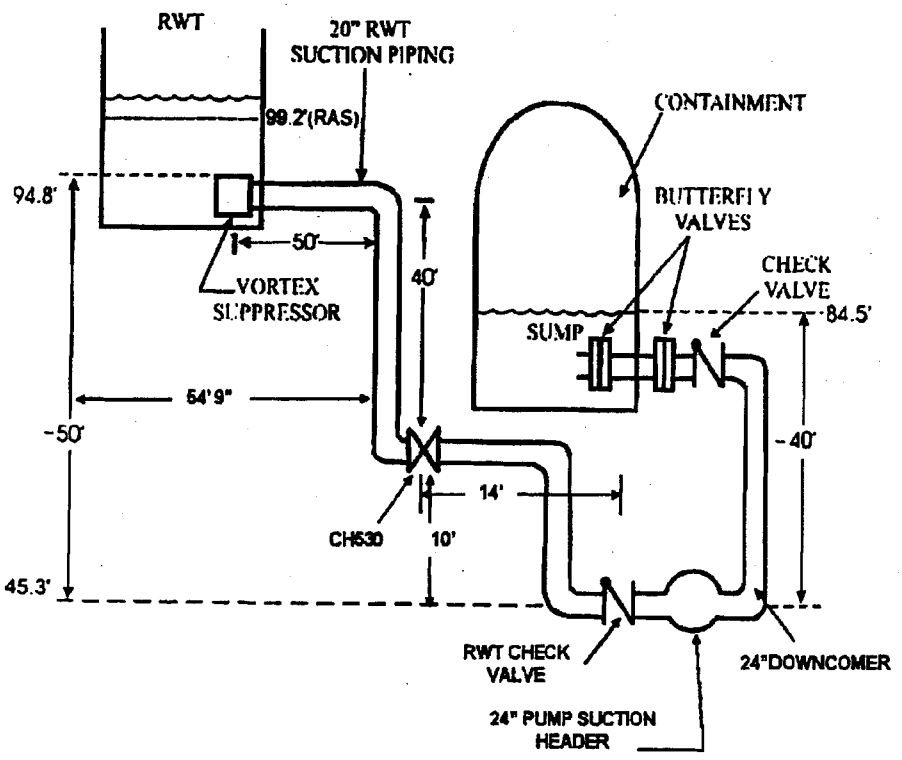
The interaction between APS and the contract inspector started out routinely. APS first showed him how the potential for air entrainment in the RWT suction line had been dealt with in NRC's operating license review of the plant, and how the conditions flowing from that review had been factored into Palo Verde's design. That approach was deemed insufficient by the contract inspector. Then came the new question: What about the dynamic behavior of the air water mixture during the switch-over of pump suction from the RWT to the containment sump? Because the new question went beyond the original licensing basis of the plant, it could not be readily answered by APS. Accordingly, the safety systems in question were declared inoperable, and the two operating units (Units 2 and 3) were shut down on October 11 in accordance with their Technical Specifications. Unit 1 was already shut down for refueling at the time. The NRC's surprise question was resolved sufficiently to support a system operability declaration for Units 2 and 3, and they were restarted on October 20. The total outage time for each of the two units was about nine days. The RWT issue did not prolong the Unit 1 refueling outage.

Q. PLEASE DESCRIBE IN MORE DETAIL THE QUESTION THAT THE NRC CONTRACTOR RAISED THAT APS COULD NOT READILY ANSWER.

A. I will do that, but first I need to describe the safety systems involved in the question. The question concerned the design of the suction piping (labeled as 20" RWT SUCTION PIPING in the schematic diagram shown below) that feeds the containment spray system and the emergency core cooling system (ECCS). These systems are required to function to mitigate the consequences of a breach in the reactor coolant system that leads to a loss of coolant accident (LOCA).

The suction header (a line running perpendicular to the lowest horizontal line in the schematic diagram and labeled '24" PUMP SUCTION HEADER') receives water from several sources during recovery from a LOCA. First, during the so-

called injection phase of a LOCA, makeup water is pumped from the refueling water tank into the reactor coolant system, to replenish water that has discharged out the breach through which the loss of coolant occurs, and to the containment to cool the steam that discharged from the breach. When the RWT is emptied, recovery from the accident enters its recirculation phase. An instrument that detects low water level in the refueling water tank sends a signal to the control room noting the changeover from injection to recirculation. The signal is called the recirculation actuation signal or RAS and the corresponding water level in the RWT is shown in the schematic diagram.



In the recirculation phase, water is recirculated from the containment sump, through the ECCS or containment spray pumps, into the reactor or containment atmosphere. The switchover from the injection phase to the recirculation phase of recovery from a LOCA occurs in every pressurized water reactor (PWR).

The Palo Verde units were among the last to be designed in the United States. They were based on a standardized design (System 80) provided by the Combustion Engineering Company. As such, they incorporated design refinements that had been made on earlier models sold by Combustion and other manufacturers of PWRs. To many people, the Palo Verde design is among the best now operating anywhere in the world. Refinements in this design include the arrangement of the two lines from the RWT and the containment sump that feed the suction header so that neither the closure of an automatic isolation valve nor prompt operator action is required after a LOCA occurs. Rather, there are passive design features that assure emergency pump suction is transferred from the RWT to the containment sump at the appropriate time. Later, after the transfer has occurred, the operating procedures at Palo Verde require the operators to close motor operated valves in the lines coming from the RWT. (Palo Verde Emergency Operating Procedure 40EP-9EO03, Revision 20, pages 24 and 25 of 69, Steps 50 and 51, and Associated Technical Guideline 40DP-9AP08 Revision 13, pages 39 and 40 of 64)

The foregoing schematic diagram serves to illustrate the passive nature of this design, a design feature that is much admired in reactor safety systems because, in general, the fewer parts that have to move in an emergency the better. The two lines feeding the pump suction header are the RWT suction piping and the line from the containment sump (labeled in the schematic as 24" DOWNCOMER). With this arrangement, when the water level drops low in the suction piping from the RWT, the pressure in the containment sump line leading to the suction header overcomes the pressure in the RWT suction piping leg and closes the check valve in that piping (labeled as RWT CHECK VALVE in the schematic). After the check valve closes, all of the supply of water to the ECCS and containment spray pumps comes from the containment sump.

When Combustion Engineering designed this arrangement it required that Palo

Verde and other plants incorporating the System 80 standardized design must supply 16 feet of elevation difference between the water in the containment sump and the pump suction header. As can be seen in the schematic, the Palo Verde layout provides 40 feet of elevation difference, more than enough to assure that the check valve in the RWT suction piping would close, thus assuring that the ECCS and containment spray pumps would perform their function during the recirculation phase of LOCA recovery.

This arrangement enabled the switchover from the injection phase to the recirculation phase of recovery from a LOCA to occur without credit being given for operator action in the safety analysis. Over the years, as a general philosophy, NRC had encouraged the development of safety system designs that did not depend on early manual action by operators to cause equipment to change in the high stress environment that would follow a LOCA. Designers had struggled with how to implement this idea on the RWT suction lines typical of pressurized water reactors. Some of them had opted for a valve that automatically closed to isolate the RWT from the containment sump. Others relied on early operator action. The disadvantage of the automatic valve design was that the valve might malfunction and close prematurely, thereby shutting off the supply of water to the ECCS. The disadvantage of relying on early operator action is that the operator would be distracted by other events and forget to accomplish the required actions. The arrangement developed by Combustion Engineering in the System 80 design used at Palo Verde solved this dilemma. It eliminated the need to rely on either operator action or automatic isolation valves. (Although operators are instructed in the emergency operating procedures to close the isolation valves in these lines (labeled CH350 in the schematic) as an added precaution, they are not required to do so in the immediate aftermath of a LOCA and their action to do so is not credited in the safety analysis.)

The NRC headquarters staff reporting to me approved this passive design feature

as part of its review in the late 1970s and early 1980s of the Safety Analysis Report for System 80 and the Final Safety Analysis Report for Palo Verde. Our conclusion that the Palo Verde design was sufficient to prevent air entrainment from the RWT did not include consideration of the dynamic effects that could occur in switching the pump suction from the refueling water tank to the containment sump following a loss of coolant accident. The calculations for Palo Verde were like the calculations we accepted for every other PWR in the Untied States; they were static calculations (i.e., stationary water sitting in the lines), not dynamic calculations (i.e., water oscillating up and down as pressure fluctuates in the lines during switchover).

Just before the NRC supplemental inspection in October 2005, Craig Baron, one of the contractors serving on the NRC inspection team, told APS that the inspection team would look at the refueling water tank and other water sources to determine if their designs had been implemented. APS and its contractors assembled 35 volumes of documentation on the RWT and five other safety systems in preparation for the inspection to demonstrate how the original designs of these systems had been implemented. Early in the inspection Baron asked whether, during the switchover from injection to recirculation, air from the RWT could be entrained in the suction piping leading to the suction header and then be carried into the pumps, leading to their damage and loss of function.

Q. HOW DID APS INITIALLY RESPOND TO THIS QUESTION?

A. The APS staff prepared a short summary of the licensing basis described above for the RWT suction piping leading to the suction header. The document showed how the interface requirements (between the System 80 reactor and the rest of the plant supplied by the plant's architectural and engineering contractor, Bechtel) that were approved in the operating licensing review by NRC had been met by the design configuration at Palo Verde that had been in existence since the plants first went into operation (including the requirement for 16 feet of elevation difference

between the containment sump level and the suction header). The document provided by APS to Mr. Baron concluded that the original design basis was intended to preclude air entrainment. (NRC 95002 Inspection Action Item 51 "Isolation of the PVNGS RWT and Potential for Air Entrainment at RAS, Revised Assessment attaching original assessment," APS, October 4, 2005. RJM_WP10RB)

Q. DID THE NRC CONTRACT INSPECTOR ACCEPT THE FIRST APS ANSWER?

A. No. Baron pointed out that, during the draw down period when the water level drops out of the RWT down into the line leading to the suction header, a vortex could form and entrain air in the section of pipe that transitions from a horizontal to a vertical run (see schematic diagram above). At that time, most of the flow to the pump suction header is coming from the RWT suction piping, and the check valve is open. The issue Baron raised is a dynamic effect as compared to the static analysis made in the original design.

A revised APS response to his question, issued on October 6, said that there was sufficient margin in the design to assure that these dynamic effects could be overcome and the intent of the design would be met. The revised response also provided evidence that Combustion Engineering had been aware of the potential for air entrainment when the interface requirements related to the design had been established. The revised response was discussed with Baron, and additional calculations were requested of APS's consultant Westinghouse to confirm that the margin in the static design basis was sufficient to accommodate the dynamic effect raised by Baron. The APS Engineering staff and Operations staff judged the revised response sufficient to justify continued operation of Units 2 and 3.

The information supplied to Baron on October 6 is important because it is the source of an apparent misunderstanding on his part that eventually made its way

erroneously into the January 27, 2006 Supplemental Inspection Report. The information he received included a question by the NRC staff and an answer by Combustion Engineering back in 1976 that was part of the licensing basis for Palo Verde. The information is identified by the title "ECCS Piping Interface Requirement per 'Outstanding CESSAR Review Matter' Number 38," Calculation MISC-REC-249, Combustion Engineering, Inc., Engineering Department, Approved by R. P. O'Neill, 1/19/76. (RJM_WP11RB) It describes the problem raised by the NRR licensing staff (possible air entrainment in the RWT suction piping) and then goes on to describe how CE would resolve the issue by providing an elevation difference between the containment sump level and the check valve in the RWT line to assure closure of the check valve soon after the RWT was emptied and before air from the RWT could enter the sump suction header.

This CE document clearly shows that air entrainment in the line from the RWT to the ECCS and containment spray pumps and the potential for cavitation in the pumps was considered by CE and foreclosed by the CESSAR design and interface requirements. It also shows that NRC staff raised this matter and, because the 16-foot elevation differential was accepted in the Final Safety Analysis Report for Palo Verde, the NRC staff accepted the answer.

These facts are at variance with statements at page 12 of the January 27, 2006 NRC Supplemental Inspection Report concerning this point. (Attachment 3 of GDS report) At page 12 of the report, NRC said, "The inspectors determined that the potential air entrainment into the ECCS suction header from the RWT was a licensee performance deficiency. This condition did not conform to the plant design basis and had not been analyzed." To the contrary, the plant was in conformance with its design basis, the design basis had taken into account the potential for air entrainment, the design had been found by NRC in the late 1970s to preclude entry of air into the suction header, and the inspectors had been provided with documentary evidence to prove those points. The problem that then

arose was that the inspector did not accept the technical basis for the design that had been accepted by the NRC in the original licensing of Palo Verde. Instead, he asked for a dynamic analysis to prove the adequacy of the design.

Thus, the new question the contract inspector raised did not concern compliance with the design (i.e., the issue that had led to the yellow cornerstone on which the inspection was intended to follow up and for which APS had prepared). Rather the new question concerned the adequacy of the design. The inspector challenged the adequacy of the license authorization that the NRC granted 20 years ago. He wanted more and better evidence that air entrainment would not damage the ECCS and containment spray pumps. He wanted dynamic calculations not static calculations. It is unreasonable to expect that APS could have anticipated that he would do so, and that essentially is what Mallett told the ACC on January 26, 2006 (quoted above). This is an understanding of the situation that is in stark contrast to the story told by GDS at page 32 and 33 of its report wherein it is claimed that APS did not do a thorough enough extent of condition of analysis in preparation for the inspection and APS did not understand the design of its plant. Clearly, the facts described above show those conclusions by GDS to be erroneous.

Q. HOW DID APS ADDRESS THE NEW QUESTION, AND HOW DID IT TURN OUT?

A. APS engaged Westinghouse to provide an answer to the question. Westinghouse initially tried to prove that margin provided by containment pressure tended to support the adequacy of the static design to account for the dynamic design question. It was not until late in the afternoon of October 11 that word was received by APS from Westinghouse that the calculations could not support the adequacy of the static design to account for the dynamic design question if there were low temperatures in the RWT at the time of a LOCA, temperatures that were allowed by the Plant's Technical Specifications. This new information from Westinghouse resulted in discussions at Palo Verde among staff from Operations,

Engineering and Regulatory Affairs at a Management Review Team meeting, leading to a decision in the control rooms to declare the RWTs inoperable and shut down Units 2 and 3. Their shutdowns were commenced about 4 o'clock in the afternoon on October 11.

Q. THEN WHAT HAPPENED?

A. APS promptly undertook maintenance work in Units 2 and 3 so as not to waste the opportunities afforded by access to the containment during reactor shutdown, e.g., maintenance on reactor coolant, main feedwater and auxiliary feedwater pumps and the main generator in Unit 2, and repair of some valves and the auxiliary feedwater pump in Unit 3. Meanwhile, the APS engineering staff worked with a consultant to develop a new analytical approach for determining whether the as-built conditions of the RWT suction piping and the pump suction header were adequate to preclude air being entrained into the safety pumps for the dynamic design scenario posed by the contract inspector.

Q. WHAT WAS THE NEW ANALYTICAL APPROACH?

A. APS engaged a subsidiary of Westinghouse called Fauske and Associates and a subject matter expert named Robert Henry who works there to develop models and perform analyses that had never been attempted before in the design or licensing of any nuclear power plant in America. This is an important point – the question raised by the NRC contractor was sufficiently beyond the design basis of any power reactor in the country that one of the leading hydrodynamic analysts in the world had to be engaged in a crisis atmosphere to advance the state of the art.

Q. WOULD YOU CALL THIS A BACKFIT, I.E., A CHANGE TO THE PREVIOUSLY APPROVED LICENSING BASIS THAT APS COULD NOT ANTICIPATE?

A. Yes, but when you have a NRC technical question about a plant's safety, you are expected to get an answer not challenge the appropriateness or fairness of the question of the question. Once such a question is posed for the operations crew at an operating plant, that is, a question about the ability of the safety equipment to

perform its intended function, it has to be answered by a senior reactor operator in a short time prescribed by the Technical Specifications or the equipment needs to be declared inoperable and the appropriate steps taken. In this case the plant had to be shut down until the question could be answered and the operability of the safety equipment involved could be demonstrated.

Q. HOW DID DR. HENRY'S ANALYTICAL APPROACH TURN OUT?

A. He produced a 36-page report on October 17 concluding that the original design was adequate. Specifically his report said that the design interface criterion assures closure of the flow path through the RWT suction piping to the pump suction header, once the RWT inventory is depleted; that the interface criterion is satisfied in a conservative manner at Palo Verde (40 feet elevation difference rather than 16 feet between the containment sump water level and the ECCS suction header); and that when consideration is given to the dynamic response of the water flowing through the check valve there is always sufficient pressure differential to close the RWT check valve in all LOCA sequences. He went on to say that although some air would be pulled into the RWT suction piping, it would not result in air being pulled into the safety pumps.

Q. DID NRC ACCEPT DR. HENRY'S CONCLUSIONS?

A. Yes. The NRC sent its own subject matter expert from its headquarters staff in Rockville, Maryland, Steve Unikewicz, to Palo Verde to review Henry's report. According to APS staff, Unikewicz accepted the technical analyses that were presented in the report but asked APS to have it revised so that it could stand alone. Dr. Henry provided Revision 1 of the report on November 17, 2005. The report expanded from 36 to 103 pages between the two editions and the conclusion was essentially unchanged, namely, "Dynamic hydraulic mechanisms associated with suction transfer are presented that demonstrate that the RWT suction flow terminates, and full suction flow is provided by the containment sump *prior to the point* where significant (bulk) quantities of air are entrained in the RWT suction and subsequently transported to the High Pressure Safety Injection and

Containment Spray pump suctions." In other words, the check valve closes before air can damage the pumps.

Q. WHEN DID THE TWO SHUTDOWN UNITS RETURN TO POWER OPERATIONS?

A. Units 2 and 3 returned to power shortly after midnight on October 21, based on the justification provided by Dr. Henry's first report.

Q. DO YOU HAVE ANY UNDERSTANDING OF WHY THE EXPERT FROM NRC HEADQUARTERS REQUESTED THAT THE REPORT BE MODIFIED AFTER THE UNITS HAD BEEN RESTARTED AND THE REVISED REPORT FILED ON THE PALO VERDE LICENSING DOCKET AT NRC?

A. My understanding is that the NRC Headquarters' project manager for Palo Verde told APS staff that he was requesting that the report be filed on the Palo Verde licensing docket (as opposed to simply letting the documents be filed in station records as the basis for the plant operability decisions that had been made) so that it would become available for NRC to use to "solve some issues at other plants." He also pressed them for the data that APS had obtained in tests it conducted in connection with the voided piping issue in 2004 to support its claim that pumps could function with the amount of air that was involved.

Q. PLEASE EXPLAIN WHY NRC WOULD WANT THAT INFORMATION PUT ON THE PALO VERDE LICENSING DOCKET.

A. Earlier in my testimony I described the process by which NRC addresses generic issues. In the case of its apparent concern with air entrainment in RWT suction piping, NRC would be expected to issue a Generic Letter if it was a safety issue of sufficient significance to require a new analysis to be performed, and potentially a design modification, as occurred at Palo Verde. For reasons unknown to me, the issue is being raised on a case-by-case basis rather than as a generic issue.

Q. YOU SAY THAT THIS AIR ENTRAINMENT ISSUE IS BEING PURSUED ON A CASE-BY-CASE BASIS. AT PAGE 35 OF ITS REPORT, GDS SEEMS TO AGREE WITH YOU BY PROVIDING A LONG QUOTATION FROM THE NRC'S JANUARY 27, 2006 INSPECTION REPORT THAT

CRITICIZED BUT DID NOT ISSUE A VIOLATION TO APS FOR NOT KNOWING ABOUT CERTAIN "OPERATING EXPERIENCES". WAS APS IMPRUDENT FOR NOT KNOWING OF THESE PREVIOUS REGULATORY EXPERIENCES?

A. I conclude that APS's lack of knowledge of these experiences was not because of imprudence and not from a lack of programs that keep the company current on developments in the industry. Rather, the lack of knowledge by APS owed to the obscurity of the information about these events and the failure of NRC to attach generic significance to them.

In the January 27, 2006 Inspection Report NRC staff referred to two other plants where NRC had raised the issue (i.e., a regulatory issue, not "operating experience"), namely, Brunswick and D.C. Cook, the former being a boiling water reactor compared to the PWRs at Palo Verde and the latter being a PWR with different reactor and containment designs than Palo Verde.

I have reviewed descriptions of the pump suction issues that NRC raised at those two plants. In the case of D.C. Cook, a contract inspector of the NRC raised a question about whether the containment sump would fill rapidly enough with water to be able to supply the required suction pressure for the ECCS pumps before the refueling water tank was empty and pump suction was switched to the sump. American Electric Power, the licensee for the Cook plant, could not answer the question quickly because it was beyond the original design basis of the plant. Accordingly, both units at Cook were shut down. Although the issue at Cook involved pump suction issues, it was different in significant ways from Palo Verde, namely, it involved a different postulation of circumstances leading to air entrainment in the RWT suction piping, it involved a different piping configuration (horizontal rather than vertical), and it involved a highly compartmentalized ice condenser pressure-suppression containment rather than a much larger and less compartmentalized dry containment like Palo Verde. (E-mail entitled "ASME

Study" from Jeffrey Clark, NRC Region IV, Chief of Engineering Branch 1, to Daniel Hautala, APS, November 2, 2005, transmitting an ASME paper from the Proceedings of the 2001 International Joint Power Generation Conference, New Orleans, June 4-7, 2001, "Air Entrainment in a Partially Filled Horizontal Pump Suction Line," R. C. Sanders, et al.)

The circumstances at Brunswick were even more remote from the Palo Verde situation. The experience was documented in an INPO Operating Experience Report dated November 10, 2003. In short, it involved potential air entrainment in the Condensate Storage Tank due to vortexing prior to completion of the auto transfer (on reaching low level in the condensate storage tank) of the suction of the high pressure coolant injection pump to the torus of the containment. (Brunswick is an old, small, boiling water reactor with a first generation pressure suppression containment that has no resemblance to the dry containment used at Palo Verde.)

APS had not reviewed reports of either the Cook or Brunswick experiences prior to the Fall 2005 Supplemental Inspection at Palo Verde. Neither of these reports would be expected to set off alarm bells at Palo Verde, or any of the other operating PWRs with large dry containments, because Brunswick is a boiling water reactor with a pressure suppression containment and Cook has an ice condenser containment. Thus, neither experience has direct applicability for large dry containments that are typical of the vast majority of PWRs. The NRC Supplemental Inspection Report of January 27, 2006 at pages 10 and 11 identified APS's failure to know of these experiences in advance of the inspection as a "performance deficiency" but did not identify it as either a finding or a violation.

It is instructive to note that no malfunction or other off-normal events were associated with either the Cook or Brunswick situations, so the experiences were regulatory experiences not operating experiences. Licensees depend primarily on NRC to use generic communications to inform them of new regulatory

requirements or new safety information flowing from regulatory experiences. NRC has not done so in the case of air entrainment in ECCS suction lines. Also, I do not fault APS staff for failure to know of the ASME publication associated with the Cook experience because of the large number of technical reports published, the relative obscurity of this particular conference, the lack of a nexus between the Cook design and the Palo Verde design, and the lack of notice of the importance the NRC staff or its consultants attached to the paper. Thus, I do not find that APS can be faulted for being unaware of or failing to take advantage of these two experiences before the RWT-related shutdown at Palo Verde.

Q. SUBSEQUENT TO RAISING IT AT PALO VERDE, HAS THE NRC RAISED THE RWT AIR ENTRAINMENT ISSUE ELSEWHERE?

A. Yes. After raising the RWT air entrainment issue at Palo Verde, Region IV inspectors raised it at San Onofre, a two unit nuclear station that was designed by Combustion Engineering and is operated by Southern California Edison. San Onofre is in the same peer group as and began operation a few years before Palo Verde. Edison was only able to answer the NRC's question without shutting down its station because APS supplied the Henry Report for Southern California Edison to use in answering the NRC's query.

Q. HAVE YOU RECENTLY LEARNED OF ANOTHER PLANT WHERE NRC RAISED AIR ENTRAINMENT ISSUES RELATIVE TO SAFETY SYSTEM PERFORMANCE?

A. Yes, I have learned in preparing for this testimony that on January 27, 2005, the same NRC contract inspector, Craig Baron, raised the issue of air entrainment on a special NRC "pilot inspection" at the Kewaunee nuclear power plant in Wisconsin. This was one of four pilot inspections of this type that includes challenges to the adequacy of the existing design basis. No such inspection has yet been conducted at Palo Verde. Baron asked if air entrainment had been considered in the design of the auxiliary feedwater (AFW) system at Kewaunee. After several days of analysis by the licensee, the unit was shut down because a way to get air into the pumps was discovered that had not been considered in the original design. On December

22, 2005, the Wisconsin Public Service Commission found "that the costs associated with [this outage] were not imprudently incurred because the record does not support the allegations [by witness William R. Jacobs, Jr. of GDS Associates, Inc.] that revisions to the AFW system should have been made in the past in order to avoid the issues resulting in the outage." (RJM_WP12RB, pg. 24)

Q. WHAT IS THE SIGNIFICANCE OF THIS INFORMATION ABOUT HOW THE AIR ENTRAINMENT ISSUE WAS RAISED AT PALO VERDE AND OTHER NUCLEAR POWER PLANTS TO THE QUESTION OF THE PRUDENCE OF APS?

A. I conclude that APS was not imprudent for not anticipating the surprise question from contract inspector Baron because

- APS had no reasonable way to be informed of the regulatory issues raised by NRC at Brunswick and Cook or of the ASME paper that was associated with the Cook experience, and
- APS had no reasonable way to be informed of the air entrainment issue raised by NRC contract inspector Baron at Kewaunee on January 25, 2005 as part of a new inspection initiative NRC was undertaking on a pilot basis.

The fact that NRC inspectors later raised the issue at San Onofre is further proof to me that the inspectors are following an unauthorized, case-by-case imposition of a new requirement.

The actions by the NRC inspectors to raise the dynamic aspects of the switchover of ECCS suction in PWRs from the RWT to the sump constitute a backfit because such effects were not considered in the original licensing basis for these plants. Disregard for the original licensing basis is one of the complaints that the nuclear industry has voiced about NRC implementation of the reactor oversight process, as I described in Section 4, above. Additionally, this backfit was not done in accord with NRC procedures, which would have required it to be technically justified as being required for assurance of adequate protection of public health and safety. It also would have had to be approved by senior management in NRC's Office of

Nuclear Reactor Regulation. There is no reasonable way APS or any other NRC licensee can anticipate spontaneous backfits of this type, conducted outside of NRC's rules and procedures.

Nonetheless, after the new question about dynamic effects was raised at Palo Verde, APS had to either answer it on the spot or shut the operating units down until it was answered. The latter approach was the only one available to APS because of the way the issue was raised by the NRC, i.e., without advance notice of the backfit, and because of the technical complexity of the method required to be used to answer the question. Thus, APS actions were prudent, both before and after the question was raised. Also, Region IV Administrator Mallett in his January 26, 2006 discussion with the ACC gave this event as an example of APS actions that "have been in compliance with our requirements and timely and thorough in response to events and emergent issues." (Transcript page 19 – 20)

In the final analysis, the original design of the RWT suction piping was shown to be adequately safe to justify resumption of operations of the two units with the same plant equipment, operating procedures and training that existed prior to their shutdown and the same ones that are in use at all three Palo Verde units today.

7. SUMMARY OF CONCLUSIONS

Q. WHAT GENERAL CONCLUSIONS HAVE YOU MADE ABOUT THE NRC REGULATORY PROCESS THAT RELATE TO THIS PROCEEDING?

A. I have made the following conclusions about the NRC process for overseeing reactor safety as it bears on the issues of this case:

- There are differences between the standards the NRC employs and the

standards applicable to a prudence determination.

- The NRC's first and foremost requirement is that nuclear plants operate safely, and there is no dispute that Palo Verde has done so.
- The NRC does not consider whether utility management's actions were reasonable at the time such actions were taken, unlike economic regulatory bodies such as the ACC. Rather, the NRC uses hindsight to continually improve safety performance and has done so successfully over the years. NRC actions and documents generally can be relevant only to the prudence of utility management actions taken after learning of the NRC action or receiving the NRC document in question.
- The NRC license for every nuclear power plant in the U.S. contains technical specifications with prescriptive rules concerning how operability of safety equipment must be quickly determined whenever questions are raised about conformance with those specifications.
- NRC normally uses Generic Letters or Information Notices for new safety issues, and industry depends on NRC to do so, but they have not done so in the case of the RWT air entrainment issue that NRC inspectors brought to Palo Verde in October 2005.
- NRC has rejected some of its past efforts, such as the Watch List, as being unduly subjective and lacking in guidance to licensees.
- The current Reactor Oversight Process is generally recognized as a considerable improvement over the past, but the NRC and the stakeholders in the process have recognized that it has weak areas, including areas that bear on NRC assessments of Palo Verde, e.g., NRC inspector acceptance of the original design basis of a plant and the role of NRC's identification of cross cutting issues.

Q. WHAT CONCLUSIONS HAVE YOU FORMED REGARDING THE SAFETY OF THE PALO VERDE UNITS DURING THE TIME PERIOD 2004 TO 2005?

A. There is no indication in the NRC correspondence, in my interviews with APS

staff, or in APS documents I reviewed that the Palo Verde's units were operated unsafely at any point in this time period. On January 26, 2006, Bruce Mallett, Administrator of NRC Region IV addressed the ACC and made the same conclusion.

Q. WHAT GENERAL CONCLUSIONS HAVE YOU MADE ABOUT THE PERFORMANCE OF THE PALO VERDE STATION?

A. The Performance Indicator data reveal that Palo Verde has performed within industry norms when compared to its peer group, other PWRs and the nuclear industry. More specifically, the performance of the Palo Verde units was average or above in 16 of the 18 performance indicators that I examined from 1995 to 2005. Palo Verde's performance relative to its peers, PWRs and the industry slipped in 2004 and 2005, but all plants have their ups and downs. To account for this, I recommend the approach suggested by the ACC in a previous ruling, i.e., one must look at both a plant's "successes" and "failures" in order to perform a fair review. The NRC performance indicator data show Palo Verde's performance to be superior when viewed over the period 1995 to 2005.

Q. WHAT CONCLUSIONS HAVE YOU FORMED ABOUT APS'S REGULATORY PERFORMANCE?

A. Palo Verde was treated by NRC as a superior plant under NRC's old process for overseeing nuclear power plants. It received SALP scores that averaged 1.5, was never on the NRC's Watch List, never received a Trending Letter, and never received a shutdown order.

The new reactor oversight process that NRC implemented in 2000 provides four levels of increasing scrutiny of licensees above the normal level of NRC oversight. Although Palo Verde is now at the second level of increased oversight, it is there because of an action that was taken in 1992, and there are indications that it will successfully return to the lowest level of NRC scrutiny. The vast majority of nuclear power plants have undergone increased inspection efforts by NRC at some

time in their life.

NRC has raised concerns with cross-cutting aspects of Palo Verde operations (human performance and problem identification and resolution). These issues did not cause the yellow cornerstone or the outages experienced in 2005. NRC has recently acknowledged difficulty in understanding and dealing with cross-cutting findings and in early 2006 proposed new ways of dealing with them.

The Performance Improvement Process underway since October 2005 is beyond NRC's expectations for a station at Palo Verde's current level of performance. The PIP is typical of improvement programs that have been implemented at many operating plants, usually when they were experiencing worse performance problems than Palo Verde. Such processes always involve self-assessments that use hindsight to identify opportunities for improvement, and they often do so in harsh terms that are expected by NRC and the industry.

Q. WHAT CONCLUSION HAVE YOU FORMED ABOUT ECONOMIC PERFORMANCE INCENTIVES?

A. From its statements made in 1991 and 2001 summarized in my foregoing testimony, I conclude that the NRC is concerned that ill-chosen economic performance incentives set by State public utility commissions could create disincentives to safe operation of nuclear power plants. Accordingly, the NRC has offered advice in its statements that may be helpful in selecting performance standards that promote both safe and economic performance and in avoiding performance standards that would be counter to safety. The GDS recommendation to apply such a standard to Palo Verde is not consistent with the NRC advice on this matter. Finally, I conclude that an economic performance standard is not needed for Palo Verde at this time based on its long-term record of superior performance and the Performance Improvement Program now underway to ensure such performance in the future.

Q. WHAT CONCLUSIONS HAVE YOU FORMED REGARDING THE TWO-UNIT OUTAGE ASSOCIATED WITH THE AIR ENTRAINMENT ISSUE THAT THE NRC RAISED FOR THE REFUELING WATER TANK?

A. I have formed several conclusions for the RWT-related shutdown of Units 2 and 3 for nine days in October 2005, as follows:

- APS responded reasonably to the line of inquiry about air entrainment in the suction piping from the RWT by showing proof that air entrainment had been considered in a static calculation recorded in the original licensing basis of the plant.
- APS could not have anticipated that the contract inspector would then have questioned the adequacy of the original design by asking if there was a dynamic analysis, because static analysis was the basis for design and licensing of ECCS suction lines for all pressurized water reactors in the U.S., not just Palo Verde.
- Thus, the question was typical of one of the problems that have been identified to the NRC by the industry in its annual feedback associated with the reactor oversight process, namely, the inspection part of the reactor oversight process has begun to address the adequacy of the original licensing process wherein the safety basis was established;
- However, once NRC raised the question, APS was required to address it. When APS could not answer the question in the time prescribed by the plant's Technical Specifications, the two operating units had to be shut down until the answer could be developed. The answer required extending the state of the art for such analysis.
- As Region IV Administrator Mallett told the Arizona Corporation Commission on January 26, 2006, the issue was a new question, one that NRC and APS had not come across before, APS did what NRC expected, and NRC did not determine that APS should have found the issue beforehand.
- The units restarted and continue to run today without any changes in the

equipment, training or procedures associated with the systems in question.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Attachment RJM-1RB

ATTACHMENT RJM-1RB. ACRONYMS

ACC	Arizona Corporation Commission
AEC	Atomic Energy Commission
AFW	Auxiliary Feedwater (System)
AIT	Augmented Inspection Team (from NRC)
APS	Arizona Public Service Company
BNL	Brookhaven National Laboratory
BWR	Boiling Water Reactor
CAP	Corrective Action Program
CE	Combustion Engineering
CFR	Code of Federal Regulations
CRDR	Condition Report/Disposition Request
CSS	Containment Spray System
ECCS	Emergency Core Cooling System
EPA	Environmental Protection Agency
FSAR	Final Safety Analysis Report
HPCI	High Pressure Coolant Injection (part of ECCS on BWR)
HPSI	High Pressure Safety Injection (a subsystem of the ECCS on a PWR)
I&C	Instrumentation and Control (Systems)
IEAL	International Energy Associates Limited
NCV	Non Cited Violation
NRC	Nuclear Regulatory Commission
OCS	Operations Computer Systems
ORR	Operational Readiness Review
PI&R	Problem Identification and Resolution
PVNGS	Palo Verde Nuclear Generating Station
PWR	Pressurized Water Reactor
RAS	Recirculation Actuation Signal
RHR	Residual Heat Removal
ROP	Reactor Oversight Process (of the NRC)
RWT	Refueling Water Tank
SIS	Safety Injection System (part of ECCS, another name for HPSI)
UFSAR	Updated Final Safety Analysis Report

Attachment RJM-2RB

ATTACHMENT RJM-2RB. RESUME OF ROGER J. MATTSON

Summary

Forty-two years in nuclear safety and related fields
Thirty-nine years in nuclear facility licensing
Expert in nuclear safety, licensing and risk management

Education

Ph.D., Mechanical Engineering, University of Michigan, 1972
M.S., Mechanical Engineering, University of New Mexico, 1966
B.S., Mechanical Engineering, University of Nebraska, 1964, cum laude

Qualifications

Reactor Licensing – Dr. Mattson participated in the licensing programs of the U.S. government for 17 years, the last 7 directing the technical review of applications to construct and operate nuclear power plants and to amend their operating licenses. The scope of his responsibilities included reactor systems, nuclear fuel and core design, balance of plant, associated structures, and electrical, mechanical, and fluid systems; radiation protection and emergency preparedness; and geology, seismology, and meteorology. He introduced probabilistic risk assessment and TMI requirements into the licensing process. He has participated in technical safety reviews of every U.S. nuclear power plant. Since leaving government service, he has helped NRC licensees implement regulatory requirements and assisted NRC with new rules for advanced reactors and life extension/license renewal. He assisted DOE in designing a system of safety criteria for tritium production reactors that met or exceeded requirements of NRC. In 2006 he assisted DOE in an independent review of two advanced, commercial nuclear power plant designs that are to be submitted to the NRC for combined construction permits and operating licenses. In 2005 and 2006, he assisted Idaho National Laboratory in upgrading the Advanced Test Reactor in comparison to commercial reactor safety standards, in a review of safety and licensing aspects of the Next Generation Nuclear Plant that utilizes high temperature gas technology, and in a review of the development plan for the Global Nuclear Energy Partnership.

Non Reactor Nuclear Facility Licensing – In addition to reactor licensing experience Dr. Mattson has experience with licensing projects for non reactor facilities, including the setting of NRC licensing standards for safety, radiation protection, and environmental protection of fuel cycle facilities, including waste management facilities; representation of NRC in EPA's rulemaking for uranium fuel cycle standards; assistance to nuclear power plants in utilization of dry cask storage for spent nuclear fuel destined for shipment to DOE's Yucca Mountain facility; independent analysis of the licensing history of decommissioned uranium and mixed oxide fuel fabrication plants; and independent review of the test phase plan for the Waste Isolation Pilot Plant at Carlsbad.

Nuclear Safety – Dr. Mattson conducted safety reviews for AEC and NRC for 17 years covering more than 110 nuclear power plants and other radiological facilities. His nuclear safety review experience includes all types of safety systems. He assisted the International Atomic Energy Agency by co-chairing the development of safety principles for nuclear power plants after the accident at Chernobyl (INSAG-3, updated to INSAG-12) that were promulgated to all member nations for implementation. He developed NRC's new requirements after the accident at Three Mile Island in 1979. He has served as a consultant to DOE and its operating contractors in overseeing safety of nuclear facilities, including Rocky Flats, Savannah River Plant, Los Alamos National Laboratory, Pantex Plant, Mound Laboratory, Idaho National Laboratory and Livermore National Laboratory. He has served on nuclear safety review boards for five operating nuclear power plants, the N Reactor at Hanford, the Rocky Flats Environmental Technology Site and the DynEx Program

at Los Alamos. He oversaw two environmental radiochemistry labs involved in radioactive waste management. He assisted in streamlining the safety authorization basis for decommissioning of Rocky Flats.

Safety Analysis – Dr. Mattson developed and applied safety analysis techniques for nuclear facilities, including plant dynamic analysis, systems interaction studies, probabilistic safety (risk) assessment, reliability analysis, hazards analysis, technical safety appraisals, operational readiness reviews, independent design reviews, fire protection reviews, and management reviews. He pioneered use of independent analyses by nuclear safety oversight groups in the United States and abroad. He assisted in NRC analysis of the TMI accident in 1979 and the Chernobyl accident in 1986, including plant failure modes and effects analysis. He has reviewed Hazards Analysis Reports and Safety Analysis Reports and developed Safety Evaluation Reports for a range of private and government facilities.

System Safety Appraisals – Dr. Mattson participated in safety analysis and field reviews of nearly 150 nuclear facilities in the United States, Europe, the former Soviet Union, China, Taiwan and Korea. Such reviews included licensing reviews, hazard assessments, inspections of construction progress, incident response, preparation for litigation, independent design reviews, safety system functional inspections, safety and security vulnerability assessments, and operational readiness assessments.

Regulatory Policy – Dr. Mattson developed and applied regulatory policies of AEC, NRC, EPA, and DOE. He has conducted policy studies in nuclear safety, radiation protection, environmental monitoring, worker protection, standardized design, independent commissions, and security of nuclear facilities and materials. He assisted DOE and its operating contractors with order compliance for advanced and operating reactors, plutonium manufacturing plants, and nuclear weapons facilities. He participated in the Nuclear Utility Safety Standards program of the International Atomic Energy Agency and assisted development of regulatory policy for nuclear facilities in China, Taiwan, Japan, Korea, Spain, Russia, Ukraine, Kazakhstan, and Egypt.

Operational Readiness Reviews - In 1980 Dr. Mattson organized the transfer of operational readiness review (ORR) practices from NASA and DOD to the NRC for general application in the nuclear industry. He has reviewed the results of ORRs on a number of commercial and government facilities and has led ORRs at Limerick 2 nuclear power plant, the plutonium chemistry facility at Rocky Flats Plant, and K-Reactor at Savannah River Plant. He was the senior advisor to DOE managers in their first application of ORR techniques in 1990, developing the first Criteria and Review Approach Document and assisted later in the drafting of predecessor requirements to DOE Order 425.1A. He assisted a review of Kaiser-Hill's ORR program at Rocky Flats.

Decommissioning – Dr. Mattson oversaw the decommissioning of two licensed radiochemistry laboratories in the private sector. He advised the Department of Energy on approaches for decommissioning of plutonium contaminated ductwork at Rocky Flats Production Plant and Hanford Plutonium Finishing Plant. He assisted in streamlining the safety authorization basis for facilities undergoing decommissioning at Rocky Flats Environmental Technology Site and served as Vice Chairman of the Nuclear Safety Review Board for the Rocky Flats decommissioning project. He has reviewed decommissioning activities for NUMEC/B&W uranium and mixed oxide fuel fabrication facilities in preparation for litigation. He led an independent oversight team in selection of the decommissioning approach for Maine Yankee nuclear power plant and assisted the President of Maine Yankee and Connecticut Yankee in management of decommissioning activities. He participated in a study of alternative decommissioning approaches for Millstone 1 nuclear power plant.

Emergency Preparedness – Dr. Mattson assisted in response to the accident at Three Mile Island and several other nuclear incidents. He directed the NRC's radiation protective measures team in the headquarters emergency response organization. He coordinated EPA's national radiation emergency response network. He has participated in emergency response exercises for commercial and government-owned radiological facilities in a number of states. He developed federal regulations for radiological emergency preparedness and directed their implementation. He helped to establish the earliest interagency coordination program for response to clandestine fission explosives.

Criticality Safety – Dr. Mattson participated as senior safety expert in criticality safety assessments of DOE's plutonium facilities at Hanford, Rocky Flats and Los Alamos. He assisted in a root cause review of an intentional violation of criticality limits at Rocky Flats. He conducted independent reviews of the criticality safety program at Rocky Flats and has reviewed the criticality safety programs at other nuclear materials processing facilities.

Radiation Protection – Dr. Mattson has managed radiation protection activities as an employee of the AEC, NRC and EPA and has assisted DOE, NRC, and private companies in implementing radiation protection measures for workers and the public. He chaired the radiation protection committee of a radiochemistry laboratory, led the development of Federal radiation guidelines for all licensed radiological facilities in the U.S., including those related to 10 CFR Parts 20, 50, and 70, and 40 CFR Part 190. He managed the review of radiation protection measures for U.S. nuclear power plants. He reviewed radiation protection programs for DOE and commercial nuclear facilities.

Environmental Protection – Dr. Mattson wrote environmental impact statements and developed federal guidelines to implement Clean Air, Clean Water, Safe Drinking Water, and National Environmental Policy Acts. He has managed consulting and laboratory services in environmental risk management. He developed and implemented environmental standards for ionizing and nonionizing radiation. He led historical reconstructions of radioactive source terms for several nuclear facilities following guidelines of the National Academy of Sciences.

Quality Assurance – Dr. Mattson implemented federal regulations governing nuclear quality assurance by reviewing license applications for nuclear power plants and assisting oversight of QA programs at nuclear plants under construction and in operation. He assisted Dupont Corporation in the application of nuclear QA techniques to the Savannah River Plant. He assisted DOE and its prime contractors in implementing nuclear QA programs for nuclear facilities. He has performed independent analysis of the effects of QA requirements on safety and cost of nuclear facilities.

Expert Testimony – Dr. Mattson has testified on the effects of regulation on safety and costs of nuclear facilities before the United States Congress, several Presidential Commissions, the Nuclear Regulatory Commission, the Defense Nuclear Facilities Safety Board, the Advisory Committee on Nuclear Facility Safety, the Advisory Committee on Reactor Safeguards, Federal and State Courts, panels of the American Arbitration Association, and State Public Utility Commissions.

Security – Dr. Mattson developed NRC's security standards for the commercial nuclear industry in the mid 1970s and managed security-consulting services in the 1980s. He has written threat definitions and participated in security response for nuclear facilities and materials. From 1987 to 2002 he oversaw security equipment research by SCIENTECH for a range of U.S. government clients.

Site-Related Disciplines – Dr. Mattson led the siting standards development effort for NRC and

assisted the International Atomic Energy Agency in its development of siting standards for nuclear power plants. The standards addressed site safety, geology, meteorology, hydrology, demographics and environmental protection.

Employment

Independent Consultant, 2002 – present time, Risk Management, Licensing, Safety, Quality, Security, and Management Assessments

SCIENTECH, Inc., Senior Vice President, 1987-2002, Safety Analysis and Appraisals, Operational Readiness Reviews, Nuclear Safety and Licensing, Strategic Planning, Decommissioning, Security

International Energy Associates Limited, Engineer then President, 1984 -1987, Nuclear Safety and Licensing, Management, Litigation Support, Security

U.S. Nuclear Regulatory Commission, Director of Systems Integration, Nuclear Reactor Regulation, 1981-1984, Nuclear Safety and Licensing, Regulatory Policy, Emergency Preparedness, QA, Radiological Protection

U.S. Environmental Protection Agency, Director, Radiation Surveillance, Radiation Programs Office, 1980-1981, Radiological Protection, Emergency Preparedness, Management

U.S. Nuclear Regulatory Commission, Director of Systems Safety, Nuclear Reactor Regulation, 1977-1980, Nuclear Safety Regulation, TMI Response

U.S. Nuclear Regulatory Commission, Director of Site, Health, Safeguards Standards, 1975-1977, Environmental and Radiological Protection, Emergency Preparedness, Site Related Disciplines, Security

U.S. Atomic Energy Commission, Engineer then Supervisor, 1967-1975, Safety Analysis, Nuclear Design, Assistant to Commissioner, Security of Nuclear Materials and Facilities

Sandia Corporation, Engineer, 1964 -1967, Hardware Design, Safety Analysis, Thermal-Hydraulic Analysis

Honors

NRC Distinguished Service Award, 1980, for work on TMI accident
NRC Meritorious Service Award, 1976, for leadership in standards development
NRC and AEC letters of commendation for performance on various task forces
National Science Foundation Research Assistantship, 1971
Sigma Xi (Science Honorary Society)
Pi Tau Sigma (Mechanical Engineering Honorary Society)
Pi Mu Epsilon (Mathematics Honorary Society)
Sigma Tau (Engineering Honorary Society)

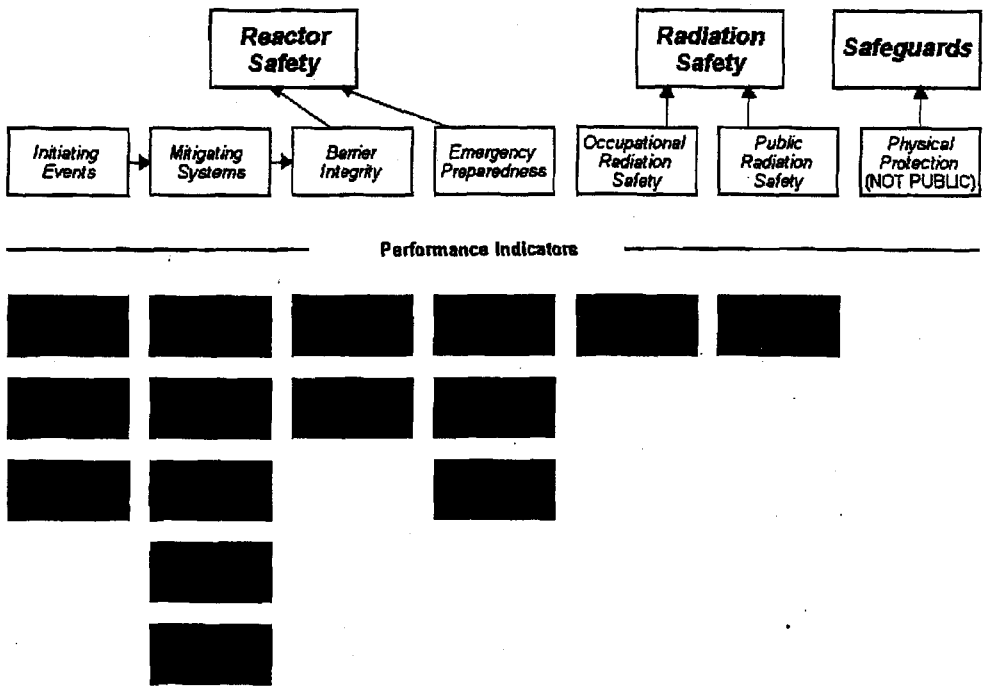
Attachment RJM-3RB

ATTACHMENT RJM-3RB. PERFORMANCE INDICATOR DATA

The NRC established a Performance Indicators Program in 1986 to provide data for early indication of declining trends in plant performance. Based on experience with its use, the first performance indicator program was discontinued in 1999 and replaced in 2000 by the Reactor Oversight Process that included another set of performance indicators. NRC has used performance indicators from 1986 to today to help identify issues or circumstances that the NRC should examine further, i.e., where to apply its inspection resources.

The first NRC Performance Indicator Program monitored plant performance in the following areas: automatic scrams while critical, safety system actuations, significant events, safety system failures, forced outage rate, and equipment forced outages per 1,000 critical hours, collective radiation exposure and the causes of Licensee Event Reports (LERs). The new performance indicators are arrayed in seven cornerstones of safety namely, Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness, Occupational Radiation Safety, Public Radiation Safety, and Physical Protection.

Under the Reactor Oversight Process, color-coded summaries of performance indicators and inspection findings are provided quarterly for each plant in what NRC calls action matrices. The action matrix for a particular plant determines NRC's regulatory response to current circumstances. If the findings in a matrix are all green or if there are no findings, then the NRC applies its baseline inspection program. If the findings in the matrix are not all green but include some white, yellow or red cornerstones, then the NRC applies additional inspection resources. In rare instances when actions different from those indicated by the Action Matrix are needed, NRC may increase or decrease its response. Since 2000, these deviations have been to provide heightened NRC oversight at five nuclear power stations, Davis-Besse, Salem, Hope Creek, Indian Point 2 and Point Beach. The NRC's Performance Indicator Action Matrix for Palo Verde Unit 1 for the last quarter of 2005 is shown below.



Performance indicators can be compared among plants of similar vintage and design that the NRC has grouped into "peer groups." The performance indicators for particular plants can also be compared to their generic design type (pressurized water reactors or PWRs in the case of Palo Verde) and to the entire industry. Such comparisons aid the assessment of Palo Verde's performance against industry performance norms.

The charts provided below graphically depict Palo Verde's performance for each of the performance indicators that I chose. I chose indicators that bear on the reliability and safety of operations. I left out those relating to emergency preparedness and security. I have provided a definition and a chart for each of the indicators. Each chart shows by year the average performance of the Palo Verde plants and the performance of other plants appropriate for comparisons for that indicator. It is important to remember as one looks at these charts that at any given point in time, say 1998, the NRC and the managers of Palo Verde would have only been able to utilize this information in hindsight.

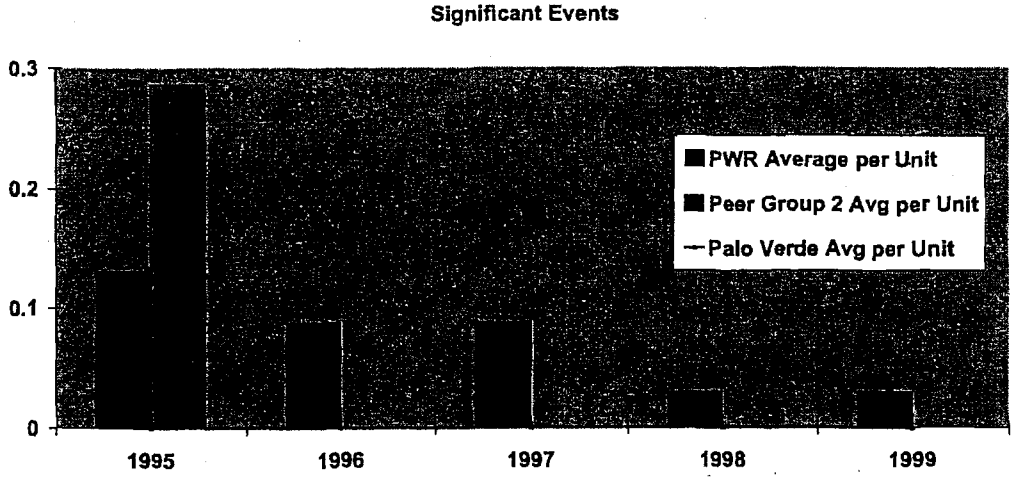
In sum, there are 18 indicators, some treating similar variables over the two periods, 1995 to

1999 and 2000 to 2005. The average performance of the Palo Verde units meets or exceeds the average performance of the PWRs or all nuclear power plants for 16 of these 18 indicators. The average performance of Palo Verde is better than its peer group for 15 of the 18 indicators. I made these comparisons on a year-by-year basis, not accounting for how much the Palo Verde performance was under or over the comparison groups in any one year.

The performance in each of these 18 areas is described in the following numbered paragraphs.

1. Significant Events

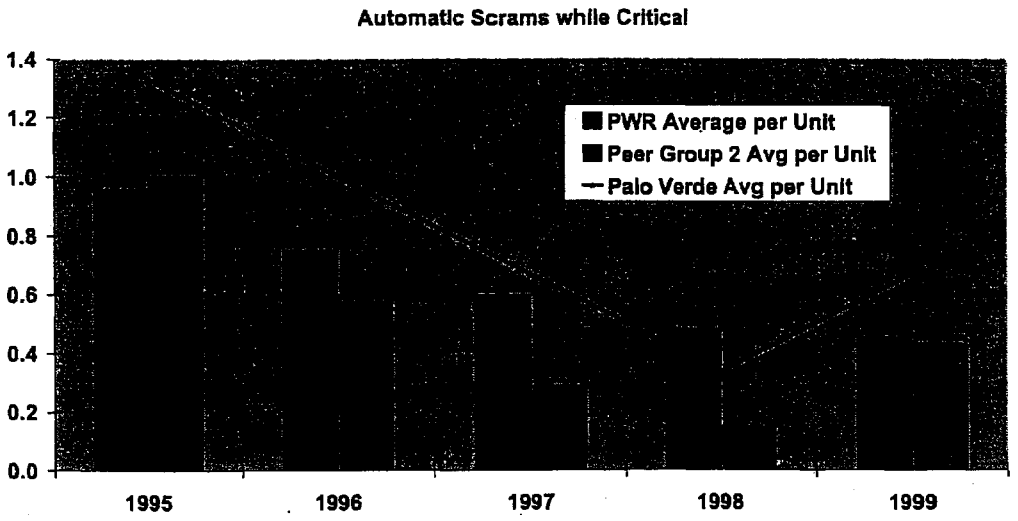
This indicator is the total number of events during the year that directly challenged the safety of the unit, such as degradation of important safety equipment, unexpected plant response to a transient, degradation of fuel integrity or the primary pressure boundary, or reactor scram with complications. On average, between 1995 and 1999, U.S. nuclear units experienced one significant event approximately every 10 years. The Palo Verde Units experienced none of these events in that time period, performing better in this category than their peer group and the other PWRs, as illustrated by the following chart. NRC eliminated this indicator when the new ROP came into being in 2000.



2. Automatic Scrams While Critical

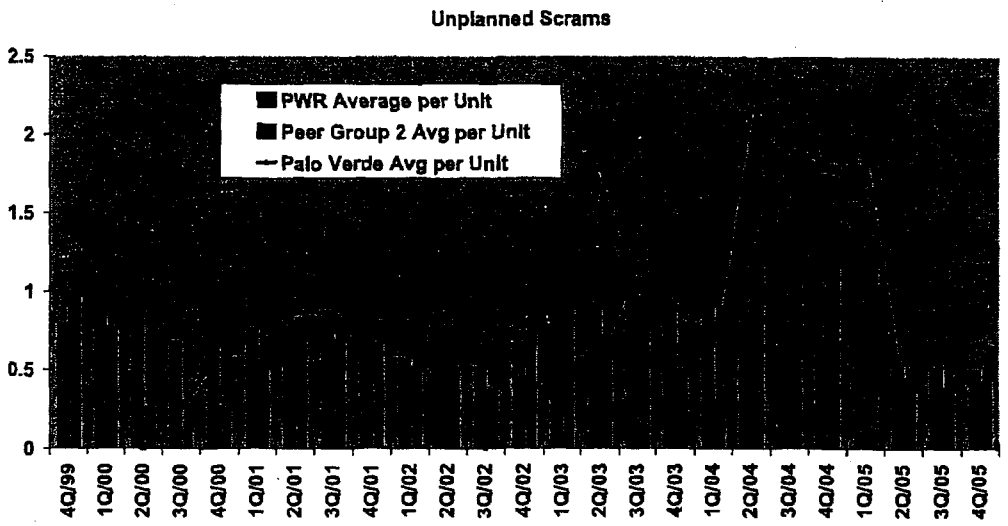
This indicator is the total number of unplanned automatic reactor scrams that occur while the reactor is critical and that automatically and promptly shut the reactor down. Such scrams require the reactor operators and the plant equipment to perform in a stressful and off normal manner,

thus providing a challenge to plant safety. The reactor is said to be critical when it is being started up and when it is in power operation. This indicator is one way to track how often plant safety is challenged by unanticipated events. Palo Verde Units 1, 2 and 3 had more scrams than both their peer group and the other PWRs during the period 1995 to 1999, as shown in the following graph. This indicator was dropped in 2000 with the advent of the new ROP and replaced by another indicator called Unplanned Scrams.



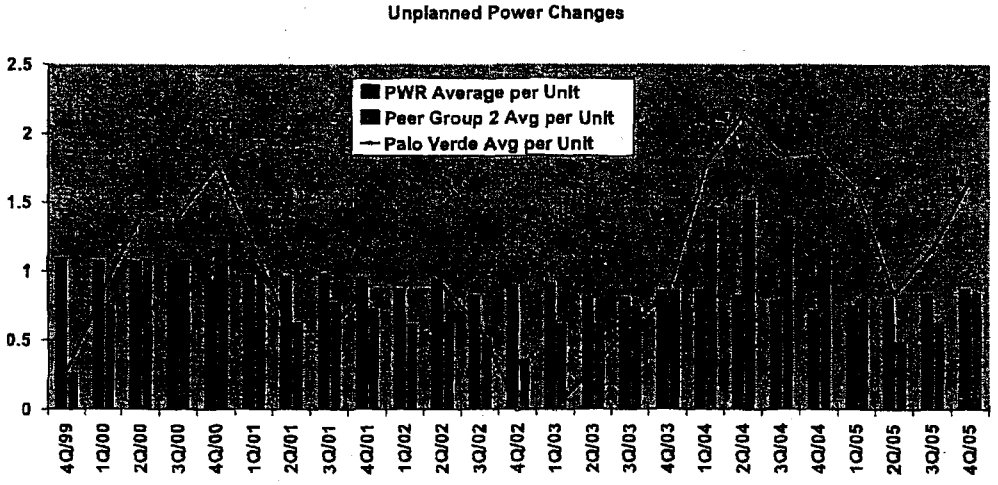
3. Unplanned Scrams

This indicator was adopted by NRC in 2000 and is an input to the Initiating Events Cornerstone. It is similar to the automatic scrams while critical indicator described above, but includes unplanned manual scrams. The indicator is equal to the number of unplanned scrams while the reactor was critical in the previous 4 quarters, times 7000 hours, divided by the number of hours critical in the previous 4 quarters. As shown in the following chart the Palo Verde units averaged slightly better than their peers and other PWRs for this indicator over the period 2000 to 2005. The graph illustrates the fact that once a unit has a failure of this type, the indicator stays high for four quarters (from the second quarter of 2004 to the first quarter of 2005, for example). The high values in 2004 reflect the loss of offsite power event that led to the trip of all three units, plus trips in individual units in May, June and July.



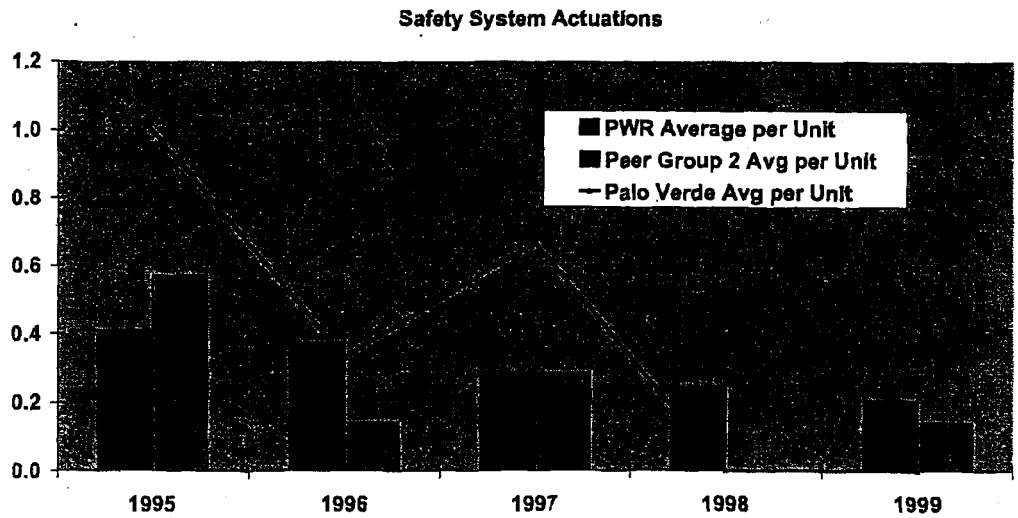
4. Unplanned Power Changes per 7,000 Critical Hours

This indicator was created at the time the ROP was initiated. It monitors the number of unplanned power changes (excluding scrams) that could have, under other plant conditions, challenged safety functions. It is equal to the number of unplanned power changes in reactor power greater than 20% of full power over the previous 4 quarters, times 7,000 hours, and divided by the total number of hours critical in the previous 4 quarters. As shown in the following graph, since the indicator was created and through the fourth quarter of 2005, the Palo Verde Units on the average performed equal to or better than the average of all PWRs 13 quarters out of 25, and 8 out of 25 when compared to their peer group. This is another indicator whose definition causes a high reading for each such power change to persist for 12 months.



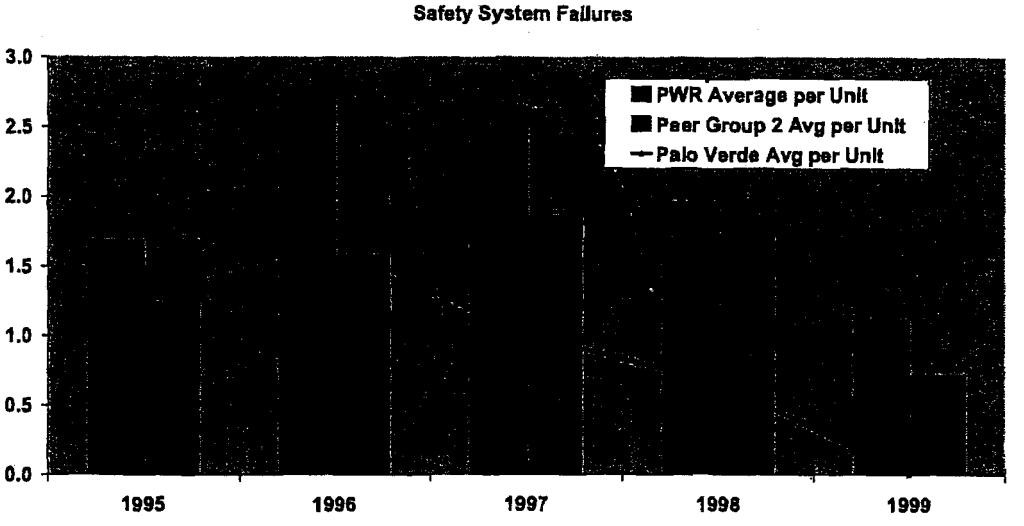
5. Safety System Actuations

This indicator combines manual and automatic actuations of the logic or equipment of either certain Emergency Core Cooling Systems or the Emergency AC Power System. It includes both faulty and authentic actuations. It is a measure of how frequently safety systems are being challenged – the more frequent the challenge, the greater the likelihood of eventual failure. The Palo Verde Units had a better than average number of safety system actuations compared to other PWRs from 1995 to 1999 and slightly worse than the average of their peer group, as shown in the following graph. The NRC eliminated this indicator when the new ROP was initiated in 2000.



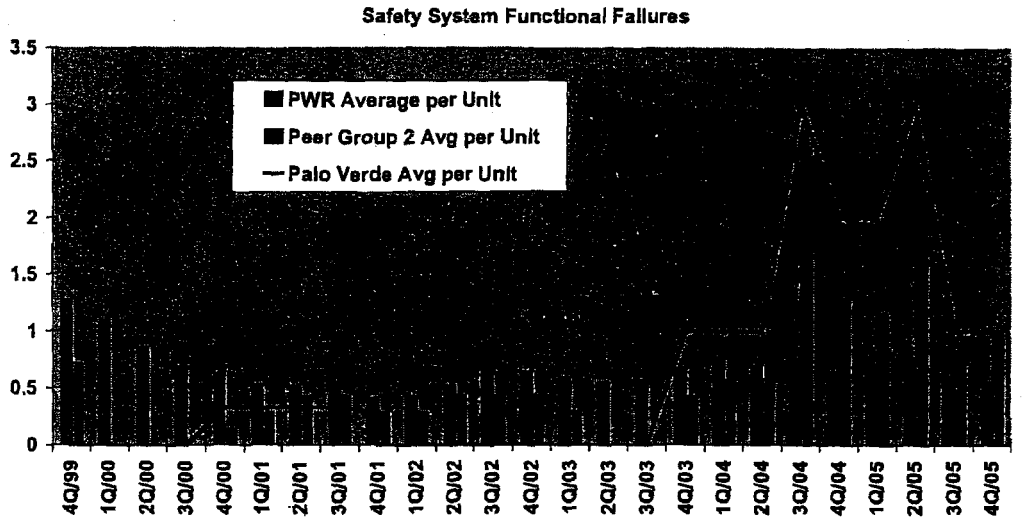
6. Safety System Failures

These are events or conditions that could prevent the fulfillment of the safety function of structures, systems or components related to safety. This indicator includes failures on demand and failures during testing. It is a measure of how well the safety equipment in a plant is designed and maintained. As shown in the following graph, the Palo Verde Units performed better than both their peer group and other PWRs for this indicator for the period 1995 to 1999. In 2000, with the advent of the ROP, an indicator called Safety System Functional Failures replaced this indicator, as discussed next.



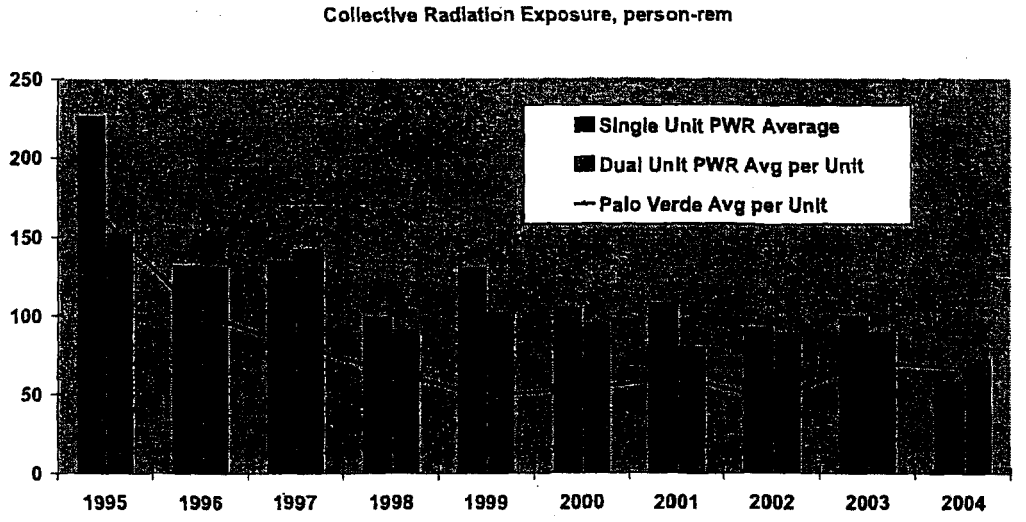
7. Safety System Functional Failures

This indicator is an input to the Mitigating Systems Cornerstone in the NRC's Reactor Oversight Process. It is equal to the number of events or conditions in the previous 4 quarters that prevented or could have prevented the fulfillment of the safety functions of reactor shutdown, removal of residual heat, control of radioactivity releases, and mitigation of accident consequences. The Palo Verde Units on the average have equaled or outperformed other PWRs 16 quarters out of the 25 that this indicator has been used, and their peer group 15 out of 25. The following graph again illustrates the fact that once a unit has a failure of this type, the indicator stays high for four quarters. In the fourth quarter of 2003 the containment pedestal cranes were found to have a seismic qualification issue in all three units. The high number of failures that show up in this indicator at Palo Verde in the third quarter of 2004 relate to the voided sump suction lines and the loss of offsite power that both affected all three units. Similarly, the flattening of the Palo Verde line late in 2005 is related to the declared inoperability of the refueling water tank in the fourth quarter of 2005.



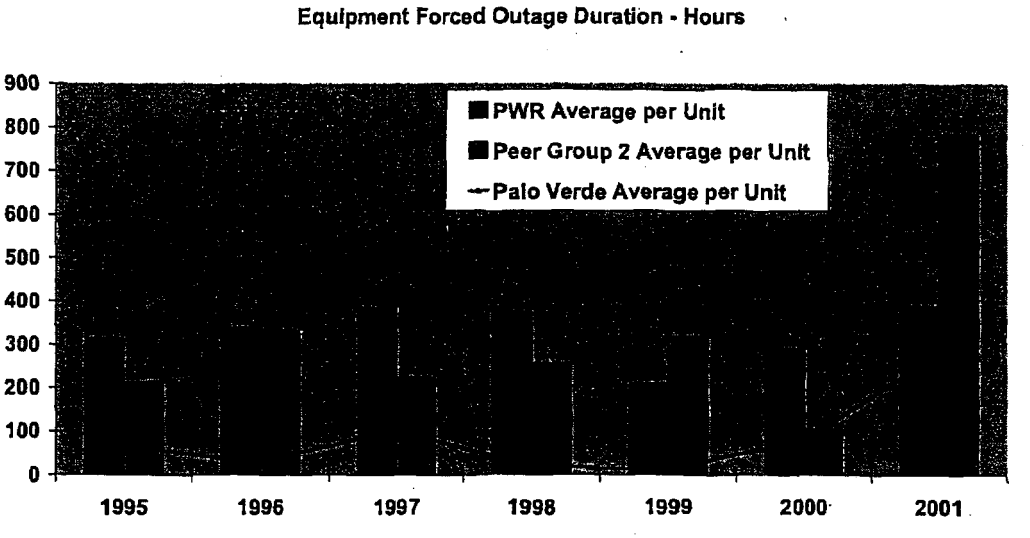
8. Collective Radiation Exposure

This indicator is the total radiation dose accumulated by plant personnel. It indicates the effectiveness in planning and performing work in a manner that minimizes exposure of workers to radiation. It also is an indicator of how well the physical condition of a unit is maintained as it ages. Between 1995 and 2004, the last year for which data are available, the average exposure for the Palo Verde Units generally was better than the PWR averages for both single and dual unit plants, as shown in the following graph.



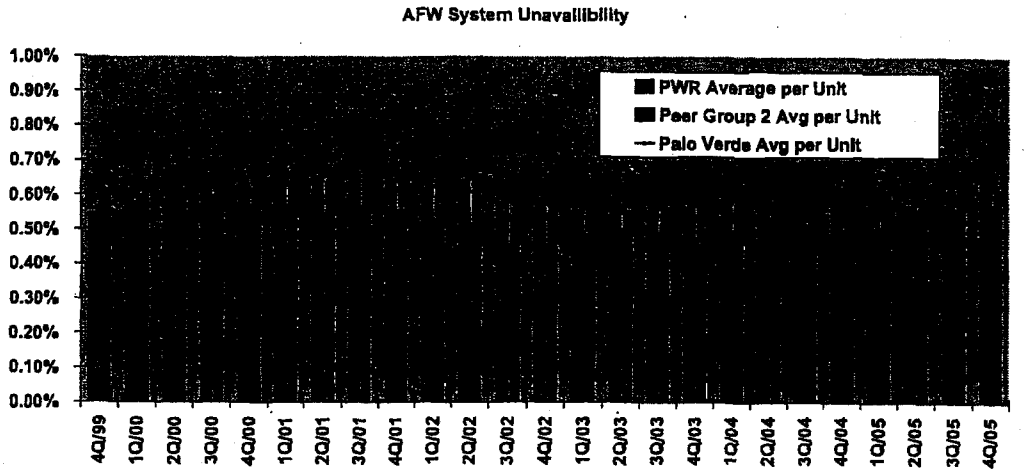
9. Equipment Forced Outage Duration

Equipment Forced Outage Duration is the number of hours of forced outage of safety equipment. For the period 1995-2001, the Palo Verde Units had average equipment forced outage durations that were better than their peers and the other PWRs, as shown in the following graph. This performance indicator was eliminated in 2000 with the advent of the ROP.



10. Safety System Unavailability

In 2000 with the advent of the ROP the Equipment Forced Outage indicators of the NRC were replaced by indicators of the unavailability of four key safety systems, namely, auxiliary feedwater, residual heat removal, high pressure safety injection, and emergency AC power. These four indicators provide important input to the Mitigating Systems Cornerstone concerned with the ability to prevent or reduce the consequences of accidents. As shown in the four graphs that follow, The Palo Verde Units on the average perform as well as or better than their peers and other PWRs except for the high pressure safety injection system or HPSI. This system is performing adequately whenever its unavailability is less than 2%. For the years 2001 to 2003 it averaged about the same unavailability as the peer plants, then the unavailability trended higher in 2004 and 2005 due to the voided sump suction and refueling water tank issues.


AFW System Unavailibility
PWR Average per Unit
Peer Group 2 Avg per Unit
Palo Verde Avg per Unit
1.00%
0.90%
0.80%
0.70%
0.60%
0.50%
0.40%
0.30%
0.20%
0.10%
0.00%
4Q/99
1Q/00
2Q/00
3Q/00
4Q/00
1Q/01
2Q/01
3Q/01
4Q/01
1Q/02
2Q/02
3Q/02
4Q/02
1Q/03
2Q/03
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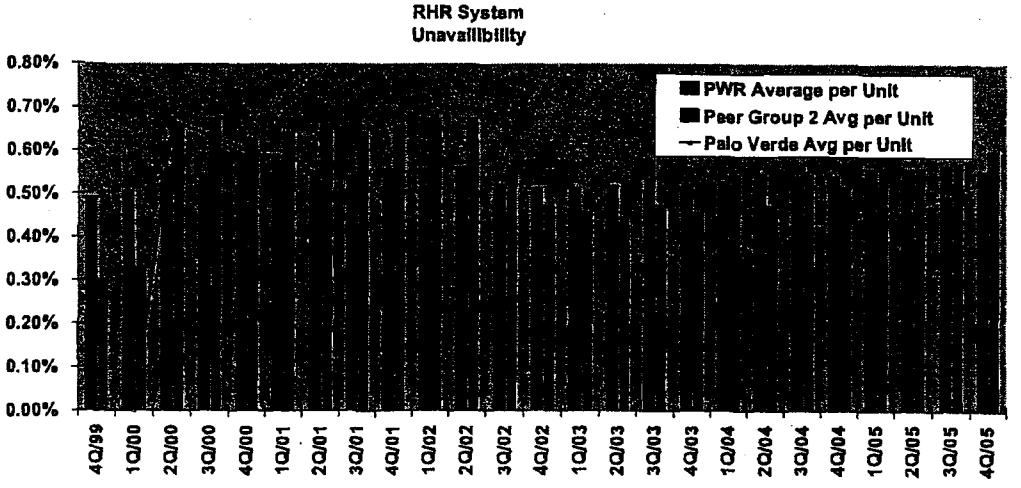
2Q/05
3Q/05
4Q/05


RHR System
Unavailibility
PWR Average per Unit
Peer Group 2 Avg per Unit
Palo Verde Avg per Unit
0.80%
0.70%
0.60%
0.50%
0.40%
0.30%
0.20%
0.10%
0.00%
4Q/99
1Q/00
2Q/00
3Q/00
4Q/00
1Q/01
2Q/01
3Q/01
4Q/01
1Q/02
2Q/02
3Q/02
4Q/02
1Q/03
2Q/03
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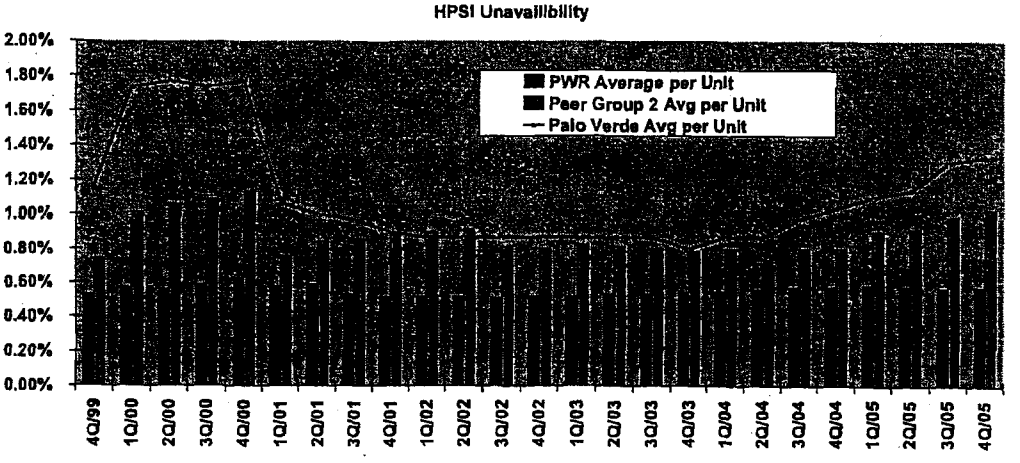
2Q/05
3Q/05
4Q/05


HPSI Unavailibility
PWR Average per Unit
Peer Group 2 Avg per Unit
Palo Verde Avg per Unit
2.00%
1.80%
1.60%
1.40%
1.20%
1.00%
0.80%
0.60%
0.40%
0.20%
0.00%
4Q/99
1Q/00
2Q/00
3Q/00
4Q/00
1Q/01
2Q/01
3Q/01
4Q/01
1Q/02
2Q/02
3Q/02
4Q/02
1Q/03
2Q/03
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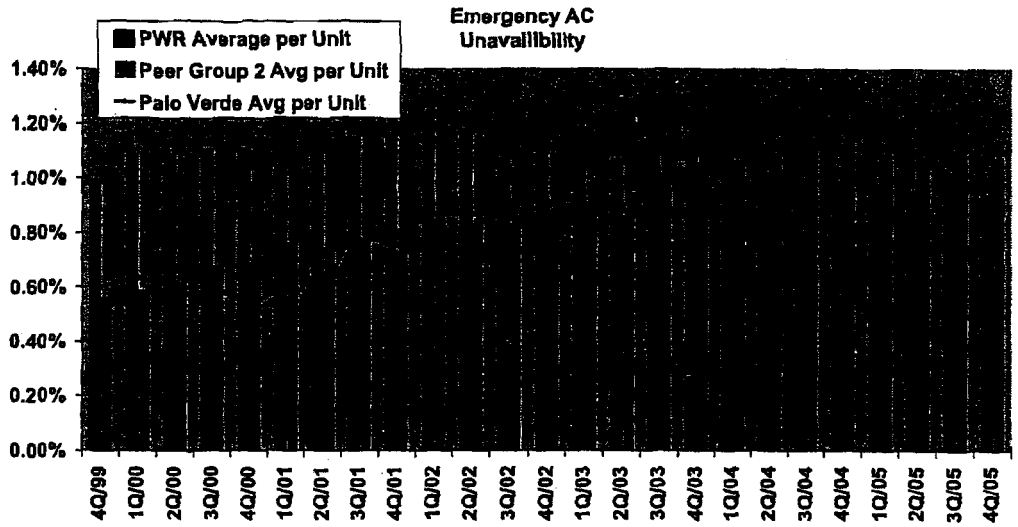
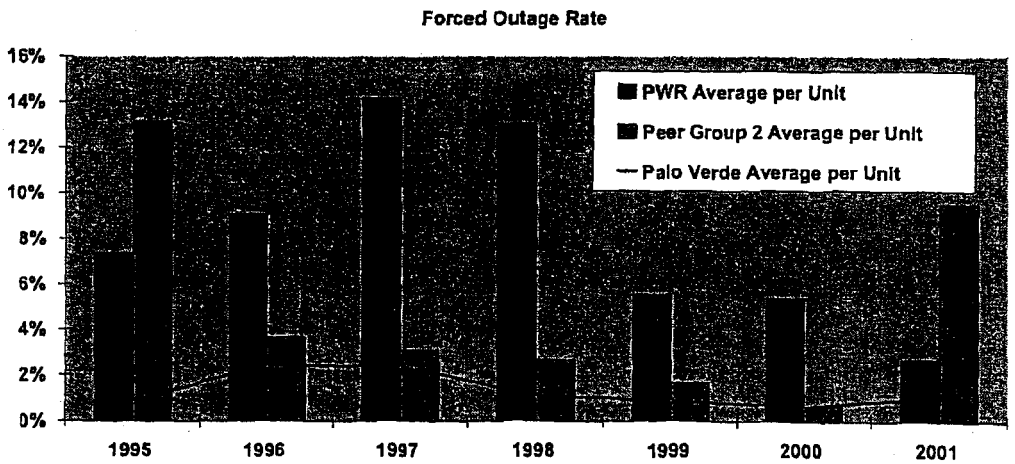
1Q/05
2Q/05
3Q/05
4Q/05



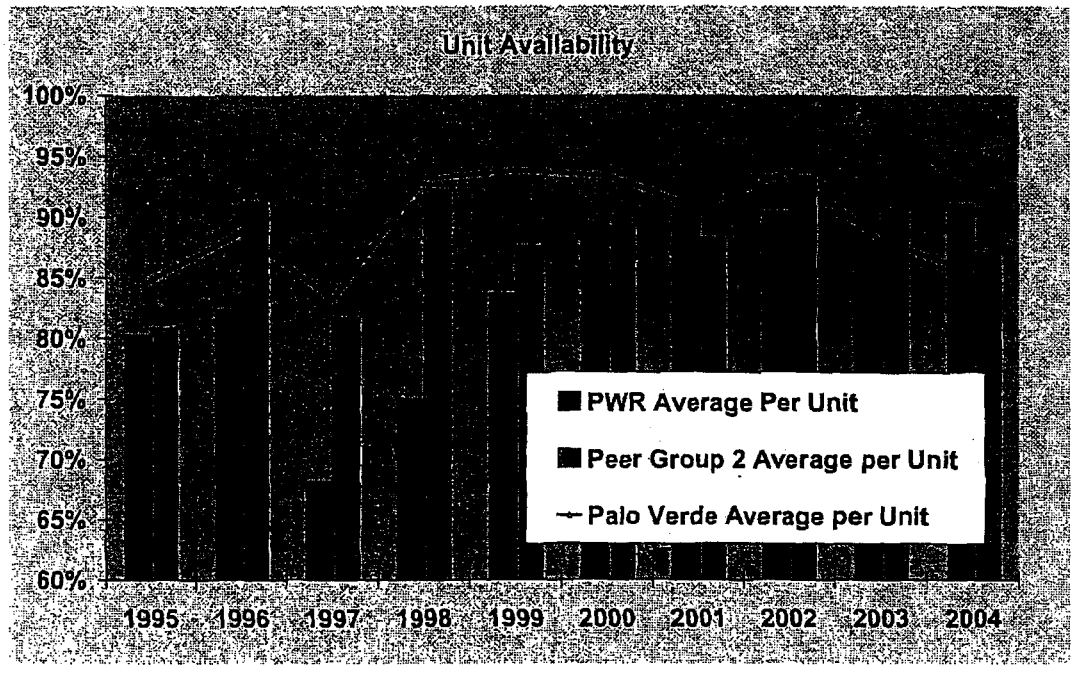
11. Forced Outage Rate

This indicator consists of the number of forced outage hours, multiplied by 100, divided by the sum of the unit service hours and forced outage hours. It is a measure of how long unanticipated conditions require a unit to be shut down relative to the total time it otherwise would have been available to produce power. For the period 1995 – 2001, the Palo Verde Units on the average achieved a forced outage rate better than their peer group and other PWRs, as shown in the following graph. This performance indicator was eliminated in 2000 with the advent of the ROP. APS has calculated that the Forced outage Rate of the Palo Verde Units averaged 5.5% in 2004 and 6.1% in 2005.



12. Yearly Average Availability

This indicator is a measure of the performance of the plant in producing power. It is computed by dividing the actual yearly power output in megawatt hours by the theoretical maximum output (100% power times the number of hours in a year). The low average availability in the industry in 1997 was caused by extended outages at a number of plants. The average availability factors for the Palo Verde Units were generally better than their peer group and other PWRs over the period 1995 – 2004, as shown in the following graph. In 2005, the availability of the Palo Verde Units averaged about 78%.

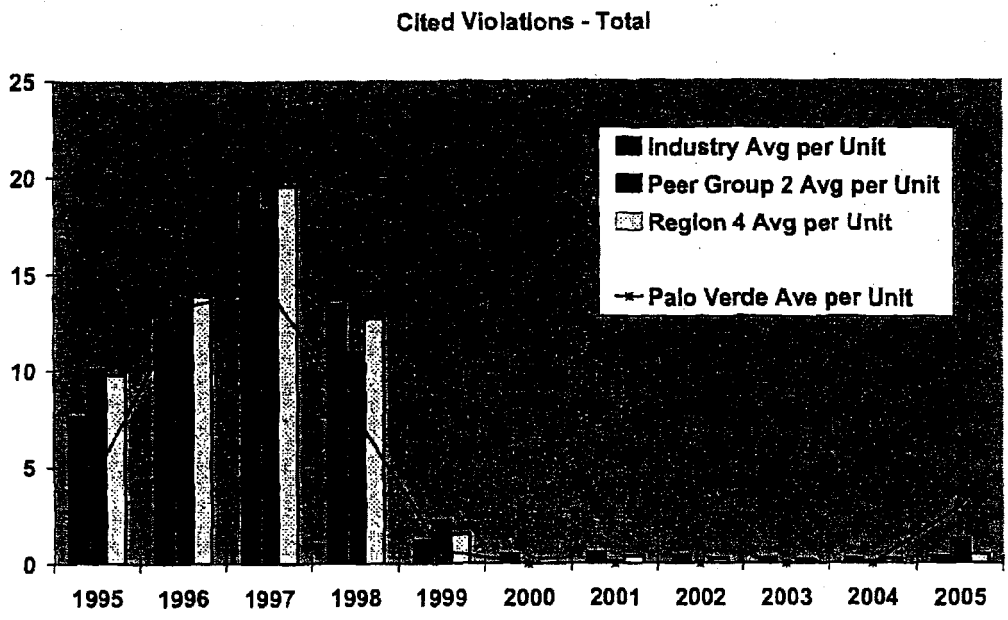


13. Violations of NRC Requirements

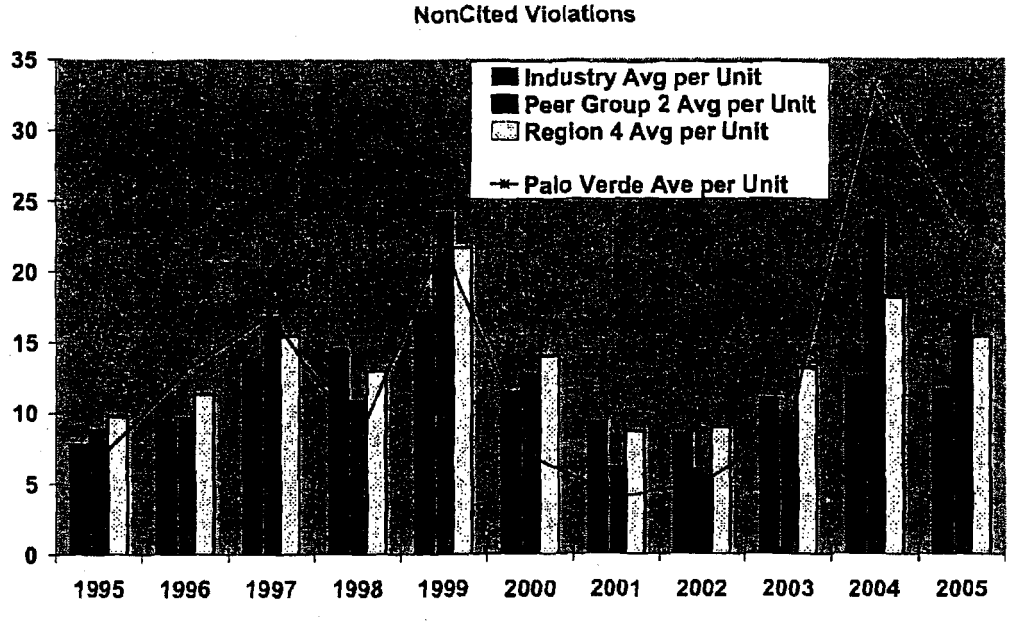
Comparisons of the numbers of violations cited against licensees over time provide a sense of how a particular licensee is fairing relative to others in the receipt of negative NRC feedback. As described above, NRC issues both cited and non-cited violations, and the relative number of the two changed with the advent of the ROP in 2000 (in fact, the number of cited violations took a precipitous drop in 1999 as the new ROP was being discussed internally to the NRC and prepared for implementation in 2000).

Palo Verde has had good performance in terms of the number of cited violations. During the period 1995 through 2005, the three Palo Verde units averaged fewer notices of violation than

the industry average (BWRs and PWRs), fewer than the average for their NRC-defined peer group, and fewer than the other units in Region IV, as shown in the following graph.

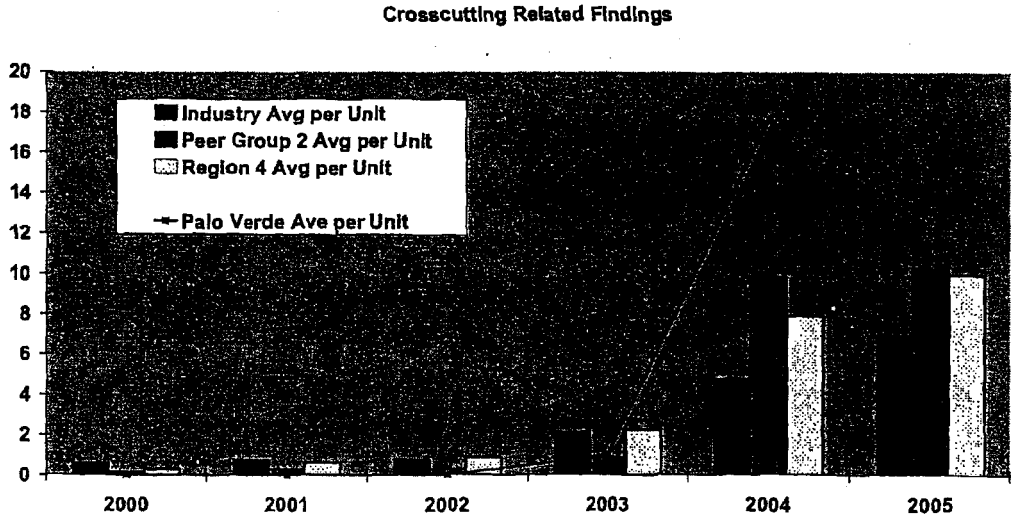


As shown in the following chart of non-cited violations, the Palo Verde Units also averaged better than their peers, other units in Region IV and other units in the industry (BWRs and PWRs) for most of the 11-year period from 1995 to 2005.



14. Cross-Cutting Findings

These are findings defined by the ROP as inadequacies in a licensee's activities that affect all or most safety cornerstones. There are only three areas defined by the NRC for cross-cutting issues, namely, problem identification and resolution, human performance, and safety conscious work environment. NRC says that findings in these areas are important because they indicate systemic weaknesses that could degrade multiple cornerstones if not corrected. The performance indicator shows excellent performance by Palo Verde from 2000 to 2003 with only one such issue identified in 4 years, and then a very steep increase in 2004 when NRC found all that the three units averaged 16 such issues. Performance at Palo Verde improved in 2005 as the indicator for the three units moved back toward the averages for the peer group and Region IV. This trend is consistent with the industry trend information identified by the U. S. Government Accountability Office and discussed in Section 3, above, i.e., between 2001 and 2005 cross-cutting issues grew from 23% to 68% of all NRC inspection findings.



15. Onsite Inspection Hours

This parameter reflects the level of NRC scrutiny applied to a particular site each year. It shows that NRC averages about 6000 hours per year (3 person years) at single- and dual-plant sites and about 8000 hours (4 person years) at 3-plant sites. Prior to 2004, Palo Verde received average or less oversight than the one other 3-unit site. This level of oversight changed in 2004 when NRC expended 12,000 person hours at PVNGS. In 2005, the NRC oversight at PVNGS dropped back toward the average level for the 3-Unit sites.

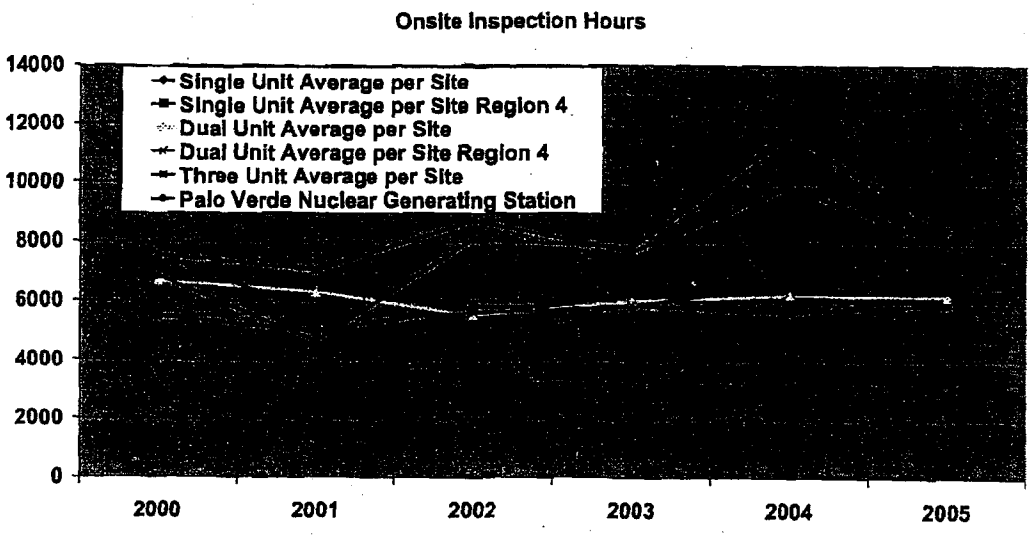

Onsite Inspection Hours
14000
12000
10000
8000
6000
4000
2000
0
Single Unit Average per Site
Single Unit Average per Site Region 4
Dual Unit Average per Site
Dual Unit Average per Site Region 4
Three Unit Average per Site
Palo Verde Nuclear Generating Station
2000
2001
2002
2003
2004
2005

EXHIBIT
APS-88
Admitted

REJOINDER TESTIMONY OF ROGER J. MATTSON, PH.D.

On Behalf of Arizona Public Service Company

DOCKET NO. E-01345A-05-0816
DOCKET NO. E-01345A-05-0826
DOCKET NO. E-01345A-05-0827

November 3, 2006

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2. RWT Outages	3
3. Palo Verde Performance	15
4. Summary of Conclusions	26

ATTACHMENTS

Attachment RJM-1RJ Acronyms 33

1. PURPOSE AND SUMMARY

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

A. My name is Roger J. Mattson and my business address is 2511 Fossil Trace Court, Golden, CO 80401. I am self-employed.

Q. DID YOU FILE REBUTTAL TESTIMONY IN THIS CASE?

A. Yes.

Q. WHAT IS THE PURPOSE OF THIS REJOINDER TESTIMONY?

A. The purpose of this Rejoinder Testimony is to respond to the Surrebuttal Testimony of witness Dr. William R. Jacobs, Jr.

Q. HOW IS YOUR REJOINDER TESTIMONY ORGANIZED?

A. I will first address Dr. Jacobs' testimony on the outages of Units 2 and 3 in October 2005 relating to the new question raised by the Nuclear Regulatory Commission (NRC) regarding the dynamic aspects of air entrainment in the suction line from the refueling water tank (RWT), and then I will address his testimony on the performance of the Palo Verde station. (A list of Acronyms is provided in Attachment RJM-1RJ.)

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS FOR THIS REJOINDER TESTIMONY.

A. The October 2005 outages at Units 2 and 3 were not the result of APS imprudence. Palo Verde personnel responded reasonably to a new question the NRC raised – a question that the Company should not have anticipated. Once APS answered the NRC's new question, the units restarted without any change to the equipment, training or procedures related to the systems in question.

Palo Verde's performance has been within industry norms over the decade from 1995 to 2005. Palo Verde has performed better than the average nuclear plant and better than the average of plants in its peer group in almost all of the indicators that

the NRC tracks. On its own initiative, APS has recently undertaken a Performance Improvement Program that involves close oversight by the NRC. Self-critical reports and assessments are always a part of such improvement efforts and are not an indicia of imprudence. The fact that APS and NRC are engaged in this way has no bearing on the prudence of the outages experienced in 2005. Given Palo Verde's long term good performance, a nuclear performance standard is unnecessary.

Dr. Jacobs' Surrebuttal Testimony is insufficient to counter these conclusions. Furthermore, his testimony is flawed because of its serious misunderstandings of the federal regulatory process. His most significant errors occur in the following areas:

- the distinction between a question involving air entrainment in water coming from the RWT that was asked in the original licensing of Palo Verde and the new question that was asked by an NRC contract inspector in October 2005;
- the reliance NRC places on the design basis in regulating operating nuclear power plants;
- the interpretation of statements reportedly made by the senior resident inspector at Palo Verde and his rejection of statements made by the inspector's superior, Regional Administrator Mallett, during his appearance before this Arizona Corporation Commission (ACC or Commission);
- the distinction NRC makes between a degraded cornerstone of safety and other, all-green, noncited violations that exhibit cross-cutting aspects;
- the occurrence of hindsight bias in all retrospective analyses and how the ACC might account for such bias in NRC and company reports; and
- the importance of NRC 's concerns with economic performance standards.

Dr. Jacobs' fundamental contention with respect to the refueling water tank (RWT) outages – that APS should have anticipated the NRC's new question – even if

correct, should not result in any disallowance. As I explain below, the outages would still have occurred and the resulting replacement power costs would still have been incurred.

Finally, Dr. Jacobs' attempted dismissal of NRC's concern about the potentially negative effects of a nuclear performance standard as a "red herring" is unpersuasive. The NRC remains concerned about the potential disincentives to safety of such a standard.

2. RWT OUTAGES

Q. PLEASE REMIND US OF THE CIRCUMSTANCES SURROUNDING THESE OUTAGES.

A. The RWT outages occurred to Units 2 and 3 in October 2005 when NRC was onsite for a followup inspection to the one it conducted in 2004 concerning the voided sump suction line. The general purpose of this followup inspection was for NRC to determine if APS had implemented the corrective actions for the root causes that APS had determined to be responsible for that earlier condition. APS had undertaken an extensive design basis implementation review to determine the extent of condition related to the voided pump suction pipe discovered in 2004 in advance of the arrival of the second NRC inspection team to demonstrate what APS had done to correct the root causes and to examine the generic implications (or extent of condition) of the prior discovery. In advance of the arrival of the inspection team, APS was informed that questions would be asked about the possibility of air entrainment in the RWT suction line that leads to some emergency cooling pumps.

Then, early in that followup inspection, a contractor to the NRC who was on the inspection team asked if the possibility of air entrainment had been considered in the design of the suction line from the RWT to the emergency pumps. The APS staff responded that air entrainment had been considered in the design and that the design measures proposed by APS and approved by NRC to preclude this

possibility had been implemented in the construction of the plant and remained in existence to the present time. Plant records from the original licensing review in 1976 were provided to demonstrate this claim.

The contract inspector challenged the response provided by APS, saying in effect that the calculation provided from the plant records was based on static principles. It did not include the possibility of air entrainment by a back-and-forth movement of the water/air interface in the suction line. APS could not provide a quick answer to that question because no such calculation had ever been performed for Palo Verde or, for that matter, any other plant of its type.

The technical specifications for Palo Verde, like every other nuclear power plant, require that when the operability of a safety system is called into question it must be answered in a short time (a time related to the risk associated with the safety equipment being out of service) or the reactor must be de-powered and placed in an inherently safe shutdown condition (that condition is called cold shutdown).

APS determined that the RWTs for Units 2 and 3 were inoperable on October 11, 2005 and took the two units offline and placed them in cold shutdown. Unit 1 had the same issue but was already shut down for refueling. APS engaged a leading expert in the field of dynamic, two-component flow phenomena to develop an answer to the contract inspector's question. The expert's answer was provided to the inspection team shortly after it was finished, on October 17. The answer was reviewed and accepted by the NRC and the two units were returned to power on October 20. The RWT and associated systems and procedures were not changed before the return to power and remain today the same as they were in all three units before the new question was asked. That is, the original design basis of the plant remains acceptable for current operations.

Three months later, on January 26, 2006, NRC Region IV Administrator Bruce Mallett appeared before this Arizona Commission. He said (transcript pages 42-44)

> In the October [2005] time frame, when we raised this issue about the design flaw, it was a new question, okay, one that we hadn't

> come across before, nor had they [APS] to the best of my recollection. And so they did what we expected. They searched that out and said we can't answer the question – I am over simplifying – so that would put us in a condition we don't believe is within our design. If you can't answer [the] NRC, and we [APS] can't answer it within this certain time frame, we have to shut the plant down by our technical specifications until we get it resolved. And that's what they did....***All I can say in this case is that it was a question we raised and they did the right thing when they couldn't answer the question....In this instance we didn't determine that they should have found it beforehand....*** But the issue, I think, was it was a new question that was asked. If they were investigating and looking at that system, you would expect them to find out, but I am not sure we would expect them to go in and look at that system at the time we were looking at it....We have an inspection we are conducting at the time and we have a report that is coming out....we will probably issue it tomorrow....And that report will make our conclusions final in that instance that we looked at. [emphasis added]

Dr. Mallett also gave this event as an example of APS actions that "have been in compliance with our requirements and timely and thorough in response to events and emergent issues." (Transcript pages 19-20) In the inspection report that Mallett signed on the following day, NRC did not issue a violation for APS not asking itself the new question in advance of it being asked by the contract inspector.

I concluded in my Rebuttal Testimony that APS was prudent in its handling of the RWT air entrainment issue because it could not reasonably have anticipated the emergence of the new question that NRC raised, and, once the question was asked, APS followed its only available course of action.

Q. DOES DR. JACOBS ACCEPT YOUR DESCRIPTION OF THESE RWT OUTAGES AND YOUR DETERMINATION THAT APS WAS PRUDENT?

A. Dr. Jacobs seems to agree with me on how the outage came about, but he claims APS should have anticipated the new question asked by the contract inspector and thereby avoided the outage. From this he concludes APS was imprudent. However, he does not say how he thinks the outage could have been avoided if the question had been raised by APS in advance of NRC. Although I do not agree with Dr. Jacobs that APS should have anticipated the NRC's new question, even if APS had

done so, the outages would still have occurred, the replacement power costs would still have been incurred, and there would be no imprudent costs.

Q. WOULD THE OUTAGES STILL HAVE OCCURRED IF, RATHER THAN THE NRC RAISING THE QUESTION, APS HAD DONE SO?

A. Yes. Let's consider a hypothetical situation along the lines implied by Dr. Jacobs. Say APS engineer Smith comes to one of the Palo Verde control rooms one day in the summer of 2005, during the examination of the generic implications of the voided sump suction line, and tells the on-duty senior reactor operator that he doubts that the original licensing basis of the RWT is adequate because the dynamic behavior of the air/water mixture in the RWT suction pipe might entrain more air than the design can accommodate. If the SRO is convinced, then the technical specifications require a SRO in the control room of each operating unit to declare the RWTs inoperable and shut the operating units down, just like APS did for the question raised by the NRC contract inspector.

In summary, the RWT outages would not have been avoided if APS had asked the question in advance in the summer of 2005 during the examination that was performed by APS that was required by the yellow cornerstone determination by the NRC. Once this basic fact is recognized, any remaining differences between Dr. Jacobs and me on the RWT outages are moot.

Q. AT PAGE 9 OF HIS SURREBUTTAL TESTIMONY, DR. JACOBS CITES THE QUESTION LEADING TO THE RWT OUTAGES AS AN EXAMPLE OF WHERE NRC IS FINDING PROBLEMS AND NOT APS. DO YOU AGREE?

A. No. As I explain at length in Section 6 of my Rebuttal Testimony, the issue arose when the contract inspector, without advance notice, went beyond the questions originally asked about possible air entrainment in the RWT suction line during the licensing of Palo Verde nearly 30 years before this imposition of a new requirement, i.e., the requirement to perform a new type of analysis that went beyond the analysis required by the NRC when it gave its approval for the plant operating license is called a backfit. (The term "backfit" is defined in 10 CFR

50.109 as the modification of equipment, approvals or procedures at a plant required by a change in NRC requirements or in NRC staff interpretations of NRC requirements, imposed after a plant was originally constructed.)

The actions by the NRC inspectors to raise the dynamic aspects of the switchover of ECCS suction in PWRs from the RWT to the sump constitute a backfit because such effects were not considered in the original licensing basis for these plants. Additionally, this backfit was not done in accord with NRC procedures, which would have required it to be technically justified as being required for assurance of adequate protection of public health and safety. It also would have had to be approved by senior management in NRC's Office of Nuclear Reactor Regulation. There is no reasonable way APS or any other NRC licensee can anticipate spontaneous backfits of this type, conducted outside of NRC's rules and procedures.

Q. AT PAGE 25 OF HIS SURREBUTTAL TESTIMONY, DR. JACOBS SAYS THAT "APS' FAILURE TO ADEQUATELY EVALUATE THE SCOPE OF THE YELLOW FINDING OUTAGE IN 2004 [VOIDED SUMP SUCTION LINE] RESULTED IN THE FAILURE TO IDENTIFY THE RWT PROBLEM PRIOR TO 2005." DO YOU AGREE?

A. No. First, Dr. Jacobs offers no proof of this statement, and I know of none. Second, as I noted above, NRC did not issue a violation to APS for not anticipating this issue. Third, Regional Administrator Mallett told this Commission that, "In this instance we didn't determine that they should have found it beforehand…"

Q. AT THAT SAME PAGE 25, DR. JACOBS SAYS THAT ONCE THE CONTRACT INSPECTOR RAISED THE QUESTION, "APS WAS NOT ABLE TO DEMONSTRATE THAT AIR ENTRAINMENT FROM THE RWT WOULD NOT RENDER THE ECCS PUMPS INOPERABLE." IS THIS REALLY WHAT HAPPENED?

A. No. As I demonstrated in my Rebuttal Testimony (pages 54-55), the designers of the plant and NRC were aware, back in the 1970s, of the potential for air entrainment in the RWT suction line, and requirements had been established in the design that were met by the plant construction to foreclose this possibility. Proof of this fact was provided to the contract inspector who raised the question. In my

Rebuttal Testimony, I provided a copy of the proof of this fact that was given to NRC (Attachment RJM_WP11RB. CESSAR Review Matter Number 38, January 19, 1976). That document reads, in part, as follows:

> Under present design...the closing of the RWT discharge valves during the switchover from injection to recirculation is the result of operator action. The consequence of the operator failing to close the valves at the proper time, assuming the combination of (1) low containment pressure relative to refueling water ambient pressure and (2) an insufficient elevation of the sump water level above the piping junction (the TEE) between the RWT, sump, and safeguards pumps...could be the following. With safeguards pump suction being taken from the sump, the water level in the RWT and then in the RWT [suction] lines continues to drop until it reaches the TEE. This exposes the sump-to-pumps flow to dry lines and pump cavitation results from air in the suction lines. The calculation which follows will define an elevation for a suitable pressure differential which will preclude the above described system dysfunction [i.e., air entrainment into the pumps].

There follows in this CE document a calculation to prove that 16 feet of elevation difference between the sump water level and the top of the piping junction between the RWT and the sump (see figure at page 50 of my Rebuttal Testimony) is sufficient to preclude air entrainment. The Palo Verde units in actuality have 40 feet of elevation difference between these two points, much more than enough to satisfy the design requirement.

It is incorrect for Dr. Jacobs to say that APS could not demonstrate that air entrainment would not render the ECCS pumps inoperable because that is what the above quotation from the original licensing basis for Palo Verde does, using static analysis. It shows that air entrainment will not occur if the required elevation difference is met, which it is at Palo Verde, with margin. And the contract inspector was told so.

What happened next, which Dr. Jacobs apparently does not understand, was the contract inspector said that the original calculation (i.e., the original licensing basis) was not good enough. He wanted another level of proof, namely, a dynamic calculation that showed how the air/water mixture would move in the RWT

suction pipe to assure that it would not lead to a damaging level of air entrainment into the pumps.

The contract inspector could have asked APS to investigate the adequacy of the design basis of some other part of the plant that, like the RWT, had never proven inadequate in service. If he had done so, like the case of the RWT, it would have been just as much of a surprise to APS. Adherence to the design basis of nuclear power plants is strenuously enforced by the NRC. The design basis can only be changed by formal processes that conform with requirements in the NRC regulations. They are not changed thoughtlessly. When brought into doubt by some operating event in the industry, they are often reexamined, but no such thing had happened with RWT lines in the industry. Furthermore, when the unforeseeable question of dynamic movement of the air/water mixture in the RWT suction line was addressed by APS to the NRC's satisfaction, no change in the Palo Verde design resulted.

Q. AT PAGES 26 AND 27 OF HIS SURREBUTTAL TESTIMONY, DR. JACOBS QUOTES AT LENGTH FROM THE 95002 INSPECTION REPORT. DO ANY OF THOSE PARTICULAR QUOTATIONS HAVE ANYTHING TO DO WITH THE CAUSE OR THE DURATION OF THE OUTAGES?

A. None at all. These particular quotations have to do with opportunities for improvement observed by NRC in the course of APS' decision making to enter the RWT outage. The cause and the duration of the outages owed to a separate matter, i.e., the new question about the dynamic aspects of air entrainment in the RWT suction line.

In discussing the peripheral matters that he quotes, Dr. Jacobs says at page 27 that "...the NRC found many deficiencies in APS'...management of the design basis information that led to the RWT outage." If you go back to page 26 and read the only quotation he cites from the NRC inspection report relating to management of design basis information, you find the following: "The licensee also noted, ***in other ongoing programs*** at the facility, that design basis information was not handled

with appropriate attention to detail." (emphasis added) Thus, the only issue relating to management of design basis information had nothing to do with the RWT outage.

The preceding paragraph on page 26 (top bullet) of his Surrebuttal Testimony (page 26) may hold the key to what Dr. Jacobs is missing. That paragraph is quoted from the NRC inspection report. In it NRC faults APS for not expending "...a thorough enough effort to validate the design criteria." (lines 11 and 12) At the time of this inspection, there was no requirement for licensees to validate the adequacy of their design bases unless they had some operating experience that called the design into question or unless NRC issued some new question about the design derived from its broader view of the nuclear industry. Basically, that is what the contract inspector did – he asked a new question (as Dr. Mallett described it to this Commission), one that could not be anticipated and that tested the validity of the existing design basis. Such disregard for the original licensing basis is one of the complaints that the nuclear industry has voiced about NRC implementation of the Reactor Oversight Process, as I described in my Rebuttal Testimony.

Q. ON PAGE 27 OF HIS SURREBUTTAL TESTIMONY DR. JACOBS CITES AN "INVESTIGATION CHARTER" WRITTEN BY APS CONCERNING THE RWT OUTAGES. HE QUOTES A STATEMENT FROM THAT DOCUMENT TO THE EFFECT THAT IT WAS APS' "INABILITY TO PROVIDE A TIMELY RESPONSE TO THE NRC QUESTION" THAT RESULTED IN THE OUTAGES. DO YOU AGREE WITH THE MANNER IN WHICH HE OFFERS THIS QUOTATION?

A. No, he is misinterpreting the timeliness issue. This document is simply saying APS could not provide a response within the short time limits of the Technical Specifications for the reasons I have elaborated above and that Dr. Mallett addressed – it was a new question – so the units had to be shut down pursuant to those Technical Specifications while an answer was developed. As Dr. Mallett told this Commission, "This shutdown was what was expected, in fact, it is required by [their] Technical Specifications."

APS supplied the answer to the question from the contract inspector almost

immediately. The fact that he judged the answer to be inadequate for his purposes has nothing to do with its timeliness.

Administrator Mallett also stated that the APS response was timely. He said, "I should also note there are some areas where their performance is not degraded and their actions have been in compliance with our requirements ***and timely and thorough in response to events and emergent issues***. I will give you some examples....Most recently, and I know you are interested in this event, in October 2005 the licensee did shut down Units 2 and 3 in response to a potential design deficiency, that the NRC raised, until that design deficiency was addressed." (transcript pages 18-19, emphasis added)

Q. AT PAGES 28 TO 30 OF HIS SURREBUTTAL TESTIMONY, DR. JACOBS QUOTES FROM SEVERAL APS REPORTS ABOUT ITS INTERNAL INVESTIGATIONS AFTER THE RWT OUTAGES. ON PAGE 30 AT LINE 14 HE CONCLUDES THOSE QUOTATIONS BY NOTING THAT THERE WERE "...MANY OPPORTUNITIES FOR APS TO HAVE IDENTIFIED THE RWT ISSUE EARLIER." DOES THIS CONCLUSION SUPPORT HIS CONTENTION THAT THE OUTAGE WAS IMPRUDENT?

A. No. Dr. Jacobs does not distinguish between what could have been done and what should have been done. The root cause assessments he quotes do not make that distinction because they were performed by APS according to NRC and industry expectations – in nuclear power plant operations you have to learn from hindsight so the future is always safer than the past, you don't have to distinguish between could and should. In a prudence review such as this one, the difference between could and should is essential.

Dr. Jacobs does not address this distinction. However, for the specific reasons that I have articulated, it is unreasonable to expect that APS should have anticipated the question in advance. Dr. Mallett's statements are consistent with that judgment. Furthermore, even if APS had anticipated the question, it would not have changed the duration of the outage that resulted while the new question was being answered.

It is also important to note that prior to October 2005 many people had looked at

the RWT suction piping and the possibility of air entrainment and had not thought the static design basis at Palo Verde might be inadequate. Those people included the original NRC license reviewers, the original plant designers from Combustion Engineering and Bechtel Corporations, several decades of plant engineering and operations personnel at APS, similarly qualified professionals at other plants having the same design (such as San Onofre and Waterford), and the NRC headquarters thermal-hydraulic experts who have remained cognizant of this system down through the years. After decades of acceptance that air entrainment from the RWT was adequately addressed by static design methods, the new question was raised by a contract inspector and the end result of his question has been no design change.

Q. DID DR. JACOBS ADDRESS YOUR CONTENTION THAT A NEW ISSUE BROUGHT UP BY NRC LED TO THE RWT OUTAGES?

A. Yes, he did so at page 31 of his Surrebuttal Testimony. In essence he says he disagrees because air entrainment is not a new issue and there were lots of earlier opportunities to bring it up. I agree that air entrainment is not a new issue. It was addressed in the original licensing review of every nuclear power plant in the country. I know; I was there. What he misses is the fact that no one prior to the contract inspector at Palo Verde in October 2005 said the dynamic nature of the physical processes invalidated the original designs of all those prior plants. It is not the case that the dynamic nature of the processes involved was not understood all along – I can tell you it was understood. Rather, it was that scores of engineers in and out of government had judged that the static approach to this design, when applied with sufficient conservatism, would accommodate the dynamic effects. The contract inspector said "show me." APS showed him. The show cost 9 days of down time for two large power plants. The plants returned to power with no design change. It was not imprudence on the part of APS that led to these consequences.

Dr. Jacobs goes on to belittle APS' efforts to explain this situation ("Gee, we never thought of that."). The ACC should not be distracted by flippant comments. It is a fact of regulation of nuclear power in the United States that NRC personnel are

allowed and indeed encouraged to think outside the box. The fact that a licensee does not anticipate such creative thinking is not an indicator of imprudence.

Q. DR. JACOBS REJECTS ADMINISTRATOR MALLETT'S CONCLUSIONS THAT THE RWT QUESTION WAS A NEW ISSUE AND NOT ONE THAT APS SHOULD HAVE ANTICIPATED. IS THIS APPROPRIATE?

A. No. He addresses Dr. Mallett's statements to this Commission at page 31-33 of his Surrebuttal Testimony. He says that "The idea that this was a new question appears to be an attempt to shift responsibility for the design of Palo Verde to the NRC." Why Administrator Mallett would want to do such a thing is a mystery to me. It certainly would be counter to every statement ever made by the NRC, of which I am aware, on the question of where such responsibility lies, namely with the licensees. Dr. Mallett would not be so foolish as to say what Dr. Jacobs says. I take Dr. Mallett at his word, it was a new question. He could not have said it more succinctly or simply.

Dr. Jacobs goes on to say "Dr. Mallett's opinion on this [whether the RWT issue should have been seen by APS in advance] is not supported by the facts or NRC's findings." Of course, it is Dr. Mallett who signed the inspection report upon which Dr. Jacobs relies. It seems much more plausible to me that, rather than Dr. Mallett's statements and report being contradictory, it is Dr. Jacobs' interpretation of the inspection report that is wrong.

Administrator Mallett's language and message were stated in clear, simple terms. They help to explain a very complex situation involving two important regimes of regulation, economic performance and safety performance. His statements should be taken at face value. He is the most senior official of the NRC that has been involved in matters important to this case. Dismissing his opinions on those matters would be wrong.

Q. DR. JACOBS SEEMS TO PLACE HIGHER CREDENCE ON THE STATEMENTS ABOUT THE RWT OUTAGES THAT HE SAYS SENIOR RESIDENT INSPECTOR WARNICK MADE DURING A GDS INTERVIEW. WHAT DO YOU THINK OF THAT?

A. At pages 26 and 27 of my Rebuttal Testimony I gave six reasons to suspect that Senior Resident Inspector Warnick's reported statement that the RWT outages could have been avoided should not be interpreted in the way Dr. Jacobs has. They were as follows:

- The senior resident inspector in question was not a member of the inspection team that dealt with the RWT issue nor did he write the January 27, 2006 report of that inspection (Attachment 3 to GDS report of August 17, 2006),
- As noted above, NRC inspectors are not trained or qualified to make such judgments,
- Region IV Administrator Mallett told the ACC on January 26, 2006 that NRC did not determine that APS should have found the new question beforehand,
- The inspection report of January 27, 2006 that dealt with this matter did not contain an NRC finding or a violation for APS's failure to find the new question beforehand,
- The NRC's approval of the GDS interview of the senior resident inspector was approved by the NRC in a letter dated March 15, 2006 from Troy W. Pruett of NRC to Janet Wagner of ACC (RJM_WP2RB) and did not include solicitation of the inspector's opinion on the reasonableness of APS actions in connection with the outages in 2005, and
- There is an alternate interpretation of the senior resident's statement, i.e., he was speaking from his NRC perspective of continuous improvement using hindsight, not from the ACC perspective of judging prudent performance according to information reasonably available at the time.

Dr. Jacobs implies that I was impugning the value and credibility of NRC inspectors by my statement that "... NRC inspectors are not trained or qualified to make such judgments." To the contrary, I was referring to a statement made by a

1 senior regional manager of the NRC regarding a prudence question at the Indian
2 Point nuclear power station, i.e., "...the NRC does not have the 'role to review or
3 judge that [prudence], nor do I endeavor to have the expertise to decide such
4 matters; NRC inspections are not designed to obtain the necessary information or
5 perspectives to judge such matters.' (A. Randolph Blough, NRC Region I Division
6 Director, July 26, 2000 E-mail to Region I staff. RJM_WP1RB)" Again, I prefer
7 this written statement of the NRC official at face value, and my own experience as
8 a senior NRC manager, rather than the interpretations provided by Dr. Jacobs of
9 statements attributed to Inspector Warnick.

10 Finally, the reported statement of Inspector Warnick is irrelevant to this
11 proceeding where the ACC is examining what APS should have done to avoid the
12 outages, not what APS could have done. If the NRC had asked for a dynamic, two-
13 component flow calculation before the plants were licensed, or asked for it in a
14 generic communication that allowed the question to be answered while the plants
15 continued to operate, the outages could have been avoided. Besides those
16 alternatives, if either NRC or APS had raised the question while the units were
17 operating, the outages would not have been avoided.

18 **3. PALO VERDE PERFORMANCE**

19 **Q. ASIDE FROM THE RWT OUTAGES, DOES DR. JACOBS ADDRESS**
20 **OTHER PALO VERDE PERFORMANCE ISSUES USING NRC**
21 **DOCUMENTS AND STATEMENTS?**

22 **A.** He does, and his interpretations of NRC reports and operating data are flawed in
23 many respects and have nothing to do with the outages experienced in 2005.

24 **Q. AT PAGE 6 OF HIS SURREBUTTAL TESTIMONY, DR. JACOBS SAYS**
25 **HE AGREES WITH YOU THAT THERE HAS BEEN A DECLINE IN**
26 **REGULATORY PERFORMANCE AT APS. DO YOU THINK THAT THE**
27 **TWO OF YOU ARE REALLY IN AGREEMENT ON THIS POINT?**

28 **A.** No. I think his statements gloss over the difference we have on this point. First, the
29 decline in regulatory performance as indicated by the number of noncited
30 violations, cross-cutting issues and the yellow degraded cornerstone have no

bearing on the outages in 2005. He says the yellow cornerstone has a nexus with the RWT outage. I have shown that not to be the case. Second, his testimony muddies the water concerning the difference between power production efficiency (as measured by capacity factors, for example) and regulatory performance. When NRC finally removes the degraded yellow cornerstone has no bearing whatsoever on the cause and length of the outages in 2005. When and how cross-cutting issues are ultimately resolved by APS and NRC also have nothing to do with the cause and length of those outages. He opines at length about the current difficulty of resolving those issues, but he cannot show how they caused or lengthened outages that occurred a year or more ago. So, we may agree that there has been a decline in regulatory performance, but we certainly do not agree on how that matters to the outages being examined in this case.

Q. AT PAGES 2-3 OF HIS SURREBUTTAL TESTIMONY, DR. JACOBS ADDRESSES THE RECENT CAPACITY FACTORS OF PALO VERDE IN COMPARISON TO THE REST OF THE INDUSTRY. WHAT IS YOUR REACTION TO THIS TESTIMONY?

A. As he did in his Direct Testimony, Dr. Jacobs relies on an article in the *Nuclear News* of May 2006 for his analysis of capacity factors. A complicating factor for the data presented in that article is that they are averaged over three year periods and are detailed by individual units only for two periods, 2000-2002 and 2003-2005.

Relying on data from that article, Dr. Jacobs says that "...Palo Verde generation and capacity factor have been declining since 2002..." (Surrebuttal Testimony, p. 2, line 19) He does not mention that 2002 was Palo Verde's best year for generation, and that although productivity declined in the years 2003 and 2004, they were still the sixth and seventh highest years of production in Palo Verde's lifetime. From the NRC data summarized in my Rebuttal Testimony (Attachment RJM-3RB), I can tell you that instead of being worst in the industry as Dr. Jacobs portrays its performance, Palo Verde's average availability for the years 2002-2004 was 89.1% compared to an average of 89.8% for all PWRs, placing Palo Verde in

the middle of the pack for the period – the period in which APS also accomplished steam generator replacements in Unit 2.

Another conclusion that Dr. Jacobs derives from the data in the *Nuclear News* article is that Palo Verde's productivity declined more than other plants between the period 2000-2002 and the period 2003-2005. He fails to mention that Palo Verde accomplished steam generator replacements in both Units 2 and 3 in the latter time period. These steam generator replacements required approximately 70 extra days of outage time, compared to about 175 days of non-refueling outage days due to unanticipated events in that same three-year period. Dr. Jacobs would have the ACC believe that the decrease in productivity compared to the prior three years owed entirely to unplanned outages. The fact is that nearly 30% of the down time in the years he addresses was for planned steam generator replacements.

There is no doubt that the average availability of the Palo Verde units of 78% in 2005 was lower compared to other years of operation and compared to industry averages. However, there is a need to keep perspective on this performance indicator. Such perspective is provided in the same *Nuclear News* article on which Dr. Jacobs relies,

> As has been noted in this annual series of surveys, the most remarkable development in the U.S. power reactor community in the past quarter century is not that some reactors had managed to get their three-year capacity factors above 90 percent (which no reactor had done until the early 1990s), but that every one of the operating reactors has improved to the point where a factor well over 80 percent is expected. When these reactors were being planned and built, utilities would routinely make their case to state-level rate-making commissions for the recovery of plant costs in electricity rates by basing the reactor's performance on a capacity factor of about 65%.

I recommended in my Rebuttal Testimony that nuclear power plant performance should be viewed over a long enough period of time to avoid misperceptions created by the vagaries of statistics and sufficient to average out the effects of

refueling and other unavoidable outages. Seeing how the three year averages used by *Nuclear News* are susceptible to misunderstanding suggests to me that a somewhat longer period and a rolling average are more appropriate. Apropos this same point, I reiterate something I said in my Rebuttal Testimony (page 16): It is my understanding that the ACC in a previous decision (Decision No. 55118, page 20) has stated that "a realistic analysis of operating performance must look at both the 'successes' and the 'failures' if it is to avoid setting unobtainable goals of absolute perfection." This is one of the reasons why my analysis examines whether Palo Verde has been operating within industry norms over the past decade, a period over which any company could be expected to have some "successes" and "failures."

Q. AT PAGE 4 OF HIS SURREBUTTAL TESTIMONY DR. JACOBS OPINES THAT "IF THE DECLINE IN PERFORMANCE HAD BEEN RECOGNIZED IN 2003, MANAGEMENT COULD HAVE IMPLEMENTED MEASURES TO ADDRESS THE PROBLEM WITHOUT PALO VERDE SINKING TO THE BOTTOM OF THE INDUSTRY." DO YOU AGREE?

A. No, for several reasons. First of all Palo Verde has not "sunk to the bottom of the industry" as I have shown above. Second, in 2003, but for the outage for the steam generator replacements in Unit 2, the three units were having outstanding operating runs. (Unit 1 had only 7 outage days in 2003, Unit 2 had one day besides the steam generator/refueling outage, and Unit 3 had only 8 days in addition to its normal refueling outage.) Third, in 2003, APS was receiving high marks from NRC and INPO. It is hard to recognize a "decline" in the midst of that kind of performance.

I note that Dr. Jacobs only opines here that management could have done something, he does not say management should have done something nor does he say what management could have done. Also, it is important to recognize that Dr. Jacobs' conclusion, whether right or wrong, had nothing to do with the outages experienced in 2005. He has not shown how the time of detection of a decline in performance has anything to do with any of the outages that occurred in 2005.

Q. AT PAGES 5 AND 6 OF HIS SURREBUTTAL TESTIMONY, DR. JACOBS DISCUSSES THE EFFECT OF OUTAGES IN 2005 ON THE CAPACITY FACTOR OF PALO VERDE THAT YEAR. DR. JACOBS SAYS PALO VERDE'S PERFORMANCE WAS ABYSMAL. YET HE ONLY CHALLENGES 23 DAYS AS BEING IMPRUDENT. HOW MUCH CHANGE IN THE AVAILABILITY OF THE STATION OWES TO THOSE 23 DAYS?

A. The three unit station has the potential to produce a maximum of 1,095 full power days in a year. Losing 23 such days reduces the average availability of the units by 2.1% each. That is, the lost production owing to the outages he contests is very small. In sum, Dr. Jacobs' capacity factor arguments are off the mark for reasons I have discussed above and, in any event, bear no relationship to the outages that are in question in this case.

Q. FROM PAGES 7 TO 14 OF HIS SURREBUTTAL TESTIMONY, DR. JACOBS CITES VARIOUS NRC DOCUMENTS TO MAKE THE POINT THAT HE DISAGREES WITH YOUR TESTIMONY THAT THERE ARE RECENT INDICATIONS THAT THE STATION WILL BE SUCCESSFULLY RETURNED TO THE LOWEST LEVEL OF NRC SCRUTINY. DO YOU STAND BY YOUR EARLIER TESTIMONY TO THAT EFFECT OR HAS HE CHANGED YOUR MIND?

A. I stand by my earlier testimony. All the documents he now cites were available at the time I filed my Rebuttal Testimony in this case, and, with the exception of one document that summarizes the others, all were available at the time Dr. Jacobs filed his Direct Testimony. That is, I reached my earlier conclusion about there being recent indications of returning to a normal level of scrutiny by the NRC fully aware of the documents he cites. One of the indications identified in my Rebuttal Testimony was Administrator Mallett's statement to the ACC on January 26, 2006 (transcript page 24),

> They [APS] are in what we call the third column or yellow column [i.e., the second column of increased oversight] of our action matrix because they had a finding with this voiding issue in their emergency core cooling pipe system late 2004 that was risk significant. And we felt that needed to be corrected. So that's what put them into that column. Once they correct [accomplish] the actions they need to take for that specific issue and complete it, they will go back to the first column, or green column of

> performance where we don't have increased oversight of them.
>
> In addition to that action matrix, however, these other problems I listed, we issued them based on their performance, these two cross-cutting issues [of] problem identification and resolution and human performance. These have to be corrected by them [APS]. They have to address those issues. But they will still be in the green column with those issues.
>
> The reason we identified them [cross-cutting issues] is those are indicators that we believe lead you to getting into one of the columns to the right of the matrix… the yellow or red column. So we identify those issues early and hope to turn them around so…their performance doesn't get worse.

At pages 11 to 13 of his Surrebuttal Testimony, Dr. Jacobs discusses the substantive crosscutting issues that NRC has identified for Palo Verde. He again fails to mention that these issues all concern non-cited violations (green ones in the NRC parlance, i.e., low safety significance) and are all addressed by the normal levels of NRC scrutiny. They are not the cause of increased scrutiny, as explained by Mallett in the quotation provided above. Dr. Jacobs also ignores the perspective I provided in my Rebuttal Testimony (pages 10 and 35) that these cross-cutting issues recently have been growing in number around the industry. Since the performance of the industry is known to be rising in this same time period, there must be something about these cross-cutting issues that doesn't directly correlate with performance. I offered a number of insights to this phenomenon in my Rebuttal Testimony, and Dr. Jacobs did not counter the points I made there.

In any case, I do not read the recent letters from NRC to APS to be as dire as Dr. Jacobs apparently does. The difference may be discerning a glass that is half empty from one that is half full. Let me explain. Performance improvement programs of the type now underway at Palo Verde are not expected to produce results overnight. The NRC letters that Dr. Jacobs cites are chronicling the improvement process at Palo Verde as it progresses under the direction of the PIP. While this theorizing on how things will go with the NRC in the future is interesting, it has nothing to do with the outages experienced in 2005.

Q. AT PAGES 14 AND 15, DR. JACOBS SAYS THAT "ROOT CAUSE EVALUATIONS AND OTHER OUTAGE REVIEWS CONDUCTED BY THE COMPANY DO NOT RELY ON HINDSIGHT...[AND] THE NRC DOES NOT RELY ON HINDSIGHT..." DO YOU AGREE?

A. No. Root cause assessments are only conducted after the fact, i.e., after the outcome of some set of circumstances is known. They are not contemporaneous to the occurrence of the preceding circumstances that led to the outcome. By definition, they are retrospective. They are fully informed of the outcome of the preceding factors. That is what hindsight means. My *American Heritage Dictionary* says hindsight is the "perception of the significance and nature of events after they occur."

This is very important to understand when one relies on information in root cause assessments performed by NRC or its licensees because those assessments are full of hindsight, and they do not attempt to distinguish between what could have been known and what should have been known at the time prior events occurred. It is important that people using these reports understand that distinction because any judgment about the reasonableness of what other people did in real time to control those prior events must make such a distinction.

Q. AT PAGE 15 OF HIS SURREBUTTAL TESTIMONY DR. JACOBS SAYS THAT NRC DOCUMENTS AND COMPANY SELF ASSESSMENTS "PROVIDE A CONTEMPORANEOUS ASSESSMENT" OF PLANT PERFORMANCE AND THAT "THE USE OF COMPANY ASSESSMENTS AND NRC DOCUMENTS HAS BEEN ALLOWED IN EVERY ONE OF THE MANY JURISDICTIONS IN WHICH I HAVE TESTIFIED ON NUCLEAR PLANT OUTAGES." IS THAT CORRECT?

A. No. Moreover, the more important question is whether those jurisdictions accepted his claim that such documents provide a contemporaneous assessment of plant performance, not based on hindsight. In my Rebuttal Testimony I quoted a decision from one of the jurisdictions in which Dr. Jacobs has appeared. I used the quote to show that backfitting at the Kewaunee Nuclear Power Plant (KNPP) by the same NRC contract inspector involved in this Arizona case had been found by the Wisconsin PUC not to be the source of imprudent action, contrary to testimony

offered there by Dr. Jacobs. Here is what that same Commission had to say about Dr. Jacobs' use of KNPP's root cause analysis in that case (page 24 of RJM_WP14RB):

> Dr. Jacobs primarily relied upon the Root Cause Analysis and other reports regarding the 2005 outage as the basis for his opinion that past NMC [Nuclear Management Corporation, the licensee] management was careless and, therefore, imprudent. These reports were prepared by NMC for the NRC in the course of the 2005 outage. The documents include a summary of prior KNPP conduct regarding the AFW [Auxiliary Feedwater] and other systems and observations of past opportunities to have made improvements. Dr. Jacobs primarily relies upon these documents as the basis for his opinion that KNPP failure to make repairs in the past was the result of imprudent management.
>
> ***These documents and their assessments***, however, were prepared for the NRC in 2005 and ***do not provide definitive evidence of past imprudent management. The record does not include documents contemporaneous with these past opportunities that show KNPP failed to exercise reasonable management*** with respect to the AFW system or other repairs made during the 2005 outage. Furthermore, the record does not include specific evidence that these repairs should have been made consistent with industry standards prevalent in the past when these opportunities occurred. As a consequence, the record does not present sufficient evidence to demonstrate that imprudent past management practices lead to the 2005 outage. (emphasis added)

So, a root cause assessment by the licensee and similar documents were allowed into the record in the Wisconsin case, but they were found to be inappropriate for the purpose for which they were offered by Dr. Jacobs. A similar finding is warranted in this case for the uses that Dr. Jacobs has made of APS' and NRC's retrospective analyses and reports because of his failure to account for hindsight bias contained in those documents.

Q. DO OTHER TECHNOLOGICAL ENDEAVORS RECOGNIZE THAT THERE IS HINDSIGHT IN RETROSPECTIVE ANALYSES?

A. Yes. The inherent nature of hindsight in root cause assessments is not unique to the nuclear industry. The following is a brief description of the phenomenon (called Hindsight Bias in the literature) as it is observed in the practice of medicine:

> There are a variety of factors that block or inhibit the learning processes central to a high reliability culture. One is the hindsight bias (Fischhoff, 1975; Woods et al., 1994; Woods and Cook, 1999). The hindsight bias is one of the most reproduced research findings relevant to accident analysis and reactions to failure. Knowledge of outcome biases our judgment about the processes that led up to that outcome.
>
> In the typical study, two groups of judges are asked to evaluate the performance of an individual or team. Both groups are shown the same behavior; the only difference is that one group of judges are told the episode ended in a poor outcome; while other groups of judges are told that the outcome was successful or neutral. Judges in the group told of the negative outcome consistently assess the performance of humans in the story as being flawed in contrast with the group told that the outcome was successful. Surprisingly, this hindsight bias is present even if the judges are told beforehand that the outcome knowledge may influence their judgment.
>
> (From a paper "Behind Human Error: Human Factors Research to Improve Patient Safety," David Woods, Past President, Human Factors and Ergonomics Society, published by American Psychological Association, 2006, RJM_WP1RJ)

The NRC makes no effort to remove hindsight bias from its retrospective assessments or those of its licensees. Rather, NRC values hindsight because it provides insight to what might be done in the future to foster continuous improvement. NRC does not make judgments about the reasonableness of past actions – the outcomes of those actions either meet the regulations or they do not meet the regulations, as far as NRC is concerned. But many other organizations do need to correct for hindsight bias because those organizations deal with the reasonableness of past actions, just as does this Commission. A recent, brief exploration on the Internet showed the range of organizations that acknowledge or correct for Hindsight Bias in their retrospective analyses of events. Documents illustrating this are provided as RJM_WP2RJ.

In sum, hindsight bias exists, it is human nature when looking back. NRC takes advantage of the bias to strengthen the assurances it provides of future nuclear safety. So does APS. Others correct for it, as should this Commission in reading

retrospective reports by NRC and its licensees.

Q. AT PAGES 15 AND 16 OF HIS SURREBUTTAL TESTIMONY, DR. JACOBS REFERS TO A DECISION BY FERC JUDGE COWAN IN 1998 INVOLVING PERMANENT SHUTDOWN OF THE CONNECTICUT YANKEE ATOMIC POWER PLANT. HE SAYS THAT COWAN'S DECISION TO USE INFORMATION FROM NRC AND COMPANY ASSESSMENTS TO REACH AN ECONOMIC REGULATORY JUDGMENT SHOULD BE FOLLOWED IN THIS CASE. DO YOU AGREE?

A. No. Judge Cowan was dealing with a very different situation than we are here, as he said in the paragraphs just preceding the ones quoted by Dr. Jacobs.

> In the instant case, the prudence inquiry, while broad-ranging, is not so much to determine whether certain costs sought to be recovered in rates were prudently incurred as it is to determine whether a pattern of utility managerial conduct was unreasonable and imprudent, compelling the closure of a plant with, arguably, some remaining economic life. The distinction between the prudence inquiry here and the more typical analysis of the prudence of certain incurred costs is not so much one of principle as one of approach.
>
> In the more typical prudence case, an inquiry into the reasonableness of management conduct surrounding a certain set of costs can follow an auditable trail more readily than the more complex prudence issue in the instant case. In both types of cases, the object is similar, to wit, to determine whether a reasonable utility management would have performed similarly under the same circumstances at the relevant point in time. ***But, given the broad nature of the inquiry here, encompassing a pattern of managerial conduct involving a wide range of issues over a span of time, the proof of imprudence will be more difficult to come by and will, of necessity, take a different form.*** (emphasis added)

Accordingly, the FERC ALJ decided to make use of NRC and Company documents due to "the absence of more traditional analysis and evidence." Judge Cowan pointed out that there are significant differences between a normal prudence case like this case and the one involving Connecticut Yankee. In the Yankee case, the plant allegedly had been operated and maintained in such a manner that its useful life for producing power was far shorter than originally intended. The FERC case had to do with the

1 recovery of decommissioning and other costs associated with the
2 premature, permanent shutdown of that plant. Clearly, the Connecticut
3 Yankee situation was not the same as this Palo Verde case where only a
4 few short outages are in question. Thus, the unusual course chosen by
5 Judge Cowan should not be followed here. This Commission's decision
6 should be based on what it was reasonable for APS to have done in the
7 various circumstances it faced where reasonableness is judged free of
8 hindsight bias.

9 It bears repeating that, if one is careful to differentiate what could have been
10 known from what should have been known, NRC and Company documents
11 generated with hindsight bias can be used in cases such as this one. However, I
12 have seen no effort by Dr. Jacobs to point out such distinctions in the testimony he
13 has offered in this case, testimony that is nearly all based on retrospective NRC
14 and APS documents.

15 **Q. AT PAGE 17 OF HIS SURREBUTTAL TESTIMONY, DR. JACOBS**
16 **DISAGREES WITH YOUR STATEMENT THAT HE HAS TAKEN SOME**
17 **OF THE COMPANY'S ANALYSES OUT OF CONTEXT. IS HE**
18 **CORRECT?**

19 **A.** No, the reasons he cites for disagreeing with me have nothing to do with the point I
20 was making at page 11 of my Rebuttal Testimony where I said, " Although I agree
21 with the GDS report at pages 2 and 11 that the PIP should be successful in
22 improving performance at Palo Verde, I strongly disagree with the manner in
23 which GDS has taken out of context the harsh self criticism of the APS analyses
24 connected with the PIP and incorrectly portrayed them as self condemnation."

25 My criticism about his use of NRC and APS documents has nothing to do with the
26 length of his quotations or of the documents he has provided, as he asserts.

27 Rather, my criticism relates to what I have stressed in the preceding answers. That
28 is, Dr. Jacobs makes no attempt in his testimony to put the harsh self-criticism
29 found in APS documents in context. Had he done so he would have pointed out
30 that they were written after the fact. He would have shown in specific details

where they contained hindsight bias. Also, he would have acknowledged that they were written in a style that is the established norm in this industry – all licensees use harsh self-criticism in their retrospective analyses of operating events or other unusual conditions.

Q. IN YOUR REBUTTAL TESTIMONY AT PAGES 45 TO 47 YOU PROVIDED INFORMATION ABOUT NRC'S CONCERN FOR ECONOMIC PERFORMANCE STANDARDS THAT MIGHT BE SET BY OTHERS FOR THE NUCLEAR POWER PLANTS NRC REGULATES. DR. JACOBS CALLS THIS CONCERN "SOMETHING OF A RED HERRING" AT PAGE 38 OF HIS SURREBUTTAL TESTIMONY. DO YOU AGREE WITH THE REASONING HE PRESENTS THERE?

A. I do not. As I discussed above, Dr. Jacobs would have this Commission disregard the words of an NRC Regional Administrator, the senior-most NRC official who has reviewed the RWT outages. Now, Dr. Jacobs would have this Commission ignore the statements of the NRC Commissioners themselves on another important topic, as those statements are found in the *Federal Register* and in a statement the NRC presented to Congress.

As I pointed out in my Rebuttal Testimony, NRC is concerned about economic performance standards because they can provide disincentives to safety. The importance of not creating such incentives was stressed by the President's Commission on the Accident at Three Mile Island. The avoidance of safety disincentives has attracted the attention of every NRC Commission since then. Because they are of concern at the highest levels of our government, I wouldn't call safety disincentives a red herring. Speaking frankly, the NRC does not like economic performance standards because of its concern for disincentives to safety. The NRC has offered some detailed advice on how to structure such standards if a state decides it has to have them. But NRC does not favor or encourage them.

4. SUMMARY OF CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS ABOUT THE RWT OUTAGES IN LIGHT OF DR. JACOBS' SURREBUTTAL TESTIMONY.

A. My conclusions about the RWT outages are unchanged from those stated in my

Rebuttal Testimony. I reiterate them here for convenience.

- APS responded reasonably to the line of inquiry about air entrainment in the suction piping from the RWT by showing proof that air entrainment had been considered in a static calculation recorded in the original licensing basis of the plant.
- APS could not have anticipated that the contract inspector would then have questioned the adequacy of the original design by asking if there was a dynamic analysis, because static analysis was the basis for design and licensing of ECCS suction lines for all pressurized water reactors in the U.S., not just Palo Verde.
- Thus, the question was typical of one of the problems that have been identified to the NRC by the industry in its annual feedback associated with the reactor oversight process, namely, the inspection part of the reactor oversight process has begun to address the adequacy of the original licensing process wherein the safety basis was established;
- However, once NRC raised the question, APS was required to address it. When APS could not answer the question in the time prescribed by the plant's Technical Specifications, the two operating units had to be shut down until the answer could be developed. The answer required extending the state of the art for such analysis.
- As Region IV Administrator Mallett told the Arizona Corporation Commission on January 26, 2006, the issue was a new question, one that NRC and APS had not come across before, APS did what NRC expected, and NRC did not determine that APS should have found the issue beforehand.
- The units restarted and continue to run today without any changes in the equipment, training or procedures associated with the systems in question.

I disagree with much of what Dr. Jacobs has said in rebuttal of these conclusions, specifically,

- Dr. Jacobs argues that APS should have asked the new question about RWT air ingestion before the NRC asked it. I disagree because that question went beyond the design basis of the plant and there was no operating or other experience that called that design basis into question. However, even if APS had asked the new question in advance of the NRC, it would not have avoided the RWT outages.
- Dr. Jacobs says the RWT issue arose because NRC, not APS, was finding problems. I disagree. The air entrainment connection between the voided sump suction line and the RWT was addressed by APS in the expected and reasonable manner, i.e., by recourse to how the original design basis accommodated this concern. It was not reasonable for APS to have anticipated NRC's rejection of that answer and its raising of the new question about dynamic effects. In the end, no design changes have been required to answer the new question.
- Dr. Jacobs says APS was not able to demonstrate that air entrainment in the lines coming from the RWT would not disable the emergency pumps. I disagree. APS did make such a demonstration, and it was provided to NRC almost immediately after APS was asked to do so. The demonstration came form the original licensing records for the plant. That was a reasonable approach for APS to have taken. The contract inspector then asked the new question that had not been asked before and it took some time and one of the leading experts in the field to develop an answer.
- Dr. Jacobs offers no proof for his claim that APS should have known of the new question in advance. NRC did not cite APS for failure to anticipate the new question, and NRC Regional Administrator Mallett told the ACC that, "In this instance we didn't determine that they should have found it beforehand..." Dr. Jacobs dismisses the statements by Administrator Mallett on the RWT outages. I find Dr. Mallett's statements to be consistent with the inspection report he signed and conclude that it is Dr.

Jacobs' reading of the documents that is incorrect.

- Dr. Jacobs did not respond in his Surrebuttal Testimony to the interpretation that I have suggested the ACC should apply to senior resident inspector Warnick's reported statement to Dr. Jacobs about the avoidance of the RWT outages, i.e., Warnick was making a "could have avoided" statement not a "should have avoided" statement. Even if Inspector Warnick really meant that the outages should have been avoided, he was wrong and is in conflict with his superior Dr, Mallett.

- If APS had raised the new question before the contract inspector raised it, the RWT outages would still have occurred because technical specifications on the timing of operability determinations would have applied without regard to the source of the question that brought RWT operability into doubt.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS ABOUT THE PERFORMANCE OF PALO VERDE IN LIGHT OF DR. JACOBS SURREBUTTAL TESTIMONY.

A. My conclusions about Palo Verde's power production and regulatory performance are unchanged from my Rebuttal Testimony. I reiterate some of the key conclusions here for convenience.

- Palo Verde's performance has been within industry norms over the decade from 1995 to 2005. Although it has experienced a decline recently, as most plants do at some point, APS is addressing this decline through its Performance Improvement Program. Self-critical reports and assessments are always a part of such improvement efforts and are not an indicia of imprudence.

- The new reactor oversight process that NRC implemented in 2000 provides four levels of increasing scrutiny of licensees above the normal level of NRC oversight. Palo Verde is now at the second level of increased oversight (yellow cornerstone), and there are indications that it will

successfully return to the lowest level of NRC scrutiny. In the meantime, NRC has not interfered with its continued operations.

- NRC has raised concerns with cross-cutting aspects of Palo Verde operations (human performance and problem identification and resolution). These issues did not cause the yellow cornerstone or the outages experienced in 2005, and they have been controversial within the industry. In response to general industry criticism of the cross-cutting issues, NRC has recently acknowledged it has its own difficulty in understanding and dealing with cross-cutting findings and in early 2006 proposed new ways of dealing with them.
- The Performance Improvement Process underway since October 2005 is beyond NRC's expectations for a station at Palo Verde's current level of performance. The PIP is typical of improvement programs that have been implemented at many operating plants, usually when they were experiencing worse performance problems than Palo Verde. Such processes always involve self-assessments that use hindsight to identify opportunities for improvement, and they often do so in harsh terms that are expected by NRC and the industry.

I disagree with much of what Dr. Jacobs has said in rebuttal of these conclusions, specifically,

- Although APS' recent performance has not been as high as prior levels of excellence, over the six year period that Dr. Jacobs purports to analyze, Palo Verde's performance is somewhat below average and nowhere near as bleak as depicted by Dr. Jacobs in his Surrebuttal Testimony.
- Dr. Jacobs opines that if the decline in performance had been detected in 2003 it could have been corrected earlier. I note that he did not say it should have been detected earlier, and I have listed some reasons why it was not reasonable for a decline in performance to have been detected in

2003.

- Dr. Jacobs and I agree that there was a decline in regulatory performance at Palo Verde, but I conclude there is no connection between that decline and the outages that occurred in 2005.

- Dr. Jacobs disagrees with my conclusion that there are signs that Palo Verde will return to a normal level of NRC oversight. His citation of recent statements by NRC about the yellow cornerstone and the cross-cutting issues fails to account for the inherently negative tone of NRC inspection reports, and he has not countered the indicators I cite, including statements to this Commission by Administrator Mallett that once the yellow cornerstone is cleared up the plant will return to normal oversight.

- Dr. Jacobs says that NRC and APS do not use hindsight in their retrospective analyses. He is wrong. NRC has stressed this aspect of accident analysis since the accident at Three Mile Island and the emphasis it placed on the value of retrospective, "What If" analyses of operating experience. Hindsight bias has been shown to be an inherent human psychological phenomenon that has been examined in the scientific literature. Some agencies and organizations intentionally discount the effects of hindsight bias in their retrospective analyses. NRC does not. The ACC should take care to identify and discount hindsight bias in its prudence determinations, certainly when using NRC documents, but also when asked to rely on the testimony of experts such as Dr. Jacobs who deny its existence.

- Dr. Jacobs claims in his testimony before this Commission that NRC documents and company root cause assessments have been allowed in every jurisdiction in which he has testified. However, although he was able to cite such documents in the Kewaunee case, the Wisconsin Commission easily detected the hindsight bias they contained and expressly ruled against the use for which he cited the documents.

- Dr. Jacobs persists in this case in making no effort to differentiate what could have been known from what should have been known when he relies on NRC and company documents generated with hindsight bias.
- Dr. Jacobs dismisses NRC's concern for economic performance standards. The subject deserves more serious consideration than he has given it because of the NRC-perceived potential of such standards to create disincentives to safety. Although the NRC has offered some detailed advice on how to structure such standards if a state decides it has to have them, NRC does not favor or encourage them.

Q. DOES THIS CONCLUDE YOUR REJOINDER TESTIMONY?

A. Yes.

ATTACHMENT RJM-1RJ. ACRONYMS

ACC	Arizona Corporation Commission
AEC	Atomic Energy Commission
AFW	Auxiliary Feedwater (System)
AIT	Augmented Inspection Team (from NRC)
APS	Arizona Public Service Company
BNL	Brookhaven National Laboratory
BWR	Boiling Water Reactor
CAP	Corrective Action Program
CE	Combustion Engineering
CFR	Code of Federal Regulations
CRDR	Condition Report/Disposition Request
CSS	Containment Spray System
ECCS	Emergency Core Cooling System
EPA	Environmental Protection Agency
FSAR	Final Safety Analysis Report
HPCI	High Pressure Coolant Injection (part of ECCS on BWR)
HPSI	High Pressure Safety Injection (a subsystem of the ECCS on a PWR)
I&C	Instrumentation and Control (Systems)
IEAL	International Energy Associates Limited
KNPP	Kewaunee Nuclear Power Plant
NCV	Non Cited Violation
NMC	Nuclear Management Corporation
NRC	Nuclear Regulatory Commission
OCS	Operations Computer Systems
ORR	Operational Readiness Review
PI&R	Problem Identification and Resolution
PVNGS	Palo Verde Nuclear Generating Station
PWR	Pressurized Water Reactor
RAS	Recirculation Actuation Signal
RHR	Residual Heat Removal
ROP	Reactor Oversight Process (of the NRC)
RWT	Refueling Water Tank
SIS	Safety Injection System (part of ECCS, another name for HPSI)
UFSAR	Updated Final Safety Analysis Report

EXHIBIT
APS-89
Admitted

REBUTTAL TESTIMONY OF ROBERT E. DENTON ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY

(Docket No. E-01345A-05-0816)

September 15, 2006

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REBUTTAL TESTIMONY OF ROBERT E. DENTON
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)

I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Robert Elmo Denton. My business address is 79 Redwood Lane, Weems, Virginia 22576.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I have a Bachelor of Science degree in Physics from Duke University (1965). I completed the U.S. Navy Nuclear Power Training course prior to serving in the fleet. I also attended the following educational programs: The Executive Management Program, Pennsylvania State University, and the Executive Leadership Program of the Edison Electric Institute.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am self-employed and provide management and technical consulting to the utility industry.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND, WORKING TOWARDS THE PRESENT.

A. After having served five years in the Navy Nuclear Propulsion Program, I was employed by Baltimore Gas and Electric (BG&E) in 1970, and between 1970 and 1978 I received various operating job assignments during the construction, startup and early operation of the Calvert Cliffs Nuclear Units. In 1974 I obtained a Senior Operators license from the Atomic Energy Commission, and held that license for eight years.

From 1978 – 1980, I served as the General Supervisor of Operations at Calvert Cliffs, and from 1980 – 1985 I headed the plant technical services group.

In 1989, after a four year assignment in the Corporate Finance Division, I returned to the nuclear power plant as Manager – Quality Assurance and Staff Services.

In 1990, I was promoted to Plant General Manager and was responsible for the operation and maintenance of Calvert Cliffs. During this time I oversaw the improvement process which resulted in the removal of Calvert Cliffs from the Nuclear Regulatory Commission (NRC) "Troubled Plants" list, also known as the "Watch List," in early 1992.

From 1992 – 1996, I served as Vice President of Nuclear Energy and was responsible for all aspects of the nuclear power program.

From 1996 – 2000, I was Senior Vice President and then Executive Vice President of Generation at BG&E and Chief Nuclear Officer for the BG&E nuclear program. In this capacity I was responsible for all regulated generation facilities, i.e., nuclear, fossil, and hydro-electric.

In July of 2000, the State of Maryland deregulated electric generation facilities. At that time, BG&E remained as the regulated distribution company and the generation facilities were placed in non-regulated companies as wholly owned subsidiaries of the Constellation Energy Group. I became the President and CEO of Constellation Nuclear, a subsidiary of the Constellation Energy Group, which owned and operated the Calvert Cliffs and Nine Mile Point Nuclear Units. At the same time, I continued as Chief Nuclear Officer for Constellation Nuclear. I retired effective January 1, 2002.

Q. HAVE YOU SERVED ON ANY NUCLEAR INDUSTRY COMMITTEES?

A. Yes. I have served on various committees and advisory boards for the Institute of Nuclear Power Operations (INPO), the Electric Power Research Institute (EPRI), the Nuclear Energy Institute (NEI), and the Association of Edison Electric Illuminating Companies (AEIC).

Q. HAVE YOU SERVED ON ANY CORPORATE OR UNIVERSITY BOARDS?

A. Yes. I was a director on the Board of Directors of Baltimore Gas and Electric Company and the Safe Harbor Water Power Corporation. I have also served on advisory boards of engineering schools at the University of Maryland and Duke University. I was appointed by the Governor of Maryland to the Board of Trustees of the Chesapeake Bay Trust.

Q. HOW DOES THE EXPERIENCE YOU HAVE DESCRIBED ABOVE RELATE TO YOUR TESTIMONY IN THIS PROCEEDING?

A. My experience at BG&E in front line assignments at Calvert Cliffs and later in executive and senior executive capacities is directly applicable to my review of the Palo Verde operations. The Calvert Cliffs plant is a ten year older, slightly smaller version of Palo Verde. The nuclear steam supply system for both facilities was designed and manufactured by Combustion Engineering, Inc. of Windsor, Connecticut. The layout of the plants, much of the equipment, the licensing basis, the Technical Specifications, and the operating practices are the same or very similar at both facilities. Moreover, as a former senior nuclear plant executive, whose responsibilities included, among other things, the successful elimination of Calvert Cliff's "troubled plant" status, I have extensive experience in dealing with the NRC and INPO.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been engaged by Arizona Public Service Company (APS) to review its actions as the operator of the Palo Verde Nuclear Generating Station (Palo Verde or Company) in connection with certain outages that occurred at Palo Verde during 2005. I have also been asked to evaluate portions of the report of GDS Associates, Inc. (GDS) and the testimony of GDS Vice President, Dr. William Jacobs, testifying on behalf of the Staff claiming that APS acted imprudently in some instances. In that regard, I address in this testimony GDS' conclusions that Palo Verde was safely operated and that the Company's Performance Improvement Program will be successful in returning Palo Verde to the level of excellence it enjoyed for so many years. I also address the appropriateness of GDS' reliance on NRC reports, INPO reports and Company self-critical documents to prove imprudence on APS' part with respect to certain outages. Third, I address GDS' recommendation to the Commission that it should consider whether APS has sought appropriate remedies from vendors whose equipment caused certain of the 2005 outages. Finally, I address GDS' conclusion that APS was imprudent in connection with an outage that occurred at Unit 1 in March of 2005 due to the failure of a diesel generator governor.

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. As discussed above, I reviewed the GDS report and the Company's actions regarding the 2005 outages. From this review, I made the following conclusions, which are described in more detail in my testimony below:

- I agree with GDS that Palo Verde was operated safely in 2005.
- I also agree with GDS and am optimistic that Palo Verde's Performance Improvement Plan will return it to excellent performance.

- GDS inappropriately used NRC, INPO, and Company self-critical documents in attempts to show imprudence.

- The Palo Verde contracts that I reviewed are typical contracts in the nuclear industry. It is a normal practice in this industry to exclude liabilities for consequential damages for contractor negligence.

- Finally, I conclude that Palo Verde was prudent regarding the March 2005 diesel generator governor outage because Palo Verde stored the governor at a higher level than the manufacturer recommended and could not have discovered any rust in the governor during a reasonable pre-installation inspection.

III. PALO VERDE PERFORMANCE

Q. HAVE YOU REVIEWED THE SECTION OF THE GDS REPORT ENTITLED "PALO VERDE PERFORMANCE"?

A. Yes I have.

Q. DO YOU CONCUR WITH GDS' CONCLUSIONS REGARDING SAFETY?

A. Yes I do. Based on my own review of Palo Verde operations, I too conclude that the plant was operated safely during 2005.

Q. HAVE YOU REVIEWED THE PALO VERDE PERFORMANCE IMPROVEMENT PLAN ISSUED ON OCTOBER 15, 2005?

A. Yes. I reviewed that plan, and based on my experience I find it to be well designed and comprehensive. I share GDS' optimism that when the plan is fully implemented the result will be a return to excellent performance.

Q. FOR PURPOSES OF EVALUATING THE PRUDENCE OF APS' ACTIONS, WHAT STANDARD OF PRUDENCE DID YOU APPLY?

A. I applied the following standard set forth in the Arizona Administrative Code regarding prudent utility investments:

> "Prudently invested" – Investments which under ordinary circumstances would be deemed reasonable and not dishonest or obviously wasteful. All investments shall be presumed to have been prudently made, and such presumptions may be set aside only by clear and convincing evidence that such investments were imprudent, when viewed in the light of all relevant conditions known or which in the exercise of reasonable judgment should have been known, at the time such investments were made.

Q. IS THIS STANDARD CONSISTENT WITH YOUR OWN VIEW OF PRUDENT UTILITY INDUSTRY PRACTICE?

A. Yes. In a plant operated in accordance with prudent utility practice, management's actions should be consistent with those that a reasonable manager, with appropriate education, training and experience, would take in light of the information available at the time the actions were taken. The decisions made and the actions taken should be reasonable efforts intended to maintain nuclear safety, to comply with the regulatory requirements of the NRC, and to achieve industry standards of reliability and efficiency.

An evaluation to determine whether management's actions met this standard should avoid hindsight; i.e., judgments based upon the results of management decisions or based upon information that could reasonably have become known only after the decisions were made.

Q. IN DETERMINING WHETHER THE STANDARD OF REASONABLENESS HAS BEEN MET, IS IT APPROPRIATE TO RELY ON NRC OR INPO DOCUMENTS, OR ON SELF-CRITICAL COMPANY DOCUMENTS?

A. Usually, the answer would be no.

Q. WHY?

A. Because such documents are usually prepared with full benefit of hindsight, and they typically do not present a balanced view of events. Additionally, they are not intended to, and do not, measure reasonableness of management actions.

Q. WHAT ARE THE ROLES OF THE NRC AND INPO IN CONNECTION WITH COMMERCIAL NUCLEAR POWER PLANTS?

A. NRC and INPO are the two organizations principally responsible for setting standards for commercial nuclear plants. The NRC is an independent agency of the U.S. government. The stated NRC mission is to "ensure adequate protection of public health and safety to promote the common defense and security and to protect the environment." The NRC is purely a regulator of nuclear plant safety – it is not concerned with efficiency or production results. As such, the NRC publishes rules and standards for the civilian nuclear industry aimed at ensuring the protection of the public from hazards associated with the operation of nuclear reactors. Plants are then inspected to ensure compliance with these rules and standards.

It should be noted here that the NRC primarily uses hindsight to evaluate the results of the decisions made by plant management. One of the principal lessons learned from the 1978 incident at Three Mile Island Unit 2 (TMI-2) was the need to continually learn from the operating experience of every nuclear plant. Therefore, every incident, event, or deviation from standards, even those of very low safety significance, is analyzed for "lessons learned." Consequently, all organizations are expected to make improvements to prevent similar or more serious future events.

Keeping in mind the NRC's mission and methods, it is my experience that NRC written reports have what appears to be an overwhelming amount of criticism.

They come across as principally negative documents even when plants are highly regarded as excellent performers. This flavor is due to the method of examining each detailed variation from standards, no matter how small, to learn and improve. It is my understanding that Dr. Mattson will address the role of the NRC in greater detail in his testimony.

Additionally, the nuclear electric utility industry created INPO in 1979 after the TMI-2 incident. INPO's mission is to promote the highest levels of safety and reliability and to promote excellence in the operation of nuclear electric generating plants. All U.S. organizations that operate commercial nuclear power plants are INPO members. Among INPO's activities are:

- Analysis of reported events and dissemination of the lessons learned.
- Promoting the exchange of information and good practices among all nuclear utilities.
- Benchmarking against international best practices.
- Developing and monitoring a set of 10 performance indicators.
- Maintaining evaluation and peer review programs.

All U.S. nuclear plants are inspected by a team of INPO staff and peer industry personnel every 18 to 24 months. Note that INPO does include production in its review – it is weighted heavily in the 10 performance indicators. The INPO team compares plant performance to the best practices in the industry and its reports point out where deficiencies, when compared to best practices, are present. These are referred to as "areas for improvement." This standard is explicitly set forth in the INPO report upon which GDS relies, although GDS makes no mention of the standard. INPO states that "areas for improvement are based on best practices

observed in the industry, rather than on minimum acceptable standards or requirements." Again, this focus leads to a negative-sounding report.

Q. HAVE YOU REVIEWED THE SECTION OF THE GDS REPORT ENTITLED INPO EVALUATION RESULTS?

A. Yes, and even though the GDS report appears to accurately reflect the areas pointed out by INPO as "areas for improvement," I do not agree with the GDS characterization of these areas as "significant problems." My own review of the same INPO report and my experience with numerous INPO reviews concludes that the INPO term "area for improvement," as I mentioned earlier, is compared to the best practices in the industry. This is in keeping with INPO's mission to promote excellence in operations.

Q. ARE THERE OTHER AREAS IN THE GDS DISCUSSION OF INPO RESULTS WITH WHICH YOU DISAGREE?

A. Yes. The GDS definition of a grade of 3 from the INPO review is not correct. The GDS report characterizes an INPO 3 as denoting "a plant with significant problems." In my experience, having attended numerous INPO exit meetings, an INPO 3 is assigned to plants at which overall performance is generally in keeping with the high standards of the nuclear industry. However, improvements are needed in a number of areas, and a few significant weaknesses may exist. My recollection is also consistent with APS' data request response PB-3.9. Again, weaknesses mentioned in the INPO definition are measured against a standard of best practices, not good practices or minimum acceptable practices.

Also, GDS does not correctly characterize Table 2 of its report. The INPO performance indicator is a mix of parameters as stated by GDS, but the production numbers such as capability factor are most heavily weighted, much more so than safety system performance for example. Thus, even though GDS concurs that the

bulk of the outage time that the Palo Verde units experienced in 2005 was not due to imprudence, the INPO Performance Index will still "penalize" Palo Verde for these prudent outages. This is why it is inappropriate to rely on INPO reports or the INPO Performance Index in a prudence evaluation.

Q. DOES THE INPO APPROACH OF CRITICISM AGAINST A STANDARD OF EXCELLENCE FIND ITS WAY INTO INTERNAL UTILITY AUDITS AND REPORTS?

A. Yes. As described previously, the culture fostered in the nuclear industry is to always seek to improve, and one of the principal methods is to be openly accepting of and in fact to promote strong self-criticism. Therefore, to the uninitiated, internal reports will also appear overwhelmingly negative, as do the NRC and INPO reports I mentioned earlier.

Q. DO YOU FIND EXAMPLES OF THIS IN THE GDS REPORT?

A. Yes I do. The excerpts on pages 13 and 14 of the GDS report, from the CRDRs submitted as Attachments 6 and 7, when taken out of the context of a purposefully self-critical report, appear to be much more onerous than when set in context of the continuous improvement standard of the industry.

Q. IN DETERMINING WHETHER THE STANDARD OF REASONABLENESS HAS BEEN MET, IS IT APPROPRIATE TO RELY ON SELF-ASSESSMENT AND IMPROVEMENT EFFORTS?

A. No, because good nuclear power plant managers undertake improvement efforts to attempt to keep pace with the rising standards that are a fact of life in the U.S. commercial nuclear power industry. Therefore, using the results of Company self-assessment and improvement efforts as evidence of mismanagement would be inappropriate. To the contrary, such efforts to identify areas for improvement, and to make improvements, are evidence of good management. Successful

management is an iterative process. Not all management plans are immediately successful, nor can every project be given top priority.

Using NRC reports, INPO documents, or Company self-critical documents as proof of "imprudence" creates a disincentive for a company to engage in critical self-examination, thereby potentially impeding the effort to improve performance. I urge the Commission not to go down this path.

Q. WHAT DO YOU CONCLUDE FROM YOUR REVIEW OF THIS PORTION OF GDS' REPORT?

A. I conclude the following based on both my review of the GDS report and my evaluation of APS management performance:

1. I agree with GDS that the Palo Verde units were operated safely in 2005.

2. I agree with GDS that when the Performance Improvement Plan is fully implemented the plants will return to a standard of excellence in operations.

3. I believe GDS has unfairly utilized the continuous improvement/self-critical culture of the industry to portray a more onerous and damaging sense of the areas for improvement noted in various reports than actually exists.

Q. PLEASE DESCRIBE YOUR APPROACH TO THE EVALUATION OF APS MANAGEMENT PERFORMANCE.

A. First, I did an extensive review of documentation. I did an initial round of interviews in conjunction with this document review. I then toured Unit 3 and inspected the equipment and plant areas of importance. Fortunately, since the plant was in a refueling outage at the time, I was able to gain access to portions of the plant not otherwise readily accessible. I then conducted further interviews of both plant personnel and senior management.

Q. HOW DID YOU USE THE INFORMATION THAT YOU OBTAINED?

A. I applied the knowledge and experience I acquired during my over 35 years involvement in naval and commercial nuclear power plant operation to evaluate the documentary, physical and interview information I obtained.

Q. HAVE YOU REVIEWED GDS' RECOMMENDATION THAT THE COMMISSION REVIEW THE DEGREE TO WHICH APS HAS SOUGHT REMEDIES AGAINST VENDORS WHOSE EQUIPMENT CAUSED CERTAIN OF THE 2005 OUTAGES?

A. Yes.

Q. HAVE YOU HAD ANY EXPERIENCE WITH RESPECT TO CONTRACTS WITH VENDORS FOR UTILITY POWER PLANTS?

A. Yes. As plant manager at Calvert Cliffs Nuclear Plant, Vice President of Nuclear for BG&E and as Executive VP of Generation for BG&E, I had contract approval authority on behalf of the corporation for increasing levels of expenditure.

Q. HAVE YOU REVIEWED THE "LIMITATION OF LIABILITY" PORTION OF CERTAIN CONTRACTS PROVIDED TO YOU ON BEHALF OF APS RELATED TO THE GDS REPORT?

A. Yes, I have reviewed those provisions of the following contracts and purchase orders:

1. The contracts between APS and Combustion Engineering Inc. for Field Services, Engineering Services, and Renewal Parts and Factory Repair Work. These contracts relate to the Core Protection Calculator (CPC) software upgrade.

2. The Purchase Order for the purchase of the Reactor Coolant Pump upper thrust bearing o-rings.

The Limitation of Liability provisions are similar in the contracts that I reviewed. For example, Section 10.1 of Agreement No. PV 87-10370 on Field Services

between APS and Combustion Engineering (now Westinghouse) states the following:

> Contractor and its subcontractors of any tier shall not be liable, whether in contract, tort (including negligence), or otherwise, to Participants, for any loss or damages in the nature of partial or complete loss of use of any generating facility, loss of power, cost of replacement of power, for any loss of interest, revenue, or anticipated profits resulting therefrom, or any other indirect or consequential loss or damages of a similar nature.

Q. HAVE YOU SEEN SIMILAR PROVISIONS IN OTHER CONTRACTS INVOLVING NUCLEAR POWER PLANT EQUIPMENT OR SERVICES?

A. Yes. I have seen many contracts like those at issue here that specifically state that the supplier will not be responsible for consequential damages for negligence, including the cost of replacement power. The Palo Verde contracts that I reviewed are typical of those used in the nuclear industry.

Q. IN YOUR EXPERIENCE, WHY ARE SUCH DAMAGES EXCLUDED?

A. In the electric utility business, a plant shutdown or substantial power limitation, especially on a base load plant, often results in substantial replacement power costs. Even the largest supplier companies are unwilling to take on the risk of guaranteeing such costs, especially since most have multiple contracts that could substantially compound these liabilities.

Q. DID YOU SIGN OR APPROVE CONTRACTS WITH SUCH PROVISIONS?

A. Yes.

Q. WHY DID YOU DO SO?

A. As I stated, suppliers would not agree to provide services or equipment and accept the risks I mentioned above. The nuclear industry already has fewer suppliers than

we would like to have. As an executive of a company in that industry, I accepted that as a normal practice liabilities for consequential damages associated with contractor negligence were excluded. Of course, there may be contractor liability under other factual situations not precluded by such provisions.

Q. DID APS ACT REASONABLY IN ENTERING INTO THE CONTRACTS WITH COMBUSTION ENGINEERING (NOW WESTINGHOUSE) AND THE O-RING SUPPLIER?

A. Yes. As noted above, the contracts that I reviewed between APS and Combustion Engineering (now Westinghouse) and the O-ring supplier use wording that is typical of the contracts used in the nuclear industry.

Q. HAVE YOU REVIEWED THE FAILURE OF THE UNIT 1 EMERGENCY DIESEL GENERATOR (EDG) 'A' GOVERNOR RELATED TO THE UNPLANNED OUTAGE OF MARCH 18-21, 2005?

A. Yes. I have reviewed CRDR 2782680 (provided as Attachment 10 to the GDS Report) and interviewed the system engineers responsible for the EDG. This CRDR includes a root cause investigation of the governor failure. The exact root cause of the failure was not found, but several probable causes were set forth.

Q. WHAT WERE THESE PROBABLE CAUSES?

A. The three most probable causes (CRDR 2782680, pp. 15-16) identified are:

1. Rust caused by water introduced during the refurbishment of the governor at Woodward Governor Company in June 2000 and not fully removed when the unit was returned to Palo Verde.

2. Rust forming while the governor was stored in the warehouse drained of lube oil for approximately 9 months, i.e., any water left in the governor during refurbishment and the draining of oil at Woodward combined with the addition of

air during the 9 months of storage could lead to rust formation in the internals of the governor.

3. Water introduced during an oil change in April 2004. However, walk down of the oil change process could not identify any possible source of water.

Q. WHY WAS THE OIL DRAINED BEFORE THE GOVERNOR WAS SHIPPED FROM WOODWARD TO PALO VERDE?

A. The oil was drained to comply with Department of Transportation regulations.

Q. DOES THE GOVERNOR MANUFACTURER, WOODWARD GOVERNOR COMPANY, MAKE ANY RECOMMENDATIONS REGARDING STORAGE OF THE EQUIPMENT?

A. Yes, in a letter (Attachment RED-1RB) to Engineering Systems Inc., Woodward recommends that the equipment be stored in a "clean and dry condition: any items stored where condensation and moisture is a problem should be sent to a qualified facility for examination every five (5) years." Woodward did not recommend that governors should be stored filled with oil.

Q. WHAT ARE THE STORAGE CONDITIONS FOR GOVERNORS AT PALO VERDE?

A. Palo Verde stores the governors in a "Level B" area. Level B is defined in Palo Verde's Nuclear Administrative and Technical Manual (Attachment RED-2RB) as fire resistant, tear resistant, weather tight, and well ventilated building or equivalent enclosure. The manual states that items in Level B storage shall be placed on pallets or shoring to permit air circulation and the minimum temperature should be 40°F and a maximum of 140°F.

Q. IN YOUR EXPERIENCE, IS THIS STORAGE LEVEL WHAT YOU WOULD EXPECT FOR THE TYPE OF EQUIPMENT?

A. This level is actually higher than what I would expect for this type of equipment, especially considering the very low humidity conditions at the Palo Verde site.

Q. WHAT ABOUT THE WOODWARD RECOMMENDATION REGARDING MOISTURE AND CONDENSATION?

A. The governor was received from Woodward in July 2000 and installed in April 2001, much sooner than the 5 year examination recommended for storage in areas of moisture and condensation.

Q. IN YOUR ESTIMATION, IS THE ANALYSIS OF THIS EVENT IN THE GDS REPORT ACCURATE?

A. No. I do not believe the outage was avoidable. There was no reason for Palo Verde to suspect that water had been left in the governor assembly. That being the case, storage in a Level B storage area was entirely appropriate. The GDS report provides no supporting data for the statement that this storage method "is not a good practice."

Q. WHAT IS YOUR VIEW OF THE QUOTATIONS FROM THE WOODWARD GOVERNOR TECHNICAL MANUAL THAT GDS INCLUDES IN ITS REPORT?

A. The GDS quotations from the Woodward Governor Technical Manual regarding oil contamination and particles of dirt and water in the oil do not address the probable causes in this case. It is postulated here that the rust occurred either at Woodward or during the 9 month storage period following refurbishment. Thus, these quotations from the Woodward manual provide no support to GDS' claim that APS storage practices were imprudent.

Q. GDS ALSO CLAIMS THAT THIS OUTAGE COULD HAVE BEEN AVOIDED BY PRE-INSTALLATION INSPECTION OF THE GOVERNOR. DO YOU AGREE?

A. No. To find the rust which was eventually discovered at the test facility, Engine Systems Inc. (ESI), the governor would have to be completely disassembled. It would not be reasonable to expect the plant to disassemble all critical components, and then reassemble them prior to installation.

Q. HAVE YOU REVIEWED THE PRUDENCE STANDARD SET FORTH IN THE GDS REPORT?

A. Yes, I have. They propose essentially the same standard as I do.

Q. IN YOUR ESTIMATION, DID GDS IMPLEMENT THIS STANDARD WITH RESPECT TO ITS EDG GOVERNOR ANALYSIS?

A. No, GDS did not. GDS' standard requires it to make comparisons "without the benefit of hindsight." In the case of the EDG governor, GDS contends that Palo Verde should have instituted special climate controlled storage requirements for the governor to prevent rusting, when there was no reason to believe water had been introduced into the governor. As stated above, Palo Verde actually stored the governor at a level (Level B) that was higher than that recommended by the manufacturer. Only with the benefit of the post-failure disassembly could one be aware of the rust and potential residual water in the mechanism.

IV. CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. First, Palo Verde operated in a safe manner throughout 2005 and has implemented a Performance Improvement Plan which should return it to a level of excellent performance. Second, GDS inappropriately relied on NRC, INPO, and Company self-critical documents in its report. GDS analyzed Palo Verde using a standard much higher than prudence. Third, the contracts that I reviewed between Palo Verde and certain vendors are typical of those used in the nuclear industry. It was reasonable for Palo Verde to enter into these contracts. Finally, Palo Verde was

prudent with respect to the March 2005 outage due to the EDG governor. Palo Verde exceeded the storage requirements for the governor and the only way that Palo Verde could have discovered any rust prior to installation would have been to disassemble the governor, which is unreasonable.

Q. DOES THIS CONCLUDE YOUR WRITTEN REBUTTAL TESTIMONY?

A. Yes.

Attachment RED-1RB

WOODWARD GOVERNOR COMPANY
SERVING PRIME MOVER CONTROL AND ACCESSORY MARKETS
ENGINE CONTROLS
1000 East Drake Road • P.O. Box 1519 • Fort Collins, Colorado 80522-1519
Telephone 303 482-5811 • Fax 303 498-3058 • Telex 4-5891
ESTABLISHED 1870

Frank Amend
Engine Systems Incorporated/Power Control Services
Post Office Box 1928
Rocky Mount, NC 27802-1928

Reference: Oil Changes and Governor Refurbishment

Dear Frank,

I am writing this letter to explain Woodward Governor Company's recommendations on governor oil change and refurbishment cycle times.

Since the most important variable affecting governor life is the environment in which it operates, Woodward Governor Company has no precise guidelines for governor maintenance. However, we offer the following general recommendations which could be incorporated into preventative maintenance specifications for nuclear applications:

Oil Change Interval: Woodward Governor Company recommends that mechanical actuator/governor oil should be changed at the second or third refueling outage. If there has been no indication of problems with the unit (specifically water and/or rust), this interval can be extended. If problems do occur, Woodward Governor Company recommends the interval to be shortened to every first or second refueling outage and/or until the problem's root cause has been identified and corrected.

Overhaul Interval: Woodward Governor Company recommends that mechanical hydraulic governors and actuators be refurbished every five (5) to ten (10) years.

Shelf Life: Mechanical hydraulic governors and actuators should be stored in a clean and dry condition: any items stored where condensation and moisture is a problem should be sent to a qualified facility for examination every five (5) years.

As Woodward Governor Company has chosen Engine Systems Incorporated/Power Control Services to qualify, support, and market controls for nuclear applications, I request that you inform the nuclear industry of these latest guidelines. If any questions develop within the nuclear industry pertaining to these guidelines, Woodward Governor Company requests that they be direct to your organization.

Regards,

Steve Thompson
Nuclear Coordinator/Contract Review

Attachment RED-2RB

3.3 Material Storage

As described in ANSI N45.2.2, levels and methods of storage necessary are defined to minimize the possibility of damage or lowering of quality due to corrosion, contamination, deterioration, or physical damage from the time an item is stored upon receipt until the time the item is removed from storage and placed in its final location.

3.3.1 Levels of Storage

ANSI N45.2.2 defines levels of Storage. PVNGS storage levels are identified for each APN and are as follows:

Level A - PVNGS does not require Level A storage. The MLIS equivalent is considered to be temperature/humidity controlled.

Level B - APNs stored to Level B shall be stored within a fire resistant, tear resistant, weathertight and well ventilated building or equivalent enclosure. Precautions shall be taken against vandalism. The floor shall be paved or equal, well drained and not subject to floods.Items shall be placed on pallets or shoring to permit air circulation.The minimum temperaure shall be 40°F and a maximum of 140°F. The MLIS equivalent is considered to be "temperature controlled" Storage Level.

Level C - APNs stored to Level C shall be stored indoors or in equivalent environment with all provisions and requirements as set forth in Level B, except that heat and temperature control are not required. The MLIS, equivalent is considered to be "Indoor" Storage Level.

Level D - APNs stored to Level D may be stored outdoors in an area marked and designated for storage, which is well drained and preferably gravel covered or paved. Items shall be stored on cribbing or equivalent to allow for air circulation and avoid trapping water. The MLIS equivalent is considered to be "outdoor" Storage Level.

EXHIBIT
APS-90
Admitted

REJOINDER TESTIMONY OF ROBERT E. DENTON ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY

Docket No. E-01345A-05-0816
Docket No. E-01345A-05-0826
Docket No. E-01345A-05-0827

November 3, 2006

REJOINDER TESTIMONY OF ROBERT E. DENTON
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)
(Docket No. E-01345A-05-0826)
(Docket No. E-01345A-05-0827)

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Robert Elmo Denton. My business address is 79 Redwood Lane, Weems, Virginia 22576.

Q. DID YOU PROVIDE REBUTTAL TESTIMONY ON BEHALF OF APS IN THIS DOCKET?

A. Yes. I provided Rebuttal Testimony on behalf of APS on September 15, 2006.

Q. HAVE YOU READ THE SURREBUTTAL TESTIMONY SUBMITTED BY WILLIAM R. JACOBS, JR. FOR THIS CASE, SUBMITTED OCTOBER 13, 2006?

A. Yes, I have.

I. SUMMARY

Q. PLEASE SUMMARIZE YOUR REJOINDER TESTIMONY.

A. My Rejoinder Testimony addresses two issues: (1) The March Diesel Generator Outage, and (2) the use of NRC reports and Company self-critical documents. In both areas I disagree with Dr. Jacobs' conclusions. I believe Dr. Jacobs overemphasizes the role of the Diesel Generators to make his point. I also believe he incorrectly characterizes the nature of the content of NRC reports and Company self-critical documents.

II. MARCH DIESEL GENERATOR OUTAGE

Q. HAVE YOU REVIEWED THE SECTION BEGINNING ON PAGE 17 OF DR. JACOBS' SURREBUTTAL TESTIMONY TITLED "UNIT 1 EMERGENCY DIESEL A GOVERNOR FAILURE MARCH 18-21, 2005"?

A. Yes, I have.

Q. DO YOU AGREE WITH DR. JACOBS' CHARACTERIZATION OF THE EMERGENCY DIESEL GENERATORS?

A. To the extent that the Emergency Diesel Generators (EDG) are important to the safe operation of a nuclear plant, I agree. However, I believe Dr. Jacobs has overemphasized the role of the EDGs to make his point.

Q. IN WHAT WAY HAS DR. JACOBS OVEREMPHASIZED THE ROLE OF THE EDGS?

A. Dr. Jacobs overemphasizes the role of the equipment when he states that "Failure of a diesel generator to function when needed could result in a serious nuclear accident." In fact, the EDGs are 100% redundant, and the failure of one machine to start is fully backed up by another diesel and a completely redundant set of equipment. Furthermore, for the EDGs to be called upon in the first place, a precipitating accident event must have occurred simultaneous with a loss of offsite power. Yes, the EDGs are important, but not of the singular importance implied by Dr. Jacobs.

Q. HOW DOES THIS OVEREMPHASIS AFFECT DR. JACOBS' ARGUMENT FOR IMPRUDENCE?

A. When applied to his corollary that "the care given to operating and maintaining a piece of equipment must be commensurate with the importance and function of the equipment," Dr. Jacobs reaches the conclusion that extraordinary surveillance of the EDG governor is warranted, in the form of extra oil samples. There are literally hundreds of pieces of equipment in a nuclear plant equally as important as the EDGs. There was no reason for the Company to sample the new oil added to the governor at the time of installation or at the time of the 2004 oil change. The new oil added to the governor is carefully controlled. These controls were reviewed and

found to be effective, as described in CRDR 2782680. In fact, the oil removed and sampled on 4/19/04 contained only 104 ppm of water – well below the 1500 ppm limit. It would virtually be impossible, and certainly prohibitively costly, to provide extraordinary coverage for all this equipment, as suggested by Dr. Jacobs.

Q. DO YOU CONTINUE TO BELIEVE THAT THE OUTAGE IN QUESTION WAS NOT DUE TO ANY IMPRUDENCE ON THE PART OF THE COMPANY?

A. Yes. The Palo Verde staff fully implemented the surveillances of the EDGs required by the manufacturer and the plant's NRC-approved Technical Specifications. The shipping and storage of the governor was also in full accordance with Woodward (the manufacturer) instructions. The oil used was stored and transported with proper controls. There was no reason to go even further with extraordinary inspections. Thus, the Company did "use a standard of care commensurate with the importance of the diesel generator."

III. USE OF NRC REPORTS AND COMPANY SELF-CRITICAL DOCUMENTS

Q. HAVE YOU READ THE SECTION BEGINNING ON PAGE 14 OF DR. JACOBS' SURREBUTTAL TESTIMONY TITLED "USE OF NRC REPORTS AND SELF-ASSESSMENTS"?

A. Yes, I have.

Q. DO YOU AGREE WITH DR. JACOBS' CHARACTERIZATION OF SUCH REPORTS AS NOT RELYING ON HINDSIGHT?

A. I do not. Even though Dr. Jacobs has extensive experience as a consultant, he has little experience in operating or managing the operation of nuclear power plants. On the other hand, I operated and managed nuclear plants for 32 years and can state with full assurance that such reports do rely on hindsight.

In fact, the very purpose of these types of reports is to look back and suggest ways to improve operations based on knowledge of the outcome of what took place. For example, if a complex trouble shooting effort delayed an outage step past its predicted end point, an after- the- fact root cause analysis, with full benefit of the knowledge of the outcome, including paths taken that may have been fruitless, could point to a more effective trouble shooting plan to be used in the future.

If these reports were only a "contemporaneous assessment" as stated by Dr. Jacobs, they would be no more than a list of facts or a log document. Without the benefit of hindsight, such analyses and reports could not provide suggestions to promote continuous improvement in operations.

Q. SINCE THESE REPORTS ARE HEAVILY BASED ON HINDSIGHT, WHAT IS YOUR OPINION OF DR. JACOBS' "TORTURED LOGIC" ARGUMENT?

A. Since Dr. Jacobs portrays these reports as only presenting "...facts and circumstances...," his argument is very much oversimplified. It is my opinion that such reports must be read carefully to recognize "what was known when" in the context of reasonableness at the time management decisions were made. Additionally, as stated in my Rebuttal Testimony, the reader must be fully aware of the self-critical negative nature of these reports.

Q. WAS HINDSIGHT USED IN THE ROOT CAUSE EVALUATION FOR THE MARCH DIESEL GENERATOR GOVERNOR OUTAGE?

A. Yes. It was only determined <u>after</u> failure of the EDG that rust was present in the governor. This conclusion does not mean that the Company should have known at the time of the outage that there was rust in the governor. Until the failure of the governor was discovered, the Company had no reason to believe that there was any rust. This key finding in the root cause evaluation, rust in the governor, was only determined after the outage and after physical disassembly of the governor. A root

cause evaluation, such as the one performed here, typically does not focus on culpability, but focuses on the facts determinable after the event and on the improvements that can be made with the benefit of hindsight to prevent similar occurrences in the future.

Q. DOES THIS CONCLUDE YOUR REJOINDER TESTIMONY?

A. Yes.

REBUTTAL TESTIMONY OF GEORGE L. FITZPATRICK

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

September 15, 2006

EXHIBIT

APS 91

Admitted

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REBUTTAL TESTIMONY OF GEORGE L. FITZPATRICK
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)

I. INTRODUCTION:

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. George L. Fitzpatrick, 898 Veterans Highway, Suite 430, Hauppauge New York 11788.

Q. WHAT IS YOUR CORPORATE AFFILIATION?

A. I am the Managing Principal and CEO of Harbourfront Group, Inc. I have been engaged as a management and technical consultant, and Managing Principal, with Harbourfront Group, Inc. and its predecessor company, Applied Energy Group, for the past 25 years.

Q. WOULD YOU PLEASE DESCRIBE YOUR QUALIFICATIONS RELATED TO THE TESTIMONY YOU ARE NOW GIVING?

A. I have been performing statistical and econometric analyses for electric and gas utilities since 1974. Further, I have developed Performance Standard-related measurement analyses for companies such as Georgia Power Company, Atlanta Gas Light, El Paso Electric Company, Westar Energy and Long Island Lighting Company.

I have developed and testified to statistically based normalization and forecast analyses for such utilities as Western Resources, Texas Utilities Corp., Georgia Power Company, Freeport Electric, KeySpan Energy, Long Island Lighting Company, The New York Power Pool, El Paso Electric Company, Oklahoma Natural Gas, Missouri Public Service Company, The Empire District Electric Company, Union Gas Limited and Minnegasco.

I have been performing and evaluating econometric, econometric-end use, and statistical-based analyses for over 30 years for such utilities as American Electric Power, Arizona Public Service Company, Atlanta Gas Light Company, Bermuda Electric Light Company Limited, Consolidated Edison Company of New York Inc., Long Island Lighting Company, Freeport Electric, Georgia Power Company, El Paso Electric Company, The Empire District Electric Company, New York Power Authority, Union Gas Limited, Texas Utilities Corp. (TXU), Kansas Gas & Electric Company, Missouri Public Service Company, San Diego Gas & Electric Company, Western Resources Inc., and Westar Energy. I have also been engaged in the planning, design, and evaluation of Demand Side Management (DSM) programs and technologies, having directed the evaluation of approximately 400 DSM programs over my career for over twenty utilities.

On the subject of nuclear and fossil power generation economics, I have performed over thirty lifecycle comparative economic analyses on a variety of generation and renewable alternatives including nuclear, coal, combined-cycle gas turbines and wind generation for the following companies: American Electric Power Company, Arizona Public Service Company, Consolidated Edison Company of New York, El Paso Electric Company, Georgia Power Company, Kansas City Power & Light Company, Kansas Gas & Electric Company, Long Island Lighting Company, New York Power Authority, San Diego Gas & Electric Company, Texas Utilities Company (TXU) and Western Resources. A complete list of my qualifications can be found in Attachment GLF-1RB to my testimony.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I have presented testimony on behalf of the Arizona Public Service Company ("APS" or "Company") in ACC Docket Nos.U-1345-85-156 and U-1345-85-367.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is threefold:

First, I rebut Dr. Jacob's assertion that Palo Verde's historical operating performance has been "poor" based upon taking a one-year, 2005, look at Palo Verde performance.

Second, and consistent with the recognition by the Arizona Corporation Commission ("ACC" or "Commission") in its Decision No.55118 on page 20, that it is appropriate to consider both a utility's "successes" and "failures" in order to perform "a realistic analysis of operating performance", I will assess the full impact of APS' total baseload generation performance on its customers, rather than focus on one plant as does the one-year snapshot that Dr. Jacobs provides in the GDS report and his testimony, in order to refute the notion that a disallowance for Palo Verde performance in 2005 is appropriate.

Third, I will provide commentary on, and analysis of, Dr. Jacobs' Palo Verde Performance Standard proposal from both regulatory fairness and statistical perspectives. Although I am not proposing the Commission adopt a performance standard in this instance, I will describe elements of what an appropriate performance standard for APS baseload generation should include if the Commission were to consider adopting such a standard.

II. SUMMARY OF REBUTTAL TESTIMONY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY

A. Looking at Palo Verde standing alone, the year 2005 brought with it a number of challenges for Palo Verde, resulting in a performance level that was below expectations. However, this occurrence is common among all nuclear plants and is not significant enough to enable one to portray Palo Verde performance as "poor" as Dr. Jacobs contends. Over a longer time period, Palo Verde has clearly performed better than its peers and over the 10 year period prior to 2005 (i.e., 1995 thru 2004), the performance of Palo Verde has resulted in a net benefit to APS and its customers of approximately 2,016,000 MWHs which equates to $91.8 million in avoided purchased power costs; (using 2005 Average Purchased Power Costs/MWH).

More fundamentally, instead of the one year Palo Verde-only snapshot approach Dr. Jacobs uses in his prudence analysis, I present an approach that 1) is more consistent with the principles underlying the prospective standard that he proposes and 2) more accurately reflects the net benefits/burdens that APS' baseload generation performance confers on its customers by also looking at the performance of APS's baseload coal generating plants. After performing these calculations and analyses, I have concluded that:

- Over the 10 year period between 1995 and 2004, APS' coal baseload generating units outperformed their respective comparison plant groups, resulting in APS and its customers enjoying a net benefit of approximately 4,382,000 MWHs which equates to $149 million in avoided purchased power costs (using 2005 Average Purchased Power Costs/MWH).

- In 2005, and recognizing that all of Palo Verde's lower-than-average performance was due to outages that were not the result of alleged imprudence, the very significant better-than-average 2005 performance of APS' coal units more than outweighed the disallowance that Dr. Jacobs proposes.

Turning to the issue of a prospective performance standard, Dr. Jacob's performance standard is too general and omits key technical and fairness components. Due to the Palo Verde successful performance over the long term a performance standard does not appear to be necessary. If the Commission decides to consider a performance standard, such a standard should provide for an equal probabilistic opportunity for compensation to both customers, for lower-than-expected baseload power plant performance, and to APS shareholders, for better-than-average baseload power plant performance. Any such standard should also include the appropriate performance metric for each generation type included, statistically-derived deadbands surrounding the targets developed, specific and symmetric limits on the magnitude of both rewards and penalties, explicit consideration of APS' aging generating fleet, planned outage scheduling, and differences in the annual probabilistic planned outage frequency differences between comparison samples. There should also be recognition of the NRC's concerns over the potential safety impact of such a plan. Further, I would suggest that all of APS' baseload generation units be considered in any performance standard ultimately imposed. Other suggestions on the statistical construct of such a standard are included below.

It is my opinion that the imposition of a fair performance standard for Palo Verde would be uniquely difficult since Palo Verde's configuration and location makes it a "one of a kind" plant. For example, Palo Verde is the only three unit nuclear plant in the U.S., regardless of type (i.e., PWR or BWR). Palo Verde's unique wastewater treatment system for processing effluent into purified cooling water for all three units is unique to the industry and adds another layer of complexity to the plant's operation.

III. DR. JACOBS' CRITICISM OF HISTORICAL PALO VERDE PERFORMANCE IS UNFOUNDED

Q. HAVE YOU REVIEWED THAT PORTION OF DR. JACOBS' REPORT THAT CHARACTERIZES PALO VERDE'S PERFORMANCE AS "POOR" BASED ON CERTAIN CAPACITY FACTOR AND PRODUCTION COST DATA?

A. Yes.

Q. HAVE YOU ANALYZED PALO VERDE'S CAPACITY FACTOR PERFORMANCE PRIOR TO 2005?

A. Yes. I have evaluated Palo Verde's historical capacity factor performance from two statistically-based perspectives using my standard performance group of U.S. pressurized water reactors ("PWR's"), specifically those greater than 1000 MW, as well as the group that Dr. Jacobs has recommended as appropriate for the benchmarking of Palo Verde (greater than 600 MW U.S. PWR's). The following table displays those capacity factor average results:

Table GLF1

Comparison of Palo Verde Capacity Factors to Two PWR Comparison Groups

Period	Palo Verde	>600 MW PWR	>1000 MW PWR
1995-2004	89.5%	87.4%	87.7%
2002-2004	88.4%	90.8%	90.7%

Q. WHAT DID YOU CONCLUDE FROM THIS COMPARISON?

A. Over the 1995-2004 timeframe, Palo Verde performed better than either peer comparison group.

Q. HAVE YOU QUANTIFIED THE BENEFIT FROM THIS BETTER THAN AVERAGE PERFORMANCE?

A. Yes. As described more fully on pages 13 and 14 of my testimony, I calculated the additional MWH's produced by Palo Verde as a result of its higher-than-comparison group performance over the 1995-2004 time period. I then calculated the savings of the additional MWH production using the dollar difference between APS' 2005 average purchased power costs per MWH and Palo Verde's average 2005 variable production costs per MWH. This calculation resulted in a net benefit to APS and its customers of $91.8 million over this 10 year time period.

Q. WHAT ABOUT THE THREE-YEAR PERIOD REFERENCED BY DR. JACOBS?

A. Looking at the time period 2002-2004, Palo Verde's performance was somewhat lower. However, in evaluating such comparative performance between three year samples of different sizes, I would not place much value in simplistic point estimates comparisons, regardless of whether the subject plant was underperforming or outperforming the comparison group selected. Rather, I would construct confidence bandwidths around the larger sample estimates in order to recognize some degree of normal year-to-year variability in the operation of such plants. For example, I have calculated the Standard Deviation for both the "> 600MW PWR Group" (+/-8.8 percentage points of annual Capacity Factor for the 2002-2004 three year average) and for the ">1000 MW PWR Group" (+/-9.2 percentage points of annual Capacity Factor for the 2002-2004 three year average). When confidence bands (+/- (.678 * Standard Deviation)) that would capture the middle 50 % of all comparison group observations are placed around the two comparison groups, Palo Verde's 2002-2004 Capacity Factor average (88.4 %) falls well within a reasonable range of both comparison groups. Further, when one recognizes that one of the Palo

Verde units underwent a Steam Generator replacement in 2003, thus reducing the overall Palo Verde plant capacity factor by approximately 1% over that three year period, this would serve to adjust Palo Verde's average 2002-2004 capacity factor to within approximately 1.4% if the actual peer group average. Thus, while recent Palo Verde performance has been below expectations, it is inappropriate to take this short term snapshot and characterize Palo Verde performance as "poor."

Q. IS THE USE OF SIMPLE INDUSTRY AVERAGES THE BEST WAY TO EVALUATE THE PERFORMANCE OF PALO VERDE?

A. No. The use of simple averages can be quite misleading in the case of PWR's, especially Palo Verde. Palo Verde is a one-of-a-kind, three unit PWR plant with a unique cooling water acquisition and treatment system. While there are economies of scale in the purchasing and warehousing of spare parts, for example, there are other aspects of Palo Verde's operation related to locational and climatic considerations that disadvantage its operating performance.

Q. COULD YOU ELABORATE ON THAT LAST SENTENCE?

A. Yes. When originally designed and constructed, Palo Verde was one of the most ambitious baseload generation projects ever undertaken by a group of electric utilities. Palo Verde's 3808 MW Maximum Dependable Capacity, proximity to the APS load center (approximately 60 miles to the west) and its use of reclaimed water for cooling were and continue to be important attributes that have contributed to the economic growth and vitality, as well as improved electric system reliability, of Phoenix and surrounding areas. While most nuclear power plants are located near significant bodies of water, Palo Verde has its cooling water delivered approximately 60 miles through a pipeline. This adds to

the cost of operation but provides a proximate and reliable source of relatively low cost energy for APS customers.

The three unit configuration of Palo Verde presents additional challenges to outage planning personnel to coordinate all outages in the safest and most cost effective manner. These challenges are not as significant at one or even two unit sites. Moving to an 18 month refueling cycle has helped Palo Verde outage planners become even more efficient, but, as with all nuclear plants, safety is always the number one priority.

IV. CRITIQUE OF DR. JACOBS' PROPOSED PALO VERDE DISALLOWANCE

Q. DO YOU AGREE WITH DR. JACOBS' PROPOSED DISALLOWANCE FOR 2005 PALO VERDE PERFORMANCE?

A. No. Other APS witnesses have addressed the substance of Dr. Jacobs prudence argument and the technical reasons why the proposed dollar disallowance is inappropriate. I have focused on an important financial counterbalancing argument that Dr. Jacobs has not addressed which is that the Commission ought to give considerable weight to the superior and offsetting performance of the Company's coal units during that same and other time periods.

Q. WHY HAVE YOU ELECTED TO INCLUDE APS' COAL-FIRED BASELOAD GENERATION IN YOUR ANALYSES?

A. I have performed many nuclear and fossil generation benchmarking analyses, and have proposed performance standards for nuclear and fossil generation, distribution reliability, and customer service performance elements. In my opinion, it is relevant to provide evidence to this Commission on the overall performance of APS' baseload generation, of which Palo Verde's capacity represents only 39%. That baseload generation includes APS' coal-fired units

which, like nuclear units, enjoy a significant cost advantage over purchased power and have the potential to confer a substantial benefit on APS' customers when run successfully

Q. WHY HAVE YOU ELECTED TO INCLUDE ONLY BASELOAD PLANTS IN YOUR PERFORMANCE ANALYSIS?

A. Baseload power plants are constructed by utilities to be the backbone of their electric production systems. Especially in the case of APS, baseload power plants are dispatched for power production into the APS system most of the time that they are available for safe operation.

Baseload power plants are also relatively higher capital cost investments that utility shareholders fund and commissions typically evaluate for the prudency of the capital spent for these assets. While more expensive to construct, these assets have the advantage of producing electricity at significantly lower costs per KWH, often for a longer lifecycle than either intermediate or peaking capacity.

Finally, intermediate and peaking power plants are operated for the purpose of electric production relatively few hours of each year, and are often substituted by utility system operators with other sources that have lower operating costs whenever practical.

Thus, since the lion's share of capital investment and electric system reliance is placed upon baseload generation, it is logical that these baseload plants, taken together, be evaluated for their collective contribution to the APS electric production system.

Q. PLEASE DISCUSS THE METHODOLOGY THAT YOU EMPLOYED IN PERFORMING YOUR HISTORICAL BASELOAD GENERATION PERFORMANCE ANALYSES OF APS' PLANTS.

A. As a start, APS provided me with a list of all of the generating units that it operates which are considered to be baseload generating resources. Attachment (GLF-2RB), entitled, "APS Baseload Generation Summary", provides a list of these units, along with the vintage (Commercial Operation Year), most recent MW rating and APS's share of that plant. Additionally, I asked APS to provide me with a general description of the generating technology employed at each unit so that my engineering staff could group units, where possible, in order to minimize the development of distinct unit comparison groups. Attachment (GLF-3RB), entitled "Performance Comparison of APS Coal Baseload Generation vs. Representative Comparison Groups" contains listings of the units included in final four baseload coal plant comparison groups that were ultimately selected for this comparative analysis.

Next, my staff reviewed the North American Electric Reliability Council's GADS (General Availability Data System) database in order to draw representative samples in terms of similar commercial operating date, maximum dependable capacity and vintage for the four major comparison groups for the most recently available 10-year period (1995-2004). Performance data for the year 2005 was not available at the time this testimony was prepared.

Attachment (GLF-4RB) entitled, "Statistical Comparisons of APS Baseload Plant Performance vs. Performance of Relevant Comparison Group: Average Group Values for 2002-2004, 1999-2004 and 1995-2004", contains the summary statistical data for these comparison groups for the measures Equivalent Availability Factor (EAF), Net Capacity Factor (NCF), and Effective Forced Outage Rate (EFOR). Statistical analyses of the data included the computation of Means, Medians, Standard Deviations, Standard Errors of the

Mean and Coefficients of Skewness for each measure selected for both APS units and each relevant comparison group.

For the purposes of developing "apples to apples" comparisons for the coal generating units, I selected EAF as the most relevant measure for assessing comparative coal unit performance even though I used net capacity factor or "NCF" in my earlier discussion of Palo Verde. NCF or simply CF is the most relevant measure for assessing comparative nuclear unit performance. Dr. Jacobs also employs Capacity Factor in his proposed nuclear performance standard.

Q. HOW DID YOU CALCULATE THE POTENTIAL DOLLAR IMPACTS FOR DIFFERING LEVELS OF COAL PLANT PERFORMANCE IN YOUR ANALYSES?

A. It was quite similar to the method used to calculate the earlier benefits of Palo Verde performance. As a first step, I calculated the weighted average cost for Purchased Power that APS incurred during the calendar year 2005 ($50.91 per MWH) using APS records for each transaction. This information was obtained from SNL Financial Services, a well recognized sector-specific information and research firm in the financial information marketplace specializing in the banking, specialized financial services, insurance, real estate, and energy sectors. Next, I received from APS its average variable production costs for its coal plants ($16.80/MWH), also for 2005. The resultant purchased power impacts were then calculated using this information in combination with the MWH deficits or surpluses resulting from the comparative analyses by plant type.

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR ANALYSES.

A. The following are the key results of my analysis:

Over the 10-year period, 1995-2004, APS Coal units, on a weighted average basis, outperformed their respective peer groups similarly weighted. APS and its customers experienced an approximate total net benefit of $149 million over this period. Attachment (GLF-5RB, Page 1 of 2), entitled "Comparison of APS Weighted Baseload Generation(Combined NCF and EAF) vs. Relevant Comparison Groups for the Period 1995-2004", shows the details of this calculation.

Next, I looked at the performance of the APS Coal Baseload Units, taken together, for the most recent full year, 2005, and compared to the peer group performance for the most recently available GADS six-year averages for the relevant comparison groups (i.e., 1999--2004). The six year average is appropriate based upon the standard maintenance/overhaul cycle that APS employs at its coal plants. I then took Dr. Jacobs' recommended 2005 Palo Verde disallowance based upon his calculation of the financial impact of 2005 Palo Verde outages that he alleges to be imprudent. I compared the calculated coal plant benefit with Dr. Jacobs' recommended Palo Verde disallowance. Netting out the Baseload Coal purchased power cost savings of $27,492,000 (based on the 6-year average comparison) from Dr. Jacobs' recommended disallowance served to more than eliminate Dr. Jacobs' recommended Palo Verde disallowance of $17,373,000. Attachment (GLF-6RB, Page 3 of 3) entitled "Comparison of APS Weighted Baseload Coal Generation (EAF) 2005 Only vs. Relevant Comparison Groups for the Period 1999-2004" shows the details of this calculation).

. This analysis, based upon a three-year average comparison, shows a cost saving for the Coal units of $25,749,000 . Attachment (GLF-6RB, Page 1 of 3) entitled "Comparison of APS Weighted Baseload Coal Generation EAF vs. Relevant Comparison Groups for the Periods 2002-2004 and 2005 Only" shows the details of this calculation).

This approach recognizes the fact that although Palo Verde did not perform as well as expected in 2005, there were only 25 Palo Verde outage days whose prudence Dr. Jacobs challenges. The remainder of the 2005 Palo Verde outage occurrences were not identified as being imprudent by Dr. Jacobs in his report. While the financial benefit of APS' coal unit performance was significant, another way of looking at this performance is in terms of the additional MWH's that were available from the APS baseload units as compared to the relevant industry peer groups. The following table highlights this information:

Table GLF 2

1995-2004 Additional Coal and Nuclear MWH Made Available to APS and its Ratepayers from APS Baseload Generation

APS's Palo Verde	2,016,000 MWH
APS Baseload Coal	4,382,000 MWH

Q. WHAT WOULD HAVE BEEN THE RESULTS OF THIS ANALYSIS IF CAPACITY FACTOR WAS USED AS THE EVALUATION PERFORMANCE MEASURE?

A. The calculated benefit for APS baseload coal units would have been dramatically higher than the EAF-based comparison. For the 1995-2004 period, for example, the net benefit based upon Capacity Factor comparison would have been approximately 11,742,000 MWH or $401 million using 2005 purchased

power and APS coal variable productions costs. See Attachment (GLF-5RB, Page 2 of 2), entitled, "Comparison of APS Weighted Baseload Generation NCF Only vs. Relevant Comparison Groups for the Periods 1995-2004 " for the detail of this analysis.

Q. DO THESE RESULTS REINFORCE YOUR EARLIER CONCLUSIONS REGARDING THE APPROPRIATENESS OF DR. JACOBS' RECOMMENDATION FOR A TOTAL DISALLOWANCE OF $17,373,000?

A. Yes. Imposition of Dr. Jacobs' recommended disallowance by the Commission would be most inappropriate based upon Dr. Jacobs' focus on only part of the available relevant facts in this case.

First, as I discussed in the prior Section, Palo Verde has performed well over an extended time period. Even if one used a shorter time period, when one applies even a relatively small confidence band to the performance of Palo Verde, and either Dr. Jacobs' or my choice for a comparison group, Palo Verde's average capacity factor falls within the range of reasonable performance compared to both comparison groups.

Second, the above average performance of APS' other baseload units in 2005 more than made up for the costs that Dr. Jacobs concludes were incurred as the result of Palo Verde imprudence.

Thus, based on my quantitative analyses of the good performance of APS baseload coal units in 2005, the recommendation for a disallowance by GDS is not appropriate. APS' coal units have delivered real, measurable value to APS ratepayers in the very timeframe that Dr. Jacobs recommends penalizing the Company for one aspect of its total performance in 2005.

V. REVIEW AND CRITIQUE OF DR. JACOBS' PROPOSED PERFORMANCE STANDARD:

Q. HAVE YOU REVIEWED DR. JACOBS' RECOMMENDATIONS FOR THE CONSTRUCTION OF A NUCLEAR PERFORMANCE STANDARD?

A. Yes.

Q. DO YOU AGREE WITH THE ATTRIBUTES AND FEATURES THAT HE HAS PROPOSED?

A. I don't agree that a Palo Verde performance standard should be imposed in this instance, because of the long term performance and unique characteristics of Palo Verde which I discussed earlier, and because of the concerns noted in APS witnesses Mattson's and Wheeler's Rebuttal Testimony concerning the potential for creating unintended incentives to shortcut maintenance and safety concerns. But if the Commission were to consider instituting such a standard, I would suggest that the following critical comments on Dr. Jacobs' proposal be recognized and specifically addressed by the Commission since Dr. Jacobs' recommendations are too general, and omit key technical and fairness components:

1) Dr. Jacobs does not include APS Base Load Coal Units in his performance standard recommendations. These units should be included if a performance standard is adopted because they have a significant bearing on the ultimate cost of power to APS customers. Palo Verde accounts for only 39% of APS baseload capacity and, thus, should not be the sole focus of a generation performance standard. APS coal units do enjoy a significant $/MWH economic advantage over purchased power and contribute significant benefit to APS customers.

2) Any performance standard imposed should allow for both disallowances and benefits. In the interest of symmetry and fairness, if APS and its shareholders are now to be exposed to additional risk, then there should now also be an opportunity for shareholders to realize a monetary benefit from better-than-average performance. If a disallowance-only performance standard is to be imposed, then the Commission should

consider granting an increase in APS' Allowed Return on Equity in recognition of the additional risk that APS shareholders would be shouldering.

3) Concerning the magnitude of any potential benefit or disallowance, I agree with Dr. Jacobs that there should be a cap on the potential magnitude of these adjustments to APS earnings. However, Dr. Jacobs is silent on the magnitude of that cap, does not propose how any "penalties" would be calculated, and does not recognize the need for symmetry. Further, Dr. Jacobs recommendations do not recognize the reality that APS earnings are currently below its allowed ROE as indicated in Mr. Brandt's Rebuttal testimony. This is an important factor for the Commission to consider before there is any detailed discussion of the specific structural elements of a performance standard.

4) A three-year average for the computation of such a metric may be appropriate for nuclear plants if a "deadband" is calculated and placed around the Comparison Group Mean Value in order to recognize, for example, the probabilistic differences in the frequency of normally occurring outages in the comparison group sample vs. the Palo Verde sample. However, a rolling "previous six year" evaluation cycle would have to be employed for APS' baseload coal units. The reason for this is that APS utilizes a six-year preventive maintenance and overhaul cycle for each of its large coal baseload units. Thus, utilization of a six-year average would insure that the Comparison Groups and APS Coal Unit Groups would be compared in a synchronized manner. However, consideration may need to be given for future changes in the preventative maintenance and overhaul cycles.

5) Dr. Jacobs recommends a comparison group of PWR's >600MW. I believe that a comparison group of PWR's >1000MW is more appropriate for the measurement of Palo Verde since this family of plants is more consistent with Palo Verde's design and operational considerations. Looking at both groups for the most recently available 2002-2004 comparison period yields the following averages and calculated deadbands:

Comparison Group	# of PWR'	Mean CF	Standard Deviation-CF
>600 MW	34	90.8%	8.8%
>1000MW	27	90.7%	9.2%

6) For the development of the Coal Plant Comparison Group component of any performance standard, the comparison groups that would be employed must recognize the age, size and key technological aspects of the APS units to which they will be compared. Further, I would recommend that the Equivalent Availability Factor be the metric used for comparison. In my earlier comparisons, I have recognized each of these factors in order to draw the most representative comparisons. For more detail on this component, please see Attachments GLF-2RB, GLF-3RB and GLF-4RB to my testimony.

7) Dr. Jacobs proposal includes elements that the NRC considers inappropriate in economic performance incentives and fails to include those features the agency considers more appropriate as described in its policy statement attached to Dr. Mattson's rebuttal testimony.

Q. DO YOU AGREE WITH DR. JACOBS' RECOMMENDATION #3 THAT CALLS FOR THE EXCLUSION OF ANY "...U.S. PWR'S WITH A 3-YEAR CAPACITY FACTOR OF LESS THAN 60%..."?

A. Not automatically; it would be important for the Commission and Company to understand the circumstances surrounding the abnormally poor three year performance of any comparison PWR that met that condition in order to insure that there are not any design issues or operating conditions that are common to Palo Verde as well. Evaluation of such an event may lead to suspension or modification of any adopted performance standard.

Q. PLEASE SUMMARIZE THE MAJOR CONCLUSIONS OF YOUR TESTIMONY?

A. The major conclusions of my testimony are as follows: 1) over the 1995-2004 time period Palo Verde outperformed the PWR comparison group that has been recommended by Dr. Jacobs. The total benefit that has accrued to APS and its

ratepayers totals $91.8 million. 2) Dr. Jacobs' recommendation of a $17,373,000 disallowance for 2005 Palo Verde outages is more than compensated for by the excellent performance of APS' baseload coal units. 3) Dr. Jacobs' performance standard recommendations are too general and omit key technical and fairness components. While I would not recommend the imposition of a performance standard in this instance, I have provided a summary list of missing performance standard elements that should be considered by the Commission if they choose to pursue an even-handed, statistically appropriate and comprehensive measurement process.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Attachment_GLF-1RB:

GEORGE L. FITZPATRICK
PRINCIPAL/CEO
Harbourfront Group, Inc.
898 Veterans Memorial Highway
Hauppauge, New York 11788
631.348.4090

OVERVIEW

George L. Fitzpatrick is the Managing Principal/CEO of Harbourfront Group, Inc. His professional experience includes eight years of service at Long Island Lighting Company managing the Load Research, Forecasting, and Cost of Service Divisions. After that, he held the position of Vice President of Demand Planning with Stone and Webster Management Consultants, Inc.

Twenty-two years of his career have been spent with Applied Energy Group, Inc. as its founder, CEO and Managing Principal. Over his tenure as CEO, he built the firm from one consultant to over twenty-five employees. In 2002, he reached an agreement to sell his share of the firm in order to pursue management consulting and expert witness assignments that were specific to his experience, expertise and past utility client relationships.

In 2002, Mr. Fitzpatrick formed Harbourfront Group, Inc. to focus on the provision of expert witness services and litigation support in areas that have been central to Mr. Fitzpatrick's practice over his career. More information about the firm and its professional resources can be found at www.harbourfrontllc.com.

Mr. Fitzpatrick has provided expert direct and rebuttal testimony before federal and state regulatory bodies and judicial authorities on subjects such as:

- Lifecycle Economic Evaluation of Utility Investments
- Econometric/statistically-based Load and Energy Forecasting
- Weather Normalization Studies of both gas and electric test year sales
- Weather Normalization probabilistic correction of System Peaks and Class components
- Strategic Planning
- Comparative Economics of Electric Generation Investments
- Load Research Program Sample Design, Implementation and Analysis
- Nuclear and Fossil Power Plant Cost and Performance analyses
- Econometric and Statistical Studies on Utility- related Issues
- Rate Design
- Cost of Service Studies
- DSM/ Renewable Program Evaluation
- Performance Standard design and statistical construction
- SAIDI / SAIFI-related statistical investigations

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- Rebuttal testimony on a wide range of statistical and econometric-related subjects.

Specific to the subject of nuclear and fossil cost and performance analyses, Mr. Fitzpatrick has developed a series of statistical analyses that have been used by his clients in both regulatory, confidential negotiations and arbitration proceedings as recently as 2005-2006. On the subject of Nuclear Plant (PWR) cost and performance analyses, Mr. Fitzpatrick has developed a series of pooled non-linear multiple regression models that explain and quantify variations in O&M Costs, Capital Additions Costs, Planned and Forced Outage Rates, Capacity Factors and other related measures. These models capture regional cost differentials, key design differences, and multiple unit operating efficiencies, among other key variables. These models were originally used in the mid-1980's by Mr. Fitzpatrick as part of an overall comparative lifecycle economic analysis comparing nuclear vs. other generation-or DSM- alternatives. Now they are used to evaluate nuclear cost and performance performance, set the value of a plant being purchased or as a due diligence tool for minority plant owners. On the subject of Fossil Plant costs and performance, similar statistical analyses have been developed for similar metrics. In addition to the development of these analyses, Mr. Fitzpatrick has provided both expert testimony and cross-examination assistance on the technical analyses that underlie these studies from 1984 to the present.

Over Mr. Fitzpatrick's consulting career he has provided services to over 50 electric and gas utility clients both in the U.S. and abroad. However, there are a number of clients that have utilized his services on an ongoing basis over the years as a senior management consultant and/or expert witness. These clients include:

- Arizona Public Service Company (Pinnacle West)
- American Electric Power
- Bermuda Electric Light Company Limited
- Consolidated Edison Company of New York
- El Paso Electric Company
- Entergy
- Freeport Electric
- Georgia Power Company (Southern Company)
- KeySpan Energy
- New England Electric System
- Niagara Mohawk Power Corp. (National Grid)
- New York Power Authority
- Northeast Utilities
- San Diego Gas & Electric Co.
- TXU Electric (TXU)
- Union Gas Limited
- Westar Energy (and its three predecessor companies)

Over his 26 year professional consulting career, he has also served his client base as a negotiator, often playing a key role in the negotiation of multi-million dollar, short and long term utility power supply and franchise contracts (e.g., Ft Bliss, White Sands Missile Range, University of Texas, and El Paso Water Utilities and El Paso Electric Vs. the City of Las Cruces).

Mr. Fitzpatrick has a Master of Business Administration degree in Economic Theory and a Bachelor of Arts in Economics, both from St. John's University. He has also completed course work toward a Master of Science degree in Management Engineering from Long Island University (C.W. Post) as well as advanced training in Box Jenkins forecasting techniques and econometric and statistical modeling. He possesses a Certificate of Mastery in Reengineering from the Hammer Institute and is a member of the Association of Energy Engineers (AEE) and the Energy Services Marketing Society.

PROFESSIONAL EMPLOYMENT

2003-Present Harbourfront Group, Inc.
Managing Principal and CEO

Founded Harbourfront in 2002. HFG's focus is the development of strategies, analyses and expert testimony to assist its primarily investor-owned utility client base in objectively and expertly presenting and defending issues central to the client's corporate mission. Primary areas of the practice are electric and gas forecast development and review; engineering economic studies; comparative economic studies; lifecycle economic studies; statistical and econometric analyses and rebuttal; rate design and cost of service studies; performance standard statistical design and rebuttal; distribution reliability-related analyses and utility accounting-related matters.

1982 - 2003 Applied Energy Group, Inc.
Founder, President & CEO

Founded AEG in 1982. The focus of this consulting practice centered in the areas of Peak Load and Energy Forecasting, Load Research program sample design, implementation and analysis, Demand Side Management Program Evaluation, Electric and Gas Weather Normalization Studies, Nuclear and Fossil Generation Cost and Performance Studies and Comparative Engineering Economic Studies of Utility Generation and other investments. Mr. Fitzpatrick provided expert testimony on the above-mentioned areas and also provided clients with leadership services in the startup of new diversification ventures.

1979 - 1981 Stone & Webster Management Consultants, Inc.
Vice President—Demand Planning

Responsible for the coordination and direction of consulting activities in the Planning, Load Research, Load Forecasting, and Load Management areas within the corporation. Additional responsibilities included analysis of data processing requirements and potential new markets for consulting activities - a diversification from Stone & Webster's traditional lines of business.

1971 - 1979 Long Island Lighting Company
Manager—Load Research, Costing and Forecast Division

Primary responsibilities centered on Electric Peak and Energy Forecasts; Electric and Gas Weather Normalization; Statistical Sample Design Development; Load Research Study Implementation; Load Data Management and Analysis; Long Island Lighting Company's Annual Population Survey; all Long-Range Demographic Projections; the collection, processing, and overall supervision of the billing of customers under the Long Island Lighting Company's commercial/industrial time-of-use rate, the Electric Class of Customer Annual System Load Research Study; and all statistical and econometric- based studies performed by Long Island Lighting Company's Economic Research Department.

In 1978, responsibilities were expanded to include fully allocated and marginal cost-of-service studies for electric and gas and total factor productivity studies.

PROFESSIONAL EXPERIENCE

EXPERT TESTIMONY AND REGULATORY SUPPORT (SELECTED ASSIGNMENTS)

El Paso Electric vs. City of Las Cruces, New Mexico-2000 Federal Court-Ordered Mediation:
Participated as part of El Paso Electric's officer/attorney team in the final court-ordered mediation sessions that resulted in the settlement of the 10-year dispute between the two parties. Prior to this mediation, worked on behalf of the Company to negotiate a settlement with the City's consultants.

Freeport Electric-1995 Docket No. 95-E-0676, 2001 Docket No. 01-E0965, 2003Docket No. 03-E-0686:
Provided direct testimony supporting Freeport's KWH sales and peak demand forecasts in four NYPSC proceedings. Constructed econometric models based forecast methodology by calls along with weather normalization of the test year sales. Provided testimony on the selection of Freeport-specific DSM programs to meet Commission requirements.

Indian Point 2 and Indian Point 3 / Consolidated Edison Company of New York, Inc. and New York Power Authority - NRC Docket Nos. 50-247-SP and 50-286-SP:
Prepared rebuttal testimony comparing the economics of early retirement of the Indian Point units vs. potential conservation investment alternatives in New York State.

KeySpan Energy-1998 Docket Nos. ER98-11-000 and EL98-22-000, 2003; Docket Nos. ER04-112-000 and ER04-112-001:
Provided expert testimony before FERC on the appropriate segmentation of fossil generating plant fixed and variable O&M Costs. Developed statistical models, by plant, to support this segmentation. Testimony was updated again in 2003 for the FERC Docket related to the renewal of the contract that was originally brought before FERC in 1998.

Palo Verde 1, 2, & 3 / Arizona Public Service Company-Docket Nos. U-1345-85-156 and U-1345-85-367:
Provided direct testimony presenting comparative economic analysis of Palo Verde vs. hypothetical coal unit alternative. Provided econometrically developed estimates of Operation and Maintenance Costs, as well as Capital Additions Costs. Provided independent statistically derived estimates of lifecycle Capacity Factors for the Palo Verde units.

Palo Verde 1 & 2 / El Paso Electric Company / Texas - Docket No. 7460:
Provided direct testimony on lifecycle economics of nuclear vs. coal alternative. Provided direct testimony on decisional prudency of company to enter into nuclear investment. Provided load forecast of company's future energy and peak demand needs. Participated in the training of Company witnesses.

Palo Verde 1, 2, & 3 / El Paso Electric Company Docket Nos. 8892, 9069 and 9165:
Provided Direct Testimony presenting comprehensive industry analysis and statistical analysis of Nuclear Performance Standards. Presented statistically derived optimal Performance Standard for Palo Verde Units 1, 2, and 3. Provided Rebuttal Testimony discussing theoretical and statistical flaws in intervenor's Performance Standard proposal.

Plant Hatch and Plant Vogtle / Georgia Power Company / Georgia - Docket Nos. 3554-U and 3673-U:
For the Vogtle Financing Case, the Vogtle Rate Case and the Hatch Rate Case: Provided rebuttal testimony on comparative economics of Plant Vogtle, provided rebuttal testimony (with presentation to Commission) on Vogtle's economics, and statistically derived projections of Vogtle's performance and Hatch O&M Costs, participated in witness training, and developed internal statistically-based O&M and Capital Additions "Targets" for Plant Hatch and Plant Vogtle.

Plant Hatch and Plant Vogtle / Georgia Power Company - Docket No. 3840-U:
Provided Rebuttal Testimony that pointed out methodological and statistical flaws in Staff consultant's Performance Standard proposal. Presented parameters for a statistically unbiased, optimal Performance Standard.

Shoreham / Long Island Lighting Company / New York-Docket No. 28252:
Provided rebuttal testimony on most likely performance of Shoreham Unit. Provided testimony on most likely Operation and Maintenance Cost levels and Capital Additions Cost level for Shoreham based upon econometric analysis of nuclear industry. Provided testimony on demand-side vs. supply-side alternatives for the Long Island Lighting Company.

Westar Energy-2005 KCC Docket No. 05-WSEE-981-RTS
Provided direct and rebuttal testimony on the subjects of distribution reliability and reliability-based performance standards. Developed a series of statistical analyses that set performance standards for five utility performance metrics: SAIDI, SAIFI, EFOR, Answered Calls and Meters Read. Developed daily 1998-2004 SAIDI and SAIFI non-linear multiple regression-based weather normalization models for use by the Company.

Western Resources-2001 KCC Docket No. 1-WSRE-436-RTS:
Provided direct testimony and supporting statistical / engineering economic analyses on the prudence of Western's investment in the Stateline Generating Plant. Also provided direct testimony on the statistical weather normalization of test year sales.

Developed comparative economic analysis on the benefits to Westar and remaining customers of special power supply contracts for Large C&I customers.

Western Resources – 1996 KCC Docket Nos.193, 305 and 193,30; -U96-KG&E-100-RTS:
Developed an accelerated depreciation plan for Wolf Creek Nuclear Unit to reduce cost of production to market-based competitive levels by 2000 - 2005.

Western Resources – 1996 KCC Docket No. 193,307-U96-WSRE-101-DRS:
Provided expert testimony and supporting statistical analysis for test year, class weather normalization, as well as, primary and secondary economic benefits of key customer discounted contracts.

Western Resources - Missouri Testimony in Generic Proceeding (1994:)
Provide expert testimony during the Missouri Public Service Commission's rule making proceeding concerning Integrated Resource Planning. The testimony discussed the consideration of alternative fuel sources as an end-use measure when developing their resource plan. (MPSC Docket)

Wolf Creek / Kansas Gas and Electric Company / Kansas City Power and Light Company/Kansas-1984 Docket Nos. 84-KG&E-197-R-142, O98-U / Missouri Docket #ER-85-128, EO-85-185:

Provided rebuttal testimony on lifecycle economics of nuclear vs. coal alternative. Provided first-year and lifecycle statistically based estimates of Wolf Creek's Operation and Maintenance Costs and Capital Additions Costs. Provided first-year and lifecycle estimates of Wolf Creek's Capacity Factors. Participated in the preparation of KG&E witnesses on the subjects of statistics, econometrics, forecasting, and engineering economics.

Atlanta Gas Light – Georgia (1997):
Worked with senior management to develop testimony for a performance based rate plan in support of the unbundling of gas service.***El Paso Electric Company -Texas (1997-1998):***
Developed unbundling strategy and performance based rate plan in support of ongoing Texas PUC workshops on the unbundling of electric service.

Empire District - Missouri (1992):
Provided econometric rebuttal testimony critiquing MPSC Staff's direct testimony on Empire District's forecast. Staff accepted rebuttal testimony and the Company's forecast was accepted for use in the rate case.

Minnegasco - Docket No. G-008/GR-92-400 (1993 - 1994):
Developed a set of econometrically derived, short run forecasts for Minnegasco's major customer classes. Provided direct expert testimony regarding the use of these forecasts as a factor in determining the need for and magnitude of Minnegasco's requested rate increase. Assisted in preparation of cross-examination of intervening parties.

On rebuttal, supported the implementation of weather normalization adjustments and discussed the effects of an adjustment on varying classes of customer use.
All testimony was accepted by Staff.

Missouri Public Service (MOPUB) - (1992):
Provided econometric-based rebuttal testimony critiquing MPSC Staff's direct case criticizing MOPUB's forecast. Rebuttal testimony resulted in Staff stipulating to the use of the Company's forecast.

Palo Verde / Arizona Nuclear Power Project:
Developed computer software to facilitate budget tracking and comparison. Developed econometric-based target estimation models of Operation and Maintenance Costs. Developed target estimation of Capital Additions Costs based upon econometric modeling. Developed forced and planned outage statistical models to be used in regulatory proceedings for all participants as well as for internal outage planning. Acted as Advisor to Palo Verde Participant's Engineering and Operating Committee on Palo Verde Cost and Performance budget targeting.

Iowa Power Company:
Preparation of a generic proceeding-related evaluation of Iowa Power Company's current and planned DSM activities in light of its specific planning related need for DSM resources.

Long Island Lighting Company :(1974-1979)
Testified as an expert witness, usually in both the direct and rebuttal phases, in the following New York State Public Service Commission proceedings: Docket Numbers:

- 26733
- 26829
- 26985
- 27136
- 27154
- 80003
- 27319
- 27374
- 27375
- 28223
- 28252

on subjects such as econometric and econometric-end use Electric and Gas Peak and Energy Forecasts, Load Research studies for cost-of-service analysis, Load Management, Cogeneration, Conservation and statistical studies for weather normalization of gas send out and electric energy requirements data.

SELECTED CONSULTING ASSIGNMENTS

Westar Energy
Mr. Fitzpatrick served as the Principal Statistical Consultant on a joint Distribution Reliability project with Davies Consulting. This project had as its objective the evaluation of Westar's distribution integrity and repair metrics (i.e.; SAIFI and SAIDI) and the development of non-linear multiple regression models to normalize these metrics over time for those major weather elements affecting SAIFI and SAIDI performance. The results of this analysis were presented to both Westar Senior Management and the Kansas Corporation Commission.

Generation Investment Analysis (Westar La Cygne 2 and SDGE SONGS related analysis.)

Westar La Cygne 2 Sale Leaseback Analysis
Provided an industry based statistical study of lifecycle availability and O&M cost Expectation in connection with Westar Sale/Leaseback of the La Cygne 2 Unit.

San Diego Gas & Electric SONGS O&M and Capital Additions
Served as the technical project manager for the development of several non-linear multiple regression analysis developed to evaluate SONGS mayor cost components as compared to a focused sample of like plants.

American Electric Power 2005
Served as the subject matter expert and project manager for the development of the DSM and Renewables Components for AEP's Comprehensive 2005 Integrated Resource Plan for each of its 10 operating areas.

Freeport Electric
Served as the principal-in-charge of the statistical analysis to develop the Freeport Electric 2005 Normalized System Peak and the estimation of Freeport's 2006 ICAP peak responsibility for the New

York ISO. Also served as the project manager for the development of Freeport Electric's 2005 Load & Energy Forecasts.

Duquesne Light
Served as the Principal-in-charge of the statistical analysis to develop Duquesne Light's 2005 Normalized Summer Peak as well as the development of the major rate class contribution to that peak.

El Paso Electric Company
Developed a business plan for and then implemented an Energy Services Business Unit (ESBU) that had as its mission key customer retention contracting and the provision of value added products and services in the areas of energy efficiency, power quality, standby generation, and "behind the fence" maintenance and support services.

Bermuda Electric Light Company, Ltd.
Consulted senior management on opportunities for diversification and franchise protection; from 1993 through 1997. Businesses developed include a full service ESCO (BESCO) and Power Protection Leasing Programs for Residential and Commercial customers.

Western Resources
In 1995, was retained by Western Resources to provide expert advisory services and supporting research to assist in the development of a non-traditional Energy Service Company (ESCO). This engagement also involved the analysis of profitability of certain customer classes.

WPI Group International
In 1993 through 1994, provided advisory services for the acquisition of MICROPALM by WPI. After acquisition, provided strategic market and product planning advisory services to the CEO.

Delmarva Power & Light Company (DP&L)
From 1994 to 1998, supported a market research and business plan development project for the development of a dispatchable photovoltaic power supply system business. Based on our initial contribution, DP&L turned over the entirety of the Phase II commercialization to my firm.

Richardson & Associates
Since 1982, has provided expert technical, economic and business plan analysis for over 15 energy-related venture capital business opportunities. This consulting relationship is ongoing.

Applied Energy Technologies Corporation (AET)
Led the formation of a jointly held subsidiary with Delmarva Power & Light Company, A.C. Battery Corporation (a subsidiary of General Motors) to advance both grid-connected and non-grid-connected dispatchable photovoltaics to domestic and international commercialization. Other contributors include the U.S. Department of Energy, Solarex Corporation (a division of Amoco/Enron), and Ascension Technologies

NCR Corporation
In 1981 through 1983, was retained by NCR to develop a diversification business in the automatic meter-reading field. Developed business plans, marketing plans, and product functional specifications. Worked with NCR's CEO and senior management team.

Confidential Diversification Studies and Business Planning Engagements
Senior Management advisory services, development of business plans, and diversification strategies for twelve nationally known organizations. Since these assignments are governed by strict confidentiality agreements, they cannot be publicly identified.

Time of Use Rate and Load Management-Related Experience (selected Projects)

Development of the First Residential and Commercial Time of Use Rates in the US
One of the authors of Long Island Lighting Company's SC-2MRP and SC-1 MRP time of use rates. Mr. Fitzpatrick led the load research-related activities necessary to identify the width of the rating periods and the relative cost of service levels associated with those rating periods. At the time that these rates were developed, Mr. Fitzpatrick managed the Load Research, Cost of Service and Forecasting Divisions of the Long Island Lighting Company.

Development of Energy Cooperative Programs for PG&E, Long Island Lighting Company and El Paso Electric
Mr. Fitzpatrick led teams of professionals in the setting up of the design, pricing, implementation and evaluation of results for these programs at the host utilities. This type of program involved working with large commercial-industrial customers to first identify significant, isolatable load shedding opportunities within a customer's facility and then negotiating a contract that would provide incentives for performance and sometimes, penalties for non-performance. Finally, a two-way communication strategy would be custom designed to keep customers interested in the program and provide the mechanism with which to notify them that a load shed would be required within a certain number of hours of notification.

Tasks included the setting of cost-justified rebate levels, program marketing strategies, metering selection and implementation, Utility-commercial/industrial participating customer communication strategies and equipment; setting criteria for the calling of "critical days" for load shedding purposes; calculation and delivery of rebates in manners that fostered longer term commitments.

This type of program was allowed to be counted as "spinning reserve" by New York Power Pool. Fitzpatrick participated in the PG&E installation and managed the installation of the LILCO and El Paso Electric programs.

DSM Load Shedding/ LOAD Shifting and Time Of Use Rate Program Evaluations
Mr.Fitzpatrick served as the Principal-in Charge for over 400 DSM- related process and impact evaluations for 10 utilities in primarily in the North East. Many of these programs had time of use considerations associated with them.

DOE PV Bonus Program
Mr.Fitzpatrick served as the Principal-In –Charge for the Project Management of DOE's PV Bonus Program. This program was a multimillion collaborative effort among the DOE, GM and Shell Solar to develop a stand alone power source that utilized photovoltaic arrays married to battery technology in a stand alone package. Projected use of this type of system was for "village power" in remote locations and remote distribution reinforcement in rural areas. Successful prototypes in the 30kw range were successfully built and tested.

Stand-By Generation Program

Mr. Fitzpatrick served as the Principal-in Charge for the development and implementation of a standby generation program and an associated rate design that was instrumental in placing over 40 MW of customer-owned generation in the El Paso Electric service territory. Unit sizes ranged from 750 kw to 20 MW. Customers were given incentive to run their generation through the use of an Interruptible-type rate. These units were used in three ways- to pick up a segment of a customer's load, thus removed that load from the customer's metered demand, to isolate the customer from the grid and pick up the entire load of the customer, and to synchronize with the grid and feed surrounding areas.
This program was a win-win for customers with critical loads, and provided bill savings to customers while reducing EPE's overall cost to serve.

Four Million Gallon Chilled Storage Project for the University of Texas-El Paso
In order to prevent the University of Texas-El Paso from adopting a proposal to install self generation and disconnect from the EPE grid, Fitzpatrick was the Principal-in –Charge for the development, funding, rate design and contracting for an 12 MW load shedding project that had as its mission the provision of all of UTEP space conditioning needs with chilled storage. Mr. Fitzpatrick worked with UTEP, the university of Texas system and its performance contractor in making this project a reality and providing a win for all parties involved.

The contract between UTEP and the rate design employed within that contract served to both decrease UTEP's effective electric rates and overall energy costs while actually making this customer a more profitable customer for EPE to serve.

Planning & Forecasting (Selected Projects)

New York State Electric & Gas Corporation (NYSEG) - (1994 -1997)
Served as Responsible Officer for AEG's development of a Multi-Equational Small Area Forecast Modeling System. This system is used to track monthly sales geographically in the NYSEG system, identifying significant weather normalized monthly variances almost in "real time" so that NYSEG can recognize and react to significant changes in a shorter elapsed time.

Western Resources/Westar - (1984 - 2004)
Provide continuing advisory services to Western Resources (now Westar) on potential methodological upgrades to their forecast and weather normalization methodologies.

Long Island Lighting Company (LILCO)
Directed the preparation of LILCO's Annual Long Range Peak and Energy Forecasts during the years 1974 - 1979. Constructed the first Engineering End Use and Econometric End Use models for electric forecasting in New York State; utilized Box-Jenkins stochastic and multiple transfer functions for short run electric forecasts; employed two and three stage regression techniques in SIC-based commercial-industrial forecasting.

In 1994, provided advisory services to review adequacy of the econometric methodologies for the capture of "market transformation" DSM and efficiency effects.

Saudi Arabia - 1995
Selected from an international list of experts to perform a comprehensive review of Saudi Arabia's largest utility's overall planning and forecasting procedures, methodologies, and results. This two-phase project also called for the reengineering of these processes once the analytical and fact-finding phase was complete.

Bermuda Electric Light Company, Ltd. (BELCO) - (1994)
Reviewed BELCO's existing forecasting process and provided a "phase in" solution for enhancing their forecasting systems.

Freeport Light & Power - (1995-2004)
Have and continue to prepare Freeport's short and long-term electric peak and energy forecasts. Have presented and defended Freeport's forecasts and weather normalization studies in its last three rate cases.

Innovative Market Segmentation & Profitability Studies

Western Resources
Served as Responsible Officer for a Competitive Assessment of Western Resources key customer's responses to cost competition.

Union Gas Limited-2004
Performed a detailed evaluation of the Union Gas forecasting methodology and results. Developed a written report containing an evaluation opinion and forecast improvement suggestions. This report was filed with the Ontario Energy Board.

CINergy
In 1995, advisor to senior staff in a multi-phase project that had as its objective the meaningful (from a risk-profit perspective) segmentation of CINergy key customer markets and the analysis of profitability of the segments. This was followed by the development of strategies to optimize the use of CINergy's marketing resources to maximize shareholder returns while ensuring the long-term viability of the company.

Demand-Side Management Program Design, Reengineering, & Evaluation

Bermuda Electric Light Company, Ltd.
Directed a multi-faceted evaluation of the potential for DSM on Bermuda. Conducted in-depth research of various customer classes to determine likelihood of adoption of available DSM technologies. Building on this research, developed a series of pilot programs that were implemented in 1993, as well as evaluation strategies to be employed at the programs' conclusion.

Consolidated Edison Company of New York, Inc.
Project Manager for a Conservation Assessment Study which included designing a methodology and performing analysis to impact Conservation measures in the residential and commercial sectors to meet requirements imposed by New York PSC in Case No. 28223.

Long Island Lighting Company (LILCO)
Directed a research project focusing on the right-sizing of LILCO's DSM program in the face of a maturing market condition, as well as on the measurement of the extent to which LILCO's programs have successfully moved the market to energy efficient technologies. Research includes an assessment of the impacts of pure market forces on DSM and the role of rebates and information in overall market capture for DSM technologies.

Project Manager for LILCO's 1992 Research and Development Initiative entitled, "Institutional Barriers to Conservation in Master-Metered, Tenant-Occupied Commercial Office Space." The project involved determining the market conservation potential, identifying institutional barriers through focus groups and interviews with landlords and tenants, and establishing a pilot program and blueprint lease to implement in order to enhance DSM measures in the relevant market.

Directed the comprehensive evaluation of LILCO's 1987 Conservation and Load Management Programs. This evaluation is contained in a three-volume report, which has been called the "most comprehensive" effort to date in this area.

Directed the evaluation of LILCO's 1988 and 1989 Conservation and Load Management Programs. Directed the preparation of a June 1988 Load Management Study. Specific responsibilities included estimating Load Management reductions included in LILCO's Load Forecasts by major components.

Minnegasco
Served as the Senior Management Advisor to Minnegasco's DSM/Load Research Program from 1993 through mid-1995. Responsibilities included contract negotiations with consultants, supervision of consultant's activities, and resolution of technical issues, and on-site presence as required to effectively oversee all Load Research-related activities.

New York Power Authority (NYPA)
Served as the Senior Management Advisor for NYPA's $120 million High Efficiency Lighting Program (HELP) having primary responsibility for drafting and negotiating DSM cost sharing umbrella contracts with New York State and New York City.

Analysis on behalf of NYPA of Energy Systems Research Group's (ESRG) Conservation Assessment Report submitted in FERC Case No. 2729: Prattsville Pumped Storage Facility.

Supervised the development of an evaluation of potential Load Management strategies for the NYPA's municipal customers, including a cost/benefit analysis and specific Load Management test programs.

Named "Advisor" to NYPA's extensive Conservation Ten-Year Program.

New York Power Pool
Analyzed the conservation forecasts contained within the Member Systems' individual long-range forecasts and critiqued intervenors' conservation forecasts and analyses.

New York State Electric & Gas Corporation (NYSEG)
Served as Responsible Officer for NYSEG's 1991 & 1992 Commercial / Industrial Process and Impact Evaluations. Served as Responsible Officer in the development of NYSEG's June 1994 DSM Market Transformation Study.

Orange and Rockland Utilities (O&R)
Assessed the potential for and designed an Energy Cooperative Program for O&R's commercial customers. Directed project to assess new regulated and unregulated business opportunities to diversify O&R from its core business.

Rochester Gas & Electric Corporation
Served as Responsible Officer for RG&E's 1990-94 DSM Evaluations. Represented RG&E in all DSM-related interactions with PSC Staff.

Load Research

Electric Power Research Institute (EPRI)
Advisor to EPRI's Demand Program. Author of RP 1588-3 "Load Data Management and Analysis"; co-author of EPRI Rate Design Study Topic Paper 3: "Issues in Load Research."

Elizabethtown Gas Company
Asked by Senior Management to assess Elizabethtown's Load Research Program and develop a set of recommendations that would result in full cost-effective utilization of the Load Research resource, developed study plan, conducted in-depth technical interviews of potential load research clients, and presented findings and recommendations to all levels of Management.

Iowa Power Company
Directed weather normalization analysis on historical system peak demands. Results from analysis will be utilized in future system peak demand forecasts.

Long Island Lighting Company (LILCO)
Designed and implemented stratified sampling software that employed Dalenius-Hodges and Neyman Allocation techniques with stratum optimization and validation. Also directed LILCO's Load Research Program.

New England Power Service Company (NEPSCo)
Reviewed NEPSCo's Load Research Data Management and Analysis System from analytical and data perspectives and developed a NEPSCo-specific computer hardware and software plan for implementation.

New York Power Authority
Directed the review of the existing Load Research Program and formulated a Management Plan to specify future needs in the areas of sample design, hardware, software, and staffing.

Assisted in the development of specifications for a microcomputer-based Load Research Data Collection, Editing and Analysis System.

New York State Electric & Gas Corporation (NYSEG)
Served as Technical Advisor to the Manager of NYSEG's Load Research Department.

Northeast Utilities Service Company
Performed a comprehensive audit of the technical, software, and organizational aspects of the Northeast Utilities Load Research Program, including the identification of current uses and recommended future cost-effective uses within the company.

Supervised development of a study to analyze load research, weather, and attribute data for the small Commercial and Industrial customer group.

Northern States Power Company (NSP)
Directed the review of all aspects of NSP's load research process and presented findings in a comprehensive presentation to senior management.

Pacific Gas & Electric Company (PG&E)
Performed a comprehensive audit of the PG&E Load Research Data Management and Analysis System. Also, assessed the value of Load Research to all relevant departments in the company including recommendations for more cost-effective uses of Load Research data for both current and future applications.

Tennessee Valley Authority (TVA)
Conducted review of TVA's Sampling Plan strategies and methodologies.

DSM Bidding

Orange and Rockland Utilities
Directed the economic evaluation of the first utility bidding program in New York State.

Cogeneration

Caribbean Gulf Refining Corporation
Performed an economic review for the construction of a nine-megawatt Cogeneration facility.

Day and Zimmermann, Inc.
Performed a detailed analysis on the potential for Cogeneration Systems in the United States, which included the development of a comprehensive marketing strategy.

Orange and Rockland Utilities
Developed a Corporate Strategy for Cogeneration in the O&R service territory.

PUBLICATIONS, PRESENTATIONS, AND SEMINARS

Speaker, "The Electrotechnologies Conference," El Paso Electric Company; El Paso, Texas; March 31, 1998.

Speaker, "The Customer Information Seminar," El Paso Electric Company; El Paso, Texas; October 7, 1997.

Speaker, "The Energy Revolution Conference," El Paso Electric Company; UTEP Campus; El Paso, Texas; June 3, 1997.

Speaker, "Customer/Market Segmentation to Optimize Competitive Opportunities," AMRA 1996 Annual Symposium; New Orleans, Louisiana; September 10, 1996.

Speaker, "Customer Segmentation," Infocast; Deloitte & Touche; Strategic Marketing Seminar; Atlanta, Georgia; May 1996.

Speaker, "Reengineering Customer Service & DSM - Keys to Building Competitive Advantage in the Future" with Steven J. Maslak; CARILEC CEO Conference; Freeport, Bahamas; June 1 & 2, 1995.

Speaker, "A Presentation To The Deloitte & Touche Partners" with Steven J. Maslak; Public Utilities SLIP Meeting; Las Vegas, Nevada; December 12-13, 1994.

Speaker, "Demand Side Management Alternatives for the Caribbean," Caribbean High-Level Workshop on Renewable Energy Technologies; December 5-9, 1994.

Speaker, "Projects For Energy Efficiency, And The Conservation Of Economic And Environmental Resources," The Caribbean Workshop On Renewable Energy Technologies; St. Lucia, West Indies; December 5-8, 1994.

Speaker, "Demand Side Management As An Economic Development Tool," MEUA Conference; Syracuse, New York; October 13, 1994.

Speaker, "The Effect Of The Market Transformation Phenomenon On DSM And Utility Competitiveness," EUMMOT Fall 1994 Meeting; Corpus Christi, Texas; September 9, 1994.

Speaker, "Evaluation Protocols: Preparing For DSM Evaluation," Presentation to the 4th Quarter EUMMOT Meeting; Columbia Lakes, Texas; December 13, 1993.

Author, "Incentive Regulation in the United States: an Update," EEI; 1992.

Speaker, "The Career Challenges Facing the Electric Industries in the 1990's," Hofstra University, M.B.A. Career Forum; Hempstead, New York; April 1992.

Speaker, "DSM Evaluation for Incentives: How Heavy Should the Burden of Proof Be?" Washington Gas Least-Cost Planning Conference; Washington D.C.; April 1992.

Speaker, "Practical Cases in Evaluating Energy Efficiency Initiatives," Hydro-Quebec Symposium; Montreal, Canada; November 1992.

Author, "Integration of Load Research into the DSM Evaluation Framework," Chapter 8; DOE DSM Evaluation Handbook.

Speaker, "Measuring the Impacts of Demand Side Management Programs," Northern States Power DSM Evaluation Overview; Minneapolis, Minnesota; December 1991.

Speaker, "Incentive Regulation an Overview of Operating Incentive Programs in the U.S. Today," The Southeastern Electric & Gas Conference; University of Georgia; Atlanta, Georgia; August 1991.

Speaker, "The Comparative Costs of and Sensitivities Surrounding the ALWR vs. Alternate Generation Options," EEI Working Group; Washington D.C.; July 1991.

Speaker, "The Role of Load Research in DSM Evaluation," NYSEG Conference; Saratoga Springs, New York; May 1991.

Speaker, "The Role of Load Research in Demand Side Management" with Joseph Lopes; Northeast AEIC Load Research Conference; Farmington, Connecticut; September 1989.

Speaker, "The Role of Load Research in Demand Side Management," 1989 APPA Accounting, Finance, Rates and Information Systems Workshop; Chicago, Illinois; September 1989.

Speaker, "Demand Side Management; The Key to Measuring Success and Cost Recovery," Iowa Utility Association; Integrated Resource Planning Conference; Des Moines, Iowa; August 1989.

Speaker, "DSM Program Monitoring & Evaluation Workshop," Rochester, New York; December 1988.
Speaker, "The Massachusetts Joint Utility Monitoring Projects" with Eric P. Cody; Northeast Regional AEIC Load Research Conference; Farmington, Connecticut; September 1986.

Author, "The Load Research Process Above and Beyond PURPA," Public Utilities Fortnightly; March 18, 1982.

"Load Data Management and Analysis," EPRI RP1588-3; December 1981.

Co-Author, "Issues in Load Research," Topic Paper 3; EPRI Rate Design Study; 1981.

Instructor, "Load Research and Load Management Seminar," Stone and Webster Utility Management Development Course; New York (2 courses); 1980.

Speaker, "Allocating Revenues Between Service Classifications: Necessary Load Research," National Regulatory Research Institute; Ohio State University; 1980.

Speaker, "Issues in Load Research," EPRI Rate Design Study Executive Transfer Conferences; San Francisco, Kansas City, and Washington D.C.; 1980.

"How Electric Utilities Forecast," EPRI Peak Load Forecasting Methodologies; EPRI Symposium Proceedings; New Orleans, Louisiana; 1979.

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Speaker, "Load Forecasting Working Group Chairman Reports (3)," Utility Modeling Forum (EPRI sponsored); San Francisco, California; 1979.

"Report of the Member Electric Systems of the New York Power Pool and the Empire State Electric Energy Research Corporation pursuant to Article 8, Section 149-b of the Public Service Law, Exhibit 7," LILCO Load Forecast Methodology; 1974-1978.

AFFILIATIONS

Association of Energy Engineers

American Statistical Association

American Economic Association

Mathematical Association of America

Omicron Delta Epsilon

Advisor to American Management Association

EDUCATION

St. John's University, M.B.A., Economic Theory, 1972

St. John's University, B.A., Economics, 1969

C.W. Post College, course work toward an MS, Management Engineering

Mr. Fitzpatrick has also completed course work in Engineering Economics, Load Research, Demand Forecasting in Electric Power Systems, Box-Jenkins Forecasting Techniques, logistic curve analyses; two and three stage multiple regression techniques; advanced econometric modeling and the utilization and interpretation of multiple regression models and associated analytical techniques. Mr. Fitzpatrick also holds a "Certificate of Mastery" in Reengineering from the Hammer Institute's Speaker: Center for Reengineering Leadership.

APS Baseload Generation Summary

Unit Name	Type	Year in Service	Fuel	Ownership	Net Accredited Capacity (MW)	PNW Share (%)	Capacity Owned by PNW (MW)	Category for Comparison
CHOLLA								
Unit 1	Steam	1962	Coal	APS	110	100	110	A - Small Old
Unit 2	Steam	1978	Coal	APS	260	100	260	B- Small New
Unit 3	Steam	1980	Coal	APS	260	100	260	B- Small New
FOUR CORNERS								
Unit 1	Steam	1963	Coal	APS	170	100	170	A - Small Old
Unit 2	Steam	1963	Coal	APS	170	100	170	A - Small Old
Unit 3	Steam	1964	Coal	APS	220	100	220	A - Small Old
Unit 4	Steam	1969	Coal	APS-SRP-PNM-	750	15	113	C- Large Pressurized
Unit 5	Steam	1970	Coal	SCE-TEP-EPE	750	15	113	C- Large Pressurized
NAVAJO								
Unit 1	Steam	1974	Coal	APS-SRP-NPC-	750	14	105	D - LG Balance Draft
Unit 2	Steam	1975	Coal	U.S.-TEP-	750	14	105	D - LG Balance Draft
Unit 3	Steam	1976	Coal	LADWP	750	14	105	D - LG Balance Draft
PALO VERDE								
Unit 1	Steam	1986	Uranium	APS-SRP-EPE-	1247	29.1	363	E-PWRs
Unit 2	Steam	1986	Uranium	SCE-PNM-SCP-	1314	29.1	382	E-PWRs
Unit 3	Steam	1988	Uranium	LADWP	1247	29.1	363	E-PWRs

Type	Average Age	Group	Average Size	Total APS Owned	% of Base Load
Mid Size - Coal	1963	A - Small Old	168	670	24%
Mid Size - Coal	1979	B- Small New	260	520	18%
Large Size - Coal	1970	C- Large Pressurized	750	226	8%
Large Size - Coal	1975	D - LG Balance Draft	750	315	11%
Nuclear	1986	E-PWRs	1269	1108	39%
		APS Total		**2,839**	

Performance Comparison of APS Coal Baseload Generation vs. Representative Comparison Groups

Group:	**A-Old**
Plant Query Design:	
Unit Type:	Fossil-Steam
Date Range	1960-1966
Net Dependable Capacity (MW)	100-200

	Utility	Region	Unit Name	Commercial Date
1	HOLYOKE WATER POWER CO.	NPCC	MT TOM #1	7/1/1960
2	NRG ENERGY (NIAGARA MOHAWK POWER CORP.	NPCC	DUNKIRK #4	8/21/1960
3	MIRANT NEW YORK (ORANGE& ROCKLAND)	NPCC	LOVETT #4	3/20/1996
4	MIRANT - NEW ENGLAND	NPCC	LOVETT #4	3/20/1996
5	NRG - NEW YORK	NPCC	DUNKIRK #4	8/21/1960
6	FIRST ENERGY (PENN ELECTRIC)	MAAC	SHAWVILLE #4	4/4/1960
7	POTOMAC ELECTRIC POWER CO.	MAAC	DICKERSON #2	4/14/1960
8	POTOMAC ELECTRIC POWER CO.	MAAC	DICKERSON #3	3/16/1962
9	MIRANT POTOMAC RIVER	MAAC	DICKERSON #2	4/14/1960
10	MIRANT POTOMAC RIVER	MAAC	DICKERSON #3	3/16/1962
11	RELIANT ENERGY SYSTEMS - WEST	MAAC	SHAWVILLE #4	4/4/1960
12	PROGRESS ENERGY CAROLINAS	SERC	ASHEVILLE #1	4/22/1964
13	PROGRESS ENERGY CAROLINAS	SERC	ROBINSON #1	4/30/1960
14	GULF POWER CO.	SERC	SMITH 1	6/1/1995
15	SAVANNAH ELECTRIC AND POWER CO.	SERC	KRAFT #3	5/24/1995
16	SOUTH CAROLINA ELECTRIC & GAS CO.	SERC	CANADYS #1	4/1/1962
17	SOUTH CAROLINA ELECTRIC & GAS CO.	SERC	CANADYS #2	5/1/1964
18	VIRGINIA POWER	SERC	CHESTERFIELD #4	6/28/1960
19	VIRGINIA POWER	SERC	CHESAPEAKE #4	5/15/1962
20	CINERGY (CINCINNATI GAS & ELECTRIC CO.)	ECAR	MIAMI FORT #6	11/30/1960
21	DUQUESNE LIGHT CO.	ECAR	ELRAMA #4	11/30/1960
22	EAST KENTUCKY POWER COOP., INC.	ECAR	COOPER #1	2/9/1965
23	INDIANAPOLIS POWER & LIGHT CO.	ECAR	HARDING ST #6	5/3/1961
24	LOUISVILLE GAS AND ELECTRIC CO.	ECAR	CANE RUN #4	5/4/1962
25	LOUISVILLE GAS AND ELECTRIC CO.	ECAR	CANE RUN #5	5/13/1966
26	FIRST ENERGY (OHIO EDISON)	ECAR	WH SAMMIS #2	7/1/1960
27	FIRST ENERGY (OHIO EDISON)	ECAR	WH SAMMIS #3	7/1/1961
28	FIRST ENERGY (OHIO EDISON)	ECAR	WH SAMMIS #4	11/13/1962
29	PENNSYLVANIA POWER CO.	ECAR	NEW CASTLE #5	8/1/1964
30	CINERGY (P.S. COMPANY OF INDIANA)	ECAR	GALLAGHER #3	4/15/1960
31	CINERGY (P.S. COMPANY OF INDIANA)	ECAR	GALLAGHER #4	3/1/1961
32	FIRST ENERGY (TOLEDO EDISON)	ECAR	BAYSHORE #3	8/1/1963
33	CINERGY	ECAR	GALLAGHER #3	4/15/1960
34	CINERGY	ECAR	GALLAGHER #4	3/1/1961
35	CINERGY	ECAR	MIAMI FORT #6	11/30/1960
36	AMEREN (CENTRAL ILLINOIS LIGHT)	MAIN	E.D EDWARDS #1	5/1/1960
37	AMEREN-CIPS	MAIN	MEREDOSIA #3	7/14/1960
38	WISCONSIN PUBLIC SERVICE CORP.	MAIN	PULLIAM #8	12/1/1964
39	BASIN ELECTRIC POWER COOP., INC.	MAIN	LELAND OLDS #1	1/30/1966
40	MID AMERICAN ENERGY CO.	MAPP	RIVERSIDE #5	4/11/1961
41	XCEL ENERGY (NORTHERN STATES POWER CO.)	MAPP	BLACK DOG #4	10/1/1960
42	OMAHA PUBLIC POWER DISTRICT	MAPP	NORTH OMAHA #4	2/28/1963
43	KANSAS CITY POWER & LIGHT CO.	SPP	MONTROSE #2	4/9/1960
44	KANSAS CITY POWER & LIGHT CO.	SPP	MONTROSE #3	4/20/1964
45	KPL, A WESTERN RESOURCE CO.	SPP	TECUMSEH #8	4/17/1962
46	KPL, A WESTERN RESOURCE CO.	SPP	LAWRENCE #4	3/11/1960
47	ARIZONA PUBLIC SERVICE CO.	WECC	FOUR CORNERS #1	5/1/1963
48	ARIZONA PUBLIC SERVICE CO.	WECC	FOUR CORNERS #2	6/1/1963
49	ARIZONA PUBLIC SERVICE CO.	WECC	FOUR CORNERS #3	4/1/1964
50	ARIZONA PUBLIC SERVICE CO.	WECC	CHOLLA #1	3/8/1962
51	XCEL ENERGY (PS CO. OF COLORADO)	WECC	CHEROKEE #3	6/15/1962
52	XCEL ENERGY (PS CO. OF COLORADO)	WECC	VALMONT #5	5/1/1964
53	XCEL ENERGY (PS CO. OF COLORADO)	WECC	HAYDEN #1	7/19/1965
54	PACIFICORP	WECC	NAUGHTON #1	5/15/1963

Performance Comparison of APS Coal Baseload Generation vs. Representative Comparison Groups

Group:	**B-New**
Plant Query Design:	
Unit Type:	Fossil-Steam
Date Range	1975-1985
Net Dependable Capacity (MW)	250-400

	Utility	Region	Unit Name	Commercial Date
1	SOUTH CAROLINA PUBLIC SERVICE	SERC	WINYAH #2	3/31/1977
2	SOUTH CAROLINA PUBLIC SERVICE	SERC	WINYAH #3	4/24/1980
3	SOUTH CAROLINA PUBLIC SERVICE	SERC	WINYAH #4	5/30/1981
4	COLUMBUS SOUTHERN POWER CO.	ECAR	CONESVILLE #5	11/24/1976
5	COLUMBUS SOUTHERN POWER CO.	ECAR	CONESVILLE #6	6I 1/1978
6	EAST KENTUCKY POWER COOP., INC.	ECAR	SPURLOCK #1	7/25/1977
7	LOUISVILLE GAS AND ELECTRIC CO.	ECAR	MILL CREEK #3	6/28/1978
8	NORTHERN INDIANA PUBLIC SERVICE	ECAR	R.M. SCHAHFER #17	3/29/1983
9	AMEREN (CENTRAL ILLINOIS LIGHT)	MAIN	DUCK CREEK #1	6/26/1976
10	ALLIANT ENERGY (WISCONSIN P&L)	MAIN	EDGEWATER #5	3/1/1985
11	WISCONSIN PUBLIC SERVICE CORP.	MAIN	WESTON #3	12/23/1981
12	DAIRYLAND POWER COOP.	MAPP	MADGETT #1	11/3/1979
13	ALLIANT ENERGY (INTERSTATE PWR)	MAIN	LANSING #4	5/10/1977
14	OTTER TAIL POWER CO.	MAPP	COYOTE #1	5/1/1981
15	SOUTHWESTERN PUBLIC SERVICE CO.	SPP	HARRINGTON #1	7/2/1976
16	SOUTHWESTERN PUBLIC SERVICE CO.	SPP	HARRINGTON #2	5/18/1978
17	SOUTHWESTERN PUBLIC SERVICE CO.	SPP	HARRINGTON #3	5/28/1980
18	SUNFLOWER ELECTRIC COOP., INC.	SPP	HOLCOMB #1	8/1/1983
19	WESTERN FARMERS ELECTRIC COOP	SPP	HUGO #1	4/1/1982
20	ARIZONA PUBLIC SERVICE CO.	WECC	CHOLLA #2	5/15/1978
21	ARIZONA PUBLIC SERVICE CO.	WECC	CHOLLA #3	5/15/1980
22	MONTANA POWER CO.	WECC	COLSTRIP #2	9/23/1975
23	MONTANA POWER CO.	WECC	COLSTRIP #1	5/22/1976
24	NEVADA POWER CO.	WECC	REID GARDNER #4	6/10/1983
25	PLATTE RIVER POWER AUTHORITY	WECC	RAWHIDE #1	4/1/1984
26	XCEL ENERGY (PS CO. OF COLORADO)	WECC	COMANCHE #2	11/25/1975
27	XCEL ENERGY (PS CO. OF COLORADO)	WECC	HAYDEN #2	9/1/1976
28	SALT RIVER PROJECT	WECC	CORONADO #1	7/21/1979
29	SALT RIVER PROJECT	WECC	CORONADO #2	8/2/1980
30	PACIFICORP	WECC	HUNTER #1	6/1/1978
31	PACIFICORP	WECC	HUNTER #2	6/4/1980
32	PACIFICORP	WECC	HUNTER #3	6/1/1983
33	PACIFICORP	WECC	CHOLLA #4	6/5/1981
34	PACIFICORP	WECC	HUNTINGTON #1	6/1/1977
35	TUCSON ELECTRIC POWER CO.	WECC	SPRINGERVILLE #1	6/1/1985

Performance Comparison of APS Coal Baseload Generation vs. Representative Comparison Groups

Group:	**C-Pressurized**
Plant Query Design:	
Unit Type:	Fossil-Steam
Date Range	1960-1966
Net Dependable Capacity (MW)	100-200
Furnance Draft Type	Pressurized Draft

	Utility	Region	Unit Name	Commercial Date
1	FIRST ENERGY "PENN ELECTRIC)	MAAC	KEYSTONE #1	6/18/1967
2	FIRST ENERGY "PENN ELECTRIC)	MAAC	KEYSTONE #2	8/13/1968
3	PENNSYLVANIA POWER & LIGHT CO.	MAAC	BRUNNER ISLAND #3	6/13/1969
4	PENNSYLVANIA POWER & LIGHT CO.	MAAC	MONTOUR #1	2/1/1971
5	PENNSYLVANIA POWER & LIGHT CO.	MAAC	MONTOUR #2	4/30/1973
6	RELIANT ENERGY SYSTEMS - WEST	MAAC	KEYSTONE #1	6/18/1967
7	RELIANT ENERGY SYSTEMS - WEST	MAAC	KEYSTONE #2	8/13/1968
8	ALABAMA POWER CO.	SERC	BARRY 5	10/19/1971
9	GEORGIA POWER CO.	SERC	BOWEN 1	10/21/1971
10	GEORGIA POWER CO.	SERC	BOWEN 2	9/26/1972
11	APPALACHIAN POWER CO.	ECAR	AMOS #1	9/1/1971
12	APPALACHIAN POWER CO.	ECAR	AMOS #2	6/6/1972
13	COLUMBUS SOUTHERN POWER CO.	ECAR	CONESVILLE #4	6/7/1973
14	KENTUCKY POWER CO.	ECAR	BIG SANDY #2	7/24/1969
15	OHIO POWER CO.	SCAR	MITCHELL #1	4/22/1970
16	OHIO POWER CO.	SCAR	MITCHELL #2	3/18/1971
17	ARIZONA PUBLIC SERVICE CO.	WECC	FOUR CORNERS #4.	5/22/1969
18	ARIZONA PUBLIC SERVICE CO.	WECC	FOUR CORNERS #5	4/6/1970
19	SOUTHERN CALIFORNIA EDISON CO.	WECC	MOHAVE #1	11/27/1970
20	SOUTHERN CALIFORNIA EDISON CO.	WECC	MOHAVE #2	7/21/1971

Performance Comparison of APS Coal Baseload Generation vs. Representative Comparison Groups

Group:	**D-Balance Draft**
Plant Query Design:	
Unit Type	Fossil-Steam
Date Range	1970-1980
Net Dependable Capacity (MW)	650-850
Furnance Draft Type	Balanced Draft

	Utility	Region	Unit Name	Commercial Date
1	FIRST ENERGY (PENN ELECTRIC)	MAAC	CONEMAUGH #1	5/21/1970
2	FIRST ENERGY (PENN ELECTRIC)	MAAC	CONEMAUGH #2	5/27/1971
3	RELIANT ENERGY SYSTEMS - WEST	MAAC	CONEMAUGH #1	5/21/1970
4	RELIANT ENERGY SYSTEMS - WEST	MAAC	CONEMAUGH #2	5/27/1971
5	ALABAMA POWER CO.	SERC	GORGAS10	10/27/1972
6	DUKE POWER CO.	SERC	MARSHALL #4	5/1/1970
7	GEORGIA POWER CO.	SERC	WANSLEY 1	8/1411976
8	GEORGIA POWER CO.	SERC	WANSLEY 2	1/14/1978
9	DETROIT EDISON CO.	ECAR	MONROE #1	5/3/1971
10	DETROIT EDISON CO.	ECAR	MONROE #2	1/14/1973
11	DETROIT EDISON CO.	ECAR	MONROE #3	3/11/1973
12	DETROIT EDISON CO.	ECAR	MONROE #4	3/16/1974
13	PENNSYLVANIA POWER CO.	ECAR	BRUCE MANSFIELD #1	4/5/1976
14	PENNSYLVANIA POWER CO.	ECAR	BRUCE MANSFIELD #2	10/1/1977
15	PENNSYLVANIA POWER CO.	SCAR	BRUCE MANSFIELD #3	9/29/1980
16	ALLEGHENY ENERGY SUPPLY (ECAR)	SCAR	HARRISON #3	12/31/1974
17	KANSAS CITY POWER & LIGHT CO.	SPP	LA CYGNE #1	6/1/1973
18	SALT RIVER PROJECT - ARIZONA PUBLIC SERVICE	WECC	NAVAJO #1	2/1/1974
19	SALT RIVER PROJECT - ARIZONA PUBLIC SERVICE	WECC	NAVAJO #2	12/3/1974
20	SALT RIVER PROJECT - ARIZONA PUBLIC SERVICE	WECC	NAVAJO #3	11/29/1975

Statistical Comparison of APS Baseload Plant Performance vs.
Performance of Relevant Comparison Group:
Average Group Values for 2002-2004, 1999-2004 and 1995-2004

Group:	**A-Old**
Plant Query Design:	
Unit Type	Fossil-Steam
Date Range	1960-1966
Net Dependable Capacity (MW)	100-200

	2002-2004			1999-2004			1995-2004		
Computation of:	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**
Mean (Includes Cholla (1) Four Corners (1,2,3))	70.14	85.62	6.03	68.49	85.23	5.70	66.07	85.55	5.88
Mean (Excludes Cholla (1) Four Corners (1,2,3))	68.56	85.36	5.84	66.96	85.13	5.59	64.78	85.39	5.74
Mean (Cholla (1) Four Corners (1,2,3))	85.18	88.09	7.84	83.16	86.18	9.69	78.82	87.09	9.06
Median (Includes Cholla (1) Four Corners (1,2,3))	69.63	88.02	4.52	67.81	87.33	4.43	66.72	88.13	4.53
Median (Excludes Cholla (1) Four Corners (1,2,3))	68.11	87.47	4.33	66.91	87.19	3.97	65.12	87.96	4.11
Median (Cholla (1) Four Corners (1,2,3))	86.30	89.40	7.68	83.15	88.40	9.12	80.80	88.55	8.75
Standard Deviation (Includes Cholla (1) Four Corners (1,2,3))	11.65	8.78	6.11	12.67	9.35	6.36	14.31	9.44	6.14
Standard Deviation (Excludes Cholla (1) Four Corners (1,2,3))	11.01	9.04	6.37	12.19	9.63	6.47	14.05	9.69	6.19
Standard Deviation (Cholla (1) Four Corners (1,2,3))	4.84	5.38	1.92	6.10	6.10	3.06	9.95	6.36	3.35
Count (Includes Cholla (1) Four Corners (1,2,3))	126.00	126.00	126.00	254.00	254.00	254.00	436.00	436.00	436.00
Count (Excludes Cholla (1) Four Corners (1,2,3))	114.00	114.00	114.00	230.00	230.00	230.00	396.00	396.00	396.00
Count (Cholla (1) Four Corners (1,2,3))	12.00	12.00	12.00	24.00	24.00	24.00	40.00	40.00	40.00
Standard Error (Includes Cholla (1) Four Corners (1,2,3))	1.04	0.79	0.55	0.80	0.59	0.40	0.69	0.45	0.29
Standard Error (Excludes Cholla (1) Four Corners (1,2,3))	1.04	0.85	0.60	0.81	0.64	0.43	0.71	0.49	0.31
Standard Error (Cholla (1) Four Corners (1,2,3))	1.46	1.62	0.58	1.27	1.27	0.64	1.59	1.02	0.54
Skewness (Includes Cholla (1) Four Corners (1,2,3))	0.13	(0.82)	0.74	0.16	(0.67)	0.60	(0.13)	(0.82)	0.66
Skewness (Excludes Cholla (1) Four Corners (1,2,3))	0.12	(0.70)	0.71	0.01	(0.64)	0.75	(0.07)	(0.79)	0.79
Skewness (Cholla (1) Four Corners (1,2,3))	(0.70)	(0.73)	0.25	0.00	(1.09)	0.56	(0.60)	(0.69)	0.28

Statistical Comparison of APS Baseload Plant Performance vs.
Preformance of Relevant Comparison Group:
Average of each Group by Year

Group:	**A-Old**
Plant Query Design:	
Unit Type	Fossil-Steam
Date Range	1960-1966
Net Dependable Capacity (MW)	100-200

	1995			1996			1997			1998			1999		
Computation of:	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**
Mean (Includes Cholla (1) Four Corners (1,2,3))	59.80	86.22	6.89	59.80	86.22	6.89	62.41	84.04	5.50	66.74	86.62	5.36	65.70	84.91	6.00
Mean (Excludes Cholla (1) Four Corners (1,2,3))	59.13	85.85	7.00	59.13	85.85	7.00	60.88	83.67	5.14	65.89	86.99	4.74	64.40	84.94	5.51
Mean (Cholla (1) Four Corners (1,2,3))	66.71	90.03	5.75	66.71	90.03	5.75	78.48	87.92	9.26	75.48	82.77	11.69	79.37	84.61	10.98
Median (Includes Cholla (1) Four Corners (1,2,3))	61.26	89.62	4.35	61.26	89.62	4.35	63.78	87.03	4.90	66.51	87.50	5.14	66.74	86.80	5.08
Median (Excludes Cholla (1) Four Corners (1,2,3))	60.35	89.62	3.99	60.35	89.62	3.99	63.30	86.67	4.50	66.32	87.86	4.78	65.02	86.80	4.17
Median (Cholla (1) Four Corners (1,2,3))	68.48	90.73	6.44	68.48	90.73	6.44	80.56	90.50	8.04	77.31	83.13	11.90	78.63	84.85	9.09
Standard Deviation (Includes Cholla (1) Four Corners (1,2,3))	18.24	10.79	7.77	18.24	10.79	7.77	16.01	10.42	4.15	12.87	7.76	3.56	14.43	10.78	5.32
Standard Deviation (Excludes Cholla (1) Four Corners (1,2,3))	18.84	11.04	8.09	18.84	11.04	8.09	15.57	10.64	4.03	13.02	7.97	2.87	14.41	11.21	5.17
Standard Deviation (Cholla (1) Four Corners (1,2,3))	8.75	7.82	3.53	8.75	7.82	3.53	12.33	7.62	3.87	7.37	3.81	4.20	3.54	4.78	4.74
Count (Includes Cholla (1) Four Corners (1,2,3))	45.00	45.00	45.00	45.00	45.00	45.00	46.00	46.00	46.00	45.00	45.00	45.00	46.00	46.00	45.00
Count (Excludes Cholla (1) Four Corners (1,2,3))	41.00	41.00	41.00	41.00	41.00	41.00	42.00	42.00	42.00	41.00	41.00	41.00	42.00	42.00	41.00
Count (Cholla (1) Four Corners (1,2,3))	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00

Statistical Comparison of APS Baseload Plant Performance vs.
Preformance of Relevant Comparison Group:
Average of each Group value by Year

Group:	**A-Old**
Plant Query Design:	
Unit Type	Fossil-Steam
Date Range	1960-1966
Net Dependable Capacity (MW)	100-200

	2000			2001			2002			2003			2004		
Computation of:	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**
Mean (Includes Cholla (1) Four Corners (1,2,3))	67.45	85.47	4.07	66.44	84.14	6.03	70.30	86.42	5.59	69.34	84.52	6.81	70.81	85.98	5.70
Mean (Excludes Cholla (1) Four Corners (1,2,3))	67.02	85.47	5.24	64.91	84.34	5.24	68.72	86.25	5.27	67.83	84.16	6.63	69.16	85.72	5.63
Mean (Cholla (1) Four Corners (1,2,3))	83.49	85.47	10.29	80.59	82.27	13.38	84.94	87.98	8.47	84.09	88.02	8.62	86.50	88.44	6.43
Median (Includes Cholla (1) Four Corners (1,2,3))	67.45	88.54	4.07	65.38	85.20	3.84	70.44	88.61	3.18	68.45	86.66	4.94	71.07	87.98	5.45
Median (Excludes Cholla (1) Four Corners (1,2,3))	66.75	88.75	3.56	64.41	85.83	3.11	69.45	88.34	3.02	67.96	85.60	4.89	68.17	87.47	5.07
Median (Cholla (1) Four Corners (1,2,3))	85.03	87.59	10.44	81.20	81.79	12.18	86.12	89.61	8.11	86.31	88.87	8.84	86.38	89.61	6.09
Standard Deviation (Includes Cholla (1) Four Corners (1,2,3))	12.43	9.35	5.65	13.42	9.59	8.86	11.85	8.64	7.16	11.86	10.18	6.95	11.47	7.33	4.21
Standard Deviation (Excludes Cholla (1) Four Corners (1,2,3))	11.82	9.60	5.71	12.97	9.85	8.81	11.31	8.94	7.46	11.31	10.48	7.24	10.66	7.52	4.42
Standard Deviation (Cholla (1) Four Corners (1,2,3))	7.58	7.61	2.03	9.22	7.54	5.79	4.54	5.85	1.84	5.25	6.46	2.71	5.78	5.38	1.22
Count (Includes Cholla (1) Four Corners (1,2,3))	41.00	41.00	41.00	41.00	41.00	41.00	41.00	41.00	41.00	43.00	43.00	43.00	42.00	42.00	42.00
Count (Excludes Cholla (1) Four Corners (1,2,3))	37.00	37.00	37.00	37.00	37.00	37.00	37.00	37.00	37.00	39.00	39.00	39.00	38.00	38.00	38.00
Count (Cholla (1) Four Corners (1,2,3))	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00

Statistical Comparison of APS Baseload Plant Performance vs.
Preformance of Relevant Comparison Group:
Average Group Values for 2002-2004, 1999-2004 and 1995-2004

Group:	**B-New**
Plant Query Design:	
Unit Type	Fossil-Steam
Date Range	1975-1985
Net Dependable Capacity (MW)	250-400

	2002-2004			1999-2004			1995-2004		
Computation of:	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**
Mean (Includes Cholla (2,3))	77.54	87.22	6.11	77.72	87.44	5.63	75.26	87.53	5.59
Mean (Excludes Cholla (2,3))	77.82	87.31	5.78	77.76	87.50	5.34	75.30	87.40	5.47
Mean (Cholla (2,3))	73.00	80.27	11.17	77.17	84.73	10.07	74.59	89.15	6.96
Median (Includes Cholla (2,3))	78.75	88.04	4.42	78.17	88.40	4.21	76.94	88.73	4.17
Median (Excludes Cholla (2,3))	78.75	87.93	4.72	77.96	88.29	4.20	76.94	88.51	4.19
Median (Cholla (2,3))	79.51	96.30	11.17	81.04	93.55	10.07	77.03	94.65	7.24
Standard Deviation (Includes Cholla (2,3))	11.18	8.50	6.71	10.41	7.94	5.49	12.23	8.02	5.41
Standard Deviation (Excludes Cholla (2,3))	10.76	7.47	5.36	10.24	7.41	4.63	12.26	7.71	5.03
Standard Deviation (Cholla (2,3))	17.32	29.52	10.92	13.41	19.88	7.82	12.19	15.95	4.83
Count (Includes Cholla (2,3))	104.00	104.00	104.00	205.00	205.00	205.00	345.00	345.00	345.00
Count (Excludes Cholla (2,3))	98.00	98.00	98.00	193.00	193.00	193.00	325.00	325.00	325.00
Count (Cholla (2,3))	6.00	3.00	3.00	12.00	6.00	6.00	20.00	10.00	10.00
Standard Error (Includes Cholla (2,3))	1.10	0.84	0.66	0.73	0.56	0.38	0.66	0.43	0.29
Standard Error (Excludes Cholla (2,3))	1.09	0.76	0.54	0.74	0.53	0.33	0.68	0.43	0.28
Standard Error (Cholla (2,3))	7.74	20.87	7.73	4.04	8.89	3.50	2.80	5.32	1.61
Skewness (Includes Cholla (2,3))	-0.32	-0.29	0.75	(0.13)	(0.36)	0.78	-0.41	-0.45	0.78
Skewness (Excludes Cholla (2,3))	-0.26	-0.25	0.59	(0.06)	(0.32)	0.74	-0.40	-0.43	0.76
Skewness (Cholla (2,3))	-1.13	-1.63	0.00	(0.87)	(1.33)	(0.00)	-0.60	-1.03	-0.17

Statistical Comparison of APS Baseload Plant Performance vs.
Preformance of Relevant Comparison Group:
Average of each Group by Year

Group:	**B-New**
Plant Query Design:	
Unit Type	Fossil-Steam
Date Range	1975-1985
Net Dependable Capacity (MW)	250-400

	1995			1996			1997			1998			1999		
Computation of:	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**
Mean (Includes Cholla (2,3))	69.52	87.99	4.37	69.56	87.69	5.43	70.42	85.49	6.36	76.74	89.51	5.11	77.71	88.55	4.73
Mean (Excludes Cholla (2,3))	69.81	87.37	4.52	69.63	87.14	5.54	70.26	85.05	6.61	76.77	89.48	5.07	77.73	88.78	4.38
Mean (Cholla (2,3))	64.84	98.13	2.01	68.48	96.70	3.71	73.04	92.85	2.35	76.27	90.00	2.21	77.27	84.80	10.21
Median (Includes Cholla (2,3))	73.19	89.02	3.36	72.11	90.79	4.41	72.71	87.04	4.40	75.00	90.04	4.14	77.30	89.23	3.91
Median (Excludes Cholla (2,3))	73.19	88.29	3.54	72.65	89.30	4.50	71.75	86.20	4.63	75.00	90.04	4.14	77.30	89.23	3.51
Median (Cholla (2,3))	64.84	98.13	4.75	68.48	96.70	3.71	73.04	77.85	2.35	76.27	90.00	2.21	77.27	84.80	10.21
Standard Deviation (Includes Cholla (2,3))	15.75	8.26	3.36	15.53	9.39	4.64	12.89	8.64	6.63	10.16	5.76	3.66	8.65	7.06	3.46
Standard Deviation (Excludes Cholla (2,3))	15.78	8.10	3.41	15.98	9.39	4.76	13.28	8.70	6.76	10.44	5.78	3.67	8.74	6.89	3.08
Standard Deviation (Cholla (2,3))	20.52	0.53	3.50	5.82	1.27	0.95	1.05	0.92	0.82	5.52	7.78	0.05	9.81	12.02	6.15
Count (Includes Cholla (2,3))	34	35	34	34	35	34	34	35	34	34	35	34	34	35	34
Count (Excludes Cholla (2,3))	32	33	32	32	33	32	32	33	32	32	33	32	32	33	32
Count (Cholla (2,3))	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2

Statistical Comparison of APS Baseload Plant Performance vs.
Preformance of Relevant Comparison Group:
Average of each Group value by Year

Group:	**B-New**
Plant Query Design:	
Unit Type	Fossil-Steam
Date Range	1975-1985
Net Dependable Capacity (MW)	250-400

	2000			2001			2002			2003			2004		
Computation of:	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd
Mean (Includes Cholla (2,3))	79.26	87.75	5.11	76.43	86.57	6.44	77.22	88.25	5.80	77.20	87.01	6.29	77.96	86.40	6.23
Mean (Excludes Cholla (2,3))	79.04	87.80	5.01	75.94	86.38	6.26	77.30	88.15	5.87	78.27	88.04	4.96	77.71	85.76	6.50
Mean (Cholla (2,3))	82.75	87.00	6.64	83.60	89.50	9.01	75.90	89.85	4.63	60.63	70.65	26.92	82.08	96.95	1.97
Median (Includes Cholla (2,3))	79.86	87.59	3.87	77.83	88.81	4.36	77.95	87.76	5.21	78.68	90.00	4.10	78.86	87.61	3.97
Median (Excludes Cholla (2,3))	79.86	87.59	3.35	76.30	88.81	4.09	78.39	87.76	5.50	78.68	90.00	3.99	78.39	87.01	4.68
Median (Cholla (2,3))	82.75	87.00	6.64	83.60	89.50	9.01	75.90	89.85	4.63	60.63	70.65	26.92	82.08	96.95	1.97
Standard Deviation (Includes Cholla (2,3))	7.87	5.61	3.89	12.14	9.17	8.33	10.06	5.74	4.40	13.66	10.75	8.77	10.24	8.49	6.94
Standard Deviation (Excludes Cholla (2,3))	7.88	5.55	3.99	12.38	9.38	8.56	10.36	5.67	4.53	12.10	8.12	4.48	10.51	8.32	7.07
Standard Deviation (Cholla (2,3))	9.57	9.19	0.17	4.03	6.08	3.92	3.06	9.12	1.34	31.42	34.58	30.89	1.60	1.91	0.54
Count (Includes Cholla (2,3))	33	34	33	31	32	31	34	35	34	33	34	33	34	35	34
Count (Excludes Cholla (2,3))	31	32	31	29	30	29	32	33	32	31	32	31	32	33	32
Count (Cholla (2,3))	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2

Statistical Comparison of APS Baseload Plant Performance vs.
Preformance of Relevant Comparison Group:
Average Group Values for 2002-2004, 1999-2004 and 1995-2004

Group:	**C-Pressurized**
Plant Query Design:	
Unit Type	Fossil-Steam
Date Range	1960-1966
Net Dependable Capacity (MW)	100-200

	2002-2004			1999-2004			1995-2004		
Computation of:	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**
Mean (Includes Four Corners (4,5))	73.57	83.43	7.84	72.53	82.35	8.68	71.76	82.41	8.57
Mean (Excludes Four Corners (4,5))	72.46	83.51	7.59	71.09	82.12	8.42	70.22	82.06	8.31
Mean (Four Corners (4,5))	82.43	82.83	9.89	83.83	84.23	10.74	83.99	85.16	10.64
Median (Includes Four Corners (4,5))	72.99	86.64	5.87	73.15	84.61	6.73	72.56	85.30	6.28
Median (Excludes Four Corners (4,5))	72.78	86.45	5.76	72.34	83.24	5.89	71.63	84.35	5.60
Median (Four Corners (4,5))	89.55	89.70	9.89	87.55	88.20	10.74	87.55	88.20	10.64
Standard Deviation (Includes Four Corners (4,5))	9.47	9.52	7.41	10.39	9.33	7.84	11.92	9.67	7.85
Standard Deviation (Excludes Four Corners (4,5))	8.23	8.92	7.50	9.50	9.19	8.14	11.29	9.62	7.97
Standard Deviation (Four Corners (4,5))	14.42	14.57	5.39	10.52	10.59	3.48	9.66	9.81	4.63
Count (Includes Four Corners (4,5))	54.00	54.00	54.00	106.00	106.00	106.00	178.00	178.00	178.00
Count (Excludes Four Corners (4,5))	48.00	48.00	48.00	94.00	94.00	94.00	158.00	158.00	158.00
Count (Four Corners (4,5))	6.00	6.00	6.00	12.00	12.00	12.00	20.00	20.00	20.00
Standard Error (Includes Four Corners (4,5))	1.30	1.31	1.02	1.01	0.91	0.76	0.90	0.73	0.59
Standard Error (Excludes Four Corners (4,5))	1.20	1.30	1.09	0.99	0.95	0.84	0.90	0.77	0.64
Standard Error (Four Corners (4,5))	6.45	6.52	2.41	3.17	3.19	1.05	2.22	2.25	1.06
Skewness (Includes Four Corners (4,5))	0.18	(1.01)	0.80	(0.18)	(0.72)	0.74	(0.20)	(0.90)	0.88
Skewness (Excludes Four Corners (4,5))	(0.12)	(0.99)	0.73	(0.39)	(0.37)	0.93	(0.37)	(0.71)	1.02
Skewness (Four Corners (4,5))	(1.48)	(1.41)	-	(1.06)	(1.13)	-	(1.11)	(0.93)	-

Statistical Comparison of APS Baseload Plant Performance vs.
Preformance of Relevant Comparison Group:
Average of each Group by Year

Group:	**C-Pressurized**
Plant Query Design:	
Unit Type	Fossil-Steam
Date Range	1960-1966
Net Dependable Capacity (MW)	100-200

	1995			1996			1997			1998			1999		
Computation of:	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**
Mean (Includes Four Corners (4,5))	69.63	84.05	7.74	67.42	79.70	8.92	72.44	84.07	8.72	72.22	82.16	9.84	73.12	83.59	8.22
Mean (Excludes Four Corners (4,5))	67.47	82.67	8.09	65.78	79.09	9.05	72.00	84.65	7.54	70.49	81.53	9.47	71.73	83.19	7.87
Mean (Four Corners (4,5))	86.99	95.06	4.94	80.48	84.55	7.85	75.93	79.45	18.21	86.06	87.19	12.82	84.23	86.79	10.98
Median (Includes Four Corners (4,5))	69.36	88.16	4.75	69.59	80.69	5.35	73.02	87.11	5.57	72.18	84.81	8.00	74.26	85.68	6.70
Median (Excludes Four Corners (4,5))	69.00	86.01	4.75	68.12	80.07	4.99	73.02	87.11	5.57	69.98	82.75	6.56	71.03	84.47	5.31
Median (Four Corners (4,5))	86.99	95.06	4.94	80.48	84.55	7.85	75.93	79.45	18.21	86.06	87.19	12.82	84.23	86.79	10.98
Standard Deviation (Includes Four Corners (4,5))	16.10	10.72	8.00	14.41	11.24	8.91	11.70	9.41	8.73	12.27	9.58	6.71	10.60	7.12	5.84
Standard Deviation (Excludes Four Corners (4,5))	15.76	10.58	8.44	14.42	11.67	9.43	11.87	8.95	6.93	11.87	10.00	7.04	10.42	7.46	6.12
Standard Deviation (Four Corners (4,5))	1.18	1.19	1.19	5.06	7.27	3.49	13.63	15.99	19.31	3.88	1.02	1.03	1.94	1.70	1.46
Count (Includes Four Corners (4,5))	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
Count (Excludes Four Corners (4,5))	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Count (Four Corners (4,5))	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2

Statistical Comparison of APS Baseload Plant Performance vs.
Preformance of Relevant Comparison Group:
Average of each Group value by Year

Group:	**C-Pressurized**
Plant Query Design:	
Unit Type	Fossil-Steam
Date Range	1960-1966
Net Dependable Capacity (MW)	100-200

	2000			2001			2002			2003			2004		
Computation of:	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**
Mean (Includes Four Corners (4,5))	72.95	81.38	7.36	67.62	78.43	11.34	73.87	84.08	6.99	74.64	84.57	7.24	72.28	81.69	9.30
Mean (Excludes Four Corners (4,5))	71.64	81.11	7.13	65.03	77.27	11.13	73.55	85.10	6.00	72.75	83.81	7.33	71.08	81.61	9.44
Mean (Four Corners (4,5))	83.40	83.55	9.18	85.80	86.52	12.79	76.50	75.90	14.97	89.76	90.63	6.45	81.90	82.38	8.25
Median (Includes Four Corners (4,5))	74.22	81.76	5.77	70.18	78.91	9.04	74.61	87.97	4.83	72.26	87.12	5.49	72.91	84.11	7.28
Median (Excludes Four Corners (4,5))	73.96	81.76	4.66	68.89	77.07	6.86	74.61	87.97	4.50	71.14	86.05	5.49	72.91	84.11	7.28
Median (Four Corners (4,5))	83.40	83.55	9.18	85.80	86.52	12.79	76.50	75.90	14.97	89.76	90.63	6.45	81.90	82.38	8.25
Standard Deviation (Includes Four Corners (4,5))	9.15	6.93	6.34	13.35	12.39	11.74	9.27	10.45	7.19	8.56	6.86	6.73	11.04	10.95	8.31
Standard Deviation (Excludes Four Corners (4,5))	8.43	6.76	6.71	12.09	12.82	12.57	7.61	9.07	6.64	6.94	6.87	7.13	10.15	10.63	8.74
Standard Deviation (Four Corners (4,5))	10.65	10.92	0.62	4.24	4.01	3.03	24.03	21.78	8.59	2.83	3.20	2.38	17.93	18.46	5.20
Count (Includes Four Corners (4,5))	18	18	18	16	16	16	18	18	18	18	18	18	18	18	18
Count (Excludes Four Corners (4,5))	16	16	16	14	14	14	16	16	16	16	16	16	16	16	16
Count (Four Corners (4,5))	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2

Statistical Comparison of APS Baseload Plant Performance vs.
Preformance of Relevant Comparison Group:
Average Group Values for 2002-2004, 1999-2004 and 1995-2004

D-Balance Draft

Group:	Fossil-Steam
Plant Query Design:	1970-1980
Unit Type	650-850
Date Range	
Net Dependable Capacity (MW)	

	2002-2004			1999-2004			1995-2004		
Computation of:	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd
Mean (Includes Navajo (1,2,3))	78.15	84.66	6.07	75.66	84.13	6.31	72.62	84.11	6.76
Mean (Excludes Navajo (1,2,3))	77.92	83.36	6.69	74.67	82.67	6.99	71.96	82.90	7.41
Mean (Navajo (1,2,3))	79.32	91.11	2.99	80.51	91.23	2.97	75.92	90.07	3.58
Median (Includes Navajo (1,2,3))	79.17	86.01	3.33	77.07	86.34	3.89	74.90	86.66	4.22
Median (Excludes Navajo (1,2,3))	78.41	83.54	4.33	75.21	84.42	4.72	74.35	86.10	4.82
Median (Navajo (1,2,3))	80.80	93.80	2.94	81.30	93.05	3.07	77.35	91.15	3.36
Standard Deviation (Includes Navajo (1,2,3))	11.40	9.87	5.89	13.68	10.29	6.39	16.79	10.64	7.37
Standard Deviation (Excludes Navajo (1,2,3))	12.30	9.89	6.28	14.60	10.40	6.81	17.95	10.87	7.90
Standard Deviation (Navajo (1,2,3))	5.20	7.11	0.93	5.92	6.00	1.13	8.53	6.93	1.70
Count (Includes Navajo (1,2,3))	54.00	54.00	54.00	106.00	106.00	106.00	178.00	178.00	178.00
Count (Excludes Navajo (1,2,3))	45.00	45.00	45.00	88.00	88.00	88.00	148.00	148.00	148.00
Count (Navajo (1,2,3))	9.00	9.00	9.00	18.00	18.00	18.00	30.00	30.00	30.00
Standard Error (Includes Navajo (1,2,3))	1.57	1.36	0.81	1.34	1.00	0.62	1.26	0.80	0.55
Standard Error (Excludes Navajo (1,2,3))	1.85	1.49	0.95	1.57	1.11	0.73	1.48	0.90	0.65
Standard Error (Navajo (1,2,3))	1.84	2.51	0.33	1.44	1.45	0.27	1.58	1.29	0.32
Skewness (Includes Navajo (1,2,3))	(0.27)	(0.41)	1.40	(0.31)	(0.64)	1.14	(0.41)	(0.72)	1.04
Skewness (Excludes Navajo (1,2,3))	(0.12)	(0.05)	1.13	(0.11)	(0.50)	1.00	(0.40)	(0.88)	0.98
Skewness (Navajo (1,2,3))	(0.85)	(1.13)	0.15	(0.40)	(0.91)	(0.26)	(0.50)	(0.47)	0.40

Statistical Comparison of APS Baseload Plant Performance vs.
Preformance of Relevant Comparison Group:
Average of each Group by Year

D-Balance Draft

Group:	
Plant Query Design:	
Unit Type	Fossil-Steam
Date Range	1970-1980
Net Dependable Capacity (MW)	650-850

	1995			1996			1997			1998			1999		
Computation of:	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd
Mean (Includes Navajo (1,2,3))	65.92	82.90	7.39	66.73	83.82	6.82	69.53	85.65	7.53	70.55	84.04	8.02	69.32	82.68	7.47
Mean (Excludes Navajo (1,2,3))	63.76	80.56	8.10	67.57	84.38	7.50	70.12	85.36	7.54	70.48	82.63	8.96	68.15	81.29	8.47
Mean (Navajo (1,2,3))	76.74	94.60	3.81	62.54	81.02	3.40	66.59	87.09	7.46	70.92	91.06	3.31	75.17	89.66	2.45
Median (Includes Navajo (1,2,3))	72.01	88.95	4.47	69.60	87.08	5.68	72.60	85.63	4.76	74.37	89.56	3.94	71.72	84.42	4.28
Median (Excludes Navajo (1,2,3))	67.79	88.18	5.18	73.20	88.17	5.77	73.79	85.54	4.56	76.09	89.12	4.37	71.04	83.78	5.56
Median (Navajo (1,2,3))	77.17	97.09	2.91	62.68	81.03	2.82	63.50	87.74	5.87	73.88	95.19	3.51	73.06	88.52	2.60
Standard Deviation (Includes Navajo (1,2,3))	21.29	14.60	11.16	18.75	8.38	5.93	18.74	7.35	7.64	21.55	13.55	10.64	20.34	9.62	7.46
Standard Deviation (Excludes Navajo (1,2,3))	22.77	14.84	12.13	20.44	8.88	6.23	20.47	7.32	8.27	23.64	14.16	11.47	22.08	9.67	7.81
Standard Deviation (Navajo (1,2,3))	3.30	4.85	2.11	5.50	5.48	2.61	5.81	8.95	4.19	6.00	8.22	1.30	6.55	6.58	0.95
Count (Includes Navajo (1,2,3))	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
Count (Excludes Navajo (1,2,3))	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Count (Navajo (1,2,3))	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3

Statistical Comparison of APS Baseload Plant Performance vs.
Preformance of Relevant Comparison Group:
Average of each Group value by Year

D-Balance Draft

Group:	Fossil-Steam
Plant Query Design:	1970-1980
Unit Type	
Date Range	
Net Dependable Capacity (MW)	650-850

	2000			2001			2002			2003			2004		
Computation of:	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**
Mean (Includes Navajo (1,2,3))	78.07	86.09	6.38	71.49	81.77	5.82	76.50	83.49	6.87	77.86	84.17	5.66	79.98	86.32	5.68
Mean (Excludes Navajo (1,2,3))	77.02	84.60	7.10	68.21	79.67	6.32	75.83	81.22	7.62	78.41	83.83	6.05	79.53	85.05	6.38
Mean (Navajo (1,2,3))	83.30	93.56	2.77	85.71	90.86	3.65	79.87	94.86	3.12	75.15	85.88	3.69	82.26	92.70	2.16
Median (Includes Navajo (1,2,3))	79.93	89.59	4.57	72.94	86.65	4.52	75.64	81.57	3.56	77.93	85.03	3.29	82.47	88.18	3.13
Median (Excludes Navajo (1,2,3))	78.55	88.39	5.01	70.71	83.25	4.75	74.48	79.27	7.51	78.41	85.51	2.34	82.39	87.22	3.14
Median (Navajo (1,2,3))	82.67	94.56	2.73	82.42	88.35	4.28	77.51	95.85	3.39	72.69	84.54	3.99	82.55	96.12	1.45
Standard Deviation (Includes Navajo (1,2,3))	10.61	9.51	5.40	12.67	13.23	7.79	11.75	10.50	5.76	10.04	8.20	5.72	12.71	11.02	6.20
Standard Deviation (Excludes Navajo (1,2,3))	11.34	9.70	5.66	11.27	13.68	8.56	12.71	9.99	6.05	10.78	8.56	6.22	13.78	11.23	6.57
Standard Deviation (Navajo (1,2,3))	2.80	3.16	0.40	8.30	6.15	2.66	4.59	2.16	0.70	5.55	7.33	0.59	5.82	8.72	1.50
Count (Includes Navajo (1,2,3))	18	18	18	16	16	16	18	18	18	18	18	18	18	18	18
Count (Excludes Navajo (1,2,3))	15	15	15	13	13	13	15	15	15	15	15	15	15	15	15
Count (Navajo (1,2,3))	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3

Statistical Comparison of APS Baseload Plant Performance vs.
Preformance of Relevant Comparison Group:
Average Group Values for 2002-2004, 1999-2004 and 1995-2004

Group:	**E-PWRs Greater than 600MW**
Plant Query Design:	
Unit Type	Nuclear
Date Range	1980-1989
Net Dependable Capacity (MW)	>600

	2002-2004			1999-2004			1995-2004		
Computation of:	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**
Mean (Includes Palo Verde)	90.57	89.64	2.82	90.16	89.26	3.27	87.60	86.91	5.29
Mean (Excludes Palo Verde)	90.80	89.95	2.73	90.20	89.40	3.34	87.41	86.84	5.57
Mean (Palo Verde)	88.44	86.56	3.68	89.84	87.94	2.68	89.49	87.53	2.66
Median (Includes Palo Verde)	91.76	90.20	1.43	91.17	90.04	1.34	89.98	88.50	2.17
Median (Excludes Palo Verde)	92.01	90.76	1.31	91.35	90.16	1.27	90.03	88.66	2.20
Median (Palo Verde)	89.13	87.40	3.67	89.555	87.65	2.53	87.90	86.20	2.34
Standard Deviation (Includes Palo Verde)	8.77	8.05	3.88	9.60	8.08	5.79	12.36	10.90	8.70
Standard Deviation (Excludes Palo Verde)	8.81	7.96	3.85	9.83	8.17	5.96	12.77	11.23	8.97
Standard Deviation (Palo Verde)	8.59	8.70	1.60	7.22	7.20	1.30	7.14	7.00	1.32
Count (Includes Palo Verde)	96.00	96.00	96.00	193.00	193.00	193.00	323.00	323.00	323.00
Count (Excludes Palo Verde)	87.00	87.00	87.00	175.00	175.00	175.00	293.00	293.00	293.00
Count (Palo Verde)	9.00	9.00	9.00	18.00	18.00	18.00	30.00	30.00	30.00
Standard Error (Includes Palo Verde)	0.90	0.83	0.40	0.69	0.58	0.42	0.69	0.61	0.48
Standard Error (Excludes Palo Verde)	0.95	0.86	0.41	0.74	0.62	0.45	0.75	0.66	0.53
Standard Error (Palo Verde)	3.04	3.08	0.57	1.75	1.75	0.32	1.33	1.30	0.25
Skewness (Includes Palo Verde)	(0.40)	(0.21)	1.07	(0.31)	(0.29)	1.00	(0.58)	(0.44)	1.08
Skewness (Excludes Palo Verde)	(0.41)	(0.30)	1.11	(0.35)	(0.28)	1.04	(0.62)	(0.49)	1.13
Skewness (Palo Verde)	(0.24)	(0.29)	0.02	0.12	0.12	0.33	0.67	0.57	0.72

Statistical Comparison of APS Baseload Plant Performance vs.
Preformance of Relevant Comparison Group:
Average of each Group by Year

E-PWRs Greater than 600MW

Group:	Nuclear
Plant Query Design:	1980-1990
Unit Type	>600
Date Range	
Net Dependable Capacity (MW)	

	1995			1996			1997			1998			1999		
Computation of:	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd
Mean (Includes Palo Verde)	80.996	81.281	6.4055	82.812	81.874	11.373	83.4988	82.9194	9.01281	87.7897	87.4764	6.5	87.7897	87.4764	6.5
Mean (Excludes Palo Verde)	80.699	81.203	6.7882	82.269	81.377	12.263	82.749	82.4283	9.6431	87.3277	87.16	6.98214	87.3277	87.16	6.98214
Mean (Palo Verde)	83.967	82.06	2.8333	88.06	86.683	2.7633	90.7467	87.6667	2.92	92.41	90.64	2	92.41	90.64	2
Median (Includes Palo Verde)	81.64	82.39	4.01	85.305	84.635	5.35	85.965	85.595	2.575	89.94	89.11	1.73	89.94	89.11	1.73
Median (Excludes Palo Verde)	80.995	81.65	4.035	84.62	85.72	6.24	85.21	85.75	2.41	89.985	89.24	1.69	89.985	89.24	1.69
Median (Palo Verde)	84.4	82.63	1.87	86.3	83.55	1.85	86.79	84.46	2.76	87.8	86.73	1.73	87.8	86.73	1.73
Standard Deviation (Includes Palo Verde)	13.878	13.669	4.01	13.939	14.166	21.133	13.9371	13.5191	13.2525	17.0329	11.7426	13.8103	17.0329	11.7426	13.8103
Standard Deviation (Excludes Palo Verde)	14.497	14.326	3.5244	14.361	14.595	22.033	14.3011	14.0061	13.925	17.6999	12.1287	14.471	17.6999	12.1287	14.471
Standard Deviation (Palo Verde)	4.4558	3.5792	2.6878	8.8719	9.496	1.8298	7.78021	7.01325	0.39509	8.00208	7.52939	0.47634	8.00208	7.52939	0.47634
Count (Includes Palo Verde)	33	33	31	32	32	32	32	32	31	33	33	31	33	33	31
Count (Excludes Palo Verde)	30	30	28	29	29	29	29	29	28	30	30	28	30	30	28
Count (Palo Verde)	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3

Statistical Comparison of APS Baseload Plant Performance vs.
Preformance of Relevant Comparison Group:
Average of each Group value by Year

E-PWRs Greater than 600MW

Group:	Nuclear
Plant Query Design:	1980-1990
Unit Type	>600
Date Range	
Net Dependable Capacity (MW)	

	2000			2001			2002			2003			2004		
Computation of:	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd	NCF	EAF	EFORd
Mean (Includes Palo Verde)	91.2534	89.8769	2.08034	89.1572	90.0169	2.58452	90.9734	89.7303	2.03786	89.5547	88.4625	3.68034	91.005	90.6856	2.74967
Mean (Excludes Palo Verde)	91.1193	89.7855	2.09308	89.2648	90.4379	2.75071	90.6197	89.4397	2.1708	89.9483	88.7607	3.81154	91.8183	91.6603	2.2137
Mean (Palo Verde)	92.55	90.76	1.97	88.1167	85.9467	1.03333	94.3933	92.54	0.93	85.75	85.58	2.54333	83.1433	81.2633	7.57333
Median (Includes Palo Verde)	90.87	89.66	0.95	93.725	92.38	1.03	91.68	90.025	1.415	91.48	90.155	1.14	91.87	92	1.745
Median (Excludes Palo Verde)	91.05	90.41	0.945	93.79	93.75	1.06	91.35	90.04	1.45	91.79	90.27	1.015	92.54	92.79	1.47
Median (Palo Verde)	90.25	88.66	2.12	87.79	86.29	0.32	92.03	89.95	0.25	87.47	85.88	2.45	84.59	82.81	8.32
Standard Deviation (Includes Palo Verde)	8.27144	7.73059	3.03155	14.4546	9.57541	6.2633	8.62887	7.79123	1.99026	9.4294	8.44795	6.90854	8.78499	8.07806	2.74333
Standard Deviation (Excludes Palo Verde)	8.49488	7.90722	3.19256	15.1608	9.89744	6.56798	8.81964	7.95148	2.03057	9.25707	8.41418	7.29509	8.54176	7.47582	2.21919
Standard Deviation (Palo Verde)	6.88445	7.04866	1.11261	4.33923	4.72437	1.43932	6.76218	6.53217	1.39083	12.4296	10.0634	0.89366	8.5127	9.05957	2.51456
Count (Includes Palo Verde)	32	32	29	32	32	31	32	32	28	32	32	29	32	32	30
Count (Excludes Palo Verde)	29	29	26	29	29	28	29	29	25	29	29	26	29	29	27
Count (Palo Verde)	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3

Statistical Comparison of APS Baseload Plant Performance vs.
Preformance of Relevant Comparison Group:
Average Group Values for 2002-2004, 1999-2004 and 1995-2004

Group:	**E-PWRs Greater than 1000MW**
Plant Query Design:	
Unit Type	Nuclear
Date Range	1980-1989
Net Dependable Capacity (MW)	>1000

	2002-2004			1999-2004			1995-2004		
Computation of:	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**
Mean (Includes Palo Verde)	90.46	89.47	3.02	90.53	89.42	2.93	87.86	86.80	5.26
Mean (Excludes Palo Verde)	90.73	89.85	2.93	90.62	89.62	2.97	87.65	86.70	5.61
Mean (Palo Verde)	88.44	86.56	3.66	89.84	87.94	2.57	89.49	87.53	2.56
Median (Includes Palo Verde)	92.27	90.38	1.51	91.55	90.03	1.27	89.98	88.52	2.17
Median (Excludes Palo Verde)	92.67	91.54	1.33	92.22	90.42	1.16	90.12	88.80	2.27
Median (Palo Verde)	89.13	87.40	3.76	89.56	87.65	2.66	87.90	86.20	2.45
Standard Deviation (Includes Palo Verde)	9.12	8.16	4.18	9.65	8.04	4.67	12.36	11.37	9.95
Standard Deviation (Excludes Palo Verde)	9.22	8.08	4.19	9.94	8.15	4.84	12.87	11.83	10.45
Standard Deviation (Palo Verde)	8.59	8.70	1.66	7.22	7.20	1.21	7.14	7.00	1.31
Count (Includes Palo Verde)	78.00	78.00	78.00	156.00	156.00	156.00	262.00	262.00	262.00
Count (Excludes Palo Verde)	69.00	69.00	69.00	138.00	138.00	138.00	232.00	232.00	232.00
Count (Palo Verde)	9.00	9.00	9.00	18.00	18.00	18.00	30.00	30.00	30.00
Standard Error (Includes Palo Verde)	1.04	0.93	0.48	0.77	0.65	0.38	0.76	0.70	0.62
Standard Error (Excludes Palo Verde)	1.12	0.98	0.51	0.85	0.70	0.41	0.85	0.78	0.69
Standard Error (Palo Verde)	3.04	3.08	0.59	1.75	1.75	0.29	1.33	1.30	0.24
Skewness (Includes Palo Verde)	(0.59)	(0.33)	1.08	(0.32)	(0.22)	1.06	(0.52)	(0.45)	0.93
Skewness (Excludes Palo Verde)	(0.63)	(0.63)	1.14	(0.48)	(0.29)	1.13	(0.58)	(0.53)	0.96
Skewness (Palo Verde)	(0.24)	(0.29)	(0.19)	0.12	0.12	(0.22)	0.67	0.57	0.25

Statistical Comparison of APS Baseload Plant Performance vs.
Preformance of Relevant Comparison Group:
Average of each Group by Year

Group:	**E-PWRs Greater than 1000MW**
Plant Query Design:	
Unit Type	Nuclear
Date Range	1980-1990
Net Dependable Capacity (MW)	>1000

	1995			1996			1997			1998			1999		
Computation of:	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**
Mean (Includes Palo Verde)	81.28	81.36	7.32	82.61	81.52	11.88	81.89	81.31	9.93	89.63	87.35	5.96	89.84	86.61	3.45
Mean (Excludes Palo Verde)	80.94	81.28	7.95	81.90	80.84	13.00	80.88	80.48	10.81	89.28	86.94	6.54	89.44	86.04	3.76
Mean (Palo Verde)	83.97	81.96	2.69	88.06	86.79	2.94	89.64	87.67	2.88	92.41	90.64	1.65	92.98	86.04	1.32
Median (Includes Palo Verde)	82.36	82.63	4.06	85.31	84.64	4.87	84.68	84.25	2.63	90.03	89.11	2.55	89.58	87.31	1.17
Median (Excludes Palo Verde)	82.00	83.19	4.40	84.62	85.72	6.08	83.84	84.03	2.52	90.76	89.24	2.74	89.54	87.40	1.12
Median (Palo Verde)	84.40	82.63	1.68	86.30	83.55	2.39	86.79	84.46	2.76	87.80	86.73	1.72	89.98	87.40	1.32
Standard Deviation (Includes Palo Verde)	14.81	14.75	13.37	14.68	15.02	22.86	14.55	14.07	22.83	13.80	12.57	12.40	5.81	6.76	5.29
Standard Deviation (Excludes Palo Verde)	15.66	15.64	14.15	15.27	15.63	24.06	15.08	14.64	24.12	14.44	13.12	13.14	5.76	6.69	5.60
Standard Deviation (Palo Verde)	4.46	3.73	2.68	8.87	9.37	1.72	6.35	7.01	0.44	8.00	7.53	0.94	6.37	6.69	0.23
Count (Includes Palo Verde)	27	27	25	26	26	27	26	26	27	27	27	25	26	26	24
Count (Excludes Palo Verde)	24	24	22	23	23	24	23	23	24	24	24	22	23	23	21
Count (Palo Verde)	3	3	3	3	3	3	3	3	3	3	3	3	3	23	3

Statistical Comparison of APS Baseload Plant Performance vs.
Preformance of Relevant Comparison Group:
Average of each Group value by Year

Group:	**E-PWRs Greater than 1000MW**
Plant Query Design:	
Unit Type	Nuclear
Date Range	1980-1990
Net Dependable Capacity (MW)	>1000

	2000			2001			2002			2003			2004		
Computation of:	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**	**NCF**	**EAF**	**EFORd**
Mean (Includes Palo Verde)	91.29	89.77	2.23	90.69	91.72	2.82	91.42	90.09	2.15	89.45	88.27	3.92	90.48	90.05	2.99
Mean (Excludes Palo Verde)	91.12	89.64	2.27	91.03	92.47	3.04	91.04	89.76	2.31	89.71	88.63	4.14	91.43	91.17	2.33
Mean (Palo Verde)	92.55	90.78	1.95	88.12	85.95	1.16	94.39	92.60	1.02	87.42	85.50	2.39	83.14	81.46	7.57
Median (Includes Palo Verde)	90.63	88.80	1.08	93.87	93.91	0.85	92.02	90.09	1.45	92.97	89.95	1.16	91.69	92.00	1.92
Median (Excludes Palo Verde)	90.69	88.91	0.98	94.12	94.66	0.84	92.03	90.04	1.49	93.26	90.68	1.04	93.69	92.79	1.47
Median (Palo Verde)	90.25	88.66	2.12	87.79	86.29	1.20	92.01	90.13	0.52	87.47	91.44	2.45	84.59	82.81	8.32
Standard Deviation (Includes Palo Verde)	8.11	7.71	3.25	14.89	8.85	6.96	8.00	7.10	2.08	10.06	8.97	7.52	9.52	8.60	2.95
Standard Deviation (Excludes Palo Verde)	8.38	7.92	3.46	15.79	9.05	7.41	8.20	7.24	2.13	10.27	9.00	8.03	9.38	8.05	2.40
Standard Deviation (Palo Verde)	6.88	7.09	1.14	4.34	4.72	0.94	6.77	6.50	1.33	9.84	8.32	1.13	8.51	9.32	2.51
Count (Includes Palo Verde)	26	26	24	26	26	25	26	26	25	26	26	24	26	26	24
Count (Excludes Palo Verde)	23	23	21	23	23	22	23	23	22	23	23	21	23	23	21
Count (Palo Verde)	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3

Comparison of APS Weighted Baseload Generation (Combined NCF and EAF) vs. Relevant Comparison Groups for the Period 1995-2004

Categories for Comparison are:	Group	Comparison Group Age	Comparison Group Size (MW)	Total APS MWs Owned	Performance Metric Used	1995-2004 Group Performance	1995-2004 APS Performance	APS 1995-2004 Vs Group 1995-2004 Average Yearly MHWs	Formula
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Steam Mid - Coal	A-Old	1963	200	670	EAF	85.39	87.09	99,499	
Steam Mid - Coal	B-New	1980	260	520	EAF	87.40	89.15	79,709	
Steam Large - Coal	C-Pressurized	1973	750	226	EAF	82.06	85.16	61,316	
Steam Large - Coal	D-Balance Draft	1973	750	315	EAF	82.90	90.07	197,746	
								438,270	(b)
Nuclear	E-PWRs	1986	>600	1,108	NCF (3)	87.41	89.49	201,635	(a)

Variable Nuclear Production Costs	5.37 Per MWH					
Variable Coal Production Costs	16.80 Per MWH					
Purchase Power Minus Nuclear Prod Costs:	45.54 Per MWh (1)	(c)	**Calc Benefit / (Burden) 2005 Dollars Annual**	$	**9,182,472**	**e = (a) * (c)**
Purchase Power Minus Coal Prod Costs:	34.11 Per MWh (2)	(d)	**Calc Benefit / (Burden) 2005 Dollars Annual**	$	**14,949,443**	**f = (b) * (d)**
(1) Arizona Public Service Co. 2005 Purchased Power Contracts Weighted Average $/MWh: - Minus Nuclear $/MWh			**Total Nuclear Calc Benefit / (Burden) x 10yrs.**	$	**91,824,720**	**= e * 10**
(2) Arizona Public Service Co. 2005 Purchased Power Contracts Weighted Average $/MWh: - Minus Coal $/MWh			**Total Coal Calc Benefit / (Burden) x 10yrs.**	$	**149,494,434**	**= f * 10**

(3) 87.41% Capacity Factor is based upon the Average NCF of all PWR Greater than 600 MW

Comparison of APS Weighted Baseload Generation NCF only vs. Relevant Comparison Groups for the Period 1995-2004

Categories for Comparison are:	Group	Comparison Group Age	Comparison Group Size (MW)	Total APS MWs Owned	Performance Metric Used	1995-2004 Group Performance	1995-2004 APS Performance	APS 1995-2004 Vs Group 1995-2004 Average Yearly MHWs	Formula
		(1)	(2)	(3)	(4)	(5)	(6) 7	(7)	(8)
Steam Mid - Coal	A-Old	1963	200	670	NCF	64.78	78.82	823,997	
Steam Mid - Coal	B-New	1980	260	520	NCF	75.30	74.60	(31,770)	
Steam Large - Coal	C-Pressurized	1973	750	226	NCF	70.22	83.99	272,686	
Steam Large - Coal	D-Balance Draft	1973	750	315	NCF	71.96	75.92	109,365	
								1,174,278	(b)
Nuclear	E-PWRs	1986	>600	1,108	NCF (3)	87.41	89.49	201,635	(a)

Variable Nuclear Production Costs	5.37 Per MWH					
Variable Coal Production Costs	16.80 Per MWH					
Purchase Power Minus Nuclear Prod Costs:	45.54 Per MWh (1)	(c)	Calc Benefit / (Burden) 2005 Dollars	$	9,182,472	e = (a) * (c)
Purchase Power Minus Coal Prod Costs:	34.11 Per MWh (2)	(d)	Calc Benefit / (Burden) 2005 Dollars	$	40,054,752	f = (b) * (d)
(1) Arizona Public Service Co. 2005 Purchased Power Contracts Weighted Average $/MWh: - Minus Nuclear $/MWh			Total Nuclear Calc Benefit / (Burden) x 10yrs.	$	91,824,720	= e * 10
(2) Arizona Public Service Co. 2005 Purchased Power Contracts Weighted Average $/MWh: - Minus Coal $/MWh			Total Coal Calc Benefit / (Burden) x 10yrs.	$	400,547,519	= f * 10

(3) 87.41% Capacity Factor is based upon the Average NCF of all PWR Greater than 600 MW

Comparison of APS Weighted Baseload Coal Generation EAF vs. Relevant Comparison Groups for the Periods 2002-2004 and 2005 Only

Categories for Comparison are:

	Group	Comparison Group Age (1)	Comparison Group Size (MW) (2)	Total APS MWs Owned (3)	Performance Metric Used (4)	2002-2004 Group Performance (5)	2002-2004 APS Performance (6)	2002-2004 Group Performance (7)	2005 Only APS Performance (8)	APS 2002-2004 Vs Coal 2002-2004 Average Yearly MHW's (9)	APS Coal 2005 Only Benefit With Jacobs' Nuclear Disallowance (10)	Formula (11)
Steam Mid - Coal	A - Small Old	1963	168	670	EAF	85.36	88.09	85.36	92.28	160,533	406,061	
Steam Mid - Coal	B- Small New	1979	260	520	EAF	87.31	85.82	87.31	90.60	(68,006)	149,885	
Steam Large - Coal	C- Large Pressurized	1970	750	226	EAF	83.51	82.83	83.51	86.35	(13,326)	56,295	
Steam Large - Coal	D - LG Balance Draft	1975	750	315	EAF	83.36	91.11	83.36	88.53	213,774	142,643	
										292,975	754,884	(a)

Variable Coal Production Costs	$ 16.80	Per MWH	
Weighted Purchased Power Costs	$ 50.91	Per MWH	
Purchased Power Minus Coal Prod Costs	$ 34.11	*Per MWH	(b)

* Arizona Public Service Co. 2005 Purchased Power Contracts Weighted Average $/MWh: - Minus Coal $/MWh

Jacobs' Nuclear Disallowance		$ (17,373,000)	
Calc Benefit / (Burden) 2005 Dollars	$ 9,993,367	$ 25,749,082	c = (a) * (b)
Total Calc Benefit / (Burden)	$ 9,993,367	$ 8,376,082	
Total Calc Benefit / (Burden) x 3 yrs.	$ 29,980,102		= c * 3 yrs.

Comparison of APS Weighted Baseload Coal Generation NCF vs. Relevant Comparison Groups for the Periods 2002-2004 and 2005 Only

Categories for Comparison are:

	Group	Comparison Group Age (1)	Comparison Group Size (MW) (2)	Total APS MWs Owned (3)	Performance Metric Used (4)	2002-2004 Group Performance (5)	2002-2004 APS Performance (6)	2002-2004 Group Performance (7)	2005 Only APS Performance (8)	APS 2002-2004 Vs Coal 2002-2004 Average Yearly MHW's (9)	APS Coal 2005 Only Benefit With Jacobs' Nuclear Disallowance (10)	Formula (11)
Steam Mid - Coal	A - Small Old	1963	168	670	NCF	68.56	85.17	68.56	90.95	975,041	1,314,021	
Steam Mid - Coal	B- Small New	1979	260	520	NCF	77.82	73.00	77.82	84.10	(219,324)	286,099	
Steam Large - Coal	C- Large Pressurized	1970	750	226	NCF	72.46	82.42	72.46	85.95	197,308	267,123	
Steam Large - Coal	D - LG Balance Draft	1975	750	315	NCF	77.92	79.32	77.92	84.20	38,613	173,284	
										991,639	2,040,528	(a)

Variable Coal Production Costs	$ 16.80	Per MWH	
Weighted Purchased Power Costs	$ 50.91	Per MWH	
Purchased Power Minus Coal Prod Costs	$ 34.11	*Per MWH	(b)

Jacobs' Nuclear Disallowance		$ (17,373,000)	
Calc Benefit / (Burden) 2005 Dollars	$ 33,824,808	$ 69,602,401	c = (a) * (b)
Total Calc Benefit / (Burden)	$ 33,824,808	$ 52,229,401	
Total Calc Benefit / (Burden) x 3 yrs.	$ 101,474,425		= c * 3 yrs.

* Arizona Public Service Co. 2005 Purchased Power Contracts Weighted Average $/MWh: - Minus Coal $/MWh

Comparison of APS Weighted Baseload Coal Generation (EAF) 2005 Only vs. Relevant Comparison Groups for the Period 1999-2004

Categories for Comparison are:	Group	Comparison Group Age	Comparison Group Size (MW)	Total APS MWs Owned	Performance Metric Used	1999-2004 Group Performance	2005 Only APS Performance	APS Coal Benefit With Jacobs' Nuclear Disallowance	Formula
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Steam Mid - Coal	A - Small Old	1963	168	670	EAF	85.13	92.28	419,094	
Steam Mid - Coal	B- Small New	1979	260	520	EAF	87.50	90.60	141,379	
Steam Large - Coal	C- Large Pressurized	1970	750	226	EAF	82.12	86.35	83,837	
Steam Large - Coal	D - LG Balance Draft	1975	750	315	EAF	82.67	88.53	161,661	
								805,970	(a)

Variable Coal Production Costs	$ 16.80 Per MWH		
Weighted Purchased Power Costs	$ 50.91 Per MWH	**Jacobs' Nuclear Disallowance**	**$ (17,373,000)** (d)
Purchased Power Minus Coal Prod Costs:	$ 34.11 *Per MWH (b)	**Calc Benefit / (Burden) 2005 Dollars**	**$ 27,491,653** c = a * b
		Total Calc Benefit / (Burden)	**$ 10,118,653** = (d) - c
		Total Calc Benefit / (Burden) x 6 yrs.	**$ 164,949,916** = c * 6 yrs.

* Arizona Public Service Co. 2005 Purchased Power Contracts Weighted Average $/MWh: - Minus Coal $/MWh

REJOINDER TESTIMONY OF GEORGE L. FITZPATRICK

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816
Docket No. E-01345A-05-0826
Docket No. E-01345A-05-0827

November 3, 2006

EXHIBIT
APS 92
Admitted

REJOINDER TESTIMONY OF GEORGE L. FITZPATRICK
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)
(Docket No. E-01345A-05-0826)
(Docket No. E-01345A-05-0827)

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. George L. Fitzpatrick, 898 Veterans Highway, Suite 430, Hauppauge, New York 11788.

Q. HAVE YOU PREVIOUSLY FILED REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed Rebuttal Testimony on September 15, 2006 on behalf of the Arizona Public Service Company ("APS" or "Company").

Q. WHAT IS THE PURPOSE OF THIS REJOINDER TESTIMONY?

A. The purpose of my Rejoinder Testimony is to respond to William R. Jacobs, Jr.'s Surrebuttal Testimony in this docket on behalf of the Utilities Division of the Arizona Corporation Commission.

Q. HAVE YOU REVIEWED PAGES 34-39 OF DR. JACOBS' SURREBUTTAL TESTIMONY REGARDING A NUCLEAR PERFORMANCE STANDARD?

A. Yes.

Q. DO YOU AGREE WITH DR. JACOBS' ARGUMENTS REGARDING A NUCLEAR PERFORMANCE STANDARD?

A. No. As I testified in my September 15, 2006 Rebuttal Testimony, I do not believe a performance standard should be imposed at Palo Verde. Nonetheless, if the Commission decides to institute a performance standard, I believe it must be much different than the standard proposed by Dr. Jacobs. Dr. Jacobs' Surrebuttal Testimony does not convince me otherwise, and contains a number of major flaws.

These flaws include his discussion of the Georgia Power Company's rate case, his conclusion that coal baseload generation should not be included in a performance standard, and his discussion of the uniqueness of Palo Verde.

Q. PLEASE DISCUSS THE FLAWS WITH DR. JACOBS' DISCUSSION OF THE GEORGIA POWER RATE CASE.

A. It is important to set the record straight concerning Dr. Jacobs' use of and reference to performance standard-related information from a recent Georgia Power Company (GPC) rate case as support for his contention that a penalty-only, not a symmetrical (i.e., reward and penalty), Nuclear Performance Standard will cause APS to achieve better Palo Verde performance. In his Surrebuttal Testimony, on page 35, lines 18-21, Dr. Jacobs states: "I asked Georgia Power what actions they had taken for improved performance that would not have been taken absent the incentive provided by the program. The answer was one word – 'none.'" (Emphasis added).

However, as the record in that case clearly shows, GPC was asked the following question, presumably by Dr. Jacobs, in Staff Data Request No. STF-GDS-1-42:

> Question: Please describe in detail any activities or programs conducted because of the existence of the Nuclear Performance Standard that would not have been conducted if the Nuclear Performance Standard did not exist.

GPC's response to this question was "None." There is nothing in this question that specifically asks about only the incentive or the penalty side of the standard. Thus, Dr. Jacobs has wrongly characterized this question as pertaining to "incentives only." GPC stated that neither a reward nor a penalty performance standard had any effect on the way they managed their nuclear plants. Rather, the economics of nuclear power and the overriding focus on safety are sufficient key motivators for any nuclear plant management.

Q. WHAT DID DR. JACOBS RECOMMEND TO THE GEORGIA COMMISSION CONCERNING A NUCLEAR PERFORMANCE STANDARD?

A. In the GPC rate case that Dr. Jacobs references, he testified that a Nuclear Performance Standard that was then in place for Georgia Power's Plant Vogtle and Plant Hatch should be terminated. He stated that: "The Nuclear Performance Standard should be terminated because it does not have any effect on the operation of the Company's nuclear plants." (Jacobs Direct Testimony, Docket No.18300-U, page 4). Dr. Jacobs did not recommend removing only the incentive portion of the performance standard, but recommended termination of the entire performance standard. Ultimately, the Georgia Public Service Commission agreed with Dr. Jacobs' recommendation regarding the Nuclear Performance Standard, and issued a December 21, 2004 Order in that docket approving a Stipulation that terminated the Nuclear Performance Standard. (Order, Docket No. 18300-U, page 7). Clearly, the position taken by Dr. Jacobs in the GPC case -- that the Nuclear Performance Standard should be terminated in its entirety -- is at odds with his position in this case that this Commission should adopt an asymmetrical "penalty-only" type of plan.

Q. PLEASE DISCUSS YOUR DISAGREEMENT WITH DR. JACOBS REGARDING THE INCLUSION OF COAL BASELOAD GENERATION IN ANY PERFORMANCE STANDARD.

A. I reiterate my conclusion on page 16 of my Rebuttal Testimony that APS Base Load Coal Units "should be included if a performance standard is adopted because they have a significant bearing on the ultimate cost of power to APS customers." Dr. Jacobs' arguments against the inclusion of baseload coal plants in a performance standard are the same arguments that would apply to the imposition of any Nuclear Performance Standard in the first place. On page 36, lines 5-13, Dr.

Jacobs attempts to develop reasons why APS' coal plants should not be included in a performance standard. Each of his arguments is addressed below.

First, Dr. Jacobs states: "Nuclear and coal-fired generation are fundamentally different." He points out that nuclear plants have higher capital costs but lower production costs than coal plants. That distinction does not support excluding coal plants from any standard this Commission might adopt. The fact remains that both plants serve the same baseload function, generate great value for customers, and are very important to any evaluation of APS' performance. These units should be included if a performance standard is adopted because they have a significant bearing on the ultimate cost of power to APS customers. As stated in my earlier Rebuttal Testimony, Palo Verde accounts for only 39% of APS baseload capacity and, thus, should not be the sole focus of a generation performance standard. APS coal units do enjoy a significant $/MWH economic advantage over purchased power and contribute significant benefit to APS customers.

Second, Dr. Jacobs states: "The issues and regulations affecting the operation of these plants are also very different." This statement in fact is a good argument why, because of the extensive regulatory scrutiny surrounding nuclear generation, nuclear plants should be *excluded* from any performance standard. Instead, Dr. Jacobs cites this element as a reason to exclude coal plants from a performance standard.

Third, Dr. Jacobs further states: "My proposed NPS offers a method to share the risk of nuclear operation between ratepayers and the Company." Further in that same answer, Dr. Jacobs concludes that "the Company is rewarded by means of its opportunity to earn a rate of return on rate base and does not need additional incentive." These statements contradict each other. The first statement discusses a

sharing of the risk between APS and the ratepayers, while the second statement does not allow for any sharing.

Finally, Dr. Jacobs' most telling statement is: "A company wide performance plan for all baseload plants would be vastly different and is beyond the scope of my testimony." My Rebuttal Testimony addressed this issue and provides detail on how such plants could be included. Dr. Jacobs has had a chance to critique my testimony on coal unit performance measurement and chose not to do so. Dr. Jacobs has passed on the issue of coal plant inclusion by his above statement and does not provide credible reasons why such plants cannot and should not be included if this Commission decides to impose a performance standard. My Rebuttal Testimony on this matter has provided a methodological template for the inclusion of baseload coal plants in a performance standard, and is consistent with the recognition by this Commission in its Decision No. 55118 (page 20), that it is appropriate to consider both a utility's "successes" and "failures" in order to perform "a realistic analysis of operating performance."

Q. PLEASE ADDRESS DR. JACOBS' DISCUSSION ON PAGES 36-37 OF HIS SURREBUTTAL TESTIMONY ABOUT THE UNIQUENESS OF PALO VERDE.

A. Dr. Jacobs takes issue with my statement in my Rebuttal Testimony that Palo Verde is a one-of-a-kind plant, but then goes on to state that "all nuclear plants are unique." He continues by stating that "[e]ven sister plants are not exactly the same." Such statements in fact demonstrate why any Nuclear Performance Standard, because it can be so difficult to properly develop, is ill-advised. At a minimum, these statements by Dr. Jacobs lend support to my recommendation for the imposition of a symmetrical deadband if the Commission decides to impose a performance standard. In my years of modeling PWR capacity factors, my models have, at best, only been able to explain about 64% of the year to year variation in

PWR capacity factors. Thus, 36% of the remaining yearly variation appears to occur due to factors that are random across all plants. Although using a three year average for both the target plant and the comparison group helps dampen some of this unexplained variation, a statistically derived deadband would be an important feature of any performance standard to be considered.

Q. PLEASE SUMMARIZE THE CONCLUSIONS OF YOUR REJOINDER TESTIMONY.

A. A Nuclear Performance Standard has not been proven necessary at Palo Verde, nor has Dr. Jacobs proposed a complete, workable, or fair plan. Nonetheless, if any performance standard is adopted, my earlier Rebuttal Testimony provides a number of characteristics, most importantly the inclusion of baseload coal plants, a reasonable deadband, and symmetrical rewards and penalties, which should be considered and included in any performance standard. Dr. Jacobs' Surrebuttal Testimony does not change any of these characteristics. In fact, Dr. Jacobs' earlier testimony before the Georgia Public Service Commission, which he raises in his recent Surrebuttal Testimony, supports not having a Nuclear Performance Standard, because, as he argued to that Commission, a performance standard does not change the way that a nuclear plant is operated by a utility. As Dr. Mattson pointed out in his Rebuttal Testimony, the NRC has expressed its concern on several occasions that a Nuclear Performance Standard could negatively impact safety. However, even assuming that Dr. Jacobs is correct, and that a performance standard does not affect the way that a plant is operated, this supports my conclusion that a performance standard should not be imposed on APS.

Q. DOES THIS CONCLUDE YOUR REJOINDER TESTIMONY?

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

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COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
BARRY WONG

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744	Docket No. E-01345A-05-0816 **NOTICE OF ERRATA**
IN THE MATTER OF THE INQUIRY INTO THE FREQUENCY OF UNPLANNED OUTAGES DURING 2005 AT PALO VERDE NUCLEAR GENERATING STATION, THE CAUSES OF THE OUTAGES, THE PROCUREMENT OF REPLACEMENT POWER AND THE IMPACT OF THE OUTAGES ON ARIZONA PUBLIC SERVICE COMPANY'S CUSTOMERS	Docket No. E-01345A-05-0826
IN THE MATTER OF THE AUDIT OF THE FUEL AND PURCHASED POWER PRACTICES AND COSTS OF THE ARIZONA PUBLIC SERVICE COMPANY	Docket No. E-01345A-05-0827

Arizona Public Service Company hereby files its Notice of Errata to Rebuttal Testimony filed on September 15, 2006, by James Levine, attached hereto as Exhibit A, Peter Ewen, attached hereto as Exhibit B, and George Fitzpatrick, attached hereto as Exhibit C and Rejoinder Testimony filed on October 4, 2006, by George Fitzpatrick, attached hereto as Exhibit D.

EXHIBIT
APS 93
Admitted

RESPECTFULLY SUBMITTED this 5th day of December, 2006.

ARIZONA PUBLIC SERVICE COMPANY

By: _____
Thomas Mumaw
Karilee Ramaley
Pinnacle West Capital Corp.
400 East Van Buren
Phoenix, AZ 85004-2202

Original and 13 copies filed with Docket Control and copies mailed December 5, 2006, to:

Donna Bronski
Deputy City Attorney
3939 Drinkwater Blvd.
Scottsdale, AZ 85251

S. David Childers
AZ Competitive Power Alliance
Low & Childers, PC
2999 North 44th St., Suite 250
Phoenix AZ 85018

C. Webb Crockett
AECC & Phelps Dodge Mining
3003 N. Central Ave., Ste 2600
Phoenix, AZ 85012-2913

Michael M. Grant
Arizona Utility Investors Assoc,
c/o Gallagher & Kennedy, P.A.
2575 East Camelback Road
Phoenix, AZ 85016

Timothy Hogan
SWEEP & WRA
202 E. McDowell Rd., Ste 153
Phoenix, AZ 85004

Jay I. Moyes
AZAG Group
c/o Moyes Storey Ltd.
1850 N. Central Ave., Ste 1100
Phoenix, AZ 85004

Bill Murphy
DEAA
5401 N. 25 St.
Phoenix, AZ 85016

Greg Patterson
AZ Competitive Power Alliance
916 W. Adams, Suite 3
Phoenix, AZ 85007

Lawrence Robertson, Jr.
Southwest Power Group II
c/o Munger Chadwick
PO Box 1448
Tubac, AZ 85646

Sean Seitz, President
AZ Solar Energy Industries Assoc.
3008 N. Civic Center Plaza
Scottsdale AZ 85251

Tracy Spoon
Sun City Taxpayers Association
12630 N. 103rd Ave., Suite 144
Sun City, AZ 85351-3476

Scott Wakefield
Chief Counsel, RUCO
1110 W. Washington St, Suite 220
Phoenix, AZ 85007

LTC Karen White
Chief. Air Force Utility Litig. Team
Federal Executive Agencies
139 Barnes Drive
Tyndall AFB, Florida 32403

Dan Austin
Comverge, Inc.
6509 W. Frye Road, Ste 4
Chandler, AZ 85226

David Berry
Western Resource Advocates
PO Box 1064
Scottsdale AZ 85252-1064

Andrew W. Bettwy
Southwest Gas Corporation
5241 Spring Mountain Road
Las Vegas, NV 89150

George Bien-Willner
3641 N. 39th Ave.
Phoenix, AZ 85034

Douglas Fant
3655 W. Anthem Way
Suite A-109, PMB 411
Anthem, AZ 85086

Robert Geake
Arizona Water Company
PO Box 29006
Phoenix, AZ 85038-9006

Eric Guidry
Western Resource Advocates
2260 Baseline Road, Suite 200
Boulder, CO 80302

Michael Kurtz
The Kroger Company
c/o Boehm Kurtz & Lowry
36 E. Seventh St, Suite 1510
Cincinnati, OH 45202

Michelle Livengood
Unisource Energy Services
One South Church St., Ste. 200
Tucson, AZ 85702

Walter Meek
Arizona Utility Investors Association
2100 N. Central Ave., Suite 210
Phoenix, AZ 85067

Amanda Ormond
InterWest Energy Alliance
7650 West McClintock, Suite 103-282
Tempe, AZ 85284

Michael Patten
Roshka DeWulf & Patten, PLC
One Arizona Center
400 E. Van Buren St., Suite 800
Phoenix, AZ 85004-3906

Jeff Schlegel
SWEEP Arizona
1167 W. Samalayuca Drive
Tucson, AZ 85704-3224

Kenneth R. Saline
K.R. Saline & Associates PLC
160 North Pasadena, Ste. 101
Mesa, AZ 85201

Tammie Woody
10825 W. Laurie Lane
Peoria, AZ 85345

David Kennedy
Arizona Interfaith Coalition on Energy
818 E. Osborn Road, Ste. 103
Phoenix AZ 85014

Joseph Knauer
Jewish Community of Sedona
PO Box 10242
Sedona, AZ 86339

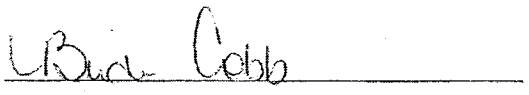

EXHIBIT A

APS 2005 RATE CASE
Docket Nos. E-01345A-05-0816; E-01345A-05-0826; E-01345A-05-0827
11111.0964

CORRECTION AND/OR CHANGE SHEET TO REBUTTAL TESTIMONY FILED ON SEPTEMBER 15, 2006 BY JAMES LEVINE

Page	Line	Correction/Change	
		From	To
18	26	("RCPs") 1A and 2A had **decreased** to the point that Palo Verde in all likelihood	(RCPs") 1A and 2A had **increased** to the point that Palo Verde in all likelihood

EXHIBIT B

APS 2005 RATE CASE
Docket Nos. E-01345A-05-0816; E-01345A-05-0826; E-01345A-05-0827
11111.0964

CORRECTION AND/OR CHANGE SHEET TO REBUTTAL TESTIMONY FILED ON SEPTEMBER 15, 2006 BY PETER EWEN

Page	Line	Correction/Change	
		From	To
22	2	"outages that would have occurred prior to Unit 2's **scheduled refueling** outage"	"outages that would have occurred prior to Unit 2's **next** outage"

EXHIBIT C

APS 2005 RATE CASE
Docket Nos. E-01345A-05-0816; E-01345A-05-0826; E-01345A-05-0827
11111.0964

CORRECTION AND/OR CHANGE SHEET TO REBUTTAL TESTIMONY FILED ON SEPTEMBER 15, 2006 BY GEORGE FITZPATRICK

Page	Line	Correction/Change	
		From	To
5	22	"nuclear plant in the U.S., regardless of type (i.e., PWR or BWR)."	"nuclear plant in the U.S., regardless of type (i.e., PWR or BWR), **with individual units greater than 1000 megawatts in size.**"

Docket Nos. E-01345A-05-0816; E-01345A-05-0826; E-01345A-05-0827
11111.0964

CORRECTION AND/OR CHANGE SHEET TO REJOINDER TESTIMONY FILED ON NOVEMBER 3, 2006 BY GEORGE FITZPATRICK

Page	Line	Correction/Change	
		From	To
6	14	"Testimony does not **change** any of these characteristics. …"	"Testimony does not **challenge** any of these characteristics. …"

REBUTTAL TESTIMONY OF JAMES LEVINE

On Behalf of Arizona Public Service Company

DOCKET NO. E-01345A-05-0816

September 15, 2006

EXHIBIT
APS 94
Admitted

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REBUTTAL TESTIMONY OF JAMES LEVINE
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)

I. BACKGROUND

Q. PLEASE STATE YOUR NAME AND POSITION WITH APS.

A. My name is Jim Levine. I am the Executive Vice President Generation for Arizona Public Service Company ("APS" or "Company"). In this capacity, I have overall responsibility for the safe and reliable operations of the Company's fleet of generating units.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND AND EXPERIENCE?

A. I received a Bachelor of Science degree in Mechanical Engineering from Tri-State University in Angola, Indiana, in 1972. From 1972 to 1975, I worked as a field engineer for Westinghouse Electric Corporation in their Power Generation Service Division. From 1975 to 1981, I worked as a supervisor in the Operations, Engineering, and Maintenance departments for the Connecticut Yankee Atomic Power Company at the Connecticut Yankee Atomic Power Station. From 1981 to 1989, I worked in various positions of increasing responsibility at the Arkansas Power and Light Company's Arkansas Nuclear One (ANO) nuclear power plant. In my last position at Entergy, I was the Executive Director, Nuclear Support.

In September 1989, I joined APS as the Vice President of Nuclear Production for the Palo Verde Nuclear Generating Station ("Palo Verde"). In this role I was responsible for the day-to-day operations of Palo Verde. In September 1996, I

was named the Senior Vice President Nuclear for APS. In this role, I was responsible for all nuclear-related activities associated with the operation of Palo Verde. In 1999, I was named to my current position of Executive Vice President Generation for APS.

With regard to my industry experience, I served as a member of the Advisory Council of the National Academy and the Institute of Nuclear Power Operations' ("INPO") Industry Review Group for Evaluation and Assessment. This group advises and oversees the nuclear industry's comprehensive program of independent, performance evaluations and assessments to high standards of safety and reliability. I currently serve as Chairman of INPO's National Nuclear Accrediting Board, which formally verifies and accredits or rejects the operations, maintenance and technical training programs for key positions at each member's nuclear utility. I am also a member of the Nuclear Energy Institute's ("NEI") Nuclear Strategic Issues Advisory Committee. I serve as Chairman of NEI's Risk Informed Regulatory Working Group and I am a member of the Materials Executive Oversight Group. In May 1999, I was appointed by Governor Hull to the Arizona Radiation Regulatory Hearing Board, and I serve in that capacity today.

Q. ARE THERE OTHER WITNESSES TESTIFYING ON BEHALF OF APS IN REBUTTAL TO THE GDS REPORT?

A. Yes. Steven Wheeler, Executive Vice President, Customer Service & Regulation, will address the issue of GDS' recommendation regarding a nuclear performance standard, as well as other policy issues. Robert Denton, the former President and Chief Executive Officer of Constellation Nuclear, which owned

and operated the Calvert Cliffs and Nine Mile Point nuclear plants will testify on the prudence of certain outages and contracting practices in the utility industry. Roger Mattson, a former senior official at the Nuclear Regulatory Commission ("NRC"), will testify regarding the differences between NRC regulatory practices and the prudence standard applicable to this proceeding, the NRC's views regarding nuclear performance standards, and the prudence of the outages at Units 2 and 3 in October 2005 due to a question posed by the NRC. George Fitzpatrick, the chief executive of Harbourfront Group, Inc., with over 30 years experience in performing statistical analyses for electric and gas utilities, will testify regarding GDS' recommendation that the Commission adopt a nuclear performance standard, as well as the appropriateness of GDS' disallowance recommendation in light of both Palo Verde's past performance and the performance of APS' other baseload plants. Finally, Peter Ewen, APS' Manager of the Revenue and Fuel Analysis and Forecasts Department, will testify regarding the appropriateness of a number of the disallowance calculations contained in GDS' report, the appropriateness of GDS' recommendation that certain costs should not be considered in establishing base fuel costs in the pending rate case, and the performance of APS' baseload coal plants versus the normalized amounts included in the Company's base rates.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. On February 2, 2006, APS filed with the Commission an application for approval of a Power Supply Adjuster ("PSA") surcharge. APS' application is being adjudicated before the Commission in Docket No. E-01345A-06-0063. APS is seeking recovery of replacement power costs that were incurred as a

result of various short notice outages and forced outages at Palo Verde. The actual recovery of these costs would be through the Power Supply Adjustment mechanism.

My testimony addresses APS' operation of Palo Verde and responds to certain conclusions and recommendations set forth in the report of the Staff's consultant, GDS Associates, Inc. ("GDS") and in the testimony of GDS' Vice President, William R. Jacobs, Jr.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Not in a formal proceeding, but I have appeared before the Commission on several occasions to discuss Palo Verde related issues.

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony will demonstrate the following:

- Safe operation of the Palo Verde units is our overriding priority and Palo Verde has operated safely.
- Over the last 10 years, Palo Verde has performed well in comparison to other nuclear plants.
- The Integrated Performance Improvement Program that APS is currently implementing at Palo Verde is an aggressive effort to return Palo Verde performance to the level of excellence it achieved during the last decade.
- GDS' recommendation to disallow $15.344 million in replacement power costs in connection with the forced outage of Units 2 and 3 in October

2005 is not appropriate. As NRC Regional Administrator, Bruce Mallet told the Commission during his appearance on January 25, 2006, this outage (1) was caused by a new question that the NRC asked; (2) Palo Verde personnel took the correct action in taking the units out of service when the question could not be immediately answered; and (3) it was not an issue that Palo Verde should have reasonably addressed before the NRC raised it. Moreover, the original design was determined to be adequate and the units returned to service nine days later without any change to the equipment. Finally, Palo Verde performed equipment maintenance during the outage that would otherwise have caused a unit to be taken out of service, and thereby avoided between $4.4 million and $7.0 million in future replacement power costs.

- GDS' recommendation to disallow $1.134 million in replacement power costs associated with a delay in start-up following an August 2005 Unit 1 outage because of an operator's error should be rejected. In light of Palo Verde's excellent performance over the past decade this one error should not be a basis for a finding of imprudence. Moreover, GDS has not presented an analysis of why Palo Verde actions were imprudent but has simply relied on Company self-critical documents developed with the full benefit of hindsight.
- GDS' criticism of Palo Verde's storage of the Unit 1 Diesel Generator A governor, the failure of which led to a three-day outage in March of 2005, is inappropriate. GDS' recommendation is inappropriate because the actual cause of the governor failure was not determined and Palo Verde personnel complied with the manufacturer's storage instructions. Nor

could Palo Verde personnel have detected the problem through a pre-installation inspection. Additionally, this outage predates the PSA and has no bearing on this case.

- APS' actions in connection with pursuing potential remedies against vendors whose equipment caused certain of the 2005 outages have been appropriate.
- The Company is willing to file the report recommended by GDS in its fourth recommendation regarding plant performance, although confidential information would be made available for review only. Moreover, the Company cannot commit to provide INPO data, or even to make INPO data available, without INPO's consent. The Company has informed INPO of GDS' recommendation, and will supplement this testimony upon receiving INPO's response. With respect to GDS' fifth and sixth recommendations, the Company is willing to file such reports. However, although GDS referred to other nuclear plants that "have been successful in managing aging equipment issues" in its fifth recommendation, and to "other nuclear plants that have been successful in avoiding outages due to installation of incorrect parts," in its sixth recommendation, GDS stated in data request responses that it was unaware of any plants with these characteristics and recommended that APS contact INPO. We will do so, but the extent to which APS can file the recommended reports will depend on the results of the contact with INPO.

III. OPERATING PHILOSOPHY

Q. COULD YOU PLEASE EXPLAIN APS' ROLE IN OPERATING PALO VERDE?

A. Palo Verde is jointly owned by seven companies. They are: APS (29.1%); Salt River Agricultural Improvement and Power District (17.5%); Southern California Edison Company (15.8%); El Paso Electric Company (15.8%); Public Service Company of New Mexico (10.2%); Southern California Public Power Authority Association (5.9%); and Department of Water and Power City of Los Angeles (5.9%).

APS is the licensed operator and the operating agent for Palo Verde on behalf of Palo Verde's owners. In this regard, APS manages the employees and contractors working at Palo Verde, and makes all decisions with regard to the safe and reliable operation of the station such as scheduling maintenance and refueling outages, shutting a unit down for an outage when an issue arises, and re-starting a unit after an outage. APS confers, and receives approval from the other owners on a number of things, including all major capital projects such as steam generator replacements and turbine upgrades.

Q. ARE THERE DIFFERENCES BETWEEN OPERATING A NUCLEAR POWER PLANT AND OTHER POWER PLANTS?

A. Absolutely. Certain aspects of regulation can greatly impact a nuclear unit's performance. Nuclear stations are licensed and regulated by the NRC. As a condition of its license, each station is required to designate strict plant operating standards, plant designs and technical specifications that must be complied with to meet the license standards. If an anomalous situation occurs,

technical specifications require that certain actions must be performed and conditions met within specific timeframes in order to continue to operate the unit. In some cases, when these predetermined timeframes cannot be met, the technical specifications require that the unit be taken out of service. NRC regulations, radiological conditions, and prescriptive operating procedures require the unit to follow a specific process for shutdown, outages and restart.

Since nuclear power plants are strictly regulated to assure their safety, the operating requirements are vastly different from those applicable to coal or gas-fired plants of similar size. For example, the radiological conditions of the plant are highly controlled and monitored, and access to specific areas is restricted during normal plant operations. When a nuclear plant is taken out of service, access to certain areas is restricted until radiological, temperature and other conditions are met. Despite Palo Verde's success in minimizing the effect of radiological conditions on outages, the ability of employees to work during outages is still more restricted than comparable maintenance or repair in a fossil station.

Each U.S. nuclear station contains multiple systems as well as engineering practices and operational features that create redundancy -- or multiple barriers -- to ensure safe operations. Regulations and maintenance practices in nuclear stations are in place to replace, repair and ensure the safety margin of the primary and secondary systems. That means that the unit may be down-powered or removed from service to repair a system that does not directly impact the operations or output of the plant but rather, to ensure the safe operation of the

back-up systems. Palo Verde has specific operating and maintenance procedures (and corresponding training for personnel) that control plant operation. These procedures cover not only normal plant operation, but a multitude of other conditions – such as emergency and abnormal operations. As a result, plant operators have extremely limited discretion in how the plant is to be operated in any specific condition. For example, in one of the outages discussed below, we had to shut down two of the Palo Verde units (the third was already in a steam generator replacement outage) when the NRC posed a question that raised doubt about whether a safety system would function adequately if called upon in the event of an extremely unlikely but theoretically possible accident. By contrast, fossil units do not have strict technical specifications that require the unit to be taken out of service under such circumstances. Nuclear unit shutdown under normal conditions takes about one day. From shutdown conditions to returning to the grid takes about two days, and return to 100 percent power takes an additional one to two days. In contrast, return of a gas or coal plant to service can be achieved in as little as, or less than, one day.

IV. HISTORICAL PERFORMANCE

Q. HOW HAS PALO VERDE PERFORMED OVER THE LAST DECADE?

A. Over the last decade, Palo Verde has performed very well. For the 13th year in a row, Palo Verde in 2004 was the most productive single power station in the country, producing more than 28 million megawatt-hours. From 1995 through 2004, the 10-year average capacity factor for all three Palo Verde units was 89.5% compared with an industry average of 82% and with a pressurized water

reactor (PWR) average of 87%. This was far superior to the 75% capacity factor anticipated when the units were designed and built. As Mr. Fitzpatrick addresses in his testimony, this superior performance resulted in a net benefit to APS and its customers of over $90 million during the period of 1995 to 2004 as compared to the average performance of pressurized water reactors of greater than 600 megawatts.

V. PERFORMANCE DURING 2005

Q. HOW WOULD YOU CHARACTERIZE PALO VERDE'S PERFORMANCE IN 2005?

A. Palo Verde generated 25,803,512 MWh of electricity, the greatest output of any station in the United States. However, in 2005 Palo Verde admittedly fell short of our own very high standards. For example, our 2005 internal goal for production was 28 million megawatt hours and we finished the year about 10 percent short of that goal. Also, our year-end capacity factor goal was 86 percent, and we achieved a plant-wide capacity factor of 77.4 percent. So in terms of production and capacity factor we fell about 10 percent shy of our high targets in 2005.

Q. CAN YOU PROVIDE AN EXPLANATION FOR WHY PALO VERDE DID NOT MEET THE COMPANY'S HIGH PERFORMANCE EXPECTATIONS?

A. Yes, the decrease in performance is directly related to the greater than typical number and duration of plant outages that we experienced in 2005. In several instances these outages necessitated repairs and/or inspections that required the affected unit to remain out of production for a period of time. These outages

were not the result of imprudence. Prudence only requires that reasonable actions be taken based on information that was or should have been known at the time of an action, without the use of hindsight. As Mr. Denton and Dr. Mattson explain in their testimony, prudence does not depend on the results achieved, and certainly does not require perfection.

Q. DO YOU AGREE WITH THE STAFF CONSULTANT GDS' RELIANCE ON THE PLANT'S 2005 CAPACITY FACTOR TO SHOW THAT PERFORMANCE IN 2005 WAS "POOR" (GDS, P. 8)?

No. GDS claims that plant performance was poor because of low capacity factor, yet it acknowledges that the bulk of the outages that cause the low capacity factor were prudent. For example, Unit 1's capacity factor was only 66%. However, this was due in large part to the 77 day steam generator replacement outage, which GDS describes in its report as "a complex outage that was well planned and executed." Thus, the only Unit 1 outages challenged equal five days of Unit 1 outage time, three of which predate the PSA, and two days for a reactor trip upon startup of Unit 1 in August.

Q. GDS ALSO COMMENTS ON THE COMPANY'S PERFORMANCE IMPROVEMENT PLAN. DO YOU AGREE WITH THOSE COMMENTS?

A. GDS describes the Performance Improvement Plan as "a comprehensive plan with substantial resources and the full backing and commitment of APS management." (GDS, p. 10). I agree with this description and assure the Commission that the plan has my full commitment and that of all the Company's senior management. It is our goal to return Palo Verde's performance to the sustained level of excellence at which it performed for a decade, and we are

working as hard as possible to achieve that goal as quickly as possible. I appreciate and share in GDS' optimism that the plan "will be successful in improving the performance of Palo Verde to the desired level." (GDS, p. 11)

Q. WERE THERE ANY SAFETY ISSUES RELATED TO ANY OF THE 2005 OUTAGES?

A. No. In keeping with the conservative philosophy with which we operate Palo Verde, in each case the affected unit was promptly shut down until the problem could be repaired or the issue appropriately analyzed. As you will recall, Dr. Bruce Mallet, the NRC's Regional Administrator for Region IV also addressed this issue in his January 26, 2006 appearance before the Commission. Dr. Mallet stated:

> First and foremost, the licensee, Arizona Public Service, has operated the Palo Verde nuclear plant in a safe and secure condition. They have ensured the protection of the public health and safety. And they have ensured the protection of the environment. They have also responded to emergent plant conditions and emergency events with safety as a primary focus.

(Transcript at 6-7.) I would note that GDS also observed that "[n]one of the outages investigated resulted in or from unsafe operations and, in fact, demonstrated that APS was willing to shut down the plant when any safety conditions were identified. Palo Verde was safely operated throughout 2005." (GDS, p. 18) Operating the plant with safety as a primary focus is how we always have operated the plant and how we always will operate Palo Verde.

VI. 2005 OUTAGES CHALLENGED BY GDS AS IMPRUDENT

Q. BEFORE ADDRESSING THE OUTAGES THAT GDS CLAIMS WERE CAUSED BY IMPRUDENT APS CONDUCT, WOULD YOU EXPLAIN WHAT IS MEANT BY A FORCED OUTAGE?

A. A forced outage can be of two types. The first is an immediate outage where the unit "trips" (i.e., automatically begins to shut down) or an equipment issue requires immediate removal from service, and plant personnel respond. The second type is the situation where the plant's technical specifications require that actions be performed or conditions met within a specified time frame in order to continue to operate the unit. If required actions cannot be taken or specific conditions met within the pre-determined time frame, the unit must be removed from service. These situations often involve the need to make what is known as an operability determination.

Q. WHAT IS AN "OPERABILITY DETERMINATION"?

A. The NRC defines "operable/operability" as the condition when a safety-related system, subsystem, train, component or device is capable of performing its specified safety functions, and when "all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication and other auxiliary equipment that are required for the system, subsystem, train, component or device to perform its function(s) are also capable of performing their related support function(s)." NRC Inspection Manual, Part 9900, addressing operability determinations, defines an operability declaration as "a decision by a senior licensed operator on the operating shift crew that there is a reasonable expectation that a SSC [a safety system, structure or component] can perform its specified safety function." See Section 3.7 of Part 9900. The

NRC emphasizes that the "reasonable expectation" standard is a high standard. See Section 3.9. The NRC further states that "determinations of operability are appropriate whenever a review, TS [technical specification] surveillance, or other information calls into question the ability of SSCs to perform specified safety functions." Significantly, an SSC may be deemed inoperable even though there is no current need for the SSC to operate and even if it is highly unlikely that the SSC will be called upon to operate. Such operability determinations resulted in the outages at Units 2 and 3 in October of 2005.

Q. GDS RECOMMENDS A DISALLOWANCE FOR THE FORCED OUTAGE AFFECTING UNITS 2 AND 3 BETWEEN OCTOBER 11 AND OCTOBER 20, 2005. WHAT WAS THE ISSUE THAT CAUSED THIS OUTAGE?

A. It arose during a follow-up inspection that the NRC was conducting to address the Company's response to the "yellow" finding related to the pipe void issue the Company identified in 2004. During the inspection, one of the inspectors asked a question about the possibility of air ingestion into piping after what is called a recirculation actuation signal. A detailed explanation of how the containment spray system and emergency core cooling systems work in the event of a loss of coolant accident and the Company's response to the NRC inspector's question is set forth in the testimony of Dr. Roger Mattson. In summary, however, it was a new question that, as the NRC's Regional Administrator Bruce Mallet acknowledged in his appearance before the ACC on January 26, 2006, the NRC had never asked before, (Transcript at 43), not during Palo Verde's licensing nor during the subsequent almost two decades of operation.

Q. WHY WOULD SUCH A QUESTION REQUIRE THE PLANT TO SHUT DOWN?

A. The question went to the adequacy of what is referred to as the design basis of the plant. As Dr. Mallet explained in his appearance before the Commission, the NRC's question required the plant to make an operability determination which required the plant to be shut down.

> In the October [2005] time frame, when we raised this issue about the design flaw, it was a new question, okay, one that we hadn't come across before, nor had they [APS] to the best of my recollection. And so they did what we expected. They searched that out and said we can't answer the question – I am over simplifying – so that would put us in a condition we don't believe is within our design. If you can't answer [the] NRC, and we [APS] can't answer it within this certain time frame, we have to shut the plant down by our technical specifications until we get it resolved. And that's what they did . . . . All I can say in this case is that it was a question we raised and they did the right thing when they couldn't answer the question. . . .
>
> (Transcript at pp. 45-46.)

Q. SHOULD APS HAVE ANTICIPATED THE NRC'S QUESTION?

A. No. Commissioner Mayes asked this same question of Dr. Mallet who responded that "we didn't determine that they should have found it beforehand." (Transcript at 46.) Without getting too far into the technical detail Dr. Mattson provides in his testimony, the basic reason we would not have asked ourselves this question earlier is because the plant was in conformity with its design basis based on the static calculations the NRC had accepted back when it issued the license for the Palo Verde units. When the NRC inspection team asked the question that required going beyond these static calculations and required dynamic calculations – the "new question" that NRC Regional Administrator Mallet was referring to – we had to retain expert help to do those calculations.

Because we could not assure ourselves (i.e., make the operability determination) that the system would perform properly in the hypothetical situation the NRC inspector posed, we had no choice but to take the plant out of service while the expert work was being performed. We obtained the services of a premier expert in hydrodynamics who did the analysis and confirmed that the original design would perform as intended. The NRC promptly accepted this analysis, and the plant returned to service as quickly as possible, i.e., nine days, and without any change to plant equipment.

Q. DO YOU AGREE WITH GDS' ASSERTION THAT APS SHOULD HAVE IDENTIFIED THE NRC INSPECTOR'S CONCERN IN 2004, AND THAT THEREFORE, THE OCTOBER 2005 OUTAGE WAS AVOIDABLE?

A. I do not agree with GDS' claim nor apparently does the senior NRC official involved. As noted above, Dr. Mallet told the Commission that "we didn't determine that they should have found it beforehand." (Transcript at 46.) In fact, Dr. Mallet asked Mr. Pruett, a Region IV Branch Chief, and one of the principal NRC officials responsible for NRC oversight of Palo Verde to correct him if he was incorrect. Mr. Pruett did not add anything. (Transcript at 46.)

Q. DID DR. MALLET ALSO STATE THAT AN UPCOMING REPORT TO BE ISSUED THE NEXT DAY WOULD MAKE THE NRC'S CONCLUSIONS FINAL WITH RESPECT TO THE REFUELING WATER TANK OUTAGE?

A. Yes, and while that report is critical of the Company in a number of respects, it does not contradict the remarks that Dr. Mallet made to the Commission about the new nature of the question the NRC posed and his conclusion that this was not a question the Company should have considered previously. Had the NRC

believed otherwise, it would have issued a violation on this point, and while the report does contain some minor violations for other matters, it does not issue a violation for failure to properly assess the extent of condition associated with the voided pipe issue.

Q. GDS ALSO STATES IN ITS REPORT THAT GDS PERSONNEL SPOKE WITH MR. WARNICK, ONE OF THE NRC RESIDENT INSPECTORS, AND THAT MR. WARNICK TOLD GDS THAT THE OUTAGE WAS AVOIDABLE. IS MR. WARNICK WRONG?

A. First, unlike the remarks of Mr. Warnick's superior, Dr. Mallet, there is no transcript of what Mr. Warnick told GDS. Second, Mr. Warnick was not a member of this inspection team. Third, assuming that Mr. Warnick said that the outage was avoidable, in NRC parlance, that does not mean that APS should have foreseen the question or that it acted imprudently. As described in detail in Dr. Mattson's testimony, the NRC does not focus on prudence, but uses hindsight to identify lessons learned from events in order to constantly improve the safety of nuclear plants. In hindsight, the outage may have been avoidable if, back at the time the NRC initially licensed the plant, the NRC had asked the question in the same way the inspector posed the question in 2005. However, as GDS acknowledges, such hindsight is impermissible in a prudence review.

Q. GDS QUOTES EXTENSIVELY FROM THE NRC'S JANUARY 26, 2006 INSPECTION REPORT TO SUPPORT ITS CLAIM OF IMPRUDENCE. IS GDS' RELIANCE ON THAT REPORT APPROPRIATE?

A. No. Not surprisingly, that report does not contradict Dr. Mallet's representation to this Commission that the NRC did not determine that APS should have found the issue before the NRC raised it in 2005. Indeed, Dr. Mallet signed the cover letter forwarding the report to me, and page i of the report states that it was

"Approved By: Bruce Mallet, Regional Administrator." It only makes sense to read that report in a manner that is consistent with Dr. Mallet's statements to this Commission.

Q. WAS ANY OTHER WORK PERFORMED ON UNIT 2 DURING THE REFUELING WATER TANK OUTAGE?

A. Yes. When we are required to shut down a unit due to unforeseen events, we always try to perform as much work as possible in order to improve equipment reliability, maximize plant performance, and shorten future outages.

Q. PLEASE DESCRIBE THE WORK THAT WAS PERFORMED ON UNIT 2.

A. Palo Verde performed the following work on Unit 2:

- Replaced Thrust Bearing Oil Seal on RCP 1A
- Replaced Thrust Bearing Oil Seal on RCP 2A
- Performed Complete Oil Change Out on RCPs 1A and 2A
- Replaced Inboard and Outboard Oil Seals for "A" Main Feedwater Pump
- Replaced Control Circuit Resistor for "A" Auxiliary Feedwater Pump
- Repaired Steam Leak on "A" Heater Drain Pump
- Replaced Main Generator Excitation Bushings
- Repaired RU-151
- Performed EW Heat Exchanger Thermal Performance Test

Q. DID THE PERFORMANCE OF THIS WORK PREVENT OR REDUCE THE LENGTH OF A LATER OUTAGE?

A. Yes. The oil leakage from the thrust bearing oil seals on reactor coolant pumps ("RCPs") 1A and 2A had decreased to the point that Palo Verde in all likelihood

would have had to shut down Unit 2 prior to the unit's next outage to replace the oil seals. Therefore, when Unit 2 was shut down due to the issues with the refueling water tank, we decided that we should use the opportunity to replace these oil seals.

Q. DID GDS PROVIDE ANY CONCLUSIONS REGARDING OUTAGES DUE TO OIL LEAKAGE FROM THE RCP OIL SEALS?

A. Yes. GDS analyzed other outages based on this same problem of oil leakage from the RCP oil seals, and concluded in its report (p. 39) that Palo Verde's actions regarding the oil seals have been "reasonable and prudent."

Q. WAS THE OIL LEAKAGE FROM THE UNIT 2 RCPS THE SAME AS FOR THE OUTAGES THAT GDS ANALYZED?

A. Yes. All of the outages occurred due to the same issue of oil leakage from RCP oil seals.

Q. WHAT AMOUNT OF REPLACEMENT POWER COSTS DID PALO VERDE AVOID BY PERFORMING THE WORK ON THE RCP OIL SEALS DURING THE REFUELING WATER TANK OUTAGE?

A. Palo Verde avoided a minimum of $4.4 million and potentially $6.1 million by performing this work on the RCPs during the October outage. The details of these calculations are addressed in Peter Ewen's testimony. It is difficult to know precisely when the outage would have occurred, but I believe, based on the performance of the oil seals at the time of their replacement in October 2005, had the seals not been replaced as part of the RWT outage, we would have had to shut down Unit 2 shortly thereafter in order to replace the seals.

Palo Verde also performed maintenance on the Unit 2 main generator excitation bushings. Had this work not been performed during the October outage, it likely would have also caused an independent outage, and Unit 2 would have had to shut down. Nonetheless, this work would have been performed in concurrence with the work on the RCP oil seals. Therefore, the performance of the main generator excitation bushing maintenance in October did not avoid any replacement power costs separate from the costs avoided by the RCP maintenance discussed above.

Q. DID PALO VERDE PERFORM ANY ADDITIONAL WORK ON UNIT 2 THAT PREVENTED A LATER OUTAGE OR REDUCTION IN POWER?

A. Yes. The work listed above that was performed on a main feedwater pump and a heater drain pump in October would likely have required a reduction of power in Unit 2 to replace various seals on the pumps had the work not been performed during this outage. Using the same methodology above used to calculate the values for the RCPs, the avoided replacement power costs due to the work performed on the main feedwater pump and the heater drain pump increases the total replacement power costs avoided for all maintenance on Unit 2 from $6.1 million to $7.0 million. The details of these calculations are described in Peter Ewen's testimony.

Q. WAS ANY OTHER WORK PERFORMED ON UNIT 3 DURING THE REFUELING WATER TANK OUTAGE?

A. Yes. As stated above, when we must shut down a unit due to unforeseen events, we perform maintenance in order to improve equipment reliability and maximize plant performance. In the case of Unit 3, as with Unit 2, we

performed a variety of such tasks. However, we cannot say definitively that any of these tasks would have directly shortened or prevented later outages, but could have been accomplished during the normal course.

Q. DO YOU AGREE WITH GDS' RECOMMENDATION THAT $7.672 MILLION FOR UNIT 2 AND $7.672 MILLION FOR UNIT 3 SHOULD BE DISALLOWED FOR THE REFUELING WATER TANK OUTAGE?

A. No. The question posed by the NRC was a new question. We responded promptly and appropriately by shutting down Units 2 and 3 when we could not immediately answer the question and assure ourselves that we did not have a safety issue. Once the question was adequately resolved, we started up Units 2 and 3 without any change to plant equipment. Therefore, GDS' recommendation of any amount of disallowance for this outage is inappropriate. Additionally, Peter Ewen's rebuttal testimony provides further corrections to these numbers recommended by GDS.

Q. GDS ALSO CHALLENGES THE PRUDENCE OF PALO VERDE'S ACTIONS IN CONNECTION WITH A REACTOR TRIP AT UNIT 1 IN AUGUST 2005. WOULD YOU DESCRIBE THE EVENTS OF THIS OUTAGE?

A. On August 26, 2005, Palo Verde was in the process of starting up Unit 1 following the outage to repair the Unit 1 Diesel Generator B voltage regulator. At about 2% reactor power during the startup, the Secondary Control Room Operator switched the system that controls the level in the steam generator to automatic. The operator did not believe the automatic control was adequately maintaining the level in the steam generator, so the operator switched the system to manual control. However, as GDS acknowledges, the operator failed to request concurrence from the Control Room Supervisor when he shifted to

manual operation. In attempting to maintain proper level in the steam generator, the operator altered the level setpoint and switched between manual and automatic control several times. These attempts, combined with the expansion of the water in the steam generator due to rising temperatures, were unsuccessful, and the reactor ultimately tripped due to a high level in the steam generator.

Q. HOW HAS PALO VERDE PERFORMED WITH RESPECT TO UNPLANNED REACTOR TRIPS?

A. As Dr. Mattson shows in Attachment RJM-3RB of his rebuttal testimony, over time Palo Verde has performed as well as or better than similar plants based on NRC's "Unplanned Scrams" performance indicator. In fact, during the quarter in which this trip occurred, the average "Unplanned Scrams" value at Palo Verde was lower than the average for all pressurized water reactors and for reactors in Peer Group 2.

Q. IS THE EVOLUTION OF SWITCHING TO AUTOMATIC STEAM GENERATOR LEVEL CONTROL A FREQUENT OCCURRENCE?

A. No. This evolution only occurs during startup. Very few startups occur at Palo Verde each year, and each unit has six different crews of operators with several operators on each crew who can perform the evolution. Additionally, a modification was made in 2004 to change from an analog to digital system. All of these factors combine such that each operator only rarely performs this evolution of switching to automatic control, and it could be years between performances of this evolution for a specific operator.

Q. HOW HAS PALO VERDE RESPONDED TO THIS EVENT?

A. We have learned from this event and have performed corrective actions to try to prevent the reoccurrence of a similar event. These corrective actions include additional training, clarification of procedures, and modifications to the system. These actions do not suggest that Palo Verde was imprudent, but only that Palo Verde is willing to respond to problems. It would have been imprudent not to have made these or similar changes based on the knowledge we had following this outage. These actions are part of the "continuous improvement" environment that exists in the nuclear industry.

Q. WHAT IS YOUR REACTION TO GDS' CLAIM THAT THE OPERATORS SHOULD HAVE RECEIVED MORE TRAINING ON THIS EVOLUTION?

A. Following a reactor trip that involves some element of human error, it is always easy to speculate, using hindsight, that additional training should have been performed on the specific issue that would have prevented the error. Nuclear power plants are complex systems that involve complex evolutions. We train our operators based on our best judgment of what the most significant issues are and what will best assist in the safe and efficient operation of the plant.

Q. ON PAGES 25-26 OF ITS REPORT, GDS LISTS THE DIRECT CAUSES AND ROOT CAUSES AND THEN CONCLUDES THAT THE OUTAGE WAS IMPRUDENT BASED ON THE ROOT CAUSE REPORT. DO YOU AGREE WITH THIS APPROACH?

A. No. A root cause evaluation is a self-critical document that takes full advantage of hindsight. We perform the evaluation in order to better understand an event and to ensure that it does not recur. The causes listed on pages 25-26 are based on hindsight. This is not the standard of prudence. Additionally, GDS simply

recites portions of the root cause report and concludes (without any analysis) on page 26 that "[t]he 8/26/05 reactor trip and resulting outage extension would have been avoided with prudent operation and management." As stated above, critical comments in a root cause evaluation are not based on a standard of prudence. Therefore, GDS' conclusion, based solely on the root cause report, is insufficient to show imprudence.

Q. PAGE 26 OF THE GDS REPORT STATES THAT THE NET REPLACEMENT POWER COST DUE TO THE REACTOR TRIP IS $1.260 MILLION. DOES APS AGREE WITH THIS AMOUNT?

No. The correct value is $1.162 million, as explained in Peter Ewen's rebuttal testimony.

Q. GDS RECOMMENDS THAT "[T]HE AMOUNT OF $1.623 MILLION INCURRED BEFORE APRIL 1, 2005 SHOULD NOT BE ELIGIBLE FOR CONSIDERATION IN ESTABLISHING BASE FUEL COSTS IN THE PENDING RATE CASE." DO YOU AGREE WITH THIS RECOMMENDATION?

A. No. First, and most importantly, Palo Verde took appropriate actions regarding the outages that occurred prior to April 2005. Additionally, as the ACC Staff has indicated in other testimony, the prudence of any outages prior to April 2005 (before the PSA) does not have any bearing on the rate case.

The ACC Staff presented its position through the direct testimony of John Antonuk, the President of The Liberty Consulting Group, who testified regarding an audit his company performed with the ACC Staff on the "management and operations of fuel and purchased-power functions of APS." The testimony (p. 23) regarding 2005 fuel and energy costs discusses GDS'

recommendations of disallowances, and questions whether Mr. Antonuk has considered the impact of the outages in these proceedings. Mr. Antonuk responded by stating that APS witness Ewen's "normalization did not rely upon actual 2005 performance of any generating unit, including Palo Verde." Therefore, Mr. Antonuk concluded that "it is not necessary to make any further adjustment to the Ewen normalization in order to remove the effects of below standard performance of Palo Verde or any other generating units during 2005."

Q. IF GDS' RECOMMENDATION REGARDING THE PRE-APRIL 2005 OUTAGES HAS NO BEARING ON THE RATE CASE, WHY ARE YOU ADDRESSING THIS ISSUE IN YOUR TESTIMONY?

A. GDS contends in its report (p. 24) that "[t]his outage was the result of imprudence and was avoidable by ensuring that the storage conditions and pre-installation inspection of the re-furbished governor were commensurate with the importance of this equipment." I disagree with this statement and believe that it is important that the Commission understand that we were not imprudent with respect to this outage.

Q. PLEASE DESCRIBE THIS OUTAGE INVOLVING THE UNIT 1 EMERGENCY DIESEL GENERATOR A GOVERNOR IN MORE DETAIL.

A. On March 17, 2005, the Unit 1 Diesel Generator A failed to reach full speed during a post-maintenance retest. We investigated the problem and determined that the governor (which controls the speed of the diesel generator) should be replaced. Palo Verde's technical specifications require that the plant be shut down in order to perform the necessary retests following replacement of the governor. Therefore, Unit 1 was shut down and we performed the retests.

Q. DID PALO VERDE INVESTIGATE THE CAUSES OF THE PROBLEM WITH THE GOVERNOR?

A. Yes. We performed a Root Cause Investigation ("RCI") to evaluate the problems with the governor which led to this outage. The RCI is provided in part as Attachment 10 to the GDS report.

Q. WHAT WERE THE CONCLUSIONS OF THE ROOT CAUSE INVESTIGATION?

A. The RCI (p. 15) determined that the direct cause of the governor failure was "oil contamination of the lube oil in the governor actuator." Additionally, the RCI (p. 3) identifies the three most probable root causes as water introduced during refurbishment that was not completely drained, governor storage drained of oil in the Palo Verde warehouse, and water introduced during oil change. Nonetheless, the RCI (p. 15) clearly states that "[n]o root cause could be found for this event." Therefore, Palo Verde does not know for certain what led to the problems with the governor.

Q. WHY DO YOU DISAGREE WITH GDS' CLAIM REGARDING STORAGE OF THE GOVERNOR?

A. Palo Verde properly stored the governor in accordance with the manufacturer's recommendations. Woodward Governor Company, the manufacturer of the governor, recommends the following (Attachment JML-1RB): "Mechanical hydraulic governors and actuators should be stored in a clean and dry condition; any items stored where condensation and moisture is a problem should be sent to a qualified facility for examination every five (5) years." The governor was stored in Palo Verde warehouse Level B storage, and meets these conditions. Furthermore, the manufacturer only recommends examination every five years.

The governor at issue was rebuilt and shipped to Palo Verde in July 2000, and was installed in April 2001, much shorter than the five year recommendation.

Q. GDS ALSO ASSERTS THAT "STORAGE OF THE GOVERNOR DRAINED OF OIL IN A WAREHOUSE THAT WAS NOT CLIMATE CONTROLLED IS NOT A GOOD PRACTICE." IS THIS ACCURATE?

A. No. As discussed above, Palo Verde stored the governor in accordance with the instructions from the manufacturer and did not come close to the five year limit before a recommended examination.

Q. GDS ALSO STATES THAT THIS OUTAGE "WAS AVOIDABLE BY ENSURING THAT THE . . . PRE-INSTALLATION INSPECTION OF THE RE-FURBISHED GOVERNOR [WAS] COMMENSURATE WITH THE IMPORTANCE OF THIS EQUIPMENT." DO YOU AGREE WITH THIS STATEMENT?

A. No. Palo Verde personnel inspected the governor as it was installed and could not have detected any internal rust. Following this outage, the faulty governor was sent to Engine Systems Inc. ("ESI") for testing and failure analysis. ESI's report is provided as Attachment JML-2RB. Following its receipt inspection, ESI stated (p. 1) that "[t]he internal inspection with the top cover removed indicated the governor internals were clean and in very good condition." The rust in the governor was only identified after a "disassembly inspection" by ESI (p. 2). This rust would only have been identified during a pre-installation inspection had Palo Verde dismantled the governor. It is not reasonable to require Palo Verde personnel to disassemble a component before installation. In fact, this disassembly would only increase the possibility of contaminating the equipment.

Q. WHAT IS YOUR CONCLUSION REGARDING THIS OUTAGE?

A. Palo Verde personnel stored the governor in accordance with the manufacturer's recommendations. Additionally, the only inspection that would have revealed any rust would have required disassembling the governor. It is unreasonable to require this, and would likely cause more problems than it would correct. Furthermore, the exact cause for the oil contamination that we believe led to the problems with the governor is unknown. Since Palo Verde properly stored and inspected the governor, the outage cannot be attributed to imprudent actions by Palo Verde.

VII. PALO VERDE CONTRACTS WITH VENDORS

Q. ARE YOU FAMILIAR WITH THE RECOMMENDATION BY GDS THAT THE COMMISSION ADDRESS THE ISSUE OF "THE DEGREE TO WHICH APS HAS SOUGHT APPROPRIATE LEGAL REMEDIES OR OTHER REMEDIES" AGAINST VENDORS WHOSE EQUIPMENT CAUSED CERTAIN OF THE 2005 OUTAGES?

A. Yes, GDS' report states that "[w]e have evaluated APS' actions related to these specific outages and have concluded that APS' actions were not imprudent." (GDS, p. 3). The specific outages that GDS identified as being the result of "faulty vendor supplied equipment" were (1) the February 16 – February 19, 2005 Unit 1 outage caused by a reactor coolant pump oil seal o-ring being made of the wrong material; (2) the May 22 – June 24, 2005 Unit 3 outage due to improperly manufactured pressurizer heaters supplied by Framatome–ANP and its subcontractor Thermocoax; and (3) the August 22 – August 25, 2005 Unit 2 outage caused by an error in core protection calculator system software provided by Westinghouse.

Q. HAS APS TAKEN ANY STEPS TO OBTAIN A REMEDY FROM THESE VENDORS?

A. Yes. APS obtained replacement o-rings from the vendor at no charge. Similarly, Westinghouse corrected the software error at no charge. The contracts in question precluded the recovery of consequential damages in these two instances. In the case of the Framatome – ANP pressurizer heaters, to date APS has recovered $3.1 million, including $2.7 million to offset the cost of the new heaters from other vendors and the original design costs, as well as a $400,000 credit for future purchases from Framatome – ANP. The remaining claims (relating to the recovery of replacement power costs) will be submitted to non-binding mediation. If mediation is unsuccessful, APS has retained the right to litigate the issue.

Q. WHY DID APS ENTER INTO CONTRACTS WITH WESTINGHOUSE AND THE O-RING MAKER THAT PRECLUDED RECOVERY OF CONSEQUENTIAL DAMAGES?

A. My understanding is that equipment vendors, particularly in the nuclear industry but also with respect to power plant equipment generally, will not enter into contracts that permit recovery of consequential damages. That is especially true where, as here, the potential consequential damages would be vastly disproportionate to the value of the equipment or service provided. For example, the o-ring seals in question cost $90.

Such limitations however, are not applicable in all instances (such as where conduct of a vendor is deemed to be willful or grossly negligent). This is why, without discussing the nature of APS' litigation strategy, that APS believes that it has a claim for recovery of replacement power costs in the case of Framatome

– ANP pressurizer heaters. In contrast, in the case of the Westinghouse computer error and the case of the o-ring made of the wrong material, we had no evidence to suggest that those vendors had done anything willful or grossly negligent. Given the relatively small number of vendors for much of the equipment and many of the services needed at nuclear power plants, it would be counterproductive and highly detrimental from a business standpoint for APS to bring claims against vendors without having a reasonable factual basis to do so.

VIII. OTHER GDS RECOMMENDATIONS

Q. HAVE YOU REVIEWED ADDITIONAL GDS RECOMMENDATIONS?

A. Yes.

Q. DO YOU HAVE ANY COMMENTS ON THOSE RECOMMENDATIONS?

A. Yes. GDS' fourth recommendation states the following:

> The Commission should order APS to file a semi-annual report with the Commission's Docket Control, describing the plant performance levels, explaining any negative reporting by NRC and INPO Inspectors, and, finally, providing details of the corrective actions taken by the utility. This report should also include information on the replacement cost of power resulting from forced outages of the Palo Verde units. APS should submit this report semi-annually until the Commission decides that it is no longer necessary.

As noted above, the Company is willing to file the report recommended by GDS in its fourth recommendation regarding plant performance, although confidential information would be made available for review only. Moreover, the Company cannot commit to provide INPO data, or even to make INPO data available,

without INPO's consent. The Company has informed INPO of GDS' recommendation, and will supplement this testimony upon receiving INPO's response.

GDS' fifth recommendation states the following:

> Effective programs must be developed to deal with aging equipment issues. The Palo Verde units are now 20 years old and age related problems will become more numerous. The Commission should order APS to evaluate its programs to deal with aging equipment at Palo Verde. This evaluation should consider industry experience with aging equipment, programs established at other nuclear plants that have been successful in managing aging equipment issues, and recent experience at Palo Verde. APS should submit a report to the Commission within 120 days of the Commission's order in this matter describing the findings of the evaluation and the actions taken to improve APS' management of aging equipment issues.

Palo Verde is willing to file the report in GDS' fifth recommendation, but requested GDS' input regarding "nuclear plants that have been successful in managing aging equipment issues." In response to data request APS/Staff/TBD 2.42, GDS stated that it had not identified specific plants with successful programs in managing aging equipment issues, and suggested that APS contact INPO for a list of such plants. We will do so, but obviously the extent to which APS can file the recommended report will be dependent upon the results of the contact with INPO.

GDS' sixth recommendation states the following:

> Procedures for 1) receipt inspection of materials and 2) verification of materials and equipment prior to installation should be improved. Two of the 2005 outages could have been avoided with better inspection of parts and components prior to installation. The Commission should

> order APS to evaluate its programs for receipt inspection and verification of parts prior to installation. This evaluation should consider industry experience, programs established at other nuclear plants that have been successful in avoiding outages due to installation of incorrect parts, and experience at Palo Verde. APS should submit a report to the Commission within 120 days of the Commission's order in this matter describing the findings of the evaluation and the actions taken to improve receipt inspection and pre-installation verification of parts at Palo Verde.

One of the two 2005 outages that GDS states "could have been avoided with better inspection of parts" is likely the March 2005 outage regarding the diesel generator governor. As discussed above, Palo Verde disagrees with GDS' conclusion that Palo Verde was imprudent with respect to this outage. Nonetheless, Palo Verde is willing to file the report in GDS' sixth recommendation, but requested input from GDS regarding "other nuclear plants that have been successful in avoiding outages due to installation of incorrect parts." In response to data request APS/Staff/TBD 2.43, GDS stated that it had "not identified specific plants with successful programs in management of installation of incorrect parts." GDS recommended that APS contact INPO for a list of such plants. We will do so, but obviously the extent to which APS can file the recommended report will be dependent upon the results of the contact with INPO.

IX. CONCLUSIONS

Q. WOULD YOU PLEASE SUMMARIZE YOUR CONCLUSIONS?

A. Palo Verde has been a valuable asset to APS and the people of Arizona for many years. Although we were disappointed in 2005 results, GDS' characterization of Palo Verde's 2005 performance as "poor" is inappropriate, particularly in light

of GDS' recognition that most of the 2005 outages were prudently incurred. On the other hand, we appreciate GDS' recognition that the plant was safely and conservatively operated during 2005 as well as its confidence that the Performance Improvement Plan is well-designed to return the plant to its prior excellent performance level.

As to the specific outages that GDS challenges, as NRC Regional Administrator Mallet told the Commission when he appeared before it in January, the October 2005 outages at Units 2 and 3 were caused by the NRC raising a new question, and Palo Verde acted appropriately in shutting the units down until the question could be answered. The question was not one which Palo Verde personnel should reasonably have anticipated because the plant was in conformity with its design basis based on the calculations NRC accepted when it issued the Palo Verde license. Palo Verde quickly addressed the question and returned Units 2 and 3 to service without any change to plant equipment. Additionally, Palo Verde performed equipment maintenance during the outage that prevented a later unplanned outage, and thereby avoided between $4.4 million and $7.0 million in future replacement power costs.

With respect to the August Unit 1 reactor trip, I do not contest that the trip was due to certain errors made by our personnel. However, it is an operation infrequently performed and Palo Verde's historic performance in terms of numbers of reactor trips is as good as or better than the industry norm. Such an isolated event does not constitute imprudence.

GDS' contentions that the March Unit 1 outage resulting from the failure of a diesel generator governor would have been avoided if Palo Verde had stored the governor differently or done a better pre-installation inspection are not supported by the facts. Palo Verde more than met the governor manufacturer's storage directions, and GDS provides no support for its assertion that Palo Verde's storage requirements did not conform to good industry practice. The rust in question could have been detected only if Palo Verde fully disassembled the governor. To do so would not have been reasonable. Finally, GDS' recommendation is inconsistent with the fact that the 2005 Palo Verde outages have no bearing on the rate case as those costs were not reflected in APS' normalization calculations.

With respect to GDS' recommendation that the Commission address whether APS is appropriately pursuing vendors whose equipment caused some of the 2005 outages, we have done so and are continuing to do so. Both Westinghouse and the o-ring vendor corrected their errors. To date, we have obtained over $3 million from Framatome and are pursuing our claims for replacement power costs where there is a contractual basis upon which to do so. With respect to GDS' recommendations regarding the filing of various reports, APS is willing to do so where feasible, e.g., where there are other plants against which to compare as discussed above with respect to GDS' fifth and sixth recommendations.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Attachment JML-1RB

WOODWARD GOVERNOR COMPANY
SERVING PRIME MOVER CONTROL AND ACCESSORY MARKETS
ENGINE CONTROLS
1000 East Drake Road • P.O. Box 1519 • Fort Collins, Colorado 80522-1519
Telephone 303 482-5811 • Fax 303 498-3058 • Telex 4-5691
ESTABLISHED 1870

Frank Amend
Engine Systems Incorporated/Power Control Services
Post Office Box 1928
Rocky Mount, NC 27802-1928

Reference: Oil Changes and Governor Refurbishment

Dear Frank,

I am writing this letter to explain Woodward Governor Company's recommendations on governor oil change and refurbishment cycle times.

Since the most important variable affecting governor life is the environment in which it operates, Woodward Governor Company has no precise guidelines for governor maintenance. However, we offer the following general recommendations which could be incorporated into preventative maintenance specifications for nuclear applications:

Oil Change Interval: Woodward Governor Company recommends that mechanical actuator/governor oil should be changed at the second or third refueling outage. If there has been no indication of problems with the unit (specifically water and/or rust), this interval can be extended. If problems do occur, Woodward Governor Company recommends the interval to be shortened to every first or second refueling outage and/or until the problem's root cause has been identified and corrected.

Overhaul Interval: Woodward Governor Company recommends that mechanical hydraulic governors and actuators be refurbished every five (5) to ten (10) years.

Shelf Life: Mechanical hydraulic governors and actuators should be stored in a clean and dry condition; any items stored where condensation and moisture is a problem should be sent to a qualified facility for examination every five (5) years.

As Woodward Governor Company has chosen Engine Systems Incorporated/Power Control Services to qualify, support, and market controls for nuclear applications, I request that you inform the nuclear industry of these latest guidelines. If any questions develop within the nuclear industry pertaining to these guidelines, Woodward Governor Company requests that they be direct to your organization.

Regards,

Steve Thompson
Nuclear Coordinator/Contract Review

Attachment JML-2RB

ENGINE SYSTEMS, INC.
175 Freight Road, Rocky Mount, NC 27804
P.O. Box 1928, Rocky Mount, NC 27802-1928
Telephone: 252/977-2720
Fax: 252/446-3830

Engine Systems Inc.

Document Number: 8000367-FA
Revision 0, June 06, 2005

Failure Analysis

For

Woodward EGB-50PLS Governor Assembly

P/N 9903-254

S/N 1524051

For

Arizona Public Service Company
Palo Verde Nuclear Generating Station

PO #500285962

ESI IWO 8000367

Prepared By:		Date: 06 Jun 2005
Technical Review:		Date: 06/06/2005
Approved By:		Date: 6/8/05
Quality Review:		Date: 6/8/05

Record of Revisions

REV	DATE	PAGE	PARA	DESCRIPTION

Overview

Palo Verde Generating station experienced a fail to start on one of their Cooper KSV Emergency Diesel Generators. The start failure occurred upon startup following maintenance activities performed during an LCO. The maintenance activities performed included replacement of air control valves associated with the fuel control cylinder. Following replacement, an engine start was attempted during which the engine cranked over at approximately 100 RPM for a 15 second duration and did not start. A typical start of this unit cranks at 100 RPM for approximately 3 seconds, the engine starts and accelerates to rated speed in less than 10 seconds total duration.

The engine fuel system on the Cooper KSV includes the Woodward EGB-50PLS, the fuel control cylinder and mechanical linkage to the right hand and left hand banks of the engine. During normal engine operation, the fuel cylinder is in the collapsed condition and the terminal shaft of the EGB governor controls the fuel rack travel to the right and left hand banks of the engine. If the engine controls require the engine to be shut down, the fuel control cylinder extends and overrides the governor shaft position and forces the engine fuel to minimum level. The fuel control cylinder is pneumatically operated. Refer to Attachment #1 for control linkage layout.

Visual inspections following the failure revealed that the fuel control cylinder was collapsed and the fuel rack position was approaching the minimum fuel level of approximately 10mm rack length. This is not sufficient fuel to support engine startup. Further investigation indicated that the fuel rack and fuel control cylinder were easily moved by hand; this is not expected as there typically is resistance to movement encountered.

It was suspected that there was an internal failure of the EGB-50PLS which would not allow the fuel racks to be moved to the run position. The governor was removed and sent to ESI for test and failure analysis.

Receipt Inspection:

The governor assembly was received at ESI and visually inspected prior to performing tests or disassembly. The following conditions are noted:

External:

- The pallet for the governor assembly was broken.
- Outside oily (indicating unit had been on its side at some point during shipment).
- Indicator pointer and scale on left side marked with grease
- Indicator pointer on right side faded
- Woodward Governor P/N: 9903-254
- Woodward Governor S/N: 1524051
- Governor knob position: Droop: **0.4**; Speed: **13.42**; Load Limit: **Max**

Internal:

- The internal inspection with the top cover removed indicated the governor internals were clean and in very good condition.

Test As Received:

The EGB-50PLS governor was initially filled with 15W40 oil as required on Woodward Governor Specification TSP 883 Sheet 32. At the request of the site representative, Mr. A.T.Fernandez (Palo Verde Mechanical Maintenance Engineer), the governor was started without purging to determine the amount of time required to build oil pressure and move the terminal shaft to the maximum fuel position. This was found to be 2.87 seconds @ 72.2° F with a corresponding oil pressure of 520 PSIG. The governor was allowed to run to reach the required operational test temperature. The unit was stopped and a repeat of the fast start was performed with the unit in a hot condition. The time was found to be 1.34 seconds @ 180° with 520 PSIG pressure. After completion of this testing, the standard Woodward functional test was performed.

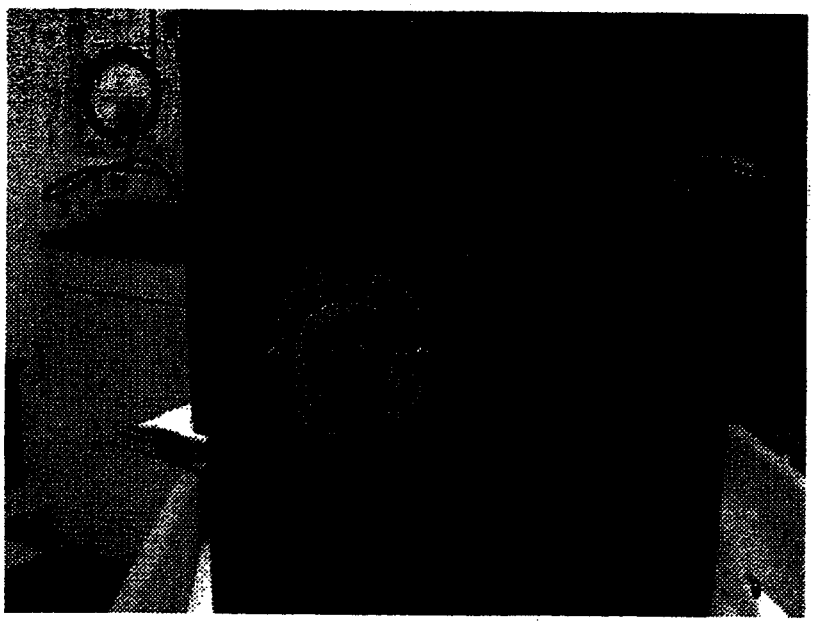
The P/N 9903-254 EGB-50PLS governor is required to be tested in accordance with Woodward Governor test specification TSP 883 Sheets 32 & 33. The governor performed satisfactorily and no out of tolerance conditions were reported. See Attachment #2 for completed test record sheets.

Following testing, the governor was allowed to sit overnight and a repeat of the quick start was performed. The initial governor temperature was 71.9°F. For this test the governor was driven at a speed of 135 RPM (approximate drive speed during engine start) and oil pressure developed to 520 PSIG in 3.68 Seconds.

Disassembly Inspection:

The governor was disassembled and the following conditions were discovered:

- No internal damage.
- A small amount of foreign material (rust) found in the sump pocket area. (see accompanying photos).
- Slight rusting found in accumulator area and on accumulator springs.
- Foreign material (rust) found in the lower end of the base area near the seal retainer (see accompanying photos).
- The drive shaft sealing area found scored from the seal. This is considered to be normal wear.
- The seal retainer has rust on lower drive end. (see accompanying photos).
- A small amount of Teflon tape found in the site glass during cleaning.



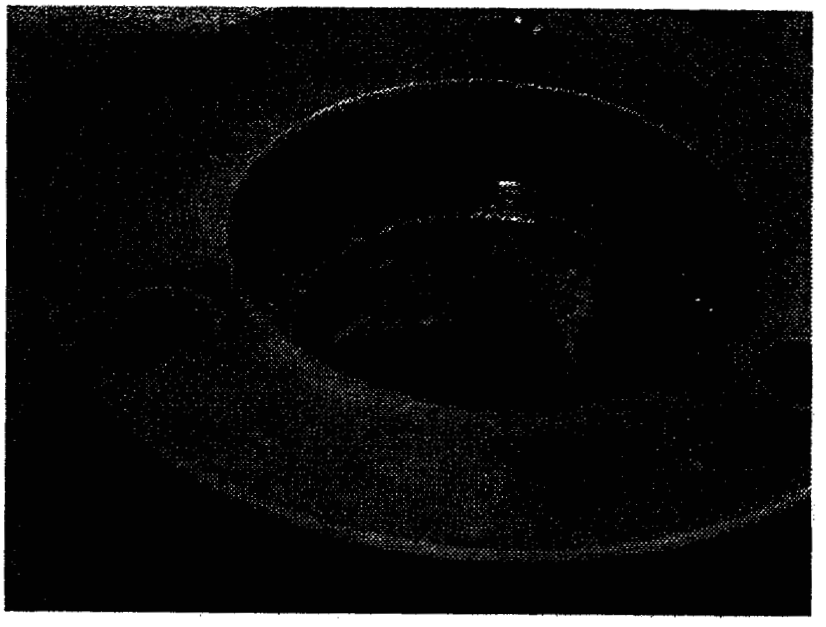
Photograph #1

Left Side View

Note grease residue around scale and pointer

Photograph #2

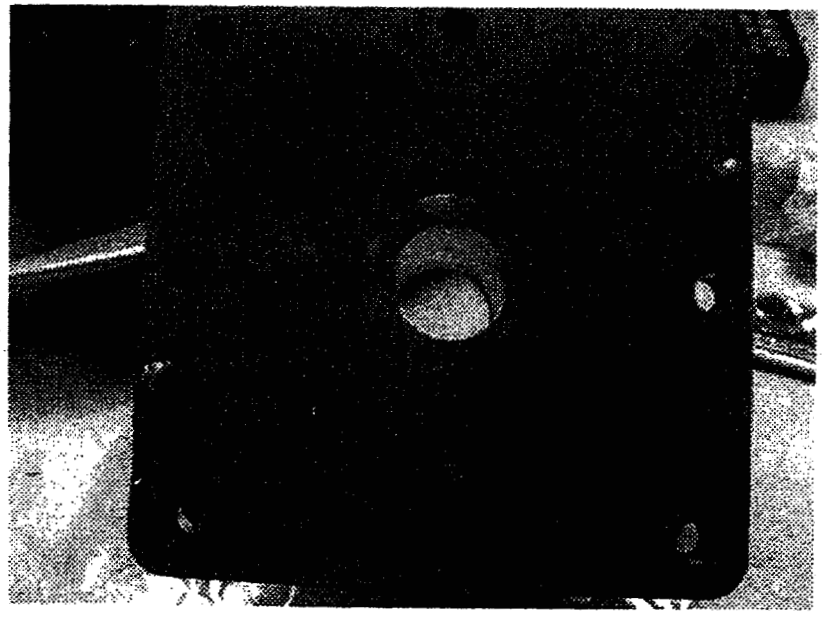
Right Side View



Photograph #3

Oil Seal Retainer Area

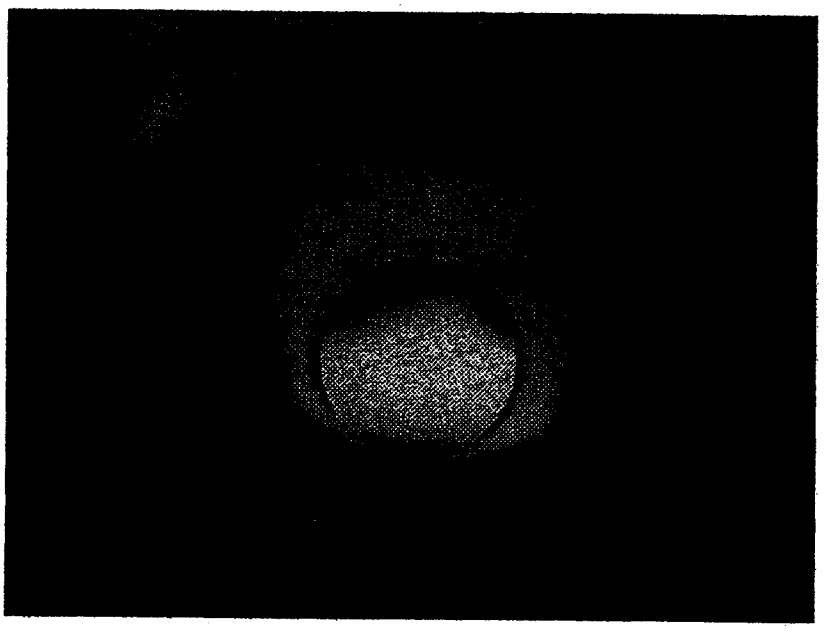
Note foreign material presence



Photograph #4

Base

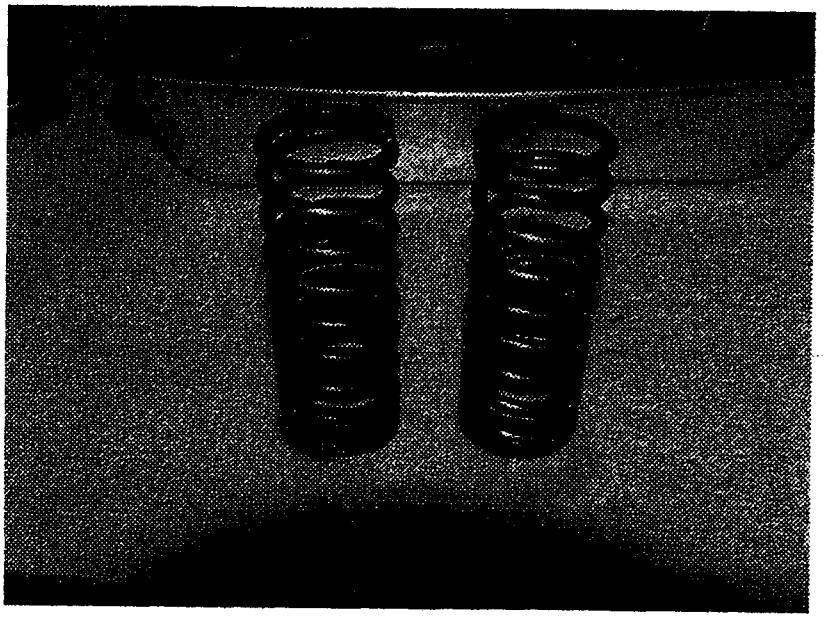
Note discoloration due to rust contamination



Photograph #5

Base bore

Note foreign material on surface



Photograph #6

Accumulator Springs

Note discoloration due to rust contamination

Photograph #7

Oil Seal Retainer

Note foreign material presence

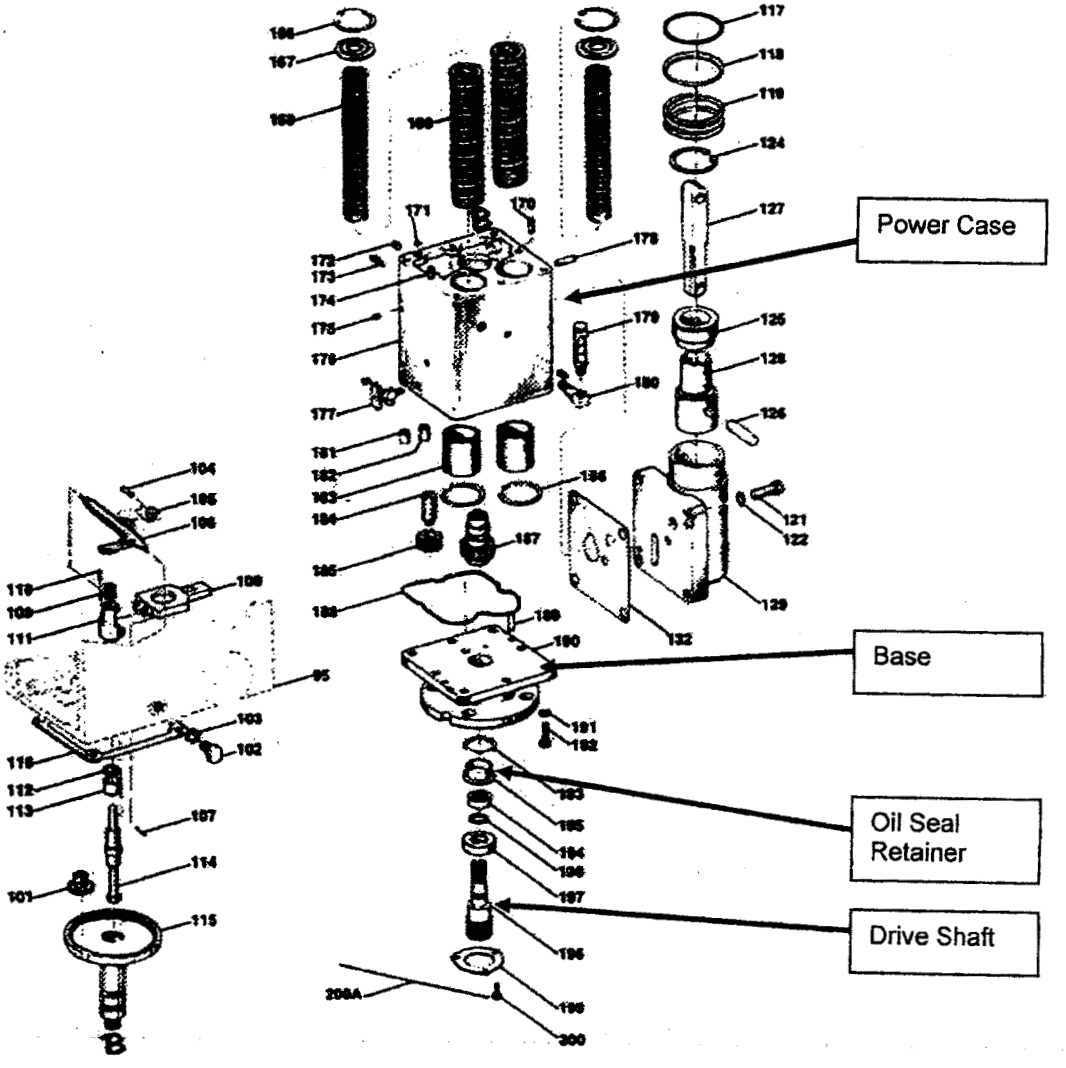


Figure #1
EGB Power Case

Conclusion:

The condition of the EGB-50PLS governor was in an operable state when received at Engine Systems. The Test As received was performed in accordance with manufacturer's instructions with no malfunctions or otherwise out of specification performance. Additional testing was performed to confirm that the governor was capable of developing sufficient work capacity to properly position the fuel racks during startup.

During disassembly and internal inspections there was evidence of foreign material presence in the power case. Based on the condition of the components and the location of the contaminants, it is not expected to have adversely influenced the performance of the governor assembly.

No indications were found to contribute to the fail to start issue.

REJOINDER TESTIMONY OF JAMES LEVINE

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816
Docket No. E-01345A-05-0826
Docket No. E-01345A-05-0827

November 3, 2006

EXHIBIT
tabbies
APS 95
Admitted

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IV. PALO VERDE PERFORMANCE 11

APS' Response to Data Request WRJ 21-8 ..... JML-1RJ

Unit 3 RCP 1A Oil Leakage Prior to October 2, 2005 Outage JML-2RJ

REJOINDER TESTIMONY OF JAMES LEVINE
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)
(Docket No. E-01345A-05-0826)
(Docket No. E-01345A-05-0827)

I. BACKGROUND

Q. PLEASE STATE YOUR NAME AND POSITION WITH APS.

A. My name is Jim Levine. I am the Executive Vice President Generation for Arizona Public Service Company ("APS" or "Company").

Q. DID YOU FILE REBUTTAL TESTIMONY ON BEHALF OF APS IN DOCKET NUMBER E-01345A-05-0816?

A. Yes. I filed Rebuttal Testimony on September 15, 2006.

Q. WHAT IS THE PURPOSE OF YOUR REJOINDER TESTIMONY IN THIS PROCEEDING?

A. The purpose of my Rejoinder Testimony is to respond to the October 13, 2006 Surrebuttal Testimony of William R. Jacobs, Jr., who provided testimony on behalf of the Utilities Division of the Arizona Corporation Commission ("ACC" or "Commission").

Q. ARE THERE OTHER WITNESSES TESTIFYING ON BEHALF OF APS IN RESPONSE TO DR. JACOBS' SURREBUTTAL TESTIMONY?

A. Yes. Robert Denton, the former President and Chief Executive Officer of Constellation Nuclear, which owned and operated the Calvert Cliffs and Nine Mile Point nuclear plants, will testify regarding the March Diesel Generator outage and use of Nuclear Regulatory Commission ("NRC") and Company

documents. Roger Mattson, a former senior official at the NRC, will testify regarding the RWT outage, Palo Verde performance, use of NRC and Company documents, and the proposed Nuclear Performance Standard. George Fitzpatrick, the chief executive of Harbourfront Group, Inc., with over 30 years experience in performing statistical analyses for electric and gas utilities, will testify regarding the proposed Nuclear Performance Standard. Finally, Peter Ewen, APS' Manager of the Revenue and Fuel Analysis and Forecasts Department, will testify regarding the quantification of outage costs.

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony begins by addressing Dr. Jacobs' rebuttal concerning the facts of outages at Palo Verde in 2005, whose prudence he challenges. Dr. Jacobs has not presented any evidence to counter my earlier conclusions in my Rebuttal Testimony that APS was prudent regarding those outages. First, the October RWT outage was directly caused by a new question from the NRC, and the NRC Regional Administrator stated that it was not a question that he would have expected APS to have addressed earlier. Dr. Jacobs' primary response is that this Commission should reject the statements of Dr. Mallett, the senior NRC official involved, which he made when he appeared before this Commission at the Commission's invitation. Second, although Dr. Jacobs has not established a basis for any disallowance, Palo Verde prudently performed maintenance during this outage that either shortened or prevented later outages or downpowers, which would significantly reduce any disallowance otherwise found. Third, the August reactor trip was caused by an individual's error in controlling the steam

generator water level, and such human error does not constitute management imprudence. Finally, the March diesel generator governor outage was not caused by imprudence because there was no indication that rust was in the governor, and Palo Verde properly stored and inspected the governor prior to installation.

Rather than focus on the facts of the 2005 outages in question, Dr. Jacobs devotes most of his Surrebuttal Testimony to *subsequent* correspondence between the Company and the NRC and to *subsequent* self-critical Company analyses. However, his testimony does not establish any causal connection between the matters discussed in those documents, e.g., cross-cutting issues and the yellow cornerstone, and the events that caused the outages at issue.

Finally, my Rejoinder Testimony addresses Palo Verde's overall performance. Palo Verde has performed very well over the last decade, and Dr. Jacobs' characterization of Palo Verde's 2005 performance is seriously flawed. For instance, there is no basis to describe Palo Verde's 2005 performance as "abysmal" when he challenges a total of only 23 days of outage time at the three units. We realize that the plant did not perform to the Company's high standards in 2005, but this does not change the fact that Palo Verde's high performance over the past decade has saved Arizona ratepayers a significant amount of money. We take seriously the improvement efforts that are in process. However, those improvement efforts have no bearing on the prudence of the four outages at issue.

III. PALO VERDE OUTAGES

A. October RWT Outage

Q. HAVE YOU REVIEWED DR. JACOBS' ANALYSIS OF THE OCTOBER RWT OUTAGE ON PAGES 23-34 OF HIS SURREBUTTAL TESTIMONY?

A. Yes.

Q. WHAT IS YOUR RESPONSE TO DR. JACOBS' CONCLUSION THAT PALO VERDE WAS IMPRUDENT?

A. Dr. Jacobs is unable to rebut the facts set forth on pages 14-17 of my September 15, 2006 Rebuttal Testimony regarding this outage. The October RWT outage was initiated because an NRC inspector asked a question about the possibility of air ingestion during certain scenarios involving the refueling water tanks, and the Company did not have an immediate answer. As stated by the NRC's Regional Administrator, Bruce Mallett, before the ACC on January 26, 2006, this was a new question. Furthermore, Dr. Mallett responded to Commissioner Mayes' specific question about whether Palo Verde should have anticipated the question by stating that "we didn't determine that they should have found it beforehand."

Q. DOES DR. JACOBS RESPOND TO THE STATEMENTS MADE BY DR. MALLETT?

A. Yes. Dr. Jacobs states on page 32 of his Surrebuttal Testimony that "Dr. Mallet's opinion on this is not supported by the facts" and on page 33 that "Dr. Mallet's oral statements . . . are not consistent with the NRC's various written materials." Dr. Mallett's statements to the ACC, that the NRC raised a new question and Palo Verde should not have recognized the issue earlier, do not conflict with the

NRC's inspection report -- a report that Dr. Mallett, the senior NRC official involved, approved.

Q. PLEASE RESPOND TO DR. JACOBS' COMMENTS ON PAGE 33 OF HIS SURREBUTTAL TESTIMONY REGARDING NRC RESIDENT INSPECTOR WARNICK.

A. First, Dr. Jacobs fails to respond to the substance of the points I made on page 17 of my Rebuttal Testimony regarding Mr. Warnick's reported conversation with Dr. Jacobs. APS in no way disagrees with Dr. Jacobs' statement that "NRC resident inspectors [are] a valuable and credible source of information," but this is not responsive to my testimony. As I pointed out, Mr. Warnick was not a member of the inspection team, and unlike Dr. Mallett, did not sign off on the inspection report. Finally, any statement by Mr. Warnick that the outage was avoidable does not equate to evidence, let alone proof of imprudence. As Dr. Mattson explains, the NRC does not use a prudence standard, and an NRC employee's statement that an outage was avoidable would be made taking full advantage of hindsight. Obviously, many events are "avoidable" in hindsight that could not have been reasonably foreseen.

Q. DO YOU AGREE WITH DR. JACOBS' STATEMENT ON PAGE 40 OF HIS SURREBUTTAL TESTIMONY THAT "MR. EWEN'S CLAIM THAT THE WORK PERFORMED DURING THE RWT OUTAGE WOULD REDUCE THE REPLACEMENT POWER COSTS ATTRIBUTED TO THE RWT OUTAGE IS FLAWED"?

A. No. As addressed in my Rebuttal Testimony on pages 18-20, Palo Verde performed a significant amount of work during the October RWT outage, including some work that prevented or reduced the length of a later outage or downpower. To clarify, we are not claiming that all maintenance performed

during this outage offsets the replacement power costs associated with the RWT outage. Rather, we are stating that had certain work not been performed during the outage, the equipment in question would have caused later unplanned outages or downpowers that would have resulted in separate replacement power costs. Some of this work, such as the work to repair Reactor Coolant Pump ("RCP") oil seals, already has been determined by GDS and Dr. Jacobs to be prudent when it occurred during other outages.

If this Commission determines, as the facts surrounding the outage support, that Palo Verde was not imprudent with the RWT outage, then an evaluation of this other work is unnecessary. If the Commission determines that part or all of the RWT outage was imprudent, any disallowance of associated replacement power costs should be offset by the replacement power costs that were avoided because of the performance of this other work during the outage in question. The amount of these avoided costs is set forth in Peter Ewen's September 15, 2006 Rebuttal Testimony.

Contrary to Dr. Jacobs' assertion that there is no evidence to support APS' claims, the Company's response to data request WRJ 21-8 (provided as Attachment JML-1RJ) demonstrates that had this work not been performed during the RWT outage, it would have resulted in later outages that would have resulted in separate replacement power costs.

As discussed in the data request response, had Unit 2 not been shut down for the RWT outage, it would have had to have been shut down shortly thereafter to

repair the RCP 2A oil seal. As stated in the response to WRJ 21-8(b), Palo Verde initiated unplanned outages to repair RCP oil seals when the "pump-up" rate for the oil, which directly corresponds to oil leakage rate, was between 3-12 hours. The Unit 2 RCP 2A oil leakage had worsened to the point that it was well within this range. As shown by an attachment to WRJ 21-8(c) (document APS08334), the pump-up rate for Unit 2 RCP 2A was approximately every 9 hours during the last days prior to the October RWT outage. This 9 hour pump-up rate was worse than the pump-up rate in Unit 3 RCP 1A when Unit 3 was shut down on October 2, 2005 to make necessary repairs to the RCP oil seals to correct the oil leakage. As shown in Attachment JML-2RJ, the oil leakage for Unit 3 RCP 1A had decreased to approximately 12 hours during the days before the October 2 outage. Palo Verde prevented later replacement power costs by repairing the Unit 2 RCP 2A oil seals during the October RWT outage, and this amount should be subtracted from any costs that the Commission determines should be disallowed for the RWT outage.

B. August Reactor Trip Outage

Q. HAVE YOU REVIEWED DR. JACOBS' ANALYSIS OF THE AUGUST REACTOR TRIP OUTAGE ON PAGES 20-23 OF HIS SURREBUTTAL TESTIMONY?

A. Yes.

Q. WHAT IS YOUR RESPONSE TO DR. JACOBS' TESTIMONY ON THE REACTOR TRIP?

A. On pages 21-22 of his Surrebuttal Testimony, Dr. Jacobs attempts to combine the cause of the reactor trip with other problems that had occurred at Palo Verde,

such as NRC-identified cross-cutting issues. However, his testimony establishes no connection between these other issues and the reactor trip. Dr. Jacobs has also provided no direct evidence that Palo Verde management was imprudent regarding this reactor trip. The reactor trip was primarily the result of improper actions of an individual operator. Dr. Jacobs incorrectly states on page 21 of his Surrebuttal Testimony that "[p]roblems with the Digital Feedwater Controls System (DFWCS) were not identified in a timely manner and effectively resolved." This is inaccurate because the problem was not with the DFWCS, but with the perception of the system by operators. This perception problem is illustrated by Root Cause #2 for the outage, quoted on page 21 of Dr. Jacobs' Surrebuttal Testimony, which discusses "operational strategies to cope with perceived system instability at low power levels." (Emphasis added) Had the operator that overfilled the steam generator simply left the system in automatic control, the reactor would not have tripped.

Q. PLEASE EXPLAIN WHY YOU BELIEVE THIS INCIDENT WAS NOT "REFLECTIVE OF THE CROSS-CUTTING ISSUES IN HUMAN PERFORMANCE AND PROBLEM IDENTIFICATION AND RESOLUTION" AS DR. JACOBS ASSERTS AT PAGES 21-23 OF HIS SURREBUTTAL TESTIMONY.

A. First, let me reiterate my understanding that human error does not equate to imprudence. As this Commission has previously pointed out, Palo Verde was built and is now operated "by human beings, not mistake – proof automata" (Decision No. 54204 at p. 15), and APS is not charged with achieving "unobtainable goals of absolute perfection." (Decision No. 55118 at p. 20). As I also pointed out in my Rebuttal Testimony (p. 22), Palo Verde has performed well in comparison to other plants with respect to unplanned reactor trips.

Consistent with our goal to continuously improve performance, we made certain procedural changes and increased training following the reactor trip. However, those improvements do not detract from the fact that the reactor trip was an isolated event caused primarily by the failure of an individual operator to follow procedures, and was not the result of imprudence by Palo Verde management. Dr. Jacobs' quotation from various passages of the root cause report does not alter this conclusion. In fact, the Company's "CRDR" regarding problem identification and resolution from which Dr. Jacobs also quotes extensively criticizes the CRDR/root cause process, stating that the "[p]ropensity to create procedure revisions or formal training as a corrective action to isolated occurrences reduces ownership and accountability," page 14 of CRDR 2780286 (GDS Report, Attachment 7). Prudence does not require avoidance of all such isolated occurrences, and human errors will occur even under the most prudent circumstances.

C. March Diesel Generator Governor Outage

Q. HAVE YOU REVIEWED DR. JACOBS' ANALYSIS OF THE MARCH DIESEL GENERATOR OUTAGE ON PAGES 17-20 OF HIS SURREBUTTAL TESTIMONY?

A. Yes.

Q. WHAT IS YOUR RESPONSE TO THIS TESTIMONY ON THE DIESEL GENERATOR OUTAGE?

A. Although I agree with some statements made by Dr. Jacobs, I disagree with much of his analysis and with his conclusion that Palo Verde was imprudent.

I agree with Dr. Jacobs that because this outage occurred prior to implementation of the PSA, it is not subject to a disallowance. Apparently, Dr. Jacobs has withdrawn his earlier recommendation that the costs associated with this outage not be included in establishing base fuel costs.

Additionally, I agree with Dr. Jacobs that diesel generators are important pieces of equipment. However, Palo Verde has many important pieces of equipment, in addition to the diesel generators, and we treat each piece of equipment accordingly. As with most pieces of important equipment, the diesel generators are part of an extensive redundant system. As Dr. Jacobs acknowledges on page 18 of his Surrebuttal Testimony, the diesel generators are only necessary if there is a loss of all offsite power simultaneous with certain major plant accidents. This combination of events is extremely rare. Additionally, if one diesel generator fails to start during this scenario, it is still backed up by an identical redundant system that would supply all necessary electrical power. By pointing out these facts, I do not intend to minimize the role of the diesel generators. However, they are one of literally hundreds of important pieces of equipment that we inspect and maintain pursuant to manufacturer recommendations and governing plant procedures.

Q. ON PAGE 20 OF HIS SURREBUTTAL TESTIMONY, DR. JACOBS STATES THAT "THE COMPANY DID NOT USE A STANDARD OF CARE COMMENSURATE WITH THE IMPORTANCE OF THE DIESEL GENERATOR." DO YOU AGREE WITH THIS STATEMENT?

A. No. As discussed above, although the diesel generators are important, a malfunction does not mean that Palo Verde was imprudent. Dr. Jacobs does not

identify what he believes the standard of care should be for this equipment. As I described in my Rebuttal Testimony on pages 26-28, Palo Verde stored the diesel generator governor in accordance with the manufacturer's recommendations. Additionally, Palo Verde reasonably inspected the governor prior to installation, and as supported by the failure analysis for the diesel generator, which is provided as Attachment JML-2RB to my Rebuttal Testimony, any rust could only be identified through disassembly of the governor. These actions provided the appropriate standard of care for the diesel generator governor.

Q. DO YOU AGREE WITH DR. JACOBS' CONCLUSIONS THAT PALO VERDE COULD HAVE PREVENTED THIS PROBLEM BY SAMPLING THE OIL DIFFERENTLY?

A. No. As stated on page 9 of the root cause investigation (Attachment 10 to the GDS Report), a sample of the lube oil on April 19, 2004 showed only 104 ppm of water, well within the upper limit of 1500 ppm. Palo Verde had no reason to believe water was an issue. Additionally, as discussed on page 16 of the root cause investigation, following the outage, Palo Verde personnel performed a careful review of the process used for changing and sampling oil and could not determine any potential source of water addition.

IV. PALO VERDE PERFORMANCE

Q. HAVE YOU REVIEWED PAGES 2-14 OF DR. JACOBS' SURREBUTTAL TESTIMONY REGARDING PALO VERDE'S PERFORMANCE?

A. Yes.

Q. WHAT IS YOUR RESPONSE TO DR. JACOBS' CONCLUSIONS IN THIS SECTION OF HIS SURREBUTTAL TESTIMONY?

A. Dr. Jacobs' arguments in this section are unconvincing, and in some areas are even contradictory. For example, Dr. Jacobs argues both ways, first focusing on a small portion of Palo Verde's past performance and then later stating that the past is irrelevant. On page 3 he states that "when considering any individual specific outage, it is neither necessary nor appropriate to consider prior performance and, in fact, the issue of prior performance is irrelevant when determining the responsibility for additional costs incurred due to any individual imprudent event." Therefore, although Dr. Jacobs states that past performance is "irrelevant" and not "appropriate," significant parts of the GDS Report and of his testimony focus on past Palo Verde performance.

Dr. Jacobs takes an inappropriately limited view of performance at Palo Verde. He takes issue with looking at performance over the past decade, and instead compares performance from the 2000-2002 timeframe to performance during the 2003-2005 timeframe. Palo Verde's performance during 2000-2002 was one of the best periods of performance since the operation of the plant began. Performance during 2003-2005 was lower, not only due to the higher number of unplanned outages in 2005, but also due to two steam generator replacements. The steam generator replacements involved lengthy outages that directly affected measured performance, but not due to any fault of Palo Verde. Similarly, with respect to the 2005 unplanned outages, Dr. Jacobs only challenges four of these outages totaling 23 days. As Dr. Mattson quantifies in his Rejoinder Testimony, this contributes a very small reduction in Palo Verde's capacity factor during 2005. When one considers these facts, it is clear that both

GDS' initial claims in its report that 2005 Palo Verde performance was "poor," as well as Dr. Jacobs' more extreme assertions in his Surrebuttal Testimony that Palo Verde performance was "abysmal" are incorrect.

Q. DR. JACOBS STATES ON PAGE 4 OF HIS SURREBUTTAL TESTIMONY THAT MANAGEMENT ALLOWED PERFORMANCE AT PALO VERDE TO DECLINE "FOR SEVERAL YEARS WITHOUT CORRECTIVE ACTION." IS THIS STATEMENT ACCURATE?

A. No. Dr. Jacobs' statement that APS did not take any corrective action for years while performance declined is incorrect. Palo Verde conducted a number of assessments and instituted a number of programs prior to 2005 that were appropriate given the available performance indicators. The current Performance Improvement Program is, in significant part, an effort to unify and address the earlier improvement efforts in a more programmatic manner. APS provided a number of documents evidencing these efforts to ACC Staff in response to data requests. See responses to PB 1.14, 1.21, 1.22. For example, PB 1.22 sought a description of "performance improvement program or initiatives planned or implemented in 2004 or 2005." Included in the response to this request was a program description of the Palo Verde Prevent Event Strategies 2004 which was directed at reducing significant human performance events across all departments. See JML – WP1RJ.

Q. ON PAGES 4-5 OF HIS SURREBUTTAL TESTIMONY, DR. JACOBS STATES THAT YOUR REBUTTAL TESTIMONY DOES NOT AGREE WITH EARLIER STATEMENTS THAT YOU MADE REGARDING PERFORMANCE IN 2005. DO YOU AGREE THAT YOUR STATEMENTS WERE INCONSISTENT?

A. No. Dr. Jacobs takes statements from my testimony and the Performance Improvement Plan out of context. On page 10 of my Rebuttal Testimony I state

that "the decrease in performance is directly related to the greater than typical number and duration of plant outages that we experienced in 2005." Here, I was talking about the 2005 capacity factor at Palo Verde in response to a follow-up question to my discussion about capacity factor in the previous answer. On the other hand, the discussion of performance in the Performance Improvement Plan is not focused on economic performance. In fact, the same page from which Dr. Jacobs quotes expressly states that "while the economic performance at Palo Verde continues to be at or near the top industry quartile there is a need for improvement in implementing programs and processes."

Q. DOES THIS CONCLUDE YOUR REJOINDER TESTIMONY?

A. Yes.

Attachment JML-1RJ

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY-FIRST SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY
Docket No. E-01345A-05-0816; E-01345A-05-0826 and E-01345A-05-0827
SEPTEMBER 28, 2006

WRJ 21-8 Referring to Mr. Ewen's discussion of the Unit 2 RWT outage beginning on page 21 of his rebuttal testimony, please provide:

a. Any documents that demonstrate that Unit 2 was scheduled for an outage for the period from October 11, 2005 to the next planned refueling outage.
b. The criteria used by APS to decide when RCP seal oil leakage is excessive and it is necessary to shut a unit down to repair the RCP oil seals.
c. The Unit 2 RCP seal oil leakage measured daily for each day, or as often as it is available, from January 1, 2005 to October 11, 2005.
d. The Unit 3 RCP seal oil leakage rate prior to the Unit 3 shutdowns in May 2005 and July 2005.
e. Any documents that demonstrate that Unit 2 power reduction to perform main feedwater pump repair work and heater steam drain repair work would have been required during the period between October 11, 2005 and the next scheduled Unit 2 refueling outage. Include the criteria that would apply to determine the need for the power reduction and equipment operating data that demonstrate the need for the power reduction.

Response:

a. Unit 2 was not scheduled for an outage during the October 2005 timeframe, however, the criteria provided in response to parts b and c of this request indicate that an unplanned outage in Unit 2 was probable based on previous experience.

Palo Verde constantly monitors the status of equipment to determine when an outage will be necessary and the team is prepared to perform maintenance when a short notice outage is initiated so that equipment reliability issues are addressed before conditions deteriorate further and possibly result in a longer or less advantageously timed outage.

b. The decision of when to shut down a unit to repair RCP oil seals because of excessive RCP oil seal leakage is based on management and engineering judgment. Numerous criteria are analyzed to determine the best time to shut down for these repairs. These criteria include time until the next shutdown, other maintenance that must be performed, status of the other units, and the extent of the oil leakage.

The extent of the oil leakage is determined by how frequently oil must be added to the RCP thrust bearing reservoir. As oil leaks from the RCP oil seals, the level of oil in the RCP thrust bearing reservoir decreases. The leaked oil is collected in an external Hydraulic Power Unit ("HPU") reservoir. When the RCP thrust bearing reservoir oil level indicates low alarm, the HPU lift pump is manually started to "pump up" oil from the HPU reservoir to the RCP thrust bearing reservoir to return the oil level to the normal range. A pump-up is required when the reservoir level is at approximately 64%. The pump-up frequency is used to determine the extent of oil leakage and whether a unit should be shut down to repair or replace oil seals. Palo Verde has shut down to replace RCP oil seals when the time between pump-ups occurs in the range of 3 - 12 hours.

c. When Palo Verde shut down Unit 2 in October 2005 to respond to questions regarding air entrainment, a separate shutdown to replace various Unit 2 RCP oil seals, based on previous experience, was probable. At the time of the October outage, the time between pump-ups for Unit 2 RCP 2A was less than 12 hours and decreasing (as shown in yellow on attachments) and was approximately every 3 days and decreasing for Unit 2 RCP 1A (as shown in green on attachments.) Palo Verde engineering and management were closely watching these RCP oil seals to determine if a shutdown was necessary. As discussed above, RCP 2A had entered the range of time when Palo Verde has performed a shutdown to repair or replace RCP oil seals.

Documents showing the pump-up and leakage rates for the Unit 2 RCP oil seals from January 1 to April 2, 2005, and May 21 to October 11, 2005, are provided as APS08330 through APS08334.

- The first chart provides data from January 1 to April 2, 2005. See APS08330.
- On April 1, 2005, Unit 2 entered a planned refueling outage. The unit was returned to service on May 20.
- The next chart provides data from May 20 through July 1, 2005. See APS08331.
- The next chart provides data from July 1 through September 27, 2005. See APS08332.
- The final two charts (APS08333 and APS08334) provide weekly snapshots from September 27 - October 4 and October 4 - 11, 2005. These display in detail the information monitored by management during the days preceding the October shutdown.

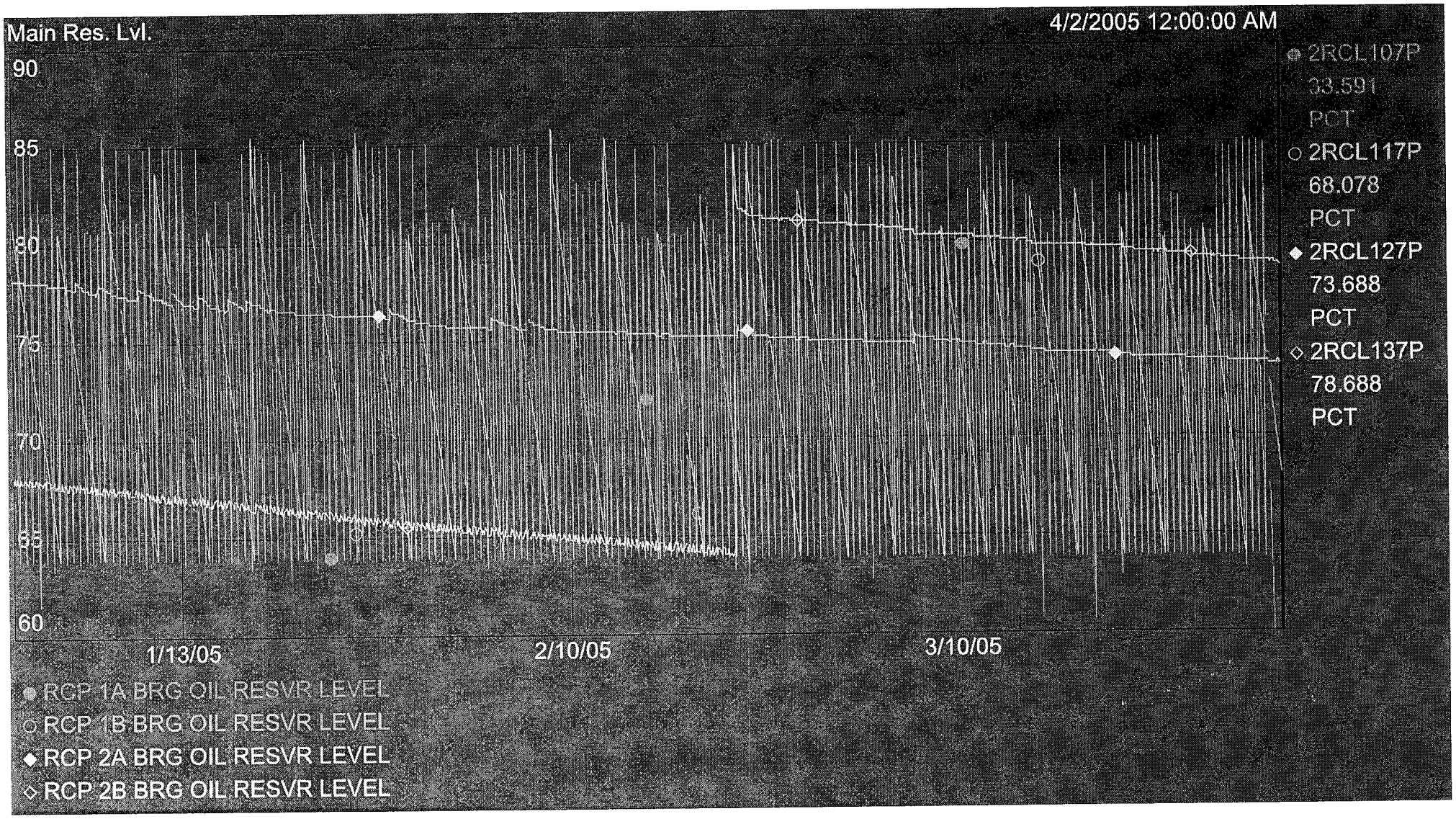
d. In May 2005, the time between pump-ups for the Unit 3 RCP 1A oil seal had decreased to about every 3 hours when Unit 3 was shut down to replace pressurizer heaters and to replace oil seals. In July 2005, the time between pump-ups for the Unit 3 RCP 1A oil seal had decreased to about every 4 hours when Unit 3 was shut down to replace the oil seal.

e. As noted above, Palo Verde constantly monitors the status of equipment and impacts to safety and operation to determine if and when an outage will be necessary.

Down power of the unit and subsequent repairs are made based on potential impacts to personnel safety and equipment operation/reliability. The decision of when to make these repairs is based on management and engineering judgment.

Documents describing component operations related to main feedwater pump oil seal repair and heater steam drain repair work are attached as APS08325 through APS08329, which are confidential and are being provided pursuant to an executed Protective Agreement.

Witness: Jim Levine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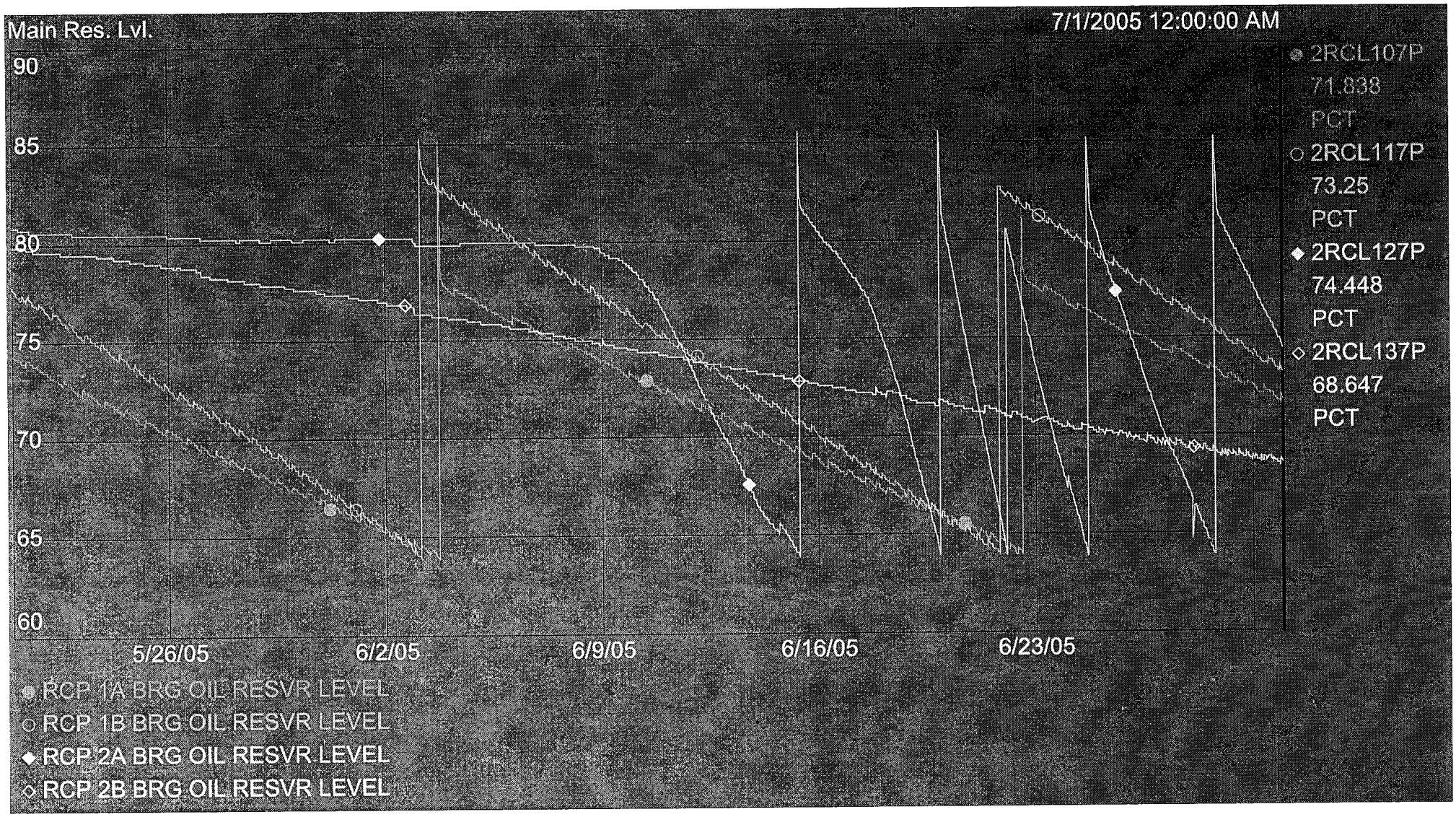
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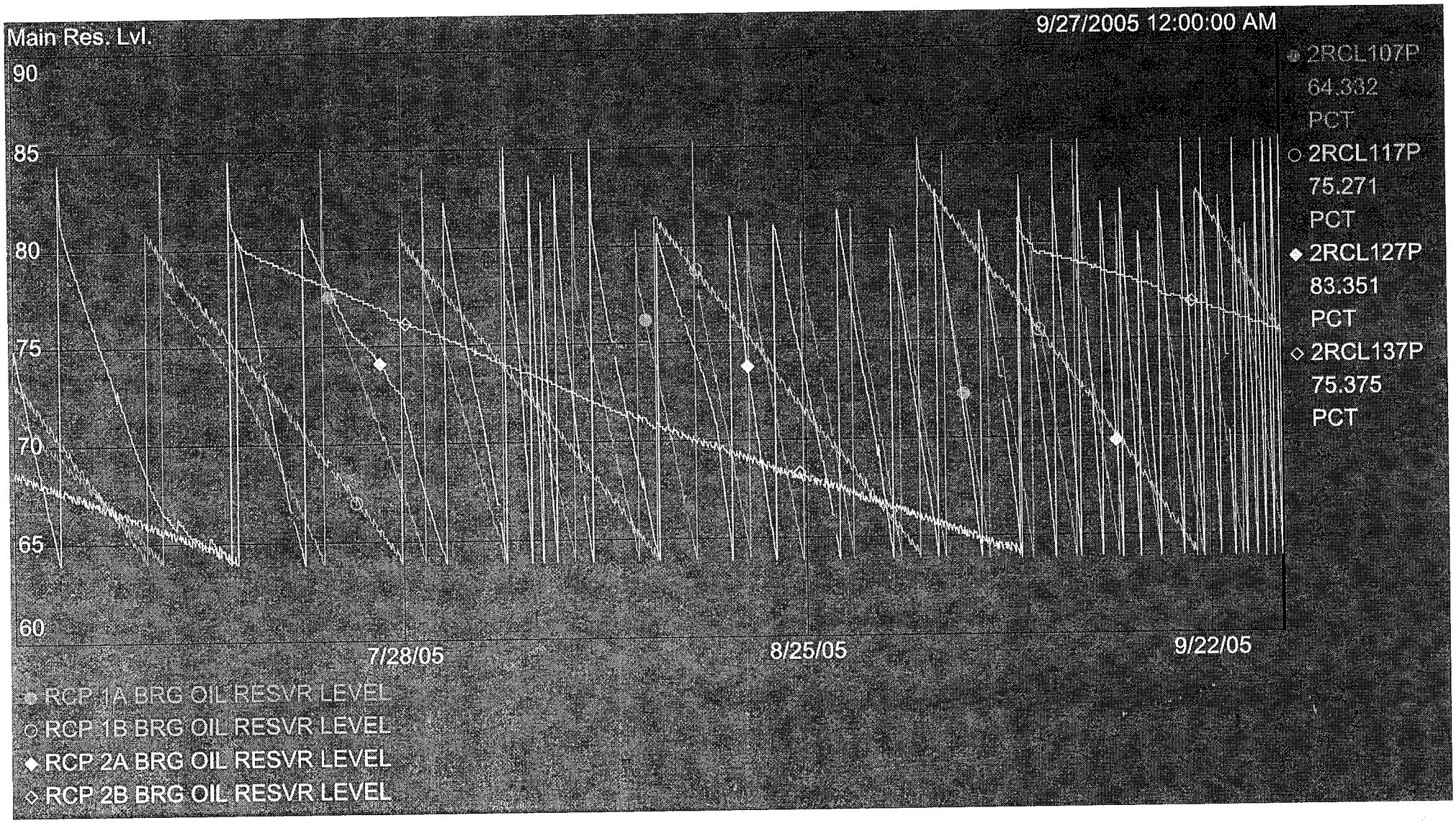
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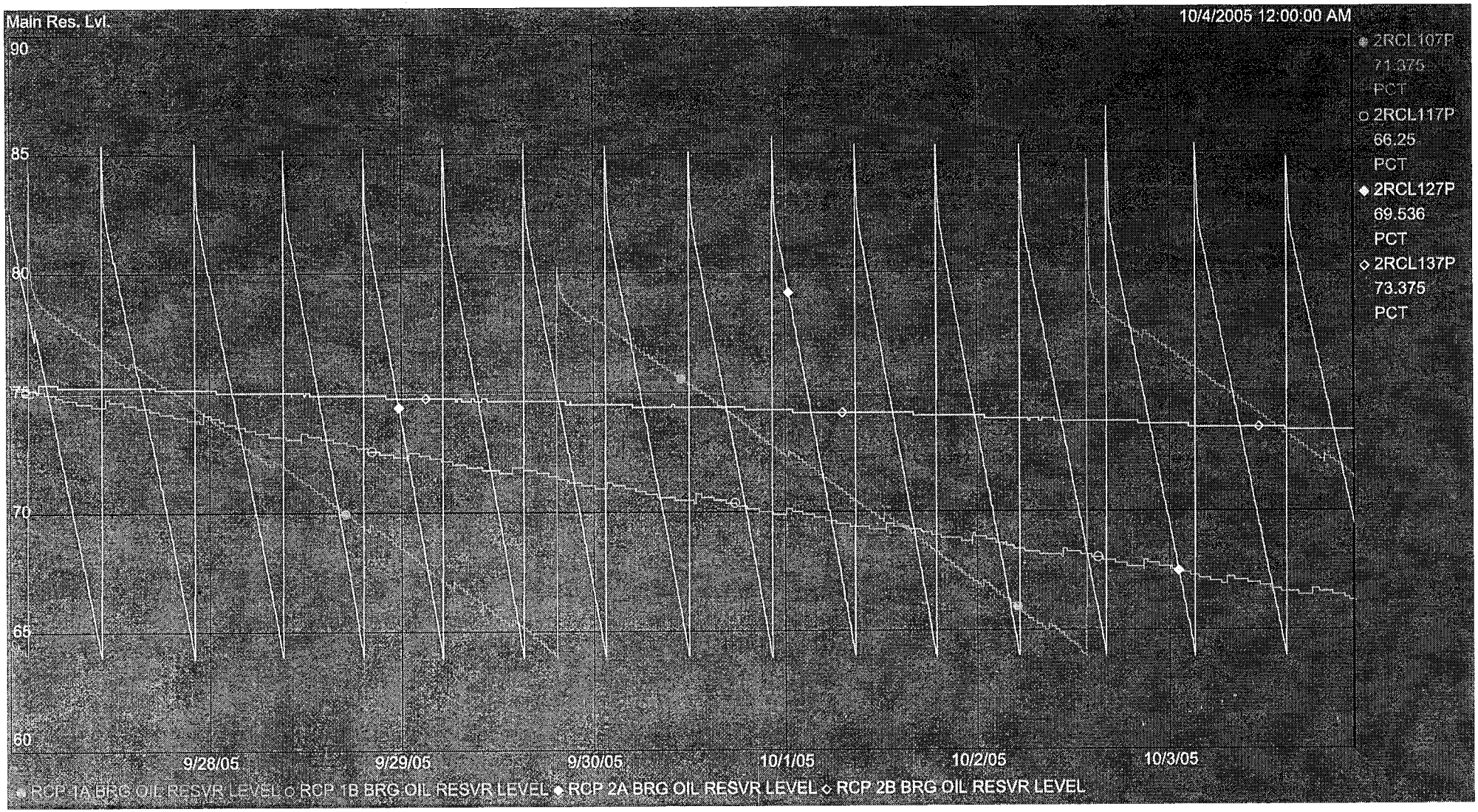
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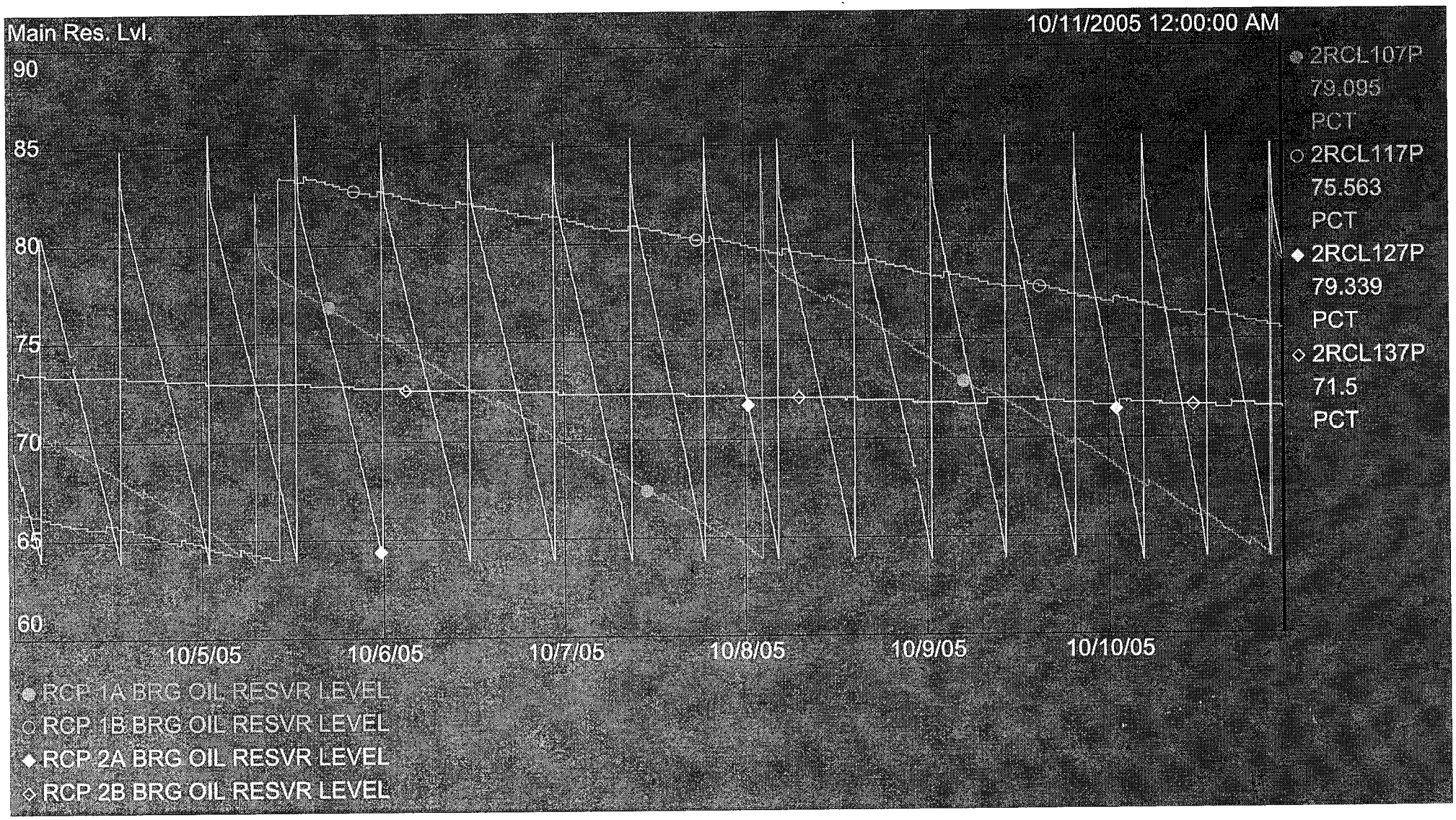
APS08333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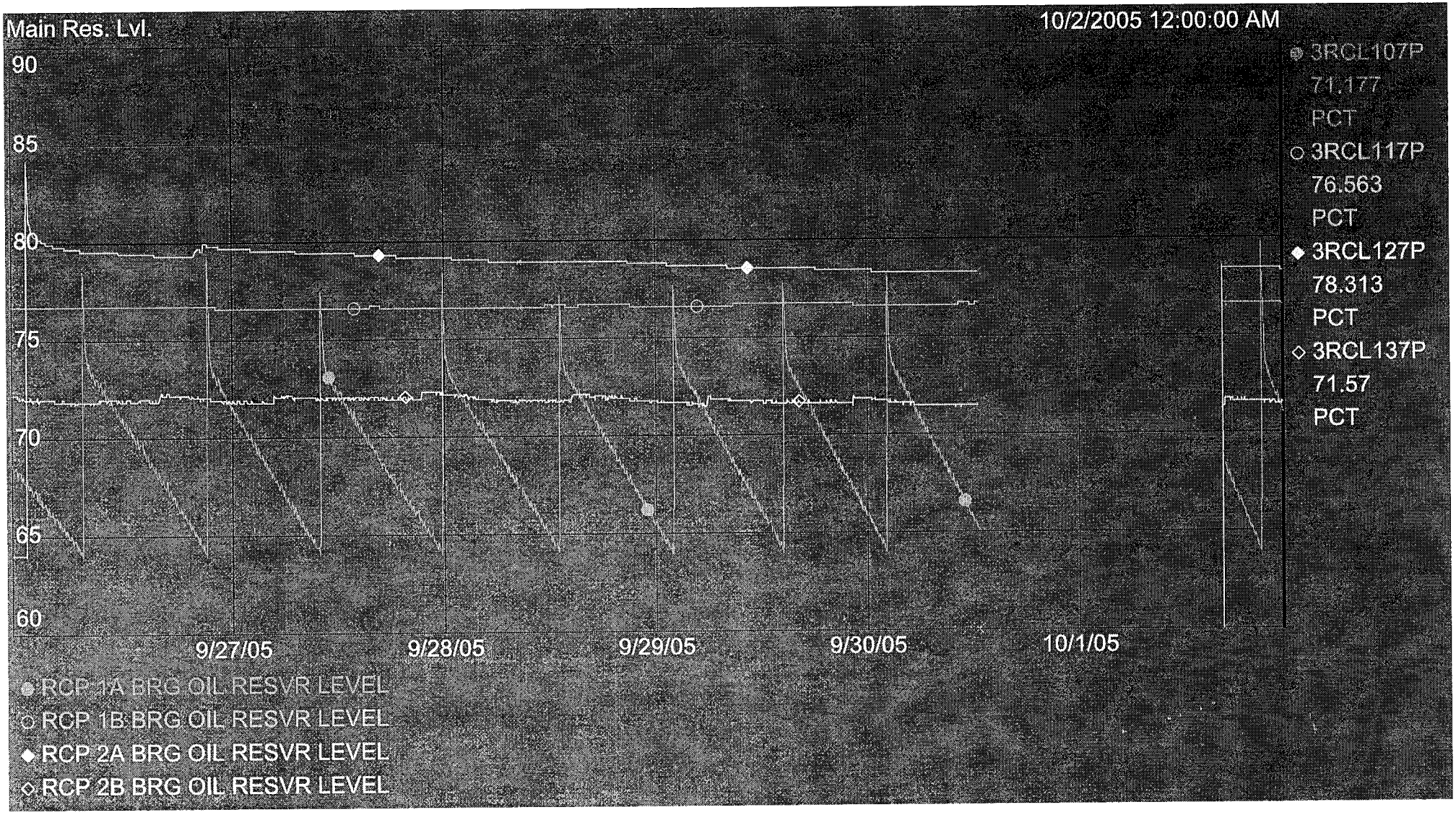
APS08334

Attachment JML-2RJ


Main Res. Lvl.
10/2/2005 12:00:00 AM
90
85
80
75
70
65
60
9/27/05
9/28/05
9/29/05
9/30/05
10/1/05
3RCL107P
71.177
PCT
3RCL117P
76.563
PCT
3RCL127P
78.313
PCT
3RCL137P
71.57
PCT
RCP 1A BRG OIL RESVR LEVEL
RCP 1B BRG OIL RESVR LEVEL
RCP 2A BRG OIL RESVR LEVEL
RCP 2B BRG OIL RESVR LEVEL