Rand
SANTA MONICA, CA

October 26, 1984

Mr. J. C. Peterson
Room AR-5037
Nuclear Regulatory Commission
Washington, DC 20555

Dear Jim:

I appreciated receiving a copy of your study on incentive regulation and the other help you gave me by phone. As I promised, enclosed is a copy of my testimony. You may find particularly interesting the discussion of incentive plans on pp. 35-52.

Of course, I would welcome any comments you have, especially since I hope to expand the study of incentive regulation, for distribution to a wider audience.

With our mutual interests I hope we can stay in touch.

Sincerely,

Lee

Leland L. Johnson
Senior Economist

LLJ:jd
Enclosure as noted

Wash, D.C office 296-5000

THE RAND CORPORATION, 1700 MAIN STREET, P.O. BOX 2138, SANTA MONICA, CALIFORNIA 90406-2138, PHONE: (213) 393-0411

Q. Please state your name and business address.

A. Leland L. Johnson, The Rand Corporation, 1700 Main Street, Santa Monica, California 90406.

Q. With whom are you affiliated?

A. I am a Senior Economist with The Rand Corporation. During my 28 years of career experience within and outside of Rand, I have been particularly concerned with how regulatory policies and other government activities interact with market forces to affect the behavior of firms, especially those in the telecommunications and electric utility industries.

Q. Please summarize your educational background and professional experience.

A. I received a B.S. degree in Business Administration from the University of Oregon in 1952, an M.A. degree in Economics from the University of Oregon in 1953, and a Ph.D. degree in Economics from Yale University in 1957.

After serving for a year as Instructor on the Yale Economics Department faculty in 1956-57, I joined The Rand Corporation. One of my early assignments involved examination of the effects of communications satellites on international telephone rates. This involved taking into account the extent to which AT&T would have incentives to use the new technology efficiently, in light of its investments in other technologies and the role of government regulatory policies.

As an outgrowth of that work a Rand colleague, Harvey Averch, and I wrote an article, "Behavior of the Firm under Regulatory Constraint," that appeared in the *American Economic Review*, December 1962. We

hypothesized that a firm facing a binding rate of return constraint on its rate base, and whose allowed cost of capital exceeds its actual cost of capital, has an incentive to engage in excessively capital-intensive production processes. This article has been widely referenced and discussed, and a number of empirical studies have addressed the quantitative significance of this potential bias, particularly in electric utilities. This bias is commonly referred to as the "Averch-Johnson" or "A-J" effect.

In 1967, I left Rand to become Director of Research of the President's Task Force on Communications Policy in Washington, D.C. The Task Force was chaired by Eugene Rostow who was then Undersecretary of State. The research agenda for the Task Force focused on ways that the introduction of competition in the heavily regulated telephone industry would affect its economic efficiency.

After the Task Force report was transmitted to the President in late 1968, I returned to Rand and served until 1978 as manager of Rand's Communications Policy Program. Again, questions of how firms are likely to behave under alternative regulatory regimes was a key component of my work.

In addition, I led two projects directly involving electric utilities. One dealt with analysis of federally funded demonstration projects, including a study of the commercialization of light water nuclear reactor technologies. The objective was to determine the structure of incentives, for both private industry and government agencies, that would increase the chances that technologies funded by the government in their early stages of development would be commercially successful.

The second involved analysis of commercializing breeder reactor technology, taking into account the experience with the Clinch River project whose development was partially financed by a consortium of electric utilities.

In 1978, I left Rand to become Associate Administrator for Policy Analysis and Development with the National Telecommunications Information Administration, U.S. Department of Commerce, in Washington, D.C. Growing competition among telecommunications firms raised many pressing questions about the appropriate market structure for capital intensive industries subject to rapid technological change.

In 1979, I rejoined Rand and during 1980-83 was Director of Rand's Energy Conservation Program. Among other responsibilities, I examined the incentives provided under the Public Utility Regulatory Policies Act for electric utilities to purchase power from cogenerators and small power plant operators under the "avoided" cost criteria defined in the Act. I also examined the potential of cogeneration, solar, and other decentralized power sources to substitute for central-station power.

Appendix A contains my detailed resume, including other professional activities and my major publications.

Q. In what capacity are you testifying today?

A. Because of the Commission's interest in a regulatory incentive plan for APS, the Company offered to provide up to $50,000 to fund testimony by an outside organization chosen by the Commission to independently assess the incentive concerns of the Commission and the particular incentive plan proposed by APS. Rand was chosen for this task because of its long experience in the electric utility field and

because it is a nonprofit corporation with a long-standing record of independence and objectivity. Let me emphasize that, although APS is funding this testimony, it has no control whatsoever over the scope of my investigation or my conclusions. Moreover, the views expressed here are my own and do not necessarily reflect those of Rand or of its research sponsors.

Q. What is the purpose of your testimony with respect to regulatory incentives?

A. I have three main objectives:

First, I examine the incentives faced by APS under current regulatory policy, taking particularly into account issues relating to CWIP within and outside of the rate base and the effect of rate shock on the efficient use of generating capacity.

Second, I seek to develop, for the Commission's consideration, incentive mechanisms that hold promise for improving utility performance. This task involves identification of criteria by which such mechanisms should be judged, and a survey of experiences in other states with incentive programs that the Commission should take into account.

Third, I assess the regulatory incentive plan proposed by APS in terms of how it is likely to affect the incentives of APS to operate efficiently, and to offer recommendations for modifying or rejecting the plan.

My testimony consists of a study of incentive regulation attached as a single exhibit. I will refer to specific pages in that exhibit in response to your questions.

Q. What are your major conclusions with respect to your first objective of examining incentives under current regulatory policy?

A. I have three major conclusions:

First, it is impossible to determine whether existing regulatory policies on balance encourage APS to overinvest or underinvest in generating facilities, because key factors move in opposite directions and one cannot disentangle their effects. In particular, while including CWIP in the rate base may generate perverse incentives, the *exclusion* of CWIP from the rate base can *also* generate perverse incentives for utilities with severe problems of cash flow (pp. 14-20).

Second, there is nothing in economic principles to support the notion that cost recovery from ratepayers should begin only after plant is used and useful. It is notable that prices set by competitive firms can also cover some of the costs of CWIP, depending on relationships between price movements and marginal cost (pp. 21-23).

Third, traditional accounting techniques produce rate shocks that take us in *exactly* the wrong direction in terms of economic efficiency. It forces prices upward at the very time that the costs of using plant are declining. Given that prices should reflect marginal costs as a basic incentive to *both* APS and its consumers to behave efficiently, rate shock should be reduced. This can be done by a variety of techniques, including putting CWIP in the rate base (pp. 23-34).

Q. You said that competitive firms may also recover a portion of CWIP from current customers. But don't competitive firms generally capitalize CWIP carrying costs?

A. Yes, but one cannot determine how competitive firms set prices by simply looking at the way they keep their books, as I explain on p. 22.

Q. What are your major conclusions with respect to your second objective of seeking an alternative incentive program for APS?

A. Incentive programs used in other states are subject to a number of problems:

- It is impossible to determine persuasively whether they have improved utility performance (pp. 38-42).
- The "partial" nature of incentive programs may distort incentives so that attempts by the utility to gain rewards in the performance area targeted for improvement may result in less efficient behavior in other areas (pp. 42-45).
- It is difficult to control for external effects, including the identification and response to conditions of force majeure (pp. 45-46).
- "Subsequent round" offsets--regulatory action after rewards or penalties are conferred--may, in effect, take away or reduce rewards and penalties (pp. 46-49).
- A dilemma arises in setting the size of penalties and rewards that are large enough to be effective and at the same time don't adversely affect the utility's cost of capital (pp. 49-50).
- Finally, the credibility of incentive plans is compromised because of possible pressures on regulators to modify the reward structure if a utility consistently earns large rewards,

and because of the effects of subsequent-round offsets (p. 50).

In view of these problems, I cannot suggest a detailed incentive program for APS that would not itself generate controversy. A better approach is to critique the APS proposal in light of the desirable characteristics and the problems I have identified with incentive programs in Sec. III of my exhibit.

Q. What are your basic conclusions with respect to the APS proposal?

A. The APS proposal is notable on two counts. First, it recognizes the importance of including a combination of incentive mechanisms that together may lead to more favorable results than if only one were offered. Second, it is simple. The criteria by which performance is to be judged are straightforward, with rewards and penalties well defined.

I conclude that the proposed $3.15 billion ceiling on Palo Verde costs for ratemaking purposes is too high, and that the operating incentives proposal for Four Corners and Palo Verde should be revised. However, APS should be able to modify its proposal without adding undue complexity. As revised, the plan will provide a reasonably sound basis for the Commission to make decisions in Phase II of the current rate proceeding.

Q. What conclusions have you reached with respect to the proposed extension by APS of the 1.20 AFUDC offset?

A. This is an attractive way of putting CWIP into the rate base, while giving APS the incentive to maintain or even accelerate the current schedule for Palo Verde I (PV-1). The sooner the plant is declared commercially operational, the sooner will it receive normal

rate base treatment. However, perverse incentives also could arise. In principle, APS might be tempted to cut corners and let costs rise during start-up to achieve early commercial operation and normal rate base treatment, at the expense of lower subsequent equivalent availabilities and higher O&M expenses. This is why it is important to consider this incentive mechanism in combination with others that APS proposes, to determine whether the overall package makes sense (pp. 55-56)..

Q. What are your conclusions with respect to the proposed penalty of 50 percent of equity return if schedule slippage occurs?

Q. This mechanism works in the same direction as the 1.20 offset in pushing APS to stay on schedule, and it is also subject to the same perverse incentives. This incentive component applies only to whatever CWIP remains outside of the rate base (pp. 56-57).

Q. What are your conclusions with respect to the cap on total Palo Verde costs for ratemaking purposes?

A. For three reasons, I conclude that the cap is too high. First, I have examined the cost expenditure patterns of seven other nuclear units selected on the basis that they all began commercial operation after the Three-Mile Island accident. These patterns suggest that the APS will probably not suffer cost escalation by as much as the 10 percent contingency it wants above the $2.86 billion total cost it currently estimates for its share of Palo Verde (pp. 57-62).

Second, if the Commission approves the 10 percent contingency limitation, APS would have less incentive to avoid incurring costs up to that limit.

Third, other factors would reduce the risks to APS of large cost overruns. APS proposes that (a) it be protected by a force majeure provision, and (b) cost overruns above the 10 percent contingency be recovered over a period not to exceed 10 years, with only the denial to stockholders of a return on their investment. Moreover, some overruns might be caused by negligence of contractors, providing APS with legal grounds for recovery (p. 63).

Q. What are your conclusions with respect to the APS operating incentive plan?

A. The $15 million maximum penalty suggested by APS is meaningless, because the proposed reward/penalty functions virtually guarantee that the maximum penalty would never be incurred. As an alternative, I urge that APS simply incur the full additional economic loss of performance below the deadband and keep as a reward the full economic gain from performance above the deadband (pp. 74-78).

This result would be similar to that of competitive firms, which can keep the full gains or suffer the full costs of their actions. By raising the penalties and rewards for given plant equivalent availabilities, my approach would strengthen APS incentives for efficient operation.

Even under my proposal, however, the probability of APS incurring large losses would be low. In my illustrative example based on APS asssumptions about replacement cost of power and plant fuel costs, I estimate that the probability of APS incurring its maximum proposed penalty of $9.6 million (or more) for Four Corners would be only about 0.005--one chance in 200. The probability of APS incurring its maximum

proposed penalty of \$5.4 million (or more) for PV-1 would be only about 0 04--one chance in 25 (pp. 78-80).

Q. But how would ratepayers gain from the plan if APS absorbs all the economic losses and keeps all the economic gains as you suggest?

A. They gain because APS takes these penalties and rewards only *outside* the deadband. In my illustrative example, if the strengthened incentives I propose were to induce an increase in the equivalent availability of PV-1 from 40 percent to 65 percent, APS would avoid a penalty of \$8.8 million, whereas ratepayers would gain an additional \$5.8 million (p. 80).

Q. Since the Commission's basic concern is with Palo Verde, why should Four Corners be included at all in the operating incentive mechanism?

A. It is important to include Four Corners because if the incentive plan is effective, its application to Four Corners would generate additional economic gains. Indeed, I would recommend that Navajo 1, 2, and 3 also be included, but because Navajo is managed by the Salt River Project rather than by APS, the effect of the incentive plan on Navajo would be problematical (pp. 82-83).

Q. What, in summary, do you recommend that the Commission do about the incentive plan proposed by APS?

A. I recommend that the Commission take the following action:

- Accept the extension of the 1.20 AFUDC offset as proposed by APS for placing CWIP in the rate base, in the absence of evidence that a different level of offset would lead to better results.

- Accept the APS proposal for a penalty in schedule slippages in placing PV-1, PV-2, and PV-3 into commercial operation, in the absence of evidence that a modified or different approach would lead to better results.
- Accept the APS proposal to place a ceiling on Palo Verde costs for purposes of ratemaking, but to reduce or eliminate the 10 percent cost contingency to strengthen the incentives for cost control.
- Reject the operating incentive plan as proposed by APS and require it to propose a revised plan to cover the time during which only Four Corners would be in the plan and the time during which PV-1 would be included. The revisions should be based on the following requirements.

  -- APS should refine the estimates of economic gains and losses from changes in the equivalent availability of Four Corners before the time PV-1 is included in the plan. These estimates should reflect differences in the cost of replacement power between summer and winter and, unless APS shows that these differences are small, it should propose separate reward-penalty functions for the two seasons. These estimates should also take into account variable O&M expenses in addition to fuel.

  -- Using these refined estimates, APS should propose a reward/penalty function for Four Corners such that APS would absorb all economic losses for performance falling below the deadband and would retain all economic gains for performance

above the deadband (subject to force majeure provisions). APS should be free to adjust the proposed deadband so that the expected value of rewards is equal to the expected value of penalties; but it should also present evidence satisfactory to the Commission that the reward/penalty function it proposes does achieve neutrality. If APS seeks a ceiling on the maximum penalty to which it should be exposed, it should demonstrate why its proposed maximum is reasonable in light of the estimated probability of that maximum being incurred.

-- APS should refine its estimates of economic gains and losses from changes in equivalent availability for both Four Corners and PV-1, to take into account the effects of PV-1 on the costs of replacement power and on variable O&M costs. The estimates should, among other things, reflect the extent to which PV-1 would likely displace Four Corners as baseload units.

-- Using these estimates for both plants, APS should propose reward and penalty functions such that it absorbs all losses and gains from performance outside the deadbands (again subject to force majeure provisions). As in the case when only Four Corners is in the plan, APS should be free to propose alteration of the deadbands to help ensure neutrality between rewards and penalties and, if it proposes a ceiling on penalties for the two plants, to show why its proposed maximum is reasonable.

-- APS should demonstrate why Navajo 1, 2, and 3 should be excluded from the plan, as it proposes.

-- APS should propose to undertake analysis for comparing its

O&M expenditures for plants included in the incentive plan with those of similar plants elsewhere, for the Commission's use on a continuing basis. The methodology could include use of regression analysis and the data bases suggested on p. 85, or alternatives if they are shown to produce better results.

Q. What are your conclusions about the rate moderation plan that APS may propose next year?

A. Rate moderation is terribly important to maintain prices that retain some reasonable relationship to underlying marginal costs. While I cannot comment on the details of the APS plan yet to be developed, rate moderation may be even more important than the incentive package. Despite all the fine tuning one might do with the incentive plan, the Commission cannot be sure that the plan will do much good because of the problems of evaluation. The other problems I discuss in Sec. III of the exhibit, such as subsequent-round offsets, problems of controlling for external circumstances, and long-term credibility, will also remain. While I believe that the incentive package is worth adopting, it is the method of capital cost recovery that will be of key relevance to efficient use of Palo Verde and other baseload capacity during the next decade, if not to the end of the century.

Q. Does this conclude your testimony?

A. Yes, it does.

LELAND L. JOHNSON

Education

University of Oregon
B.S., Business Administration (1952)
M.A., Economics (1953)
Yale University
Ph.D., Economics (1957)

Professional Experience

Dr. Johnson has spent many years dealing with questions of appropriate incentives of private firms whose activities are regulated, or subsidized, by government agencies. In 1976, he was co-principal investigator of a study dealing with federally funded demonstration projects, which included study of the commercialization of light water nuclear reactor technology. During the same time he was the principal investigator of a study dealing with the alternative institutional arrangements for developing and commercializing breeder reactor technology, which, among other things, focused on the lessons learned from the Clinch River project. During 1980-83, he was Director of Rand's Energy Conservation Program, where his responsibilities included examination of the effects of cogeneration and utility-sponsored conservation activities on utilities' long-term capital requirements. He has dealt extensively with government regulatory policy toward the telephone and cable television industries, whose capital-intensive structures, in the face of rapid technological advance, pose issues similar to those in the energy field. He has also evaluated the use of formal cost-benefit methodologies, relevant to a wide range of applications within and outside the energy field, in connection with work sponsored by Rand's Institute for Civil Justice.

September 1979-present--Senior Economist, The Rand Corporation, Santa Monica, California

1978-1979--Associate Administrator, Policy Analysis and Development, National Telecommunications and Information Administration, U.S. Department of Commerce, Washington, D.C.

1968-1978--Manager, Communications Policy Program, The Rand Corporation, Santa Monica, California

1967-1968--Director of Research, President's Task Force on Communications Policy, U.S. Department of State, Washington, D.C.

1957-1967--Economist, The Rand Corporation, Santa Monica, California

1956-1957--Instructor, Yale University, New Haven, Connecticut

Other Professional Activities

Consultant, Interstate Natural Gas Association of America (1983-1984).

Consultant, the Ford Foundation (1966).

Member, Board of Directors, International Institute for Communications (1971-1978).

Member, Advisory Board, Committee for Economic Development (1975).

Member, Telecommunications Panel, American Society of International Law (1973-1975).

Member, Telecommunications Committee, the Twentieth Century Fund (1969-1970).

Teaching Positions While Employed at Rand

Lecturer, (International Trade), UCLA, 1967.

Visiting Professor, (International Trade and Economic Growth), Claremont Graduate School, 1965-1966.

Lecturer, (Statistics for Economics and Business), California State College at Northridge, 1958-1959.

Professional Organizations/Honors

American Economics Association

Society of Government Economists

Sterling Fellowship, Yale University (1955)

Standard Oil Fellowship for Leadership, University of Oregon (1951)

Publications in the Energy Field

After Energy Price Decontrol: The Role of Government Conservation Programs, (with Stanley Besen), N-1903-DOE, October 1982.

An Analysis of the Department of Energy's Nonprice Regulation of Industrial Energy Use, (with David Seidman), N-1876-DOE, May 1982.

"Economic Implications of Mandated Efficiency Standards for Households Appliances: Comment," (with Stanley M. Besen), *Energy Journal*, October 1981.

Alternative Institutional Arrangements for Developing and Commercializing Breeder Reactor Technology, The Rand Corporation, R-2069-NSF, November 1976, (coauthored).

Analysis of Federally Funded Demonstration Projects: Executive Summary, Final Report, and *Supporting Case Studies* The Rand Corporation, R-1925-DOC, and R-1927-DOC, respectively, April 1976, (coauthored).

Other Publications

Scientific and Technology Information Transfer: Issues and Options, N-2131-NSF (coauthored), March 1984.

An Analysis of the Federal Communications Commission's Group Ownership Rules, N-2097-MF (with Stanley M. Besen), January 1984.

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Competition and Cross-Subsidization in the Telephone Industry, R-2976-RC, December, 1982.

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"Equity and Efficiency in the Telephone Industry: Comments," Conference Proc. of the Michigan State University Institute of Public Utilities, 1981.

"The Sustainability of Monopoly in Electronic Mail Service," *Perspectives on Postal Service Issues*, American Enterprise Institute, May 1980.

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"Boundaries to Monopoly and Regulation in Modern Telecommunications," in *Communications for Tomorrow,* (Glen O. Robinson, ed.), Praeger, New York, 1978.

Domestic Common Carriers and the Communications Act of 1934, The Rand Corporation, P-5798, April 1977.

"A Review of the Positions of AT&T and the FCC Regarding the Consumer Communications Reform Act of 1976," *Journal of Telecommunications Policy,* March 1977.

"Comment on the Pricing of Satellite Services in the International Telecommunications Industry," in Harry M. Trebing (ed.), *New Dimensions in Public Utility Pricing,* The Institute of Public Utilities, Graduate School of Business Administration, Michigan State University, East Lansing, Michigan, 1976.

"Problems of Regulating Specialized Telecommunications Common Carriers," in *Refocusing Government Communications Policy,* Aspen Institute for Humanistic Studies, Washington, D.C., 1976.

"Problems of Competition and Monopoly in Electronic Fund Transfer Services," Testimony before the National Commission on Electronic Fund Transfers, San Francisco, December 14, 1976.

"Distributional Effects of Regulation," in *Rate of Return Regulation,* Federal Communications Commission Future Planning Conference, July 1976.

Problems of Regulating Specialized Telecommunications Common Carriers, The Rand Corporation, P-5638, May 1976.

Projecting the Growth of UHF Television Broadcasting: Implications for Spectrum Use, The Rand Corporation, R-1841, February 1976, (coauthored).

The Social Effects of Cable Television, The Rand Corporation, P-5390, March 1975.

Expanding the Use of Commercial and Noncommercial Broadcast Programming on Cable Television Systems, The Rand Corporation, R-1677-MF, January 1975.

The Cabinet Committee Report to the President on Cable Communications, The Rand Corporation, P-5193, February 1974.

"Government Regulation and Technological Advance," in *Rand 25th Anniversary Volume,* The Rand Corporation, 1973.

"Behavior of the Firm Under Regulatory Constraint: A Reassessment," *American Economic Review, May 1973.*

Cable Television: The Process of Franchising, The Rand Corporation, R-1135-NSF, March 1973, (coauthored).

"Issues of Franchising," *Cable Communications in the Dayton Miami Valley: Basic Report*, The Rand Corporation, R-943-KF/FF, January 1972.

Cable Communications in the Dayton Miami Valley: Summary Report, The Rand Corporation, R-942-KF/FF, January 1972, (coauthored).

Cable Television and Higher Education: Two Contrasting Experiences, The Rand Corporation, R-828-MF, September 1971.

Cable Television and Questions of Protecting Local Broadcasting, The Rand Corporation, R-597-MF, October 1970.

"Technical Advance and Market Structure in Domestic Telecommunications," *The American Economic Review*, May 1970.

The Future of Cable Television: Some Problems of Federal Regulation, The Rand corporation, RM-6199-FF, January 1970.

"New Technology: Its Effect on Use and Management of the Radio Spectrum," *Washington University Law Quarterly*, Fall 1968.

"New Communications Technologies and National Security," *Adelphi Papers*, The Institute for Strategic Studies, March 1968.

"Joint Cost and Price Discrimination: The Case of Communications Satellites," *University of Chicago Journal of Business*, September 1963.

"Behavior of the Firm Under Regulatory Constraint," *American Economic Review*, December 1962, (coauthored).

Communications Satellites and Telephone Rates: Problems of Government Regulation, The Rand Corporation, RM-2845-NASA, October 1961.

May 1984

I. INTRODUCTION

Like many other utilities, Arizona Public Service Company (APS) became interested in the possibilities of using nuclear power in the early 1970s. Studies conducted by APS showed that estimated costs for nuclear plants compared favorably with those of coal-fired units, and forecasts of demand showed that substantial additional base-load capacity would be needed by the early 1980s. Moreover, the National Environmental Policy Act, passed in 1969, cast doubt on the feasibility of heavy future reliance on coal because of air quality standards that might be promulgated under the Act.[1]

APS saw itself as particularly vulnerable because it was already heavily dependent on coal. It was operating five units at Four Corners, New Mexico, and was participating in other coal plants under construction. It discarded possibilities of building oil or gas base-load plants because of expected increases in fuel costs (even before the Arab embargo of 1973). Thus, APS perceived nuclear as the only candidate for diversifying its base-load resources.

[1]Concern about meeting air quality standards was reinforced in 1971 when APS installed wet scrubbers on units 1, 2, and 3 of its Four Corners plants. Difficulties with these scrubbers were so severe "that the capacity factors of these plants suffered appreciably for the next several years" (APS, undated mimeo., p. 2). Much of the background information presented here is drawn from this APS document and from a project history described in the Arizona Corporation Commission (ACC) (undated mimeo.).

THE ARIZONA NUCLEAR POWER PROJECT

In 1972, APS and other utilities established the Arizona Nuclear Power Project. During the next two years, the group selected Bechtel Power Corporation as prime contractor for the Palo Verde site, Combustion Engineering for the nuclear steam supply components, General Electric for turbines and generators, and Westinghouse Electric for uranium fuel. Plans called for as many as five 1270 MW units.

After the Nuclear Regulatory Commission granted a construction permit in 1976, commercial operating dates for the first three units (PV-1, PV-2, and PV-3) were set for May 1982, May 1984, and May 1986. Total construction cost for the three units was estimated at $2.77 billion. Utility ownership shares, which have varied over time, are shown in Table 1.1. The three units together will increase APS's total generating capacity by about one-third.

Table 1.1

OWNERSHIP SHARES, PALO VERDE NUCLEAR GENERATING STATION

Utility	Share (Percent)
Arizona Public Service	29.10
Salt River Project	17.49
Public Service of New Mexico	10.20
El Paso Electric	15.80
Southern California Edison	15.80
Los Angeles Department of Water and Power	5.70*
Southern California Public Power Authority	5.91
	100.00

*Ownership share for LADWP, to be transferred from the Salt River Project, is contingent on commercial operation of PV-1.

In May 1979, the planned startup date of PV-1 was pushed back one year, and the estimated total costs were revised upward to $3.24 billion. APS cited shortages of skilled labor and unusually bad weather as the major problems.[2] Two months later PV-4 and PV-5 were cancelled because, according to APS, the California participants were unable to get necessary regulatory approval in part because of repercussions from the accident at Three Mile Island However, only $4.3 million had been spent on these two units, because they had not yet progressed beyond early planning.

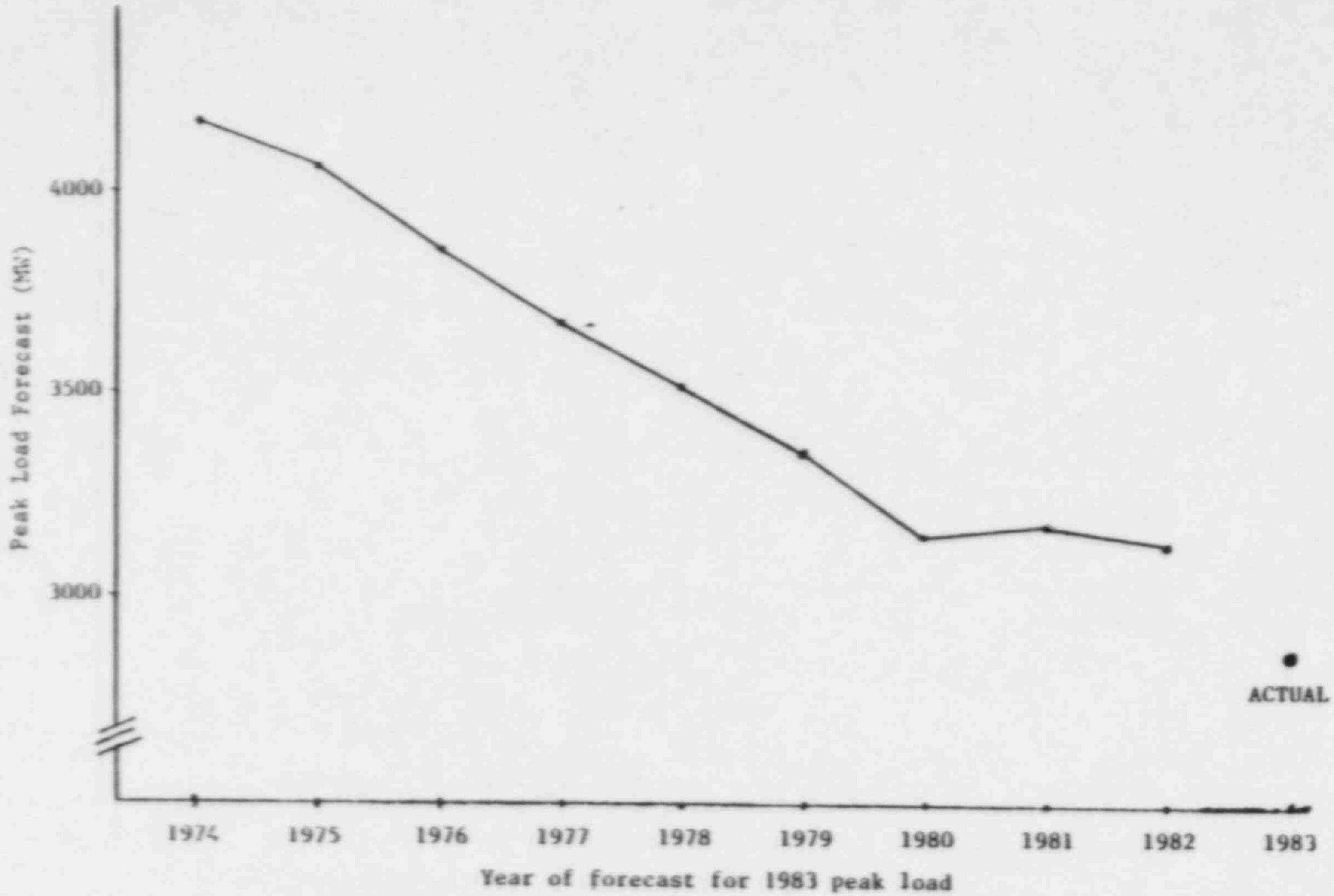
Moreover, the earlier peak load forecasts were adjusted downward, because of unanticipated slowing in the growth of demand for electricity. But even the revised forecasts proved overly optimistic. Figure 1.1 shows the downward progression of forecasts for 1983, with the actual peak load for 1983 of 2885 MW falling 9 percent below the forecast of 3179 MW that had been made only a year before.

Further delays and cost escalations have subsequently occurred. Table 1.2 shows the currently planned milestones for the three units. PV-1 has slipped by more than three years, and PV-2 and PV-3 have slipped by about two years and one year, respectively. Construction costs are now estimated at about $4.7 billion--about 70 percent above the initial estimate.[3] Construction of PV-1 and PV-2 is virtually complete, with both units in various stages of startup. By March 1984, construction of PV-3 was 87 percent complete.[4] Total costs, including

[2]ACC (undated mimeo., p. 3).

[3]ACC, "Summary of Cost Measures, Baseline Estimate--Forecast, #15 Delayed," (3/84) (unpublished).

[4]Testimony of Woods (1984, p. 2).



SOURCE: APS, "Peak Load Forecast Analysis" (undated, unpublished).

Fig. 1.1--APS forecast vs. actual peak load for 1983

Table 1.2

ESTIMATED PALO VERDE TIME SCHEDULE

Unit	Fuel Load	Commercial Operation by
PV-1	1st Quarter, 1985	December 31, 1985
PV-2	4th Quarter, 1985	June 30, 1986
PV-3	1st Quarter, 1987	June 30, 1987

SOURCES: Fuel Load, APS files, July 13, 1984 unpublished; Commercial Operation, Sargent testimony in APS (1984, p. 15).

startup and carrying costs on the investment, are expected to exceed $9 billion. Table 1.3 shows the APS share and its components.

FINANCIAL CONSEQUENCES

A key feature of Table 1.3 is the AFUDC (allowance for funds used during construction) component, which makes up about one-third of total cost. This component reflects the carrying costs--the cost of borrowing and shareholder contributions--to finance the cost of "construction work in progress" (CWIP). Rather than collecting these carrying costs from ratepayers as they are incurred, they are capitalized and included in CWIP during the time of construction. The periodic increase in AFUDC is included in earnings. However, this component of earnings does not represent realized, or cash, earnings but is, in effect, a "promise to pay" by future ratepayers. Under traditional regulatory procedure, it is only after the plant is completed and judged to be "used and useful" that its costs, including accumulated AFUDC, are placed in the rate base and recovered from ratepayers through depreciation allowances over the life of the plant.

Table 1.3

PALO VERDE COST ESTIMATE, ARIZONA PUBLIC SERVICE PORTION

($ Millions)

Plant	Expenditure	AFUDC	Property Tax	Total
		Construction		
PV-1	$ 482	$206	$23	$ 711
PV-2	429	287	20	736
PV-3	459	326	21	806
Total	$1,370	$819	$64	$2,253
		Pre-Operation and Startup		
PV-1	$ 156	$ 49	$ 2	$ 207
PV-2	113	15	1	129
PV-3	107	20	1	128
Total	$ 376	$ 84	$ 4	$ 464
Grand Total	$1,746	$903*	$68	$2,717*

SOURCE: APS files, July 13, 1984.
*This estimate assumes that the Company's request for CWIP in rate base and the corresponding AFUDC reduction included in Docket U-1345-83-155 is adopted by the Commission.

The amount of AFUDC is sensitive to delays in construction as well as to construction cost escalation; even if all construction ceases for a period of time, AFUDC continues to accumulate. Largely because of Palo Verde's mounting construction costs and delays, the increment to AFUDC in 1983 accounted for about 85 percent of APS earnings during that year, compared to about 5 percent in 1960.[5]

Such a trend is, of course, not unique to APS. Other utilities with large construction programs face similar situations. For investor-owned utilities together, AFUDC accounted for nearly 50 percent of total earnings in 1981, compared to about 7 percent in 1967.[6]

[5] APS files, June 28, 1984.
[6] U.S. Department of Energy (1983, p. 6-29).

This trend poses problems for APS, as well as for other utilities. Even though the utility may be earning close to its allowed rate of return, such a large noncash portion seriously constrains cash flow. At the same time, when a large portion consists of AFUDC, representing only a promise to pay, investors become uneasy. Depending on regulatory decisions far into the future, this portion may or may not be fully recovered. Consequently, investors tend to discount earnings that include large portions of AFUDC.

An obvious way to alleviate these problems is to permit utilities to include at least a portion of CWIP in the rate base to permit utilities to start collecting immediately from ratepayers. However, this practice violates the principle of collecting from ratepayers only when a plant is "used and useful."[7] This principle is predicated on the notion that including CWIP in the rate base forces current ratepayers to cover the costs of plant from which they do not benefit, thereby subsidizing consumption by future ratepayers. Nevertheless, some commissions have responded to the severe cash flow problems of utilities and the reduction in quantity of their earnings by permitting CWIP in the rate base.[8]

Whether CWIP should be allowed in the rate base remains a point of bitter controversy in Arizona and elsewhere. As an ad hoc committee of the National Association of Regulatory Commissioners emphasizes, "Because allowing CWIP to earn a current cash return violates the

[7]See the discussion in Pomerantz and Suelflow, (1975, Ch. 7).

[8]A tabulation of states according to the conditions under which they permit inclusion of CWIP in rate base appears in The National Regulatory Research Institute (1984, pp. 3-6).

traditional 'used and useful' principle, the issues surrounding CWIP are probably the most sensitive, emotional, and politically charged questions which any regulator has to face" (NARUC, 1982, p. 34).

Because of problems caused in part by exclusion of CWIP from its rate base, APS filed for rate increases (for both its electricity and gas business) in August 1982 with the ACC. The Commission's rate order in September 1983 granted only about 50 percent of the amount APS had requested and disallowed the inclusion of CWIP in the rate base.[9]

Soon thereafter, credit rating agencies downgraded APS fixed income securities. As Moody's assessed the situation, "The combined pressure on the Company from the delayed completion and incurred costs of Palo Verde and the reduced prospect for needed rate relief in the years ahead makes us less optimistic about the Company's ability to sustain the financial strength appropriate for a higher credit rating category."[10]

The current proceeding, of which this study is one input, is Phase II of a two-step process. In Step 1, APS applied for a rate increase that would amount to a total of $122 million in additional annual revenues, generated in large part by placing $395 million of CWIP in the rate base. In response, the Commission granted an "interim" rate increase amounting to $60 million in revenues effective February 1, 1984.[11] It also ordered APS to cease accruing AFUDC on $327 million of CWIP related to PV-1, which results in a reduction of $1.20 in noncash earnings for every $1.00 increase in cash earnings.[12] However, this

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[9]ACC (1983).

[10]Moody's Investors Service (1983). See also Standard and Poor's (1983) and Duff and Phelps, Inc. (1983).

[11]ACC (1984).

[12]The Commission's decision was based on the following calculations: The $60 million of (before tax) cash earnings it granted are equal to $28.72 million of after-tax earnings at a conversion factor of 2.089. To offset each dollar of after-tax earnings by $1.20 of noncash earnings, cessation of $34.46 million in AFUDC accrual was

rate increase is subject to revision or modification, depending on the Commission's final decision in Step 1.

In the current phase of the proceeding (Phase II), APS is requesting (a) a revenue increase equal to whatever difference remains between the Company's Step 1 request of approximately $122 million and the amount finally granted by the Commission in Step 1, and (b) an additional revenue increase of $79 million generated by placing an additional $348 million of CWIP in the rate base at the time fuel loading takes place for PV-1.

In response to the schedule delays and cost escalations experienced at Palo Verde and the consequent requests by APS for revenue increases, the Commission is seeking ways in Phase II of this proceeding to help ensure that APS does not overbuild or in other ways operate inefficiently in the future. A basic concern, shared by regulators throughout the nation, is that granting rate increases to pass on to ratepayers whatever cost increases are incurred by the utility weakens the utility's incentives to exercise firm cost control and, more generally, to operate efficiently.

INCENTIVES FOR ECONOMICALLY EFFICIENT BEHAVIOR

Of central concern to the Commission is how its Phase II decisions will affect the incentives for APS to operate efficiently. Especially, the questions of CWIP in the rate base raises issues of incentives. As J. W. Wilson observed in earlier testimony, "the reflection of CWIP in

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required. At an accrual rate of 10.54 percent used in the Commission's decision, cessation of AFUDC accrual on $327 million of CWIP generated the required reduction of $34.46 million (since 34.46 divided by .1054 is equal to 327). This offset of $1.20 was decided on grounds that "the Company's financial problems are related to its cash earnings rather than total earnings, which include AFUDC and...that cash earnings are more valuable than AFUDC earnings." Sargent testimony in APS (1984, p. 12).

rate base...will tend to eliminate incentives for discipline and efficiency which encourage more economical planning as well as incentives to put plant on line quickly and at lowest possible cost consistent with proper design and operating considerations" (1984, p. 22). Similarly, H. B. Trebing writes, "CWIP in the rate base provides another strong incentive for overinvestment. It allows the utility to earn a full return on plant under construction while at the same time suffering no penalty for construction delays or errors in forecasting" (1981, p. 373).

More generally, the Commission is interested in the possibility of adopting an explicit incentive program that would encourage efficiency in future utility operations. Such programs are defined as activities that have

- specific intent to provide incentives to regulated utilities to improve performance,
- established standards or targets that utilities work to meet or exceed, and
- a mechanism for providing rewards and/or penalties to the utilities based on their performance as it relates to the standards.[13]

These components distinguish a formal incentive program from regulatory oversight activities such as prudence investigations and management audits that do not have ex ante performance standards on which subsequent rewards and penalties are based.

[13]This definition is taken from the Edison Electric Institute (1984, p. 5).

In response to the Commission's interests and concerns, APS has proposed a detailed regulatory incentive program to be established in return for near-term rate relief.[14]

PURPOSE OF THIS STUDY

In response to issues before the Commission in Phase II of this proceeding, this study has three basic purposes.

- To assess how the pricing of electricity, with and without CWIP in the rate base, affects the incentives of APS to operate efficiently. To do so requires consideration of how economically efficient pricing is related to the time profile of recovering the costs of Palo Verde (as well as other generating units). This relationship is affected by the demand for electricity by both APS customers in its service territory and by other utilities, and by the costs of meeting these demands.
- To seek to develop, for the Commission's consideration, incentive mechanisms that hold promise for improving utility performance. This task involves identification of criteria by which such mechanisms should be judged, and a survey of experiences in other states with incentive programs that the Commission should take into account.
- To assess the regulatory incentive plan proposed by APS in terms of how likely it is to affect the incentives of APS to operate efficiently, and to offer recommendations, if any, for modifying or rejecting the plan.

[14] APS (1984).

II. THE INCENTIVE EFFECTS OF ELECTRICITY PRICING

In this section, I address the incentive effects on APS of current regulatory policy. This assessment addresses four interrelated topics: (a) the concept of economic efficiency, (b) the issue of overinvestment under traditional regulatory policy, (c) the incentive effects of including CWIP in the rate base, and (d) the incentive effects on both ratepayers and APS of "rate shock" caused by traditional regulatory treatment of revenue requirements, and alternatives for improving outcomes.

THE CONCEPT OF ECONOMIC EFFICIENCY

Because a key question before the Commission is how its current and possible alternative policies affect the incentives of APS to operate efficiently, it is vital to treat at the outset the concept of economic efficiency. Two aspects of efficiency are relevant here. The first is "cost efficiency" or inefficiency. The firm operates efficiently, in this sense, if it minimizes the cost to society of producing any specified output. A widely expressed concern is that the "cost plus" nature of conventional regulation gives utilities little incentive to be efficient. If the costs of mismanagement, unnecessary expenses, and inappropriately designed plant can be passed on to ratepayers, utilities can survive without facing the discipline of the marketplace. Improved cost efficiency is the goal of regulatory incentive plans with formal structures of rewards and penalties assessed in Secs. III and IV.

However, if cost efficiency were our only goal, the easiest way to encourage it would be simply to deregulate APS as well as other utilities. That way the firm could keep whatever "rewards" it earns from cutting costs or, on the other hand, pay the penalties.

Although many analysts advocate deregulation, on a phased basis, of the wholesale power market, the current regulatory scheme is predicated on the notion that utilities have monopoly power that should be constrained.[1] Operation of an unregulated monopolist leads to another inefficiency: "allocative inefficiency." Even if the monopolist is cost efficient as discussed above, its attempt to maximize profits will lead it to set price and output at nonoptimal levels, because price will exceed marginal cost. To appreciate the problem, we must consider the characteristics of efficient pricing.

As a basic principle of both cost and allocative efficiency (subject to modifications discussed below) the price of electricity should be equal to the additional (or marginal) cost of providing an additional unit of electricity. If the price is lower than marginal cost, the consumer will tend to purchase an "excessive" amount of electricity, i.e., an amount whose cost exceeds its value to the consumer. If price exceeds marginal cost, the consumer will tend to use "too little" electricity, i.e., he will forgo an additional amount even though the price he would be willing to pay would cover its cost. Setting price equal to marginal cost is "efficient" because it ensures that society's scarce resources are devoted to their highest valued uses.

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[1]APS buys and sells in the semicompetitive wholesale market, regulated by the Federal Energy Regulatory Commission, but retains a monopoly over retail sales.

Another concern is that the unregulated monopolist is free to earn excess profits at the expense of consumers, and that this is "unfair." Although this is a legitimate concern, it is relevant to issues of how gains from trade should be distributed between consumers and the firm, rather than to issues of economic efficiency. Economists claim no special expertise in addressing distributional issues.

To treat incentives within a broad context most useful to the Commission, it is important to consider both cost efficiency and allocative efficiency in this study.

INCENTIVES TO OVERINVEST

Many have complained that utilities, including APS, tend to overinvest in generating plant. They point to existing high reserve margins in many parts of the country and the numerous plants whose construction has been cancelled only after large expenditures have been made. With respect to APS in particular, some asserted in earlier testimony that ample evidence existed in the early 1970s that entry into the nuclear field was risky,[2] and that "the need for Palo Verde has not been established."[3]

These assertions raise questions about the prudency of APS in its activities that go far beyond the scope of this study. Questions of prudency can be settled, if at all, only after long and detailed investigation. However, I do address the issue of overinvestment to provide a broad overview of forces that may encourage a utility either to overinvest or to underinvest. One especially important reason for

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[2]Lowes (1984, pp. 4-10).

[3]Copeland, (January 1984, p. 34).

doing so is to highlight the difficulty of quantifying the effects of perverse incentives of concern throughout this study.

Two factors are important with respect to possible bias toward overinvestment. First is the normalization, rather than flowthrough, of investment tax credits and tax benefits of accelerated depreciation. The utility is given, in effect, interest-free loans at the expense of the taxpayer. The existence of investment tax credits and accelerated depreciation for tax purposes results not from regulatory policy of concern here but from the provisions of the federal tax code. But it is important to recognize the role of tax provisions, because any observed tendencies of utilities to overinvest could mistakenly be attributed to regulatory policy rather than to utilities simply taking advantage of favorable tax treatment.[4]

The second is the "Averch-Johnson" or "A-J" effect.[5] If the firm is subject to a binding constraint on its return on investment, and if its allowed rate of return exceeds its cost of capital, it will have an incentive to use overly capital-intensive production processes. For example, it would have a bias toward building nuclear plants rather than less capital-intensive fossil-fuel plants. The A-J effect has been the subject of numerous empirical studies, with some finding evidence of bias, while others find none.[6] In any event, methodological problems

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[4]However, other elements of the tax system may discourage investment. These include taxation of earnings from savings, double taxation of corporate dividends, and the "inflation tax" on capital gains. Investment tax credits and accelerated depreciation may be socially desirable offsets to these other biases.

[5]Averch and Johnson (1962).

[6]For discussion of these studies see Arzac and Edwards (1979, pp. 41-51). Rand colleague Derek McKay concludes in a study (1977) that differential features of property taxes and other capital taxes can work in the other direction to eliminate any A-J bias.

and difficulties in obtaining adequate data cast doubt on the validity of conclusions.

As has been commonly observed, conditions were more conducive to an A-J bias in the 1960s and early 1970s than has been true since. In that earlier period, electric utilities as a group earned rates of return that exceeded allowed rates because of rapid technological advance. Since the early 1970s the reverse has been true, as a consequence of inflation combined with regulatory lag.[7] APS has not earned its allowed rate of return since 1972.[8]

Other factors, however, encourage *underinvestment*. Use of energy adjustment clauses, combined with rapid inflation and regulatory lag, can discourage a firm from making highly capital-intensive investments. On the one hand, the utility is reasonably assured of getting quick passthrough for fuel and other costs through increasing rates to customers. On the other, the gap between its allowed and earned rate of return makes less assured full cost recovery of capital investments.

The conventional treatment of AFUDC also encourages underinvestment. If investment is embodied in plant with long construction times, and especially if slippages of years and cost overruns occur, the rising portion of earnings consisting of AFUDC can compromise the credit worthiness of the utility, as discussed with respect to APS in Sec. I.

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[7]These relationships are illustrated in U.S. Department of Energy (1983, p. ES-18).

[8]APS files, June 28, 1984. Comparative data for APS are not available before 1972.

Thus, the utility can face problems from two directions. Erosion of credit worthiness raises its cost of capital, and inflation plus regulatory lag drives the earned rate of return below the allowed rate.

Considering the pressures to overinvest and underinvest together, what can be said about the incentives of APS under traditional regulatory policy? Not much. On the one hand, the A-J effect could conceivably have contributed to the Company's enthusiasm for planning as many as five large nuclear units in the early 1970s, while encouraging it to discount the rumblings that risks in nuclear plants were higher than utility executives were earlier led to believe.[9] If a utility is anxious to justify a large investment program, resulting from a bias toward overinvestment, it would also have a bias toward overestimating future load growth so that at any point in time its projected reserves over the next decade or so look "reasonable." The persistent overestimation of load shown in Fig. 1.1 is consistent with, though does not prove, the existence of a bias toward overinvestment.[10]

On the other hand, concerns about meeting environmental regulations with coal plants were not groundless--nor are they today with the continuing controversy about acid rain and other environmental effects. Moreover, it was not obvious that the growth in electricity demand would slacken. Even with no bias toward investment induced by regulatory policy, APS might have acted as it did in the early 1970s. But whether

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[9]Any tax incentives to overinvest in the early 1970s would have been minor, because APS flowed through the benefits of both accelerated depreciation and investment tax credits before 1977.

[10]A comparison of the errors in forecasting loads between privately owned and publicly owned utilities might provide useful evidence about such bias.

this is the case gets into questions of prudency, going beyond the scope of this study.

After the early 1970s, the world changed for the electric utilities. The reduced quality of earnings with massive accumulations of AFUDC, and the difficulties or impossibility of earning the allowed rate of return, lead to widespread concerns nowadays that utilities may have a bias to underinvest. Among other things, they may postpone the replacement of oil- and gas-fired base-load plant with more capital-intensive coal-fired units, even though the present value of future net benefits from the new investment exceeds the present value of those from existing plant.[11]

Whether or not APS has a current bias toward underinvestment or overinvestment, its investment plans are well established over the next decade. Its three nuclear units are scheduled to come on line at closely spaced intervals during the next three years. APS plans no other large investments until the Chollo 5 coal-fired plant with 340 MW capacity becomes operational in 1995.[12] Plans for Chollo 5 can be altered, depending on developments later in the 1980s.

The major issues for APS and the Commission involve the effects of including CWIP in the rate base, and the longer-run regulatory treatment of Palo Verde to ensure that its capacity is used efficiently. It is to these issues that I now turn.

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[11]This argument is strongly advanced in U.S. Department of Energy (1984).

[12]APS, "1984 Long-Range Forecast--Loads and Resources," May 10, 1984.

ISSUES OF INCLUDING CWIP IN THE RATE BASE

The question of whether CWIP should be put into the rate base must be separated from the question of whether the investment was prudently incurred. I suspect that resistance to the notion of putting into the rate base CWIP for costly new investments--whether Palo Verde or such plants elsewhere in the country--arises in part from the concern about prudency. It is tempting to argue that current ratepayers should not be forced to cover the costs of uncompleted plant if suspicions exist that the plant is more costly than it "should" be or if it will provide more capacity than will be "needed." However, the question of prudency is no more relevant to CWIP than it is to plant in service. Investment in either may be prudent or imprudent. As emphasized above, treatment of these issues would go far beyond the scope of this study.

With questions of prudency set aside, two major issues arise with respect to including CWIP in the rate base: the incentive effects on APS and the justification for recovering costs from ratepayers for plant not yet "used and useful."

Incentive Effects of Including CWIP in the Rate Base

As frequently emphasized in the Commission's deliberations, if a utility is permitted to earn a return on incomplete plant, it will have weaker incentives to complete the plant quickly and at low cost. Moreover, if it believes that this treatment will continue, the utility may favor uneconomic capital-intensive projects in the future. Thus, the policy of including CWIP in the rate base could convey the "wrong signals" not only to APS but to other utilities under the Commission's jurisdiction.

At the same time, *exclusion* of CWIP from the rate base can also create perverse incentives. With the urgency to convert AFUDC into cash earnings, the utility could be under great pressure to complete the plant quickly and rush it into the rate base. To do so, it could be tempted to cut corners in design, construction, and testing that will reduce the plant's operational reliability and increase operating and maintenance costs.[13] Moreover, the utility may be willing to incur excessive costs for pre-operation and startup to avoid or reduce schedule slippage.

Two additional points must be emphasized. First, adverse effects on incentives from including CWIP in the rate base are reduced by the $1.20 AFUDC offset that the Commission has adopted in granting the interim rate increase in early 1984. By requiring APS to forgo $1.20 in AFUDC noncash earnings for each $1.00 in cash earnings, the utility still has incentives to get plant into service quickly to shorten the time during which the penalty must continue to be paid. Incentives might remain of "cutting corners" as noted above for the sake of hastening normal rate base treatment. But they would likely be less serious because of the reduced pressures on the utility to obtain cash earnings.

Second, to reduce the likelihood of perverse incentives, it is important to consider *combinations* of incentive mechanisms (of which the $1.20 AFUDC offset is only one) that may contribute, on balance, to improving utility performance. I return to this key point in my assessment in Sec. IV of the incentive plan proposed by APS.

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[13]An open question is whether the regulations of the Nuclear Regulatory Commission, and its inspections, seriously constrain attempts to cut corners for nuclear plants, especially in matters not related to safety.

Cost Recovery of Plant Not Yet in Service

It is important to recognize that nothing in economic principles supports the orthodox regulatory policy of recovering from ratepayers the cost of plant only after it becomes "used and useful." It is not necessarily true that current ratepayers bear no "responsibility" for the cost of plant under construction and, hence, should bear none of its cost. Therefore, it is not necessarily true that "the continued capitalization of AFUDC has a clear advantage over CWIP because it...results in an appropriate matching of cost incurrence with service rendered."[14]

To understand why, consider a competitive firm that faces an unexpected increase in demand for its product. To maximize its profit, the firm will try to expand output to the point at which its additional revenues are just equal to its additional (marginal) costs. (To go beyond that point would result in a profit reduction since marginal revenues would fall below marginal cost.) With the increase in demand it could simply raise price and sell the same output as before. But, with the increased demand, its marginal revenues would exceed marginal costs at the original output level. So it could do even better by expanding output to the point where marginal revenues and costs are again equated. With a given size of plant, however, marginal costs may rise sharply, because of capacity constraints. Although the firm may be making large profits from using only the original plant and charging higher prices, it may find that it could make even larger profits by expanding its plant or building a new and larger one.

[14]Wilson, (1984, p. 17). See also Hadaway (1984, p. 5).

The key point is that the firm may use at least some of its additional current revenues to finance new construction. It may also borrow funds and issue stock, with the objective of achieving a mix of borrowing, equity, and use of current revenues that minimizes the overall cost of financing a given level of expansion. The upshot is that its current customers may contribute to financing the additional plant *at the time it is being built*.

To be sure, competitive firms commonly capitalize carrying charges on plant under construction, as Wilson emphasizes (1984, p. 21). But one must be careful to distinguish between the economic behavior of the firm and the way it keeps its accounts. If demand is so strong that the firm cannot expand output without increasing its capacity, one would expect it to raise prices to a market-clearing level while it builds additional plant. The firm would surely exhibit bizarre behavior if it did not raise prices, because its revenues already cover its costs (including a "reasonable" return on investment in its currently operating plant), and only later tried to raise prices after the new plant had opened!

A basic assumption behind the firm's using current revenues to finance construction is that the increase in demand is unanticipated. If the firm (and its competitors) had perfect foresight, it would have built the new plant sooner, and would use the additional revenues generated by the (anticipated) increase in demand to help recover the costs of that plant after it is in service. Conversely, facing an unanticipated reduction in demand, the firm would be unable to cover its total costs and, under competitive pressures, its owners would suffer losses.

All this does not mean that a regulated utility should necessarily be allowed to put CWIP in the rate base. What it does mean, rather, is that a utility should not be prevented from putting CWIP in the rate base simply because of a fallacious assertion that competitive firms do not use current revenues to finance construction and that, therefore, it is wrong in principle for current utility customers to help pay for construction costs.

Nor does this analysis imply that APS should be allowed to put CWIP in the rate base. No evidence exists to suggest that APS has faced large unanticipated increases in demand. Indeed Fig. 1.1 suggests just the opposite.

However, other grounds may exist for putting at least some CWIP in the rate base because of problems of rate shock and the optimal time profile of capital recovery--subjects to which we now turn.

PROBLEMS OF RATE SHOCK

As is well known, traditional accounting treatment, involving straight-line depreciation based on original cost, front loads cost recovery of the plant at the time it goes into service. Revenue requirements escalate rapidly at that time because of expansion in the rate base with the associated cost of capital, forcing an increase in electricity prices. Subsequently, revenue requirements and electricity prices fall as plant is depreciated.

The phenomenon of rate shock, which occurs as a consequence of accounting convention rather than from changes in underlying cost, has been severely criticized by other analysts.[15] A basic difficulty with

[15]See, for example, Streiter (1982); Perl (1984); and Stauffer and Navarro (1981).

this traditional approach is that it goes *exactly* in the wrong direction in terms of allocative efficiency. Prices go up at the very time that costs (relevantly defined) go down. Marginal costs do not suddenly rise on the day that plant goes into the rate base; only the method of recovering embedded costs changes. Indeed, short-run marginal costs presumably would *fall* when the plant goes into service because it would reduce the use of other plant with higher operating and maintenance costs and would reduce the probabilities of outages and other service degradation. If prices track marginal costs, they would tend to rise before the plant goes into service and then fall when it goes on line and marginal costs are reduced.

Figure 2.1 illustrates the problem. The planned in-service dates for PV-1, PV-2, and PV-3 are shown along with the marginal costs calculated by APS for the peak summer period for the years 1984-1994.[16] Residential rates, calculated on the basis of a constant rate of return and conventional depreciation practices, rise as the Palo Verde units come on line. Rates decline in later years as plant is depreciated, the rate base falls and, consequently, revenue requirements decline.[17] But in the 1990s marginal costs start to rise as forecast expanded load requires increased use of plant with higher operating costs. Moreover, the hump in residential rates emerges even though APS computes them

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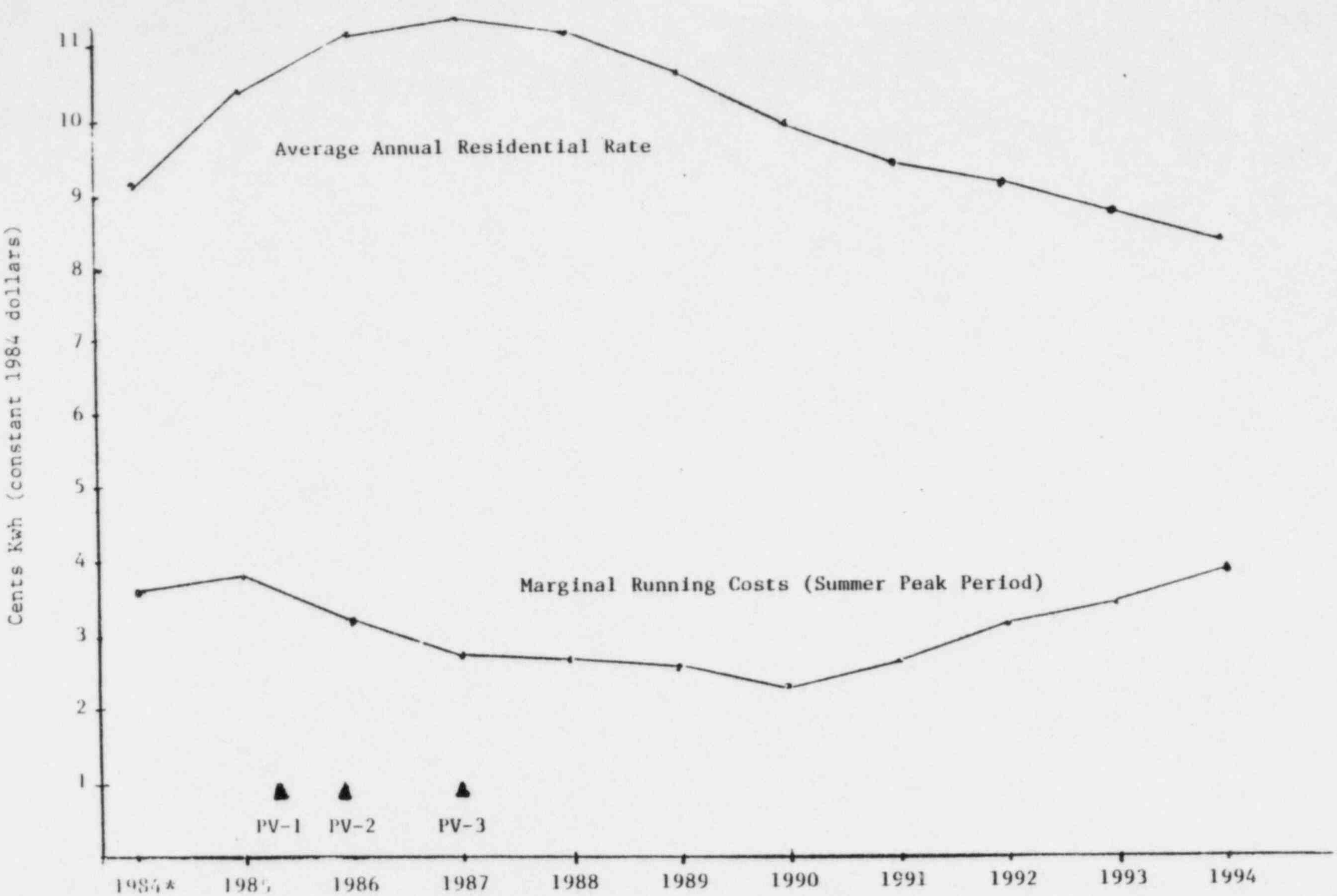
[16]APS calculates these costs also for the summer off-peak period and for both the winter peak and off-peak periods. These series follow the same general downward and upward pattern shown in Fig. 2.3. Marginal costs calculated by APS do not include the costs to consumers of quality degradation or outages. The methodology and data sources underlying these estimates are described by Branom in earlier testimony (1983). The running costs in Fig. 2.1 are only one measure of relevant costs. The costs of service degradation as loads push against capacity constraints should also be included.

[17]These rates, taken from APS files, are the same as those APS uses in its "Long-Range Forecast--Loads and Resources," May 10, 1984.



SOURCE: APS files (undated).

▲ -- PV in-service dates

*Data for last six months only.

Fig. 2.1 -- Marginal Power Costs for APS and Residential Rates

under the assumptions that it receives its full request for inclusion in the rate base of $395 million of PV-1 CWIP in Phase I, and its full request of $348 million of PV-1 CWIP in the current Phase II of its rate application.[18] Were no CWIP allowed in the rate base, the real rate increase from mid-1985 to mid-1986 would, presumably, be much sharper than the 8 percent shown in Fig. 2.1, whereas rates in later years would be lower than otherwise.[19]

Combined with this pattern is the increase after 1986 in forecast APS capacity, above reserves based on APS reserve criteria, shown in Table 2.1. With the inclusion of Palo Verde, and other adjustments in APS resources, excess reserves rise to a peak of 238 MW in 1990. Moreover, this is an excess based on APS reserve criteria to cover peak summer load. Excess capacity would be even greater during other times of the year, as suggested by Fig. 2.2, where a substantial amount of "availability capacity not needed" arose during off-peak periods of 1983.[20]

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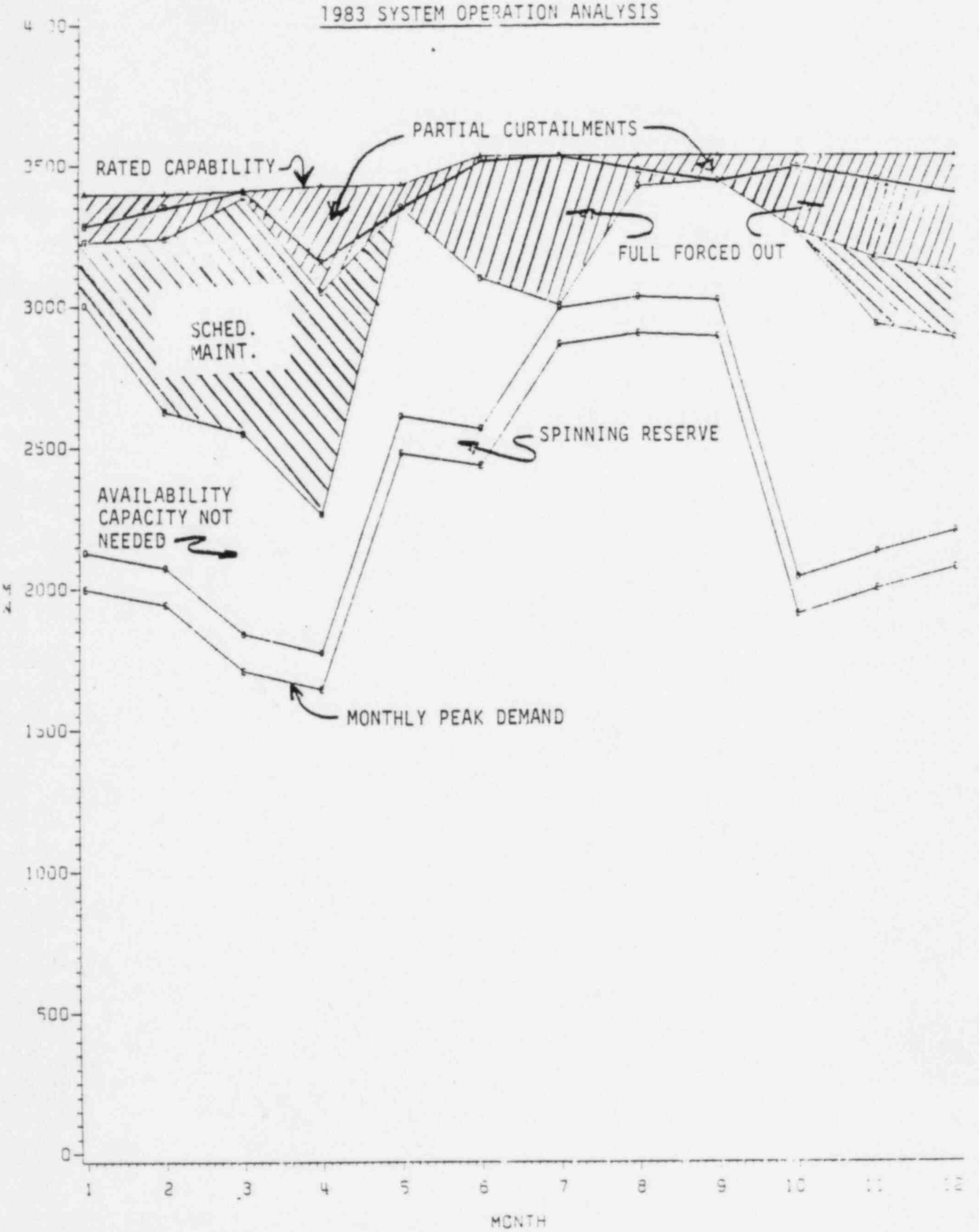
[18]Other APS assumptions underlying these figures are that (a) no CWIP from PV-2 and PV-3 is included in the rate base, (b) approximately a one-year lag occurs between rate request and Commission action and, (c) no other rate mitigation mechanisms are employed, such as those APS plans to propose in 1985, as discussed in Sec. IV.

[19]According to Trout's testimony (1984, Exhibit 5), excluding PV-1 CWIP from the rate base would require a 36 percent nominal increase in rates (34 percent real) during 1985. His analysis was based on earlier assumed in-service dates for PV-1, PV-2, and PV-3 than those currently planned.

[20]Of course, all this assumes that the latest forecasts (May 10, 1984) turn out to be accurate. If loads continue to be overestimated, as they have in the past (illustrated in Fig. 1.1), the problem of excess capacity will be intensified.

ARIZONA PUBLIC SERVICE COMPANY

1983 SYSTEM OPERATION ANALYSIS



SOURCE: APS files (undated).

Figure 2.2

Table 2.1

GENERATING CAPACITY IN EXCESS OF RESERVES
BASED ON APS PLANNED RESERVE CRITERIA

Year	Estimated Excess Capacity (MW)
1985	0
1986	(21)
1987	212
1988	233
1989	214
1990	238
1991	62
1992	42
1993	(8)
1994	(20)

SOURCE: APS, 1984 "Long-Range Forecast--Loads and Resources," May 10, 1984.

The price-marginal cost relationships shown in Fig. 2.1 are undesirable on three counts. First, the high prices early in the period encourage customers to cut back electricity usage, causing even greater underuse of capacity illustrated in Table 2.1. If, for example, real rates could be cut by 10 percent below those shown in Fig. 2.1 for 1986 and 1987 and if we assume a price elasticity of -0.3 for adjustments extending over two or three years, the excess capacity of 233 MW for 1988 in Table 2.1 might be cut by about 40 percent.[21]

Second, later in the period 1984-1994 real prices fall, helping to reduce excess reserves below zero in 1993 and 1994. The reduction in prices does not reflect any reduction in cost--indeed marginal costs are rising over time--but only the way that capital costs are recovered.

[21]A 103 MW reduction is calculated as 3 percent of the load forecast of 3446 MW for 1988. An excellent assessment of methodologies and results of prior attempts to estimate price elasticities is provided by Taylor (1975).

To be sure, one could encourage greater allocative efficiency by modifying rate structures, despite the capital recovery profile underlying the rates shown in Fig. 2.1. For example, low Kwh rates could be set roughly equal to marginal running costs, and high "customer" (fixed) charges could be levied to recover capital costs. Or one could use "Ramsey" prices, setting rates for various customer classes above marginal cost inversely related to their price elasticities of demand. (Thus, a customer class with a highly inelastic demand would pay higher rates than one with a relatively elastic demand.)[22]

But these pricing approaches bring us to the third problem with the capital recovery profile--that of intergenerational equity. Either with high customer charges or Ramsey prices, some customers who face high prices in the early years are not the same ratepayers as those in later years. During such a long period, some leave APS service territory; others enter it; some die; yet others are born. Many would regard as "unfair" a situation in which one group pays relatively high prices early in the cycle to recover the costs of plant that benefits no less the later users who incur lower charges.

All this brings us to the question of the optimal time profile of capital recovery. In response, consider first the situation faced by competitive firms. For them "economic" depreciation is key--the decline in market value of the asset from year to year, where market value is equal to the present value of the asset's future net revenues. If the

[22]A detailed explanation and justification of Ramsey prices as a way to minimize efficiency losses when an overall budget constraint must be satisfied is contained in Baumol and Bradford (1970).

firm fails to cover economic depreciation, along with its other costs, it will eventually be forced out of business. If it more than covers this amount, it will earn excess profits that will attract other firms into the industry, tending to reduce price and force profits down to a "normal" level.

Unfortunately, we have no good measure of market value for a regulated utility's generating plant because it is not readily traded in the market.[23] Therefore, we must resort to analysis based on simplifying assumptions. Suppose we have a world of no inflation with an asset that (a) generates a constant and certain net revenue stream throughout its life, (b) at the end of its life becomes totally useless, and (c) is unaffected by technological change. Under these conditions, the annual depreciation of the asset would *increase* each year at the real (and nominal) rate of interest; the annual earnings (at the same interest rate) on the asset would decline with the depreciated value (rate base) of the asset; and the total revenue requirement would remain constant over the life of the asset. Thus, economic depreciation would be equal to straight-line depreciation only if the interest rate were zero.

Now let us add a given rate of inflation to the analysis. Here we would have a "trended" rate base, where (a) the revenue requirement would rise by the rate of inflation (but remain constant, as above, in real terms), (b) depreciation would rise at the nominal rate of interest (and thus rise at the same real rate as above), (c) the rate base would

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[23]It is for this reason that many urge the eventual deregulation of the generating portion of the electric utility industry. With vigorous competition among power suppliers, market values for generating plant would be established, and those firms unable to cover costs would fail while more efficient firms would thrive.

appreciate at the inflation rate, so that the nominal value of the rate base would rise in the early years and later fall when depreciation more than offsets appreciation.[24]

Suppose that the Palo Verde units (a) met the earlier simplifying assumptions, (b) accounted for all of APS generating resources, and (c) came on line all at once. Capital recovery could be shown on Fig. 2.1 as a curve that rises with the real rate of interest, and total real revenue requirements would be shown by a horizontal line. The real price per Kwh would also be constant, if it is set to just cover the revenue requirements.

Despite the need for simplifying assumptions, we have from the above some general guidance in designing a time profile of capital recovery for Palo Verde that would improve on the situation shown in Fig. 2.1. Let us alter the assumptions above to account for the more realistic conditions surrounding Palo Verde. Presumably, the level of operation (capacity factor) for the units will expand in the early years as the units reach "maturity." Then the units presumably will operate at a more or less constant level through much of their life. Toward the end of their lives aging may substantially reduce capacity factor. This pattern suggests a cost recovery schedule that shows little depreciation in the early years; depreciation subsequently growing at roughly the real rate of interest as discussed above and more rapid depreciation toward the end--a far cry from conventional straight-line depreciation practices.

[24]See the numerical examples and discussion in Streiter (1982).

This analysis suggests that real revenue requirements be smoothed out over much of the lives of the plants, with an increase near the end. The (residential) rate schedule accompanying this revenue requirement would differ from that in Fig. 2.1 by avoiding or at least reducing the hump, having higher rates than those shown in the 1990s, and still higher rates as the plants show the effects of aging in the next century. This pattern would be desirable because (a) it would mitigate the intergenerational problem noted above, and (b) it would more closely track marginal costs, reducing allocative efficiency losses reflected in underuse of plant shown in Table 2.1.

A number of accounting techniques could be selected, more or less ad hoc, that would generate this desirable profile: reduced depreciation schedules in the early years, a more gradual phase-in of operating plant into the rate base, and deferral of expenses, among others.[25]

But all this does not mean we are home free. Two other factors are paramount. First, this pattern poses more severe cash flow problems than does conventional treatment, because the utility would be obliged to postpone cost recovery over a longer period of time. This postponement adds to lenders' risk because no one yet knows with confidence the lifetimes of large nuclear plants, or how they will age toward the end of their lives, since experience with these facets of nuclear plant operation is so limited. Shorter lifetimes or more detrimental aging effects than expected pose less severe problems for the utility under straight-line depreciation, because it would have

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[25] These techniques are discussed by Trout in earlier testimony (1984, pp. 17-22). I have no comment on their relative merits.

recovered most of its costs earlier in the life of the plant.[26] Greater cash flow problems and higher risks translate into higher marginal capital costs for the utility. By permitting relatively rapid cost recovery, conventional accounting practices shift a portion of risk from the utility to ratepayers.

Second, we must consider the discount rates of consumers. With positive discount rates, they would always prefer to pay a given amount later rather than sooner. However, the longer rate increases are postponed, the higher they must be to cover the utility's carrying costs.

Thus, the time profile of capital recovery should take into account the discount rates of both the utility and its customers. The discount rate for customers, which surely varies among income classes and types of customers, cannot be described by a single point estimate. Nor is the utility's marginal capital cost easy to estimate.

Nevertheless, one should be able to achieve rough approximations, through iterative techniques, to a time profile of capital recovery that would stand a good chance of showing a striking improvement over the results based on conventional accounting treatment. For example, one could start the analysis with the levelized revenue requirement based on economic depreciation to determine the severity of cash flow problems. If the problem seems not serious, suggesting a relatively low marginal cost of capital, the profile could be tilted upward to postpone some cost recovery and rate increases to reflect a reasonable range of possible customer discount rates. If, in contrast, levelized revenue requirements would pose severe problems, various downward tilts could be

[26] See the discussion by Perl (1984, pp. 9-10).

tested to determine how they would affect the marginal cost of capital, and then one could select a path to strike a rough balance between that cost and an estimated range of customer discount rates.

Finally, we must return to the question of including CWIP in the rate base, abstracting from questions of incentives already discussed. As has been reiterated throughout earlier testimony in this proceeding, inclusion of CWIP in the rate base, while increasing rates to customers immediately, reduces them in later years. And as noted earlier, without the assumptions by APS of PV-1 CWIP in the rate base, the jump shown for residential rates in Fig. 2.1 would be sharper than shown. If APS currently faces severe problems of cash flow, as it asserts, this implies that its marginal cost of capital is higher--perhaps substantially higher--than its average cost. An amount of CWIP should go into the rate base such that the APS marginal cost of capital falls within the range of reasonable estimates of customer's discount rates.[27]

In this section we have been concerned primarily with allocative efficiency and issues of including CWIP in the rate base. But the question of cost efficiency is also paramount. Although it is hard or impossible to quantify ways that current regulatory policy affects the cost efficiency of utilities, the Commission, and regulators throughout the country, remain concerned about the possibly detrimental effects of "cost-plus" regulation. For this reason, a number of states have adopted explicit regulatory incentive programs to which we now turn.

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[27]A similar approach was used by Hadaway in earlier testimony (1984, pp. 11-19).

III. INCENTIVE MECHANISMS TO IMPROVE UTILITY PERFORMANCE

Desirable features that designers of incentive programs should seek can be quickly tabulated.

- Rewards reflecting the program's favorable effect on utility performance rather than performance improvements caused by other factors.
- Avoidance of perverse incentives so that, for example, the utility does not forgo long-term gains for the sake of collecting a reward for short-term cost savings that are less valuable to society.
- Incentive formulas with reasonable probabilities for rewards and penalties being incurred.
- Incentive formulas for reasonable sharing of losses and gains between the utility and its customers.
- Rewards and penalties tied to performance results that are within the control of the utility.
- Easily defined performance measures free of subjective judgment in application and invulnerable to accounting and other manipulations by the firm or by regulators.
- A program easy to administer.

With this tabulation in mind, I have sought to determine the feasbility of designing an incentive program in light of the Commission's interests. I have surveyed the experience of jurisdictions where programs are, or have been, in place.[1] On balance, these programs

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[1]The survey included assessment of previous studies of incentive mechanisms, Brown et al. (1983); Costello (1983, 1984); Edison Electric

may have beneficial effects although, as discussed below, it is impossible to determine conclusively whether this is so. A number of problems arise that make difficult or impossible the design of a program that one can confidently predict will be successful. To demonstrate this I treat briefly the nature of programs in various states, and the nature of problems that arise.

INCENTIVE PROGRAMS IN STATE JURISDICTIONS

A number of states, and the Federal Energy Commission, have established (and in some cases terminated) incentive programs as defined in Sec. I. According to a recent survey by the Edison Electric Institute (EEI), 18 commissions have existing programs, with three states (California, New Hampshire, and New York) having two programs; four states have discontinued a total of six programs.[2] Performance criteria used in existing programs are shown in Table 3.1.

The definitions of most of these criteria are self-evident. But two--capacity factor and equivalent availability--merit explicit definition here, both because they play important roles in many state plans and because they are of key relevance to the incentive plan proposed by APS, discussed in Sec. IV. The capacity factor is the ratio (times 100) of the amount of electricity actually generated by a plant during a given period to the total amount of electricity that it is theoretically capable of producing during that period (measured by the rated capacity of the plant times the number of hours in the period). Equivalent availability is the ratio (times 100) of the amount of

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Institute (1984); Goins et al. (1983); and Peterson (1984); plus materials received directly from regulatory commissions in California, Florida, Illinois, Michigan, New Jersey, and New York, listed in the bibliography.

[2]EEI (1984, p. 1).

Table 3.1

REGULATORY INCENTIVE PROGRAMS
CRITERIA TO MEASURE PERFORMANCE

Criterion	No. of Programs Using Criterion
Heat rate (actual and/or average)	9
Capacity factor	8
Availability (operating and/or equivalent)	7
Fuel costs	6
Outage rates (scheduled and/or forced)	4
Purchased power costs	4
Construction costs	3
Generation mix	2
Operating and maintenance expenses	2
Return on equity (difference between authorized and earned)	2
Capital investment (conservation, coal conversion, etc.)	2
Fuel pricing policies	1
Aggregate cost-of-service	1

SOURCE: Edison Electric Institute (1984, p. 11).

electricity available from the plant during the period (after allowances are made for full and partial outages) to the amount of electricity it is theoretically capable of producing. Differences between capacity factor and equivalent availability arise whenever the plant's output is curtailed because of less expensive power available from other sources.

Despite the widespread use of incentive programs, one cannot assume that they can easily be designed and administered, or that they significantly affect utility performance. Their use poses a number of problems.

KEY PROBLEMS

Evaluation

A major difficulty is that one cannot determine the degree to which programs have favorably affected utility performance. For obvious reasons, successful ex poste evaluations are difficult or impossible to conduct. Determining what would have happened in the absence of the incentive plan being investigated is, to say the least, a challenging task.

Some states have undertaken evaluations, with inconclusive results. For example, in 1980 the Florida Public Service Commission established a Generating-Performance Incentive Factor (GPIF), based on unit equivalent availability and average heat rate for base-load units.[3] Projections of expected performance are set each six months for these two performance factors for each unit, with weights assigned to provide systemwide targets. At the end of each six-month period, performance is compared with the targets and rewards and penalties are imposed accordingly. During the two-year period after the program started, Florida Power Corporation received two awards totaling $655,000 and paid two penalties totaling $697,000, while Florida power and Light received three awards totaling $1,914,000 and one penalty of $182,000.[4]

A Florida PUC staff report concluded that, in general, generating performance had improved after the GPIF program was established. But the evaluation did not control for other variables to show persuasively

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[3]Florida Public Service Commission (1981).

[4]Florida Public Service Commission (undated, pp. 5, 8). Tampa Electric Company and Gulf Power Company, also covered by the program, were subject to both rewards and penalties during that time.

that the GPIF program, rather than other factors, was responsible. The authors recognize this difficulty by concluding that "it is tempting to attribute this improvement to the existence of the GPIF but no such claim can be made with any certainty."[5]

The experience in Michigan was similar. In 1977, the Michigan Public Service Commission adopted a "System Availability Incentive Program" focused on Detroit Edison's and Michigan Consumers Power's systemwide plant availability. The scale of incentive adjustments, as originally adopted for Detroit Edison, is shown in Table 3.2.[6] During the four-year period 1978-1982, Detroit Edison earned $37 million in additional revenues under the plan.[7] Not suprisingly, questions arose

Table 3.2

SCALE OF INCENTIVE ADJUSTMENTS: MICHIGAN PLAN

Annual Average System Availability %	Equity Return Incentive Adjustment
0 - 70	-0.25
70.1 - 80	0.00
80.1 - 85	+0.25
85.1 - 100	+0.50

SOURCE: Michigan Public Service Commission (1977), p. 57.

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[5]Ibid., p. 17.

[6]In 1981, the Commission modified the plan to include more steps in the scale, with a reduction in the deadband from 10 percentage points to 6 percentage points. It also added a 7 percent "periodic factor" (reflecting estimated scheduled maintenance to system availability in the revised incentive scale to discourage the utility from reducing the time for scheduled maintenance as a way to increase availability in the short run). See Michigan Public Service Commission (1980, Exhibit D, p. 2).

about whether the incentive plan itself had much to do with Detroit Edison's performance. An evaluation in 1982 by Commission staff showed that availability did increase in the years after the plan was established--going from 75.0 in 1977 to 81.1 in 1982 for base-load units.[8] Recognizing the difficulty of controlling for other factors, the authors conclude that "No one factor such as increases in PME [production maintenance expense], the Incentive Provision, Commission awareness, management awareness, or utility operating practices can solely be attributed as the reason for improved availability performance."[9]

One could imagine a similar situation in Arizona. Suppose that an incentive plan focused on capacity factors had been instituted for APS coal-fired units in the mid-1970s. It turned out that APS capacity factors rose after 1975, as described by W. J. Post in earlier testimony (1983, p. 61):

> The APS composite coal plant capacity factor has shown marked improvement from 1975 to 1982, going from 62.34% to 77.94%, and has increased every year since 1978. On the basis of the most recent North American Electric Reliability Council (NERC) data for coal plants over 100 MW capacity, APS' 1982 coal plant capacity factor of 77.94 was approximately 30% better than the latest industry average of 59.73.

In this case, APS might have been rewarded under the incentive plan, even if it had contributed to no additional improvement in performance. An evaluation based on performance before and after the plan was established would have shown the same inconclusive results as those in Florida and Michigan.[10]

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[7]Anderson (1983, p.12).
[8]Padgett and MacGregor (1982, p. 10).
[9]Ibid.
[10]Sound evaluation may have to await the time when a large enough

Serious consequences can arise from the lack of persuasive evidence that incentive plans have positive effects and that the gains are fairly apportioned between the utility and ratepayers. Objections were raised by the State Attorney General and others that the Michigan plan's incentive scale was set so high that it unduly rewarded Detroit Edison.[11] Four consecutive rewards, with no penalties, only added to these concerns. These controversies, fueled by lack of evidence that the plan was beneficial, led to its demise in 1983. The views of Commissioner Edwyna G. Anderson (1983, p. 12) expressed at the time merit reflection by the ACC and others contemplating a similar plan for APS:

> I have argued for more than two years now that it makes no sense to reward a company for doing what it was created to do.
>
> There never has been a nexus between power plant availability and attendant adjustments in the return on common equity. If a company's generating units are not available when they should be, this Commission should discover why the company is performing poorly, and use available regulatory tools to ensure or encourage correction of the difficulty.
>
> Detroit Edison and every other utility should be ordered to keep its plants used and useful at all times. This is their job and no carrot and stick approach should have been required in the first place. I am grateful it [the System Availability Incentive Program] has been eliminated.

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number of states have adopted similar incentive plans to enable one to estimate whether the presence or absence of the incentive plan is statistically significant in explaining differences in utility performance among states.

[11]Michigan Public Service Commission (1980, pp. 71-72), and Brown et al. (1983, p. 20).

A convincing evaluation showing that an incentive program has positive net benefits, and that these benefits would have been lost in the absence of the program, would help to defuse the notion that the utility in question should not be rewarded "for doing what it was created to do." Lacking such an evaluation, however, regulators and utilities involved in incentive programs will continue to be vulnerable to criticism of the sort voiced by Commissioner Anderson.

Distortions in Incentives

Incentive plans generally focus on one or a few performance measures, such as heat rate or capacity, as shown in Table 1.1, for one or more power plants in the utility's inventory. This limited focus reflects the need to keep the plan administratively simple. But it is commonly recognized that this limited focus can distort incentives, possibly leading to cost increases elsewhere in the utility's system. As J. E. Haas expressed it in Phase I of this rate case (1984, p. 30), "the difficulty with partial plans is that the plan may end up prompting direct costs which exceed the direct savings they caused, and to ascertain this is difficult."[12]

A plan targeted on capacity factors or equivalent availability would encourage the utility to exceed the target by spending excessively on operation and maintenance (O&M) and passing these costs on to the ratepayer. Conceivably, the increased O&M cost could more than offset the benefits to ratepayers of increased availability or capacity factors. But detecting and measuring this bias is difficult or

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[12]See also the discussion by Goins et al. (1983, Vol. 1, pp. 2.3-2.4); and Brown et al. (1983, pp. 11-14).

impossible, especially with new plants (such as Palo Verde) for which one cannot make comparisons with extensive past records of O&M costs. The fact that numerous studies have addressed the question of whether the A-J bias exists, with conflicting results as noted in Sec. II, illustrates the difficulty of detecting and measuring the effects of perverse incentives.

An obvious alternative is to broaden the focus to encompass all the utility's costs. One possibility that has received substantial analytical attention is total factor productivity, which reflects the efficiency with which inputs are combined to produce electricity. If only a single homogenous input and a single homogenous output were involved, the problem of designing an effective incentive program would be vastly simplified. The utility could be rewarded if it succeeds in reducing over time the quantity of input for a given level of output. But there are many inputs, including a heterogenous collection of labor, fuel, materials, capital, and purchased power. Nor is the output--electricity--homogenous because of the differing requirements of customer classes. Although detailed analyses of total factor productivity for particular utilities have been carried out, the results have been inconclusive and controversial because of severe methodological and other problems.[13] Consequently, no state has yet adopted an incentive plan based on a utility's total factor productivity.

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[13]The difficulties of using total factor productivity as a regulatory tool are discussed at length by Goins et al. (1983, Vol. 1, pp. B.1-B.17). See also Baumol (1982); Sudit (1979); and Cowing and Stevenson (1981).

Another possibility that avoids the bias in factor inputs associated with partial plans, suggested by Goins et al. (1983, Vol.1), focuses simply on the utility's revenue per Kwh. Presumably, the lower are its revenues per Kwh, the greater is its overall efficiency and the stronger the grounds for granting a reward. The salient advantage of this approach is the ease of measurement, since revenues per Kwh can be taken from routinely reported accounting data.

But the drawbacks are severe. Revenue per Kwh poorly reflects underlying costs when conventional accounting techniques are used, as discussed in Sec. II. If rate shock arises as a consequence of meeting revenue requirements as conventionally computed, the utility could be penalized for a high revenue per Kwh even though this measure has nothing to do with efficiency. Nor would the reduction in revenue per Kwh necessarily reflect improvement in the utility's performance in later years, as plant is depreciated and rate base falls.

Moreover, even if revenues per Kwh accurately track costs, the question arises of how to structure rewards and penalties around this measure. The utility could be rewarded or penalized depending on how its revenue per Kwh during a specified time period compares with the level achieved in an earlier period. But this procedure leaves open the question of whether the change is a consequence of management performance, or the operation of exogeneous effects discussed below. For example, if the utility enjoys economies of scale such that its average costs fall as a function of output, a reduction in revenue per Kwh could merely reflect a movement down the cost curve, rather than any improvement in performance as measured by a downward *shift* in the cost

curve. The converse holds if the utility faces increasing average costs.

Alternatively (or in addition), the utility's revenue per Kwh could be compared with that of other "comparable" utilities. However, identification of groups of utilities that are, in fact, comparable is difficult and controversial. Much criticism was leveled by utility executives, analysts, and others of interutility comparisons proposed by Goins et al. (1983, Vol. 2).[14]

Control for External Effects

As Brown et al. noted, "An incentive system should be based exclusively on variables within the control of management. Penalties and rewards should not be assessed or awarded for performance resulting from conditions outside the control of management" (1983, p. 34). Some events (such as natural disasters or changes in NRC regulations) can easily be seen as beyond the control of management. But between these and others that fall clearly in management's lap lies a wide spectrum of ambiguous possibilities. The extent to which poor management, or other factors, caused a particular forced outage, for example, could lead to tedious investigation and inconclusive results.

Even if an event is beyond management control, the *response* to the event could be subject to controversy. For example, consider an unscheduled outage caused by an external event. Under an incentive plan focused on plant capacity factor, the downtime would not be counted in determining rewards and penalties. But disagreement could arise about the appropriate duration of the downtime under "good" management. The

[14]See especially the criticisms by Landon of National Economic Research Associates in Goins et al. (1983, Vol. 2, pp. 13-22).

regulatory body could find itself on treacherous ground in trying to enforce its judgment on this issue. Suppose that the regulator's engineering staff concludes that the outage could be corrected in a month; but the utility disagrees, claiming that unless three months are allowed, repairs will have to be so hastily made that they will contribute to future outages, or even worse, that premature resumption of plant operation could pose safety hazards. What should the regulator do?

But note that protection of the utility from external circumstances varies from the situation faced by competitive firms, which are affected by all sorts of external circumstances. Witness, for example, a housing construction firm that goes bankrupt because of rising interest rates over which it has no control. The difficulty, however, of denying utilities such protection is that we would have to be prepared to let some utilities go bankrupt and others to earn very high profits. Neither of these prospects is especially disturbing to many observers except for one problem: the difficulty of establishing a baseline or competitive norm for exposing utilities to these two extreme outcomes. Perhaps the most basic difficulty of seeking to mimic competitive behavior in a regulated industry is establishment of a competitive norm where competition does not exist.

Subsequent-Round Offsets

If a utility is rewarded for good performance, its additional revenues benefit its shareholders, as a "first-round" effect. Conversely, if the utility is penalized for poor performance, such as disallowance of expenditures on grounds of "imprudence," appropriate accounting adjustments show that shareholders, and not ratepayers,

suffer the consequences. But is it true that the utility is able to keep the full rewards, or must it suffer the full consequences of penalties, in the longer run?

If the utility uses its reward to enhance its financial position (as opposed to, say, donating the reward to charity) it would be in a weaker position to argue for a given rate increase in a subsequent rate case, than would the unrewarded utility. The converse situation holds for the utility that, suffering a penalty, is in a poorer financial condition than otherwise. This is not to say that, in the long run, the utility, its shareholders, and its ratepayers are unaffected (in present-value terms) by whatever rewards and penalties are accorded by regulators; for the subsequent effects may well fall short of offsetting dollar-for-dollar the first-round ones. Nevertheless, the possibilities of subsequent offsets are important to keep in mind when considering alternatives for improving utility performance, because the incentives of any given reward and penalty system may be weaker than one would suppose from observing only first-round consequences.

For example, in testimony during Phase I of this case, H. B. Sargent of APS noted that "The Company's current fuel clause allows the company to keep all interchange profits above a specified level [of sales] while suffering the loss if the sales do not meet that level" (1984, p. 13). Yet, gains and losses from such interexchange sales presumably affect APS financial statements, such as those shown in Exhibit HBS-11 in his testimony, and thereby may affect the outcome of Phase I of this rate case. APS would not be able "to keep all interchange profits" but would share them with Arizona ratepayers to the extent that these profits strengthen the financial position of APS and

lead to smaller approved rate increases than otherwise.[15] Thus, the incentives of APS to sell to other utilities may be weakened as a consequence of subsequent offsets.

As another example, consider the frequently voiced view that regulatory lag provides positive incentives for imprc ed utility performance. As the argument goes, during the time between a request for rate increase and the point at which it is granted the utility is free to keep any additional revenues it earns through improved efficiency. However, if these revenues improve the utility's financial position, its ability to obtain rate increase could be compromised in *later* rate cases.

To appreciate more fully the importance of this point, consider two utilities, A and B, identical in all respects except that B is able to improve its performance and achieve additional profits during the delay between its request for an increase in rate case X, and the approval of its request. Assume further that B's improved performance during the delay does not affect the rate increase finally approved. At the conclusion of rate case X, B's financial position is stronger than A's as measured, for example, by a greater interest coverage ratio that reduces its cost of capital. Now suppose that after rate case X both utilities are affected by general inflation so that both must eventually file for further rate increases. However, because of B's stronger financial position, it may file later than A and/or the rate increase B obtains may be smaller than A's. Thus, some of the gain achieved by B during rate case X would subsequently be transferred to ratepayers.

[15] Indeed, because APS is also in the retail natural gas business, profits on intersystem electricity sales could redound to the benefit of gas customers, who would pay lower rates than otherwise. APS has received approval to sell its gas business at the end of 1984.

Subsequent offsets are likely to be mitigated, and hence the effectiveness of incentive devices strengthened, when inflation is low or zero and earned rates of return are judged by regulators within a wide band of "reasonableness." After rate case X above, utility B would enjoy a higher earned rate of return than A. As long as its rate of return remains below the upper bound of reasonableness, regulators would have no grounds for requiring reductions in electricity rates. In the absence of inflationary pressures, earned rates of return for both A and B might remain within the zone of reasonableness indefinitely, but with B, and its shareholders, being better off than A as a consequence of its greater efficiency.

The Size of Rewards and Penalties

It is commonly recognized that an incentive scheme with large rewards and penalties can adversely affect the risks perceived by investors and, hence, the utility's cost of capital. Hence, some have urged that rewards and penalties should be small enough so as not to significantly affect these risks. For example, J. H. Landon cautions that "the extent of any reward or penalty should be limited, or capped, at a level sufficient to motivate management but well below an amount which would measurably increase the risk to the firm and thereby its cost of capital" (1984, p. 13). But this view immediately poses a dilemma. If the reward/penalty structure is set so low that it does not affect risks, it may also do little to motivate management to improve performance. Indeed, the effectiveness of the incentive scheme may be directly related to the degree to which it *does* affect risk.

In response, regulators might adopt a structure of relatively large rewards and penalties, while being mindful of the advice of Goins et al. that "any increase in the cost-of-capital associated with an incentive program [should] not outweigh the expected dollar savings to ratepayers associated with implementing the mechanism" (1983, p. 1.5). But this approach involves isolating the effects of the incentive plan from the effects of all other factors on the cost of capital--a difficult or impossible task.

Moreover, one cannot safely assume that simply because a particular reward or penalty is small, it has no effect on costs of capital. Measurable effects on costs of capital can be expected to arise from a *cumulation* of "small" factors--such as growth over years in AFUDC as a proportion of reported earnings, or accumulated cost escalations on Palo Verde--rather than the occurrence of a single identifiable "big" event.[14] The *ratio* of the factor's magnitude to the factor's contribution to a change in the cost of capital need bear no particular relationship to the factor's magnitude. Hence, a small reward or penalty could have the same *relative* effect on the cost of capital as a large one, although in any event the magnitude of the effect would be difficult or impossible to measure.

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[14] For example, the downgrading by Moody's of APS's first mortgage bonds from A3 to Baa2 in September 1983 was "prompted by the rate Order issued on September 28, 1983 by the Arizona Corporation Commission which granted only 51% of the amount the Company requested." But the downgrading did not arise solely because of the Commission's decision, but rather because of the cumulation of such factors as "poor cash flow and low quality earnings and fixed charge coverage ratios," in addition to the Commission's decision (Moody's Investors Service, 1983).

Credibility

Suppose that a utility is so successful in improving performance, in response to the incentive program, that it earns a string of large rewards. How likely is it that the regulatory commission will resist pressures to adjust the reward structure to reduce or eliminate these rewards at some point in the future? This problem is linked to that of evaluation discussed earlier. If it could be shown persuasively that large gains--shared with ratepayers--do occur from the program, it would be easier to maintain a credible incentive structure to permit continued earning of large rewards for improved performance. But the absence of such evaluation, combined with the effects of subsequent-round offsets, weakens credibility and, hence, the effectiveness of the incentive mechanism.

CONCLUSIONS

In light of the above problems, an obvious question is whether it is worthwhile for the Arizona Corporation Commission to consider seriously an incentive plan for APS. I conclude that the Commission should do so because the chances are good that a well-designed plan would, on balance, help. Other writers have shown that even small positive changes in utility performance could lead to large cost savings.[17] While perverse incentives and the other problems would reduce these potential gains, it is reasonable to expect that net benefits would accrue if the costs of administering the plan are low. Once a large number of states have adopted similar plans and have some years of experience with them, we may be able to determine whether the

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[17]Brown et al. (1983, pp. 5-7).

covered utilities in those states perform better than utilities elsewhere.

To avoid the kinds of problems discussed above, many observers are nowadays urging that the power generation portion of the industry be deregulated so that, under competitive pressures, utilities would have strong incentives to improve performance. But numerous institutional and other obstacles must be dealt with before highly competitive markets for power could emerge, and years would be required in making the transition. In the meantime, an important role may exist for regulatory incentive programs.

However, because of the complexities of designing a plan, I am unable to develop independently an approach that will not itself generate a good deal of controversy. A better approach is to take the APS proposal, reflecting the regulatory, financial, and market situations as APS perceives them, and to let others critique it in light of the desirable characteristics and the problems of incentive programs discussed above. My critique is contained in Sec. IV.

IV. THE PLAN PROPOSED BY APS FOR INCENTIVE REGULATION

In connection with its Phase II request for a rate increase, APS filed a proposed plan for incentive regulation with the Commission in July 1984.[1] The plan has four major components.

- Extension of the $1.20 AFUDC offset against each $1.00 in cash earnings (originally established for the interim rate increase of February 1, 1984, discussed in Sec. I) to all Palo Verde CWIP included in the rate base as a consequence of APS rate requests in Phase I and in Phase II of the present proceeding.
- Cessation of 50 percent of the common equity component of AFUDC on each Palo Verde unit during any delay in the start of commercial operation of up to 12 months.
- A ceiling of $3.15 billion on the total cost to be included in the rate base for the three Palo Verde units (with the ceiling adjusted downward for cessation of AFUDC related to interim rates or CWIP authorized in the rate base).
- Establishment of a schedule of explicit rewards and penalties based on equivalent availability achieved for the Four Corners plant and for Palo Verde.[2]

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[1]ACC (1984).

[2]The plan has a fifth component involving a specific set of criteria for establishing the date of "commercial operation" at which time the Palo Verde units would be accorded normal rate base treatment. APS proposes that a Palo Verde unit be considered in commercial operation at the time it has operated at 80 percent of its licensed reactor power for 100 continuous hours. I have no comments on the merits of this definition of initial commercial operation.

In addition, "if the Commission grants rate relief in this proceeding which is sufficient to produce reasonable financial indicators,"[3] APS will commit itself to developing a rate moderation plan to be presented, in 1985, as part of its next rate application. This plan will be designed to cope with the problem of rate shock discussed in Sec. II.

The APS proposal is notable on two grounds. First, it recognizes the importance of including a *combination* of incentive mechanisms that together may lead to more favorable results than if only one were offered. As emphasized in Sec. II, for example, the incentive effects (see p.19) of including CWIP in the rate base depend on the nature of other pressures that APS faces. Conceivably, the perverse effects of including CWIP in the rate base noted by earlier writers could be offset by other incentive mechanisms.

Second, the plan is simple. The criteria by which performance is to be judged are straightforward, and rewards and penalties are well defined. Implementation and operation should pose few administrative problems, except for the force majeure provisions and the need to adjust the reward/penalty functions over time.

In the following assessment of the plan, I conclude that the ceiling of $3.15 billion is too high and that revisions should be made in the operating incentives plan for Four Corners and Palo Verde. However, APS should be able to take these revisions into account without adding undue complexity. As revised, the plan will provide a reasonably sound basis for the Commission to make decisions in Phase II of the current rate proceeding.

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[3]Sargent testimony in APS (1984, p. 30).

CWIP IN RATE BASE: AFUDC OFFSET

Inclusion of the $1.20 offset for CWIP placed in the rate base as a result of the Commission's Phase I and Phase II decisions will strengthen APS's incentives to complete PV-1 quickly so that it can be awarded normal rate base treatment. If its rate requests are granted, APS estimates that the additional $0.20 loss of noncash earnings per dollar of cash earnings will result in a $28 million reduction in the amount of PV-1 costs that will appear in the rate base at the time the plant goes into service--a "give up of investment cost on which return and recovery by stockholders are abandoned forever."[a] The sooner PV-1 becomes commercially operational, the sooner APS will have the opportunity to earn its full allowed rate of return on the investment, and the sooner will it stop losing $1.20 in noncash earnings for each $1.00 of cash earnings.

In principle, this positive incentive could be accompanied by negative incentives as noted in Sec. II. Anxious to get normal rate base treatment, a utility could be tempted to cut corners in the startup phases that would affect the subsequent equivalent availability of the plant and/or lead to higher O&M expenses during the life of the plant. The utility might also be less concerned with cost control in the late construction and startup phases if doing so expedites getting the plant into the rate base, and if these additional costs can subsequently be recovered.

[a]Sargent in APS (1984, pp. 13-14).

In the case of APS, no way exists to determine the quantitative importance of such potential positive and negative incentives. As discussed in Sec. II, one can theorize about how a firm might behave under such pressures, but the degree to which they actually affect behavior is unknown. One must consider these pressures in light of how they interact with other components of the APS proposal to make a reasoned judgment about whether the overall incentive package encourages economically efficient behavior.

PENALTY FOR SLIPPAGE IN COMMERCIAL OPERATION

The second component of the APS proposal is cessation of 50 percent of the common equity component of AFUDC per month of schedule slippage of up to 12 months on any of the three Palo Verde units. For 1984, the AFUDC rate has been established at 10.11 percent (net of tax).[5] The common equity portion accounts for 6.19 percent of this figure. A 50 percent reduction would, therefore, reduce the AFUDC rate to about 7.01 percent during the time period of any slippage. APS estimates that the maximum common equity AFUDC that could be lost under this part of the proposal would be $97 million over the three-year period 1986-1988.[6]

This potential reduction in AFUDC reinforces both the positive and negative incentives of the first component noted above. On the one hand, APS would be under greater pressure not to slip beyond the present schedule. On the other, it could conceivably be tempted to cut corners to keep the slippage to a minimum, perhaps at the expense of future

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[5]APS files, "Computation of AFUDC Rate by Order No. 561 Method for the Year 1984," revised January 25, 1984, unpublished. With semiannual compounding, the annual effective rate is 10.37 percent.

[6]Sargent in APS (1984, p. 18).

plant availability and O&M expenditures. It might also be more willing to accept cost overruns to reduce the slippage, if the 50 percent loss of AFUDC equity earnings would be more than compensated by a reduction in the length of slippage itself and the quicker achievement of normal rate base treatment.

Three provisions of this incentive component are notable:

- The reduced AFUDC rate, taken by APS as a penalty, applies only to CWIP that is not included in the rate base.
- A force majeure condition is also attached. If slippages arise from conditions outside of APS control, the utility may appeal the automatic application of the AFUDC penalty. As discussed in Sec. III, this provision may complicate administration of the plan and compromise the effectiveness of this incentive device, insofar as ambiguities may arise about (a) whether a particular circumstance in fact constitutes force majeure, and (b) if so, whether the utility's response to the problem is appropriate.[7]

PALO VERDE COST LIMIT FOR RATEMAKING

APS proposes a cap on the cost of Palo Verde at $3.15 billion for the purpose of setting rates for its customers. In principle, such a cost limitation is attractive because it would help to counter the perverse incentives that could conceivably arise from the previous components of its proposal. With a cost cap in place, the utility would be less tempted to let costs mount as a way to (a) reduce schedule

[7]For example, a revision in regulations by the Nuclear Regulatory Commission presumably would constitute force majeure. But the amount of schedule slippage that ought to be allowed to accommodate the revision could be the subject of dispute between the Commission and APS.

slippage, or (b) bring the plant on line ahead of schedule to hasten the day of normal rate base treatment and thereby reduce losses caused by the 1.20 AFUDC offset. The key issue here is whether the cost ceiling is set so high that it will have little incentive effect.

The cap is established by adding 10 percent to the estimated share of APS total Palo Verde costs of $2.86 billion. However, already built into the $2.86 billion estimate is a contingency of about $90 million, and cost escalation factors ranging from 4 percent to 7 percent for labor, engineering, and other inputs.[8]

The history of financial distress and outright disaster in the nuclear field is reason enough for APS to want generous contingency budgets for Palo Verde. But construction of both PV-1 and PV-2 is essentially complete and the units are in various stages of startup.[9] A question arises as to how much additional cost escalation is likely to arise for plants close to commercial operation. The question is all the more pressing because if the Commission approves a specific contingency limit, APS would have weaker incentive to avoid incurring costs up to that limit.

To assess whether the additional 10 percent contingency is reasonable for a cost cap, I have examined the cost experience of other nuclear units close to the time they began commercial operation. The best data base I have found for this purpose, covering more than 100 units, is compiled by the Michigan Public Service Commission.[10] It

[8] APS, "PVNGS Baseline Estimate--Forecast #15 Delayed, Summary of Cost Increases," undated mimeo.

[9] For a description of the status of PV-1 see the testimony of Van Brunt in APS (1984).

[10] Michigan Public Service Commission (1984, Appendix E).

shows the additional capital costs reported for each year up to (and beyond) the time each unit goes into commercial operation, ending with the year 1982.

From this data base I have taken the seven plants that went into commercial operation after the Three Mile Island accident, to account for the most recent and relevant experiences. The percentage of total capital cost recorded at 18 months, 24 months, and 36 months before commercial operation of these plants is shown in Table 4.1. These time periods correspond to the time at which PV-1, PV-2, and PV-3 are planned for commercial operation beyond the most recent date--June 30, 1984--for which reported accumulated costs for the three units are available. For example, Salem 2 shows that 85 percent of its total cost was incurred 18 months before commercial operation, whereas 91 percent of the total estimated cost of PV-1 has been incurred 18 months before its planned date of commercial operation.

From these data I have taken two scenarios: First, is a "worst case" scenario where I select from the seven units the smallest percentage shown for each time period. For example, La Salle 1 recorded the smallest percentage--74 percent--of cost incurred prior to 18 months before commercial operation; and also the smallest percentage--66 percent--prior to 24 months before commercial operation. North Anna 2 showed the smallest percentage--49 percent--prior to 36 months before commercial operation. These figures appear in Table 4.2 in the worst case scenario. By dividing the $838 million for PV-1 by 0.74, I estimate PV-1's total cost at $1,132 million, as shown. With similar computations for the other units, the total runs to about $2,960 million, or 9 percent above present total estimated cost for Palo Verde.

Table 4.1

CAPITAL COSTS: PALO VERDE AND SEVEN OTHER NUCLEAR UNITS

Plant	Plant No.	Date Commercial Operation	Total Capital Cost (Million $)	Percent of Total Cost Incurred Before Commercial Operation: 18 Months Before	24 Months Before	36 Months Before
Salem 2	47	10/81	747.5	85	81	74
North Anna 2	71	12/80	530.2	92	84	49
Joseph Farley 2	75	7/81	705.3	80	73	59
Arkans Nuc One 2	78	3/80	651.0	76	68	54
Edwin Hatch 2	79	9/79	487.0	88	78	59
William McGuire 1	84	12/81	905.3	77	69	57
LaSalle 1	89	10/82	1231.9	74	66	54
Palo Verde 1	122	12/85*	918*	91*		
Palo Verde 2	123	6/86*	865*		65*	
Palo Verde 3	124	6/86*	934*			51*

SOURCE: Operating Nuclear Units: Michigan Public Service Commission (1984, Appendix E).

Palo Verde Units: Tables 1.2, 1.3. APS files (undated).

NOTES: All costs are in mixed dollars and include AFUDC. Palo Verde capital costs are APS share only. Cost for a portion of a year is based on proration of annual cost.

Estimated.

Table 4.2

ESTIMATED TOTAL CAPITAL COSTS: PALO VERDE

Total	Total Cost Reported to 6/30/84 (Millions $)	% of Cost Incurred Before Commercial Operation	Estimated Total Palo Verde Cost (Millions $)
	Worst Case		
PV-1	838	74 (18 months)	1,132
PV-2	562	66 (24 months)	852
PV-3	478	49 (36 months)	976
Total Cost			2,960
Estimated Cost of PV			2,717
Estimated Overrun			9 percent
	Median Case		
PV-1	838	80 (18 months)	1,048
PV-2	562	73 (24 months)	770
PV-3	478	57 (36 months)	839
Total Cost			2,657
Estimated cost of PV			2,717
Estimated Overrun			(2 percent)

SOURCE: Table 4.1.

Thus, even the worst case suggests that the 10 percent contingency would not be exceeded.

I consider a second "median" case, by taking the median percentages among the seven operating units--80 for 18 months, 73 for 24 months, and 57 for 36 months--drawn from Table 4.1. Computations with these figures in Table 4.2, using the same procedure as above, show a 2 percent underrun for Palo Verde.

The implication that the 10 percent contingency is too high is strengthened by two other considerations. First, the seven units shown generally experienced double-digit inflation during the final stages before commercial operation. Second, they were probably more seriously affected by events at Three Mile Island in these final stages, whereas Palo Verde was able to take that experience into account earlier in its construction.[11]

One factor goes in the other direction, however. These seven units were "successful" in that they actually began commercial operation. Other units have suffered long delays after completion (Diablo Canyon is a good example). APS could exceed the 10 percent--or conceivably even a much greater contingency--in a situation so fraught with uncertainty.

For three reasons, I conclude that reducing or eliminating the contingency would strengthen APS incentives for effective cost control. First, the above evidence suggests that a 10 percent contingency is too high. Second, Commission approval of a specific contingency limit would weaken APS's incentive to avoid incurring costs up to that limit.

[11] As Woods noted in earlier testimony, "The timing of Palo Verde has been fortuitous in relation to the experience of other nuclear projects in a construction schedule ahead of Palo Verde" (1984, p. 5).

Third, the risks to APS of large cost overruns would be reduced by the following factors:

- A force majeure provision, proposed by APS, would apply to the cap on cost. Hence, cost overruns outside the control of APS would permit it to exceed the ceiling without penalty. For example, a return to double-digit inflation or changes in NRC regulations would, presumably, be regarded as force majeure.
- In cases of slippage after construction is completed, the AFUDC component, rather than construction cost, would likely be most affected. For APS, however, the accumulation of AFUDC would be slowed, at least for as long as 12 months of slippage, because of the reduced AFUDC rate APS proposes, as discussed above.
- Cost escalations caused by negligence on the part of contractors would, presumably, be grounds for court action by APS for recovery. While the litigation process is cumbersome, costly, and uncertain in its results, the potential role of the civil justice system is relevant in this proceeding.
- Finally, even if APS exceeds the ceiling it would not bear the full additional costs. APS proposes only that shareholders be denied a return on these additional costs, which are to be passed on to its customers "over a period not to exceed ten years."[12]

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[12]Sargent in APS (1984, p. 23). One might opt for maintaining a 10 percent cost contingency while reducing these other protections--for example, forcing the APS to absorb, say, 50 percent rather than none of any overrun above its proposed cost limitation. But the problem would remain that ACC approval of the 10 percent contingency limit would weaken APS's incentive to avoid incurring costs up to that limit. One might also urge that these other protections be reduced even with a zero cost contingency. I have no comment on the merits of reducing these other protections.

OPERATING INCENTIVES FOR BASE-LOAD PLANTS

The fourth component of the APS proposal is a reward/penalty mechanism tied to equivalent availability of its Four Corners and Palo Verde plants. This component is important, because, among other reasons, it would blunt possible perverse incentives arising from the other components. As noted above, conceivably APS could be tempted to cut corners during construction and startup phases at the expense of future equivalent availability of the Palo Verde units, to avoid slippage penalties and to reduce the effects of the 1.20 AFUDC offset. An effective incentive system tied to equivalent availability would help to counter this possibility.

APS proposes that the plan become effective on January 1, 1985 for the five Four Corners units and be extended to each Palo Verde unit six months after it becomes commercially operational. Thus, during a period of about 18 months, only Four Corners would be included in the incentive plan if PV-1 becomes commercially operational at the end of 1985 as currently projected.

As shown in Fig. 4.1, the annual schedule proposed initially for the five Four Corners units combined would have (a) a reward starting at 75.5 percent equivalent availability and reaching a maximum of $11.7 million at 88.5 percent, (b) a penalty starting at 64.5 percent equivalent availability and reaching a maximum of $15 million at 48.5 percent, and (c) a deadband between 64.5 and 75.5. The maximum potential penalty of $15 million is set high enough to "be adequate for the operating incentive purpose" and yet low enough to avoid "significant side-effects on the Company's cost of capital."[11] The

[11]Sargent testimony in APS (1984, pp. 28 and 27).

maximum reward is set so that the plan will not be biased to favor either the Company or its customers. "That is, the maximum reward is set such that the expected (in a statistical sense) reward/penalty is zero."[14] The penalty/reward function in Fig. 4.1 is based on the frequency distribution of availabilities of "comparable" plants recorded in the National Electric Reliability Council's Generating Availability Data Set, and adjusted for Four Corners' "special characteristics" shown in Fig. 4.2.[15]

This $15 million maximum penalty, imposed initially only on Four Corners, is to remain the Company-wide maximum when PV-1 comes on line.[16] This penalty is to be allocated between Four Corners and PV-1 in accordance with their relative economic importance as shown in Table 4.3. Thus, APS estimates that about 64 percent (or $9.6 million) of the penalty should be allocated to Four Corners and 36 percent (or $5.4 million) should be allocated to PV-1. The reward/penalty schedule for PV-1 is shown in Fig. 4.3. It is based on probabilities of achieving specified capacity factors estimated from historical performance of similar nuclear units as reported by the Nuclear Regulatory Commission, with APS estimates for PV-1 shown in Fig. 4.4. This reward/penalty

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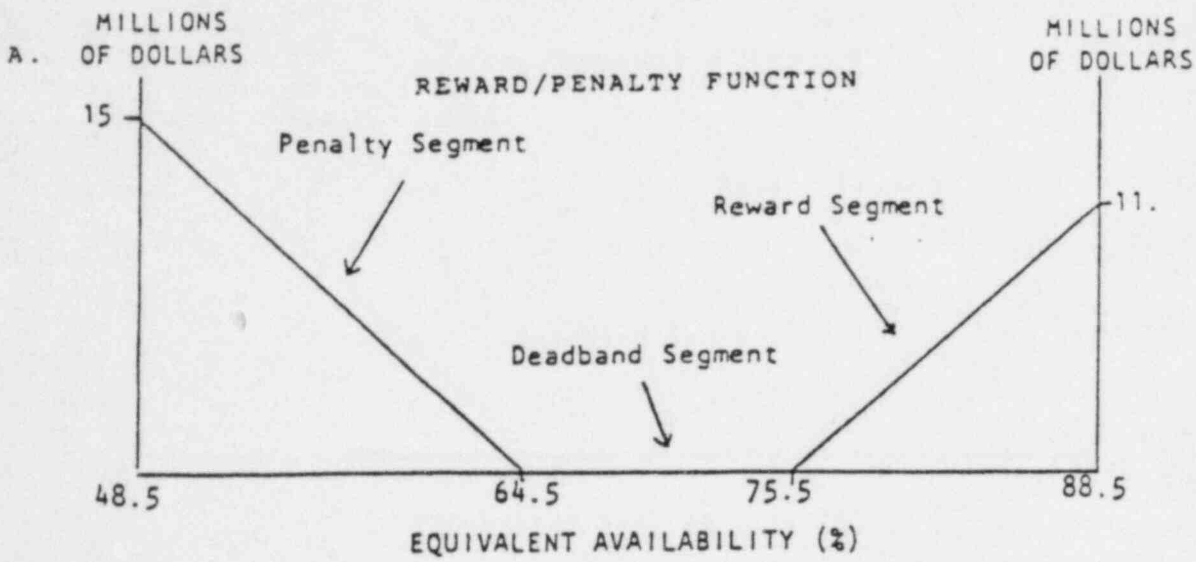
[14] Haas testimony in APS (1984, p. 14).

[15] According to Haas in APS (1984, pp. 28-29) the average equivalent availability of the Four Corners plant during the last five years has been 72.2 percent, compared to a 74.2 figure simulated from the performance of plants used in the APS sample. This difference is explained by the presence of scrubbers on units 1, 2, and 3 that reduce availability (yet few of the plants in the sample have scrubbers) and by the lower quality of coal at Four Corners than is generally available elsewhere.

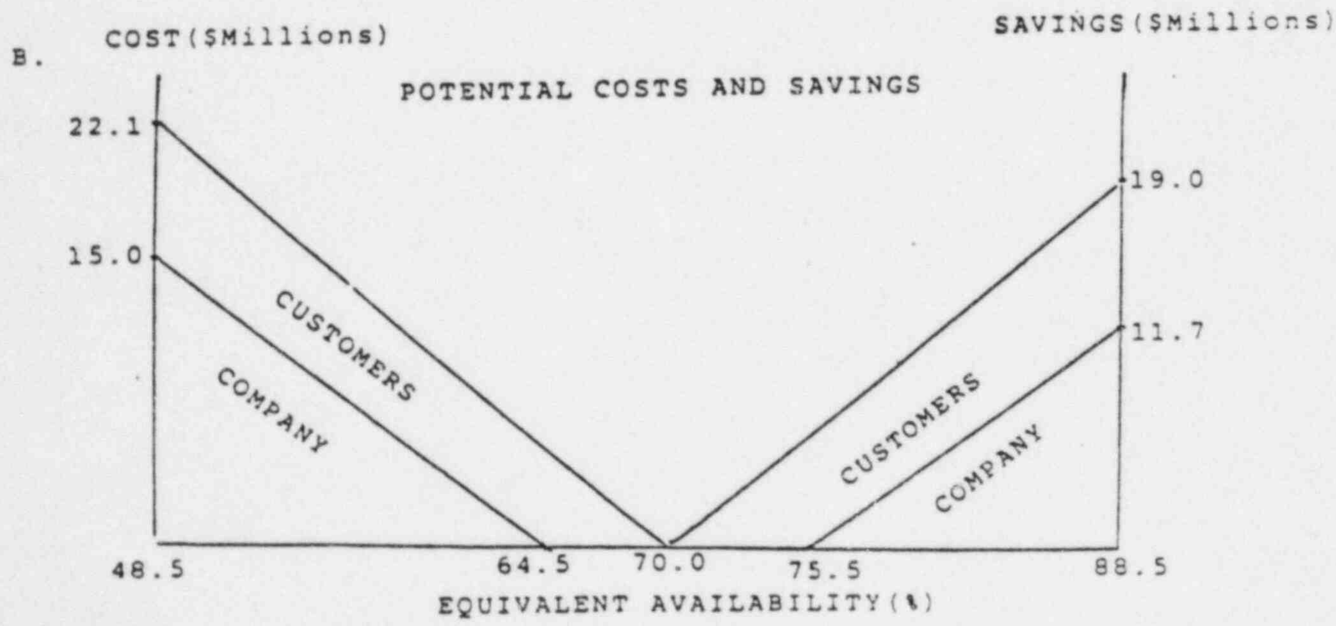
[16] APS proposes the maximum potential penalty of $15 million annually for 1985 and 1986. "For subsequent years, we recommend that the maximum penalty be determined at the time of a general rate hearing for the Company." Sargent testimony in APS (1984, p. 27).

OPERATING INCENTIVE SYSTEM FOR FOUR CORNERS
(excluding Palo Verde)

A.



B.



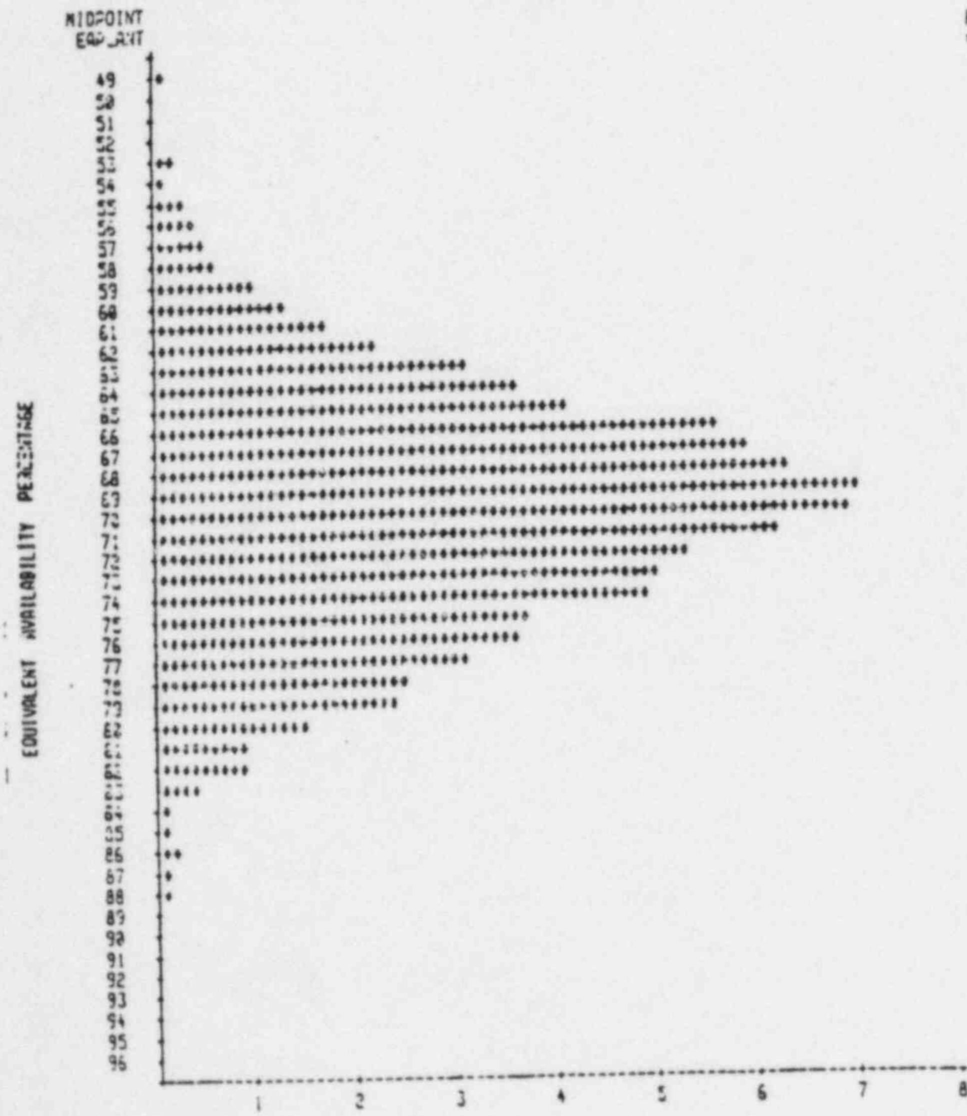
SOURCE: Haas in APS (July 1984, Exhibit JEH-9).

Figure 4.1

SIMULATED FOUR CORNERS PLANT
ANNUAL EQUIVALENT AVAILABILITY

FREQUENCY DISTRIBUTIONS
MIDPOINT EVERY POINT

PERCENTAGE BAR CHART



FREQ	CUM FREQ	PERCENT	CUM PERCENT
1	1	0.05	0.05
0	1	0.00	0.05
0	1	0.00	0.05
0	1	0.00	0.05
3	4	0.15	0.20
2	6	0.10	0.30
5	11	0.25	0.55
7	18	0.35	0.90
9	27	0.45	1.35
11	38	0.55	1.90
21	59	1.05	2.95
27	86	1.35	4.30
33	119	1.65	5.95
44	163	2.20	8.15
62	225	3.10	11.25
72	297	3.60	14.25
82	379	4.10	18.95
112	491	5.60	24.55
117	608	5.85	30.40
126	734	6.30	36.70
159	893	7.95	44.65
158	1051	7.90	52.55
143	1194	7.15	59.70
125	1319	6.25	65.95
119	1438	5.95	71.90
118	1556	5.90	77.80
94	1650	4.70	82.50
91	1741	4.55	87.05
81	1822	4.05	91.10
50	1872	2.50	93.60
48	1920	2.40	96.00
29	1949	1.45	97.45
18	1967	0.90	98.35
17	1984	0.85	99.20
7	1991	0.35	99.55
1	1992	0.05	99.60
2	1994	0.10	99.70
4	1998	0.20	99.90
1	1999	0.05	99.95
1	2000	0.05	100.00
0	2000	0.00	100.00
0	2000	0.00	100.00
0	2000	0.00	100.00
0	2000	0.00	100.00
0	2000	0.00	100.00
0	2000	0.00	100.00
0	2000	0.00	100.00
0	2000	0.00	100.00

SOURCE: Haas in APS (July 27, 1984, Exhibit JEH-4).

Figure 4.2

schedule, as well as that for Four Corners, would change when PV-2 and PV-3 are included in the incentive plan. APS proposes a minimum of two years between changes in schedules, except at times when new units are included in the plan.

A force majeure provision would enable the Company to request an adjustment to achieved equivalent availability factors in the computation of rewards and penalties,

A major strength of the APS operating incentive plan lies in its simplicity. Measurement of performance and computation of rewards and penalties are straightforward. Indeed, it is the ease of administering a plan based on equivalent availability that has already led other states to move in the same direction, as discussed in Sec. III.

Table 4.3

ALLOCATION OF MAXIMUM PENALTY PROPOSED BY APS

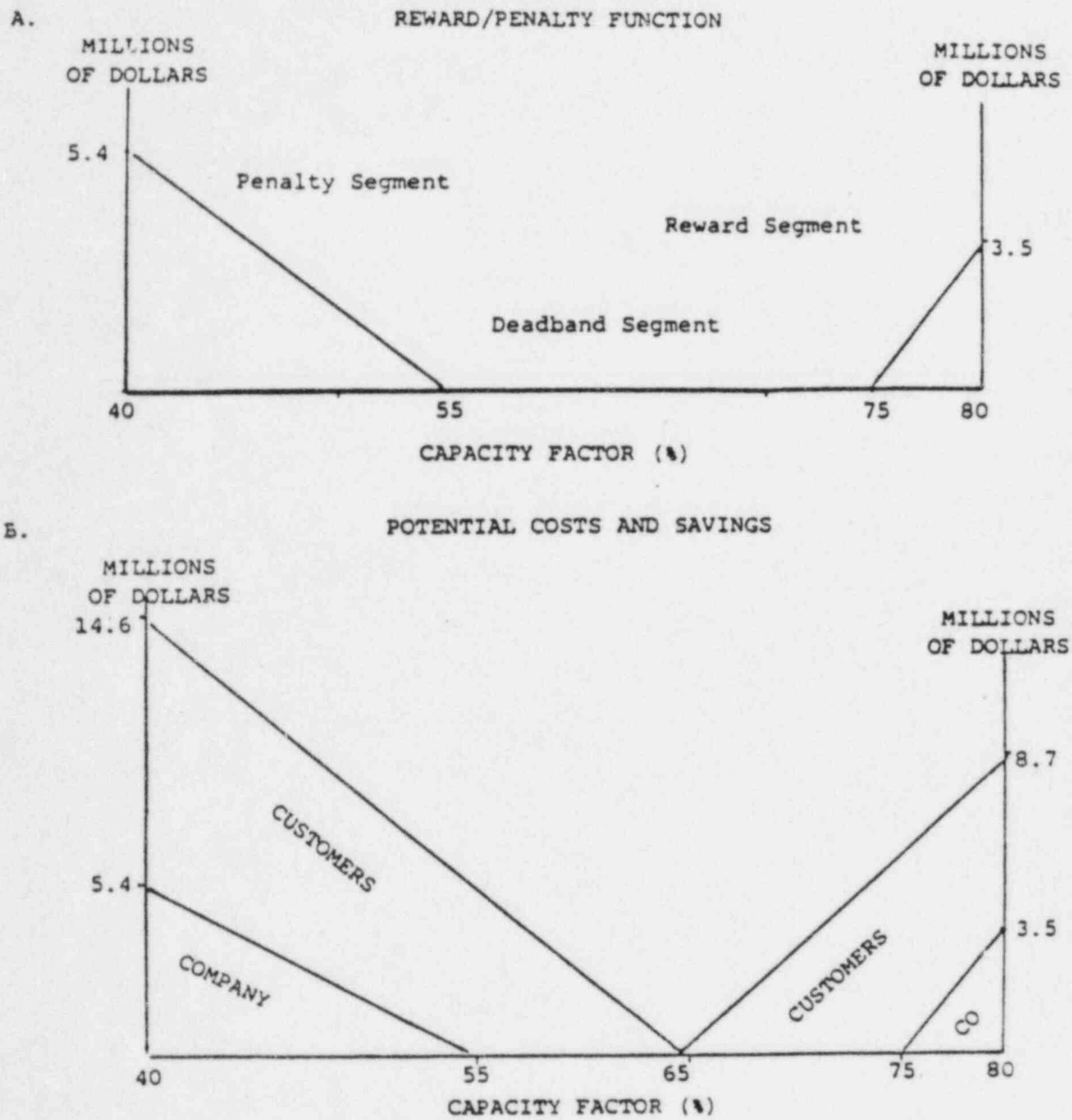
Plant	Components		Replacement Power Cost
	Fuel Cost	APS Capacity	
Four Corners	1.1c/Kwh	784 MW	2.6c/Kwh
PV-1	0.8c/Kwh	370 MW	2.6c/Kwh

Penalty allocation formula $\dfrac{784 \times (2.6-1.1)}{370 \times (2.6-0.8)} = 1.77$ to 1

Allocation to Four Corners -- \$9.6 million
Allocation to PV-1 -- \$5.4 million

SOURCE: Haas in APS (1984, p. 40).

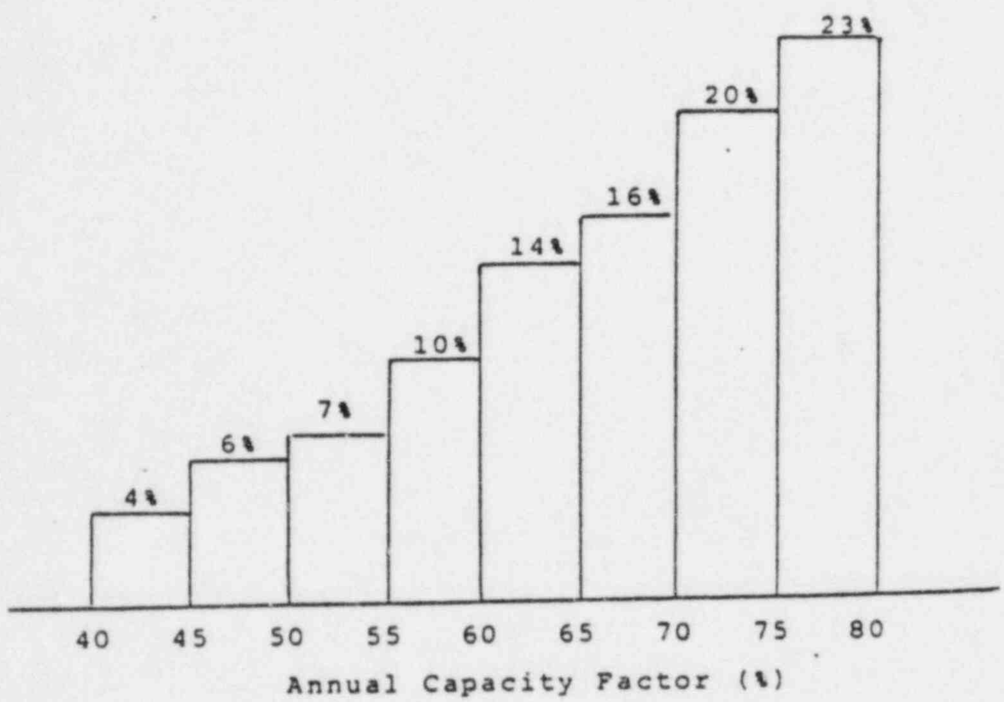
OPERATING INCENTIVE SYSTEM FOR PALO VERDE
(Unit No. 1 Only)



SOURCE: Haas in APS (July 1984, Exhibit JEH-9).

Figure 4.3

PALO VERDE PLANT (Unit No. 1)
POTENTIAL CAPACITY FACTOR



SOURCE: Haas in APS (July 1984, Exhibit JEH-8).

Figure 4.4

At the same time, two areas of the APS proposal require modification: the reward/penalty function for both Four Corners and Palo Verde, and provisions for dealing with perverse incentives.

The Reward/Penalty Function

Three problems arise with respect to the proposed reward/penalty function:

Variable O&M Expenses. Economic gains and losses estimated by APS for changes in equivalent availability are overstated to the extent that they do not include variable O&M costs in addition to fuel. These estimates by APS of economic gains and losses are shown in Figs. 4.1 and 4.3. For example, in Fig. 4.1 the economic loss resulting from a fall in equivalent availability from 70 percent to 48.5 percent is $22.1 million, whereas the economic gain in moving from 70 percent to 88.5 percent is $19.0 million. But in computing these figures, APS considers only the difference between the estimated cost of replacement power and the fuel cost of the plants (along with APS capacity), as shown in Table 4.3. However, the calculations should also include whatever other O&M expenses vary with the output of these plants.[17]

Replacement Power Cost. Using a single estimated replacement power cost of 2.6 cents per Kwh, shown in Table 4.3, is questionable on two grounds. First, the cost of replacement power varies by the time of year, day, and even hour. The APS summer peak load is about 75 percent greater than its winter peak, as shown in Fig. 2.2. If the cost of

[17]Total O&M expenses plus fuel in 1981 were reported to be 13.98 mills for Four Corners units 1, 2, and 3, and 11.65 mills for units 4 and 5--compared with 11.0 mills (U.S. Department of Energy, 1984, p. 110).

replacement power differs significantly between summer and winter, APS should estimate separate rewards and penalties for the two seasons.[18]

Second, the difference between equivalent availability and the capacity factor, or electricity "available" but not generated, should not be valued at the same level per Kwh as electricity that *is* generated and sold. Differences between equivalent availability and capacity factor arise when electricity can be obtained from less expensive sources (including other APS plants), resulting in the plant's output being reduced for economic reasons. The difference between equivalent availability and capacity factor would be valued more appropriately in accordance with its contribution to reserve margins. One would expect the equivalent availability and capacity factor for Palo Verde to be essentially identical because of the relatively low running costs of nuclear units. (Indeed, in its proposal APS uses the two terms interchangeably for PV-1.) But the same may not be true of Four Corners, especially when the Palo Verde units come on line. The partial displacement of Four Corners 1, 2, and 3 by Palo Verde for base load is illustrated in Fig. 4.5.

Thus, as recognized in the APS plan, periodic adjustment of the reward/penalty function, based on estimated economic gains and losses from changes in equivalent availability, is of key importance. But the process will add to administrative burdens, with possible controversy about measurement of gains and losses.

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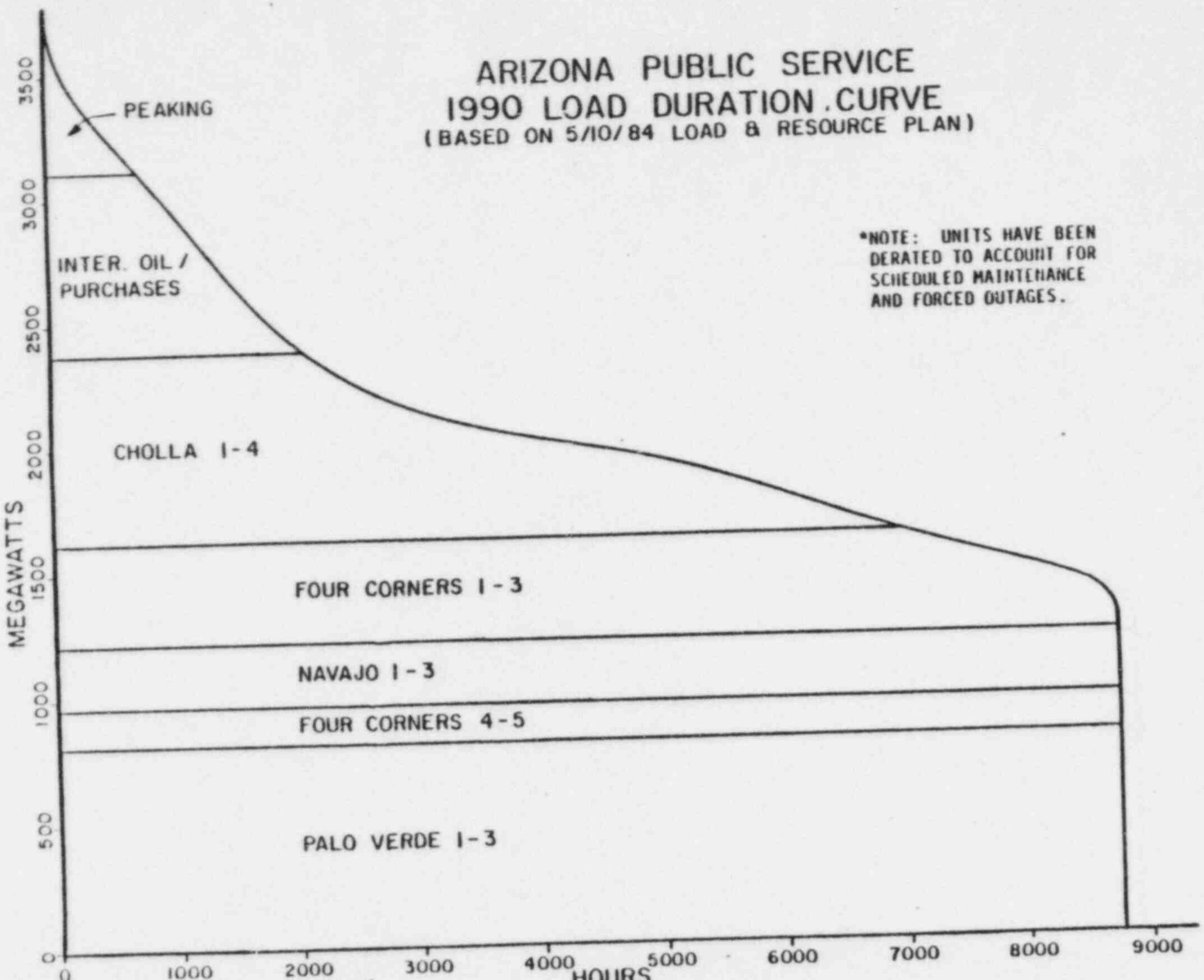
[18]The figure of 2.6 cents per Kwh (2.7 cents in 1986) is referred to as a "proxy" by Hart in APS (1984, p. 5). A suitable incentive scheme must go beyond the use of proxies to assess more fully the economic gains and losses of changes in equivalent availability.



SOURCE: APS files (undated).

Figure 4.5

Probabilities of Rewards and Penalties. The reward/penalty function proposed by APS virtually guarantees that the maximum Company-wide penalty of $15 million will not be incurred for Four Corners and PV-1. No less important than the level of reward or penalty is its *probability* of occurrence. The probability of the maximum penalty being incurred is near zero. I devote the remainder of my assessment of the proposed reward/penalty function to demonstrating why the function should be revised and to offer a methodology for doing so.

Revising the Reward/Penalty Function. Consider the time period (about 18 months according to current plan) during which only Four Corners will be covered by the incentive plan. The frequency distribution in Fig. 4.2 shows that the probability of an equivalent availability of 48.5 percent or lower is only about 0.0005. Thus, the chances are only about 1 in 2000 that the maximum penalty would be incurred. Even if we take a somewhat higher availability such as 53 percent, which would generate a lower penalty of about $10.8 million, the probability of a penalty as high as $10.8 million is only 1 in 500. Low probabilities of such occurrences are reflected in the data shown in Table 4.4, indicating that at no time during the last 10 years did equivalent availability drop to anywhere near 48.5 percent or even 53 percent.

When PV-1 is included in the operating incentive plan, APS proposes that the maximum penalty of $15 million be allocated between Four Corners and PV-1 as shown in Table 4.3. But the penalty functions p oposed by APS again make it virtually impossible that the maximum penalty would ever be imposed.

Table 4.4

ARIZONA PUBLIC SERVICE COMPANY
FOUR CORNERS EQUIVALENT AVAILABILITY FACTORS
1974-1983
(Actual and Adjusted)

UNITS	1974	1975	1976	1977	1978	1979	1980[2]	1981	1982	1983
1, 2, 3	66.05	65.56	70.04	68.34	74.56	65.87	75.45	76.03	76.40	79.20
4, 5	60.29	46.55	56.79	58.64	48.99	55.55[1]	71.89	58.87	66.09	81.27
Total APS Share	64.33	59.94	66.13	65.43	66.97	62.73	74.38	71.20	73.42	79.50

[1] Prior to 01/01/79 Capacity Factor on Units 4 and 5 figured on 800 MW each.

[2] Adjusted Capacity Factor was not reported until 1980.

SOURCE: APS files (undated).

The maximum proposed penalty for PV-1 is $5.4 million at an equivalent availability of 40 percent or less, as shown in Fig. 4.3. APS estimates a 4 percent probability of the capacity factor of PV-1 falling within the range of 40 to 45 percent, shown in Fig. 4.4. It is impossible to estimate closely the probability of an equivalent availability of 40 percent or less from the wide performance bands shown in Fig. 4.4. But let us say that the probability is about 0.008--estimated by dividing the 0.04 probability in the band 40-45 by 5. In this case, the chances are less than 1 in 100 that the maximum penalty would be levied.

Moreover, the probability of the maximum penalties being levied *simultaneously* against Four Corners and Palo Verde is far smaller. It is unlikely that conditions that affect the equivalent availabilities of PV-1 over time would be the same as the conditions that affect Four Corners, since one is a nuclear plant, the other is a coal-fired plant, and they are more than 300 miles apart. In other words, the equivalent availabilities of PV-1 and Four Corners are likely to be uncorrelated over time.[19] If so, the probability of the maximum penalty is reduced because the Company diversifies its risks across a "portfolio" of generating units. The probability of PV-1 having an availability of (about) 40 percent or less to trigger a penalty of $5.4 million, combined with the probability of Four Corners having an availability of 48.5 or less to trigger a maximum penalty of $9.6 million, is approximately 0.000004--about one chance in 250,000![20] Thus, the

[19]Conceivably, a regional catastrophe could knock out or cripple both plants, but such an event would surely be considered a force majeure.

[20]This figure is computed by multiplying the 0.008 probability of a PV-1 equivalent availability of about 40 percent or less by the 0.0005 probability of a Four Corners equivalent availability of 48.5 or less.

examination by APS of how a $15 million maximum penalty would affect its shareholders is a meaningless exercise.[21]

Moreover, the relevant probabilities are even lower than the estimates used here because the historical performance data shown in Figs. 4.2 and 4.4 surely include cases of force majeure. That is, at least some instances of low availabilities experienced by comparable plants arise, one must assume, from conditions beyond the control of management. Were it possible to control for the effects of force majeure, the distributions shown in Figs. 4.2 and 4.4 would shift to the right, further reducing the probabilities of APS paying large penalties.

Fortunately, the reward/penalty function can be revised in accordance with a simple principle: Let APS absorb the full economic loss from achieving equivalent availabilities that fall below the deadband, and let it enjoy a reward equal to the full economic gain from achieving equivalent availabilities above the deadband.

Figures 4.6 and 4.7 illustrate use of this principle for the penalty segment. Figure 4.6 reproduces the economic loss function, denoted by line "C," from the lower panel of Fig. 1.1, and shows the penalty function, denoted by "E," that is proposed by APS after PV-1 is included in the plan. Similarly, Fig. 4.7 reproduces the economic loss function for PV-1, line C, and the APS proposed penalty function, line E, from Fig. 4.3. The $9.6 million and the $5.4 million proposed maximum penalties for Four Corners and PV-1 are shown, respectively, on the vertical axes of Figs. 4.6 and 4.7. The penalty functions, revised in accordance with the above principle, are simply lines D, drawn parallel to the economic loss functions C in Figs. 4.6 and 4.7. For

[21]Haas in APS (1984, pp. 36-37).

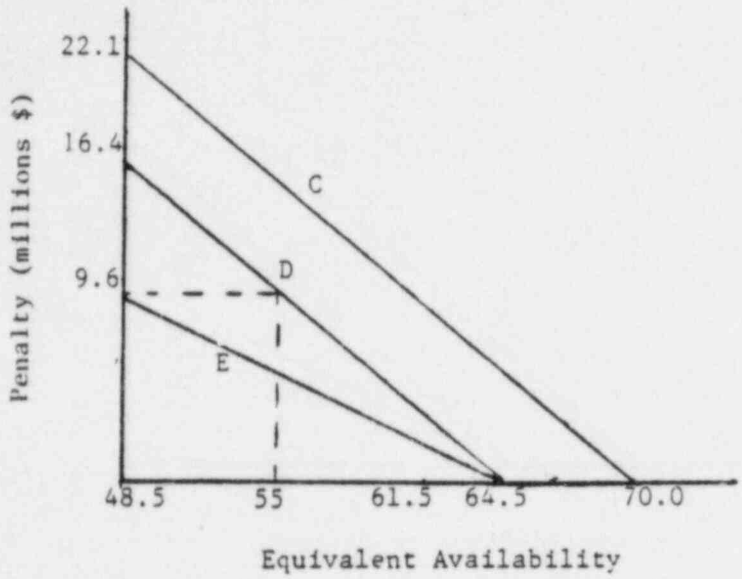


Fig. 4.6--Four Corners Penalty Schedule with PV-1 in Incentive Plan

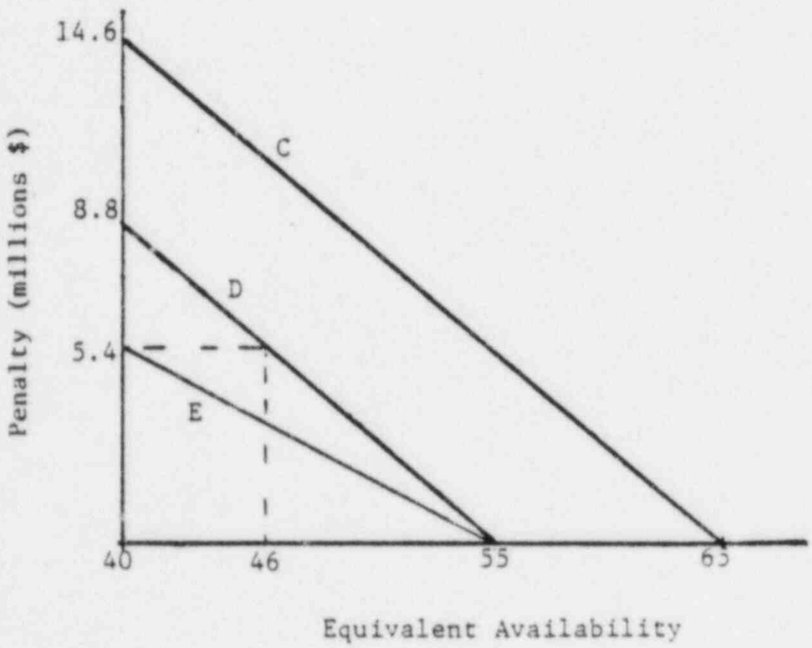


Fig. 4.7--PV-1 Penalty Schedule

example, line D in Fig. 4.6 shows that were equivalent availability to fall from 64.5 percent to 48.5 percent, the economic loss would be $16.4 million, which would be equal to the penalty imposed on APS. (The probability of the penalty being incurred is the same extremely low estimate as for the $9.6 million proposed by APS.) Thus, at a 48.5 percent equivalent availability, the economic loss in moving from the target of 70 percent is $22.1 million, whereas the economic loss--and the penalty--measured from the lower end of the deadband at 64.5 percent is $16.4 million. Figure 4.7 shows the similar relationships for PV-1, with a maximum penalty of $8.8 million (again, at a very low probability) being imposed. Similarly, reward functions can be drawn as lines parallel to the economic gain functions taken from Figs. 4.1 and 4.3 for equivalent availabilities that exceed 75.5 percent and 75 percent, respectively.

The maximum penalties of $16.4 million and $8.8 million arising from using this principle shown, respectively, in Figs. 4.6 and 4.7, are greater than those proposed by APS. But the probability of APS incurring its proposed $15 million (or more) is still very low. For example, with the penalty function D in Fig. 4.6, a penalty of $9.6 million or more for Four Corners would occur at an equivalent availability of about 55 percent or less.[22] The probability of equivalent availability falling to 55 percent or less, as read from Fig. 4.2, is about 0.005--one chance in 200. With the penalty function D for PV-1 in Fig. 4.7, a penalty of $5.4 million or more would arise if equivalent availability falls below about 46 percent. The probability

[22]Notice that the penalty function D in Fig. 4.6 is only slightly above that proposed by APS for Four Corners before the time PV-1 is included in the plan.

of this happening, read from Fig. 4.4, is about 0.04--one chance in 25. The probability of APS facing a penalty of $9.6 million or more for Four Corners at the same time it incurs a penalty of $5.4 million or more for PV-1 is only about 0.0002--one chance in 5000.

Note that although APS absorbs all the economic losses and keeps all the economic gains when it operates outside the deadbands, ratepayers stand to gain from the plan. For example, if the strengthened incentives were to increase the equivalent availability of PV-1 from 40 percent to 65 percent, APS would avoid a penalty of $8.8 million, and ratepayers would gain an additional $5.8 million.

The major appeal of using this principle, aside from its simplicity, is that the results are consistent with those in competitive industries where firms absorb the full losses and enjoy the full gains resulting from their actions. This result should strengthen APS incentives beyond those resulting from use of its proposed reward/penalty functions.

I must emphasize three points in the Commission's adoption of my proposed principle for establishing the reward/penalty functions for Four Corners and Palo Verde.

First, there is nothing special about establishing the lower bound of the penalty at 48.5 percent and 40 percent, respectively, for Four Corners and for PV-1 as shown on Figs. 4.6 and 4.7. Similarly, the upper bounds of the rewards function shown at 88.5 and 80, respectively, in Figs. 4.1 and 4.3 are no less arbitrary. One could establish a reward/penalty function ranging all the way from zero up to 100 percent equivalent availability, with APS absorbing *whatever* economic losses

occur from its performance below the deadband and enjoying *whatever* economic gains arise from its performance above the deadband. If the Commission decides that the APS penalty should be capped at some maximum, it could limit the lower bounds of penalties for the two plants depending on its judgment about the "reasonableness" of the maximum penalties. For example, if it decided to approve the maximums of $9.6 million and $5.4 million proposed by APS for Four Corners and PV-1, respectively, it would set the lower bound equivalent availabilities for the two plants at the 55 percent and 46 percent levels as shown, respectively, in Figs. 4.6 and 4.7.

Second, the APS proposed lower and upper ends of the deadband, as shown in Figs. 4.1 and 4.3, are also arbitrary. There is no persuasive reason for penalties to start for Four Corners and PV-1 at 64.5 percent and at 55 percent equivalent availabilities, respectively; and similarly for the 75.5 percent and 75 percent levels for the upper ends of the deadbands. Given the low probabilities of the maximum penalties illustrated in Figs. 4.6 and 4.7 being incurred (especially in combination) the Commission might adopt a plan that raises the lower end of the deadband for either one or both of the plants. The upper ends of the deadband could also be shifted to conform to the APS proposal that the expected values of rewards (rewards multiplied by their probabilities) be equal to the expected values of penalties, so that APS would expect neither to gain nor to lose from the plan.[23]

[23]The expectation of no net loss or gain would be based on experience with comparable plants. If the plan succeeds in raising the equivalent availabilities of Four Corners and PV-1, APS would earn net rewards since its performance would improve over time relative to that of comparable plants.

A difficulty, however, with the APS submission is that it illustrates the neutrality between rewards and penalties only in a hypothetical example.[24] It does not present evidence showing the neutrality between rewards and penalties APS proposes for Four Corners and for PV-1.

Third, and most important, my illustrative examples from Figs. 4.6 and 4.7 are based on APS assumptions that (a) the replacement cost of power is constant at 2.6 cents, and (b) economic gains and losses reflect the difference between this replacement cost and only the fuel cost (rather than other variable O&M costs as well) for the plant in question. As discussed above, these assumptions are troublesome, given the severe summer peaking characteristics of the APS load and the possible partial displacement by Palo Verde of Four Corners for base load.

Going beyond these three points, some may ask why Four Corners should be included at all in the incentive plan. Although Four Corners faced difficulties in the early 1970s, especially with scrubber operation, the plant is now performing well in terms of equivalent availability and cost per Kwh. In contrast, Palo Verde is of central concern to the Commission in terms of the issues raised in Phase II of the present rate case. Therefore, why not direct the incentives to where the problem is--Palo Verde?

The reason for including Four Corners is that an additional Kwh of electricity from Four Corners induced by an incentive system is no less valuable than a Kwh of electricity from Palo Verde (after taking

[24]Haas in APS (1984, Exhibit JEH-2).

relative fuel costs and other variable O&M expenses into account). The exclusion of Four Corners from the incentive plan would reduce the potential gains to ratepayers

Indeed, in principle, Navajo 1, 2, and 3 ought also to be included, since it too is a base-load plant as shown in Fig. 4.5. However, the Salt River Project, not APS, has management responsibility for Navajo. Thus, a question arises, which the Commission should address, about the value of an incentive plan for a plant managed by others, and the extent to which a nonmanaging participant can influence the operation of the plant.

A situation similar to that of Navajo, but in reverse, exists for Four Corners 4 and 5. Although APS manages all five units, it owns only 15 percent of units 4 and 5. Southern California Edison is the largest participant in units 4 and 5, with 48 percent ownership, and several other utilities hold smaller shares.[25] Moreover, Southern California Edison is already covered by an incentive plan focused on capacity factor (as well as heat rate) in accordance with a decision by the California Public Utilities Commission in 1981.[26] To the extent that Southern California Edison has strengthened incentives to achieve high capacity factors for units 4 and 5 it could, presumably, exert influence through the Engineering and Operations Committee of the plant even though it does not have overall management responsibility. Of course, any increase in performance would also redound to the benefit of APS and to the other owners.

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[25]The other participants and their shares in units 4 and 5 are: Public Service of New Mexico--13 percent; Salt River Project--10 percent; El Paso Electric--7 percent; and Tucson Electric Power--7 percent. APS holds 100 percent of units 1, 2, and 3.

[26]California Public Utilities Commission, Decision D.93363, July 22, 1981.

Perverse Incentives

A basic problem of partial incentive plans, discussed in Sec. III, is that focusing on only one or a few performance indicators distorts the utility's incentives with respect to others. APS explicitly recognizes this as a weakness in its own plan. As Haas notes, "it opens the theoretical possibility that the Company could be motivated to spend substantial funds on capital improvements and O&M activities that would result in an improvement in equivalent availability, but may not be cost effective to customers" (pp. 19-20).

In response to this problem, Haas notes that the Commission "has an opportunity to review capital improvement outlays for rate base treatment as well as set the level of O&M costs for the test year; it thereby controls the extent to which customers pay the costs of achieving a higher level of equivalent availability" (p. 21). However, the ability of the Commission to effectively monitor these expenditures will depend on the reliability of data and other information it will need for comparative analysis.

Fortunately, the task of Commission monitoring may pose little difficulty for Four Corners, where APS has had more than 20 years of operating experience with units 1, 2, and 3 and about 15 years with units 4 and 5. The levels and variations in expenditures recorded during that long time period may provide a good basis for detecting and evaluating any unusual or questionable deviations that might result from the incentive plan. Moreover, this historical experience could be supplemented by the data base of coal-fired plants that APS has used to establish its proposed reward/penalty function for Four Corners.

Palo Verde poses more serious difficulties. No operating data exist for these nuclear units not yet in service. Moreover they have unique or unusual features (e.g., the first units to use the "System 80" reactor; the use of effluent for cooling) that may exacerbate problems of comparing operating and maintenance requirements with those of other nuclear plants.

Of course, one might ask, "if the nuclear plant data base used by APS is good enough to establish the proposed reward/penalty function for Palo Verde equivalent availability, why is it not also good enough to establish an incentive function for O&M expenditures?" The answer lies in the complicated relationships between O&M expenditures and equivalent availability. Some O&M components are essentially fixed regardless of availability. Others vary linearly with output, and others vary in nonlinear and more complex ways. And, of course, the particular design and construction characteristics of plants make a difference. Table 3.1 discloses only two cases where O&M expenditures have been a focus for state incentive programs.[27] Consequently, I agree with APS that an explicit reward/penalty incentive plan for O&M expenses would be infeasible, at least until APS has had some years of operating experience with Palo Verde.

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[27]In Michigan, O&M expenses have been indexed to the Consumer Price Index. However, the indexing of O&M expenses, as well as the "System Availability Program" discussed in Sec. III, was discontinued in 1983. Utah had planned to include an O&M monitoring scheme, based on regression analysis, as part of a comprehensive incentive plan, but the Commission decided in 1983 not to adopt the plan. See EEI (1984, p. 9-10).

Nevertheless, APS could provide information to the Commission that would help it to monitor O&M expenditures. Multiple regression analysis of data from other nuclear plants could be employed to determine in an approximate way how O&M expenses vary with such factors as plant age and size, type of reactor, and geographical location. With this information, the Commission may be able to detect Palo Verde expenditures that seem out of line with results shown by regression equations, and to inquire into the reasons for discrepancies.

It would be useful to the Commission if the APS incentive plan included a provision for supplying on a routine and updated basis an analysis of O&M expenditures from the data base of the nuclear plants used in establishing the reward/penalty function for Palo Verde's equivalent availability.

To be sure, such analysis by no means will provide a fully reliable way to detect bias toward uneconomic O&M expenditures. Among other problems, the idiosyncratic characteristics of individual plants may reduce, perhaps seriously, the value of regression analyses. Moreover, interpretation of the data can generate controversy--especially difficult to resolve if issues arise of how particular O&M expenditures affect plant safety.

At bottom, no satisfactory way has yet been found, to my knowledge, of coping with perversities in partial incentive programs. The best one can hope for here is a more structured analysis than is now available to the Commission for monitoring O&M expenditures.

CONCLUSIONS

In principle, the four components of the APS plan fit well together: The 1.20 AFUDC offset will encourage APS to continue expeditiously with PV-1 even with CWIP in the rate base, and the 50 percent penalty on shareholder earnings from schedule slippage will also help to keep the units on track. The possible perverse incentives of these two components--additional costs and the cutting of corners to hasten normal rate base treatment--will be offset, more or less, by the cost cap for ratemaking purposes and by the reward/penalty system for equivalent availabilities. Unfortunately, it is impossible to quantify the effects of the positive and perverse incentives or the degree to which they will interact within the package.

In light of the limited information likely to be available in the foreseeable future about the effects of these incentives, I recommend that the Commission take the following action:

- Accept the extension of the 1.20 AFUDC offset as proposed by APS for placing CWIP in the rate base, in the absence of evidence that a different level of offset would lead to better results.
- Accept the APS proposal for a penalty in schedule slippages in placing PV-1, PV-2, and PV-3 into commercial operation, in the absence of evidence that a modified or different approach would lead to better results.
- Accept the APS proposal to place a ceiling on Palo Verde costs for purposes of ratemaking, but to reduce or eliminate the 10 percent cost contingency to strengthen the incentives for cost control.

- Reject the operating incentive plan as proposed by APS and require it to propose a revised plan to cover the time during which only Four Corners would be in the plan and for the time during which PV-1 would be included. The revisions should be based on the following requirements.

  -- APS should refine the estimates of economic gains and losses from changes in the equivalent availability of Four Corners before the time PV-1 is included in the plan. These estimates should reflect differences in the cost of replacement power between summer and winter and, unless APS shows that these differences are small, it should propose separate reward/penalty functions for the two seasons. These estimates should also take into account variable O&M expenses in addition to fuel.

  -- Using these refined estimates, APS should propose a reward/penalty function for Four Corners such that APS would absorb all economic losses for performance falling below the deadband and would retain all economic gains for performance above the deadband (subject to force majeure provisions). APS should be free to adjust the proposed deadband so that the expected value of rewards is equal to the expected value of penalties; but it should also present evidence satisfactory to the Commission that the reward/penalty function it proposes does achieve neutrality. If APS seeks a ceiling on the maximum penalty to which it should be exposed, it should demonstrate

why its proposed maximum is reasonable in light of the estimated probability of that maximum being incurred.

-- APS should refine its estimates of economic gains and losses from changes in equivalent availability for both Four Corners and PV-1, to take into account the effects of PV-1 on the costs of replacement power and on variable O&M costs. The estimates should reflect, among other things, the extent to which PV-1 would likely displace Four Corners as base-load units.

-- Using these estimates for both plants, APS should propose reward and penalty functions such that it absorbs all losses and gains from performance outside the deadbands (again subject to force majeure provisions). As in the case when only Four Corners is in the plan, APS should be free to propose alteration of the deadbands to help ensure neutrality between rewards and penalties and, if it proposes a ceiling on penalties for the two plants, to show why its proposed maximum is reasonable.

-- APS should demonstrate why Navajo 1, 2, and 3 should be excluded from the plan, as it proposes.

-- APS should propose to undertake analysis on a continuing basis for comparing its O&M expenditures for plants included in the incentive plan with those of similar plants elsewhere, for the Commission's use. The methodology could include use of regression analysis and the data bases as suggested above, or alternatives if they are shown to produce better results.

However, it is important to bear in mind that even if APS revises the plan in accordance wth my recommendations, the plan will still face problems like those of incentive plans adopted in other states:

- *Evaluation.* The Commission will not have enough information in the coming years to determine conclusively whether the program has done much good.
- *Control for external effects.* The force majeure provisions could cause serious controversy and inconclusive resolutions of disputes. Depending on how these disputes are resolved, the positive incentives under the plan could be weakened.
- *Subsequent-round offsets.* Despite elaborate analysis of reward and penalty functions to maintain strong incentives and unbiased operating decisions among baseload plants, the nagging problem will remain of whether rewards and penalties will fully "stick" as a conseqence of subsequent rate proceedings by both the state and by FERC. To the extent that subsequent-round offsets are strong, the incentive factors of the program will be weakened.
- *Credibility.* The fact that reward/penalty functions will be adjusted, perhaps at two-year intervals, may make more difficult the continued earning of large rewards if APS shows marked and continuous improvement in performance. Combined with the effects of subsequent-round offsets, these adjustments could weaken the credibility and the effectiveness of the plan.

In addition to this incentive program, APS may propose a rate moderation plan in 1985. Although I cannot comment now on the details of the plan yet to be formulated, rate moderation may be more important to economic efficiency than the incentive package. The method of capital cost recovery will be of key relevance to efficient use of Palo Verde and of other base-load capacity during the next decade, if not to the end of the century.

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