UNITED STATES GENERAL ACCOUNTING OFFICE
WASHINGTON, D.C.

FOR RELEASE ON DELIVERY
EXPECTED
FEBRUARY 7, 1984

123359

STATEMENT OF F. KEVIN BOLAND
SENIOR ASSOCIATE DIRECTOR
RESOURCES, COMMUNITY, AND ECONOMIC DEVELOPMENT DIVISION
BEFORE THE
SUBCOMMITTEE ON ENERGY CONSERVATION AND POWER
COMMITTEE ON ENERGY AND COMMERCE
UNITED STATES HOUSE OF REPRESENTATIVES

Chairman and Members of the Subcommittee:

We appreciate this opportunity to discuss the Department of Energy's (DOE) Electricity Policy Project (Project). The Project report "The Future of Electric Power in America: Economic Supply for Economic Growth" has received considerable attention most notably because of its conclusion that the industry needs to build substantial amounts of new large generating capacity at a time when existing reserve margins are high and growth in demand for electricity is relatively low.

Forecasting the need for new electricity resources, especially on a nationwide basis over two decades, has become an increasingly uncertain process. DOE ran 25 cases of their model to project electric demand through 2000. The model's estimated most likely electric demand growth rate was 2.49 percent per year. This result was about mid-way between DOE's 25 estimates which ranged from 1.10 percent to 3.82 percent annually. Based on revised electricity price estimates, which increased the 2.49 percent growth rate to 3 percent, DOE then chose the 3 percent rate as the basis for estimating needed new capacity resources. Using this higher growth rate led to DOE's forecast being over 80,000 megawatts higher than originally estimated by their model's most likely case.

DOE's estimate of available generating capacity by 2000 assumes utility supply plans are limited to 1991 even though some plants are currently scheduled for commercial operation after 1991. DOE considered but did not include nonconventional supply strategies such as cogeneration and load management in their supply estimate. This has the effect of further increasing their projection of needed new central-station generating capacity.

National forecasts of electricity supply and demand have some severe limitations regardless of the specific estimates. Significant regional variations exist not only in the current level and composition of electric demand and supply, but also in factors affecting future demand and specific supply alternatives available to reliably and economically meet that demand. By not accounting for such variations or by generalizing conclusions based on limited regional applicability, DOE's forecast of needed new generating capacity cannot be readily applied to specific regions.

DOE made extensive use of contractors during the Project to increase its analytical capability and obtain views of other groups while meeting their expected one year completion target. Almost $2.7 million of the $3 million spent on the Project by DOE was to support 27 reports through 15 contracts and subcontracts. DOE used a variety of contracting arrangements and awarded 5 contracts on a sole source basis. DOE relied extensively on a contracting procedure known as task order contracts, under which 20 reports were produced. As we have previously reported, DOE's use of sole source and task order contracts limits competition and may not assure that quality products are obtained at the least cost. DOE used these type of contracts because of the one year target date for the study. According to DOE program officials, their experience in awarding contracts under the competitive process has taken about 12 to 18 months. Required conflict [illegible] did not contain the data needed to determine whether the assessment had been completed.

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Mr. Chairman and Members of the Subcommittee:

We appreciate this opportunity to discuss the Department of Energy's (DOE) Electricity Policy Project (Project) and their report. As you are aware, DOE issued their report "The Future of Electric Power in America: Economic Supply for Economic Growth" in June 1983, culminating an 18-month effort examining the problems surrounding the electric utility industry. This report has received considerable attention most notably because of its conclusion that the electric utility industry needs to build substantial amounts of new central-station generating capacity at a time when existing reserve margins are high and growth in demand for electricity relatively low.

The original impetus for this Project was an October 8, 1981, Presidential directive to study obstacles to nuclear energy. However, the Project subsequently focused on the electric utility industry's financial ability and willingness to invest in additional generating facilities regardless of the fuel source. As many as 18 federal departments and agencies, the White House staff, and 15 electric utility industry leaders were associated with some phase of the Project.

The attachment to this testimony contains our answers to specific questions referenced in your October 20, 1983, letter.

Our testimony and answers to your questions are based on our review of DOE's report and contractor studies, interviews with DOE program and procurement officials, and an examination of contracting documents between DOE and their contractors.

My statement today contains two basic parts which highlight our responses to your questions.

--First, an analysis of DOE's electric demand and supply projections.

--Second, comments on DOE's use of contractors to help complete their responsibilities under the Project.

DOE'S FORECAST OF NEW ELECTRIC GENERATING CAPACITY

Forecasting electricity demands has become an increasingly complex and inexact process with results critically dependent on study assumptions and methodology. No clear consensus exists concerning the most appropriate forecasting technique and, even more importantly, specific values that should be assigned to variables affecting electric demand. It is not surprising, therefore, that there are many different electric demand forecasts. During recent years the most consistent result from forecasts has been that each year's demand estimate is lower than the preceding year. For example, the North American Electric Reliability Council has revised downward its ten-year demand forecast every year since 1974.

Differences in forecasts can also have profound implications for planning new capacity resources. For example, if realized average annual electric demand differed from DOE model's most likely projection by 0.1 percent, this small change by 2000 would result in a 15,000 megawatt (MW) capacity shortage or surplus which for an average size nuclear unit would be equivalent to about 15 units.

DOE'S demand modeling considered a range of values for several key variables considered critical to utility forecasting techniques. DOE ran 25 cases of their model to estimate electric demand through 2000 using different economic assumptions. The model's estimated most likely electric demand growth rate was 2.49 percent per year. This result was about mid-way between their 25 estimates which ranged from 1.10 percent to 3.82 percent annually or a difference by 2000 of 415,000 MW. However, DOE selected a 3 percent annual electricity demand growth rate as the basis for estimating needed new capacity resources.

The 3 percent growth rate resulted from DOE revising its mid-level demand estimate to reflect revised electricity price estimates after the original modeling was completed. According to the DOE officials responsible for managing the Project, the revised price estimates were believed to be more realistic. These revised price projections decreased DOE's original average electric price growth rate from 1.67 percent, already much lower than other energy price growth rates, to 0.5 percent per year. Although we did not review the contractor's model on which these revised prices were based, we did note that the revised electricity price growth rates identified a set of 7 projections (ranging from 0.3 percent to 1.4 percent per year) of which DOE selected an estimate that was lower than 5 of the 7 projections. DOE reported that the lower prices had the effect of increasing the annual electric demand growth rate from 2.49 percent to 3 percent.

Using the 3 percent electricity demand growth rate led to DOE's forecast being over 80,000 MW higher than originally estimated by their model's most likely case. The 3 percent forecast was also higher than 21 out of 25 of the original modeling results, including all 9 estimates which primarily used mid-level values for they key variables. DOE's forecast is also between 17,000 MW and 209,000 MW higher than other national forecasts conducted by the North American Electric Reliability Council,[1] Congressional Research Service, Electrical World, and Data Resources, Inc.

On the supply side, DOE did not consider all currently planned generating capacity and did not quantify supply-enhancing options and alternative technologies. DOE used the North American Electric Reliability Council's supply plans through 1991 to determine planned generating capacity through 2000. As a result, DOE's estimate of available generation capacity by 2000 was based on plants becoming operational by 1991. In fact, however, some plants are currently scheduled for commercial operation after 1991 and utilities usually plan capacity additions over a 20-year period.

In addition to conventional supply options, utilities can pursue other supply strategies to reduce the need for generating capacity. These options include measures to increase the efficient use of existing resources (e.g., power pooling and wheeling, electricity imports, and plant productivity improvements) and to promote non-traditional supply alternatives (e.g., conservation, load management, and cogeneration). While DOE qualitatively considered such measures, they were quantitatively excluded from their supply forecast. The effect of excluding such supply strategies was to increase DOE's estimate of needed new central-station generating capacity.

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[1]1992 forecast projected to 2000 by GAO.

I would also like to emphasize that because DOE's forecast of needed new electric generating capacity is a national estimate based on aggregated data, assumptions, and conclusions, its usefulness to individual utilities making up the industry is limited. As pointed out in a previous GAO report,[2] national forecasts are used to provide an indication of the Nation's overall supply/demand picture but are of little use in planning specific resources or in balancing supply and demand on a utility operating system level. By not accounting for utility or regional variations or by generalizing conclusions based on limited regional applicability, DOE's national forecast obscures the geographic magnitude, severity, and/or timing of regional demand and supply imbalances. While DOE did consider regional differences in their analysis from a qualitative standpoint, their quantitative analysis arriving at the forecasted need for new generating capacity was on a national basis and cannot be readily applied to specific regions. For example, actual electricity sales from 1982 to 1983 increased by 3.6 percent nationwide. Further breakdown of the growth, however, reflects some regions such as the Midwest increased by 5.8 percent while the Pacific Northwest declined by 1.4 percent.

CONTRACTOR SERVICES USED EXTENSIVELY

DOE spent about $3 million in developing the Project and final report. Almost $2.7 million of these funds were used to support contractor reports in order to increase DOE's analytical capability and obtain the views of other groups while meeting the

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[2] Analysis of Electric Utility Load Forecasting, GAO/RCED-83-170, June 22, 1983.

expected Project completion target of one year. Thirty reports were issued as part of the Project including 3 staff studies and 27 reports through 15 contracts and 7 subcontracts. We reviewed 13 of the 15 contracts (documentation for 2 contracts was not located at DOE headquarters) and found five contracts were awarded on a sole source basis. These 13 contracts involved four types of contracting arrangments including 9 task order contracts which provided funding for 20 contractor reports. Eight of the nine task order contracts used for the Project were originally awarded competitively and identified a broad scope of work in which DOE could later, within certain time and dollar limits, delineate specific tasks for the contractor to perform without further competition.

DOE's use of sole source and task order contracts for the Project raise the same concerns found in a past GAO report examining DOE contracting practices.[3] Specifically, sole source and task order contracts avoid or limit competition and, in selecting contractors for the Project, these practices may not have assured that DOE was obtaining quality products at the lowest possible cost. We would emphasize that in the scope of this review we did not make an in-depth review to determine whether these procedures actually resulted in such adverse affects for the individual contracts or reports. DOE used these type of contracts because of their expected one year target date for the study. According to DOE program officials, their previous contracting experience demonstrated that it took 12 to 18 months to issue an award under the competitive selection process while processing time using an existing task order contract was about one week.

[3]The Department of Energy's Practices for Awarding and Administering Contracts Need to be Improved, EMD-80-2, Nov. 2, 1979.

DOE's procurement regulations require that conflict of interest determinations be performed for all contracts. Although DOE contract files indicated that DOE made such assessments in most instances, the files did not contain the data needed to determine whether assessments had been completed for 4 contracts and 3 subcontracts.

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In summary, Mr. Chairman, we found that by revising its mid-level demand estimate to reflect lower electricity price estimates after the original modeling was completed, resulted in DOE's forecast being over 80,000 MW higher than originally estimated by their model's most likely case. On the supply side, DOE considered available capacity by 2000 to include only those plants expected to be in operation by 1991. DOE also excluded supply-enhancing and non-traditional supply alternatives from their forecast and thus further increased their estimate of the need for new central-station generating capacity. Because DOE's forecast of needed new electric generating capacity is a national estimate, it obscures the magnitude, severity, and/or timing of regional demand and supply imbalances.

This concludes my prepared statement. I will be pleased to respond to any questions you may have.

QUESTION 1:

Please describe the process which led to the development and publication of the DOE Report, beginning with early meetings in DOE and the White House and the formation of the Electricity Policy Project (Project) and ending in the publication of the report.

a. What was the origin of the Project and the Report?

b. What were the respective roles of DOE officials and entities in the conception of the Project, its workload and the Report?

c. With what objective did the Project commence its work? Did this objective change over the course of the work undertaken by the Project? What office supervised the Project, its workload and preparation of the Report?

g. Please describe the draft legislative initiatives developed by the Project and describe their fate.

j. Does the Project continue to exist? If so, in what form? What has the Project been doing since publication of the Report? Does DOE continue to spend money on the Project, including on additional contractor reports? Please specify. What policy direction guides the Project at present?

ANSWER:

On October 8, 1981, the President announced a series of policy initiatives to promote a revitalization of the nuclear power industry. As part of these initiatives, the President directed the Secretary of Energy and the Director of the Office of Science and Technology Policy (OSTP)[1] to meet with representatives from universities, private industry, and utilities and examine obstacles to the increased use of nuclear energy and steps needed to overcome such barriers. The President further directed a report be submitted to him by September 30, 1982.

In accordance with the President's directive, a meeting of electric utility industry leaders to discuss obstacles to nuclear power was held on February 2, 1982, at the White House. The meeting was chaired by the Vice President and included industry

[1]OSTP is organizationally located within the Executive Office of the President.

representatives from: 8 electric utility companies; 3 nuclear equipment supply firms; 2 investment firms; and 2 public utility commissions. Government officials attending the meeting included representatives from: DOE (5); OSTP (3); Commerce; Treasury; Office of Management and Budget; Federal Energy Regulatory Commission; Council of Economic Advisors; the Vice President's staff (2); and White House staff from the Office of Policy Development (2). This meeting resulted in refocusing the issue from obstacles to increased use of nuclear energy to a broader range of electric utility issues which transcends nuclear power. Specifically, the original objective was expanded to address the industry's financial ability and willingness to invest in additional generating facilities regardless of fuel source.

Following the February meeting, a group led by White House staff from the Office of Policy Development met to consider an appropriate approach to followup on issues discussed at the meeting. This group decided that the issues should be addressed through the Cabinet Council process which serves in effect as a screening or review board for policy initiatives proposed for submittal to the President. A working group was established to prepare a presentation to the Cabinet Council on Natural Resources and Environment whose membership included the leaders of the following Departments: Interior (Chairman pro tempore); State; Agriculture; Commerce; Justice; Transportation; Housing and Urban Development; and Energy along with the leaders of the Environmental Protection Agency and the Councils of Environmental Quality and Economic Advisors. Ex Officio members included the Vice President, Counsellor for the President, White House Chief of Staff, and the Assistant to the President for Policy Development.

This presentation was intended to provide a detailed statement of the problem and a strategy for how to proceed in addressing the issues raised at the February 2 meeting. The working group was chaired by DOE's Director, Office of Policy, Planning, and Analysis and consisted of 3 other DOE staff along with representatives from the Departments of: Agriculture; Commerce; Defense; Housing and Urban Development; Interior (2); Treasury;

and Justice. Other members included representatives from the: Environmental Protection Agency; Federal Energy Regulatory Commission; Nuclear Regulatory Commission; Council of Economic Advisors; National Security Council; Office of Management and Budget; OSTP; Vice President's Office; and White House staff (2). According to two DOE officials who had responsibility for managing the efforts of this working group, at least four meetings of this group occurred in April and early May.

On May 13, 1982, the results of this working group were presented before the Cabinet Council on Natural Resources and Environment. The Council agreed that issues involving whether the electric utility industry can be expected to provide adequate supplies of electricity at minimum cost over the foreseeable future were sufficiently important to merit further federal attention and study. The Council requested that the working group report within 6 months on a review of these issues and specific recommendation for federal action needed to assure sufficient and economical electric power supplies. DOE continued as the lead agency with the responsibility to perform needed work, prepare a draft summary paper, and regularly brief the working group. The White House Office of Policy Development, in both its administrative role as secretary to the Cabinet Council and member of the working group, was closely involved with DOE in the Project's development.

According to DOE officials reponsible for completing the necessary staff work, it was apparent well before the Cabinet Council's May 13, 1982, decision that there was a growing interest in electric utility issues. As a result, DOE's Office of Policy, Planning, and Analysis already had a series of ongoing internal and contractor studies, beginning as early as May 1981, to review many issues the Council formally wanted addressed. These studies were being conducted by an existing group within this Office dedicated to evaluating electric utility issues.

During the six months following the May 13 Council meeting, DOE prepared 5 drafts of a summary paper for review and comment by the working group. According to a letter to GAO from DOE's Acting Director for the Office of Policy, Planning, and Analysis, this summary paper was actually two distinct documents which included (1) a descriptive analysis of electric power markets and an evaluation of the sufficiency and efficiency of future electric supplies and (2) prescriptive recommendations for consideration by the Cabinet Council. The letter also stated that the latter document included the following options for possible federal initiatives

--do nothing since the problem of sufficiency and efficiency of future electric supplies is largely the responsibility of the states;

--cooperate with states to encourage but not force constructive reforms of state regulation including the transfer of federal electricity rate regulation to the states;

--establish federal rate making standards for state consideration;

--enact federal legislation to permit regional generating companies thus creating competition in rate regulation; and

--enact federal legislation transferring all electricity regulation to the Federal Energy Regulatory Commission allowing an opportunity to implement rate reforms consistently across the country.

The letter further pointed out that these options never received approval of the working group and were not submitted to the Cabinet Council.

DOE continued its efforts by focusing on a descriptive analysis of the electric utility industry. When DOE completed its draft report in April 1983, it was submitted for review to the Office of Management and Budget and the White House Office of Policy Development and was issued by DOE on June 8, 1983.

DOE Project efforts since the report was issued have generally been limited to analyzing public comments and occasionally making public presentations of the report. While DOE continues to study electric utility issues (e.g., attrition of utility earnings) through both staff work and contractor-sponsored efforts, these activities are being carried out as part of their normal responsibilities rather than as part of the Project.

QUESTIONS 1d: How were the contractors relied upon by DOE chosen? By competitive bidding? Sole source?

1e: Were contractors scrutinized for conflict of interest? Did contractors sign conflict of interest forms?

1f: How much money was spent by DOE in the development of contractor reports and the DOE Report itself? Include in the answer to this question all staff time and salaries as well as amounts spent on contractor studies.

1h: Were the inputs of all contractors used in the development of the DOE Report or were only selected inputs used? If the latter, please explain the manner of selection.

ANSWER:

DOE spent about $3 million in developing the Project and final report. Most of these funds, $2.7 million, were used to fund 27 reports through 15 contracts and 7 subcontracts. We reviewed 13 of the 15 contracts[1] and found five contracts were awarded on a sole source basis accounting for over 20 percent of the funds spent to obtain contractor services. DOE used four types of contracting arrangements including 9 task order contracts which were used to fund 20 contractor reports. DOE's use of sole source and task order contracts for the Project raised the same concerns found in a past GAO report examining DOE contracting practices.[2] Specifically, sole source and task order contracts avoid or limit competition and these practices do not assure that DOE obtains quality products at the lowest possible cost. DOE contract files indicated that required conflict of interest determinations were performed for all but four contracts and three subcontracts. In these cases, the files did not contain the data needed to determine whether the process had been completed.

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[1] We did not examine documentation for 2 reports because the contract files were not located at DOE headquarters.

[2] The Department of Energy's Practices for Awarding and Administering Contracts Need to Be Improved, EMD-80-2, 1979.

Contractor services used extensively

To address the questions concerning the contractor studies DOE sponsored to support the Project, we reviewed contract files located in the DOE headquarters office. From these contract files we obtained information concerning: the type of contracting arrangement used; the funds spent by DOE to support each contractor; whether DOE performed the required conflict of interest determinations; and whether the work performed was consistent with the contract work statement. In addition, we interviewed DOE procurement officials to determine their procedures in awarding and administering contracts, and officials in the DOE program office to determine their role in the contracting process.

DOE spent about $3 million in support of the Project and report. About $300,000 of this total was to support 17 DOE professional staff devoting from 5 to 75 percent of their time on this Project. The remaining $2.7 million was used to fund 27 reports through 15 contracts and 7 subcontracts.

DOE used most of these contractor reports either directly or as supporting material for subjects discussed in the report. Of the 27 contractor reports, 18 were explicitly referenced in the DOE report. DOE program officials stated that many of the remaining reports were used to provide support on topics discussed in the DOE report. However, DOE made only limited use of the six contractor reports focusing primarily on alternative solutions to utility industry problems (e.g., the three reports which involved the deregulation of electric power) because the DOE final report did not include recommendations.

Because the Project was originally expected to be completed within one year, DOE used four different contracting arrangements to expedite funding for the 25 reports we reviewed. These arrangements included purchase and cooperative agreements, existing long-term agreements with two of their national laboratories,[3]

[3]These agreements involve the management of government-owned facilities conducting long-term programs.

and task order contracts. Five of these contracts were awarded on a sole source basis accounting for over $580,000 of the $2.7 million used to support contracting efforts.

DOE relied most extensively on task order contracts, using 9 existing task order contracts to support 20 contractor reports including two contracts which accounted for a total of 11 reports. These contracts were agreements between DOE and the contractor to purchase up to a specified amount of a contractor's time at a specific rate. The initial or master agreement was awarded competitively in 8 of the 9 contracts and identified a broad scope of work in which DOE could later delineate specific task orders for the contractor to perform without further competition. According to DOE program officials, existing task order contracts were used to avoid the lengthy process involved in individually awarding contracts competitively. Their previous contracting experience demonstrated that it took 12 to 18 months to issue an award under the competitive selection process while processing time using an existing task order contract was about one week.

DOE's contracting procedures raise past GAO concerns about obtaining quality products at lowest cost

DOE's use of sole source and task order contracts for the Project raise the same concerns found in a past GAO report examining DOE contracting practices.[4] Specifically, sole source and task order contracts avoid or limit competition and these practices do not assure that DOE obtains quality products at the lowest possible cost. We found that the initial task order contracts used for the Project included general work statements which makes it difficult to compare the competency or competitiveness between the task order contractors. In addition, the elapsed time between the original award and the task assignment did not assure DOE that the contractor continued to remain the best qualified. We did not

[4]The Department of Energy's Practices for Awarding and Administering Contracts Need to be Improved, EMD-80-2, Nov. 2, 1979.

determine whether these procedures actually resulted in adversely affecting the quality or cost of individual contracts or reports.

According to the DOE program officials responsible for selecting specific contractors from among those having existing task order contracts, the selection generally relied on the contractor's availability and their perception of the contractor's expertise in a subject area rather than the scope of work detailed in the initial contract. Procurement officials then approved or disapproved this selection based primarily on whether, in the contract specialist's judgment, the original contracts scope of work statement was consistent with the proposed tasks. However, we found the scope of work statement which formed the basis for the original competitive award was so general that it allowed a wider range of subject areas to be addressed under the initial contract than may have originally been intended. For example, we found one work statement indicating the contractor's area of expertise was coal regulations although for the Project this contractor examined industrial electricity demands. In another case, the initial scope of work was for evaluating energy conservation regulations yet the contractor was selected to assess the relationship between electric generating costs and utility rates. While DOE procurement officials are responsible for assuring that specific task assignments are within the contractor's scope of work, a DOE Chief of Procurement told us that reviewing officials do not have the expertise to accurately assess whether a proposed assignment is fully within a contractor's scope of work.

Another factor limiting DOE's ability to assure the selection of the most qualified contractor for a particular assignment among those having existing task order contracts was the time elapsed since the initial contract award. Specifically, because of possible staff or organizational changes, it could be difficult to assure that contractor qualifications have not changed over time. For the Project, we found five of the nine task order contracts were awarded prior to 1980.[5]

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[5]Task order contracts are usually awarded on a one-year basis with two one-year renewal options.

In addition, DOE used two agreements with their national laboratories that were initially awarded in 1943 and, since then, extended on a noncompetitive basis.

Required conflict of interest determinations completed in most cases

According to DOE policy, the Department must identify and avoid or mitigate organizational conflicts of interest before entering into agreements with potential contractors. DOE procurement regulations[6] state that organizational conflicts of interest exist when a contractor has past, present or planned interests with another client that (1) diminish the contractor's ability to provide DOE with impartial, technically sound, and objective assistance, or (2) may gain an unfair competitive advantage. Potential contractors are required to submit all relevant information on their past, present, or planned interests related to the proposed scope of work (e.g., work, clients and fees). The Procurement Office then evaluates the information to determine whether a conflict of interest exists. Since 1979, contractors have also been required to warrant, through a clause contained in their signed contract with DOE, that no organizational conflict of interest exists and that contractors will inform DOE should a potential conflict develop after the contract is awarded.

We verified that DOE performed conflict of interest determinations prior to awarding the contracts for all but four contracts and three subcontracts we reviewed. In these other cases, DOE contract files did not contain the data needed to determine whether the assessments had been completed. DOE procurement officials could not account for the information's absence or determine whether conflict of interest assessments had been performed. Moreover, two contracts did not contain the required conflict of interest clause in the contract.

[6] 41 CFR sec. 9-1.54.

QUESTION 1i:

How were the views of interested parties taken into account, if at all, in the work of the Project and, particularly, in the development of the DOE report? Were public hearings held by the Project at any time?

ANSWER:

Beyond the groups identified previously (see pp. 1-5), DOE made no formal efforts (such as public hearings) to directly obtain views of interested parties. However, DOE funded four contractor reports which obtained and analyzed the views of other interested parties. For example, one report addressed regulatory problems affecting the industry and was prepared by a task force consisting of governors from 15 states while another report surveyed 58 industry leaders to obtain their views on a range of industry issues. A third contractor study conducted a nationwide consumer attitude study assessing public perceptions of electric utility issues. DOE used these studies in developing a report chapter discussing perceptions about the electric utility industry held by these different groups. On an informal basis, DOE program officials told us they met several times with representatives from public interest groups. DOE also made contractor reports available to the public as they were completed.

Question 2:

The DOE Report states that 438,000 megawatts of new electric generation will be required by the year 2000.

a. Based on your understanding of the methodology used by DOE, can this forecast be said to be a least cost strategy to meet demand for electric energy services in 2000?

ANSWER:

No, DOE's forecast is not based on a least cost strategy. A least cost utility planning strategy is an approach designed to find a specific combination of resources that results in providing electricity services to consumers at the minimum possible cost. Unlike traditional utility planning methods which attempts to minimize the cost of supplying a given level of electric demand, least cost strategies considers the cost effectiveness of a broad range of resources including methods to reduce electric demand. For example, least cost planning includes the consideration of both conventional and unconventional resources (solar, wind, refuse, wood, and solid waste), cogeneration, conservation, load management, increased interties and imports, and enhanced power plant productivity. While large, central-station generating plants have been the primary consideration in traditional utility planning approaches, their use may be more limited, though not excluded, if least-cost strategies are applied to utility planning. DOE limited their focus of least cost strategies to examining the flaws of other least cost studies and the practical limitations of such analysis.

In order to be considered a least-cost strategy, DOE's methodology would have had to, at minimum, evaluate the relative economic and financial merits of a broad range of demand and supply alternatives and then analyze the optimum mix, size, and timing of such resource options. Since such an optimum combination is likely to differ according to specific utility system operating characteristics (e.g., type of resources already used and consumer demand patterns), applying a least-cost planning strategy would result in at least several different solutions based on regional or utility-specific considerations. In their report, DOE clearly recognized the advantages of using such strategies

> "least-cost utility planning ... can produce the best long-term net benefits for society and can maximize the most appropriate investments in conventional or alternative technologies, conservation, load management, or fuel substitution."

DOE's approach to projecting needed new generating capacity by the year 2000, however, was based on their nationwide projections of electric demand, the amount of reserve capacity needed to reliably support projected demand, and reducing the existing inventory of generating plants for physical and economic obsolesence. The resulting estimate of 438,000 megawatts (MW) of new capability required to meet demand was then adjusted to account for 175,000 MW of publicly announced new plants coming on line, leaving 263,000 MW of what DOE called new, unplanned yet required generating requirements. Table 1 summarizes this process. Questions 2b and 2c address how their forecast considered other demand and supply alternatives.

 ATTACHMENT I

Table 1

Summary of DOE Forecast of New

Generating Requirements by 2000

Forecast variable	MW
1. Peak Demand (3% per year)	751,000
2. Reserve Requirement (1 x 20%)	150,000
3. Capability Required to Serve Peak Demand (1+2)	901,000
4. 1981 Existing Capacity	572,000
5. Capacity Lost Due to Aging[1]	21,000
6. Capacity Lost Due to Retirements[2]	50,000
7. Uneconomic Capacity[3]	38,000
8. Available Economic Capacity (4-(5+6+7))	463,000
9. New Capacity Required (3-8)	438,000
10. Planned Capacity	175,000
11. Capacity Unplanned Yet Required (9-10)	263,000

[1]Aging refers to reductions in powerplant availability, or the fraction of time that generating capacity is available for service, that normally occurs over time.

[2]Retirements refers to powerplants no longer operated or maintained to produce electricity.

[3]Uneconomic capacity refers to existing powerplants which are more costly to the consumer than new generating plants.

Source: The Future of Electric Power in America: Economic Supply for Economic Growth, U.S. Department of Energy, June 1983.

QUESTION 2b:

What is your understanding of the way in which DOE considered customer efficiency improvement measures (conservation) and utility efficiency improvement measures (improved load factors through load management techniques and improved rate design, pooling and wheeling, and productivity improvements, etc.)? Were economic potentials of these efficiency improvements analyzed by DOE or any of its contractors in the work of the Project or in the Report? If so, were these potentials factored into the DOE forecast of 438,000 megawatts?

ANSWER:

DOE's report addresses a broad range of supply and demand alternatives in concluding that 438,000 MW of new electric generating capacity will be required by 2000. However, consumer and utility efficiency improvement measures as well as other capacity enhancing alternatives are often considered only qualitatively or with limited quantitative analysis. Potentials for cost effective efficiency improvements were not analyzed for all measures and, along with other non-traditional methods of meeting the demand for electric services (cogeneration and non-utility owned generation), were excluded from their forecast.

DOE's treatment of efficiency improvement measures

While DOE did not apply least cost utility planning strategies in their report, they did examine alternatives to new capacity (e.g., conservation, load management,and cogeneration) usually considered important to least cost planning. However, DOE's treatment of such demand and supply alternatives is often only qualitatively addressed in their report and not actually included in their demand or supply estimates. DOE's analysis and treatment of specific efficiency improvement measures and capacity-enhancing alternatives follows.

--Conservation. Consumer efficiency improvements are conservation measures designed to reduce the amount of energy needed to provide a given level of service. Examples of such measures range from the installation of insulation and energy efficient equipment (e.g., light bulbs, water heaters, and refrigerators) in the residential sector to energy management control systems in the commercial and industrial sectors. DOE considered two categories of conservation in their report--price-induced and non price-induced consumer efficiency improvements.

Price-induced conservation is the consumer's demand response to changes in price levels. In examining the key variables having a major influence on future electric demand growth, DOE analyzed the responsiveness of electric demand to electricity and other energy price changes. DOE determined that consumers respond to higher electric prices by (1) reducing or eliminating activities that consume electricity, (2) substituting other energy alternatives for electricity, or (3) employing conservation measures to use less electricity to provide the same level of service. Although DOE did not isolate the portion of consumer response attributable to price-induced efficiency improvements, because their estimate of the demand for electricity was adjusted to account for price changes, their forecast implicitly assumes some level of conservation.

DOE also addressed the impact non price-induced conservation measures have on electric prices and utility methods to promote efficiency improvements. This review was limited to illustrating that conservation will not reduce electric prices in every region of the nation and that utility conservation programs such as energy audits or subsidizing customer conservation actions may not be in the consumer's best interest. Their demand forecast did not account for reducing electric consumption from utility or government-sponsored conservation programs. Finally, DOE did not analyze the economic potential of consumer efficiency improvements, characterizing such a task as forbidding if not impossible even though the potential effect is large.

--Load Management. The demand for electricity exhibits significant daily, weekly, and seasonal variations. Since electricity cannot be stored economically in large quantities, sufficient generating capacity must be available to meet demand instantaneously. Because it costs more to meet electric demand during peak periods, utilities try to reduce the difference between average and peak demand as much as possible by managing demand. Peak demand reductions also lead to reductions in the need for new generating capacity. Examples of load management techniques include installing control devices on energy-intensive appliances, using time-of-day rate schedules and contracting with large industrial consumers for "interruptible" service.

DOE's consideration of load management was limited to examining national load factor[1] trends and projections and its impact on electric prices rather than reviewing individual techniques or their economic potentials. Although finding that four of the five studies they examined projected increasing load factors, DOE concluded the evidence was not persuasive and assumed load factors would continue at 1981 levels. Therefore, DOE did not adjust their forecast to account for load management improvements.[2]

--<u>Pooling and Wheeling</u>. Electric power pooling and wheeling are methods used by utilities to improve the utilization of existing generating capacity. Power pooling usually consists of several contiguous utilities operating jointly to minimize generating costs and can provide increased reliability while simultaneously reducing the amount of generating capacity that would otherwise be needed to individually support electric demands. Wheeling is the transmission of electricity between two utilities through an intermediate utility. Where interconnections exist, wheeling can be accomplished over long distances to capture benefits similar to power pooling.

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[1]The ratio of average demand to peak demand.

[2]The effect of this assumption on DOE's forecast is discussed in question 2c.

DOE addressed the benefits of pooling and wheeling and briefly discussed the economic potential offered by these measures. They recognized that substantial improvements in coordination and interconnection will occur resulting in lower generating costs and less generating capacity needed to meet electric demand reliably. However, because of uncertainties in estimating the extent of these improvements or how much new capacity will be offset, DOE did not adjust their forecast to account for such improvements.

--<u>Power Plant Productivity</u>. Power plant productivity is a measure of a generating unit's performance in terms of operational availability, actual vs. potential output, and thermal efficiency. Productivity improvements can result in reducing operational costs and the amount of new generating capacity required to reliably meet electric demand.

DOE examined the prospects for enhanced power plant productivity using two studies: an in-house review of productivity trends and potentials and a contractor report based on a six-utility case study. These studies concluded that increasing the generating capability of existing power plants is unlikely and while prospects for increasing operational efficiency were favorable, they will not offset declines resulting from powerplant aging. DOE's forecast reflects these findings by reducing the existing level of generating capacity in 2000 by 21,000 MW to account for continued declines in powerplant productivity.

--<u>Electricity Imports</u>. Electricity imports, like power pooling and wheeling, are used by utilities to improve the utilization of existing generating capacity and reduce new capacity requirements. While imports (principally from Canada) supply only about 1.5 percent of the nation's total electric requirements, they represent an important resource in specific regions like New York where imports supply over 11 percent of electricity requirements.

DOE reviewed the prospects for increased electricity imports by examining planned utility increases over the next decade and other opportunities where imports may offer the potential to further reduce forecasted supply requirements. They found that areas in the Northeast and Plain states planned substantial increases in imports over the next 10 years. Moreover, while DOE recognizes the technical potential for additional imports is substantial, they conclude that the economic potential is small. DOE did not quantify this finding and no adjustment for imports was made in their forecast.

--<u>Cogeneration and Other Non-Utility Electric Generation</u>. Non-utility owned electric generation options represent a range of usually small-scale decentralized generating alternatives used to substitute or supplement central-station, utility-owned facilities. Similar to more direct efficiency improvement measures, decentralized generation provides an opportunity for utilities to reduce the amount of capacity otherwise needed to meet electric demand as well as utilize existing plant inventory more efficiently. Examples of decentralized generation range from industrial cogeneration to residential and commercial electric production using solar or wind resources.

DOE addressed these options by reviewing selected reports on the economic potential of cogeneration, wind, and solar non-utility electric production. They reported that cogeneration could economically reduce the need for 1,000 MW per year of new, utility-supplied capacity through 1990 and that decentralized generation opportunities from renewable resources is limited through the 1980's but may expand dramatically by 2000. However, DOE made no adjustment for such alternatives in their forecast.

QUESTION 2c:

DOE acknowledges uncertainties in variables affecting its forecast. How did DOE resolve these uncertainties? Were they resolved generally in any one direction? If so, what would be the effect on the forecasted need for new capacity of resolving the uncertainties in a neutral manner?

ANSWER:

Forecasting the need for new electricity resources, especially on a national basis over 20 years is a complex and inexact process. DOE's demand modeling considered a range of values for several key variables considered critical to utility forecasting techniques. The model's estimated most likely annual electric demand growth rate was 2.49 percent. This result was about mid-way between their 25 modeling estimates which ranged from 1.10 percent to 3.82 percent annually or a difference by 2000 of 415,000 MW. Based on revised electricity price estimates which increased the 2.49 percent growth rate to 3 percent, DOE then chose the 3 percent rate as their basis for estimating needed new capacity resources. The 3 percent forecast was also higher than 21 out of 25 of the original modeling results including all 9 base-case estimates which primarily used the mid-level values for the key variables. Using this higher electricity demand growth rate led to DOE's forecast being over 80,000 MW higher than originally estimated by their model's most likely case. On the supply side, DOE's projection of available generating capacity in 2000 was limited to those plants the industry expects in service by 1991. Together with excluding other supply or supply-enhancing alternatives, their estimate of available supply by 2000 may be low.

DOE'S ELECTRIC DEMAND MODELING AND FORECAST

Demand forecasting--
an inexact process

Forecasting electricity demands has become an increasingly complex and inexact process with results critically dependent on study assumptions and methodology. No clear consensus exists concerning the most appropriate forecasting technique and, even more importantly, specific values that should be assigned to variables affecting electric demand. It is not surprising, therefore, that there are many different electric demand forecasts. During recent years the most consistent result from forecasts has been that each year's demand estimate is lower than the preceding year. For example, the North American Electric Reliability Council (NERC), a group formed by the electric utility industry to promote reliability and adequacy of electric power supply, has annually revised downward its ten-year demand forecast since 1974. Their latest projection of average annual peak demand growth between 1983 and 1992 is 2.8 percent, less than half the 5.7 percent projected in 1977 and substantially below the 6 percent to 11.5 percent growth rates experienced during the 1960's.

Differences in forecasts can have profound implications for planning new capacity resources. For example, as illustrated in Figure 1, if realized average annual electric demand differed from DOE's base case estimate by 0.1 percent, this small change would by 2000 result in a 15,000 MW capacity shortage or surplus. In total, DOE's modeling projections demonstrate 415,000 MW difference between their high and low estimates based on varying economic assumptions.

DOE study assumptions

A recent GAO report analyzing utility demand forecasting[1] identified four key assumptions that drive demand forecasts: the price elasticity of demand; cost and availability of alternative fuels; correlation between economic growth and growth in electricity consumption; and impact of conservation. An explanation of these variables and the values DOE assigned them follow.

--Price elasticity of demand. This variable measures consumer's demand response to changing electricity prices. If a small price increase causes a large decline in demand it is categorized as being elastic (having an absolute value greater than 1.0). Conversely, if a large price increase

[1] Analysis of Electric Utility Load Forecasting, GAO/RCED-83-170, June 22, 1983.

results in a small change in demand, the relationship is categorized as inelastic (having an absolute value between 0.0 and 1.0). Although the past decade has demonstrated that electric demands are related to its price, no general agreement exists about the precise value that this variable should be assigned. For their model, DOE assumed values of 0.5, 0.6, and 0.7 for their low, base case, and high growth scenarios, respectively.

--Cross-price elasticity of demand. With few exceptions, other fuels can be substituted for many uses of electricity. To measure consumer's willingness or ability to substitute electricity for other fuels in response to a change in the prices of these other fuels, another type of elasticity measurement is used called the cross-price elasticity of demand. Specifically, while the price elasticity of demand considered above measures consumers response to higher electricity prices, cross-price elasticity measures consumers response to a change in the prices of alternate fuels.

DOE assigned a constant value of 0.25 to this variable. While below the value assumed for price elasticity, its significance depends on the assumed prices for electricity and other fuels. For example, if electricity prices rise less rapidly than oil prices, electricity's relative share will increase (cross-price elasticity effect). DOE assumed in all cases that electricity prices increase more slowly than either oil or natural gas prices. For example, DOE's base case assumes real electric prices increase at an average annual growth rate of 1.67 percent while gas, distillate, and residual oil prices increase annually by 5.45 percent, 2.54 percent, and 3.58 percent, respectively. Because relative price changes rather than absolute prices of individual energy forms are more critical to this variable, we will not detail the assumed prices for each fuel.

--Electricity/Economy Relationship. This variable measures how economic growth (as measured by the Gross National Product or GNP) will affect the level of electricity use. From 1947 to 1973 the relationship between electricity use and GNP was stable. Since 1973, however, the stability of this relationship has become the subject of much debate. Some forecasters maintain that economic growth will result in higher electric demands because of a shift away from oil and gas while other forecasters maintain that conservation and shifts in the Nation's industrial mix have "decoupled" the historical relationship. In their model, DOE assumed future overall annual GNP growth rates of 2.1 percent, 2.6 percent, and 3.0 percent for their low, base case, and high growth scenarios, respectively. Their modeling results illustrated that the ratio of electric demand growth to GNP growth in their low, base case, and high growth scenarios was 0.82, 0.96, and 1.00, respectively or, as GNP approached 3.0 percent, the average annual electric demand growth rate increased at the same rate.

--Conservation. As discussed in question 2b, this variable can be separated into two components--price-induced conservation and non price-induced conservation resulting from specific programs. Price-induced conservation was accounted for as part of DOE's price elasticity of demand assumption and not explicitly isolated and assigned a specific value. Conservation resulting from specific utility or government programs was not considered in their model.

In addition, to these variables, DOE made several other modeling assumptions that influence electric demand.

--Real income. DOE noted that increases in real income have historically been associated with higher levels of electric demand. Since such historical relationships may not remain constant in future years, DOE included in its model a variable to account for possible changes in the relationship between increases in real income and the demand for electricity. Because their model combined this variable with a similar measurement to account for changing the historical relationships between technological changes (see below), DOE could not isolate the portion associated with each variable. Moreover, according to DOE, the value assigned to this measure varies from year to year and identifying a specific numerical estimate or average value would be inappropriate. For the low and high growth scenarios, the specific value for each year was calculated at 0.8 and 1.2 times the base case estimate, respectively.

--Technological change. DOE recognized that future technology changes, while difficult to estimate, can have important implications for electric demand. DOE assumed, however, that any such changes would favor the use of electricity over other energy forms. The values assigned to this variable were discussed in the previous section.

--Demographic changes. DOE recognized that electric demand is sensitive to the relative size of the 20-40 age group. Although acknowledging the size of this group is likely to decrease through 2000 and reduce electric demand, DOE assumed other demographic changes (e.g., migration to the sun-belt areas which increases electric demand because of increased air-conditioning requirements) would offset this decrease. Therefore, DOE did not explicitly include this variable in their model.

--Foreign competition. Increased imports of goods can significantly affect electric demand, especially in the industrial sector. While DOE noted this trend may accelerate over the next two decades for electric-intensive industries (e.g., steel, automobiles, aluminum, and chemicals), they did not explicitly treat foreign competition in their model.

DOE modeling results and relationship to forecasted electricity demand

Using the assumptions described above, DOE modeled 25 different combinations of assigned values for GNP, price elasticity of demand, energy prices, and income/technology elasticity of demand. These 25 combinations included: 1 base case using mid-point values for all variables; 8 alternative base cases using a high or low assigned value for 1 variable with all others having mid-point values; and 16 boundary cases using different combinations of high and low assigned values and no mid-point values.

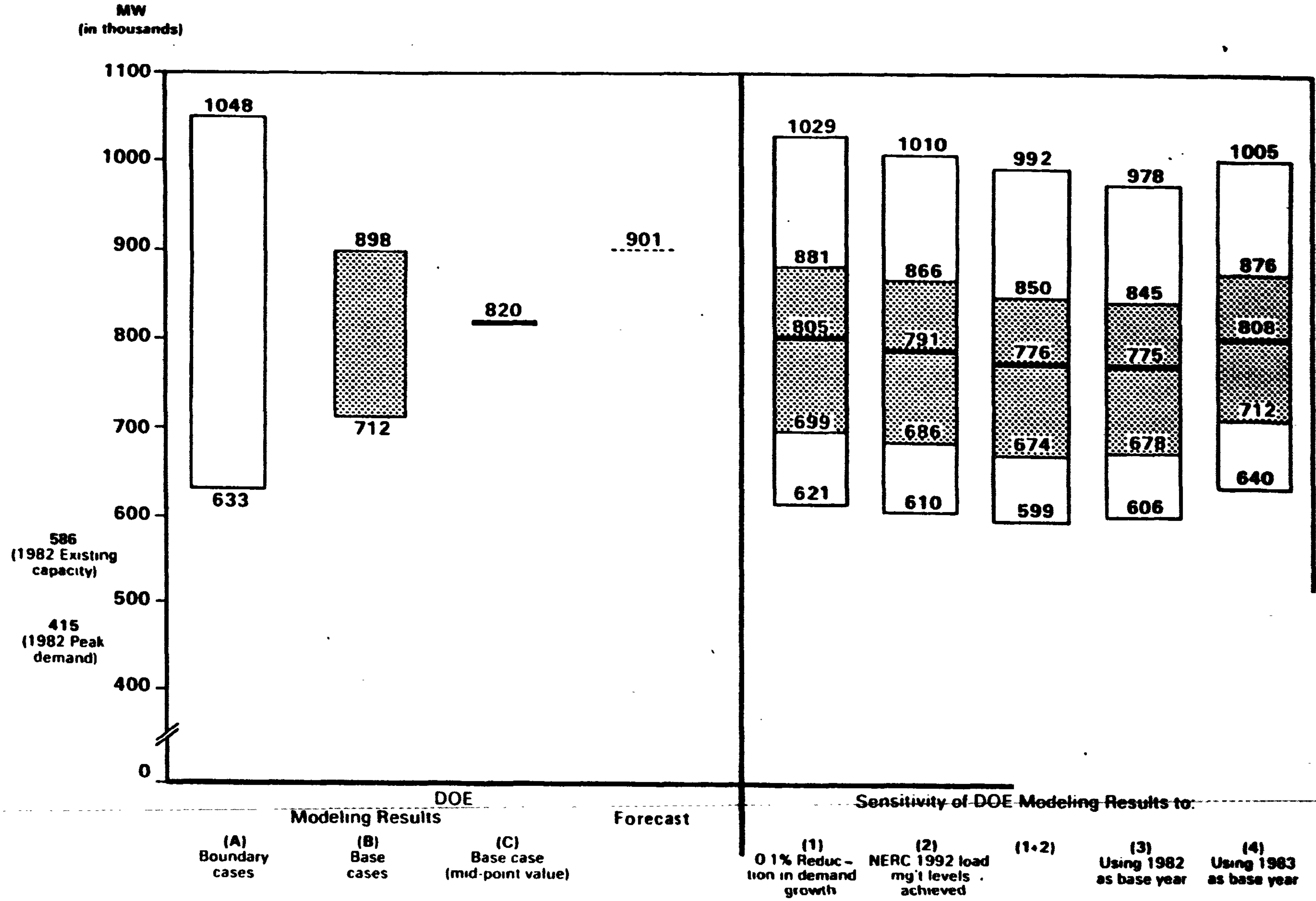
The resulting demand for electricity estimates by the year 2000, adjusted to include a 20 percent reserve margin, are illustrated in Figure 1 on the following page. DOE's modeling results showed a large difference in their full range of demand estimates ranging from 633,000 MW under the low-growth scenario (1.10 percent annual electric demand) to 1,048,000 MW in the high-growth scenario (3.82 percent annual electric demand) (see A in Figure 1). This 415,000 MW difference was reduced by more than half when a higher proportion of mid-point values were used (and therefore according to DOE a higher probability of being accurate) ranging from 712,000 MW to 898,000 MW (equivalent to an electric demand growth rate of 1.73 percent to 2.98 percent per year) (see B in Figure 1). When DOE used all mid-point values assigned to the variables, the resulting estimate was 820,000 MW (equivalent to a 2.49 percent annual electric demand growth rate) (see C in Figure 1).

DOE's modeling results also showed that electric demand growth was substantially more sensitive to assumed GNP growth rates than any other variable tested. Specifically, when GNP growth increased at an average annual rate of 2.1 percent (DOE's low-growth case), average annual electric demand growth increased by 1.73 percent. When the corresponding GNP rate was 3.0 percent (DOE's high-growth case), electric demand also increased by 3.0 percent.

To further examine the sensitivity of DOE's results to changing assumptions, we made three additional calculations. First, if

FIGURE 1

DEMAND FOR ELECTRICITY - 2000
(including 20% reserve requirement)



Sources: <u>The Future of Electric Power in America: Economic Supply for Economic Growth</u>, U.S. Department of Energy, June 1983, and GAO calculations.

realized average annual demand differed from DOE's base case demand estimate by 0.1 percent (from 2.49 percent to 2.39 percent), by 2000 this small change would result in reducing electric demand estimates from 820,000 MW to 805,000 MW or 15,000 MW (see 1 in Figure 1). Second, we calculated how electric utility industry projections of load factor improvements would alter DOE's base case estimate. We found that increasing the load factor from DOE's assumption of 61.6 percent to NERC's 1992 projection of 63.9 percent reduced estimated demand from 820,000 MW to 791,000 MW or 29,000 MW (see 2 in Figure 1). Finally, we calculated how DOE's base case estimates would change if we used 1982 or 1983 as the base year instead of 1981. The results showed that DOE's 820,000 MW estimate would be 775,000 MW using 1982 data and 808,000 MW if 1983 data is used (see 3 and 4 in Figure 1).

DOE concluded that based on their modeling results, 3.0 percent per year was a suitable long-term forecast of electric demand growth. This conclusion became the basis upon which their 438,000 MW of needed capacity was predicated. However, DOE's forecasted annual electric demand was higher than 21 out of 25 of the original modeling results including all 9 base case variants. As illustrated in Figure 1, by the year 2000 the difference between their forecast (901,000 MW) and base case estimate using all mid-point values (820,000 MW) represented over 80,000 MW. This difference increases to 110,000 MW if load factor improvements were included (see 2 in Figure 1) and as much as 125,000 MW if a more recent base year was used (see 3 and 4 in Figure 1).

According to DOE officials responsible for managing the Project, the reason for the difference between modeling results and their forecast was a reassessment of electric prices used in the model. Specifically, once their modeling was completed, DOE received another set of projected electricity prices from a contractor's study which the officials told us were more realistic than DOE's original electricity prices. DOE's revised electric price projections decreased the average annual 1982-2000 electric price growth rate from their original estimate of 1.67 percent, already much lower than other energy rates, to 0.5 percent. Although we did not review the contractor's model on which these revised prices were based, we did note that the revised electricity price growth rates identified a set of 7 projections (average annual electricity price growth rates of 1.40, 1.39, 0.98, 0.68, 0.52, 0.45, and 0.30 percent) of which DOE selected an estimate that was lower than 5 of the 7 projections. DOE reported that revising its mid-level estimate to reflect these new electricity prices had the effect of increasing the annual electric demand growth rate from 2.49 percent to 3.0 percent.

DOE'S ELECTRIC SUPPLY OUTLOOK

DOE's forecast of available generating capacity by 2000 was based on their conclusions of planned generating capacity but considered limited opportunities for supply-enhancing options or alternative technologies. DOE's treatment of these variables follow.

--Planned generating capacity. DOE assumed that utility construction plans through 2000 equal 175,000 MW based on NERC announced utility supply plans through 1991. In effect, DOE assumed current utility supply plans were limited to 1991 with no additional generating plants becoming operational between 1991 and 2000. This assumption may be based on the recent trend of plant cancellations and delays as well as that a large number of plants included in the 175,000 MW estimate have not yet begun construction.

Forecasting planned generating capacity over a ten and especially twenty-year period, like demand forecasting, is an inexact process. For example, in 1979 NERC projected a national generating capability by 1988 of 796,000 MW while their latest forecast now plans for 684,000 MW by 1988 and 725,000 MW by 1992. Much of this planned generating capacity was under construction and simply removed or delayed beyond 1992 as a rational utility response to reduced electric demand. Presumably such "paper units" could be reinserted into utility supply plans or advanced in time if conditions warranted. In fact, some generating plants are currently scheduled for commercial operation after 1991 and although not publicly announced, many utilities plan capacity additions over a twenty-year period. Given these considerations, more capacity additions are likely to occur between 1991 and 2000.

--Alternative supply options and increasing the efficiency of existing supply. In addition to conventional supply options, utilities can pursue other supply strategies to reduce the need for generating capacity. These options include measures to increase the efficient use of existing resources and promote non-traditional supply alternatives. As previously detailed (see questions 2a and 2b), DOE's consideration of such measures was generally excluded from their supply forecast.

As illustrated in Table 1 on page 14, DOE's supply forecast also included reductions for generating capacity lost due to aging, retirements, and uneconomic capacity. By 2000, these reductions totaled 21,000 MW, 50,000 MW, and 38,000 MW respectively. With regard to uneconomic generating capacity which DOE defined as those oil and gas burning plants more costly to the consumer than new generating plants, DOE's determination was based on the findings of a contractor study. This study examined the difference between total, time-adjusted consumer costs if a utility built power plants to (1) meet reserve margin requirements or (2) assure electric service is as economic as possible. The study considered central-station coal or nuclear plants and oil or gas burning combustion turbine plants as the only alternatives to satisfy electric demand. Moreover, the study's cost assumptions provided a relative advantage to large coal and nuclear plants at the expense of continued use of existing oil and gas plants or new combustion turbines. Specifically, the study assumed nuclear real capital costs would be less in 2000 than 1990, coal real capital costs would decline after 1995, coal mining and transportation costs would experience no real increases after 1985, and oil prices would increase 2 percent per year above inflation in each year of the analysis. We could not determine the effect of using alternative cost assumptions or how much of their 38,000 MW of uneconomic oil and gas capacity will still be in operation since utilities already plan to reduce oil and gas usage from its 1981 level of supplying nearly 25 percent of electric generation to less than 12 percent by 1992.

QUESTION 2d:

Are there limitations to the use by the utility industry of the forecast made by DOE in the Report? If so, please discuss in detail.

ANSWER:

Because DOE's forecast of needed new electric generating capacity is a national estimate based almost entirely on aggregated data, assumptions, and conclusions, its usefulness to individual utilities making up the industry is limited. As pointed out in a previous GAO report,[1] national forecasts are used to provide an indication of the Nation's overall supply/demand picture but are of little use in planning specific resources or in balancing supply and demand on a utility operating system level. By not accounting for utility or regional variations, DOE's national forecast obscures the geographic magnitude, severity, and/or timing of regional demand and supply imbalances. While DOE did consider regional differences in their analysis from a qualitative standpoint, their quantitative analysis arriving at the forecasted need for new generating capacity was on a national basis and cannot be readily applied to specific regions.

Large regional variations characterize the electric utility industry

In forecasting that 438,000 MW of new electric generating capacity will be required by 2000, DOE made numerous simplifying assumptions. Our answers to questions 2b and 2c detailed how DOE treated many uncertainties involved in forecasting. Yet, the electric utility industry is characterized by large regional differences in both the demand for and supply of electricity. These differences are likely to affect forecasts of needed new capacity resources and how best these needs can be met.

While DOE ultimately concluded that a 3 percent average annual electric demand growth rate is a reasonable planning estimate, the most recent NERC forecast illustrates wide disparities

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[1]Analysis of Electric Utility Load Forecasting, GAO/RCED-83-170, June 22, 1983.

among regions ranging from 1.7 percent in the Northeast and mid-Atlantic states to 4.1 percent in the Southwest. Moreover, actual electricity sales from 1982 to 1983 increased by 3.6 percent nationwide. Further breakdown of the growth, however, reflects some regions such as the Midwest increased by 5.8 percent while the Pacific Northwest declined by 1.4 percent. These variations result from large regional differences in variables influencing electric demand including: different economic conditions; variations in the composition of demand between the residential, commercial, and industrial sectors; and differences in electric prices of more than 500 percent. Regional differences are also evident in how utilities meet the demand for electricity. For example, reserve margins currently range from over 50 percent in the west and east central areas to under 30 percent in the mid-America area while the fuel used to generate electricity varies from coal supplying over 90 percent in the east central region to gas providing over 50 percent in the southwest. Although DOE discussed many of these differences, regional variations in demand-related variables were often either overlooked or assigned average values for use in their model. Similarlly, many conclusions concerning future supply alternatives which could make important regional contributions were excluded from their quantitative analysis arriving at the forecasted need for new generating capacity because of their minor national significance.

Usefulness of national forecasts to utility planning efforts

Individual utilities must assess their own systems' existing and projected operating characteristics in order to appropriately evaluate future electric power needs and how best those needs can be met. Because of wide regional disparities in operating characteristics and the underlying factors likely to influence future changes, national forecasts are of limited value in contributing to a utility's understanding of its own service territory and how to most cost-effectively satisfy future needs.

For the industry as a whole, it seems apparent that large differences in existing and projected regional conditions make any simple characterization of the industry's problems, needs, and opportunities unrealistic. Without adequately reflecting these differences, the extent, seriousness, and timing of problems cannot be appropriately defined. Even if total new capacity requirements were accurately defined, determining whether a problem exists and what solutions may be warranted would depend on whether such needs were evenly distributed among states and utilities or confined to specific regions.

QUESTION 2e:

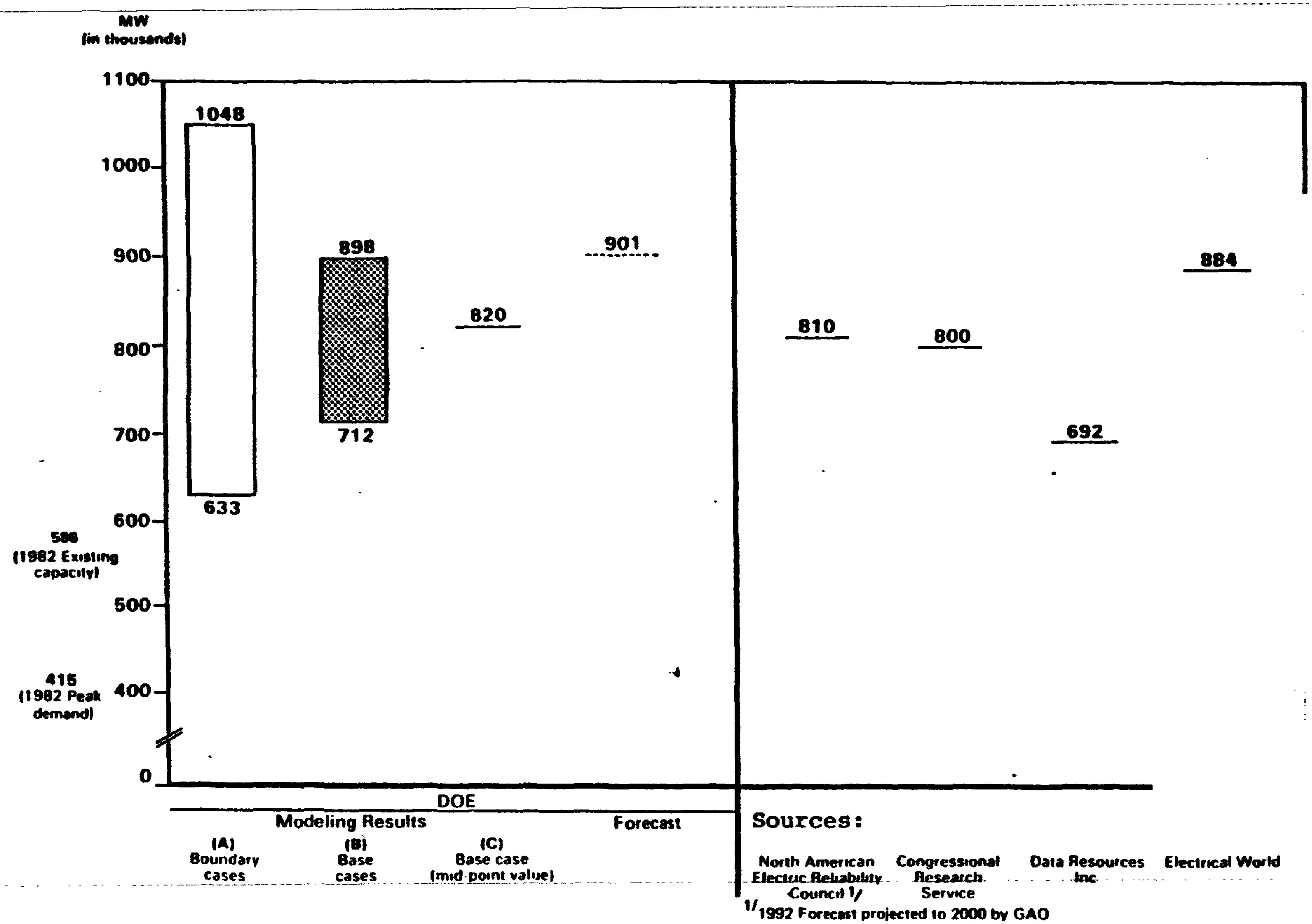
How does the DOE forecast compare with other major forecasts of the need for new electricity generation capacity?

ANSWER:

In order to provide a perspective on DOE's forecast of new generating capacity requirements, we compared projected peak demands in 2000 from DOE's model and forecast with four other recent forecasts (North American Electric Reliability Council, Congressional Research Service, Electrical World, and Data Resources, Inc.). The results of this comparison, adjusted to include a 20 percent reserve margin, are illustrated in Figure 2 on the following page. In general, the comparison demonstrates a wide difference in forecasted demand with the DOE forecast between 17,000 MW and 209,000 MW higher than the others.

FIGURE 2

COMPARISONS OF NATIONAL ELECTRICITY FORECASTS - 2000
(including 20% reserve requirement)



Source: <u>The Future of Electric Power in America: Economic Supply for Economic Growth</u>, U.S. Department of Energy, June 1983.

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