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CHAIRMAN
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IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES.	Docket No. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606.	Docket No. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR.	Docket No. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES.	Docket No. E-01933A-02-0069
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY.	Docket No. E-01933A-98-0471

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing the Direct Testimony of Dr. Richard A. Rosen on Track B issues, in the above-referenced matter.

RESPECTFULLY SUBMITTED this 12th day of November, 2002.

Scott S. Wakefield
Chief Counsel

AN ORIGINAL AND EIGHTEEN COPIES
of the foregoing filed this 12th day
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E-01933A-98-0471

By Cheryl Fraulob
Cheryl Fraulob

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE	)	
GENERIC PROCEEDINGS	)	Docket No. E-00000A-02-0051 ET.AL.
CONCERNING ELECTRIC	)	
RESTRUCTURING ISSUES	)	

DIRECT TESTIMONY

OF

DR. RICHARD A. ROSEN

On Behalf of the Arizona
Residential Utility Consumer Office

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TESTIMONY ON TRACK B ISSUES

NOVEMBER 12, 2002

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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dr. Richard A. Rosen. My business address is Tellus Institute, 11 Arlington Street, Boston, MA 02116-3411.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I hold a B.S. in Physics and Philosophy from MIT, a M.S. in Physics from Columbia University, and a Ph.D. in physics from Columbia University. Currently I am a senior research director at Tellus Institute, as well as executive vice-president and secretary/treasurer of the Institute. I am also the manager of the Institute's Electricity Program.

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF TELLUS INSTITUTE.

A. Tellus Institute is a non-profit organization specializing in energy, natural resources, and environmental research. Within Tellus Institute, the Electricity Program focuses on energy and utility research areas which include demand forecasting, conservation program analysis, electric utility dispatch and reliability modeling, least-cost utility planning and integrated resource planning, avoided cost analysis, financial analysis, cost of service and rate design, non-utility generation issues, bidding systems, incentive regulation, cost of capital analysis, and utility industry restructuring.

Q. PLEASE ELABORATE ON YOUR EXPERIENCE WITH ELECTRIC UTILITY SYSTEM SUPPLY PLANNING.

A. As past director of the Energy Group and manager of the Electricity Program, I have had wide experience assessing utility system supply options on both a service area and a regional basis. These assessments have encompassed all types of generation plant, transmission plant, purchases of capacity and energy, fuel purchases and contracting, central station district heating and decentralized cogeneration plants, and alternative sources of energy such as wind, biomass, and solar energy connected to electricity grids. These assessments have dealt with the technical, economic, environmental, regulatory, and financial aspects of supply planning, including the relationships between supply planning, load forecasting, rate design, and revenue requirements. I have also reviewed the prudence of many past supply-planning decisions by utilities.

Q. PLEASE PROVIDE A FEW ADDITIONAL DETAILS OF YOUR EXPERIENCE IN THE AREA OF UTILITY PLANNING.

A. Power supply system modeling and integrated resource planning has been a major focus of my activities for the past 22 years. My research and testimony in this area began in 1980, and I have testified in numerous cases involving generation planning and the integration of demand and supply technologies on a least-cost basis. For example, I submitted extensive generation planning testimony in the 1980 CAPCO Investigation in Pennsylvania in Case No. I-79070315, and in the 1981 Limerick Investigation as well (Case No. I-80100341). In early 1982, I prepared a major report for the Alabama Attorney General's Office entitled "Long-Range Capacity Expansion Analysis for Alabama Power Company and the Southern Company System," and I filed testimony in Docket No. 18337 before the Alabama Public Service Commission. In addition, I testified on the excess capacity issue regarding Susquehanna Unit 1 in the 1983 Pennsylvania Power and Light Co. Rate Case (No. R-822169). In 1987, I testified before the Federal Energy Regulatory Commission ("FERC") on NEPOOL's Performance Incentive Program on behalf of the Maine Public Utilities Commission in Docket No. ER-86-694-001. In 1989, I testified before the Pennsylvania Public Utility Commission on excess capacity and ratemaking treatment regarding Philadelphia Electric Co.'s Limerick 2 nuclear unit. This work was performed on behalf of the Pennsylvania Office of Consumer Advocate in Docket No. R-891364. I also testified in Vermont in Docket No. 5330 on the cost-effectiveness of the proposed purchased power contract between the Vermont utilities and Hydro-Quebec. In the 1980s, I testified in several cases involving the planning and construction of the Palo Verde nuclear units, before the Arizona Corporation Commission ("Commission" or ACC), as well as before FERC.

Finally, in January 1998, I testified before this Commission on behalf of the Residential Utility Consumer Office ("RUCO") in Docket No. U-0000-94-165 regarding public policy recommendations on key issues related to calculation, sharing, and recovery of stranded costs; and presentation of the "retail generation service" methodology for computing stranded costs. In September 1998, in Docket No. E-01933A-98-0471, I was the author of comments to the Commission entitled "Analysis and Recommendations of Residential Utility Consumer Office Regarding the Tucson Electric Power Company's Stranded Cost Filing." In November 1998, I filed testimony before the Commission in Docket Nos. E-

01933A-98-0471; E-01933A-97-0772; E-01345A-98-0473; E-01345A-97-0773; and U-00000C-94-165 on various filings related to the unbundled service tariffs, stranded cost recovery proposal for Arizona Public Service and Tucson Electric Power Company, and various other aspects of their restructuring proposals. I filed testimony before the Commission in Docket No. RE-00000C-94-0165 in July 1999 on the status of settlement discussions between RUCO and Citizens Utilities Company-Arizona Electric Division ("CUC-AED"), and summary concerns about CUC-AED's stranded cost recovery plans. In February 2002, I filed testimony before the Commission in Docket No. E-01032C-00-0751 on Citizens Communications Company's Purchased Power and Fuel Adjustment Clause and its wholesale power supply contract with Arizona Public Service. Earlier this year I also testified before the ACC regarding Track A issues in this docket.

Due to my extensive regulatory experience supporting the public interest, as outlined above, in 1988 I was chosen to serve a three-year term on the Research Advisory Committee of the National Regulatory Research Institute, an appointment made by the public utility commissioners serving on the NRRI Board of Directors. In addition, I have been the project manager on contract research that the Tellus Institute has performed for the U.S. Department of Energy, the U.S. Environmental Protection Agency, the U.S. Department of Justice, the National Association of Regulatory Utility Commissioners (NARUC), the New England Conference of Public Utility Commissioners, the New England

Governors Conference, and the National Council on Competition in the Electric Industry.

In the last six years, I have spent most of my time analyzing electric utility restructuring issues. As early as 1996, I testified before the New Hampshire Public Utilities Commission on issues affecting the design of the state's pilot programs (Docket No. 96-150), and I testified before the New York Public Service Commission on stranded costs, market structures, and other issues related to ConEd's, NYSEG's, and RG&E's restructuring plans. I also have worked on or testified on other restructuring issues in Nevada, New Mexico, New Jersey, Illinois, Missouri, Colorado, Pennsylvania, Maryland, Maine, Rhode Island, and Michigan. Exhibit___(RAR-1) provides a copy of my resume.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. In reviewing the Staff Report on Track B issues that was distributed on October 25, 2002, I have come to five major interrelated conclusions:

1. The Staff does not provide an adequate approach to determining which competitive bids for power should be selected by a distribution utility in order to ensure that the resulting electricity prices are reasonable. The Staff did not recognize that resource bids need to be evaluated in groups or portfolios, and they cannot be evaluated individually. Yet, there is no need to "reinvent the wheel", namely to try to develop a new methodology for bid selection, when a methodology for this purpose has already previously been used in Arizona and in many

other places throughout the world. (See, for example, the suspended Arizona IRP rules.)

2. There is only one reasonable way in which these competitive bids should be evaluated with respect to price, and that is to utilize a standard least-cost planning methodology. Each utility would have to take this approach anyway if it wanted to ensure that its selection methodology was prudent. The "bottom-line" for least cost planning is to minimize the present value of revenue requirements over a pre-specified planning period. This process will yield reasonable electric rates.

3. Demand-side management (DSM) program bids should be allowed from third parties, and a wide variety of DSM bids to serve all customer classes should be required from each distribution utility in amounts up to an incremental 2 percent of annual peak load in each year. If about 2 percent of the peak load is bid to be met by DSM, perhaps DSM programs of various types that will meet about 1 percent of the load will actually be chosen as more cost-effective than new generation resources. This will help guarantee that the lowest cost resources available to ratepayers will actually be evaluated as part of the competitive solicitation process.

4. Each distribution utility should be required to provide bids for peaking, cycling, and baseload power resources on a regulated basis in their own solicitation process in order to provide a "competitive price

baseline" against which unregulated market bids can be compared. Only if this is done can ratepayers be assured that they will end up paying reasonable rates as a result of this new competitive solicitation process. Only bids for new generation from highly responsible and financially capable entities should be considered in this process.

5. Once an appropriate least-cost planning process is established and correctly utilized for the purpose of evaluating resource bids, this process should automatically establish a presumption that the distribution utility, which utilized the process, carried out prudent planning for the resource portfolio selected.

Q. HOW DOES THE NEED FOR A LEAST-COST PLANNING PROCESS AND METHODOLOGY AS THE BASIC CONCEPTUAL FRAMEWORK FOR THIS COMPETITIVE SOLICITATION PROCESS HELP EXPLAIN WHAT IS MISSING IN THE BID EVALUATION METHODOLOGY OUTLINED IN THE STAFF REPORT?

A. Least-cost planning makes it clear that all resources — generation, transmission, and DSM — have to be evaluated simultaneously, as a package. Because each type of technology is different, because each bid will have a different ratio of fixed to variable costs, and because the capacity factor of each type of technology bid will depend to some extent on the mix of other technologies that co-exist with it, the mathematics of determining the least cost *portfolio,* or mix of technologies, is complex. The total present value of revenue requirements (PVRR) for all possible, technologically compatible resource portfolios have to be compared to the PVRR for all other such portfolios over the relevant planning period. No *single* resource bid or technology can be evaluated *by itself*, without reference to the cost and technical characteristics of *every other resource bid* that might be part of the least-cost portfolio. This basic concept was entirely missing from the Staff Report, which instead suggested that individual bids could be rank ordered in some absolute manner.

Q. WHAT DO YOU RECOMMEND TO THE ARIZONA CORPORATION COMMISSION AT THIS TIME?

A. The Arizona Corporation Commission (ACC) should:

1. Establish the entire competitive solicitation process within a Least Cost Planning rubric, as described in section III below, and as previously contained in the suspended Arizona IRP rules. This would not change the overall process described by the Staff in its October 25, 2002 report significantly, but it would significantly change the key details of how the price evaluation process for bids would need to be done. As described below, a least-cost planning framework allows the evaluation of all types of electric power products and contract durations at one time, on a self-consistent basis. A least-cost planning process would also allow DSM investments to be evaluated on a consistent economic basis along with new power supplies and new transmission investments.
2. The Commission should also require the utilities involved in a competitive solicitation process to prepare their own bids for "proxy" power plants on a regulated cost-of-service basis in parallel with their solicitation of third

party bids, in order to have a set of resources available on a "fall-back" basis. The Commission might have to order the construction of some of these new power plants on a regulated basis if doing so turns out to be lower in cost than a portfolio of competing bids offered by the independent power market. Arizona ratepayers should not be required to pay more for power as the result of a competitive solicitation process than they could pay under a continuation of traditional rate regulation. To do so would both indicate that the independent power market was not really sufficiently competitive at this time in history, and it would also provide a signal from Arizona's regulators that they were unwilling to hold the unregulated power market to a reasonable competitive standard in order to try to make it more competitive.

3. The Commission should not rush the establishment of an appropriate least-cost planning process. One approach, of course, would be to revive the existing Arizona IRP rules that were suspended in 1999. If such a process cannot be in place to select resource bids for the summer of 2003, those resources could be selected in a more *ad hoc* manner by each distribution utility, to which the usually prudent planning standards would apply. The final bid evaluation process could be used to select resources for 2004-2007, if the summer of 2003 cannot be included.

II. CRITIQUE OF STAFF REPORT

Q. WHAT IS THE MAJOR PROBLEM THAT YOU FIND WITH THE STAFF REPORT OF OCTOBER 25, 2002?

A. The major problem with the Staff Report is that it does not provide a logically consistent and coherent methodology for evaluating the bids solicited from the independent power producer (IPP) market. In particular, leaving non-price factors aside, it does not provide a coherent and workable methodology for evaluating bids based on their impact on utility costs, and, therefore, on the revenue requirements paid by ratepayers.

In particular, the Staff Report proposes a list of bid evaluation criteria on page 18. Of the eight categories listed there, only one, "delivered prices", directly affects ratepayer costs. The other bid evaluation criteria listed are basically non-cost items that must be satisfied sufficiently for the respective bids to be seriously considered at all. In fact, appropriately so, the Staff also lists several of these evaluation criteria on page 21 as "pre-qualification" factors. Thus, to first approximation, these other criteria can be segregated from the price or cost factors that are part of each bid.

Q. HOW DOES THE STAFF PROPOSE THAT THE PRICE OR COST FACTORS BE TAKEN INTO ACCOUNT IN DETERMINING THE WINNING BIDS?

A. The Staff describes their price evaluation methodology on pages 23-25 of the Report. They propose that the bids be evaluated in three "phases". The first phase "should be to rank order the bids by price using valuation methods that equalize volumetric and or duration differences on a price basis." This aspect of Staff's proposal seems to be describing a way to derive a dollar per kWh figure for each bid. A key assumption needed to do this is to know the capacity factor for each product in each year into the future. This fact will prove crucial in determining what an adequate price evaluation methodology would be.

Q. WHY WOULD ONE NEED TO KNOW THE CAPACITY FACTOR FOR EACH BID TO DETERMINE A DOLLAR PER MWH COST FOR EACH BID?

A. Typically, each bid for power would consist of a fixed cost component and a variable cost component, though it is possible for some bids, particularly baseload bids, to just be bid on a total dollars per MWH basis. If a bid does have a fixed cost component, it would likely be on a dollar per kW of capacity basis. In order to convert a dollar per kW bid into a dollar per kWh bid basis, one needs to know how many kWh each kW of capacity would generate in a year. That number is closely related to the capacity factor of the power plant being bid with a certain minimum capacity factor assumed. The dollars per kWh representing the fixed costs assuming a specific capacity factor, and the dollars per kWh representing variable costs in the bid, would be added together to get a <u>total</u> dollar per kWh result. However, this result would only be valid for the capacity factor assumed. A higher capacity factor would lead to a lower total cost per kWh, and *vice versa.*

Q. WHAT ARE THE SECOND AND THIRD PHASES OF THE BID EVALUATION PROCESS AS PROPOSED BY STAFF?

A. Phase two involves evaluation of deliverability, and Phase three involves evaluation of other factors, such as creditworthiness, experience and exceptions to model contract terms. These phases of the bid evaluation process are non-price related phases, and, thus, are not relevant to my critique of Staff's price evaluation process.

Q. DOES STAFF PROVIDE ANY OTHER ASPECTS OF A METHODOLOGY FOR DETERMINING THE WINNING BIDS BASED ON PRICE?

A. No. Unfortunately, Staff provides no additional guidance for the utilities subject to this competitive solicitation process, yet it insists (correctly) that the results produce "reasonable rates" as required by law. Related, but somewhat separate from this issue, Staff says on page 16 under "Identification of Products" for which prices will be bid that "the utility will specifically define the capacity and energy sought on a time-differentiated basis…" However, the Staff does not provide any details on how this would be done. For example, it does not state that a generation dispatch model would need to be run to develop this information, and, if so, how.

Q. DOES THE STAFF SUPPORT THE IDEA OF FRAMING THE BID SELECTION PROCESS WITHIN THE CONTEXT OF LEAST COST PLANNING?

A. No, the Staff explicitly rejects adopting a least-cost planning framework for the competitive solicitation process on page 39 of the Report. In fact, it does not even want least-cost planning to be an issue in this docket, which seems like a rather extreme position to take given that least-cost planning has traditionally been the way in which utilities have selected new generation resources to either construct, or for which to contract.

Q. DID THE ADMINISTRATIVE LAW JUDGE IN THIS DOCKET DISAGREE WITH STAFF ON THIS POINT?

A. Yes. In addressing RUCO's concern about assuring the lowest reasonable rates to ratepayers as a result of the solicitation process as expressed at a Track B workshop, the ALJ in this docket explicitly stated on page 5 of the Third Procedural Order on Track B Issues that she would not exclude the least cost planning issue from this case. However, in the process of doing so, the ALJ said, "RUCO believes that the Least Cost Planning framework can fit *within* [emphasis added] the Track B solicitation issues." This is not quite what RUCO meant to say. RUCO maintains that least-cost planning can fit within the Track B issues, and, therefore, least-cost planning should be included. RUCO meant to say that least-cost planning is absolutely central to the entire Track B solicitation process; it is **not** peripheral. In contrast, least-cost planning should be the single-most important organizing principle around which the entire Track B process must be structured.

Q. DID STAFF PROPOSE A KIND OF A "SAFE HARBOR" FOR BID PRICES <u>INSTEAD OF AN EXPLICIT SELECTION CRITERION FOR BIDS</u>?

A. Yes. Instead of establishing a traditional least cost planning-based selection process for generation bids, the Staff has proposed to establish a kind of "safe harbor" for bids based on their price. In order to accomplish this, Staff has proposed to calculate something they call the "prices to beat" for the products solicited for each utility. (Page 24-25) "The 'prices to beat' established by the Staff will be used for the purpose of determining whether the Staff will recommend without further analysis a finding that prices contained in any contract meeting the conditions outlined below are reasonable." (Page 25) If the contract bid price exceeds the relevant price to beat, then staff will perform some unspecified analysis and make findings about the "prudence, reasonableness and used and usefulness" of the contract price. (Page 25) Thus, this new concept of a "price to beat" appears to become a safe harbor with respect to further scrutiny by the Staff if a utility chooses such a product as part of its final resource portfolio. Of course, I assume that any other party to the relevant ACC case would still be free to challenge the reasonableness of the contract price, even if it is lower than the "price to beat" as computed by the Staff. However, Staff should confirm whether or not this is correct.

Q. DOES THE STAFF EXPLAIN WHAT METHODOLOGY WOULD BE USED TO COMPUTE THIS "PRICE TO BEAT"?

A. No. Unfortunately, Staff provides no statement at all in their Report as to how this very critical "price to beat" would be calculated. However, the text of their report gives me the feeling that there would be a single number computed for each proposed contract for each product. But I cannot discern how this would be done from the Report. In addition, in answer to RUCO data request 1.3, Staff states that it "does not intend to make the methodology it will use to calculate the price to beat public."

Q. EVEN THOUGH YOU DO NOT KNOW HOW THE "PRICE TO BEAT" WOULD BE CALCULATED, IS THERE ANY POSSIBLE METHODOLOGY THAT WOULD RESULT IN A SINGLE NUMBER FOR EACH PRODUCT

THAT COULD BE USED TO YIELD REASONABLE OVERALL RETAIL RATES FOR A DISTRIBUTION UTILITY INVOLVED IN THE PROPOSED SOLICITATION PROCESS?

A. No. There is no possible mathematical methodology of which I am aware that could possibly produce a single number for each product bid, and lead to the outcome of reasonable rates. The reason for this apparent impossibility is that the bids for each product are likely to be in the form of a separate fixed and variable cost component, unless the capacity factor of operation is already specified, as explained above. Thus, at least two separate numbers, not one bid price, will likely characterize each bid. The two separate numbers could only be combined into one total price once the capacity factor of a product (power plant) is specified. Yet, except, perhaps, for baseload power plants running full-out at their maximum possible capacity factor, neither the bidders nor the Staff will know what the capacity factor for each product is likely to be in any given future year. Thus, Staff could not compute a single bid price number such as a total cost per kWh from the bid data alone.

Q. HOW COULD THE STAFF COMPUTE A CAPACITY FACTOR FOR EACH PRODUCT BID IF IT WANTED TO DO SO?

A. If the Staff wanted to compute a capacity factor for each product bid, it would have to use a generation dispatch model to do so for each year covered by the bid. However, in order to get meaningful results for each capacity factor, the model would have to be run with enough total capacity of different products and bids to fully meet the load plus reserves, in each year. In fact, the resulting capacity factors would only be meaningful if enough new capacity is added to the existing capacity to meet the total load plus the required reserve margin. A complicating issue is, though, that the capacity factor of each bid will change depending on which other bids or products are included in the total new capacity added. Thus, the capacity factor for any given bid or product in any given year will, in general, depend on the mix of all the other products or bids included to make up enough capacity to meet the total load plus required reserves.

Q. HOW, THEN, WOULD THE STAFF KNOW WHICH OTHER BIDS SHOULD BE INCLUDED IN A DISPATCH MODEL RUN IN ORDER TO COMPUTE THE CAPACITY FACTOR FOR ANY SPECIFIC BID?

A. There would be no way for the Staff to know which set of other bids to include in running a dispatch model in order to determine the correct capacity factor for any given bid in order to compute a "price to beat", or any other single price number, for each bid. (Note that while the Staff proposes to compute the "price to beat", the utility will actually be selecting the resource bids that it believes should be included in its resource mix for the future.)

Q. HOW CAN WE GET AROUND THIS APPARENT "CHICKEN AND EGG" PROBLEM THAT ARISES WHEN ONE ATTEMPTS TO COMPUTE A "PRICE TO BEAT", SO THAT THE BEST SET OF BIDS CAN BE SELECTED IN ORDER TO RESULT IN THE LOWEST REASONABLE RATES?

A. This Staff idea of trying to develop a single number to describe the price of each bid does inevitably degenerate into a hopeless spiral. To be clear, it is a "chicken and egg" type of situation because one cannot know which comes first, the capacity factor of a particular product, or the mix of other products or bids. But there is a simple, logical way out of this loop. Least-cost planning was developed precisely to solve this mathematical problem. The problem arises when one has a set of existing generation resources, and when one then wants to minimize the overall cost of adding new generation resources to the total system. The mathematical problem that we need to solve is to simultaneously find the cost minimizing mix of new generation resources or bids that should be selected out of a much larger set of offered bids, given the variable production costs of operating the current mix of generating units.

To slightly oversimplify, each existing resource is characterized by a variable cost to operate in each year. Each new resource or bid is characterized by a fixed and variable cost component, if we add it to the system in the future. Existing resources have no fixed costs for the purpose of this calculation because they have already been included in ratebase. Thus, the mathematical problem is to compute the total cost of all combinations of new and old resources so that one can find the mix that minimizes the total cost. That combination of new resources is called the least cost plan, or the least cost mix of new resources.

Q. IS THERE ANY OTHER WAY OF EVALUATING BIDS WITH RESPECT TO PRICE IN ORDER TO END UP WITH REASONABLE RATES?

A. No. This is not a new issue. Every state and every utility has had to deal with least cost planning in the past, either implicitly or explicitly. In the past, Arizona defined in its Integrated Resource Planning Rules (IRP Rules) R14-2-701-704 (portions of the IRP Rules were suspended in 1999) how prudent planning for new resources should be done. Those Rules provided that new resources should be determined on a least-cost planning basis subject to various policy constraints that the ACC may determine. Section R14-2-703F of the IRP Rule states that the resulting plan should "tend to minimize the present value of the total cost of meeting the demand for electric energy services." Though portions of the IRP Rules have been suspended, the process they establish is a good way to accomplish the goal of selecting those resources that would imply the lowest reasonable electric rates.

Q. ON PAGE 39 OF THE STAFF REPORT IT IS STATED THAT THE BID SELECTION PROCESS PROPOSED BY STAFF "IS COMPREHENSIVE AND BASED ON SUCCESSFUL MODELS FROM OTHER JURISDICTIONS" AS MODIFIED BY THE UNIQUE CIRCUMSTANCES IN ARIZONA. DO YOU AGREE?

A. No. I do not agree that the process proposed by Staff is modeled on successful models from other states. For example, there is no state in the US that uses a "price to beat" in the sense that the ACC Staff seem to mean. The term "price to beat" has often been used in other states simply to mean the generation component of unbundled retail rates once retail competition has been established. Yet, that is not what staff means by its use of the term "price to beat."

Secondly, at the fairly general level of discussion thus far in my testimony, there is nothing unique about circumstances in Arizona that would fundamentally affect what planning process should be used. In fact, as the Staff discusses in some detail beginning on page 43 of the Staff Report, several other states use competitive solicitation processes to determine how the load of each distribution utility will be met at the lowest reasonable rates.

Q. DO OTHER STATES USE LEAST COST PLANNING PROCESSES TO SELECT THEIR GENERATION BIDS?

A. Yes. Whether or not states that rely on the competitive generation market currently call their resource selection process a "least-cost" process, or not, the process is always a "least cost" process in some fundamental sense. It is quite surprising that the Staff's description of the resource selection process in the eight states discussed on pages 43-49 of their report does not make this clear. For example, the situation of Colorado is almost identical to the situation currently found in Arizona (utilities are acquiring power for retail customers on the wholesale market.) Yet, under the current integrated resource planning (IRP) rules in effect in Colorado, the utilities perform least cost planning by minimizing the present value of revenue requirements subject to various constraints, over a fairly long planning period, e.g., 20 years, or more. I know this because I testified in the last IRP case held for Public Service Company of Colorado.

Furthermore, in the 1980s and early 1990s, the term integrated resource planning and least-cost planning were almost synonymous, and these formal planning processes were used by public utilities commissions in many, if not most, states throughout the US. For example, the state of Florida uses a planning process that determines "whether the proposed plant is the most cost-effective alternative available", as Staff states on page 44. Here "cost-effective" is just another way of saying "least-cost".

Q. WHAT DO THE OTHER SIX STATES, DISCUSSED BY STAFF, THAT HAVE ALREADY ADOPTED RETAIL COMPETITION DO TO SELECT NEW RESOURCES FOR THEIR STANDARD OFFER CUSTOMERS?

A. Basically, each of these other states either leaves the resource selection process up to the distribution utilities because standard offer rates are capped, or the state PUCs oversee a competitive solicitation process for all, or slices, of the system load. But this second group of processes is also explicitly a least cost process, in the sense that the average cost of power selected is minimized, even though there are price caps. Clearly, the distribution utilities want to pay as little as possible for generation at the wholesale level. However, the situation is not the same in Arizona currently. The Commission has decided to have the competitive solicitation process not be for the total load or for a slice of the entire system load. Instead, the Commission has determined that the competitive solicitation process should be for new resources needed over and above the amount of power that each utility's current resources can provide. Thus, as noted above, the current situation in Arizona is most similar to that of Colorado, among the eight states discussed in the Staff Report. Of course, the current situation in Arizona is also fairly similar to the current planning situation faced by most utilities that have not moved to retail competition, and many states still have least-cost planning or IRP processes in place for those utilities to follow. In fact, I am currently directly involved in the IRP processes that are on going in both Utah and Wisconsin. In particular, PacifiCorp, Arizona's neighboring utility to the north, has just completed a draft IRP report that I am reviewing. I can assure the ACC that

PacifiCorp follows least-cost planning principles by stressing the resource mix that has the lowest present value of revenue requirements over a planning period for its selection process.

Q. IN CONCLUSION, DOES THE STAFF REPORT PROVIDE AN ADEQUATE DESCRIPTION OF A METHODOLOGY THAT COULD BE USED BY ARIZONA UTILITIES TO CARRY OUT THE ACC'S MANDATE FOR A COMPETITIVE RESOURCE SOLICITATION PROCESS?

A. No, it does not. The Staff Report does not describe any logical and complete methodology at all for this purpose. The Track B solicitation process must be reconfigured to be consistent with traditional least-cost planning practices, as described in the next section.

III. A LEAST-COST PLANNING PROCESS FOR ARIZONA

Q. HOW SHOULD THE COMPETITIVE SOLICITATION PROCESS IN ARIZONA BE STRUCTURED?

A. The competitive solicitation process should be structured in a way to assure that Arizona ratepayers will end up paying the reasonably lowest electric rates that are feasible given the various physical, policy, and legal constraints faced by each distribution utility. In theory, all three basic types of electricity "resources" should be included in the process, namely generation, transmission, and demand-side investments in more efficient end-use equipment (DSM). If any one of these key types of resources is excluded, then electric rates will be higher than is reasonable.

For example, the Staff Report primarily focused on the need to evaluate generation bids from the wholesale generation market, with agreement that DSM bids would also be allowed. However, the Staff Report did not describe how new transmission investments would be evaluated in relationship to the generation or DSM bids. Because Arizona has several significant "load pockets" or load centers that are highly transmission constrained in many hours of the year, new transmission investments to relieve some of these constraints should be evaluated on a self-consistent basis with the generation and DSM bids. It is possible, if unlikely, that new baseload resources built outside a load pocket, plus a new transmission line into the load pocket from these resources, would be lower in cost than generation bids received from units built within the load pocket.

Similarly, it is possible that new DSM investments could significantly defer the construction of new generation or transmission construction in some areas within Arizona. Thus, I believe that it is important to take time now to set up a comprehensive and appropriate planning process for Arizona utilities, similar to the one that had been followed in the past, rather than rush to create a process that would tend to increase electric rates above a reasonable level.

Another key ingredient of an appropriate planning process for Arizona utilities would be for the regulated utilities themselves to bid to supply new generation, transmission, and DSM on a regulated cost-of-service basis. If these <u>regulated</u> costs for service from the three basically different kinds of resources are not included in the mix of options that could be chosen, there will be no "competitive baseline" against which to measure the economics of bids from the <u>unregulated</u> wholesale market. If the unregulated market bids can beat the regulated cost-of-service bids, then the wholesale market will have proven that it can be competitive, in the sense of being lower in cost and more efficient than regulated utilities. However, if the regulated cost-of-service bids are lower than the market-based bids, then Arizona ratepayers ought to be able to continue to benefit from the ability of vertically integrated utilities to provide electricity at a lower price. The "bottom-line" is that an appropriate Track B competitive solicitation process for Arizona could be similar to the suspended Arizona IRP rules.

Q. IS IT LIKELY, OR EVEN POSSIBLE, THAT MARKET-BASED BIDS FOR GENERATION COULD BEAT REGULATED COST-OF-SERVICE BIDS AT THE PRESENT TIME?

A. It certainly is possible that at the current time market-based bids for wholesale electric power could beat regulated bids for the same types of products. This is because the IPP industry is particularly stressed financially at the current time, so there may be some very good, fairly long-term contracts for power available now. In fact, this next year, during which Arizona's competitive solicitation will be held, may be a very good time in which to lock up some low cost, long-term purchased power contracts. On the other hand, it may also be a good time for Arizona's utilities to buy one or more power plants currently under construction in or near Arizona on a "fire-sale" basis, at a regulated cost of capital. Whatever the lowest cost way of providing wholesale electricity to Arizona's electric ratepayers is, that is the approach that should be relied on, assuming system reliability and other factors are maintained at sufficiently high levels.

On the other hand, if wholesale market participants believe that the current financial crisis will be short lived, they may hold out for fairly high prices, unless they know that they are going to have to compete against regulated cost-of-service prices for new generation. This might happen because once the financial crisis in the IPP industry is mitigated, investors in that industry may demand much higher returns on their capital investments than regulated utilities would receive. Thus, in the long run there is a strong likelihood that the cost of IPP generation may be significantly above the cost of generation provided on a regulated cost-of-service basis. This is why it is very important to provide ratepayers with a competitive baseline, or ceiling on the price that they will have to pay, as a result of the competitive solicitation process established in Arizona. The regulated alternative to the wholesale market must be preserved as an option as part of this solicitation process, or ratepayers will overpay for electricity and Arizona's economy will suffer as a consequence.

Q. HOW SHOULD THE CONCEPT OF "LEAST-COST" BE INTERPRETED AS PART OF LEAST-COST PLANNING?

A. The concept of "least-cost" has almost always been interpreted to mean the lowest present value of revenue requirements (PVRR) over a given planning period. This was true in the suspended IRP rules for Arizona. (See rule R14-2-703F.) An appropriate planning period should be at least 20 years long. A 30-year planning period might even be better because it corresponds more closely to the operational lifetime of new power plants. Of course, to compute the present value of revenue requirements over time requires the use of a discount rate. Typically, the discount rate used is the utility after-tax cost of capital, since that reflects the time value of money to utility stockholders. Alternatively, the Commission could decide to use a ratepayer discount rate, which would typically be higher than the after-tax cost of capital to a utility. The Commission may also want to consider adopting part or all of the Colorado PUC's IRP rules, which are currently undergoing revision, to define this least-cost planning process. (See the PUC website for details under Docket No. 02R-137E.)

Q. WHY DOES THE PLANNING PERIOD HAVE TO BE AS LONG AS 20 YEARS, IF MOST COMPETITIVE GENERATION MARKET BIDS ARE ANTIPATED TO BE OF MUCH SHORTER DURATION? THE STAFF REPORT DID NOT EVEN MENTION THE NEED FOR A LONG PLANNING PERIOD TO EVALUATE WHOLESALE MARKET BIDS.

A. The planning period needs to be at least 20 years in order to capture the long-run trade-offs between fixed and variable costs which represent the different kinds of new generation or DSM resources that could be purchased. If the planning period were only a few years, then the lower capital investments per kilowatt, such as new peaking units, would probably appear least cost in the short run even though they might be very expensive for ratepayers in the long run. Thus, the use of a planning period that is too short would tend to bias the results of a least-cost planning analysis. The use of a longer planning period allows low cost short-term contracts to be selected as part of a least-cost plan, but would not preclude investments or contracts that might be more expensive in the short-run but have a lower in cost when averaged (in present value terms) over the entire planning period.

When a least cost planning exercise is run using a computerized optimization model, as is necessary, proxy new plants also need to be included for the long run, namely for later in the planning period when the new resource bids would no longer be sufficient to fully meet the load growth that is projected for the relevant region. For example, if the currently planned competitive solicitation is structured in a way to select resources that will meet existing load plus load growth for the next four years, as Staff proposes, then the resource bids might be from anywhere from 1 year to 30 years in duration. The duration of the proposed contracts is not important, so long as a mechanism is in place to fairly evaluate the bids relative to each other independent of their duration. This is why the proxy plants noted above are necessary as "filler" resources. There would need to be a proxy peaking unit, cycling unit, and baseload unit that could, in theory, come on-line in any year of the planning period, as soon as it could be constructed. By a "proxy" plant, a realistic alternative, I mean a set of plants that could be actually sited where needed, at the cost assumed, to serve the loads of Arizona utilities. The computer model used in least cost planning would then select the lowest cost combination of contract bids and proxy plants over the entire planning period. The costs of the proxy plants should represent the costs for constructing and operating those types of units on a regulated basis, since those costs would provide a maximum or ceiling price on what would have to be paid for that "product" or type of power plant. These proxy plant costs would be determined by the regulated utility's bids for those types of units on a regulated cost-of-service basis required as part of their solicitation process. If, over the next four years, enough of the wholesale market bids were selected by the model as being part of the least cost plan to satisfy their total load, then contracts for those bids would be signed, and no proxy plants would need to be constructed on a regulated basis. If, however, the optimization model selected some bids and some proxy plants, then both types of actions would need to occur. The same optimization model could also be used to select cost-effective DSM resources.

Q. WHAT SHOULD BE DONE TO PREVENT A SITUATION WHEREBY THE MARKET PARTICIPANTS DID NOT BID ALL REASONABLY COST-EFFECTIVE DSM MEASURES INTO THE SOLICITATION PROCESS?

A. It is important to structure the solicitation process in a way that insures that the end result (the least-cost plan) will include a significant amount of cost-effective DSM. If the plan actually implemented did not reflect a significant fraction of all possible cost-effective DSM over the next few years, then not only would electric rates be higher than necessary in the long run, but the environmental impacts of power plant and transmission line siting, and plant operations would also be greater than necessary. To ensure that sufficient amounts of cost-effective DSM will be bid into the proposed solicitation process, the Commission should require the regulated utility to also bid DSM programs on a regulated cost-of-service basis, just as they would submit bids for generation resources. The types of DSM programs bid should be broad in variety, and should be programs for all customer classes, particularly programs for low-income residents. Load management as well as energy conservation programs should be bid. The types of DSM programs bid might include fairly expensive DSM programs that may or may not turn out to be cost-effective, which means that they may not be part of the least-cost plan chosen. As a guideline for utilities in a high growth region like Arizona, each distribution utility involved in a competitive solicitation process should bid incremental or new DSM programs that would reduce its peak load each year by up to 2 percent on a successive basis. This should provide enough new DSM program options to choose from each year in order to yield a reasonable least cost plan over the long run. Perhaps about 1 percent in DSM caused load reductions would actually be shown to be cost-effective.

Q. IN ITS ANSWERS TO INTERROGATORIES, ARIZONA PUBLIC SERVICE STATED THAT IT COULD PROBABLY PURCHASE A SIGNIFICANT AMOUNT OF ECONOMY PURCHASES OVER THE NEXT FOUR YEARS TO REPLACE SOME GENERATION FROM ITS CURRENT GENERATING UNITS. HOW SHOULD POSSIBLE ECONOMY PURCHASES BE DEALT WITH IN THIS SOLICITATION PROCESS?

A. Again, the Staff Report did not deal with the issue of how economy purchases should be dealt with as part of the solicitation process. How to treat economy purchases is a potential issue in a competitive solicitation process because economy purchases are different from other purchases that could be made from the wholesale generation market on a longer-term bilateral contract basis. In APS response MR 1.5, which is part of Appendix II to the Staff Report, APS stated that it "expects to procure a certain amount of economy energy in each of these years [2003-2007] depending solely on the actual energy cost of APS resources compared with market prices for power." Then, APS provides an estimate of how much economy energy might be available in each year.

Q. PLEASE DEFINE WHAT "ECONOMY ENERGY" IS, AND EXPLAIN WHY THIS RAISES A NEW ISSUE THAT IS RELEVANT TO THE SOLICITATION PROCESS.

A. Economy energy is power purchased from the regional utility grid on a fairly short-run, basis at a lower price than it would cost to operate its marginal generating units. Because economy energy is purchased on an "as available" basis that cannot be planned for very far ahead of time, a utility cannot rely on economy energy to meet its peak demand requirements. In fact, economy energy is least likely to be available during times of peak demand. However, the benefit of economy energy is its low price when it is available.

The reason why a utility's ability to buy economy energy raises an interesting issue is that because economy energy can save the utility money. The mere existence of a competitive solicitation process should not preclude spontaneous purchases of economy energy when it is available. On the other hand, since a utility cannot plan on economy purchases being available on a firm basis, the existence of economy energy should <u>not</u> subtract from the energy requirements that a utility would have based on the availability of its own generating resources. Thus, APS' figures for their energy requirements that appear on their attachment to MR 1.5 should still be valid even taking their projections of the availability of economy energy into account. The Commission should recognize the benefits that purchases of economy energy have for all ratepayers, and the competitive solicitation process should not ban such purchases outside of that process.

Q. DOES THIS MEAN THAT THE COMPETITIVE SOLICITATION PROCESS CAN COMPLETELY IGNORE THE POSSIBILITY OF ECONOMY ENERGY PURCHASES IN THE FUTURE BECAUSE THEY WILL HAVE NO IMPACT ON THE PROCESS?

A. No. The possibility of making significant amounts of economy purchases can influence the mix of new resources that would be part of a least-cost plan. By reducing the cost of the energy component, or the variable cost component, of rates to customers, the existence of economy energy tends to make new baseload resources less cost effective relative to other types of resources. This is because economy energy tends to substitute for new baseload resources to some extent by making the energy component of electric production somewhat cheaper. Thus, realistic assumptions about the availability of economy energy in each year should be included when running a least-cost planning optimization model. Because economy energy can more likely substitute for baseload resources, but not likely for peaking resources, the availability of economy energy will tend to shift the least-cost mix of new resources towards new peaking resources and away from new baseload resources.

Q. CAN A LEAST-COST PLANNING MODEL INCLUDE THE ANALYSIS OF THE ECONOMICS OF NEW TRANSMISSION INVESTMENTS SIMULTANEOUSLY WITH THE ECONOMICS OF NEW GENERATION AND DSM INVESTMENTS? IF NOT, HOW SHOULD THIS EVALUATION BE HANDLED AS PART OF THE COMPETITIVE SOLICITATION PROCESS IN ARIZONA?

A. The commercially available least-cost optimization models of which I am aware are not sophisticated enough to evaluate the economics of new transmission along with new generation and DSM. Thus, Arizona utilities should utilize an iterative process between running a least-cost optimization model for evaluating only the generation and DSM bids, and analyzing the economics of new transmission separately.

In order to make this assessment, the optimization model could first be run with no new transmission lines assumed. Then, if the generation bids that turn out to be part of the least-cost plan can all be accommodated sufficiently (i.e. transmitted to the load centers) without any new transmission lines being built, the bid evaluation process would be complete. On the other hand, if a generation bid that is initially part of the least cost plan would require new transmission to serve native load, then the costs of building that new transmission would need to be included in the total PVRR of that scenario. If the total PVRR of that scenario were less than the total costs of all other mixes of generation and DSM bids that do <u>not</u> require new transmission, then building this transmission line would be part of a least-cost plan. However, if another mix of generation and DSM bids has a lower PVRR than the total cost of the scenario that includes new transmission, then no new transmission is needed, and that alternative mix of generation bids should be selected. (Note that being part of a least-cost plan defines the word "need" in this context.) Again, this process is not new. It is how prudent utility planning has usually been done in the past.

Q. GIVEN THE NEED TO STRUCTURE BID EVALUATIONS AROUND A LEAST-COST PLANNING CONCEPTUAL FRAMEWORK, WHAT DO YOU RECOMMEND FOR THE SCHEDULE OF THE RESULTING TRACK B LEAST-COST PLANNING PROCESS?

A. Unfortunately, even if one could rely on bids from the wholesale power market for 100 percent of the new resource to be evaluated (which one cannot), the appropriate Track B bid evaluation process is somewhat more complicated than

Staff suggests. Thus, somewhat more time than Staff has allowed for in their proposed schedule will be required to re-design a reasonable process. Because of this unavoidable situation, I recommend that the competitive solicitation process not be used to provide energy and capacity for the summer of 2003. I recommend that the distribution utilities use a more *ad hoc,* but prudent, planning process in order to cover their needs for next summer. The more formal competitive solicitation process could begin for resources required for 2004-2006 at one time, once the process has been properly structure.

Obviously, if developing the details for a proper least-cost planning process can be done in time to acquire resources for the summer of 2003, then, of course, that period could be included. But it is far more important to get the solicitation process structured properly for the long run, than to rush the process through to completion too quickly. Too much ratepayer money is at stake in the long run to not get the details of the solicitation process right for the current Track B process. My recommendation might also imply that the distribution utilities should focus on acquiring fairly short-term firm power contracts to cover their needs through 2003, unless an obviously super-good deal comes their way on a longer-term basis. Of course, least cost planning would also have to be used by the utility to evaluate such a long-term bid.

Q. SHOULD A LEAST-COST PLANNING PROCESS, IF DONE CORRECTLY, HAVE ANY IMPLICATIONS FOR THE PRUDENCE OF THE RESULTING INVESTMENT COMMITMENTS ON THE PART OF THE REGULATED UTILITIES INVOLVED?

A. Yes. Any contract or build order for new resources that results from the Commission's review and approval of an appropriate least-cost planning process should convey to the regulated utilities the presumption of prudence (this is the case in Colorado). After all, what is determined in the least-cost planning process is the same thing the utilities need to demonstrate in a later review of planning prudence for cost recovery purposes. Presumably, there would be two kinds of prudence issues raised in any cost recovery review. The first would be the prudence of planning. Clearly, this would be covered by the initial bid evaluation process if my recommendations are adopted, so it would not be fair for the Commission to second guess the <u>initial</u> planning process. The second prudence issue would whether the utility acted prudently based on whatever information became available <u>after</u> the initial planning process was completed, both to implement the least-cost plan and to adjust the plan if required due to this new information. This second prudence issue should be reserved for the final cost recovery hearing, but the first issue should not be reopened.

Q. IN LIGHT OF THE LIKELIHOOD THAT THE TYPE OF LEAST-COST PLANNING PROCESS THAT YOU RECOMMEND CAN NOT BE CARRIED OUT FOR RESOURCES FOR THE SUMMER OF 2003, HOW SHOULD THESE TWO PRUDENCY ISSUES BE ADDRESSED FOR THOSE RESOURCES?

A. If the resources needed for the summer of 2003 cannot be evaluated as part of the final least-cost solicitation process developed, then both types of prudence issues would need to be reviewed as part of the Commission's cost recovery hearings for those resources, unless no contracts for those resources extended beyond July 1, 2004 for APS and January 1, 2005 for TEP. The prudence issues may not need to be addressed by the Commission at all if none of these contracts extend beyond those dates, because the retail rates for these two utilities are frozen during those time periods, and thus it will be in the interest of those utilities' stockholders to minimize wholesale power costs until new retail rates are set by the Commission to come into effect after those dates.

Q. COULD THE COMMISSION JUST LIFT THE SUSPENSION OF THE EXISTING IRP RULES IN ARIZONA IN ORDER TO BEGIN TO REDEFINE AN APPROPRIATE LEAST-COST PLANNING PROCESS FOR USE AS A COMPETITIVE SOLICITATION PROCESS?

A. Yes, the Commission could lift the 1999 suspension of the existing IRP rules in order to provide a basis for a least-cost competitive solicitation process for use next year. However, I would suggest that the old rules be reviewed for any revisions that may be desirable under the current circumstances. In particular, the old rules should be reviewed to make sure that they fully allow for any potential benefits from the competitive wholesale generation market to be captured for Arizona's ratepayers. However, section R14-2-703D of the old rules did include the need to evaluate potential purchased power contracts as part of doing least-cost planning, so not much modification to the old rules may be required.

IV. CRITIQUE OF APS AND TEP TESTIMONY

Q. PLEASE SUMMARIZE MR. CARLSON'S TESTIMONY AS TO HOW APS PLANS TO CARRY OUT ITS TRACK B SOLICITATION PROCESS.

A. Mr. Carlson calls for a "multi-layered procurement effort". APS would issue an RFP to solicit bids for three specific "products", i.e. types of electric generation. Unfortunately, APS is prejudging the entire bid selection process, and is proposing to limit the types of products solicited to peaking products only. Thus, APS is not proposing to solicit any cycling or baseload products, even if there might be some very low cost products of this type available for the short-run or long-run. The reason why APS is only proposing to solicit peaking products appears to be because the load factor of their unmet reliability needs is very low, like a peaking product. While APS' plan may correctly yield a least cost outcome, it also might not. For example, it could be the case that in the current financially stressed generation market, some baseload products would be available that could provide both capacity for peak demand, and would also save enough in energy costs from some of APS' existing generators to be even more economically desirable than a peaking product.

Furthermore, it is very important to point out that APS does not explicitly support a long-run least cost planning approach to evaluating its Track B resource bids. In fact, APS is not planning to solicit any products for the long run, so it would not even be able to determine if long-run products offer a better deal for ratepayers than short-run products. Mr. Carlson states that APS will only select bids for up to four years in duration. (Page 9)

Q. DOES APS' RELUCTANCE TO SOLICIT BASELOAD AND CYCLING PRODUCTS ILLUSTRATE ANOTHER CONCEPTUAL PROBLEM WITH THE SOLICITATION METHODOLOGY PROPOSED IN THE STAFF REPORT?

A. Yes, APS seems to just be following the Staff methodology in bidding out only the unmet amounts of capacity and energy that its own generating units cannot provide. This is what they call their "unmet reliability needs". This is the right approach to take for bidding capacity, but there is no good reason to limit the amount of energy bid out to the amount of energy that cannot be generated by the company's own generating assets. Soliciting bids for generating capacity is more fundamental, because once a utility has enough capacity, the dispatch of that capacity, which yields the amount of energy needed from each generating unit, will be determined by the variable cost for each MW of capacity and the demand in each hour. Thus, bids should be solicited for all types of capacity - low, medium, and high cost capacity, with low, medium, and high variable costs.

The least-cost planning process, through the use of a dispatch model, will determine how much energy should come from each kind of capacity. Again, it may be cheaper, as indicated above, for some of the energy that could have been produced by a utility's generating units, to be displaced by lower variable cost capacity that would be bid into a well-constructed solicitation process. Whatever solicitation process is used, the bids solicited by each distribution utility should not be limited with respect to the total amount of energy requested. The amount of energy that it is optimal to take each year from each capacity option offered will automatically be determined as an outcome of the least cost planning process, if one is used.

Q. WHAT DOES MR. CARLSON SAY ABOUT HOW APS WILL DETERMINE THE PORTFOLIO OF RESOURCES THAT WILL RESULT FROM THE TRACK B PROCESS?

A. Mr. Carlson is not at all clear as to what methodology APS will use to select its final resource portfolio as a result of the Track B process. On page 16 of his testimony, Mr. Carlson states "there is no magic formula, and if there were, I would not disclose it to potential suppliers in this public forum." "You study the market (both present and future), weigh credit considerations, evaluate regulatory risk, and factor in the inherent uncertainty of any load forecast." (Page 16) While I do appreciate the desire of APS to be able too exercise sound business judgment as part of the Track B process, APS also needs to understand that judgment alone is not a prudent way of selecting a final resource portfolio. This is why formal least-cost planning or IRP methodologies were developed by the utility industry, and why Arizona had IRP rules in force in the past. A <u>systematic</u> resource selection methodology is required to yield reasonable electric rates. The Commission cannot allow APS, or any other utility, to just use their judgment in this unspecified way. To do so would not represent prudent planning.

Q. DO YOU HAVE ANY CONCERNS ABOUT THE BID EVALUATION PROCESS THAT MR. HUTCHENS PROPOSES FOR TEP?

A. Yes, I do. On the whole, TEP's proposed approach for their bid evaluation process is much better than APS' proposed approach. On page 4 of his testimony, Mr. Hutchens acknowledges that the amount of energy that might be acquired as a result of the bid evaluation process could be greater than the amount of energy included in the "contestable load," which is the energy that could not be produced by the company's generating assets. In addition, on page 10, Mr. Hutchens states that TEP will perform "a least cost analysis of the bids." It is only after that least-cost analysis is completed that TEP will determine how much of the capacity and energy from each bid to purchase. This is the correct logical sequence for carrying out a bid evaluation process.

However, one concern that I have with the TEP process is that TEP still seems to be significantly limiting the types of generation products that they will solicit. These products are listed on lines 7-10 of Mr. Hutchens' testimony. While the range of products listed here appears to be somewhat broader than the range of products that APS has proposed soliciting, there should be no limitations placed on the types of products that either TEP or APS should solicit. I believe that Arizona's utilities should solicit all the potentially favorable types of electric generating capacity and products that the wholesale market will offer, and then determine the most cost-effective types of bids to accept during the least-cost planning process. By definition, if any types of bids are prematurely excluded, the resulting least-cost portfolio will not have as low a cost as it might otherwise have had. It is also not clear from Mr. Hutchen's testimony what range of durations over which TEP will solicit bids. But, again, I urge the Commission to require that all distribution utilities seek a full range of durations for bids, because there may be some good long-term bargains available now that could help these utilities meet their load growth over a longer period than just 2003-2006. By comparing the bids received from the wholesale market to cost-of-service based bids for new utility-owned generation resources that I believe the Commission should require from the regulated utilities themselves in the context of a least-cost planning process, the utilities will be able to determine if it is a good time to make some longer term purchases.

Q. DO YOU AGREE WITH TEP THAT THEY SHOULD BE ABLE TO INCLUDE THE TWO COMBUSTION TURBINES COMPLETED IN THE SUMMER OF 2001 TOTALING 95 MW IN THEIR LIST OF EXISTING ASSETS?

A. Yes, I do. I cannot understand why it would not be appropriate to include these two relatively new units in TEP's list of existing generating resources for the purpose of determining TEP's remaining capacity needs to be bid out. This is especially true since TEP constructed these generating units within their regulated utility affiliate.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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Education

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Experience

1998-2001	Director of Energy Group, Tellus Institute
1997-present	Manager of Electricity Group, Tellus Institute.
1993-1997	Director of Energy Group, Tellus Institute.
1991-present	Director of Planning, Tellus Institute.
1977-present	Energy Group. Responsibility for a broad range of research on integrated resource planning energy conservation; electric generation planning issues; and modeling studies of long-range energy demand, utility system reliability, energy demand curtailment, and environmental externalities and energy planning.
1978-1980	Consultant to Brookhaven National Laboratory.
1979	Consultant to the National Academy of Sciences, Puerto Rico Energy Study Committee.
1976-1978	Assistant Physicist, Economic Analysis Division, National Center for the Analysis of Energy Systems, Brookhaven National Laboratory.
1974-1976	National Research Council - National Academy of Sciences Resident Research Fellow, Goddard Institute for Space Studies, New York.
1973	Instructor, Putney - Antioch Graduate School.

Testimony

Agency	**Case or Docket No.**	**Date**	**Topic**
Public Service Commission of Wisconsin	05-CE-117, 05-CE-130, 05-AE-109 (Tellus 02-070)	August 2002	Review components of Phase I of proposed Power The Future investment plan; recommend changes in assumptions and methodology to improve WEPCO's Application for both Phase I and Phase II
		September 2002	Surrebuttal testimony in above dockets
Arizona Corporation Commission	E-00000A-02-0051 (Tellus 02-072)	May 2002	Market Power in the Context of Deregulated Electricity Markets
Arizona Corporation Commission	E-04345A 01-0822 (Tellus 01-199)	March 2002	Arizona Public Service Company's Request for a Variance of Certain Requirements of A.A.C. R14-2-1606
Arizona Corporation Commission	E-01032C-00-0751 (Tellus 00-172)	February 2002	Citizens Communications Company wholesale purchased power costs
United States District Court for the Southern District of Ohio – Eastern Division	C2-9901181 (Tellus 00-205)	November 2001	Evaluation of whether Ohio Edison should have forecasted that 11 activities undertaken at W.H. Sammis plant would cause net emissions increases exceeding the allowable Clean Air Act thresholds for SO_2, NO_x, and PM_{10} at the time the activities occurred
		August 2000	Supplemental Expert Testimony in above docket.
Colorado Public Utilities Commission	00A-600E (Tellus 00-204)	March 2001	Review of evidence filed by Public Service Company of Colorado in support of a proposed transmission line and high voltage DC converter between Lamar, CO and Holcomb, KS
Wisconsin Public Service Commission	05-CE-113 (Tellus	Nov. 2000	Review and critique of Application supporting construction of Arrowhead-

	99-207)		Weston transmission line
		Dec. 2000	Sur-rebuttal Testimony in above docket
Colorado Public Utilities Commission	99A-549E Phase I (Tellus 00-128)	Nov. 2000	Review of the adequacy of PSCo's selection of the electric generation resource bids that it has chosen for its final IRP plan
Colorado Public Utilities Commission	00A-007E (Tellus 00-021)	March 2000	Review of methodologies on which PSCo's summer peak demand and sales forecasts are based, and recommendations how its load forecasting could, and should, be improved
New Hampshire Public Utilities Commission	DE99-099 (Tellus 99-136)	Dec. 1999	Discussion of the Transition Service Energy Charges that might be applied in New Hampshire
New Hampshire Public Utilities Commission	DE 99-099 (Tellus 99-136)	Nov. 1999	Non-rate design aspects of the proposed Settlement Agreement between PSNH and the State of New Hampshire
Delaware Public Service Commission	99-457 (Tellus 99-145)	Nov. 1999	Analysis of the stranded cost-related issues in the Delaware Electric Cooperative, Inc.'s filing and sponsoring of an estimate of stranded costs for the DEC
		Dec. 1999	Rebuttal testimony
Federal Energy Regulatory Commission	EC97-56-000 ER97-4669-000 (Tellus 97-230)	Sept. 1999	Description of, and results of, an independent analysis of market power performed to demonstrate potential impact on regional electricity prices of proposed KCPL/Western Resources merger, and to illustrate several key aspects of how market power analysis for a merger should be done
Arizona Corporation Commission	RE-00000C-94-0165 (Tellus 98-147)	July 1999	The status of settlement discussions between Residential Utility Consumer Office (RUCO) and Citizens Utilities Company-Arizona Electric Division, and summary of concerns about CUC-AED's stranded cost recovery plans

Public Utilities Commission of New Hampshire	DR 96-150 (Tellus 98-237)	June 1999	Clarification of the regulatory policy implications of the New Hampshire Supreme Court decision of December 23, 1998, as it applies to the future recovery of stranded costs in the rates that the PUC will set for Public Service of New Hampshire
Missouri Public Service Commission	Case No. EM-97-515 (Tellus 97-230)	April 1999	Review and critique of the analyses of market power specific to the proposed merger of Kansas City Power & Light Company and Western Resources, performed by Dr. Robert Spann on behalf of the Applicants. Also a description of, and the results of, an independent analysis of market power performed in order to demonstrate the potential impact on regional electricity prices of the proposed merger.
Arizona Corporation Commission	E-01933A-98-0471; E-01933A-97-0772; E-01345A-98-0473 E-01345A-97-0773 and U-00000C-94-165. (Tellus 98-147)	November 1998	Analysis of various filings related to the unbundled service tariffs, stranded cost recovery proposals for Arizona Public Service and Tucson Electric Power Company, and various other aspects of their restructuring proposals
New Mexico Public Utility Commission	2867/2868 (Tellus 98-195)	November 1998	Application of Residential Electric Incorporated for a CCN to provide electric service and its request that Public Service of New Mexico offer transmission, distribution, and customer-related services, at unbundled rates
Public Utilities Commission of Nevada	98-7023 (Tellus 98-111)	November 1998	Analysis of stranded generation costs of Sierra Pacific Power Co. and the Nevada Power Co.; analysis of conditions under which competitive wholesale power markets could be created in Nevada, particularly given the severe transmission constraints in the state
Maine Public Utility Commission	97-580 (Tellus 98-007)	May 1998	Central Maine Power's proposed Standby rates and related policy issues
		August	Surrebuttal testimony in above docket

		1998	
Maine Public Utility Commission	97-580 (Tellus 98-007)	April 1998	Alternative estimate of value of stranded costs of Central Maine Power Company based on three changes to their methodology, and alternative estimate of CMP's non-utility generation stranded costs arising from the Regional Waste Systems purchased power contract
New Hampshire Public Utilities Commission	DR 98-012 (Tellus 98-019)	April 1998	Proposed Offer of Settlement in the Granite State Electric Company restructuring docket
New Mexico Public Utility Commission	2761 (Tellus 97-135)	April 1998	Investigation of the potential of using market pricing for the unbundled generation portion of rates in a way that will allow Public Service Company of New Mexico to realize the fair market value of its generation plant over the long run, beginning with the test year 1996
New Hampshire Public Utilities Commission	DE97-251 (Tellus 98-019)	March 1998	Evaluation of whether or not the proposed transfer of the generating assets and purchased power agreements of the New England Power Company to USGenNE is in the public interest for the citizens of New Hampshire
Arizona Corporation Commission	U-0000-94-165 (Tellus 97-289)	Jan. 1998	Public policy recommendations on key issues related to calculation, sharing, and recovery of stranded costs; presentation of "retail generation service" methodology for computing stranded costs
		Feb. 1998	Sur-Rebuttal testimony in above docket
New Jersey Office of Administrative Law	BPU EO9707-0465 OAL PUC-7309-97 BPU EO9707-0464 OAL PUC-7310-97 Tellus (97-203/A4)	Jan. 1998	The importance of pricing retail generation services for use in the appropriate methodology for making stranded cost calculations (Rockland Electric Company)

		March 1998	Sur-rebuttal Testimony in above docket
New Jersey Office of Administrative Law	BPU E097070 456 OAL PUC 7311-97 (Tellus 97-203/A6)	Nov. 1997	Importance of pricing retail generation services for use in the appropriate methodology for making stranded cost calculations (Atlantic City Electric)
New Jersey Office of Administrative Law	BPU EO9707 0459 OAL PUC-7308-97 BPU E09707 0458 OAL PUC-7307-97 (Tellus 97-203/A3)	Nov. 1997	Pricing of retail generation services relative to the appropriate methodology for making stranded cost calculations (Jersey Central Power & Light dba GPU Energy)
New Jersey Office of Administrative Law	BPU E09707 0462 OAL PUC-7347-97 BPU EO9707 0461 OAL PUC-7348-97 (Tellus 97-203/A1)	Nov. 1997	Pricing of retail generation services relative to the appropriate methodology for making stranded cost calculations (Public Service Electric & Gas Company)
		Jan. 1998	Sur-rebuttal testimony in above dockets
Public Utility Commission of Texas	473-96-2285 and 16705 Tellus 97-046)	Sept. 1997	Competitive issues
Michigan Public Service Commission	U-11283 (Tellus 97-093)	May 1997	Recommendations on key policy issues related to determining the appropriate division between transmission and local distribution facilities, and the appropriate cost allocations, as required under FERC Order No. 888 using FERC's seven-point test

Michigan Public Service Commission	U-11337 (Tellus 97-093)	May 1997	Recommendations on key policy issues related to determining the appropriate division between transmission and local distribution facilities, and the appropriate cost allocations, as required under FERC Order No. 888 using FERC's seven-point test
New York Public Service Commission	96-E-0898 (Tellus 97-009)	May 1997	Public policy recommendations on key issues related to stranded costs, a preliminary range of estimates of the stranded generation costs of Rochester Gas and Electric Corp., and public policy recommendations on key issues related to market structure, market power, and the likelihood of RG&E's proposed retail access program actually leading to competition
New York Public Service Commission	96-E-0897 (Tellus 97-009)	April 1997	Public policy recommendations on key issues related to stranded costs, a preliminary range of estimates of the stranded generation costs of Consolidated Edison Company of New York, Inc., and public policy recommendations related to market structure and market power
New York Public Service Commission	96-E-0891 (Tellus 97-009)	February 1997	Public policy recommendations on key issues related to stranded costs, a preliminary range of estimates of the stranded generation costs of New York State Electric and Gas Company, and public policy recommendations on key issues related to market structure and market power
Missouri Public Service Commission	EM-96-149 (Tellus 96-214)	Nov. 1996	Various issues related to market power
Federal Energy Regulatory Commission	EC96-10-000 (Tellus 96-050F)	Sept. 1996	Review of the joint application of Baltimore Gas & Electric Company and Potomac Electric Power Company for approval of their proposed merger and organization
Maryland Public Service Commission	8725 (Tellus 96-050)	July 1996	Review of the joint application of BGE and PEPCO for approval of their proposed merger and reorganization
Illinois Commerce	95-0551	March	Review of joint application of Central

Commission	(Tellus 95-302)	1996	Illinois PSC, CIPSCO Incorporated, and Union Electric Company for approval of their proposed merger and reorganization
Vermont Public Service Board	5724 (Tellus 94-064)	July 1994	Review of Central Vermont Public Service's planning for its power supply resources over the past 5 years and its management of its resource portfolio
Illinois Commerce Commission	94-0065 (Tellus 94-112A)	June 1994	Assessment of the extent to which Byron 2, Braidwood 1 and Braidwood 2 nuclear units may be considered used and useful for ratemaking purposes by Commonwealth Edison, and recommendation of an appropriate ratemaking treatment of the units based on this assessment
		July 1994	Rebuttal Testimony in above docket
Kansas Corporation Commission	180,056-U	February 1994	Oral Testimony (no written testimony) on establishment of IRP rules for electric and gas utilities
Public Utilities Commission of Hawaii	7257 (Tellus 93-144A3)	December 1993	Critique of HECO IRP plan. Recommendations re: better and simpler approach to taking environmental externalities into account in integrated resource planning
Arkansas Public Service Commission	93-132-U (Tellus 93-148)	November 1993	Review application of Arkansas Electric Cooperative Corporation (AECC) for a certificate of public convenience and necessity for the construction, ownership, operation, and maintenance of a hydro-electric generating facility at Dam No. 2 ("H.S. #2") on the Arkansas River
		January 1994	Sur-Rebuttal Testimony in above docket
Public Utilities Commission of Georgia	4152-U (Tellus 93-100)	August 1993	Review of ratemaking aspects of the Clean Air Act Compliance plans of Georgia Power Company and Savannah Electric and Power Company

Pennsylvania Public Utility Commission	A-110300 F. 051 (Tellus 92-026)	July 1993	Critique of certain aspects of the Joint Applicants' filing with respect to whether the Joint Applicants have satisfied the requirements of the Pennsylvania PUC's siting regulation
Public Utilities Commission of Ohio	91-635-EL-FOR 92-312-EL-FOR 92-1172-EL-FOR (Tellus 92-165)	April 1993	Comments and recommendations re: Cincinnati Gas & Electric Company's integrated resource plan submitted in the Company's 1992 Electric Long Term Forecast Report
Georgia Public Service Commission	4133-U, 4136-U (Tellus 92-078)	October 1992	Review of the need for new capacity on the Georgia Power Company, Savannah Electric & Power Company, and Southern Company system over the next three years, 1992-1995
Public Utilities Commission of Ohio	92-708-EL-FOR 92-1123-EL-FOR (Tellus 92-041A)	September 1992	Comment on Centerior Energy Corporation's integrated resource plan and Clean Air Act compliance plan submitted in the Company's Long Term Forecast Report; specific recommendations for action on behalf of the Company to improve components of its resource and Clean Air Act compliance planning process
Public Service Commission of the State of Georgia	4131-U, 4136-U (Tellus 91-266)	June 1992	Adequacy of the 1992 Integrated Resource Plans of Georgia Power Company (GPC) and Savannah Electric Power Company (SEPCO)
U.S. Bankruptcy Court - Manchester, NH	BK-91-11336 Chapter 11	March 1992	Adequacy of bankruptcy plan filed by New Hampshire Electric Cooperative, Inc.
Public Utilities Commission of Ohio	91-410-EL-AIR (Tellus 91-082)	December 1991	Ratemaking treatment of Cincinnati Gas & Electric Company's 39.63% share in the Zimmer plant under the jurisdiction of the Public Utilities Commission of Ohio (PUCO)

Public Utilities Commission of Ohio	92-418-EL-AIR (Tellus 91-091)	December 1991	Ratemaking treatment of Columbus Southern Power Company's 24.20% share in the Zimmer plant under the jurisdiction of the Public Utilities Commission of Ohio (PUCO)
Maine Public Utilities Commission	89-193, 89-194, 89-195 (ESRG 89-189B & 90-039)	August 1990	Review of Bangor Hydro-Electric Company's solicitation of bids with a request for proposals dated July 24, 1989, and its approach to the evaluation of the respondents' bids.
New Hampshire Public Utilities Commission	DF 89-085 (ESRG 90-051)	July 1990	Assessment of Eastern Utilities Associates' Plan to acquire UNITIL Corporation: Issues Affecting NH Consumers
		September 1990	Supplemental Testimony in above docket.
Florida Public Service Commission	891345-EI (ESRG 90-017)	April 1990	Rate base treatment of Gulf Power Company's 63-MW ownership share of the Scherer 3 generating unit.
Michigan Public Service Commission	U-9458 (ESRG 89-158)	February 1990	Implications of excess capacity on the Indiana Michigan system for the costs that should be included in the Company's 1990 PSCR plan.
Vermont Public Service Board	5330 (ESRG 89-078)	December 1989	Presentation of results of ESRG Study: *The Role of Hydro-Quebec Power in a Least-Cost Energy Resource Plan for Vermont.*
		February 1990	Further Testimony in above Docket
		February 1990	Surrebuttal Testimony in above Docket
Pennsylvania Public Utility Commission	R-891364 (ESRG 89-90A)	October 1989	Recommendations regarding the proper ratemaking treatment for PECo's Limerick 2 nuclear unit.
Florida Public Service Commission	881167-EI (ESRG 89-034)	May 1989	Ratebase Treatment of Gulf Power Scherer 3 Capacity

Federal Energy Regulatory Commission	ER88-630-000 (ESRG 88-153)	April 1989	Pass Through of Performance Incentive Program Charges by New England Power Company
Public Service Commission of the District of Columbia	Formal Case No. 877 (ESRG 88-128D)	February 1989	Evaluation of the Need and Justification for 210 MW CTs at Benning Road Site Proposed by PEPCO
	(ESRG 88-128E)	March 1989	Rebuttal Testimony
Michigan Public Service Commission	U-8871 (ESRG 88-32)	April 1988	Review of the Appropriate Avoided Costs for the CPCo System
	(ESRG 88-32A)	August 1988	Rebuttal Testimony
Maine Public Utilities Commission	87-268 (ESRG 30A)	April 1988	Review Related to the Staff's Evaluation of the Desirability of the Purchase of Power from Hydro Quebec Proposed by Central Maine Power
	87-268 (ESRG 87-30A1)	August 1988	Supplemental Testimony
Pennsylvania Public Utility Commission	M-870111, G-870087 G-870088 (ESRG 88-01)	February 1988	Review of Pennsylvania Power Company's Requested Recovery of Purchased Power Costs
Pennsylvania Public Utility Commission	R-870732 (ESRG 87-80)	November 1987	Investigation into Pennsylvania Power Company's Share of Perry 1 Nuclear Unit and Assessment of Physical Excess Capacity. Direct and Rebuttal Testimony.
Michigan Public Service Commission	U-7830 (ESRG 85-35E)	December 1987	Review of the Application of Consumers Power Company to Recover Its Midland Investment
Pennsylvania Public Utility Commission	R-870651 (ESRG 87-50D)	October 1987	Investigation into Whether Perry 1 and Beaver Valley 2 Capacity Is Economically Used and Useful on the Duquesne System.

Federal Energy Regulatory Commission	ER-86-694-001	September 1987	Analysis of NEPOOL's PIP Program on Behalf of Maine Public Utilities Commission
Maine Public Utilities Commission	86-85	June 1987	Investigation of Reasonableness of Rates
		August 1987	Surrebuttal
Maryland Public Service Commission	7972	February 1987	Investigation by the Commission of the Justness and Reasonableness of the Rates of Potomac Electric Power Company
Arizona Corporation Commission	U-1345-85-367 (Tellus 86-42B)	February 1987	Concerning the Prudence of Palo Verde Investment
Michigan Public Service Commission	U-8578 (Tellus 86-055A)	January 1987	Power Supply Cost Recovery Plan for Detroit Edison
Michigan Public Service Commission	U-8585	January 1987	Power Supply Cost Recovery Plan for Upper Peninsula Power Company
Pennsylvania Public Utility Commission	R-860378 (Tellus 85-083A)	September 1986	Economics of Duquesne Light Company's Share of Perry 1
		November 1986	Surrebuttal
Pennsylvania Public Utility Commission	R-850267 (Tellus 85-083B)	September 1986	Economics of Penn Power's Share of Perry 1
		November 1986	Surrebuttal
		March 1987	Supplemental

Michigan Public Service Commission	U-8348	July 1986	Palisades Performance Standards
Michigan Public Service Commission	U-8291	April 1986	Power Supply Cost Recovery Plan for Detroit Edison
Michigan Public Service Commission	U-8286	February 1986	Power Supply Cost Recovery Plan for Consumers Power
Michigan Public Service Commission	U-8297	January 1986	Power Supply Cost Recovery Plan for Upper Peninsula Power Company
Michigan Public Service Commission	U-8285	January 1986	Power Supply Cost Recovery Plan for Indiana & Michigan Company
Division of Public Utilities, Dept. of Business Regulation	85-2011-01 85-999-08	January 1986	Construction of a Transmission Line and Transmission Facilities in Southwestern Utah
New York Public Service Commission	28252	October 1985	Shoreham - Rate Moderation
		January 1986	Surrebuttal
Missouri Public Service Commission	ER-85-128 EO-85-185 EO-85-224 (Tellus 83-089)	June 1985	Wolf Creek Excess Capacity and the Prudency of Company Planning
Federal Energy Regulatory Commission	ER-84-560-000 (Tellus 85-019)	April 1985	Callaway Excess Capacity and a Review of Union Electric Planning
State Corporation Commission of the State of Kansas	120-924-U 142-098-U 142-099-U 142-100-U	April 1985	General Investigation by the Commission of the Projected Costs and Related Matters of the Wolf Creek Nuclear Generation Facility at Burlington, Kansas
Michigan Public Service Commission	U-8042	February 1985	Power Supply Cost Recovery Plan for Consumers Power Company

Michigan Public Service Commission	U-8020	January 1985	Power Supply Cost Recovery Plan for Detroit Edison Company
Massachusetts Department of Public Utilities	84-49, 84-50, 84-140, 627, 1656 & 1957	January 1985	Economics of Completing Seabrook 1 for Four Massachusetts Utilities

List of other testimony prior to 1985 available upon request.

Tellus Research

2001 *Comments on the Interim Pricing Report on New York State's Independent System Operator.* Prepared for the Public Utility Law Project. Tellus No. 00-213. Co-author.

1999 *A Comparison of Studies by U.S. DOE and Stone & Webster on the Effect of Electric Restructuring in Colorado.* A Report Prepared for: National Rural Electric Cooperative Association. Tellus Study No. 99-085. September. Co-author..

1999 *Comments of the OCC to the Colorado Electricity Advisory Panel on Market Power.* The Potential Exercise of Horizontal Market Power in a Deregulated Colorado Electricity Market. Tellus No. 98-124. June. Co-author.

1999 *Funding for Energy-Related Public Benefits: Needs and Opportunities With and Without Restructuring.* A report to the Governor's Office of Energy Conservation. Tellus Study No. 98-002/C2. May. Co-author.

1998 *New England Tracking System (NETS).* A report of the New England Governors' Conference, Inc. Tellus Study No. 97-063. October. Project manager.

1998 "Analysis and Recommendations of Residential Utility Consumer Office Regarding the Tucson Electric Power Company's Stranded Cost Filing." Comments to Arizona Corporation Commission. Docket No. E-01933A-98-0471. September. Co-author.

1998 "Analysis and Recommendations of Residential Utility Consumer Office Regarding the Arizona Public Service Company's Stranded Cost Filing." Comments to Arizona Corporation Commission. Docket No. E-10345A-98-0473. September. Co-author.

1998 "Analysis and Recommendations of Residential Utility Consumer Office Regarding the Citizens Utilities Company's Stranded Cost Filing." Comments to Arizona Corporation Commission. Docket No. E-1032C-98-0474. September. Co-author.

1998 "Modeling Electricity Pricing in a Deregulated Generation Industry: The Potential for Oligopoly Pricing in a Poolco," the *Energy Journal.* Vol 19, no. 3. June. Co-author.

1998 *Use of Computer Simulation Models to Analyze Market Power in Electricity Markets.* Comments of Tellus Institute before the Federal Energy Regulatory Commission. Docket No. PL98-6-000. Tellus No. 98-074. June. Co-author.

1997 *Restructuring the Electric Industry in Delaware.* A Draft Report by the Delaware Public Service Commission Staff. PSC Docket No. 97-229. Tellus Study No. 96-099. November. Co-author. Final Draft Report.

1997 *Comments on NEPOOL Executive Committee Market Power Analysis and Mitigation*

Filings. A report for: The New England Conference of Public Utility Commissioners (NECPUC). Tellus No. 97-054. July. Co-author.

1997 *Sustainable Electricity for New England: Developing Regulatory and Other Governmental Tools to Promote and Support Environmentally-Sustainable Technologies in the Context of Electric Industry Restructuring.* The R/EST Project. A report to the New England Governors' Conference, Inc. Tellus No. 95-310. January. Project manager.

1996 *Comments on FERC's CRT NOPR in Docket No. RM96-11-000.* Submitted to: The National Association of State Utility Consumer Advocates. Tellus Study No. 96-142. October. Principal investigator.

1996 *Potential Costs and Benefits of Electric Industry Restructuring.* Tellus No. 95-95-190. July. Co-author.

1996 *Achieving Efficiency and Equity in Nevada's Electric Industry - Comments Submitted by the Attorney General's Office of Advocate for Customers of Public Utilities on Issues Posed by the State Assembly in A.C.R. #49 Directing a Study of Competition in the Generation, Sale, and Transmission of Electricity.* Tellus Study No. 95-153A1. January. Co-author.

1995 *Promoting Environmental Quality in a Restructured Electric Industry.* A Report to: The National Association of Regulatory Utility Commissioners. Tellus Study No. 95-056. December. Co-author.

1995 *Power Pools and Least-Cost Compliance with the Clean Air Act.* A Report to: the Pew Charitable Trusts. Tellus Study No. 94-113. October. Principal investigator.

1995 *Costing Energy Resource Options: An Avoided Cost Handbook for Electric Utilities.* Tellus Study No. 93-251. September. Principal investigator.

1995 Discussion Paper: An Overview of the Generic Issues Related to the Amendment to Illinois Senate Bill 1058. Submitted to the Illinois Consumer Utility Board. Tellus Study No. 95-210. September.

1995 Tellus' Initial Comments on CEEP's Discussion and Conclusions of its Electric Competition Investigation (PA PUC Docket No. I-940032). Submitted to: Pennsylvania Office of Consumer Advocate. Tellus Study No. 94-012. September. Co-author.

1995 *Analysis of Economics of the Sherman Biomass Generating Unit.* Prepared for: Wheelabrator Environmental Systems, Inc. Tellus Study No. 95-154. May. Co-author.

1995 *Order on Application for Reconsideration, Formal Case No. 813, Order No. 10590.* Public Service Commission of the District of Columbia. Tellus No. 94-051. March.

1995 *Order on Application for Reconsideration, Formal Case No. 813, Order No. 10554.* Public Service Commission of the District of Columbia. Tellus No. 94-051. January.

1995 In the Matter of a Notice of Inquiry to Consider Section III of the Energy Policy Act of 1992 - Integrated Resource Planning and Energy Efficiency Investments in Power Generation and Supply for Electric Utilities. Docket No. 94-342-U. Prepared for: Arkansas Public Service Commission. Tellus No. 92-153A4. January. Co-author.

1994 *Competition and the Tennessee Valley Authority.* White paper prepared for TVA's Board of Directors. Tellus Study No. 94-096. October. Co-author. Draft.

1994-1995 Independent Advisors to the Tennessee Valley Authority's Board of Directors during the Utility's Development of its First Integrated Resource Plan. Tellus Study No. 94-096. May 1994-December 1995. Project manager.

1994 *Report on Notice of Advanced Rulemaking Relating to Commission Review of Siting and Construction of Electric Transmission Lines.* Submitted to: Pennsylvania Office of Consumer Advocate. Docket No. L-00940091. Tellus Study No. 94-223. December. Co-author.

1994 "Comments in Response to Edison Electric Institute's Petition for Statement of Policy on the Ratemaking Treatment of the Costs Associated with SO_2 Emissions Allowances." Docket No. PL95-1-000. Federal Energy Regulatory Commission. Tellus Study No. 94-113. November. Co-author.

1994 *Electric Transmission Pricing.* A report to: American Wind Energy Association. Tellus Study No. 94-39. September. Co-author.

1994 *Review of Union Electric Company's Electric Utility Resource Planning Compliance Filings.* Prepared for: The Missouri Office of Public Counsel. Tellus Study No. 93-300. April. Co-author.

1993 *Aligning Rate Design Policies with Integrated Resource Planning.* A report to: National Association of Regulatory Utilities Commissioners. Tellus Study No. 92-047. December. Co-author.

1993 A Report to: The Public Service Commission of the State of Delaware Regarding Docket 35: Adoption of the Guidelines for Integrated Resource Planning by Electric Cooperatives. Tellus Study No. 93-053. August. Co-author.

1993 A Report to: The Public Service Commission of the State of Delaware Regarding Docket 39: PURPA Standards as Amended by the Energy Policy Act of 1992. Tellus Study No. 93-054. August. Co-author.