STATE OF UTAH
BEFORE THE
PUBLIC SERVICE COMMISSION

DOCKET NO. 01-035-01

APPLICATION OF PACIFICORP FOR APPROVAL OF ITS PROPOSED ELECTRIC RATE SCHEDULES AND ELECTRIC SERVICE REGULATIONS

REBUTTAL TESTIMONY OF DR. DENNIS W. GOINS ON BEHALF OF NUCOR STEEL

August 31, 2001

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ON BEHALF OF
NUCOR STEEL

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

A. My name is Dennis W. Goins. I operate Potomac Management Group, an economics and management consulting firm. My business address is 5801 Westchester Street, Alexandria, Virginia 22310.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Ph.D. degree in economics and a Master of Economics degree from North Carolina State University. I also earned a B.A. degree with honors in economics from Wake Forest University. From 1974 through 1977 I worked as a staff economist at the North Carolina Utilities Commission. During my tenure at the Commission, I testified in numerous cases involving electric, gas, and telephone utilities on such issues as cost of service, rate design, intercorporate transactions, and load forecasting. While at the Commission, I also served as a member of the Ratemaking Task Force in the national Electric Utility Rate Design Study sponsored by the Electric Power Research Institute (EPRI) and the National Association of Regulatory Utility Commissioners (NARUC).

Since 1978 I have worked as an economic and management consultant to firms and organizations in the private and public sectors. My assignments focus primarily on market structure, planning, pricing, and policy issues involving firms that operate in energy markets. For example, I have conducted detailed analyses of product pricing, cost of service, rate design, and power pool planning, operations, and pricing; prepared analyses related to utility mergers, transmission access and pricing, and the emergence of competitive markets; evaluated and developed regulatory incentive mechanisms applicable to utility operations; and assisted clients in analyzing and negotiating interchange agreements and power and fuel supply contracts. I have also assisted clients on electric power market restructuring issues in Arkansas, New Jersey, New York, South Carolina, Texas, and Virginia.

I have submitted testimony and affidavits in more than 100 proceedings before state and federal agencies as an expert in utility planning and operating practices, competitive market issues, regulatory policy, cost of service, and rate design. These agencies include the Federal Energy Regulatory Commission, the Circuit Court of Kanawha County, West Virginia, and regulatory agencies in Arkansas, Georgia, Illinois, Louisiana, Maine, Massachusetts, Minnesota, Mississippi, New Jersey, New York, North Carolina, Ohio, Oklahoma, South Carolina, Texas, Utah, Vermont, Virginia, and the District of Columbia.

I have participated on behalf of firm and nonfirm customers before the Utah Public Service Commission in numerous cases involving PacifiCorp (Docket Nos. 99-035-10, 89-039-10, 85-035-01, 84-035-01) and Mountain Fuel Supply (Docket No. 93-057-01). In addition, I participated in the merger case before this Commission involving PacifiCorp and ScottishPower (Docket No. 98-2035-04) and the merger case before FERC involving Pacific Power & Light and Utah Power & Light (Docket No. EC88-2-007).

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of Nucor Steel, a division of Nucor Corporation. Nucor Steel owns and operates a steel mill in Plymouth, Utah, which is served by PacifiCorp (doing business as Utah Power) under a special contract approved by this Commission.

Q. WHAT ASSIGNMENT WERE YOU GIVEN WHEN YOU WERE RETAINED?

A. I was asked to undertake two primary tasks:

1. Review and evaluate the direct testimony and related documents filed by PacifiCorp, the Division of Public Utilities (DPU), and intervenors in the cost of service and spread of rates phase of this docket.
2. On the basis of this review and evaluation, provide any necessary rebuttal comments related to specific policy positions and rate design proposals advocated by the DPU and other intervenors.

Q. WHAT SPECIFIC INFORMATION DID YOU REVIEW IN CONDUCTING YOUR EVALUATION?

A. I reviewed testimony, exhibits, schedules, workpapers, and various responses to requests for information filed by selected witnesses for PacifiCorp and intervenors in both the cost of service and spread of rates and revenue requirements phases of this case. I also reviewed information found on PacifiCorp's web site related to its concurrent rate and restructuring filings in other states, as well as information concerning its future resource requirements.

CONCLUSIONS

Q. WHAT CONCLUSIONS HAVE YOU REACHED?

A. On the basis of my review and evaluation, I have concluded that:

1. The DPU and the Committee for Consumer Services (Committee) have conducted cost-of-service analyses that produce significantly different results with respect to customer class cost responsibility.

   - According to DPU witness Dr. Laura Nelson, the results of her cost-of-service study reflect positions on various costing issues the DPU has taken in previous PacifiCorp rate cases as well as Commission precedents established in prior rate case orders.
   - In contrast, Committee witness George Sterzinger recommends a series of different modifications and adjustments to PacifiCorp's cost-of-service study. Mr. Sterzinger first rejects PacifiCorp's interclass retail allocation of the wholesale sales and system (in contrast to firm *situs*) Special Contracts revenue credits, claiming that too much of the credits assigned to Utah are allocated to retail classes on the basis of energy relative to the interjurisdictional allocation of the credits. He recommends using class demand factors (F10) to allocate almost all of the wholesale revenue credit and all of the system Special Contracts revenue credit among retail classes. He then recommends excluding the firm *situs* Special Contracts class from the interclass allocation of both wholesale sales and system Special Contracts revenue credits, primarily because of his mistaken belief that rates for customers in the firm *situs* class do not reflect any embedded capacity costs.

2. The DPU and the Committee have also recommended significantly different interclass spreads for any retail base rate increase that the Commission allows. The different revenue spreads are related to the results of the independent cost-of-service analyses prepared by DPU witness Nelson and Committee witness Sterzinger.

   - DPU witness Rebecca Wilson used Dr. Nelson's cost-of-service study results, in conjunction with the DPU's three long-standing cost-of-service principles—cost causation, equal rates of return, and gradualism—in developing the DPU's recommended interclass revenue spread. Under this spread (and using the DPU's initial, pre-Stipulation revenue requirement recommendation), rates for Residential Schedule No. 1, Irrigation Schedule No. 10, and Mobile Home Park Schedule No. 25 will each receive a base rate increase of approximately 1.9 percent. Base rates for all other classes will remain unchanged under the DPU's proposed interclass revenue spread. (See Exhibit No. DPU 8.7.)

- On the basis of his adjusted costing analysis, Mr. Sterzinger recommends an across-the-board spread (excluding Schedule 23) of any allowed base revenue change if the Committee's proposed net power cost adjustment is adopted. Alternatively, Mr. Sterzinger recommends a 50/50 hybrid allocation scheme that uses "both the earned rate of return on rate base and the increase per kWh of any proposed revenue allocation." (Sterzinger direct at page 4. In addition, see Sterzinger direct at pages 11 and 21.)

3. In response to PacifiCorp's proposed 50-MW limit on service eligibility under General Service-High Voltage Schedule No. 9, DPU witness Wilson has recommended eliminating PacifiCorp's proposed 50-MW limit, and has proposed a new rate for 138-kV transmission customers. The rate includes a $98.29 per month customer charge, a $5.19 per kW-month demand charge, and a $0.019391 per kWh energy charge.

4. Committee witness Sterzinger and Utah Ratepayers Alliance witness Dr. Charles Johnson make several recommendations related to Special Contracts. Mr. Sterzinger's recommendations not only could violate fundamental provisions in *existing* Special Contracts, and also would arbitrarily assign PacifiCorp's highest incremental resource costs to Special Contract customers. In contrast, Dr. Johnson recommends that the

Commission require reopener and time-of-day pricing provisions in *new* retail special contracts.[1]

5. Utah Energy Office witnesses Dr. David Nichols and Jeff Burks, along with Rick Gilliam for the Land and Water Fund of the Rockies, recommend a major initiative related to new demand-side management (DSM) programs. To pay for the new DSM initiative, these witnesses recommend a new DSM cost-recovery rate rider.

RECOMMENDATIONS

Q. WHAT DO YOU RECOMMEND ON THE BASIS OF THESE CONCLUSIONS?

A. I recommend that the Commission:

1. Adopt the cost-of-service analysis sponsored by DPU witness Dr. Laura Nelson and explicitly reject the costing analyses recommended by Committee witness George Sterzinger. In particular, the Commission should reject Mr. Sterzinger's recommendation regarding PacifiCorp's jurisdictional and Utah retail allocation of revenue credits and his recommendation to exclude firm *situs* Special Contract customers from the revenue credit allocation. In her cost analysis, Dr. Nelson has correctly dealt with the wholesale sales revenue credit issue raised by Mr. Sterzinger by allocating this credit (Account 447) among Utah retail classes on the basis of a composite F10/F30 factor weighted by the relative demand and energy components of wholesale sales revenue (Account 555). In contrast to Mr. Sterzinger, Dr. Nelson has also properly allocated the system Special Contract revenues using both demand (F10) and energy (F30) allocation factors.[2] In addition, unlike Mr. Sterzinger, Dr. Nelson

[1] Neither Mr. Sterzinger nor Mr. Johnson distinguishes between system and *situs* Special Contracts in his discussion of contract adjustments.
[2] See PacifiCorp's response to DPU Data Request No. 11.6.

correctly recognizes that the firm *situs* Special Contracts class should not be excluded from the system Special Contract revenue credit allocation.

2. Adopt the revenue spread sponsored by DPU witness Rebecca Wilson and presented in Exhibit No. DPU 8.7. The Commission should explicitly reject both revenue spread alternatives recommended by Committee witness Sterzinger since both are based on seriously flawed costing analyses and one (the 50/50 hybrid spread) has no basis in fundamental cost-of-service and ratemaking principles.

3. Reject PacifiCorp's proposed service eligibility restrictions for service under General Service-High Voltage Schedule No. 9—thereby allowing large customers to be served under the rate. In addition, Ms. Wilson's proposed 138-kV rate should be adopted and made available to 138-kV customers. However, the rate should also be amended soon after this case to include an interruptible service option. Because of the complexity in developing an interruptible service option, I recommend that the Commission order PacifiCorp to work with the DPU and other interested parties to develop an interruptible service option for the 138 kV rate[3] and to submit the option for the Commission's review in a formal hearing no later than 90 days following the final order in this case.

4. Reject Committee witness Sterzinger's recommendation for Special Contract adjustments and Utah Ratepayers Alliance witness Johnson's recommendation for mandatory time-of-day pricing provisions in new Special Contracts. While time-of-day pricing should be considered as a potential pricing option, it may not be the most efficient or cost-effective pricing mechanism available for specific customers.

5. Reject the cost-recovery mechanism proposed by Utah Energy Office witnesses Nichols and Burks, and LAW Fund witness Gilliam for the

[3] In future rate proceedings, the firm and interruptible components of the 138-kV class could be split to facilitate cost-of-service analyses.

recommended DSM initiative, and consider any explicit, stand-alone rate mechanism to fund such investments only in conjunction with a comprehensive assessment of specific programs brought to the Commission for its consideration and approval. This current rate case does not provide a proper forum to consider the host of issues associated with expansive and costly DSM programs—including any proposed DSM cost-recovery mechanism.

COST OF SERVICE

Q. DID COST-OF-SERVICE ANALYSES CONDUCTED BY THE DPU AND THE COMMITTEE PRODUCE SIMILAR RESULTS?

A. No. The DPU and the Committee for Consumer Services conducted cost-of-service analyses that produce significantly different results with respect to customer class cost responsibility for two major customer classes. More specifically, the analyses differ with respect to Schedule No. 1 residential customers and Schedule No. 9 high-voltage transmission customers.[4] The DPU analysis conducted by Dr. Nelson indicates that Residential Schedule No. 1 is priced below cost of service, while General Service-High Voltage Schedule No. 9 is priced above cost of service. The Committee's analysis conducted by Mr. Sterzinger shows exactly the opposite results for these two major rate classes.

Q. WHAT IS THE BASIS FOR THE SIGNIFICANTLY DIFFERENT COST-OF-SERVICE RESULTS FOR THESE TWO MAJOR CLASSES?

A. The different results are caused by the different adjustments Dr. Nelson and Mr. Sterzinger made to PacifiCorp's cost-of-service study. According to DPU witness Nelson, she adjusted PacifiCorp's study to reflect positions on various costing issues the DPU has taken in previous PacifiCorp rate cases as well as Commission precedents established in prior rate case orders. (Nelson direct at pages 3-6.)

In contrast, Committee witness Sterzinger recommends a series of different modifications and adjustments to PacifiCorp's cost-of-service study. With respect to cost allocation, Mr. Sterzinger first rejects PacifiCorp's interclass retail allocation of the wholesale sales and system (in contrast to firm *situs*) Special Contracts revenue credits, claiming that too much of the credits assigned to Utah are allocated to retail classes on the basis of energy relative to the interjurisdictional allocation of the credits. He recommends using class demand factors (F10) to allocate almost all of the wholesale revenue credit and all of the system Special Contracts revenue credit among retail classes. He then recommends excluding the firm *situs* Special Contracts class from the interclass allocation of both wholesale sales and system Special Contracts revenue credits, primarily because of his mistaken belief that rates for customers in the firm *situs* Special Contracts class do not reflect any embedded capacity costs.[5]

Q. DOES THE DPU'S COST-OF-SERVICE ANALYSIS ADDRESS ANY OF THE COMMITTEE'S CONCERNS?

A. Yes. In her cost analysis, Dr. Nelson has correctly dealt with the wholesale sales revenue credit issue raised by Mr. Sterzinger by allocating this credit (Account 447) among Utah retail classes on the basis of a composite demand (F10) and energy (F30) factor weighted by the relative demand and energy components of wholesale sales revenue (Account 555). In contrast to Mr. Sterzinger, Dr. Nelson has also properly allocated the system Special Contract revenues using both demand (F10) and energy (F30) allocation factors. In addition, unlike Mr. Sterzinger, Dr. Nelson correctly recognizes that the firm *situs* Special Contracts class should not be excluded from the system Special Contract revenue credit allocation.

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[4] Both analyses indicate that rates for customers served under Schedules 10 and 25 and Firm Industrial Contracts (that is, *situs* Special Contracts for firm service) are below PacifiCorp's cost of service. See DPU Exhibit No. 11.1 and CCS Exhibit 9.4.

[5] In PacifiCorp's cost-of-service study, the firm *situs* Special Contracts class is allocated both generation-related costs and purchased power costs.

Q. WHICH COST-OF-SERVICE ANALYSIS SHOULD THE COMMISSION ADOPT?

A. I recommend that the Commission adopt the DPU's cost-of-service analysis and explicitly reject the costing analysis conducted by Committee witness Sterzinger. In particular, the Commission should reject Mr. Sterzinger's recommendation regarding PacifiCorp's jurisdictional and Utah retail allocation of revenue credits and his recommendation to exclude firm *situs* Special Contracts customers from the revenue credit allocation.

REVENUE SPREAD

Q. DID THE REVENUE SPREAD ANALYSES CONDUCTED BY THE DPU AND THE COMMITTEE PRODUCE SIMILAR RESULTS?

A. No. The DPU and the Committee have recommended significantly different interclass spreads for any retail base rate increase that the Commission allows. The different revenue spreads are related to the results of the independent cost-of-service analyses prepared by DPU witness Nelson and Committee witness Sterzinger.

Q. PLEASE DESCRIBE THE DPU'S PROPOSED REVENUE SPREAD.

A. DPU witness Rebecca Wilson developed the DPU's recommended interclass revenue spread using Dr. Nelson's cost-of-service study results in conjunction with the DPU's three long-standing cost-of-service principles—cost causation, equal rates of return, and gradualism. Under this spread (and using the DPU's initial, pre-Stipulation revenue requirement recommendation), rates for Residential Schedule No. 1, Irrigation Schedule No. 10, and Mobile Home Park Schedule No. 25 will each receive a base rate increase of approximately 1.9 percent. Base rates for all other classes will remain unchanged under the DPU's proposed interclass revenue spread. (See Exhibit No. DPU 8.7.)

Q. HOW DOES THE COMMITTEE'S PROPOSED REVENUE SPREAD DIFFER FROM THE DPU'S PROPOSAL?

A. On the basis of his adjusted costing analysis, Mr. Sterzinger recommends an across-the-board spread (excluding Schedule 23) of any allowed base revenue change if the Committee's proposed net power cost adjustment is adopted. Alternatively, Mr. Sterzinger recommends a 50/50 hybrid allocation scheme that uses "both the earned rate of return on rate base and the increase per kWh of any proposed revenue allocation." (Sterzinger direct at pages 3-4. In addition, see Sterzinger direct at pages 11 and 21.)

Q. IS THE 50/50 HYBRID REVENUE SPREAD SCHEME REASONABLE?

A. No. The 50/50 hybrid scheme "assigns 50% of the increase to each class on an equal percent basis and 50% on an equal kWh basis." (Sterzinger direct at page 9.) The apparent justification for this scheme is that it supposedly reflects changes over time in the major drivers (measured by changes in unit cost of service by function, cost classification, or class of service) of retail rate increases. In addition, the scheme supposedly reduces the rate increase bias introduced by across-the-board percentage increases for distribution level customer classes relative to transmission customers. (See Sterzinger direct at page 4.)

Mr. Sterzinger relies too heavily on unit cost analysis—that is, determining the average cost of service by function (for example, generation, transmission, or distribution) or cost classification (for example, demand, energy, or customer), and comparing changes in these unit costs over time. Unit cost by function can change dramatically on a yearly basis because of such factors as plant additions or retirements, temporary fuel cost changes, and changes in customer load factors and customer growth rates. Regardless of the drivers that cause changes in unit costs by function, the changes provide no meaningful insights into how revenue increases should be spread among classes. In contrast, changes in unit cost by cost classification may provide information useful in determining how a rate change should be reflected in demand, energy, and customer charges.

Q. IS AN ACROSS-THE-BOARD PERCENTAGE REVENUE SPREAD BIASED AGAINST DISTRIBUTION CUSTOMERS RELATIVE TO TRANSMISSION CUSTOMERS?

A. No. Mr. Sterzinger's comments imply that an across-the-board percentage revenue spread unfairly penalizes distribution customers relative to transmission customers because distribution customers—but not transmission customers—are allocated distribution-related costs. As a result, an across-the-board percentage increase may produce a greater increase in the average kWh cost of serving distribution customers relative to the average kWh cost of serving transmission customers. This fact is not evidence of revenue spread bias—it simply demonstrates that applying the same percentage increase to two different numbers will produce a unit change in the larger number that is greater than the unit change in the smaller number. In contrast to this imaginary revenue spread bias, the results of DPU witness Nelson's cost-of-service analysis confirm real bias against transmission (Schedule No. 9) customers relative to distribution (Residential Schedule No. 1) customers when rates are not adjusted to produce interclass equal rates of return.

Q. WHICH REVENUE SPREAD SHOULD THE COMMISSION ADOPT?

A. I recommend that the Commission adopt the revenue spread sponsored by DPU witness Wilson and presented in Exhibit No. DPU 8.7. The Commission should explicitly reject both revenue spread alternatives recommended by Committee witness Sterzinger since both are based on seriously flawed costing analyses and one (the 50/50 hybrid spread) has no basis in fundamental cost-of-service and ratemaking principles.

RATE OPTIONS FOR LARGE 138-KV CUSTOMERS

Q. HAS PACIFICORP PROPOSED RESTRICTING SERVICE ELIGIBILITY UNDER RATE SCHEDULE NO. 9?

A. Yes. PacifiCorp has proposed restricting service under General Service-High Voltage Schedule No. 9 to customers with loads of 50 MW or less.

Q. IS PACIFICORP'S PROPOSED SERVICE ELIGILITY RESTRICTION JUSTIFIED?

A. No. Currently no Schedule 9 customer has an average load exceeding 50 MW. However, PacifiCorp has provided no evidence that existing Schedule 9 customers would be harmed if larger customers were served under the rate.

Q. SHOULD PACIFICORP'S PROPOSED 50-MW SERVICE ELIGIBILITY RESTRICTION BE APPROVED?

A. No.[6] Large customers not served under Special Contracts should have reasonable rate options available to them. Two such options are to:

- Allow large customers to be served under Schedule 9 unless PacifiCorp convincingly demonstrates that such service would harm smaller Schedule No. 9 customers.
- Establish a new rate for 138-kV customers.

Q. WHICH APPROACH HAS THE DPU TAKEN WITH RESPECT TO PACIFICORP'S PROPOSED SERVICE ELIGIBILITY RESTRICTION?

A. DPU witness Rebecca Wilson rejects PacifiCorp's proposal, and instead recommends a new rate for 138-kV customers. According to Ms. Wilson, she "developed a rate for this new schedule by comparing the costs for the Firm Industrial Contracts with those of Rate 9." (Wilson direct at page 20) That is, the proposed charges were derived on the basis of comparing Special Contract unit

[6] In their direct testimony, Alan Chalfant for the Utah Industrial Energy Consumers (at pages 3-5) and Dr. Kevin Higgins for Utah Association of Energy Users Intervention Group (at pages 3-6) also recommend rejecting PacifiCorp's proposed 50-MW eligibility restriction.

costs to Schedule 9 unit costs, taking the difference between the unit costs, and adjusting Schedule 9's demand and energy components downward by the difference. The proposed 138-kV rate includes a $98.29 monthly customer charge, a $5.19 per kW-month demand charge, and a $0.019391 per kWh energy charge. (Wilson direct at Exhibit No. DPU 8.9)

Q. DO YOU AGREE WITH THE DPU'S PROPOSED 138-KV RATE?

A. Yes. Ms. Wilson's proposed 138-kV rate should be adopted and made available to 138-kV customers. However, large 138-kV customers should also have the option to be served under Schedule No. 9.

Q. DO YOU RECOMMEND ANY MODIFICATION TO THE PROPOSED 138-KV RATE?

A. Yes. I recommend adding an interruptible service option.[7] Such an option would provide a key demand-side resource to PacifiCorp while offering cost-based rate reductions to large customers with flexible operations.

Q. WHY SHOULD THE 138-KV RATE INCLUDE AN INTERRUPTIBLE SERVICE OPTION?

A. Properly designed interruptible rates can promote efficient consumption and investment decisions. Rates designed to promote efficient end-user consumption and investment decisions are necessary to ensure that a utility achieves its integrated resource objectives. Rates that fail to reflect the range of cost-effective service options will encourage a utility to make inefficient investment and operating decisions with respect to its generation, transmission, and distribution plant investments.

Interruptible load is often a cornerstone of the DSM component in a utility's integrated resource plan. For example, industrial customers that take interruptible service typically represent the highest per customer capacity savings associated

[7] In my testimony I use the term *interruptible* to refer to both interruptible and curtailable loads even though the costs of serving and the system benefits from the two types of loads are different. The interruptible service option should accommodate both types of nonfirm service.

with any DSM program. Interruptible service creates DSM benefits through capacity cost savings associated with a utility's not having to build capacity to serve interruptible load, economic growth and jobs associated with competitive industrial electricity prices, and increased planning flexibility.[8]

Q. WHAT TYPES OF CAPACITY SAVINGS ARE ATTRIBUTABLE TO INTERRUPTIBLE SERVICE?

A. Interruptible service can be structured to provide capacity savings from both a planning and an operating perspective. From a planning perspective, the utility avoids the capacity required to meet interruptible customers' expected loads, plus the installed reserve capacity normally added to ensure reliable service. From an operating perspective, a utility can also substitute interruptible loads for operating reserve capacity if it properly structures its interruptible service program. For example, utilities can offer instantaneous or no-notice interruptible service, and use such loads to offset part of their spinning reserve requirement (that is, on-line reserve capacity available instantaneously if an operating generating unit shuts down or reduces output). Similarly, utilities can use 10-minute or less notice interruptible service loads to offset part of their nonspinning reserve requirement. The availability of such reserves can be quite valuable during operating emergencies.

Q. CAN INTERRUPTIBLE SERVICE PROMOTE COMPETITION IN ELECTRIC POWER MARKETS?

A. Yes. Not all customers demand firm service. Interruptible customers want less-than-firm power on an as-available basis at prices significantly below firm service rates. Utilities willing to provide a variety of cost-based interruptible services that differ in price and interruption notice, frequency, and duration have a competitive advantage over utilities that do not offer such services. Innovative utilities

[8] The potential for and benefits from additional interruptible load in Utah were noted in testimony filed by Dr. David Nichols for the Utah Energy Office in the revenue requirements phase of this case. See Nichols direct (revenue requirements) at page 13.

recognize that such service variety is necessary to be competitive in attracting and retaining industrial loads. Moreover, interruptible services that differ in interruption notice, frequency, and duration enable a utility to minimize its capital resource outlays while maximizing the value of its supply resources—thereby enhancing its ability to compete against less efficient firms.

Q. HAVE YOU DEVELOPED AN INTERRUPTIBLE SERVICE OPTION FOR THE DPU'S PROPOSED 138-KV RATE?

A. No. Because of the complexity in developing this option, I recommend that the Commission defer implementing the interruptible service option for the new 138-kV rate at this time. Instead, I recommend that the Commission order PacifiCorp to work with the DPU and other interested parties to develop an interruptible service option for the 138 kV rate[9] and to submit the option for the Commission's review in a formal hearing no later than 90 days following the order in this case.

SPECIAL CONTRACTS ISSUES

Q. DID ANY WITNESS ADDRESS ISSUES RELATED TO ADJUSTING SPECIAL CONTRACTS?

A. Yes. Committee witness George Sterzinger and the Utah Ratepayers Alliance witness Dr. Charles Johnson make several recommendations concerning adjustments to Special Contracts.[10] Mr. Sterzinger first makes a series of unsubstantiated or irrelevant claims regarding Special Contracts. For example, he asserts: "Special Contracts…do not make a payment towards the fixed cost of generation equipment.…" (Sterzinger direct at page 24.) On this point, Mr. Sterzinger simply provides no evidence that prices in Special Contract rates do not reflect any contribution to fixed generating capacity costs. Similarly, he says regarding the firm *situs* Special Contracts in Utah that "once the revenue credits

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[9] In future rate proceedings, the firm and interruptible components of the 138-kV class could be split to facilitate cost-of-service analyses.

[10] As noted earlier, neither Mr. Sterzinger nor Dr. Johnson distinguishes between system and *situs* Special Contracts in his discussion of contract adjustments.

given to them by PacifiCorp are removed, the sales do not cover the costs of providing them service." As shown in the DPU's cost-of-service analysis, the same is true of residential, irrigation, and mobile home park customer classes even with revenue credits allocated to them.

Mr. Sterzinger uses the bogeyman of discounted rates in Special Contracts to support radical changes in existing contracts. In my opinion, these recommended changes, which are presented in a confidential portion of his testimony (Sterzinger direct at page 26), could violate fundamental provisions in *existing* Special Contracts (for example, requiring economic interruptions for a firm service contract). In addition, his proposal would also arbitrarily assign PacifiCorp's highest incremental resource costs to Special Contract customers. If not paying fully allocated embedded generation costs justifies such radical and discriminatory proposals, then Mr. Sterzinger should at least be consistent and apply his recommendation to any class—including the residential, irrigation, and mobile home park classes—whose earned rate of return is below the system average rate of return. Conversely, Mr. Sterzinger should also be demanding rate reductions for each class whose earned rate of return is above the system average. If he is unwilling to apply the same type of recommendations consistently to all customer classes—not just to Special Contracts, then his recommendations regarding Special Contract customers should be ignored.

Q. PLEASE DESCRIBE DR. JOHNSON'S PROPOSED SPECIAL CONTRACT ADJUSTMENTS.

A. Dr. Johnson recommends that *new* retail special contracts contain reopener and time-of-day pricing provisions.

Q. DO YOU AGREE THAT NEW SPECIAL CONTRACTS SHOULD INCLUDE MANDATORY TIME-OF-DAY PRICING PROVISIONS?

A. While time-of-day pricing should be considered as a potential pricing option, it may not be the most efficient or cost-effective pricing mechanism available in every circumstance. For example, using non-time-differentiated rates for a customer's stable firm load and interruptible prices for the customer's flexible load may yield significantly more system cost savings than minor load shifts that may occur with time-of-day rates. Moreover, for high load factor loads operating on a 24/7 production schedule, time-of-day prices may have little or no impact on customer load shapes since the total sales revenue collected under properly designed, embedded cost rates will be about the same regardless whether time-differentiated rates are employed. I do not mean to imply that time-of-day rates cannot be an efficient and cost-effective rate option. I simply disagree that such rates should be mandatory for new Special Contracts.

Q. WHAT DO YOU RECOMMEND REGARDING THE SPECIAL CONTRACT ADJUSTMENT PROPOSALS?

A. I recommend that the Commission reject Committee witness Sterzinger's recommendation for Special Contract adjustments and Utah Ratepayers Alliance witness Johnson's recommendation for mandatory time-of-day pricing provisions in new Special Contracts.

DSM INITIATIVES AND COST RECOVERY

Q. HAS ANY PARTY PROPOSED A NEW COST-RECOVERY MECHANISM FOR DEMAND-SIDE MANAGEMENT INVESTMENTS?

A. Yes. Intervenor witnesses Dr. David Nichols and Jeff Burks for the Utah Energy Office, along with witness Rick Gilliam for the Land and Water Fund of the Rockies, recommend a major initiative related to new demand-side management (DSM) programs.[11] To pay for the new DSM initiative, these witnesses recommend a new, explicit DSM cost-recovery rate mechanism that they generally refer to as a tariff rider.

[11] I understand from reading transcripts and briefs from the revenue requirements phase of this case that these parties have amended their proposal by excluding a specific $35 million first-year increase in rates to cover the cost of the DSM initiative. Although a discussion of a new cost-recovery mechanism makes sense only in the context of a specific cost initiative, I have chosen to discuss the DSM cost-recovery mechanism because the parties have not withdrawn their proposal at this time.

Q. HOW DOES PACIFICORP CURRENTLY RECOVER ITS DEMAND-SIDE RESOURCE INVESTMENT COSTS?

A. PacifiCorp currently recovers its costs of demand-side resource investments through its bundled base rates—that is, through an implicit rate mechanism approved by the Commission.

Q. ON WHAT BASIS DO THE PROPONENTS OF AN EXPLICIT COST-RECOVERY MECHANISM JUSTIFY SWITCHING FROM IMPLICIT TO EXPLICIT FUNDING OF DEMAND-SIDE RESOURCE INVESTMENTS?

A. The proponents generally cite three major types of alleged benefits to justify switching to an explicit rate mechanism to fund demand-side resource investments. These alleged benefits are:

- Funding stability for demand-side investments compared to implicit rate funding that fluctuates with base rate changes.
- Protection from competitive cost-cutting pressures.[12]
- Assured DSM cost recovery to offset the time lag between DSM expenditures and electricity supply cost savings.

Q. DO THESE ALLEGED BENEFITS JUSTIFY SWITCHING TO AN EXPLICIT RATE MECHANISM TO FUND DEMAND-SIDE RESOURCE INVESTMENTS?

A. No. The proponents of an explicit DSM cost-recovery mechanism do not demonstrate that the additional DSM opportunities identified in Dr. Nichols' analysis[13] could not be achieved under the current implicit method of DSM cost recovery.

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[12] For example, Mr. Gilliam says the following: "Once the [test-year] cost level is established and approved by the Commission, the incentive for the utility is to minimize expenditures between rate cases." (Gilliam direct at page 4.)

[13] David Nichols and David Von Hippel, *An Economic Analysis of Achievable New Demand-Side Management Opportunities in Utah*, Tellus Institute, Boston, Massachusetts, May 2001.

Q. IS THE PROPOSED FUNDING MECHANISM PROPERLY DESIGNED?

A. No. The proposed cost-recovery mechanism is defined only in general terms and lacks specificity regarding such critical program areas as administrative procedures, customer application, and proper funding levels.[14] For example, the proponents of an explicit DSM cost-recovery mechanism fail to:

- Lay out a clear process for administering the mechanism.
- Specify clearly how an explicit DSM cost-recovery mechanism would be applied to customers.
- Specify how the annual revenue requirement for approved DSM programs will be determined and adjusted.

Q. WHAT DO YOU RECOMMEND REGARDING THE PROPOSED DSM COST-RECOVERY MECHANISM?

A. I recommend that the Commission reject the cost-recovery mechanism proposed by Utah Energy Office witnesses Nichols and Burks, and LAW Fund witness Gilliam. Moreover, in my opinion, the Commission should consider a stand-alone explicit rate mechanism to fund DSM investments only in conjunction with a comprehensive assessment of specific programs brought to the Commission for its consideration and approval. Because this current rate case does not provide a proper forum to consider the host of issues associated with the proposed DSM initiative and associated cost-recovery mechanism, the Commission should continue to rely on the existing implicit rate mechanism to recover approved DSM costs in base rates.

Q. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?

A. Yes.

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[14] For example, see Gilliam direct at pages 6-8. Dr, Nichols has estimated the annual charges for a residential and nonresidential rider that would recover the cost of his recommended multiyear DSM initiative ($35 million in first-year funding). (Nichols direct at page 7.) However, he has not presented a comprehensive rider that addresses all of the issues raised not only in my testimony, but also in his testimony.