BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS INTERIM AND BASE RATES AND CHARGES FOR ELECTRIC SERVICE.	)	CASE NO. IPC-E-03-13

DIRECT TESTIMONY OF DAVE SCHUNKE

IDAHO PUBLIC UTILITIES COMMISSION

FEBRUARY 20, 2004

1 Q. Please state your name and business address for
2 the record.
3 A. My name is David Schunke and my business address
4 is 472 West Washington Street, Boise, Idaho.
5 Q. By whom are you employed and in what capacity?
6 A. I am employed by the Idaho Public Utilities
7 Commission as a Public Utilities Engineer.
8 Q. What is your educational and experience
9 background?
10 A. I received my Bachelor of Science Degree in
11 Civil Engineering at Montana State University in 1972. I
12 have been licensed as a Registered Professional Engineer
13 in Idaho since 1977. I have worked in various capacities,
14 including a Cost and Materials Engineer with Morrison
15 Knudsen Co., Inc. and a consulting engineer with Stevens,
16 Thompson & Runyan (STRAAM Engineers). As a consultant, I
17 worked as Project Engineer on numerous civil engineering
18 projects in Idaho and Oregon for more than six years.
19 Since joining the Commission Staff as a
20 Utilities Engineer in 1979, I have been continuously
21 involved in rate design and regulatory matters with
22 virtually all the water, gas and electric utilities
23 regulated by the Commission. I served as the Engineering
24 Section Supervisor from 1983 to 1991, Utilities Division
25 Deputy Administrator from 1991 through 2000 and Engineer

1 Manager from 2001 to present.

2 **INTRODUCTION AND SUMMARY**

3 Q. What is the purpose of your testimony?

4 A. The purpose of my testimony is to describe
5 Staff's rate design proposal for tariff and special
6 contract customers.

7 Q. How is your testimony organized?

8 A. A summary of my recommendations is followed by:

9 (a) A general discussion of my rate design
10 objectives and long-term goals,

11 (b) An explanation of how Staff proposes to cap
12 the increase to irrigators and redistribute the revenue
13 requirement to the other customer classes, and

14 (c) Based on the resulting revenue requirement
15 for the various customer classes, I then provide specific
16 rate design proposals for each customer class.

17 Q. Please summarize your testimony.

18 A. In general I am recommending small increases in
19 customer charges and believe the Company's proposed
20 increases in the various customer charges are too large.
21 I am also recommending increased energy rates in the
22 summer months for Schedules 1, 7, 9 and 19. I believe it
23 is important for rates to reflect the differences in cost
24 depending on time-of-use and I am recommending time-of-use
25 (TOU) rates wherever they are practical. Staff recommends

that rates for all customer classes move closer to cost of service. However, the irrigation class should be moved only one-third of the way to full cost of service because of the magnitude of the increase that otherwise would be required. Staff is also proposing that any rate reduction dictated by cost of service analysis be limited to one-third the amount indicated in the cost of service study. The rate design proposal presented in my testimony is based on Staff's initial determination of an overall revenue requirement increase of 3.14%. The Staff recommended revenue requirement is actually less than that, as discussed in Staff witness Keith Hessing's testimony. The Staff recommended increase for each customer class is shown in Staff Exhibit No. 127:

(a) Residential Schedule 1 would receive an overall average increase of 2.51%. I am recommending that the monthly customer charge be increased from $2.51 to $3.00 and that there be an increased energy rate for the summer months for energy use above 800 kWh per month.

(b) General Service Schedule 7 would receive an overall average revenue increase of 4.17%. I am recommending that the monthly customer charge be increased to $3.50.

(c) Large General Service Schedule 9 Secondary Service would receive an overall average revenue decrease

of 0.13% while Primary and Transmission Service would receive an overall average revenue increase of 13.31%. For Secondary Service, I am recommending no change in the Customer Charge or in the Basic Charge. The demand and energy rates would be increased about 10% in the summer and decreased about 4% in the non-summer months to reflect the higher cost to serve in the summer.

(d) For Schedule 9 Primary Service, I am recommending that the Customer Charge increase from $85.58 to $100.00 and that the Basic Charge be increased by 13% from $0.77 to $0.87. The demand and energy rates would be increased about 25% in the summer and increased about 9% in the non-summer months to reflect the higher cost to serve in the summer.

(e) Large Power Schedule 19 would have no change in the overall average revenue. Time-of-use and seasonal rates would be implemented in a manner consistent with the Company's proposal.

(f) Schedule 24 customers would receive an overall average revenue increase of 15%. The in-season customer charge would increase from $10.07 to $12.00. The out-of-season customer charge ("bills out-of-season") along with the minimum charge would increase from $2.51 to $3.00. The in-season demand charge would increase from $3.58 to $4.00 and I am proposing an out-of-season demand

charge of $0.80. Currently the energy charge is higher in the out-of-season than in the in-season, and I am proposing a single energy rate for both in-season and out-of-season.

(g) Schedules 15, 40, and 41 would receive overall average revenue decreases of 36.6%, 10.48% and 7.91%, respectively. Schedule 42 would have no change in the overall average revenue.

(h) Micron, Schedule 26, and Simplot Schedule 29, would receive overall average revenue decreases of 2.01% and 3.43%, respectively. DOE Schedule 30 would receive an overall average increase in revenue of 1.05%.

RATE DESIGN OBJECTIVES

Q. What are Staff's rate design objectives?

A. The electricity industry and this Commission have had a long history of pricing power differently to customers with different load and usage characteristics. Residential customer rates differ from those of commercial and industrial customer rates because the cost of providing service differs depending on the characteristics of the end use. Large loads with high-load factors (constant use) tend to be less costly per kWh to serve than smaller loads with large fluctuations. Time-of-use is also a major factor in determining the cost of service. These differences are generally addressed by grouping

customers with similar end-use characteristics together. They form a rate class such as residential, commercial, irrigation, industrial or lighting. The cost of providing service to the various customer classes has been addressed in the cost of service (COS) studies discussed in Staff witness Hessing's testimony. The first objective in rate design is to set rates that are more closely aligned to the cost of providing service.

The cost of providing power varies greatly from month to month and there is considerable variation in the cost depending on the time of day that the usage occurs. The time-of-use (TOU) is a major factor in the cost of providing service and is becoming increasingly important as Idaho Power's peak load continues to increase relative to its average load. However, currently most customer class rates are not dependent on TOU. Therefore, another rate design objective is to consider the time-of-use implications in rate design. I believe it is becoming increasingly important to discourage energy use during peak periods by providing proper rate signals or through direct load control programs, both of which will help to mitigate the increasingly high costs that Idaho Power incurs to provide peak load capacity.

It is also an objective to keep rates reasonable by balancing the cost of service goals with the goals for

simplicity, for minimizing rate shock, and for promoting conservation - especially during high cost periods.

Finally, in my specific rate design proposal for individual customer classes, I attempted to distribute the increase in revenue requirement to the customer classes by increasing the rate components somewhat uniformly.

CUSTOMER CLASS REVENUE ALLOCATION

Q. What cost of service study is Staff's rate design proposal based on?

A. Staff witness Hessing has completed a number of cost of service (COS) analyses which he discusses in his testimony. In particular, Staff considered the Company's proposed cost of service analysis which uses a monthly weighting to calculate the demand and energy allocators. The five months with the most critical conditions, with respect to power supply cost, hydro conditions, and loads, were chosen. This is the methodology that Staff believes is most appropriate and is the one Staff has based its rate design analysis on.

Q. Do you propose to move the irrigation class to full COS as determined by the class cost of service study?

A. No. While I believe that their rates should be increased sufficiently to move the irrigation class in a significant way toward COS, I also believe that some cap is necessary in order to keep the increase reasonable.

The lower the cap, the greater the subsidy required from other rate classes. A competing goal is to minimize the subsidy. With these goals in mind, I propose to cap the total increase to the irrigation class at approximately one-third the increase dictated by COS, or 15%. I also propose to cap any class revenue requirement decreases at one-third the full COS amount. All other customer classes would move to full cost of service with two adjustments that are discussed later. If the overall increase awarded the Company is substantially greater than the 3.14% recommended by Staff, I believe this cap should be reevaluated.

Q. If the irrigation class rate increase is capped at 15%, how do you propose to spread the revenue shortfall?

A. The revenue shortfall is redistributed to the other classes in proportion to their revenue requirements at full cost of service.

Q. What effect does this redistribution have on the customer classes?

A. The primary effect is that the revenue responsibility of the irrigation class is reduced by over $19 million and this amount is reallocated to the other customer classes. Staff's proposal for the redistribution of this amount plus the Cost of Service Adjustment is

shown in Staff Exhibit No. 127, Column 6, "Revised Revenue Requirement."

The secondary effect is a credit of about $2.7 million that occurs as a result of the cap on any decreases. This amount is redistributed as a credit to the remaining customer classes requiring an increase (except irrigation). The Final Revenue Adjustment is shown in Column 7. It includes the Cost of Service Adjustment, the adjustment for the reallocation of the irrigation costs and the adjustment for the reallocation of the credit resulting from limited decreases. This Final Adjustment is added to the Current Base Revenue to arrive at the Staff-Proposed Base Revenue shown in Column 8 of Staff Exhibit No. 127. This is the amount that Staff used in its rate design proposals.

Q. If Staff had chosen a different cost of service study to base its rate design proposal on, how would this have affected Staff's recommended average change in rates to the various customer classes?

A. If the increase to the irrigation class is capped at 15% (about one-third) and decreases are capped at one-third, then the choice of COS studies makes little difference. Even if the most extreme cost of service study were chosen where all the months are weighted equally (the un-weighted study), the difference in the

final revenue requirement proposal for the customer classes after the adjustments are made changes less than 1% for most customer classes. The increase for the irrigation class would still be greater than 15% to achieve full cost of service.

SEASONAL AND TIME-OF-USE

Q. The Company has proposed time differentiated rates, both seasonal and TOU, for several customer classes. Are seasonal and TOU rates consistent with your rate design objectives?

A. Yes. Deaveraging rates so they can be priced higher in peak periods and lower in off-peak periods provides two important price signals. The higher price during the periods when costs are higher encourages customers to reduce consumption and allows rates to be lower when the cost of power is lower, thus encouraging use during these off-peak periods. By shifting load, peaking facilities and peak power purchases can be reduced and existing base load facilities can be better utilized.

Both the Company's proposal and the Staff's proposal would accomplish this through the recommendation for seasonal and TOU rates.

Q. How is the winter peak addressed in your proposal?

A. Neither the Staff nor the Company proposal would

provide a direct price signal in the winter months. However, the summer peak is the critical peak. As Ms. Brilz stated in her testimony (page 26, line 12):

> The Company faces its highest power supply costs during the months of June, July, and August.
>
> …it is the peak usage during these three months, along with the usually low hydro conditions during the months of November and December, which are driving the need for the Company to seek new peaking resources…
>
> Seasonal rates…are intended to signal customers that consumption during the summer months is more costly.

I agree with Ms. Brilz that the three summer months are the most critical, but the low hydro conditions during the November-December winter peak also contribute to the Company's need to seek new peaking resources. If the Commission determines that the seasonal rates should be extended to winter peak months, it would not be difficult to make that change to either the Company proposal or to my proposal. I believe that either seasonal rate proposal provides a reasonable step in the right direction.

Q. What are the advantages and disadvantages of seasonal rates compared to TOU rates?

A. Seasonal rates are easier to implement and do not require the special equipment that TOU rates do. The primary disadvantage of seasonal rates is that they do not

1 differentiate between heavy-load hours and light-load
2 hours. They can only differentiate between high-load
3 seasons and low-load seasons. All the energy used within
4 the season is priced at the average for that season.
5 Therefore, customers would be charged the same seasonal
6 rate for power that they use both night and day, even
7 though the cost of power at night is lower. TOU rates
8 provide a greater degree of deaveraging and the
9 opportunity to shift loads between hours within the day.
10 This gives customers another tool to control their energy
11 bill. By simply shifting energy use to a different time
12 customers can lower their bill. As off-peak usage
13 increases, the utility facilities are better utilized and
14 the need to add peaking resources is avoided or delayed.
15 For these reasons, I believe TOU and seasonal rates should
16 be encouraged wherever practical.
17 Q. Are there other ways to provide the proper rate
18 signal?
19 A. Yes. There are a number of rate designs that
20 can provide proper price signals. Each has its advantages
21 and disadvantages. Tiered rates, for example, are an
22 imperfect but effective way to provide a proper price
23 signal to customers. A tiered rate structure charges a
24 higher rate for energy as consumption increases.
25 Generally higher cost generation is coincident with higher

use, so when a customer's usage is high for space heating or air conditioning it is during the winter and summer when energy costs and the total Company load are high. Therefore, tiered rates provide an effective way of providing proper price signals without having to define peak seasons. However tiered rates, like seasonal rates, do not differentiate between high- and low-load hours.

Q. Does the Company currently have TOU rates or other load shaping programs that target the peak hours in the summer months?

A. Yes, currently there are a number of pilot programs and tariffs that the Commission has recently ordered that are specifically designed for this purpose. Commission Order No. 29362 authorized the installation of automatic meter reading equipment in the Emmett and McCall service areas. Along with the testing of the automatic meter reading capability, this effort will test TOU rates to determine their effectiveness in reducing both summer and winter peaks. The Company also has an air conditioning load control program authorized in Commission Order No. 29207. This program is designed to reduce loads in the peak hours of the summer months. Schedule 25 is a TOU Irrigation tariff designed to provide peak hour pricing in the summer months with the hope of reducing the peak load during that period. The Commission presently

has an Idaho Power application before it in Case No. IPC-E-04-3 to implement a "Peak Clipping" program designed to reduce irrigation loads during the peak summer hours. In this rate case, the Company is proposing TOU rates for Schedule 19 customers where TOU metering is already in place. All these programs are designed to go beyond what seasonal rates can do by reducing the peak-hour load and ultimately avoid supply-side resources.

Staff believes that these programs should be aggressively pursued; they are the type of programs that the Commission was referring to in its Bennett Mountain Order No. 29410:

> Although we grant the certificate, we concur with the thrust of the Advocates and Staff comments regarding Idaho Power's obligation to aggressively consider alternatives to supply-side resources. We have not retreated from our belief that DSM and peak-load management programs offer viable alternatives to the incremental construction of peaking generation units. According to the Staff, the Company's most recent load-resource balance analysis demonstrate a significant need for capacity and associated energy (or load shedding/shifting alternatives) during peak hours in the summer and winter. Programs or procedures that reduce critical peak hourly demand have great value to both ratepayers and the Company. Idaho Power must vigorously pursue all available cost-effective DSM or other conservation programs.

RATE DESIGN - RESIDENTIAL

Q. What change in revenue requirement is Staff recommending for Residential Schedule 1?

A. Staff recommends an average overall increase in revenue of 2.51% to Residential Schedule 1.

Q. What is your recommendation for the Residential Schedule 1 rate design?

A. I am recommending that (1) the customer charge be increased to $3.00; (2) the energy rate for the base period remain the same as the current energy rate, $0.049303/kWh; and (3) the rate for energy use in excess of 800 kWh/month in the peak summer months (June, July and August) be priced at $0.059022/kWh.

Staff Exhibit No. 128 shows the existing and proposed rates along with the resulting revenue for Residential Schedule 1.

Q. The Company has proposed an increase in the residential customer charge from $2.51 to $10.00. Do you agree with this proposal?

A. No. The Company's proposal increases the customer charge about 300%. This would have a disproportionate affect on customers with low usage. It would increase 10% of the residential customers' bills more than 50%. The Company's proposal for such a large customer charge would also be inconsistent with energy conservation goals.

Historically the Idaho Commission has been careful to provide the proper price signal in customers'

rates. This was especially true during and shortly following the energy crisis of 2000 and 2001. Large amounts of consumption were billed at a higher rate, reflecting the increased cost to meet higher system peaks. The Company's customer charge proposal in this case would send exactly the opposite message. The Company's Exhibit No. 44, page 1, shows that the customer with the lowest usage would see a 298% increase while the largest users would see only an 8% increase.

Q. What is the history of Idaho Power's customer charge?

A. In 1987, the Company proposed to replace the minimum charge with a $5.00 customer charge in the U-1006-265 case. The Commission denied the Company's proposal, stating in Order No. 21365 that:

> ...promoting additional energy usage through a general policy change is not in the long-term best interest of the Company or its customers. Furthermore, the proposed customer charge is too high because it is based upon cost of service studies that allocate fixed plant costs into customer-related costs. (Emphasis added)

In Idaho Power's last general rate case in 1995, the Commission accepted the Company's proposal for a $2.50 customer charge. Order No. 25880.

Q. Do you believe some increase in the customer charge is justified?

A. Yes. I am recommending that the residential customer charge be increased to $3.00.

Q. What did you base the $3.00 amount on?

A. The customer charge should be based on the direct cost of meter reading and billing and should not include any fixed plant cost. I believe this is consistent with the finding in Commission Order No. 21365 that it was not appropriate to base the customer charge on fixed plant cost. The monthly cost associated with meter reading and billing is $4.20 for this customer class. Given the relatively small overall increase in rates that Staff is recommending, I believe $3.00 is the appropriate amount for the customer charge. This would cover the majority of the cost of meter reading and billing. If additional revenue is required from the residential class, I believe a customer charge that moves closer to full cost of meter reading and billing would be reasonable.

Q. If a $4.20 customer charge can be justified from cost of service, why are you recommending only $3.00?

A. A one dollar increase in the residential customer charge produces $4 million in additional revenue. If the customer charge were increased to $4.00, the full increase in revenue requirement recommended by Staff for Schedule 1 would be recovered and the energy rate for the peak summer period could not be increased without an

offsetting decrease in the non-summer energy rate. Although this is an option, it is not Staff's recommendation.

Q. Please describe Staff's recommended Residential Schedule 1 energy rate?

A. The energy rate would consist of two components. The base usage rate would apply to all energy used in the non-summer period and the first 800 kWh per month used in the summer period. The peak period rate would apply only in the summer months for energy used above 800 kWh of base monthly usage. The peak period energy rate would be about 20% higher than the base use rate to reflect the higher power supply cost in that period. This is similar to the summer/non-summer differential that the Company is proposing except it would apply only to energy used above base monthly usage during the peak summer period, rather than all energy used in the summer.

Q. Why should the peak period rate only apply to energy used in excess of 800 kWh per month in the summer months?

A. The rate for the first 800 kWh/month in the summer is based on the cost of generation from non-peaking resources. Although the cost to produce energy varies greatly from month to month throughout the year and from hour to hour throughout the day, energy rates currently

are based on the average cost of providing energy throughout the year. Seasonal rates are a step toward proper price signals because they deaverage the annual cost and provide seasonal (or monthly) rates that are more reflective of the average cost in that month. To achieve the best possible match between power cost and rates, the monthly cost could be deaveraged and provide hourly rates that are more reflective of the average cost in that hour or group of hours. In the absence of TOU meters, however, energy used during the heavy-load hours of the month cannot be distinquished from energy used in light-load hours. Much of the base load energy used for refrigeration, lighting, water heating and small appliances occurs off-peak. By contrast, energy used for air conditioning typically occurs during the peak period. By allotting each customer a base amount of energy, 800 kWh/month, that is priced at the lower base usage rate, some recognition is given to this off-peak energy use that occurs in high-cost months but during low-cost hours.

A base and peak energy rate is also justified by looking at the utilization or dispatch of system generation resources. The Company meets system load by dispatching low-cost generation resources first. Then as load increases the higher cost resources are dispatched, and only in the peak periods are the very high cost

peaking units dispatched to a small portion of the total load. The lowest cost resources supply energy for the base load consumption during the entire year, even during peak demand in the summer months.

It is only when customer demand exceeds this base level of consumption that higher cost resources are needed. When this occurs, as it does during the summer peak period, energy rates provide a price signal indicating that higher priced resources are being utilized. Therefore, Staff believes that the peak period energy charge should only be applied to incremental energy provided by expensive marginal resources or peaking units to meet load above base level consumption.

Q. How did you determine that 800 kWh was the right amount to use for base level consumption?

A. Staff Exhibit No. 129 shows the monthly average residential load which varies from just over 800 kWh in the spring and fall to over 1100 kWh in the summer and over 1300 kWh in the winter. The expensive peak generation is only required in the summer and winter. The system utilizes less expensive generation to meet the fall and spring load. Therefore, I selected 800 kWh to define the base level consumption that can be met by low-cost base load generation. This is the same level of consumption established by the Commission to define the

first block of the tiered rates in place during the 2001-2002 PCA period in Order No. 28852.

Q. How did you determine a peak period rate?

A. The differential recommended by Staff is 20%, approximately the same as what the Company is recommending. I believe that increase achieves a reasonable balance that sends an appropriate price signal to customers, is affordable, and is cost-justified based on the higher cost resources needed to meet higher loads.

Q. How do the proposed rates compare with current rates?

A. Staff Exhibit No. 130 shows a graphic comparison between current bills and Staff's proposed summer and non-summer bills at various kWh usage. Because Staff's proposed non-summer energy rate is the same as the current energy rate and because the proposed non-summer customer charge is only $0.49 higher than the current customer charge, at all levels of usage the graph of current bills and proposed non-summer bills appear to be the same.

The Staff-proposed summer energy rate would be the same as the non-summer energy rate for usage up to 800 kWh/month. Therefore bills would be the same in summer or non-summer up to the 800 kWh, and $0.49 higher than current bills. For usage in excess of 800 kWh, the summer rate is higher than the non-summer rate; therefore summer

bills are higher than non-summer bills for usage above 800 kWh. For example, at 2000 kWhs of usage a residential customer would pay $101.12 under current rates, $101.61 under Staff-proposed non-summer rates, and $113.27 under Staff-proposed summer rates.

Q. Please explain Staff Exhibit No. 131.

A. Staff Exhibit No. 131 is a graphic display of the total annual Residential Bill Frequency analysis results for November 2002 through October 2003. It shows the number of customer bills at various blocks of energy usage. The highest number of bills occur around 600 to 700 kWhs per month. The number of bills per block of monthly usage begins to drop off quickly as usage gets above 1000 kWhs. Almost 80% of the bills are for usage below 1500 kWhs and about 90% of the bills are for usage below 2000 kWhs. Only 3% of the total bill exceed 3000 kWhs per month. The number of kWhs billed in the block and the number of kWhs in the block are also shown on this graph.

Q. What are the revenue effects of changing the summer peak rate and the base energy rate?

A. Under my proposal for residential customers, a one-cent/kWh increase in the summer peak rate over existing base rates will produce $3.4 million in additional revenue. A one-cent increase in the base rates

over the current base rate will produce $38 million in additional revenue. As previously discussed a $1.00 increase in the customer charge produces $4 million in additional revenue.

RATE DESIGN SCHEDULE 7

Q. What change in revenue requirement is Staff recommending for Small General Service Schedule 7?

A. Staff is recommending an average overall increase in revenue of 4.17% to Small General Service Schedule 7.

Q. What is your recommendation for the Small General Service Schedule 7 rate design?

A. I am recommending that (1) the customer charge be increased to $3.50; (2) the energy rate for the base period remain the same as the current energy rate, $0.059649/kWh; and (3) the rate for energy use in excess of 600 kWh in the peak summer months (June, July and August) be increased 16.5% to $0.069459/kWh. Staff Exhibit No. 132 shows the existing and Staff-proposed rates along with the resulting revenue for Schedule 7.

Q. The Company has proposed an increase in the Schedule 7 customer charge from $2.51 to $10.00. Do you agree with this proposal?

A. No. For the same reasons cited for the residential customers, I am opposed to a $10.00 customer

charge.

Q. Do you believe some increase in the customer charge is justified?

A. Yes. I am recommending that the Schedule 7 customer charge be increased to $3.50.

Q. What did you base the $3.50 amount on?

A. The same rationale presented in my discussion of the residential rates applies here. The customer charge should be based on the direct cost of meter reading and billing. According to the Company's analysis, the monthly cost associated with meter reading and billing for Schedule 7 is $4.34. Given the relatively small overall increase in rates that Staff is recommending, I believe $3.50 is the appropriate amount for the customer charge. This would cover the majority of meter reading and billing costs. However, if additional revenue is required from Schedule 7 customers, I believe a customer charge that moves closer to the full cost of meter reading and billing would be reasonable.

Q. Why are you recommending a higher customer charge for Schedule 7 than for Residential Schedule 1?

A. Schedule 7 has a higher cost of billing and meter reading and Staff's overall proposed revenue increase for Schedule 7 is higher than residential Schedule 1.

Q. Describe the Small General Schedule 7 proposed energy rate.

A. The energy rate would consist of two components. The base use rate which would apply to all energy used in the non-summer period and the first 600 kWh per month in the summer period. The peak period energy rate would apply only in the summer months for energy used in excess of 600 kWh/month. The peak period energy rate would be about 17% higher than the base rate to reflect the higher power supply cost in that period. This is similar to the summer/non-summer differential that the Company is proposing and it would apply only to energy used above base monthly usage during the peak summer period.

Q. Why should the peak period rate only apply to energy used in excess of 600 kWh per month in the summer months?

A. The justification for this peak period rate design was previously discussed in the residential rate section of my testimony.

Q. How did you determine that 600 kWh was the right amount to use for the base level of consumption?

A. Staff Exhibit No. 133 shows that the average Schedule 7 load varies from about 650 to 700 kWh per month in the spring and fall to almost 900 kWh per month in the summer. Therefore, I have selected 600 kWh to define the

base level of monthly consumption that can be met by low-cost base load generation.

Q. How was the peak period rate determined?

A. The peak period rate of $0.069459/kWh is about 16.5% higher than the base use rate of $0.059649/kWh. The relative differential between the base use rate and the peak period rate is less than the differential recommended by the Company between summer and non-summer. However, I believe it is large enough to provide a reasonable price signal to customers reflecting the higher cost of generating resources.

RATE DESIGN LARGE GENERAL SERVICE SCHEDULE 9

Q. What is the overall rate change recommended by Staff for the Large General Service Schedule 9 (secondary service)?

A. Staff recommends an overall rate decrease of 0.13%.

Q. What is your recommendation for the Large General Service Schedule 9 secondary service rate design?

A. I am recommending that (1) the customer charge and the basic charge remain the same; (2) the summer demand charge be increased from $2.73 to $3.00 and the non-summer demand be reduced from $2.73 to $2.62 for an overall reduction in the demand charges of 0.4%, and (3) the energy rate for the non-summer period be reduced 4%

and the summer energy rate increase 10% for an overall decrease in the energy rate of 0.1%. These rates are shown on Staff Exhibit No. 134, page 1 of 3.

Q. The Company has proposed an increase in the Schedule 9 (secondary service) customer charge from $5.54 to $21.00. Do you agree with this proposal?

A. No. Because the overall rate change proposed is a decrease of 0.13%, I am recommending no change in the customer charge. Furthermore, the direct cost of meter reading and billing for these customers is $4.56, so the current charge already covers the full cost of meter reading and billing.

Q. What is the overall rate change recommended by Staff for Large General Service Schedule 9 (primary and transmission)?

A. Staff recommends an overall increase of 13.31%.

Q. What are your rate design recommendations for Schedule 9 primary service?

A. I am recommending that (1) the customer charge for primary service be increased from $85.58 to $100.00, a 13% increase; (2) the basic charge be increased from $0.77 to $0.87, a 13% increase; (3) the summer demand charge be increased 25% from $2.65 to $3.32, with the non-summer demand charge increasing 9% from $2.65 to $2.89 for an overall increase of 13% in the demand charges; and (4) an

overall energy rate increase of 13%, with the summer rate increasing 25% and non-summer increasing 9%. These rates are shown on Staff Exhibit No. 134, page 2 of 3.

Q. What are your rate design recommendations for Schedule 9 transmission service?

A. I am recommending that (1) the customer charge for transmission service be increased from $85.58 to $100.00, a 13% increase; (2) the basic charge be increased from $0.39 to $0.44, a 13% increase; (3) the summer demand charge increase 25% from $2.57 to $3.22, with the non-summer demand increasing 9% from $2.57 to $2.80 for an overall increase of 13% in the demand charges; and (4) an overall energy rate increase of 13%, with the summer rate increasing 25% and non-summer increasing 9%. These rates are shown on Staff Exhibit No. 134, page 3 of 3.

RATE DESIGN LARGE POWER SERVICE SCHEDULE 19

Q. What is Staff's recommended change in the revenue requirement for Large Power Schedule 19?

A. Because Staff's COS analysis shows no change in revenue requirement for Schedule 19, my proposed changes in rate design are revenue neutral. I am recommending rate design changes in the demand and energy charges, consistent with the Company's proposal for seasonal and time-of-use rates. TOU rates are most appropriate for Schedule 19 customers who are sophisticated enough to

1 understand them and where the metering equipment already
2 exists.
3 Q. Please summarize the rates you are proposing for
4 Schedule 19.
5 A. For Schedule 19 I am recommending no change in
6 the customer charge or the basic charge. Currently there
7 is no distinction in the demand or energy charges between
8 summer and non-summer, peak and non-peak. My proposal,
9 like that of the Company's, would be to price peak demand
10 and energy higher in the summer and in the peak periods.
11 The specific rates that I am proposing are shown in Staff
12 Exhibit No. 135, page 1, Schedule 19 Secondary; page 2,
13 Schedule 19 Primary; and page 3, Schedule 19 Transmission.
14 **RATE DESIGN IRRIGATION SCHEDULE 24**
15 Q. What is Staff's recommended revenue requirement
16 increase for Irrigation Schedule 24?
17 A. Staff recommends that Schedule 24 rates be
18 increased by 15% or about one-third the amount dictated by
19 the COS study.
20 Q. Why is Staff not recommending that Schedule 24
21 rates be increased the full amount dictated in COS?
22 A. The increase to move Schedule 24 to the full COS
23 would be 47.2%. Staff believes that amount of increase is
24 excessive and should not be made all at one time. The
25 amount of increase that is reasonable is a matter of

judgment. While irrigators would receive a substantial rate increase (15%), the one-third move requires that over $19 million attributable to irrigation customers be reallocated to the other customer classes. If this reallocation amount were much greater, other customer classes would be affected to the point that some would actually require increases larger than that required for Schedule 24. Staff felt that a one-third move toward COS was a reasonable balance between the objectives of COS, the subsidy required from other classes, and the ability of the irrigation class to absorb the rate increase.

Q. What is the history of COS for the Irrigation Schedule 24?

A. In the U-1006-265 rate case, the increase needed to bring Schedule 24 to the full COS rate of 40.24 mills/kWh, was 31.71%. The Commission ordered a 5.02% increase bringing the average rate for the Schedule to 32.08 mills/kWh. Order No. 20610.

In the next general rate case, IPC-E-94-5, the increase needed to bring Schedule 24 to the full COS rate of 40.78 mills/kWh, was 17.99%. The Commission ordered a 10.23% increase bringing the average rate for the Schedule to 38.10 mills/kWh. Order No. 25880.

Currently, Schedule 24 is paying an average rate of 37.2 mills/kWh. The Staff's COS study indicates that

the full cost of service rate is 54.76 mills/kWh and would require a 47.22% increase. With the 15% increase that Staff is proposing, the Schedule 24 rate would increase to 42.77 mills/kWh.

It is interesting to note that if one were to rely on the COS study that the Commission used in the U-1006-265 case in 1986, Schedule 24 would require an 8.2% increase to bring them to the full 1986 COS rate even with no overall increase in revenue to the Company. Today, Staff's proposal for the 15% increase would bring Schedule 24 to a rate just 2.5 mills above their 1986 COS rate.

Q. What is your rate design proposal for Schedule 24?

A. I am proposing an overall increase in the Schedule 24 rates of 15%. The in-season customer charge ("bills in-season") would increase from $10.07 to $12.00; the out-of-season customer charge ("bills out-of-season") and the minimum charge would increase from $2.50 to $3.00. The in-season demand charge would increase from $3.58 to $4.00 and I am proposing that there be an out-of-season demand charge of $0.80. I propose to reduce the out-of-season energy rate so that it is no longer higher than the in-season rate. The in-season energy rate would increase 16%, and the out-of-season energy rate would decrease 9% so that both rates are equal at $0.032830/kWh. These

rates are summarized on Staff Exhibit No. 136.

Q. How did you arrive at your proposed increase for the bills in-season, bills out-of-season and the minimum charge?

A. I applied the average increase of 15% to the existing rate and rounded to an even dollar amount. For example, a 15% increase to the $2.50 minimum charge or bills out-of-season would be $2.88, which I rounded up to $3.00. Under my proposal the Residential Schedule 1 and the Irrigation Schedule 24 would have the lowest minimum charge of any customer class at $3.00.

Q. How did you arrive at the amount of your proposed increase for the in-season demand charge?

A. I applied the average increase of 15% to the existing rate and rounded to an even dollar amount.

Q. Why are you proposing an out-of-season demand charge?

A. Currently there is no demand charge out-of-season. Any fixed cost that would normally be collected in a demand charge are now collected in the out-of-season energy rate. This results in an out-of-season energy rate that is 27% higher than the in-season energy rate. Although I understand why this may have occurred in the past, it now seems inconsistent with proposed rate structures designed to send price signals reflecting

higher costs in peak periods than in off peak periods. I am proposing an out-of-season demand charge that would recover the fixed costs that are now being collected in the out-of-season energy rate so that an out-of-season energy rate can be set that is no higher than the in-season energy rate.

Q. How did you arrive at the amount of your proposed out-of-season demand charge?

A. If the current out-of-season energy rate were set equal to the current in-season energy rate, it would collect $2.4 million less revenue. I propose to collect that amount plus 15% (the average proposed increase) in the out-of-season demand charge, or $0.80. This protects the current split between in-season revenue and out-of-season revenue, but it collects fixed demand-related costs in the demand charge and not in the energy charge. This restores an energy rate that is more reflective of power supply cost.

Q. How did you establish the energy rate?

A. I calculated the average energy rate necessary to produce the total revenue requirement with the in-season energy rate set equal to the out-of-season energy rate. The resulting energy rate is $0.03283/kWh, which is 15% higher than the current in-season rate and 9% lower than the current out-of-season rate.

Q. How will this new out-of-season demand charge affect irrigation customers?

A. Staff Exhibit No. 137 shows what an irrigation bill would be for operation of a 100 horsepower pump using various amounts of energy under the proposed rate 1) with a demand charge and lower out-of-season energy rate, and 2) without a demand charge but with the higher out-of-season energy rate. It shows that for usage above 6843 kWh in a month the customer will actually pay less under the proposed rate than he or she would under rates without a demand charge. Customers with high demand and low usage will pay more and those with low demand and high usage will pay less. If an irrigation customer started a single 100 horsepower pump and ran it for only 10 hours in the entire month, having no other usage, he would pay $34.20 under the rate without a demand charge as compared to $87.56 under the proposed rate with the demand charge. If that same horsepower pump were to operate for 200 hours, the bills would be $552.00 under the rate without a demand charge and $624.00 under the proposed rate with the demand charge.

Q. What is the overall change in revenue that Staff recommends for the TOU Irrigation Schedule 25?

A. Staff recommends an overall average increase in rates for TOU Irrigation of 15%, which is the same as that

recommended for the Irrigation Schedule 24.

Q. What are your rate design recommendations for Schedule 25?

A. I am making the same rate design proposal for Schedule 25 as I made for Schedule 24 except the energy rates are dependant on TOU.

(a) In-season charges would increase from $10.07 to $12.00; out-of-season charges and minimum charges would increase from $2.50 to $3.00; the meter charge would remain at $3.00; the in-season demand charge would increase from $3.58 to $4.00; and the out-of-season demand charge would be established at $0.80.

(b) I maintained the same relationship between the On-peak, Mid-peak and Off-peak rates while reducing the out-of-season rate to be equal to the Mid-peak rate. The resulting energy rates are 19.7% higher than current rates except for the out-of-season rate, which is 5.9% lower. The energy rates are as follows:
On-peak $0.059544/kWh; Mid-peak $0.034025/kWh; Off-peak $0.017013/kWh; and Out-of-Season $0.034025/kWh. The rates are shown on Staff Exhibit No. 138.

Q. What are your recommendations for Dusk to Dawn Lighting Schedule 15, Unmetered General Service Schedule 40, Street Lighting Schedule 41, and Traffic Control Lighting Schedule 42?

A. I am recommending a uniform change in all the rates (except the minimum charges) for Schedules 15, 40, and 41 for an overall reduction of 36.6%, 10.48%, and 7.91%, respectively. I am recommending no change in Schedule 42.

Q. What is your recommendation for the following contract schedules: Schedule 26 Micron, Schedule 29 Simplot, and Schedule 30 DOE?

A. I am recommending a uniform change reduction in rates for Micron of 2.01%, a uniform reduction in rates of 3.43% for Simplot, and a uniform increase in rates of 1.05% for DOE.

Q. Do you have any other rate design recommendations?

A. Yes, I am recommending no change in the Energy Efficiency Rider Schedule 91.

Q. Does this conclude your direct testimony in this proceeding?

A. Yes, it does.