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IDAHO PUBLIC
UTILITIES COMMISSION

STATE OF IDAHO
BEFORE THE 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**

BRIEF OF THE KROGER CO.

I. INTRODUCTION

On October 16, 2003, Idaho Power Company ("the Company") filed an Application with the Idaho Public Utilities Commission ("Commission") for authority to increase the Company's general rates an average of 18 percent. If approved, Company revenues would increase by nearly $86 million annually. Idaho Power provides electric service to approximately 405,000 residential, commercial, industrial and irrigation customers in southern Idaho including The Kroger Co. ("Kroger"). Kroger operates 11 retail grocery and general merchandise facilities in the state of Idaho served by the Company. These stores purchase more than 30 million kWh of electricity from the Company annually.

Kroger submits this Brief in support of its argument that: 1) If any rate increase is applied to Rate 9, the same percentage increase should be applied to Rates 9-S, 9-P, and 9-T so that a reasonable, cost-based price differential is retained among them; 2) time-of-use rates should be available to Schedule 9 customers, so that these customers could better respond to price signals, as well as pay rates that are more closely aligned with the costs they cause; 3) Kroger generally agrees with the Company's proposal to weight any rate increases relatively more heavily on the

demand charge, as opposed to the energy charge, for those rate schedules with demand meters; and 4) the Commission should modify the Company's proposed rate cap for the Irrigation class if an overall base-rate increase of less than 18 percent is approved and gradually phase in a rate increase to the irrigators over the next several years in order to align Irrigation class rates with cost of service and relieve the burden borne by the other classes that are subsidizing the Irrigators.

II. ARGUMENT

1. If Any Rate Increase Is Applied To Rate 9, The Same Percentage Increase Should Be Applied To Rates 9-S, 9-P, And 9-T So That A Reasonable, Cost-Based Price Differential Is Retained Among Them That Recognizes That Taking Service At Primary Voltage Is Less Expensive For The Utility To Serve Than Taking Service At Secondary Service.

Staff has recommended a 0.13 percent rate reduction for Rate 9-S and a 13.31 percent rate increase for Rates 9-P and 9-T. Although Kroger generally agrees with Staff that cost-of-service analysis should be given a very strong weight in determining rate spread, it is also important to have a rational pricing regime within rate schedules. Staff's recommendation contains a serious flaw (perhaps unintended) because it results in primary voltage customers paying almost the same rate as secondary voltage customers.

In the case of the relationship between secondary and primary service within a rate schedule (such as between 9-S and 9-P) it is important for prices to indicate that *for any given customer*, taking service at primary voltage is less expensive for the utility to serve than taking service at secondary service. Unfortunately, Staff's rate spread proposal for Rate 9 would cause the price differential between primary service and secondary service to all but disappear. This

result would not only lead to irrational pricing within Rate 9, it would be punitive to customers who invested in the necessary transformer equipment to take primary service based on the current price differential. By making the investment in such equipment themselves, primary service customers allow the utility to conserve capital, slow the growth in distribution system rate base, and absorb less line losses. All across the country these utility cost savings result in primary service being less expensive than secondary.

The price differential between Rates 9-S and 9-P under current rates and under Staff's proposed rates is shown in Attachment A. The analysis utilizes hypothetical customers of various sizes and load factors. A summary of these results are shown in the Table below.

Table 1[1]
Comparison of Rates 9-S and 9-P
(Positive % indicates Primary is less expensive than Secondary)

Customer	Current Primary Discount	Staff Proposed Primary Discount
500 kw, 45% l.f.	9.41%	-2.61%
500 kw, 60% l.f.	11.20%	-0.54%
500 kw, 75% l.f.	12.41%	0.84%
750 kw, 45% l.f.	9.87%	-2.07%
750 kw, 60% l.f.	11.57%	-0.11%
750 kw, 75% l.f.	12.72%	1.21%
1000 kw, 45% l.f.	10.10%	-1.80%
1000 kw, 60% l.f.	11.78%	0.11%
1000 kw, 75% l.f.	12.87%	1.39%

The above Table shows that under current rates, primary service is about 9 to 13 percent less expensive than secondary for any given customer. But under Staff's proposal, this differential is virtually eliminated. In fact, in many cases, primary service would actually become more expensive than secondary. This abnormal result could not have been intended since nearly

[1] Higgins, Rebuttal Testimony, p. 4. lines 1-20.

equalized primary and secondary rates is contrary to customary and standard ratemaking principles.

Staff Exhibit No. 127 does show that under its proposal, the average price per kWh for Rate 9-S would be 3.645 cents per kWh, and the average price per kWh for Rate 9-P would be 3.369 cents per kWh. At first glance, this information might appear to contradict the Table above. However, there is no contradiction. The lower average price for Rate 9-P reflects the larger size and higher load factor of the average customer in this group relative to Rate 9-S. These same customers would have lower-than-average rates if they were on secondary service, as well, given their load characteristics. The problem is that under Staff's proposal, for each of these primary customers individually, the primary and secondary rates would become almost indistinguishable, even though for each of these customers, primary service is less expensive to provide.[2]

Primary service is less expensive to provide than secondary service for two main reasons: (1) Primary service requires fewer utility-provided facilities, as primary customers provide their own transformers, thereby reducing the amount of utility capital expenditures needed to provide distribution service; and (2) primary service incurs fewer line losses to the customers' meter, meaning that for each hundred kilowatt-hours delivered to a customer's meter, the utility needs to generate fewer kilowatt-hours to serve a customer on primary service than on secondary service. On Idaho Power's system, the line loss differential between primary and secondary service is about 3 percent.[3]

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[2] Higgins Rebuttal Testimony, p. 4, lines 23-33.
[3] Said Workpapers, pp. 3-4.

It is clear that primary service is less expensive to serve than secondary, even though the cost-of-service study produced a result that lead Staff to propose raising Rate 9-P so much that the differential between Rate 9-S and Rate 9-P disappears. Cost-of-service analysis allocates system costs to groupings of customers based on a series of allocation factors. Generally, allocation factors are intended to capture information about the pattern of usage of each customer group taken as a whole, such as relative usage during a monthly system peak hour. During the test year, the Rate 9-P group, taken as a whole, exhibited a usage pattern that was allocated a greater increase in cost responsibility relative to current revenues than Rate 9-S. This was due, in part, to a higher per-unit allocation of production costs.[4]

As noted above, it is important to have a rational pricing regime that recognizes that *for any given customer*, taking service at primary voltage is less expensive for the utility to serve than taking service at secondary service.

It is also important to recognize that, theoretically, for any sub-group of Rate 9, a cost-of-service allocation could be performed that would produce results that varied from the results for Rate 9 as a whole. These results would reflect the mix of customers in the sub-group. An important question, then, is whether the most appropriate criteria are being used to define the sub-group. For example, it is useful to avoid categorizing customers into relatively small sub-groups of otherwise similarly-situated customers. Smaller groups tend to have less diversity with respect to their coincident peaks and their non-coincident demands. A lack of diversity adversely impacts the per-unit charges derived for the group from the allocation of peak-related costs.

[4] Higgins, Rebuttal Testimony p. 5, lines 15-20; p. 6. lines 1-2. See Also, Idaho Power Exhibit No. 42, pp. 4-5.

In addition to providing time-of-use price signals, which is addressed below, it is important that customers be grouped, for cost-of-service purposes, in a manner that minimizes the likelihood of anomalous results.

In the case of Rate 9, the customer qualifications to take service under Rates 9-S, Rate 9-P, and Rate 9-T are identical, except for the voltage level at which service is taken. In addition, Rate 9-S is a much larger group than either 9-P or 9-T. In this situation, allocating a demand-related function (such as production) to Rate 9-P separately from the rest of Rate 9 might lead to anomalous results.[5]

Rates 9-S, 9-P, and 9-T should be combined and a reasonable, cost-based price differential should be retained among them. This price differential would recognize that *for any given customer*, taking service at primary voltage is less expensive for the utility to serve than taking service at secondary service.

Attachment B summarizes Kroger's proposal to combine Rates 9-S, 9-P, 9-T. The same overall revenue requirement to the aggregate of 9-S, 9-P, and 9-T is applied as in the Staff's recommendation, but is spread on an equal percentage basis across the entire Rate 9. This results in a 1.16 percent increase on all the Rate 9 customers. This approach would retain a reasonable price differential between Rate 9-S and 9-P. Kroger recommends that this modification to Staff's Rate 9 rate spread be adopted by the Commission.

2. Time-Of-Use Rates Should Be Made Available To Schedule 9 Customers, In Order For These Customers To Better Respond To Price Signals, And To More Closely Align Costs With The Cost-Causers.

[5] Higgins, Rebuttal Testimony, p. 7, lines 1-6.

Time-of-use rates should be available to Schedule 9 customers, so that these customers could better respond to price signals, as well as pay rates that are more closely aligned with the costs they cause. Idaho Power is proposing mandatory time-of-use rates for Schedule 19 in order to send improved price signals to customers. The Company also has an optional time-of-use rate for Irrigation service that is in place on a pilot basis. However, the Company neither has, nor proposes, any time-of-use options for Schedule 9 customers, who represent 26 percent of the retail energy consumed on the Idaho Power system.[6]

Energy costs vary across the hours of the day, with the most expensive hours typically occurring from the late morning to early evening. Designing the energy price to end-use customers to reflect these variations in energy costs sends the proper signal to customers regarding the relative cost to operate the system during the peak, mid-peak, and off-peak hours. Customers would then use this pricing information to alter their discretionary patterns of usage, increasing efficiency and lowering the overall cost of energy to the system.

As Schedule 9 customers represent over a quarter of the retail energy consumption on the Idaho Power system, the failure to offer time-of-use rates to them deprives this class of customers of the opportunity to save money by responding to appropriate price signals. It also deprives the system of the benefit of a more efficient load pattern that would result from this responsive behavior. Basic fairness also dictates that customers whose patterns of energy consumption are less expensive to serve than the average in their class should see that lower cost reflected in their bills. Idaho Power is moving in this direction for Schedule 19. The Company should also take steps in this direction for Schedule 9.

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[6] See Idaho Power Exhibit No. 43, p. 1, col. 3.

Time-of-use rates are widely available throughout the west for customers of comparable size to Schedule 9. Table KCH-1 below is a partial list of other western utilities that offer time-of-use rates to customers with billing demands of 1000 kw of less, comparable to Schedule 9.

Table KCH-1[7]

Western Utilities with Time-of-Use Rates for Customers with Billing Demands of 1000 kw or less

State	Utility	Type
Arizona	Arizona Public Service	Pilot*
Arizona	Salt River Project	Optional
Arizona	Tucson Electric Power	Optional
California	LADWP	Optional <500 kw
California	LADWP	Mandatory >500 kw
California	PG&E	Optional <500 kw
California	PG&E	Mandatory >500 kw
California	SDG&E	Optional <500 kw
California	SDG&E	Mandatory >500 kw
California	So. Cal. Edison	Optional <500 kw
California	So. Cal. Edison	Mandatory >500 kw
California	SMUD	Mandatory
Colorado	Public Service Colorado	Optional
Nevada	Sierra Pacific	Optional
Oregon	PacifiCorp	Optional
Oregon	Portland General	Optional
Utah	PacifiCorp	Optional

* Permanent TOU rate proposed in pending rate case

In Idaho, PacifiCorp offers an optional time-of-use rate, but the rate design only differentiates between on-peak and off-peak demand – not energy. As such, it should not be incorporated here.

Due to the certain difficulty in mandating an immediate change to time-of-use rates, Schedule 9 time-of-use rates should be made available for the upcoming rate-effective period on a voluntary basis. At a minimum, such a rate should be offered as part of a pilot program, which

[7] Higgins Testimony, pp. 9-10.

could be used to gather information on the price responsiveness and benefits derivable from expanding time-of-use rates more broadly to Schedule 9 customers. This voluntary time-of-use option for Schedule 9 should offer peak, mid-peak and off-peak energy prices that properly reflect time-of-use cost differences. It is not necessary to add the complexity of the two-tiered demand charge that the Company is proposing for Schedule 19.

The Commission should order the Company, as part of any compliance filing in this case, to file a voluntary time-of-use rate for Schedule 9 customers that provides peak, mid-peak, and off-peak energy prices that properly reflect time-of-use cost differences. A general rate case is the best time to adopt a new time-of-use rate, as it allows for the full consideration of the revenue effects that accompany the creation of a new rate schedule. In addition, Idaho Power has noted its increased gas price risk in recent years associated with purchased power, with the attendant higher energy costs.[8] It is important to take appropriate rate design steps now, rather than delaying. If it is another ten years until the next Idaho Power rate case, and this issue is simply deferred for later action, the opportunity to send efficient price signals for Schedule 9 customers could be delayed a decade.

3. Kroger Supports The Company's Proposal To Weigh Any Rate Increases Relatively More Heavily On The Demand Charge.

Kroger generally agrees with the Company's proposal to weight any rate increases relatively more heavily on the demand charge, as opposed to the energy charge, for those rate schedules with demand meters. Weighting any increase toward the demand charge would tend to

[8] See, for example, pre-filed direct testimony of J. LaMont Keen, p. 5, line 21 – p. 6, line 20.

reflect the composition of the Company's underlying costs.[9] For this reason, if there is an increase, weighting it toward the demand charge is preferable to weighting it toward the energy charge.

4. The Commission Should Modify The Company's Proposed Rate Cap For The Irrigation Class If An Overall Base-Rate Increase Of Less Than 18 Percent Is Approved.

Idaho Power proposes a significant subsidy to the Irrigation class. According to the Company's cost-of-service analysis, it would require a 67 percent increase in Irrigation base rates for this class to fully recover its costs if the Company's requested overall base-rate increase of 18 percent is approved.[10] To mitigate the impact of the base-rate increase for this class, the Company proposes to cap the Irrigation increase at 25 percent, with the difference spread to the other rate classes. Although it is reasonable to cap rates in order to mitigate the impact of a large rate increase for a deeply subsidized customer class, the Commission should modify the Company's proposed rate cap for the Irrigation class if an overall base-rate increase of less than 18 percent is approved. Additionally, the Commission should gradually phase in a rate increase to the irrigators over the next several years in order to align Irrigation class rates with cost of service and relieve the burden borne by the other classes that are subsidizing the Irrigators.

In its request for an 18 percent rate increase the Company proposes to cap the Irrigation base-rate increase at 25 percent, with the difference spread to the other rate classes.[11] Capping the base rate increase at 25 percent for any customer class for the purpose of limiting rate shock is reasonable. However, it is also important to adopt additional guidelines for spreading rates in

[9] Idaho Power Exhibit No. 42, See Also Pre-filed direct testimony of Maggie Brilz, p. 50, lines 18-25.
[10] Higgins, Testimony p. 4, lines 5-9.
[11] IPC Ex. No. 61.

the event that the Commission reduces the Company's proposed overall rate increase. In that case, the base-rate increase to the Irrigation class should be capped at 25 percent, or twice the system average increase, whichever is less. This would retain the 25 percent cap proposed by the Company, but would also apply a sliding scale to the Irrigation class increase that would lessen the amount of the subsidy to the extent the rate increase is smaller than proposed by the Company. So, for example, if the Commission approved an overall base-rate increase of 10 percent, the base-rate increase to the Irrigation class would be capped at 20 percent.

Additionally, the Commission should take steps toward eliminating the subsidy to the Irrigation class by adopting a multi-year phase-in toward cost of service rates. This could be accomplished by setting a cost of service target and taking incremental steps toward that target over several years. Specifically, Kroger recommends a rate plan that moves Irrigation base-rates one-third of the way to full cost of service rates in three steps over three years, measured from the initial rates approved in this proceeding. The revenue from the annual adjustments would be used to alleviate the subsidy paid by the other rate classes by reducing their rates on an equal percentage basis each of the three years. For example, the maximum phase-in adjustment would occur if the Company's proposed base-rate increase of 18 percent is adopted. This case is illustrated in Attachment C. In this case, Irrigation customers would require a 67 percent base-rate increase to move to cost of service rates, but would only receive a 25 percent initial increase. Movement to full cost of service rates would require another 42 percent increase, one-third of which is 14 percent. The latter would represent the phase-in target, which would be reached in three installments over three years of 4.7 percent per year.

The revenues from the 4.7 percent annual phase-in would be used to reduce the subsidy from other classes, amounting to a .67 percent annual base-rate decrease for those classes each year, for a cumulative base-rate reduction of 2 percent.

It is imperative that the Commission set a plan into action that will reduce the subsidy to the Irrigation class over time rather than revisiting this issue in the Company's next rate case. There is no assurance that a rate case will be filed in the next three years. Indeed, it has been about ten years since the last Idaho Power rate case. Locking in a significant subsidy for an indefinite period of time is not reasonable to the customer classes providing the subsidy and is counter to the fundamental consideration of rate making; cost of service.

Kroger is well aware that the Commission has traditionally discounted cost of service studies as inherently inaccurate and "*a balance of art and economic principles*"[12] due to the perception that a cost of service study can be easily manipulated to align to a party's interest rather than actual cost-causation. This view of cost-based rates is in the distinct minority given the near-universal belief among other regulatory bodies[13] and scholars that cost-causation be the primary consideration in setting rates.

> *"True, other factors of ratemaking are potent and are sometimes controlling ...* [b]*ut the cost standard has the widest range of application. Rates found to be far in excess of cost are at least highly vulnerable to a charge of unreasonableness. Rates found*

[12] IPUC, Case No. WWP-E-98-11, Order No. 28097, p. 27 (1999).

[13] *"Cost allocation is simply an attempt to spread costs among various customer classes on the basis of a factor that is closely correlated with the incurrence of costs".* Re: Kentucky Utilities Co., 15 FERC ¶61,222 (1981). *"The Commission's long standing practice has been to base class revenue allocations on the cost-of-service."* Re: Central Illinois Light Co., 158 PUR 4th 1 (Illinois PSC 1994). See also Connecticut Power and Light, 144 PUR 4th 161 (Connecticut Department of Public Utility Control, 1993) (Commission moved all rates of return closer to company average thus reducing cost-of-service differentials and improving the state's business climate); Re Niagara Mohawk Power Corp., 140 PUR 4th 481 (New York PSC, 1993) (Commission approved rate design based on cost-of-service study which resulted in residential rate increase of 5.8% versus industrial rate increase of 1.4%); Re North Carolina Power, 142 PUR 4th 117 (North Carolina PUC, 1993) (utility was directed to realign its rates to move toward equalized rates of return. Accordingly, residential customers were assigned a greater portion of the rate increase than the large power customers who had already been paying in excess of their share of costs).

> *well below cost are likely to be tolerated, if at all, only as a necessary and temporary evil. For if rates are not compensatory, they are not subsidy free. In fact, the golden rule of socially optimal ratemaking is that, whenever possible, prices should track all identifiable ... costs occasioned by a service's provision."* James Bonbright, Principles Of Public Utility Rates pp. 109-110 (1988)
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> "*A major goal of cost allocation is the avoidance of cross-subsidization between classes of customers ... A cardinal rule of ratemaking is that where cross-subsidization is practiced, it should be wittingly practiced, rather than unwittingly or accidentally, and fully supported by reasoned decision making.*" Leonard Saul Goodman, The Process Of Ratemaking p. 374 (1998).

This is not to say that Idaho Commission precedent turns a blind eye to cost of service in setting rate. When the evidence is clear that one group of customers is subsidizing another, as it is in this case, Commission precedent dictates that such subsidies should be eliminated or dramatically cut back. In Case No. IPC-E-94-5 the Commission articulated its rule concerning proper rate allocation when there is reliable evidence of cross-subsidization between classes.

> "*Recognizing that cost-of-service studies are not precise, we think it important that cross subsidies among customer classes should be minimized. Accordingly, as outlined below we take significant steps to move each class closer to its indicated cost-of-service."* Order No. 25880 at. 34 (1995).

The phase-in approach detailed above accomplishes the worthwhile goal of blunting the initial impact on an under-recovering class, while continuing to move toward cost-of-service rates over time. If a rate case is filed during the phase-in period, then any rates approved from that case should supercede the phase-in rates, as of the rate-effective period associated with the new case.

III. CONCLUSION

Kroger argues that 1) If any rate increase is applied to Rate 9, the same percentage increase should be applied to Rates 9-S, 9-P, and 9-T so that a reasonable, cost-based price differential is retained among them; 2) time-of-use rates should be available to Schedule 9 customers, so that these customers could better respond to price signals, as well as pay rates that are more closely aligned with the costs they cause; 3) Kroger generally agrees with the Company's proposal to weight any rate increases relatively more heavily on the demand charge, as opposed to the energy charge, for those rate schedules with demand meters; and 4) the Commission should modify the Company's proposed rate cap for the Irrigation class if an overall base-rate increase of less than 18 percent is approved and gradually phase in a rate increase to the irrigators over the next several years in order to align Irrigation class rates with cost of service and relieve the burden borne by the other classes that are subsidizing the Irrigators.

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April 23, 200

Rate 9 Primary Discount Under Current and Staff Proposed Rate

500 kW Customer
@ 45%, 60% and 75% LF

		STAFF PROPOSED RATES Secondary				CURRENT RATES Secondary				STAFF PROPOSED RATES Primary				CURRENT RATES Primary				Primary Discount vs. Secondary	
		Billed Demand	Customer Charge	Energy Charge	Basic Charge	Billed Demand	Customer Charge	Energy Charge	Basic Charge	Billed Demand	Customer Charge	Energy Charge	Basic Charge	Demand Charge	Customer Charge	Energy Charge	Basic Charge	Current Primary vs. Current Secondary	Staff Primary vs. Staff Secondary
	Summer	$3.00	$5.54	$0.028744	$0.36	$2.73	$5.54	$0.026150	$0.36	$3.32	$100.00	$0.026652	$0.87	$2.65	$85.58	$0.021308	$0.77		
	Non-Summer	$2.62	$5.54	$0.025200	$0.36					$2.89	$100.00	$0.023150	$0.87						
45%																			
Customer Charge			$66				$66				$1,200				$1,027			($960)	($1,134)
Summer Demand	500 kW	$4,500				$4,095				$4,980				$3,975				$120	($480)
Winter Demand	500 kW	$11,790				$12,285				$13,005				$11,925				$360	($1,215)
Electricity Summer	496,800 kWh			$14,280				$12,991				$13,241				$10,586		$2,406	$1,039
Electricity Winter	1,474,200 kWh			$37,150				$38,550				$34,128				$31,412		$7,138	$3,022
Max Demand	500 kW				$2,160				$2,160				$5,220				$4,620	($2,460)	($3,060)
Load Factor	45%																		
	Totals	$16,290	$66	$51,430	$2,160	$16,380	$66	$51,542	$2,160	$17,985	$1,200	$47,368	$5,220	$15,900	$1,027	$41,998	$4,620	$6,603	($1,827)
			Annual Total		$69,946		Annual Total		$70,148		Annual Total		$71,773		Annual Total		$63,545	9.41%	-2.61%
60%																			
Customer Charge			$66				$66				$1,200				$1,027			($960)	($1,134)
Summer Demand	500 kW	$4,500				$4,095				$4,980				$3,975				$120	($480)
Winter Demand	500 kW	$11,790				$12,285				$13,005				$11,925				$360	($1,215)
Electricity Summer	662,400 kWh			$19,040				$17,322				$17,654				$14,114		$3,207	$1,386
Electricity Winter	1,965,600 kWh			$49,533				$51,400				$45,504				$41,883		$9,517	$4,029
Max Demand	500 kW				$2,160				$2,160				$5,220				$4,620	($2,460)	($3,060)
Load Factor	60%																		
	Totals	$16,290	$66	$68,573	$2,160	$16,380	$66	$68,722	$2,160	$17,985	$1,200	$63,158	$5,220	$15,900	$1,027	$55,997	$4,620	$9,784	($473)
			Annual Total		$87,099		Annual Total		$87,329		Annual Total		$87,563		Annual Total		$77,544	11.20%	-0.54%
75%																			
Customer Charge			$66				$66				$1,200				$1,027			($960)	($1,134)
Summer Demand	500 kW	$4,500				$4,095				$4,980				$3,975				$120	($480)
Winter Demand	500 kW	$11,790				$12,285				$13,005				$11,925				$360	($1,215)
Electricity Summer	828,000 kWh			$23,800				$21,652				$22,068				$17,643		$4,009	$1,732
Electricity Winter	2,457,000 kWh			$61,916				$64,251				$56,880				$52,354		$11,897	$5,037
Max Demand	500 kW				$2,160				$2,160				$5,220				$4,620	($2,460)	($3,060)
Load Factor	75%																		
	Totals	$16,290	$66	$85,716	$2,160	$16,380	$66	$85,903	$2,160	$17,985	$1,200	$78,947	$5,220	$15,900	$1,027	$69,997	$4,620	$12,965	$881
			Annual Total		$104,233		Annual Total		$104,509		Annual Total		$103,352		Annual Total		$91,544	12.41%	0.84%

Kroger Rebuttal Exhibit No. 903
Case No. IPC-E-03-13
K.C. Higgins
3/19/04

Rate 9 Primary Discount Under Current and Staff Proposed Rate

750 kW Customer
@ 45%, 60% and 75% LF

		STAFF PROPOSED RATES Secondary				CURRENT RATES Secondary				STAFF PROPOSED RATES Primary				CURRENT RATES Primary				Primary Discount vs. Second	
		Billed Demand	Customer Charge	Energy Charge	Basic Charge	Billed Demand	Customer Charge	Energy Charge	Basic Charge	Billed Demand	Customer Charge	Energy Charge	Basic Charge	Demand Charge	Customer Charge	Energy Charge	Basic Charge	Current Primary vs. Current Secondary	Staff Primary Staff Second
	Summer	$3.00	$5.54	$0.028744	$0.36	$2.73	$5.54	$0.026150	$0.36	$3.32	$100.00	$0.026652	$0.87	$2.65	$85.58	$0.021308	$0.77		
	Non-Summer	$2.62	$5.54	$0.025200	$0.36					$2.89	$100.00	$0.023150	$0.87						
Customer Charge			$66				$66				$1,200				$1,027			($960)	($1,134)
Summer Demand	750 kW	$6,750				$6,143				$7,470				$5,963				$180	($720)
Winter Demand	750 kW	$17,685				$18,428				$19,508				$17,888				$540	($1,823)
Electricity Summer	745,200 kWh			$21,420				$19,487				$19,861				$15,879		$3,608	$1,559
Electricity Winter	2,211,300 kWh			$55,725				$57,825				$51,192				$47,118		$10,707	$4,533
Max Demand	750 kW				$3,240				$3,240				$7,830				$6,930	($3,690)	($4,590)
Load Factor	45%																		
	Totals	$24,435	$66	$77,145	$3,240	$24,570	$66	$77,312	$3,240	$26,978	$1,200	$71,053	$7,830	$23,850	$1,027	$62,997	$6,930	$10,385	($2,174)
			Annual Total		$104,885		Annual Total		$105,189		Annual Total		$107,060		Annual Total		$94,804	9.87%	-2.07%
Customer Charge			$66				$66				$1,200				$1,027			($960)	($1,134)
Summer Demand	750 kW	$6,750				$6,143				$7,470				$5,963				$180	($720)
Winter Demand	750 kW	$17,685				$18,428				$19,508				$17,888				$540	($1,823)
Electricity Summer	993,600 kWh			$28,560				$25,983				$26,481				$21,172		$4,811	$2,079
Electricity Winter	2,948,400 kWh			$74,300				$77,101				$68,255				$62,825		$14,276	$6,044
Max Demand	750 kW				$3,240				$3,240				$7,830				$6,930	($3,690)	($4,590)
Load Factor	60%																		
	Totals	$24,435	$66	$102,860	$3,240	$24,570	$66	$103,083	$3,240	$26,978	$1,200	$94,737	$7,830	$23,850	$1,027	$83,996	$6,930	$15,157	($143)
			Annual Total		$130,601		Annual Total		$130,960		Annual Total		$130,744		Annual Total		$115,803	11.57%	-0.11%
Customer Charge			$66				$66				$1,200				$1,027			($960)	($1,134)
Summer Demand	750 kW	$6,750				$6,143				$7,470				$5,963				$180	($720)
Winter Demand	750 kW	$17,685				$18,428				$19,508				$17,888				$540	($1,823)
Electricity Summer	1,242,000 kWh			$35,700				$32,478				$33,102				$26,465		$6,014	$2,598
Electricity Winter	3,685,500 kWh			$92,875				$96,376				$85,319				$78,531		$17,845	$7,555
Max Demand	750 kW				$3,240				$3,240				$7,830				$6,930	($3,690)	($4,590)
Load Factor	75%																		
	Totals	$24,435	$66	$128,575	$3,240	$24,570	$66	$128,854	$3,240	$26,978	$1,200	$118,421	$7,830	$23,850	$1,027	$104,995	$6,930	$19,928	$1,888
			Annual Total		$156,318		Annual Total		$156,731		Annual Total		$154,429		Annual Total		$135,802	12.72%	1.21%

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Rate 9 Primary Discount Under Current and Staff Proposed Rate

1,000 kW Customer
@ 45%, 60% and 75% LF

		STAFF PROPOSED RATES Secondary				CURRENT RATES Secondary				STAFF PROPOSED RATES Primary				CURRENT RATES Primary				Primary Discount vs. Secondary	
		Billed Demand	Customer Charge	Energy Charge	Basic Charge	Billed Demand	Customer Charge	Energy Charge	Basic Charge	Billed Demand	Customer Charge	Energy Charge	Basic Charge	Demand Charge	Customer Charge	Energy Charge	Basic Charge	Current Primary vs. Current Secondary	Staff Primary vs Staff Secondary
	Summer	$3.00	$5.54	$0.028744	$0.36	$2.73	$5.54	$0.026150	$0.36	$3.32	$100.00	$0.026652	$0.87	$2.65	$85.58	$0.021308	$0.77		
	Non-Summer	$2.62	$5.54	$0.025200	$0.36					$2.89	$100.00	$0.023150	$0.87						
45%																			
Customer Charge			$66				$66				$1,200				$1,027			($960)	($1,134)
Summer Demand	1,000 kW	$9,000				$8,190				$9,960				$7,950				$240	($960)
Winter Demand	1,000 kW	$23,580				$24,570				$26,010				$23,850				$720	($2,430)
Electricity Summer	993,600 kWh			$28,560				$25,983				$26,481				$21,172		$4,811	$2,079
Electricity Winter	2,948,400 kWh			$74,300				$77,101				$68,255				$62,825		$14,276	$6,044
Max Demand	1,000 kW				$4,320				$4,320				$10,440				$9,240	($4,920)	($6,120)
Load Factor	45%																		
	Totals	$32,580	$66	$102,860	$4,320	$32,760	$66	$103,083	$4,320	$35,970	$1,200	$94,737	$10,440	$31,800	$1,027	$83,996	$9,240	$14,167	($2,521)
			Annual Total		$139,826		Annual Total		$140,230		Annual Total		$142,347		Annual Total		$126,063	10.10%	-1.80%
60%																			
Customer Charge			$66				$66				$1,200				$1,027			($960)	($1,134)
Summer Demand	1,000 kW	$9,000				$8,190				$9,960				$7,950				$240	($960)
Winter Demand	1,000 kW	$23,580				$24,570				$26,010				$23,850				$720	($2,430)
Electricity Summer	1,324,800 kWh			$38,080				$34,644				$35,309				$28,229		$6,415	$2,771
Electricity Winter	3,931,200 kWh			$99,066				$102,801				$91,007				$83,766		$19,035	$8,059
Max Demand	1,000 kW				$4,320				$4,320				$10,440				$9,240	($4,920)	($6,120)
Load Factor	60%																		
	Totals	$32,580	$66	$137,146	$4,320	$32,760	$66	$137,444	$4,320	$35,970	$1,200	$126,316	$10,440	$31,800	$1,027	$111,995	$9,240	$20,529	$187
			Annual Total		$174,113		Annual Total		$174,591		Annual Total		$173,826		Annual Total		$154,062	11.76%	0.11%
75%																			
Customer Charge			$66				$66				$1,200				$1,027			($960)	($1,134)
Summer Demand	1,000 kW	$9,000				$8,190				$9,960				$7,950				$240	($960)
Winter Demand	1,000 kW	$23,580				$24,570				$26,010				$23,850				$720	($2,430)
Electricity Summer	1,656,000 kWh			$47,600				$43,304				$44,136				$35,286		$8,018	$3,464
Electricity Winter	4,914,000 kWh			$123,833				$128,501				$113,759				$104,708		$23,784	$10,074
Max Demand	1,000 kW				$4,320				$4,320				$10,440				$9,240	($4,920)	($6,120)
Load Factor	75%																		
	Totals	$32,580	$66	$171,433	$4,320	$32,760	$66	$171,805	$4,320	$35,970	$1,200	$157,895	$10,440	$31,800	$1,027	$139,994	$9,240	$26,891	$2,895
			Annual Total		$208,399		Annual Total		$208,952		Annual Total		$205,505		Annual Total		$182,061	12.87%	1.39%

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Kroger Rebuttal Exhibit No. 904
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K.C. Higgins
3/19/04

Summary of Schedule 9 Rate Spread Using IPUC Staff's Proposed Revenue Requirement

	STAFF PROPOSED	STAFF PROPOSED	KROGER PROPOSED
	Large General Service Secondary	Large General Service Primary & Trans.	Large General Service Total
Schedule No.	9S	9P & 9T	9S, 9P & 9T
2003 Average No. of Customers	17,299	116	17,415
2003 Sales Normalized (kWh)	2,667,376,237	347,050,749	3,014,426,986
Current Base Revenue ($)	97,349,138	10,319,874	107,669,012
Staff Proposed Final Rev. Adjustments ($)	(123,369)	1,373,312	1,249,943
Staff Proposed Base Revenue ($)	97,225,769	11,693,186	108,918,955
Percent Change	-0.13%	13.31%	1.16%

Data Source: IPUC Staff Exhibit No. 127 (D. Shunke)

Attachment B

Example of Three-Year Phase-In Toward Cost-of-Service Rates
Using Idaho Power's Proposed $86 Million Base Rate Increase

Normalized 12-Months ending December 31, 2003

Line No.	Tariff Description	(1) Rate Sch. No.[1]	(2) Current Base Revenue[1]	(3) COS Revenue Adjustments[2]	(4) COS Percent Change	(5) IPCo Proposed Revenue Adjustments[1]	(6) IPCo Proposed Percent Change	(7) COS Phase-in Annual Adjustment[3] (%)	(8) COS Phase-in Annual Adjustment[3] ($)
	Uniform Tariff Rates								
1	Residential Service	1	214,289,414	28,666,058	13.38%	40,786,881	19.03%	-0.67%	(1,426,221)
2	Small General Service	7	16,798,476	2,563,674	15.26%	3,529,614	21.01%	-0.67%	(111,804)
3	Total Large General Service	9	107,669,012	10,309,059	9.57%	16,194,270	15.04%	-0.67%	(716,600)
4	Dusk to Dawn Lighting	15	1,389,106	(1,412,294)	-101.67%	69,323	4.99%	-0.67%	(9,245)
5	Large Power Service	19	55,063,573	4,660,409	8.46%	7,639,707	13.87%	-0.67%	(366,480)
6	Agricultural Irrigation Service	24	60,291,575	40,456,288	67.10%	15,078,364	25.01%	4.68%	2,819,769
7	Unmetered General Service	40	907,689	(221,178)	-24.37%	45,246	4.98%	-0.67%	(6,041)
8	Street Lighting	41	1,809,269	(267,473)	-14.78%	90,219	4.99%	-0.67%	(12,042)
9	Traffic Control Lighting	42	284,145	21,332	7.51%	36,598	12.88%	-0.67%	(1,891)
10	*Total Uniform Tariffs*		458,502,259	84,775,875	18.49%	83,470,222	18.20%	0.04%	169,445
	Special Contracts								
11	Micron	26	16,204,104	465,070	2.87%	1,296,405	8.00%	-0.67%	(107,848)
12	J R Simplot	29	4,632,571	(82,642)	-1.78%	144,341	3.12%	-0.67%	(30,832)
13	DOE	30	4,622,414	403,609	8.73%	654,392	14.16%	-0.67%	(30,765)
14	*Total Special Contracts*		25,459,089	786,037	3.09%	2,095,138	8.23%	-0.67%	(169,445)
15	*Total Idaho Retail Sales*		483,961,348	85,561,911	17.68%	85,565,360	17.68%	0.00%	(0)

Data Sources:
1. IPCo Exhibit No. 43, p. 1 of 22
2. IPCo Exhibit No. 41

Note:
3. Annual adjustment for 3 years.

KROGER EXHIBIT NO. 2
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Attachment C