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IDAHO PUBLIC
UTILITIES COMMISSION

REBUTTAL TESTIMONY OF KEVIN C. HIGGINS

On Behalf of The Kroger Co.,

Doing Business as Fred Meyer and Smith's

Case No. IPC-E-03-13

March 19, 2004

REBUTTAL TESTIMONY OF KEVIN C. HIGGINS

Introduction

Q. Please state your name and business address.

A. Kevin C. Higgins, 39 Market Street, Suite 200, Salt Lake City, Utah, 84101.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by The Kroger Co., ("Kroger"), doing business as Fred Meyer and Smith's.

Q. Are you the same Kevin C. Higgins who has previously filed direct testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. I am recommending a modification to Staff's rate spread proposal for Rate 9.

Q. What recommendation do you make in your rebuttal testimony?

A. Staff witness Dave Schunke recommends a 0.13 percent rate reduction for Rate 9-S and a 13.31 percent rate increase for Rates 9-P and 9-T. I point out in my rebuttal testimony that if the Commission adopts this recommended change without modification, the price differential between primary service and secondary service will all but disappear for Rate 9 customers. In my view, this would result in an irrational price signal, because all other things equal, primary service is less expensive to serve than secondary service.

As an alternative, I suggest that Rates 9-S, 9-P, and 9-T be combined for rate spread purposes. The same revenue that would be generated from Mr. Schunke's overall proposal for Rate 9 can be achieved with a 1.16 percent increase on all the Rate 9 customers. This approach would retain a rational price differential between Rate 9-S and 9-P.

<u>Rate spread for Rate 9</u>

Q. What rate spread has Staff proposed for Rate 9?

A. As I stated in the Introduction above, 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. This proposal is described in the direct testimony of Mr. Schunke.[1]

Q. What is the basis of Staff's recommendation?

A. My understanding is that it is based on Staff's cost-of-service analysis, adjusted to incorporate the Irrigation subsidy paid by Rate 9.

Q. What comments do you have regarding Staff's rate spread recommendation for Rate 9?

A. I agree with Staff that cost-of-service analysis should be given a very strong weight in determining rate spread. However, it is also important to have a rational pricing regime within rate schedules. 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 a any given customer*,

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[1] Pre-filed direct testimony of Dave Schunke, p. 3, line 24 – p. 4, line 2.

taking service at primary voltage is less expensive for the utility to serve than taking service at secondary service. Unfortunately, however, 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 unfair to customers who invested in the necessary 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 and slow the growth in distribution system rate base.

Q. To what extent does Staff's proposal change the price differential between Rates 9-S and 9-P?

A. In Kroger Rebuttal Exhibit No. 1, I calculate the price differential between Rates 9-S and 9-P under current rates and under Staff's proposed rates. The analysis utilizes hypothetical customers of various sizes and load factors. A summary of the results is shown in Table KCH-R1, on the next page.

The results show 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.

Table KCH-R1
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%

Q. But doesn't Staff's analysis indicate that under its proposal, the average price per kwh for Rate 9-P customers would be less than Rate 9-S?

A. Yes. Staff Exhibit No. 127 shows 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 I am pointing out 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.

Q. Why is primary service less expensive to serve than secondary service, all other things equal?

A. 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.[2]

Q. If primary service is less expensive to serve than secondary, how can a cost-of-service study produce a result that leads Staff to propose raising 9-P so much that the differential between 9-S and 9-P disappears?

A. 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

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[2] Said Workpapers, pp. 3-4.

Rate 9-S. This was due, in part, to a higher per-unit allocation of production costs.[3]

Q. Should this result be the final word on the rate spread between and Rate 9-S and Rate 9-P?

A. Not in this case. As I stated above, 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.

Q. What do you propose to address this problem?

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

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[3] I base this conclusion on my review of Idaho Power Exhibit No. 42, pp. 4-5, which uses a production allocation methodology similar to Staff.

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.

I recommend that for rate spread purposes, Rates 9-S, 9-P, and 9-T be combined, and that a reasonable, cost-based price differential 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.

In Kroger Rebuttal Exhibit No. 2, I apply the same overall revenue requirement to the aggregate of 9-S, 9-P, and 9-T as in Staff's recommendation, but spread it 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. I recommend that this modification to Staff's Rate 9 rate spread be adopted by the Commission.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

Rate 9 Primary Discount Under Current and Staff Proposed Rate

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

		Staff Proposed Rates – Secondary: Billed Demand	Customer Charge	Energy Charge	Basic Charge	Current Rates – Secondary: Billed Demand	Customer Charge	Energy Charge	Basic Charge	Staff Proposed Rates – Primary: Billed Demand	Customer Charge	Energy Charge	Basic Charge	Current Rates – Primary: Demand Charge	Customer Charge	Energy Charge	Basic Charge	Primary Discount vs. Secondary: 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						
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%
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	$87,090			Annual Total	$87,329			Annual Total	$87,563			Annual Total	$77,544	11.20%	-0.54%
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%

Rate 9 Primary Discount Under Current and Staff Proposed Rate

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

		STAFF PROPOSED RATES				CURRENT RATES				STAFF PROPOSED RATES				CURRENT RATES				Primary Discount vs. Secondary	
		Secondary				Secondary				Primary				Primary					
		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						
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	$82,997	$6,930	$10,385	($2,174)
				Annual Total	$104,886			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	$156,316			Annual Total	$156,731			Annual Total	$154,429			Annual Total	$136,802	12.72%	1.21%

Rate 9 Primary Discount Under Current and Staff Proposed Rate

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

		STAFF PROPOSED RATES				CURRENT RATES				STAFF PROPOSED RATES				CURRENT RATES				Primary Discount vs. Secondary	
		Secondary				Secondary				Primary				Primary					
		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						
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	$128,063	10.10%	-1.80%
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	$173,926			Annual Total	$154,062	11.76%	0.11%
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	$3,484
Electricity Winter	4,914,000 kWh			$123,833				$128,501				$113,759				$104,708		$23,794	$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	$171,806	$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%

Kroger Rebuttal Exhibit No. 2
Case No. IPC-E-03-13
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)