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Attorneys for the Commission Staff

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF PACIFICORP DBA ROCKY MOUNTAIN POWER FOR AUTHORITY TO IMPLEMENT POWER COST ADJUSTMENT RATES FOR ELECTRIC SERVICE FROM APRIL 1, 2010 THROUGH MARCH 31, 2011 THROUGH THE ENERGY COST ADJUSTMENT MECHANISM	)	**CASE NO. PAC-E-10-01** **COMMENTS OF THE COMMISSION STAFF**

COMES NOW the Staff of the Idaho Public Utilities Commission, by and through its Attorney of record, Scott Woodbury, Deputy Attorney General, and in response to the Notice of Application, Notice of Modified Procedure, Notice of Comment/Protest Deadline and Notice of Reply Deadline issued on February 12, 2010, submits the following comments.

BACKGROUND

On February 1, 2010, PacifiCorp dba Rocky Mountain Power (PacifiCorp; Company) filed an Application with the Idaho Public Utilities Commission (Commission) for authority to implement a power cost adjustment to rates for all customer classes excluding tariff contract customers (Monsanto Company and Agrium, Inc.).[1] The proposed power cost adjustment is calculated pursuant to an Energy Cost Adjustment Mechanism (ECAM) approved by the Commission on September 29, 2009 in Case No. PAC-E-08-08, Order No. 30904. The primary purpose of the ECAM is to collect from customers or credit to customers a portion of the difference between base net power costs included in base rates, and actual net power costs incurred by the Company. The ECAM also includes several other adjustments approved by the Commission. The initial deferral period was July 1, 2009 through November 30, 2009. The Company is proposing to recover approximately $2.2 million in total deferred net power costs. The energy cost adjustment is set forth in a new electric service Schedule No. 94. The proposed effective date is April 1, 2010. The Settlement Stipulation accepted by the Commission in Order No. 30904 identifies in substantial part the procedures, dates and components associated with the ECAM.

The Net Power Cost (NPC) portion of the ECAM includes costs typically booked to the following Federal Energy Regulatory Commission (FERC) accounts.

> Account 447 – Sales for resale, excluding on-system wholesale sales and other revenues that are not modeled in GRID.
>
> Account 501 – Fuel, steam generation, excluding fuel handling, start-up fuel/gas,[2] diesel fuel, residual disposal and other costs that are not modeled in GRID.
>
> Account 503 – Steam from other sources.
>
> Account 547 – Fuel, other generation.
>
> Account 555 – Purchased power, excluding BPA residential exchange credit pass-through, if applicable.
>
> Account 565 – Transmission of electricity by others (wheeling).

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[1] Tariff contract loads (Monsanto and Agrium) are not subject to any ECAM surcharges/credits until January 1, 2011. Reference Case No. PAC-E-07-05, Order No. 30482.

[2] Start-up fuel is accounted for separately from the primary fuel for steam-powered generation plants. Start-up costs are not accounted for separately for natural gas plants, and therefore all fuel for natural gas plants is included in the determination of both base NPC and actual NPC.

In addition to NPC, the ECAM includes three other components: a Load Growth Adjustment, a credit for SO2 allowance sales, and a Renewable Resource Adder. The ECAM also includes an interest calculation and a symmetrical sharing band of 90% (customers)/10% (Company) that is applied to most components.

The Renewable Resources Adder recognizes that the Company has made significant investments in renewable generation projects that are not yet being recovered in Idaho rates, even though these projects provide significant NPC benefits to customers. Specifically, the adjustment recognizes that actual NPC were reduced by power generated from these renewable generation projects. Pursuant to Commission Order No. 30904, the Commission approved a renewable resource adjustment of $55 per megawatt-hour (MWh) multiplied by the actual MWh output generated by the renewable resources that were not included in rates in the Company's last rate case, Case No. PAC-E-08-07.

The components making up the deferred ECAM balance are reflected in the following table:

NPC Differential	$ 121,504
Load Growth Adjustment	1,499,793
SO2 Credit	(120,562)
Sub-Total	$1,500,735
	90%
Customer Responsibility	$1,350,662
Renewable Resource Adder	811,412
Interest	8,022
Total Idaho Deferral	$2,170,096

In Schedule 94 the Company proposes the following rates by delivery voltage:

Secondary Distribution Rate	0.107 ¢/kWh
Primary Distribution Rate	0.100 ¢/kWh
Transmission Rate	0.098 ¢/kWh

The proposed Schedule 94 ECAM rates would have the following rate impacts:

Residential Customers – an increase of 1.29%, i.e., approximately $0.91 per month for the average residential home using 850 kWh per month.

Irrigation Customers (Schedule 10): 1.55% increase

General Service
Schedule 23/23A: 1.34% increase
Schedule 6/6A/8/35: 1.70% increase
Schedule 9: 2.13% increase
Schedule 19: 1.57% increase

Public Street Lighting
Schedules 7/7A, 11, 12: 0.46% increase

STAFF ANALYSIS

ECAM Deferral

Staff notes that this is the first ECAM filing made by the Company subsequent to approval of the mechanism in Commission Order No. 30904. As a result, the ECAM filing in this case differs in several respects from Company filings that will be made in subsequent years. (1) This filing includes adjustments for Net Power Cost Differential, Load Growth Adjustment, and SO2 Sales for the 5-month period of July1, 2009 through November 30, 2009; future filings will be for the 12-month period of December 1 through November 30 of the application year. (2) The Renewable Resource Adder will only be included in the ECAM until the costs and benefits can be included in base rates in the Company's next general rate case. A rate case will eliminate the need for this special adjustment. (3) In future years there will be a "true up" between the deferral balance and amounts actually recovered; any over- or under-recovery that occurs as a result of this ECAM filing will result in an adjustment to future ECAMs.

The Commission Staff has reviewed the Company's ECAM filing and audited the Company's actual results as they pertain to the ECAM. Staff recommends changes to the Company's proposal as defined and discussed below.

<u>Net Power Cost Differential</u> – The Net Power Cost differential is the driving force behind the creation and need for a power cost adjustment mechanism. Normally this differential is the single largest cost component of the mechanism. In this case it is a small portion of the total deferral. Two primary reasons for this are (1) the review period is only five months instead of twelve months and (2) the actual system load was lower than the base load assumed in the Company's last general rate case. The lower system load is probably associated with the current economic downturn.

Staff reviewed transaction activity in the FERC accounts used to record net power costs. Specifically, base and actual NPC include amounts booked to the following FERC accounts:

Account 447 (sales for resale, excluding on-system wholesale sales and other revenues not modeled in GRID), Account 501 (fuel, steam generation, excluding fuel handling, start up fuel/gas, diesel fuel, residual disposal and other costs not modeled in GRID), Account 503 (steam from other sources), Account 547 (fuel, other generation), Account 555 (purchased power, excluding BPA residential exchange credit pass-through if applicable), and Account 565 (transmission of electricity by others). Staff's analysis did not find any transaction that was not reasonable or significantly out-of-trend with previous activity. Staff notes, however, that the audit period in this case included only five months of transactions; future audits that encompass an entire year will provide better data for trend analysis and transaction evaluation.

The Idaho share of net power costs increased by $121,504; the Idaho customers' share of the increased cost is $109,354 after 90/10 sharing. This amount represents 5.43% of the Company's proposed total ECAM deferral.

Load Growth Adjustment – The Load Growth Adjustment is by far the largest component of this ECAM deferral. During the five month review period actual Idaho loads were down 85,810 MWh or 7.95% from the same 2007 normalized five month period used to calculate Idaho base load. At an approved adjustment rate of $17.48/MWh, this results in an adjustment of $1,499,793. The Idaho customer share is $1,349,814 after 90/10 sharing. These are the same results presented by the Company.

The theory behind the LGAR is that the Company should not be allowed to collect growth related power supply costs through an ECAM surcharge and then also collect base revenue from that new load to cover the same power supply costs. The same theory has been applied when loads decline. The Company should not be required to provide a credit to customers when power supply costs decline due to declining load and also suffer the loss of base revenue from the lost load. In this case, power supply costs increased slightly at the same time load decreased significantly. Rather than offsetting lost revenue that the Company already gave back in an ECAM credit, the Load Growth Adjustment simply reimbursed the Company for lost revenue due to lost load. This is very similar to decoupling or the Fixed Cost Adjustment Mechanism (FCA) in place for Idaho Power Company.

While Staff does not propose to remove the Load Growth Adjustment in this case given that a symmetrical mechanism was approved by the Commission, we note that decoupling has not been approved in Idaho for PacifiCorp. Staff also notes that all three Idaho utilities have ECAM/PCA's in place with similar provisions. Staff believes that further investigation is necessary in conjunction with Company filings for all three mechanisms to determine if a Load Growth Adjustment is appropriate when the adjustment exceeds the magnitude of the ECAM/PCA surcharge/credit or is otherwise reasonable when loads decline.

SO2 Credits – In Commission Order No. 30904 the Commission accepted a stipulated settlement that required that the ECAM include and share revenues from the sale of SO2 credits between the Company and its customers (90% customers/10% Company). This applied to all SO2 sales beginning July 2009. The Company calculated the Idaho portion of the SO2 credit sale proceeds by multiplying total sales by the Idaho energy allocation factor of 6.5865%. The Idaho portion of the SO2 credit sale proceeds was then further reduced to an Idaho tariff customer portion based on the percent of the Idaho tariff load to total Idaho load in each month. (Shu Direct Testimony p. 5, lines 18-23 through p. 6, lines 1-5 and Company Exhibit 1, lines 13-17). The Company calculated the Idaho tariff customer portion to be $108,506 after the 90/10 sharing.

Staff agrees that SO2 sales proceeds should be allocated to Idaho based on the energy allocation factor. However, Staff believes further adjustment by the percentage representing the tariff customer portion of total Idaho Load is not consistent with prior rate case treatment of SO2 credit sale proceeds to tariff customers. Ratemaking treatment of SO2 credit sale proceeds prior to the ECAM resulted in 100% of the sale proceeds reducing the approved rate increase whether contract customers were affected or not. Staff believes the 10% sharing represents the appropriate Company share as the sale of SO2 credits are moved from base rates to the ECAM. This final Company proposed reduction in Idaho SO2 proceeds, which have already been reduced to 90% of the originally allocated amount, results in an even smaller allocation to Idaho tariffed customers and an even larger share retained by the Company. This should not occur simply because an ECAM has been implemented. Therefore, Staff recommends that the Commission reject the Company's proposal to further reduce Idaho SO2 credits. Eliminating the reduction results in a net SO2 credit of $142,609 after 90/10 sharing, increasing the Idaho tariff customer credit by $34,104.

Renewable Resource Adder – The Renewable Resource Adder is a relatively short term adjustment included in the ECAM by Commission order. This adjustment allows the ECAM to include a cost for renewable resources that have come on-line since base power costs were set in the Company's last rate case, Case No. PAC-E-08-07. The costs are included at $55/MWh. The costs of these resources are not included in base rates but generation from the resources reduces actual Net Power Costs. In the Company's next general rate case the costs and benefits of these resources will be included in base rates which will eliminate the need for this special adjustment. The Idaho customer share of this cost is $811,412. These are the same results presented by the Company.

Goose Creek Transmission Sale Credit – Commission Order No. 30904 required the Company to include an Idaho customer benefit for the sale of Goose Creek Transmission assets in its ECAM calculation. The amount that was to be included as an Idaho customer benefit was established as $156,434. The Company inadvertently left this credit out of its filing. Shortly after the filing was made the Company contacted Staff and identified the error. Staff has included the credit in its calculations.

Interest – As required by Commission Order No. 30904, the Company included interest on monthly deferral balances at the Commission approved customer deposit interest rate. This rate is 2% for 2009. The Company calculated the interest amount to be $8,022. Due to the addition of the Goose Creek Sale Credit and the adjustment for SO2 sales, Staff calculates a slightly different interest amount than the Company calculated. Staff calculates interest of $7,329 resulting in an adjustment of $693.

Incorporating the Staff adjustments discussed above, Staff calculates the ECAM components and Total Idaho Deferral to be:

NPC Differential	$ 121,504
Load Growth Adjustment	1,499,793
SO2 Credit	(158,455)
Sub-Total	$1,462,842
	90%
Customer Responsibility	$1,316,558
Renewable Resource Adder	811,412
Goose Creek Sale Credit	(156,434)
Interest	7,329
Total Idaho Deferral	$1,978,865

The Staff adjustments reduce the deferral amount from the Company calculation of $2,170,096 to $1,978,865. The sum of all Staff adjustments reduced the ECAM deferral by $191,231. Attachment A shows Staff's calculations in more detail.

ECAM Rates

The methodology for calculating ECAM rates is generally defined in the Settlement Stipulation accepted by the Commission in Order No. 30904. The details of the rate design were accepted by participating parties in discussions after Order No. 30904 was issued. The rates were to be energy rates (¢/kWh) and they were to be differentiated based on delivery losses. In Company Exhibit No. 3, the Company proposes three different energy rates that vary by delivery voltage. In general the lower the delivery voltage the higher the losses associated with serving the load. Higher losses translate into higher ECAM rates and lower losses, due to higher delivery voltages, translate into lower ECAM rates. Attachment B to these comments shows the calculation of the three loss differentiated rates on the right hand side of the box at the bottom of the Attachment. Staff calculates the ECAM rates for customers taking service at the secondary distribution voltage level to be .00098 $/kWh (0.098 ¢/kWh). The ECAM rate for those taking service at the Primary Distribution voltage level is 0.00091 $/kWh (0.091 ¢/kWh). Finally, customers taking service at the Transmission voltage level should pay an ECAM rate of 0.00089 $/kWh (0.089 ¢/kWh). These rates applied to the Company's customer Classes produce the percentage increases shown on the right hand side of the "Revenues" column of Attachment B. The Staff proposed ECAM rate adjustment results in an average rate increase to tariff customers of 1.34%.

It may be noted that the application of these three rates to the estimated metered energy sales produce a revenue amount of approximately $1,981,000 which is approximately $2,000 above the deferral amount. This occurs because the rates are rounded to five decimal places like all Rocky Mountain Power energy rates. This is not a problem because this difference, or any other difference, between the deferral amount and amounts actually recovered is carried back into the following years deferral balance as a true up.

CONSUMER ISSUES

Customer Notice and Press Release

The Customer Notice and Press Release were included in Rocky Mountain Power's Application. The Application was received on February 1, 2010. Staff reviewed the customer notice and press release and determined they were in compliance with the requirements of Rule 102, Utility Customer Information Rules (UCIR), IDAPA 31.21.02.102. The customer notice was mailed to Rocky Mountain's customers with cyclical billings beginning February 1, 2010 and ending March 1, 2010.

Customer Comments

Customers were given until March 10, 2010 to file comments. As of March 10, 2010, two comments had been received. Both commenters opposed any increase in rates.

RECOMMENDATIONS

The Commission Staff recommends that the Commission accept an Idaho ECAM deferral balance of $1,978,865 for the July 1, 2009 through November 30, 2009 deferral period. This number includes a Goose Creek Transmission Sale credit, an adjustment to the SO2 sale credit, and an adjustment to the Company's interest calculation as previously discussed in these comments.

Staff also recommends that the Commission approve the following loss differentiated energy rates to be included in Schedule 94:

Secondary Distribution Rate	0.098 ¢/kWh
Primary Distribution Rate	0.091 ¢/kWh
Transmission Rate	0.089 ¢/kWh

Staff further recommends that the rates become effective April 1, 2010 as requested by the Company.

As previously discussed in these comments, Staff also recommends that the application and implementation of the Load Growth Adjustment be further evaluated either in the Company's next general rate case or in a separate case before the next annual ECAM filing.

Respectfully submitted this 10th day of March 2010.

Scott Woodbury
Deputy Attorney General

Technical Staff: Keith Hessing
Cecily Vaughn
Marilyn Parker

i:umisc:comments/pace10.01swkhcvmp comments

Idaho ECAM Deferral (PAC-E-10-01)
July 2009 through November 2009

With Staff Adjustments
Include Regulatory Liability as Ordered
All Idaho SO2 Credits to Idaho Customers

Line No.			Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Total
1	Base NPC Rate ($/MWh) - See (1) below		23.64	21.87	13.80	17.50	15.99	
2	Total Company Adjusted Actual NPC ($)		115,657,309	108,989,204	88,855,313	78,447,370	70,858,584	
3	Actual Retail Load (MWh)		5,323,973	5,022,310	4,596,422	4,508,840	4,753,268	
4	Actual NPC ($/MWh)	Line 4 = Line 2 / Line 3	21.72	21.70	19.33	17.40	14.91	
5	NPC Differential $/MWh	Line 5 = Line 4 - Line 1	(1.92)	(0.17)	5.53	(0.10)	(1.09)	
6	Actual Idaho Tariff Load (MWh)		336,350	219,010	173,842	130,746	133,747	
7	Actual Idaho Tariff Contract Load (MWh) - See (2) below							
8	**NPC Differential for Deferral ($)**	Line 8 = Line 5 * Sum of Lines 6 and 7	**(644,436)**	**(37,665)**	**961,608**	**(12,777)**	**(145,227)**	**121,504**
9	Base Load - See (1) & (3) below		354,204	264,049	172,532	144,866	143,855	
10	Difference Base Load to Actual Load	Line 10 = Line 6 + Line 7 - Line 9	(17,854)	(45,039)	1,310	(14,119)	(10,108)	
11	Load Growth Adjustment Rate ($/MWH)		$17.48	$17.48	$17.48	$17.48	$17.48	
12	**Load Growth Adjustment Revenues**	Line 12 = -Line 10 x Line 11	**312,050**	**787,195**	**(22,902)**	**246,779**	**176,671**	**1,499,793**
13	SO2 Allowances Sales		0	(1,455,000)	(950,750)	0	0	
14	Idaho SE Factor		6.5865%	6.5865%	6.5865%	6.5865%	6.5865%	
15	Idaho Allocation	Line 15 = Line 13 x Line 14	0	(95,834)	(62,621)	0	0	
16	Idaho Tariff Customers Percent		100.00%	100.00%	100.00%	100.00%	100.00%	
17	**Idaho SO2 Offset**	Line 17 = Line 15 x Line 16	**0**	**(95,834)**	**(62,621)**	**0**	**0**	**(158,455)**
18	**Total NPC Differential + LGA + SO2**	Line 18 = Line 8 + Line 12 + Line 17	**(332,386)**	**653,697**	**876,084**	**234,002**	**31,445**	**1,462,842**
19	Customer / Company Sharing ratio		90.0%	90.0%	90.0%	90.0%	90.0%	
20	**Customer / Company Sharing (90/10)**	Line 20 = Line 18 x Line 19	**(299,147)**	**588,327**	**788,476**	**210,602**	**28,300**	**1,316,558**
21	Renewables Generation (MWhs)		42,039	42,262	63,311	116,695	143,828	
22	Renewable Adder Rate per MWh		$55.00	$55.00	$55.00	$55.00	$55.00	
23	Total Renewable Resources Adder	Line 23 = Line 21 x Line 22	2,312,145	2,324,410	3,482,105	6,418,225	7,910,540	
24	Idaho SG Factor		6.0479%	6.0479%	6.0479%	6.0479%	6.0479%	
25	Idaho Allocation	Line 25 = Line 23 x Line 24	139,836	140,578	210,594	388,168	478,422	
26	Idaho Tariff Customers Percent	Line 26 = Line 16	80.43%	79.95%	70.18%	51.96%	49.56%	
27	**Renewable Resources Adder**	Line 27 = Line 25 x Line 26	**112,464**	**112,389**	**147,787**	**201,680**	**237,092**	**811,412**
28	**Recovery of Deferred Balances**							
29	Deferred Balance ($)	Line 29 = Line 42						
30	Projected Retail Sales (MWh)							
31	ECAM Surcharge Rate ($/MWh)	Line 31 = Line 29 / Line 30						
32	Actual Idaho Tariff Sales (MWh)							
33	Actual Tariff Contract Sales (MWh) - See (2) below							
34	**Recovery of Deferral ($)**	Line 34 = Line 31 * Lines 32+33						
35	**Balancing Account ($)**							
36	Beginning Balance		0	(186,838)	514,150	1,295,616	1,710,401	
37	Incremental Deferral		(299,147)	588,327	788,476	210,602	28,300	
38	Renewable Resources Adder		112,464	112,389	147,787	201,680	237,092	
39	Recovery Adjustment	Line 39 = -Line 34	0	0	0	0	0	
40	Regulatory Liability Write-off (Un-Amortized Balance at Jan 2010)				(156,434)			
41	Interest		(156)	273	1,637	2,503	3,072	7,329
42	**Ending Balance ($)**		**(186,838)**	**514,150**	**1,295,616**	**1,710,401**	**1,978,865**	
43	Interest Rate		2.00%	2.00%	2.00%	2.00%	2.00%	

(1) Base NPC Rate and Load from Case No. PAC-E-08-07 $982 million
(2) Customers served under tariff contracts 400 and 401 are not impacted by the ECAM until January 1, 2011
(3) Includes only the loads which are part of the calculation

Attachment A
Case No. PAC-E-10-01
Staff Comments
03/10/10

TABLE A
ROCKY MOUNTAIN POWER
ESTIMATED IMPACT OF PROPOSED REVENUES ON NORMALIZED PRESENT REVENUES
FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN IDAHO
12 MONTHS ENDING DECEMBER 2007
Line Loss Adjusted to Generation

							At Meter MWH				At Generation MWH				Revenues (000's)				
Line No.	Description	Present Sch.	Proposed Sch.	Average No. of Customers	MWH	Base Revenue	Sec	Pri	Trans	Total	Sec	Pri	Trans	Total	Sec	Pri	Trans	Total	%
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	
											1.11389	1.07089	1.04543		0.00098	0.00091	0.00089		
	Residential Sales																		
1	Residential Service	1	1	39,215	399,023	$36,237	399,023			399,023	444,467			444,467	391			391	1.08%
2	Residential Optional TOD	36	36	16,369	317,378	$23,268	317,378			317,378	353,524			353,524	311			311	1.34%
3	AGA-Revenue	--	--	--	--	$5													
4	**Total Residential**			55,585	716,401	$59,510	716,401			716,401	797,992			797,992	702			702	1.18%
5	**Commercial & Industrial**																		
6	General Service - Large Power	6	6	1,028	298,916	$18,447	247,955	50,962		298,916	332,960	54,574		387,534	243	46		289	1.57%
7	General Svc. - Lg. Power (R&F)	6A	6A	247	36,068	$2,482	36,068			36,068	40,176			40,176	35			35	1.42%
8	Subtotal-Schedule 6			1,275	334,984	$20,930	284,022	50,962		334,984	373,135	54,574		427,710	278	46		325	1.55%
9	General Service - Med. Voltage	8	6	2	2,848	$155		2,848		2,848		3,050		3,050		3		3	1.67%
10	General Service - High Voltage	9	9	12	130,895	$6,009			130,895	130,895			136,842	136,842			116	116	1.94%
11	Irrigation	10	10	5,331	697,666	$48,201	697,666			697,666	777,123			777,123	684			684	1.42%
12	Comm. & Ind. Space Heating	19	19	148	8,236	$562	8,236			8,236	9,175			9,175	8			8	1.44%
13	General Service	23	23	6,183	122,778	$9,709	121,336	1,442		122,778	136,761	1,544		138,306	119	1		120	1.24%
14	General Service (R&F)	23A	23A	1,383	18,166	$1,515	18,165	1		18,166	20,234	1		20,235	18	0		18	1.18%
15	Subtotal-Schedule 23			7,567	140,944	$11,224	139,501	1,443		140,944	156,996	1,545		158,541	137	1		138	1.23%
16	General Service Optional TOD	35	35	3	2,587	$130	2,587			2,587	2,882			2,882	3			3	1.96%
17	Tariff Contract-Monsanto			1	1,319,624	$53,545			1,319,624	1,319,624			1,379,575	1,379,575			0	0	0.00%
18	Tariff Contract-Nu West			1	109,115	$4,239			109,115	109,115			114,072	114,072			0	0	0.00%
19	AGA-Revenue	--	--	--	--	$477													
20	**Total Commercial & Industrial**			14,340	2,746,900	$145,472	1,132,013	55,252	1,559,635	2,746,900	1,319,311	59,169	1,630,489	3,008,969	1,109	50	116	1,276	0.88%
21	**Total Commercial & Industrial (Excluding Monsanto)**			14,339	1,427,276	$91,926	1,132,013	55,252	240,010	1,427,276	1,319,311	59,169	250,914	1,629,394	$1,109	$50	$116	$1,276	1.39%
22	**Public Street Lighting**																		
23	Security Area Lighting	7	7	239	284	$104	284			284	317			317	0			0	0.27%
24	Security Area Lighting (R&F)	7A	7A	195	138	$54	138			138	154			154	0			0	0.25%
25	Street Lighting - Company	11	11	32	121	$52	121			121	135			135	0			0	0.23%
26	Street Lighting - Customer	12	12	294	1,974	$370	1,974			1,974	2,199			2,199	2			2	0.52%
27	AGA-Revenue	--	--	--	--	$0													
28	**Total Public Street Lighting**			760	2,517	$581	2,517	0	0	2,517	2,804	0	0	2,804	2	0	0	2	0.42%
29	**Total Sales to Ultimate Customers**			70,685	3,465,818	$205,562	1,850,931	55,252	1,559,635	3,465,818	2,120,106	59,169	1,630,489	3,809,764	1,814	50	116	1,981	0.96%
30	**Total Sales to Ultimate Customers (Excluding Monsanto & Nu-West)**			70,683	2,037,079	$147,778	1,850,931	55,252	130,895	2,037,079	2,120,106	59,169	136,842	2,316,117	1,814	50	116	1,981	1.34%

	Proposed Revenue ($000's)	Proposed Rate/ kWh	
Secondary	1,811	0.00098	Rounded
Primary	51	0.00091	Rounded
Transmission	117	0.00089	Rounded
Total Revenue	1,979	0.00097	
Rate @ Generator/kWh	0.00085		

$	1,978,865	Input

Attachment B
Case No. PAC-E-10-01
Staff Comments
03/10/10

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 10TH OF MARCH 2010, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. PAC-E-10-01, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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