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July 7, 2010

VIA ELECTRONIC FILING AND U.S. MAIL

PUC Filing Center
Public Utility Commission of Oregon
PO Box 2148
Salem, OR 97308-2148

Re: Docket UE 216 - PacifiCorp's 2011 Transition Adjustment Mechanism Schedule 201, Cost-Based Supply Service

Enclosed for filing are an original and five copies of the Stipulation joined by all parties to this proceeding. The parties plan to file testimony in support of the Stipulation in the next two weeks.

A copy of this filing has been served on all parties to this proceeding, as indicated on the attached Certificate of Service.

Very truly yours,

Amie Jamieson

cc: Service List

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document in UE 216 on the following named person(s) on the date indicated below by email and first-class mail addressed to said person(s) at his or her last-known address(es) indicated below.

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DATED: July 7, 2010

Amie Jamieson

McDowell Rackner & Gibson PC
520 SW Sixth Avenue, Suite 830
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BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 216

In the Matter of: PACIFICORP, dba PACIFIC POWER 2011 Transition Adjustment Mechanism Schedule 201, Cost-Based Supply Service	**STIPULATION**

This Stipulation is entered into for the purpose of resolving the issues among the parties to UE 216, PacifiCorp's (or the "Company") proposed transition adjustment mechanism ("TAM").

PARTIES

1. The parties to this Stipulation are PacifiCorp, Staff of the Public Utility Commission of Oregon ("Staff"), the Citizens' Utility Board of Oregon ("CUB"), the Industrial Customers of Northwest Utilities ("ICNU"), and Sempra Energy Solutions LLC ("Sempra") (together, the "Parties"). The Parties represent all participants and intervenors in this docket.

BACKGROUND

2. On February 26, 2010, PacifiCorp filed revised tariff sheets for Schedule 201, Net Power Costs, Cost-Based Supply Service, to be effective January 1, 2011, which implements PacifiCorp's 2011 TAM. The purpose of the TAM filing is to update net power costs ("NPC") for 2011 and to set transition adjustments for Oregon customers who choose direct access in the November 2010 open enrollment window.

3. The February 26, 2010 TAM filing ("Initial Filing") reflected total forecasted normalized system-wide NPC for the test period (12 months ending December 31, 2011) of approximately $1.28 billion. On an Oregon-allocated basis, the forecasted normalized NPC in the Initial Filing were approximately $312.8 million. This amount is approximately $56.6 million higher than the $256.1 million included in rates through the NPC baseline established

in the 2010 TAM (Docket UE 207), or $69.2 million as adjusted for forecasted load loss in 2011. This would have resulted in an overall increase to Oregon rates of approximately 7.0 percent.

4. All Parties participated in three settlement conferences on June 10, 2010, June 14, 2010 and June 24, 2010.

5. The Parties have reached a comprehensive settlement of all issues raised prior to the Rebuttal Update in this case. The settlement establishes the baseline 2011 TAM NPC in rates, subject to TAM updates, and various TAM-related policy issues.

AGREEMENT

6. 2011 NPC. The Parties agree that the total-Company NPC for 2011 will be $1.233 billion, subject to the Rebuttal and Final Updates described in Section 7. The Parties agree that this is an Oregon-allocated NPC of $301.8 million or an increase of $58.2 million, including the load change adjustment, as shown in Exhibit A. This is based on the Parties agreement that Oregon-allocated NPC shall be reduced by $11.0 million. The $11.0 million reduction reflects consideration of the issues in the testimony of Staff, ICNU, CUB and Sempra; changes in net power costs for corrections identified in the Company's April 21, 2010 filing; and corrections for the addition of a reserve requirement to the Dunlap wind project, the addition of Tieton Hydro to non-owned generation reserve requirements, and a correction to Lower Valley Energy Upper Facility qualifying facility pricing. These adjustments resolve all issues related to Net Power Costs as of the date of the Company's July 7, 2010 update, and as reflected in paragraph 7, the correction of errors resulting from future updates are the only error corrections that may be made after execution of this Stipulation. The Parties, including PacifiCorp, cannot make additional error corrections or other changes to the Company's previous filings.

7. NPC Baseline and Rebuttal and Final Updates. The Company will update its Initial Filing consistent with the schedule adopted in this proceeding and as specified in the

TAM Guidelines, adopted in Order No. 09-274 and modified in Order No. 09-432. The Company shall file its Rebuttal Update on July 7, 2010, its Indicative Filing on November 8, 2010 and the Final Update on November 15, 2010 (collectively the Indicative Filing and the Final Update are referred to as the Final Updates). Parties agree that errors resulting from future updates are the only error corrections that may be made after execution of this Stipulation. Staff and Intervenors reserve the right to challenge all other elements of the Updates. The Updates may increase or decrease the Oregon-allocated increase of $58.2 million from base NPC.

8. Adjustments to NPC. The Parties agree that the stipulated $11 million reduction to the baseline NPC is for settlement purposes only and does not imply agreement on the merits of any adjustment, nor does it imply that the Parties have accepted any elements of the Company's NPC study. The Company does, however, agree to reflect the methodology changes listed in this paragraph in the 2012 TAM. The Company will also make the methodology changes listed in this paragraph in subsequent TAM filings, absent a change in facts or circumstances identified by the Company. The Company agrees to provide Parties with the details of these modeling changes by mid-January 2011 and to meet with Parties, if requested. The obligations in Paragraph 8 apply to the Company. Staff and Intervenors reserve the right to review, challenge and propose alternatives to the methodological changes listed below.

a. Screens – The Company will use a daily screening methodology that is more effective than that used in UE 216 and is based on logic which commits all gas plants up and backs down those that are not economic.

b. Black Hills CTs – The Company will use a four-year average for the costs of the Black Hills combustion turbines.

c. Heat Rates – The Company will not implement adjustments for scrubbers or other capital projects, but instead will rely on the traditional analysis of four years of actual data to derive the heat rate inputs.

d. APS Supplemental Coal and Other – The Company will model the option contracts to be exercised only when economic.

e. The Company will not include inter-hour wind integration charges for non-owned wind facilities.

f. The Company will include modeling of non-firm transmission links and costs using a four-year average.

9. Other Revenue in Future Stand-Alone TAM Filings. In future stand-alone TAM filings, the Company will reflect forecast changes in Other Revenue for items that have a direct relation to NPC, for which a revenue baseline has been established in rates in Docket UE 217. Exhibit B contains the revenue baselines from Docket UE 217 for the storage and exchange agreements for Seattle City Light Stateline and the non-Company owned Foote Creek projects, revenues from the Bonneville Power Administration associated with the South Idaho Exchange, steam revenues for Little Mountain and royalty offset revenues for the Georgia Pacific Camas contract.

10. Wind Integration Charges for Non-Owned Wind Facilities/Line Losses. The Company agrees to file to modify its Open Access Transmission Tariff to include charges for wind integration services to non-owned wind facilities and update line loss charges in its next rate case before the Federal Energy Regulatory Commission, which is scheduled to be filed in June 2011.

11. UM 1355 – Forced Outage Rates. The Company agrees to reflect the final Commission decision in Docket UM 1355 in the 2011 TAM if the decision is timely and issued prior to the Indicative Filing. The Parties agree that the adopted schedule in UM 1355, including the proposed Commission decision date, would result in a timely final order.

PacifiCorp will implement the final Commission decision in UM 1355, even if a party in UM 1355 seeks rehearing, reconsideration or appeal of the Commission decision. The Parties agree that this provision does not contain an express or implied waiver of PacifiCorp's rights, including but not limited to the right to seek clarification or challenge the UM 1355 decision or to seek to have the impact of the decision made subject to refund or deferral.

12. UM 1465 – 2010 TAM ICNU Deferral. ICNU agrees to dismiss and not refile its deferred accounting application in Docket UM 1465 based upon the resolution of the Company's application in Docket UP 260, authorizing the Company to sell Oregon-allocated renewable energy credits generated in 2010 that are ineligible for Oregon's renewable portfolio standard, with net proceeds to be credited to the property sales balancing account.

13. Attestation with Indicative Filing. The Company agrees to file an attestation with the Indicative Filing in this case and in future TAM filings. The attestation will confirm that all contracts executed prior to the contract lockdown date have been included in the Indicative Filing and will identify any exceptions and the reason why such contracts were excluded.

14. Challenges to Final Updates. Without waiving any procedural rights, the Parties agree to make a good faith effort to follow the following procedures for challenges to the Final Updates and compliance filing. Staff and Intervenors retain their procedural rights to raise any issue regarding the Company's Final Updates to the Commission prior to and during the Commission public meeting, including filing for a deferral of costs related to the final TAM updates or requesting that a portion of the TAM be allowed subject to refund. These procedures will apply to the 2011 and 2012 TAM filings. During the 2013 TAM filing, the Parties will review the effectiveness of these procedures.

a. PacifiCorp agrees to make a good faith effort to respond to all discovery requests after the Indicative Filing in five business days.

b. At least 10 business days before the Commission public meeting scheduled immediately prior to the effective date of the compliance filing, a Party will provide notice to the Parties of any potential concerns with the Company's Final Updates. The notice will identify the specific elements of the Updates that are relevant to the potential challenge and provide an explanation of the Party's concern.

c. No more than five business days after receiving the Party's notice, the Company will provide an initial response to the Parties regarding the concerns raised in the notice and the Parties will work to reach resolution of the issue.

d. If the matter is not resolved by the Parties prior the Commission public meeting, the Parties may make recommendations to the Commission at the public meeting to set a process to resolve the matter, if additional process is required. The recommendations may include that a specific amount of the tariff change will be subject to deferral until the Commission resolves the matter through additional process.

e. PacifiCorp will not oppose the filing of a deferral of any limited and specific cost which is identified by the Parties at least 10 business days before the Commission public meeting. Specifically, the Company will not challenge the deferral on the basis that it fails to meet the Commission's standards for deferred accounting as initially set forth in Order No. 05-1070 (Docket UM 1147), including issues related to the materiality of the filing and a showing of substantial harm. PacifiCorp otherwise retains the right to object to subject to refund or deferral treatment.

f. The Parties agree to request a schedule that will result in a Commission decision within 90 days of the effective date for new rates for any additional process after the Commission public meeting.

g. If the final Commission decision on any challenges to the Final Updates results in changes to the transition adjustments approved in Schedules 294 and 295, the Company may reflect in the direct access balancing account any difference between the approved transition adjustments and the transition adjustments that would have been in effect consistent with the Commission's decision on the challenged items.

15. Schedule for Future PacifiCorp TAMs. The Parties will work collaboratively to develop a proposal by fall of 2010 to consider a change to PacifiCorp's TAM schedule from an annual filing with a rate effective date of January 1 to an annual filing with a rate effective date of July 1. The proposal will consider mechanisms to mitigate financial impacts to PacifiCorp due to a potential six-month delay during the transition period. The Parties agree to work in good faith to reach agreement in a timeframe that will avoid a March 1, 2011 TAM and general rate case filing date.

16. BPA Transmission Credit for Direct Access. PacifiCorp agrees to increase the Schedule 294 transition adjustment by $(0.50)/MWh for the 2011 TAM for Schedule 747 and 748 customers to reflect the potential value associated with reselling BPA Point to Point ("PTP") wheeling rights from Mid-C to the Company's Oregon Service territory that are freed-up as a result of customers choosing direct access.

PacifiCorp also agrees to meet with an Energy Service Supplier ("ESS") upon request in advance of the November 2010 shopping window to discuss price, terms and potential quantities of BPA PTP wheeling rights to be purchased from PacifiCorp for delivery from all points of receipt considered to be Mid-C to the Company's Oregon service territory to serve direct access load.

Nothing in this agreement obligates PacifiCorp to sell any transmission rights to an ESS. PacifiCorp further agrees to evaluate this issue using the actual direct access customer data that results from the November 2010 shopping window, report its findings back to the parties, and use any knowledge gained to guide its filing of the 2012 TAM.

17. Direct Access Billing Information. PacifiCorp will continue to respond as appropriate to individual bill inquiries by potential direct access customers. To the extent that additional information is requested by a participating direct access customer on an on-going basis, the Company will endeavor to provide such information as practicable, consistent with

Schedule 300, Rule 11-2. Nothing in this provision prejudges the appropriateness of application of Schedule 300, Rule 11-2 in these circumstances.

Prior to the November 2010 shopping window, PacifiCorp will work with interested Parties to identify the billing information that PacifiCorp's CSS billing system can provide on a routine basis to direct access customers sufficient to allow such customers to reconcile their bills to the PacifiCorp tariff. If resolution of this issue is not reached by the start of the 2011 shopping window, the Parties agree to support the establishment of a collaborative process to address this issue.

18. Schedule 201. The Company will revise the Schedule 4 rates in Schedule 201 to reflect the rate design agreed to by the parties in Docket UE 217, the Company's general rate case proceeding. The rate spread will be as shown in Exhibit C.

19. Tariff. Upon approval of this Stipulation and concurrent with the filing of the Final Update, PacifiCorp will file revised Schedule 201 rates and revised transition adjustment Schedules 294 and 295 as a compliance filing in Docket UE 216, to be effective January 1, 2011, reflecting rates as agreed in this Stipulation.

20. This Stipulation will be offered into the record as evidence pursuant to OAR 860-014-0085. The Parties agree to support this Stipulation throughout this proceeding and any appeal, provide witnesses to sponsor this Stipulation at hearing, and recommend that the Commission issue an order adopting the Stipulation.

21. If this Stipulation is challenged by any other party to this proceeding, the Parties agree that they will continue to support the Commission's adoption of the terms of this Stipulation. The Parties agree to cooperate in cross-examination and put on such a case as they deem appropriate to respond fully to the issues presented, which may include raising issues that are incorporated in the settlements embodied in this Stipulation.

22. The Parties have negotiated this Stipulation as an integrated document. If the Commission rejects all or any material portion of this Stipulation or imposes additional material

conditions in approving this Stipulation, any Party shall have the rights provided in OAR 860-014-0085, including the right to withdraw from the Stipulation, and shall be entitled to seek reconsideration or appeal of the Commission's Order.

23. By entering into this Stipulation, no Party shall be deemed to have approved, admitted, or consented to the facts, principles, methods, or theories employed by any other Party in arriving at the terms of this Stipulation, other than those specifically identified in the body of this Stipulation. No Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding, except as specifically identified in this Stipulation.

24. This Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

This Stipulation is entered into by each party on the date entered below such Party's signature.

PACIFICORP

By: Andrea Kelly

Date: 6 July 2010

STAFF

By: ______________________

Date: ______________________

CUB

By: ______________________

Date: ______________________

ICNU

By: ______________________

Date: ______________________

SEMPRA

By: ______________________

Date: ______________________

PACIFICORP

By: ______________________________

Date: ______________________________

STAFF

By: ______________________________

Date: 7/6/10

CUB

By: ______________________________

Date: ______________________________

ICNU

By: ______________________________

Date: ______________________________

SEMPRA

By: ______________________________

Date: ______________________________

PACIFICORP

By: ______________________________

Date: ______________________________

STAFF

By: ______________________________

Date: ______________________________

CUB

By: ______________________________

Date: 7-6-2010

ICNU

By: ______________________________

Date: ______________________________

SEMPRA

By: ______________________________

Date: ______________________________

PACIFICORP

By: ______________________________

Date: ______________________________

STAFF

By: ______________________________

Date: ______________________________

CUB

By: ______________________________

Date: ______________________________

ICNU

By: Irion Sanger

Date: July 6, 2010

SEMPRA

By: ______________________________

Date: ______________________________

PACIFICORP

By: ______________________________

Date: ______________________________

STAFF

By: ______________________________

Date: ______________________________

CUB

By: ______________________________

Date: ______________________________

ICNU

By: ______________________________

Date: ______________________________

SEMPRA

By: [signature]

Date: July 6, 2010

Exhibit A

CY 2011 TAM

	ACCOUNT	UE-207 FINAL CY 2010	**TAM CY 2011**		Factors CY 2010	2011 GRC Factors CY 2011	UE-207 FINAL CY 2010	**TAM CY 2011**
Sales for Resale								
Existing Firm PPL	447	24,974,154	**25,032,103**	SG	26.877%	26.177%	6,712,274	**6,552,676**
Existing Firm UPL	447	25,490,589	**25,490,589**	SG	26.877%	26.177%	6,851,076	**6,672,694**
Post-Merger Firm	447	641,195,998	**594,135,708**	SG	26.877%	26.177%	172,333,505	**155,527,424**
Non-Firm	447	55,979,012	**-**	SE	25.002%	24.283%	13,995,816	**-**
Total Sales for Resale		747,639,753	**644,658,400**				199,892,672	**168,752,793**
Purchased Power								
Existing Firm Demand PPL	555	58,677,959	**47,758,104**	SG	26.877%	26.177%	15,770,807	**12,501,681**
Existing Firm Demand UPL	555	46,338,071	**48,168,584**	SG	26.877%	26.177%	12,454,230	**12,609,132**
Existing Firm Energy	555	57,763,587	**52,340,132**	SE	25.002%	24.283%	14,441,994	**12,709,916**
Post-merger Firm	555	376,161,158	**490,088,073**	SG	26.877%	26.177%	101,100,399	**128,290,783**
Secondary Purchases	555	(12,954,749)	**-**	SE	25.002%	24.283%	(3,238,933)	**-**
Seasonal Contracts	555		**-**	SSGC	0.000%	0.000%	-	**-**
Other Generation Expense	555	7,682,475	**38,855,180**	SG	26.877%	26.177%	2,064,810	**10,171,154**
Total Purchased Power		533,668,503	**677,210,072**				142,593,306	**176,282,667**
Wheeling Expense								
Existing Firm PPL	565	43,189,893	**40,049,244**	SG	26.877%	26.177%	11,608,098	**10,483,726**
Existing Firm UPL	565	168,268	**259,960**	SG	26.877%	26.177%	45,225	**68,050**
Post-merger Firm	565	100,936,303	**99,966,153**	SG	26.877%	26.177%	27,128,533	**26,168,227**
Non-Firm	565	253,429	**101,247**	SE	25.002%	24.283%	63,362	**24,586**
Total Wheeling Expense		144,547,893	**140,376,605**				38,845,218	**36,744,589**
Fuel Expense								
Fuel Consumed - Coal	501	610,479,015	**638,135,027**	SE	25.002%	24.283%	152,631,345	**154,960,306**
Cholla / APS Exchange	501	55,113,078	**56,675,765**	SSECH	25.408%	24.812%	14,003,311	**14,062,190**
Fuel Consumed - Gas	501	7,304,914	**6,171,919**	SE	25.002%	24.283%	1,826,367	**1,498,746**
Natural Gas Consumed	547	410,130,960	**390,763,656**	SE	25.002%	24.283%	102,540,527	**94,890,350**
Simple Cycle Combustion Turbines	547	11,664,948	**9,951,264**	SSECT	23.286%	22.403%	2,716,330	**2,229,400**
Steam from Other Sources	503	3,498,000	**3,555,701**	SE	25.002%	24.283%	874,566	**863,442**
Total Fuel Expense		1,098,190,915	**1,105,253,332**				274,592,445	**268,504,434**
Net Power Cost		1,028,767,558	**1,278,181,609**				256,138,297	**312,778,897**

Settlement Adjustment		(11,000,000)
OR-Allocated NPC Baseline in Rates		301,778,897
Increase Absent Load Change		**45,640,600**
Weighted Ave OR Allocation Factor		0.24471
Updated NPC Baseline in Rates		1,233,229,734
Oregon-allocated NPC Baseline in Rates from UE 207	256,138,297	
$ Change due to load variance from UE-207 forecast	(12,529,976)	
2011 Recovery of NPC in Rates	243,608,321	
Increase Including Load Change		**58,170,576**

PacifiCorp
Other Revenues - Baseline

	12 ME Dec 2011	OR Factor	OR %	OR Alloc	Reference
Seattle City Light - Stateline Wind Farm	4,923,706	SG	26.177%	1,288,883	Attachment OPUC 21 (UE-216)
Non-company owned Foote Creek	2,277,984	SG	26.177%	596,310	Attachment OPUC 21 (UE-216)
BPA South Idaho Exchange	8,553,309	SG	26.177%	2,239,007	Attachment OPUC 21 (UE-216)
Little Mountain Steam Revenues	6,873,305	SG	26.177%	1,799,231	UE 217 Exhibit PPL/1102, Page 5.2
James River Royalty Offset	5,430,652	SG	26.177%	1,421,586	UE 217 Exhibit PPL/1102, Page 5.2
Total Other Revenue	28,058,956			7,345,017	

Exhibit C

PACIFIC POWER
ESTIMATED EFFECT OF PROPOSED PRICE CHANGE
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN OREGON
FORECAST 12 MONTHS ENDED DECEMBER 31, 2011

						Present Revenues ($000)			Proposed Revenues ($000)			Change				
		Pre	Pro									Base Rates		Net Rates		
Line		Sch	Sch	No. of		Base		Net	Base		Net					Line
No.	Description	No.	No.	Cust	MWh	Rates	Adders[1]	Rates	Rates	Adders[1]	Rates	($000)	%[2]	($000)	%[2]	No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	
								(6) + (7)			(9) + (10)	(9) - (6)	(12)/(6)	(11) - (8)	(14)/(8)	
	Residential															
1	Residential	4	4	484,011	5,306,840	$472,654	$19,369	$492,023	$497,805	$19,369	$517,174	$25,151	5.3%	$25,151	5.1%	1
2	**Total Residential**			484,011	5,306,840	$472,654	$19,369	$492,023	$497,805	$19,369	$517,174	$25,151	5.3%	$25,151	5.1%	2
	Commercial & Industrial															
3	Gen. Svc. < 31 kW	23	23	74,207	1,013,838	$94,181	($628)	$93,553	$99,099	($628)	$98,471	$4,918	5.2%	$4,918	5.3%	3
4	Gen. Svc. 31 - 200 kW	28	28	10,419	2,011,827	$133,835	$10,844	$144,679	$142,877	$10,844	$153,721	$9,042	6.8%	$9,042	6.3%	4
5	Gen. Svc. 201 - 999 kW	30	30	882	1,386,076	$85,559	$4,215	$89,774	$91,653	$4,215	$95,868	$6,094	7.1%	$6,094	6.8%	5
6	Large General Service >= 1,000 kW	48	48	212	2,349,055	$128,583	($2,726)	$125,857	$138,860	($2,726)	$136,134	$10,277	8.1%	$10,277	8.2%	6
7	Partial Req. Svc. >= 1,000 kW	47	47	7	381,991	$19,268	($446)	$18,822	$20,887	($446)	$20,441	$1,619	8.1%	$1,619	8.2%	7
8	Agricultural Pumping Service	41	41	6,211	149,120	$16,054	($3,276)	$12,778	$16,604	($3,276)	$13,328	$550	3.4%	$550	4.3%	8
9	Agricultural Pumping - Other	33	33	2,056	127,459	$5,327	$272	$5,599	$5,327	$272	$5,599	$0	0.0%	$0	0.0%	9
10	**Total Commercial & Industrial**			93,994	7,419,366	$482,807	$8,255	$491,062	$515,307	$8,255	$523,562	$32,500	6.7%	$32,500	6.6%	10
	Lighting															
11	Outdoor Area Lighting Service	15	15	7,167	10,138	$1,332	$136	$1,468	$1,457	$136	$1,593	$125	9.4%	$125	8.5%	11
12	Street Lighting Service	50	50	258	10,594	$1,198	$144	$1,342	$1,305	$144	$1,449	$107	8.9%	$107	8.0%	12
13	Street Lighting Service HPS	51	51	710	16,563	$3,021	$338	$3,359	$3,286	$338	$3,624	$265	8.8%	$265	7.9%	13
14	Street Lighting Service	52	52	65	1,061	$117	$15	$132	$130	$15	$145	$13	11.1%	$13	9.9%	14
15	Street Lighting Service	53	53	266	9,250	$605	$83	$688	$653	$83	$736	$48	7.9%	$48	7.0%	15
16	Recreational Field Lighting	54	54	103	847	$75	$7	$82	$83	$7	$90	$8	10.7%	$8	9.8%	16
17	**Total Public Street Lighting**			8,569	48,453	$6,348	$723	$7,071	$6,914	$723	$7,637	$566	8.9%	$566	8.0%	17
18	**Total Sales to Ultimate Consumers**			586,574	12,774,659	$961,809	$28,347	$990,156	$1,020,026	$28,347	$1,048,373	$58,217	6.1%	$58,217	5.9%	18
19	**Employee Discount**				18,045	($397)	($17)	($414)	($418)	($17)	($435)	($21)		($21)		19
20	**Total Sales with Employee Discount**			586,574	12,774,659	$961,412	$28,330	$989,742	$1,019,608	$28,330	$1,047,938	$58,196	6.1%	$58,196	5.9%	20
21	AGA Revenue					$2,800		$2,800	$2,800		$2,800	$0		$0		21
22	**Total Sales with Employee Discount and AGA**			586,574	12,774,659	$964,212	$28,330	$992,542	$1,022,408	$28,330	$1,050,738	$58,196	6.0%	$58,196	5.9%	22

[1] Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), Public Purpose Charge (Sch. 290) and Energy Conservation Charge (Sch. 297).

[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

Exhibit C

Line No.	Description	Pre Sch No.	Line No.
	(1)	(2)	
	Residential		
1	Residential	4	1
2	**Total Residential**		2
	Commercial & Industrial		
3	Gen. Svc. < 31 kW	23	3
4	Gen. Svc. 31 - 200 kW	28	4
5	Gen. Svc. 201 - 999 kW	30	5
6	Large General Service >= 1,000 kW	48	6
7	Partial Req. Svc. >= 1,000 kW	47	7
8	Agricultural Pumping Service	41	8
9	Agricultural Pumping - Other	33	9
10	**Total Commercial & Industrial**		10
	Lighting		
11	Outdoor Area Lighting Service	15	11
12	Street Lighting Service	50	12
13	Street Lighting Service HPS	51	13
14	Street Lighting Service	52	14
15	Street Lighting Service	53	15
16	Recreational Field Lighting	54	16
17	**Total Public Street Lighting**		17
18	**Total Sales to Ultimate Consumers**		18
19	**Employee Discount**		19
20	**Total Sales with Employee Discount**		20
21	AGA Revenue		21
22	**Total Sales with Employee Discount and AGA**		22

[1] Excludes effects of the Low Income Bill Payment Ass

[2] Percentages shown for Schedules 48 and 47 reflect th