



## ATCO Electric Ltd.

2006 Interim Transmission Facility Owner and Distribution Tariffs

December 13, 2005

**ALBERTA ENERGY AND UTILITIES BOARD**

Decision 2005-133: ATCO Electric Ltd.

2006 Interim Transmission Facility Owner and Distribution Tariffs

Application No. 1423181

December 13, 2005

Published by

Alberta Energy and Utilities Board

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# ALBERTA ENERGY AND UTILITIES BOARD

Calgary Alberta

## ATCO ELECTRIC LTD. 2006 INTERIM TRANSMISSION FACILITY OWNER AND DISTRIBUTION TARIFFS

Decision 2005-133  
Application No. 1423181

### 1 INTRODUCTION

By letter dated October 12, 2005, ATCO Electric Ltd. (AE) filed an application (Application) for a 2006 Interim Transmission Facility Owner (TFO) tariff and a 2006 Interim Distribution Tariff (DT). AE requested that both the TFO tariff and DT be approved on an interim refundable basis effective January 1, 2006. AE also requested approval to discontinue the current Rider G and Rider Q effective January 1, 2006.

In addition, AE requested approval to continue to flow through the transmission access components of the distribution tariff for transmission connected customers. AE also noted that in Board Order [U2005-371](#) the Board approved AE's application to convert monthly fixed charges and monthly demand charges to daily rates effective January 1, 2006. By filing the proposed price schedules using daily rates, AE is complying with a Board direction to file these rates by December 5, 2005.

AE applied for the Interim TFO tariff, in accordance with Section 124(2) of the *Electric Utilities Act*. AE noted that it currently has before the Board its 2005-2006 Transmission and Distribution General Tariff Application No. 1399997 (GTA), which it filed in May of 2005. AE's GTA was the subject of a public hearing that commenced on October 11, 2005. A final decision on the GTA is not expected until sometime in 2006. As a result, AE is proposing to utilize an Interim TFO Tariff until such time as it receives approval for its final 2006 TFO rates.

Table 1. Proposed Interim TFO Tariff (Per Application)

	\$Millions
2006 Transmission Tariff as filed in AE's 2005-2006 GTA	175.1
Decrease based on the Impact of Omissions and Updates filed October 6, 2005	(3.5)
Updated Annual 2006 Transmission Tariff applied for on an interim refundable basis	171.6
Monthly Charge (on an interim refundable basis)	14.300

AE stated that the monthly charge to the Alberta Electric System Operator (AESO) will be on an interim refundable basis. All amounts included in this Application will be trued up once the Board renders its final GTA determinations.

With respect to the DT, AE noted that it had proposed 2006 final distribution rates in its 2005-2006 GTA based on a pro-ration of the 2004 final distribution rates that were approved in Decision [2005-074](#). AE proposes to scale the transmission and distribution components of all distribution rates by a scaling factor. The scaling adjustment to the transmission component is based on collecting the forecast Transmission Access Payment (TAP) amounts to be charged to AE by the AESO. The scaling adjustment to distribution rates relates only to the recovery of

costs specifically assigned to the distribution function, that is, the distribution revenue requirement minus the transmission access charges.

AE proposes to apply the same scaling factors as proposed for the 2006 Final Distribution rates in its 2005-2006 GTA to the currently approved 2005 Interim Distribution rates to obtain the 2006 Interim Refundable rates that will become effective January 1, 2006. The proposed scaling factors are noted below:

**Table 2. AE Proposed Scaling Factors for 2006 Interim Rates (Per Application)**

Rate Class	Transmission Access		Distribution		
	Demand	Energy	Customer	Demand	Energy
D11	N/A	2.085	1.067	1.067	1.067
D61	2.091	N/A	1.067	1.067	1.067
D63	2.080	N/A	1.067	1.067	1.067
T31	1.000	1.000	1.067	1.067	1.067
Others	2.837	1.276	1.067	1.067	1.067

The Board notes that based on 2006 billing determinants and current rates, the proposed revenue for 2006 would be \$245,721,000.<sup>1</sup> As a result of applying the scaling factors as noted above, proposed revenue will increase to \$307,699,000, an increase of \$61,978,000.

At the commencement of the AE 2005-2006 GTA hearing, the Board made the following comments:

On October 6th, 2005, ATCO filed updated information with respect to transmission access payments. The Board understands that ATCO Electric will soon be filing a request for interim rates commencing January 2006 that contains the updated transmission access payment information. The Board may canvass parties in this proceeding with respect to the appropriate process that should be followed to deal with the interim application.<sup>2</sup>

On October 13, 2005, the Board circulated the Application to interested parties on the AE 2005-2006 GTA distribution list.

The Board issued a letter dated October 24, 2005 and made the following observations with respect to the requested approvals:

The Board notes that the 2006 interim applications mirror AE's GTA which is currently before the Board for determination. In addition, the Board notes that the proposed TFO and DT are on an interim refundable basis, any differences between these rates and the rates ultimately approved by the Board will be refunded to customers. Given the relatively short time frame available to deal with this application, and the interim refundable nature of the proposed rates, the Board considers that it would be appropriate to deal with this application by way of a short written proceeding.

According to the written proceeding established by the Board, the Board forwarded an initial set of Information Requests to AE. These were followed up with a second set of Information Requests (IRs). The Board notes that additional IRs were not submitted by other interested

<sup>1</sup> BR-ATCO-01(a) Attachment 10

<sup>2</sup> Tr., p.4 starting at line 23

parties. Argument was received from FIRM<sup>3</sup> on November 10, 2005 and AE on November 14, 2005, with Reply Argument from AE on November 16, 2005.

The Board received a late request from AE dated December 5, 2005 to consider implementing a refund rider (Rider F) that will flow from the Balancing Pool through the AESO to all customers with the exception of small general service, large general service and oilfield customers in isolated industrial areas served on Price Schedule D24, Price Schedule D34, and Price Schedule D44. The Board notes that the Balancing Pool Refund was approved as a flow through in Decision [2005-131](#) (AESO Refiling of the GTA per Decision 2005-096). For purposes of this proceeding, the Board considers that the record closed as of December 5, 2005.

The Division of the Board assigned to consider and decide this Application consists of A. J. Berg, P. Eng. (Presiding Member), T. McGee, (Member), and M. L. Asgar-Deen, P. Eng (Acting Member).

## 2 ISSUES

FIRM made the following submissions with respect to the Application:

**Table 3. Issues Identified by FIRM with Respect to 2006 Interim Rates**

Requested Approvals	Issues Identified by FIRM
<b>Transmission</b>	
Approval of \$171.6M Interim TFO tariff.	FIRM noted that the proposed Interim TFO tariff represented a \$10.4M increase over the 2005 Interim rate of \$161.2M. Given that the 2005-2006 GTA is ongoing, FIRM recommend that only 50% of the proposed increase be approved on an interim basis.
<b>Distribution</b>	
Approval of 2006 Interim rates, based on scaling factors being applied to the current 2005 interim distribution rates.	<p><u>Transmission Component of Distribution Rates</u> FIRM considered that the transmission component should be based on a final decision from the Board. Absent a decision, the transmission component should be based on the assumption that POD charges will not be implemented in 2006. FIRM estimated that this would result in a reduction of \$8.6M to the transmission component, if POD charges were collected as part of the demand charge.</p> <p>FIRM was not opposed to the scaling factor approach with respect to the transmission component of distribution rates for interim rate purposes. FIRM recommended that a Phase II proceeding should be held to examine the transmission component allocated to each rate class.</p> <p><u>Distribution Component of Distribution Rates</u> FIRM noted that the scaling factor of 6.7% translates into an increase of \$11.2M in distribution costs on an annualized basis. Given that the 2005-2006 GTA is ongoing, FIRM recommend that only 50% of the proposed increase be approved on an interim basis.</p>
Approval to continue to flowing through the transmission tariff directly to transmission connected customers	FIRM supported the continuation of flowing through the transmission access component of the tariff to transmission connected customers.
Approval to discontinue Rider G and Q effective January 1, 2006.	FIRM supported the discontinuation of these two riders.
Approval of daily rates	FIRM did not comment on this issue.

<sup>3</sup> FIRM Group is composed of the UCA, CCA, AIPA, AUMA, PICA, AFREA and AAMDC

As seen from the preceding table, at issue in this proceeding, are the amounts that should be approved with respect to the TFO tariff, and the transmission and distribution components of the distribution tariff. The Board will deal with each of these issues first and will then address any other matters that need to be determined in order that appropriate rates for the 2006 Interim tariffs can be set.

### **3 DISCUSSION OF ISSUES**

#### **3.1 TFO Tariff**

AE has requested an increase of \$10.4 million above the current interim TFO tariff of \$161.2 million that was approved in Decision [2005-102](#). The request is based on AE's view that the applied-for 2006 interim TFO rates would more closely reflect the circumstances that exist in transmission in 2006 than the interim rates currently in place.<sup>4</sup>

The Board notes that in AE's 2005-2006 GTA currently before the Board, AE requested approval of significantly different TFO tariff amounts for each of 2005 and 2006. The Board agrees with AE that, to the extent possible, AE's 2006 interim rate should reflect the circumstances that exist in transmission in 2006. Therefore, notwithstanding the Board's view in Decision 2005-102 that the 2005 interim TFO tariff should remain in effect until a final decision is made with respect to AE's 2005-2006 GTA, the Board is prepared to consider AE's request to increase its current interim TFO rate effective January 1, 2006.

FIRM has recommended that only 50% of the applied-for increase in the TFO tariff for 2006 be approved. FIRM's recommendation is based, in part, on the fact that the Board has not yet rendered a final decision on the circumstances that exist in transmission for 2006.

The Board considers that FIRM's recommendation represents a fair balance between the Board's view in Decision 2005-102 respecting the continuation of the 2005 interim TFO tariff and AE's request for a tariff that reflects transmission circumstances that may exist in 2006. Furthermore, the Board considers that approving 50% of the applied-for increase (\$5.2 million) at this time will minimize any future adjustments that may need to be made and will provide rate stability to both the AESO and AE.

Given that all amounts associated with AE's 2005 and 2006 interim TFO tariffs will be tried up once a final decision is rendered with respect to the 2005-2006 GTA proceeding, the Board considers it appropriate to approve an increase to AE's current interim TFO tariff.

Therefore, the Board approves an interim refundable TFO tariff for AE for 2006 of \$166.4 million, which represents an increase of \$5.2 million over the currently-approved interim TFO tariff of \$161.2 million

#### **3.2 Distribution Tariff**

Based on the 2006 billing determinants, the Board notes that adopting the scaling factors proposed by AE results in a revenue increase of \$61.978 million, bringing the total DT to

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<sup>4</sup> BR-ATCO-4(b)

\$307.7 million. From its review of the evidence before it, the Board considers that there are three factors which have contributed to this increase, namely the impact of the *Transmission Regulation*, AESO Refiling and the 2005-2006 GTA. These factors are noted below:

Table 4. Contributing Factors to the 2006 Interim Distribution Tariff Increase

		Increase \$M		Percentage of Total Increase	
Transmission		50,147		81	
	Impact of the Transmission Regulation		36,665		59
	AESO Refiling		13,482		22
Distribution		11,831		19	
	2005-2006 GTA		11,831		19
Total Increase		61,978	61,978	100	100

#### *Impact of the Transmission Regulation*

The Board notes that the *Transmission Regulation* is a significant driver of the proposed increase to AE's DT. In particular, the Board notes the impact of Section 30 of the *Transmission Regulation* which has resulted in 100% of the wires cost component of the AESO revenue requirement being allocated to load customers. Prior to the enactment of the *Transmission Regulation*, the AESO's wires costs were borne equally between load and generation customers. The impact of this change to the AESO's cost allocation methodology accounts for approximately \$37 million or 59% of the requested \$62 million increase.

#### *AESO Refiling*

The Board notes that AE updated its forecast of TAP charges to reflect the significant changes in the AESO tariff for 2006 as a result of the compliance filing submitted to the Board by the AESO pursuant to Decision [2005-096](#). As a result of this update, AE has forecast that TAP charges will increase by approximately \$13 million, which represents 22% of the requested total increase.

In aggregate, the transmission access component of distribution rates represents \$50 million or about 80% of the proposed \$62 million requested increase.

### **3.2.1 Transmission Component**

FIRM submitted that the level and structure of AESO charges should be based on any final determination made by the Board. Absent a Decision from the Board, the transmission charges should be based on the assumption POD charges would likely not be implemented in 2006, and would result in transmission access costs being reduced by \$8.6 million.

AE responded to this suggestion as follows:

Simply assuming that no fixed POD charges in the AESO tariffs will result for 2006 is arbitrary and without factual support.<sup>5</sup>

and

Additionally AE notes that the AESO is still proposing to implement a POD charge, possibly with some relief to PODs 5 MW or less based on their recent proposal to the

<sup>5</sup> AE Reply Argument p. 2

Board dated November 14. If this proposal is accepted by the Board, the relief to the small PODs will increase the POD charges for the remaining customers resulting in no significant changes to the overall TAP costs to AE.<sup>6</sup>

Further, the Board notes that Section 31 (3) of the *Transmission Regulation* requires the AESO tariff that is approved by the Board to take effect on January 1, 2006.

The Board agrees with the position of AE with respect to the AESO tariffs, and notes that on December 6, 2005 the Board released Decision 2005-132, (AESO Review and Variation of Customer Related POD Charge) which deals with POD charges for certain customers with loads less than 5 MW. In light of this, the Board considers that FIRM's argument with respect to POD charges and transmission access costs being reduced by \$8.6 million to be moot.

Moreover, the Board, in arriving at its decision, has considered the fact that AE has proposed that:

...any changes in the yearly TAP costs due to changes in the AESO tariffs or differences in the actual or forecasted pool prices will be subject to deferral account.<sup>7</sup>

Given these considerations, the Board approves the scaling factors proposed by AE to determine the transmission component of the 2006 interim distribution rates.

### 3.2.2 Distribution Component

FIRM noted that the use of AE's proposed distribution scaling factor of 1.067 results in an \$11.2 million increase in distribution costs on an annualized basis. FIRM argued that since the Board has not ruled on the 2005-2006 GTA proceeding, the distribution costs should only be increased by 50% or \$5.6 million.

In general, the Board considers that such an approach has merit when setting interim rates as it strikes a middle ground, balancing the requests of both the company and interveners. However, the Board cannot ignore the significant change to the cost structure of the transmission system resulting from Section 30 of the *Transmission Regulation*, the impact of which is significant in terms of the proposed increase requested.

The Board considers that approving the distribution component of the tariff on the basis recommended by FIRM may result in interim rates significantly under-recovering the 2006 final revenue requirement. This would result in a rate increase later in the year, coupled with a rate rider to recover the shortfalls. In the Board's view, this approach would not result in rate stability. Therefore, the Board cannot accept the recommendation made by FIRM.

The Board notes that although the change to the allocation of costs for the transmission system as set out in Section 30 of the *Transmission Regulation* will have a significant impact on distribution rates<sup>8</sup>, this impact will be tempered by AE's proposal to discontinue Rider G and Rider Q January 1, 2006. Discontinuing these Riders will result in most rate classes experiencing

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<sup>6</sup> AE Reply Argument, p. 2

<sup>7</sup> AE Application, pp. 2-3 lines 6-8

<sup>8</sup> BR-ATCO-05 – Schedule 1

a +/- 4% change<sup>9</sup> in their monthly electricity bills as noted in Table 5 below. Given these offsetting changes, the Board considers that the most prudent approach at this point in time would be to approve the rates as requested by AE. Such an approval would result in small fluctuations in rates now with an outlook of longer term stability.

**Table 5. Percentage Impact of Board Approved Interim Rates vs. Current Rates for Average Use Customers**

Rate Class	December 2005				January 2006				Impact
	DT Base Rates	Energy	Rider G & Q	Net Amount	DT Base Rates	Energy	Rider G & Q	Net Amount	
	\$/month				\$/month				
D-11 Residential	45.87	51.22	6.09	103.18	53.45	51.22	0.00	104.66	1%
D-21 Commercial	218.30	572.17	50.15	840.62	262.96	572.17	0.00	835.13	-1%
D-25 Irrigation	860.66	840.92	368.74	2,070.32	1,110.09	840.92	0.00	1,951.01	-6%
D-26 REA Irrigation	390.26	840.92	368.74	1,599.92	609.33	840.92	0.00	1,450.25	-10%
D-31 Industrial	377.84	1,181.28	189.64	1,748.76	498.21	1,181.28	0.00	1,679.48	-4%
D-41 Oilfield	280.05	651.88	(184.49)	747.44	332.19	651.88	0.00	984.07	24%
D-51 REA Farm	36.04	98.76	11.63	146.44	47.59	98.76	0.00	146.36	0%
D-56 Farm	54.94	99.76	15.14	169.85	67.51	99.76	0.00	167.27	-2%
D-61 Street Lighting	7.84	9.02	(1.18)	15.68	9.03	9.02	0.00	18.05	13%
D-63 Private Lighting	11.05	9.02	(1.88)	18.19	12.38	9.02	0.00	21.40	15%

Therefore, for all of the foregoing considerations, the Board approves the distribution scaling factors proposed by AE in calculating the 2006 interim distribution component of the distribution tariff. The Board notes that the net amounts shown for January 2006 do not reflect the Balancing Pool refund, customers may experience differing distribution amounts based on their individual consumption.

## 4 OTHER MATTERS

### 4.1 Transmission Tariff Flow Through, Riders G and Q, and Daily Rates

The Board notes AE's request for Board approval to continue to flow through the transmission tariff directly to transmission connected customers and to discontinue Rider G and Q, were unopposed.

The Board notes that to date a significant amount of work has been undertaken to harmonize the DISCO interconnection policies with that of the AESO for direct connected customers. Therefore, the Board considers it would be appropriate to continue to flow through the transmission access components of the distribution tariff for transmission connected customer as proposed by AE. Accordingly, the Board approves AE's request to continue to flow through the transmission tariff directly to transmission connected customers.

As noted previously, the discontinuance of Riders G and Q temper the impact of the *Transmission Regulation* and AESO re-filing. Continuing these Riders would result in over-collections that would eventually need to be refunded to customers. Therefore, the Board approves AE's request to discontinue Rider G and Rider Q effective January 1, 2006.

<sup>9</sup> AE 2006 Interim Tariff Application, Appendix B Schedules B.1-B.13

With respect to daily rates, the Board notes that daily rates did not garner comment from FIRM in this proceeding, and that AE is complying with a directive issued in Order [U2005-371](#). The Board considers that the conversion to daily rates is a mechanical process based on the number of days and months in the year. Therefore, the Board approves the daily fixed charges and demand charges as proposed by AE.

#### **4.2 Balancing Pool Refund**

The Board is also in receipt of a letter dated December 5, 2005 from AE, with respect to the Balancing Pool Refund of \$1.00/MW.h. In its letter, AE noted that it had been asked by the Balancing Pool to implement this refund as soon as possible, and stated:

ATCO Electric would not be opposed to flowing through this amount as a separate refund rider of \$1.00/MW.h, effective January 1, 2006 on an interim refundable basis.

In Decision [2005-131](#), the AESO 2005-2006 Refiling, the Board approved the flow through of a Balancing Pool Refund of \$1.00/MW.h to the AESO customers via Rider F.

The Board notes that parties have not had the opportunity to comment on this issue. However, based on section 58 of the *Public Utilities Board Act (RSA 2000)*, the Board may on the grounds of urgency or for other reason appearing to the Board to be sufficient, issue orders without notice. The Board considers that due to the short time available to implement this proposal, and the limited time available for parties to comment on the submission, that it would be appropriate for the Board to directly rule on this issue.

The Board considers that it would be appropriate to approve the flow through of the Balancing Pool Refund to AE's customers effective January 1, 2006. Such a measure would avoid accumulating amounts that would need to be refunded to AE's customers at a later date. Further, Refund Rider F as proposed by AE in [Appendix 4](#) of this Decision will further reduce the impact of the *Transmission Regulation* and lower distribution charges for AE's customers as noted in Table 6 below. Therefore the Board approves the flow through of the Balancing Pool Refund as Rider F to AE's customers effective January 1, 2006.

As noted, Table 6 takes into account the Balancing Pool Refund; however AE's customers may experience different net distribution amounts based on their individual consumption.

**Table 6. Percentage Impact of Board Approved Interim Rates plus the Balancing Pool Refund vs. Current Rates for Average Use Customers**

Rate Class	December 2005	January 2006					Impact
	Net Amount (From Table 5)	DT Base Rates	Energy	Rider G & Q	Balancing Pool Refund	Net Amount	
	\$/month	\$/month					
D-11 Residential	103.18	53.45	51.22	0.00	(0.60)	104.06	1%
D-21 Commercial	840.62	262.96	572.17	0.00	(7.30)	827.83	-2%
D-25 Irrigation	2,070.32	1,110.09	840.92	0.00	(11.68)	1,939.33	-7%
D-26 REA Irrigation	1,599.92	609.33	840.92	0.00	(11.68)	1,438.57	-11%
D-31 Industrial	1,748.76	498.21	1,181.28	0.00	(16.65)	1,662.83	-5%
D-41 Oilfield	747.44	332.19	651.88	0.00	(8.76)	975.31	23%
D-51 REA Farm	146.44	47.59	98.76	0.00	(1.26)	145.10	-1%
D-56 Farm	169.85	67.51	99.76	0.00	(1.26)	166.01	-2%
D-61 Street Lighting	15.68	9.03	9.02	0.00	(0.09)	17.96	13%
D-63 Private Lighting	18.19	12.38	9.02	0.00	(0.09)	21.31	15%

## 5 ORDER

IT IS HEREBY ORDERED THAT:

- (1) ATCO Electric Ltd's Transmission Facility Owner Tariff Rate as shown in [Appendix 3](#), of this Decision, is approved on an interim refundable basis, effective January 1, 2006.
- (2) ATCO Electric Ltd's Distribution Tariff Rates based on the scaling factors and daily basis, as shown in [Appendix 4](#), of this Decision, are approved on an interim refundable basis, effective January 1, 2006.
- (3) ATCO Electric Ltd's Rider G and Rider Q are to be discontinued effective January 1, 2006.
- (4) ATCO Electric Ltd's Rider F, the flow through of the Balancing Pool Refund of \$1.00/MW.h, as shown in [Appendix 4](#), of this Decision is approved effective January 1, 2006.

Dated in Calgary, Alberta on December 13, 2005.

### ALBERTA ENERGY AND UTILITIES BOARD

*(original signed by)*

A. J. Berg, P. Eng.  
Presiding Member

*(original signed by)*

T. McGee  
Member

*(original signed by)*

M. L. Asgar-Deen, P. Eng.  
Acting Member

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**APPENDIX 1 – HEARING PARTICIPANTS**

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Name of Organization (Abbreviation)  
Counsel or Representative (APPLICANTS)

---

ATCO Electric (AE)  
L. G. Keough  
Bennett Jones LLP

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Farm, Institutional, Residential and Municipal Customers (FIRM)  
Consisting of:

Alberta Federation of REA's Ltd. (AFREA)  
Alberta Association of Municipal Districts and Counties (AAMDC)  
Alberta Irrigation Projects Association (AIPA)  
Alberta Urban Municipalities Association (AUMA)  
Consumers Coalition of Alberta (CCA)  
Public Institutional Consumers of Alberta (PICA)  
Utility Consumer Advocate (UCA)

N. McKenzie  
Nancy J. McKenzie Professional Corp.

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Alberta Energy and Utilities Board

Board Panel

A. J. Berg, P.Eng, Presiding Member  
T. McGee, Member  
M. L. Asgar-Deen, P.Eng., Acting Member

Board Staff

C. Wall (Board Counsel)  
C. Burt

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## APPENDIX 2 – SUMMARY OF KEY FINDINGS OR BOARD FINDINGS AND CONCLUSIONS

This section is provided for the convenience of readers. In the event of any difference between the Approvals in this section and those in the main body of the Decision, the wording in the main body of the Decision shall prevail.

1. Therefore, the Board approves an interim refundable TFO tariff for AE for 2006 of \$166.4 million, which represents an increase of \$5.2 million over the currently-approved interim TFO tariff of \$161.2 million ..... 4
2. Given these considerations, the Board approves the scaling factors proposed by AE to determine the transmission component of the 2006 interim distribution rates. .... 6
3. Therefore, for all of the foregoing considerations, the Board approves the distribution scaling factors proposed by AE in calculating the 2006 interim distribution component of the distribution tariff. The Board notes that the net amounts shown for January 2006 do not reflect the Balancing Pool refund, customers may experience differing distribution amounts based on their individual consumption. .... 7
4. The Board notes that to date a significant amount of work has been undertaken to harmonize the DISCO interconnection policies with that of the AESO for direct connected customers. Therefore, the Board considers it would be appropriate to continue to flow through the transmission access components of the distribution tariff for transmission connected customer as proposed by AE. Accordingly, the Board approves AE’s request to continue to flow through the transmission tariff directly to transmission connected customers..... 7
5. As noted previously, the discontinuance of Riders G and Q temper the impact of the *Transmission Regulation* and AESO refile. Continuing these Riders would result in over-collections that would eventually need to be refunded to customers. Therefore, the Board approves AE’s request to discontinue Rider G and Rider Q effective January 1, 2006. .... 7
6. With respect to daily rates, the Board notes that daily rates did not garner comment from FIRM in this proceeding, and that AE is complying with a directive issued in Order U2005-371. The Board considers that the conversion to daily rates is a mechanical process based on the number of days and months in the year. Therefore, the Board approves the daily fixed charges and demand charges as proposed by AE. .... 8
7. The Board considers that it would be appropriate to approve the flow through of the Balancing Pool Refund to AE’s customers effective January 1, 2006. Such a measure would avoid accumulating amounts that would need to be refunded to AE’s customers at a later date. Further, Refund Rider F as proposed by AE in Appendix 4 of this Decision will further reduce the impact of the *Transmission Regulation* and lower distribution charges for AE’s customers as noted in Table 6 below. Therefore the Board approves the flow through of the Balancing Pool Refund as Rider F to AE’s customers effective January 1, 2006..... 8

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**APPENDIX 3 – ATCO ELECTRIC LTD. - INTERIM 2006 RATE SCHEDULE  
TRANSMISSION FACILITIES OWNER TARIFF**



Appendix 3 - Interim  
2006 TFO Tariff.doc

(Consists of 1 page)

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## **APPENDIX 4 – ATCO ELECTRIC LTD. – INTERIM 2006 DT RATE SCHEDULES**



Appendix 4 - Interim  
2006 DT Rate Schedu

(Consists of 52 pages)

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## APPENDIX 5 – RATE IMPACT SCHEDULES



Appendix 5 - Rate  
Impact Schedules.xls

(Consists of 16 pages)

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**APPENDIX 6 – IMPACT OF TRANSMISSION REGULATION, AESO REFILE AND  
2005-2006 GTA ON DISTRIBUTION BASE RATES FOR AVERAGE USE CUSTOMERS**



Appendix 6 - Monthly  
Comparisons.xls

(Consists of 1 page)

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**EFFECTIVE: 2006-01-01**

**ATCO ELECTRIC LTD.  
2006 RATE SCHEDULE  
INTERIM TRANSMISSION TARIFF**

**AVAILABLE:** To the Transmission Administrator

**APPLICABLE:** To the Transmission Administrator for use of the Company's transmission facility for the 2006 calendar year.

**RATE:** Interim Charges to the Transmission Administrator for the 2006 calendar year shall be:

Annual Tariff: \$166,400,000

Monthly Charges: \$13,866,667

**APPENDIX 4**

**ATCO ELECTRIC LTD.  
2006 INTERIM DISTRIBUTION TARIFF  
INTERIM PRICE SCHEDULES  
EFFECTIVE JANUARY 1, 2006**

**PRICE SCHEDULE INDEX****RESIDENTIAL SERVICE**

Standard Residential Service Price Schedule D11

**SMALL GENERAL SERVICE**

Standard Small General Service Price Schedule D21

Small General Service - Energy Only Price Schedule D22

Small General Service - Isolated Industrial Areas - Distribution Connected Price Schedule D24

Irrigation Pumping Service Price Schedule D25

REA Irrigation Pumping Service Price Schedule D26

**LARGE GENERAL SERVICE/INDUSTRIAL**

Large General Service/Industrial - Distribution Connected Price Schedule D31

Large General Service/Industrial - Transmission Connected Price Schedule T31

Generator Interconnection and Standby Power - Distribution Connected Price Schedule D32

Transmission Opportunity Rate - Distribution Connected Price Schedule D33

Transmission Opportunity Rate - Transmission Connected Price Schedule T33

Large General Service/Industrial - Isolated Industrial Areas - Distribution Connected Price Schedule D34

**OILFIELD**

Small Oilfield and Pumping Power Price Schedule D41

Small Oilfield and Pumping Power - Isolated Industrial Areas - Distribution Connected Price Schedule D44

**FARM SERVICE**

REA Farm Service Price Schedule D51

REA Farm Service - Excluding Wires Service Provider Functions Price Schedule D52

Farm Service Price Schedule D56

**LIGHTING SERVICE**

Street Lighting Service Price Schedule D61

Private Lighting Service Price Schedule D63

**PRICE OPTIONS**

Idle Service Option F

Service for Non-Standard Transformation and Metering Configurations Option H

REA Distribution Price Credit Option P

**PRICING ADJUSTMENTS (RIDERS)**

Municipal Assessment Rider A-1

Special Facilities Charge Rider E

Balancing Pool Adjustment Rider F

Temporary Adjustment Rider G

Interim Adjustment Rider J

Interim RRT Adjustment Rider Q

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## Price Schedule D11 – Standard Residential Service

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### **Availability**

- For System Access Service and Distribution Access Service for all Points of Service throughout the territory served by the Company.
- For single-phase service at secondary voltage through a single meter.
- For normal use by a single and separate household.
- Not applicable to any commercial or industrial use.

### **Price**

The charge for service in any one billing month is the sum of the Customer Charge and Energy Charge, determined for each individual Point of Service.

	<b>Customer Charge</b>	<b>Energy Charge</b>
<b>Transmission</b>	-	1.63 ¢ / kW.h
<b>Distribution</b>	37.28 ¢ / day	3.80 ¢ / kW.h
<b>Service</b>	32.28 ¢ / day	-
<b>TOTAL PRICE</b>	<b>69.56 ¢ / day</b>	<b>5.43 ¢ / kW.h</b>

The minimum monthly charge is the Customer Charge.

### **Application**

1. **Price Option** - the following price option may apply:  
Idle Service (Option F)
2. **Price Adjustments** - the following price adjustments (riders) may apply:  
Municipal Assessment (Rider A-1)  
Balancing Pool Adjustment (Rider F)  
Temporary Adjustment (Rider G)  
Interim Adjustment (Rider J)  
Interim RRT Adjustment (Rider Q)

---

## Price Schedule D21 – Standard Small General Service

---

### **Availability**

For System Access Service and Distribution Access Service for all Points of Service throughout the territory served by the Company, with single or three-phase electric service at secondary voltage. Not applicable for any service in excess of 500 kW.

### **Price**

Charges for service in any one billing month shall be the sum of the Customer Charge, Demand Charge, and Energy Charge, determined for each individual Point of Service.

	Customer Charge	Demand Charge	Energy Charge	
			For the first 200 kW.h per kW of billing demand	For energy in excess of 200 kW.h per kW of billing demand
<b>Transmission</b>	-	7.00 ¢/kW/day	0.48 ¢ / kW.h	0.48 ¢ / kW.h
<b>Distribution</b>	-	13.51 ¢/kW/day	2.27 ¢ / kW.h	-
<b>Service</b>	46.88 ¢ / day	-	-	-
<b>TOTAL PRICE</b>	<b>46.88 ¢ / day</b>	<b>20.51 ¢/kW/day</b>	<b>2.75 ¢ / kW.h</b>	<b>0.48 ¢ / kW.h</b>

The billing demand may be estimated or measured and will be the greater of the following:

- (a) the highest metered demand during the billing period;
- (b) 85% of the difference between the highest metered demand in the twelve month period including and ending with the billing period and 150 kW, if this is greater than zero;
- (c) the estimated demand;
- (d) the contract demand;
- (e) 5 kilowatts.

The minimum monthly bill is the sum of the Service Charge and the total Demand Charge.

### **Application**

1. **Power Factor Correction** - where a Customer's power factor is found to be less than 90%, the Company may require the Customer to install corrective equipment.
2. **Price Options** - the following price options may apply:  
Idle Service (Option F)  
Service for Non-Standard Transformation and Metering Configurations (Option H)  
REA Distribution Price Credit (Option P)
3. **Price Adjustments** - the following price adjustments (riders) may apply:  
Municipal Assessment (Rider A-1)  
Balancing Pool Adjustment (Rider F)  
Temporary Adjustment (Rider G)  
Interim Adjustment (Rider J)  
Interim RRT Adjustment (Rider Q)

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## Price Schedule D22– Standard Small General Service – Energy Only

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### **Availability**

For System Access Service and Distribution Access Service for all Points of Service throughout the territory served by the Company, with single or three-phase electric service at secondary voltage. Not applicable for any service in excess of 50 kW.

### **Price**

Charges for service in any one billing month shall be the Energy Charge, determined for each individual Point of Service.

	Energy Charge	
	For the first 50 kW.h per kW of billing demand	For energy in excess of 50 kW.h per kW of billing demand
<b>Transmission</b>	0.51 ¢ / kW.h	0.51 ¢ / kW.h
<b>Distribution</b>	14.84 ¢ / kW.h	6.25 ¢ / kW.h
<b>Service</b>	-	-
<b>TOTAL PRICE</b>	<b>15.35 ¢ / kW.h</b>	<b>6.76 ¢ / kW.h</b>

The billing demand may be estimated or measured and will be the greater of the following:

- (a) the highest metered demand during the billing period;
- (b) the estimated demand;
- (c) the contract demand;
- (d) 5 kilowatts.

The minimum annual charge is 12 times the sum of:

- (a) the Service Charge from Price Schedule D21; and
- (b) the Total Demand Charge from Price Schedule D21 multiplied by the higher of the DCD or 5 kW.

### **Application**

1. **Power Factor Correction** - where the power factor at a Point of Service is found to be less than 90%, the Company may require the installation of corrective equipment.
2. **Price Options** - the following price option may apply:  
Idle Service (Option F)  
Service for Non-Standard Transformation and Metering Configurations (Option H)
3. **Price Adjustments** - the following additional charges (riders) may apply:  
Municipal Assessment (Rider A-1)  
Balancing Pool Adjustment (Rider F)  
Temporary Adjustment (Rider G)  
Interim Adjustment (Rider J)  
Interim RRT Adjustment (Rider Q)

## **Price Schedule D24 – Standard Small General Service Isolated Industrial Areas**

### **Availability**

For Distribution Access Service, single or three-phase, for all Points of Service throughout the territory served by the Company distribution connected from an isolated industrial areas. Not applicable for any service in excess of 500 kW.

### **Price**

Charges for service in any one billing month shall be the sum of the Customer Charge, Demand Charge, and Energy Charge, determined for each individual Point of Service.

	Customer Charge	Demand Charge	Energy Charge	
			For the first 200 kW.h per kW of billing demand	For energy in excess of 200 kW.h per kW of billing demand
<b>Distribution</b>	-	13.51 ¢/kW/day	2.27 ¢ / kW.h	-
<b>Service</b>	46.88 ¢ / day	-	-	-
<b>TOTAL PRICE</b>	<b>46.88 ¢ / day</b>	<b>13.51 ¢/kW/day</b>	<b>2.27 ¢ / kW.h</b>	-

The billing demand may be estimated or measured and will be the greater of the following:

- (a) the highest metered demand during the billing period;
- (b) 85% of the difference between the highest metered demand in the twelve month period including and ending with the billing period and 150 kW, if this is greater than zero;
- (c) the estimated demand;
- (d) the contract demand;
- (e) 5 kilowatts.

The minimum monthly bill is the sum of the Service Charge and the total Demand Charge.

### **Application**

1. **Power Factor Correction** - where a Customer's power factor is found to be less than 90%, the Company may require the Customer to install corrective equipment.
2. **Price Options** - the following price options may apply:  
Idle Service (Option F)  
Service for Non-Standard Transformation and Metering Configurations (Option H)  
REA Distribution Price Credit (Option P)
3. **Price Adjustments** - the following price adjustments (riders) may apply:  
Municipal Assessment (Rider A-1)  
Temporary Adjustment (Rider G)  
Interim Adjustment (Rider J)

**Price Schedule D25 – Irrigation Pumping Service**

**Availability**

For System Access Service and Distribution Access Service for all Points of Service throughout the territory served by the Company, between April 1 and October 31 for seasonal irrigation pumping loads. Not applicable for any service in excess of 150 kW.

**Price**

Charges for service in any one billing month during one Season shall be the sum of the Customer Charge, Demand Charge, and Energy Charge, determined for each individual Point of Service.

	<b>Customer Charge</b>	<b>Demand Charge</b>	<b>Energy Charge</b>
<b>Transmission</b>	-	3.43 ¢/kW/day	0.52 ¢ / kW.h
<b>Distribution</b>	-	8.54 ¢/kW/day	-
<b>Service</b>	11.55 ¢ / day	-	-
<b>TOTAL PRICE</b>	<b>11.55 ¢ / day</b>	<b>11.97 ¢/kW/day</b>	<b>0.52 ¢ / kW.h</b>

The billing demand may be estimated or measured and will be the greater of the following:

- (a) the highest metered demand during the billing period;
- (b) the estimated demand;
- (c) the contract demand;
- (d) 5 kilowatts.

For non-demand metered services, demand shall be estimated based on equipment nameplate ratings as **kW Billing Demand = kW Nameplate Rating**, or **kW Billing Demand = HP Nameplate x 0.746**.

**Application**

1. **Billing** - the minimum charge for the month during the season shall be the Service Charge and the Demand Charge. Previously, charges for service for one Season was the sum of the Service Charge, Demand Charge, and Energy Charge, determined for each individual Point of Service, where one Season is defined as the period from April 1 to October 31. Due to monthly billing, rates for the Customer Charge and Demand Charge are one-seventh the season charge.
2. **Idle Service** - in the event the service remains idle for two consecutive seasons, the Company may remove its facilities, unless the Customer pays the minimum charge for the upcoming season prior to December 31, of the preceding year.
3. **Power Factor Correction** - where a Customer's power factor is found to be less than 90%, the Company may require the Customer to install corrective equipment.
4. **Price Adjustments** - the following price adjustments (riders) may apply:  
Balancing Pool Adjustment (Rider F)  
Temporary Adjustment (Rider G)  
Interim Adjustment (Rider J)  
Interim RRT Adjustment (Rider Q)

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## Price Schedule D26 – REA Irrigation Pumping Service

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### **Availability**

For System Access Service and Distribution Access Service for all Points of Service throughout the territory served by the Company, between April 1 and October 31 for seasonal irrigation pumping loads of Rural Electrification Association Customers and individual co-operative and colony farms with their own distribution systems. Not applicable for any service in excess of 150 kW.

### **Price**

Charges for service in any one billing month during one Season shall be the sum of the Customer Charge, Demand Charge, and Energy Charge, determined for each individual Point of Service.

#### **Customers in the REA O & M Pool**

	Customer Charge	Demand Charge	Energy Charge
<b>Transmission</b>	-	3.43 ¢/kW/day	0.52 ¢ / kW.h
<b>Distribution</b>	-	2.68 ¢/kW/day	-
<b>Service</b>	11.55 ¢ / day	-	-
<b>TOTAL PRICE</b>	<b>11.55 ¢ / day</b>	<b>6.12 ¢/kW/day</b>	<b>0.52 ¢ / kW.h</b>

#### **Customers outside of the REA O & M Pool**

	Customer Charge	Demand Charge	Energy Charge
<b>Transmission</b>	-	3.43 ¢/kW/day	0.52 ¢ / kW.h
<b>Distribution</b>	-	-	-
<b>Service</b>	11.55 ¢ / day	-	-
<b>TOTAL PRICE</b>	<b>11.55 ¢ / day</b>	<b>3.43 ¢/kW/day</b>	<b>0.52 ¢ / kW.h</b>

The billing demand may be estimated or measured and will be the greater of the following:

- (a) the highest metered demand during the billing period;
- (b) the estimated demand;
- (c) the contract demand;
- (d) 5 kilowatts.

For non-demand metered services, demand shall be estimated based on equipment nameplate ratings as **kW Billing Demand = kW Nameplate Rating**, or **kW Billing Demand = HP Nameplate x 0.746**.

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## Price Schedule D26 – REA Irrigation Pumping Service

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### REA Specific Charges:

Other charges are applied on behalf of the REAs as defined in contracts and are subject to change from time to time.

These charges include operation and maintenance charges and deposit reserve charges, and are in addition to the charges contained in this price schedule.

The minimum charge for the season shall be 7 times the Service Charge and 7 times the Demand Charge.

### Application

1. **Billing** - the minimum charge for the month during the season shall be the Service Charge and the Demand Charge. Previously, charges for service for one Season was the sum of the Service Charge, Demand Charge, and Energy Charge, determined for each individual Point of Service, where one Season is defined as the period from April 1 to October 31. Due to monthly billing, rates for the Customer Charge and Demand Charge are one-seventh the season charge.
2. **Idle Service** - in the event the service remains idle for two consecutive seasons, the Company may remove its facilities, unless the Customer pays the minimum charge for the upcoming season prior to December 31, of the preceding year.
3. **Power Factor Correction** - where a Customer's power factor is found to be less than 90%, the Company may require the Customer to install corrective equipment.
4. **Price Adjustments** - the following price adjustments (riders) may apply:  
Balancing Pool Adjustment (Rider F)  
Temporary Adjustment (Rider G)  
Interim Adjustment (Rider J)  
Interim RRT Adjustment (Rider Q)

## **Price Schedule D31 – Large General Service / Industrial Distribution Connected**

### **Availability**

- For System Access Service and Distribution Access Service, single or three-phase distribution connected, for all Points of Service throughout the territory served by the Company from the Alberta Interconnected System.
- For distribution connected loads greater than 500 kW, the Point of Service must be equipped with interval data metering.

### **Price**

Charges for service in any one billing month shall be the sum of the Customer Charge, Demand Charge, Energy Charge and Charge for Deficient Power Factor, determined for each individual Point of Service:

	<b>Customer Charge</b>	<b>Demand Charge</b>		<b>Energy Charge</b>
		For the first 500 kW of billing demand	For all billing demand over 500 kW	
<b>Transmission</b>	-	9.34 ¢/kW/day	10.82 ¢/kW/day	0.48 ¢ / kW.h
<b>Distribution</b>	-	15.85 ¢/kW/day	7.92 ¢/kW/day	-
<b>Service</b>	\$1.35 / day	-	1.15 ¢/kW/day	-
<b>TOTAL PRICE</b>	<b>\$1.35 / day</b>	<b>25.18 ¢/kW/day</b>	<b>19.89 ¢/kW/day</b>	<b>0.48 ¢ / kW.h</b>

The billing demand for the Distribution and Service charges shall be the higher of:

- The highest metered demand during the billing period (including any demand delivered and billed under Price Schedules D32 and D33);
- 85% of the highest metered demand (including any demand delivered and billed under Price Schedules D32 and D33) in the 12-month period including and ending with the billing period;
- the estimated demand;
- the Distribution Contract Demand (DCD);
- 50 kilowatts.

The billing demand for the Transmission charges shall be the higher of:

- The highest metered demand during the billing period (excluding any demand delivered and billed under Price Schedules D32 and D33);
- 85% of the highest metered demand (excluding any demand delivered and billed under Price Schedules D32 and D33) in the 12-month period including and ending with the billing period;
- the estimated demand;
- the Transmission Contract Demand (TCD);

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**Price Schedule D31 – Large General Service / Industrial Distribution Connected**

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- (e) if any of the above are equal to or greater than 1000 kW, 80% of the highest metered demand (excluding any demand delivered and billed under Price Schedules D32 and D33) in the period which is the shorter of:
- i. the 36-month period including and ending with the current billing period; or
  - ii. the period commencing with the first billing period in the year 2000, and ending with the current billing period.
- (f) 50 kilowatts.

If energy is also taken under Transmission Opportunity Rate (Price Schedule D33), during the billing period, the billing demand will be the Price Schedule D31 **Base Demand** as specified under the corresponding agreement.

For non-demand metered services, demand will be estimated based on equipment nameplate ratings as **kW Billing Demand = kW Nameplate Rating**, or **kW Billing Demand = HP Nameplate x 0.746**.

**Charge for Deficient Power Factor** - For customer power factor which is less than 90%, an additional charge for deficient power factor of 29.59 ¢/kV.A/day will be applied to the difference between the highest metered kV.A demand and 111% of the highest metered kW demand in the same billing period.

**Application**

1. **Price Options** - the following price options may apply:
  - Idle Service (Option F)
  - Service for Non-Standard Transformation and Metering Configurations (Option H)
  - REA Distribution Price Credit (Option P)
2. **Price Adjustments** - the following price adjustments (riders) may apply:
  - Municipal Assessment (Rider A-1)
  - Special Facilities Charge (Rider E)
  - Balancing Pool Adjustment (Rider F)
  - Temporary Adjustment (Rider G)
  - Interim Adjustment (Rider J)
  - Interim RRT Adjustment (Rider Q)

## Price Schedule T31 – Large General Service / Industrial Transmission Connected

### Availability

- For System Access Service, single or three-phase, for all Points of Service throughout the territory served by the Company from the Alberta Interconnected System, that are directly connected to a transmission substation, and do not make any use of distribution facilities owned by ATCO Electric.
- The Point of Service must be equipped with interval data metering.

### Price

Charges for service in any one billing month shall be the sum of the Demand Charge, Energy Charge and charge for deficient power factor, determined for each individual Point of Service.

	Demand Charge		Energy Charge
	For the first 500 kW of billing demand	For all billing demand over 500 kW	
<b>Transmission</b>	Current AESO DTS Rate Schedule less under frequency load shedding credit	Current AESO DTS Rate Schedule less under frequency load shedding credit	Charges per current AESO DTS Rate Schedule
<b>Distribution</b>	2.60 ¢/kW/day	-	-
<b>Service</b>	2.10 ¢/kW/day	-	-
<b>TOTAL PRICE</b>	<b>4.70 ¢/kW/day + Current AESO DTS Rate Schedule less under frequency load shedding credit</b>	<b>Current AESO DTS Rate Schedule less under frequency load shedding credit</b>	

The billing demand for the Distribution and Service charges shall be the higher of:

- The highest metered demand during the billing period (including any contract opportunity demand delivered and billed under Price Schedule T33);
- 85% of the highest metered demand (including any contract opportunity demand delivered and billed under Price Schedule T33) in the 12-month period including and ending with the billing period;
- the estimated demand;
- 50 kilowatts.

The billing demand for the Transmission charge shall be the higher of:

- The billing demand charged to ATCO Electric by AESO at a Point of Delivery, that is attributable to the customer at that Point of Delivery;
- the highest metered demand during the billing period;
- the ratchet level as set out by the AESO at a Point of Delivery,  
where (a) through (c) exclude any contracted Opportunity Demand delivered and billed under Price Schedule T33;
- the estimated demand;
- the Transmission Contract Demand (TCD);
- 50 kilowatts

---

**Price Schedule T31 – Large General Service / Industrial Transmission Connected**

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The '**highest metered demand**' is defined for the purposes of this price schedule, according to the current approved AESO DTS Rate Schedule.

If energy is also taken under Transmission Opportunity Rate (Price Schedule T33), during the billing period, the billing demand will be the Price Schedule T31 **Base Demand** as specified under the corresponding agreement.

**Charge for Deficient Power Factor** – Power Factor Charges according to the current approved AESO DTS Rate Schedule will apply.

**Application**

1. **Price Options** - the following price option may apply:  
Service for Non-Standard Transformation and Metering Configurations (Option H)
  
2. **Price Adjustments** - the following price adjustments (riders) may apply:  
Municipal Assessment (Rider A-1)  
Special Facilities Charge (Rider E)  
Balancing Pool Adjustment (Rider F)  
Temporary Adjustment (Rider G)  
Interim Adjustment (Rider J)

## **Price Schedule D32 – Generator Interconnection and Standby Power**

### **Availability**

- For Points of Service served by the Company from the Alberta Interconnected System, with on-site generating equipment connected to the distribution system, which may be used to supply load at the same site.
- To provide standby power to the on-site load in the event of a forced outage or derate of on-site generating equipment, to provide power for generator startup, and to provide supplemental power if the on-site demand requirements exceed the generator capacity.
- To provide credits to Generators for reduced DTS charges from AESO.
- To charge Generators if the Point of Delivery attracts STS charges from AESO.
- For interconnection of the generator to the distribution system.
- The Point of Service must be equipped with 4-quadrant interval data metering, for both supply and demand, the cost of which will be in addition to the charges under this rate.

### **Price**

Charges for service in any one billing month shall be the sum of the Customer Charges, Demand Charges, Energy Charges, Other Charges, Charge for Deficient Power Factor (determined for each individual Point of Service), and Fixed Charges defined below.

	Customer Charge	Demand Charge		Energy Charge
		For the first 500 kW of billing demand	For all billing demand over 500 kW	
<b>Transmission</b>	-	9.34 ¢/kW/day	10.82 ¢/kW/day	0.48 ¢ / kW.h
<b>Distribution</b>	-	15.85 ¢/kW/day	7.92 ¢/kW/day	-
<b>Service</b>	\$1.35 / day	-	1.15 ¢/kW/day	-
<b>TOTAL PRICE</b>	<b>\$1.35 / day</b>	<b>25.18 ¢/kW/day</b>	<b>19.89 ¢/kW/day</b>	<b>0.48 ¢ / kW.h</b>

The billing demand for the Distribution and Service charges shall be the higher of:

- (a) The highest metered demand during the billing period (including any demand delivered and billed under Price Schedule D33);
- (b) 85% of the highest metered demand (including any demand delivered and billed under Price Schedule D33) in the 12-month period including and ending with the billing period;
- (c) the estimated demand;
- (d) the Distribution Contract Demand (DCD).

---

## Price Schedule D32 – Generator Interconnection and Standby Power

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The billing demand for the Transmission charges shall be the higher of:

- (a) The highest metered demand during the billing period (excluding any demand delivered and billed under Price Schedule D33);
- (b) 85% of the highest metered demand (excluding any demand delivered and billed under Price Schedule D33) in the 12-month period including and ending with the billing period;
- (c) the estimated demand;
- (d) the Transmission Contract Demand (TCD);
- (e) if any of the above are equal to or greater than 1000 kW, 80% of the highest metered demand (excluding any demand delivered and billed under Price Schedules D33) in the period which is the shorter of:
  - i. the 36-month period including and ending with the current billing period; or
  - ii. the period commencing with the first billing period in the year 2000, and ending with the current billing period.

If energy is also taken under Transmission Opportunity Rate (Price Schedule D33), during the billing period, the billing demand will be the Price Schedule D32 **Base Demand** as specified under the corresponding agreement.

For non-demand metered services, demand will be estimated based on equipment nameplate ratings as **kW Billing Demand = kW Nameplate Rating**, or **kW Billing Demand = HP Nameplate x 0.746**.

**Charge for Deficient Power Factor** - For customer power factor which is less than 90%, an additional charge for deficient power factor of 29.59 ¢/kV.A/day will be applied to the difference between the highest metered kV.A demand and 111% of the highest billing kW demand in the same billing period, where billing demand is as defined in this price schedule.

If the Company incurs an increase to the Point-of-Delivery (POD) billing demand with AESO as a result of a standby event of the customer (i.e. the new demand at the POD is coincident with an outage of the generator), then an additional charge may apply, equal to the Transmission Demand Charge for Price Schedule T31, multiplied by the incremental POD demand incurred. This charge will apply for the current billing period, and for the next 11 billing periods.

### Capital Recovery Charges:

The cost of the Incremental Interconnection Facilities will be determined as set out in Section 9.6 of the Terms and Conditions for Distribution Service Connections. The total amount will be collected from the customer in accordance with Section 9.8 of the Terms and Conditions for Distribution Service Connections. A contract will be arranged between the customer and the Company, specifying the contract term and the monthly amount, which will be calculated using the Company's Rate of Return, Income Tax and Depreciation in effect at the commencement of the contract term.

The Generating customer will be required to pay all replacement costs for incremental facilities as per Section 9.6 of the Terms and Conditions for Distribution Service Connections.

### Incremental Operations and Maintenance Charges:

The minimum monthly incremental Operations and Maintenance charge will be:

**(0.0128% X Incremental Interconnection Cost) per day**

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## Price Schedule D32 – Generator Interconnection and Standby Power

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The Generating customer will be required to pay for switching or isolation as per Section 9.6 of the Terms and Conditions.

### Incremental Administration and General Charges:

The minimum monthly incremental Administration and General charge will be:

**(0.00422% X Incremental Interconnection Cost) per day**

### Generator Credits for reduction in Billing Determinants at the Point of Delivery:

**Credit = DTS \* (A – B)                      Where:**

**A** = Monthly Gross Billing Determinants at the POD to which the generator is connected (which will be determined by adding the interval output data metered at the generator to the net interval data metered at the POD).

**B** = Monthly Net Billing determinants at the POD to which the generator is connected.

**DTS** = The charges as per AESO's effective DTS tariff.

The Company will calculate the generator credits on a calendar quarterly basis after all power production information has been provided to the Company in accordance with Section 9.5.4 of the Terms and Conditions for Distribution Service Connections.

### Generator Charges for a Point of Delivery:

**Charge = STS \* A                                      Where:**

**A** = Monthly **Net** Supply Billing determinants at the POS to which the generator is connected.

**STS** = The charges as per AESO's effective STS tariff.

### Application

1. **Price Options** - the following price options may apply:  
Idle Service (Option F)  
Service for Non-Standard Transformation and Metering Configurations (Option H)
2. **Price Adjustments** - the following price adjustments (riders) may apply:  
Municipal Assessment (Rider A-1)  
Balancing Pool Adjustment (Rider F)  
Temporary Adjustment (Rider G)  
Interim Adjustment (Rider J)  
Interim RRT Adjustment (Rider Q)

## Price Schedule D33 – Transmission Opportunity Rate Distribution Connected

### Availability

- Available only to Points of Service which are eligible as determined by AESO for Demand Opportunity Service, throughout the territory served by the Company from the Alberta Interconnected System for loads greater than 1,000 kW.
- Available only when AESO determines that there is sufficient transmission capacity. Service on this rate is interruptible for transmission system security reasons at AESO's request.
- The Point of Service must be equipped with revenue approved time of use metering. The cost of the time of use metering is in addition to the charges in this rate.
- Telemetry is required for all points of service on this rate with demands greater than 2,500 kW, and any associated costs will be in addition to the charges in this rate.

### Price

Charges for service in any one billing month shall be the sum of the following charges determined for each individual Point of Service. The AESO DOS charges will be applied according to the terms of the DOS option selected by the Customer:

	<b>Customer Charges</b>	<b>Demand Charges</b>	<b>Demand Charges</b>	<b>Energy Charges</b>	<b>Energy Charges</b>
		For all kW of Opportunity Contract Demand	For the peak kW above the Opportunity Contract Demand	For all kW.h metered above the Base Demand, not exceeding the Opportunity Contract Demand	For all kW.h metered above the Opportunity Contract Demand
<b>Transmission</b>	Transaction Charge per AESO DOS Rate Schedule	-	Per Price Schedule D32	Per AESO DOS Rate Schedule	Per Price Schedule D32
<b>Distribution</b>	-	15.85 ¢/kW/day	7.92 ¢/kW/day	-	-
<b>Service</b>	\$1.35 / day	0.00 ¢/kW/day	1.15 ¢/kW/day	-	-
<b>TOTAL PRICE</b>	<b>\$1.35 / day + AESO DOS Rate</b>	<b>15.85 ¢/kW/day</b>	<b>9.07 ¢/kW/day + D32</b>	<b>Per AESO DOS Rate Schedule</b>	<b>Per Price Schedule D32</b>

The attached form must be completed and submitted to the Company, and serves as an Opportunity Contract which specifies the period and the Opportunity Demand requested by the Customer, as well as the DOS option selected.

The charges according to the AESO DOS Rate Schedule will be the approved charges in effect during the billing period, and will be revised in accordance with AESO's charges as required.

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## Price Schedule D33 – Transmission Opportunity Rate Distribution Connected

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### **Application**

1. **Base Demand** - A Customer qualifying for this rate must establish a Base Demand with the Company on Price Schedule D31 prior to receiving service under this rate (which will be submitted as part of the attached form).
  - (a) For existing Customers, the Price Schedule D31 Base Demand will normally be the maximum billing demand in the 12 most recent billing periods.
  - (b) New Customers qualifying for this rate may select the Large General Service/Industrial D31 Base Demand based on forecast loads and economics, provided the Company agrees that the conditions of applicability are satisfied.
  - (c) Once established, the Price Schedule D31 Base Demand remains fixed for the purposes of billing all future service on this rate.
2. **Applicable Charges** – This rate schedule applies in conjunction with rate D31, in that the first block demand charges apply only to the first 500 kW of the combined demand (i.e. D31 and D33, and D32 should there be an excursion above contracted opportunity demand), and the remainder of the combined demand is subject to the second block demand charges. The Service Customer Charge does not apply again as it has already been applied to the base load on Price Schedule D31.
3. **Options** - A Customer requesting service under this rate must select the provisions of one of AESO's DOS Rate Schedules. The Customer is subject to AESO's minimum Opportunity Service charges, attributable to that customer.
4. **Notice Period** - A Customer requesting service under this rate is required to provide notification as prescribed in the AESO tariff in relation to DOS service.
5. **Load Curtailment** - When a load curtailment directive is given, the load at the point of service must not exceed the Price Schedule D31 Base Demand until the Company gives notification that the interruption period is over, at which time consumption of energy may be resumed.
6. **Non-Compliance Charges** – In the event of a load curtailment directive, if the load served under this rate is not curtailed for the entire interruption period, any charges incurred by the Company will be charged to the Point of Service on this rate.
7. **Price Options** – the following price options may apply:  
Service for Non-Standard Transformation and Metering Configurations (Option H)
8. **Price Adjustments** - the following price adjustments may apply:  
Municipal Assessment (Rider A-1)  
Balancing Pool Adjustment (Rider F)  
Temporary Adjustment (Rider G)  
Interim Adjustment (Rider J)

**Price Schedule D33 – Transmission Opportunity Rate Distribution Connected**

This form will be completed and signed by ATCO Electric after a telephone request from a Customer for Transmission Opportunity Service. The form will be faxed to the Customer upon which the Customer will confirm the information with a signature and fax the completed form back to ATCO Electric Control Centre – (780) 632-5959.

<b>Customer Name:</b>	<input style="width: 95%;" type="text"/>			
<b>Date of Request:</b>	<input style="width: 95%;" type="text"/>			
<b>Time of Request:</b>	<input style="width: 95%;" type="text"/>			
<b>1. OPPORTUNITY CONTRACT PERIOD:</b>	<b>Start Date:</b>	<input style="width: 60%;" type="text"/>	<b>Start Time:</b>	<input style="width: 60%;" type="text"/>
	<b>End Date:</b>	<input style="width: 60%;" type="text"/>	<b>End Time:</b>	<input style="width: 60%;" type="text"/>
	<b>Number of Hours in Contract Period:</b>		<input style="width: 60%;" type="text"/>	<b>Hours</b>
<b>2. TRANSMISSION OPPORTUNITY SERVICE OPTION:</b>	<b>AESO "DEMAND OPPORTUNITY SERVICE":</b>			
	DOS 7 Minutes:	<input style="width: 40%;" type="text"/>		
	DOS 1 Hour:	<input style="width: 40%;" type="text"/>		
	DOS Term:	<input style="width: 40%;" type="text"/>		
<b>3. OPPORTUNITY CONTRACT DEMAND:</b>	<input style="width: 100px;" type="text"/>		<b>kW</b>	
<b>4. BASE DEMAND:</b>	<b>Large General Service/Industrial Price Schedule D31 Base Demand:</b>			
		<input style="width: 100px;" type="text"/>	<b>kW</b>	
	<b>Sum of Demands on all Opportunity Service Contracts:</b>	<input style="width: 100px;" type="text"/>	<b>kW</b>	
	<b>Total Base Demand:</b>	<input style="width: 100px;" type="text"/>	<b>kW</b>	

**Confirmation:** 1) \_\_\_\_\_ for ATCO Electric  
 2) \_\_\_\_\_ for \_\_\_\_\_

## **Price Schedule T33 – Transmission Opportunity Rate Transmission Connected**

### **Availability**

- For System Access Service, single or three-phase, for all Points of Service throughout the territory served by the Company from the Alberta Interconnected System, that are directly connected to a transmission substation, and do not make any use of distribution facilities owned by ATCO Electric.
- Available only to Points of Service which are eligible as determined by AESO for Demand Opportunity Service, throughout the territory served by the Company from the Alberta Interconnected System for loads greater than 1,000 kW.
- Available only when AESO determines that there is sufficient transmission capacity. Service on this rate is interruptible for transmission system security reasons at AESO's request.
- The point of service must be equipped with revenue approved time of use metering. The cost of the time of use metering is in addition to the charges in this rate.
- Telemetry is required for all points of service on this rate with demands greater than 2,500 kW, and any associated costs will be in addition to the charges in this rate.

### **Price**

Charges for service in any one billing month shall be the sum of the following charges determined for each individual Point of Service. The current approved AESO DOS charges will be those according to the terms of the DOS option selected by the Customer:

	<b>Transaction Charge</b>	<b>Demand Charges</b>	<b>Demand Charges</b>	<b>Energy Charges</b>	<b>Energy Charges</b>
		For all kW of Opportunity Contract Demand	For the peak kW above the Opportunity Contract Demand	For all kW.h metered above the Base Demand, not exceeding the Opportunity Contract Demand	For all kW.h metered above the Opportunity Contract Demand
<b>Transmission</b>	Per AESO DOS Rate Schedule	-	Per Price Schedule T31	Per AESO DOS Rate Schedule	Per Price Schedule T31
<b>Distribution</b>	-	Per Price Schedule T31	Per Price Schedule T31	-	-
<b>Service</b>	-	Per Price Schedule T31	Per Price Schedule T31	-	-
<b>TOTAL PRICE</b>	<b>Per AESO DOS Rate Schedule</b>	<b>Per Price Schedule T31</b>	<b>Per Price Schedule T31</b>	<b>Per AESO DOS Rate Schedule</b>	<b>Per Price Schedule T31</b>

The attached form must be completed and submitted to the Company, and serves as an Opportunity Contract which specifies the period and the Opportunity Demand requested by the Customer, as well as the DOS option selected.

The charges according to the AESO DOS Rate Schedule will be the approved charges in effect during the billing period, and will be revised in accordance with AESO's charges as required.

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## **Price Schedule T33 – Transmission Opportunity Rate Transmission Connected**

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### **Application**

1. **Base Demand** - A Customer qualifying for this rate must establish a Base Demand with the Company on Price Schedule T31 prior to receiving service under this rate.
  - (a) For existing Customers, the Price Schedule T31 Base Demand will normally be the maximum billing demand in the 12 most recent billing periods.
  - (b) New Customers qualifying for this rate may select the Large General Service/Industrial T31 Base Demand based on forecast loads and economics, provided the Company agrees that the conditions of applicability are satisfied.
  - (c) Once established, the Price Schedule T31 Base Demand remains fixed for the purposes of billing all future service on this rate.
2. **Applicable Charges** - This rate schedule applies in conjunction with rate T31, in that the first block demand charges apply only to the first 500 kW of the combined demand (i.e. T31 and T33, and T31 again should there be an excursion above contracted opportunity demand), and the remainder of the combined demand is subject to the second block demand charges.
3. **Options** - A Customer requesting service under this rate must select the provisions of one of AESO's DOS Rate Schedules. The Customer is subject to AESO's minimum Opportunity Service charges, attributable to that customer.
4. **Notice Period** - A Customer requesting service under this rate is required to provide notification as prescribed in the AESO tariff in relation to DOS service.
5. **Load Curtailment** - When a load curtailment directive is given, the load at the point of service must not exceed the Price Schedule T31 Base Demand until the Company gives notification that the interruption period is over, at which time consumption of energy may be resumed.
6. **Non-Compliance Charges** – In the event of a load curtailment directive, if the load served under this rate is not curtailed for the entire interruption period, any charges incurred by the Company will be charged to the Point of Service on this rate.
7. **Price Options** – the following price option may apply:  
Service for Non-Standard Transformation and Metering Configurations (Option H(d))
8. **Price Adjustments** - the following price adjustments may apply:  
Municipal Assessment (Rider A-1)  
Balancing Pool Adjustment (Rider F)  
Temporary Adjustment (Rider G)  
Interim Adjustment (Rider J)

**Price Schedule T33 – Transmission Opportunity Rate Transmission Connected**

This form will be completed and signed by ATCO Electric after a telephone request from a Customer for Transmission Opportunity Service. The form will be faxed to the Customer upon which the Customer will confirm the information with a signature and fax the completed form back to ATCO Electric Control Centre – (780) 632-5959.

<b>Customer Name:</b>	<input style="width: 100%;" type="text"/>		
<b>Date of Request:</b>	<input style="width: 100%;" type="text"/>		
<b>Time of Request:</b>	<input style="width: 100%;" type="text"/>		
<b>1. OPPORTUNITY CONTRACT PERIOD</b>			
<b>Start Date:</b>	<input style="width: 100%;" type="text"/>	<b>Start Time:</b>	<input style="width: 100%;" type="text"/>
<b>End Date:</b>	<input style="width: 100%;" type="text"/>	<b>End Time:</b>	<input style="width: 100%;" type="text"/>
	<b>Number of Hours in Contract Period:</b>		<input style="width: 100%;" type="text"/> <b>Hours</b>
<b>2. TRANSMISSION OPPORTUNITY SERVICE OPTION:</b>			
AESO "DEMAND OPPORTUNITY SERVICE":		DOS 7 Minutes:	<input style="width: 100%;" type="text"/>
		DOS 1 Hour:	<input style="width: 100%;" type="text"/>
		DOS Term:	<input style="width: 100%;" type="text"/>
<b>3. OPPORTUNITY CONTRACT DEMAND:</b>			
	<input style="width: 100%;" type="text"/>	<b>kW</b>	
<b>4. BASE DEMAND:</b>			
Large General Service/Industrial Price Schedule T31 Base Demand:		<input style="width: 100%;" type="text"/>	<b>kW</b>
Sum of Demands on all Opportunity Service Contracts:		<input style="width: 100%;" type="text"/>	<b>kW</b>
<b>Total Base Demand:</b>		<input style="width: 100%;" type="text"/>	<b>kW</b>

**Confirmation:** 1) \_\_\_\_\_ for ATCO Electric  
 2) \_\_\_\_\_ for \_\_\_\_\_

## Price Schedule D34 – Large General Service/Industrial Isolated Industrial Areas

### Availability

For Distribution Access Service, single or three-phase, for all Points of Service throughout the territory served by the Company from an isolated industrial area.

### Price

Charges for service in any one billing month shall be the sum of the Customer Charge, Demand Charge, and Charge for Deficient Power Factor, determined for each individual Point of Service.

	Customer Charge		Demand Charge	
		For the first 500 kW of billing demand	For all billing demand over 500 kW	
<b>Distribution</b>	-	15.85 ¢/kW/day	7.92 ¢/kW/day	
<b>Service</b>	\$1.35 / day	-	1.15 ¢/kW/day	
<b>TOTAL PRICE</b>	<b>\$1.35 / day</b>	<b>15.85 ¢/kW/day</b>	<b>9.07 ¢/kW/day</b>	

The billing demand for the Distribution and Service charges shall be the higher of:

- (a) The highest metered demand during the billing period;
- (b) 85% of the highest metered demand during the 12-month period including and ending with the billing period;
- (c) the estimated demand;
- (d) the Distribution Contract Demand (DCD);
- (e) 50 kilowatts.

For non-demand metered services, demand will be estimated based on equipment nameplate ratings as **kW Billing Demand = kW Nameplate Rating**, or **kW Billing Demand = HP Nameplate x 0.746**.

**Charge for Deficient Power Factor** - For customer power factor which is less than 90%, an additional charge for deficient power factor of 29.59 ¢/kV.A/day will be applied to the difference between the highest metered kV.A demand and 111% of the highest metered kW demand in the same billing period.

### Application

1. **Price Options** - the following price options may apply:  
Idle Service (Option F)  
Service for Non-Standard Transformation and Metering Configurations (Option H)  
REA Distribution Price Credit (Option P)
2. **Price Adjustments** - the following price adjustments (riders) may apply:  
Municipal Assessment (Rider A-1)  
Special Facilities Charge (Rider E)  
Temporary Adjustment (Rider G)  
Interim Adjustment (Rider J)

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## Price Schedule D41 – Small Oilfield and Pumping Power

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### **Availability**

For System Access Service and Distribution Access Service, single or three-phase, for all Points of Service throughout the territory served by the Company from the Alberta Interconnected System, for production energy requirements in the petroleum and natural gas industries including related operations, such as rectifiers, cathodic protection and radio transmitters.

### **Price**

Charges for service in any one billing month shall be the sum of the Customer Charges, Demand Charges, Energy Charges and charge for deficient power factor, determined for each individual Point of Service.

	Customer Charge	Demand Charge	Energy Charge
<b>Transmission</b>	-	8.12 ¢/kW/day	0.48 ¢ / kW.h
<b>Distribution</b>	-	36.49 ¢/kW/day	-
<b>Service</b>	74.93 ¢ / day	-	-
<b>TOTAL PRICE</b>	<b>74.93 ¢ / day</b>	<b>44.61 ¢/kW/day</b>	<b>0.48 ¢ / kW.h</b>

The billing demand for the Distribution and Service charges shall be the higher of:

- (a) The highest metered demand during the billing period;
- (b) 85% of the highest metered demand during the 12-month period including and ending with the billing period;
- (c) the estimated demand;
- (d) the Distribution Contract Demand (DCD);
- (e) 4 kilowatts.

The billing demand for the Transmission charges shall be the higher of:

- (a) The highest metered demand during the billing period;
- (b) 85% of the highest metered demand during the 12-month period including and ending with the billing period;
- (c) the estimated demand;
- (d) the Transmission Contract Demand (TCD);
- (e) 4 kilowatts.

For non-demand metered services, demand will be estimated based on equipment nameplate ratings as **kW Billing Demand = kW Nameplate Rating**, or **kW Billing Demand = HP Nameplate x 0.746**.

The 85% ratchet applies only to demand metered loads. The cost of converting an energy meter to a demand meter will be in addition to the charges on this rate.

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## Price Schedule D41 – Small Oilfield and Pumping Power

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**Estimated Demands** - Where it is impractical to meter a point of service, the Company may bill on the basis of estimated maximum demands. In such case, the monthly bill shall be the demand charge above applied to the estimated demand, plus a flat rate of \$1.47 per kW in lieu of the charge for energy.

The **Metered demand** will be the greater of the registered demand in kW, or 90% of the registered demand in kV.A where a kW reading is not available.

**Charge for Deficient Power Factor** - where a Customer's power factor is found to be less than 90%, the Company may require such Customers to install corrective equipment. For Customer power factor which is less than 90%, an additional charge for deficient power factor of 29.59 ¢/kV.A/day will be applied to the difference between the highest metered kV.A demand and 111% of the highest metered kW demand in the same billing period.

### **Application**

1. **Demand Metered** - where services are demand metered, the meter will normally be read and reset at least once every two months.
2. **Price Options** - the following price option may apply:  
Idle Service (Option F)
3. **Price Adjustments** - the following price adjustments (riders) may apply:  
Municipal Assessment (Rider A-1)  
Special Facilities Charge (Rider E)  
Balancing Pool Adjustment (Rider F)  
Temporary Adjustment (Rider G)  
Interim Adjustment (Rider J)  
Interim RRT Adjustment (Rider Q)

## **Price Schedule D44 – Small Oilfield and Pumping Power Isolated Industrial Areas**

### **Availability**

For Distribution Access Service, single or three-phase, for all Points of Service throughout the territory served by the Company from an isolated industrial area, for production energy requirements in the petroleum and natural gas industries including related operations, such as rectifiers, cathodic protection and radio transmitters.

### **Price**

Charges for service in any one billing month shall be the sum of the Customer Charges, Demand Charges, and charge for deficient power factor, determined for each individual Point of Service:

	<b>Customer Charge</b>	<b>Demand Charge</b>
<b>Distribution</b>	-	36.49 ¢/kW/day
<b>Service</b>	74.93 ¢ / day	-
<b>TOTAL PRICE</b>	<b>74.93 ¢ / day</b>	<b>36.49 ¢/kW/day</b>

The billing demand shall be the higher of:

- (a) The highest metered demand during the billing period;
- (b) 85% of the highest metered demand during the 12-month period including and ending with the billing period;
- (c) the estimated demand;
- (d) the Distribution Contract Demand (DCD);
- (e) 4 kilowatts.

For non-demand metered services, demand will be estimated based on equipment nameplate ratings as **kW Billing Demand = kW Nameplate Rating**, or **kW Billing Demand = HP Nameplate x 0.746**.

The 85% ratchet applies only to demand metered loads. The cost of converting an energy meter to a demand meter will be in addition to the charges on this rate.

**Estimated Demands** - Where it is impractical to meter a point of service, the Company may bill on the basis of estimated maximum demands. In such case, the monthly bill shall be the demand charge above applied to the estimated demand.

The **Metered demand** will be the greater of the registered demand in kW, or 90% of the registered demand in kV.A where a kW reading is not available.

**Charge for Deficient Power Factor** - where a Customer's power factor is found to be less than 90%, the Company may require such Customers to install corrective equipment. For Customer power factor which is less than 90%, an additional charge for deficient power factor of 29.59 ¢/kV.A/day will be applied to the difference between the highest metered kV.A demand and 111% of the highest metered kW demand in the same billing period.

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## **Price Schedule D44 – Small Oilfield and Pumping Power Isolated Industrial Areas**

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### **Application**

1. **Demand Metered** - where services are demand metered, the meter will normally be read and reset at least once every two months.
2. **Price Options** - the following price options may apply:  
Idle Service (Option F)
3. **Price Adjustments** - the following price adjustments (riders) may apply:  
Municipal Assessment (Rider A-1)  
Special Facilities Charge (Rider E)  
Temporary Adjustment (Rider G)  
Interim Adjustment (Rider J)

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## Price Schedule D51 – REA Farm Service

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### Availability

For System Access Service and Distribution Access Service, for all Points of Service throughout the territory served by the Company, for farming operations which are connected to a Rural Electrification Association's distribution system.

### Price

- Charges for service in any one billing month are the sum of the Customer, Demand and Energy charges as indicated below, determined for each individual Point of Service.
- Please refer to individual REA Tariffs to determine applicable REA charges.

### REA Farms in O & M Pool

	Customer Charge	Demand Charge	Energy Charge
<b>Transmission</b>	-	6.15 ¢/kV.A/day	0.48 ¢ / kW.h
<b>Distribution</b>	-	7.10 ¢/kV.A/day	-
<b>Service</b>	39.19 ¢ / service / day	-	-
<b>REA Specific Charges</b>	See REA Tariff	-	-
<b>Total Price</b>	<b>C<sub>1</sub> ¢ / service/ day</b>	<b>13.25 ¢/kV.A/day</b>	<b>0.48 ¢ / kW.h</b>

### REA Farms Outside of O & M Pool

	Customer Charge	Demand Charge	Energy Charge
<b>Transmission</b>	-	6.15 ¢/kV.A/day	0.48 ¢ / kW.h
<b>Distribution</b>	See REA Tariff	See REA Tariff	-
<b>Service</b>	See REA Tariff	-	-
<b>REA Specific Charges</b>	See REA Tariff	-	-
<b>Total Price</b>	<b>C<sub>1</sub> ¢ / service /day</b>	<b>D<sub>1</sub> ¢/kV.A/day</b>	<b>0.48 ¢ / kW.h</b>

kV.A capacity for billing purposes will be determined as follows:

- (a) For breakered services of 25 kV.A or less, the kV.A capacity will be set by the breaker size as shown below:

Breaker Amperes	25/41	35/50	50/75	75/110	100/150	200
<b>Transformer Capacity in kV.A</b>	3	5	7.5	10	15	25

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**Price Schedule D51 – REA Farm Service**

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- (b) For non-breakered REA farm services of 25 kV.A or greater, the kV.A capacity for billing purposes is the greater of:
- i. the highest metered kV.A demand during the billing period;
  - ii. the estimated demand;
  - iii. 25 kV.A.

**REA Specific Charges**

Other charges are applied on behalf of the REAs as defined in contracts and are subject to change from time to time.

These charges include operation and maintenance charges and deposit reserve charges, and are in addition to the charges contained in this price schedule.

The minimum monthly charge is the sum of the Customer and demand charges plus any REA specific charges that may apply.

**Application**

1. **Demand Metering** - when the Company determines, by estimation or measurement, that a 25 kV.A breakered service may be overloaded, the company may require replacement of the breaker with a demand meter and modification of the service facilities in accordance with the Terms and Conditions.
2. **Price Option** - the following price option may apply:  
Idle Service (Option F)
3. **Price Adjustments** - the following price adjustments (riders) may apply:  
Balancing Pool Adjustment (Rider F)  
Temporary Adjustment (Rider G)  
Interim Adjustment (Rider J)

**Price Schedule D52 – REA Farm Service Excluding Wire Services Provider Functions**

**Availability**

- Applicable to any Rural Electrification Association, for whom the Company is not acting as the Wire Services Provider, as defined in the EUA.
- For all Points of Service throughout the territory served by the Company, for farming operations which are connected to the Rural Electrification Association's distribution system.

**Price**

Charges for service in any one billing month are the sum of the Customer, Demand and Energy charges as indicated below, determined for each individual Point of Service.

	<b>Customer Charge</b>	<b>Demand Charge</b>	<b>Energy Charge</b>
<b>Transmission</b>	-	6.15 ¢/kV.A/day	0.48 ¢ / kW.h
<b>Distribution</b>	-	-	-
<b>Service</b>	20.42 ¢/service/day	-	-
<b>TOTAL PRICE</b>	<b>20.42 ¢/service/day</b>	<b>6.15 ¢/kV.A/day</b>	<b>0.48 ¢ / kW.h</b>

kV.A capacity for billing purposes will be determined as follows:

- (a) For breakered services of 25 kV.A or less, the kV.A capacity will be set by the breaker size as shown below:

<b>Breaker Amperes</b>	25/41	35/50	50/75	75/110	100/150	200
<b>Transformer Capacity in kV.A</b>	3	5	7.5	10	15	25

- (b) For non-breakered REA farm services of 25 kV.A or greater, the kV.A capacity for billing purposes is the greater of:
- the highest metered kV.A demand during the billing period;
  - the estimated demand;
  - 25 kV.A.

The minimum monthly charge is the sum of the Customer and Demand charge.

**Application**

- Demand Metering** - when the Company determines, by estimation or measurement, that a 25 kV.A breakered service may be overloaded, the company may require replacement of the breaker with a demand meter and modification of the service facilities in accordance with the Terms and Conditions.
- Price Option** - the following price option may apply:  
Idle Service (Option F)
- Price Adjustments** - the following price adjustments (riders) may apply:  
Balancing Pool Adjustment (Rider F)  
Temporary Adjustment (Rider G)  
Interim Adjustment (Rider J)  
Interim RRT Adjustment (Rider Q)

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## Price Schedule D56 – Farm Service

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### **Availability**

For System Access Service and Distribution Access Service, for all Points of Service throughout the territory served by the Company, for farming operations which are connected to the Company's distribution system.

### **Price**

Charges for service in any one billing month are the sum of the Customer, Demand, and Energy Charges as indicated below, determined for each individual Point of Service.

	<b>Customer Charge</b>	<b>Demand Charge</b>	<b>Energy Charge</b>
<b>Transmission</b>		6.15 ¢/kV.A/day	0.48 ¢ / kW.h
<b>Distribution</b>	15.95 ¢/service/day	10.98 ¢/kV.A/day	0.51 ¢ / kW.h
<b>Service</b>	39.19 ¢/service/day		
<b>TOTAL PRICE</b>	<b>55.13 ¢/service/day</b>	<b>17.13 ¢/kV.A/day</b>	<b>0.99 ¢ / kW.h</b>

kV.A capacity for billing purposes will be determined as follows:

- (a) For breakered services of 25 kV.A or less, the kV.A capacity will be set by the breaker size as shown below:

<b>Breaker Amperes</b>	25/41	35/50	50/75	75/110	100/150	200
<b>Transformer Capacity in kV.A</b>	3	5	7.5	10	15	25

- (b) For non-breakered farm services of 25 kV.A or greater, the kV.A capacity for billing purposes is the greater of:
- i. the highest metered kV.A demand during the billing period;
  - ii. the estimated demand;
  - iii. the contract demand;
  - iv. 25 kV.A.

The minimum monthly charge is the sum of the Customer and Demand Charges.

### **Application**

1. **Demand Metering** - when the Company determines, by estimation or measurement, that a 25 kV.A breakered service may be overloaded, the company may require replacement of the breaker with a demand meter and modification of the service facilities in accordance with the Terms and Conditions for Distribution Service Connections.
2. **Price Options** - the following price option may apply:  
Idle Service (Option F)

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## Price Schedule D56 – Farm Service

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3. **Price Adjustments** - the following price adjustments (riders) may apply:
- Balancing Pool Adjustment (Rider F)
  - Temporary Adjustment (Rider G)
  - Interim Adjustment (Rider J)
  - Interim RRT Adjustment (Rider Q)

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## Price Schedule D61 – Street Lighting Service

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### **Availability**

- For System Access Service and Distribution Access Service for all Points of Service throughout the territory served by the Company, for street lighting.
- Not available for private lighting.

### **Price**

Charges for service in any one billing month are the sum of the Customer Charge and Demand Charge, determined for each individual Point of Service.

### **Decorative Lighting (61 A)**

- For decorative lighting fixtures installed, owned and maintained by the Company.
- The customer is responsible for the full cost of installation.
- Includes maintenance only.
- Specific contracts may require customers to purchase and maintain inventory of decorative lamps if the customer's lighting fixtures are not the same as the standard used by the company.

<b>Decorative Lamps</b>		
	<b>Customer Charge</b>	<b>Demand Charge</b>
<b>Transmission</b>	-	0.021 ¢ /watt/day
<b>Distribution</b>	20.09 ¢/fixture/day	0.012 ¢ /watt/day
<b>Service</b>	1.78 ¢/fixture/day	-
<b>TOTAL PRICE</b>	<b>21.86 ¢/fixture/day</b>	<b>0.033¢ /watt/day</b>

### **Investment Option (61 B)**

- For standard lighting fixtures installed, owned, and maintained by the Company.

<b>All Lamps</b>		
	<b>Customer Charge</b>	<b>Demand Charge</b>
<b>Transmission</b>	-	0.021 ¢ /watt/day
<b>Distribution</b>	42.54 ¢/fixture/day	0.012 ¢ /watt/day
<b>Service</b>	1.78 ¢/fixture/day	-
<b>TOTAL PRICE</b>	<b>44.32 ¢/fixture/day</b>	<b>0.033 ¢ /watt/day</b>

## Price Schedule D61 – Street Lighting Service

### **Distribution Investment Option (61 C)**

- For customer owned and installed lighting.
- For installation and maintenance of distribution facilities up to, but not including the customer owned conductor serving the light fixtures.
- The Company may require that the Point of Service be metered and served on Price Schedule D21, if the load requirements change over time, or if loads that are not lighting loads are served from the same Point of Service.

	<b>All Lamps</b>	
	<b>Customer Charge</b>	<b>Demand Charge</b>
<b>Transmission</b>	-	0.021 ¢ /watt/day
<b>Distribution</b>	26.60 ¢/fixture/day	0.012 ¢ /watt/day
<b>Service</b>	1.78 ¢/fixture/day	-
<b>TOTAL PRICE</b>	<b>28.37 ¢/fixture/day</b>	<b>0.033 ¢ /watt/day</b>

### **No Investment Option (61 D) (This option is no longer available)**

- ~~The customer is responsible for the full cost of installation.~~
- ~~The customer is responsible for the full cost of replacement.~~
- ~~Includes maintenance only.~~
- ~~This portion of the rate is closed to new Points of Service and will be phased out by the end of 2005.~~
- ~~All customers served under Option 61D may at any time between January 1, 2005 and December 31, 2005, elect to have service billed under Option 61E or Option 61B.~~

<b>YEAR:</b>	<b>All Lamps</b>	
<b>2005</b>	<b>Customer Charge</b>	<b>Demand Charge</b>
Transmission	-	0.31¢ /watt
Distribution	\$5.22	0.33¢ /watt
Service	\$0.51	-
<b>TOTAL PRICE</b>	<b>\$5.73 / fixture</b>	<b>0.64¢ / watt of billing demand</b>

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## Price Schedule D61 – Street Lighting Service

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### **No Investment Option (61 E)**

- Available for new installations only.
- For lighting fixtures installed, owned and maintained by the Company.
- The customer is responsible for the full cost of installation.
- The customer is responsible for the full cost of replacement.
- Includes maintenance only.

<b>All Lamps</b>		
	<b>Customer Charge</b>	<b>Demand Charge</b>
Transmission	-	0.021 ¢ /watt/day
Distribution	19.46 ¢/fixture/day	0.012 ¢ /watt/day
Service	1.78 ¢/fixture/day	-
<b>TOTAL PRICE</b>	<b>21.24 ¢/fixture/day</b>	<b>0.033 ¢ /watt/day</b>

### **Application**

1. **Price Option** - the following price option may apply:  
Idle Service (Option F)
2. **Price Adjustments** – the following price adjustments (riders) may apply:  
Municipal Assessment (Rider A-1)  
Balancing Pool Adjustment (Rider F)  
Temporary Adjustment (Rider G)  
Interim Adjustment (Rider J)  
Interim RRT Adjustment (Rider Q)

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## Price Schedule D63 – Private Lighting Service

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### **Availability**

For System Access Service and Distribution Access Service for all Points of Service throughout the territory served by the Company, for sentinel lighting.

### **Price**

Charges for service in any one billing month are the sum of the Customer Charge and Demand Charge determined for each individual Point of Service.

### **Investment Option (63 A)**

For standard sentinel lighting fixtures installed, owned, and maintained by the Company

	<b>Customer Charge</b>	<b>Demand Charge</b>
Transmission	-	0.021 ¢ /watt/day
Distribution	13.48 ¢/fixture/day	0.014 ¢ /watt/day
Service	19.04 ¢/fixture/day	-
<b>TOTAL PRICE</b>	<b>32.52 ¢/ fixture/day</b>	<b>0.035 ¢ / watt/day</b>

### **Summer Village Option (63 B)**

- For standard sentinel lighting fixtures installed, owned and maintained by the Company
- For seasonal use only (six month minimum period) by Municipal Corporations in summer villages.
- This portion of the rate is closed.

	<b>Customer Charge</b>	<b>Demand Charge</b>
Transmission	-	0.021 ¢ /watt/day
Distribution	21.44 ¢/fixture/day	0.014 ¢ /watt/day
Service	19.04 ¢/fixture/day	-
<b>TOTAL PRICE</b>	<b>40.47 ¢/fixture/day</b>	<b>0.035 ¢ / watt/day</b>

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## Price Schedule D63 – Private Lighting Service

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### **No Investment Option (63 C)**

- Available for new installations only.
- For standard lighting fixtures installed, owned, and maintained by the Company.
- The customer is responsible for the full cost of installation.
- The customer is responsible for the full cost of replacement.
- Includes maintenance only.

	<b>Customer Charge</b>	<b>Demand Charge</b>
Transmission	-	0.021 ¢ /watt/day
Distribution	7.13 ¢/fixture/day	0.004 ¢ /watt/day
Service	19.04 ¢/fixture/day	-
<b>TOTAL PRICE</b>	<b>26.17 ¢/fixture/day</b>	<b>0.025 ¢ / watt/day</b>

### **Metering Option (63 D)**

- For standard lighting fixtures installed, owned, and maintained by the Company.
- For service through the meter at the Point of Service.
- This portion of the rate is closed.

	<b>Customer Charge</b>	<b>Demand Charge</b>
Transmission	-	0.021 ¢ /watt/day
Distribution	14.14 ¢/fixture/day	0.014 ¢ /watt/day
Service	19.04 ¢/fixture/day	-
<b>TOTAL PRICE</b>	<b>33.17 ¢/fixture/day</b>	<b>0.035 ¢ / watt/day</b>

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## Price Schedule D63 – Private Lighting Service

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### **Distribution Investment Option (63 E)**

- For customer owned and installed lighting.
- For installation and maintenance of distribution facilities up to, but not including the customer owned conductor serving the light fixtures.
- The Company may require that the Point of Service be metered and served on Price Schedule D21, if the load requirements change over time, or if loads that are not lighting loads are served from the same Point of Service.

	<b>Customer Charge</b>	<b>Demand Charge</b>
Transmission	-	0.021 ¢ /watt/day
Distribution	9.24 ¢/fixture/day	0.014 ¢ /watt/day
Service	19.04 ¢/fixture/day	-
<b>TOTAL PRICE</b>	<b>28.28 ¢/fixture/day</b>	<b>0.035 ¢ / watt/day</b>

### **Application**

1. **Price Adjustments** - the following price adjustments (riders) may apply:
  - Municipal Assessment (Rider A-1)
  - Balancing Pool Adjustment (Rider F)
  - Temporary Adjustment (Rider G)
  - Interim Adjustment (Rider J)
  - Interim RRT Adjustment (Rider Q)

**Option F Idle Service****Availability**

The Idle Service charge will apply to all Price Schedules listed below for Points of Service served by the Company throughout the territory when the Point of Service is temporarily disconnected with the intention of restoring service at a future date.

**Price Adjustment**

The Idle Service charges shall be:

<b>Price Schedule</b>	<b>Applicability</b>	<b>Idle Service Charge</b>
D11	Service outside cities, towns, villages, hamlets, Indian reserves and Metis settlements	The price schedule monthly Distribution Customer Charge plus the Transmission Customer Charge.
D21 D22	Service outside cities, towns, villages, hamlets, Indian reserves and Metis settlements	The sum of the Distribution Demand Charge plus the Transmission Demand Charge where: (a) Distribution Demand Charge is the greater of the contract demand or rate minimum, and (b) Transmission Demand Charge is the price schedule rate minimum
D24 D34 D44	All Points of Service	The sum of the Distribution Demand Charge where the Distribution Demand Charge is the greater of the contract demand or rate minimum.
D25 D26	Does not apply (no charges apply when Point of Service is placed on idle).	Does not apply (no charges apply when Point of Service is placed on idle).
D31 D32 D41	All Points of Service	The sum of the Distribution Demand Charge plus the Transmission Demand Charge where: (a) Distribution Demand Charge is the greater of the contract demand or rate minimum, and (b) Transmission Demand Charge is the greater of the contract demand or rate minimum
D33	All Points of Service	Charges based on base demand level established under Price Schedule D31.
T31	Does not apply (no charges apply when Point of Service is placed on idle).	Does not apply (no charges apply when Point of Service is placed on idle).
T33	Does not apply (no charges apply when Point of Service is placed on idle).	Does not apply (no charges apply when Point of Service is placed on idle).
D51 D52 D56	All Points of Service	The sum of the Distribution Customer charge and the Distribution and Transmission Demand Charges applicable to a 3 kV.A service.
D61	All Points of Service	The sum of the Distribution Demand Charge plus the Transmission Demand Charge
D63	Does not apply (no charges apply when Point of Service is placed on idle).	Does not apply (no charges apply when Point of Service is placed on idle).

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## **Option F Idle Service**

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### **Application**

1. If the Customer's Point of Service is reconnected within 12 months of disconnection, the minimum monthly charge for each month of disconnection will be applied to the Point of Service.
2. For further information on idle services, refer to Terms and Conditions 14.1 – Disconnection and Idle Service.

The Retailer will be responsible for any costs that the Company incurs from AESO as a result of a point of service going idle. If the point of service is not enrolled with a Retailer, the costs incurred from AESO will be charged directly to the Customer.

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## **Option H – Service for Non-Standard Transformation and Metering configurations**

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### **Availability**

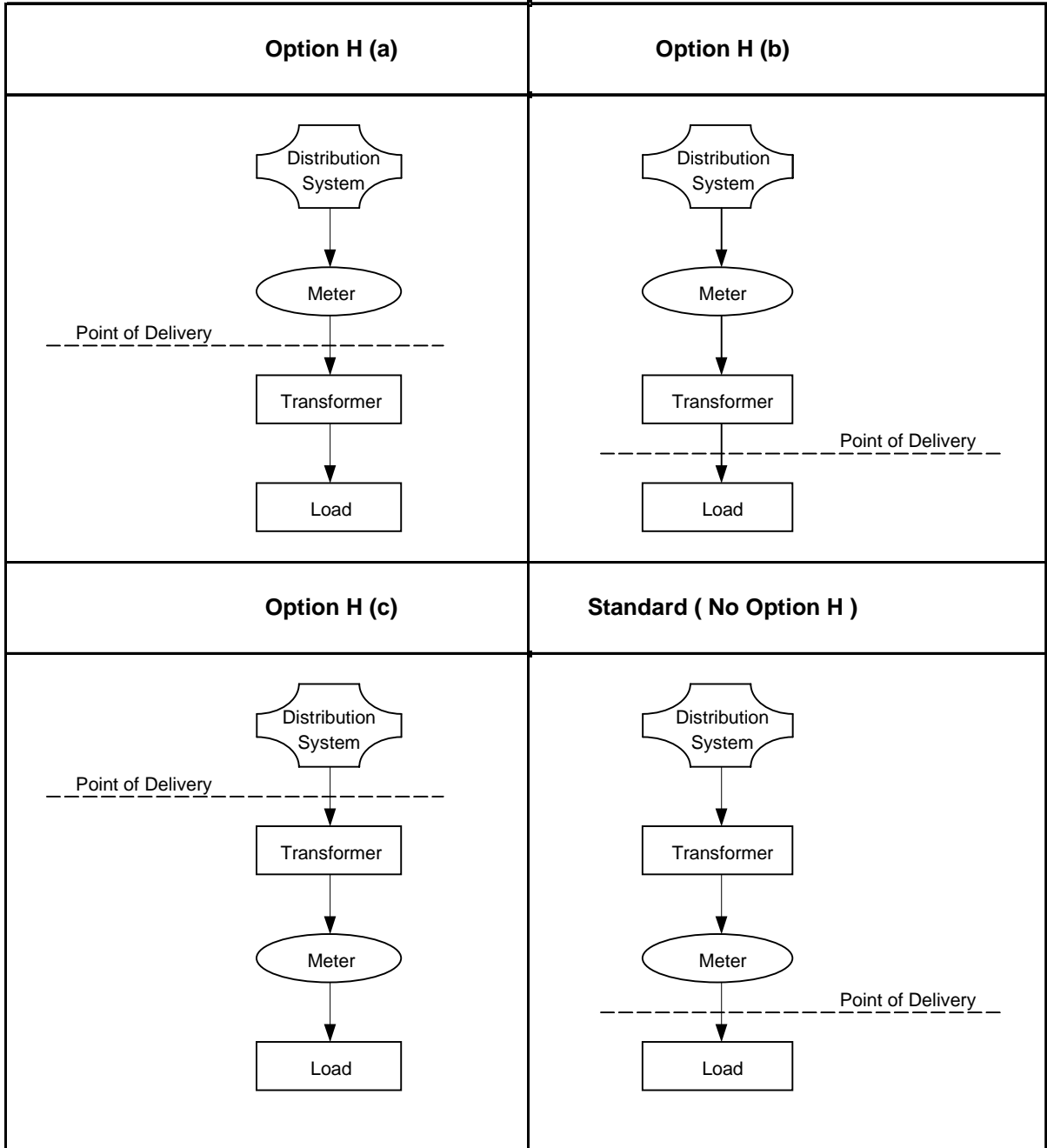
- For Points of Service throughout the territory served by the Company under Price Schedule D21, D22, D31, T31, D32 where metering and / or delivery voltage are non-standard.
- Standard service for distribution connected customers is delivered and metered at the utilization voltage. When delivery or metering is necessary at other voltages, for the convenience of either the customer or the Company, bills for service will be adjusted as outlined below in (a) to (c).
- Standard service for transmission connected customers is delivered to the customer and metered at the substation voltage. When delivery is required at lower voltages, bills for service will be adjusted as outlined below in (d). Section (b) may also apply to transmission connected customers.

### **Price Adjustment**

- (a) If the point of delivery and metering is on the primary side (25 kV) of a transformer (including cases where one-point service is required by the customer for more than a single utilization voltage or point of use), and the customer owns or rents the necessary transformer(s), a **discount of 2.47 ¢/kW/day** of billing demand will be applied. This adjustment does not apply to customers connected directly to the transmission system who are exempt from the Distribution Charge on the applicable rate.
- (b) If primary or higher voltage delivery metering is desirable for the convenience of the Company, or to improve accessibility, etc., **demand and energy measurements will be reduced by 1%** so as to approximate secondary voltage delivery conditions.
- (c) If primary or higher voltage delivery is made to customer owned transformers, but metering is at secondary or utilization voltage for the Company's convenience, **demand and energy measurements will be increased by 1%** so as to approximate primary or transmission voltage delivery conditions and **a discount, as specified in (a)** shall apply.
- (d) Customers who are connected directly to the transmission system, but take service from the low side of a transformer (with primary side 25kV), and do not own or rent any necessary transformer(s), and are exempt from the Distribution Charge on the applicable rate, a **surcharge of 2.47 ¢/kW/day** of billing demand will apply.

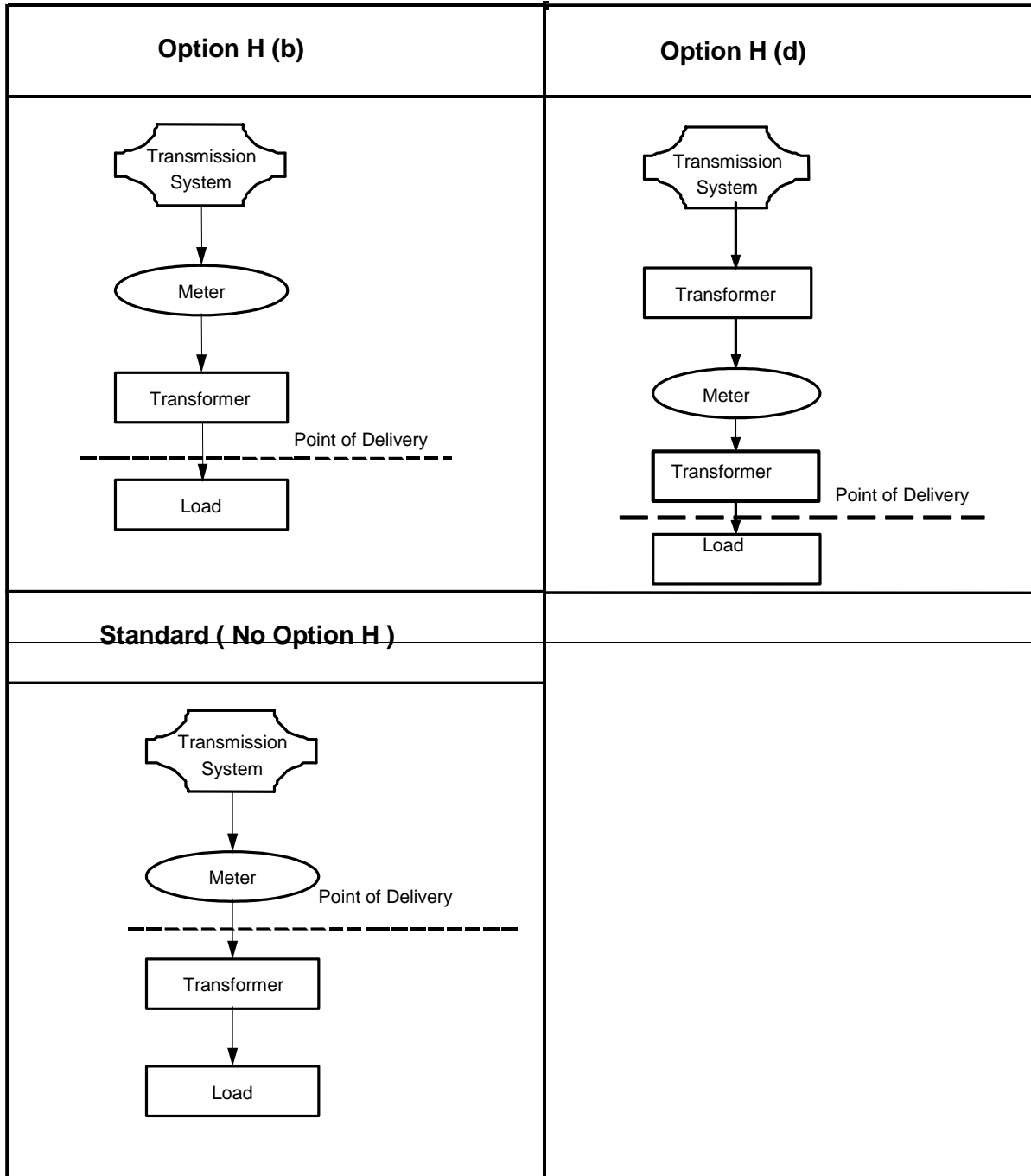
**Option H – Service for Non-Standard Transformation and Metering configurations**

**Schematic of Metering and Transformation Configurations for Option H Definitions  
 (Distribution Connected Customers)**



**Option H – Service for Non-Standard Transformation and Metering configurations**

**Schematic of Metering and Transformation Configurations for Option H Definitions  
 (Transmission Connected Customers)**



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## **Option P REA Distribution Price Credit**

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### **Availability**

For all Pooled O&M REA Farm Points of Service throughout the territory served by the Company, served under Price Schedule D21 or Price Schedule D31.

### **Price Adjustment**

#### **Standard Small General Service Price Schedule D21**

For REA farm Points of Service electing to take service under Small General Service Price Schedule D21, a credit adjustment of 49% will be applied to the base bill.

#### **Large General Service / Industrial Price Schedule D31**

For REA farm Points of Service electing to take service under Large General Service / Industrial Price Schedule D31, a credit adjustment of 37% will be applied to the base bill.

## Rider A-1 Municipal Assessment

### **Availability**

- Applicable throughout the territory served by the Company to electric service within the municipalities identified in Table 2.
- The following are exempt from the surcharge:
  - (a) Farm customers (Price Schedules D51, D52 and D56)
  - (b) Irrigation Pumping customers (Price Schedule D25 and D26)
  - (c) Customers within Indian Reservations not listed in Table 2
  - (d) Special Facilities Charge (Rider E) customers

### **Price Adjustment**

- The Company pays to a municipality each year or month, in accordance with the franchise agreement between the Company and the municipality, a percent of the gross revenue, or wires revenue, of the Company derived from the sale or delivery of electricity to the consumers in the municipality.
- The percentage of gross revenue (franchise fee and/or tax), or wires revenue, to be paid by the Company to its franchised municipalities is given by category number in Table 1. The municipalities, and their category numbers, are listed in Table 2. For Category 7 the municipalities and percentages of yearly wires revenue are listed in Table 3. For Category 8 the municipalities and percentages of monthly wires revenue are listed in Table 4.
- For all categories except Category 8, an estimated surcharge will be added to each customer's bill within a municipality in order to recover the above payments. Adjustments will be made once each year for any difference between the estimated surcharge collected and the actual surcharge required.
- For Category 8, the percentages listed in Table 4 will be applied to the monthly billing. The amount billed will be paid to the municipality in accordance with the franchise agreement between the Company and the municipality.

**Table 1 – Percent of Gross Revenue by Category**

<b>CATEGORY 1</b>	2% of the first \$100,000 of gross revenue; 3% of the next \$200,000 of gross revenue; 4% of the next \$200,000 of gross revenue; 5% of gross revenue in excess of \$500,000.
<b>CATEGORY 5</b>	1.0% of the first \$100,000 of gross revenue; 1.5% of the next \$200,000 of gross revenue; 2.0% of the next \$200,000 of gross revenue; 2.0% of gross revenue in excess of \$500,000.
<b>CATEGORY 6</b>	An amount equal to taxes assessed pursuant to the Municipal Government Act Chap. M-26. 1.
<b>CATEGORY 7</b>	A percentage of the wires revenue of a municipality as listed in Table 3.
<b>CATEGORY 8</b>	A percentage of monthly wires revenue of a municipality as listed in Table 4.

**Rider A-1 Municipal Assessment**

**Table 2 – Category Numbers of Municipalities**

Alliance 8, 6	Empress 7,6	Jasper Nat'l Park 5	Sexsmith 7
Andrew 7 8, 6	Fairview 8, 6	Kinuso 8, 6	Slave Lake 7
Beaverlodge 7	Falher 7	Kitscoty 7, 6	Smoky Lake 8, 6
Berwyn 7	Forestburg 7	Linden 8, 6	Spirit River 8, 6
Big Valley 7	Fort McMurray 7	Lloydminster 7, 6	St Paul 8, 6
Bonnyville 8, 6	Fox Creek 8, 6	Manning 7	Stettler 7,6
Botha 7	Gadsby 6	Mannville 8, 6	Swan Hills 8,6
Carbon 7	Galahad 7	Marwayne 7, 6	Three Hills 8, 6
Castor 7	Girouxville 7	McLennan 7	Trochu 8, 6
Cereal 7	Glendon 8, 6	Minburn 6	Two Hills 8, 6
Cold Lake 8, 6	Grande Cache 8, 6	Morrin 7	Valleyview 7
Consort 7	Grande Prairie 7 8, 6	Mundare 6	Vegreville 6
Coronation 8, 6	Grimshaw 7	Munson 7,6	Vermilion 8, 6
Delburne 7	Halkirk 8, 6	Myrnam 6	Veteran 7 8, 6
Delia 8, 6	Hanna 8, 6	Nampa 7	Vilna 8, 6
Derwent 6	Heisler 8, 6	Oyen 7	Waskatenau 6
Dewberry 8, 6	High Level 8, 6	Paradise Valley 7	Wembley 7
Donalda 8, 6	High Prairie 7	Peace River 7	Willingdon 6
Donnelly 7	Hines Creek 7	Radway (County 7) 7	Youngstown 7, 6
Drumheller 8,6	Hythe 7	Rainbow Lake 8, 6	
Elk Point 8, 6	Innisfree 7	Rosalind 8, 6	
Elnora 8, 6	ID Jasper 7	Rycroft 7	

**Table 2 – Category Numbers of Municipalities**

Category 6 also applies to the following non-franchised municipalities:

Bonnyville Beach	County No. 30 Lamont	M.D. of Peace No. 135
Horseshoe Bay	County No. 89 Lakeland	M.D. of Fairview No. 136
Lavoy	M.D. of Greenview No. 16	I.D. No. 12 & ID No. 24
Pelican Narrows	M.D. of Opportunity No. 17	Allison Bay B219
Rochon Sands	M.D. of Wood Buffalo No. 18	Fort McMurray Band B352
Wanham	M.D. of Birch Hills No. 19	Peavine N172
Warspite	M.D. of Saddle Hills No. 20	Gift Lake N173
Whitesands	M.D. of Clear Hills No. 21	East Prairie N174
County No. 01 Grande Pr.	M.D. of Northern Lights No. 22	Elizabeth N187
County No. 06 Stettler	M.D. of MacKenzie No. 23	Fishing Lake N188
County No. 07 Thornhild	M.D. of Acadia No. 34	Paddle Prairie N221
County No. 13 Smoky Lake	M.D. of Starland No. 47	Special Areas
County No. 16 Wheatland	M.D. of Kneehill No. 48	Sturgeon Lake I.R. #154
County No. 18 Paintearth	M.D. of Bonnyville No. 87	Whitefish Lake Band B924
County No. 19 St. Paul	M.D. of Bonnyville Annexed No. 88	Busche River I.R. No. 207*
County No. 21 Two Hills	M.D. of Lesser Slave River No. 124	Hay Lake I.R. No. 209*
County No. 22 Camrose	M.D. of Big Lake No. 125	Upper Hay River I.R. No. 212*
County No. 23 Red Deer	M.D. of Smoky R. No. 130	Doghead I.R. No. 218*
County No. 24 Vermilion R.	M.D. of Northern Sunrise County	Bigstone Wabasca I.R. No. 166*
County No. 27 Minburn	M.D. of Spirit River No. 133	Loon River Cree I.R.*
County No. 29 Flagstaff		

\* Additional Municipalities

**Rider A-1 Municipal Assessment****Table 3 – Percent of Wires Revenue by Municipality (Category 7)**

<b>Beaverlodge</b>	7.20%	<b>Galahad</b>	6.75%	<b>Munson</b>	3.00%
<b>Berwyn</b>	5.25%	<b>Girouxville</b>	7.00%	<b>Nampa</b>	5.00%
<b>Big Valley</b>	3.75%	<b>Grimshaw</b>	7.50%	<b>Oyen</b>	7.75%
<b>Botha</b>	4.50%	<b>High Prairie</b>	7.80%	<b>Paradise Valley</b>	3.50%
<b>Carbon</b>	3.50%	<b>Hines Creek</b>	6.50%	<b>Peace River</b>	7.25%
<b>Castor</b>	5.00%	<b>Hythe</b>	7.25%	<b>Radway (County 7)</b>	3.00%
<b>Cereal</b>	5.00%	<b>Innisfree</b>	5.25%	<b>Rycroft</b>	4.30%
<b>Consort</b>	5.25%	<b>Jasper (ID)</b>	7.50%	<b>Sexsmith</b>	8.20%
<b>Delburne</b>	3.75%	<b>Kitscoty</b>	5.00%	<b>Slave Lake</b>	8.70%
<b>Donnelly</b>	5.00%	<b>Lloydminster</b>	13.00%	<b>Stettler</b>	7.50%
<b>Empress</b>	5.25%	<b>Manning</b>	7.50%	<b>Valleyview</b>	7.60%
<b>Falher</b>	7.50%	<b>Marwayne</b>	4.00%	<b>Wembley</b>	6.70%
<b>Forestburg</b>	4.00%	<b>McLennan</b>	8.25%	<b>Youngstown</b>	4.00%
<b>Fort McMurray</b>	7.60%	<b>Morrin</b>	6.00%		

**Table 4 – Percent of Monthly Wires Revenue by Municipality (Category 8)  
Paid in addition to other taxes**

<b>Alliance</b>	4.00%	<b>Fox Creek</b>	4.50%	<b>Rainbow Lake</b>	4.75%
	6.00%				7.75%
<b>Andrew</b>	2.00%	<b>Glendon</b>	1.50%	<b>Rosalind</b>	0.50%
<b>Bonnyville</b>	6.80%	<b>Grande Cache</b>	4.60%	<b>Smoky Lake</b>	3.25%
<b>Cold Lake</b>	4.25%	<b>Grande Prairie</b>	7.75%	<b>Spirit River</b>	4.50%
<b>Coronation</b>	3.75%	<b>Halkirk</b>	1.00%	<b>St Paul</b>	7.00%
<b>Delia</b>	0.50%	<b>Hanna</b>	3.50%	<b>Swan Hills</b>	4.00%
<b>Dewberry</b>	0.00%	<b>Heisler</b>	0.00%	<b>Three Hills</b>	5.00%
<b>Donalda</b>	1.50%	<b>High Level</b>	6.50%	<b>Trochu</b>	3.50%
<b>Drumheller</b>	9.00%	<b>Kinuso</b>	3.50%	<b>Two Hills</b>	2.75%
<b>Elk Point</b>	3.60%	<b>Linden</b>	4.00%	<b>Vermilion</b>	3.50%
<b>Elnora</b>	1.00%	<b>Mannville</b>	2.50%	<b>Veteran</b>	1.00%
<b>Fairview</b>	6.00%	<b>MD Badlands</b>	9.00%	<b>Vilna</b>	4.00%

**Note:** Andrew, Grande Prairie and Veteran were removed from Table 3 and added to Table 4.  
MD Badlands has been added to Table 4.

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## **Rider E Special Facilities Charge**

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### **Availability**

Applicable to facilities constructed by the Company on customer owned or leased property, as requested by the customer.

### **Price**

The Facilities charge will be set out in a contract, negotiated between the customer and the Company, and will recover the revenue requirement of the applicable facilities. The revenue requirement will be calculated on a rate base of net book value and will include Return, Income Tax, Depreciation, and Operations and Maintenance costs.

### **Application**

- Facility charges will normally be billed monthly. Monthly charges are subject to change as new facilities are added or currently installed facilities are retired.
- For facilities shared among more than one customer, a separate contract will be established for each customer making use of the facilities.
- Facilities constructed under Rider E are owned and maintained by the Company.

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## Rider F Balancing Pool Adjustment

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### **Availability**

- This Rider F is designed to flow through a Balancing Pool Refund from the Alberta Electric System Operator (AESO).
- Applicable to all customers with the exception of customers served on Price Schedule D24, Price Schedule D34, and Price Schedule D44, at points of service, throughout the territory served by the Company for energy consumption effective January 1, 2006.
- The Company's applicable charges under the following Price Schedules will be adjusted by the amounts noted below:

Applicable Distribution Tariff Price Schedule	Charge (¢/kW.h)
	“+” = Charge “-” = Refund
D11 Residential	-0.10
D21 Small General Service	-0.10
D22 Small General Service – Energy Only	-0.10
D25 Irrigation Pumping Service	-0.10
D26 REA Irrigation Pumping Service	-0.10
D31 Large General Service/Industrial – Distribution Connected	-0.10
T31 Large General Service/Industrial – Transmission Connected	-0.10
D32 Generator Interconnection and Standby Power	-0.10
D33 Transmission Opportunity Rate – Distribution Connected	-0.10
T33 Transmission Opportunity Rate – Transmission Connected	-0.10
D41 Small Oilfield and Pumping Power	-0.10
D51 REA Farm Service	-0.10
D52 REA Farm Service – Excluding Wires Service Provider	-0.10
D56 Farm Service	-0.10
D61 Street Lighting Service	-0.10
D63 Private Lighting Service	-0.10

**Note: Rider F does not apply to Rider A-1, Rider E, Rider G, Rider J, and Rider Q.**

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## Rider G Temporary Adjustment

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### **Availability**

- This Rider G is designed to true-up 2004 Rider G and dispense of new deferral balances.
- Applicable to all customers, at points of service, throughout the territory served by the Company for energy consumption effective January 1, 2006.
- The Company's applicable charges under the following Price Schedules will be adjusted by the amounts noted below:

Applicable Distribution Tariff Price Schedule	Charge (¢/kW.h)
	“+” = Charge “-” = Refund
D11 Residential	0.00
D21 Small General Service	0.00
D22 Small General Service – Energy Only	0.00
D25 Irrigation Pumping Service	0.00
D26 REA Irrigation Pumping Service	0.00
D31 Large General Service/Industrial – Distribution Connected	0.00
T31 Large General Service/Industrial – Transmission Connected	0.00
D32 Generator Interconnection and Standby Power	0.00
D33 Transmission Opportunity Rate – Distribution Connected	0.00
T33 Transmission Opportunity Rate – Transmission Connected	0.00
D41 Small Oilfield and Pumping Power	0.00
D51 REA Farm Service	0.00
D52 REA Farm Service – Excluding Wires Service Provider	0.00
D56 Farm Service	0.00
D61 Street Lighting Service	0.00
D63 Private Lighting Service	0.00

**Note: Rider G does not apply to Rider A-1, Rider E, Rider J, and Rider Q.**

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## **Rider J Interim Adjustment**

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### **Availability**

Applies to all electric service throughout the territory served by the Company when a charge or refund is approved by the AEUB.

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## Rider Q Interim RRT Adjustment

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### **Availability**

- Rider Q is designed to true-up 2001 to 2004 RROT deferral account balances.
- The Company's applicable charges under the following Price Schedules will be adjusted by the amounts noted below:

### **Price**

This Rider will apply on energy consumption effective January 1, 2006.

Regulated Rate	Applicable Distribution Tariff Price Schedule	Charge (¢/kW.h)
		“+” = Charge “-” = Refund
E1	D11 Residential	0.00
E2	D21, D22 Small General Service	0.00
E3	D31, T31, D32 Large General Service/Industrial & Generator Interconnection	0.00
E4	D41 Small Oilfield and Pumping Power	0.00
E51	D51, D52 REA Farm Service	0.00
E56	D56 Farm Service	0.00
E6	D61, D63 Lighting Service	0.00
E7	D25, D26 Irrigation Pumping Service	0.00

**Note: Rider Q does not apply to Rider A-1, Rider E, Rider J and Rider G.**

**Summary of Rate Impact to Typical Bills (Distribution Tariff Base Rates - Without Retail Energy Purchases)**

Rate Class	January 1, 2005				June 1, 2005				August 1, 2005				January 1, 2006				
	DT Base Rates	Rider G	Rider Q	Net	DT Base Rates	Rider G	Rider Q	Net	DT Base Rates	Rider G	Rider Q	Net	DT Base Rates	Rider G	Rider Q	Rider F	Net
D11 Residential 600 kWh	\$48.78	-\$10.14		\$38.64	\$48.78			\$48.78	\$45.87	\$6.40	-\$0.31	\$51.96	\$53.45			-\$0.60	\$52.85
D21 Commercial 20 kW; 7300 kWh	\$295.60	-\$95.78		\$199.82	\$295.60			\$295.60	\$218.30	\$54.09	-\$3.94	\$268.45	\$262.96			-\$7.30	\$255.66
D31 Industrial 50 kW; 16,650 kWh	\$380.57	-\$48.29		\$332.28	\$380.57			\$380.57	\$377.84	\$33.63	\$156.01	\$567.48	\$498.21			-\$16.65	\$481.56
D41 Oilfield 20 kW; 8,760 kWh	\$260.46	-\$3.77		\$256.69	\$260.46			\$260.46	\$280.05	\$29.78	-\$214.27	\$95.56	\$332.19			-\$8.76	\$323.43
D51 REA Pooled 7.5 kVA; 1,255 kWh	\$36.76	-\$6.60		\$30.16	\$36.76			\$36.76	\$36.04	\$1.62	\$10.01	\$47.67	\$47.59			-\$1.26	\$46.34
D56 Farm 7.5 kVA; 1,255 kWh	\$53.82	-\$10.57		\$43.25	\$53.82			\$53.82	\$54.94	\$5.13	\$10.01	\$70.08	\$67.51			-\$1.26	\$66.26
D61 Street Lights 250 Watts	\$7.29	-\$2.52		\$4.77	\$7.29			\$7.29	\$7.84	\$1.36	-\$2.54	\$6.66	\$9.03			-\$0.09	\$8.94
D63 Private Lights 250 Watts	\$10.50	-\$1.88		\$8.62	\$10.50			\$10.50	\$11.05	\$0.66	-\$2.54	\$9.17	\$12.38			-\$0.09	\$12.29

**Schedule B.1 - Example Rate Rider Effects: Residential Class - RRO Eligible**

GST not included

Row	Rate Component	Effective Date	Typical			
			300 kWh per month	600 kWh per month	1200 kWh per month	
1	Dec. 1999 Rate	1999	\$32.81	\$54.25	\$97.13	
2	Dec 2000 Rate	2000	\$39.72	\$61.94	\$106.39	
3	New Combined Rate (AB Government Rebate Included), July 1 - Dec. 31, 2001	July 1 - Dec. 31, 2001	\$33.34	\$84.85	\$187.86	
4	Combined Rate, Jan. 1, 2002	Jan 1, 2002	\$51.46	\$80.02	\$137.14	
5	Combined Rate, July 1, 2002	Jul 1, 2002	\$51.41	\$79.91	\$136.92	
6	Combined Rate, January 1, 2003	Jan 1, 2003	\$53.22	\$83.54	\$144.18	
7	Predicted Combined Rate, December 1, 2003	Dec 1, 2003	\$63.58	\$104.26	\$185.61	
8	Predicted Combined Rate, January 1, 2004	Jan 1, 2004	\$57.01	\$91.11	\$159.32	
9	Predicted Combined Rate, May 1, 2004	May 1, 2004	\$49.78	\$76.67	\$130.43	
10	Predicted Combined Rate, June 1, 2004 (Rider G set to \$0/kWh)	May 1, 2004	\$54.85	\$86.81	\$150.71	
<b>August 1, 2005</b>						
11	Forecast Energy Rates, Aug 1, 2005	Aug 1, 2005	\$28.70	\$51.22	\$96.25	
12	+RRO Deferral (5 month recovery - August 2005 - December 2005)	Aug 1, 2005	-\$0.15	-\$0.31	-\$0.61	
13	2005 Energy Related Charge Row 11 + Row 12	Aug 1, 2005	\$28.55	\$50.91	\$95.64	
14	AE Interim DT Base Rates (2004 Proposed Final Rates)	Aug 1, 2005	\$32.85	\$45.87	\$71.91	
15	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Aug 1, 2005	\$3.20	\$6.40	\$12.79	
16	Net DT Charges Row 14+ Row 15	Aug 1, 2005	\$36.05	\$52.27	\$84.70	
17	Predicted Combined Rate, August 1, 2005 Row 13 + Row 16	Aug 1, 2005	\$64.59	\$103.18	\$180.34	
<b>January 1, 2006</b>						
18	Forecast Energy Rates, Jan 1, 2006	Jan 1, 2006	\$28.70	\$51.22	\$96.25	
19	+No RRO Deferral	Jan 1, 2006	\$0.00	\$0.00	\$0.00	
20	2005 Energy Related Charge Row 18 + Row 19	Jan 1, 2006	\$28.70	\$51.22	\$96.25	
21	AE Interim DT Base Rates (Scaled 2004 Final Rates)	Jan 1, 2006	\$37.16	\$53.45	\$86.03	
22	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Jan 1, 2006	-\$0.30	-\$0.60	-\$1.20	
23	Net DT Charges Row 21 + Row 22	Jan 1, 2006	\$36.86	\$52.85	\$84.83	
24	Predicted Combined Rate, January 1, 2006 Row 20 + Row 23	Jan 1, 2006	\$65.56	\$104.06	\$181.08	
<b>Comparisons</b>						
	Combined Rate (Jan 2002- Jul 2002)	Row 5 vs Row 4	difference %	-\$0.05 0%	-\$0.11 0%	-\$0.22 0%
	Combined Rate (Jul 2002- Jan 2003)	Row 6 vs Row 5	difference %	\$1.82 4%	\$3.63 5%	\$7.26 5%
	Combined Rate (Jan 2003- Dec 2003)	Row 7 vs Row 6	difference %	\$10.36 19%	\$20.71 25%	\$41.43 29%
	Combined Rate (Dec 2003- Jan 2004)	Row 8 vs Row 7	difference %	-\$6.57 -10%	-\$13.15 -13%	-\$26.29 -14%
	Combined Rate (Jan 2004- May 2004)	Row 9 vs Row 8	difference %	-\$7.22 -13%	-\$14.44 -16%	-\$28.89 -18%
	Combined Rate (May 2004- Aug 2005)	Row 17 vs Row 9	difference %	\$14.81 30%	\$26.51 35%	\$49.91 38%
	Combined Rate (Jun 2005- Aug 2005)	Row 17 vs Row 10	difference %	\$9.74 18%	\$16.37 19%	\$29.63 20%
	Combined Rate (Aug 2005- Jan 2006)	Row 24 vs Row 17	difference %	\$0.96 1%	\$0.89 1%	\$0.74 0%

**Schedule B.2 - Example Rate Rider Effects: Small General Service Class - RRO Eligible** GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge			Small General Service Class Consumption Levels Cost per Customer (\$/month)			
			5475 kWh per month Demand 15 kW	Typical 7300 kWh per month Demand 20 kW	9125 kWh per month Demand 25 kW	
Row	Rate Component	Effective Date				
1	Dec. 1999 Rate	1999	\$353.79	\$471.72	\$589.65	
2	Dec 2000 Rate	2000	\$396.05	\$528.07	\$660.09	
3	New Combined Rate (AB Government Rebate Included), July 1 - Dec. 31, 2001	July 1 - Dec. 31, 2001	\$740.70	\$983.25	\$1,225.80	
4	Combined Rate, Jan. 1, 2002	Jan. 1, 2002	\$498.05	\$659.52	\$820.99	
5	Combined Rate, July 1, 2002	Jul 1, 2002	\$481.46	\$637.40	\$793.34	
6	Combined Rate, January 1, 2003	Jan 1, 2003	\$777.65	\$1,032.32	\$1,286.99	
7	Predicted Combined Rate, December 1, 2003	Dec 1, 2003	\$532.43	\$705.36	\$878.30	
8	Predicted Combined Rate, January 1, 2004	Jan 1, 2004	\$583.92	\$774.01	\$964.11	
9	Predicted Combined Rate, May 1, 2004	May 1, 2004	\$500.98	\$663.43	\$825.88	
10	Predicted Combined Rate, June 1, 2004 (Rider G set to \$0/kW.h)	May 1, 2004	\$572.82	\$759.21	\$945.60	
<b>August 1, 2005</b>						
11	Forecast Energy Rates, Aug 1, 2005	Aug 1, 2005	\$430.69	\$572.17	\$713.64	
12	+RRO Deferral (5 month recovery - August 2005 - December 2005)	Aug 1, 2005	-\$2.96	-\$3.94	-\$4.93	
13	2005 Energy Related Charge	Aug 1, 2005	\$427.74	\$568.22	\$708.71	
	Row 11 + Row 12					
14	AE Interim DT Base Rates (2004 Proposed Final Rates)	Aug 1, 2005	\$167.07	\$218.30	\$269.54	
15	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Aug 1, 2005	\$40.57	\$54.09	\$67.62	
16	Net DT Charges	Aug 1, 2005	\$207.63	\$272.39	\$337.15	
	Row 14+ Row 15					
17	Predicted Combined Rate, August 1, 2005	Aug 1, 2005	\$635.37	\$840.62	\$1,045.86	
	Row 13 + Row 16					
<b>January 1, 2006</b>						
18	Forecast Energy Rates, Jan 1, 2006	Jan 1, 2006	\$430.69	\$572.17	\$713.64	
19	+No RRO Deferral	Jan 1, 2006	\$0.00	\$0.00	\$0.00	
20	2005 Energy Related Charge	Jan 1, 2006	\$430.69	\$572.17	\$713.64	
	Row 18 + Row 19					
21	AE Interim DT Base Rates (Scaled 2004 Final Rates)	Jan 1, 2006	\$200.74	\$262.96	\$325.19	
22	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Jan 1, 2006	-\$5.48	-\$7.30	-\$9.13	
23	Net DT Charges	Jan 1, 2006	\$195.26	\$255.66	\$316.06	
	Row 21 + Row 22					
24	Predicted Combined Rate, January 1, 2006	Jan 1, 2006	\$625.96	\$827.83	\$1,029.70	
	Row 20 + Row 23					
<b>Comparisons</b>						
	Combined Rate (Jan 2002- Jul 2002)	Row 5 vs Row 4	difference %	-\$16.59 -3%	-\$22.12 -3%	-\$27.65 -3%
	Combined Rate (Jul 2002- Jan 2003)	Row 6 vs Row 5	difference %	\$296.19 62%	\$394.92 62%	\$493.65 62%
	Combined Rate (Jan 2003- Dec 2003)	Row 7 vs Row 6	difference %	-\$245.22 -32%	-\$326.96 -32%	-\$408.70 -32%
	Combined Rate (Dec 2003- Jan 2004)	Row 8 vs Row 7	difference %	\$51.49 10%	\$68.65 10%	\$85.81 10%
	Combined Rate (Jan 2004- May 2004)	Row 9 vs Row 8	difference %	-\$82.94 -14%	-\$110.58 -14%	-\$138.23 -14%
	Combined Rate (May 2004- Aug 2005)	Row 17 vs Row 9	difference %	\$134.39 27%	\$177.18 27%	\$219.98 27%
	Combined Rate (Jun 2005- Aug 2005)	Row 17 vs Row 10	difference %	\$62.55 11%	\$81.41 11%	\$100.26 11%
	Combined Rate (Aug 2005- Jan 2006)	Row 24 vs Row 17	difference %	-\$9.41 -2%	-\$12.79 -2%	-\$16.16 -2%

**Schedule B.3 - Example Rate Rider Effects: Small General Service Class - Not RRO Eligible** GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge			Small General Service Class Consumption Levels Cost per Customer (\$/month)			
			5475 kWh per month Demand 15 kW	Typical 7300 kWh per month Demand 20 kW	9125 kWh per month Demand 25 kW	
Row	Rate Component	Effective Date				
1	Dec. 1999 Rate	1999	\$353.79	\$471.72	\$589.65	
2	Dec 2000 Rate	2000	\$396.05	\$528.07	\$660.09	
3	New Combined Rate (AB Government Rebate Included), July 1 - Dec. 31, 2001	July 1 - Dec. 31, 2001	\$740.70	\$983.25	\$1,225.80	
4	Combined Rate, Jan. 1, 2002	Jan. 1, 2002	\$498.05	\$659.52	\$820.99	
5	Combined Rate, July 1, 2002	Jul 1, 2002	\$543.88	\$720.62	\$897.37	
6	Combined Rate, January 1, 2003	Jan 1, 2003	\$777.65	\$1,032.32	\$1,286.99	
7	Predicted Combined Rate, December 1, 2003	Dec 1, 2003	\$506.10	\$670.25	\$834.40	
8	Predicted Combined Rate, January 1, 2004	Jan 1, 2004	\$583.92	\$774.01	\$964.11	
9	Predicted Combined Rate, May 1, 2004	May 1, 2004	\$500.98	\$663.43	\$825.88	
10	Predicted Combined Rate, June 1, 2004 (Rider G set to \$0/kW.h)	May 1, 2004	\$572.82	\$759.21	\$945.60	
<b>August 1, 2005</b>						
11	Forecast Energy Rates, Aug 1, 2005	Aug 1, 2005	\$430.69	\$572.17	\$713.64	
12	+RRO Deferral (5 month recovery - August 2005 - December 2005)	Aug 1, 2005	\$0.00	\$0.00	\$0.00	
13	2005 Energy Related Charge	Aug 1, 2005	\$430.69	\$572.17	\$713.64	
	Row 11 + Row 12					
14	AE Interim DT Base Rates (2004 Proposed Final Rates)	Aug 1, 2005	\$167.07	\$218.30	\$269.54	
15	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Aug 1, 2005	\$40.57	\$54.09	\$67.62	
16	Net DT Charges	Aug 1, 2005	\$207.63	\$272.39	\$337.15	
	Row 14+ Row 15					
17	Predicted Combined Rate, August 1, 2005	Aug 1, 2005	\$638.33	\$844.56	\$1,050.79	
	Row 13 + Row 16					
<b>January 1, 2006</b>						
18	Forecast Energy Rates, Jan 1, 2006	Jan 1, 2006	\$430.69	\$572.17	\$713.64	
19	+No RRO Deferral	Jan 1, 2006	\$0.00	\$0.00	\$0.00	
20	2005 Energy Related Charge	Jan 1, 2006	\$430.69	\$572.17	\$713.64	
	Row 18 + Row 19					
21	AE Interim DT Base Rates (Scaled 2004 Final Rates)	Jan 1, 2006	\$200.74	\$262.96	\$325.19	
22	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Jan 1, 2006	-\$5.48	-\$7.30	-\$9.13	
23	Net DT Charges	Jan 1, 2006	\$195.26	\$255.66	\$316.06	
	Row 21 + Row 22					
24	Predicted Combined Rate, January 1, 2006	Jan 1, 2006	\$625.96	\$827.83	\$1,029.70	
	Row 20 + Row 23					
<b>Comparisons</b>						
	Combined Rate (Jan 2002- Jul 2002)	Row 5 vs Row 4	difference %	\$45.83 9%	\$61.10 9%	\$76.38 9%
	Combined Rate (Jul 2002- Jan 2003)	Row 6 vs Row 5	difference %	\$233.78 43%	\$311.70 43%	\$389.63 43%
	Combined Rate (Jan 2003- Dec 2003)	Row 7 vs Row 6	difference %	-\$271.55 -35%	-\$362.07 -35%	-\$452.59 -35%
	Combined Rate (Dec 2003- Jan 2004)	Row 8 vs Row 7	difference %	\$77.82 15%	\$103.76 15%	\$129.70 16%
	Combined Rate (Jan 2004- May 2004)	Row 9 vs Row 8	difference %	-\$82.94 -14%	-\$110.58 -14%	-\$138.23 -14%
	Combined Rate (May 2004- Aug 2005)	Row 17 vs Row 9	difference %	\$137.34 27%	\$181.13 27%	\$224.91 27%
	Combined Rate (Jun 2005- Aug 2005)	Row 17 vs Row 10	difference %	\$65.51 11%	\$85.35 11%	\$105.19 11%
	Combined Rate (Aug 2005- Jan 2006)	Row 24 vs Row 17	difference %	-\$12.37 -2%	-\$16.73 -2%	-\$21.09 -2%

**Schedule B.4 - Example Rate Rider Effects: Large General Service Distribution - RRO Eligible** GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge			Large General Service Class			
			Consumption Levels Cost per Customer (\$/month)			
			12,200 kWh per month Demand 50 kW	Typical 16,650 kWh per month Demand 50 kW	20,800 kWh per month Demand 59 kW	
Row	Rate Component	Effective Date				
1	Dec. 1999 Rate	1999	\$1,031.32	\$1,113.38	\$1,335.04	
2	Dec 2000 Rate	2000	\$816.46	\$984.14	\$1,204.73	
3	New Combined Rate (AB Government Rebate Included), July 1 - Dec. 31, 2001	July 1 - Dec. 31, 2001	\$1,390.02	\$1,785.23	\$2,206.62	
4	Combined Rate, Jan. 1, 2002	Jan. 1, 2002	\$959.64	\$1,193.27	\$1,466.13	
5	Combined Rate, July 1, 2002	Jul 1, 2002	\$675.14	\$804.99	\$981.07	
6	Combined Rate, January 1, 2003	Jan 1, 2003	\$1,574.01	\$2,031.73	\$2,513.58	
7	Predicted Combined Rate, December 1, 2003	Dec 1, 2003	\$1,037.54	\$1,299.58	\$1,598.94	
8	Predicted Combined Rate, January 1, 2004	Jan 1, 2004	\$1,134.98	\$1,432.56	\$1,765.07	
9	Predicted Combined Rate, May 1, 2004	May 1, 2004	\$1,002.49	\$1,251.74	\$1,539.18	
10	Predicted Combined Rate, June 1, 2004 (Rider G set to \$0/kWh)	May 1, 2004	\$1,076.66	\$1,352.97	\$1,665.64	
<b>August 1, 2005</b>						
11	Forecast Energy Rates, Aug 1, 2005	Aug 1, 2005	\$866.79	\$1,181.28	\$1,474.56	
12	+RRO Deferral (5 month recovery - August 2005 - December 2005)	Aug 1, 2005	\$114.31	\$156.01	\$194.90	
13	2005 Energy Related Charge	Aug 1, 2005	\$981.11	\$1,337.29	\$1,669.45	
14	AE Interim DT Base Rates (2004 Proposed Final Rates)	Aug 1, 2005	\$360.93	\$377.84	\$443.29	
15	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Aug 1, 2005	\$24.64	\$33.63	\$42.02	
16	Net DT Charges	Aug 1, 2005	\$385.57	\$411.47	\$485.31	
17	Predicted Combined Rate, August 1, 2005	Aug 1, 2005	\$1,366.68	\$1,748.76	\$2,154.76	
<b>January 1, 2006</b>						
18	Forecast Energy Rates, Jan 1, 2006	Jan 1, 2006	\$866.79	\$1,181.28	\$1,474.56	
19	+No RRO Deferral	Jan 1, 2006	\$0.00	\$0.00	\$0.00	
20	2005 Energy Related Charge	Jan 1, 2006	\$866.79	\$1,181.28	\$1,474.56	
21	AE Interim DT Base Rates (Scaled 2004 Final Rates)	Jan 1, 2006	\$476.85	\$498.21	\$586.11	
22	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Jan 1, 2006	-\$12.20	-\$16.65	-\$20.80	
23	Net DT Charges	Jan 1, 2006	\$464.65	\$481.56	\$565.31	
24	Predicted Combined Rate, January 1, 2006	Jan 1, 2006	\$1,331.44	\$1,662.83	\$2,039.87	
<b>Comparisons</b>						
	Combined Rate (Jan 2002- Jul 2002)	Row 5 vs Row 4	difference %	-\$284.50 -30%	-\$388.28 -33%	-\$485.06 -33%
	Combined Rate (Jul 2002- Jan 2003)	Row 6 vs Row 5	difference %	\$898.87 133%	\$1,226.74 152%	\$1,532.50 156%
	Combined Rate (Jan 2003- Dec 2003)	Row 7 vs Row 6	difference %	-\$536.47 -34%	-\$732.15 -36%	-\$914.64 -36%
	Combined Rate (Dec 2003- Jan 2004)	Row 8 vs Row 7	difference %	\$97.44 9%	\$132.98 10%	\$166.13 10%
	Combined Rate (Jan 2004- May 2004)	Row 9 vs Row 8	difference %	-\$132.49 -12%	-\$180.82 -13%	-\$225.89 -13%
	Combined Rate (May 2004- Aug 2005)	Row 17 vs Row 9	difference %	\$364.20 36%	\$497.02 40%	\$615.58 40%
	Combined Rate (Jun 2005- Aug 2005)	Row 17 vs Row 10	difference %	\$290.02 27%	\$395.79 29%	\$489.11 29%
	Combined Rate (Aug 2005- Jan 2006)	Row 24 vs Row 17	difference %	-\$35.24 -3%	-\$85.93 -5%	-\$114.89 -6%

**Schedule B.5 - Example Rate Rider Effects: Large General Service Distribution - Not RRO Eligible** GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge			Large General Service Class Consumption Levels Cost per Customer (\$/month)			
			657,000 kWh per month Demand 1500 kW	Typical 876,000 kWh per month Demand 2000 kW	1,095,000 kWh per month Demand 2500 kW	
Row	Rate Component	Effective Date				
1	Dec. 1999 Rate	1999	\$34,380.07	\$45,558.25	\$55,150.47	
2	Dec 2000 Rate	2000	\$32,564.31	\$42,924.70	\$53,285.08	
3	New Combined Rate (AB Government Rebate Included), July 1 - Dec. 31, 2001	July 1 - Dec. 31, 2001	\$64,616.21	\$85,725.60	\$106,834.99	
4	Combined Rate, Jan. 1, 2002	Jan. 1, 2002	\$40,981.14	\$54,188.64	\$67,396.14	
5	Combined Rate, July 1, 2002	Jul 1, 2002	\$46,624.77	\$61,713.48	\$76,802.19	
6	Combined Rate, January 1, 2003	Jan 1, 2003	\$74,066.35	\$98,302.25	\$122,538.15	
7	Predicted Combined Rate, December 1, 2003	Dec 1, 2003	\$40,991.00	\$54,201.78	\$67,412.57	
8	Predicted Combined Rate, January 1, 2004	Jan 1, 2004	\$50,423.54	\$66,778.51	\$83,133.48	
9	Predicted Combined Rate, May 1, 2004	May 1, 2004	\$43,288.52	\$58,763.11	\$73,114.23	
10	Predicted Combined Rate, June 1, 2004 (Rider G set to \$0/kW.h)	May 1, 2004	\$47,283.08	\$62,591.23	\$77,899.38	
<b>August 1, 2005</b>						
11	Forecast Energy Rates, Aug 1, 2005	Aug 1, 2005	\$46,434.81	\$61,911.54	\$77,388.27	
12	+RRO Deferral (5 month recovery - August 2005 - December 2005)	Aug 1, 2005	\$0.00	\$0.00	\$0.00	
13	2005 Energy Related Charge	Aug 1, 2005	\$46,434.81	\$61,911.54	\$77,388.27	
	Row 11 + Row 12					
14	AE Interim DT Base Rates (2004 Proposed Final Rates)	Aug 1, 2005	\$9,045.17	\$11,752.37	\$14,459.57	
15	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Aug 1, 2005	\$1,327.14	\$1,769.52	\$2,211.90	
16	Net DT Charges	Aug 1, 2005	\$10,372.31	\$13,521.89	\$16,671.47	
	Row 14+ Row 15					
17	Predicted Combined Rate, August 1, 2005	Aug 1, 2005	\$56,807.12	\$75,433.43	\$94,059.74	
	Row 13 + Row 16					
<b>January 1, 2006</b>						
18	Forecast Energy Rates, Jan 1, 2006	Jan 1, 2006	\$46,434.81	\$61,911.54	\$77,388.27	
19	+No RRO Deferral	Jan 1, 2006	\$0.00	\$0.00	\$0.00	
20	2005 Energy Related Charge	Jan 1, 2006	\$46,434.81	\$61,911.54	\$77,388.27	
	Row 18 + Row 19					
21	AE Interim DT Base Rates (Scaled 2004 Final Rates)	Jan 1, 2006	\$12,725.19	\$16,653.39	\$20,581.59	
22	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Jan 1, 2006	-\$657.00	-\$876.00	-\$1,095.00	
23	Net DT Charges	Jan 1, 2006	\$12,068.19	\$15,777.39	\$19,486.59	
	Row 21 + Row 22					
24	Predicted Combined Rate, January 1, 2006	Jan 1, 2006	\$58,503.00	\$77,688.93	\$96,874.86	
	Row 20 + Row 23					
<b>Comparisons</b>						
	Combined Rate (Jan 2002- Jul 2002)	Row 5 vs Row 4	difference %	\$5,643.63 14%	\$7,524.84 14%	\$9,406.05 14%
	Combined Rate (Jul 2002- Jan 2003)	Row 6 vs Row 5	difference %	\$27,441.58 59%	\$36,588.77 59%	\$45,735.96 60%
	Combined Rate (Jan 2003- Dec 2003)	Row 7 vs Row 6	difference %	-\$33,075.35 -45%	-\$44,100.47 -45%	-\$55,125.59 -45%
	Combined Rate (Dec 2003- Jan 2004)	Row 8 vs Row 7	difference %	\$9,432.55 23%	\$12,576.73 23%	\$15,720.92 23%
	Combined Rate (Jan 2004- May 2004)	Row 9 vs Row 8	difference %	-\$7,135.02 -14%	-\$8,015.40 -12%	-\$10,019.25 -12%
	Combined Rate (May 2004- Aug 2005)	Row 17 vs Row 9	difference %	\$13,518.60 31%	\$16,670.32 28%	\$20,945.51 29%
	Combined Rate (Jun 2005- Aug 2005)	Row 17 vs Row 10	difference %	\$9,524.04 20%	\$12,842.20 21%	\$16,160.36 21%
	Combined Rate (Aug 2005- Jan 2006)	Row 24 vs Row 17	difference %	\$1,695.88 3%	\$2,255.50 3%	\$2,815.12 3%

**Schedule B.6 - Example Rate Rider Effects: Small Oilfield Class - RRO Eligible** GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge			Small Oilfield Class Consumption Levels Cost per Customer (\$/month)			
			6570 kWh per month Demand 15 kW	Typical 8760 kWh per month Demand 20 kW	10950 kWh per month Demand 25 kW	
Row	Rate Component	Effective Date				
1	Dec. 1999 Rate	1999	\$383.64	\$511.52	\$639.40	
2	Dec 2000 Rate	2000	\$414.19	\$552.25	\$690.31	
3	New Combined Rate (AB Government Rebate Included), July 1 - Dec. 31, 2001	July 1 - Dec. 31, 2001	\$753.67	\$1,000.51	\$1,247.35	
4	Combined Rate, Jan. 1, 2002	Jan. 1, 2002	\$524.06	\$694.17	\$864.28	
5	Combined Rate, July 1, 2002	Jul 1, 2002	\$309.16	\$407.63	\$506.11	
6	Combined Rate, January 1, 2003	Jan 1, 2003	\$867.99	\$1,152.74	\$1,437.49	
7	Predicted Combined Rate, December 1, 2003	Dec 1, 2003	\$508.32	\$654.52	\$814.71	
8	Predicted Combined Rate, January 1, 2004	Jan 1, 2004	\$611.98	\$811.40	\$1,010.81	
9	Predicted Combined Rate, May 1, 2004	May 1, 2004	\$524.41	\$694.63	\$864.85	
10	Predicted Combined Rate, June 1, 2004 (Rider G set to \$0/kW.h)	May 1, 2004	\$586.89	\$777.94	\$968.98	
<b>August 1, 2005</b>						
11	Forecast Energy Rates, Aug 1, 2005	Aug 1, 2005	\$490.48	\$651.88	\$813.29	
12	+RRO Deferral (5 month recovery - August 2005 - December 2005)	Aug 1, 2005	-\$160.70	-\$214.27	-\$267.84	
13	2005 Energy Related Charge	Aug 1, 2005	\$329.78	\$437.61	\$545.45	
	Row 11 + Row 12					
14	AE Interim DT Base Rates (2004 Proposed Final Rates)	Aug 1, 2005	\$215.38	\$280.05	\$344.72	
15	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Aug 1, 2005	\$22.34	\$29.78	\$37.23	
16	Net DT Charges	Aug 1, 2005	\$237.71	\$309.83	\$381.95	
	Row 14+ Row 15					
17	Predicted Combined Rate, August 1, 2005	Aug 1, 2005	\$567.49	\$747.44	\$927.40	
	Row 13 + Row 16					
<b>January 1, 2006</b>						
18	Forecast Energy Rates, Jan 1, 2006	Jan 1, 2006	\$490.48	\$651.88	\$813.29	
19	+No RRO Deferral	Jan 1, 2006	\$0.00	\$0.00	\$0.00	
20	2005 Energy Related Charge	Jan 1, 2006	\$490.48	\$651.88	\$813.29	
	Row 18 + Row 19					
21	AE Interim DT Base Rates (Scaled 2004 Final Rates)	Jan 1, 2006	\$254.76	\$332.19	\$409.61	
22	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Jan 1, 2006	-\$6.57	-\$8.76	-\$10.95	
23	Net DT Charges	Jan 1, 2006	\$248.19	\$323.43	\$398.66	
	Row 21 + Row 22					
24	Predicted Combined Rate, January 1, 2006	Jan 1, 2006	\$738.67	\$975.31	\$1,211.95	
	Row 20 + Row 23					
<b>Comparisons</b>						
	Combined Rate (Jan 2002- Jul 2002)	Row 5 vs Row 4	difference %	-\$214.90 -41%	-\$286.54 -41%	-\$358.17 -41%
	Combined Rate (Jul 2002- Jan 2003)	Row 6 vs Row 5	difference %	\$558.83 181%	\$745.11 183%	\$931.39 184%
	Combined Rate (Jan 2003- Dec 2003)	Row 7 vs Row 6	difference %	-\$359.67 -41%	-\$498.23 -43%	-\$622.78 -43%
	Combined Rate (Dec 2003- Jan 2004)	Row 8 vs Row 7	difference %	\$103.67 20%	\$156.88 24%	\$196.10 24%
	Combined Rate (Jan 2004- May 2004)	Row 9 vs Row 8	difference %	-\$87.58 -14%	-\$116.77 -14%	-\$145.96 -14%
	Combined Rate (May 2004- Aug 2005)	Row 17 vs Row 9	difference %	\$43.09 8%	\$52.82 8%	\$62.55 7%
	Combined Rate (Jun 2005- Aug 2005)	Row 17 vs Row 10	difference %	-\$19.40 -3%	-\$30.49 -4%	-\$41.59 -4%
	Combined Rate (Aug 2005- Jan 2006)	Row 24 vs Row 17	difference %	\$171.18 23%	\$227.86 23%	\$284.55 23%

**Schedule B.7 - Example Rate Rider Effects: Small Oilfield Class - Not RRO Eligible** GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge			Small Oilfield Class Consumption Levels Cost per Customer (\$/month)			
			6570 kWh per month Demand 15 kW	Typical 8760 kWh per month Demand 20 kW	10950 kWh per month Demand 25 kW	
Row	Rate Component	Effective Date				
1	Dec. 1999 Rate	1999	\$383.64	\$511.52	\$639.40	
2	Dec 2000 Rate	2000	\$414.19	\$552.25	\$690.31	
3	New Combined Rate (AB Government Rebate Included), July 1 - Dec. 31, 2001	July 1 - Dec. 31, 2001	\$753.67	\$1,000.51	\$1,247.35	
4	Combined Rate, Jan. 1, 2002	Jan. 1, 2002	\$524.06	\$694.17	\$864.28	
5	Combined Rate, July 1, 2002	Jul 1, 2002	\$610.79	\$809.80	\$1,008.82	
6	Combined Rate, January 1, 2003	Jan 1, 2003	\$867.99	\$1,152.74	\$1,437.49	
7	Predicted Combined Rate, December 1, 2003	Dec 1, 2003	\$525.13	\$695.60	\$866.06	
8	Predicted Combined Rate, January 1, 2004	Jan 1, 2004	\$611.98	\$811.40	\$1,010.81	
9	Predicted Combined Rate, May 1, 2004	May 1, 2004	\$524.41	\$694.63	\$864.85	
10	Predicted Combined Rate, June 1, 2004 (Rider G set to \$0/kW.h)	May 1, 2004	\$586.89	\$777.94	\$968.98	
<b>August 1, 2005</b>						
11	Forecast Energy Rates, Aug 1, 2005	Aug 1, 2005	\$490.48	\$651.88	\$813.29	
12	+RRO Deferral (5 month recovery - August 2005 - December 2005)	Aug 1, 2005	\$0.00	\$0.00	\$0.00	
13	2005 Energy Related Charge	Aug 1, 2005	\$490.48	\$651.88	\$813.29	
	Row 11 + Row 12					
14	AE Interim DT Base Rates (2004 Proposed Final Rates)	Aug 1, 2005	\$215.38	\$280.05	\$344.72	
15	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Aug 1, 2005	\$22.34	\$29.78	\$37.23	
16	Net DT Charges	Aug 1, 2005	\$237.71	\$309.83	\$381.95	
	Row 14+ Row 15					
17	Predicted Combined Rate, August 1, 2005	Aug 1, 2005	\$728.19	\$961.71	\$1,195.24	
	Row 13 + Row 16					
<b>January 1, 2006</b>						
18	Forecast Energy Rates, Jan 1, 2006	Jan 1, 2006	\$490.48	\$651.88	\$813.29	
19	+No RRO Deferral	Jan 1, 2006	\$0.00	\$0.00	\$0.00	
20	2005 Energy Related Charge	Jan 1, 2006	\$490.48	\$651.88	\$813.29	
	Row 18 + Row 19					
21	AE Interim DT Base Rates (Scaled 2004 Final Rates)	Jan 1, 2006	\$254.76	\$332.19	\$409.61	
22	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Jan 1, 2006	-\$6.57	-\$8.76	-\$10.95	
23	Net DT Charges	Jan 1, 2006	\$248.19	\$323.43	\$398.66	
	Row 21 + Row 22					
24	Predicted Combined Rate, January 1, 2006	Jan 1, 2006	\$738.67	\$975.31	\$1,211.95	
	Row 20 + Row 23					
<b>Comparisons</b>						
	Combined Rate (Jan 2002- Jul 2002)	Row 5 vs Row 4	difference %	\$86.72 17%	\$115.63 17%	\$144.54 17%
	Combined Rate (Jul 2002- Jan 2003)	Row 6 vs Row 5	difference %	\$257.20 42%	\$342.94 42%	\$428.67 42%
	Combined Rate (Jan 2003- Dec 2003)	Row 7 vs Row 6	difference %	-\$342.86 -39%	-\$457.14 -40%	-\$571.43 -40%
	Combined Rate (Dec 2003- Jan 2004)	Row 8 vs Row 7	difference %	\$86.85 17%	\$115.80 17%	\$144.75 17%
	Combined Rate (Jan 2004- May 2004)	Row 9 vs Row 8	difference %	-\$87.58 -14%	-\$116.77 -14%	-\$145.96 -14%
	Combined Rate (May 2004- Aug 2005)	Row 17 vs Row 9	difference %	\$203.79 39%	\$267.09 38%	\$330.39 38%
	Combined Rate (Jun 2005- Aug 2005)	Row 17 vs Row 10	difference %	\$141.31 24%	\$183.78 24%	\$226.25 24%
	Combined Rate (Aug 2005- Jan 2006)	Row 24 vs Row 17	difference %	\$10.48 1%	\$13.60 1%	\$16.71 1%

**Schedule B.8 - Example Rate Rider Effects: REA Farm Service Class (Pooled) - RRO Eligible** GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge			REA Farm Service Class Consumption Levels Cost per Customer (\$/month)			
			755 kWh per month 7.5 kVA	Typical 1255 kWh per month 7.5 kVA	1755 kWh per month 7.5 kVA	
Row	Rate Component	Effective Date				
1	Dec. 1999 Rate	1999	\$62.68	\$87.81	\$112.94	
2	Dec 2000 Rate	2000	\$58.50	\$78.26	\$98.01	
3	New Combined Rate (AB Government Rebate Included), July 1 - Dec. 31, 2001	July 1 - Dec. 31, 2001	\$59.88	\$105.41	\$150.94	
4	Combined Rate, Jan. 1, 2002	Jan. 1, 2002	\$72.60	\$99.25	\$125.90	
5	Combined Rate, July 1, 2002	Jul 1, 2002	\$74.85	\$102.99	\$131.13	
6	Combined Rate, January 1, 2003	Jan 1, 2003	\$77.04	\$106.63	\$136.22	
7	Predicted Combined Rate, December 1, 2003	Dec 1, 2003	\$79.56	\$110.82	\$142.08	
8	Predicted Combined Rate, January 1, 2004	Jan 1, 2004	\$85.06	\$119.96	\$154.87	
9	Predicted Combined Rate, May 1, 2004	May 1, 2004	\$76.62	\$105.93	\$135.24	
10	Predicted Combined Rate, June 1, 2004 (Rider G set to \$0/kWh)	May 1, 2004	\$80.59	\$112.53	\$144.47	
<b>August 1, 2005</b>						
11	Forecast Energy Rates, Aug 1, 2005	Aug 1, 2005	\$61.91	\$98.76	\$135.61	
12	+RRO Deferral (5 month recovery - August 2005 - December 2005)	Aug 1, 2005	\$6.02	\$10.01	\$14.00	
13	2005 Energy Related Charge	Aug 1, 2005	\$67.94	\$108.78	\$149.62	
	Row 11 + Row 12					
14	AE Interim DT Base Rates (2004 Proposed Final Rates)	Aug 1, 2005	\$34.14	\$36.04	\$37.94	
15	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Aug 1, 2005	\$0.97	\$1.62	\$2.26	
16	Net DT Charges	Aug 1, 2005	\$35.11	\$37.66	\$40.20	
	Row 14 + Row 15					
17	Predicted Combined Rate, August 1, 2005	Aug 1, 2005	\$103.05	\$146.44	\$189.82	
	Row 13 + Row 16					
<b>January 1, 2006</b>						
18	Forecast Energy Rates, Jan 1, 2006	Jan 1, 2006	\$61.91	\$98.76	\$135.61	
19	+No RRO Deferral	Jan 1, 2006	\$0.00	\$0.00	\$0.00	
20	2005 Energy Related Charge	Jan 1, 2006	\$61.91	\$98.76	\$135.61	
	Row 18 + Row 19					
21	AE Interim DT Base Rates (Scaled 2004 Final Rates)	Jan 1, 2006	\$45.19	\$47.59	\$49.99	
22	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Jan 1, 2006	-\$0.76	-\$1.26	-\$1.76	
23	Net DT Charges	Jan 1, 2006	\$44.44	\$46.34	\$48.24	
	Row 21 + Row 22					
24	Predicted Combined Rate, January 1, 2006	Jan 1, 2006	\$106.35	\$145.10	\$183.85	
	Row 20 + Row 23					
<b>Comparisons</b>						
	Combined Rate (Jan 2002- Jul 2002)	Row 5 vs Row 4	difference %	\$2.25 3%	\$3.74 4%	\$5.23 4%
	Combined Rate (Jul 2002- Jan 2003)	Row 6 vs Row 5	difference %	\$2.19 3%	\$3.64 4%	\$5.09 4%
	Combined Rate (Jan 2003- Dec 2003)	Row 7 vs Row 6	difference %	\$2.52 3%	\$4.19 4%	\$5.86 4%
	Combined Rate (Dec 2003- Jan 2004)	Row 8 vs Row 7	difference %	\$5.50 7%	\$9.14 8%	\$12.79 9%
	Combined Rate (Jan 2004- May 2004)	Row 9 vs Row 8	difference %	-\$8.44 -10%	-\$14.04 -12%	-\$19.63 -13%
	Combined Rate (May 2004- Aug 2005)	Row 17 vs Row 9	difference %	\$26.43 35%	\$40.51 38%	\$54.59 40%
	Combined Rate (Jun 2005- Aug 2005)	Row 17 vs Row 10	difference %	\$22.46 28%	\$33.91 30%	\$45.35 31%
	Combined Rate (Aug 2005- Jan 2006)	Row 24 vs Row 17	difference %	\$3.30 3%	-\$1.33 -1%	-\$5.97 -3%

**Schedule B.9 - Example Rate Rider Effects: Farm Service Class - RRO Eligible** GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge			Farm Service Class Consumption Levels Cost per Customer (\$/month)			
			755 kWh per month 7.5 kVA	Typical 1255 kWh per month 7.5 kVA	1755 kWh per month 7.5 kVA	
Row	Rate Component	Effective Date				
1	Dec. 1999 Rate	1999	\$83.32	\$108.45	\$133.57	
2	Dec 2000 Rate	2000	\$96.04	\$123.84	\$151.65	
3	New Combined Rate (AB Government Rebate Included), July 1 - Dec. 31, 2001	July 1 - Dec. 31, 2001	\$62.35	\$101.33	\$140.30	
4	Combined Rate, Jan. 1, 2002	Jan. 1, 2002	\$88.06	\$116.31	\$144.56	
5	Combined Rate, July 1, 2002	Jul 1, 2002	\$84.23	\$109.94	\$135.65	
6	Combined Rate, January 1, 2003	Jan 1, 2003	\$92.74	\$124.09	\$155.44	
7	Predicted Combined Rate, December 1, 2003	Dec 1, 2003	\$95.02	\$127.88	\$160.74	
8	Predicted Combined Rate, January 1, 2004	Jan 1, 2004	\$100.52	\$137.03	\$173.53	
9	Predicted Combined Rate, May 1, 2004	May 1, 2004	\$89.69	\$119.02	\$148.35	
10	Predicted Combined Rate, June 1, 2004 (Rider G set to \$0/kW.h)	May 1, 2004	\$96.05	\$129.59	\$163.13	
<b>August 1, 2005</b>						
11	Forecast Energy Rates, Aug 1, 2005	Aug 1, 2005	\$61.91	\$99.76	\$137.61	
12	+RRO Deferral (5 month recovery - August 2005 - December 2005)	Aug 1, 2005	\$6.02	\$10.01	\$14.00	
13	2005 Energy Related Charge	Aug 1, 2005	\$67.94	\$109.78	\$151.62	
14	AE Interim DT Base Rates (2004 Proposed Final Rates)	Aug 1, 2005	\$50.64	\$54.94	\$59.24	
15	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Aug 1, 2005	\$3.09	\$5.13	\$7.18	
16	Net DT Charges	Aug 1, 2005	\$53.73	\$60.07	\$66.42	
17	Predicted Combined Rate, August 1, 2005	Aug 1, 2005	\$121.66	\$169.85	\$218.03	
<b>January 1, 2006</b>						
18	Forecast Energy Rates, Jan 1, 2006	Jan 1, 2006	\$61.91	\$99.76	\$137.61	
19	+No RRO Deferral	Jan 1, 2006	\$0.00	\$0.00	\$0.00	
20	2005 Energy Related Charge	Jan 1, 2006	\$61.91	\$99.76	\$137.61	
21	AE Interim DT Base Rates (Scaled 2004 Final Rates)	Jan 1, 2006	\$62.56	\$67.51	\$72.46	
22	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Jan 1, 2006	-\$0.76	-\$1.26	-\$1.76	
23	Net DT Charges	Jan 1, 2006	\$61.80	\$66.25	\$70.70	
24	Predicted Combined Rate, January 1, 2006	Jan 1, 2006	\$123.71	\$166.01	\$208.31	
<b>Comparisons</b>						
	Combined Rate (Jan 2002- Jul 2002)	Row 5 vs Row 4	difference %	-\$3.84 -4%	-\$6.38 -6%	-\$8.92 -7%
	Combined Rate (Jul 2002- Jan 2003)	Row 6 vs Row 5	difference %	\$8.52 10%	\$14.16 13%	\$19.80 15%
	Combined Rate (Jan 2003- Dec 2003)	Row 7 vs Row 6	difference %	\$2.28 3%	\$3.79 3%	\$5.30 4%
	Combined Rate (Dec 2003- Jan 2004)	Row 8 vs Row 7	difference %	\$5.50 6%	\$9.14 7%	\$12.79 8%
	Combined Rate (Jan 2004- May 2004)	Row 9 vs Row 8	difference %	-\$10.83 -11%	-\$18.00 -13%	-\$25.18 -15%
	Combined Rate (May 2004- Aug 2005)	Row 17 vs Row 9	difference %	\$31.97 36%	\$50.83 43%	\$69.68 47%
	Combined Rate (Jun 2005- Aug 2005)	Row 17 vs Row 10	difference %	\$25.61 27%	\$40.26 31%	\$54.91 34%
	Combined Rate (Aug 2005- Jan 2006)	Row 24 vs Row 17	difference %	\$2.05 2%	-\$3.83 -2%	-\$9.72 -5%

**Schedule B.10 - Example Rate Rider Effects: Street Light Service Class D61 Option A** GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge			Street Light Service Class Consumption Levels Cost per Customer (\$/month)			
			1 Fixture Demand 100 watts	1 Fixture Demand 250 watts	1 Fixture Demand 400 watts	
Row	Rate Component	Effective Date				
1	Dec. 1999 Rate	1999	\$9.29	\$13.97	\$18.64	
2	Dec 2000 Rate	2000	\$11.36	\$16.22	\$21.08	
3	New Combined Rate (AB Government Rebate Included), July 1 - Dec. 31, 2001	July 1 - Dec. 31, 2001	\$9.25	\$14.52	\$19.71	
4	Combined Rate, Jan. 1, 2002	Jan. 1, 2002	\$8.24	\$11.54	\$14.79	
5	Combined Rate, July 1, 2002	Jul 1, 2002	\$6.48	\$7.11	\$7.74	
6	Combined Rate, January 1, 2003	Jan 1, 2003	\$10.32	\$16.77	\$23.11	
7	Predicted Combined Rate, December 1, 2003	Dec 1, 2003	\$9.46	\$14.59	\$19.65	
8	Predicted Combined Rate, January 1, 2004	Jan 1, 2004	\$8.70	\$12.70	\$16.63	
9	Predicted Combined Rate, May 1, 2004	May 1, 2004	\$7.20	\$8.91	\$10.60	
10	Predicted Combined Rate, June 1, 2004 (Rider G set to \$0/kW.h)	May 1, 2004	\$8.20	\$11.42	\$14.60	
<b>August 1, 2005</b>						
11	Forecast Energy Rates, Aug 1, 2005	Aug 1, 2005	\$5.92	\$9.02	\$12.06	
12	+RRO Deferral (5 month recovery - August 2005 - December 2005)	Aug 1, 2005	-\$1.01	-\$2.54	-\$4.04	
13	2005 Energy Related Charge	Aug 1, 2005	\$4.91	\$6.48	\$8.02	
Row 11 + Row 12						
14	AE Interim DT Base Rates (2004 Proposed Final Rates)	Aug 1, 2005	\$6.88	\$7.84	\$8.80	
15	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Aug 1, 2005	\$0.54	\$1.36	\$2.17	
16	Net DT Charges	Aug 1, 2005	\$7.42	\$9.20	\$10.97	
Row 14+ Row 15						
17	Predicted Combined Rate, August 1, 2005	Aug 1, 2005	\$12.33	\$15.68	\$18.99	
Row 13 + Row 16						
<b>January 1, 2006</b>						
18	Forecast Energy Rates, Jan 1, 2006	Jan 1, 2006	\$5.92	\$9.02	\$12.06	
19	+No RRO Deferral	Jan 1, 2006	\$0.00	\$0.00	\$0.00	
20	2005 Energy Related Charge	Jan 1, 2006	\$5.92	\$9.02	\$12.06	
Row 18 + Row 19						
21	AE Interim DT Base Rates (Scaled 2004 Final Rates)	Jan 1, 2006	\$7.55	\$9.03	\$10.52	
22	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Jan 1, 2006	-\$0.04	-\$0.09	-\$0.14	
23	Net DT Charges	Jan 1, 2006	\$7.51	\$8.95	\$10.38	
Row 21 + Row 22						
24	Predicted Combined Rate, January 1, 2006	Jan 1, 2006	\$13.43	\$17.96	\$22.44	
Row 20 + Row 23						
<b>Comparisons</b>						
	Combined Rate (Jan 2002- Jul 2002)	Row 5 vs Row 4	difference %	-\$1.76 -21%	-\$4.43 -38%	-\$7.05 -48%
	Combined Rate (Jul 2002- Jan 2003)	Row 6 vs Row 5	difference %	\$3.84 59%	\$9.66 136%	\$15.37 199%
	Combined Rate (Jan 2003- Dec 2003)	Row 7 vs Row 6	difference %	-\$0.87 -8%	-\$2.18 -13%	-\$3.46 -15%
	Combined Rate (Dec 2003- Jan 2004)	Row 8 vs Row 7	difference %	-\$0.75 -8%	-\$1.90 -13%	-\$3.02 -15%
	Combined Rate (Jan 2004- May 2004)	Row 9 vs Row 8	difference %	-\$1.51 -17%	-\$3.79 -30%	-\$6.03 -36%
	Combined Rate (May 2004- Aug 2005)	Row 17 vs Row 9	difference %	\$5.13 71%	\$6.78 76%	\$8.39 79%
	Combined Rate (Jun 2005- Aug 2005)	Row 17 vs Row 10	difference %	\$4.13 50%	\$4.26 37%	\$4.39 30%
	Combined Rate (Aug 2005- Jan 2006)	Row 24 vs Row 17	difference %	\$1.10 8%	\$2.28 13%	\$3.45 15%

**Schedule B.11 - Example Rate Rider Effects: Irrigation Pumping Service** GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge			Irrigation Pumping Service Class			
			Consumption Levels Cost per Customer (\$/month)			
Row	Rate Component	Effective Date	8760 kWh per month Demand 30 kW	Typical 11680 kWh per month Demand 40 kW	14600 kWh per month Demand 50 kW	
1	Dec. 1999 Rate	1999	\$1,177.79	\$1,570.39	\$1,962.98	
2	Dec 2000 Rate	2000	\$1,259.73	\$1,679.64	\$2,099.55	
3	New Combined Rate (AB Government Rebate Included), July 1 - Dec. 31, 2001	July 1 - Dec. 31, 2001	\$1,304.55	\$1,732.12	\$2,153.85	
4	Combined Rate, Jan. 1, 2002	Jan. 1, 2002	\$1,032.82	\$1,369.45	\$1,706.09	
5	Combined Rate, July 1, 2002	Jul 1, 2002	\$536.74	\$708.02	\$879.29	
6	Combined Rate, January 1, 2003	Jan 1, 2003	\$1,373.40	\$1,823.56	\$2,273.72	
7	Predicted Combined Rate, December 1, 2003	Dec 1, 2003	\$1,077.41	\$1,428.91	\$1,780.40	
8	Predicted Combined Rate, January 1, 2004	Jan 1, 2004	\$1,170.21	\$1,552.64	\$1,935.08	
9	Predicted Combined Rate, May 1, 2004	May 1, 2004	\$1,189.94	\$1,578.95	\$1,967.96	
10	Predicted Combined Rate, June 1, 2004 (Rider G set to \$0/kW.h)	May 1, 2004	\$1,152.44	\$1,528.96	\$1,905.47	
<b>August 1, 2005</b>						
11	Forecast Energy Rates, Aug 1, 2005	Aug 1, 2005	\$632.26	\$840.92	\$1,049.59	
12	+RRO Deferral (5 month recovery - August 2005 - December 2005)	Aug 1, 2005	\$391.13	\$521.51	\$651.89	
13	2005 Energy Related Charge	Aug 1, 2005	\$1,023.39	\$1,362.43	\$1,701.48	
	Row 11 + Row 12					
14	AE Interim DT Base Rates (2004 Proposed Final Rates)	Aug 1, 2005	\$651.29	\$860.66	\$1,070.03	
15	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Aug 1, 2005	-\$114.58	-\$152.77	-\$190.97	
16	Net DT Charges	Aug 1, 2005	\$536.71	\$707.88	\$879.06	
	Row 14+ Row 15					
17	Predicted Combined Rate, August 1, 2005	Aug 1, 2005	\$1,560.10	\$2,070.32	\$2,580.54	
	Row 13 + Row 16					
<b>January 1, 2006</b>						
18	Forecast Energy Rates, Jan 1, 2006	Jan 1, 2006	\$632.26	\$840.92	\$1,049.59	
19	+No RRO Deferral	Jan 1, 2006	\$0.00	\$0.00	\$0.00	
20	2005 Energy Related Charge	Jan 1, 2006	\$632.26	\$840.92	\$1,049.59	
	Row 18 + Row 19					
21	AE Interim DT Base Rates (Scaled 2004 Final Rates)	Jan 1, 2006	\$838.74	\$1,110.09	\$1,381.43	
22	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Jan 1, 2006	-\$8.76	-\$11.68	-\$14.60	
23	Net DT Charges	Jan 1, 2006	\$829.98	\$1,098.41	\$1,366.83	
	Row 21 + Row 22					
24	Predicted Combined Rate, January 1, 2006	Jan 1, 2006	\$1,462.24	\$1,939.33	\$2,416.41	
	Row 20 + Row 23					
<b>Comparisons</b>						
	Combined Rate (Jan 2002- Jul 2002)	Row 5 vs Row 4	difference %	-\$496.08 -48%	-\$661.44 -48%	-\$826.80 -48%
	Combined Rate (Jul 2002- Jan 2003)	Row 6 vs Row 5	difference %	\$836.66 156%	\$1,115.55 158%	\$1,394.43 159%
	Combined Rate (Jan 2003- Dec 2003)	Row 7 vs Row 6	difference %	-\$295.99 -22%	-\$394.66 -22%	-\$493.32 -22%
	Combined Rate (Dec 2003- Jan 2004)	Row 8 vs Row 7	difference %	\$92.80 9%	\$123.74 9%	\$154.67 9%
	Combined Rate (Jan 2004- May 2004)	Row 9 vs Row 8	difference %	\$19.73 2%	\$26.30 2%	\$32.88 2%
	Combined Rate (May 2004- Aug 2005)	Row 17 vs Row 9	difference %	\$370.16 31%	\$491.37 31%	\$612.58 31%
	Combined Rate (Jun 2005- Aug 2005)	Row 17 vs Row 10	difference %	\$407.65 35%	\$541.36 35%	\$675.07 35%
	Combined Rate (Aug 2005- Jan 2006)	Row 24 vs Row 17	difference %	-\$97.86 -7%	-\$130.99 -7%	-\$164.13 -7%

**Schedule B.12 - Example Rate Rider Effects: REA Irrigation Pumping Service** GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge			REA Irrigation Pumping Service Class			
			Consumption Levels Cost per Customer (\$/month)			
Row	Rate Component	Effective Date	8760 kWh per month Demand 30 kW	Typical 11680 kWh per month Demand 40 kW	14600 kWh per month Demand 50 kW	
1	Dec. 1999 Rate	1999	\$630.68	\$840.90	\$1,051.13	
2	Dec 2000 Rate	2000	\$843.01	\$1,124.02	\$1,405.02	
3	New Combined Rate (AB Government Rebate Included), July 1 - Dec. 31, 2001	July 1 - Dec. 31, 2001	\$1,039.95	\$1,379.32	\$1,718.69	
4	Combined Rate, Jan. 1, 2002	Jan. 1, 2002	\$754.12	\$997.85	\$1,241.59	
5	Combined Rate, July 1, 2002	Jul 1, 2002	\$650.93	\$860.26	\$1,069.60	
6	Combined Rate, January 1, 2003	Jan 1, 2003	\$1,094.70	\$1,451.96	\$1,809.22	
7	Predicted Combined Rate, December 1, 2003	Dec 1, 2003	\$798.71	\$1,057.31	\$1,315.90	
8	Predicted Combined Rate, January 1, 2004	Jan 1, 2004	\$891.51	\$1,181.04	\$1,470.58	
9	Predicted Combined Rate, May 1, 2004	May 1, 2004	\$725.09	\$959.15	\$1,193.21	
10	Predicted Combined Rate, June 1, 2004 (Rider G set to \$0/kWh)	May 1, 2004	\$873.74	\$1,157.36	\$1,440.97	
<b>August 1, 2005</b>						
11	Forecast Energy Rates, Aug 1, 2005	Aug 1, 2005	\$632.26	\$840.92	\$1,049.59	
12	+RRO Deferral (5 month recovery - August 2005 - December 2005)	Aug 1, 2005	\$391.13	\$521.51	\$651.89	
13	2005 Energy Related Charge	Aug 1, 2005	\$1,023.39	\$1,362.43	\$1,701.48	
	Row 11 + Row 12					
14	AE Interim DT Base Rates (2004 Proposed Final Rates)	Aug 1, 2005	\$298.49	\$390.26	\$482.03	
15	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Aug 1, 2005	-\$114.58	-\$152.77	-\$190.97	
16	Net DT Charges	Aug 1, 2005	\$183.91	\$237.48	\$291.06	
	Row 14+ Row 15					
17	Predicted Combined Rate, August 1, 2005	Aug 1, 2005	\$1,207.30	\$1,599.92	\$1,992.54	
	Row 13 + Row 16					
<b>January 1, 2006</b>						
18	Forecast Energy Rates, Jan 1, 2006	Jan 1, 2006	\$632.26	\$840.92	\$1,049.59	
19	+No RRO Deferral	Jan 1, 2006	\$0.00	\$0.00	\$0.00	
20	2005 Energy Related Charge	Jan 1, 2006	\$632.26	\$840.92	\$1,049.59	
	Row 18 + Row 19					
21	AE Interim DT Base Rates (Scaled 2004 Final Rates)	Jan 1, 2006	\$463.17	\$609.33	\$755.48	
22	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Jan 1, 2006	-\$8.76	-\$11.68	-\$14.60	
23	Net DT Charges	Jan 1, 2006	\$454.41	\$597.65	\$740.88	
	Row 21 + Row 22					
24	Predicted Combined Rate, January 1, 2006	Jan 1, 2006	\$1,086.67	\$1,438.57	\$1,790.46	
	Row 20 + Row 23					
<b>Comparisons</b>						
	Combined Rate (Jan 2002- Jul 2002)	Row 5 vs Row 4	difference %	-\$103.19 -14%	-\$137.59 -14%	-\$171.99 -14%
	Combined Rate (Jul 2002- Jan 2003)	Row 6 vs Row 5	difference %	\$443.77 68%	\$591.70 69%	\$739.62 69%
	Combined Rate (Jan 2003- Dec 2003)	Row 7 vs Row 6	difference %	-\$295.99 -27%	-\$394.66 -27%	-\$493.32 -27%
	Combined Rate (Dec 2003- Jan 2004)	Row 8 vs Row 7	difference %	\$92.80 12%	\$123.74 12%	\$154.67 12%
	Combined Rate (Jan 2004- May 2004)	Row 9 vs Row 8	difference %	-\$166.42 -19%	-\$221.90 -19%	-\$277.37 -19%
	Combined Rate (May 2004- Aug 2005)	Row 17 vs Row 9	difference %	\$482.21 67%	\$640.77 67%	\$799.33 67%
	Combined Rate (Jun 2005- Aug 2005)	Row 17 vs Row 10	difference %	\$333.55 38%	\$442.56 38%	\$551.57 38%
	Combined Rate (Aug 2005- Jan 2006)	Row 24 vs Row 17	difference %	-\$120.63 -11%	-\$161.35 -11%	-\$202.08 -11%

**Schedule B.13 - Example Rate Rider Effects: Private Lighting Service Class D63 Option A** GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge			Private Street Light Service Class Consumption Levels Cost per Customer (\$/month)			
			1 Fixture Demand 100 watts	1 Fixture Demand 250 watts	1 Fixture Demand 400 watts	
Row	Rate Component	Effective Date	Typical			
1	Dec. 1999 Rate	1999	\$8.36	\$12.59	\$16.82	
2	Dec 2000 Rate	2000	\$9.95	\$14.17	\$18.36	
3	New Combined Rate (AB Government Rebate Included), July 1 - Dec. 31, 2001	July 1 - Dec. 31, 2001	\$11.87	\$17.59	\$23.23	
4	Combined Rate, Jan. 1, 2002	Jan. 1, 2002	\$10.99	\$14.75	\$18.47	
5	Combined Rate, July 1, 2002	Jul 1, 2002	\$9.16	\$10.14	\$11.13	
6	Combined Rate, January 1, 2003	Jan 1, 2003	\$13.06	\$19.95	\$26.73	
7	Predicted Combined Rate, December 1, 2003	Dec 1, 2003	\$11.14	\$17.43	\$22.73	
8	Predicted Combined Rate, January 1, 2004	Jan 1, 2004	\$11.45	\$15.91	\$20.31	
9	Predicted Combined Rate, May 1, 2004	May 1, 2004	\$10.20	\$12.75	\$15.28	
10	Predicted Combined Rate, June 1, 2004 (Rider G set to \$0/kWh)	May 1, 2004	\$10.95	\$14.64	\$18.28	
<b>August 1, 2005</b>						
11	Forecast Energy Rates, Aug 1, 2005	Aug 1, 2005	\$5.92	\$9.02	\$12.06	
12	+RRO Deferral (5 month recovery - August 2005 - December 2005)	Aug 1, 2005	-\$1.01	-\$2.54	-\$4.04	
13	2005 Energy Related Charge	Aug 1, 2005	\$4.91	\$6.48	\$8.02	
	Row 11 + Row 12					
14	AE Interim DT Base Rates (2004 Proposed Final Rates)	Aug 1, 2005	\$9.98	\$11.05	\$12.11	
15	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Aug 1, 2005	\$0.26	\$0.66	\$1.04	
16	Net DT Charges	Aug 1, 2005	\$10.24	\$11.70	\$13.15	
	Row 14 + Row 15					
17	Predicted Combined Rate, August 1, 2005	Aug 1, 2005	\$15.15	\$18.18	\$21.17	
	Row 13 + Row 16					
<b>January 1, 2006</b>						
18	Forecast Energy Rates, Jan 1, 2006	Jan 1, 2006	\$5.92	\$9.02	\$12.06	
19	+No RRO Deferral	Jan 1, 2006	\$0.00	\$0.00	\$0.00	
20	2005 Energy Related Charge	Jan 1, 2006	\$5.92	\$9.02	\$12.06	
	Row 18 + Row 19					
21	AE Interim DT Base Rates (Scaled 2004 Final Rates)	Jan 1, 2006	\$10.81	\$12.38	\$13.96	
22	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Jan 1, 2006	-\$0.04	-\$0.09	-\$0.14	
23	Net DT Charges	Jan 1, 2006	\$10.77	\$12.29	\$13.82	
	Row 21 + Row 22					
24	Predicted Combined Rate, January 1, 2006	Jan 1, 2006	\$16.69	\$21.31	\$25.88	
	Row 20 + Row 23					
<b>Comparisons</b>						
	Combined Rate (Jan 2002- Jul 2002)	Row 5 vs Row 4	difference %	-\$1.84 -17%	-\$4.61 -31%	-\$7.34 -40%
	Combined Rate (Jul 2002- Jan 2003)	Row 6 vs Row 5	difference %	\$3.90 43%	\$9.81 97%	\$15.60 140%
	Combined Rate (Jan 2003- Dec 2003)	Row 7 vs Row 6	difference %	-\$1.92 -15%	-\$2.52 -13%	-\$4.00 -15%
	Combined Rate (Dec 2003- Jan 2004)	Row 8 vs Row 7	difference %	\$0.31 3%	-\$1.52 -9%	-\$2.42 -11%
	Combined Rate (Jan 2004- May 2004)	Row 9 vs Row 8	difference %	-\$1.26 -11%	-\$3.16 -20%	-\$5.03 -25%
	Combined Rate (May 2004- Aug 2005)	Row 17 vs Row 9	difference %	\$4.95 49%	\$5.43 43%	\$5.89 39%
	Combined Rate (Jun 2005- Aug 2005)	Row 17 vs Row 10	difference %	\$4.20 38%	\$3.54 24%	\$2.89 16%
	Combined Rate (Aug 2005- Jan 2006)	Row 24 vs Row 17	difference %	\$1.54 9%	\$3.13 15%	\$4.70 18%

**Schedule B.14 - Example Rate Rider Effects: Large General Service Transmission - Not RRO Eligible**

GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge			Large General Service Class Consumption Levels Cost per Customer (\$/month)		
			766,500 kWh per month Demand 1500 kW	Typical 1,022,000 kWh per month Demand 2000 kW	1,277,500 kWh per month Demand 2500 kW
Row	Rate Component	Effective Date			
<b>August 1, 2005</b>					
11	Forecast Energy Rates, Aug 1, 2005	Aug 1, 2005	\$54,173.18	\$72,229.36	\$90,285.55
12	+RRO Deferral (5 month recovery - August 2005 - December 2005)	Aug 1, 2005	\$0.00	\$0.00	\$0.00
13	<b>2005 Energy Related Charge</b> Row 11 + Row 12	Aug 1, 2005	\$54,173.18	\$72,229.36	\$90,285.55
14	AE Interim DT Base Rates (2004 Proposed Final Rates)	Aug 1, 2005	\$5,349.40	\$3,686.40	\$4,608.00
15	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Aug 1, 2005	-\$3,656.21	-\$4,874.94	-\$6,093.68
16	<b>Net DT Charges</b> Row 14+ Row 15	Aug 1, 2005	\$1,693.20	-\$1,188.54	-\$1,485.68
17	<b>Predicted Combined Rate, August 1, 2005</b> Row 13 + Row 16	Aug 1, 2005	\$55,866.37	\$71,040.82	\$88,799.87
<b>January 1, 2006</b>					
18	Forecast Energy Rates, Jan 1, 2006	Jan 1, 2006	\$54,173.18	\$72,229.36	\$90,285.55
19	+No RRO Deferral	Jan 1, 2006	\$0.00	\$0.00	\$0.00
20	<b>2005 Energy Related Charge</b> Row 18 + Row 19	Jan 1, 2006	\$54,173.18	\$72,229.36	\$90,285.55
21	AE Interim DT Base Rates (Scaled 2004 Final Rates)	Jan 1, 2006	\$26,789.80	\$25,428.39	\$26,624.99
22	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Jan 1, 2006	-\$766.50	-\$1,022.00	-\$1,277.50
23	<b>Net DT Charges</b> Row 21 + Row 22	Jan 1, 2006	\$26,023.30	\$24,406.39	\$25,347.49
24	<b>Predicted Combined Rate, January 1, 2006</b> Row 20 + Row 23	Jan 1, 2006	\$80,196.47	\$96,635.75	\$115,633.04

**ATCO ELECTRIC**  
**2006 Interim Rate Application**  
**Energy Rates Used in Schedules D.1 to D.14**

	Admin. Charges		Cost of Energy (\$ / kWh)
	Fixed (\$ / Month)	Variable (\$ / kWh)	
D11	6.18	0.00031	0.07475
D21	6.27	0.00031	0.07442
D31	4.62	0.00031	0.07036
T31	4.62	0.00031	0.07036
D41	6.27	0.00031	0.07087
D51	6.27	0.00031	0.07339
D56	6.27	0.00031	0.07339
D25	6.27	0.00031	0.07115
D61	3.87	0.00031	0.05821
D63	3.87	0.00031	0.05821
D26	6.27	0.00031	0.07115

Rates used are the RRO Rates as posted on Direct Energy Regulated Services website (Oct. 5/2005)  
These rates are used for the August 1, 2005 and January 1, 2006 scenarios.

Rate	Billing Determinants	Condition	Monthly Revenue Total	Change from Previous Condition	Percentage Change From Condition i	Total Yearly Rate Class Revenue (\$000)	Change from Previous Condition (\$000)	Percentage Change From Condition i	
D11 Residential	30.4 days 600 kW.h	i Current Approved Rates ii 2006 GTA	Total \$45.86			\$68,575			
			Transmission \$7.56	\$2.88	6.3%	\$11,265	\$4,320	6.3%	
			Distribution \$44.00	\$2.82	6.1%	\$65,955	\$4,326	6.3%	
		iii AESO Refiling	Total \$51.56	\$5.70	12.4%	\$77,221	\$8,646	12.6%	
			Total \$53.73	\$2.17	17.2%	\$80,232	\$3,011	17.0%	
D21 Commercial	30.4 days 7300 kW.h 20 kW	i Current Approved Rates ii 2006 GTA	Total \$218.24			\$27,275			
			Transmission \$73.78	\$31.05	14.2%	\$7,325	\$2,892	10.6%	
			Distribution \$187.88	\$17.31	7.9%	\$24,445	\$1,603	5.9%	
	Blk1 4000 3300 Blk2	iii AESO Refiling	Total \$261.66	\$43.41	19.9%	\$31,770	\$4,495	16.5%	
			Total \$264.79	\$3.14	21.3%	\$33,263	\$1,493	22.0%	
D25 Irrigation	30.4 days 1670 kW.h 40 kW	i Current Approved Rates ii 2006 GTA	Total \$122.89			\$82			
			Transmission \$32.77	\$11.13	9.1%	\$29	\$11	13.8%	
			Distribution \$108.24	\$6.98	5.7%	\$69	\$5	5.5%	
		iii AESO Refiling	Total \$141.01	\$18.11	14.7%	\$98	\$16	19.3%	
			Total \$157.75	\$16.74	28.4%	\$106	\$8	28.7%	
D26 REA Irrigation	30.4 days 1670 kW.h 40 kW	i Current Approved Rates ii 2006 GTA	Total \$55.73			\$0.227			
			Transmission \$32.77	\$11.13	20.0%	\$0.034	\$0.013	5.8%	
			Distribution \$36.37	\$2.28	4.1%	\$0.220	\$0.014	6.4%	
		iii AESO Refiling	Total \$69.14	\$13.41	24.1%	\$0.254	\$0.028	12.1%	
			Total \$86.49	\$17.35	55.2%	\$0.263	\$0.009	15.9%	
D31 Industrial	30.4 days 876,000 kW.h 2000 kW	i Current Approved Rates ii 2006 GTA	Total \$11,747.75			\$84,687			
			Transmission \$9,454.00	\$3,886.43	33.1%	\$60,782	\$25,265	29.8%	
			Distribution \$6,613.73	\$433.54	3.7%	\$52,630	\$3,460	4.1%	
		iii AESO Refiling	Total \$16,067.73	\$4,319.97	36.8%	\$113,412	\$28,724	33.9%	
			Total \$17,144.56	\$1,076.83	45.9%	\$118,299	\$4,887	39.7%	
						* excludes power factor revenue			
D41 Oilfield	30.4 days 8760 kW.h 20 kW	i Current Approved Rates ii 2006 GTA	Total \$279.91			\$19,140			
			Transmission \$87.99	\$37.31	13.3%	\$4,396	\$1,779	9.3%	
			Distribution \$245.32	\$16.08	5.7%	\$17,695	\$1,171	6.1%	
		iii AESO Refiling	Total \$333.30	\$53.39	19.1%	\$22,091	\$2,951	15.4%	
			Total \$336.06	\$2.75	20.1%	\$22,701	\$610	18.6%	
						* excludes power factor revenue			
D51 REA Pooled	30.4 days 1255 kW.h 7.5 kV.A	i Current Approved Rates ii 2006 GTA	Total \$36.02			\$3,548			
			Transmission \$15.88	\$6.16	17.1%	\$1,769	\$666	18.8%	
			Distribution \$28.13	\$1.83	5.1%	\$2,616	\$172	4.8%	
		iii AESO Refiling	Total \$44.01	\$7.99	22.2%	\$4,385	\$838	23.6%	
			Total \$48.15	\$4.14	33.7%	\$4,960	\$575	39.8%	
D56 Farm	30.4 days 1255 kW.h 7.5 kV.A	i Current Approved Rates ii 2006 GTA	Total \$54.91			\$12,652			
			Transmission \$15.88	\$6.16	11.2%	\$3,691	\$1,409	11.1%	
			Distribution \$48.31	\$3.12	5.7%	\$11,098	\$728	5.8%	
		iii AESO Refiling	Total \$64.19	\$9.28	16.9%	\$14,789	\$2,137	16.9%	
			Total \$68.24	\$4.05	24.3%	\$15,846	\$1,057	25.2%	
D61-A Street Lights	30.4 days - kW.h 250 W	i Current Approved Rates ii 2006 GTA	Total \$7.84			\$3,513			
			Transmission \$1.22	\$0.44	5.6%	\$263	\$102	2.9%	
			Distribution \$7.59	\$0.53	6.7%	\$3,587	\$235	6.7%	
		iii AESO Refiling	Total \$8.80	\$0.97	12.4%	\$3,849	\$337	9.6%	
			Total \$9.16	\$0.35	16.9%	\$3,914	\$65	11.4%	
D63-A Private Lights	30.4 days - kW.h 250 W	i Current Approved Rates ii 2006 GTA	Total \$11.04			\$682			
			Transmission \$0.76	-\$0.01	-0.1%	\$51	\$19	2.9%	
			Distribution \$10.98	\$0.71	6.5%	\$696	\$46	6.7%	
		iii AESO Refiling	Total \$11.74	\$0.70	6.3%	\$747	\$65	9.6%	
			Total \$12.55	\$0.81	13.7%	\$759	\$12	11.3%	
Totals						i	\$245,721		
						ii	\$109,185	\$36,665	14.9%
							\$185,032	\$11,831	4.8%
							\$294,217	\$48,495	19.7%
						iii	\$307,699	\$13,482	25.2%
							* includes power factor revenue		