

## Attachment 1 (DERS' September 27, 2005 Letter to EUB)

Item	Reference to CG Item	Relevant IR Responses	Application Section	DERS' Description of Item	Proposed Status/ Process
1) Response to Board Directives (a) Billing Envelope  (b) Service Quality Reporting	16. Use of DERS billing Envelope  15. Customer Service Measures Reporting	(a) CG IRs (3, 43, 44)  (b) CG IRs (1, 2)	Section 2 (page 12)	(a) DERS has provided the Billing Envelope policy and has provided the details on the pricing established for all affiliate inserts. In addition all affiliate inserts have been provided. DERS believes that it has met and fulfilled the requirements of this directive.  (b) DERS has provided all the Service Quality reports filed with the EUB in response to Directive 003 and in response to the directives given in Decision 2003-098. As displayed on these reports, no significant customer service quality issues have been identified. DERS is requesting relief from the reporting under Decision 2003-098.	(a) Completed  (b) Completed
2) Customer and Load Forecasts	17. (a) Forecast customer numbers 17. (b) Usage per customer	Board IRs (6,7,8,80) CG IRs (15,16)	Section 3 (page 22-25)	DERS' 2005-2006 forecast customer count and load forecast is appropriate and reasonable considering all revenues and the majority of costs are subject to deferral account treatment. Year end customer numbers for DRT service in 2005 is forecast to be 873,256 and in 2006 is forecast to be 882,134. The RRT year end customer numbers for 2005 is forecast to be 174,421 and 176,412.	Negotiated Settlement
3) Capital Expenditure (2004-2006)	1. (a) Review of Actual 2004 additions 1. (b) Review of forecast 2005 additions 6. Capital forecasts 8. Split of capital between gas and electric	Board IRs (9, 27, 28, 29, 30, 31, 32, 33, 34, 35, 36, 37) CG IRs (20, 21, 22, 23)	Section 4 (page 25-28), Attachment #1-3	DERS has proposed 4 capital projects to be completed in 2005 and 2006. Business cases have been provided and discussed in the relevant IRs. Total cost of the proposed capital projects is forecast to be \$924,000 in 2005 and \$3,676,800 in 2006. DERS has forecast \$2,700,000 for a gas settlement system in 2006 and has requested deferral treatment for this expenditure. Capital projects that benefit both the DRT and RRT customers have been allocated on the basis of sites because for the most part, the applied-for capital projects are performed at the service account level.	Negotiated Settlement
4) Amortization period	13. Amortization	CG IRs (39)	Section 5.3.12 (page 61)	DERS has proposed a 60 month amortization period for all capital beginning the month the asset is put in service, which is appropriate and is also consistent with the treatment of 2003-04 capital in Decision 2003-106.	Negotiated Settlement
5) Customer Care Costs	4. Customer Care Costs – 95% level 11. Customer	Board IRs (10, 12, 13, 16, 18, 38, 87) CG IRs (11, 26)	Section 5.3.3 (page 38-46), Attachment 4(a),	Decision 2005-105 does not determine 2005-2006 unit costs to derive customer care costs, therefore unit costs for 2005-2006 need to be determined. DERS utilized July 2004 to December 2004 activity assumptions to	Negotiated Settlement

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	Care volumes 9. O&M		Attachment 4(b)	determine the 2005/06 forecast activity assumptions in order to calculate the forecast customer care costs. DRT customer care costs are forecast to be \$46.3 million in 2005 and \$46.4 million in 2006. For RRT, 2005 customer care costs are forecast to be \$9.3 million and \$9.4 million in 2006. On a per customer basis, the DRT and RRT customer care costs at 100% of unit costs are less than a 0.5% increase over 2004 approved costs (90% of unit costs).	
6) Working Capital (Rate of Return)	9. O&M	Board IRs (53, 54, 73, 74, 75, 76, 79) CG IRs (17)	Section 5.3.4 (page 46-49), Appendix #1	DERS has proposed what it believes is an objective, defensible and pragmatic solution to the subject which has historically been an industry area causing considerable debate (for example the Generic Cost of Capital hearings). DERS has applied for the ATCO Electric and ATCO Gas allowed return (grossed up for statutory tax) of 9.7% and 10.2% respectively in determination of the RRT and DRT working capital. Refer to Appendix 1 of the filing and the relevant IRs.	Negotiated Settlement or Written Process
7) Working Capital (lead-lag)	9. O&M	Board IRs (52) CG IRs (38)	Attachment #5	DERS has used the same methodology in calculating the working capital ratios and has updated the revenue lag with actual 2004 billing data. The increase in the DRT revenue lag of 3.5 days is a result of the separation between the distribution and retail functions which requires additional time and billing processes. The updated RRT revenue lag resulted in minor changes of 0.4 days. The impact resulting from updating the revenue lag is approximately \$1.5 million increase in the DRT revenue requirement and \$0.015 million increase in the RRT revenue requirement. These changes must be incorporated in order to account for changes in the industry and adequately represent DERS' working capital requirements.	Negotiated Settlement
8) Credit Charges	9. O&M	Board IRs (23, 72)	Section 5.3.5 (page 49-50)	DERS has included costs related to credit support for the I-Tek MSA. Credit costs included in this application are forecast to be \$386,700 for DRT and \$69,600 for RRT in each year. Consistent with direction given by the EUB in decision 2003-106, both LOC and PCG cost have been included. DERS views these costs as prudent and allocated on 90% regulated 10% de-regulated basis.	Negotiated Settlement
9) Hearing costs and EUB Assessment	9. O&M	CG IRs (7, 28)	Section 5.3.6 (page 50-52)	DERS' forecast of \$1.0 million in hearing costs and the EUB assessment of \$0.9 million DRT and \$0.2 million for	Negotiated Settlement

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				RRT are based on a reasonable estimate of intervener and DERS legal costs and preliminary estimates from the EUB.	
10) Interest Security Deposits	9. O&M		Section 5.3.9 (page 52)	DERS has included interest costs of \$365,100 for DRT and \$48,300 for RRT related to interest paid on security deposits at an annual rate of 2.5%.	N/A –no issues have been identified
11) Bad Debt, Penalty Revenue and Revenue Offsets	9. O&M	Board IRs (18, <b>20, 21</b> ) CG IRs (27, 29)	Section 5.3.8, 5.3.9, 5.3.10 (page 52-55)	The forecast of bad debt for DRT in 2005 is \$4.895 million and \$4.949 million in 2006. DERS has forecast penalty revenue at (\$4.164) million and (\$4.210) for 2006. DRT bad debt and penalty revenue has been allocated 70% to the energy revenue requirement. The forecast of bad debt for RRT in 2005 is \$1.288 million and \$1.307 million in 2006. DERS has forecast penalty revenue at (\$1.267) million and (\$1.285) for 2006. RRT bad debt and penalty revenue has been allocated 50% to the energy revenue requirement. The 2005 and 2006 bad debt and penalty revenue estimates are based on data from May 2004 to March 2005. These estimates are reasonable given DERS' limited data set and are subject to deferral account treatment.	Negotiated Settlement
12) FTE's	Incremental FTEs	Board IRs (43, 55, 56, <b>57</b> , 58, <b>59</b> , 60, 83) CG IRs ( <b>31</b> )	Section 5.3.11 (page 55-61)	DERS has forecast for 2005, an average of 5.3 additional FTEs over 2004 actual average levels and for 2006 an additional 5.3 FTEs over 2005 average levels. These FTEs are required to support the regulated business over the test period. These increases result in a greater than anticipated workload over what was projected in the 2003/04 application. In addition, excessive overtime and additional projects, initiatives and directives required DERS to hire additional FTEs over 2004 approved levels and demonstrate the need for the additional 5.3 FTEs for each 2005 and 2006 test periods.	Negotiated Settlement
13) Staff Remuneration	1. Cost per FTE 1. (a) Salary Levels 2. Short Term incentive pay 3. Long term incentive pay 9. O&M	Board IRs (46, 47, <b>48, 49</b> , 50, 81, <b>82</b> ) CG IRs (25, <b>49</b> )	Section 5.3.2 (page 34-38), Section 5.3.11 (page 55-61), Appendix #2	Total labour costs and average salary costs for employees allocated to DERS are \$4.430 million in total costs (\$135,900 average total compensation excluding long term incentive) in 2005 and \$5.160 total labour costs (\$134,900 average total compensation excluding long term incentive) in 2006. DERS engaged Mercer to evaluate DEML's total remuneration against comparator employers. Mercer found that overall DEML's total remuneration is 3.3% below the market. In order to attract and retain talent in the Alberta labour market,	Negotiated Settlement

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				which will ultimately add value to DERS' customers, DEML must ensure that it is at least at the market rate for all aspects of compensation.	
14) Customer Education and Energy Awareness	13. Customer Education and energy Awareness costs	Board IRs (61, 62) CG IRs (32, 33, 34)	Section 5.3.13 (page 61-66)	The DRT and RRT provider is appropriately positioned to play a significant role in meeting customer education needs of understanding energy choices and how regulated rates are set. DERS' customer education and awareness budget of \$2.240 million in 2005 and \$2.283 million in 2006 is vital in developing a longer term, strategic approach to consumer education. DERS supports the recommendations contained in the Navigant report that customer education should be centrally directed but with multiple program delivery agencies.	Negotiated Settlement
15) Other Admin Costs	9. O&M	Board IRs (22) CG IRs (30)	Section 5.3.14 (page 66)	Other admin costs of \$.8 million in 2005 and 2006 include facility costs, travel costs, membership costs, and training and development costs. The 2005 and 2006 costs have been based on the 2004 annualized costs and are required to support DERS' staff as well as carry out the required financial and compliance audits.	Negotiated Settlement
16) Corporate Costs	10. Corporate Costs 9. O&M	Board IRs (63, 64, 65, 66) CG IRs (35)	Section 5.3.15 (page 66-72)	DERS is not structured as a stand-alone entity and receives certain services from its parent company at an appropriate and fair cost. As a result of these centralized corporate services DERS realizes cost and process efficiencies. DERS has included total corporate costs in the 2005 revenue requirement of \$3.5 million and \$3.6 million in 2006.	Negotiated Settlement
17) Energy Related Costs		Board IRs (5)	Section 5.4 (page 73-76)	DERS has re-allocated RRT costs of \$131,500 in 2005 and \$135,200 in 2006 from the non-energy revenue requirement to the energy revenue requirement. Currently DERS includes a majority of non-energy costs through the quarterly RRT energy rate; this proposal allocates all remaining energy related costs to the energy component. In addition, this approach is consistent with the GCFR cost structure.	Negotiated Settlement
18) Allocation to Rate Class	Phase II 2. Allocation of Rev. Requirement to Rate class	Board IRs (11, 15, 17, 25, 86) CG IRs (36)	Section 6.1-6.2 (page 76-78)	DERS has developed and revised the cost allocation methodology for customer care costs in this application. As a result of each cost item in the MSA utilizing different cost drivers, it was no longer appropriate to determine the costs at an aggregate level and allocate them on bills, instead DERS built-up the customer care costs by rate class. Non-energy working capital has been	Negotiated Settlement

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				allocated on the basis of sites vs. the previous allocation on the basis of energy. No other allocations have changed since the 2003/04 application. Attachment BR-DERS-11 shows the rate class percentage share of revenue requirement using the 2004 allocation vs. the proposed 2005/06 allocation. The difference in the RRT rate class share for 2004 vs. 2005/06 costs is largely a result of the inclusion of REA customers, for the DRT, the differences in the 2004 to 2005/06 rate class share is largely due to updating the consolidation factors.	
19) 2006 proposed rates	Phase II 3. 2005 vs 2006 rates 4. Rate design and rates	Board IRs (14, 44, 67, 70)	Section 7.1-7.2 (page 78-81)	Considering that a Board decision on this Application will not be released until late this year or early next year, DERS has only determined final 2006 rates. In order to achieve rate stability and minimize rate changes, DERS has proposed to implement 2006 rates once the Board has issued a decision and implement a rider to collect or refund the difference relating to the 2005 revenue requirement. DERS has also proposed to eliminate the variable rate as none of the non-energy components have been directly allocated or are directly attributable to energy.	Negotiated Settlement
20) Daily Rates	Phase II 1. Daily/ monthly admin charges	Board IRs (68) CG IRs (13, 37)	Section 7.1 (page 79)	Daily fixed charges have been proposed for 2006. This would ensure that all customers pay the correct amount based on the number on billing days. In addition, ATCO Gas and ATCO Electric have also proposed a similar change to their distribution rates.	Negotiated Settlement
21) Terms and Conditions	Phase II 5. Terms and Conditions of Service	Board IRs (1)	Section 10 (page 86)	DERS is participating in the UCA process to develop a standard set of RRT Terms and Conditions.	N/A – being dealt with through UCA process
<b>Other Items</b>					
22) Code of Conduct	14.Code of Conduct matters	CG IRs (42, 46)		DERS has provided a process map detailing the transactions and industry protocol of each participant to transfer customers from regulated services to a competitive retailer. As stated in CG-DERS-42, DERS does not take an active role in the transfer of a customer, but rather DERS is advised by the Distributor that the site is no longer on regulated service. Any contravention of the Code of Conduct Regulation would involve either the EUB or MSA and be dealt with accordingly as a separate matter, not part of this tariff application.	N/A in DRT and RRT non-energy application

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23) Income Tax	2. Income Tax	Board (9)		DERS would propose to calculate an adjustment arising from the timing differences in CCA rate and amortization rates and incorporate in a refiling, if other tax related issues such as those noted in the rate of return evidence are also taken into consideration.	Negotiated Settlement
24) REA		Board IRs (39) CG IRs (14, 47)		DERS submits that it is appropriate for REA customers to be served by DERS. The inclusion of REA sites benefits all RRT customers (including REAs) as the fixed costs are allocated over a larger customer base.	Negotiated Settlement
25) Allocation of costs to affiliate (credit and capital costs)	7. Split of Capital and O&M between reg and non-reg	Board IRs (23, 26, 33, 72) CG IRs (19, 48)	Section 5.2 (page 32)	DERS has proposed for this test period to allocate I-Tek related credit costs and capital projects that cover both the regulated and competitive business on the basis of 90% regulated and 10% competitive. DERS submits this is appropriate as the current level of competitive customers is below the 10% threshold and has been confirmed by the compliance auditor. Currently the competitive business is apportioned a larger share of costs than a pro-ration of customers would determine. In addition, DERS has proposed to change this allocation in 10% increments on a prospective basis with each test period.	Negotiated Settlement
26) Allocation to DRT or RRT	8. Split of Capital and O&M between Gas and Electric		Section 5.2 (page 30-32)	For costs that benefit both the DRT and RRT customers, costs are allocated on the basis of customer count, FTE's, or 50/50 depending on the type of cost. The costs that have been allocated between DRT and RRT are as follows: Credit charges, hearing costs, labour, Capital, customer education, other admin costs, and corporate costs.	Negotiated Settlement
27) Streetlight Rates		Board IRs (14,15,70)		As a result of DERS' cost structure a large percentage of costs are determined at the site level. Base billing fees, and base credit management fees are incurred at the site level, as well, capital and other charges have been allocated appropriately on the basis of sites. The resulting proposed lighting rate reflects the costs incurred by DERS to provide retail service to this customer class.	Negotiated Settlement
28) Annualization factors	5. Annualization factors	Board IRs (10, 51, 84) CG IRs (18,45)		As a result of DERS' operations commenced May 5, 2004 there is not a full year of actual financial data. Annualization numbers are based on several assumptions. Most of the annual costs were developed by using and annualization factor of 12/8. Bad debt and penalty revenue were annualized using a factor or	Negotiated Settlement

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				<p>12/7.5, interest on security deposits were annualized a factor of 12/7 and revenue offset were annualized using a factor of 12/6. For the most part, the annual numbers were not used to develop the 2005 and 2006 forecast, but rather were provided for illustrative purposes. Revenue offsets and Other Admin costs were the only items that used the annualized numbers to forecast 2005 and 2006.</p>	
29) Adjustments to Filed Revenue Requirement		BR IRs (48, 9)		<p>Since the original filing made on May 5, 2005 DERS has identified several items that were not included in the original filing or could be updated to reflect current market conditions. As discussed in BR-DERS-48(a) long term incentive costs were not included in the original application. The costs that should have been included are \$0.2 million each year relating to individuals in the functional departments and \$0.5 million in each year for corporate individuals. DERS would also propose to calculate an adjustment arising from the timing differences in CCA rate and amortization rates and incorporate in a refiling, if other tax related issues such as those noted in the rate of return evidence are also taken into consideration.</p> <p>In order to develop the working capital, bad debt and penalty revenue forecasts, DERS based the commodity costs on an annual average gas cost of \$7.12 per GJ and assumed electricity costs of \$65.17 per MWh. Changes in these estimates will impact the original forecasts and the differences will be captured in a deferral account. DERS is prepared to update the commodity costs with current data in order to minimize the level of the deferral account. DERS proposes to incorporate all changes through one refiling.</p>	Negotiated Settlement
30) Revenue Requirement		BR IRs (42)	Overview (page 4-12)	<p>On May 5, 2005 DERS filed 2005 and 2006 DRT and RRT application. DERS applied for a 2005 DRT non-energy revenue requirement of \$59.7 million and energy revenue requirement of \$2.2 million and a 2006 DRT non-energy revenue requirement of \$61.2 million and energy revenue requirement of \$2.3 million. DERS applied for a 2005 RRT non-energy revenue requirement of \$13.7 million and energy revenue requirement of \$0.132 million and a 2006 RRT non-energy revenue</p>	Negotiated Settlement

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				requirement of \$14.1 million and energy revenue requirement of \$0.135 million. Approximately 85% of the DRT non-energy revenue requirement and 75% of the RRT non-energy revenue requirement is subject to deferral account treatment.	

- Note: The CG items are taken from the July 18<sup>th</sup> 2005 letter.
- DERS considers CG Item # 9. O&M to be the same as CG Item # 3. Operation and Maintenance Expense and has only used #9 in the table above.