## 1.0 Reference: Exhibit B-1, Appendix A, Schedule 7.2, and Exhibit B-3-1, BCUC IR#1 4.1 Revenue: Proof re Proposed Rates

**Q1.1 Please provide a schedule in the format of Schedule 7.2 of the COSA showing that the proposed rates recover the 2009 Revenue Requirements adjusted for the 4.6 percent general rate increase and the BC Hydro wholesale tariff increase.**

A1.1 Table BCUC IR2 A1.1 below compares the 2009 Revenue at proposed rates, as compared to existing rates. The detailed analysis for the table below is attached to this response as BCUC IR2 Attachment A1.1.

**Table BCUC IR2 A1.1**

| | COSA Assumed Revenue ($000s) | 2009 Proposed Revenue ($000s) | Difference from COSA ($000s) | Difference from COSA (%) |
|---|---|---|---|---|
| Residential | 106,867 | 106,669 | -198 | -0.2% |
| General Service 20 | 17,994 | 17,971 | -23 | -0.1% |
| General Service 21 | 41,640 | 41,589 | -51 | -0.1% |
| Industrial ID30 | 9,812 | 9,801 | -11 | -0.1% |
| Industrial ID31 | 3,301 | 3,295 | -6 | -0.2% |
| Industrial ID33 | 898 | 897 | -1 | -0.1% |
| Street Light | 1,992 | 1,989 | -3 | -0.1% |
| Irrigation | 2,727 | 2,703 | -24 | -0.9% |
| Kelowna | 16,431 | 16,409 | -21 | -0.1% |
| Penticton | 19,331 | 19,310 | -21 | -0.1% |
| Summerland | 5,567 | 5,561 | -6 | -0.1% |
| Grand Forks | 2,312 | 2,308 | -4 | -0.2% |
| Lardeau | 698 | 697 | -1 | -0.1% |
| Yahk | 183 | 183 | 0 | -0.1% |
| Nelson | 5,675 | 5,670 | -4 | -0.1% |
| **Total** | **235,427** | **235,052** | **-374** | **-0.2%** |

The revenues at proposed rates were designed to be revenue neutral with the rates as of September 2009. Those rates include a 2.2 percent rate increase above the rate in place during the first 8 months of 2009. The adjustment was made to recover the added cost associated with the BC Hydro wholesale rate increase applied to the entire year. Because the entire added cost was collected in only 4 months, the rates in September through December were higher than what they would have been if the rates would have been changed in January of 2009. Applying these rates for all of 2009 would overstate the revenues when compared to the revenues used within the COSA.

The revenues in the COSA reflect the revenues at the lower January 2009 rates, adjusted for the added cost of the higher wholesale rate. In the COSA, the adjustment for the entire year was added to the annual revenues rather than to the rates themselves.

For this reason, the revenues collected at proposed rates were reduced by 2.2 percent in the first 8 months of the year to be consistent with the required annual revenues contained in the COSA.

As a result of this analysis, FortisBC has adjusted the proposed rate schedules 20, 21 and 31 to better match forecast revenues. These changes have been reflected in all filed documents as contained in Errata 4.

# BCUC Schedule A1.1
# 2009 Baseline Revenues at Proposed Rates

| RESIDENTIAL | | | Total | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Accounts Billed | | | 1,156,960 | 95,840 | 95,895 | 96,075 | 95,898 | 96,150 | 96,496 | 96,525 | 96,417 | 96,580 | 96,800 | 97,031 | 97,255 |
| Consumption | *kWh* | | **1,221,674,870** | 143,810,401 | 133,587,255 | 122,736,750 | 108,427,119 | 93,122,593 | 81,073,492 | 70,102,639 | 77,178,162 | 75,229,040 | 89,588,369 | 99,073,490 | 127,745,562 |
| Account Fixed Charge | *Bi-monthly/2* | $ | 12.13 | | | | | | | | | | | | |
| Unit Energy Charge | *$/kWh* | $ | 0.07627 | | | | | | | | | | | | |
| Fixed Charge Revenue (includes 1% late fees) | *$,000* | | $14,174 | $1,174 | $1,175 | $1,177 | $1,175 | $1,178 | $1,182 | $1,183 | $1,181 | $1,183 | $1,186 | $1,189 | $1,191 |
| Energy Charge Revenue (includes 1% late fees) | *$,000* | | $94,109 | $11,078 | $10,291 | $9,455 | $8,352 | $7,173 | $6,245 | $5,400 | $5,945 | $5,795 | $6,901 | $7,632 | $9,841 |
| Total Billed Revenue (000's) | *$,000* | | **$108,283** | $12,252 | $11,465 | $10,632 | $9,527 | $8,351 | $7,428 | $6,583 | $7,126 | $6,978 | $8,087 | $8,821 | $11,032 |
| Less 2.2% Increase | | | $1,614 | $270 | $252 | $234 | $210 | $184 | $163 | $145 | $157 | | | | |
| 2009 Proposed Revenue (000's) | | | **$106,669** | $11,983 | $11,213 | $10,398 | $9,318 | $8,168 | $7,264 | $6,438 | $6,970 | $6,978 | $8,087 | $8,821 | $11,032 |
| COSA Assumed Revenue | | | **$106,867** | | | | | | | | | | | | |
| Difference from COSA | | | **-$198** | **-0.2%** | | | | | | | | | | | |

| GENERAL SERVICE | | | Total | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Accounts Billed | | | 107,865 | 8,884 | 8,900 | 8,913 | 8,917 | 8,942 | 8,993 | 9,020 | 9,029 | 9,044 | 9,062 | 9,071 | 9,089 |
| Consumption | *Total* | | **203,446,005** | 19,924,547 | 14,701,642 | 17,605,493 | 13,941,916 | 16,516,947 | 14,661,868 | 19,781,723 | 15,765,838 | 18,180,843 | 16,182,021 | 19,712,090 | 16,471,076 |
| | *kWh to 16000* | | 158,294,563 | 15,124,631 | 10,591,347 | 13,780,361 | 11,649,417 | 13,695,175 | 12,671,489 | 14,695,433 | 10,855,016 | 13,237,599 | 13,003,254 | 15,915,730 | 13,075,112 |
| | *Next 184000 kWh* | | 40,029,017 | 4,614,451 | 3,241,485 | 3,671,009 | 2,124,360 | 2,659,345 | 1,990,380 | 4,447,713 | 4,176,959 | 4,445,141 | 2,564,133 | 3,350,188 | 2,743,855 |
| | *kWh over* | | 5,122,424 | 185,466 | 868,811 | 154,123 | 168,139 | 162,426 | - | 638,578 | 733,863 | 498,103 | 614,635 | 446,172 | 652,109 |
| Account Fixed Charge | *Bi-monthly/2* | $ | 14.62 | | | | | | | | | | | | |
| Unit Energy Charge - 0-8000 | *$/kWh* | $ | 0.08187 | | | | | | | | | | | | |
| Unit Energy Charge - next 92,000 | *$/kWh* | $ | 0.08187 | | | | | | | | | | | | |
| Unit Energy Charge - Balance of kWh | *$/kWh* | $ | 0.08187 | | | | | | | | | | | | |
| Fixed Charge Revenue | *$,000* | | $1,577 | $130 | $130 | $130 | $130 | $131 | $131 | $132 | $132 | $132 | $132 | $133 | $133 |
| Energy Charge Revenue | *$,000* | | $16,656 | $1,631 | $1,204 | $1,441 | $1,141 | $1,352 | $1,200 | $1,620 | $1,291 | $1,488 | $1,325 | $1,614 | $1,348 |
| Total Billed Revenue (000's) | *$,000* | | **$18,233** | $1,761 | $1,334 | $1,572 | $1,272 | $1,483 | $1,332 | $1,751 | $1,423 | $1,621 | $1,457 | $1,746 | $1,481 |
| Less 2.2% Increase | | | $262 | $39 | $29 | $35 | $28 | $33 | $29 | $39 | $31 | | | | |
| 2009 Proposed Revenue (000's) | | | **$17,971** | $1,722 | $1,304 | $1,537 | $1,244 | $1,450 | $1,303 | $1,713 | $1,391 | $1,621 | $1,457 | $1,746 | $1,481 |
| COSA Assumed Revenue | | | **$17,994** | | | | | | | | | | | | |
| Difference from COSA | | | **-$23** | **-0.1%** | | | | | | | | | | | |

| GENERAL SERVICE GS21 | | | Total | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Accounts Billed | | | 29,597 | 2,438 | 2,442 | 2,445 | 2,447 | 2,453 | 2,468 | 2,475 | 2,478 | 2,481 | 2,487 | 2,489 | 2,494 |
| Consumption | *Total* | | **474,707,344** | 46,490,610 | 34,303,832 | 41,079,484 | 32,531,137 | 38,539,543 | 34,211,026 | 46,157,354 | 36,786,955 | 42,421,967 | 37,758,050 | 45,994,876 | 38,432,510 |
| | *kWh to 8000* | | 92,146,278 | 8,875,832 | 6,002,801 | 7,730,457 | 7,088,704 | 7,951,352 | 6,590,251 | 7,987,897 | 6,086,379 | 9,458,629 | 7,487,480 | 9,533,775 | 7,352,721 |
| | *kWh to 100000* | | 237,209,508 | 24,228,065 | 18,471,360 | 21,832,171 | 16,273,381 | 18,819,073 | 16,262,622 | 21,764,475 | 17,197,098 | 20,257,650 | 19,106,522 | 23,159,041 | 19,838,051 |
| | *kWh over* | | 145,351,558 | 13,386,713 | 9,829,671 | 11,516,856 | 9,169,052 | 11,769,118 | 11,358,154 | 16,404,982 | 13,503,479 | 12,705,688 | 11,164,048 | 13,302,061 | 11,241,737 |
| | *kW* | | 1,522,280.0 | 139,745.0 | 129,348.1 | 123,106.5 | 119,059.0 | 123,698.4 | 127,274.5 | 131,893.9 | 133,450.4 | 127,451.0 | 125,736.9 | 119,403.6 | 122,112.6 |
| Account Fixed Charge | *Monthly* | $ | 14.61 | | | | | | | | | | | | |
| Unit Energy Charge - 0-8000 | *$/kWh* | $ | 0.08187 | | | | | | | | | | | | |
| Unit Energy Charge - next 92000 | *$/kWh* | $ | 0.05882 | | | | | | | | | | | | |
| Unit Energy Charge - Balance of kWh | *$/kWh* | $ | 0.05882 | | | | | | | | | | | | |
| Unit Demand Charge | *$/KVA* | $ | 7.70 | | | | | | | | | | | | |
| Fixed Charge Revenue | *$,000* | | $432 | $36 | $36 | $36 | $36 | $36 | $36 | $36 | $36 | $36 | $36 | $36 | $36 |
| Energy Charge Revenue | *$,000* | | $30,046 | $2,939 | $2,156 | $2,594 | $2,077 | $2,450 | $2,164 | $2,899 | $2,304 | $2,713 | $2,394 | $2,925 | $2,430 |
| Demand Charge Revenue | *$,001* | | $11,722 | $1,076 | $996 | $948 | $917 | $952 | $980 | $1,016 | $1,028 | $981 | $968 | $919 | $940 |
| Total Billed Revenue (000's) | *$,000* | | **$42,200** | $4,051 | $3,188 | $3,578 | $3,029 | $3,438 | $3,180 | $3,951 | $3,368 | $3,731 | $3,398 | $3,881 | $3,407 |
| Less 2.2% Increase | | | $611 | $89 | $70 | $79 | $67 | $76 | $70 | $87 | $74 | | | | |
| 2009 Proposed Revenue (000's) | | | **$41,589** | $3,962 | $3,118 | $3,499 | $2,963 | $3,363 | $3,110 | $3,864 | $3,294 | $3,731 | $3,398 | $3,881 | $3,407 |
| COSA Assumed Revenue | | | **$41,640** | | | | | | | | | | | | |
| Difference from COSA | | | **-$51** | **-0.1%** | | | | | | | | | | | |

# BCUC Schedule A1.1
# 2009 Baseline Revenues at Proposed Rates

| **INDUSTRIAL ID30** | | **Total** | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Accounts Billed | | 396 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 |
| Consumption | *kWh* | **141,018,352** | 11,711,699 | 11,305,845 | 11,810,860 | 11,757,036 | 12,484,524 | 12,125,836 | 12,101,478 | 10,704,218 | 9,537,494 | 11,759,915 | 13,219,843 | 12,499,603 |
| | *MVA* | 478.3 | 44.2 | 45.1 | 38.7 | 36.0 | 34.4 | 34.6 | 34.7 | 38.0 | 42.9 | 44.2 | 41.8 | 43.6 |
| Account Fixed Charge | *Monthly* $ | 748.73 | | | | | | | | | | | | |
| Unit Energy Charge | *$/kWh* $ | 0.04383 | | | | | | | | | | | | |
| Unit Demand Charge | *$/KVA* $ | 7.25 | | | | | | | | | | | | |
| Fixed Charge Revenue | *$,000* | $296 | $25 | $25 | $25 | $25 | $25 | $25 | $25 | $25 | $25 | $25 | $25 | $25 |
| Energy Charge Revenue | *$,000* | $6,181 | $513 | $496 | $518 | $515 | $547 | $531 | $530 | $469 | $418 | $515 | $579 | $548 |
| Demand Charge Revenue | *$,001* | $3,468 | $321 | $327 | $281 | $261 | $250 | $251 | $251 | $276 | $311 | $320 | $303 | $316 |
| Total Billed Revenue (000's) | *$,000* | **$9,945** | $859 | $847 | $823 | $801 | $822 | $807 | $806 | $770 | $754 | $860 | $907 | $888 |
| Less 2.2% Increase | | $144 | $19 | $19 | $18 | $18 | $18 | $18 | $18 | $17 | | | | |
| 2009 Proposed Revenue (000's) | | **$9,801** | $840 | $829 | $805 | $784 | $804 | $790 | $789 | $753 | $754 | $860 | $907 | $888 |
| COSA Assumed Revenue | | **$9,812** | | | | | | | | | | | | |
| Difference from COSA | | **-$11** | **-0.1%** | | | | | | | | | | | |

| **INDUSTRIAL ID31** | | **Total** | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Accounts Billed | | 36 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Consumption | *kWh* | **66,680,240** | 5,251,269 | 5,072,069 | 5,717,098 | 5,488,736 | 5,763,604 | 6,049,592 | 6,170,322 | 5,271,674 | 4,823,496 | 5,258,309 | 6,119,453 | 5,694,617 |
| | *MVA Contract* | 133.2 | 11.1 | 11.1 | 11.1 | 11.1 | 11.1 | 11.1 | 11.1 | 11.1 | 11.1 | 11.1 | 11.1 | 11.1 |
| | *MVA Actual* | 109.5 | 11.7 | 11.7 | 12.5 | 10.9 | 10.9 | 8.9 | 5.8 | 5.8 | 6.8 | 7.9 | 8.1 | 8.4 |
| Account Fixed Charge | *Monthly* $ | 2,246.22 | | | | | | | | | | | | |
| Unit Energy Charge | *$/kWh* $ | 0.03867 | | | | | | | | | | | | |
| Wires Demand Charge | *$/KVA* $ | 3.50 | | | | | | | | | | | | |
| Power Supply Demand Charge | *$/KVA* $ | 2.00 | | | | | | | | | | | | |
| Fixed Charge Revenue | *$,000* | $81 | $7 | $7 | $7 | $7 | $7 | $7 | $7 | $7 | $7 | $7 | $7 | $7 |
| Energy Charge Revenue | *$,000* | $2,579 | $203 | $196 | $221 | $212 | $223 | $234 | $239 | $204 | $187 | $203 | $237 | $220 |
| Demand Charge Revenue | *$,000* | $685 | $62 | $62 | $64 | $61 | $61 | $57 | $51 | $50 | $53 | $55 | $55 | $56 |
| Total Billed Revenue (000's) | *$,000* | **$3,345** | $272 | $265 | $292 | $280 | $290 | $297 | $296 | $261 | $246 | $265 | $298 | $283 |
| Less 2.2% Increase | | $50 | $6 | $6 | $6 | $6 | $6 | $7 | $7 | $6 | | | | |
| 2009 Proposed Revenue (000's) | | **$3,295** | $266 | $259 | $285 | $273 | $284 | $291 | $289 | $255 | $246 | $265 | $298 | $283 |
| COSA Assumed Revenue | | **$3,301** | | | | | | | | | | | | |
| Difference from COSA | | **-$6** | **-0.2%** | | | | | | | | | | | |

| **INDUSTRIAL ID33** | | **Total** | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Accounts Billed | | 12 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Consumption | ***Total kWh*** | **16,500,000** | 1,656,924 | 1,596,729 | 1,249,585 | 1,446,198 | 1,600,442 | 1,102,881 | 967,783 | 1,042,252 | 802,233 | 1,678,324 | 1,678,324 | 1,678,324 |
| | *kWh On* | 7,845,933 | 629,631 | 606,757 | 724,759 | 838,795 | 928,256 | 639,671 | 367,758 | 396,056 | 465,295 | 973,428 | 637,763 | 637,763 |
| | *kWh Off* | 8,654,067 | 1,027,293 | 989,972 | 524,826 | 607,403 | 672,186 | 463,210 | 600,026 | 646,196 | 336,938 | 704,896 | 1,040,561 | 1,040,561 |
| Account Fixed Charge | *Monthly* $ | 2,065.18 | | | | | | | | | | | | |
| Unit Energy Charge - Winter | *$/kWh On* $ | 0.12667 | | | | | | | | | | | | |
| Winter | *$/kWh Off* $ | 0.03589 | | | | | | | | | | | | |
| Shoulder | *$/kWh On* $ | 0.04054 | | | | | | | | | | | | |
| Shoulder | *$/kWh Off* $ | 0.02135 | | | | | | | | | | | | |
| Summer | *$/kWh On* $ | 0.16897 | | | | | | | | | | | | |
| Summer | *$/kWh Off* $ | 0.02792 | | | | | | | | | | | | |
| Fixed Charge Revenue | *$,000* | $25 | $2 | $2 | $2 | $2 | $2 | $2 | $2 | $2 | $2 | $2 | $2 | $2 |
| Energy Charge Revenue | *$,000* | $885 | $117 | $112 | $41 | $47 | $52 | $36 | $79 | $85 | $26 | $55 | $118 | $118 |
| Total Billed Revenue (000's) | *$,000* | **$910** | $119 | $114 | $43 | $49 | $54 | $38 | $81 | $87 | $28 | $57 | $120 | $120 |
| Less 2.2% Increase | | $13 | $3 | $3 | $1 | $1 | $1 | $1 | $2 | $2 | | | | |
| 2009 Proposed Revenue (000's) | | **$897** | $116 | $112 | $42 | $48 | $53 | $37 | $79 | $85 | $28 | $57 | $120 | $120 |
| COSA Assumed Revenue | | **$898** | | | | | | | | | | | | |
| Difference from COSA | | **-$1** | **-0.1%** | | | | | | | | | | | |

# BCUC Schedule A1.1
# 2009 Baseline Revenues at Proposed Rates

| STREET LIGHT | | Total | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Consumption | *MWh* | **13,866,327** | 1,172,370 | 1,021,572 | 1,132,778 | 1,014,144 | 1,152,947 | 1,243,991 | 1,236,031 | 1,097,065 | 1,088,745 | 1,304,110 | 1,311,349 | 1,091,224 |
| Unit Energy Charge | *$/kWh* | $0.1455 | | | | | | | | | | | | |
| Energy Charge Revenue | *$,000* | $2,018 | $171 | $149 | $165 | $148 | $168 | $181 | $180 | $160 | $158 | $190 | $191 | $159 |
| Total Billed Revenue (000's) | *$,000* | **$2,018** | $171 | $149 | $165 | $148 | $168 | $181 | $180 | $160 | $158 | $190 | $191 | $159 |
| Less 2.2% Increase | | $29 | $4 | $3 | $4 | $3 | $4 | $4 | $4 | $4 | | | | |
| 2009 Proposed Revenue (000's) | | **$1,989** | $167 | $145 | $161 | $144 | $164 | $177 | $176 | $156 | $158 | $190 | $191 | $159 |
| COSA Assumed Revenue | | **$1,992** | | | | | | | | | | | | |
| Difference from COSA | | **-$3** | **-0.1%** | | | | | | | | | | | |

| IRRIGATION IR60 | | Total | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Accounts Billed | | 12,612 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 |
| Consumption | *kWh* | **47,802,478** | 552,628 | 583,394 | 371,980 | 623,673 | 3,463,753 | 5,570,622 | 9,110,437 | 10,656,806 | 8,390,595 | 5,657,206 | 1,949,500 | 871,883 |
| Account Fixed Charge | *Monthly* $ | 14.62 | | | | | | | | | | | | |
| Unit Energy Charge -Irrigation Season | *$/kWh* | $0.05065 | | | | | | | | | | | | |
| GS20 (0-16000 kWh) | *$/kWh* | $0.08187 | | | | | | | | | | | | |
| GS20 (16000 - 184000 kWh) | *$/kWh* | $0.08187 | | | | | | | | | | | | |
| GS20 (184000 kWh - MAX) | *$/kWh* | $0.08187 | | | | | | | | | | | | |
| Fixed Charge Revenue | *$,000* | $184 | $ 15 | $ 15 | $ 15 | $ 15 | $ 15 | $ 15 | $ 15 | $ 15 | $ 15 | $ 15 | $ 15 | $ 15 |
| Energy Charge Revenue | *$,000* | $2,556 | 45 | 48 | 30 | 32 | 175 | 282 | 461 | 540 | 425 | 287 | 160 | 71 |
| Total Billed Revenue (000's) | *$,000* | **$2,741** | $61 | $63 | $46 | $47 | $191 | $298 | $477 | $555 | $440 | $302 | $175 | $87 |
| Less 2.2% Increase | | $38 | $1 | $1 | $1 | $1 | $4 | $7 | $10 | $12 | | | | |
| 2009 Proposed Revenue (000's) | | **$2,703** | $59 | $62 | $45 | $46 | $187 | $291 | $466 | $543 | $440 | $302 | $175 | $87 |
| COSA Assumed Revenue | | **$2,727** | | | | | | | | | | | | |
| Difference from COSA | | **-$24** | **-0.9%** | | | | | | | | | | | |

| WHOLESALE WH40 - Kelowna | | Total | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Accounts Billed | | 48 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 |
| Consumption | *KWh* | **300,580,396** | 31,670,124 | 28,418,812 | 25,843,110 | 22,947,572 | 20,189,302 | 21,639,922 | 21,676,701 | 23,687,558 | 22,013,863 | 23,334,721 | 26,498,260 | 32,660,451 |
| | *MVA Actual* | 654.7 | 64.5 | 57.8 | 50.6 | 48.2 | 47.1 | 55.1 | 59.0 | 59.0 | 42.3 | 48.8 | 54.4 | 67.9 |
| | *MVA Contract* | 1,101.6 | 91.8 | 91.8 | 91.8 | 91.8 | 91.8 | 91.8 | 91.8 | 91.8 | 91.8 | 91.8 | 91.8 | 91.8 |
| Account Fixed Charge | *Monthly* $ | 1,729.08 | | | | | | | | | | | | |
| Unit Energy Charge | *$/kWh* $ | 0.02290 | | | | | | | | | | | | |
| Wires Demand Charge | *$/KVA* $ | 6.70 | | | | | | | | | | | | |
| Power Supply Demand Charge | $ | 3.52 | | | | | | | | | | | | |
| Fixed Charge Revenue | *$,000* | $83 | $7 | $7 | $7 | $7 | $7 | $7 | $7 | $7 | $7 | $7 | $7 | $7 |
| Energy Charge Revenue | *$,000* | $6,883 | $725 | $651 | $592 | $525 | $462 | $496 | $496 | $542 | $504 | $534 | $607 | $748 |
| Demand Charge Revenue | *$,000* | $9,685 | $842 | $819 | $793 | $785 | $781 | $809 | $823 | $823 | $764 | $787 | $806 | $854 |
| Total Billed Revenue (000's) | *$,000* | **$16,652** | $1,574 | $1,476 | $1,392 | $1,317 | $1,250 | $1,312 | $1,326 | $1,372 | $1,275 | $1,328 | $1,420 | $1,609 |
| Less 2.2% Increase | | $242 | $35 | $32 | $31 | $29 | $28 | $29 | $29 | $30 | | | | |
| 2009 Proposed Revenue (000's) | | **$16,409** | $1,540 | $1,444 | $1,361 | $1,288 | $1,223 | $1,283 | $1,297 | $1,342 | $1,275 | $1,328 | $1,420 | $1,609 |
| COSA Assumed Revenue | | **$16,431** | | | | | | | | | | | | |
| Difference from COSA | | **-$21** | **-0.1%** | | | | | | | | | | | |

# BCUC Schedule A1.1
# 2009 Baseline Revenues at Proposed Rates

| **WHOLESALE WH40 - Penticton** | | **Total** | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Accounts Billed | | 60 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Consumption | *KWh* | **355,153,151** | 37,420,086 | 33,578,473 | 30,535,132 | 27,113,885 | 23,854,830 | 25,568,822 | 25,612,278 | 27,988,222 | 26,010,654 | 27,571,325 | 31,309,230 | 38,590,215 |
| | *MVA Actual* | 739.0 | 73.1 | 65.7 | 57.1 | 56.8 | 46.8 | 62.1 | 67.1 | 68.3 | 45.6 | 54.0 | 61.4 | 81.0 |
| | *MVA Contract* | 1,817.0 | 151.417 | 151.417 | 151.417 | 151.417 | 151.417 | 151.417 | 151.417 | 151.417 | 151.417 | 151.417 | 151.417 | 151.417 |
| Account Fixed Charge | *Monthly* | $ 1,729.08 | | | | | | | | | | | | |
| Unit Energy Charge | *$/kWh* | $ 0.01990 | | | | | | | | | | | | |
| Wires Demand Charge | *$/KVA* | $ 5.52 | | | | | | | | | | | | |
| Power Supply Demand Charge | | $ 3.24 | | | | | | | | | | | | |
| Fixed Charge Revenue | *$,000* | $104 | $9 | $9 | $9 | $9 | $9 | $9 | $9 | $9 | $9 | $9 | $9 | $9 |
| Energy Charge Revenue | *$,000* | $7,068 | $745 | $668 | $608 | $540 | $475 | $509 | $510 | $557 | $518 | $549 | $623 | $768 |
| Demand Charge Revenue | *$,000* | $12,424 | $1,073 | $1,049 | $1,021 | $1,020 | $988 | $1,037 | $1,053 | $1,057 | $983 | $1,011 | $1,035 | $1,098 |
| Total Billed Revenue (000's) | *$,000* | **$19,595** | $1,826 | $1,726 | $1,637 | $1,568 | $1,471 | $1,554 | $1,572 | $1,623 | $1,510 | $1,568 | $1,667 | $1,875 |
| Less 2.2% Increase | | $285 | $40 | $38 | $36 | $34 | $32 | $34 | $35 | $36 | | | | |
| 2009 Proposed Revenue (000's) | | **$19,310** | $1,786 | $1,688 | $1,601 | $1,534 | $1,439 | $1,520 | $1,537 | $1,587 | $1,510 | $1,568 | $1,667 | $1,875 |
| COSA Assumed Revenue | | **$19,331** | | | | | | | | | | | | |
| Difference from COSA | | **-$21** | **-0.1%** | | | | | | | | | | | |

| **WHOLESALE WH40 - Summerland** | | **Total** | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Accounts Billed | | 24 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| Consumption | *KWh* | **98,651,430** | 10,394,234 | 9,327,143 | 8,481,790 | 7,531,465 | 6,626,192 | 7,102,290 | 7,114,361 | 7,774,331 | 7,225,019 | 7,658,529 | 8,696,812 | 10,719,263 |
| | *MVA* | 218.2 | 23.0 | 20.3 | 17.7 | 17.5 | 13.8 | 17.2 | 17.4 | 17.8 | 12.5 | 16.7 | 18.6 | 25.7 |
| | *MVA Contract* | 344.0 | 28.7 | 28.7 | 28.7 | 28.7 | 28.7 | 28.7 | 28.7 | 28.7 | 28.7 | 28.7 | 28.7 | 28.7 |
| Account Fixed Charge | *Monthly* | $ 1,729.08 | | | | | | | | | | | | |
| Unit Energy Charge | *$/kWh* | $ 0.02465 | | | | | | | | | | | | |
| Wires Demand Charge | *$/KVA* | $ 6.74 | | | | | | | | | | | | |
| Power Supply Demand Charge | | $ 3.90 | | | | | | | | | | | | |
| Fixed Charge Revenue | *$,000* | $41 | $3 | $3 | $3 | $3 | $3 | $3 | $3 | $3 | $3 | $3 | $3 | $3 |
| Energy Charge Revenue | *$,000* | $2,432 | $256 | $230 | $209 | $186 | $163 | $175 | $175 | $192 | $178 | $189 | $214 | $264 |
| Demand Charge Revenue | *$,000* | $3,169 | $283 | $272 | $262 | $261 | $247 | $260 | $261 | $263 | $242 | $258 | $266 | $293 |
| Total Billed Revenue (000's) | *$,000* | **$5,643** | $543 | $506 | $475 | $451 | $414 | $439 | $440 | $458 | $423 | $451 | $483 | $561 |
| Less 2.2% Increase | | $82 | $12 | $11 | $10 | $10 | $9 | $10 | $10 | $10 | | | | |
| 2009 Proposed Revenue (000's) | | **$5,561** | $531 | $495 | $464 | $441 | $405 | $429 | $430 | $448 | $423 | $451 | $483 | $561 |
| COSA Assumed Revenue | | **$5,567** | | | | | | | | | | | | |
| Difference from COSA | | **-$6** | **-0.1%** | | | | | | | | | | | |

| **WHOLESALE WH40 - Grand Forks** | | **Total** | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Accounts Billed | | 36 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Consumption | *KWh* | **42,413,094** | 4,468,781 | 4,010,008 | 3,646,566 | 3,237,994 | 2,848,791 | 3,053,479 | 3,058,669 | 3,342,409 | 3,106,244 | 3,292,622 | 3,739,010 | 4,608,520 |
| | *MVA* | 83.4 | 8.2 | 7.4 | 6.6 | 6.3 | 5.7 | 6.2 | 7.0 | 7.4 | 5.8 | 6.5 | 7.0 | 9.1 |
| | *MVA Contract* | 276.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 | 23.0 |
| Account Fixed Charge | *Monthly* | $ 1,729.08 | | | | | | | | | | | | |
| Unit Energy Charge | *$/kWh* | $ 0.01728 | | | | | | | | | | | | |
| Wires Demand Charge | *$/KVA* | $ 4.76 | | | | | | | | | | | | |
| Power Supply Demand Charge | | $ 2.80 | | | | | | | | | | | | |
| Fixed Charge Revenue | *$,000* | $62 | $5 | $5 | $5 | $5 | $5 | $5 | $5 | $5 | $5 | $5 | $5 | $5 |
| Energy Charge Revenue | *$,000* | $733 | $77 | $69 | $63 | $56 | $49 | $53 | $53 | $58 | $54 | $57 | $65 | $80 |
| Demand Charge Revenue | *$,000* | $1,547 | $132 | $130 | $128 | $127 | $126 | $127 | $129 | $130 | $126 | $128 | $129 | $135 |
| Total Billed Revenue (000's) | *$,000* | **$2,342** | $215 | $205 | $196 | $188 | $180 | $185 | $187 | $193 | $185 | $190 | $199 | $220 |
| Less 2.2% Increase | | $34 | $5 | $5 | $4 | $4 | $4 | $4 | $4 | $4 | | | | |
| 2009 Proposed Revenue (000's) | | **$2,308** | $210 | $200 | $192 | $184 | $176 | $181 | $183 | $189 | $185 | $190 | $199 | $220 |
| COSA Assumed Revenue | | **$2,312** | | | | | | | | | | | | |
| Difference from COSA | | **-$4** | **-0.2%** | | | | | | | | | | | |

# BCUC Schedule A1.1
# 2009 Baseline Revenues at Proposed Rates

| **WHOLESALE WH40 - Lardeau** | | **Total** | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Accounts Billed | | 12 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Consumption | *KWh* | **9,228,226** | 972,316 | 872,496 | 793,419 | 704,522 | 619,839 | 664,375 | 665,504 | 727,240 | 675,855 | 716,408 | 813,533 | 1,002,720 |
| | *MVA* | 30.4 | 4.8 | 3.7 | 2.5 | 3.4 | 1.8 | 1.6 | 1.7 | 1.7 | 1.9 | 2.1 | 2.0 | 3.2 |
| | *MVA Contract* | 57.6 | 4.8 | 4.8 | 4.8 | 4.8 | 4.8 | 4.8 | 4.8 | 4.8 | 4.8 | 4.8 | 4.8 | 4.8 |
| Account Fixed Charge | *Monthly* | $ 1,729.08 | | | | | | | | | | | | |
| Unit Energy Charge | *$/kWh* | $ 0.02707 | | | | | | | | | | | | |
| Wires Demand Charge | *$/KVA* | $ 6.00 | | | | | | | | | | | | |
| Power Supply Demand Charge | | $ 3.01 | | | | | | | | | | | | |
| Fixed Charge Revenue | *$,000* | $21 | $2 | $2 | $2 | $2 | $2 | $2 | $2 | $2 | $2 | $2 | $2 | $2 |
| Energy Charge Revenue | *$,000* | $250 | $26 | $24 | $21 | $19 | $17 | $18 | $18 | $20 | $18 | $19 | $22 | $27 |
| Demand Charge Revenue | *$,000* | $437 | $43 | $40 | $36 | $39 | $34 | $34 | $34 | $34 | $35 | $35 | $35 | $39 |
| Total Billed Revenue (000's) | *$,000* | **$708** | $71 | $65 | $60 | $60 | $53 | $53 | $54 | $55 | $55 | $56 | $59 | $67 |
| Less 2.2% Increase | | $10 | $2 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | | | | |
| 2009 Proposed Revenue (000's) | | **$697** | $70 | $64 | $58 | $58 | $52 | $52 | $52 | $54 | $55 | $56 | $59 | $67 |
| COSA Assumed Revenue | | **$698** | | | | | | | | | | | | |
| Difference from COSA | | **-$1** | **-0.1%** | | | | | | | | | | | |

| **WHOLESALE WH40 - Yahk** | | **Total** | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Accounts Billed | | 12 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Consumption | *KWh* | **2,817,036** | 296,812 | 266,341 | 242,201 | 215,064 | 189,214 | 202,809 | 203,154 | 222,000 | 206,314 | 218,693 | 248,341 | 306,093 |
| | *MVA* | 6.5 | 0.6 | 0.5 | 0.5 | 0.5 | 0.8 | 0.4 | 0.4 | 0.4 | 0.6 | 0.6 | 0.7 | 0.7 |
| | *MVA Contract* | 8.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 |
| Account Fixed Charge | *Monthly* | $ 1,729.08 | | | | | | | | | | | | |
| Unit Energy Charge | *$/kWh* | $ 0.02555 | | | | | | | | | | | | |
| Wires Demand Charge | *$/KVA* | $ 8.12 | | | | | | | | | | | | |
| Power Supply Demand Charge | | $ 3.49 | | | | | | | | | | | | |
| Fixed Charge Revenue | *$,000* | $21 | $2 | $2 | $2 | $2 | $2 | $2 | $2 | $2 | $2 | $2 | $2 | $2 |
| Energy Charge Revenue | *$,000* | $72 | $8 | $7 | $6 | $5 | $5 | $5 | $5 | $6 | $5 | $6 | $6 | $8 |
| Demand Charge Revenue | *$,000* | $93 | $7 | $6 | $6 | $6 | $9 | $8 | $8 | $8 | $9 | $9 | $9 | $9 |
| Total Billed Revenue (000's) | *$,000* | **$186** | $16 | $15 | $14 | $13 | $16 | $15 | $15 | $15 | $16 | $16 | $17 | $18 |
| Less 2.2% Increase | | $3 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | | | |
| 2009 Proposed Revenue (000's) | | **$183** | $16 | $15 | $14 | $13 | $15 | $14 | $14 | $15 | $16 | $16 | $17 | $18 |
| COSA Assumed Revenue | | **$183** | | | | | | | | | | | | |
| Difference from COSA | | **$0** | **-0.1%** | | | | | | | | | | | |

| **WHOLESALE WH41 - Nelson** | | **Total** | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Accounts Billed | | 36 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Consumption | *kWh* | **112,532,033** | 11,856,739 | 10,639,505 | 9,675,208 | 8,591,169 | 7,558,521 | 8,101,608 | 8,115,377 | 8,868,206 | 8,241,604 | 8,736,111 | 9,920,484 | 12,227,500 |
| | *MVA Actual* | 246.5 | 24.5 | 22.5 | 18.7 | 17.3 | 13.5 | 18.4 | 16.9 | 14.2 | 18.4 | 25.1 | 26.5 | 30.4 |
| | *MVA Contract* | 540.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 |
| Account Fixed Charge | *Monthly* | $ 1,729.08 | | | | | | | | | | | | |
| Unit Energy Charge | *$/kWh* | $ 0.01923 | | | | | | | | | | | | |
| Wires Demand Charge | *$/KVA* | $ 4.59 | | | | | | | | | | | | |
| Power Supply Demand Charge | | $ 4.25 | | | | | | | | | | | | |
| Fixed Charge Revenue | *$,000* | $62 | $5 | $5 | $5 | $5 | $5 | $5 | $5 | $5 | $5 | $5 | $5 | $5 |
| Energy Charge Revenue | *$,000* | $2,164 | $228 | $205 | $186 | $165 | $145 | $156 | $156 | $171 | $158 | $168 | $191 | $235 |
| Demand Charge Revenue | *$,000* | $3,526 | $311 | $302 | $286 | $280 | $264 | $285 | $278 | $267 | $285 | $313 | $319 | $336 |
| Total Billed Revenue (000's) | *$,000* | **$5,752** | $544 | $512 | $477 | $451 | $415 | $446 | $440 | $443 | $448 | $486 | $515 | $576 |
| Less 2.2% Increase | | $82 | $12 | $11 | $10 | $10 | $9 | $10 | $10 | $10 | | | | |
| 2009 Proposed Revenue (000's) | | **$5,670** | $532 | $501 | $467 | $441 | $405 | $436 | $430 | $433 | $448 | $486 | $515 | $576 |
| COSA Assumed Revenue | | **$5,675** | | | | | | | | | | | | |
| Difference from COSA | | **-$4** | **-0.1%** | | | | | | | | | | | |

**2.0 Reference: Exhibit B-3-1, BCUC IR#1, 49.2**

**Revenue: Variation**

**Table BCUC A49.2 on page 80 of the response to BCUC IR No. 1 shows the variation between the revenue forecasts for Revenue Requirements purposes versus those calculated for the COSA.**

**Q2.1 Given the material level of variation between the Revenue Requirements and the COSA revenue forecasts, would it be appropriate to adjust the R/C ratios to account for the variation of the COSA forecast from the RR forecast? If not, why not? If so, what would the resulting R/C ratios be?**

A2.1 The COSA uses an updated revenue forecast and therefore the revenue to cost ratios already reflect the adjustment in revenues.

**3.0 Reference: Exhibit B-3-1, BCUC IR#1, 23.2, and 80.1**

**Revenue: Rebalancing Impact**

**"Because this RDA addresses changes in the rate structure as opposed to the overall rate level, there are no real rate increases involved in the RDA." [BCUC, 23.2]**

Table BCUC A80.1a
Rebalancing Rate Changes with 2009 COSA as Filed

| | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 |
|---|---|---|---|---|---|
| Residential | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Small General Service | -3.3% | -3.0% | -1.3% | 0.0% | 0.0% |
| General Service | -3.3% | -3.0% | -2.8% | -3.5% | -1.0% |
| Large General Service-Transmission (33) | 5.0% | 5.0% | 5.0% | 5.0% | 5.0% |
| Large General Service Primary (30) | -3.3% | -3.0% | -2.8% | -3.5% | -3.2% |
| Large General Service-Transmission (31) | -3.3% | -1.4% | 0.0% | 0.0% | 0.0% |
| Lighting | 5.0% | 5.0% | 5.0% | 1.0% | 0.0% |
| Irrigation | 5.0% | 5.0% | 5.0% | 5.0% | 0.4% |
| Kelowna Wholesale | 5.0% | 0.9% | 0.0% | 0.0% | 0.0% |
| Penticton Wholesale | 5.0% | 5.0% | 5.0% | 5.0% | 1.2% |
| Summerland Wholesale | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Grand Forks Wholesale | 5.0% | 5.0% | 5.0% | 5.0% | 5.0% |
| BCH Lardeau Wholesale | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| BCH Yahk Wholesale | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Nelson Wholesale | 5.0% | 5.0% | 5.0% | 3.5% | 0.0% |

**Q3.1 Please explain why FortisBC states that "no real rate increases [are] involved in the RDA," when Table BCUC A80.1a indicates rate rebalancing increases exceeding recent CPI increases of roughly 2.0 percent per year.**

A3.1 FortisBC draws a distinction between the structural elements of the rate design, which produce rates that are revenue neutral with current rates and the rebalancing which is subsequently applied over the new rates. In effect, rate design and rebalancing are separate processes that could be applied independently.

**Q3.2 Does FortisBC expect that rebalancing implications associated with the existing rate structure (i.e., without TOU/AMI-based rates) will be superseded by the introduction of TOU/AMI-based rates in the relatively near future?**

A3.2 FortisBC does not believe this will be the case. The inequities in the revenue-to-cost ratios will still need to be addressed regardless of the impact and timing of the implementation of TOU/AMI based rates. Any new TOU/AMI based rates will be designed to be revenue neutral with rates that are in place at the time.

**4.0 Reference: Exhibit B-3-1, BCUC IR#1, 36.2**

**Revenue: Rebalancing - Wholesale Customers**

**In response to BCUC IR#1 36.2, FortisBC stated as follows:**

A36.2 FortisBC does not have a monthly 2011 forecast of metered demand which is necessary to calculate revenue under proposed rates. However, because proposed rates are revenue neutral to current rates prior to incorporating any rate rebalancing the revenues at both current and proposed rates would be the same assuming the 2011 billing determinants were identical to the 2009 forecast used in the COSA. Therefore the only difference between the revenues at current and proposed rate structures in 2011 will be due to rate rebalancing. The 2011 forecast under current rate structures is provided below:

| Revenue Forecast - Rates effective Jan 1, 2010 | 2011 Forecast Revenue ($) |
|---|---|
| BC Hydro - Kingsgate/Arrow Crk | 271,719.67 |
| BC Hydro - Lardeau | 664,052.61 |
| City of Grand Forks | 2,374,728.02 |
| Corp of the City of Kelowna | 18,311,432.53 |
| Corp of the City of Penticton | 20,391,550.95 |
| District of Summerland | 5,762,200.87 |
| Nelson Hydro | 4,945,300.03 |
| | 52,720,984.67 |

**Q4.1 Why are forecasts of demand used to develop the 2009 Resource Plan not suitable for forecasting the 2011 demand of its wholesale customers?**

A4.1 The response to BCUC IR No. 1 Q36.2 does not indicate that the 2011 demand forecast is not suitable, and in fact, the revenues presented in the table above are estimated based on such forecasts. They do however rely on current billing determinants. Data that will be used as billing determinants in the new rate has not been gathered for use in the Resource Plan. As indicated in the response to BCUC IR No. 1 Q36.2, only the rebalancing adjustments will cause any variation in expected revenues as the new and old rates are revenue neutral.

**Q4.2 Please provide a table similar to that shown in response to question 36.2 but with an additional column that shows the 2011 forecast under the proposed rate structure, including the impact of rate rebalancing.**

A4.2 The impact of rebalancing on the wholesale class can be seen in Table BCUC IR2 A4.2 below. The data reflects the 5 percent maximum rebalancing increase applied to Grand Forks, Kelowna, Penticton, and Nelson. The two BC Hydro accounts along with Summerland are within the range of reasonableness and receive no increase. The additional revenue collected from the wholesale customers would be used to reduce rates for other classes.

**Table BCUC IR2 A4.2**

| Revenue Forecast - Rates effective Jan 1, 2010 | 2011 Forecast Revenue | 2011 Forecast Revenue with Rebalancing |
|---|---|---|
| | ($) | |
| BC Hydro - Kingsgate/Arrow Crk | 271,719.67 | 271,719.67 |
| BC Hydro - Lardeau | 664,052.61 | 664,052.61 |
| City of Grand Forks | 2,374,728.02 | 2,493,464.42 |
| Corp of the City of Kelowna | 18,311,432.53 | 19,227,004.16 |
| Corp of the City of Penticton | 20,391,550.95 | 21,411,128.50 |
| District of Summerland | 5,762,200.87 | 5,762,200.87 |
| Nelson Hydro | 4,945,300.03 | 5,192,565.03 |
| **Total** | **52,720,984.68** | **55,022,135.26** |

**Q4.3 Please complete the following table showing 2009 revenues under each of the existing and proposed rate designs, assuming that the pattern of consumption was the same as actually observed—i.e., assume no impact related to price elasticity.**

| Wholesale Customer | 2009 Revenue, Existing Rate Design | 2009 Revenue, Proposed Rate Design |
|---|---|---|
| BC Hydro - Kingsgate/Arrow Crk | | |
| BC Hydro - Lardeau | | |
| City of Grand Forks | | |
| Corp of the City of Kelowna | | |
| Corp of the City of Penticton | | |
| District of Summerland | | |
| Nelson Hydro | | |

A4.3 Table BCUC IR2 A4.3 below shows the revenues under the existing and proposed rate design using actual energy delivered during 2009. The revenues are higher for BC Hydro Lardeau, since the rate design was based on actual demand, which was lower in 2009 than the original forecast in the COSA.

**Table BCUC IR2 A4.3**

| Wholesale Customer | 2009 Delivery Revenue, calculated on existing rate | 2009 Delivery Revenue, Proposed Rate Design | Percentage change |
|---|---|---|---|
| BC Hydro - Kingsgate/Arrow Crk | $225,922.86 | $221,060.12 | -2.15% |
| BC Hydro - Lardeau | $292,909.80 | $323,660.09 | 10.50% |
| City of Grand Forks | $2,288,857.09 | $2,329,106.00 | 1.76% |
| Corp of the City of Kelowna | $17,965,708.60 | $18,161,440.64 | 1.09% |
| Corp of the City of Penticton | $19,125,201.94 | $19,488,846.60 | 1.90% |
| District of Summerland | $5,291,707.92 | $5,494,359.15 | 3.83% |
| Nelson Hydro | $5,481,808.93 | $5,690,798.53 | 3.81% |

**5.0 Reference: Exhibit B-3-1, BCUC IR#1 6.3**

**Rate Design: Residential Time-of-Use (TOU) and the Summer Peak**

**In the response to BCUC IR#1 6.3 it states: "The 'rapidly increasing summer peak' is likely due at least in part to the increased use of air conditioning. It is not clear whether the use at peak is largely due to residential customers or other customer classes due to the lack of interval data for most customers."**

**Q5.1 After the full implementation of AMI and the introduction of wide-scale TOU rates, would these TOU rates be mandatory for residential customers?**

A5.1 As stated in the Application on page 23, lines 12 to 16 (Exhibit B-1):

> *Since properly designed time-based rates support the reduction of system peak demand, it is the current intention of FortisBC, after adequate consultation and consideration, to introduce mandatory time-based conservation rates, once electric usage interval data is made available through the implementation of an AMI, for all metered customer classes.*

**Q5.2 Is FortisBC considering implementing mandatory TOU rates for customers other than its residential customers in 2014?**

A5.2 Please refer to the response to BCUC IR No. 2 Q5.1.

**Q5.3 If the answer to the previous question is "no", then explain why residential customers alone will be, effectively, responsible for reducing the summer peak by virtue of them being the only class that will receive price signals.**

A5.3 Please refer to the response to BCUC IR No. 2 Q5.1.

**6.0 Reference: Exhibit B-3-1, BCUC IR#1, 68.6**

**Rate Design: Rate Stability vs. TOU/AMI**

**Q6.1 If Time of Use pricing was widely introduced for the FortisBC system, what proportion of the time would a peak TOU rate likely be in effect during the period used to calculate the 2CP proposed in the Application (i.e., how many hours during the 2CP period used in the COSA would be expected to be priced at the highest TOU rate)?**

A6.1 All four hours in the 2CP calculation would likely be in the highest TOU rate period.

**Q6.2 Does FortisBC anticipate that TOU rates for DEC and JAN loads would generally be higher than those for HE18 loads over the course of the year? Please comment.**

A6.2 At this time FortisBC has not determined whether or not TOU rates would be seasonal, but if they were FortisBC anticipates that in December and January the rates in effect during HE 18 would be higher than the annual average rate in effect at that time.

**7.0 Reference: Exhibit B-3-1, BCUC IR#1 6.6**

**Rate Design: Residential Rates - Inclining Block Rate**

**Q7.1 In its response to BCUC IR#1 6.6, is FortisBC suggesting that residential customers will only reduce their energy consumption towards the end of a billing period in order to remain below the threshold of the second block?**

A7.1 FortisBC is suggesting in its response that the rate would be most effective if customers knew if they were in, or near, the second block. This may happen well before the end of a billing period since it depends on how much energy is being used, not on elapsed time.

**Q7.2 Would not such behaviour require a much more drastic reduction in energy consumption for a short period of time, rather than a permanent shift in behavior leading to a more efficient use of energy?**

A7.2 It is not clear precisely how customers will respond to pricing signals, but it is reasonable to expect that over time customers will adopt consistent behaviours and make investments that will minimize consumption in the second block. Initially, they may take more “drastic” actions to minimize second block consumption if they are price sensitive and they have real time information available. FortisBC expects that real-time information would enhance and quicken the response to inclining block rates.

**Q7.3 Does FortisBC not expect residential customers to make simple, permanent changes to reduce their energy consumption in response to an inclining block structure, rather than respond to real-time information in the manner suggested?**

A7.3 Please refer to the response to BCUC IR No. 2 Q7.2.

**8.0 Reference: Exhibit B-3-1, BCUC IR#1 19.2**

**Rate Design: Small General and General Service Rate Classes**

**In its response to BCUC IR#1 19.2, FortisBC states that: "*94 percent of all General Service bills were above 24 kVA*."**

**Q8.1 What percentage of General Service bills were above 45 kVA?**

A8.1 Forty eight percent of all General Service bills were above 45 kVA.

**9.0 Reference: Exhibit B-3-1, BCUC IR#1 21.1, and**
**Exhibit B-3-2, BCOAPO IR#1 14.1**
**Rate Design: Reasonability Range**

**In its response to BCUC IR#1 21.1, FortisBC states: "The recommended ratios are reflective of the availability in the assumptions made of the interval load data. If the Company had perfect information with respect to load data and if there was no uncertainty or variation possible in the COSA methods, then the Company would agree that an indefinite cross-subsidy could occur."**

**Q9.1 Is FortisBC therefore assuming that the assumptions made of the interval load data have an inherent bias of +/- 5 percent, which are taken into account by the target revenue to cost ratios?**

A9.1 No. The interval load data does not have a +/- 5 percent variability in measurement. The COSA does contain uncertainty in addition to load data, including the selection of methodologies and potential errors in both loads and costs since the COSA uses a 2009 test year. While it is impossible to quantify the level of uncertainty, those classes with interval metering will have a lesser amount of uncertainty than those classes without interval metering.

**Q9.2 If the answer to the previous question is "yes", then why would these biases not be taken into account when performing the COSA study?**

A9.2 Please refer to the response to BCUC IR No. 2 Q9.1.

**Q9.3 If the answer to the first question is "no", and assuming that there was a random, +/- 5 per cent uncertainty or variation in the load data or COSA methods, then why would FortisBC not set a design target revenue to cost ratios of 100 percent in order to achieve a actual ratios that, with a high degree of statistical confidence, lay within the range of 95 to 105 percent?**

A9.3 Using a target of unity implies a level of certainty that does not exist in any COSA.

**Q9.4 If FortisBC were to set as a target, revenue to cost ratios of 100 percent, over what time period would it propose that the rebalancing should occur?**

A9.4 FortisBC cannot dictate the time over which rebalancing would occur if the target was changed. The time period is determined by the parameters chosen. The combination of total allowable increase, rebalancing increase cap, and starting revenue-to-cost ratio would determine the amount of time required to bring all classes to 100 percent.

**10.0 Reference: Exhibit B-3-1, BCUC IR#1, 8.1, 33.2, and 33.3, and Exhibit B-3-6, OEIA IR#1 3.2, and Exhibit B-1, Rate Design Application, pp. 4,5, 60, and 67**

**Rate Design: Conservation Impacts**

**"The Company maintains its commitment with respect to Policy Action #1 of the BC Energy Plan, which sets a conservation target of offsetting 50 percent of FortisBC incremental energy growth through conservation by 2020." [Ex. B-1, p. 60]**

**"Note that in designing rates, FortisBC has a set revenue requirement to collect. Any increase in one rate will lead to a decrease in another rate. The impacts of elasticity are therefore difficult to assess and must be differentiated between classes and between demand and energy to provide the true impacts of various rate changes." [BCUC 8.1]**

**"In evaluating the requests in this Application, the Company submits that the Commission should bear in mind the following factors detailed below... in the years preceding this filing, provincial energy policy has become increasingly focused on conservation. The BC Energy Plan as well as other policies has encouraged utilities to find ways to reduce usage; this priority was consequently an influential factor in rate design... Finding ways to encourage conservation is a benefit to all customers through reductions in power purchase and infrastructure costs." [Ex. B-1, pp. 4,5]**

**"While a demand charge does not necessarily result in reductions at the system peak, the proposed increase does deliver an improved price signal for demand conservation, while maintaining reasonable intra-class bill changes." [Ex. B-1, p. 67]**

**"FortisBC does not have experience with price elasticity for electricity demand, and is not aware of any research or studies in this area. Therefore, FortisBC cannot estimate the effect of a 10 percent increase in demand**

**charges." [BCUC 33.2]**

**"The RDA will be an important consideration in determining the achievable potential in the 2010 Conservation Potential Review (currently under development), and the CPR in turn will be the primary reference document for the 2011 DSM plan." [OEIA 3.2]**

**Q10.1 FortisBC offers no specific estimates of the impact of changing the demand charges for General Service or other rate classes. Given the absence specific conservation impact estimates, explain why it should not be concluded that the proposed Rate Design is strictly COSA-related (i.e., historically-based), rather than reflecting a specific strategy designed to promote conservation awareness (i.e., forward-looking).**

A10.1 While FortisBC has not estimated elasticity for the RDA and therefore has not quantified any impacts associated with a change in rate design, it does not follow that FortisBC does not expect to see any impacts. Quantifying impacts is always imprecise and would be difficult in this case given the amount of time since the rate structure has changed, the uncertainty of increases associated with revenue requirements, and the fact that actual impacts associated with the change in the BC Hydro rate structure have not been in place long enough to be measured.

FortisBC relied on the COSA in setting rates but considered all of the principles listed on page 33 of the Application (Exhibit B-1). This includes Principle 3, which states:

> *Price signals that encourage efficient use and discourage inefficient use (consideration of social issues including environmental and energy policy)*

Use of the COSA results contributes to rates that send price signals reflecting the costs faced by the utility. Since a higher demand charge for the General Service class better reflects both embedded costs for FortisBC and capacity constraints that FortisBC expects to see in the near future, this rate design change is seen as promoting an efficient use of resources and a tool for reducing demand levels such that an avoidance or delay in new resources is possible.

FortisBC has not introduced new “conservation-based” rate structures in this application but plans to do so in its next RDA in conjunction with the addition of AMI. The goal of this RDA was to reduce or eliminate rate design features that would inhibit conservation and move towards a closer alignment of rates and costs.

**Q10.2 At what date does FortisBC intend to file a 2010 Conservation Potential Review Report with the Commission?**

A10.2 FortisBC intends to file a Conservation Potential Review report with its 2011 DSM Plan, expected to be filed in the first half of 2010.

**Q10.3 Please explain how the proposed Rate Design will be used by FortisBC to increase its awareness of price elasticity impacts, with respect to future rate designs—particularly with regard to promoting conservation and reducing future infrastructure costs.**

A10.3 FortisBC may use the proposed Rate Design to increase its knowledge of price elasticity impacts of commercial energy rates by studying the response to the proposed rate changes to Small General Service and General Service energy rates. The Company will also be able to study the price elasticity impacts of varying General Service and Large General Service demand charges. Residential price elasticity has been the subject of many recent pricing pilots, and FortisBC intends to rely on the study referenced in the Application, page 24, lines 18-20 for that information (Exhibit B-1).

**11.0 Reference: Exhibit B-3-1, BCUC IR#1, 22.2**

**Rate Design: Conservation Impacts - Basic and Demand Charges**

**"FortisBC is not aware of any research regarding the conservation effects of basic charges or demand charges. However, it is generally accepted that demand for energy is price responsive – higher marginal prices for energy result in lower demand for energy, with the inverse also being true. FortisBC would expect the same type of marginal price responsiveness in the demand for electrical demand. A change in the basic charge by itself would not be expected to result in any change to the demand for energy or electrical demand since such a change does not affect the marginal price to the customer."**

**Q11.1 Does FortisBC believe that there is no income effect (i.e., that a change in Basic Charges affects a customer's overall budget) associated with changes in Basic Charges? If so, explain why that assumed by FortisBC.**

A11.1 FortisBC assumed in its response that there was no income effect. This may not be an accurate assumption for all customers, particularly for those with relatively low energy consumption for whom the customer charge may have more impact.

**Q11.2 What are FortisBC's views as to the extent to which the changes to each of Basic Charges, Demand Charges, and Energy Charges influence customer decisions concerning appliance selection (for Residential customers, including the selection of electric heating) or equipment selection (for Industrial customers)?**

A11.2 Customers generally will be most sensitive to marginal costs when making decisions regarding energy consuming devices such as appliances, heating systems and equipment. Therefore, customers are assumed to be most sensitive to incremental energy costs and demand charges and not the basic charge. Higher marginal energy and demand rates will dissuade customers with a fuel choice from selecting electricity as a fuel. Higher marginal energy and demand rates for customers without a fuel choice will provide an incentive for selecting the most energy efficient appliance, heating system or equipment.

**12.0 Reference: Exhibit B-1, pp. 73-74**

**Rate Design: Schedule 33, Time-of-Use**

**The application states on page 73 that:**

**"Therefore, in this extraordinary situation, FortisBC proposes to price the wires-based demand charge at $0 per kVA to begin, with all rebalancing increases for this rate schedule to be applied solely by increasing this demand charge. The current Basic Charge and TOU energy rates will be left unchanged to begin, then subject only to any annual general rate increases."**

**Q12.1 Please show the anticipated demand charges over the next 5 years to reach the year 5 R/C ratio shown in table 8.1b assuming no general rate increases.**

A12.1 The following demand charges are expected given a 5 percent rebalancing increase and no general rate increase for the next five years.

| | |
|---|---|
| Year 1 | $0.09 per kW-month |
| Year 2 | $0.19 per kW-month |
| Year 3 | $0.30 per kW-month |
| Year 4 | $0.41 per kW-month |
| Year 5 | $0.52 per kW-month |

**Q12.2 Will general rate increases be applied only to the Basic Charge and TOU energy rates or will they be applied to all three components of the proposed rate, and if the latter in what proportion?**

A12.2 General rate increases will be applied to all rate components at the percentage approved by the British Columbia Utilities Commission.

**Q12.3 With reference to Table 14.3b on page 74, please explain why, when the winter peak demand is higher than the summer peak demand, the rate for winter on-peak rate is lower than the summer on-peak rate.**

A12.3 The TOU rates shown in Table 14.3b were originally based on the costs associated with different time periods. Outputs from resources vary by season and market purchases differ across the year both in terms of amounts and prices. The prices for on-peak market purchases are much higher in the summer months than in the winter months due to the loads and resources for the entire west coast. This drives the costs for FortisBC in the summer on-peak periods even though the loads are less than in the winter on-peak periods.

**13.0 Reference: Exhibit B-3-1, BCUC IR#1, 26.1**

**Rate Design: Option #3**

**Q13.1 For the sake of clarity, please confirm that the basic charge in option #3 of the response is intended to read $32 rather than $24?**

A13.1 Confirmed. Please see Errata 4.

**14.0 Reference: Exhibit B-3-1, BCUC IR#1 34.4**

**Rate Design: Large General Service – Transmission**

**Q14.1 Please revise table A34.4 to reflect a contract demand limit of 5,000 kVA, a 95 per cent power factor, an 80 percent load factor, and ignoring the effect of the demand ratchet. Please provide the calculations in the table for monthly billed demand in the range of 5,000 to 15,000 kVA, rather than 1,500 to 4,000 kVA as was provided in the response.**

A14.1 Please refer to Table BCUC IR2 A14.1 below:

**Table BCUC IR2 A14.1**

| Monthly Billed Demand | Demand Charges at Existing Rate ($) | Energy Charges at Existing Rate ($) | Total Charges at Existing Rate ($) | Wires Charges at Proposed Rate ($) | Power Supply Charges at Proposed Rate ($) | Energy Charges at Proposed Rate ($) | Total Charges at Proposed Rate ($) | Increase/ (Decrease) |
|---|---|---|---|---|---|---|---|---|
| kVA | $ | | | | | | | % |
| 5,000 | 329,400 | 1,399,147 | 1,755,502 | 210,000 | 120,000 | 1,354,982 | 1,711,937 | -2.5% |
| 6,000 | 395,280 | 1,678,977 | 2,074,257 | 252,000 | 144,000 | 1,625,979 | 2,021,979 | -2.5% |
| 7,000 | 461,160 | 1,958,806 | 2,419,966 | 294,000 | 168,000 | 1,896,975 | 2,358,975 | -2.5% |
| 8,000 | 527,040 | 2,238,636 | 2,765,676 | 336,000 | 192,000 | 2,167,972 | 2,695,972 | -2.5% |
| 9,000 | 592,920 | 2,518,465 | 3,111,385 | 378,000 | 216,000 | 2,438,968 | 3,032,968 | -2.5% |
| 10,000 | 658,800 | 2,798,294 | 3,457,094 | 420,000 | 240,000 | 2,709,964 | 3,369,964 | -2.5% |
| 11,000 | 724,680 | 3,078,124 | 3,802,804 | 462,000 | 264,000 | 2,980,961 | 3,706,961 | -2.5% |
| 12,000 | 790,560 | 3,357,953 | 4,148,579 | 504,000 | 288,000 | 3,251,957 | 4,044,023 | -2.5% |
| 13,000 | 856,440 | 3,637,783 | 4,494,223 | 546,000 | 312,000 | 3,522,954 | 4,380,996 | -2.5% |
| 14,000 | 922,320 | 3,917,612 | 4,839,932 | 588,000 | 336,000 | 3,793,950 | 4,717,974 | -2.5% |
| 15,000 | 988,200 | 4,197,442 | 5,185,642 | 630,000 | 360,000 | 4,064,947 | 5,054,947 | -2.5% |

## 15.0 Reference: Exhibit B-3-1, BCUC IR#1, 40.2 and 43.1

## Rate Design: System Extensions and Rate Schedule 74

Table BCUC A40.2

| | | Existing Tariff | | | | Proposed Tariff | | | |
|---|---|---|---|---|---|---|---|---|---|
| Extension Cost | Description | Customer Contribution | FortisBC Contribution | Extension Cost | Connection Charge | Customer Contribution | FortisBC Contribution | Extension Cost | Connection Charge |
| Low | New 200 amp residential service, 46 meter secondary extension, 35 ft pole mid-span with anchoring | $4,282 | $239 | $4,521 | $500 | $2,756 | $1,765 | $4,521 | $533 |
| Mid-low | New 200 amp residential service, 25 kVA pole mount transformer, 46m span, 35 ft pole mid-span | $2,373 | $3,842 | $6,215 | $500 | $4,450 | $1,765 | $6,215 | $533 |
| Mid-high | Two new 200 amp residential services, 5 pole overhead extension, Two 25 kVA overhead transformers | $26,109 | $4,323 | $30,432 | $1,000 | $26,902 | $3,530 | $30,432 | $1,066 |
| High | 42 unit multi-residential condo, 1000 amp underground service, 500 kVA padmount transformer, conversion of existing overhead system fronting property to be converted to underground | $75,855 | $20,829 | $96,684 | $4,620 | $22,554 | $74,130 | $96,684 | Actual costs to connect service |

**Q15.1 Please provide a copy of FortisBC's current System Extension test methodology.**

A15.1 Rate Schedule 74 specifies the only method that FortisBC is authorized to use in calculating customer contributions for distribution system extensions, and constitutes a System Extension Test insofar as it is a fixed contribution test. Rate Schedule 74 was approved by the BCUC following a generic hearing on the system extension policies in which FortisBC (then West Kootenay Power) participated.

**Q15.2 Please explain how the proposed Rate Schedule 74 Tariff incorporates appropriate signals concerning the net social costs of less efficient energy use.**

A15.2 Schedule 74 was not intended to incorporate price signals concerning the net social costs of less efficient energy use, but to hold all other customers harmless from the incremental costs of supplying new localized distribution poles, conductors and transformers.

**Q15.3 Please provide a version of Table BCUC 40.2, with the same columns, but that includes rows showing figures for a) a 200W Upgrade, b) a 400W Upgrade, and c) a 400W extension. Please use figures reflecting the average cost of actual projects undertaken during 2008, which were listed in response to BCUC IR#1 43.1.**

A15.3 Please see Table BCUC IR2 A15.3 below. Note, FortisBC is unable to calculate the average cost of a new 400 amp extension undertaken in 2008 based on the figures provided in the response to BCUC IR No. 1 Q43.1 as extension costs are not easily aggregated for averaging purposes according to service size. As such, the average costs for new 400 amp extensions used the table below are based upon a manually extracted 10 percent sample of new 400 amp extensions constructed in 2008.

**Table BCUC IR2 A15.3**

| | | Existing Tariff | | | | Proposed Tariff | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Extension Cost/Type** | **Description** | **Customer Contribution** | **FortisBC Contribution** | **Extension Cost** | **Connection Charge** | **Customer Contribution** | **FortisBC Contribution** | **Extension Cost** | **Connection Charge** |
| Low | New 200 amp residential service, 46 meter secondary extension, 35 ft pole mid-span with anchoring | $4,282 | $239 | $4,521 | $500 | $2,756 | $1,765 | $4,521 | $533 |
| Mid-low | New 200 amp residential service, 25 kVA pole mount transformer, 46m span, 35 ft pole mid-span | $2,373 | $3,842 | $6,215 | $500 | $4,450 | $1,765 | $6,215 | $533 |
| Mid-high | Two new 200 amp residential services, 5 pole overhead extension, Two 25 kVA overhead transformers | $26,109 | $4,323 | $30,432 | $1,000 | $26,902 | $3,530 | $30,432 | $1,066 |
| High | 42 unit multi-residential condo, 1000 amp underground service, 500 kVA padmount transformer, conversion of existing overhead system fronting property to be converted to underground | $75,855 | $20,829 | $96,684 | $4,620 | $22,554 | $74,130 | $96,684 | Actual costs to connect service |
| 200A Upgrade | Service upgrade to 200 amp | N/A | N/A | N/A | $500 | N/A | N/A | N/A | $533 |
| 400A Upgrade | Service upgrade to 400 amp | N/A | N/A | N/A | $1,100 | N/A | N/A | N/A | $937 |
| 400A Extension | New extension for 400 amp service, 50 kVA overhead transformer | $3,795 | $7,210 | $11,005 | $1,100 | $9,240 | $1,765 | $11,005 | $937 |

**16.0 Reference: Exhibit B-3-1, BCUC IR#1 40.5**

**Rate Design: System Extensions - Customer Contributions - Irrigation**

**Q16.1 Why can the billing demand of irrigation customers not be estimated based on the capacity of the pump motor?**

A16.1 Billing demand could be estimated based on the capacity of the pump motor. However, without accurate demand data for existing irrigation customers, FortisBC cannot determine an appropriate demand based contribution and as such the development of a per kW extension credit is likely to be less accurate than a contribution determined on a per customer basis.

**Q16.2 Why can the billing demand of RS20 customers be estimated, but that of RS60 and RS61 customers can not be?**

A16.2 Please refer to the response to BCUC IR No. 2 Q16.1 above.

**17.0 Reference: Exhibit B-1, Appendix A, Schedule 8.1, and Exhibit B-3-2, BCOAPO IR#1 29.5**
**Rate Design: Lighting - NCP Demand**

**In its response to BCOAPO IR#1 29.5, FortisBC states: "The load factors for the lighting class were based on the number of hours of daylight when streetlights would be operating. This created a low load factor in the summer months as lights were on fewer hours. The lower load factors created a higher peak demand in the summer months."**

**Q17.1 Please confirm whether or not the load factors presented in Schedule 8.2 are determined through a calculation of the relative number of hours of daylight in a 24 hour period.**

A17.1 Confirmed.

**Q17.2 If as suggested in the response to BCOAPO IR#1 29.5, the peak demand of the lighting class is determined by the demand attributed to streetlights and if street lights are on for fewer hours in the summer, then would not the energy consumption for the lighting class also be reduced in the summer and to such an amount as to keep the load factor constant?**

A17.2 While the load factors based on hours of daylight are appropriate, they were applied to energy use for the class that was set at a relatively flat level due to the lack of metering for the class. The energy by month could have been differentiated according to the same calculations using average hours of daylight each month.

**Q17.3 Is not the peak demand determined directly by the number of streetlights and other lighting systems on at the same time rather than indirectly through a calculation of the load factors?**

A17.3 The peak demand is not determined directly by the number of street lights as FortisBC does not have metered data for the class providing either peak demand or energy.

**Q17.4 Does a higher NCP demand for the lighting class in the summer not mean that a larger lighting load is on at the same time as compared to the winter?**

A17.4 The Company would expect the NCP for lighting to be as high in the winter as in the summer. Because the NCP calculation takes the higher of the winter and summer loads, the NCP allocation would be the same if the winter NCP were adjusted to be at a comparable level to the summer NCP.

**Q17.5 What other lighting applications, other than street lighting, receives service under Schedule 50?**

A17.5 In addition to street lighting, Rate Schedule 50 is also used to bill individual customers who have dusk-to-dawn lights at their premises.

**Q17.6 Referring to the response to the previous question, how would the diversity of lighting applications affect the group coincidence factor?**

A17.6 Dusk-to-dawn lighting is on the same duty cycle as street lighting and therefore will not affect the coincidence factor of the group.

**18.0 Reference: Exhibit B-3-1, BCUC IR#1, 41.1**

**Rate Design: Type II Lighting - Customer & FortisBC Contributions**

**"Fortis BC did not set line extension credits on the basis of the revenue to cost [R/C] ratios for each customer class. It is the goal to move towards 95-105 percent revenue to cost ratio for each class over time, and the line extension credits reflect that goal."**

**Q18.1 Please explain how the above approach is consistent with fully recovering costs from parties benefitting from the extensions, given the R/C ratios in the 2009 COSA.**

A18.1 The line extension credit is set to 100 percent of the costs resulting from the COSA. To the extent that a customer class is paying more or less than 100 percent in their retail revenues, it does not change the line extension credit to be more or less than 100 percent of cost. For example, the General Service Class has a 2009 revenue to cost ratio of 138.9 percent. The line extension credit is set at 100 percent of cost for that class, not 138.9 percent to be consistent with the retail rates, and not at a level below cost to make up for the overpayment in retail rates.

**Q18.2 Please explain how the above approach is consistent with provincial conservation objectives.**

A18.2 The above approach is consistent with conservation objectives in that the customer is responsible for the actual costs associated with providing service. This allows for the most efficient use of resources.

**Q18.3 Are Lighting customer contributions under Rate Schedule 74 attributed to the revenues of the Rate Schedule 50 customer class? If not confirmed, please explain why not.**

A18.3 Revenues associated with customer contributions are not tracked by customer class and therefore could not be directly assigned to the Lighting Class. Further, the CIAC amounts would be attributed as an offset to the rate base for the class, not as a revenue source.

**19.0 Reference: Exhibit B-3-1, BCUC IR#1, 42.1**

**Rate Design: Load Analysis Service Charge**

**"FortisBC will charge the customer an amount equal to the Company's cost to perform the service. The Company will provide the customer with an estimate for approval prior to commencing any work."**

**Q19.1 Is Load Analysis Service available from private sector suppliers?**

A19.1 Yes, Load Analysis Service is available from private sector suppliers other than FortisBC.

**20.0 Reference: Exhibit B-3-1, BCUC IR#1, 9.1 and 9.2**

**COSA: Budget for Future Studies**

**"Any future Rate Design Application will be supported by an updated cost of service study. FortisBC anticipates that it will likely update the 2009 COSA and RDA with the filing of the AMI Application and submit a new COSA and RDA in a further three to five years." [BCUC 9.1]**

**Q20.1 At what date will FortisBC file an updated Cost of Service study with the Commission?**

A20.1 Based on the forecast AMI implementation schedule, FortisBC expects to file an updated Cost of Service study in Q1 of 2014.

**Q20.2 What is FortisBC's existing budget balance for performing Cost of Service studies?**

A20.2 Of the $1 million total budget for the current RDA/COSA process that was included in the 2010 Revenue Requirement Application (November 2, 2009 update), FortisBC has $213,000 remaining. The budget for any COSA process in future years has not been established and would be submitted as part of a future regulatory filing.

**21.0 Reference: Exhibit B-3-1, BCUC IR#1, 18.1 and 68.6, and Exhibit B-1, Appendix A, Cost of Service Study, p. 13**

**COSA: Selection of 2CP and Summer Peak Growth**

**"Future system investments are not considered in the COSA estimates. The estimates used are based on a particular test year and future investments are addressed as they occur, in future COSA estimates." [BCUC 18.1]**

**"Demand-related transmission costs were allocated using the 2 CP method (sum of 2 winter and 2 summer peaks) to take the significance of the growth in summer peak into consideration. "[COSA, p. 13]**

**Q21.1 Please explain how not including anticipated system investments in the COSA estimates (as described in the response to BCUC 18.1) is consistent with selecting a transmission cost allocator (the 2 CP method) which (as alluded to in the above citation) takes summer peak growth into consideration, given that load data (BCUC 68.6) shows no summer hour during 2009 with a load as high during winter hours.**

A21.1 The costs included in the COSA reflect only those capital costs expected through the forecast for 2009. Since it is an embedded, rather than a marginal COSA, it is not appropriate to directly incorporate future investments in the rate base or revenue requirements of the COSA. Further, the 2CP method uses forecast peaks for 2009, consistent with the same test year for the revenue requirements. As with capital costs, the loads expected after 2009 are not directly included in the COSA calculations.

**22.0 Reference: Exhibit B-3-1, BCUC IR#1, 44.1 and 68.6, and Exhibit B-1, Appendix A, Cost of Service Study, p. 13**

**COSA: Selection of 2CP and FortisBC System Loads**

**"Forecast system peak loads for revenue requirement purposes are based on a probable total system peak from actual historical peaks plus forecast increases due to load growth." [BCUC 44.1]**

**"Demand-related transmission costs were allocated using the 2 CP method (sum of 2 winter and 2 summer peaks) to take the significance of the growth in summer peak into consideration."[COSA, p. 13]**

**Q22.1 Are the winter and summer peaks referred to in the citation instantaneous (momentary), or averaged (sustained) peak loads? If the latter, please describe the average used.**

A22.1 The peaks would reflect a 1-hour integrated load. (A time weighted average of load over the hour.)

**23.0 Reference: Exhibit B-3-1, BCUC IR#1, 54.3**

**COSA: Functionalization of General Plant**

**The response to BCUC IR#1, question 54.3 states that:**

***"Because the cost of General Plant is more closely tied to the number of employees rather than the cost of other plant items, the Company determined it was appropriate to use labour ratios for classification."***

**Q23.1 How common is the use of labour ratios, versus the proportion of rate base assigned to other functions, to functionalize and classify general plant?**

A23.1 FortisBC does not have data on the use of labour ratios by other utilities, but confirms that both methods are commonly used by other utilities. The use of General Plant as opposed to labour ratios for classification would have virtually no impact on the COSA results.

**24.0 Reference: Exhibit B-1, Appendix A, Schedule 8.1, and Exhibit B-3-1, BCUC IR#1 20.2**

**COSA: Irrigation Service CP & Load Factor**

**Q24.1 What was the Irrigation Service's annual coincident peak load factor in 1997?**

A24.1 The coincident peak load factor used for the 1997 COSA Study was 27 percent.

**25.0 Reference: Exhibit B-3-1, BCUC IR#1, 58.7 and 59.1**

**COSA: Classification of Generation**

**The response to BCUC IR#1, question 58.7 states that:**

***"Generation used to serve base loads rather than peaking are generally considered energy related and are not allocated on the basis of non-coincident peak ("NCP")."***

**Q25.1 Would FortisBC agree that the table and graph on page 102 (response to question 59.1) appears to suggest that the FBC plant serves base load? If not, why not? If so, why was the 100 percent energy-related method rejected?**

A25.1 While the FortisBC Resources as shown in IR1, BCUC Table A59.1 (Exhibit B-3-1) are relatively flat across all months, they do vary from 178 to 210 MW. This is nearly a 20 percent swing in the plant output. The 100 percent method was rejected because the FortisBC resources provide both energy and capacity. If only energy were provided, the resource could not be relied upon to meet 30 percent of the peak load on the system.

In applying a base-intermediate-peak approach, a base resource would be considered energy-related while a peak resource would be considered demand-related. This approach was not used for FortisBC and as such there are no resources that are designated as energy only or peak only. All of the resources used by FortisBC contribute both energy and capacity to the utility and all of the costs are split between the demand and energy components.

**Q25.2 If a Demand/Energy split is used was 1CP, 2CP or NCP demand used? Why?**

A25.2 The 2CP method was used for allocating both generation and transmission demand-related rate base, as stated on page 25 of the COSA. The rationale is provided in great detail on pages 25 through 30 of the COSA. (Appendix A of Exhibit B-1)

**Q25.3 What is the impact on the R/C ratios if the FBC generation plant is functionalized and classified in the COSA as 100 percent energy?**

A25.3 Please see the Table BCUC IR2 A25.3 below. The change to 100% energy has a very small impact on the R/C ratios.

**Table BCUC IR2 A25.3**

| | 80% Energy/ 20% Demand (As Filed) | 100% Energy |
|---|---:|---:|
| Residential | 98.3% | 98.4% |
| Small General Service (20) | 113.4% | 113.2% |
| General Service (21) | 138.9% | 138.9% |
| Industrial Primary (30) | 122.4% | 122.2% |
| Industrial Transmission (31) | 109.9% | 108.1% |
| Industrial Transmission TOU (33) | 23.5% | 24.0% |
| Lighting | 81.9% | 81.3% |
| Irrigation | 78.6% | 78.7% |
| Kelowna Wholesale | 89.9% | 89.8% |
| Penticton Wholesale | 78.0% | 78.0% |
| Summerland Wholesale | 96.6% | 96.7% |
| Grand Forks Wholesale | 68.1% | 68.0% |
| BC Hydro Lardeau Wholesale | 101.8% | 103.6% |
| BC Hydro Yahk Wholesale | 103.5% | 103.3% |
| Nelson Wholesale | 80.0% | 80.1% |
| Total | 100.0% | 100.0% |

**26.0 Reference: Exhibit B-3-1, BCUC IR#1 62.2**

**COSA: Minimum System - PLCC Value**

**FortisBC cited jurisdictions where PLCC adjustments ranged from 0.25 to 2.0 kW per customer.**

**Q26.1 For the Cost of Service study, was the FortisBC system treated as conductor-constrained or transformer-constrained? Please explain.**

A26.1 The FortisBC system was treated as conductor-constrained. In the COSA, feeders were classified into three groups: urban, urban/rural and rural, typically based on location and feeder length. For each classification, end-of-line voltage drop determined the maximum rating on the feeder.

**27.0 Reference: Exhibit B-3-1, BCUC IR#1 88.1**

**COSA: Minimum System – Current Costs**

**"If the shift towards customer-related costs did result due to the higher amperage, the COSA could result in a bias towards the newer customer with higher amp service. However, the PLCC adjustment compensates for this, increasing as the minimum size of facilities increases."**

**Q27.1 Please explain whether the compensation referred to above is a result of using current costs (as opposed to historical costs) in Minimum System Analysis generally, or whether it reflects FortisBC customer trends in particular.**

A27.1 The compensation would occur generally in a Minimum System analysis. The change would occur over time as the COSA and Minimum System would be updated to reflect changes in facilities and costs over time.

**Q27.2 Please confirm that the COSA-indicated Customer costs are used, unadjusted, in System Extension calculations forming part of the 2009 Rate Design. If not, please explain why not.**

A27.2 The Customer-related costs included in the Line Extension Calculations are unadjusted.

**28.0 Reference: Exhibit B-3-1, BCUC IR#1, 65.1**

**COSA: Classification of Administrative & General Expenses**

**The response to BCUC IR#1 65.1 discusses the use of rate base versus Operations and Maintenance expenses to classify A&G.**

**Q28.1 How common in COSA is the use of rate base to classify A&G relative to O&M?**

A28.1 A specific survey to see what percent use each method was not done, however the Company has seen consistent use of both methods by other utilities. The use of O&M expense as opposed to rate base for classification would have virtually no impact on the COSA results.

**29.0 Reference: Exhibit B-3-1, BCUC IR#1 66.10 and 68.4, and Exhibit B-3-1, BCMEU IR#1 Appendix A15.1A, pp. 299-306**

**COSA: Selection of 2CP: – Component Loading**

**Q29.1 For the system components listed in the "Load Forecast" tables in the 2009 SDP Update on pages 299 through 306, please provide a summary table showing, for each listed system element, the maximum percent of rated capacity (i.e., percent of overload compared to the manufacturer's equipment rating) experienced during 2009 (or the most recent 12 months for which data are available), and identifying the time (date and hour) when the maximum was recorded.**

A29.1 Please refer to Table BCUC IR2 A29.1 below.

**Table BCUC IR2 A29.1 – Substation Transformer Peak Utilization**

| Region | Station | Transformer | % of maximum equipment rating | Time of % of max. equipment rating | Comments |
|---|---|---|---|---|---|
| NOK | Glenmore | T2 | 68% | n/a | No time available. |
| NOK | Glenmore | T3 | 71% | 2009/07/22 17:45 | |
| NOK | Hollywood | T1 | 72% | 2009/07/27 17:30 | |
| NOK | Hollywood | T3 | 86% | 2009/07/27 17:30 | |
| NOK | Okanagan Mission | T1 | 88% | 2009/07/27 18:00 | |
| NOK | Okanagan Mission | T2 | 40% | 2009/07/27 18:00 | |
| NOK | Recreation | T1 | 75% | 2009/12/10 17:00 | |
| NOK | Sexsmith | T1 | 95% | 2009/07/22 15:30 | |
| NOK | Saucier | T1 | 62% | 2009/07/28 16:15 | |
| NOK | Duck Lake | T1 | 57% | 2009/07/21 18:00 | |
| NOK | Joe Rich | T1 | 13% | 2009/12/24 9:00 | |
| NOK | D.G. Bell | T1 | 66% | 2009/08/01 18:00 | |
| NOK | Lee | T tert | 34% | 2009/07/27 18:15 | |
| NOK | Ellison | T1 | 23% | 2009/12/23 17:15 | Station came online in December 2009 |
| NOK | Black Mountain | T1 | 26% | 2009/12/14 17:45 | |
| NOK | Big White | T1 | 31% | 2008/12/31 18:00 | |
| SOK | Huth | T4/5/6/7 | 83% | n/a | No time available. |
| SOK | Huth 13kV(HUT1) | T8 | 21% | n/a | No time available. |
| SOK | Kaleden | T1 | 72% | n/a | No time available. |
| SOK | Naramata (Arawana) | T1 | 52% | 2009/12/08 8:45 | |
| SOK | Okanagan Falls | T1 | 62% | n/a | No time available. |
| SOK | Summerland | T2 | 72% | 2009/12/14 17:45 | |
| SOK | Waterford | T1 | 44% | 2009/08/01 17:15 | |
| SOK | West Bench | T1 | 79% | n/a | No time available. |
| SOK | Westminster | T1/T2 | 68% | n/a | No time available. |
| SOK | Trout Creek | T1 | 42% | n/a | No time available. |
| SOK | Pine Street | T1 | 36% | 2009/07/28 15:00 | |
| SOK | Pine Street | T2 | 54% | 2009/07/22 16:45 | |
| SOK | Osoyoos | T1 | 52% | 2009/08/01 17:15 | |
| SOK | Osoyoos | T2 | 43% | 2009/07/17 18:15 | |
| SOK | Keremeos | T1 | 49% | 2009/07/22 15:30 | |
| SOK | Hedley | T1 | 41% | 2009/12/08 7:15 | |

**Table BCUC IR2 A29.1 – Substation Transformer Peak Utilization Cont'd**

| Region | Station | Transformer | % of maximum equipment rating | Time of % of max. equipment rating | Comments |
|---|---|---|---|---|---|
| SOK | Anderson | T3 | 93% | 2009/07/22 14:45 | |
| SOK | Oliver | T1 | 66% | n/a | No time available. |
| SOK | Princeton | T4 | 37% | 2009/12/07 19:15 | |
| SOK | Nk'Mip | T1 | 24% | 2009/08/01 18:00 | |
| SOK | BC Gas (Terasen) | - | n/a | | Transmission interconnection |
| SOK | Mascot | - | n/a | | Transmission interconnection |
| KT | Kaslo | T1 | 47% | 2009/12/08 7:45 | |
| KT | Coffee Creek | T3 | 62% | n/a | No time available. |
| KT | Crawford Bay | T4 | 0% | n/a | Standby spare - normally unloaded |
| KT | Crawford Bay | T5 | 33% | 2009/12/08 8:30 | |
| KT | Wyndell | T1 | n/a | n/a | Decommissioned |
| KT | Creston | T1 | 73% | 2009/12/08 7:00 | |
| KT | Creston | T2 | 53% | 2009/12/08 8:00 | |
| KT | Lambert | T2 | 29% | 2009/12/08 8:15 | |
| KT | Valhalla | T1 | 45% | 2009/12/08 20:00 | |
| KT | Valhalla | T2 | n/a | n/a | Added in Fall 2009. Picks up load from old SLO T1. Meter not available yet for data. |
| KT | Passmore | T1 | 52% | 2009/12/08 19:15 | |
| KT | Playmor | T1 | 61% | 2009/12/08 7:30 | |
| KT | Slocan City | T1 | 95% | n/a | Decommissioned in fall 2009. Now Valhalla T2. |
| KT | Tarrys | T1 | 122% | n/a | No time available. |
| KT | Whitewater | T1 | n/a | | Decommissioned |
| KT | Cottonwood | T1 | 4% | 2009/12/29 11:00 | |
| KT | Salmo | T1 | 39% | 2009/12/08 8:15 | |
| KT | Hearns | T1 | 71% | n/a | No time available. |
| KT | Fruitvale | T1 | 86% | n/a | No time available. |
| KT | Ymir | T1 | 48% | n/a | No time available. |
| KT | Castlegar | T1 | 67% | 2009/12/08 16:45 | |
| KT | Blueberry | T1 | 43% | 2009/12/08 17:30 | |
| KT | Ootischenia | T1 | 33% | 2009/12/08 17:30 | |
| KT | Trail | T1 | n/a | | Decommissioned |
| KT | Beaver Park | T1 | 78% | 2009/07/29 15:15 | |

**Table BCUC IR2 A29.1 – Substation Transformer Peak Utilization Cont'd**

| Region | Station | Transformer | % of maximum equipment rating | Time of % of max. equipment rating | Comments |
|---|---|---|---|---|---|
| KT | Glenmerry | T1 | 48% | n/a | No time available. |
| KT | Stoney Creek | T1 | 72% | n/a | No time available. |
| KT | Paterson | T1 | n/a | | Decommissioned |
| KT | Cascade | T1 | 36% | 2009/12/27 18:00 | |
| KT | Celgar | - | n/a | | Transmission interconnection |
| KT | P&T - Castlegar | - | n/a | n/a | Transmission interconnection |
| KT | City of Nelson | - | n/a | n/a | Transmission interconnection |
| BND | Christina Lake | T1 | 85% | n/a | No time available. |
| BND | Ruckles | T1 | 49% | n/a | No time available. |
| BND | Ruckles | T2 | 70% | 2009/12/09 11:45 | |
| BND | Grand Forks Terminal | T3 | 38% | 2009/12/08 17:45 | |
| BND | Kettle Valley | T1/T2 | 11% | 2009/12/08 8:45 | |
| BND | Midway | T1 | n/a | n/a | Decommissioned |
| BND | Rock Creek | T1 | n/a | n/a | Decommissioned |
| BND | Rock Creek | T2 | n/a | n/a | Decommissioned |
| BND | Baldy | T1 | n/a | n/a | Decommissioned |
| BND | Greenwood | T1 | n/a | n/a | Decommissioned |
| BND | Roxul | - | n/a | n/a | Transmission interconnection |

**30.0 Reference: Exhibit B-3-1, BCUC IR#1, 68.6**

**COSA: Residential Customer Loads as Residual**

**Q30.1 What approximate percentage (or range of percentage) of hourly load can be attributed to Residential customers as the residual of that identified for directly-metered customers?**

A30.1 The residential class is assumed to have a range of 45 to 65 percent when their assumed peak monthly load is compared to the peak monthly load for the classes without hourly demand meters. This is based on the 2009 forecast as provided in the COSA (Appendix A to Exhibit B-1).

**31.0 Reference: Exhibit B-1, Appendix A, Cost of Service Study, Schedule 8.1 COSA: Forecast Customers & Energy Sales: Residential Customers**

**Q31.1 Please explain why the number of Residential customers in Cost of Service Study, Schedule 8.1 decreases during some months in 2009.**

A31.1 Year-end customers were provided in the forecast for 2009. The monthly forecast was based on the pattern exhibited in 2008. Move-outs exceed move-ins in some months of the year, resulting in a decrease in customer count for those months .

**32.0 Reference: Exhibit B-3-2, BCOAPO IR#1, 32.3, and Exhibit B-1, Appendix A, pp. 25-28**

**COSA: Selection of Demand Allocator**

**Q32.1 Please provide electronic copies of the FERC and OEB documents (or, if very large documents, the relevant sections) setting out their respective tests for which demand allocator should be used.**

A32.1 The requested documents are provided as BCUC IR2 Appendix A32.1.

**33.0 Reference: Exhibit B-3-1, BCUC IR#1, 84.3, and**
**Exhibit B-1, Appendix A, Schedule 3.2**
**COSA: Power Purchases**

**Exhibit B-1, Appendix A, Schedule 3.2, Shows annual Power Purchases as being $52,400,770. Exhibit B-3-1, Table BCUC A84.3 shows Market Capacity – Energy projected as $1,841 for 2015, and Market Energy Purchase as $5,260 for 2015.**

**Q33.1 Please confirm that, aside from other differences, the Annual Power Purchases contained in Schedule 3.2 includes BC Hydro Power Purchases, whereas Table BCUC A84.3 does not.**

A33.1 Confirmed.

**Q33.2 Please provide a table similar to Table A84.3 that shows BC Hydro Power Purchases and other power purchases for 2009 and reconcile those figures to the totals found in Schedule 3.2.**

A33.2 The requested information is provided below in Table BCUC IR2 A33.2. This is consistent with the total found in Exhibit B-1, Appendix A, Schedule 3.2.

**Table BCUC IR2 A33.2**
**Energy Portion of Purchased Power Costs - 2009**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | $000s | | | | | | |
| IPP Costs | 14 | 11 | 20 | 17 | 71 | 63 | 77 | 17 | 20 | 14 | 23 | 23 | 370 |
| BCH Purchase | 3,577 | 3,081 | 3,054 | 1,750 | 947 | 921 | 1,318 | 1,000 | 1,756 | 2,685 | 3,578 | 3,697 | 27,365 |
| Market Capacity - ENERGY | 55 | 0 | 251 | 0 | 0 | 0 | 283 | 1 | 0 | 0 | 6 | 0 | 596 |
| Brilliant Base Plant (1) | 2,055 | 1,580 | 1,431 | 2,242 | 2,173 | 1,980 | 2,174 | 2,360 | 1,812 | 1,707 | 1,726 | 1,784 | 23,023 |
| Brilliant Upgrade (1) | 10 | (9) | (7) | 157 | 223 | 208 | 223 | 205 | 16 | 10 | 5 | 5 | 1,047 |
| **Total Energy Charges** | **5,712** | **4,663** | **4,749** | **4,167** | **3,415** | **3,172** | **4,076** | **3,582** | **3,603** | **4,416** | **5,337** | **5,509** | **52,401** |

(1) Reflects the portion of costs determined to be energy-related. Please refer to Exhibit B-1, Appendix A, page 23 for additional information.

**Q33.3 Please provide a table similar to that requested above for 2015.**

A33.3 The requested information is provided below in Table BCUC IR2 A33.3.

**Table BCUC IR2 A33.3**
**Energy Portion of Purchased Power Costs - 2015**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | $000s | | | | | | | | | | | | |
| IPP Costs | 16 | 12 | 22 | 19 | 78 | 69 | 84 | 19 | 22 | 16 | 25 | 25 | 405 |
| BCH Purchase | 4,541 | 4,101 | 3,699 | 2,167 | 1,161 | 1,320 | 1,717 | 1,877 | 2,220 | 3,593 | 4,394 | 4,541 | 35,330 |
| Market Capacity - ENERGY | 435 | 30 | 450 | 0 | 0 | 15 | 727 | 41 | 0 | 21 | 94 | 29 | 1,841 |
| Market Energy Purchase | 440 | 967 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1,161 | 2,692 | 5,260 |
| Brilliant Base Plant (1) | 2,675 | 2,057 | 1,863 | 2,671 | 2,589 | 2,358 | 2,590 | 2,812 | 2,158 | 2,033 | 2,056 | 2,125 | 27,988 |
| Brilliant Upgrade (1) | 13 | (12) | (8) | 181 | 257 | 239 | 257 | 236 | 18 | 11 | 5 | 6 | 1,203 |
| **Total Energy Charges** | **8,120** | **7,156** | **6,025** | **5,038** | **4,084** | **4,001** | **5,375** | **4,984** | **4,418** | **5,674** | **7,735** | **9,417** | **72,026** |

(1) Reflects the portion of costs determined to be energy-related. Please refer to Exhibit B-1, Appendix A, page 23 for additional information.

**34.0 Reference: Exhibit B-3-3-2, BCMEU IR#1 4.1, 23.1, and 34.2, and Exhibit B-1, Appendix A, Cost of Service Study**

**COSA: Wholesale and Industrial Supply Agreements and System Details**

**Q34.1 Please provide a one-line diagram of the FortisBC transmission system. Please indicate operating voltages, points of interconnection with other utilities, all transmission substations with high-side and low-side operating voltages and points of delivery for the seven Wholesale customers listed in the EES Cost of Service Study (COSA).**

A34.1 Please refer to BCUC IR2 Appendix A34.1.

**Q34.2 For each Wholesale customer, please provide the following information for each point of delivery for each Wholesale customer; a one-line diagram of the facilities used to deliver service at wholesale at the voltages referenced in the supply agreements with each Wholesale customer; a listing of the dedicated facilities used to serve each Wholesale customer at each point of delivery showing the book cost by FERC account number.**

A34.2 Please refer to BCUC IR2 Appendix A34.2 for the substation single-line diagrams of the wholesale municipal interconnections.

For interconnection stations which provide service both to FortisBC customers and to wholesale municipal customers, FortisBC is unable to provide the book value of just the wholesale dedicated facilities as the company does not track the asset values on this basis. Examples of these shared facilities include the Coffee Creek, Glenmore, Huth, Ruckles, R.G.Anderson and Trout Creek substations.

For all other sites, the substations exist solely to supply the wholesale municipal customers and thus the values previously provided in the response to BCMEU IR No. 1 Q6.1 (Exhibit B-3-3) represent the requested book costs.

**Q34.3 Please provide a listing of actual monthly billing demands for each for Wholesale customer by each point of delivery for the test period used in the COSA. Identify any month which the billing demand exceeded 95 percent of the demand limits listed in each Wholesale Agreement.**

A34.3 The following Tables BCUC IR2 A34.3(a) through A34.3(e) provide a listing of actual monthly billing demands for each Wholesale customer by each point of delivery for the year 2008. During this period, the months in which the actual demand exceeded 95 percent of the demand limit are greyed out in the tables below.

**Table BCUC IR2 A34.3(a) – Grand Forks**

| | City 5 kV (kVA) | Demand Limit (kVA) | % of Demand Limit | City 13 kV (kVA) | Demand Limit (kVA) | % of Demand Limit | Donaldson Dr. (kVA) | Demand Limit (kVA) | % of Demand Limit |
|---|---|---|---|---|---|---|---|---|---|
| Jan-08 | 3,361 | 8,000 | 42.01% | 4,534 | 8,000 | 56.68% | 281 | 8,000 | 3.51% |
| Feb-08 | 3,036 | 8,000 | 37.95% | 4,317 | 8,000 | 53.96% | 73 | 8,000 | 0.91% |
| Mar-08 | 3,114 | 8,000 | 38.93% | 1,824 | 8,000 | 22.80% | 1,728 | 8,000 | 21.60% |
| Apr-08 | 3,014 | 8,000 | 37.68% | 1,769 | 8,000 | 22.11% | 1,565 | 8,000 | 19.56% |
| May-08 | 2,726 | 8,000 | 34.08% | 1,578 | 8,000 | 19.73% | 1,451 | 8,000 | 18.14% |
| Jun-08 | 2,702 | 8,000 | 33.78% | 1,767 | 8,000 | 22.09% | 1,825 | 8,000 | 22.81% |
| Jul-08 | 3,608 | 6,000 | 60.13% | 1,782 | 6,000 | 29.70% | 1,857 | 6,000 | 30.95% |
| Aug-08 | 3,735 | 6,000 | 62.25% | 1,857 | 6,000 | 30.95% | 1,889 | 6,000 | 31.48% |
| Sep-08 | 2,864 | 8,000 | 35.80% | 1,493 | 8,000 | 18.66% | 1,475 | 8,000 | 18.44% |
| Oct-08 | 2,904 | 8,000 | 36.30% | 1,896 | 8,000 | 23.70% | 1,728 | 8,000 | 21.60% |
| Nov-08 | 2,771 | 8,000 | 34.64% | 2,194 | 8,000 | 27.43% | 1,917 | 8,000 | 23.96% |
| Dec-08 | 3,621 | 8,000 | 45.26% | 5,298 | 8,000 | 66.23% | - | 8,000 | 0.00% |

### Table BCUC IR2 A34.3(b) - Kelowna

| | **Saucier (kVA)** | **% of Demand Limit** | **Recreation Feeder (kVA)** | **% of Demand Limit** | **Glenmore (kVA)** | **% of Demand Limit** | **Pollution Control (kVA)** | **% of Demand Limit** |
|---|---|---|---|---|---|---|---|---|
| | ***Demand Limit of 30,000 KVA*** | | ***Demand Limit of 30,000 KVA*** | | ***Demand Limit of 20,000 KVA*** | | ***Demand Limit of 11,800 KVA*** | |
| Jan-08 | 20,664 | 68.88% | 20,916 | 69.72% | 13,489 | 67.45% | 7,003 | 59.35% |
| Feb-08 | 18,204 | 60.68% | 19,479 | 64.93% | 11,696 | 58.48% | 6,293 | 53.33% |
| Mar-08 | 16,230 | 54.10% | 18,106 | 60.35% | 9,421 | 47.11% | 5,532 | 46.88% |
| Apr-08 | 15,522 | 51.74% | 17,261 | 57.54% | 8,435 | 42.18% | 5,623 | 47.65% |
| May-08 | 14,868 | 49.56% | 17,778 | 59.26% | 8,013 | 40.07% | 5,725 | 48.52% |
| Jun-08 | 18,573 | 61.91% | 18,288 | 60.96% | 10,726 | 53.63% | 5,991 | 50.77% |
| Jul-08 | 19,204 | 64.01% | 21,386 | 71.29% | 10,466 | 52.33% | 5,964 | 50.54% |
| Aug-08 | 19,100 | 63.67% | 22,484 | 74.95% | 10,487 | 52.44% | 6,392 | 54.17% |
| Sep-08 | 14,400 | 48.00% | 14,673 | 48.91% | 6,725 | 33.63% | 4,875 | 41.31% |
| Oct-08 | 15,096 | 50.32% | 17,563 | 58.54% | 7,632 | 38.16% | 5,696 | 48.27% |
| Nov-08 | 16,584 | 55.28% | 19,465 | 64.88% | 10,008 | 50.04% | 5,903 | 50.03% |
| Dec-08 | 22,320 | 74.40% | 20,914 | 69.71% | 13,925 | 69.63% | 7,526 | 63.78% |

1 **Table BCUC IR2 A34.3(c) - Nelson**

| | Rosemont (kVA) | % of Demand Limit | Coffee Creek (kVA) | % of Demand Limit |
|---|---|---|---|---|
| | ***Demand Limit of 30,000 KVA*** | | ***Demand Limit of 5,000 KVA*** | |
| Jan-08 | 21,377 | 71.26% | 3,871 | 77.42% |
| Feb-08 | 19,810 | 66.03% | 3,320 | 66.40% |
| Mar-08 | 16,289 | 54.30% | 2,939 | 58.78% |
| Apr-08 | 21,008 | 70.03% | 3,014 | 60.28% |
| May-08 | 14,027 | 46.76% | 1,865 | 37.30% |
| Jun-08 | 7,747 | 25.82% | 1,121 | 22.42% |
| Jul-08 | 17,430 | 58.10% | 0 | 0.00% |
| Aug-08 | 15,465 | 51.55% | 1,416 | 28.32% |
| Sep-08 | 9,867 | 32.89% | 1,637 | 32.74% |
| Oct-08 | 22,962 | 76.54% | 2,736 | 54.72% |
| Nov-08 | 17,626 | 58.75% | 3,024 | 60.48% |
| Dec-08 | 25,370 | 84.57% | 4,238 | 84.76% |

### Table BCUC IR2 A34.3(d) - Penticton

| | Huth 8 kV (kVA) | Demand Limit | % of Demand Limit | Huth 13 kV (kVA) | Demand Limit | % of Demand Limit | R.G Anderson (kVA) | Demand Limit | % of Demand Limit |
|---|---|---|---|---|---|---|---|---|---|
| Jan-08 | 13,325 | 13,600 | 97.98% | 6,032 | 40,000 | 15.08% | 13,247 | 25,000 | 52.99% |
| Feb-08 | 12,274 | 13,600 | 90.25% | 5,947 | 40,000 | 14.87% | 13,340 | 25,000 | 53.36% |
| Mar-08 | 10,504 | 13,600 | 77.24% | 5,383 | 40,000 | 13.46% | 11,712 | 25,000 | 46.85% |
| Apr-08 | 10,597 | 13,600 | 77.92% | 5,154 | 40,000 | 12.89% | 12,149 | 25,000 | 48.60% |
| May-08 | 8,994 | 13,600 | 66.13% | 5,288 | 40,000 | 13.22% | 9,477 | 25,000 | 37.91% |
| Jun-08 | 10,222 | 13,600 | 75.16% | 6,344 | 40,000 | 15.86% | 11,923 | 25,000 | 47.69% |
| Jul-08 | 11,030 | 10,500 | 105.05% | 6,417 | 32,000 | 20.05% | 13,857 | 20,000 | 69.29% |
| Aug-08 | 11,514 | 10,500 | 109.66% | 6,687 | 32,000 | 20.90% | 12,600 | 20,000 | 63.00% |
| Sep-08 | 8,450 | 13,600 | 62.13% | 4,862 | 40,000 | 12.16% | 10,301 | 25,000 | 41.20% |
| Oct-08 | 10,144 | 13,600 | 74.59% | 4,888 | 40,000 | 12.22% | 11,796 | 25,000 | 47.18% |
| Nov-08 | 11,760 | 13,600 | 86.47% | 5,369 | 40,000 | 13.42% | 12,029 | 25,000 | 48.12% |
| Dec-08 | 10,998 | 13,600 | 80.87% | 6,177 | 40,000 | 15.44% | 18,846 | 25,000 | 75.38% |

| | Waterford (kVA) | Demand Limit | % of Demand Limit | Westminster (kVA) | Demand Limit | % of Demand Limit |
|---|---|---|---|---|---|---|
| Jan-08 | 16,815 | 40,000 | 42.04% | 20,957 | 38,000 | 55.15% |
| Feb-08 | 13,999 | 40,000 | 35.00% | 17,843 | 38,000 | 46.96% |
| Mar-08 | 11,916 | 40,000 | 29.79% | 15,601 | 38,000 | 41.06% |
| Apr-08 | 11,830 | 40,000 | 29.58% | 15,136 | 38,000 | 39.83% |
| May-08 | 9,595 | 40,000 | 23.99% | 11,919 | 38,000 | 31.37% |
| Jun-08 | 15,116 | 40,000 | 37.79% | 16,310 | 38,000 | 42.92% |
| Jul-08 | 15,938 | 32,000 | 49.81% | 17,763 | 31,000 | 57.30% |
| Aug-08 | 16,371 | 32,000 | 51.16% | 18,792 | 31,000 | 60.62% |
| Sep-08 | 8,782 | 40,000 | 21.96% | 11,612 | 38,000 | 30.56% |
| Oct-08 | 11,096 | 40,000 | 27.74% | 13,905 | 38,000 | 36.59% |
| Nov-08 | 13,640 | 40,000 | 34.10% | 17,081 | 38,000 | 44.95% |
| Dec-08 | 18,420 | 40,000 | 46.05% | 23,537 | 38,000 | 61.94% |

1 **Table BCUC IR2 A34.3(e) - Summerland**

| | City 8 kV (kVA) | Demand Limit | % of Demand Limit | Trout Creek 8 kV (kVA) | Demand Limit | % of Demand Limit |
|---|---|---|---|---|---|---|
| Jan-08 | 15,629 | 20,000 | 78.15% | 5,732 | 10,000 | 57.32% |
| Feb-08 | 13,823 | 20,000 | 69.12% | 5,042 | 10,000 | 50.42% |
| Mar-08 | 12,187 | 20,000 | 60.94% | 4,262 | 10,000 | 42.62% |
| Apr-08 | 11,862 | 20,000 | 59.31% | 4,405 | 10,000 | 44.05% |
| May-08 | 9,387 | 20,000 | 46.94% | 2,949 | 10,000 | 29.49% |
| Jun-08 | 11,932 | 20,000 | 59.66% | 3,704 | 10,000 | 37.04% |
| Jul-08 | 12,113 | 16,000 | 75.71% | 4,121 | 6,000 | 68.68% |
| Aug-08 | 12,481 | 16,000 | 78.01% | 4,212 | 6,000 | 70.20% |
| Sep-08 | 8,509 | 20,000 | 42.55% | 3,081 | 10,000 | 30.81% |
| Oct-08 | 11,487 | 20,000 | 57.44% | 3,682 | 10,000 | 36.82% |
| Nov-08 | 12,784 | 20,000 | 63.92% | 4,434 | 10,000 | 44.34% |
| Dec-08 | 17,430 | 20,000 | 87.15% | 6,581 | 10,000 | 65.81% |

**8.02 Totalizing Metering**
The Company shall also, at its expense, install totalizing metering to compensate for demand diversity at the different Points of Delivery.

**Q34.4 Please explain the practices of FortisBC with regards to "Totalizing Metering" referenced in paragraph 8.02 of the Wholesale Agreements. Please provide an example of how this contract provision is implemented and how often this language has been applied to the determination of billing demand for the Wholesale customers.**

A34.4 FortisBC uses hourly interval data from the municipal Wholesale customer Points of Delivery ("POD") to calculate totalized demand each month. Totalized demand is calculated by summing the demand at each POD for each hour of the month. The highest hourly total during the month is the totalized demand for billing purposes for that month.

The following sample data is used to illustrate the calculation:

| | POD #1 (kVA) | POD #2 (kVA) | POD #3 (kVA) | Totalized (kVA) |
|---|---|---|---|---|
| **Hour 1** | 5.0 | 10.0 | 5.0 | 20.0 |
| **Hour 2** | 10.0 | 6.0 | 6.0 | 22.0 |
| **Hour 3** | 5.0 | 5.0 | 10.0 | 20.0 |
| **Max by POD** | 10.0 | 10.0 | 10.0 | 30.0 |

In the above example, the monthly totalized demand for billing purposes would be 22.0 kVA whereas the "non-totalized" demand (the sum of the maximum demand for the month at each POD) is 30.0 kVA.

**Q34.5 Please provide a copy of the Wholesale service agreements for BC Hydro Lardeau service and the BC Hydro Yahk service.**

A34.5 The requested service agreements are attached as BCUC IR2 Appendix A34.5.

**Q34.6 Please provide the following information for each point of delivery for each industrial customer served under Rate Schedules 31 and 33; a one-line diagram of the facilities used to deliver service to each industrial customer; a listing of the dedicated facilities used to serve each industrial customer at each point(s) of delivery showing the book cost by FERC account number.**

A34.6 Note that for Rate Schedule 31 and Rate Schedule 33 customers, the substation facilities are owned by the customer and thus FortisBC has no single-line diagrams to provide for these sites. The FortisBC interconnection facilities are shown in the FortisBC System Single-Line Diagram drawing 4-000-0403 which is attached to these responses as BCUC IR2 Appendix A34.1.

Similar to the response to BCUC IR No. 2 Q34.2, FortisBC is unable to provide the book cost for the interconnection-related assets for these customers. The equipment associated with these interconnections is captured within the total values of the interconnecting transmission line or substation.

**Q34.7 Please provide copies of the service contracts for all Rate Schedules 31 and 33 industrial customers referenced in the COSA.**

A34.7 Attached as BCUC IR2 Appendix A34.7 are the requested service contracts for Rate Schedules 31 and 33.

**35.0 Reference: Exhibit B-3-1, BCUC IR#1, 12.1**

**Contract Demand: Use by Other Utilities**

**"In Alberta, transmission rates are set by the Alberta Electric System Operator (AESO) and the charge for transmission is set on the basis of the highest of actual demand, 90% of a 24-month ratchet or 90% of contract demand... the use of contract demand as a billing determinant is a common feature of the rate schedules applied to large customers in many electric utility tariffs including BC Hydro, Southeastern Power Administration, Bonneville Power Administration..."**

**Q35.1 What is the rationale behind AESO's use of 90 percent of contract demand? Please explain, with particular reference to why 100 percent is not used, and providing background materials if possible.**

A35.1 The 100 percent ratchet on contract demand was lowered to 90 percent as a result of the February 2, 2000 AEUB Decision concerning a general tariff application by ESBI Alberta Ltd. The move was described as being made largely to allow greater operation flexibility for ESBI's customers, which had a different composition with different issues than those FortisBC customers affected by contract demand. The relevant decision is attached to this response a BCUC IR2 Appendix A35.1. While Alberta provides an example of a contract demand based ratchet, it is the opinion of FortisBC that 100 percent ratchet is appropriate in order to protect the recovery by the Company of its fixed costs. Implementation of the ratchet also ensures that other FortisBC retail customers are insulated from the investments made for the benefit of others.

**Q35.2 Please provide (up to three) examples of how BC Hydro uses contract demand in its Electric Tariff, consistent with the proposals in the FortisBC 2009 Rate Design.**

A35.2 The FortisBC proposed rates use Contract Demand as a billing determinant for several classes including 21 – General Service, 30 – Large General Service – Primary, 31 - Large General Service – Transmission, and the Wholesale rate schedules.

BC Hydro also uses Contract Demand as a billing determinant for several rate classes including;

- **SCHEDULE 1823 - TRANSMISSION SERVICE - STEPPED RATE;**
- **SCHEDULE 1825 - TRANSMISSION SERVICE - TIME-Of-USE (TOU) RATE;**
- **SCHEDULE 1827 - TRANSMISSION SERVICE - RATE FOR EXEMPT CUSTOMERS; and**
- **SCHEDULE 1852 - TRANSMISSION SERVICE - MODIFIED DEMAND**

Each of the rate schedules above contains the following excerpt (bold added):

*Billing Demand*

*The Demand for billing purposes shall be:*

1. *The highest kV.A demand in the Billing Period during the High Load Hours (HLH); or*
2. *75% of the highest Billing Demand for the Customer's Plant in the immediately preceding period of November to February, both months included; or.*
3. *50% of the **Contract Demand** stated in the Electricity Supply Agreement for the Customer's Plant,*

*whichever is the highest value.*

**Q35.3 Please provide (up to three) examples of how Bonneville Power Administration uses contract demand in its tariff, which are consistent with the proposals in the FortisBC 2009 Rate Design.**

A35.3 Bonneville Power Administration rates UFT-10, IM-10 and PTP-10 are attached as BCUC IR2 Appendix A35.3. Each of these rates uses a capacity reservation as a billing determinant in a manner similar to the contract demand provisions in the proposed FortisBC COSA and RDA.

**36.0 Reference: Exhibit B-3-1, BCUC IR#1, 57.2**

**Contract Demand: BC Hydro Power Purchase Agreement**

A57.2 Yes, FortisBC pays a demand charge under its Power Purchase Agreement ("PPA") contract with BC Hydro. However, the charge is not based on the contracted maximum of 200 MW. It is based on the greatest of three calculations:

1. 50 percent of the nominated demand. Nominations are between zero and 200 MW and are made five years in advance. For many years now the Company has nominated 200 MW and expects to continue to do so for the foreseeable future;
2. The actual monthly usage;
3. 75 percent of the previous 11 months highest actual usage.

For all practical purposes, (1) above is never used except to establish a firm forward financial commitment to pay for 100 MW each month in the Company's forward looking financial reporting. Assuming the Company uses the 200 MW each winter, the actual monthly charge will be between 150 and 200 MW.

**Q36.1 Does FortisBC agree that its Power Purchase Agreement with BC Hydro could reasonably be viewed as analogous with the Agreements for Supply of Electricity between FortisBC and its Wholesale customers? Please explain, by listing and describing the differences between the two types of Agreements.**

A36.1 No FortisBC does not agree due to the following differences.

- BC Hydro PPA does not supply all of the energy and capacity that FortisBC requires; FortisBC must arrange for the majority of its power purchase needs, whereas FortisBC does supply nearly all of the energy and capacity to the wholesale customers with the exception of Nelson. However, the Company still has the obligation to meet the balance of the Nelson load.
- FortisBC is capped on energy and capacity take and pays penalties for exceeding that take, whereas FortisBC wholesale customers currently have no penalties.

- FortisBC is required to nominate capacity requirements at each point of delivery and pays penalties for exceeding that take.
- FortisBC pays for 100 percent of any costs related to connections to the BC Hydro transmission system, whereas FortisBC pays a substantial portion of these costs at the points of delivery with the wholesale customers.

## 37.0 Reference: Exhibit B-3-1, BCUC IR#1, 15.1

## Contract Demand: System Development Plan

Table BCUC A15.1

| T&D Forecast Expenditures for 2010 | | | | | |
|---|---|---|---|---|---|
| | Forecast | Nature of Project / Upgrade | | | |
| Transmission Projects | ($000s) | Energy | Capacity | Customer | Prime Driver |
| Ellison Distribution Source | 500 | | X | | Expansion |
| Okanagan Transmission Reinforcement | 62,325 | | X | | Expansion |
| Benvoulin Distribution Source | 13,301 | | X | | Expansion |
| Recreation Capacity Increase Stage 1,2,3 | 2,257 | | X | | Expansion |
| Kelowna Distribution Capacity Requirements | 517 | | X | | Expansion |
| Huth Substation Upgrade | 413 | | X | | Expansion |
| 30 Line Conversion | 2,340 | | X | | Expansion |
| Transmission Sustaining | 4,871 | X | X | | Replacement |
| Stations Sustaining | 5,303 | X | X | | Replacement |
| **Transmission & Stations Total** | **91,827** | | | | |
| | | | | | |
| Distribution Projects | | | | | |
| New Connects System Wide | 10,670 | | | X | Expansion |
| Airport Way Upgrade (Ellison Feeder 3) | 1,551 | | X | | Expansion |
| Hollywood Feeder 3 - Sexsmith Feeder 4 Tie | 365 | | X | | Expansion |
| Beaver Park - Fruitvale Distribution Tie | 1,227 | | X | | Expansion |
| Small Growth Projects | 137 | | X | | Expansion |
| Small Capacity Improvements Unplanned | 994 | | X | | Expansion |
| Distribution Sustaining | 14,525 | X | X | | Replacement |
| **Total** | **29,469** | | | | |
| | | | | | |
| **Total for Transmission and Distribution:** | **121,296** | | | | |
| **Category totals:** | | **24,699** | **110,126** | **10,670** | |
| **Percentage of total T&D:** | | **20%** | **91%** | **9%** | |

**Q37.1 Please explain how the figures shown in the "Capacity totals" row were arrived at.**

A37.1 Please refer to Errata 4 to BCUC IR No. 1 Q15.1, as well as BCUC IR No. 2 Q37.2 below. FortisBC has corrected the table to indicate that there are no significant energy-driven Transmission and Distribution projects.

**Q37.2 For the rows labelled "Transmission Sustaining", "Stations Sustaining", and Distribution Sustaining", what is the rationale behind the distribution of costs between Energy and Capacity? Please explain.**

A37.2 In general, transmission and distribution projects only have capacity, reliability or condition-related drivers. However, a small subset of these projects also provides an ancillary energy benefit primarily through the reduction of system losses. Thus, the inclusion of the sustaining projects in the "Energy" category of Table BCUC A15.1 was intended only to indicate that these projects may also have some ancillary energy benefits.

**38.0 Reference: Exhibit B-3-1, BCUC IR#1, 12.1, and**
**Exhibit B-3-3-2, BCMEU IR#1 30.1 and Appendix A15.1A, p. 160**
**Contract Demand: vs. System Development Plan**

**"The major factor influencing changes to the Transmission and Station (Growth) projects is the substation load forecast. The 2005 load forecast showing actual loads for the past four years, together with forecast loads for the next six years is found in Appendix 1." [BCMEU App. A15.1A]**

**Q38.1 Please confirm that FortisBC System Development Plans are based on, and adjusted for, actual loads and forecasts thereof, rather than contract demand.**

A38.1 FortisBC's previous System Development Plans were based on forecasts of actual load provided the system meets the criteria identified in the response to BCUC IR No. 2 Q38.2.

**Q38.2 If confirmed, please explain why the proposed use of Contract Demand should not also be applied to System Development Planning, to avoid an inconsistency between the Rate Design (using Contract Demand) and System Development Plans (using Actual Demands). If not confirmed, please describe the nature of loads used in System Development Plans.**

A38.2 System Development Planning must also consider contingency planning in addition to considering the supply of contract demand. FortisBC is obligated to plan and operate the bulk transmission system in compliance with the NERC TPL standards as per BCUC Order G-67-09. NERC Standard TPL-001 ("System Performance Under Normal Conditions") states that FortisBC shall:

> *"[...] demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all*

> *transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands [...]".*

The NERC definition for "Firm Transmission Service" states that it is "highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption."

FortisBC interprets this standard as requiring the company to consider not just forecast actual loads but also contract demand (equivalent to "Firm Transmission Service commitments) when assessing the system for normal operations (N-0) compliance. To ensure compliance with this standard it is only necessary to conduct a single system study with the wholesale municipal forecast actual loads replaced by their respective contract demand limits. This assessment also ensures that FortisBC meets the contractual obligations set out in the wholesale supply agreements.

However, when considering contingency scenarios – which are the focus of System Development Planning – FortisBC reverts to using forecast actual demands (as opposed to contract demand). NERC standard TPL-002 ("System Performance Following Loss of a Single Bulk Electric System Element") states in the footnote (b) to Table I that:

> *"[…] To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers."*

FortisBC interprets this standard to indicate that for N-1 contingency planning it is permissible to use the lower value of forecast actual demand as compared to the higher contract demand value.

It is based on this reasoning that FortisBC feels that the use of forecast actual demand for System Development Planning is not inconsistent with the use of contract demand for meeting its contractual obligations.

**39.0 Reference: Exhibit B-3-3, BCMEU IR#1 30.1**

**Wholesale Customers: Contract Demand and System Planning**

**In its response to BCMEU IR#1 30.1, FortisBC states: "One reason FortisBC conducts a power flow analysis is to assess the adequacy of the transmission system in its normal (N-0) operating state with all elements in service. For the purposes of this study, the wholesale contract demand limits are used to confirm compliance with the contractual requirements"**

**and: "FortisBC more often conducts power flow studies for contingency analysis to determine if the system is capable of meeting established reliability criteria with one or more transmission elements out of service. For these purposes, FortisBC uses the forecast actual demand for wholesale customers and should the contract demand limit be required to be supplied during a contingency event the Company would endeavour to honour its contractual obligations to the Wholesale utilities."**

**Q39.1 Until now, has FortisBC sized its integrated transmission system so has to meet the contracted demand requirements of all of its Wholesale customers should they occur coincidentally during the system peak and during the transmission system's normal operating (N-0) state?**

A39.1 FortisBC began to consider the contractual obligations that are contained in the wholesale agreements in transmission planning in 2008. Historically and currently, FortisBC can meet the coincident contractual demand of all the wholesale utilities.

**Q39.2 Can the transmission system currently meet the contracted demand requirements of FortisBC's Wholesale customers should they occur coincidentally during an N-1 event occurring during the system peak?**

A39.2 No, the FortisBC system is unable to supply full contract demand to all wholesale customers under N-1 operations without experiencing some equipment loading violations. This is permitted by the NERC Reliability Standard TPL-002-0 (refer also to the response to BCUC IR No. 2 Q38.2 above).

**Q39.3 What level of demand of its Wholesale customers can be met during an N-1 event occurring during the system peak? Please select the N-1 scenario providing the highest deliverability to the Wholesale customers in aggregate and state all assumptions used in the analysis.**

A39.3 Full contract demand obligations for all wholesale customers can be met even during N-1 events, aside from Kelowna and Penticton under certain scenarios.

For both Kelowna and Penticton the violations which occur during the most severe N-1 events are transformer overloads at the F.A. Lee, D.G. Bell or R.G. Anderson terminal stations following a loss of one of the 230-kV step-down transformers at these locations. Note that the violations are independent of each other. In other words, a loss of one of the 230/138 kV transformers at F.A. Lee or D.G. Bell (the two bulk supply points for Kelowna) will impact the ability to supply contract demand to the City of Kelowna, but will not impact the supply capability to the City of Penticton. The converse is true following a loss of one of the 230/63 kV transformers at the R.G. Anderson Terminal; only the City of Penticton is impacted in this case – not the City of Kelowna. Thus, even during N-1 events, at most only one wholesale customer is impacted (in terms of a potential contract demand limitation).

For the events described above the overload levels on the remaining transformers range from approximately 105 percent to 125 percent of the allowable loading in 2011. This overload grows as the FortisBC native load continues to increase over time. The overload could be reduced and thus full contract demand supply provided even during N-1 operations, either by increasing the capacity of the 230-kV step-down transformers or by adding an additional transformer to increase the firm station capacity.

**In its response to BCMEU IR#1 30.1, FortisBC also states: "The Company intends to conduct its future transmission planning so as to meet its contractual obligations at an N-1 criteria."**

**Q39.4 Have any or all of FortisBC's Wholesale customers requested this level of reliability?**

A39.4 FortisBC is not intending to adopt the N-1 planning criteria referenced in the Information Request in response to customer requests at the present time. As discussed in the response to BCUC IR No. 2 Q38.2, curtailments of contract demand in response to N-1 events are currently permitted by the NERC transmission planning (TPL) standards.

However, it should be noted that in the United States there is a regulatory move away from accepting curtailment of firm transfers during N-1 events as a method of maintaining reliability. Indeed, the US Federal Energy Regulatory Commission has stated:

> *"...system adjustments [currently permitted] includes curtailments of contracted firm, non-recallable reserved and electric power transfers and this is not acceptable for Category B single contingencies." [p. 466; Docket No. RM06-16-000; Order No. 693]*

The current draft (unapproved) revision for the TPL standards removes the curtailment provision with an accompanying five year phase-in period to allow utilities to become fully compliant. It is likely that at some point in the future this revision will be adopted as part of the Mandatory Reliability Standards framework in British Columbia.

**Q39.5 When does FortisBC expect to be able to meet its contractual obligations to its Wholesale customers at an N-1 level of reliability?**

A39.5 The timing is dependent on the adoption of the standard discussed in the answer to BCUC IR No. 2 Q39.4.

**Q39.6 Does FortisBC expect to be able to meet its contractual obligations to its Wholesale customers at an N-1 level of reliability within the five year rate rebalancing period proposed in the Application?**

A39.6 Please refer to the responses to BCUC IR No. 2 Q39.4 and Q39.5.

**40.0 Reference: Exhibit B-3-1, BCUC IR#1, 69.1 and 69.3, and Exhibit B-3-3-2, BCMEU IR#1, 30.1 and Appendix A34.2, p. 7**

**Wholesale Customers: Curtailment Provisions**

**"The Wholesale Contracts provide for curtailment provisions set out in Sections 4.03 provided in BCMEU Appendix A34.2. These curtailment provisions allow for curtailment in certain specific situations including shortage of electricity or breakdown or failure of equipment. However, these provisions are not exhaustive and do not include for example, shortages in the event of system capacity constraints. The other rate classes do not have these provisions." [BCUC 69.1]**

**"The curtailment priority discussed in the response to BCUC IR No. 1 Q69.1 represents an enhanced level of service and is inherently reflected in the COSA by choosing to allocate costs based on the contractual obligations contained in the supply agreements." [BCUC 69.3]**

**"FortisBC more often conducts power flow studies for contingency analysis to determine if the system is capable of meeting established reliability criteria with one or more transmission elements out of service. For these purposes, FortisBC uses the forecast actual demand for wholesale customers and should the contract demand limit be required to be supplied during a contingency event the Company would endeavour to honour its contractual obligations to the Wholesale utilities." [BCMEU 30.1]**

> **4.03 Failure to Deliver**
> At any time during an actual or anticipated shortage of electricity, or in the event of a breakdown or failure of generating, transmitting or distributing plant, lines or equipment, or in order to comply with the requirements of any law, FortisBC shall have the right to curtail or discontinue the supply of electricity to the City of Grand Forks or reduce the voltage or frequency of the electricity supplied. To the extent that it is practical and reasonable, FortisBC will not unduly discriminate in favour of or against the City of Grand Forks in the supply of electricity.

**[BCMEU A34.2]**

**Q40.1 Is FortisBC saying that, in the event of a shortage resulting from a system capacity constraint, other classes would be curtailed by FortisBC while Wholesale customers would not? If not, please explain what the enhanced level of service enjoyed by Wholesale customers provides.**

A40.1 Yes, FortisBC is of the opinion that the terms of the wholesale agreements provide the wholesale utilities a higher level of reliability when considered alongside the general curtailment provisions contained in its electric tariff.

**Q40.2 Since "other rate classes do not have these provisions," would it be appropriate to characterise service to Wholesale customers as being "less firm" than to other customers? Please explain.**

A40.2 In general, the Company does not guarantee supply to customers, as can be noted by Section 8.1 of the Company's approved Electric Tariff, which is reproduced below. For the wholesale utilities, curtailment of supply is only permitted in two specific situations, which do not include curtailments for capacity constraints.

> *The Company will endeavour to provide a regular and uninterrupted supply of electricity but it does not guarantee a constant supply of electricity or the maintenance of unvaried frequency or voltage and shall not be responsible or liable for any loss, injury, damage or expense caused by or resulting from any interruption, termination, failure or defect in the supply of electricity, whether caused by the negligence of the Company, its servants or agents, or otherwise unless the loss, injury, damage or expense is directly resulting from the willful misconduct of the Company, its servants or agents provided, however, that the Company, its servants and agents are not responsible for any loss of profit, loss of revenues or other economic loss even if the loss is directly resulting from the willful misconduct of the Company, its servants or agents.*

The wholesale utilities would be the last customers to be curtailed due to a capacity constraint; therefore the wholesale utility is provided with service that is more firm, not less.

**Q40.3 The described curtailment provisions are associated with (amongst other situations) times of "actual or anticipated shortage of electricity." At which times of the year (in terms of hour and month) at which FortisBC is likely to encounter system capacity constraint conditions?**

A40.3 An actual or anticipated shortage of electricity (a circumstance which s4.03 addresses) stems not from a capacity issue but from a commodity issue. Curtailments which result from system capacity constraint issues (which s4.03 does not address) can occur at any time of the year depending on the nature of the capacity constraint in the FortisBC system. The loss of major system elements nearest to the wholesale utility supply are the most likely to have significant impact as compared to those located further upstream. Notwithstanding this, the probability of capacity constraints increases during peak load periods which for FortisBC typically occur during the months of November through February and June through August. Peak load hours during these months are typically from 7 am to 9 am and 4 pm to 7 pm.

## 41.0 Reference: Exhibit B-3-1, BCUC IR#1 71.2 and 74.3

**Wholesale Customers: Demand Figures**

**In response to questions BCUC 71.2 and 74.3, FortisBC supplied the following tables:**

Table BCUC A71.2
Wholesale Demand Comparison

| Forecast of Monthly Peaks | Kelowna | Penticton | Summerland | Grand Forks | BCH Lardeau | BCH Yahk | Nelson |
|---|---|---|---|---|---|---|---|
| Jan-09 | 61,401 | 71,883 | 20,529 | 8,062 | 4,964 | 584 | 23,855 |
| Feb-09 | 59,575 | 71,184 | 19,953 | 8,126 | 3,789 | 520 | 24,893 |
| Mar-09 | 49,408 | 60,272 | 17,176 | 6,893 | 2,580 | 483 | 20,751 |
| Apr-09 | 45,257 | 56,106 | 18,796 | 6,379 | 3,452 | 472 | 21,592 |
| May-09 | 42,415 | 48,300 | 12,579 | 5,618 | 1,798 | 800 | 16,926 |
| Jun-09 | 50,500 | 61,262 | 16,049 | 6,866 | 1,646 | 389 | 18,747 |
| Jul-09 | 45,859 | 61,151 | 15,590 | 6,607 | 1,693 | 372 | 18,173 |
| Aug-09 | 54,909 | 62,813 | 16,948 | 7,087 | 1,779 | 379 | 19,858 |
| Sep-09 | 43,527 | 52,965 | 13,982 | 6,428 | 1,919 | 625 | 16,498 |
| Oct-09 | 44,520 | 55,546 | 16,407 | 6,328 | 2,084 | 599 | 22,601 |
| Nov-09 | 57,778 | 69,624 | 19,518 | 7,833 | 2,051 | 697 | 24,354 |
| Dec-09 | 62,455 | 76,066 | 23,607 | 8,845 | 3,175 | 679 | 26,092 |

| Contract Demand | Kelowna | Penticton | Summerland | Grand Forks | BCH Lardeau | BCH Yahk | Nelson |
|---|---|---|---|---|---|---|---|
| Jan-09 | 90,882 | 155,034 | 29,700 | 23,760 | | 495 | 44,550 |
| Feb-09 | 90,882 | 155,034 | 29,700 | 23,760 | | 495 | 44,550 |
| Mar-09 | 90,882 | 155,034 | 29,700 | 23,760 | | 495 | 44,550 |
| Apr-09 | 90,882 | 155,034 | 29,700 | 23,760 | | 495 | 44,550 |
| May-09 | 90,882 | 155,034 | 29,700 | 23,760 | | 495 | 44,550 |
| Jun-09 | 90,882 | 155,034 | 29,700 | 23,760 | | 495 | 44,550 |
| Jul-09 | 90,882 | 124,245 | 21,780 | 17,820 | | 396 | 44,550 |
| Aug-09 | 90,882 | 124,245 | 21,780 | 17,820 | | 396 | 44,550 |
| Sep-09 | 90,882 | 155,034 | 29,700 | 23,760 | | 495 | 44,550 |
| Oct-09 | 90,882 | 155,034 | 29,700 | 23,760 | | 495 | 44,550 |
| Nov-09 | 90,882 | 155,034 | 29,700 | 23,760 | | 495 | 44,550 |
| Dec-09 | 90,882 | 155,034 | 29,700 | 23,760 | | 495 | 44,550 |

**[BCUC 71.2]**

Table BCUC A74.3b

| Class | Measured Demand | Contract Demand | Capacity Utilization |
|---|---|---|---|
| Nelson Hydro | 691,258 | 1,575,000 | 43.89% |
| City of Kelowna | 1,840,650 | 3,213,000 | 57.29% |
| City of Grand Forks | 246,890 | 828,000 | 29.82% |
| City of Penticton | 2,051,018 | 5,481,000 | 37.42% |
| District of Summerland | 589,039 | 1,002,000 | 58.79% |
| BC Hydro Kingsgate | 20,497 | 17,100 | 119.86% |

**[BCUC 74.3]**

**Q41.1 Please explain and show how the Contract Demand, Measured Demand, and Forecast Monthly Peak figures in Tables BCUC 71.2 are consistent with those in BCUC 74.3b.**

A41.1 The following tables have been included to aid in reconciling the tables and have also been updated in Errata 4:

41.1a Update to Table BCUC A71.2 showing Contract Demands in kVA rather than kW and showing 3 year total.

41.1b Update to Table BCUC A74.3b showing measured and Contract Demand for the full 36 months requested in the original IR. Due to the unavailability of December 2009 billing data at the time of the original response, some customers had only 35 months shown. In addition, measured demand for Nelson was shown net of power purchases. The updated table shows measured demand without this adjustment.

41.1c Update to Table BCUC A74.3b showing measured demand as the non-totalized sum of the measured demands at each point of supply. As the contract demands are specified in this manner, this provides a better comparison and more accurate value for capacity utilization.

## Table BCUC IR2 A41.1a – Updated BCUC 71.2

| Forecast Monthly Peaks | Kelowna (kW) | Penticton (kW) | Summerland (kW) | Grand Forks (kW) | BCH Lardeau (kW) | BCH Yahk (kW) | Nelson (kW) |
|---|---|---|---|---|---|---|---|
| Jan 09 | 61,401 | 71,883 | 20,529 | 8,062 | 4,964 | 584 | 23,855 |
| Feb 09 | 59,575 | 71,184 | 19,953 | 8,126 | 3,789 | 520 | 24,893 |
| Mar 09 | 49,408 | 60,272 | 17,176 | 6,893 | 2,580 | 483 | 20,751 |
| Apr 09 | 45,257 | 56,106 | 18,796 | 6,379 | 3,452 | 472 | 21,592 |
| May 09 | 42,415 | 48,300 | 12,579 | 5,618 | 1,798 | 800 | 16,926 |
| June 09 | 50,500 | 61,262 | 16,049 | 6,866 | 1,646 | 389 | 18,747 |
| July 09 | 45,859 | 61,151 | 15,590 | 6,607 | 1,693 | 372 | 18,173 |
| Aug 09 | 54,909 | 62,813 | 16,948 | 7,087 | 1,779 | 379 | 19,858 |
| Sept 09 | 43,527 | 52,965 | 13,982 | 6,428 | 1,919 | 625 | 16,498 |
| Oct 09 | 44,520 | 55,546 | 16,407 | 6,328 | 2,084 | 599 | 22,601 |
| Nov 09 | 57,778 | 69,624 | 19,518 | 7,833 | 2,051 | 697 | 24,354 |
| Dec 09 | 62,455 | 76,066 | 23,607 | 8,845 | 3,175 | 679 | 26,092 |

| Contract Demand | Kelowna (kVA) | Penticton (kVA) | Summerland (kVA) | Grand Forks (kVA) | BCH Lardeau (kVA) | BCH Yahk (kVA) | Nelson (kVA) |
|---|---|---|---|---|---|---|---|
| Jan 09 | 91,800 | 156,600 | 30,000 | 24,000 | | 500 | 45,000 |
| Feb 09 | 91,800 | 156,600 | 30,000 | 24,000 | | 500 | 45,000 |
| Mar 09 | 91,800 | 156,600 | 30,000 | 24,000 | | 500 | 45,000 |
| Apr 09 | 91,800 | 156,600 | 30,000 | 24,000 | | 500 | 45,000 |
| May 09 | 91,800 | 156,600 | 30,000 | 24,000 | | 500 | 45,000 |
| June 09 | 91,800 | 156,600 | 30,000 | 24,000 | | 500 | 45,000 |
| July 09 | 91,800 | 125,500 | 22,000 | 18,000 | | 400 | 45,000 |
| Aug 09 | 91,800 | 125,500 | 22,000 | 18,000 | | 400 | 45,000 |
| Sept 09 | 91,800 | 156,600 | 30,000 | 24,000 | | 500 | 45,000 |
| Oct 09 | 91,800 | 156,600 | 30,000 | 24,000 | | 500 | 45,000 |
| Nov 09 | 91,800 | 156,600 | 30,000 | 24,000 | | 500 | 45,000 |
| Dec 09 | 91,800 | 156,600 | 30,000 | 24,000 | | 500 | 45,000 |
| Annual | 1,101,600 | 1,817,000 | 344,000 | 276,000 | | 5,800 | 540,000 |
| 3 Year Total | 3,304,800 | 5,637,600 | 1,032,000 | 828,000 | | 17,400 | 1,620,000 |

## Table BCUC IR2 A41.1b – Updated BCUC 74.3

| Customers | Measured Demand in KVA | Contract Demand in KVA | Usage average |
|---|---|---|---|
| Nelson Hydro* | 815,999 | 1,620,000 | 50.37% |
| City of Kelowna | 1,947,551 | 3,304,800 | 58.93% |
| City of Grand Forks | 253,023 | 828,000 | 30.56% |
| City of Penticton | 2,215,149 | 5,637,600 | 39.29% |
| District of Summerland | 657,538 | 1,032,000 | 63.71% |
| BC Hydro Lardeau | 75,831 | 0 | n/a |
| BC Hydro Kingsgate | 22,966 | 17,400 | 131.99% |
| **TOTAL** | **5,988,057** | **12,439,800** | **48.14%** |

**Table BCUC IR2 A41.1c – Updated BCUC 74.3 Non –Totalized**

| Customers | Measured Demand in KVA | Contract Demand in KVA | Usage average |
|---|---|---|---|
| Nelson Hydro* | 957,226 | 1,620,000 | 59.09% |
| City of Kelowna | 2,088,401 | 3,304,800 | 63.19% |
| City of Grand Forks | 267,775 | 828,000 | 32.34% |
| City of Penticton | 2,234,314 | 5,637,600 | 39.63% |
| District of Summerland | 622,044 | 1,032,000 | 60.28% |
| BC Hydro Lardeau | 63,217 | 0 | n/a |
| BC Hydro Kingsgate | 20,497 | 17,400 | 119.86% |
| TOTAL | 6,253,474 | 12,439,500 | 50.27% |

With the information provided, it can be seen that the contract demand values in Tables BCUC IR2 A41.1b and A41.1c are consistent with A41.1a and reflect the fact that the BCUC IR No. 1 Q74.3 requested 36 months of data while BCUC IR No. 1 Q71.2 was only for one year.

The measured demands as presented in the two original tables referenced in this information request while close are not expected to match as the numbers in Table BCUC A71.2 are based on forecast 2009 monthly peaks while the values in Table BCUC A74.3 are based on actual measured demands over a 36 month period.

**Q41.2 Please provide updated versions of Tables BCUC 71.2 and BCUC 74.3b showing the units (e.g., kW) associated with the figures in each table.**

A41.2 Please refer to the response to BCUC IR No. 2 Q41.1 above.

**42.0 Reference: Exhibit B-3-1, BCUC IR#1, 71.1**

**Wholesale Customers: Voltage Conversion**

**The response to BCUC IR#. 1, question 71.1 cites as an example a 2006 voltage conversion program proposed by the City of Penticton. The response states that:**

***"The costs of the upgrade were to be borne by all of FortisBC's customers, but the bulk of the benefits from the voltage conversion program were to be for the City of Penticton. In other rate classes where facilities are dedicated for the sole use and benefit of that customer and require an upgrade, those costs are borne by that customer."***

**Q42.1 Please summarize the voltage conversion program and the potential impact on FortisBC in more detail.**

A42.1 In general terms, the City of Penticton has historically operated a 5000/8660Y volt (8 kV) distribution system which is now considered non-standard. FortisBC understands that the City has been converting portions of this legacy system to a 7200/12470Y volt (13-kV) distribution system. As the voltage conversion program is solely a City of Penticton initiative, FortisBC can only speculate on their rationale for this project, however reduced thermal losses and longer economic reach for distribution feeders are presumed to be the main drivers.

The program was first initiated in 1996/97 when a new 13-kV supply point was added to Huth substation on the request of the City of Penticton. This new supply increased the contract demand at this delivery point. The cost of this infrastructure was borne by all FortisBC rate-payers and is recovered over time.

In 2005, the Waterford substation was also converted to a 13 kV supply at the same time the station capacity was upgraded due to the load at this point exceeding the contract demand 95 percent threshold. The costs related to this upgrade were borne by all FortisBC customers.

**Q42.2 The phrasing in the quote above (‘were to be borne’, ‘were to be for’) suggests that the upgrade and associated costs may not have occurred. Did the City of Penticton’s voltage conversion program take place, and were the costs of the upgrade, in the end borne by all FortisBC customers? If not, what was the resolution of the issue?**

A42.2 The City of Penticton voltage conversion program is currently in progress. The costs of the completed upgrades up to the points of delivery were borne by all FortisBC customers, because those service points had reached 95 percent of contract demand. FortisBC expects future costs up to the points of delivery associated with the completion of the program will also be borne by all FortisBC customers when the other service points reach 95 percent of their contract demand.

**43.0 Reference: Exhibit B-3-4, Zellstoff Celgar IR#1, 16.1, and 16.5**

**Industrial Customers: Labelling of Table A 32.1(d)**

**Q43.1 Is Table Zellstoff Celgar A32.1(d) mislabelled, and should it be labelled as "Revenue to Cost Ratio Assuming Zellstoff Celgar Revenues Under Rate _31_"? If so please provide a replacement table with the corrected title.**

A43.1 Please refer to the Table BCUC IR2 A43.1 below:

**Table BCUC IR2 A43.1 – Updated Table Zellstoff Celgar A32.1(d)**
**Revenue to Cost Ratio Assuming Zellstoff Celgar Revenues Under Rate 31**

| | Year 0 | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 |
|---|---|---|---|---|---|---|
| | R/C Ratio | R/C Ratio | R/C Ratio | R/C Ratio | R/C Ratio | R/C Ratio |
| Residential | 96.1% | 96.1% | 96.1% | 96.1% | 96.1% | 96.1% |
| Small General Service | 110.5% | 108.9% | 106.4% | 105.0% | 105.0% | 105.0% |
| General Service | 134.5% | 132.6% | 128.8% | 125.7% | 122.6% | 119.3% |
| Industrial Transmission 33 | 115.2% | 113.6% | 110.3% | 107.7% | 105.0% | 105.0% |
| Industrial Primary | 118.4% | 116.7% | 113.3% | 110.6% | 107.8% | 105.0% |
| Industrial Transmission 31 | 105.5% | 105.0% | 105.0% | 105.0% | 105.0% | 105.0% |
| Lighting | 81.1% | 85.0% | 89.0% | 93.2% | 95.0% | 95.0% |
| Irrigation | 76.7% | 80.3% | 84.1% | 88.1% | 92.3% | 95.0% |
| Kelowna Wholesale | 87.0% | 91.2% | 95.0% | 95.0% | 95.0% | 95.0% |
| Penticton Wholesale | 75.9% | 79.5% | 83.3% | 87.2% | 91.4% | 95.0% |
| Summerland Wholesale | 93.4% | 95.0% | 95.0% | 95.0% | 95.0% | 95.0% |
| Grand Forks Wholesale | 66.5% | 69.7% | 73.0% | 76.5% | 80.1% | 83.9% |
| BCH Lardeau Wholesale | 99.1% | 99.1% | 99.1% | 99.1% | 99.1% | 99.1% |
| BCH Yahk Wholesale | 100.2% | 100.2% | 100.2% | 100.2% | 100.2% | 100.2% |
| Nelson Wholesale | 77.6% | 81.3% | 85.1% | 89.2% | 92.2% | 95.0% |
| Total | 99.6% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |

**44.0 Reference: Exhibit B-3-4, Zellstoff Celgar IR#1, 16.1, and 16.5**
**Industrial Customers: Satisfactory Load Factor**

**Q44.1 The response to Zellstoff Celgar question 16.1 states that in determining what constitutes an acceptable load factor (for the purpose of determining eligibility for Rate Schedule 33), "...the Company will assess each situation individually to determine whether allowing a customer to take or remain on TOU service adversely affects the remaining customers in the class, and whether a poor load factor contributes to the impact."**

**Please provide some hypothetical examples of load factors that would be respectively, satisfactory or not. With each example, please explain, what aspects make that particular load factor acceptable or not.**

A44.1 As described in Section 5.14 of the 1997 COSA, provided in the Appendix to BCMEU IR No. 1 Q34.1, the load factor restriction was intended to prevent under-recovery of costs. Therefore, an acceptable load factor would be one that results in a revenue to cost ratio within the range of reasonableness. The Company cannot determine a universally applicable numerical load factor threshold that would indicate an acceptable revenue to cost ratio.

**Q44.2 Zellstoff Celgar question 16.5 asks FortisBC to "Please explain how a customer that is successful in shifting all energy consumption to off-peak hours, as the Time of Use rate incents the customer to do, will be addressed by FortisBC in its interpretation of a satisfactory load factor."**

**FortisBC's response, A16.5, states that "*The assessment of satisfactory load factor does not change from those considerations discussed in the response to Zellstoff Celgar IR No. 1 Q16.1.*"**

**Would a customer that is successful in shifting all energy consumption to off-peak hours be considered to have a satisfactory or unsatisfactory load factor? Why? If there are other considerations involved in determining whether or not the load factor is satisfactory or unsatisfactory, please identify what those considerations are, and how each would affect the determination of whether the load factor was satisfactory or unsatisfactory.**

A44.2 A discussion of usage shifting as it affects load factor can be found in the response to Zellstoff Celgar IR No. 2 Q27.1. FortisBC does not have set criteria for evaluating load factor beyond those which were discussed in the response to BCUC IR No. 2 Q44.1.

**45.0 Reference: Exhibit B-1, Appendix B, Schedule 33, and Exhibit B-3-4, Zellstoff Celgar IR#1 1.5**

**Industrial Customers: Time of Use Rates and Cost Allocation**

**Q45.1 Would demand metered during off-peak hours be applied to the calculation of the wires demand charge? Provide an explanation justifying the response.**

A45.1 Yes, demand metered during off-peak hours would be applied to the calculation of the wires demand charge if it exceeded 100% of the Demand Limit at any time in current billing period or the past 11 billing periods. This is because the Wires Charge is intended to collect costs related to the infrastructure required to supply maximum actual demand or contractually reserved demand (whichever is greater) and not power purchase costs.

**Q45.2 Has Fortis considered separating the wires demand charge into an on-peak demand charge and an off-peak demand charge where the latter charge would remain at zero? Provide an explanation justifying the response.**

A45.2 The wires charge is intended to collect the costs of infrastructure built to meet customer loads. The facilities need to be sized to meet the maximum load on the system at any given time. Therefore it would not be appropriate to charge for wires only on the basis of on-peak demand levels. In the particular case of rate 33, where the customer has self-generation that could be off-line at any given hour, FortisBC has facilities in place to provide standby service. Charging for wires on the basis of the greater of the contract demand or the actual demand in any given hour allows FortisBC to recover the costs of facilities used to provide that standby service.

**Q45.3 Has Fortis considered separating the wires demand charge into summer on-peak and off-peak and winter on-peak and off-peak demand charges? Provide an explanation justifying the response.**

A45.3 Because the wires facilities are built based on the maximum requirements of the customer, the costs do not differ in the winter and summer. Costs to be collected from the wires charge are fixed for the year and will not differ on the basis of usage.

**Q45.4 What North American electric utilities offer Large General Transmission TOU rates that distinguish between on-peak and off-peak demand charges?**

A45.4 FortisBC has not done an extensive survey of rates for large general service/industrial customers and cannot provide a listing of all utilities with such rates. A few utilities with demand charges that differ by time period include Pacific Gas & Electric (Rate E20), Portland General Electric (Schedule 89) and San Diego Gas & Electric (Rate AL-TOU).

**Q45.5 Do any other North American electric utilities offer a Large General Transmission TOU rate that does not include a demand charge?**

A45.5 FortisBC has not done an extensive survey of rates for large general service/industrial customers and cannot provide a listing of all utilities without a demand charge. The Company is not aware of any specific utilities that do not have a demand charge for this type of rate class.

**46.0 Reference: Exhibit B-3-4, Zellstoff Celgar IR#1 2**

**Industrial Customers: Characteristics of Rate 31 and Rate 33 Customers**

**In its response to Zellstoff Celgar IR#1 2.1, FortisBC states: "given that Zellstoff Celgar is the lone Schedule 33 customer, is also a self-generator, and has a significant impact on the class as a whole, a separation for cost allocation is necessary to avoid intra-class subsidization."**

**Q46.1 Please clarify what significant impact Zellstoff Celgar has on the class as a whole.**

A46.1 The impact refers to the difference in the revenue-to-cost ratios of the transmission customers depending on whether or not Zellstoff Celgar in included with the broader group. If Zellstoff Celgar is included with the other transmission customers, the other transmission customers would see a drop in their revenue-to-cost ratio of 48 percentage points.

**47.0 Reference: Exhibit B-3-4, Zellstoff Celgar IR#1 3**

**Industrial Customers: Coincidence Factors of Rate 31 and Rate 33 Customers**

**Q47.1 Please reconcile FortisBC position that a separation of Rate 31 and Rate 33 customers was necessary for cost allocation purposes, with the decision to use the same coincidence factors for both classes.**

A47.1 Due to the volatility of the Zellstoff Celgar load data, the Company used the Rate 31 system coincidence factor. Had the COSA been based upon a multi-year average coincidence factor for Zellstoff Celgar, the resulting revenue to cost ratios would not be materially impacted.

**Q47.2 Please explain why Celgar's self generation affected the accuracy of the load data used to calculate coincidence factors for Rate 31 and Rate 33 customers?**

A47.2 The hourly data that FortisBC collects for Zellstoff Celgar is a net amount and differs greatly from month to month based on the operation of the generating plant. This differs from the other industrial customers that have a relatively consistent load profile. When using the 3-year average load factors and coincident factors for Zellstoff Celgar, the resulting peaks were lower that the average usage for the month in many cases. The use of the contract demand for allocation of costs basically makes the loads resulting from the coincidence factors inconsequential.

**Q47.3 Please provide the time of the peak demand incurred by the Rate 33 customer for each day during 2008 and 2009.**

A47.3 Please refer to Tables BCUC IR2 A47.3a and A47.3b below. N/A indicates that Celgar was generating into the FortisBC system.

## Table BCUC IR2 A47.3a – 2008

| 2008 | Time of Celgar Peak | 2008 | Time of Celgar Peak | 2008 | Time of Celgar Peak | 2008 | Time of Celgar Peak | 2008 | Time of Celgar Peak | 2008 | Time of Celgar Peak |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | HE | | HE | | HE | | HE | | HE | | HE |
| 1-Jan | 15 | 1-Mar | N/A | 1-May | N/A | 1-Jul | 1 | 1-Sep | N/A | 1-Nov | 9 |
| 2-Jan | 4 | 2-Mar | N/A | 2-May | N/A | 2-Jul | 24 | 2-Sep | 13 | 2-Nov | 1 |
| 3-Jan | N/A | 3-Mar | N/A | 3-May | N/A | 3-Jul | 3 | 3-Sep | 15 | 3-Nov | N/A |
| 4-Jan | 24 | 4-Mar | N/A | 4-May | N/A | 4-Jul | 19 | 4-Sep | 5 | 4-Nov | 23 |
| 5-Jan | 15 | 5-Mar | N/A | 5-May | N/A | 5-Jul | N/A | 5-Sep | N/A | 5-Nov | 10 |
| 6-Jan | 6 | 6-Mar | N/A | 6-May | N/A | 6-Jul | 20 | 6-Sep | N/A | 6-Nov | 22 |
| 7-Jan | 2 | 7-Mar | 10 | 7-May | 7 | 7-Jul | 10 | 7-Sep | 16 | 7-Nov | 12 |
| 8-Jan | N/A | 8-Mar | 2 | 8-May | 1 | 8-Jul | N/A | 8-Sep | N/A | 8-Nov | 1 |
| 9-Jan | 24 | 9-Mar | 1 | 9-May | N/A | 9-Jul | N/A | 9-Sep | N/A | 9-Nov | N/A |
| 10-Jan | 2 | 10-Mar | N/A | 10-May | 23 | 10-Jul | N/A | 10-Sep | 23 | 10-Nov | N/A |
| 11-Jan | 1 | 11-Mar | N/A | 11-May | 1 | 11-Jul | N/A | 11-Sep | 1 | 11-Nov | 24 |
| 12-Jan | 3 | 12-Mar | 23 | 12-May | N/A | 12-Jul | 7 | 12-Sep | 6 | 12-Nov | 4 |
| 13-Jan | N/A | 13-Mar | 11 | 13-May | N/A | 13-Jul | N/A | 13-Sep | N/A | 13-Nov | N/A |
| 14-Jan | N/A | 14-Mar | 3 | 14-May | 9 | 14-Jul | N/A | 14-Sep | N/A | 14-Nov | N/A |
| 15-Jan | N/A | 15-Mar | N/A | 15-May | N/A | 15-Jul | N/A | 15-Sep | N/A | 15-Nov | 13 |
| 16-Jan | 21 | 16-Mar | N/A | 16-May | 17 | 16-Jul | N/A | 16-Sep | 14 | 16-Nov | 3 |
| 17-Jan | 9 | 17-Mar | N/A | 17-May | N/A | 17-Jul | N/A | 17-Sep | 1 | 17-Nov | 24 |
| 18-Jan | 15 | 18-Mar | N/A | 18-May | N/A | 18-Jul | N/A | 18-Sep | N/A | 18-Nov | 20 |
| 19-Jan | 23 | 19-Mar | N/A | 19-May | N/A | 19-Jul | N/A | 19-Sep | 23 | 19-Nov | 1 |
| 20-Jan | 4 | 20-Mar | N/A | 20-May | N/A | 20-Jul | N/A | 20-Sep | 6 | 20-Nov | N/A |
| 21-Jan | N/A | 21-Mar | N/A | 21-May | N/A | 21-Jul | N/A | 21-Sep | 24 | 21-Nov | N/A |
| 22-Jan | N/A | 22-Mar | N/A | 22-May | N/A | 22-Jul | 13 | 22-Sep | 18 | 22-Nov | N/A |
| 23-Jan | N/A | 23-Mar | N/A | 23-May | 20 | 23-Jul | 22 | 23-Sep | 5 | 23-Nov | N/A |
| 24-Jan | N/A | 24-Mar | N/A | 24-May | 6 | 24-Jul | 7 | 24-Sep | N/A | 24-Nov | N/A |
| 25-Jan | N/A | 25-Mar | N/A | 25-May | 6 | 25-Jul | N/A | 25-Sep | N/A | 25-Nov | N/A |
| 26-Jan | N/A | 26-Mar | 24 | 26-May | N/A | 26-Jul | 12 | 26-Sep | 5 | 26-Nov | 24 |
| 27-Jan | N/A | 27-Mar | 8 | 27-May | 16 | 27-Jul | N/A | 27-Sep | 17 | 27-Nov | 20 |
| 28-Jan | N/A | 28-Mar | 21 | 28-May | 2 | 28-Jul | N/A | 28-Sep | 1 | 28-Nov | 3 |
| 29-Jan | 16 | 29-Mar | 19 | 29-May | N/A | 29-Jul | 5 | 29-Sep | 3 | 29-Nov | 4 |
| 30-Jan | N/A | 30-Mar | 1 | 30-May | N/A | 30-Jul | N/A | 30-Sep | N/A | 30-Nov | N/A |
| 31-Jan | N/A | 31-Mar | 3 | 31-May | N/A | 31-Jul | 3 | 1-Oct | N/A | 1-Dec | N/A |
| 1-Feb | N/A | 1-Apr | 1 | 1-Jun | N/A | 1-Aug | 24 | 2-Oct | N/A | 2-Dec | N/A |
| 2-Feb | N/A | 2-Apr | 1 | 2-Jun | N/A | 2-Aug | 11 | 3-Oct | N/A | 3-Dec | N/A |
| 3-Feb | N/A | 3-Apr | 7 | 3-Jun | 16 | 3-Aug | 5 | 4-Oct | N/A | 4-Dec | N/A |
| 4-Feb | N/A | 4-Apr | 5 | 4-Jun | 21 | 4-Aug | 8 | 5-Oct | N/A | 5-Dec | N/A |
| 5-Feb | N/A | 5-Apr | 3 | 5-Jun | 17 | 5-Aug | N/A | 6-Oct | N/A | 6-Dec | N/A |
| 6-Feb | N/A | 6-Apr | 3 | 6-Jun | N/A | 6-Aug | 18 | 7-Oct | N/A | 7-Dec | N/A |
| 7-Feb | 15 | 7-Apr | 23 | 7-Jun | N/A | 7-Aug | 5 | 8-Oct | 24 | 8-Dec | 24 |
| 8-Feb | 6 | 8-Apr | 22 | 8-Jun | N/A | 8-Aug | N/A | 9-Oct | N/A | 9-Dec | 24 |
| 9-Feb | N/A | 9-Apr | 23 | 9-Jun | N/A | 9-Aug | 10 | 10-Oct | 15 | 10-Dec | 5 |
| 10-Feb | N/A | 10-Apr | 22 | 10-Jun | N/A | 10-Aug | N/A | 11-Oct | 8 | 11-Dec | 1 |
| 11-Feb | N/A | 11-Apr | 13 | 11-Jun | N/A | 11-Aug | N/A | 12-Oct | 8 | 12-Dec | N/A |
| 12-Feb | 21 | 12-Apr | 24 | 12-Jun | N/A | 12-Aug | N/A | 13-Oct | N/A | 13-Dec | N/A |
| 13-Feb | 16 | 13-Apr | 4 | 13-Jun | N/A | 13-Aug | N/A | 14-Oct | N/A | 14-Dec | N/A |
| 14-Feb | N/A | 14-Apr | N/A | 14-Jun | 19 | 14-Aug | N/A | 15-Oct | 17 | 15-Dec | 3 |
| 15-Feb | N/A | 15-Apr | N/A | 15-Jun | N/A | 15-Aug | N/A | 16-Oct | 5 | 16-Dec | 24 |
| 16-Feb | N/A | 16-Apr | N/A | 16-Jun | 17 | 16-Aug | N/A | 17-Oct | 19 | 17-Dec | 4 |
| 17-Feb | N/A | 17-Apr | 20 | 17-Jun | N/A | 17-Aug | N/A | 18-Oct | 2 | 18-Dec | 2 |
| 18-Feb | N/A | 18-Apr | 1 | 18-Jun | 15 | 18-Aug | N/A | 19-Oct | N/A | 19-Dec | 7 |
| 19-Feb | N/A | 19-Apr | N/A | 19-Jun | 2 | 19-Aug | N/A | 20-Oct | N/A | 20-Dec | 18 |
| 20-Feb | N/A | 20-Apr | N/A | 20-Jun | N/A | 20-Aug | 23 | 21-Oct | N/A | 21-Dec | 3 |
| 21-Feb | N/A | 21-Apr | N/A | 21-Jun | 23 | 21-Aug | 10 | 22-Oct | N/A | 22-Dec | 8 |
| 22-Feb | N/A | 22-Apr | N/A | 22-Jun | N/A | 22-Aug | N/A | 23-Oct | N/A | 23-Dec | 24 |
| 23-Feb | N/A | 23-Apr | N/A | 23-Jun | 13 | 23-Aug | N/A | 24-Oct | 24 | 24-Dec | 2 |
| 24-Feb | N/A | 24-Apr | N/A | 24-Jun | 1 | 24-Aug | N/A | 25-Oct | 23 | 25-Dec | N/A |
| 25-Feb | N/A | 25-Apr | N/A | 25-Jun | 24 | 25-Aug | 24 | 26-Oct | 18 | 26-Dec | N/A |
| 26-Feb | N/A | 26-Apr | N/A | 26-Jun | 4 | 26-Aug | 1 | 27-Oct | 21 | 27-Dec | 24 |
| 27-Feb | N/A | 27-Apr | N/A | 27-Jun | 16 | 27-Aug | 3 | 28-Oct | 2 | 28-Dec | 10 |
| 28-Feb | N/A | 28-Apr | N/A | 28-Jun | N/A | 28-Aug | N/A | 29-Oct | 6 | 29-Dec | 3 |
| 29-Feb | N/A | 29-Apr | N/A | 29-Jun | N/A | 29-Aug | N/A | 30-Oct | 18 | 30-Dec | 15 |
| | | 30-Apr | N/A | 30-Jun | 23 | 30-Aug | N/A | 31-Oct | N/A | 31-Dec | 5 |
| | | | | | | 31-Aug | N/A | | | | |

### Table BCUC IR2 A47.3b – 2009

| 2009 | Time of Celgar Peak HE | 2009 | Time of Celgar Peak HE | 2009 | Time of Celgar Peak HE | 2009 | Time of Celgar Peak HE | 2009 | Time of Celgar Peak HE | 2009 | Time of Celgar Peak HE |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1-Jan | 3 | 1-Mar | N/A | 1-May | 11 | 1-Jul | N/A | 1-Sep | N/A | 1-Nov | 20 |
| 2-Jan | N/A | 2-Mar | N/A | 2-May | 3 | 2-Jul | 24 | 2-Sep | N/A | 2-Nov | 1 |
| 3-Jan | N/A | 3-Mar | N/A | 3-May | 17 | 3-Jul | 3 | 3-Sep | N/A | 3-Nov | 1 |
| 4-Jan | 5 | 4-Mar | N/A | 4-May | 11 | 4-Jul | 3 | 4-Sep | N/A | 4-Nov | 7 |
| 5-Jan | 2 | 5-Mar | N/A | 5-May | 1 | 5-Jul | 1 | 5-Sep | N/A | 5-Nov | 5 |
| 6-Jan | 1 | 6-Mar | 21 | 6-May | 22 | 6-Jul | N/A | 6-Sep | N/A | 6-Nov | 2 |
| 7-Jan | 24 | 7-Mar | 1 | 7-May | 14 | 7-Jul | N/A | 7-Sep | N/A | 7-Nov | N/A |
| 8-Jan | 10 | 8-Mar | 4 | 8-May | 12 | 8-Jul | 23 | 8-Sep | N/A | 8-Nov | N/A |
| 9-Jan | 1 | 9-Mar | N/A | 9-May | 23 | 9-Jul | 23 | 9-Sep | 18 | 9-Nov | N/A |
| 10-Jan | 9 | 10-Mar | 15 | 10-May | 24 | 10-Jul | 2 | 10-Sep | 8 | 10-Nov | N/A |
| 11-Jan | 14 | 11-Mar | N/A | 11-May | 1 | 11-Jul | N/A | 11-Sep | N/A | 11-Nov | N/A |
| 12-Jan | 3 | 12-Mar | 20 | 12-May | 23 | 12-Jul | N/A | 12-Sep | N/A | 12-Nov | N/A |
| 13-Jan | 18 | 13-Mar | 23 | 13-May | 1 | 13-Jul | 9 | 13-Sep | N/A | 13-Nov | N/A |
| 14-Jan | 11 | 14-Mar | 4 | 14-May | N/A | 14-Jul | N/A | 14-Sep | N/A | 14-Nov | 13 |
| 15-Jan | 24 | 15-Mar | 24 | 15-May | N/A | 15-Jul | 24 | 15-Sep | N/A | 15-Nov | 1 |
| 16-Jan | 1 | 16-Mar | 1 | 16-May | N/A | 16-Jul | 1 | 16-Sep | 24 | 16-Nov | 1 |
| 17-Jan | N/A | 17-Mar | 13 | 17-May | N/A | 17-Jul | 7 | 17-Sep | 2 | 17-Nov | 12 |
| 18-Jan | N/A | 18-Mar | 8 | 18-May | N/A | 18-Jul | 10 | 18-Sep | 1 | 18-Nov | 1 |
| 19-Jan | N/A | 19-Mar | 24 | 19-May | N/A | 19-Jul | 8 | 19-Sep | N/A | 19-Nov | 7 |
| 20-Jan | N/A | 20-Mar | 4 | 20-May | N/A | 20-Jul | N/A | 20-Sep | N/A | 20-Nov | 9 |
| 21-Jan | N/A | 21-Mar | N/A | 21-May | N/A | 21-Jul | N/A | 21-Sep | N/A | 21-Nov | 20 |
| 22-Jan | N/A | 22-Mar | N/A | 22-May | N/A | 22-Jul | N/A | 22-Sep | N/A | 22-Nov | 14 |
| 23-Jan | N/A | 23-Mar | N/A | 23-May | N/A | 23-Jul | N/A | 23-Sep | N/A | 23-Nov | 16 |
| 24-Jan | N/A | 24-Mar | 24 | 24-May | N/A | 24-Jul | 24 | 24-Sep | N/A | 24-Nov | 17 |
| 25-Jan | 24 | 25-Mar | 1 | 25-May | 23 | 25-Jul | 3 | 25-Sep | 17 | 25-Nov | 24 |
| 26-Jan | 9 | 26-Mar | 3 | 26-May | 5 | 26-Jul | 2 | 26-Sep | N/A | 26-Nov | 4 |
| 27-Jan | 19 | 27-Mar | N/A | 27-May | 24 | 27-Jul | N/A | 27-Sep | N/A | 27-Nov | 24 |
| 28-Jan | N/A | 28-Mar | N/A | 28-May | 4 | 28-Jul | N/A | 28-Sep | N/A | 28-Nov | 12 |
| 29-Jan | N/A | 29-Mar | N/A | 29-May | 1 | 29-Jul | N/A | 29-Sep | N/A | 29-Nov | N/A |
| 30-Jan | N/A | 30-Mar | 13 | 30-May | 23 | 30-Jul | N/A | 30-Sep | N/A | 30-Nov | 6 |
| 31-Jan | N/A | 31-Mar | N/A | 31-May | 23 | 31-Jul | N/A | 1-Oct | N/A | 1-Dec | N/A |
| 1-Feb | N/A | 1-Apr | N/A | 1-Jun | 2 | 1-Aug | N/A | 2-Oct | 8 | 2-Dec | N/A |
| 2-Feb | N/A | 2-Apr | 23 | 2-Jun | N/A | 2-Aug | N/A | 3-Oct | 18 | 3-Dec | 23 |
| 3-Feb | N/A | 3-Apr | 5 | 3-Jun | N/A | 3-Aug | N/A | 4-Oct | 4 | 4-Dec | 2 |
| 4-Feb | 5 | 4-Apr | 1 | 4-Jun | 18 | 4-Aug | N/A | 5-Oct | 6 | 5-Dec | 12 |
| 5-Feb | 19 | 5-Apr | N/A | 5-Jun | N/A | 5-Aug | 2 | 6-Oct | 2 | 6-Dec | N/A |
| 6-Feb | N/A | 6-Apr | N/A | 6-Jun | N/A | 6-Aug | N/A | 7-Oct | N/A | 7-Dec | N/A |
| 7-Feb | N/A | 7-Apr | N/A | 7-Jun | N/A | 7-Aug | N/A | 8-Oct | N/A | 8-Dec | N/A |
| 8-Feb | N/A | 8-Apr | N/A | 8-Jun | N/A | 8-Aug | 7 | 9-Oct | 23 | 9-Dec | N/A |
| 9-Feb | N/A | 9-Apr | 24 | 9-Jun | N/A | 9-Aug | N/A | 10-Oct | 4 | 10-Dec | N/A |
| 10-Feb | N/A | 10-Apr | 3 | 10-Jun | 4 | 10-Aug | N/A | 11-Oct | 3 | 11-Dec | 4 |
| 11-Feb | N/A | 11-Apr | 1 | 11-Jun | 23 | 11-Aug | N/A | 12-Oct | 16 | 12-Dec | 23 |
| 12-Feb | N/A | 12-Apr | N/A | 12-Jun | 2 | 12-Aug | 23 | 13-Oct | 2 | 13-Dec | 7 |
| 13-Feb | N/A | 13-Apr | N/A | 13-Jun | N/A | 13-Aug | 3 | 14-Oct | N/A | 14-Dec | 5 |
| 14-Feb | 10 | 14-Apr | N/A | 14-Jun | N/A | 14-Aug | 4 | 15-Oct | N/A | 15-Dec | N/A |
| 15-Feb | N/A | 15-Apr | 17 | 15-Jun | N/A | 15-Aug | 5 | 16-Oct | N/A | 16-Dec | N/A |
| 16-Feb | 14 | 16-Apr | 5 | 16-Jun | N/A | 16-Aug | N/A | 17-Oct | N/A | 17-Dec | N/A |
| 17-Feb | 16 | 17-Apr | 18 | 17-Jun | N/A | 17-Aug | N/A | 18-Oct | 20 | 18-Dec | 18 |
| 18-Feb | 17 | 18-Apr | N/A | 18-Jun | 24 | 18-Aug | N/A | 19-Oct | N/A | 19-Dec | 4 |
| 19-Feb | 18 | 19-Apr | 15 | 19-Jun | 2 | 19-Aug | 11 | 20-Oct | N/A | 20-Dec | N/A |
| 20-Feb | 6 | 20-Apr | 1 | 20-Jun | 3 | 20-Aug | 24 | 21-Oct | N/A | 21-Dec | 23 |
| 21-Feb | N/A | 21-Apr | 13 | 21-Jun | 24 | 21-Aug | 7 | 22-Oct | N/A | 22-Dec | 1 |
| 22-Feb | N/A | 22-Apr | N/A | 22-Jun | 5 | 22-Aug | 13 | 23-Oct | N/A | 23-Dec | N/A |
| 23-Feb | N/A | 23-Apr | 6 | 23-Jun | 1 | 23-Aug | N/A | 24-Oct | 24 | 24-Dec | N/A |
| 24-Feb | 17 | 24-Apr | 10 | 24-Jun | N/A | 24-Aug | N/A | 25-Oct | 1 | 25-Dec | N/A |
| 25-Feb | 4 | 25-Apr | 9 | 25-Jun | N/A | 25-Aug | N/A | 26-Oct | 12 | 26-Dec | N/A |
| 26-Feb | N/A | 26-Apr | 3 | 26-Jun | N/A | 26-Aug | 24 | 27-Oct | 1 | 27-Dec | N/A |
| 27-Feb | N/A | 27-Apr | 24 | 27-Jun | N/A | 27-Aug | 24 | 28-Oct | 2 | 28-Dec | N/A |
| 28-Feb | 13 | 28-Apr | 1 | 28-Jun | N/A | 28-Aug | 7 | 29-Oct | N/A | 29-Dec | 15 |
| | | 29-Apr | N/A | 29-Jun | N/A | 29-Aug | 22 | 30-Oct | N/A | 30-Dec | 1 |
| | | 30-Apr | 17 | 30-Jun | N/A | 30-Aug | N/A | 31-Oct | N/A | 31-Dec | 6 |
| | | | | | | 31-Aug | N/A | | | | |

**Q47.4 Please provide the time of the peak demand incurred, in aggregate, by the Rate 31 customers for each day during 2008 and 2009.**

A47.4 Tables BCUC IR2 A47.4a and A47.4b below contains the time of a partial peak demand incurred, in aggregate, by customers on Rate 31, for each day during 2008 and 2009 as not all the customers of this class are on the interval data system.

## Table BCUC IR2 A47.4a - 2008

| Date | Time of Peak | Date | Time of Peak | Date | Time of Peak | Date | Time of Peak | Date | Time of Peak | Date | Time of Peak |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | HE | | HE | | HE | | HE | | HE | | HE |
| 1/1/2008 | 400 | 3/1/2008 | 2400 | 5/1/2008 | 1200 | 7/1/2008 | 100 | 9/1/2008 | 200 | 11/1/2008 | 300 |
| 1/2/2008 | 900 | 3/2/2008 | 300 | 5/2/2008 | 500 | 7/2/2008 | 400 | 9/2/2008 | 1100 | 11/2/2008 | 2100 |
| 1/3/2008 | 900 | 3/3/2008 | 1300 | 5/3/2008 | 400 | 7/3/2008 | 2300 | 9/3/2008 | 1300 | 11/3/2008 | 1300 |
| 1/4/2008 | 800 | 3/4/2008 | 1400 | 5/4/2008 | 100 | 7/4/2008 | 100 | 9/4/2008 | 900 | 11/4/2008 | 1300 |
| 1/5/2008 | 300 | 3/5/2008 | 800 | 5/5/2008 | 500 | 7/5/2008 | 500 | 9/5/2008 | 1500 | 11/5/2008 | 1300 |
| 1/6/2008 | 2200 | 3/6/2008 | 1000 | 5/6/2008 | 400 | 7/6/2008 | 100 | 9/6/2008 | 600 | 11/6/2008 | 1400 |
| 1/7/2008 | 800 | 3/7/2008 | 1200 | 5/7/2008 | 1000 | 7/7/2008 | 300 | 9/7/2008 | 600 | 11/7/2008 | 1200 |
| 1/8/2008 | 1000 | 3/8/2008 | 300 | 5/8/2008 | 2400 | 7/8/2008 | 100 | 9/8/2008 | 1300 | 11/8/2008 | 200 |
| 1/9/2008 | 1600 | 3/9/2008 | 700 | 5/9/2008 | 200 | 7/9/2008 | 200 | 9/9/2008 | 1400 | 11/9/2008 | 2100 |
| 1/10/2008 | 800 | 3/10/2008 | 1000 | 5/10/2008 | 500 | 7/10/2008 | 2300 | 9/10/2008 | 1400 | 11/10/2008 | 2200 |
| 1/11/2008 | 1200 | 3/11/2008 | 800 | 5/11/2008 | 2300 | 7/11/2008 | 300 | 9/11/2008 | 800 | 11/11/2008 | 100 |
| 1/12/2008 | 800 | 3/12/2008 | 700 | 5/12/2008 | 1400 | 7/12/2008 | 400 | 9/12/2008 | 1300 | 11/12/2008 | 1300 |
| 1/13/2008 | 2200 | 3/13/2008 | 2400 | 5/13/2008 | 2400 | 7/13/2008 | 400 | 9/13/2008 | 100 | 11/13/2008 | 800 |
| 1/14/2008 | 1000 | 3/14/2008 | 400 | 5/14/2008 | 500 | 7/14/2008 | 400 | 9/14/2008 | 600 | 11/14/2008 | 800 |
| 1/15/2008 | 1000 | 3/15/2008 | 400 | 5/15/2008 | 100 | 7/15/2008 | 400 | 9/15/2008 | 1300 | 11/15/2008 | 100 |
| 1/16/2008 | 1300 | 3/16/2008 | 600 | 5/16/2008 | 400 | 7/16/2008 | 100 | 9/16/2008 | 1400 | 11/16/2008 | 300 |
| 1/17/2008 | 1300 | 3/17/2008 | 600 | 5/17/2008 | 500 | 7/17/2008 | 500 | 9/17/2008 | 1100 | 11/17/2008 | 1300 |
| 1/18/2008 | 800 | 3/18/2008 | 2300 | 5/18/2008 | 400 | 7/18/2008 | 2400 | 9/18/2008 | 1400 | 11/18/2008 | 1000 |
| 1/19/2008 | 100 | 3/19/2008 | 500 | 5/19/2008 | 2400 | 7/19/2008 | 100 | 9/19/2008 | 1300 | 11/19/2008 | 1000 |
| 1/20/2008 | 300 | 3/20/2008 | 300 | 5/20/2008 | 2200 | 7/20/2008 | 400 | 9/20/2008 | 100 | 11/20/2008 | 1100 |
| 1/21/2008 | 800 | 3/21/2008 | 2400 | 5/21/2008 | 200 | 7/21/2008 | 300 | 9/21/2008 | 700 | 11/21/2008 | 1500 |
| 1/22/2008 | 1000 | 3/22/2008 | 600 | 5/22/2008 | 400 | 7/22/2008 | 500 | 9/22/2008 | 1500 | 11/22/2008 | 300 |
| 1/23/2008 | 800 | 3/23/2008 | 2400 | 5/23/2008 | 200 | 7/23/2008 | 2400 | 9/23/2008 | 1400 | 11/23/2008 | 300 |
| 1/24/2008 | 1000 | 3/24/2008 | 500 | 5/24/2008 | 200 | 7/24/2008 | 400 | 9/24/2008 | 900 | 11/24/2008 | 1300 |
| 1/25/2008 | 800 | 3/25/2008 | 600 | 5/25/2008 | 400 | 7/25/2008 | 400 | 9/25/2008 | 800 | 11/25/2008 | 1300 |
| 1/26/2008 | 2200 | 3/26/2008 | 500 | 5/26/2008 | 2400 | 7/26/2008 | 500 | 9/26/2008 | 800 | 11/26/2008 | 1300 |
| 1/27/2008 | 800 | 3/27/2008 | 400 | 5/27/2008 | 400 | 7/27/2008 | 500 | 9/27/2008 | 100 | 11/27/2008 | 1300 |
| 1/28/2008 | 1000 | 3/28/2008 | 600 | 5/28/2008 | 300 | 7/28/2008 | 500 | 9/28/2008 | 500 | 11/28/2008 | 300 |
| 1/29/2008 | 1000 | 3/29/2008 | 2400 | 5/29/2008 | 500 | 7/29/2008 | 2200 | 9/29/2008 | 1300 | 11/29/2008 | 300 |
| 1/30/2008 | 1300 | 3/30/2008 | 500 | 5/30/2008 | 400 | 7/30/2008 | 200 | 9/30/2008 | 1300 | 11/30/2008 | 300 |
| 1/31/2008 | 1200 | 3/31/2008 | 600 | 5/31/2008 | 300 | 7/31/2008 | 500 | 10/1/2008 | 1300 | 12/1/2008 | 800 |
| 2/1/2008 | 1300 | 4/1/2008 | 500 | 6/1/2008 | 2400 | 8/1/2008 | 500 | 10/2/2008 | 800 | 12/2/2008 | 900 |
| 2/2/2008 | 400 | 4/2/2008 | 500 | 6/2/2008 | 200 | 8/2/2008 | 400 | 10/3/2008 | 800 | 12/3/2008 | 1000 |
| 2/3/2008 | 1800 | 4/3/2008 | 400 | 6/3/2008 | 2400 | 8/3/2008 | 200 | 10/4/2008 | 200 | 12/4/2008 | 1500 |
| 2/4/2008 | 1300 | 4/4/2008 | 1300 | 6/4/2008 | 300 | 8/4/2008 | 200 | 10/5/2008 | 2400 | 12/5/2008 | 900 |
| 2/5/2008 | 1300 | 4/5/2008 | 100 | 6/5/2008 | 2400 | 8/5/2008 | 500 | 10/6/2008 | 1000 | 12/6/2008 | 300 |
| 2/6/2008 | 1400 | 4/6/2008 | 500 | 6/6/2008 | 500 | 8/6/2008 | 400 | 10/7/2008 | 1400 | 12/7/2008 | 300 |
| 2/7/2008 | 1000 | 4/7/2008 | 200 | 6/7/2008 | 300 | 8/7/2008 | 500 | 10/8/2008 | 1300 | 12/8/2008 | 1000 |
| 2/8/2008 | 800 | 4/8/2008 | 2400 | 6/8/2008 | 300 | 8/8/2008 | 100 | 10/9/2008 | 1300 | 12/9/2008 | 1200 |
| 2/9/2008 | 900 | 4/9/2008 | 200 | 6/9/2008 | 2400 | 8/9/2008 | 200 | 10/10/2008 | 1300 | 12/10/2008 | 800 |
| 2/10/2008 | 2300 | 4/10/2008 | 300 | 6/10/2008 | 500 | 8/10/2008 | 600 | 10/11/2008 | 400 | 12/11/2008 | 800 |
| 2/11/2008 | 1400 | 4/11/2008 | 400 | 6/11/2008 | 2400 | 8/11/2008 | 600 | 10/12/2008 | 500 | 12/12/2008 | 800 |
| 2/12/2008 | 800 | 4/12/2008 | 400 | 6/12/2008 | 300 | 8/12/2008 | 300 | 10/13/2008 | 400 | 12/13/2008 | 100 |
| 2/13/2008 | 800 | 4/13/2008 | 600 | 6/13/2008 | 200 | 8/13/2008 | 2300 | 10/14/2008 | 1300 | 12/14/2008 | 2100 |
| 2/14/2008 | 900 | 4/14/2008 | 300 | 6/14/2008 | 400 | 8/14/2008 | 400 | 10/15/2008 | 800 | 12/15/2008 | 1000 |
| 2/15/2008 | 1300 | 4/15/2008 | 2400 | 6/15/2008 | 400 | 8/15/2008 | 1500 | 10/16/2008 | 1200 | 12/16/2008 | 800 |
| 2/16/2008 | 600 | 4/16/2008 | 400 | 6/16/2008 | 400 | 8/16/2008 | 200 | 10/17/2008 | 1300 | 12/17/2008 | 800 |
| 2/17/2008 | 600 | 4/17/2008 | 400 | 6/17/2008 | 400 | 8/17/2008 | 100 | 10/18/2008 | 700 | 12/18/2008 | 800 |
| 2/18/2008 | 800 | 4/18/2008 | 500 | 6/18/2008 | 400 | 8/18/2008 | 2300 | 10/19/2008 | 700 | 12/19/2008 | 1000 |
| 2/19/2008 | 800 | 4/19/2008 | 2300 | 6/19/2008 | 500 | 8/19/2008 | 2400 | 10/20/2008 | 800 | 12/20/2008 | 2400 |
| 2/20/2008 | 1300 | 4/20/2008 | 600 | 6/20/2008 | 400 | 8/20/2008 | 100 | 10/21/2008 | 800 | 12/21/2008 | 300 |
| 2/21/2008 | 800 | 4/21/2008 | 900 | 6/21/2008 | 200 | 8/21/2008 | 1200 | 10/22/2008 | 800 | 12/22/2008 | 1400 |
| 2/22/2008 | 900 | 4/22/2008 | 2300 | 6/22/2008 | 100 | 8/22/2008 | 200 | 10/23/2008 | 1300 | 12/23/2008 | 800 |
| 2/23/2008 | 1600 | 4/23/2008 | 100 | 6/23/2008 | 500 | 8/23/2008 | 300 | 10/24/2008 | 800 | 12/24/2008 | 800 |
| 2/24/2008 | 1000 | 4/24/2008 | 400 | 6/24/2008 | 400 | 8/24/2008 | 500 | 10/25/2008 | 100 | 12/25/2008 | 200 |
| 2/25/2008 | 1300 | 4/25/2008 | 900 | 6/25/2008 | 2400 | 8/25/2008 | 1300 | 10/26/2008 | 700 | 12/26/2008 | 300 |
| 2/26/2008 | 900 | 4/26/2008 | 2200 | 6/26/2008 | 400 | 8/26/2008 | 1100 | 10/27/2008 | 1400 | 12/27/2008 | 2000 |
| 2/27/2008 | 1400 | 4/27/2008 | 400 | 6/27/2008 | 400 | 8/27/2008 | 800 | 10/28/2008 | 800 | 12/28/2008 | 2100 |
| 2/28/2008 | 1200 | 4/28/2008 | 1000 | 6/28/2008 | 400 | 8/28/2008 | 1500 | 10/29/2008 | 800 | 12/29/2008 | 1300 |
| 2/29/2008 | 900 | 4/29/2008 | 2200 | 6/29/2008 | 400 | 8/29/2008 | 1400 | 10/30/2008 | 800 | 12/30/2008 | 1500 |
| | | 4/30/2008 | 400 | 6/30/2008 | 400 | 8/30/2008 | 600 | 10/31/2008 | 800 | 12/31/2008 | 1400 |
| | | | | | | 8/31/2008 | 200 | | | | |

## Table BCUC IR2 A47.4b - 2009

| Date | Time of Peak | Date | Time of Peak | Date | Time of Peak | Date | Time of Peak | Date | Time of Peak | Date | Time of Peak |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | HE | | HE | | HE | | HE | | HE | | HE |
| 1/1/2009 | 300 | 3/1/2009 | 200 | 5/1/2009 | 800 | 7/1/2009 | 400 | 9/1/2009 | 2400 | 11/1/2009 | 700 |
| 1/2/2009 | 900 | 3/2/2009 | 200 | 5/2/2009 | 500 | 7/2/2009 | 600 | 9/2/2009 | 200 | 11/2/2009 | 1500 |
| 1/3/2009 | 2100 | 3/3/2009 | 1400 | 5/3/2009 | 300 | 7/3/2009 | 300 | 9/3/2009 | 2400 | 11/3/2009 | 800 |
| 1/4/2009 | 300 | 3/4/2009 | 1000 | 5/4/2009 | 800 | 7/4/2009 | 500 | 9/4/2009 | 200 | 11/4/2009 | 800 |
| 1/5/2009 | 1400 | 3/5/2009 | 1400 | 5/5/2009 | 1400 | 7/5/2009 | 500 | 9/5/2009 | 500 | 11/5/2009 | 1500 |
| 1/6/2009 | 300 | 3/6/2009 | 1400 | 5/6/2009 | 1400 | 7/6/2009 | 2400 | 9/6/2009 | 2400 | 11/6/2009 | 1300 |
| 1/7/2009 | 200 | 3/7/2009 | 100 | 5/7/2009 | 1100 | 7/7/2009 | 500 | 9/7/2009 | 400 | 11/7/2009 | 100 |
| 1/8/2009 | 1100 | 3/8/2009 | 2300 | 5/8/2009 | 900 | 7/8/2009 | 400 | 9/8/2009 | 200 | 11/8/2009 | 600 |
| 1/9/2009 | 1100 | 3/9/2009 | 1000 | 5/9/2009 | 200 | 7/9/2009 | 100 | 9/9/2009 | 400 | 11/9/2009 | 1500 |
| 1/10/2009 | 2000 | 3/10/2009 | 700 | 5/10/2009 | 400 | 7/10/2009 | 400 | 9/10/2009 | 400 | 11/10/2009 | 800 |
| 1/11/2009 | 300 | 3/11/2009 | 1200 | 5/11/2009 | 1000 | 7/11/2009 | 400 | 9/11/2009 | 400 | 11/11/2009 | 200 |
| 1/12/2009 | 900 | 3/12/2009 | 1300 | 5/12/2009 | 1200 | 7/12/2009 | 500 | 9/12/2009 | 500 | 11/12/2009 | 1500 |
| 1/13/2009 | 800 | 3/13/2009 | 1000 | 5/13/2009 | 900 | 7/13/2009 | 2400 | 9/13/2009 | 500 | 11/13/2009 | 1100 |
| 1/14/2009 | 800 | 3/14/2009 | 2300 | 5/14/2009 | 1400 | 7/14/2009 | 500 | 9/14/2009 | 600 | 11/14/2009 | 200 |
| 1/15/2009 | 1200 | 3/15/2009 | 2100 | 5/15/2009 | 100 | 7/15/2009 | 1000 | 9/15/2009 | 2400 | 11/15/2009 | 500 |
| 1/16/2009 | 2100 | 3/16/2009 | 1400 | 5/16/2009 | 400 | 7/16/2009 | 400 | 9/16/2009 | 500 | 11/16/2009 | 1500 |
| 1/17/2009 | 300 | 3/17/2009 | 1500 | 5/17/2009 | 300 | 7/17/2009 | 400 | 9/17/2009 | 2400 | 11/17/2009 | 1000 |
| 1/18/2009 | 200 | 3/18/2009 | 1200 | 5/18/2009 | 300 | 7/18/2009 | 100 | 9/18/2009 | 200 | 11/18/2009 | 1500 |
| 1/19/2009 | 800 | 3/19/2009 | 1000 | 5/19/2009 | 1200 | 7/19/2009 | 500 | 9/19/2009 | 2300 | 11/19/2009 | 800 |
| 1/20/2009 | 1300 | 3/20/2009 | 1000 | 5/20/2009 | 100 | 7/20/2009 | 200 | 9/20/2009 | 500 | 11/20/2009 | 1500 |
| 1/21/2009 | 1000 | 3/21/2009 | 300 | 5/21/2009 | 1100 | 7/21/2009 | 900 | 9/21/2009 | 400 | 11/21/2009 | 100 |
| 1/22/2009 | 1000 | 3/22/2009 | 2300 | 5/22/2009 | 300 | 7/22/2009 | 500 | 9/22/2009 | 500 | 11/22/2009 | 700 |
| 1/23/2009 | 1300 | 3/23/2009 | 200 | 5/23/2009 | 400 | 7/23/2009 | 500 | 9/23/2009 | 400 | 11/23/2009 | 1000 |
| 1/24/2009 | 100 | 3/24/2009 | 1400 | 5/24/2009 | 500 | 7/24/2009 | 2200 | 9/24/2009 | 400 | 11/24/2009 | 1300 |
| 1/25/2009 | 2100 | 3/25/2009 | 1400 | 5/25/2009 | 500 | 7/25/2009 | 400 | 9/25/2009 | 500 | 11/25/2009 | 800 |
| 1/26/2009 | 1300 | 3/26/2009 | 500 | 5/26/2009 | 500 | 7/26/2009 | 500 | 9/26/2009 | 500 | 11/26/2009 | 800 |
| 1/27/2009 | 800 | 3/27/2009 | 2400 | 5/27/2009 | 1500 | 7/27/2009 | 400 | 9/27/2009 | 500 | 11/27/2009 | 800 |
| 1/28/2009 | 1300 | 3/28/2009 | 2400 | 5/28/2009 | 2400 | 7/28/2009 | 2400 | 9/28/2009 | 200 | 11/28/2009 | 100 |
| 1/29/2009 | 900 | 3/29/2009 | 100 | 5/29/2009 | 1100 | 7/29/2009 | 300 | 9/29/2009 | 500 | 11/29/2009 | 1200 |
| 1/30/2009 | 1200 | 3/30/2009 | 100 | 5/30/2009 | 500 | 7/30/2009 | 2300 | 9/30/2009 | 2400 | 11/30/2009 | 1300 |
| 1/31/2009 | 2100 | 3/31/2009 | 1000 | 5/31/2009 | 400 | 7/31/2009 | 500 | 10/1/2009 | 500 | 12/1/2009 | 1500 |
| 2/1/2009 | 200 | 4/1/2009 | 1100 | 6/1/2009 | 400 | 8/1/2009 | 500 | 10/2/2009 | 200 | 12/2/2009 | 800 |
| 2/2/2009 | 200 | 4/2/2009 | 300 | 6/2/2009 | 1500 | 8/2/2009 | 200 | 10/3/2009 | 2400 | 12/3/2009 | 1000 |
| 2/3/2009 | 200 | 4/3/2009 | 600 | 6/3/2009 | 1200 | 8/3/2009 | 500 | 10/4/2009 | 700 | 12/4/2009 | 800 |
| 2/4/2009 | 900 | 4/4/2009 | 100 | 6/4/2009 | 500 | 8/4/2009 | 2400 | 10/5/2009 | 400 | 12/5/2009 | 100 |
| 2/5/2009 | 1600 | 4/5/2009 | 300 | 6/5/2009 | 200 | 8/5/2009 | 500 | 10/6/2009 | 2400 | 12/6/2009 | 800 |
| 2/6/2009 | 1300 | 4/6/2009 | 1000 | 6/6/2009 | 2300 | 8/6/2009 | 300 | 10/7/2009 | 1300 | 12/7/2009 | 1500 |
| 2/7/2009 | 200 | 4/7/2009 | 1000 | 6/7/2009 | 2300 | 8/7/2009 | 2400 | 10/8/2009 | 1100 | 12/8/2009 | 1000 |
| 2/8/2009 | 300 | 4/8/2009 | 2300 | 6/8/2009 | 400 | 8/8/2009 | 500 | 10/9/2009 | 1100 | 12/9/2009 | 1300 |
| 2/9/2009 | 1300 | 4/9/2009 | 100 | 6/9/2009 | 900 | 8/9/2009 | 400 | 10/10/2009 | 100 | 12/10/2009 | 1500 |
| 2/10/2009 | 1100 | 4/10/2009 | 500 | 6/10/2009 | 1000 | 8/10/2009 | 400 | 10/11/2009 | 2200 | 12/11/2009 | 800 |
| 2/11/2009 | 800 | 4/11/2009 | 2400 | 6/11/2009 | 400 | 8/11/2009 | 400 | 10/12/2009 | 2100 | 12/12/2009 | 100 |
| 2/12/2009 | 300 | 4/12/2009 | 2400 | 6/12/2009 | 1200 | 8/12/2009 | 2400 | 10/13/2009 | 1400 | 12/13/2009 | 1100 |
| 2/13/2009 | 200 | 4/13/2009 | 400 | 6/13/2009 | 400 | 8/13/2009 | 2400 | 10/14/2009 | 1300 | 12/14/2009 | 1300 |
| 2/14/2009 | 300 | 4/14/2009 | 600 | 6/14/2009 | 500 | 8/14/2009 | 500 | 10/15/2009 | 900 | 12/15/2009 | 1500 |
| 2/15/2009 | 200 | 4/15/2009 | 400 | 6/15/2009 | 1000 | 8/15/2009 | 200 | 10/16/2009 | 1400 | 12/16/2009 | 800 |
| 2/16/2009 | 800 | 4/16/2009 | 200 | 6/16/2009 | 500 | 8/16/2009 | 200 | 10/17/2009 | 1400 | 12/17/2009 | 1500 |
| 2/17/2009 | 200 | 4/17/2009 | 2400 | 6/17/2009 | 2300 | 8/17/2009 | 500 | 10/18/2009 | 100 | 12/18/2009 | 1500 |
| 2/18/2009 | 200 | 4/18/2009 | 500 | 6/18/2009 | 400 | 8/18/2009 | 200 | 10/19/2009 | 1300 | 12/19/2009 | 100 |
| 2/19/2009 | 300 | 4/19/2009 | 300 | 6/19/2009 | 500 | 8/19/2009 | 400 | 10/20/2009 | 800 | 12/20/2009 | 900 |
| 2/20/2009 | 2100 | 4/20/2009 | 900 | 6/20/2009 | 100 | 8/20/2009 | 600 | 10/21/2009 | 2300 | 12/21/2009 | 1300 |
| 2/21/2009 | 300 | 4/21/2009 | 1100 | 6/21/2009 | 2400 | 8/21/2009 | 2400 | 10/22/2009 | 800 | 12/22/2009 | 800 |
| 2/22/2009 | 200 | 4/22/2009 | 2300 | 6/22/2009 | 100 | 8/22/2009 | 300 | 10/23/2009 | 1700 | 12/23/2009 | 800 |
| 2/23/2009 | 200 | 4/23/2009 | 1400 | 6/23/2009 | 1100 | 8/23/2009 | 600 | 10/24/2009 | 100 | 12/24/2009 | 100 |
| 2/24/2009 | 300 | 4/24/2009 | 1100 | 6/24/2009 | 500 | 8/24/2009 | 600 | 10/25/2009 | 300 | 12/25/2009 | 400 |
| 2/25/2009 | 2100 | 4/25/2009 | 100 | 6/25/2009 | 1200 | 8/25/2009 | 500 | 10/26/2009 | 1300 | 12/26/2009 | 2200 |
| 2/26/2009 | 2000 | 4/26/2009 | 500 | 6/26/2009 | 500 | 8/26/2009 | 200 | 10/27/2009 | 1300 | 12/27/2009 | 2200 |
| 2/27/2009 | 300 | 4/27/2009 | 1100 | 6/27/2009 | 300 | 8/27/2009 | 2300 | 10/28/2009 | 1000 | 12/28/2009 | 1500 |
| 2/28/2009 | 200 | 4/28/2009 | 800 | 6/28/2009 | 2400 | 8/28/2009 | 2100 | 10/29/2009 | 1300 | 12/29/2009 | 800 |
| | | 4/29/2009 | 1400 | 6/29/2009 | 1600 | 8/29/2009 | 400 | 10/30/2009 | 800 | 12/30/2009 | 1000 |
| | | 4/30/2009 | 1100 | 6/30/2009 | 500 | 8/30/2009 | 600 | 10/31/2009 | 100 | 12/31/2009 | 1000 |
| | | | | | | 8/31/2009 | 500 | | | | |

**Q47.5 Please provide the time of the system peak demand for each day during 2008 and 2009.**

A47.5 The requested information is provided in Tables BCUC IR2 A47.5a and A47.5b below.

## Table BCUC IR2 A47.5a – 2008

| 2008 | Time of FortisBC System Peak | 2008 | Time of FortisBC System Peak | 2008 | Time of FortisBC System Peak | 2008 | Time of FortisBC System Peak | 2008 | Time of FortisBC System Peak | 2008 | Time of FortisBC System Peak |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | HE | | HE | | HE | | HE | | HE | | HE |
| 1-Jan | 18 | 1-Mar | 19 | 1-May | 8 | 1-Jul | 15 | 1-Sep | 21 | 1-Nov | 19 |
| 2-Jan | 18 | 2-Mar | 19 | 2-May | 8 | 2-Jul | 17 | 2-Sep | 13 | 2-Nov | 18 |
| 3-Jan | 18 | 3-Mar | 18 | 3-May | 10 | 3-Jul | 17 | 3-Sep | 15 | 3-Nov | 18 |
| 4-Jan | 18 | 4-Mar | 19 | 4-May | 21 | 4-Jul | 19 | 4-Sep | 13 | 4-Nov | 18 |
| 5-Jan | 18 | 5-Mar | 8 | 5-May | 10 | 5-Jul | 18 | 5-Sep | 10 | 5-Nov | 18 |
| 6-Jan | 18 | 6-Mar | 8 | 6-May | 9 | 6-Jul | 18 | 6-Sep | 18 | 6-Nov | 18 |
| 7-Jan | 18 | 7-Mar | 9 | 7-May | 9 | 7-Jul | 13 | 7-Sep | 21 | 7-Nov | 18 |
| 8-Jan | 18 | 8-Mar | 19 | 8-May | 9 | 8-Jul | 18 | 8-Sep | 14 | 8-Nov | 18 |
| 9-Jan | 18 | 9-Mar | 20 | 9-May | 9 | 9-Jul | 17 | 9-Sep | 17 | 9-Nov | 18 |
| 10-Jan | 18 | 10-Mar | 9 | 10-May | 10 | 10-Jul | 13 | 10-Sep | 21 | 10-Nov | 18 |
| 11-Jan | 18 | 11-Mar | 9 | 11-May | 11 | 11-Jul | 17 | 11-Sep | 21 | 11-Nov | 18 |
| 12-Jan | 18 | 12-Mar | 9 | 12-May | 9 | 12-Jul | 18 | 12-Sep | 13 | 12-Nov | 18 |
| 13-Jan | 18 | 13-Mar | 9 | 13-May | 18 | 13-Jul | 18 | 13-Sep | 18 | 13-Nov | 18 |
| 14-Jan | 18 | 14-Mar | 9 | 14-May | 9 | 14-Jul | 18 | 14-Sep | 21 | 14-Nov | 18 |
| 15-Jan | 18 | 15-Mar | 10 | 15-May | 10 | 15-Jul | 18 | 15-Sep | 18 | 15-Nov | 18 |
| 16-Jan | 18 | 16-Mar | 20 | 16-May | 17 | 16-Jul | 17 | 16-Sep | 18 | 16-Nov | 18 |
| 17-Jan | 9 | 17-Mar | 9 | 17-May | 18 | 17-Jul | 17 | 17-Sep | 18 | 17-Nov | 18 |
| 18-Jan | 18 | 18-Mar | 9 | 18-May | 18 | 18-Jul | 14 | 18-Sep | 18 | 18-Nov | 18 |
| 19-Jan | 18 | 19-Mar | 9 | 19-May | 18 | 19-Jul | 18 | 19-Sep | 15 | 19-Nov | 18 |
| 20-Jan | 18 | 20-Mar | 9 | 20-May | 12 | 20-Jul | 19 | 20-Sep | 18 | 20-Nov | 18 |
| 21-Jan | 18 | 21-Mar | 9 | 21-May | 10 | 21-Jul | 17 | 21-Sep | 21 | 21-Nov | 18 |
| 22-Jan | 9 | 22-Mar | 10 | 22-May | 9 | 22-Jul | 17 | 22-Sep | 20 | 22-Nov | 18 |
| 23-Jan | 9 | 23-Mar | 10 | 23-May | 11 | 23-Jul | 13 | 23-Sep | 9 | 23-Nov | 18 |
| 24-Jan | 9 | 24-Mar | 9 | 24-May | 12 | 24-Jul | 19 | 24-Sep | 20 | 24-Nov | 18 |
| 25-Jan | 9 | 25-Mar | 9 | 25-May | 21 | 25-Jul | 17 | 25-Sep | 10 | 25-Nov | 18 |
| 26-Jan | 18 | 26-Mar | 10 | 26-May | 10 | 26-Jul | 13 | 26-Sep | 9 | 26-Nov | 18 |
| 27-Jan | 18 | 27-Mar | 9 | 27-May | 18 | 27-Jul | 18 | 27-Sep | 10 | 27-Nov | 18 |
| 28-Jan | 18 | 28-Mar | 10 | 28-May | 17 | 28-Jul | 18 | 28-Sep | 20 | 28-Nov | 18 |
| 29-Jan | 18 | 29-Mar | 20 | 29-May | 18 | 29-Jul | 14 | 29-Sep | 20 | 29-Nov | 18 |
| 30-Jan | 18 | 30-Mar | 21 | 30-May | 18 | 30-Jul | 18 | 30-Sep | 9 | 30-Nov | 18 |
| 31-Jan | 19 | 31-Mar | 9 | 31-May | 18 | 31-Jul | 18 | 1-Oct | 20 | 1-Dec | 18 |
| 1-Feb | 9 | 1-Apr | 9 | 1-Jun | 18 | 1-Aug | 12 | 2-Oct | 20 | 2-Dec | 18 |
| 2-Feb | 18 | 2-Apr | 8 | 2-Jun | 12 | 2-Aug | 17 | 3-Oct | 10 | 3-Dec | 18 |
| 3-Feb | 18 | 3-Apr | 8 | 3-Jun | 12 | 3-Aug | 18 | 4-Oct | 19 | 4-Dec | 18 |
| 4-Feb | 18 | 4-Apr | 9 | 4-Jun | 18 | 4-Aug | 18 | 5-Oct | 20 | 5-Dec | 18 |
| 5-Feb | 18 | 5-Apr | 10 | 5-Jun | 18 | 5-Aug | 18 | 6-Oct | 19 | 6-Dec | 18 |
| 6-Feb | 18 | 6-Apr | 20 | 6-Jun | 10 | 6-Aug | 18 | 7-Oct | 20 | 7-Dec | 18 |
| 7-Feb | 18 | 7-Apr | 9 | 7-Jun | 12 | 7-Aug | 17 | 8-Oct | 20 | 8-Dec | 18 |
| 8-Feb | 18 | 8-Apr | 9 | 8-Jun | 18 | 8-Aug | 15 | 9-Oct | 9 | 9-Dec | 18 |
| 9-Feb | 18 | 9-Apr | 8 | 9-Jun | 13 | 9-Aug | 18 | 10-Oct | 9 | 10-Dec | 18 |
| 10-Feb | 18 | 10-Apr | 8 | 10-Jun | 11 | 10-Aug | 18 | 11-Oct | 9 | 11-Dec | 18 |
| 11-Feb | 18 | 11-Apr | 8 | 11-Jun | 9 | 11-Aug | 18 | 12-Oct | 11 | 12-Dec | 18 |
| 12-Feb | 18 | 12-Apr | 10 | 12-Jun | 17 | 12-Aug | 18 | 13-Oct | 12 | 13-Dec | 18 |
| 13-Feb | 9 | 13-Apr | 21 | 13-Jun | 13 | 13-Aug | 18 | 14-Oct | 9 | 14-Dec | 18 |
| 14-Feb | 8 | 14-Apr | 21 | 14-Jun | 18 | 14-Aug | 18 | 15-Oct | 8 | 15-Dec | 19 |
| 15-Feb | 18 | 15-Apr | 9 | 15-Jun | 17 | 15-Aug | 18 | 16-Oct | 19 | 16-Dec | 18 |
| 16-Feb | 19 | 16-Apr | 8 | 16-Jun | 17 | 16-Aug | 18 | 17-Oct | 9 | 17-Dec | 18 |
| 17-Feb | 19 | 17-Apr | 8 | 17-Jun | 18 | 17-Aug | 15 | 18-Oct | 19 | 18-Dec | 18 |
| 18-Feb | 9 | 18-Apr | 9 | 18-Jun | 15 | 18-Aug | 14 | 19-Oct | 19 | 19-Dec | 18 |
| 19-Feb | 8 | 19-Apr | 11 | 19-Jun | 12 | 19-Aug | 13 | 20-Oct | 19 | 20-Dec | 18 |
| 20-Feb | 9 | 20-Apr | 21 | 20-Jun | 18 | 20-Aug | 14 | 21-Oct | 19 | 21-Dec | 18 |
| 21-Feb | 8 | 21-Apr | 9 | 21-Jun | 12 | 21-Aug | 11 | 22-Oct | 9 | 22-Dec | 18 |
| 22-Feb | 10 | 22-Apr | 8 | 22-Jun | 18 | 22-Aug | 18 | 23-Oct | 9 | 23-Dec | 18 |
| 23-Feb | 19 | 23-Apr | 9 | 23-Jun | 13 | 23-Aug | 18 | 24-Oct | 9 | 24-Dec | 10 |
| 24-Feb | 19 | 24-Apr | 9 | 24-Jun | 18 | 24-Aug | 18 | 25-Oct | 19 | 25-Dec | 17 |
| 25-Feb | 9 | 25-Apr | 9 | 25-Jun | 18 | 25-Aug | 18 | 26-Oct | 19 | 26-Dec | 18 |
| 26-Feb | 9 | 26-Apr | 9 | 26-Jun | 12 | 26-Aug | 14 | 27-Oct | 9 | 27-Dec | 18 |
| 27-Feb | 19 | 27-Apr | 21 | 27-Jun | 16 | 27-Aug | 10 | 28-Oct | 8 | 28-Dec | 18 |
| 28-Feb | 9 | 28-Apr | 9 | 28-Jun | 18 | 28-Aug | 14 | 29-Oct | 9 | 29-Dec | 18 |
| 29-Feb | 9 | 29-Apr | 9 | 29-Jun | 18 | 29-Aug | 15 | 30-Oct | 9 | 30-Dec | 18 |
| | | 30-Apr | 9 | 30-Jun | 15 | 30-Aug | 12 | 31-Oct | 9 | 31-Dec | 18 |
| | | | | | | 31-Aug | 18 | | | | |

## Table BCUC IR2 A47.5b – 2009

| 2009 | Time of FortisBC System Peak HE | 2009 | Time of FortisBC System Peak HE | 2009 | Time of FortisBC System Peak HE | 2009 | Time of FortisBC System Peak HE | 2009 | Time of FortisBC System Peak HE | 2009 | Time of FortisBC System Peak HE |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1-Jan | 18 | 1-Mar | 19 | 1-May | 9 | 1-Jul | 18 | 1-Sep | 18 | 1-Nov | 18 |
| 2-Jan | 18 | 2-Mar | 10 | 2-May | 10 | 2-Jul | 18 | 2-Sep | 18 | 2-Nov | 18 |
| 3-Jan | 18 | 3-Mar | 19 | 3-May | 17 | 3-Jul | 18 | 3-Sep | 10 | 3-Nov | 18 |
| 4-Jan | 18 | 4-Mar | 8 | 4-May | 10 | 4-Jul | 18 | 4-Sep | 16 | 4-Nov | 18 |
| 5-Jan | 18 | 5-Mar | 19 | 5-May | 10 | 5-Jul | 18 | 5-Sep | 18 | 5-Nov | 18 |
| 6-Jan | 18 | 6-Mar | 8 | 6-May | 9 | 6-Jul | 12 | 6-Sep | 18 | 6-Nov | 18 |
| 7-Jan | 18 | 7-Mar | 19 | 7-May | 10 | 7-Jul | 13 | 7-Sep | 21 | 7-Nov | 18 |
| 8-Jan | 18 | 8-Mar | 20 | 8-May | 9 | 8-Jul | 12 | 8-Sep | 11 | 8-Nov | 18 |
| 9-Jan | 18 | 9-Mar | 9 | 9-May | 10 | 9-Jul | 17 | 9-Sep | 20 | 9-Nov | 18 |
| 10-Jan | 18 | 10-Mar | 9 | 10-May | 21 | 10-Jul | 17 | 10-Sep | 21 | 10-Nov | 18 |
| 11-Jan | 18 | 11-Mar | 9 | 11-May | 9 | 11-Jul | 18 | 11-Sep | 17 | 11-Nov | 18 |
| 12-Jan | 18 | 12-Mar | 9 | 12-May | 22 | 12-Jul | 18 | 12-Sep | 18 | 12-Nov | 18 |
| 13-Jan | 18 | 13-Mar | 9 | 13-May | 9 | 13-Jul | 18 | 13-Sep | 18 | 13-Nov | 18 |
| 14-Jan | 18 | 14-Mar | 11 | 14-May | 9 | 14-Jul | 18 | 14-Sep | 18 | 14-Nov | 18 |
| 15-Jan | 18 | 15-Mar | 20 | 15-May | 9 | 15-Jul | 17 | 15-Sep | 18 | 15-Nov | 18 |
| 16-Jan | 18 | 16-Mar | 9 | 16-May | 10 | 16-Jul | 18 | 16-Sep | 18 | 16-Nov | 18 |
| 17-Jan | 18 | 17-Mar | 9 | 17-May | 22 | 17-Jul | 17 | 17-Sep | 18 | 17-Nov | 18 |
| 18-Jan | 18 | 18-Mar | 9 | 18-May | 18 | 18-Jul | 17 | 18-Sep | 17 | 18-Nov | 18 |
| 19-Jan | 18 | 19-Mar | 10 | 19-May | 10 | 19-Jul | 18 | 19-Sep | 20 | 19-Nov | 18 |
| 20-Jan | 18 | 20-Mar | 9 | 20-May | 9 | 20-Jul | 17 | 20-Sep | 20 | 20-Nov | 18 |
| 21-Jan | 18 | 21-Mar | 10 | 21-May | 9 | 21-Jul | 18 | 21-Sep | 20 | 21-Nov | 18 |
| 22-Jan | 18 | 22-Mar | 10 | 22-May | 9 | 22-Jul | 18 | 22-Sep | 20 | 22-Nov | 18 |
| 23-Jan | 18 | 23-Mar | 9 | 23-May | 18 | 23-Jul | 13 | 23-Sep | 20 | 23-Nov | 18 |
| 24-Jan | 18 | 24-Mar | 9 | 24-May | 18 | 24-Jul | 18 | 24-Sep | 20 | 24-Nov | 18 |
| 25-Jan | 18 | 25-Mar | 9 | 25-May | 18 | 25-Jul | 14 | 25-Sep | 17 | 25-Nov | 18 |
| 26-Jan | 9 | 26-Mar | 8 | 26-May | 9 | 26-Jul | 18 | 26-Sep | 18 | 26-Nov | 18 |
| 27-Jan | 18 | 27-Mar | 9 | 27-May | 18 | 27-Jul | 18 | 27-Sep | 20 | 27-Nov | 18 |
| 28-Jan | 18 | 28-Mar | 20 | 28-May | 18 | 28-Jul | 17 | 28-Sep | 20 | 28-Nov | 18 |
| 29-Jan | 9 | 29-Mar | 21 | 29-May | 18 | 29-Jul | 17 | 29-Sep | 20 | 29-Nov | 18 |
| 30-Jan | 10 | 30-Mar | 9 | 30-May | 18 | 30-Jul | 15 | 30-Sep | 20 | 30-Nov | 18 |
| 31-Jan | 18 | 31-Mar | 9 | 31-May | 18 | 31-Jul | 17 | 1-Oct | 20 | 1-Dec | 18 |
| 1-Feb | 18 | 1-Apr | 9 | 1-Jun | 17 | 1-Aug | 18 | 2-Oct | 20 | 2-Dec | 18 |
| 2-Feb | 18 | 2-Apr | 9 | 2-Jun | 18 | 2-Aug | 17 | 3-Oct | 20 | 3-Dec | 18 |
| 3-Feb | 19 | 3-Apr | 9 | 3-Jun | 18 | 3-Aug | 18 | 4-Oct | 20 | 4-Dec | 17 |
| 4-Feb | 9 | 4-Apr | 9 | 4-Jun | 18 | 4-Aug | 13 | 5-Oct | 8 | 5-Dec | 18 |
| 5-Feb | 18 | 5-Apr | 10 | 5-Jun | 17 | 5-Aug | 17 | 6-Oct | 8 | 6-Dec | 18 |
| 6-Feb | 9 | 6-Apr | 8 | 6-Jun | 18 | 6-Aug | 18 | 7-Oct | 20 | 7-Dec | 18 |
| 7-Feb | 19 | 7-Apr | 8 | 7-Jun | 19 | 7-Aug | 18 | 8-Oct | 20 | 8-Dec | 18 |
| 8-Feb | 19 | 8-Apr | 9 | 8-Jun | 13 | 8-Aug | 18 | 9-Oct | 9 | 9-Dec | 18 |
| 9-Feb | 9 | 9-Apr | 9 | 9-Jun | 18 | 9-Aug | 18 | 10-Oct | 10 | 10-Dec | 18 |
| 10-Feb | 18 | 10-Apr | 10 | 10-Jun | 18 | 10-Aug | 13 | 11-Oct | 10 | 11-Dec | 18 |
| 11-Feb | 9 | 11-Apr | 11 | 11-Jun | 18 | 11-Aug | 18 | 12-Oct | 10 | 12-Dec | 18 |
| 12-Feb | 18 | 12-Apr | 21 | 12-Jun | 18 | 12-Aug | 18 | 13-Oct | 19 | 13-Dec | 18 |
| 13-Feb | 9 | 13-Apr | 21 | 13-Jun | 16 | 13-Aug | 13 | 14-Oct | 19 | 14-Dec | 18 |
| 14-Feb | 19 | 14-Apr | 9 | 14-Jun | 18 | 14-Aug | 11 | 15-Oct | 8 | 15-Dec | 18 |
| 15-Feb | 19 | 15-Apr | 8 | 15-Jun | 18 | 15-Aug | 11 | 16-Oct | 10 | 16-Dec | 18 |
| 16-Feb | 19 | 16-Apr | 8 | 16-Jun | 17 | 16-Aug | 21 | 17-Oct | 19 | 17-Dec | 18 |
| 17-Feb | 8 | 17-Apr | 10 | 17-Jun | 14 | 17-Aug | 17 | 18-Oct | 19 | 18-Dec | 18 |
| 18-Feb | 8 | 18-Apr | 10 | 18-Jun | 17 | 18-Aug | 18 | 19-Oct | 19 | 19-Dec | 18 |
| 19-Feb | 19 | 19-Apr | 21 | 19-Jun | 18 | 19-Aug | 18 | 20-Oct | 19 | 20-Dec | 18 |
| 20-Feb | 9 | 20-Apr | 9 | 20-Jun | 18 | 20-Aug | 18 | 21-Oct | 19 | 21-Dec | 18 |
| 21-Feb | 19 | 21-Apr | 9 | 21-Jun | 18 | 21-Aug | 16 | 22-Oct | 19 | 22-Dec | 18 |
| 22-Feb | 18 | 22-Apr | 21 | 22-Jun | 12 | 22-Aug | 18 | 23-Oct | 19 | 23-Dec | 18 |
| 23-Feb | 9 | 23-Apr | 9 | 23-Jun | 18 | 23-Aug | 18 | 24-Oct | 19 | 24-Dec | 18 |
| 24-Feb | 19 | 24-Apr | 9 | 24-Jun | 12 | 24-Aug | 18 | 25-Oct | 19 | 25-Dec | 17 |
| 25-Feb | 19 | 25-Apr | 10 | 25-Jun | 13 | 25-Aug | 17 | 26-Oct | 19 | 26-Dec | 18 |
| 26-Feb | 19 | 26-Apr | 21 | 26-Jun | 14 | 26-Aug | 17 | 27-Oct | 19 | 27-Dec | 18 |
| 27-Feb | 9 | 27-Apr | 11 | 27-Jun | 18 | 27-Aug | 18 | 28-Oct | 9 | 28-Dec | 18 |
| 28-Feb | 19 | 28-Apr | 8 | 28-Jun | 18 | 28-Aug | 18 | 29-Oct | 19 | 29-Dec | 18 |
| | | 29-Apr | 9 | 29-Jun | 18 | 29-Aug | 18 | 30-Oct | 9 | 30-Dec | 18 |
| | | 30-Apr | 8 | 30-Jun | 18 | 30-Aug | 18 | 31-Oct | 19 | 31-Dec | 18 |
| | | | | | | 31-Aug | 18 | | | | |

**48.0 Reference: Exhibit B-3-4, Zellstoff Celgar IR#1 15**

**Industrial Customers: Objectives of Rate Schedule 33**

**In its response to Celgar IR#1 15.1, FortisBC states: "The intention [of implementing Time-of-Use rates] at the time was primarily to shift customer usage from on peak to off-peak periods to reduce power purchase costs and defer system capital expenditures."**

**In its response in Celgar IR#1 15.2, FortisBC states: "This hinders the ability to determine whether and to what extent peak load has been shifted or simply reduced by self generation, and whether the TOU rate has been responsible for the reduction or has simply made it economic for the self-generating customer to make investments in generation."**

**Q48.1 Why is a determination of whether peak load has been shifted versus reduced in response to a customer receiving service through a time-of-use rate relevant when assessing the effectiveness of the time-of-use rate?**

A48.1 The determination of how peak load has been shifted is generally not relevant when assessing effectiveness of time of use rates. Please also refer to Zellstoff Celgar IR No. 2 Q26.1.

**Q48.2 Since receiving service under Schedule 33, has Celgar reduced its peak demand on the FortisBC system?**

A48.2 No. Comparing the monthly peaks for 2007 and 2008 versus 2005 and 2006 shows no real difference in the monthly peak demands; in fact the peak demand was marginally higher in 2007 and 2008. There is no reason to believe that the change in rates would influence the peak since the peak tends to be set when there is an outage to the Zellstoff Celgar generator.

**Q48.3 In its 2009 Resource Plan, has FortisBC considered building new generation facilities near load centres as an alternative to expanding transmission capacity?**

A48.3 Yes. The Kelowna area is FortisBC's largest and fastest growing single load area. FortisBC's preferred resource strategy contained in FortisBC's 2009 Resource Plan (filed May 2009) contemplates new generation in the Kelowna area. This new generation has the potential to offset or delay the addition of new transmission infrastructure.

**Q48.4 Please comment on the validity of the following statement, and its applicability to the FortisBC system: "Self generation by any customers receiving service under time-of-use rate schedules is an example of a market's response to a utility's price signals related to the cost of serving peak and off-peak demand."**

A48.4 FortisBC agrees that self generation may be an example of a customer's response to pricing signals provided the generation is structured to occur during the on-peak time period.

# A Guide to FERC Electric Utility Ratemaking

Michael E. Small
Wright & Talisman, P.C.
Washington, D.C.

AIS Atlantic Information Services, Inc.
1050 17th Street, N.W., Suite 480 • Washington, D.C. 20036 • (202) 775-9008

A Guide to FERC Electric Utility Ratemaking presents a step-by-step analysis of the statutory provisions, regulations and caselaw pertinent to the establishment of electric utility rates at the Federal Energy Regulatory Commission (FERC). While it is impossible to cover all areas and issues that may arise in FERC rate cases, this book attempts to cover the major issues. It should be useful not only to companies or persons involved in FERC electric rate cases, but also to persons involved in FERC gas pipeline rate and state public utility commission proceedings, since many of the issues or authorities discussed here may aid arguments in those other proceedings.

## About the Author

Michael E. Small, is a partner in the law firm of Wright & Talisman, P.C., Washington, D.C. (202) 331-1194. Mr. Small, who also holds a B.S. in Nuclear Engineering, has been involved in hundreds of FERC cases, both as an employee of the FERC and as an outside lawyer. While at FERC, Mr. Small was one of the first FERC staff trial supervisors in the electric utility area through his position as a Special Assistant to the Deputy General Counsel for Litigation and Enforcement. On the subject of electric utility ratemaking, the author previously wrote the "FERC Electric Rate Primer," 5 *Energy Law Journal* 1, p. 107 (1984), as well as the *Federal Energy Regulatory Commission Electric Utility Handbook* (1983).

(51-100%) energy-related, it will be classified as energy. The same is also true with respect to demand related costs. FERC has accepted this method in a number of cases. *See, e.g., Arizona Pub. Serv. Co.*, 4 FERC ¶61,101, p. 61,209-10 (1978); *Illinois Power Co.*, 11 FERC ¶63,040, p. 65,255-56 (1980), *aff'd*, 15 FERC ¶61,050, p. 61,093 (1981); *Kansas City Power & Light Co.*, 21 FERC ¶63,003, p. 65,037 (1982), *aff'd*, 22 FERC ¶61,262 (1983); *Minnesota Power & Light Co.*, Opinion No. 86, 11 FERC ¶61,312, p. 61,648-49 (1980).[99]

In addition to FERC's adoption of its staff's predominance method, FERC has also adopted the staff's classification index of production O&M accounts. *Arizona Pub. Serv. Co.*, 4 FERC at 61,209-10; *KCPL*, 21 FERC at 65,037; *Minnesota Power & Light Co.*, 11 FERC at 61,648-49. In *Montaup Electric Co.*, Opinion No. 267, 38 FERC at 61,864, FERC rejected a proposed rate tilt, finding that the "proposal is inconsistent with the classification table of predominant characteristics for operation and maintenance accounts used by staff, which has been approved by the Commission."

## Allocation

After classifying costs to demand, energy, and customer categories, the next step is to allocate these costs to the various classes to determine their respective cost responsibilities. In the past, the most hotly litigated allocation issue involved demand cost allocation. Typically, FERC has allocated demand costs on a coincident peak method. Under that method, the demands used in the allocation are the demands of a particular customer or class occurring at the time of the system peak for a particular time period.

### *Coincident Peak Allocation*

In most cases, FERC has accepted one of four CP methods: 1 CP, 3 CP, 4 CP, or 12 CP. The majority of companies use a 12 CP allocation. Under a 1 CP method, the allocator for a particular wholesale class will be developed by dividing the wholesale class' CP for the peak month by the total company system peak. Similarly, for 3, 4, and 12 CP companies, the numerator would consist of the average of the wholesale class' coincident peaks for each of the peak months, while the denominator would consist of the average of the total system peaks for each of the peak months. FERC has held that interruptible loads should not be reflected in this demand allocation.[100] *See Delmarva Power and Light Co.*, Opinion No. 189, 25 FERC at 61,121; *Delmarva Power and Light Co.*, Opinion No. 185, 24 FERC ¶61,199, p. 61,462 (1983).

While FERC has not established a hard and fast rule for determining which allocation method is appropriate, it has stated that the following factors should be considered:

> [T]he full range of a company's operating realities including, in addition to system demand, scheduled maintenance, unscheduled outages, diversity, reserve requirements, and off-system sales commitments. (footnote omitted).

*Carolina Power & Light Co.*, Opinion No. 19, 4 FERC ¶61,107, p. 61,230 (1978); *Commonwealth Edison Co.*, 15 FERC ¶63,048, p. 65,196 (1981), *aff'd*, Opinion No. 165, 23 FERC ¶61,219 (1983); *Illinois Power Co.*, 11 FERC ¶63,040, p. 65,247-48 (1980), *aff'd*, 15 FERC ¶61,050 (1981).

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99 If a company is able to justify a percentage split, such as 70-30, in an account, then FERC may accept that split. However, in light of FERC precedent on this subject, any party proposing a deviation from the predominance method will likely have the burden of justifying its proposed split.

100 FERC ordered that the revenues from the interruptible loads be credited to the cost of service. *Delmarva Power and Light Co.*, 28 FERC ¶61,279, p. 61,510 (1984).

*System Demand Tests:* If a utility's system demand curve is relatively flat, FERC precedent supports the use of a 12 CP method. If a utility experiences a pronounced peak during one, three, or four consecutive months, FERC precedent supports the use of another CP method.

In determining whether a utility experiences a pronounced peak during a particular time period, FERC considers a number of tests. First, FERC has compared the average of the system peaks during the purported peak period, as a percentage of the annual peak, to the average of the system peaks during the off-peak months, as a percentage of the annual peak. FERC has held that large differences between these two figures lends support to using something other than a 12 CP method, while a smaller difference supports 12 CP, as shown below:

(1) *Louisiana Power & Light Company*, Opinion No. 813, 59 F.P.C. 968 (1977) (31% difference - 4 CP);

(2) *Louisiana Power & Light Company*, Opinion No. 110, 14 FERC ¶61,075 (1981) (26% difference - 4 CP);

(3) *Lockhart Power Company*, Opinion No. 29, 4 FERC ¶61,337 (1978) (18% difference - 12 CP);

(4) *Illinois Power Company*, 11 FERC at 65,248, (19% - 12 CP);

(5) *Commonwealth Edison Company*, 15 FERC at 65,196, (16.4-24.9% differences - 4 CP);

(6) *Southwestern Public Serv. Co.*, 18 FERC at 65,034 (average difference of 22.9%; high of 28.3% - 3 CP).

FERC has also used a second test involving the lowest monthly peak as a percentage of the annual peak. The higher the percentage, the greater the support for 12 CP. This test has been used in the following cases:

(1) *Louisiana Power & Light Company*, Opinion No. 813, 59 F.P.C. 968 (1977) (56% - 4 CP);

(2) *Idaho Power Company*, Opinion No. 13, 3 FERC ¶61,108 (1978) (58% - 3 CP);

(3) *Southwestern Electric Power Company*, Opinion No. 28, 4 FERC ¶61,330 (1978) (55.8% - 4 CP);

(4) *Lockhart Power Company*, Opinion No. 29, 4 FERC ¶61,337 (1978) (73% - 12 CP);

(5) *Southern California Edison Company*, Opinion No. 821, 59 F.P.C. 2167 (1977) (79% - 12 CP);

(6) *Alabama Power Company*, Opinion No. 54, 8 FERC ¶61,083 (1979) (75% - 12 CP);

(7) *Illinois Power Co.*, 11 FERC at 65,248, (66% - 12 CP);

(8) *Commonwealth Edison Company*, 15 FERC at 65,198, (64.6-67.8% - 4 CP);

(9) *Louisiana Power & Light Co.*, Opinion No. 110, 14 FERC ¶61,075 (1981) (61.9% - 4 CP);

(10) *El Paso Electric Co.*, Opinion No. 109, 14 FERC ¶61,082 (1981) (71% - 12 CP);

(11) *Carolina Power & Light Company*, Opinion No. 19, 4 FERC ¶61,107 (1978) (72% - 12 CP);

(12) *New England Power Company*, Opinion No. 803, 58 F.P.C. 2322 (1977) (80% - 12 CP);

(13) *Southwestern Public Serv. Co.*, 18 FERC at 65,034 (on average, almost 67 percent - 3 CP); and

(14) *Delmarva Power & Light Co.*, 17 FERC at 65,201 (71.4% - 12 CP).

Another test that has been utilized by FERC is the extent to which peak demands in non-peak months exceed the peak demands in the alleged peak months. In *Carolina Power & Light Co.*, Opinion No. 19, 4 FERC at 61,230, FERC adopted a 12 CP approach where the monthly peaks in three nonpeak months exceeded the peaks in two of the alleged peak months. In *Commonwealth Edison Co.*, 15 FERC at 65,198, FERC adopted a 4 CP method where over a four-year period, a peak in one of the four peak months was exceeded only once by a peak from a non-peak month. *See also Southwestern Public Service Co.*, 18 FERC at 65,034 (monthly peak in any non-peaking month exceeded the monthly peak in peak month only once and 3 CP adopted).

A last test involves the average of the twelve monthly peaks as a percentage of the highest monthly peak and has been used in the following cases:

(1) *Illinois Power Co.*, 11 FERC at 65,248-49 (81% - 12 CP);

(2) *El Paso*, Opinion No. 109, 14 FERC ¶61,082 (1981) (84% - 12 CP);

(3) *Lockhart Power,* Opinion No. 29, 4 FERC ¶61,337 (1978) (84% - 12 CP);

(4) *Southern California Edison*, Opinion No. 821, 59 F.P.C. 2167 (1977) (87.8% - 12 CP)

(5) *Louisiana Power & Light Co.*, Opinion No. 110, 14 FERC ¶61,075 (1981) (81.2% - 4 CP);

(6) *Commonwealth Edison Co.*, 15 FERC at 65,198, (79.4-79.5% - 4 CP);

(7) *Southwestern Public Serv. Co.*, 18 FERC at 65,035 (80.1% - 3 CP); and

(8) *Delmarva Power & Light Co.*, 17 FERC at 65,202 (83.3% - 12 CP).

***Tests Relating to Reserves/Maintenance:*** To the extent a utility uses the off-peak months to perform its scheduled maintenance, FERC has often found that supportive of the use of a 12 CP method. *Alabama Power Co.*, Opinion No. 54, 8 FERC ¶61,083, p. 61,327 (1979); *Illinois Power Co.*, 11 FERC at 65,249; *New England Power Co.*, Opinion No. 803, 58 F.P.C. 2322, 2338 (1977); *Delmarva Power & Light Co.*, 17 FERC at 65,202. *But see Commonwealth Edison*, 15 FERC at 65,199.

However, the scheduled maintenance must be considered together with the reserves available after the maintenance. To the extent the reserve margins are fairly stable after maintenance, then a 12 CP method is supported. If the reserve margins drop substantially to marginal levels during certain months, then a method other than 12 CP may be supported. *See, e.g., Illinois Power Co.*, 11 FERC at 65,249 (46 percent for 8 reserves after maintenance non-summer months and 34.5 percent for summer months—12 CP); *Commonwealth Edison Co.*, 15 FERC at 65,200 (For 1979, 36.63 percent reserves after maintenance for eight non-summer months and 22.15 percent for four summer months—4 CP).

*Projection of CP and Total System Demands*

In a number of cases, parties and FERC staff have challenged the filing company's estimated coincident peak or total system demand estimates. While FERC appears to have established few hard and fast rules, the following cases provide some guidance. First, parties have challenged projections on the basis that the historical periods used were not representative. In some cases, FERC has held that multiple years of historical data should be used in developing the estimate and not just one year. *See, e.g., Otter Tail Power Co.*, Opinion No. 93, 12 FERC ¶61,169, p. 61,429 (1980); *Commonwealth Edison Co.*, 15 FERC at 65,190, *aff'd*, Opinion No. 165, 23 FERC ¶61,219 (1983) (3 year average adopted). In other cases, however, FERC has adopted CP projections based on the use of one year's data in other cases. *See, e.g., Carolina Power & Light Co.*, Opinion No. 19, 4 FERC at 61,229-30.

Second, FERC has expressed concern that the numerator and the denominator be developed on similar bases. Thus, in *Otter Tail Power Co.*, Opinion No. 93, 12 FERC at 61,429, FERC modified a demand allocator to provide for the use of the same number of years' data in the derivation of both the numerator and the denominator.

Finally, FERC has held that billing demands should be consistent with the demands used in the demand allocator. *See El Paso Elec. Co.*, Opinion No. 109, 14 FERC ¶61,082, p. 61,147 (1981).

**Rolled-in Transmission**

A utility's transmission network will consist of transmission, [101] sub-transmission, [102] and distribution facilities. [103] Typically, the vast majority of the transmission facilities used to provide wholesale service consist of only transmission and sub-transmission facilities. FERC has often addressed the question of how transmission and sub-transmission facilities should be allocated to the wholesale customers.

In most cases, FERC has required that all transmission and sub-transmission facilities be rolled-in, *i.e.* treated alike for the purpose of allocation. [104] *Potomac Edison Co.*, 20 FERC ¶63,060 (1982); *Southern Cal. Edison Co.*, 59 F.P.C. 2167, 2179-80 (1977), *reh'g denied*, 2 FERC ¶61,018 (1978); *Florida Power & Light Co.*, 56 F.P.C. 3581, 3604-05 (1976); *Public Serv. Co. of Ind.*, 56 F.P.C. 3003, 3034-36 (1976); *Union Elec. Co.*, 47 F.P.C. 144, 151, 172 (1972); *Utah Power & Light Company*, Opinion No. 113, 14 FERC ¶61,162, p. 61,296 (1981); *Alabama Power Co.*,

101 Typically transmission voltages are 115 kv and above, though some systems have transmission facilities at lower voltage levels.

102 Sub-transmission voltages are usually between 23 kv and 115 kv, though it may again depend upon the system.

103 Distribution voltages are usually below 23 kv, though this will also depend upon the system.

104 Related to this issue is whether step-up transformers should be rolled-in with transmission costs. FERC has held that step-up transformers serve a transmission function and should be rolled-in with transmission facilities. *New York State Elec. and Gas Corp.*, Opinion No. 254, 37 FERC ¶61,151, pp. 61,364-65 (1986); *Niagara Mohawk Power Corp.*, Opinion No. 296, 42 FERC at 61,532.

**Ontario Energy Board** | **Commission de l'Énergie de l'Ontario**

Ontario

# EB-2005-0317

# COST ALLOCATION REVIEW

## Board Directions on Cost Allocation Methodology For Electricity Distributors

September 29, 2006

The above methodology must be followed by all distributors in Run 1 and Run 2 of the filing.

A distributor may use 12 NCP in its optional Run 3, provided that the distributor also provides supporting justification in its Filing Summary based on the cost characteristics of its distribution system. In such cases, the Filing Summary should highlight the impacts of the different NCP allocator used in Runs 1 and 2, versus Run 3.

## 8.3 Coincident Peak ("CP") Method

### 8.3.1 Background

CP is the generally preferred demand allocator for distribution assets designed to serve a distributor's system peak. In the cost allocation filings, assets identified as >50 kV and bulk (if any)[12] by a distributor must be allocated based on CP.

The Federal Energy Regulatory Commission has developed various tests to determine the appropriate CP to be used when allocating transmission costs. This approach has been adapted for use in the current cost allocation filings. The test below has been designed so that a 20% peak will warrant use of 1 CP rather than 4 CP. The type of CP allocator used can impact the cost allocated to a rate classification. For example, street lights may benefit from 12 CP as opposed to 1 CP under certain circumstances.

### 8.3.2 Direction - Tests for Use of CP in Filings

For distribution assets and related O&M accounts that are solely designed to meet the distributor's system demand, CP will be used as the demand allocator. For the filings, this will consist of all costs related to >50 kV and bulk assets (if any).

CP for each rate classification will be further subdivided into transmission transformation CP ("TCP") and distribution CP ("DCP"). Transmission transformation CP represents the coincident peak of all customers that use the >50kV assets deemed to be distribution assets.

The choice of 1 CP, 4 CP or 12 CP will be determined by the application of the test described below. As with the NCP test, the CP test will be incorporated into the filing model.

[12] See Chapter 6 (for example, guidance is provided there as to when a distribution station serves a bulk function and therefore its costs should be allocated using CP).

## CP Test #1

This test calculates the average of the twelve monthly system peaks as a percentage of the highest monthly system peak as follows:

> CP Test #1 = Average of 12 Monthly System Peaks ÷ Annual System Peak.

A CP Test #1 result of 83 percent or greater indicates that the distributor must use the 12 CP method for allocating demand costs that are to be allocated on a CP basis. If the test result is less than 83 percent, CP Test #2 must be conducted.

## CP Test #2

This test calculates the average of the four highest monthly peaks as a percentage of the greatest monthly peak as follows:

> CP Test #2 = Average of the 4 highest Monthly System Peaks ÷ Annual System Peak.

A CP Test #2 result of 83 percent or greater indicates that the distributor must use the 4 CP method for allocating demand costs.

A CP Test #2 result of less than 83 percent indicates that the distributor must use the 1 CP method for allocating demand costs.

### 8.4 Measurement of Peak for Demand Allocation

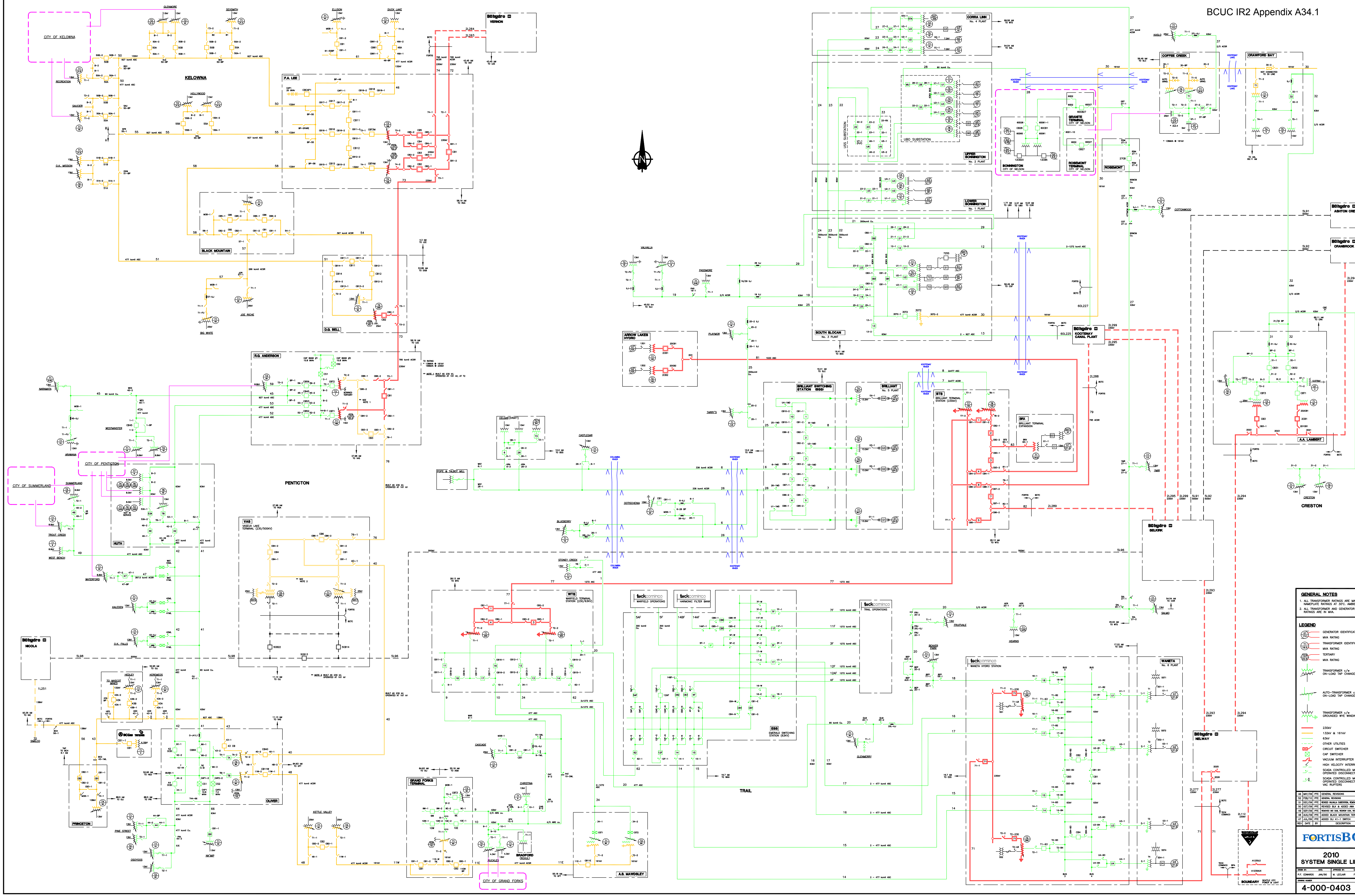
#### 8.4.1 Background

Using a one hour (i.e. clock hour) measurement of peak is the most common approach when determining the demand allocator for electricity sector cost allocation studies. A few jurisdictions (for example, Manitoba) use a longer period. It is considered that use of a one hour measurement period of peak, along with the use of the above-mentioned 4 NCP/1 NCP test, will provide an appropriate balance of policy objectives.

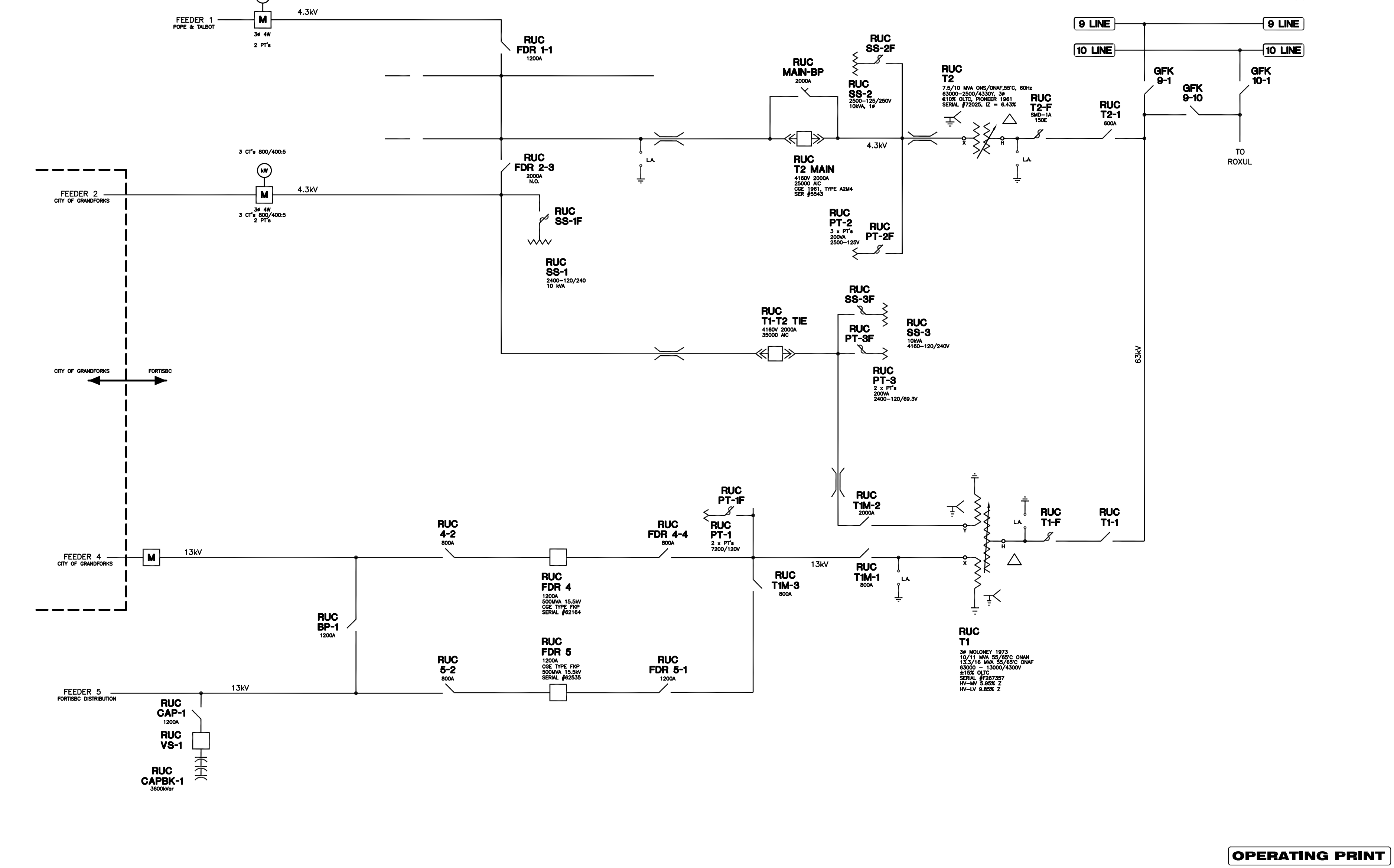
#### 8.4.2 Direction – Measurement of Hourly Peak for NCP and CP

For cost allocation purposes, the definition of peak for NCP or CP will be the standard one hour (clock hour) measurement of the peak hour. The use of a rolling 15 minute window for measuring peak will not be permitted.

BCUC IR2 Appendix A34.1



| Drawing No. | Substation | Wholesale Supply Point |
|---|---|---|
| 3-271-2000 | Ruckles | City of Grand Forks – 4.3 kV and 13 kV |
| 3-302-2000 | Glenmore | City of Kelowna – (Spall) 13 kV |
| 3-306-2000 | Recreation | City of Kelowna –13kV |
| 3-313-2000 | Saucier | City of Kelowna –13kV |
| 3-103-2000 | Coffee Creek | Reference drawing for 3-380-2002 |
| 3-103-2002 | Coffee Creek | City of Nelson – 25 kV |
| 3-380-2000 | RG Anderson | Reference drawing for 3-380-2001 |
| 3-380-2001 | RG Anderson | City of Penticton – (Carmi) 8 kV |
| 3-320-2000 | Huth | City of Penticton – 8 kV |
| 3-320-2002 | Huth | City of Penticon – 13 kV |
| 3-325-2000 | Waterford | City of Penticon – 13 kV |
| 3-327-2000 | Westminster | City of Penticton – 8 kV |
| 3-324-2000 | Summerland | City of Summerland – (Prairie Valley) 8 kV |
| 3-329-2000 | Trout Creek | City of Summerland – 8 kV |

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| 10 | | | | | | |
| 9 | | | | | | |
| 8 | SEP/02 | KAM | HJU | AS PER STATION AUDIT | | |

REVISIONS

DRAWN BY: D.F. ST.DENIS AUG/91
PLOT DATE: 02-05-09
CHECKED BY:
APPROVALS: ELEC / CIVIL / MANAGEMENT

FORTISBC

DIVISION: KOOTENAY
DEPARTMENT: PROTECTION-CONTROL
LOCATION: RUCKLES SUBSTATION
TITLE: SINGLE LINE DIAGRAM

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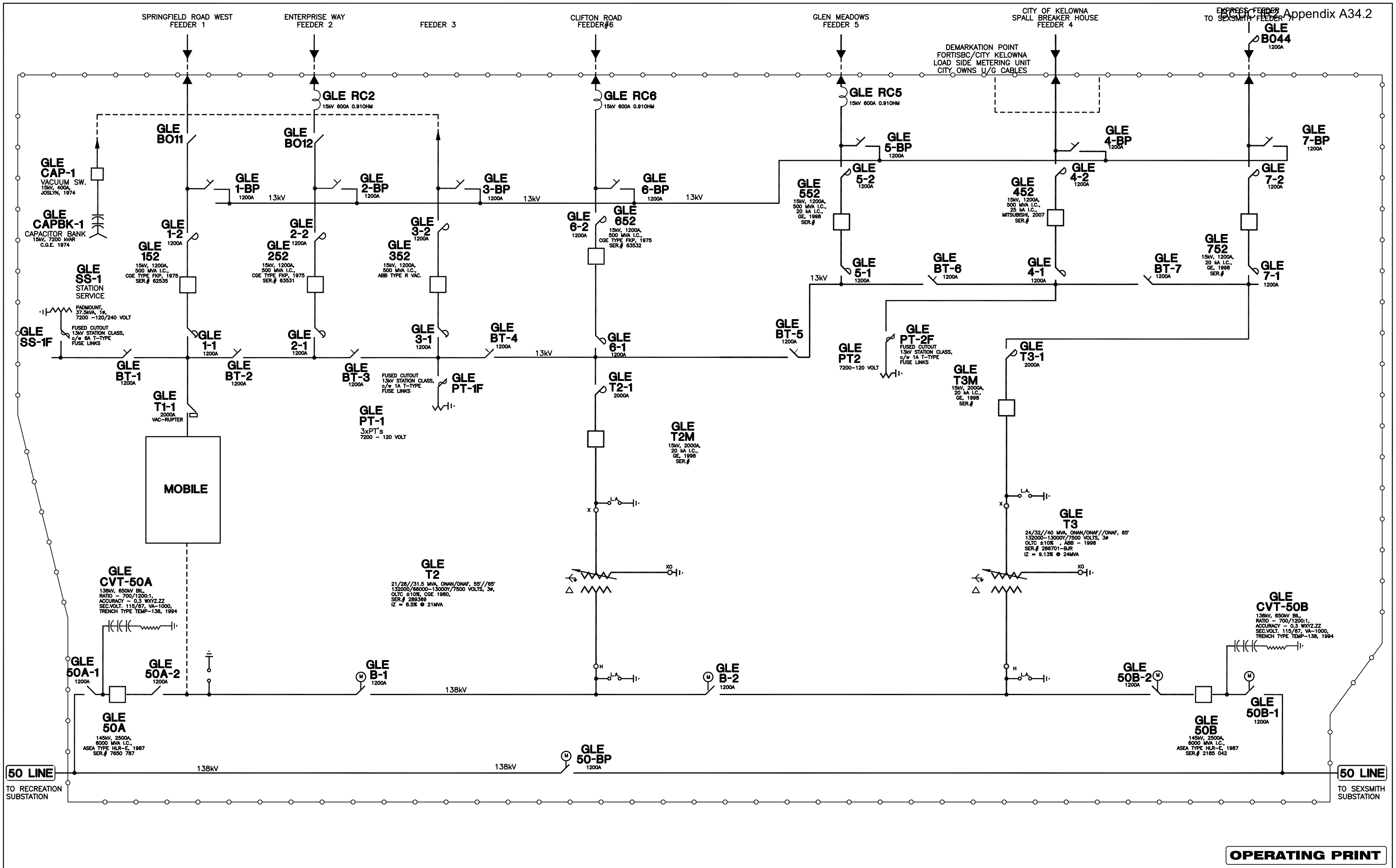
REVISION: 8

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| 29 | MAY/08 | SA | ST | AS RECORDED, HTI JOB#2708,3073,3092, FBC#SDP-TG1200.1-E.GLE, SDP-TG1825.07.1, SDP-CS0200.07.01 | J. KULCHISKY | MAY/08 |
| 28 | NOV/07 | RK | RH | GLENMORE FAULT REDUCTION, HTI JOB#2708, FBC# SDP-TG1200.1-E.GLE, ISSUED FOR CONSTRUCTION, REACTOR ON FEEDER1 IS NOT INSTALLED. | | |
| 27 | JUL/07 | MJ | JV | GLENMORE FEEDER RE-ORGANIZATION, HTI JOB# 3073, FBC#-SDP-TG1825.07.1, ISSUED FOR CONSTRUCTION. | S. TROOP | JUL/07 |

REVISIONS

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DESIGNED BY:
CHECKED BY:
APPROVALS: ELEC / CIVIL / MANAGEMENT

FORTISBC

DIVISION: OKANAGAN
DEPARTMENT: PROTECTION-CONTROL
LOCATION: GLENMORE SUBSTATION - KELOWNA
TITLE: SINGLE LINE DIAGRAM

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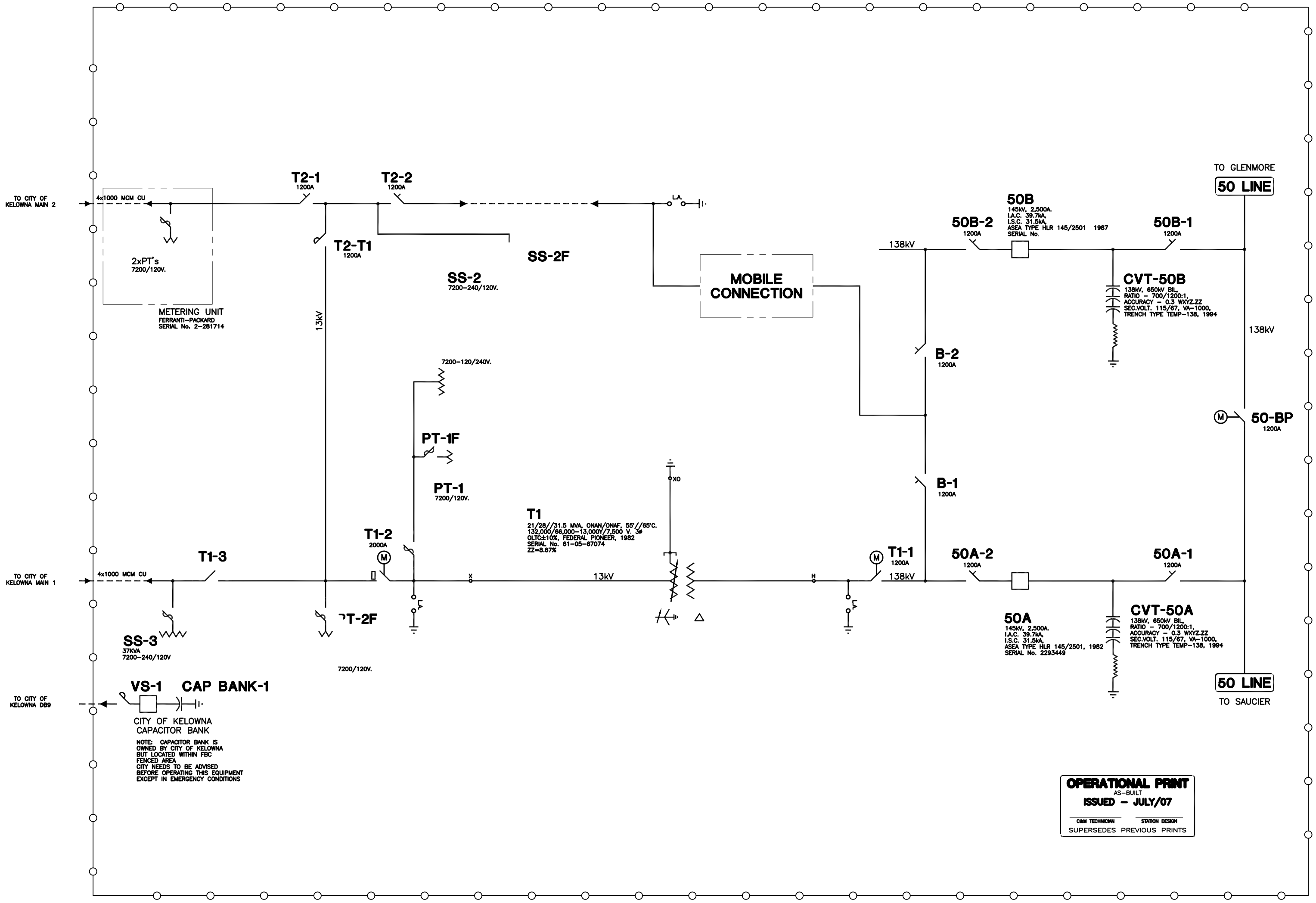


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| 23 | MAY/07 | RK | ST | RECREATION SWGR. REPLACEMENT, HTI JOB# 2908, FBC# SDP-TPP2800, ISSUED FOR CONSTRUCTION. | | |
| 25 | NOV/08 | RB | FvR | RECREATION SWGR. REPLACEMENT, HTI JOB# 2908, FBC# SDP-TPP2800, AS-BUILT | J. KULCHISKY | 09FEB09 |
| 24 | JUN/07 | ZE | ST | RECREATION SWGR. REPLACEMENT, HTI JOB# 2908, FBC# SDP-TPP2800, ISSUED FOR CONSTRUCTION. | J. KULCHISKY | JUN/07 |

DRAWN BY: P.F. EDWARDS MAY/02
DESIGNED BY:
CHECKED BY:
APPROVALS: ELEC | CIVIL | MANAGEMENT

FORTISBC

DIVISION: OKANAGAN
DEPARTMENT: PROTECTION-CONTROL
LOCATION: RECREATION SUB - FORTIS PROPERTY
TITLE: SINGLE LINE DIAGRAM

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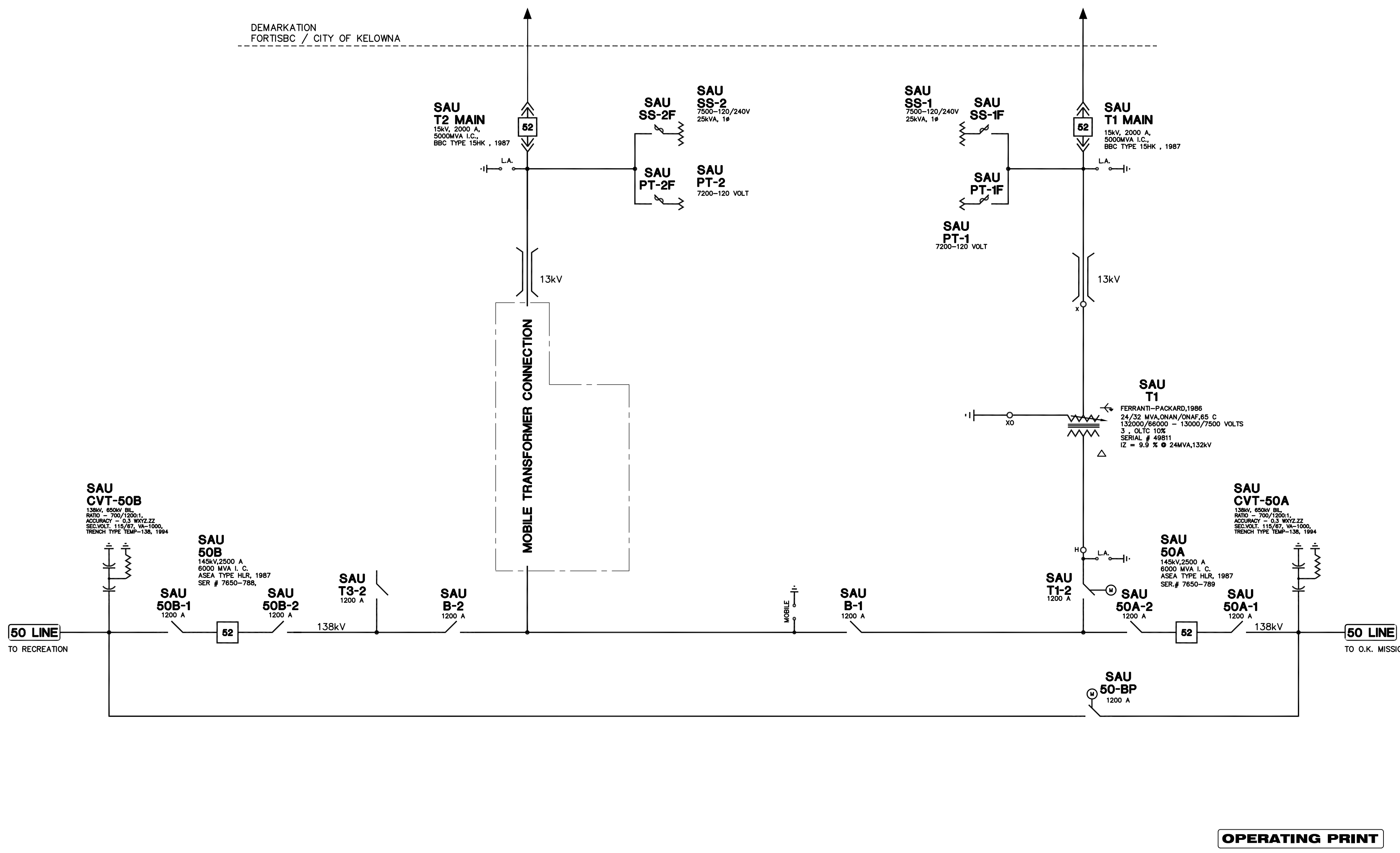


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| D12 | JUL/06 | DMC | JL | REMOVE VOLT METER, AMMETER AND SWITCHES | | |
| 12 | NOV/01 | PFE | KRH | LTC ON L.V. AS PER SCOTT REYNOLDS | | |
| 14 | MAY/07 | VVL | BMM | AS BUILT | | |

REVISIONS

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| DRAWN BY: H.URSAKI | OCT/05 |
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FORTISBC

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| DIVISION | OKANAGAN |
| DEPARTMENT | PROTECTION-CONTROL |
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| TITLE | SINGLE LINE DIAGRAM |

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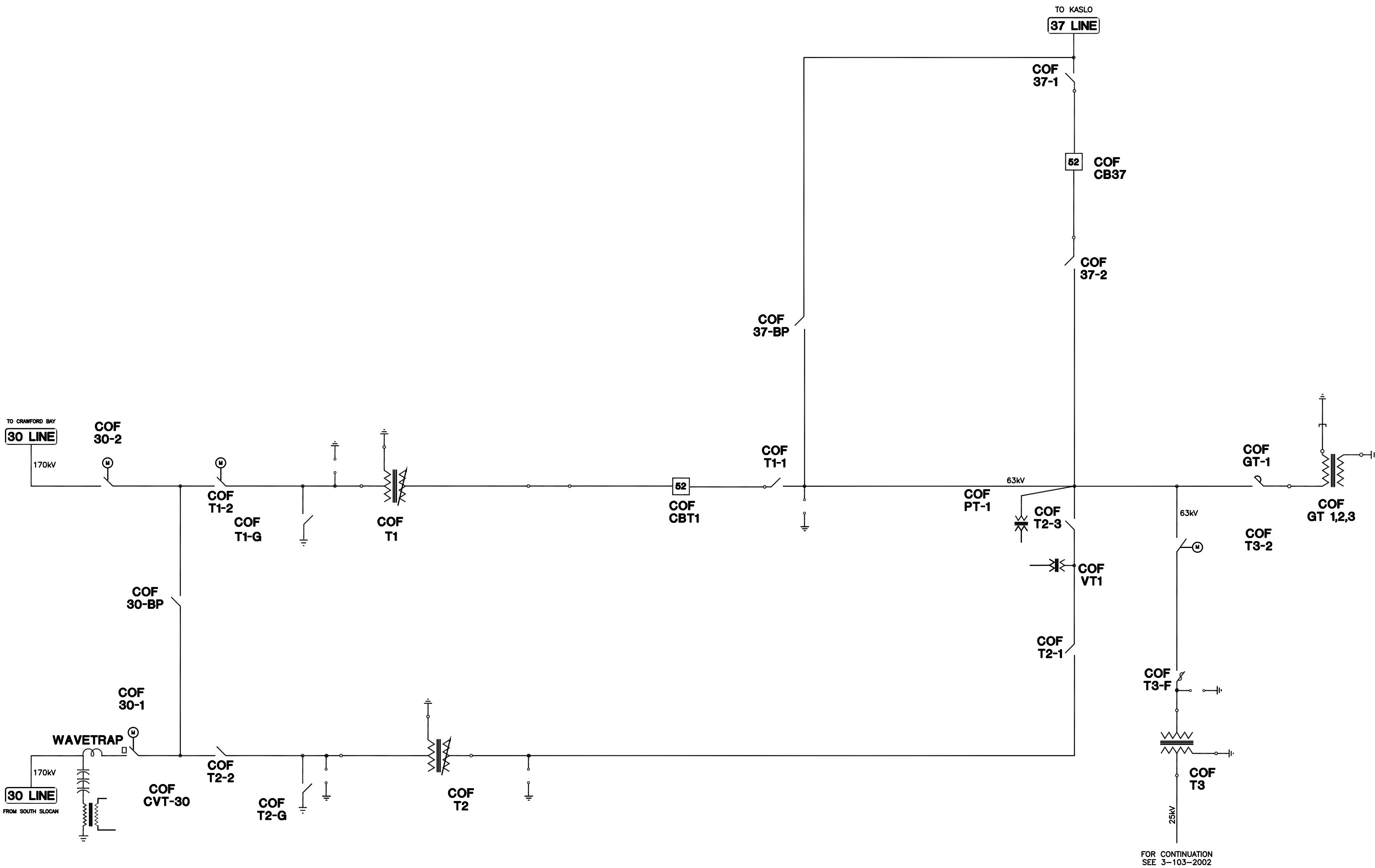


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| 16 | MAY/06 | SY | DK | COFFEE CREEK 63kV BREAKER REPLACEMENT – ISSUED FOR CONSTRUCTION | | |
| 19 | MAR/09 | JPR | KLP | 37L PROT UPGRADE – SDP-CS0500.07.1 – AS BUILT | M. LECLAIR | APR/09 |
| 18 | JUN/08 | JPR | MF | 37L PROT UPGRADE – SDP-CS0500.07.1 – ADDED 37L PY & SY PROTECTION, 86BF, TAGGING SWITCH, AND VT1 | C. KLASHINSKY | JUL/08 |

REVISIONS

DRAWN BY: H.J. URSAKI APR/95
DESIGNED BY:
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APPROVALS: ELECTRICAL | CIVIL | MANAGEMENT

FORTISBC

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| DIVISION | KOOTENAY |
| DEPARTMENT | PROTECTION-CONTROL |
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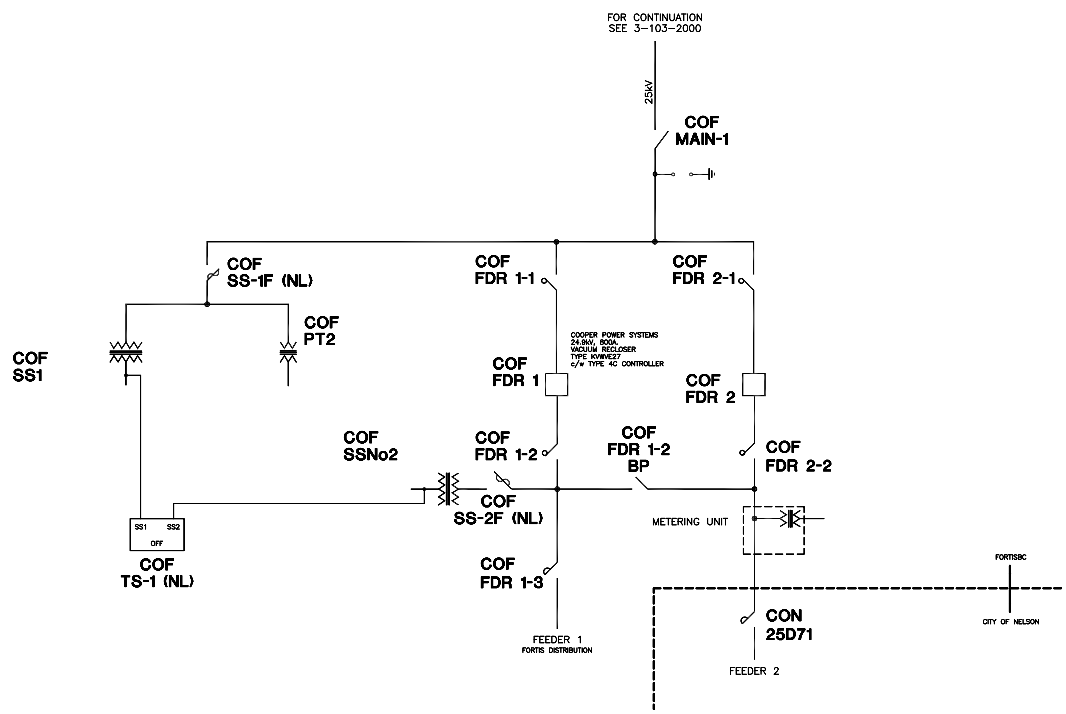


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|---|---|
| DIVISION | KOOTENAY |
| DEPARTMENT | PROTECTION-CONTROL |
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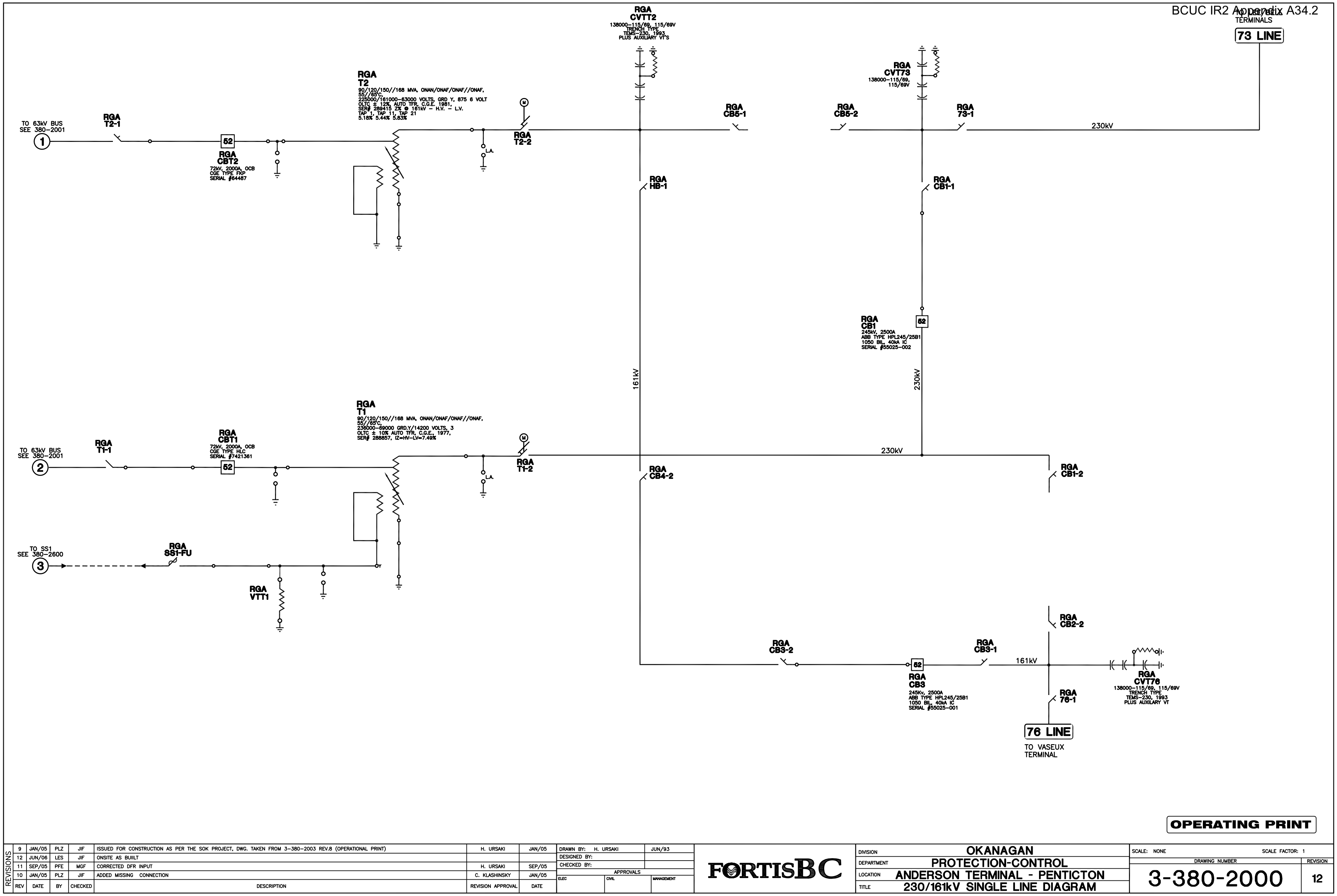
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RGA T2-2
RGA CBT2
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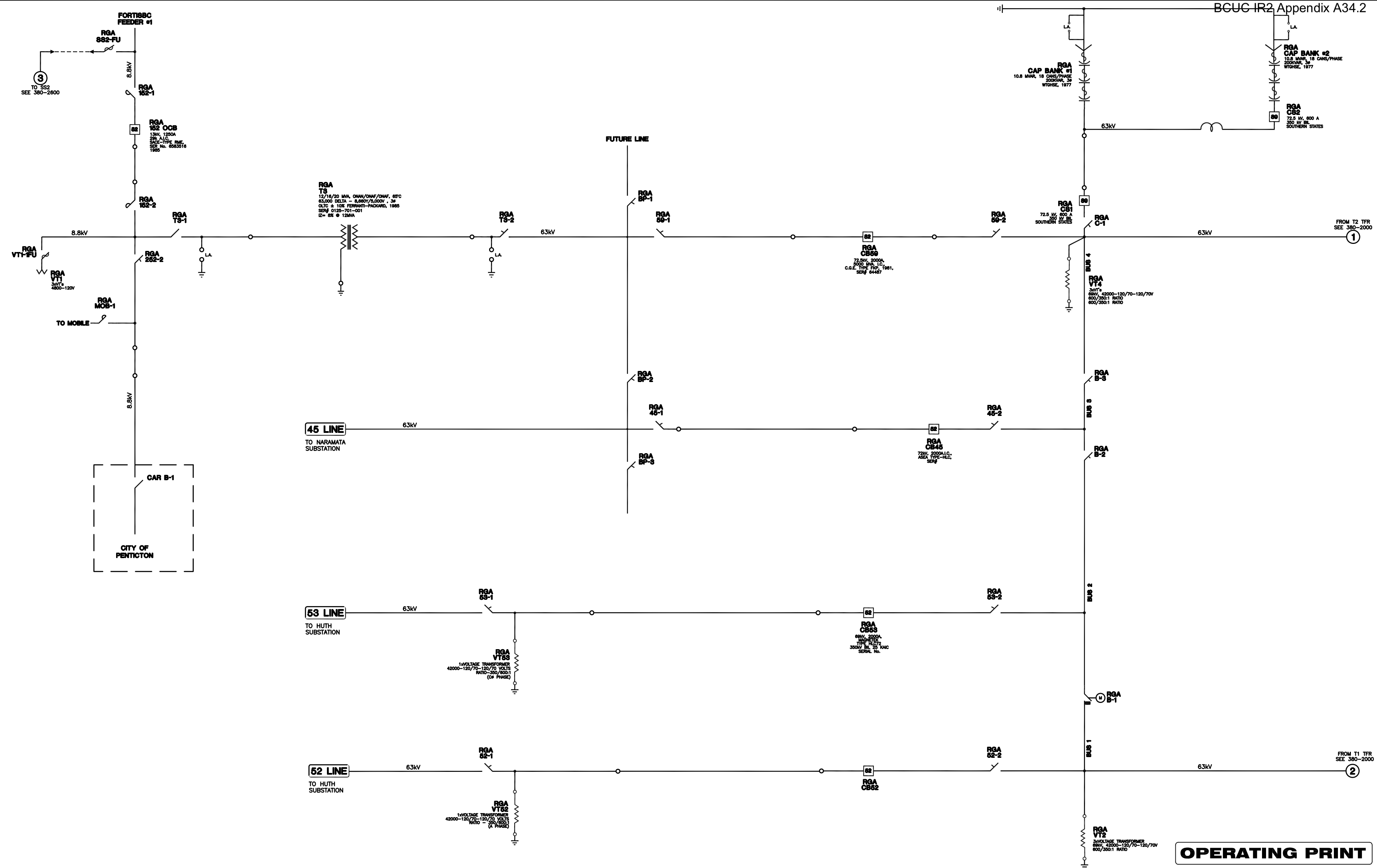
OPERATING PRINT
9 JAN/05 PLZ JIF ISSUED FOR CONSTRUCTION AS PER THE SOK PROJECT, DWG. TAKEN FROM 3-380-2003 REV.8 (OPERATIONAL PRINT) H. URSAKI JAN/05
12 JUN/06 LES JIF ONSITE AS BUILT
11 SEP/05 PFE MGF CORRECTED DFR INPUT H. URSAKI SEP/05
10 JAN/05 PLZ JIF ADDED MISSING CONNECTION C. KLASHINSKY JAN/05
REVISIONS REV DATE BY CHECKED DESCRIPTION REVISION APPROVAL DATE
DRAWN BY: H. URSAKI JUN/93
DESIGNED BY:
CHECKED BY:
APPROVALS ELEC CIVIL MANAGEMENT
FORTISBC
DIVISION OKANAGAN
DEPARTMENT PROTECTION-CONTROL
LOCATION ANDERSON TERMINAL - PENTICTON
TITLE 230/161kV SINGLE LINE DIAGRAM
SCALE: NONE
SCALE FACTOR: 1
DRAWING NUMBER 3-380-2000
REVISION 12




| REV | DATE | BY | CHECKED | DESCRIPTION | REVISION APPROVAL | DATE |
|---|---|---|---|---|---|---|
| 17 | JUN/06 | LES | HJU | ONSITE AS BUILT | | |
| 16 | JAN/05 | PLZ | JIF | ISSUED FOR CONSTRUCTION AS PER THE SOK PROJECT, DWG. TAKEN FROM 3-380-2004 REV. 15 (ASBUILT) | P. CHERNIKHOWSKY | JAN/05 |
| 15 | MAR/03 | PFE | HJU | AS PER 2003 STATION AUDIT | | |
| 14 | JAN/02 | LDD | HJU | AS PER STATION AUDIT | | |

REVISIONS

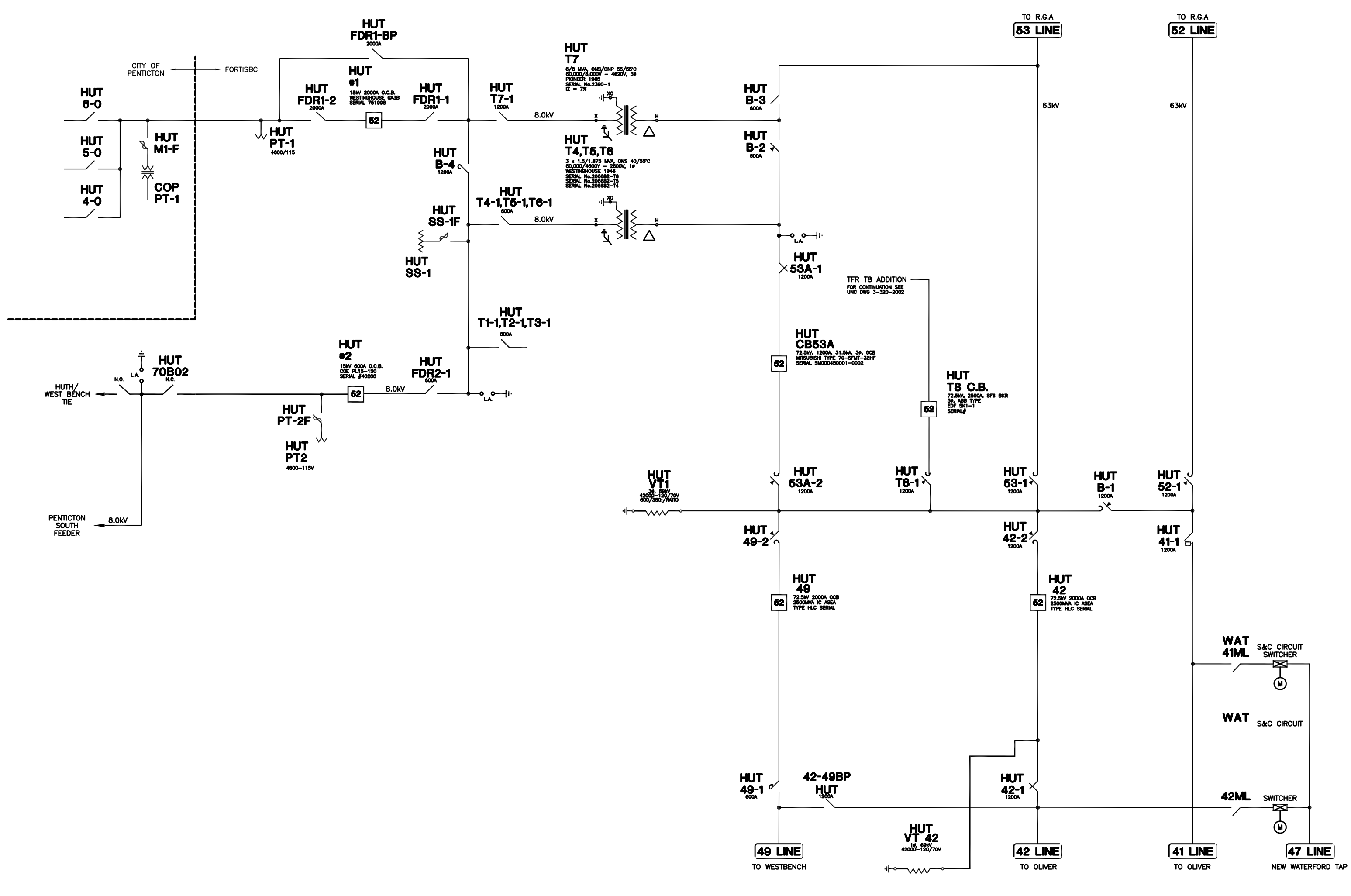
DRAWN BY: H. URSAKI SEP/93
DESIGNED BY:
CHECKED BY:
APPROVALS: ELEC / CIVIL / MANAGEMENT

FORTISBC

| | |
|---|---|
| DIVISION | OKANAGAN |
| DEPARTMENT | PROTECTION-CONTROL |
| LOCATION | ANDERSON TERMINAL - PENTICTON |
| TITLE | 63/8.8kV SINGLE LINE DIAGRAM |

SCALE: NONE SCALE FACTOR: 1.25

| DRAWING NUMBER | REVISION |
|---|---|
| 3-380-2001 | 17 |




**OPERATING PRINT**

| REV | DATE | BY | CHECKED | DESCRIPTION | REVISION APPROVAL | DATE |
|---|---|---|---|---|---|---|
| 21 | FEB/09 | PFE | JPR | PROTECTION UPGRADE – SDP-CS0500.08.1 – AS BUILT | M. LECLAIR | APR/09 |
| 20 | OCT/08 | JPR | KM | PROTECTION UPGRADE – RE-ISSUED – CHANGED 50/51-CB53A T7 INPUTS | M. FRICKE | OCT/08 |
| 19 | DEC/07 | MF | MAL | REVISED METERING FOR 42 & 49 LINES | C. KLASHINSKY | MAY/08 |
| 18 | DEC/06 | RY | RY | AS BUILT | K. HEDGES | MAY/02 |

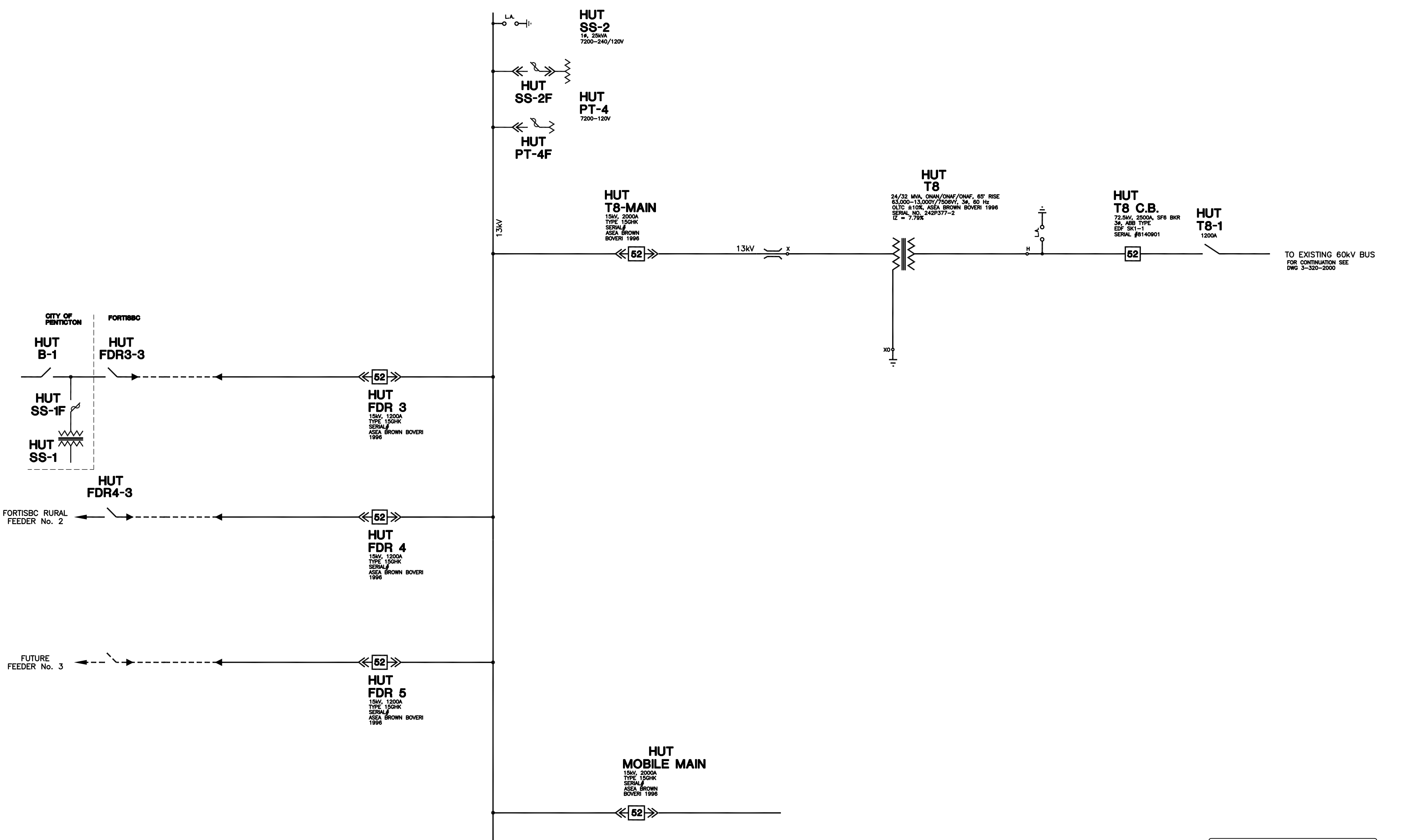
REVISIONS

DRAWN BY: K.R. HEDGES OCT/90
DESIGNED BY:
CHECKED BY:
APPROVALS: ELECTRICAL | CIVIL | MANAGEMENT

FORTISBC

DIVISION: OKANAGAN
DEPARTMENT: PROTECTION-CONTROL
LOCATION: HUTH SUBSTATION
TITLE: 60 & 8.8kV SINGLE LINE DIAGRAM

SCALE: NONE SCALE FACTOR: 1
DRAWING NUMBER: 3-320-2000
REVISION: 21




OPERATING PRINT

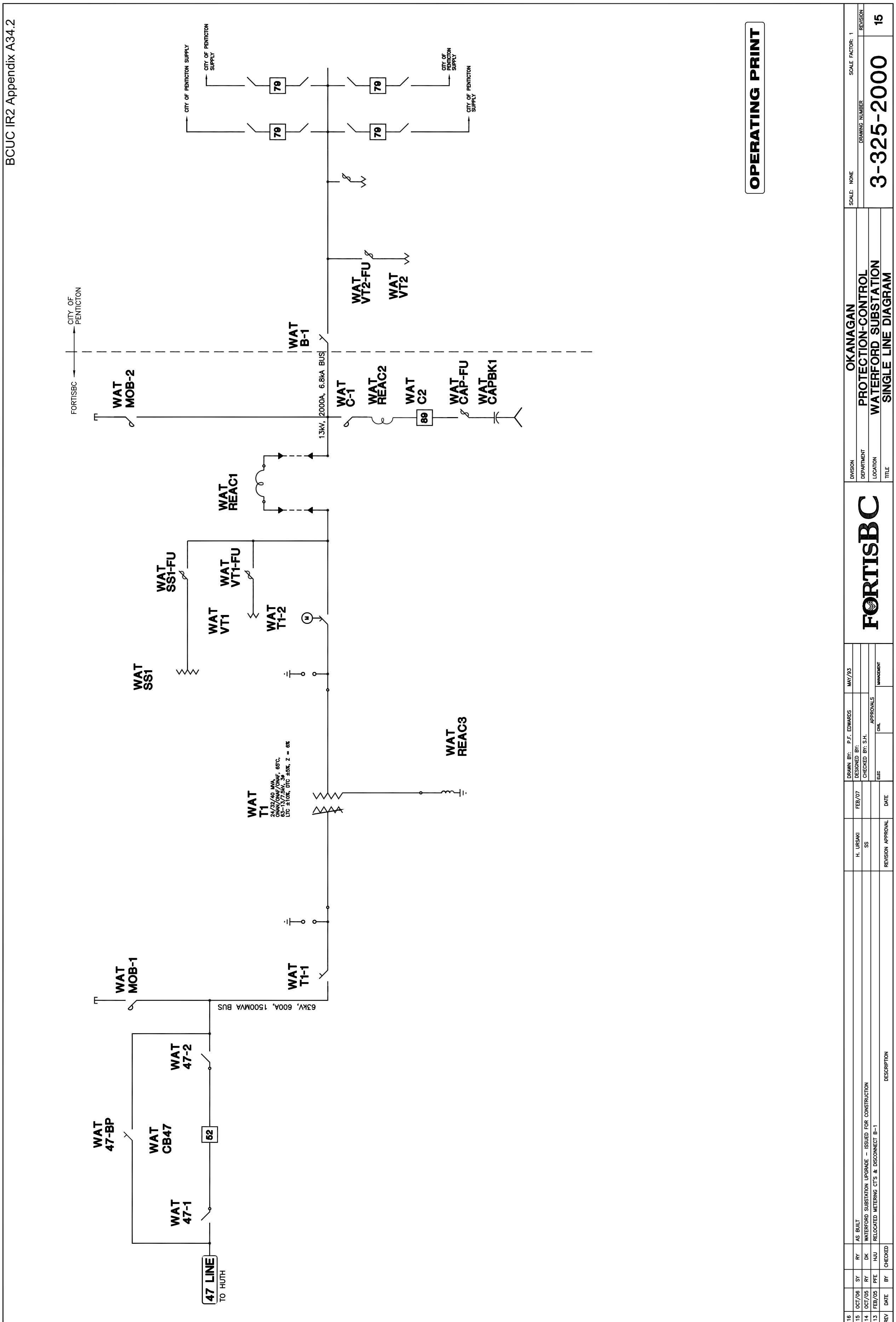
| REVISIONS | | | | | | |
|---|---|---|---|---|---|---|
| REV | DATE | BY | CHECKED | DESCRIPTION | REVISION APPROVAL | DATE |
| 10 | SEP/06 | ABZ | HJU | AS BUILT | | |
| 9 | OCT/05 | PFE | HJU | CHANGED AQUILA TO FOTISBC | | |
| 8 | AUG/05 | KRH | HJU | REPLACED SIEMENS 7UT DIFFERENTIAL RELAY WITH SEL 387 | K. HEDGES | OCT/03 |
| 7 | AUG/05 | PFE | HJU | CHANGED FEEDERS 1, 2, & 3 TO FEEDERS 3, 4 & 5 (DAVE COCHRANE SCC) | K. HEDGES | MAR/01 |

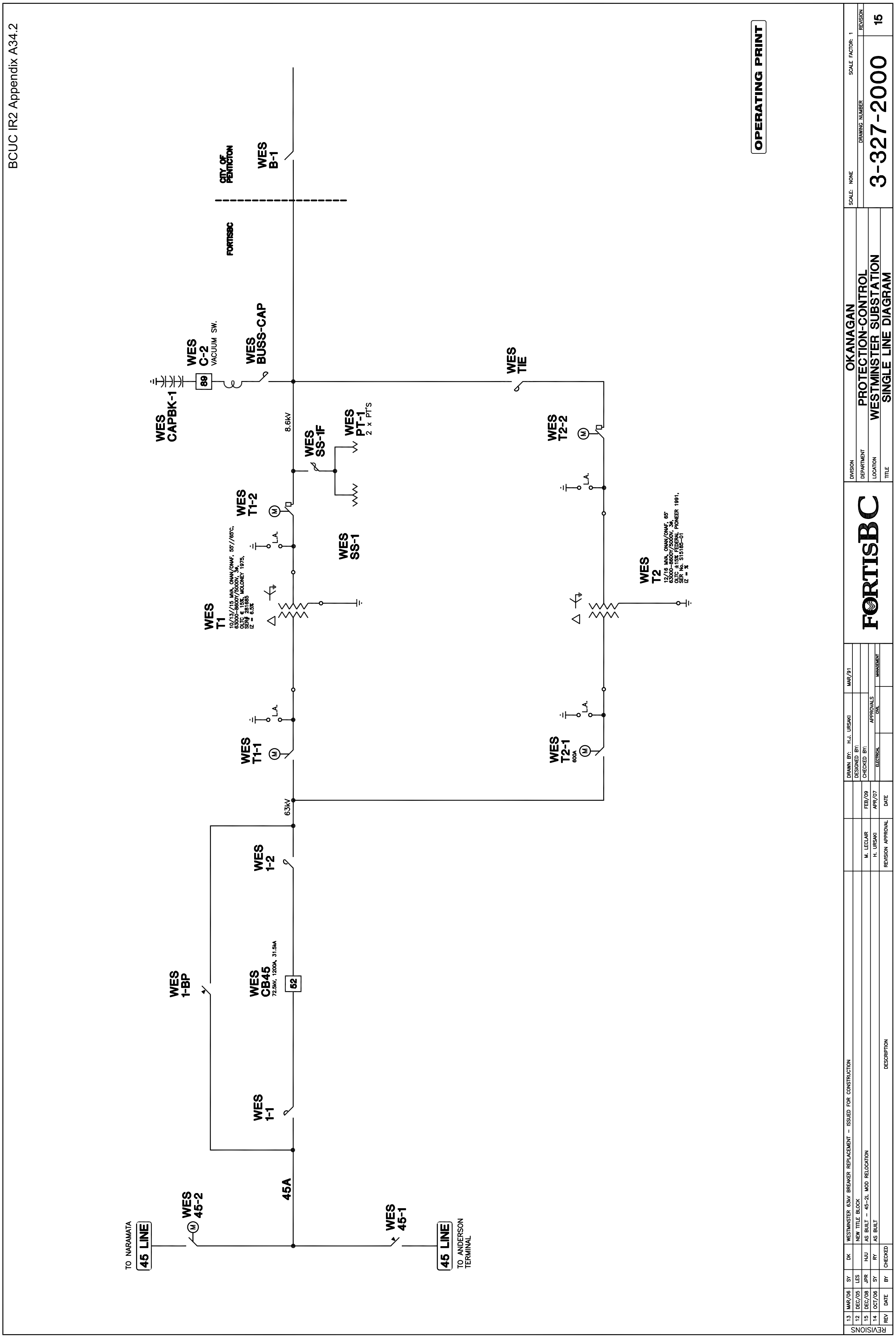
| | | |
|---|---|---|
| DRAWN BY: D. ST.DENIS | | JAN/97 |
| DESIGNED BY: | | |
| CHECKED BY: H. URSAKI | | SEP/05 |
| APPROVALS | | |
| ELEC | CIVIL | MANAGEMENT |

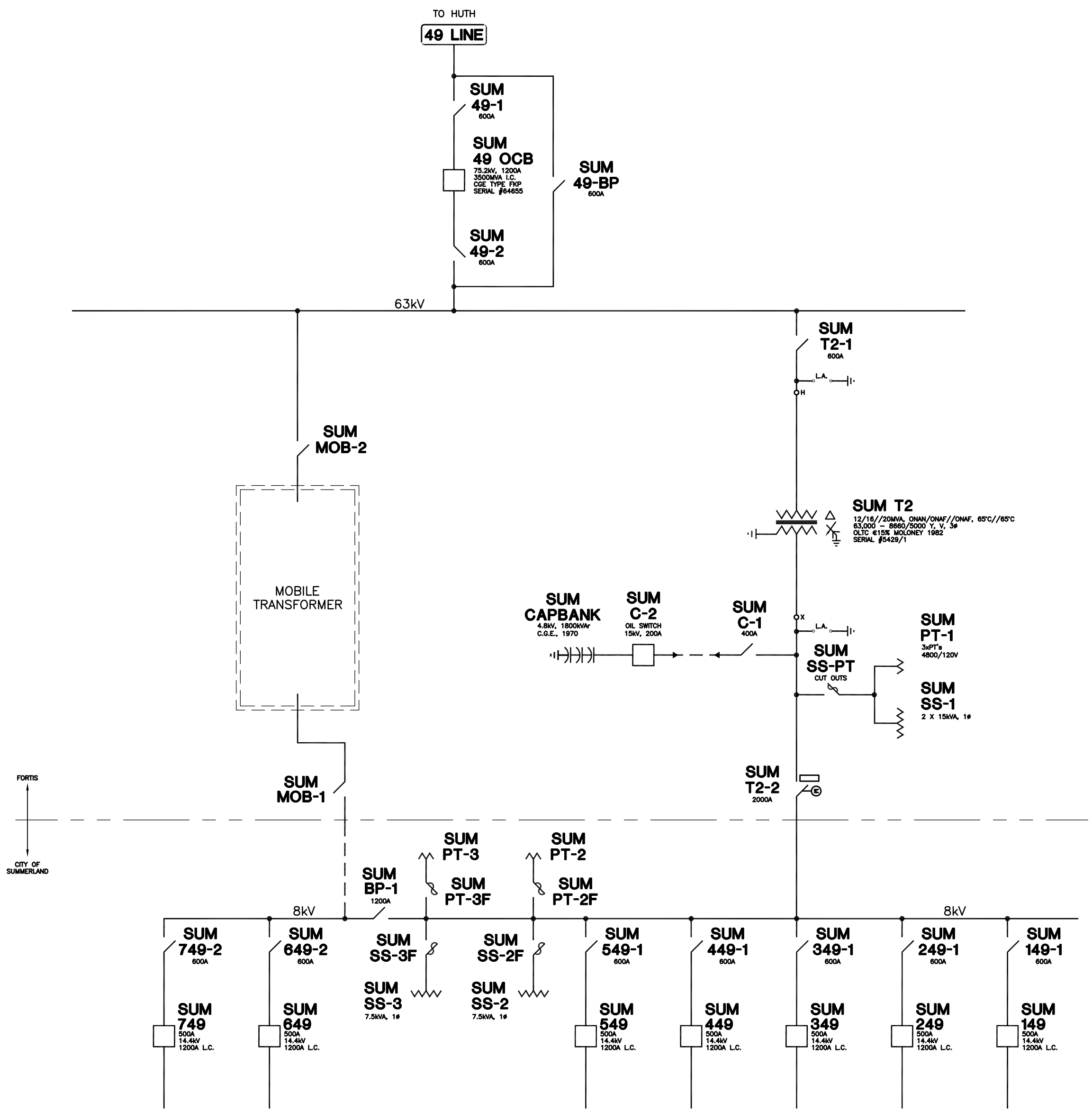
FORTISBC

| | |
|---|---|
| DIVISION | OKANAGAN |
| DEPARTMENT | PROTECTION-CONTROL |
| LOCATION | HUTH SUBSTATION |
| TITLE | 13kV SINGLE LINE DIAGRAM |

| | | |
|---|---|---|
| SCALE: NONE | SCALE FACTOR: 1 | |
| DRAWING NUMBER | | REVISION |
| 3-320-2002 | | 10 |


OPERATING PRINT
47 LINE
TO HUTH
WAT 47-1
WAT 47-BP
WAT CB47
52
WAT 47-2
WAT MOB-1
63kV, 600A, 1500MVA BUS
WAT T1-1
WAT T1
24/32/40 MVA, ONAN/ONAF/ONAF, 65°C, 63-13.7/7.9kV, 3Ø LTC ±10%, DTC ±5%, Z = 6%
WAT REAC3
WAT SS1
WAT VT1
WAT T1-2
WAT SS1-FU
WAT VT1-FU
WAT REAC1
WAT MOB-2
FORTISBC
CITY OF PENTICTON
13kV, 2000A, 6.8kA BUS
WAT B-1
WAT C-1
WAT REAC2
WAT C2
89
WAT CAP-FU
WAT CAPBK1
WAT VT2-FU
WAT VT2
79
CITY OF PENTICTON SUPPLY
REVISIONS
16
15 OCT/06 SY RY AS BUILT
14 OCT/05 RY DK WATERFORD SUBSTATION UPGRADE – ISSUED FOR CONSTRUCTION
13 FEB/05 PFE HJU RELOCATED METERING CT'S & DISCONNECT B-1
REV DATE BY CHECKED DESCRIPTION
H. URSAKI FEB/07
SS
REVISION APPROVAL DATE
DRAWN BY: P.F. EDWARDS MAY/93
DESIGNED BY:
CHECKED BY: S.H.
APPROVALS
ELEC CIVIL MANAGEMENT
FORTISBC
DIVISION OKANAGAN
DEPARTMENT PROTECTION-CONTROL
LOCATION WATERFORD SUBSTATION
TITLE SINGLE LINE DIAGRAM
SCALE: NONE
SCALE FACTOR: 1
DRAWING NUMBER 3-325-2000
REVISION 15


OPERATING PRINT
TO NARAMATA
45 LINE
WES 45-2
45A
WES 45-1
45 LINE
TO ANDERSON TERMINAL
WES 1-1
WES 1-BP
WES CB45
72.5kV, 1200A, 31.5kA
52
WES 1-2
63kV
WES T1-1
L.A.
WES T1
WES SS-1
WES T1-2
WES SS-1F
WES PT-1
2 x PT'S
8.6kV
WES CAPBK-1
89
WES C-2
VACUUM SW.
WES BUSS-CAP
FORTISBC
CITY OF PENTICTON
WES B-1
WES T2-1
600A
WES T2
WES T2-2
WES TIE
FORTISBC
OKANAGAN
PROTECTION-CONTROL
WESTMINSTER SUBSTATION
SINGLE LINE DIAGRAM
SCALE: NONE
SCALE FACTOR: 1
DRAWING NUMBER
3-327-2000
REVISION
15
DRAWN BY: H.J. URSAKI MAR/91
REVISIONS
13 MAR/06 SY DK WESTMINSTER 63kV BREAKER REPLACEMENT – ISSUED FOR CONSTRUCTION
12 DEC/05 LES NEW TITLE BLOCK
15 DEC/08 JPR HJU AS BUILT – 45-2L MOD RELOCATION
14 OCT/06 SY RY AS BUILT
REV DATE BY CHECKED DESCRIPTION




REVISIONS

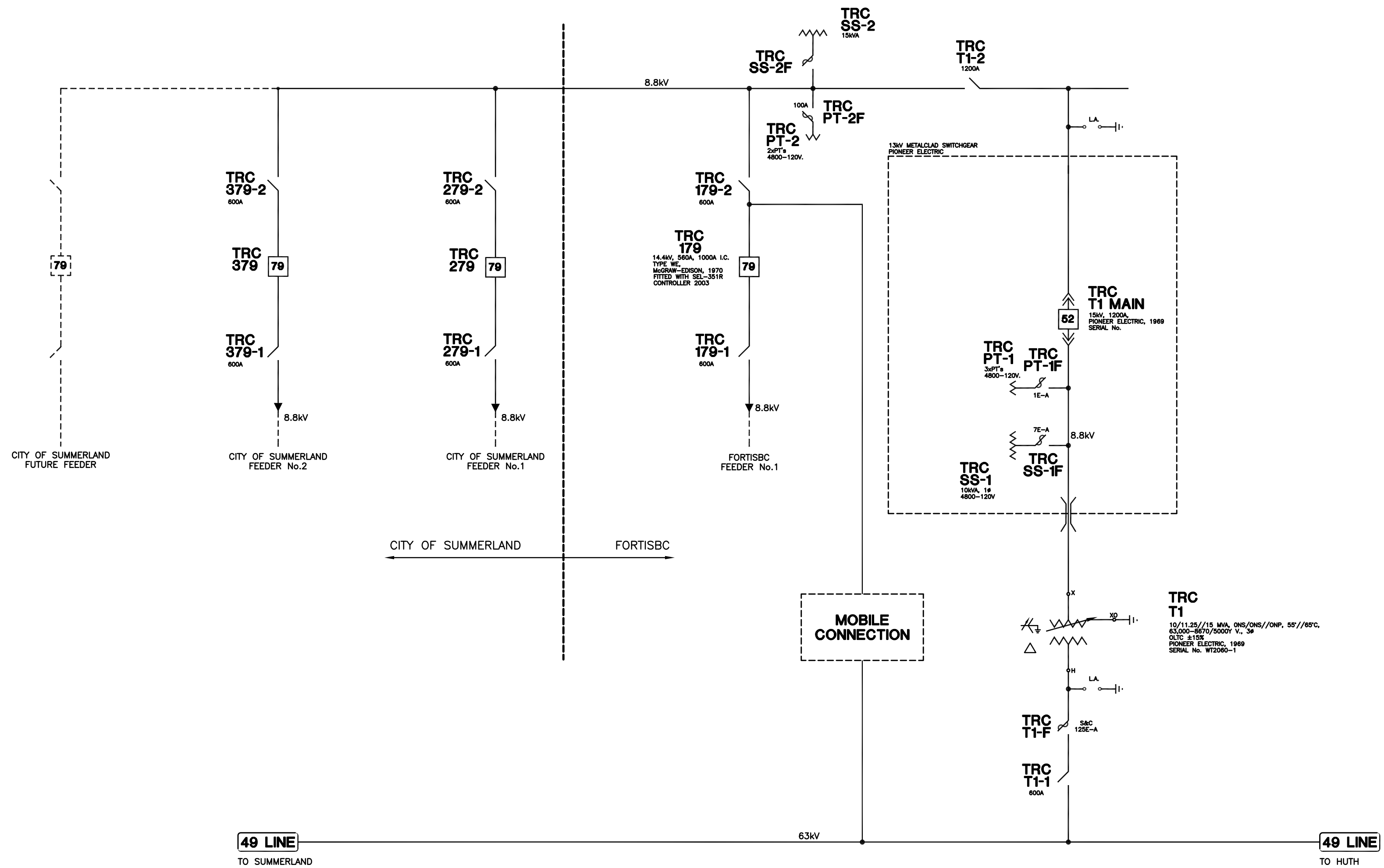
| REV | DATE | BY | CHECKED | DESCRIPTION | REVISION APPROVAL | DATE |
|---|---|---|---|---|---|---|
| 20 | MAY/08 | LMF | DFS | AS BUILT, T2-2 SWITCH REPLACEMENT/METER UPGRADE SDP-SS0100 | M. LECLAIR | MAY/08 |
| 19 | JUL/07 | JS | DFS | T2-2 SWITCH REPLACEMENT SDP-SS0100.06.6 ISSUED FOR CONSTRUCTION | I. FINKE | SEP/07 |
| 19 | JUN/06 | DMC | JL | REPLACE PML 3720 METER WITH PML 7650 METER | H. URSAKI | JAN/04 |
| 18 | FEB/06 | PFE | HJU | REVISED 649 & 749 DISCONNECT SWITCH LABELS FROM -1 TO -2 | | |

DRAWN BY: D. ST.DENIS JAN/91
DESIGNED BY:
CHECKED BY:
APPROVALS: ELEC | CIVIL | MANAGEMENT

FORTISBC

| | |
|---|---|
| DIVISION | OKANAGAN |
| DEPARTMENT | PROTECTION-CONTROL |
| LOCATION | SUMMERLAND SUBSTATION |
| TITLE | SINGLE LINE DIAGRAM |

SCALE: NONE SCALE FACTOR: 1
DRAWING NUMBER: 3-324-2000
REVISION: 20




**OPERATING PRINT**

| REV | DATE | BY | CHECKED | DESCRIPTION | REVISION APPROVAL | DATE |
|---|---|---|---|---|---|---|
| 7 | SEPT/03 | PFE | HJU | AS BUILT | | |
| 10 | OCT/05 | PFE | | CHANGED AQUILA LABEL TO FORTISBC | | |
| 9 | MAR/05 | PFE | HJU | AS BUILT | | |
| 8 | MAY/04 | PFE | HJU | REVISED TRANSFORMER ALARM & TRIP ADDED NOTE RE T1 MAIN BREAKER RECLOSING DISABLED | | |

REVISIONS

| | |
|---|---|
| DRAWN BY: P.F. EDWARDS | MAY/93 |
| PLOT DATE: | 05-10-21 |
| CHECKED BY: | |
| APPROVALS: ELEC / CIVIL / MANAGEMENT | |

FORTISBC

| | |
|---|---|
| DIVISION | OKANAGAN |
| DEPARTMENT | PROTECTION-CONTROL |
| LOCATION | TROUT CREEK SUBSTATION |
| TITLE | SINGLE LINE DIAGRAM |

SCALE: NONE SCALE FACTOR: 1

DRAWING NUMBER: 3-329-2000 REVISION: 10

To Contract file

**memorandum**

**west kootenay power**

**To** Those Listed Below

**Date** July 27, 1988

**From** Conservation Officer & Rate Engineer (LET)

**File No.**

**Subject** POWER SUPPLY TO LARDEAU/SHUTTY BENCH

**Ref.**

Attached for your file is a letter of agreement outlining the increase in contract demand to 3000 kVa effective August 1, 1988.

LET:al

Attach.

To: G.K. Harper
D. Pickard
R. A. Ross
M. Meyer

File 864-C1

**Signed** L Trickey

FORM 45 H.P.

West Kootenay Power and Light Company, Limited
Waneta Plaza, 8100 Rock Island Highway, T , B.C.
Tel. (604) 368-3321 / Telex 041-4417



POSTAL ADDRESS
Box 130, Trail, B.C. V1R 4L4

July 6, 1988

west kootenay power

British Columbia Hydro & Power Authority
970 Burrard Street
Vancouver, B.C.
V6Z 1Y3

**Attention: Mr. John E. Elliott**
**Manager, Export and Interutility Marketing Dept.**

Dear Sir:

**Re: Power Supply Agreement - Lardeau/Shutty Bench**

As provided for in Article 2 of the contract dated March 6, 1980 (the "contract") to supply electricity to the Lardeau/Shutty Bench area, West Kootenay Power hereby agrees to your request for an increase in the maximum demand to 3,000 kVA effective August 1, 1988.

All other articles and any previous amendments agreed to by both parties shall remain unchanged. Please sign and return one copy for our files.

Yours truly,

Acknowledged and agreed to this
20 day of JULY , 1988 by

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

Per: ______________
Signature

MANAGER OPERATIONS CONTROL
Title DEPARTMENT

WEST KOOTENAY POWER AND LIGHT COMPANY, LIMITED

Per: ______________ S. H. Ash.
Signature

Mgr. Commercial Affairs
Title

Central File Lardeau contract file

**memorandum**

st kootenay power

| | | | |
|---|---|---|---|
| To | Rates & Customer Services Manager (SAA) | Date | May 13, 1980 |
| From | Director, Finance (GKH) | File No. | |
| Subject | Renewal contract for power - B.C. Hydro - Lardeau | Ref. | |

The attached renewal contract for power with B.C. Hydro has been fully executed and one copy can now be forwarded to the customer.

As discussed I do have one area of concern with respect to this agreement and that has to do with the lack of a contract demand. As I see it, with a 3-year notice of termination being required, we could at some time in the future be required to maintain 1,500 K.V.A. of capacity with no revenue coming in for a period of two years - and if the contract period was for, say, 10-15 years, the "no revenue" situation could be even longer. This could arise from the customer obtaining his requirements from another source. The possibility of this ever occurring in this instance is very remote, but we should bear it in mind in the future.

GKH:cd
Attach.

Signed

FORM 45 H.P.

west kootenay power

May 16, 1980

British Columbia Hydro and Power
Authority
System Control Center
Burnaby Mountain
c/o 970 Burrard Street
Vancouver, B.C.
V6Z 1Y3

Attention: Mr. W.H. Tivy, P. Eng.
Superintendent System Operations

Dear Sirs:

Re: Renewal of Power Contract for Shutty Beach - Lardeau

Enclosed is a fully executed copy of the above noted power contract dated the 6th day of March 1980. This contract came into effect on the 1st day of April 1979 and subject to the terms of the contract shall remain in effect for the period ending with the 31st day of March 1984 and shall continue in effect after the end of that period until the expiration of thirty-six (36) months after notice of termination has been given by one party to the other.

Yours truly,

G L Laycock

G.L. Laycock
Conserv. Officer & Rate Eng.

GLL:nc
Encl.

bcc: RDDeane
GKHarper
SLRota
LHSladen
SAAsh/File

THIS CONTRACT made this 6th day of March, A.D. 1980

BETWEEN:

WEST KOOTENAY POWER AND LIGHT COMPANY, LIMITED, of the City of Trail, in the Province of British Columbia,

(hereinafter called "West Kootenay Power")

OF THE ONE PART:

AND:

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

(hereinafter called "the Consumer")

OF THE OTHER PART:

WITNESSETH THAT:

1. Supply of Power and Delivery Point

Commencing with the 1st day of April 1979, West Kootenay Power agrees to supply, and the Consumer shall take, at the point of delivery, 3-phase electrical power having a nominal frequency of sixty (60) cycles and a nominal potential of 25,000/14,400 volts. The point of delivery shall be the line side of the Consumer's 25,000/14,400 volt gang disconnecting switch at the north end of Shutty Bench near the north boundary of S.L. 23, D.L. 819, Kootenay District. The maintenance by West Kootenay Power of approximately the agreed frequency and the agreed voltage at the point of delivery shall constitute the delivery of electrical power and energy under this contract (whether any electrical energy is taken or not) and the fulfilment of all the operating obligations of West Kootenay Power.

W. K. P. & L. CO. LTD.
APPROVED
Management
Acct. Div.
Legal Div.
Opt'g Div.

2. Limitations on Taking of Power

(a) West Kootenay Power reserves the right to restrict the demand of the Consumer to one thousand five hundred (1500) K.V.A. The demand shall be measured in the manner set out in Clause 3. Failure of the Consumer to limit the maximum demand to one thousand five hundred (1500) K.V.A. upon verbal or written request by West Kootenay Power so to do (which request shall not be subject to the provisions of Clause 16 and shall be made by West Kootenay Power to the Consumer in an exchange between persons designated in writing by each) shall constitute a breach of this contract and West Kootenay Power shall, without limitation of West Kootenay Power's right to pursue any other remedy, be at liberty to discontinue supplying power to the Consumer summarily and without giving of notice. Whether or not West Kootenay Power requests the Consumer to limit the demand to one thousand five hundred (1500) K.V.A., the Consumer shall be liable to West Kootenay Power for all damage to or loss of West Kootenay Power's property which occurs from the Consumer failing to limit the demand to one thousand five hundred (1500) K.V.A. The Consumer may, at any time, request in writing an increase in the maximum demand, and if West Kootenay Power agrees, the maximum demand may be changed either by an amendment to this contract or by the parties executing a new contract.

(b) Notwithstanding the demand limitations provided for in Clause 2 (a), the Consumer will notify West Kootenay Power, in writing, of any anticipated increase in load which may cause the maximum demand in any year to exceed by more than 25% the maximum demand for any preceding year. This notice will be given by the Consumer at such time as the increased load is relatively assured.

3. Metering

(a) West Kootenay Power shall furnish and install, and the Consumer may furnish and install, each at its own expense, on the 25,000/14,400 volt circuit at the place of delivery, for measuring in terms of maximum kilovolt-ampere demand and kilowatt-hours the electrical power and energy supplied to the Consumer, (i) demand-energy meter of the thermal type, which under steady load, from a no load start, reaches ninety per cent (90%) of the constant load in sixteen (16) minutes and ninety-nine per cent (99%) of the constant load in thirty-two minutes together with (ii) the necessary instrument transformers, and each shall keep its metering equipment in repair so as to register within the limits of error prescribed by the Department of Consumer and Corporate Affairs of Canada the electrical power demand and electrical energy taken by the Consumer.

(b) Either party may, after the giving of two (2) days' written notice to the other party, inspect, in the presence of the other party, any metering equipment installed in accordance with this contract by the other party, and may request that the metering equipment be tested.

If, as a result of any test made by the Department of Consumer and Corporate Affairs of Canada, any of the metering equipment is found to be not registering within the limits of error prescribed by that Department, then the owner of that metering equipment shall pay for the cost of having it tested. If that metering equipment is found to be registering within the limits of error prescribed by that Department, the party who made the request shall pay for the cost of having it tested.

(c) The measurements recorded by West Kootenay Power's meter shall be used for computing the amount to be paid for the electrical power and energy delivered to the Consumer, except that if West Kootenay Power's meter is not in service, then the measurement of the electrical power and energy deemed to have been delivered during that time shall be estimated from the best information available.

(d) If at any time the tests mentioned in Clause 3 (b) made by the Department of Consumer and Corporate Affairs show that the metering equipment was not registering within the limits of error prescribed by that Department, and if such incorrect registration has been used for billing purposes, then the bills will be adjusted as prescribed in the Electricity Inspection Act of Canada.

4. Rate for Electrical Power and Energy

(a) Subject to Clause 4 (b), the Consumer shall pay for electrical power and energy delivered under this contract at the rates set out in West Kootenay Power's Rate Schedule 49 as filed with the British Columbia Energy Commission, a copy of which Rate Schedule is attached to this contract. This Rate Schedule may be amended by West Kootenay Power from time to time, provided such amendments are authorized by and filed with the British Columbia Energy Commission. The Consumer agrees to pay for electrical power and energy in accordance with the amended rates.

(b) At such time as West Kootenay Power purchases electric power and energy from the British Columbia Hydro and Power Authority and after six (6) months' notification to the Consumer, West Kootenay Power may discontinue billing the Consumer on Rate Schedule 49 and in its stead, bill on another Rate Schedule which may be amended from time to time, provided such Rate Schedule and amendments thereto are authorized by and filed with the British Columbia Energy Commission and upon such notification, authorization and filing, the Consumer shall pay for electrical power and energy in accordance with such other Rate Schedule.

(c) For all purposes of this contract the "Contract Demand" noted in Rate Schedule 49 or any amendment thereto or replacement thereof under sub clauses (a) or (b) above shall be deemed to be zero K.V.A.

5. Sales Tax

The Consumer shall reimburse West Kootenay Power in the amount of any sales or consumption tax or any other tax levied by any competent taxing authority on any electrical power or energy delivered pursuant to this contract.

6. Monthly Bills

Bills for electrical power and energy delivered under this contract shall be rendered to the Consumer monthly, and the Consumer agrees to pay the amount of the bill within fifteen (15) days after the receipt thereof. A bill sent by mail shall be deemed to have been received on the second day after the day on which it was mailed.

7. Use of Electrical Energy

The Consumer shall not use the said electrical energy for any purpose not directly connected with the distribution of electrical energy in the Consumer's Lardeau Power District north of the north boundary of S.L. 23, D.L. 819, Kootenay District, and shall not assign this contract, except on receipt of written permission from West Kootenay Power.

8. Power Factor and Load Fluctuations

The Consumer shall regulate its use of electrical energy so that the power factor at maximum demand is at least eighty-five per cent (85%) and shall ensure that all motors, apparatus and equipment using the electricity delivered under this contract to be operated so that they will not cause sudden fluctuations in demand for electrical power as would cause disturbances to the electrical system of West Kootenay Power. Failure of the Consumer to reduce within a reasonable time sudden fluctuations in the demand for electric power to a level acceptable to West Kootenay Power upon verbal or written request of West Kootenay Power (which request shall not be subject to the provisions of Clause 16 and shall be made by West Kootenay Power to the Consumer in an exchange between persons designated in writing by each) shall constitute a breach of this contract and West Kootenay Power shall, without limitation of West Kootenay Power's right to pursue any other remedy be at liberty to discontinue supplying power to the Consumer summarily and without giving of notice.

9. Interruptions and Defects in Service

West Kootenay Power shall exercise reasonable diligence and care to supply electrical power to the Consumer in accordance with the terms and conditions contained in this contract, and to avoid interruption of delivery of power, but nevertheless shall not be liable to the Consumer for any loss or damage owing to failure to supply electrical power, owing to other abnormal conditions of supply arising from causes beyond the reasonable control of West Kootenay Power, or owing to strikes or lock-outs. If delivery of the power to the Consumer is suspended or reduced for any of the above reasons in this Clause 9 for a period of more than four (4) consecutive hours, a proportionate adjustment shall be made in the demand charge for the month in which the suspension or reduction occurs.

10. No Responsibility Beyond Delivery Point

All responsibility of West Kootenay Power for electrical power delivered to the Consumer under this contract shall cease at the point of delivery, and the Consumer shall indemnify West Kootenay Power and save it harmless from all injury, damage and loss and all actions, suits, claims, demands and expenses caused by or arising out of the taking of electrical power by the Consumer.

11. Discontinuance of Power

(a) Whever necessary for the purpose of making repairs upon or improvements to any part of its apparatus, equipment or works, or for the purpose of safeguarding life or property West Kootenay Power or the Consumer, as the case may be, shall have the right to suspend temporarily the delivery or taking of electrical power, but in every case such reasonable notice of the suspension as circumstances permit shall be given by one party to the other. All suspensions hereunder shall be of the shortest reasonable duration and whenever practicable shall be arranged to occur at a time least objectionable to the Consumer. If the delivery of power is suspended for a period of more than four (4) consecutive hours by West Kootenay Power for any of the above reasons in this Clause 11, a proportionate adjustment shall be made in the demand charge for the month in which the suspension occurs.

(b) If any bill for electrical power and energy referred to in Clause 6 is not paid within twenty-two (22) days after the bill has been mailed to the Consumer, West Kootenay Power may, without giving notice to the Consumer, discontinue the delivery of electrical power. Without limitation of the right to pursue the remedy provided for in Clauses 2 and 8, West Kootenay Power also may discontinue the delivery of electrical power to the Consumer upon failure by the Consumer to remedy, within fifteen (15) days after the giving of notice, the breach of any other term or condition contained in this contract which is to be observed or performed by the Consumer.

(c) Any discontinuance of the delivery of power arising from the breach of any term or condition, including failure to pay bills, shall not relieve the Consumer of any obligation or lessen or change any of the Consumer's obligations under this contract. West Kootenay Power's right of discontinuance shall not operate to prevent West Kootenay Power from pursuing any other remedy provided for in this contract, and all rights and remedies of West Kootenay Power may be exercised and continued separately or concurrently. West Kootenay Power shall not be obligated to resume the delivery of electrical power to the Consumer until the Consumer gives assurance satisfactory to West Kootenay Power against recurrence of a similar breach.

12. <u>Arbitration</u>

If any difference or dispute arises between the parties hereto as to any matter arising under this contract, either party may give to the other notice of the difference or dispute and request that it be settled by submission to arbitration under the Arbitration Act of British Columbia. After the giving of the notice and the making of the request, the parties shall mutually select a single arbitrator to whom the difference or dispute shall be submitted for determination. If the parties do not concur in the appointment of a single arbitrator, the difference or dispute shall be submitted to three arbitrators, one to be appointed by each party and the third to be appointed by the two arbitrators. The procedure to be followed in connection with the submission, whether to a single arbitrator or to three arbitrators, shall be that set out in the Arbitration Act of British Columbia, and the decision of either the single arbitrator or a majority of the three arbitrators shall be final and binding on both parties.

13. Termination

West Kootenay Power may, in addition to all other rights and remedies under this contract, terminate this contract upon failure by the Consumer to remedy, within thirty (30) days after the giving of notice by West Kootenay Power, the breach of any term or condition contained in this contract which is to be observed or performed by the Consumer, but termination of the contract shall not relieve the Consumer of any obligation, or lessen or change any of the Consumer's obligations under this contract, which arose before termination, except that the Consumer shall be under no obligation to make any payment in respect to any period subsequent to the date of termination.

14. Notice

Any notice to either party hereto shall be in writing and may be given by registered letter or prepaid telegram as follows:

To West Kootenay Power - Secretary
West Kootenay Power and Light Company, Limited
Trail, British Columbia
V1R 4L4

To the Consumer - Secretary
B.C. Hydro and Power Authority
970 Burrard Street
Vancouver, British Columbia
V6Z 1Y3

15. When Notice Effective

Where notice is given by registered letter, the notice shall be deemed to have been served on the party to whom it was addressed on the second day after the day of the mailing of the letter, and where notice is given by telegram, the notice shall be deemed to have been served on the party to whom it was addressed on the day after the day of the dispatch of the telegram.

16. Effective Date and Term of Contract

(a) This contract shall come into effect on the 1st day of April, 1979; and subject to the provisions for termination contained in Clause 13, this contract shall remain in effect for the period ending with the 31st day of March, 1984, and shall continue in effect after the end of that period until the expiration of thirty-six (36) months after notice of termination has been given by one party to the other. The notice shall be given in such manner that the contract terminates with the last day of a month, and may be given before the end of the said period so as to terminate the contract at the end of that period or at the end of any month thereafter.

(b) Notwithstanding the provisions of Clause 16 (a), the Consumer may terminate this contract at the end of any month in the one year period following notification by West Kootenay Power to the Consumer of any change in rates as provided for in Clause 4 (b), and after the Consumer has given West Kootenay Power six months' prior notification of termination.

17. Previous Contract Cancelled

This contract supersedes the contract made between the Power Company and the Consumer and dated the 1st day of December 1965, and all amendments thereto, and that contract and all amendments shall come to an end when this contract comes into effect.

18. Contract Extends to Successors and Assigns

This contract shall be binding upon and enure to the benefit of the parties, their successors, administrators and permitted assigns.

IN WITNESS WHEREOF the parties hereto have executed this contract under seal.

APPROVED as to content
W. A. Best
W. A. BEST
VICE-PRESIDENT
ELECTRICAL OPERATIONS
5/3/80

WEST KOOTENAY POWER AND LIGHT COMPANY, LIMITED

Executive Vice-President and General Manager

Secretary

REGISTERED 13411

APPROVED as to form only
Solicitor

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

CHAIRMAN

ASSOCIATE SECRETARY

WEST KOOTENAY POWER AND LIGHT COMPANY, LIMITED

RATE CLASSIFICATION AND RATES (CONT'D)

SCHEDULE 49 - WHOLESALE SERVICE

AVAILABLE: In Grand Forks, Kelowna, Penticton, Princeton, Summerland, Lardeau and Yahk.

APPLICABLE: To service for resale, subject to written agreement.

MONTHLY RATE: A Demand Charge of:

$1.45 per K.V.A. of "Billing Demand" A

plus

An Energy Charge of:

1¢ per K.W.H. for first 100 K.W.H. per K.V.A. of "Billing Demand".
0.7¢ per K.W.H. for next 30,000 K.W.H.
0.4¢ per K.W.H. for the balance of the monthly consumption.

"Billing Demand"

The greatest of:

a. "Contract Demand" which is the amount of power in K.V.A. reserved for the Customer by the Company and contracted for by the Customer, or

b. The maximum demand in K.V.A. for the current month or

c. Seventy five per cent (75%) of the maximum demand in K.V.A. recorded during the preceding eleven months.

MINIMUM: The Monthly Minimum Charge shall be the demand charge.

OVERDUE ACCOUNTS: Interest on overdue accounts at 1½% per month.

Issued.....December 16, 1976..........
By......[signature]..................
SECRETARY
WEST KOOTENAY POWER AND LIGHT CO., LTD.
1385 Cedar Avenue
Trail, B.C.
V1R 4L4

Accepted for Filing.....JAN 5 1977..........
[signature]..................
SECRETARY
BRITISH COLUMBIA ENERGY COMMISSION
EFFECTIVE (Applicable to consumption on and after)
JAN 5 1977
..........................

WEST KOOTENAY POWER AND LIGHT COMPANY, LIMITED

RATE CLASSIFICATION AND RATES (CONT'D)

SCHEDULE 49 - WHOLESALE SERVICE (CONT'D)

To the extent that revenue generated under rates herein provided exceeds revenue which would have been generated by the rates in effect under this Schedule on December 31, 1975, such revenue shall, upon order of the British Columbia Energy Commission, be subject to refund with interest at 9% per annum. N

Issued.........December 16, 1976......

By......[signature]...................... SECRETARY

WEST KOOTENAY POWER AND LIGHT CO., LTD.
1385 Cedar Avenue
Trail, B.C.
V1R 4L4

Accepted for Filing..JAN..5.1977.........

.........D. Leach...................
SECRETARY
BRITISH COLUMBIA ENERGY COMMISSION

EFFECTIVE (Applicable to consumption on and after)

......................JAN..5.1977......

THIS CONTRACT made this day of 197



BETWEEN:

WEST KOOTENAY POWER AND LIGHT COMPANY, LIMITED of the City of Trail, in the Province of British Columbia,

(hereinafter called "West Kootenay Power")

OF THE ONE PART:

AND:

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

(hereinafter called "the Consumer")

OF THE OTHER PART:

WITNESSETH THAT:

1. Amount of Power, Voltage, Delivery Point

West Kootenay Power agrees to reserve for and to make available to the Consumer at the point of delivery, commencing with the 1st day of December, 1974, or later if delayed by delivery and installation of transformers, four hundred (400) K.V.A. of electrical power, (hereinafter called the "Contract Demand"),*single (1) phase, having a nominal frequency of sixty (60) cycles and a nominal potential of 14,400 volts. The point of delivery shall be the line side of the Consumer's 14,400 volt line recloser situated at the easterly end of West Kootenay Power's distribution line on highway 3 approximately five miles west of the junction of highway 3 and highway 95 south of Yahk, British Columbia. The maintenance by West Kootenay Power of approximately the agreed frequency and the agreed voltage at the point of delivery shall constitute the delivery of electrical power and energy under this contract (whether any electrical energy is taken or not) and the fulfilment of all the operating obligations of West Kootenay Power.

2. Limitations on Taking of Power

West Kootenay Power reserves the right to restrict the maximum demand of the Consumer to one hundred and twenty-five per cent (125%) of the Contract Demand. The maximum demand shall be measured in the manner set out in Paragraph 3. Failure of the Consumer to limit the demand to one hundred and twenty-five per cent (125%) of the Contract Demand within reasonable time of a verbal or written request by West Kootenay Power so to do (which request shall not be subject to the provisions of Clause 14 and shall be made by West Kootenay Power to the Consumer in an exchange between

*suitable for future conversion to three (3) phase 25 KV wye.

persons designated in writing by each) shall constitute a breach of this contract and West Kootenay Power shall, without limitation of West Kootenay Power's right to pursue any other remedy, be at liberty to discontinue supplying power to the Consumer summarily and without giving of notice. Whether or not West Kootenay Power requests the Consumer to limit the demand to one hundred and twenty-five per cent (125%) of the Contract Demand, the Consumer shall be liable to West Kootenay Power for all damage to or loss of West Kootenay Power's property which occurs from the Consumer failing to limit the demand to one hundred and twenty-five per cent (125%) of the Contract Demand. The Consumer may, at any time, request in writing an increase in the Contract Demand, and if West Kootenay Power agrees, the Contract Demand may be changed either by an amendment to this contract or by the parties executing a new contract.

3. <u>Metering</u>

(a) West Kootenay Power shall furnish and install, and the Consumer may furnish and install, each at its own expense, on the 14,400 volt single (1) phase circuit at the place of delivery, for measuring in terms of maximum kilovolt-ampere demand and kilowatt-hours the electrical power and energy supplied to the Consumer, (i) demand-energy meter of the Lincoln Sangamo thermal type, which under steady load, from a no load start, reaches ninety per cent (90%) of the constant load in sixteen (16) minutes and ninety-nine per cent (99%) of the constant load in thirty-two minutes, together with (ii) the necessary instrument transformers, and each shall keep its metering equipment in repair so as to register within the limits of error prescribed by the Department of Consumer and Corporate Affairs of Canada the electrical power demand and electrical energy taken by the Consumer.

(b) Either party may, after the giving of two (2) days' written notice to the other party, inspect, in the presence of the other party, any metering equipment installed in accordance with this contract by the other party, and may request that that metering equipment be tested.

If, as a result of any test made by the Department of Consumer and Corporate Affairs of Canada, any of the metering equipment is found to be not registering within the limits of error prescribed by that Department, then the owner of that metering equipment shall pay for the cost of having it tested. If that metering equipment is found to be registering within the limits of error prescribed by that Department, the party who made the request shall pay for the cost of having it tested.

(c) The measurements recorded by West Kootenay Power's meter shall be used for computing the amount to be paid for the electrical power and energy delivered to the Consumer, except that if West Kootenay Power's meter is not in service, then the measurement of the electrical power and energy deemed to have been delivered during that time shall be estimated from the best information available.

(d) If at any time the tests mentioned in subparagraph (b) of this paragraph made by the Department of Consumer and Corporate Affairs of Canada show that the metering equipment was not registering within the limits of error prescribed by that Department, and if such incorrect registration has been used for billing purposes, then the bills will be adjusted as prescribed in the Electricity Inspection Act of Canada.

4. Rate for Electrical Power and Energy

(a) The Consumer shall pay for electrical power and energy delivered during the term of this contract at the rates set out in West Kootenay Power's Schedule 49 as filed with the British Columbia Energy Commission, a copy of which Schedule is attached to this contract, except the Billing Demand shall be (a) the Contract Demand, or (b) the Maximum Demand in K.V.A. for the current month, or (c) 75% of the Maximum Demand in K.V.A. recorded during the preceding eleven (11) months, whichever is the greatest. This Schedule may be amended by West Kootenay Power from time to time, provided such amendments are authorized by and filed with the British Columbia Energy Commission. The Consumer agrees to pay for electrical power and energy in accordance with the amended rates.

(b) As the supply of electrical power by West Kootenay Power to the Consumer under the provisions of this contract will necessitate the construction by West Kootenay Power of certain distribution and other facilities, the Consumer agrees to pay West Kootenay Power the sum of twenty five thousand ($25,000) dollars for a single phase supply of up to five hundred (500) K.V.A. capacity, within thirty (30) days of the date of billing by West Kootenay Power. It is agreed that nothing in this agreement shall confer upon the Consumer any property in the said distribution and other facilities and that the said facilities shall, at all times, remain the absolute property of West Kootenay Power.

5. Sales Tax

The Consumer shall reimburse West Kootenay Power in the amount of any sales or consumption tax or any other tax levied by any competent taxing authority on any electrical power or energy delivered pursuant to this contract.

6. Monthly Bills

Bills for electrical power and energy delivered under this contract shall be rendered to the Consumer monthly, and the Consumer agrees to pay the amount of the bill within fifteen (15) days after the receipt thereof. A bill sent by mail shall be deemed to have been received on the second day after the day on which it was mailed.

7. Use of Electrical Energy

The Consumer shall not use the said electrical energy for any purpose not directly connected with the distribution of electrical energy in the Consumer's Yahk-Kingsgate distribution area, and shall not assign this contract, except on receipt of written permission from West Kootenay Power.

8. Power Factor and Load Fluctuations

The Consumer shall regulate its use of electrical energy so that the power factor at maximum demand is at least eighty-five per cent (85%) and shall maintain and operate its motors, apparatus and equipment in such manner as not to cause sudden fluctuations in demand for electrical power as would cause disturbances to the electrical service of West Kootenay Power. Failure of the Consumer to reduce within a reasonable time sudden fluctuations in the demand for electric power to a level acceptable to West Kootenay Power upon verbal or written request of West Kootenay Power (which request shall not be subject to the provisions of Clause 14 and shall be made by West Kootenay Power to the Consumer in an exchange between persons designated in writing by each) shall constitute a breach of this contract and West Kootenay Power shall, without limitation of West Kootenay Power's right to pursue any other remedy be at liberty to discontinue supplying power to the Consumer summarily and without giving of notice.

9. Interruptions and Defects in Service

West Kootenay Power shall exercise reasonable diligence and care to supply electrical power to the Consumer in accordance with the terms and conditions contained in this contract, and to avoid interruption of delivery of power, but nevertheless shall not be liable to the Consumer for any loss or damage owing to failure to supply electrical power, or owing to other abnormal conditions of supply arising from causes beyond the reasonable control of West Kootenay Power (including strikes), or owing to lock-outs. If delivery of the power to the Consumer is suspended or reduced for any of the above reasons in this Clause 9 for a period of more than four consecutive hours, a proportionate adjustment shall be made in the demand charge for the month in which the suspension or reduction occurs.

10. No Responsibility Beyond Delivery Point

All responsibility of West Kootenay Power for electrical power delivered to the Consumer under this contract shall cease at the point of delivery, and the Consumer shall indemnify West Kootenay Power and save it harmless from all injury, damage and loss and all actions, suits, claims, demands, and expenses caused by or arising out of the taking of electrical power by the Consumer.

11. Discontinuance of Power

(a) Whenever necessary for the purpose of making repairs upon or improvements to any part of its apparatus, equipment or works, or for the purpose of safeguarding life or property West Kootenay Power or the Consumer, as the case may be, shall have the right to suspend temporarily the delivery or taking of electrical power, but in every case such reasonable notice of the suspension as circumstances permit shall be given by one party to the other. All suspensions hereunder shall be of the shortest reasonable duration and whenever practicable shall be arranged to occur at a time least objectionable to the Consumer. If the delivery of power is suspended for a period of more than 4 consecutive hours by West Kootenay Power for any of the above reasons in this Clause 11, a proportionate adjustment shall be made in the demand charge for the month in which the suspension occurs.

(b) If any bill for electrical power and energy referred to in Paragraph 6 is not paid within twenty-two (22) days after the bill has been mailed to the Consumer, West Kootenay Power may, without giving notice to the Consumer, discontinue the delivery of electrical power. Without limitation of the right to pursue the remedy provided for in paragraphs 2 and 8, West Kootenay Power also may discontinue the delivery of electrical power to the Consumer upon failure by the Consumer to remedy, within fifteen (15) days after the giving of notice, the breach of any other term or condition contained in this contract which is to be observed or performed by the Consumer.

(c) Any discontinuance of the delivery of power arising from breach of any term or condition, including failure to pay bills, shall not relieve the Consumer of any obligation or lessen or change any of the Consumer's obligations under this contract. West Kootenay Power's right of discontinuance shall not operate to prevent West Kootenay Power from pursuing any other remedy provided for in this contract, and all rights and remedies of West Kootenay Power may be exercised and continued separately or concurrently. West Kootenay Power shall not be obligated to resume the delivery of electrical power to the Consumer until the Consumer gives assurance satisfactory to West Kootenay Power against recurrence of a similar breach.

12. Arbitration

If any difference or dispute arises between the parties hereto as to any matter arising under this contract, either party may give to the other notice of the difference or dispute and request that it be settled by submission to arbitration under the Arbitration Act of British Columbia. After the giving of the notice and the making of the request, the parties shall mutually select a single arbitrator to whom the difference or dispute shall be submitted for determination. If the parties do not concur in the appointment of a single arbitrator, the difference or dispute shall be submitted to three arbitrators, one to be appointed by each party and the third to be appointed by the two arbitrators. The procedure to be followed in connection with the submission, whether to a single arbitrator or to three arbitrators, shall be that set out in the Arbitration Act of British Columbia, and the decision of either the single arbitrator or a majority of the three arbitrators shall be final and binding on both parties.

13. Termination

West Kootenay Power may, in addition to all other rights and remedies under this contract, terminate this contract upon failure by the Consumer to remedy, within thirty (30) days after the giving of notice by West Kootenay Power, the breach of any term or condition in this contract which is to be observed or performed by the Consumer, but termination of the contract shall not relieve the Consumer of any obligation, or lessen or change any of the Consumer's obligations under this contract, which arose before termination, except that the Consumer shall be under no obligation to make any payment in respect to any period subsequent to the date of termination.

14. Notice

Any notice to either party hereto shall be in writing and may be given by registered letter or prepaid telegram as follows:

To West Kootenay Power - Secretary-Treasurer<br>West Kootenay Power and Light Company, Limited<br>Trail, British Columbia V1R 4L4

To the Consumer - B.C. Hydro and Power Authority,<br>970 Burrard Street,<br>Vancouver 1, British Columbia

15. When Notice Effective

Where notice is given by registered letter, the notice shall be deemed to have been served on the party to whom it was addressed on the second day after the day of the mailing of the letter, and where notice is given by telegram, the notice shall be deemed to have been served on the party to whom it was addressed on the day after the day of the dispatch of the telegram.

16. Effective Date and Term of Contract

This contract shall come into effect on the 1st day of December 1974; and subject to the provisions for termination contained in paragraph 13, this contract shall remain in effect for the period ending with the 30th day of November, 1984, and shall continue in effect after the end of that period until the expiration of six (6) months after notice of termination has been given by one party to the other. The notice shall be given in such manner that the contract terminates with the last day of a month, and may be given before the end of the said period so as to terminate the contract at the end of that period or at the end of any month thereafter.

IN WITNESS WHEREOF the parties hereto have executed this contract under seal.

WEST KOOTENAY POWER AND LIGHT COMPANY, LIMIT

[signature]
President & Chief Executive Officer

[signature]
Secretary-Treasurer

REGISTERED 8707

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

J. Wilson.
DIRECTOR

[signature]
SECRETARY

APPROVED as to form only
Solicitor
B. C. HYDRO

Electric Tariff P.U.C. No. 2
Fourth Revision of Schedule 49
Cancels Third Revision of Schedule 49

Effective: June 1, 1968

Filed:

WEST KOOTENAY POWER AND LIGHT COMPANY, LIMITED

RATES FOR ELECTRIC SERVICE

WHOLESALE

SCHEDULE 49

Available in Grand Forks, Kelowna, Penticton, Princeton and Summerland.

Applicable to service for resale, subject to written agreement.

MONTHLY RATE

A Demand Charge of:

$1.00 per K.V.A. of "Billing Demand"

Plus

an Energy Charge of:

1¢ per K.W.H. for first 100 K.W.H. per K.V.A. of "Billing Demand"

0.7¢ per K.W.H. for next 30,000 K.W.H.

0.4¢ per K.W.H. for the balance of monthly consumption.

"Billing Demand" means either:

a. the maximum kilovolt-ampere demand for the current month; or
b. 75% of the maximum kilovolt-ampere demand recorded during the preceding eleven months; whichever is greater.

However the maximum demand recorded for any month in (b) shall be reduced, if applicable, to 120% of the average of the maximum demands recorded for the month preceding and the month following that month.

NO DISCOUNT

MINIMUM

The Monthly Minimum Charge shall be the demand charge.

# YAHK POWER SUPPLY AGREEMENT AMENDING AGREEMENT

This Yahk Power Supply Agreement Amending Agreement made the 1st day of April, 1999

BETWEEN: BRITISH COLUMBIA HYDRO AND POWER AUTHORITY, having its Head Office at 333 Dunsmuir Street, Vancouver, British Columbia ("B.C. Hydro")

AND: WEST KOOTENAY POWER LTD., a body corporate having its Head Office at 1290 Esplanade Ave., Trail, British Columbia ("West Kootenay Power")

WITNESSES THAT:

A. Pursuant to the Yahk Power Supply Agreement made November 4, 1974 West Kootenay Power and B.C. Hydro ("Parties") have agreed to terms and conditions governing the supply of electricity from West Kootenay Power to B.C. Hydro at Yahk;

B. The Parties have agreed to enter into this Yahk Power Supply Agreement Amending Agreement.

In consideration of the mutual promises contained in this agreement, the Parties agree that as and from the 1st day of April, 1999, the Yahk Power Supply Agreement is amended as follows:

1. Section 4 is amended by the insertion of the new Section 4(c) as follows:

   For the purposes of this clause, and this clause only, capitalized items shall have the same meaning as contained in West Kootenay Power's Tariff Supplement No. 7 Terms and Conditions applicable to wholesale transmission access.

   When the West Kootenay Power Transmission System is used by B.C. Hydro or an agent to transmit power purchased from any person other than West Kootenay Power to serve B.C. Hydro's Native Load Customers at a point of interconnection, B.C. Hydro shall pay to West Kootenay Power an amount equal to the Hourly Price for Reserved Capacity which would have been payable for transmission of that energy under Rate Schedule 101 for Wholesale Service - Primary, times the amount of energy delivered.

This Yahk Power Supply Agreement Amending Agreement supplements and amends the Yahk Power Supply Agreement and this Yahk Power Supply Agreement Amending

Agreement and the Yahk Power Supply Agreement as amended hereby shall in respect of all matters which occur on or after the 1st day of April, 1999 be read together and shall have effect so far as practicable as though in respect of all matters all provisions thereof and hereof were contained in one instrument.

THE PARTIES INTENDING TO BE LEGALLY BOUND have cause this agreement to be executed under seal.

The Common Seal of BRITISH COLUMBIA HYDRO AND POWER AUTHORITY was affixed in the presence of:

APPROVED

Solicitor

B.C. HYDRO

Authorized Signatory

REGISTERED

20172

Authorized Signatory

The Common Seal of WEST KOOTENAY POWER LTD. was affixed in the presence of:

Authorized Signatory

Authorized Signatory

WEST KOOTENAY POWER

ENERGYONE

# GENERAL SERVICE POWER CONTRACT

Customer No.: 38292-9

This contract made November 16, 1998 between Homestake Canada Inc. ("the Customer") and West Kootenay Power Ltd. ( "WKP") witnesses that, for and in consideration of the mutual covenants and agreements contained herein, the parties agree as follows:

1. AGREEMENT: West Kootenay Power Ltd. agrees to supply and the Customer agrees to take and pay for electric service to the Customer's premises located at Nickle Plate Mine, approximately 5 km NE of Hedley, British Columbia.

2. THE POINT OF DELIVERY of electricity shall be the line side of the Customer's disconnect switch located at the Customer's substation at the Nickle Plate Mine Site.
WKP's responsibility for supply of electricity shall cease at the Point of Delivery.

3. The TYPE OF SERVICE to be supplied by WKP to the Customer shall be nominally 138,000 volt, three phase 3 wire 60 hertz service. The CONTRACT DEMAND is 1600 kVA . The Customer shall not exceed the DEMAND LIMIT OF 10,000 kVA unless otherwise agreed in writing.

4. Service pursuant to this contract shall be deemed to COMMENCE on November 16, 1998 or the date when electricity is first taken by the Customer, whichever is the earlier. In the event that electricity is not available to the Customer on the above commencement date, service pursuant to this contract shall then be deemed to commence on the day that it is made available. The TERM of this contract shall be for two years, and shall continue thereafter until terminated by 6 months prior notice in writing by either party to the other.

5. The RATE to be paid by the Customer for electric service made available by WKP shall be according to

   Rate Schedule 31 as may be amended, commencing from the date as determined in clause 4.

6. A REVENUE GUARANTEE of $ nil and a SECURITY DEPOSIT of $ nil will be required from the Customer pursuant to the Terms and Conditions of West Kootenay Power Ltd.'s filed Electric Tariff before WKP provides electric service.

7. A CUSTOMER CONTRIBUTION will be required with respect to the construction and installation of supply facilities and the Customer agrees to pay, in advance, the sum of $ nil pursuant to the provisions of WKP's filed Terms and Conditions and Extension Schedule.

8. THE TERMS AND CONDITIONS OF WEST KOOTENAY POWER LTD. ATTACHED HERETO HAVE BEEN FILED WITH AND APPROVED BY THE BRITISH COLUMBIA UTILITIES COMMISSION, AND FORM PART OF THIS CONTRACT AND BY THIS REFERENCE ARE INCORPORATED HEREIN. THE TERMS AND CONDITIONS AND SCHEDULES MAY BE AMENDED FROM TIME TO TIME SUBJECT TO APPROVAL BY THE COMMISSION, AND THE CUSTOMER SHALL BE SUBJECT TO ANY SUCH AMENDMENTS AND THE TERMS AND CONDITIONS AS AMENDED SHALL BECOME PART OF THIS CONTRACT.

9. This contract for electricity service replaces all previous contracts for electric service.

10. The Customer's ADDRESS for purposes of billing and notification shall be: P.O. Box 788, Penticton, BC V2A 6Y7

11. SPECIAL PROVISIONS None.

Per: ______________________ Per: ______________________

Manager, Key Accounts Okanagan Region ______________________

Title

FORTISBC

# POWER CONTRACT

Customer No: 969268116

This contract made June 9, 2008 between International Forest Products Limited ("the Customer") and FortisBC Inc. ("FortisBC").

FortisBC witnesses that, for and in consideration of the mutual covenants and agreements contained herein, the parties agree as follows:

1. AGREEMENT: FortisBC agrees to supply and the Customer agrees to take and pay for electric service to the Customer's premises located at Castlegar British Columbia.

2. THE POINTS OF DELIVERY of electricity shall be the line side of the customers disconnect switch. FortisBC's responsibility for supply of electricity shall cease at the Point of Delivery.

3. The TYPE OF SERVICE to be supplied by FortisBC to the Customer shall be nominally 60,000 volt, three phase, 60 hertz service. The CONTRACT DEMAND is 1,500 kVA. The Customer shall not exceed the DEMAND LIMIT OF 2,000 Kva, unless otherwise agreed in writing.

4. Service pursuant to this contract shall be deemed to COMMENCE on May 1st 2008 or the date when electricity is first taken by the Customer, whichever is the earlier. In the event that electricity is not available to the Customer on the above commencement date, service pursuant to this contract shall then be deemed to commence on the day that it is made available. The TERM of this contract shall be for one year.

5. The RATE to be paid by the Customer for electric service made available by FortisBC shall be according to Rate Schedule Rate 31 as may be amended, commencing from the date as determined in clause 4.

6. A REVENUE GUARANTEE of $nil and a SECURITY DEPOSIT of $143,693.65 will be required from the Customer pursuant to the Terms and Conditions of FortisBC's filed Electric Tariff before FortisBC provides electric service.

7. A CUSTOMER CONTRIBUTION will be required with respect to the construction and installation of supply facilities and the Customer agrees to pay, in advance, the sum of $nil pursuant to the provisions of FortisBC's filed Terms and Conditions and Extension Schedule.

8. THE TERMS AND CONDITIONS OF FortisBC ATTACHED HERETO HAVE BEEN FILED WITH AND APPROVED BY THE BRITISH COLUMBIA UTILITIES COMMISSION, AND FORM PART OF THIS CONTRACT AND BY THIS REFERENCE ARE INCORPORATED HEREIN. THE TERMS AND CONDITIONS AND SCHEDULES MAY BE AMENDED FROM TIME TO TIME SUBJECT TO APPROVAL BY THE COMMISSION, AND THE CUSTOMER SHALL BE SUBJECT TO ANY SUCH AMENDMENTS AND THE TERMS AND CONDITIONS AS AMENDED SHALL BECOME PART OF THIS CONTRACT.

9. This contract for electricity service replaces all previous contracts for electric service.

10. The Customer's ADDRESS for purposes of billing and notification shall be: 3500-1055 Dunsmuir Street Vancouver BC, V7X 1H7

11. SPECIAL PROVISIONS: None

Per: ______________________________ Per: ______________________________

Mark Warren, P.Eng. Director, Customer Service

WEST KOOTENAY POWER
ENERGYONE

# GENERAL SERVICE POWER CONTRACT

Customer No.: 3345063901-9

This contract made June 28, 2001 between Roxul (west) Inc ("the Customer") and West Kootenay Power Ltd. ( "WKP") witnesses that, for and in consideration of the mutual covenants and agreements contained herein, the parties agree as follows:

1. AGREEMENT: West Kootenay Power Ltd. agrees to supply and the Customer agrees to take and pay for electric service to the Customer's premises located at 6526 Industrial Parkway, Grand Forks, British Columbia.

2. THE POINT OF DELIVERY of electricity shall be the line side of the customers disconnect switch . WKP's responsibility for supply of electricity shall cease at the Point of Delivery.

3. The TYPE OF SERVICE to be supplied by WKP to the Customer shall be nominally 60 kV . The CONTRACT DEMAND is 8000 kVa . The Customer shall not exceed the DEMAND LIMIT OF 10000 kVa unless otherwise agreed in writing.

4. Service pursuant to this contract shall be deemed to COMMENCE on July 1st, 2001 or the date when electricity is first taken by the Customer, whichever is the earlier. In the event that electricity is not available to the Customer on the above commencement date, service pursuant to this contract shall then be deemed to commence on the day that it is made available. The TERM of this contract shall be for 5 years, and shall continue thereafter until terminated by one month prior notice in writing by either party to the other.

5. The RATE to be paid by the Customer for electric service made available by WKP shall be according to Rate Schedule 31 as may be amended, commencing from the date as determined in clause 4.

6. A REVENUE GUARANTEE of Nil and a SECURITY DEPOSIT of Nil will be required from the Customer pursuant to the Terms and Conditions of West Kootenay Power Ltd.'s filed Electric Tariff before WKP provides electric service.

7. A CUSTOMER CONTRIBUTION will be required with respect to the construction and installation of supply facilities and the Customer agrees to pay, in advance, the sum of Nil pursuant to the provisions of WKP's filed Terms and Conditions and Extension Schedule.

8. THE TERMS AND CONDITIONS OF WEST KOOTENAY POWER LTD. ATTACHED HERETO HAVE BEEN FILED WITH AND APPROVED BY THE BRITISH COLUMBIA UTILITIES COMMISSION, AND FORM PART OF THIS CONTRACT AND BY THIS REFERENCE ARE INCORPORATED HEREIN. THE TERMS AND CONDITIONS AND SCHEDULES MAY BE AMENDED FROM TIME TO TIME SUBJECT TO APPROVAL BY THE COMMISSION, AND THE CUSTOMER SHALL BE SUBJECT TO ANY SUCH AMENDMENTS AND THE TERMS AND CONDITIONS AS AMENDED SHALL BECOME PART OF THIS CONTRACT.

9. This contract for electricity service replaces all previous contracts for electric service.

10. The Customer's ADDRESS for purposes of billing and notification shall be: P.O. Box 2890, Grand Forks, BC, V0H 1H0

11. SPECIAL PROVISIONS None.

| | |
|---|---|
| Per: ______________________ | Per: ______________________ |
| ______________________ | Per: ______________________ |
| West Kootenay Power | Title |

# GENERAL SERVICE POWER CONTRACT

Customer No.: 4853368029

This Agreement made October 1, 2006 between Zellstoff Celgar Limited Partnership. ("the Customer") and FortisBC Inc. ("FortisBC") witnesses that, for and in consideration of the mutual covenants and agreements contained herein, the parties agree as follows:

1. AGREEMENT: FortisBC agrees to supply and the Customer agrees to take and pay for electric service to the Customer's premises located at Castlegar, British Columbia in accordance with the terms of this Agreement.

2. THE POINT OF DELIVERY of electricity shall be at the load side of FortisBC's disconnect switch near the Customer's substation located at the Customer's pulp mill. FortisBC's responsibility for supply of electricity shall cease at the Point of Delivery.

3. The TYPE OF SERVICE to be supplied by FortisBC to the Customer shall be nominally 60,000 volt, three phase, 60 hertz service. FortisBC shall make available the firm capacity reservation of 10MVA between 8:00 am and 10:00 pm and 25 MVA between 10:00 pm and 8:00 am. throughout the term of this Agreement. The Customer shall not exceed the DEMAND LIMIT OF 40,000 kVA unless otherwise agreed in writing.

4. Service pursuant to this Agreement shall be deemed to COMMENCE on October 1, 2006. In the event that electricity is not available to the Customer on the above commencement date, service pursuant to this Agreement shall then be deemed to commence on the day that it is made available. The TERM of this Agreement shall be for one year, and shall continue thereafter until terminated by 12 months prior notice in writing by either party to the other. After one year the customer has the option to revert back to Rate Schedule 31 and a contract demand of 16MVA 24 hours per day.

5. The RATE to be paid by the Customer for electric service made available by FortisBC shall be as set out in Rate Schedule 33 as same may be amended, from time to time, commencing from the date set out in clause 4.

6. A REVENUE GUARANTEE of $ nil and a SECURITY DEPOSIT of $ nil will be required from the Customer pursuant to the Terms and Conditions of FortisBC's filed Electric Tariff before FORTISBC provides electric service.

7. A CUSTOMER CONTRIBUTION will be required with respect to the construction and installation of supply facilities and the Customer agrees to pay, in advance, the sum of $ nil pursuant to the provisions of FortisBC's filed Terms and Conditions and Extension Schedule.

8. THE TERMS AND CONDITIONS OF FORTISBC INC. ATTACHED HERETO HAVE BEEN FILED WITH AND APPROVED BY THE BRITISH COLUMBIA UTILITIES COMMISSION, AND FORM PART OF THIS AGREEMENT AND BY THIS REFERENCE ARE INCORPORATED HEREIN. THE TERMS AND CONDITIONS AND SCHEDULES MAY BE AMENDED FROM TIME TO TIME SUBJECT TO APPROVAL BY THE COMMISSION, AND THE CUSTOMER SHALL BE SUBJECT TO ANY SUCH AMENDMENTS AND THE TERMS AND CONDITIONS AS AMENDED SHALL BECOME PART OF THIS AGREEMENT.

9. This Agreement replaces the previous Agreement for electric service between West Kootenay Power Ltd. and KPMG Inc. dated December 20, 2002.

10. The Customer's ADDRESS for purposes of billing and notification shall be: P.O. Box 1000, Castlegar, B.C.

11. SPECIAL PROVISIONS: The terms set out in Schedule A hereto entitled "Electricity Supply Brokerage Agreement" are incorporated by reference herein.

Per: ______________________________

Zellstoff Celgar Limited Partnership

Per: ______________________________

FortisBC Inc.

# SCHEDULE A

## SPECIAL PROVISIONS

### ELECTRICITY SUPPLY BROKERAGE AGREEMENT

Zellstoff Celgar Limited Partnership ("Customer") is a customer of FortisBC Inc. ("FortisBC") supplied under FortisBC's Rate Schedule 33 by a contract (the "Agreement") dated October 1st, 2006. This "Schedule" is incorporated into the Agreement under Section 11 thereof. The Customer operates a pulp mill at Castlegar, B.C. This mill has a total load of 46.5 MVA. Under most circumstances, this load is satisfied by the Customer's 50 MW turbo generator. From time to time, the turbo generator may be unavailable due to maintenance shutdowns or equipment failures. Since the pulp mill can operate independently of the turbo generator, the Customer would like a backup source of power above the firm supply levels of 10 MVA between 8:00 am and 10:00pm and 25 MVA between 10:00 pm and 8:00 am.

If FortisBC was required to provide this backup by contract purchase from B.C. Hydro, the Customer could incur excessive costs for relatively minimal power consumption as a result of capacity charges imposed under the BC Hydro rate of supply for FortisBC. The intent of this electricity supply brokerage agreement is that should the customer's requirements exceed the Firm Capacity reservation, described above, then the customer shall pay the equivalent of Rate Schedule 33 as more fully described below. As a result, FortisBC and the Customer have agreed as follows:

1. FORTISBC shall not be liable for any direct, indirect or consequential damage or loss to the Customer or its agents as a result of any action undertaken as a result of this Agreement.

2. The Customer shall use commercially reasonable efforts to schedule its generator maintenance for the months of April through October as much as possible. In order to minimize power purchase costs, the Customer will use commercially reasonable efforts to notify FORTISBC of any planned shutdowns with at least three months notice.

3. In the event of a failure of the Customer's turbo generator, the Customer will use its best efforts to notify FORTISBC as quickly as reasonably possible as to the amount of backup power necessary. The time of notification is of the essence.

4. The Firm Capacity reservation is as follows:

    - between the hours of 8:00 am and 10:00 pm the reservation will be 10 MVA
    - between the hours of 10:00 pm and 8:00 am the reservation will be 25 MVA

5. The Firm Capacity reservation shall not apply during any hour in which the Customer has Scheduled Exports from the FORTISBC System. "Scheduled Exports" shall be defined in the agreement governing transmission access by the Customer on the FORTISBC system.

6. FORTISBC, upon notification of a requirement by the Customer in excess of the Firm Capacity reservation, will use commercially reasonable efforts to meet that requirement as promptly as possible. FORTISBC will look to its own resources initially and, if FORTISBC has no available surplus, will then look to outside market opportunities including BC Hydro. For the purposes of this Agreement, "own resources" means power that is available to FortisBC, including power available from B.C. Hydro that does not result in incremental capacity charges, and "available surplus" means power available for delivery from FortisBC's own resources. FORTISBC will try to procure power as inexpensively as possible. In the case where FORTISBC is forced to purchase incremental capacity from BC Hydro, the Customer will reimburse FortisBC for any incremental capacity costs incurred by FortisBC in meeting

the Customers load requirements beyond the Firm Capacity reservation. For the purposes of this Agreement, "incremental capacity" means capacity that FortisBC becomes legally obliged to pay for under the B.C. Hydro Tariff, as a result of providing power to the Customer in excess of the Firm Capacity reservation, that it would not otherwise have become liable to pay for, and "incremental capacity charges" means the amount or amounts payable by FortisBC in respect thereof, from time to time.

7. Energy deliveries to the Customer will be purchased by the Customer as set out in Rate Schedule 33 at all times, including when the Customer has a requirement in excess of the applicable capacity reservation amount, except as noted in clause 8.

8. Should the customer exceed the Firm Capacity reservation of 25 MVA during the 10:00 pm to 8:00 am period, energy associated with the capacity in excess of 25 MVA will be billed at an amount per kWh equal to the Off-Peak Winter Rate. This clause will only apply after the Customer has exceeded the 25 MVA threshold for a total of 20 hours in any given month and will not apply for any period that the Customer has notified FortisBC that it was in a forced or maintenance outage situation. Such notification can be in written or e-mail form to the FortisBC System Control Centre located in Warfield, British Columbia and must be sent at least 2 days before or after such outage situation.

9. Each party will allow the other access to their respective metering devices.

10. For hours in which Customer does not have an export schedule and delivers unscheduled energy to FortisBC, the rate paid to the Customer shall be the lower of the BC Hydro 3808 energy rate, effective at January 1 of the current year, or the Mid-C Dow Jones day-ahead Index price, using the heavy load index for the heavy load hours and the light load index for the light load hours, less 2 mills. Delivery of such energy shall be in accordance with the Terms and Conditions of the B.C. Hydro Tariff, particularly Section 10.

# ESBI Alberta Ltd.

## 1999/2000 General Rate Application
## Phase 1 and Phase 2

**ALBERTA ENERGY AND UTILITIES BOARD**

**Calgary Alberta**

**Decision 2000-1**

**ESBI Alberta Ltd.** **Application No. 990005**

**1999/2000 Phase I and II** **File Nos. 1803-1, 1803-3**

# 1 INTRODUCTION AND BACKGROUND

## Background

The Alberta Energy and Utilities Board (the Board or EUB) received an application dated December 31, 1998 from ESBI Alberta Ltd. (EAL or the applicant) respecting general tariff applications for the 1999 and 2000 test years (the Application). The Application was made pursuant to Sections 49(2) and 67(1) of the Electric Utilities Act (EU Act) and Deficiency Correction Regulation AR 163/98, and requested approval of revenue requirements for 1999 and 2000 (the Phase I matters) and a revised rate design (the Phase II matters). In the Application, EAL sought approval of interim rates effective January 1, 1999. The Board approved interim rates in Order U99018, dated February 11, 1999. EAL, upon completion of a collaborative process, filed an update to both the Phase I and the Phase II portions of the Application on May 25, 1999.

Notice of hearing was published on June 23, 1999 in major daily newspapers in Alberta. Notice was also served simultaneously on interested parties by facsimile and mail. The notice included a proposed schedule of dates for the proceeding.

The Phase I portion of the hearing was held at the Board's Calgary offices on September 15 and 16, 1999. The Phase II portion of the hearing was held in the Board's Calgary offices from September 20 to 24 and in the Board's Edmonton offices from September 27 to October 18, 1999, for a total of 17 hearing days. The Application was heard by B. T. McManus, Q.C., N. W. MacDonald, P. Eng., and A. J. Berg, P. Eng., sitting as the Board Panel. The Board received written argument on November 1, 1999 and reply on November 15, 1999. Having heard the evidence and reviewed the arguments of the interested parties, the Board sets out its Decision with reasons respecting the Application.

## Appearances

The following parties were registered for the proceedings:

- Alberta Irrigation Projects Association (AIPA)
- Alberta Cogenerators Council (ACC)
- Alberta Association of Municipal Districts and Counties (AAMD&C)
- Alberta Federation of REAs Ltd.
- BP Amoco
- ATCO Power
- ATCO Electric (AE)
- Aquila Canada Corp.
- British Columbia Hydro and Power Authority

## 14.3 Ratchet

A ratchet is a useful contract provision when the cost of providing service is more or less fixed but the demand for service can vary widely, i.e. demand is at a load factor of less than unity. The ratchet is used in conjunction with demand or capacity charges and sets the billing capacity or demand charge at the peak demand or percentage thereof for a period much greater than the billing period. This ensures a more stable revenue stream, reducing the risk of cost recovery while providing more flexibility than billing at contracted demand or capacity.

### Position of EAL

EAL stated in evidence[340] that, during the course of stakeholder consultations, customers expressed discontent with billing based exclusively on a rigid contract. Contract-derived billing provided no flexibility of use and involved significant penalty provisions for over use. Operational billing based on an alternative metered demand and ratchet arrangement allowed greater flexibility for customers. EAL considered that a five-year ratchet of less than 100 per cent allowed most of the economic usage, exit provisions, and customer equity effects of contract billing to be retained, while providing greater operational flexibility.

EAL proposed the following contract provisions:

Contract Capacity—This is declared by the customers, and becomes the basis for system planning and for determination of contract maximum and minimum capacity.

Maximum Capacity—This is defined as 110 per cent of the contract capacity. Although this capacity may be available, the transmission system is not planned to provide or maintain this level. The TA retains the right to limit or withdraw transmission access service if the customer exceeds this level.

Minimum Capacity—This is defined as 90 per cent of the contract capacity and is used for minimum billing purposes.

The billing demand in any month will then be the highest of

- the highest metered demand level in the billing month,
- 90 per cent of the highest metered demand in the last 12 months,
- 85 per cent of the highest metered demand in the last 24 months,
- 80 per cent of the highest metered demand in the last 36 months,
- 75 per cent of the highest metered demand in the last 48 months,
- 70 per cent of the highest metered demand in the last 60 months, and
- the minimum contract capacity.

EAL provided for a lowering of contract capacity, subject to a five-year notice period. When the reduction in contract capacity and corresponding reductions to the maximum and minimum contract capacity became effective, the metered demand history would be adjusted downward by the same amount. EAL considered that this provision would reduce the billing impact of ratchet

[340] Exhibit 4, Tab 4, page 16 of 28

charges incurred after the reduction which might be triggered by high demands within the notice period, and provide customers an incentive to give early notice of expected demand reductions. Should a customer either terminate or reduce system access service within 10 years of the construction of new or upgraded facilities, an exit contribution, as calculated by Article 15.4 of the T&C, may be payable.

EAL submitted that the combination of the ratchet provision and the contract demand definitions provide customers with an incentive to accurately forecast capacity requirements both for growing and declining services. EAL further submitted the 90 per cent declining ratchet offered a significant increase in operational flexibility compared to the 100 per cent ratchet of the current tariff.

In argument, EAL stated that its ratchet proposal responded to customers' dislike of billing for system access based on contract demand levels. The contract level, which in many cases could not be changed for five years, was viewed by customers as an effective 100 per cent ratchet on their demands. EAL submitted that the proposed arrangement, including the five-year ratchet, struck a balance between the interest of high-load factor and low-load factor users of the system. It also struck an important balance between customers who plan to leave the system or significantly reduce their usage in the next few years and other customers who remain on the system. Customers who provide notice of declining demand, due to either a decline in resource-based activity or due to on-site generation, may have the ratcheted billing demand determinants reduced by the amount of contract demand reduction provided in their notice.

EAL noted that many individual transmission lines still operated well below their thermal capacity, despite the existence of a highly constrained system in Alberta and a vigorous growth rate. Under-utilization of a facility may result when customers exit the system. EAL submitted that, in the absence of contract-based billing, ratchets are required to produce revenue from customers leaving the system. The revenue is required to balance the financial impacts for remaining customers who are otherwise encumbered with the full cost of under-utilized facilities, after having already shared in the costs of connecting and serving the exiting customer prior to exit.

EAL submitted that the five-year term was a typical contract term for many customers and did not appear to be in dispute during the hearing. A ratchet level declining from 90 per cent to 70 per cent was reasonable, given the fixed nature of transmission costs and the lack of diversity in the system. EAL concluded that a reduction of the effective ratchet level in the first year from 100 per cent to 90 per cent, combined with a reduction from 90 per cent to 50 per cent of the wire costs allocated to load customers, provided considerable extra flexibility for customers to adjust their demand through process changes or distribution switching in the case of distribution utilities.

In reply to the positions of the Cities and ENMAX, EAL submitted that the discretion in Article 22 was necessary and required to control the activities of parties that might impose costs on the total system. EAL noted that the Cities agreed that all users of the transmission system had paid for much of the facilities that permitted load switching. EAL submitted that the proposed ratchet provisions provided the relief sought by the Cities and ENMAX.

**Position of the ACC**

The ACC noted that EAL acknowledged that billing based on either contract demands or a 100 per cent ratchet was not warranted. However, in view of the fact that Article 15.4 of the T&C provided for an exit fee, ACC believed the combined contract/ratchet provisions were overkill and did not allow the user enough flexibility. A customer's incentive to reduce demand, especially load customers, was dulled if it did not get any rate relief from the reduction.

The ACC recommended that POD customers be allowed to reduce their contract demand by up to 20 per cent, once in any 12-month period, with 6-months notice until the reduction takes effect. ACC also recommended that the ratchet provision for DTS be moderated as follows:

- 90 per cent of the highest metered demand in the past 12 months,
- 80 per cent of the highest metered demand in the past 24 months,
- 70 per cent of the highest metered demand in the past 36 months,
- 60 per cent of the highest metered demand in the past 48 months, and
- 50 per cent of the highest metered demand in the past 60 months.

Given that EAL is increasing the proportion of charges that will be recovered in a demand charge from 40 per cent to 60 per cent and the five-year provisions of the SERP, the ACC believed this moderation was fully warranted. The ACC considered that even more flexibility was warranted if not for gradualism considerations.

In argument, the ACC submitted that Dr. Rosenberg's ratchet recommendations gave much needed flexibility to customers to change their operations due to, among other things, economic conditions. At the same time, Dr. Rosenberg's recommendations did not jeopardize the ability of EAL to recover its fixed costs. The ACC noted that the EAL panel agreed that the ratchet provision collected only a small portion of the total revenue requirement. The ACC submitted that Dr. Rosenberg's recommendations were unchallenged by any party, and urged the Board to accept his recommendations.

**Position of the Cities**

In evidence[341], the Cities explained the demand ratchets as proposed did not offer the Cities operational flexibility. The difficulty was that the Cities' distribution systems are looped with service from several PODs. As an example, Lethbridge has a need to switch up to 7 MW of load at one time to provide system reliability. When applied to the average load on the five PODs on the system, this amounted to an increase of approximately 30 per cent. A one-time switching event during a five-year period would lead to adding up to 330 MW to the billing determinants and over $400,000 to the transmission charges for the five-year period. This would occur despite the fact that the switching could occur during an off-peak period when, in the Cities opinion, there was plenty of surplus capacity on the system. The Cities stated that it was unclear from the tariff what would occur in the event the POD load exceeded 110 per cent of contract demand, as would be the case with 7 MW of load switched on the Lethbridge system. There did not appear to be any penalty charges, but EAL would have the right to interrupt service. The Cities saw no improvement over the existing tariff.

341 Exhibit 49, page 10

The Cities acknowledged that, while the waiver contained in Article 22 of the T&C could potentially provide the needed relief for operational maintenance by the Cities, the waiver was proposed to be exercised at the sole discretion of EAL. The Cities submitted that EAL did not provide the Cities with adequate protection from ratchet charges due to the conditions for granting waivers. The conditions gave no certainty to the distributing utilities. The Cities submitted that EAL should not have the sole discretion to grant such waivers, and the conditions should allow for activities related to distribution maintenance. The Cities recommended that Article 22 be changed to eliminate the language "in its sole discretion", and that the conditions should be expanded to include distribution as well as transmission facilities maintenance. The Cities further recommended that Force Majeure be defined in detail and include distribution-related events. As an alternative, ratchet levels should be reduced to a lower level, starting with 80 per cent and declining to 60 per cent, to provide a level of operating flexibility consistent with the distributor's requirements.

Finally, the Cities stated that the use of contract demands, along with a minimum and maximum level, appeared to be inconsistent with the demand ratchets proposed. The addition of the contract demand negated any operational benefits provided by the introduction of the ratchets, and should be eliminated.

In argument, the Cities noted that they raised this issue in the 1996 GTA proceedings. The Cities conceded that EAL offered some relief with respect to this matter through reducing the ratchet to 90 per cent in the first year and thereafter further reducing by 5 per cent in each of the next four years, by reducing the allocation of demand-related costs to load through its 50/50 proposal and through its administration of the peak capacity waiver contained in Article 22 of the T&C. The Cities submitted that they were being unduly penalized by the ability of the TA to penalize the Cities for load switching through a 90 per cent ratchet in the first year of additional load flowing through a POD as a result of such activities. The Cities noted that Article 22 is discretionary and does not include distribution maintenance and load restoration activities. The Cities noted that the evidence from the hearing and in information responses and undertakings provided some degree of comfort that such request for waivers would not be arbitrarily turned down. However, there was no restriction upon EAL with respect to the exercise of its discretion, and distribution maintenance and load restoration activities are not included in the list of purposes for which a waiver under Article 22 can be sought.

The Cities submitted that the demand ratchet did not offer relief because of the minimum contract demand provisions, and the necessity of avoiding the potential penalties arising from exceeding the 110 per cent limit. The Cities stated that load switching was not the same as a standby customer since, when such loads come onto the system, the system is seeing on all of its elements a load that was not on any of the elements in the instant before the standby load commenced receiving service. With the switching of load, the only additional effects are on the very local facilities which have been designed in the past to accommodate such activities. Yet the Cities are being charged as though the additional load impacted on the entirety of the transmission system. The Cities submitted that this was not a fair result.

The Cities requested a change to Article 22 to apply to both distribution and maintenance activities and is not subject to the sole discretion of EAL. Alternatively, the Cities requested a reduction in the ratchet, starting at 80 per cent and declining to 60 per cent.

**Position of TransAlta**

TransAlta stated that Article 22 provided for a peak metered demand waiver for transmission facilities maintenance, but not for distribution facilities. TransAlta submitted that this was not in the interests of customers. TransAlta interpreted EAL's position to be that other rate and tariff features allow relief from unnecessary charges from the TA to the DISCO for distribution system maintenance. TransAlta considered that the DISCO would have to incur additional internal costs to avoid an unnecessary ratchet application. If more expensive DISCO operating practices must be adopted because of TA inflexibility, the end-use customer will pay the price. TransAlta requested that Article 22 be expanded to include availability of a peak metered demand waiver for distribution facilities repair and maintenance. TransAlta further requested that EAL be directed to provide a written business practice governing the availability of such a waiver when no material costs are incurred on the transmission system as a result of distribution system maintenance and repair.

TransAlta noted that both it and ENMAX requested that EAL revise their POD reduction notice requirements to allow a DISCO to obtain reductions without full notice or financial penalty when the requested reductions do not cause system costs or shift costs to other customers. EAL acknowledged the matter as one that could be reviewed, but only proposed a phase-in for the new notice requirements. TransAlta requested the Board to direct EAL to amend Article 15 to allow for such waivers and to direct EAL to provide a written business practice with respect to the application of such a waiver.

**Position of ENMAX**

ENMAX noted that EAL's witness, Mr. Stout, acknowledged that EAL would be willing to examine a tariff refinement for the purpose of operational flexibility for customers with multiple points of delivery serving loads in close geographic proximity. ENMAX noted that it had specifically designed its system to enable it to transfer loads between adjacent PODs to improve reliability, balance distribution loads, and relieve transmission constraints, as well as accommodate emergencies and for system maintenance purposes. ENMAX submitted that a DISCO should have the right to transfer loads between adjacent PODs, without the necessity of requesting a peak demand waiver (pursuant to Article 22.1 of the T&C) in each instance.

ENMAX prepared a proposed amendment to the T&C, entitled "Transfers of Contract Demand"[342]. ENMAX submitted that this proposal would rectify the deficiency contained in EAL's application by enabling DISCOs to transfer contract demand between adjacent PODs, in circumstances where a discretionary peak capacity waiver would otherwise be required to be obtained from the TA. ENMAX considered that Exhibit 97 also contained safeguards to protect the TA and other system customers against misuse of this right. ENMAX requested a direction for EAL to amend the T&C in accordance with the principles contained in the first page of Exhibit 97.

ENMAX noted that Article 15.3 of the T&C required five years' written notice by a customer of its intention to reduce contract demand at a POD or a POS. EAL filed Exhibit 67, which provided a minor measure of phased-in relief to the five-year notice requirement. ENMAX

[342] Exhibit 97

proposed an acceleration of the ratchet provision as part of Exhibit 97 in cases where loads leave a DISCO's system to pursue generation alternatives. This acceleration would be conditional upon the DISCO obtaining a standby contract, in replacement of the original load contract, as a mitigating factor. ENMAX submitted that the Board should approve this provision as an addition to Article 15.3 of the TA's T&C.

In reply, ENMAX noted the FIRM Customers' concern whether transfers of demand between PODs would cause the TA to build additional upstream facilities. ENMAX submitted that this concern and recommendation to retain EAL's discretion was unnecessary. The primary purpose for ENMAX's proposal was to remove the potential for arbitrary refusal by EAL, through exercise of its discretion, to decline to provide a peak capacity waiver. ENMAX submitted that Conditions 5 and 6 of Exhibit 97 fully addressed the FIRM Customers' concerns. These conditions expressly state that sufficient capacity must already be available within the AIES to accommodate the transfer.

**Position of Dow**

Dow noted that EAL's rationale for the five-year written notice of termination of service was that: "The contribution covers only 25 per cent of the connection cost. The remaining 75 per cent and any system expenditures undertaken as a result of accommodating the new customer would unfairly burden existing customers in the absence of the five-year termination clause." Dow considered that this provided little insight into the actual reasoning behind the five-year notification clause. Dow considered the five years to be inconsistent with Article 15.4, which stated:

> A Customer who has served notice to terminate or reduce System Access Service at a POD or POS and whose termination or reduction is effective within ten (10) years of the construction of new or upgraded facilities to accommodate its System Access Service or an increment to its Contract Capacity, shall pay an Exit Contribution calculated as the capital cost of the Facility (as defined in Paragraph 9.3) less the aggregate paid by the Customer, to the date of such termination or reduction, on account of the Customer Contribution and Interconnection Charges for the relevant System Access Service, and less any amounts paid by the Customer pursuant to paragraph 23.1.

Dow considered that the relationship between EAL's ratchet structure and the five-year notification period was not entirely clear. Dow submitted that both the five-year notification period and the ratchets are remnants of an old style of rate-making where utilities ensured that all the risks were born by the customers. Dow considered the ratchet to be a crude and one-sided tool that has been replaced by more concrete contractual arrangements in most competitive environments. For example, telephone owners do not pay ratchets to the telephone company after discontinuing a service. Instead, cellular telephone and other companies use contracts which, in exchange for lower rates, require the user to lock in with the company and pay a penalty upon premature contract termination. Dow stated that these types of arrangements are common in many industries.

Dow considered that the five-year termination clause may allow EAL to better predict the capacity required at each POD and POS. While the ability to more accurately predict capacity required at each POD and POS is clearly desirable from EAL's point of view, the five-year notice requirement is not consistent with the absence of such a requirement for new customers or existing customers who are increasing their contract capacity. Dow submitted that the requirement was also not consistent with what was common in competitive industries.

Dow concluded that EAL did not provide any valid reason to justify its five-year termination notification requirement, other than support for EAL’s ratchet structure and convenience with respect to forecasting POD and POS required capacity. In Dow’s opinion, these reasons were inadequate justification for the additional restriction EAL proposes to place on its services.

Dow stated that an unnecessarily long ratchet or uncertainty concerning the rules represented a real barrier to competition. Some customers may be able to switch to cogeneration and they need to understand the liabilities. Dow considered the exit clause should not be so onerous that it prevented an otherwise economic investment. Reasonable terms and rules are required to facilitate competition (e.g., five years is much too long if all the local investment has been repaid). New power plants can be established quickly (in one to three years from start to finish); therefore, having a ratchet longer than a year could be an impediment to competition.

Dow requested the Board to direct EAL to either forego the requirement of a five-year notice period, subject to any site-specific contributions being repaid, or reduce such notice period to not more than one year.

**Position of IPPSA**

IPPSA supported ratchet relief. If the Board approved the concept, IPPSA suggested that the Board could direct EAL to provide in the refiling an explicit ratchet exemption in the T&C for load switching. As an alternative to the load switching problem, the Board could reduce the duration and severity of ratchets and notice provisions. As a final alternative, the Board could maintain the existing 40/60 demand/energy classification as the basis for demand charges in the DTS tariff. IPPSA noted that these were all independent of the proposals for allocating costs to generation.

**Position of IPCAA**

IPCAA supported EAL’s proposal to relax the ratchet terms from the current five-year 100 per cent level down to 70 per cent over five years.

**Position of the FIRM Customers**

The FIRM Customers noted that in ENMAX’s Exhibit 97, one of the suggested conditions to be met for transfer of POD demands is that the PODs be within 10 km of each other. The FIRM Customers stated that it was not clear whether such a condition could cause the TA to build additional upstream facilities to satisfy such a liability. The FIRM Customers suggested approval of a demand transfer should be subject to EAL’s discretion as to whether potential system costs are caused.

The FIRM Customers also questioned ENMAX’s proposal in Exhibit 97 for POD demand reduction in the event a cogeneration facility is installed which causes a reduction in demand at a POD. The FIRM Customers noted that ENMAX’s proposal extinguishes the DISCO’s contract commitment in two years. The FIRM Customers submitted that this was not consistent with

EAL's proposed net billing provisions with metered demands, ratchets, and contract term. Since ENMAX's proposal could shift cost responsibility to other customers, the FIRM Customers considered the proposal should be modified to be neutral with respect to other customers.

The FIRM Customers noted that industrial customers considered the proposed ratchet and notice provisions imposed too great a penalty. The FIRM Customers supported EAL's proposals since discipline is required on the system.

In reply, the FIRM Customers calculated that the ACC's recommendation for ratchet relief effectively doubles the relief from 25 per cent of contract demand to 50 per cent of contract demand. The FIRM Customers noted that the ACC failed to provide an analysis of why this doubling is required. The FIRM Customers considered EAL's proposals struck an important balance between customers who plan to leave the system and other customers who remain on the system. The FIRM Customers submitted that the ACC's proposal did not provide the required balance for remaining customers, and should not be approved.

**Board Findings**

EAL stated in evidence[343] that, during the course of stakeholder consultations, customers expressed discontent with billing based exclusively on a rigid contract. Contract-derived billing provided no flexibility of use and involved significant penalty provisions for over use. Operational billing, based on an alternative metered demand and ratchet arrangement allowed greater flexibility for customers. EAL considered that a five-year ratchet of less than 100 per cent allowed most of the economic usage, exit provisions, and customer equity effects of contract billing to be retained, while providing greater operational flexibility. The Board agrees that the direction that EAL has taken is appropriate.

The Board notes the concerns raised by interveners about the need for flexibility for operational purposes and the concern that customers could pay increased costs even though the transmission system might not be affected.

With respect to the change in ratchet relief for load switching purposes proposed by the DISCOs, the Board considers that both the TA and the DISCO must show some flexibility when planned maintenance occurs and waivers are requested. In the case of the DISCO, planned maintenance should occur when it is possible for the TA to provide the capacity that makes a waiver possible. Similarly, the Board expects the TA to use its discretion wisely and when necessary. The information and discussion to carry this out at least cost and disruption to end-use customers must be part of the normal business relationship between the TA and the DISCO. The evidence[344] the Board received in these proceedings was that, of 100 requests for waivers since June 1, 1999, EAL has granted 93. It appears as if neither EAL nor the DISCOs are abusing the waiver process, and are planning their joint operations in a reasonable manner.

The Board, as a general matter, considers that it would be reasonable to consider a revision to Article 22 as referred to by TransAlta to provide for peak metered demand waiver for distribution facilities maintenance as implemented for transmission facilities maintenance. The Board is, however, reluctant to place too many restrictions on the waiver provisions or to be too

[343] Exhibit 4, Tab 4, page 16 of 28
[344] ENMAX-EAL.7, Tr. page 922, line 3 – 924, line 4

definitive as to when waivers are granted. This is especially so when the restructured electric industry is in the process of working out operating practices and procedures. Not all the circumstances when it is practical and/or necessary to grant ratchet waivers are currently known and provided in evidence in these proceedings. Therefore, the Board leaves it to EAL's discretion, at the moment, to provide the necessary waivers. It is always open to a party that may be financially harmed by EAL's exercise of discretion to make a complaint to the Board that the discretion was not prudently applied. The Board considers it appropriate to address the possible inclusion of waivers for distribution maintenance and load restoration further and the Board directs EAL at the next GTA to recommend appropriate business practices and T&Cs on this issue. Further, the Board directs EAL, at the time of refiling, to advise whether any tariff refinements should be implemented for 2000 and if so, how EAL intends to proceed.

The Board does not accept Dow's proposals to relax notice provisions. The Board considers that five years is well within the planning horizon of any capital-intensive industry and that industrial customers should be able to accommodate this provision within their planning processes. The Board considers that the five-year provision, as a general principle, provides a balance between flexibility for customers and the need to recover any stranded system costs from remaining customers.

Notwithstanding this general principle, the Board recognizes that special circumstances, such as the absence of stranded costs or some other benefit to the system or remaining customers, may warrant waiver of the notice provisions. For example, a given area of the Province may have transmission constraints and EAL may be preparing to issue a SO or RFP to procure generation or may be considering upgrading the transmission system. In these cases, a waiver of exit provisions or a relaxation of notice provisions may be sufficient to provide an incentive for a load to construct self-generation, thereby reducing the constraints on the system. It is difficult to predict or prescribe the exact circumstances where a waiver or a relaxation would be appropriate. Therefore, should EAL consider that circumstances may warrant a waiver of its notice provisions, the Board directs EAL to file any waivers of notice with the Board and interested parties for comment.

The Board considers that EAL has been responsive to customers' need for some flexibility in managing their operations, while not imposing undue costs on other customers using the system. In light of the foregoing, the Board approves EAL's ratchet provisions, notice provisions, and ratchet relief T&C as applied for, and directs EAL, in its refiling, to incorporate these provisions and T&C in its redesigned tariffs.

### 14.4 Gross to Net Billing

EAL proposed that pricing of transmission for energy transfers and dynamic interchanges with the interconnected transmission system be done on a net basis. For example, a stable 50 MW load, coupled with a stable 40 MW generation unit, would be treated as a 10 MW net load. It would not be treated as a separate 50 MW demand customer and 40 MW supply customer.

EAL stated that in keeping with the new transmission paradigm, net treatment of energy exchanges was appropriate for all combinations of demand and generation connected to the transmission system at a single point. EAL noted that net treatment matched the physical reality that the connection with the system need be sized only to accommodate the maximum net

# Bonneville Power Administration
# Transmission Services

# 2010
# Transmission and Ancillary Service Rate Schedules

# Effective October 1, 2009

# PTP-10
# POINT-TO-POINT RATE

## SECTION I. AVAILABILITY

This schedule supersedes Schedule PTP-08. It is available to Transmission Customers taking Point-to-Point (PTP) Transmission Service over Federal Columbia River Transmission System (FCRTS) Network and Delivery facilities, for hourly non-firm service over such FCRTS facilities for customers with Integration of Resources agreements, and to customers taking Conditional Firm (CF) Transmission Service, if BPA adopts CF Transmission Service. Terms and conditions of PTP are specified in the Open Access Transmission Tariff. This schedule is available also for transmission service of a similar nature that may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§ 824j and 824k). Service under this schedule is subject to BPA-TS's General Rate Schedule Provisions (GRSPs).

## SECTION II. RATES

### A. LONG-TERM FIRM PTP TRANSMISSION SERVICE

$1.298 per kilowatt per month

### B. SHORT-TERM FIRM AND NON-FIRM PTP TRANSMISSION SERVICE

For each reservation, the rates shall not exceed:

#### 1. Monthly, Weekly, and Daily Firm and Non-Firm Service

**a. Days 1 through 5** $0.060 per kilowatt per day

**b. Day 6 and beyond** $0.046 per kilowatt per day

#### 2. Hourly Firm and Non-Firm Service

3.74 mills per kilowatthour

## SECTION III. BILLING FACTORS

### A. ALL FIRM SERVICE AND MONTHLY, WEEKLY AND DAILY NON-FIRM SERVICE

The Billing Factor for each rate specified in sections II.A. and II.B. for all service *except* Hourly Non-Firm Service shall be the Reserved Capacity, which is the greater of:

1. the sum of the capacity reservations at the Point(s) of Receipt, or

2. the sum of the capacity reservations at the Point(s) of Delivery.

### B. HOURLY NON-FIRM SERVICE

The Billing Factor for the rate specified in section II.B.2. for Hourly Non-Firm Service shall be the scheduled kilowatthours.

Upon 60 day's notice by BPA-TS, the Billing Factor for the rate specified in section II.B.2. for Hourly Non-Firm Service shall become the Reserved Capacity.

### C. REDIRECT SERVICE

Redirecting Long-Term Firm PTP to Short-Term Firm PTP service will not result in an additional charge if the capacity reservation does not exceed the amount reserved in the existing service agreement.

## SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

### A. ANCILLARY SERVICES

Customers taking service under this rate schedule are subject to the ACS Scheduling, System Control and Dispatch Service Rate and the Reactive Supply and Voltage Control from Generation Sources Service Rate. Other Ancillary Services that are required to support PTP Transmission Service on the Network are available under the ACS rate schedule.

### B. DELIVERY CHARGE

Customers taking PTP Transmission Service over Delivery facilities are subject to the Delivery Charge specified in section II.A. of the GRSPs.

# IM-10
# MONTANA INTERTIE RATE

## SECTION I. AVAILABILITY

This schedule supersedes Schedule IM-08. It is available to Transmission Customers taking Point-to-Point (PTP) Transmission Service on BPA's share of Montana Intertie transmission capacity. Terms and conditions of service are specified in the Open Access Transmission Tariff. This schedule is available also for transmission service of a similar nature that may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§ 824j and 824k). Service under this schedule is subject to BPA-TS's General Rate Schedule Provisions (GRSPs).

## SECTION II. RATES

### A. LONG-TERM FIRM PTP TRANSMISSION SERVICE

$1.312 per kilowatt per month

### B. SHORT-TERM FIRM AND NON-FIRM PTP TRANSMISSION SERVICE

For each reservation, the rates shall not exceed:

**1. Monthly, Weekly, and Daily Short-Term Firm and Non-Firm Service**

**a. Days 1 through 5** $0.061 per kilowatt per day

**b. Day 6 and beyond** $0.043 per kilowatt per day

**2. Hourly Firm and Non-Firm Service**

3.78 mills per kilowatthour

## SECTION III. BILLING FACTORS

### A. ALL FIRM SERVICE AND MONTHLY, WEEKLY AND DAILY NON-FIRM SERVICE

The Billing Factor for each rate specified in section II.A. and II.B. for all service *except* Hourly Non-Firm Service shall be the Reserved Capacity, which is the greater of:

1. the sum of the capacity reservations at the Point(s) of Receipt, or

2. the sum of the capacity reservations at the Point(s) of Delivery.

## B. HOURLY NON-FIRM SERVICE

The Billing Factor for the rate specified in section II.B.2. for Hourly Non-Firm Service shall be the scheduled kilowatthours.

Upon 60 days' notice by BPA-TS, the Billing Factor for the rate specified in section II.B.2. for Hourly Non-Firm Service shall become the Reserved Capacity.

## C. REDIRECT SERVICE

Redirecting Long-Term Firm PTP to Short-Term Firm PTP service will not result in an additional charge if the capacity reservation does not exceed the amount reserved in the existing service agreement.

# SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

## A. ANCILLARY SERVICES

Customers taking service under this rate schedule are subject to the ACS Scheduling, System Control and Dispatch Service Rate and the Reactive Supply and Voltage Control from Generation Sources Service Rate. Other Ancillary Services that are required to support PTP Transmission Service on the Montana Intertie are available under the ACS rate schedule.

## B. FAILURE TO COMPLY PENALTY CHARGE

Customers taking service under this rate schedule are subject to the Failure to Comply Penalty Charge specified in section II.B. of the GRSPs.

## C. INTERRUPTION OF NON-FIRM PTP TRANSMISSION SERVICE

If daily, weekly, or monthly Non-Firm PTP Transmission Service is interrupted, the rates charged under section II.B.1. shall be prorated over the total hours in the day to give credit for the hours of such interruption.

When Reserved Capacity becomes the Billing Factor for Hourly Non-Firm Service, the following shall apply:

# UFT-10
# USE-OF-FACILITIES TRANSMISSION RATE

## SECTION I. AVAILABILITY

This schedule supersedes Schedule UFT-08 unless otherwise provided in the agreement, and is available for firm transmission over specified Federal Columbia River Transmission System (FCRTS) facilities. Service under this schedule is subject to BPA-TS's General Rate Schedule Provisions (GRSPs).

## SECTION II. RATE

The monthly charge per kilowatt of Transmission Demand/capacity reservations specified in the agreement shall be one-twelfth of the annual cost of capacity of the specified facilities divided by the sum of Transmission Demands/capacity reservations (in kilowatts) using such facilities. Such annual cost shall be determined in accordance with section III.

## SECTION III. DETERMINATION OF TRANSMISSION RATE

A. From time to time, but not more often than once a year, BPA-TS shall determine the following data for the facilities which have been constructed or otherwise acquired by BPA-TS and which are used to transmit electric power:

1. The annual cost of the specified FCRTS facilities, as determined from the capital cost of such facilities and annual cost ratios developed from the Federal Columbia River Power System financial statement, including interest and amortization, operation and maintenance, administrative and general, and general plant costs.

   The annual cost per kilowatt of facilities listed in the agreement, which are owned by another entity, and used by BPA-TS for making deliveries to the transferee, shall be determined from the costs specified in the agreement between BPA-TS and such other entity.

2. The yearly noncoincident peak demands of all users of such facilities or other reasonable measurement of the facilities' peak use.

B. The monthly charge per kilowatt of billing demand shall be one-twelfth of the sum of the annual cost of the FCRTS facilities used divided by the sum of Transmission Demands/capacity reservations. The annual cost per kilowatt of Transmission Demand/capacity reservation for a facility constructed or otherwise acquired by BPA-TS shall be determined in accordance with the following formula:

$$\frac{A}{D}$$

Where:

A = The annual cost of such facility as determined in accordance with A.1. above.
D = The sum of the yearly noncoincident demands on the facility as determined in accordance with A.2. above.

1. For facilities used solely by one customer, BPA-TS may charge a monthly amount equal to the annual cost of such sole-use facilities, determined in accordance with section III.A.1., divided by 12.

2. For facilities used by more than one customer, BPA-TS may charge a monthly amount equal to the annual cost of such facilities prorated based on relative use of the facilities, divided by 12.

## SECTION IV. DETERMINATION OF BILLING FACTORS

Unless otherwise stated in the agreement, the Billing Factor shall be the largest of:

A. The Transmission Demand/capacity reservation in kilowatts specified in the agreement;

B. The highest hourly Measured or Scheduled Demand for the month; or

C. The Ratchet Demand.

**Question #1**

**Reference: BCUC 1.6.1 and 1.6.2**
**BCOAPO 1.1.2**

**Q1.1 Please outline FortisBC's plans with respect to the implementation of AMI for non-residential customers.**

A1.1 Non-residential customers are expected to have AMI implemented on the same time schedule as residential customers, as articulated in the response to BCUC IR No. 2 Q5.1.

**Q1.2 What are FortisBC's plans with respect to the wide-scale implementation of time-based rates for non-residential customers?**

A1.2 FortisBC expects to implement wide-scale time-based rates for non-residential customers on the same time schedule as residential customers, as articulated in the response to BCUC IR No. 2 Q5.1.

**Question #2**

**Reference: BCUC 1.19.2**

**Q2.1 How does FortisBC currently determine when a customer should be transferred from the Small General Service to the General Service class (visa versa)?**

A2.1 FortisBC determines if an account should be transferred between Small General Service and General Service using reports which show whether the account has exceeded (or been below) 40 kW or 45 kVA. Small General Service customer accounts are moved to General Service if they exceed the threshold once. General Service customer accounts are moved to Small General Service if they are below the threshold for 12 consecutive months.

## Question #3

**Reference: BCUC 1.37.1**

**Q3.1 For each of the five residential customers please indicate the percentage change in the average monthly bill of moving to: i) Schedule 2A or ii) Schedule 1.**

A3.1 It is not possible to accurately calculate the difference between Schedule 2 and Schedule 2A since the peak time periods in the two rates are different and the current metering technology does not collect interval data (only the amount of on-peak and off-peak consumption in the defined time periods). Therefore, for each of the five residential customers, a hypothetical average monthly bill has been created based on the Schedule 2 time periods. Table BCOAPO IR2 A3.1 below shows estimated bill increases as positive numbers and estimated bill decreases as negative numbers.

**Table BCOAPO IR2 A3.1**

| Client | Schedule 2A Difference | Schedule 1 Difference |
|---|---|---|
| Client #1 | 6.00% | 18.60% |
| Client #2 | -4.44% | 4.81% |
| Client #3 | 7.28% | 28.99% |
| Client #4 | 10.17% | 10.65% |
| Client #5 | 16.67% | 28.38% |

**Question #4**

**Reference: BCUC 1.40.1**

**Q4.1 Why is FortisBC adopting fixed amount per customer when a portion of the associated distribution costs are classified as demand-related and recovered on a volumetric basis?**

A4.1 FortisBC is adopting a fixed amount per customer for those classes that are not demand metered. A demand-related amount is used for those classes where demand meters are used and where demand differs more among customers in the class.

**Question #5**

**Reference: BCUC 1.49.2 and 1.49.3**

**Q5.1 This response suggests there is significant difference between the Lighting and Irrigation revenues assumed in the COSA and what FortisBC actually receives.**

- **What is the impact on the revenue to cost ratio for this class if it is calculated based the revenues actually expected?**
- **Given the material difference in revenues why was no adjustment made in the COSA analysis?**

A5.1 There was no adjustment to the revenues in the COSA analysis to align with the 2009 Revenue Requirements revenues, as the revenues determined in the COSA analysis were more accurate than those in the 2009 Revenue Requirements. The COSA uses the revenues actually expected for these two classes and therefore the revenue to cost ratios are already based on the revenues actually expected

**Question #6**

**Reference: BCUC 1.50.2**

**Q6.1 The response makes reference to looking at a "marginal cost of power" study when considering the wide-scale implementation of conservation-based rates. Please clarify what FortisBC means by a "marginal cost of power study". Does FortisBC consider a "marginal cost based power study" to be the same as a "marginal COS study"? If not, what is the difference?**

A6.1 The Company does not consider a marginal cost based power study to be the same as a marginal COS study. A marginal cost of power study would look at the power supply costs at different load levels and time periods to determine the incremental cost of power that FortisBC would face. This would be used as a guideline in developing conservation-based rates that might differ by block or by time of use. The goal would be to set rates for customers that better reflect the cost of the next kWh of power so that customers see the marginal cost of power rather than the average embedded cost of power in making their consumption decisions.

A marginal COSA would look at the marginal costs of all cost components faced by the utility, and would allocate the marginal costs across the various classes. With a marginal COSA, the marginal costs are generally higher than the typical embedded costs. Therefore, once the costs are allocated to classes, the costs for each class need to be scaled back proportionately so that the utility collects only its embedded costs.

**Question #7**

**Reference: BCUC 1.71.2**

**Q7.1 Please explain why there is no "contract demand" for BCH Lardeau.**

A7.1 Please refer to the response to BCMEU IR No. 2 Q1.1.

**Question #8**

**Reference: BCUC 1.82.1**

**Q8.1 Is Nelson the only wholesale customer requiring back-up service as a result of operating its own generation?**

A8.1 Yes.

**Q8.2 Is FortisBC committed to meeting Nelson's power requirements in the event that Nelson's own generation fails and, if so, does this commitment affect FortisBC's costs for power supply other than when it is actually meeting these additional requirements of Nelson.?**

A8.2 FortisBC is committed to meeting Nelson's power requirements in the event that Nelson's own generation fails. This commitment does not affect FortisBC's costs for power supply other than when it is actually meeting these additional requirements, but does affect the size and cost of the infrastructure required to meet the full City of Nelson load.

The Company's System Control Center maintains hourly reserve margins that are partly driven by potential City of Nelson requirements. Given that the City of Nelson load is supplied by both FortisBC and the City's own generation, there is a greater chance for unanticipated load increases than with other customers who do not self-generate. The Company is not able to quantify this effect as it does not consider any specific customers role in load uncertainty but only the system as a whole.

**Q8.3 If the response to 8.2 is in the affirmative, how is this obligation reflected in the COSA for Nelson and other customers with whom it has similar commitments?**

A8.3 The infrastructure costs associated with this obligation are reflected by the use of contract demands in the COSA since the cost is incurred regardless of whether or not the infrastructure is used. There are no power supply costs explicitly associated with this obligation in the COSA.

**Question #9**

**Reference: BCUC 1.99.1**

**Q9.1 The response equates low income customers with low use customers. Does FortisBC have evidence that low income customers are also low use customers?**

A9.1 FortisBC disagrees that its response equates low income customers with low use customers, and specifically indicated that it does not have information on low-income electricity consumption. FortisBC repeats its response to BCUC IR No. 1 Q99.1 in its entirety here:

> *All of the alternate rate design options have features that result in low-consumption customers paying less and high-consumption customers paying more than the proposed rate design. These alternative rate design options may* ***therefore help or harm low income customers depending on their electricity consumption.*** *If they have consumption generally below 2,500 kWh bi-monthly, a customer will generally benefit from Options 1-3. If they have consumption above 2,500 kWh bi-monthly, they will generally be harmed by Options 1-3.* ***FortisBC does not have access to information regarding customer incomes, and therefore cannot provide information on low-income electricity consumption.*** *It should be noted that the proposed rate design does not change from the current rate design.* (bolded for emphasis)

**Question #10**

**Reference: BCOAPO 1.4.3**

**Q10.1 Prior to the introduction of time-based rates, does FortisBC plan to refine its DSM programs so that they are more targeted to assisting customer's response to such rates?**

A10.1 Yes, FortisBC intends to introduce DSM programs beginning in 2011 that will benefit customers taking service under time-of-use rates.

**Question #11**

**Reference: BCOAPO 1.12.1**
**OEIA 1.1.1**

**Q11.1 Please outline for what other reasons TOU, critical peak and load control rates would be implemented by FortisBC other than to address customers' power needs at a lower cost. Please reconcile this response with the response given to OEIA 1.1.1.**

A11.1 FortisBC would consider implementing TOU, critical peak and load control rates to defer the need for infrastructure additions. The deferral of infrastructure additions has potential societal and environmental benefits in addition to cost savings. This is consistent with the response to OEIA IR No. 1 Q1.1.

**Question #12**

**Reference: BCOAPO 1.15.1**

**Q12.1 Please explain why achieving rebalancing (with 95%-105%) within 5 years takes precedent over limiting customer bill impacts.**

A12.1 In general, as evidenced in FortisBC's proposed rebalancing methodology, customer rate increases are capped, which takes precedence over the speed of rebalancing and results in some customer classes not achieving a range of reasonableness in five years. However, in the specific case of BC Hydro rate increases, the timing of those increases is such that they are typically not known at the time of setting FortisBC rates. For example, FortisBC's 2010 rates were approved in December 2009, and as at time of the writing of this response, the 2010 (2011 fiscal year) BC Hydro rate increase is yet unknown.

## Question #13

**Reference: BCOAPO 1.28.1**
**BCUC 1.21.1**

**Q13.1 The response suggests that there could be some reduction in the number of transformers needed but that it would not be based strictly on load. Please confirm that this is an appropriate interpretation. If not, why not?**

A13.1 Although the response suggests there could be some reduction in the number of transformers based on load, the proximity of the transformers to the load is the dominant factor in determining the number of transformers. As such, it is unlikely that the number of transformers would change.

**Q13.2 If the response to 13.1 is in the affirmative, is this an example of why adopting a range of 0.95 to 1.05 is appropriate?**

A13.2 A range of reasonableness is adopted to reflect the fact that assumptions must be made within the COSA, and that perfect data is not always available. Load data is the greatest variable, but other factors such as those mentioned in the response to BCOAPO IR No. 2 Q13.1 above also support the use of a range of reasonableness.

**Question #14**

**Reference: BCOAPO 1.29.1**

**Q14.1 Please clarify whether the Max KVA reported on pages B-11 to B-13 is the maximum capacity the feeder could carry assuming it was constructed based on the minimum sized system.**

A14.1 Yes, this is the maximum capacity the feeder could carry based on the minimum sized system.

## Question #15

**Reference: BCOAPO 1.29.5**

**Q15.1 Please comment on the reasonableness of these results?**

A15.1 FortisBC believes that the methodology and assumptions employed in determining the load factors for the street-lighting class are sound, reflect sound cost-of-service principles, and yield results that are reasonable.

**Question #16**

**Reference: BCOAPO 1.32.1 and 1.32.3**

**16.1 The response assumes that the 4 NCP would be based on the 4 winter months, why is this necessary as opposed to basing each class' 4 NCP value on the four highest months for that class?**

A16.1 The 4CP discussed in the Application and COSA is defined as the 4 winter months, and is based on the 4CP methodology approved for BC Hydro in its last RDA. It follows that a "4 NCP" method would be interpreted to use the same approach with 4 winter peaks. It would be possible however, to use the 4 highest NCP amounts for each customer and they would not need to be in the same months as one another.

**Q16.2 Please outline how, using 4 NCP, the OEB approach would set the NCP values for each class.**

A16.2 The 4 NCP approach described by the OEB is "the use of the average of the four highest monthly non-coincident demand peaks."

## Question #17

**Reference: BCOPAO 1.33.3**

**Q17.1 Does this mean that for purposes of allocating customer-related distribution costs (e.g. the customer portion of poles, wires and transformers) each street lighting account is treated as one customer? If so, please explain why this is reasonable when each “account” will have multiple connections to the distribution system.**

A17.1 Yes, each street lighting account is treated as one customer in terms of allocating costs, although there are often multiple fixtures for each account. Charges are applied on a per fixture basis but bills are sent on a per customer basis. In most cases street lights are fed from existing distribution transformers at multiple points. Street lighting customers are considerably different from metered customer classes. While one lighting customer may be served from different transformers, they do not generally require the same infrastructure as required to connect a non-lighting customer. Given this trade off, it is reasonable to treat each lighting customer on par with other customers.

## 1.0 Reference: COSA, Schedule 8.2

**Q1.1 Please explain why Schedule 8.2 of the COSA shows no Contract Demand for the BCH Lardeu Wholesale Customer.**

A1.1 The Company was unable to locate a contract with BC Hydro Lardeau for use in preparing the COSA. Therefore, 2009 forecast demand was used for this point of delivery.

**2.0 Reference: BCMEU Table A4.1, BCMEU Attachment A6.1, Penticton Municipal Utility**

**Q2.1 Table BCMEU A4.1 and BCMEU Attachment A6.1 together seem to imply that the distribution transformation capacity for the Penticton Municipal Utility is 116 MVA (44 MVA for the Huth Substation, 40 MVA for the Waterford Substation, and 31 MVA for the Westminster Substation). Please confirm or deny. If confirmed, please explain how it is possible for Penticton to have a 156,600 kVA Winter Contract Demand. If denied, please provide the correct distribution capacity of the Distribution Substations (BCUC 362) serving this municipality and reconcile with the supposed contract demand for Penticton.**

A2.1 Please find below a comparison of the transformer capacity taken from BCMEU IR No. 1 A4.1 and the wholesale agreement with the City of Penticton. The request above has not included the 20 MVA nameplate rating for R.G. Anderson as included in the response to BCMEU IR No. 1 Q4.1. The winter contract demand amounts at Anderson and Westminster exceed the nameplate rating as they reflect the $0^{o}$ C rating of the transformers during the colder winter season and accurately reflect the capacity available to the City of Penticton during those periods. At the time of filing the previous and current IR responses, there are elements out of service at Huth which reduce the immediate capacity of the station, however, the full contract capacity can be restored and would be available on short notice should the City require it. The total contract demand at the five points of supply that the City of Penticton has included in its wholesale agreement with FortisBC is 156.6 MVA and which FortisBC is obligated to have available to the City when required. Please see Table BCMEU IR2 A2.1 below.

**Table BCMEU IR2 A2.1**

| | **BCMEU IR1 Q4.1 Response** | **Wholesale Contract** |
|---|---|---|
| **Station** | **Capacity** | **Demand Limit** |
| | **MVA** | |
| Anderson | 20 | 25 winter |
| Huth | 45.6 | 53.6 (8 kV & 13 kV) |
| Waterford | 40 | 40 |
| Westminster | 31 | 38 winter |
| **Total** | **136.6** | **156.6** |

**3.0 Reference: BCMEU Table A4.1, FortisBC T&D System Development Plan**

**Q3.1 Table BCMEU A4.1 shows that the High Voltage for the Distribution substations serving the Kelowna Wholesale Municipal utility is 132 kV, yet the FortisBC T&D System Development Plan (BCMEU Appendix A 15.1A) does not show or designate any transmission lines at that voltage, but does show a voltage of 138 kV. Is the 132 kV shown in the table an error? If not, please explain why the T&D development plan makes no mention of 132 kV equipment.**

A3.1 The 132 kV and 138 kV designations are occasionally used interchangeably to refer to “138-kV class” equipment in the FortisBC system. The correct voltage designation for the Kelowna-area sub-transmission system is 132 kV, as shown in the System Single-Line Diagram drawing 4-000-0403 which is provided as BCUC IR2 Appendix A34.1.

**4.0 Reference: FortisBC Transmission and Distribution System Development Plan and System Development Plan Updates**

**Q4.1 In the power flow and stability studies FortisBC performs to develop its Transmission and Distribution System Development Plan and System Development Plan Updates, does FortisBC model wholesale customer load at the forecasted demand for such customers or the contracted maximum demand for such customers?**

A4.1 Please refer to the response to BCUC IR No. 2 Q38.1.

**Q4.2 If modeled at the contracted maximum demand, please explain in detail why these loads are modeled at their contracted maximum demand rather than forecasted demand. Please provide all documents and/or regulatory filings in support of the response.**

A4.2 Please refer to the response to BCUC IR No. 2 Q38.2.

## 5.0 Reference: BCMEU Table A4.1, POD

**Q5.1 Please explain why Table BCMEU A4.1 designates the RG Anderson Transmission substation as a POD for the Penticton Municipal Utility but does not show any transmission PODs for the other Municipal Utilities.**

A5.1 The RG Anderson substation contains the T3 transformer which is used to provide an 8 kV wholesale supply for the City of Penticton. This is the only transmission station which also provides a distribution supply to a wholesale municipal customer.

**6.0 Reference: BCMEU Table A4.1, Station Transformers**

**Q6.1 For each of the 36 station transformers referenced in Table BCMEU A4. 1, please provide:**

**Q6.1a Its rated capacity.**

A6.1a FortisBC is unable to interpret this question as Table A4.1 in BCMEU IR No. 1 only shows 18 (not 36) transformer banks associated with the wholesale municipal POD's; the ratings for each bank are already shown in the table.

**Q6.1b The maximum demand achieved in 2009.**

A6.1b FortisBC is unable to interpret this question as Table A4.1 in BCMEU IR No. 1 only shows 18 (not 36) transformer banks associated with the wholesale municipal POD's. The maximum demand (in percent) for each transformer can be found in the response to BCUC IR No. 2 Q29.1.

**Q6.1c Whether the feeder serves the Municipal Utility or FortisBC.**

A6.1c FortisBC is unable to interpret this question as Table A4.1 in BCMEU IR No. 1 only shows 18 (not 36) transformer banks associated with the wholesale municipal POD's; the number and usage of individual feeders in each substation is shown in the "Number of Feeders" column.

## 7.0 Reference: BCMEU Attachment A8.1, Excel Files

**Q7.1 In the Excel files provided in BCMEU Attachment A8. 1, the interval data for BCMEU, tab (meter) 935171, shows zero readings after 12/19/2008, hour 9:45 and does not show positive readings again until 2/12/2009, hour 13:45. Is this data missing? If not, please provide same. Also, please identify and redress any other data points that may be missing from these spreadsheets.**

A7.1 The gap in the interval data for meter 935171 for the specified period is due to a transformer failure. A mobile substation was used during this period, for which no interval data is available.

Similarly, meter 916790's interval data is missing from 4/2/09 hour 09:30 to 4/27/09 hour 15:45 due to equipment failure where the use of a mobile substation was required.

Other missing data is due to two meters being used in parallel with only one meter recording data at any given time.

## 8.0 Reference: BCMEU IR 10.1, Peak Loads

**Q8.1 With reference to the answer to IR BCMEU Q 10, 1, are the peak loads shown 15-minute, 30-minute, or 60-minute integrated demands?**

A8.1 The peak loads are shown in 60 minute integrated demands.

## 9.0 Reference: COSA, Schedule 4.3

**Q9.1 Schedule 4.3 of the COSA (provided as BCMEU Attachment A39.1) shows that there are no CIAC credits applied to the Wholesale Municipal customers. Is it the contention of FortisBC that these customers have never made any contributions in aid of construction, either in the form of money or equipment, to the Company owned transformation equipment that serves these customers?**

A9.1 No, FortisBC does not contend that these customers have never made any contributions in aid of construction, either in the form of money or equipment, to the Company owned transformation equipment. Rather, this is a presentation issue since the CIAC account shown on Schedule 4.3 is used only for customer contributions received for new customer distribution extensions constructed under FortisBC Schedule 74, or its predecessors. In the case of work done with municipal utility input of resources (money or equipment), the net cost (after deducting any municipal utility contribution) of the transformation or other equipment that serves them is added to rate base so there is no offsetting CIAC entry recorded.

## 10.0 Reference: Princeton Light and Power

**Q10.1 Is it correct that since the 1997 ECOS was prepared, FortisBC has acquired one of its Wholesale customers, Princeton Light and Power ("PCP")? If that is correct, please provide the following data:**

**Q10.1a The contract demand or demand limit of this customer immediately prior to its acquisition by FortisBC.**

A10.1a Prior to FortisBC's acquisition of Princeton Light and Power, the contract between the two parties stated a demand limit of 17 MVA in summer and 26 MVA in winter.

**Q10.1b What was the total aggregate non-coincident demand of the PCP in 2009?**

A10.1b The metering required to answer this question no longer exists since Princeton Light and Power has been integrated into the FortisBC system.

## 11.0 Reference: BCMEU IR 8.1, KW DEL and KW REC

**Q11.1 In the electronic responses to IR BCMEU 8.1, some of the spreadsheets show KW DEL and KW REC. In those instances, would the customer be billed on only the KW DEL, or would the customer be billed on the net of KW DEL minus KW REC? Please explain your answer.**

A11.1 The customer is billed on the net of the KW DEL (delivered) minus KW REC (received) since the rates paid for each are the same.

## Issue: Separation of RS31 and RS33 customers into separate rate classes

### 1.0 Reference: Exhibit B-3-1, BCUC 3.1

**Wires-based charges**

**Q1.1 For each of the references provided in the response, please provide the pertinent and applicable portions of the tariffs that identify and explain the wires-based charges.**

A1.1 Please refer to the following attachments which provide the applicable portions of the tariffs detailing the wires-based charges for the referenced utilities.

For the City of Lethbridge (Alberta), the attachment provided details the rates that represent the wires component. The power supply is provided under the Regulated Rate Option Tariff or from competitive sources.

For PG&E (California), the attachment provided details the rates that are unbundled into generation, distribution and transmission charges. The distribution and transmission charges together would be comparable to the wires charges as proposed by FortisBC.

For PacifiCorp (Oregon), the attachment provided details the rate that applies to large customers and is for the wires component of service. Power supply is provided under Schedule 200.

## 2010 City of Lethbridge Electric Utility Distribution Tariff

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**Rate Code 991: Standard Distribution**

### Service

Service connected within the City of Lethbridge electric service area
Metered through a single cumulative meter
For monthly consumption of 3,000 kWh or less and demand of 5 kVA or less
Or, Regulated Rate Option qualifying *Rate Classification Customer*

**Transmission Access Rate**

| | | |
|---|---|---|
| a) System Usage Charge | 0.0153 | $ per kWh |
| b) Service and Facilities Charge | 0.1073 | $ per day |

**Distribution Access Rate**

| | | |
|---|---|---|
| a) System Usage Charge | 0.0085 | $ per kWh |
| b) Service and Facilities Charge | 0.5063 | $ per day |

- The minimum daily charge is the daily combined distribution and transmission service and facilities charge
- The billing period is monthly
- The City of Lethbridge Terms and Conditions of Electric Service apply to this rate
- The City of Lethbridge *Rider A* Local Access Fee (LAF) is applied to total charges under this rate

# 2010 City of Lethbridge Electric Utility Distribution Tariff

## Rate Code 994: General Distribution

## Service

Service connected within the City of Lethbridge electric service area
200 amp service
Metered through a single demand meter
System demand greater than 5 kVA and less than 150 kVA
Or, Regulated Rate Option qualifying *Other Customer*

### Transmission Access Rate

| | | |
|---|---|---|
| a) System Usage Charge | 0.0092 | $ per kWh |
| b) Service and Facilities Charge | 0.0000 | $ per day |
| c) Demand Charge | 0.0752 | $ per kVA per day |

### Distribution Access Rate

| | | |
|---|---|---|
| a) System Usage Charge | 0.0006 | $ per kWh |
| b) Service and Facilities Charge | 0.3558 | $ per day |
| c) Demand Charge | 0.1120 | $ per kVA per day |

- The minimum daily charge is the daily combined distribution and transmission demand charge plus the daily Service and Facilities Charge.
- The billing period is monthly
- Demand charge based on:
  - highest kVA demand in the last 12 months, or
  - Contract demand charge
- Contract demand charge, where a customer has a Distribution Service Agreement, is the greater of:
  - customer contract minimum
  - current month high kVA
  - contract ratchet, being 100% of the highest kVA demand greater than contract maximum in the last 12 months
- The City of Lethbridge Terms and Conditions of Electric Service apply to this rate
- The City of Lethbridge *Rider A* Local Access Fee (LAF) is applied to total charges under this rate

# ELECTRIC SCHEDULE E-1
## RESIDENTIAL SERVICES

Sheet 2

RATES:
(Cont'd.)

**UNBUNDLING OF TOTAL RATES**

| Energy Rates by Component ($ per kWh) | | | |
|---|---|---|---|
| **Generation:** | | | |
| Baseline Usage | $0.04495 | (R) | |
| 101% - 130% of Baseline | $0.05385 | (R) | |
| 131% - 200% of Baseline | $0.13086 | (R) | |
| 201% - 300% of Baseline | $0.20203 | (R) | |
| Over 300% of Baseline | $0.23934 | (I) | |
| **Distribution:** | | | (T) |
| Baseline Usage | $0.03718 | (I) | |
| 101% - 130% of Baseline | $0.04453 | (I) | |
| 131% - 200% of Baseline | $0.10822 | (I) | |
| 201% - 300% of Baseline | $0.16710 | (I) | |
| Over 300% of Baseline | $0.19795 | (I) | |
| **Transmission*** (all usage) | $0.01006 | (R) | |
| **Transmission Rate Adjustments*** (all usage) | ($0.00110) | (I) | |
| **Reliability Services*** (all usage) | $0.00069 | (I) | |
| **Public Purpose Programs** (all usage) | $0.01233 | (I) | |
| **Nuclear Decommissioning** (all usage) | $0.00029 | (I) | |
| **Competition Transition Charges** (all usage) | $0.00554 | (R) | |
| **Energy Cost Recovery Amount** (all usage) | $0.00368 | (I) | (D) |
| **DWR Bond** (all usage) | $0.00515 | (I) | (D) |

| Minimum Charge Rate by Component | **$ per meter per day** | | **$ per kWh** | | |
|---|---|---|---|---|---|
| **Distribution** | $0.12311 | (I) | | | (T) |
| **Transmission*** | – | | $0.00896 | (R) | |
| **Reliability Services*** | $0.00000 | | – | | |
| **Public Purpose Programs** | $0.00459 | (I) | – | | |
| **Nuclear Decommissioning** | $0.00011 | | – | | |
| **Competition Transition Charges** | – | | $0.00554 | (R) | |
| **Energy Cost Recovery Amount** | – | | $0.00368 | (I) | (D) |
| **DWR Bond** | – | | $0.00515 | (I) | (D) |
| **Generation**** | Determined Residually | | | | (T) |

* Transmission, Transmission Rate Adjustments, and Reliability Service charges are combined for presentation on customer bills.

** Total rate less the sum of the individual non-generation components. (D)(T)

(Continued)

## ELECTRIC SCHEDULE E-20
SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE

Sheet 4

3. RATES: (Cont'd.)

Customer/Meter Charge Rates: Customer and meter charge rates provided in the Total Rate section above are assigned entirely to the unbundled distribution component.

| Demand Rates by Component ($ per kW) | Secondary Voltage | | Primary Voltage | | Transmission Voltage | |
|---|---|---|---|---|---|---|
| **Generation:** | | | | | | |
| Maximum Peak Demand Summer | $8.74 | (R) | $9.46 | (R) | $11.12 | (R) |
| Maximum Part-Peak Demand Summer | $1.79 | (R) | $2.07 | (R) | $2.49 | (R) |
| Maximum Demand Summer | $0.00 | | $0.00 | | $0.00 | |
| Maximum Part-Peak Demand Winter | $0.00 | | $0.00 | | $0.00 | |
| Maximum Demand Winter | $0.00 | | $0.00 | | $0.00 | |
| **Distribution:** | | | | | | |
| Maximum Peak Demand Summer | $4.04 | (I) | $2.64 | (I) | $0.00 | |
| Maximum Part-Peak Demand Summer | $1.05 | (I) | $0.73 | (I) | $0.00 | |
| Maximum Demand Summer | $4.72 | (I) | $3.24 | (I) | $0.00 | |
| Maximum Part-Peak Demand Winter | $1.15 | (I) | $0.74 | (I) | $0.00 | |
| Maximum Demand Winter | $4.72 | (I) | $3.24 | (I) | $0.00 | |
| **Transmission Maximum Demand*** | $3.22 | (R) | $3.22 | (R) | $3.22 | (R) |
| **Reliability Services Maximum Demand*** | $0.22 | (I) | $0.22 | (I) | $0.22 | (I) |
| Energy Rates by Component ($ per kWh) | | | | | | |
| **Generation:** | | | | | | |
| Peak Summer | $0.11226 | (R) | $0.12077 | (R) | $0.08683 | (R) |
| Part-Peak Summer | $0.07528 | (R) | $0.07813 | (R) | $0.06635 | (R) |
| Off-Peak Summer | $0.05945 | (R) | $0.05922 | (R) | $0.05413 | (R) |
| Part-Peak Winter | $0.06542 | (R) | $0.06467 | (R) | $0.05893 | (R) |
| Off-Peak Winter | $0.05636 | (R) | $0.05517 | (R) | $0.05050 | (R) |
| **Distribution:** | | | | | | |
| Peak Summer | $0.01269 | (I) | $0.00851 | (I) | $0.00000 | |
| Part-Peak Summer | $0.00507 | (I) | $0.00340 | (I) | $0.00000 | |
| Off-Peak Summer | $0.00254 | (I) | $0.00169 | (I) | $0.00000 | |
| Part-Peak Winter | $0.00436 | (I) | $0.00281 | (I) | $0.00000 | |
| Off-Peak Winter | $0.00292 | (I) | $0.00187 | (I) | $0.00000 | |
| **Transmission Rate Adjustments* (all usage)** | ($0.00095) | (I) | ($0.00095) | (I) | ($0.00095) | (I) |
| **Public Purpose Programs (all usage)** | $0.01101 | (I) | $0.01026 | (I) | $0.00902 | (I) |
| **Nuclear Decommissioning (all usage)** | $0.00029 | (I) | $0.00029 | (I) | $0.00029 | (I) |
| **Competition Transition Charge (all usage)** | $0.00371 | (R) | $0.00352 | (R) | $0.00315 | (R) |
| **Energy Cost Recovery Amount (all usage)** | $0.00368 | (I) | $0.00368 | (I) | $0.00368 | (I) |
| **DWR Bond (all usage)** | $0.00515 | (I) | $0.00515 | (I) | $0.00515 | (I) |

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* Transmission, Transmission Rate Adjustments, and Reliability Service charges are combined for presentation on customer bills.

(Continued)

**PACIFIC POWER & LIGHT COMPANY**
LARGE GENERAL SERVICE - 1,000 KW AND OVER
DELIVERY SERVICE

**OREGON**
**SCHEDULE 48**
Page 1

**Available**

In all territory served by the Company in the State of Oregon.

**Applicable**

This Schedule is applicable to electric service loads which have registered 1,000 kW or more, more than once in a preceding 18-month period. This Schedule will remain applicable until the Consumer fails to exceed 1,000 kW for a subsequent period of 36 consecutive months. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Partial requirements service for loads of 1,000 kW and over will be provided only by application of the provisions of Schedule 47.

**Monthly Billing**

The Monthly Billing shall be the sum of the Distribution Charge and Transmission & Ancillary Services Charge plus applicable adjustments as specified in Schedule 90.

| | Delivery Voltage | | |
|---|---|---|---|
| | **Secondary** | **Primary** | **Transmission** |
| **Distribution Charge** | | | |
| Basic Charge | | | |
| Facility Capacity ≤ 4000 kW, per month | $320.00 | $330.00 | $440.00 |
| Facility Capacity > 4000 kW, per month | $600.00 | $590.00 | $810.00 |
| Facilities Charge | | | |
| ≤ 4000 kW, per kW Facility Capacity | $ 1.30 | $ 0.70 | $ 0.60 |
| > 4000 kW, per kW Facility Capacity | $ 1.20 | $ 0.65 | $ 0.60 |
| On-Peak Demand Charge, per kW | $ 1.88 | $ 2.05 | $ 1.35 |
| Reactive Power Charge, per kvar | $ 0.65 | $ 0.60 | $ 0.55 |
| **Transmission & Ancillary Services Charge** | | | |
| Per kW of On-Peak demand | $ 1.51 | $ 1.60 | $ 1.97 |

**Facility Capacity**

For determination of the Basic Charge and the Facilities Charge, the Facility Capacity shall be the average of the two greatest non-zero monthly demands established during the 12-month period, which includes and ends with the current billing month.

**Minimum Charge**

The minimum monthly charge shall be the Basic Charge and the Facilities Charge. A higher minimum may be required by contract.

**Reactive Power Charge**

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the maximum measured kilowatt demand for the same month.

*(continued)*

| | | |
|---|---|---|
| Issued: | January 28, 2010 | P.U.C. OR No. 35 |
| Effective: | With service rendered on and after February 2, 2010 | Sixth Revision of Sheet No. 48-1 |
| | | Canceling Fifth Revision of Sheet No. 48-1 |

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Andrea L. Kelly, Vice President, Regulation

TF1 48-1.E
Advice No. 10-001/ UE-210

**On-Peak Demand**

The kW shown by or computed from the readings of the Company's demand meter for the On-Peak 15-minute period of the Consumer's greatest use during the month, determined to the nearest kW. On-Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday, excluding NERC holidays.

Due to the expansions of Daylight Saving Time (DST) as adopted under Section 110 of the U.S. Energy Policy Act of 2005, the time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April and for the period between the last Sunday in October and the first Sunday in November.

**Metering Adjustment**

For a Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9688.

For a Consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0322.

**Supply Service Options**

All Consumers taking Delivery Service under this Schedule shall pay the applicable rates in Schedule 200, Base Supply Service. Additionally, each Consumer shall specify Supply Service Schedule 201 or Schedule 220, as appropriate and in accordance with the Applicable section of the specified rate schedule. If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 748, Direct Access Delivery Service.

**Special Conditions**

The Consumer shall not resell electric service received from the Company under provisions of this Schedule to any person, except by permission of the Company.

**Term of Contract**

The Company may require the Consumer to sign a written contract which shall have a term of not less than one year.

**Rules and Regulations**

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

**2.0 Reference: Exhibit B-3-1, BCUC 34.7**

**Effect of changed behaviour on re-balancing**

**"Some Schedule 31 customers may be able to adjust some aspects of their operation, such as the staggered start of large motors in order to reduce their peak demands, or the alteration of plant shift schedules."**

**Q2.1 Please confirm that if all Schedule 31 customers were able to shift operation to lower cost time periods, that revenues for the rate class would fall, and if cost recovery were to fall below the accepted range, that Schedule 31 rates would rise in the next re-balancing period, negating the effects of the time-shifted operation.**

A2.1 Ideally, any overall decrease in revenues would be matched by a reduction in costs. This was recognized when the current rates were implemented as evidenced by the following excerpts from the 1997 Rate design Application:

*If a customer is successful in moving their consumption from an on-peak period to an off-peak period, essentially two phenomena will occur. First, the commodity costs that WKP avoids because of the lower on-peak consumption will be reflected in a reduction in on-peak commodity costs, which will be matched in this cost-based rate by a reduction in on-peak commodity revenue. Therefore, this rate should have no impact on non-participating customers as a result of on-peak commodity costs.*

*The second impact occurs because some costs which are fixed in the short-term (capital costs such as substation and transmission equipment) are recovered in on-peak periods, and will not now be recovered. Therefore, this rate may impact nonparticipating customers in the short-term.*

*For instance, should an irrigation customer be successful in shifting load from the summer on-peak hours to the summer off-peak hours, transmission facilities will become less constrained, but there will be no difference in short-term total costs because the capital investment in the transmission system is fixed. In the long-term, when it is time to* *add new supply capabilities, this shift in consumption will result in lower total system costs.*

Therefore, while it is possible that the situation described may result in a short term revenue shortfall, the rationale for the adoption of TOU rates requires a longer term perspective and reactionary rate changes should not be made.

**3.0 Reference: Exhibit B-3-1, BCUC 38.1**

**Electricity usage under Rate Schedule 33**

**Q3.1 Please convert the rate shown in Table 14.3b from the Application into a "flat rate" for each period (time-weighted average cost), and provide a comparison table of the revenues for the consumption shown. in Table BCUC A38.1 for this flat rate as compared to Rate Schedule 33 shown in Table 14.3b.**

A3.1 Please refer to the following hypothetical Schedule 33 and Table IR2 Zellstoff Celgar A3.1:

Hypothetical Schedule 33 - Time-weighted seasonal flat rate

| | | ¢/kW.h |
|---|---|---|
| Winter<br>(Nov. - Feb.) | On-Peak Hours:<br>7:00 am - 12:00 pm business days<br>4:00 pm - 10:00 pm business days<br><br>Off-Peak Hours:<br>10:00 pm to 7:00 am business days<br>12:00 pm - 4:00 pm business days<br>All hours on weekends and statutory holidays | 6.467 |
| Summer<br>(July, August) | On-Peak Hours:<br>10:00 am - 9:00 pm business days<br><br>Off-Peak Hours:<br>9:00 pm - 10:00 am<br>All hours on weekends and statutory holidays | 7.171 |
| Shoulder<br>(all other months) | On-Peak Hours:<br>6:00 am - 10:00 pm, Monday to Saturday<br><br>Off-Peak Hours:<br>10:00 pm to 6:00 am - Monday to Saturday, All day Sunday | 3.205 |

The time-weighted rates are calculated based on the reference period calendar used in Table BCUC A38.1 from BCUC IR No. 1.

1 **Table Zellstoff Celgar IR2 A3.1**

| Season | Read Date | On-Peak (kWh) | Off-Peak (kWh) | Rate | Energy charges on current ID33 energy rate ($) | Simulated energy charges on time-weighted seasonal flat rate ($) |
|---|---|---|---|---|---|---|
| Winter | 11/30/2009 | 1,602,678 | 4,758,096 | ID33 | 373,779.29 | 411,341.85 |
| Shoulder | 10/31/2009 | 726,390 | 426,930 | ID33 | 38,562.81 | 36,959.37 |
| Shoulder | 09/30/2009 | 243,852 | 114,156 | ID33 | 12,322.99 | 11,472.75 |
| Summer | 08/31/2009 | 455,070 | 1,337,910 | ID33 | 114,247.63 | 128,581.32 |
| Summer | 07/31/2009 | 78,834 | 959,994 | ID33 | 40,123.61 | 74,498.25 |
| Shoulder | 06/30/2009 | 446,334 | 624,456 | ID33 | 31,426.52 | 34,314.61 |
| Shoulder | 05/31/2009 | 2,557,590 | 2,294,334 | ID33 | 152,668.73 | 155,485.07 |
| Shoulder | 04/30/2009 | 974,736 | 707,574 | ID33 | 54,622.50 | 53,911.42 |
| Shoulder | 03/31/2009 | 867,090 | 880,530 | ID33 | 53,951.14 | 56,004.35 |
| Winter | 02/28/2009 | 249,144 | 449,694 | ID33 | 47,698.59 | 45,192.82 |
| Winter | 01/31/2009 | 1,384,026 | 2,884,224 | ID33 | 278,829.37 | 276,021.41 |
| Winter | 12/31/2008 | 728,448 | 1,851,066 | ID33 | 158,707.27 | 166,813.35 |

**Q3.2 Please provide a table similar to Table BCUC A38.1 which shows the Celgar facility electricity usage separated into On-Peak and Off-Peak periods for the corresponding 12 month period as Table BCUC A38.1 immediately before the Celgar facility switched from Rate Schedule 31 to Rate Schedule 33. For instance, if the switch occurred in October 2006, please provide the data from Read Date 11/30/2005 to 12/31/2004.**

A3.2 The table below shows the Celgar facility electricity usage separated into On-Peak and Off-Peak periods for the requested 12 month period as Table BCUC A38.1 immediately before the Celgar facility switched from Rate Schedule 31 to Rate Schedule 33. It also shows the monthly billing under schedule 31 and the billing that would have applied under Schedule 33.

**Table Zellstoff Celgar IR2 A3.2**

| Season | Read Date | On-Peak (kWh) | Off-Peak (kWh) | Schedule 31 Biling ($) | Schedule 33 Billing ($) |
|---|---|---|---|---|---|
| Shoulder | 09/30/2006 | 1,147,986 | 793,464 | 166,555.76 | 63,617.76 |
| Summer | 08/31/2006 | 1,121,946 | 603,246 | 156,631.88 | 205,392.09 |
| Summer | 07/31/2006 | 853,482 | 2,149,938 | 206,251.31 | 199,242.08 |
| Shoulder | 06/30/2006 | 2,162,664 | 1,029,042 | 214,521.21 | 110,494.53 |
| Shoulder | 05/31/2006 | 3,229,632 | 1,732,122 | 286,450.58 | 166,134.85 |
| Shoulder | 04/30/2006 | 5,279,736 | 4,007,976 | 458,326.57 | 293,365.82 |
| Shoulder | 03/31/2006 | 3,778,908 | 2,901,570 | 354,867.23 | 212,314.50 |
| Winter | 02/28/2006 | 1,953,588 | 3,647,742 | 313,149.75 | 374,671.17 |
| Winter | 01/31/2006 | 1,821,750 | 3,178,938 | 287,617.65 | 337,656.80 |
| Winter | 12/31/2005 | 1,589,910 | 3,164,154 | 262,612.91 | 297,864.24 |
| Winter | 11/30/2005 | 1,672,482 | 3,388,644 | 275,218.77 | 315,261.70 |
| Shoulder | 10/31/2005 | 3,563,070 | 3,517,668 | 349,278.11 | 208,227.52 |

**Q3.3 For the period provided in the previous question, please provide a comparison of the monthly billings applied under Rate Schedule 31 and the billings that would have applied if the service would have been taken under Rate Schedule 33. Please also provide this same comparison of monthly Rate Schedule 31 billings and Rate Schedule 33 billings for the usage pattern shown in Table BCUC A38.1.**

A3.3 Please refer to Table Zellstoff Celgar IR2 A3.2 above.

**Q3.4 Does FortisBC consider the consumption pattern shown in Table BCUC A38.1 to be representative of an effort to move electricity consumption away from On-Peak Hours, and if not, why not?**

A3.4 FortisBC considers the consumption pattern shown in Table BCUC A38.1 from BCUC IR No. 1 to show generally higher off-peak consumption than on-peak consumption, particularly in the Summer and Winter periods. FortisBC cannot comment on the effort required to achieve this pattern.

**4.0 Reference: Exhibit B-1, Residential Rates p. 55; Exhibit B-3-4, ZCLP 2.1 Intra-class subsidization**

**Q4.1 Please explain how intra-class subsidization is occurring in Residential service, with urban customers subsidizing rural customers, because of the higher cost to serve rural customers as stated in the Application?**

A4.1 FortisBC believes that the prevailing postage stamp system of rates is appropriate within its service area and does not support geographically segmented rates. Within each rate class there will be variation within the cost to serve each individual customer. At this level, some degree of intra-class subsidization is acceptable and standard utility practice.

**Q4.2 Please explain why intra-class subsidization is an acceptable condition in the residential rate class, but is the criterion for creation of a separate class of service in the Large General Service ("LGS") rate class.**

A4.2 As explained in the response to Zellstoff Celgar IR No. 1 Q2.1, FortisBC believes that the impact that Zellstoff Celgar has on the transmission class as a whole, warrants the consideration of Rate Schedule 33 as a separate class for the COSA.

**Q4.3 What measure does FortisBC utilize to determine whether intra-class subsidization is significant enough to warrant creation of a separate class of service within the LGS class?**

A4.3 FortisBC does not employ a standard measure of intra-class subsidization in this manner.

**Q4.4 Having reference to the measure referred to in question 4.3 above, at what point on such scale did FortisBC determine, or does FortisBC believe, that Celgar should be separated into a standalone class of service. For example, if cost recovery ratio is the measure, at what cost recovery ratio for Celgar, as compared to the other LGS customers, does FortisBC believe justified, or justifies, the creation of a stand-alone class of service for Celgar.**

A4.4 As noted in the response to Zellstoff Celgar IR No. 2 Q4.3 above, no such measure is routinely used. With respect to revenue-to-cost ratios specifically, there is no threshold number as the question presumes, but in the opinion of the Company, a customer that affects the revenue-to-cost ratio of a customer class as significantly as Zellstoff Celgar does, (including Zellstoff Celgar, the Schedule 31 class is at a 62 percent revenue-to-cost ratio, and without is at 110 percent) warrants the consideration of Rate Schedule 33 as a separate class for COSA and rate design purposes.

**Q4.5 Other than Celgar, do any other non-wholesale customers of FortisBC constitute the only member of a "Class of Service" for cost allocation purposes?**

A4.5 No “Class of Service” in the COSA model, other than the Schedule 33 class and the wholesale customer rate class, have one customer.

**Issue: Contract Demand and associated allocation of costs**

**5.0 Reference: Exhibit B-3-1, BCUC 69.1; Exhibit B-3-4, ZCLP 19.2, Appendix A19.2**
**Curtailment Response**

**Q5.1 Please confirm that the Celgar facility has responded, in real-time, to requests from FortisBC's System Control Centre to reduce load and/or increase generation in response to capacity constraints within the FortisBC system, or at times of system peak.**

A5.1 The Company can confirm that from time to time Zellstoff Celgar has agreed to real-time requests to increase generation. The Company is not aware that Zellstoff Celgar has responded by reducing load. This increased generation is non-firm and although useful from time to time is not a resource that the Company can rely upon. On some occasions Zellstoff Celgar has not agreed to requests by FortisBC. FortisBC has not tracked these requests.

**Q5.2 Please provide a log of such requests made by the FortisBC System Control Centre since 2005 and the corresponding response by the Celgar facility, and identify the issue in the FortisBC system that precipitated the request.**

A5.2 Please see the response to Zellstoff Celgar IR No. 2 Q5.1 above.

**Q5.3 Please identify any similar requests made to other FortisBC customers and the corresponding response. If the customer identity cannot be revealed because of privacy concerns, please supply the technical details pertaining to each identified request and response.**

A5.3 FortisBC has no other customers that it makes similar requests of.

**6.0 Reference: Exhibit B-3-4, ZCLP 15.3**

**Contract Demand**

**"And although the contract demand is fixed for a period of time, by creating the wires charge the customer will no longer have an incentive to request a high contract demand for liability reasons without paying for the facilities required to meet that contract demand. As FortisBC is contractually responsible to meet contract demand levels, a lower contract demand level will conserve resources."**

**Q6.1 Has Celgar ever requested and received a contract demand level of 40 MVA?**

A6.1 As early as the 2000 General Service Agreement ("GSA") between Zellstoff Celgar and FortisBC, the demand limit was set at 40 MVA, with a fixed contract demand (as that term is used in the contractual documents between these parties) of 16 MVA. The October 2006 GSA, provided in IR No. 1 as Zellstoff Celgar Appendix A19.2, also included a 40 MVA demand limit and an on-peak and off-peak contract demand of 25 MVA and 10 MVA, respectively. Zellstoff Celgar also signed a Power Supply Agreement in August 2008, which had a contract demand of 43 MVA and a demand limit of 45 MVA. The pertinent clauses are reproduced below:

(k) **"Contract Demand"** means the amount of electricity to be made available by FortisBC to, and purchased by, Celgar hereunder, from time to time, and at all times during the term hereof, which shall be equal to the Firm Capacity Reservation as varied pursuant to Section 3.2 hereof, from time to time;

(m) **"Demand Limit"** means 45 MVA, being 2 MVA in excess of the Firm Capacity Reservation;

(s) **"Firm Capacity Reservation"** means 43 MVA of electrical generation output, being the capacity level of electricity required by Celgar to allow Celgar to operate the Mill at reasonable production levels in a reliable state;

Currently FortisBC and Zellstoff Celgar are operating under the October 2006 GSA since the 2008 Power Supply Agreement was withdrawn, as it allowed for the export of Celgar's generation at the same time they were purchasing energy from FortisBC, who was in turn purchasing energy from BC Hydro under the 3808 Rate Schedule. The Commission, on May 6, 2009, issued Order G-48-09 which prevented this sale of Celgar power and thereby rendered the Power Supply Agreement irrelevant. For the purposes of the COSA, the 40 MVA demand limit contained in the GSA has been used to allocate transmission and distribution costs. Actual Celgar loads on the FortisBC system met or exceeded the 40 MVA demand limit eight out of 12 months during the test year.

**Q6.2 Given that: (i) FortisBC does not assign specific assets to service specific customers; (ii) does not calculate percentage utilization of specific assets; (iii) relies on a complex network of transmission interconnections (including those servicing Celgar); and (iv) adheres to a postage stamp methodology for allocating costs, how does FortisBC reconcile charging Celgar, through its proposed wires charge, for utilization of specific assets (the facilities required to meet the contract demand as set out in FortisBC's response to ZCLP 15.3) where: (a) Celgar has no contractual right of priority; (b) shares use; and (c) has no right of exclusivity beyond that required to meet the applicable Firm Capacity Reservation?**

A6.2 The wires charge proposed in the application, and the response provided to Zellstoff Celgar IR No. 1 Q15.3 do not refer to specific facilities but rather apply to the integrated transmission and distribution system for FortisBC. While Celgar has no contractual rights or exclusivity to specific facilities, it does have a contractual right to take up to the 40 MVA demand limit in its contract at any time which FortisBC must be prepared to meet.

**Q6.3 Is Celgar the only ratepayer from which FortisBC seeks to recover infrastructure costs based upon maximum, rather than contractual, load?**

A6.3 All customers currently served under Rate Schedules 31, 33, 40 and 41 have proposed rates intended to recover infrastructure costs based upon the greater of maximum and contractual load.

**7.0 Reference: Exhibit 8-3-4, ZCLP 19.1, ZCLP 19.2, Appendix A19.2**

**General Service Power Contract**

**Q7.1 Appendix A19.2 to FortisBC's response ZCLP 19.2 sets out FortisBC's (unsigned) October 1, 2006 General Service Power Contract with Celgar (the "GSPC") which FortisBC references as the agreement under which Celgar is entitled to receive services under Rate Schedule 33. Having reference to the GSPC, please confirm that:**

**Q7.1.1 Celgar's Firm Capacity Reservation (as defined therein) between 8:00 a.m. and 10:00 p.m. is 10 MVA;**

A7.1.1 Confirmed.

**Q7.1.2 Celgar's Firm Capacity Reservation between 10:00 p.m. and 8:00 a.m. is 25 MVA;**

A7.1.2 Confirmed.

**Q7.1.3 FortisBC is not obliged to meet the Firm Capacity Reservation at any time that Celgar has scheduled exports of power on the FortisBC system;**

A7.1.3 Confirmed.

**Q7.1.4 FortisBC does not have a firm commitment, at any time, to supply power to Celgar at levels above the applicable Firm Capacity Reservation;**

A7.1.4 Not confirmed. FortisBC has an obligation to meet the Zellstoff Celgar load up to the demand limit of 40,000 kVA as shown in Zellstoff Celgar Appendix A19.2 General Service Power Contract. If this load is in excess of the firm capacity reservation Zellstoff

Celgar is potentially exposed to additional charges. These potential charges can be minimized through proper notice to FortisBC when Zellstoff Celgar anticipates requirements exceeding the firm capacity reservation.

**Q7.1.5 If Celgar requests power in excess of the Firm Capacity Reservation, FortisBC's sole obligation is to make commercially reasonable efforts to meet Celgar's request;**

A7.1.5 Not confirmed. Please see the response to Zellstoff Celgar IR No. 2 Q7.1.4 above.

**Q7.1.6 The commercially reasonable efforts referred to in the GSPC reference the supply of power, first from FortisBC's own capacity, if available, and thereafter the purchase of power from market sources, including BC Hydro;**

A7.1.6 Confirmed.

**Q7.1.7 When FortisBC is required to purchase power from outside sources, Celgar is obliged to reimburse FortisBC for any incremental capacity costs incurred by FortisBC in. meeting Celgar's load requirements, beyond the Firm Capacity Reservation;**

A7.1.7 Confirmed.

**Q7.1.8 Nothing in the GSPC, or in any other agreement between Celgar and FortisBC, requires FortisBC to provide power to Celgar, on a firm basis, at levels above the agreed Firm Capacity Reservation amounts;**

A7.1.8 Not confirmed. Please see the response to Zellstoff Celgar IR No.

2 Q7.1.4 above.

**Q7.1.9 To the extent that FortisBC has, in the past, provided power to Celgar in excess of Celgar's Firm Capacity Reservation, Celgar has paid all contractual charges in respect thereof, including any additional expenses incurred by FortisBC in the supply of such incremental power; and**

A7.1.9 Confirmed.

**Q7.1.10 If FortisBC is unable to supply power to Celgar at levels above Celgar's Firm Capacity Reservation, provided that FortisBC has made reasonable commercial efforts to do so, FortisBC accepts no resulting liability to Celgar under the GSPC.**

A7.1.10 Not confirmed. Please see the response to Zellstoff Celgar IR No. 2 Q7.1.4 above.

**Q7.2 Please confirm that revisions to the GSPC with Celgar are necessary to be consistent with the Decision accompanying BCUC Order No. G-48-09, and that such revisions can be reasonably expected to include changes to the contract demand and the establishment of a generator base line.**

A7.2 FortisBC agrees that a generator base line ('GBL') would be required pursuant to Order G-48-09 in order to determine (in circumstances where this issue arises) the extent to which self-generating customers such as Zellstoff Celgar will be able to export power (other than sales to BC Hydro) while purchasing PPA-derived power from FortisBC.

**Q7.3 Please confirm that FortisBC requires a new contract with Celgar before the final rates can be determined in this proceeding.**

A7.3 Zellstoff-Celgar is operating under a general service power contract with FortisBC that has been considered during the completion of both the COSA and rate design included with the Application (Exhibit B-1). FortisBC does not believe that it is necessary to enter into a new contract in order for the Commission to dispose of the Application.

**Q7.4 Please confirm that the establishment of a generator base line for Celgar and any additional revisions to the GSPC will have a material impact on the Application and related Cost of Service Analysis.**

A7.4 Not confirmed. Future changes to customers' load do not impact the test year for this Application.

**Q7.5 Does FortisBC agree with the assumptions and conclusions expressed by EES Consulting at Exhibit B-l, Appendix A, page 32, as follows: "For those customers that have customer-owned generation on site used to serve their own load throughout the year, the contractual demand is set to cover the entire load of the customer in the event the customer-owned generation is not available to meet load. FortisBC has the obligation to serve their load in that scenario, which has occurred in the past for both Celgar and Nelson"? If so, please explain the basis upon which FortisBC asserts that it is contractually obliged to service Celgar's load above the Firm Capacity Reservation.**

A7.5 FortisBC agrees with the conclusions drawn in the referenced EES report. Upon notification of a requirement by the Customer in excess of the capacity reservation, FortisBC will make all reasonable efforts to meet the requirement as promptly as possible. FortisBC will look to its own resources initially and, if no available surplus exists, will then look to outside market opportunities. The customer will be responsible for incremental costs including any BC Hydro ratchet charges incurred such that FortisBC customers are not harmed by the transaction. Should the customer accept the potential ramifications of their choice, FortisBC will take any commercial steps necessary to fulfill the request and treats this as a contractual obligation.

**Q7.6 What is the basis for FortisBC's assertion in its response to ZCLP 19.1 that 40 MVA per month is the current contract demand limit contained in the GSPC?**

A7.6 The General Service Power Contract includes a demand limit of 40,000 kVA as shown by the excerpt below.

> 3. The TYPE OF SERVICE to be supplied by FortisBC to the Customer shall be nominally 60,000 volt, three phase, 60 hertz service. FortisBC shall make available the firm capacity reservation of 10MVA between 8:00 am and 10:00 pm and 25 MVA between 10:00 pm and 8:00 am. throughout the term of this Agreement. The Customer shall not exceed the DEMAND LIMIT OF 40,000 kVA unless otherwise agreed in writing.

**Q7.7 Does FortisBC believe that it is required to maintain 40 MVA per month of dedicated capacity available at all times for use by Celgar? If so, on what basis does FortisBC premise such conclusion?**

A7.7 The General Service Power Contract that FortisBC has in place with Zellstoff Celgar contains a Demand Limit of 40 MVA. The contract obligates FortisBC to maintain facilities capable of the provision of transmission capacity at that level. There is no provision in the contract that limits this obligation at any time of the day, week, month or year.

**Q7.8 Please advise as to when, if ever, FortisBC last supplied the full mill load of Celgar, in satisfaction of a firm contractual obligation to do so. If such an example is identified, is the underlying contract that gave rise to such obligation still in effect?**

A7.8 FortisBC last supplied the full mill load of Zellstoff Celgar on Sunday, January 14, 2010. Please also see the response to Zellstoff Celgar IR No. 2 Q7.1.4 above.

**Q7.9 If the actual contract load of 25 MVA was utilized for Celgar in the COSA, rather than the imputed 40 MVA level of contract demand and/or maximum demand, what effect would such change have on the results of the COSA? Specifically, how would such change affect the calculation of Celgar's current cost recovery ratio? Please provide underlying calculations/revised charts, as applicable, including in the form of Exhibit B-l, Table 8.1a and Table 8.1b.**

A7.9 A change to a 25 MVA contract demand would change the revenue to cost ratio for Industrial Transmission 33 to 30.6%. There would still be a 5% rate increase per year associated with rebalancing plus another 5% for the assumed revenue requirement increase. The requested tables follow.

**Table Zellstoff Celgar IR2 A7.9a**
**Revenue to Cost Ratios Assuming Celgar Contract Load is 25 MVA**

| | Year 0 | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 |
|---|---|---|---|---|---|---|
| | R/C Ratio | R/C Ratio | R/C Ratio | R/C Ratio | R/C Ratio | R/C Ratio |
| Residential | 98.0% | 98.0% | 98.0% | 98.0% | 98.0% | 98.0% |
| Small General Service | 113.0% | 109.3% | 106.4% | 105.0% | 105.0% | 105.0% |
| General Service | 138.4% | 133.9% | 130.3% | 126.1% | 121.5% | 120.4% |
| Industrial Transmission 33 | 30.6% | 32.0% | 33.6% | 35.2% | 36.8% | 38.6% |
| Industrial Primary | 121.9% | 117.9% | 114.8% | 111.1% | 107.0% | 106.0% |
| Industrial Transmission 31 | 109.3% | 105.8% | 105.0% | 105.0% | 105.0% | 105.0% |
| Lighting | 81.8% | 85.7% | 89.8% | 94.1% | 95.0% | 95.0% |
| Irrigation | 78.3% | 82.0% | 85.9% | 90.0% | 95.0% | 95.0% |
| Kelowna Wholesale | 89.3% | 93.6% | 95.0% | 95.0% | 95.0% | 95.0% |
| Penticton Wholesale | 77.4% | 81.1% | 85.0% | 89.0% | 93.3% | 95.0% |
| Summerland Wholesale | 96.1% | 96.1% | 96.1% | 96.1% | 96.1% | 96.1% |
| Grand Forks Wholesale | 67.5% | 70.7% | 74.1% | 77.6% | 81.3% | 85.2% |
| BCH Lardeau Wholesale | 101.2% | 101.2% | 101.2% | 101.2% | 101.2% | 101.2% |
| BCH Yahk Wholesale | 103.2% | 103.2% | 103.2% | 103.2% | 103.2% | 103.2% |
| Nelson Wholesale | 79.3% | 83.1% | 87.1% | 91.2% | 95.0% | 95.0% |
| Total | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.1% |

**Table Zellstoff Celgar IR2 A7.9b**
**Total Rate Increase Assuming Celgar Contract Load is 25 MVA**

| | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 |
|---|---|---|---|---|---|
| | Total Rate % Increase | Total Rate % Increase | Total Rate % Increase | Total Rate % Increase | Total Rate % Increase |
| Residential | 5.0% | 5.0% | 5.0% | 5.0% | 5.0% |
| Small General Service | 1.6% | 2.2% | 3.6% | 5.0% | 5.0% |
| General Service | 1.6% | 2.2% | 1.6% | 1.2% | 4.0% |
| Industrial Transmission 33 | 10.0% | 10.0% | 10.0% | 10.0% | 10.0% |
| Industrial Primary | 1.6% | 2.2% | 1.6% | 1.2% | 4.0% |
| Industrial Transmission 31 | 1.6% | 4.2% | 5.0% | 5.0% | 5.0% |
| Lighting | 10.0% | 10.0% | 10.0% | 6.0% | 5.0% |
| Irrigation | 10.0% | 10.0% | 10.0% | 10.8% | 5.0% |
| Kelowna Wholesale | 10.0% | 6.6% | 5.0% | 5.0% | 5.0% |
| Penticton Wholesale | 10.0% | 10.0% | 10.0% | 10.0% | 7.0% |
| Summerland Wholesale | 5.0% | 5.0% | 5.0% | 5.0% | 5.0% |
| Grand Forks Wholesale | 10.0% | 10.0% | 10.0% | 10.0% | 10.0% |
| BCH Lardeau Wholesale | 5.0% | 5.0% | 5.0% | 5.0% | 5.0% |
| BCH Yahk Wholesale | 5.0% | 5.0% | 5.0% | 5.0% | 5.0% |
| Nelson Wholesale | 10.0% | 10.0% | 10.0% | 9.4% | 5.0% |
| Total | 5.0% | 5.0% | 5.0% | 5.0% | 5.0% |

**Q7.10 If Celgar and FortisBC entered into a revised power purchase agreement in which the Firm Capacity Reservation between the hours of 10:00 p.m. and 8:00 a.m. was reduced to 10 MVA, such that the maximum Firm Capacity Reservation under the contract between FortisBC and Celgar was 10 MVA, and if such contract load, rather than the 40 MVA load was utilized, what effect would such change have on the results of the COSA? Specifically, how would such change affect the calculation of Celgar's current cost recovery ratio? Please provide underlying calculations/revised charts, as applicable, including in the form of Exhibit B-1, Table 8.1 a and Table 8.1b.**

A7.10 A change to a 10 MVA contract demand would result in a revenue to cost ratio for the Industial Transmission 33 class of 48.7%. There would still be a 5% rate increase per year associated with rebalancing plus another 5% for the assumed revenue requirement increase. The requested tables follow.

**Table Zellstoff Celgar A7.10a**
**Revenue to Cost Ratios Assuming Celgar Contract Load is 10 MVA**

| | Year 0 | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 |
|---|---|---|---|---|---|---|
| | R/C Ratio | R/C Ratio | R/C Ratio | R/C Ratio | R/C Ratio | R/C Ratio |
| Residential | 97.7% | 97.7% | 97.7% | 97.7% | 97.7% | 97.7% |
| Small General Service | 112.6% | 109.0% | 106.0% | 105.0% | 105.0% | 105.0% |
| General Service | 137.8% | 133.3% | 129.6% | 125.1% | 120.4% | 117.9% |
| Industrial Transmission 33 | 48.7% | 51.0% | 53.4% | 55.9% | 58.6% | 61.4% |
| Industrial Primary | 121.3% | 117.4% | 114.2% | 110.1% | 106.0% | 105.0% |
| Industrial Transmission 31 | 108.8% | 105.3% | 105.0% | 105.0% | 105.0% | 105.0% |
| Lighting | 81.8% | 85.7% | 89.7% | 94.0% | 95.0% | 95.0% |
| Irrigation | 78.0% | 81.7% | 85.6% | 89.7% | 93.9% | 95.0% |
| Kelowna Wholesale | 88.7% | 93.0% | 95.0% | 95.0% | 95.0% | 95.0% |
| Penticton Wholesale | 76.8% | 80.5% | 84.3% | 88.4% | 92.6% | 95.0% |
| Summerland Wholesale | 95.5% | 95.5% | 95.5% | 95.5% | 95.5% | 95.5% |
| Grand Forks Wholesale | 67.0% | 70.2% | 73.5% | 77.0% | 80.7% | 84.5% |
| BCH Lardeau Wholesale | 100.7% | 100.7% | 100.7% | 100.7% | 100.7% | 100.7% |
| BCH Yahk Wholesale | 102.8% | 102.8% | 102.8% | 102.8% | 102.8% | 102.8% |
| Nelson Wholesale | 78.7% | 82.4% | 86.3% | 90.4% | 95.0% | 95.0% |
| Total | 100.0% | 100.0% | 100.1% | 100.0% | 100.0% | 100.0% |

**Table Zellstoff Celgar A7.10b**
**Total Rate Increase Assuming Celgar Contract Load is 10 MVA**

| | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 |
|---|---|---|---|---|---|
| | Total Rate % Increase | Total Rate % Increase | Total Rate % Increase | Total Rate % Increase | Total Rate % Increase |
| Residential | 5.0% | 5.0% | 5.0% | 5.0% | 5.0% |
| Small General Service | 1.6% | 2.1% | 4.0% | 5.0% | 5.0% |
| General Service | 1.6% | 2.1% | 1.3% | 1.1% | 2.8% |
| Industrial Transmission 33 | 10.0% | 10.0% | 10.0% | 10.0% | 10.0% |
| Industrial Primary | 1.6% | 2.1% | 1.3% | 1.1% | 4.0% |
| Industrial Transmission 31 | 1.6% | 4.7% | 5.0% | 5.0% | 5.0% |
| Lighting | 10.0% | 10.0% | 10.0% | 6.1% | 5.0% |
| Irrigation | 10.0% | 10.0% | 10.0% | 10.0% | 6.2% |
| Kelowna Wholesale | 10.0% | 7.3% | 5.0% | 5.0% | 5.0% |
| Penticton Wholesale | 10.0% | 10.0% | 10.0% | 10.0% | 7.8% |
| Summerland Wholesale | 5.0% | 5.0% | 5.0% | 5.0% | 5.0% |
| Grand Forks Wholesale | 10.0% | 10.0% | 10.0% | 10.0% | 10.0% |
| BCH Lardeau Wholesale | 5.0% | 5.0% | 5.0% | 5.0% | 5.0% |
| BCH Yahk Wholesale | 5.0% | 5.0% | 5.0% | 5.0% | 5.0% |
| Nelson Wholesale | 10.0% | 10.0% | 10.0% | 10.3% | 5.0% |
| Total | 5.0% | 5.0% | 5.0% | 5.0% | 5.0% |

**Q7.11 Please specify on which system peak instance occurrences Celgar's demand triggered the flow through of BC Hydro incremental Demand Charges from FortisBC.**

A7.11 July 28, 2006 at 12:00 noon triggered FortisBC to take 13 MW of excess capacity from BC Hydro. This was not the system peak for July 2006 but an unexpected high demand from Zellstoff Celgar in that particular hour.

**Q7.12 Please provide the agreement or contract under which Celgar received service prior to the GSPC.**

A7.12 The agreement is attached as Zellstoff Celgar IR2 Appendix A7.12.

**Q7.13 Please explain whether FortisBC has an obligation to serve municipal wholesale customers for consumption at any individual point of delivery in excess of the nominated contract demand, and describe the conditions and characteristics of such obligation.**

A7.13 The obligation of the Company is specified in the Wholesale Agreements typified by the clause below from the Summerland contract.

> ***Exceeding Demand Limit***
>
> *Summerland shall not take electricity in excess of the Demand Limit of a Point of Delivery without the prior written consent of FortisBC, unless an emergency condition requires that Summerland take in excess of the Demand Limit, and then only for the duration of the emergency condition. Summerland shall immediately advise FortisBC when such an emergency condition occurs. Summerland shall reduce immediately its use of electricity to the Demand Limit for that Point of Delivery or to a specified limit above the Demand Limit upon the oral or written request of FortisBC.*

Notwithstanding the above, the Paragraph 6.06 of the same contract results in the substitution of a higher Demand Limit (due to the increased supply capability), which would permit the customer to take electricity in excess of the superseded Demand Limit and further obligates the Company to increase the supply capability without cost to the customer in order for the increased Demand Limit to be accommodated.

**6.06 Maintenance of Adequate Supply Capability**

*If at any time, except in an emergency condition described in subsection 6.03, Summerland notifies FortisBC that it has taken electricity in excess of 95 percent of the Demand Limit of a Point(s) of Delivery, FortisBC shall take appropriate measures at no cost to Summerland to increase the supply capability at the Point(s) of Delivery to bring Summerland's anticipated future demand to or below 95 percent of the Demand Limit.*

**Q7.14 Please confirm that the allocators used in the rate design Application for both transmission and distribution costs are from the customer contracts where there are contract demands.**

A7.14 From the EES COSA Report, Appendix A to the Application (Exhibit B-1), page 32,

*For transmission and distribution cost allocation in the COSA, the NCP and 2 CP allocation factors have been adjusted to reflect the higher of the actual demand and the contractual demand for the wholesale and large general service / industrial customers.*

**8.0 Reference: Exhibit B-3-4, ZCLP 20.2, Exhibit B-3-3, BCMEU 8.1**

**Celgar Metered Load**

**Q8.1 Please provide the interval data for Celgar's metered load at the Kraft substation since January 2006, similar to that provided for BCMEU 8.1. Please explain why FortisBC is unable to or does not record MVA demand.**

A8.1 Zellstoff Celgar Appendix A8.1 from IR No. 1 contains the interval data from FortisBC's meter for the period from 2006 to 2009. The metered data does record both kW and kVAR which allows Zellstoff Celgar's MVA demand to be calculated. In addition the meter maintains the maximum MVA for the month in a single register; at present this isn't used since FortisBC does not bill MVA demand under Rate Schedule 33.

The system interchange data for Zellstoff Celgar that FortisBC presented is in MW only since system capacity accounting is done in MW.

**9.0 Reference: Exhibit B-3-4, ZCLP 23.2**

**Utilization of Substation Assets**

**Q9.1 Notwithstanding that it may be complicated, is FortisBC able to provide an estimate of Celgar's utilization of substation assets to the Celgar facility and provide an estimated range of percentage utilization of such assets. If not, why not?**

A9.1 FortisBC is unable to provide an estimated utilization of the substation assets related to the Celgar facility as it is unclear on what basis a valid assessment could be made. Costs could be allocated in many ways, including annual energy, peak demand or average demand.

Notwithstanding this, it should be noted that in normal system operations, one of the two 63-kV transmission lines between the Brilliant Switching Station and the Kraft Substation is fully dedicated for the Celgar facility with no other customer load connected to this line. The second transmission line is used to supply other distribution substations in the area. On this basis, it could be said that fully 100% of one of the 63-kV transmission lines and its associated substation equipment is dedicated to the Celgar facility.

**10.0 Reference: Exhibit B-3-4, ZCLP 19.2, Appendix A19.2, ZCLP 25.1, ZCLP 25.2, Appendix A25.2 Standby Service, ZCLP 25.4**

**Q10.1 In BC Hydro's Schedule 1880 rate, it is stated "BC Hydro may, without notice to the Customer, terminate the supply of Electricity under this Schedule if at any time during the Period of Use BC Hydro does not have sufficient energy or capacity". Please describe if FortisBC's service to Celgar has any such conditions.**

A10.1 Service to Zellstoff Celgar is currently delivered under the same terms as are in place with the rest of FortisBC's customers, including the Suspension of Supply provisions contained in the FortisBC Electric Tariff, Section 8. Language such as that contained in the question does not exist in this Tariff section, nor does it appear in the General Service Agreement in place with Zellstoff Celgar.

**Q10.2 Please explain why any service over 10 MVA to Celgar should not be considered "standby service", and why this is not the appropriate Contract Demand Limit for the purposes of Schedule 8.2 of Appendix A of the Application.**

A10.2 FortisBC does not currently offer a standby service rate that could be applied either as means for billing Zellstoff Celgar or as a basis for allocating costs in the COSA. If a standby service rate was developed with the same firm obligation that currently exists, the overall costs allocated to Zellstoff Celgar would be unlikely to change. It should be noted that the 10 MW (on-peak) and 25 MW (off-peak) capacity reservations relate to Power Supply and not the poles and wires charges which would be billed on the current contract demand limit of 40 MVA.

**Q10.3 In the event that FortisBC develops a rate schedule for standby service, and Celgar elects to take such service, please explain what Contract Demand Limit would be used for the purposes of Schedule 8.2 of Appendix A of the Application.**

A10.3 FortisBC would use the demand limit that resulted from negotiations with the customer. It is not clear that any of the existing capacity reservation numbers or contractual demand limit would be appropriate, although FortisBC assumes that Zellstoff Celgar agreed to appropriate numbers for the purposes of its present contractual arrangement.

**Q10.4 In the response to ZCLP 25.4, FortisBC stated it "may provide standby or back-up service to a customer on an individual basis if requested but has not developed a standard tariff due to the infrequent nature of the requirement." Please confirm that Celgar has requested a standby service rate schedule from FortisBC since 2005, and if so, please explain why FortisBC has not prepared such a rate.**

A10.4 FortisBC is not aware of a request by Zellstoff Celgar to be placed on a standby rate.

**Q10.5 Please provide a copy Terasen's Rate Schedule 22A.**

A10.5 A copy of Terasen’s Rate Schedule 22A has been attached as Zellstoff Celgar IR2 Appendix A10.5.

**Q10.6 Please confirm that Celgar is identified as one of the shippers that Terasen's Rate Schedule 22A is applicable to.**

A10.6 FortisBC confirms that Zellstoff Celgar Ltd. is listed as a shipper on Terasen’s Rate Schedule 22A.

**Q10.7 Please confirm that Terasen's Rate Schedule 22A has a rate for both firm and interruptible gas transportation, and also please confirm that it is possible for a customer on Terasen's Rate Schedule 22A to have gas transportation infrastructure available to it on an interruptible basis that is in excess of its firm/contract demand.**

A10.7 Confirmed.

**Q10.8 Has FortisBC and its sister company Terasen had discussions regarding the implications of the FortisBC position on utilizing maximum demand as a basis for allocating costs?**

A10.8 FortisBC has not had discussions with its sister company about the use of maximum demand as a basis for allocating costs, but has discussed the concept of utilizing contract demand as a basis for allocating costs.

**Q10.9 Please re-calculate the COSA Revenue to Cost Ratios found in Exhibit 1, Table 2.2 on the basis of a value of 10,000 in each month for both the "Contract Demand Limit (kW)" and "Max Demand @ Input (kW)" for the Rate 33 Industrial rate class in Exhibit B-1, Appendix A, Schedule 8.2.**

A10.9 A change to a 10 MVA contract demand, assuming that load in each month also was equal to 10 MVA, would result in a revenue to cost ratio for the Industrial Transmission 33 class of 52.3%. There would still be a 5% rate increase per year associated with rebalancing plus another 5% for the assumed revenue requirement increase.

This request helps illustrate the fact that Rate 33 revenues do not recover the full cost of power supply assigned to the class, even before allocation of wires charges or any other costs. This can be seen in Schedules 1.1 and 1.2 of the COSA (Appendix A to Exhibit B-1) where the adjusted revenues for the class are at $897,931 while the power supply costs are at $905,303. Note that the power supply costs are not based on the contract demand.

The requested tables are provided below:

**Table Zellstoff Celgar IR2 A10.9a**
**Revenue to Cost Ratios Assuming Celgar Contract and Billing Load is 10 MVA**

| | Year 0 | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 |
|---|---|---|---|---|---|---|
| | R/C Ratio | R/C Ratio | R/C Ratio | R/C Ratio | R/C Ratio | R/C Ratio |
| Residential | 97.7% | 97.7% | 97.7% | 97.7% | 97.7% | 97.7% |
| Small General Service | 112.6% | 108.9% | 105.9% | 105.0% | 105.0% | 105.0% |
| General Service | 137.7% | 133.3% | 129.6% | 124.9% | 120.5% | 117.7% |
| Industrial Transmission 33 | 52.3% | 54.8% | 57.4% | 60.1% | 63.0% | 66.0% |
| Industrial Primary | 121.3% | 117.4% | 114.1% | 110.0% | 106.1% | 105.0% |
| Industrial Transmission 31 | 108.7% | 105.2% | 105.0% | 105.0% | 105.0% | 105.0% |
| Lighting | 81.7% | 85.6% | 89.7% | 94.0% | 95.0% | 95.0% |
| Irrigation | 78.0% | 81.7% | 85.6% | 89.6% | 93.9% | 95.0% |
| Kelowna Wholesale | 88.7% | 92.9% | 95.0% | 95.0% | 95.0% | 95.0% |
| Penticton Wholesale | 76.8% | 80.5% | 84.3% | 88.3% | 92.5% | 95.0% |
| Summerland Wholesale | 95.4% | 95.4% | 95.4% | 95.4% | 95.4% | 95.4% |
| Grand Forks Wholesale | 66.9% | 70.1% | 73.4% | 76.9% | 80.6% | 84.4% |
| BCH Lardeau Wholesale | 100.6% | 100.6% | 100.6% | 100.6% | 100.6% | 100.6% |
| BCH Yahk Wholesale | 102.7% | 102.7% | 102.7% | 102.7% | 102.7% | 102.7% |
| Nelson Wholesale | 78.6% | 82.4% | 86.3% | 90.4% | 95.0% | 95.0% |
| Total | 100.0% | 100.0% | 100.1% | 100.0% | 100.0% | 100.0% |

**Table Zellstoff Celgar IR2 A10.9a**
**Total Rate Increase Assuming Celgar Contract and Billing Load is 10 MVA**

| | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 |
|---|---|---|---|---|---|
| | Total Rate % Increase | Total Rate % Increase | Total Rate % Increase | Total Rate % Increase | Total Rate % Increase |
| Residential | 5.0% | 5.0% | 5.0% | 5.0% | 5.0% |
| Small General Service | 1.6% | 2.1% | 4.1% | 5.0% | 5.0% |
| General Service | 1.6% | 2.1% | 1.2% | 1.3% | 2.6% |
| Industrial Transmission 33 | 10.0% | 10.0% | 10.0% | 10.0% | 10.0% |
| Industrial Primary | 1.6% | 2.1% | 1.2% | 1.3% | 3.9% |
| Industrial Transmission 31 | 1.6% | 4.8% | 5.0% | 5.0% | 5.0% |
| Lighting | 10.0% | 10.0% | 10.0% | 6.1% | 5.0% |
| Irrigation | 10.0% | 10.0% | 10.0% | 10.0% | 6.2% |
| Kelowna Wholesale | 10.0% | 7.4% | 5.0% | 5.0% | 5.0% |
| Penticton Wholesale | 10.0% | 10.0% | 10.0% | 10.0% | 7.8% |
| Summerland Wholesale | 5.0% | 5.0% | 5.0% | 5.0% | 5.0% |
| Grand Forks Wholesale | 10.0% | 10.0% | 10.0% | 10.0% | 10.0% |
| BCH Lardeau Wholesale | 5.0% | 5.0% | 5.0% | 5.0% | 5.0% |
| BCH Yahk Wholesale | 5.0% | 5.0% | 5.0% | 5.0% | 5.0% |
| Nelson Wholesale | 10.0% | 10.0% | 10.0% | 10.4% | 5.0% |
| Total | 5.0% | 5.0% | 5.0% | 5.0% | 5.0% |

**Q10.10 Has FortisBC ever requested that BC Hydro include Rate Schedule 3808 to be one of the "eligible customers" that is able to receive service from BC Hydro's standby service Rate Schedule 1880? If not, why not?**

A10.10 No, FortisBC has never requested that BC Hydro Rate Schedule 3808 be considered an eligible customer for Rate Schedule 1880. RS 3808 makes provision for supply beyond 200 MW and sets out the terms and conditions of such supply.

**11.0 Reference: Exhibit B-3-2, BCOAPO 31.2**

**Contract Demand in asset planning**

**Q11.1 FortisBC states in the response to BCOAPO 31.2 that facilities that are planned on the basis of total system loads, like generation and transmission, are allocated on the basis of CP including contract demand where appropriate. Please provide the CP and the contract demand used for Celgar for planning purposes.**

A11.1 For system planning purposes, the Zellstoff Celgar site is modeled as a combination of on-site generation and load. This is necessary to make assessments of the system performance in this area during contingency studies. For these studies the Zellstoff Celgar generation is adjusted such that the entire facility appears to be a "net load" of 16 MW. For area specific studies, the Zellstoff Celgar site is modeled over the full range of expected import/export values ranging from maximum generation / minimum load to zero generation / maximum load (i.e. demand limit).

**12.0 Reference: Exhibit 8-3-2, BCOAPO 35.2**

**Load shifting to Off-peak periods**

**Q12.1 Please confirm that the ability of the Rate Schedule 33 customer to shift loads to off-peak periods by virtue of self-generation benefits all customers by reducing FortisBC's requirement to procure expensive on-peak capacity during times of system peak as well as at other times.**

A12.1 Not confirmed. Zellstoff Celgar firm capacity reservation between 8:00 am and 10:00 pm is 10 MVA. The Company's power supply cost is driven by the firm capacity reservation not by the actual take. Therefore, up to the 10 MVA contractual obligation, there is no benefit related to power purchase costs to the Company or its customers if Zellstoff Celgar shifts load from on-peak to off-peak hours.

**13.0 Reference: Exhibit B-3-3, BCMEU 26.1a, BCMEU 26.1d**

**Large General Service Transmission customer consultation**

**Q13.1 Please confirm that Celgar was not consulted regarding, and did not express support for, either the contract demand methodology or the treatment of Rate Schedule 33 as a separate rate class.**

A13.1 Zellstoff Celgar was part of the consultation process that explained the contract demand methodology and its use in the COSA, as part of the May 26, 2009 meeting at the Castlegar plant. (See Zellstoff Celgar IR No. 1 Q5.1). Zellstoff Celgar did not receive advance notification that Rate 33 was to be separated from the Large General Service Class as a whole. FortisBC is not aware of Zellstoff Celgar indicating support for either item.

**Q13.2 Please confirm that FortisBC is not using contract demand as the driver for allocating transmission rate base costs to Large General Service Transmission customers, but rather is using demand limit as the driver.**

A13.2 As explained to Zellstoff Celgar at the May 26, 2009 meeting, FortisBC is using the demand limits in the contract for Rate 31 and Rate 33 customers as those limits represent the maximum loads that FortisBC is obligated to provide service for.

**Q13.3 Please restate the response to BCMEU 26.1d including Celgar as a Large General Service Transmission customer.**

A13.3 For the purposes of allocating costs within the COSA, the total aggregate contractual demand for the Large General Service Transmission Class, with Celgar served under Rate 31, as of 2009 would be 51,100 kVA.

**14.0 Reference: Exhibit 8-3-3, BCMEU 32.2**

**Industrial transmission customer system coincident factor**

**Q14.1 Please show the supporting calculations and individual industrial transmission customer contributions towards the stated system coincident factor range of 62% to 72% from the June 30 Draft Report of the COSA, as well as for the 68% to 93% range from the September 30 Report.**

A14.1 The system coincident factors for the industrial class in the June 30 version of the COSA are the same as those used in the September 30 version, as shown in Schedule 8.2 of the June 30 version of the COSA Report. The 62 percent to 72 percent range stated on page C-2 of the June 30 Draft COSA Report was an error and was corrected in the September 30 version of the Report (Exhibit B-1, Appendix A). Please see electronic attachment Zellstoff Celgar Attachment A14.1.

**15.0 Reference: Exhibit B-3-3, BCMEU 49.1**

**Re-nominated contract demands**

**"If any municipal utility considers that it requires a lower contract limit, then the amount should be lowered by an amendment to the contract. However, FortisBC must ensure that its broader customer base remains unharmed through the recovery of any costs related to existing infrastructure."**

**Q15.1 Please describe how FortisBC will ensure the broader customer base remains unharmed through the recovery of any costs related to existing infrastructure. Does this entail the recovery of the remaining book value of the assets used for the original (higher) contract limit, or some other principle?**

A15.1 FortisBC would ensure the recovery of any remaining book value associated with stranded, dedicated assets from a customer that lowered their contract limit.

**Q15.2 Please confirm the opportunity to nominate a lower contract limit is also available to Industrial Transmission customers such as Celgar.**

A15.2 Confirmed. Transmission customers such as Zellstoff Celgar would have the opportunity to renominate on the same basis that has been offered to the wholesale utilities, as described on page 30 of the Application (Exhibit B-1), lines 11 through 15:

> *These terms included the existing demand limits at the points of delivery, as well as new nominations for transmission capacity, to be provided by the individual municipal Wholesale customers to be used for both cost allocation within the COSA and as billing determinants. Also included was an automatic adjustment mechanism to correct for under-nominations.*

**Q15.3 Please provide the total remaining book value of the assets that serve Celgar's existing contract limit, and identify the assets themselves.**

A15.3 Please refer to the information (book value and system facilities) as previously provided in the response to Zellstoff Celgar IR No. 1 Q23.3.

## 16.0 Reference: Exhibit B-3-3, BCMEU 50.2

**Customer Consultation**

**Q16.1 Please explain why Celgar was not provided similar information and disclosure as that provided to wholesale customers regarding the effect of using demand limit as opposed to contract demand, as well as to highlight the significance of isolating Celgar into a stand-alone rate class, and the consequential rebalancing.**

A16.1 Zellstoff Celgar was consulted on the use of the contractual demand limits, but was not consulted on the fact that Zellstoff Celgar would be shown separately in the COSA for the reasons outlined in the response to Zellstoff Celgar IR No. 1 Q5.2.

**17.0 Reference: Exhibit B-3-7, Roxul 1(c)**

**FortisBC Service Obligation**

**"The revenue to cost ratio for Rate 33 is significantly below 100 percent because the current rate has no demand charge and the wires costs are only charged in the on-peak periods. This allows customers on this rate to avoid the majority of wires costs by generating power during the on-peak periods, while at the same time FortisBC must be ready and able to meet the full load of the customer in all hours, with facilities in place to serve that load if called upon."**

**Q17.1 Please explain how the current Rate Schedule 33 contains a wires cost only in the on-peak periods, and show the calculation that quantifies this cost.**

A17.1 The original calculation of the Large General Service – Transmission TOU Rate is contained in the IR No. 1, BCMEU Appendix A34.1 (Exhibit B-3-3) on page 95. Page 25 of the same document describes how transmission costs were allocated to peak periods.

**Q17.2 Please confirm based on the historical hourly data that the numbers calculated in the below table are correct.**

| | 2005 | 2004 |
|---|---|---|
| Power Purchases from Fortis (MWhr) | 54,432 | 59,220 |
| Total Purchase Cost (including PST) | $2,871,350 | $2,939,887 |
| Cost Per MWhr | $52.75 | $49.64 |
| | | |
| Time of Use Rate Scenario | | |
| Monthly Fee | $20,426 | $20,426 |
| Energy Cost (demand embedded) | $2,494,326 | $2,972,563 |
| Total Cost including PST | $2,690,785 | $2,972,563 |
| Cost Per MWhr | 49.43 | 50.20 |
| | | |
| Annual Savings to Celgar/ (Cost) | $180,565 | $(32,676) |

A17.2 Based on historical hourly data and billing data, the numbers calculated in the table above are incorrect. Please refer to the Table Zellstoff Celgar IR2 A17.3 provided below.

**Q17.3 Please confirm that in 2005, if Celgar was on Rate Schedule 33 instead of Rate Schedule 31, Celgar would have saved $180,000 and in 2004 being on Rate Schedule 33 would have cost Celgar $32,000 more than being on Rate Schedule 31.**

A17.3 Not confirmed. In the table below, FortisBC analysis shows that in 2005, if Celgar had been on Rate Schedule 33 instead of Rate Schedule 31, Celgar would have saved approximately $527,000 and in 2004 would have saved approximately $373,000.

**Table Zellstoff Celgar IR2 A17.3**

| | 2005 | 2004 |
|---|---|---|
| Power Purchase from Fortis (MWhr) | 54,432 | 59,220 |
| Total Purchase Cost (Including PST & GST) | $3,061,243.59 | $3,133,145.56 |
| Cost Per MWhr | $56.24 | $52.91 |
| | | |
| Time of Use Rate Scenario | | |
| Monthly Fee | $20,425.68 | $19,482.56 |
| EnergyCost (demand embedded) | $2,202,292.16 | $2,394,316.20 |
| Total Cost including PST & GST | $2,533,898.33 | $2,759,842.46 |
| Cost Per MWhr | $46.55 | $46.60 |
| | | |
| Annual Savings to Celgar/ (Cost) | $527,345.26 | $373,303.10 |

*The power purchase figures under Schedule 31 is as per the FortisBC billing records. These amounts include GST and the PST. The figures used in the time of use scenario are based on the actual Celgar interval data and the Schedule 33 applicable rates from the 2004 and 2005 rate schedule, and the applicable GST and PST at that time.*

**Issue: Rate Effects, allocation of costs, and COSA methodology**

**18.0 Reference: Exhibit B-3-1, BCUC 71.2, BCUC 71.3, BCUC 81.1**

**1997 COSA Methodology**

**Q18.1 Please repeat BCUC 71.2 and 71.3, except applying the requested methodology to the Rate Schedule 31 and Rate Schedule 33 customer classes, both separately, as in the Application, and as a single customer class, as in the draft COSA presented in the summer of 2009.**

A18.1 Table A71.2 provided in response to BCUC IR No. 1 Q71.2 would remain unchanged for both cases.

For BCUC IR No. 1 Q71.3, the table would remain unchanged with Rate 31 and Rate 33 separate. In the case where Rate 31 and Rate 33 are combined as a single customer class, the revenue to cost ratios would remain the same for all of the other rate classes. For a combined Rate 31/Rate 33 class, the following revenue to cost ratios would apply:

| | **Contract Demands for Wholesale/Industrial (As Filed)** | **Actual Demands for Wholesale/Industrial (1997 Method)** |
|---|---|---|
| Combined Rate 31/ Rate 33 Class | 61.6% | 85.8% |

Note that the revenue to cost ratio for the combined Rate 31/Rate 33 class would still be below the 95% to 105% target range, leading to a 5% per year rebalancing for both Rate 31 and Rate 33 in this case. Zellstoff Celgar would be be no better off having Rate 31 and Rate 33 combined, while the Rate 31 customers would be facing 5% per year rate increases they would otherwise not have received. This is precisely why FortisBC chose to separate Rate 31 and Rate 33 in the COSA. If Zellstoff Celgar were served under Rate 31 then it would be appropriate to include them with the three other customers in that rate class.

**Q18.2 Please confirm the number of customers in the Large General Service Transmission rate class in the 1997 COSA, and confirm the Celgar facility was a member of this class.**

A18.2 FortisBC confirms that there were three customers in the Large General Service Transmission Class, including Zellstoff Celgar, for the 1997 COSA.

**Q18.3 Please provide the R/C ratio from the 1997 COSA for the Large General Service Transmission rate class with and without the Celgar facility load, using the 1997 COSA methodology, and for the situation without the Celgar facility load, show the R/C ratio for the Celgar facility in isolation. If this level of detail was not prepared in the 1997 COSA, please utilize the historical invoices from the reference year.**

A18.3 The 1997 COSA did not contain separate load information from the Zellstoff Celgar facility. Loads used in the 1997 COSA represented 1997 forecast loads and use of 1997 actuals for Zellstoff Celgar would not be consistent with what was used for other classes. The 1997 COSA was not designed to allow a calculation of Zellstoff Celgar in isolation from the rest of the Industrial class. It is expected that the results for Zellstoff Celgar would be consistent with the rest of the class as they were all charged under the same rate at the time. One of the primary reasons that the current COSA shows Zellstoff Celgar at such a low revenue to cost ratio is the fact that the customer pays rates under Rate 33 that are far below what it would pay if it were charged the same rates as the other industrial customers under Rate 31.

**19.0 Reference: Exhibit B-3-1, BCUC 83.1**

**IPP Rate**

**Q19.1 Please explain why, in Schedule 5.2 of Appendix A of the Application, the Brilliant Regulated rate and the BCH Purchase rate increase from 28.49 in March to 31.13 in April, but the IPP Rate stays constant at 28.49 throughout the year.**

A19.1 Please refer to IR No. 1, Zellstoff Celgar Appendix A19.2, page 19, paragraph 10 which states:

> *For hours in which Customer does not have an export schedule and delivers unscheduled energy to FortisBC, the rate paid to the Customer shall be the lower of the BC Hydro 3808 energy rate, effective at January 1 of the current year, or the Mid-C Dow Jones day-ahead Index price, using the heavy load index for the heavy load hours and the light load index for the light load hours, less 2 mills. Delivery of such energy shall be in accordance with the Terms and Conditions of the B.C. Hydro Tariff, particularly Section 10.*

**20.0 Reference: Exhibit B-3-4, ZCLP 3.1, ZCLP 3.2**

**System Coincidence Factor**

**Q20.1 As Rate Schedule 33 was designed to incent moving consumption away from On-peak periods, please explain why it is appropriate to use the same System Coincidence Factor for Rate Schedule 33 customers as for Rate Schedule 31 customers, considering that Rate Schedule 31 has no incentives to shift electricity consumption from On-Peak periods.**

A20.1 Please refer to the response to BCUC IR No. 2 Q47.1.

**Q20.2 As Celgar is the only customer on Rate Schedule 33, please explain why FortisBC does not believe it is appropriate to provide the data for Celgar at its request.**

A20.2 Please see the Zellstoff Celgar IR2 electronic attachment A14.1.

**Q20.3 Please provide the analysis for a System Coincidence Factor evaluation for only the Rate Schedule 33 rate class, in the form of a functioning electronic spreadsheet as well as a summary printed response.**

A20.3 Please see Table Zellstoff Celgar IR2 Talbe A20.3 below as well as the electronic attachment Zellstoff Celgar IR2 A14.1.

**Table Zellstoff Celgar IR2 A20.3**
**3-Year Average Coincedence Factors**

| **Rate 33** | |
|---|---|
| Jan | 46.37% |
| Feb | 21.16% |
| Mar | 0.15% |
| Apr | 16.02% |
| May | 3.38% |
| Jun | 0.00% |
| Jul | 0.00% |
| Aug | 32.67% |
| Sep | 0.27% |
| Oct | 42.13% |
| Nov | 32.30% |
| Dec | 17.27% |
| **Avg** | **17.64%** |

**Q20.4 Please provide a record of the Celgar facility net power consumption or generation for the FortisBC winter and summer peak load hour for each year since 2000, including the time anddate each peak occurred, and the corresponding 1 CP and 2 CP value.**

A20.4 The data requested is provided below in Table Zellstoff Celgar IR2 A20.4. The 1CP value data is provided in Table Zellstoff Celgar IR2 A20.4a and the 2CP value data is provided in Table Zellstoff Celgar IR2 A20.4b.

**Table Zellstoff Celgar IR2 A20.4**

| Year | Month | Day | Hour | FortisBC Peak Load | Celgar Consumption | Celgar Generation | Celgar Sales | Celgar Net Generation to FortisBC |
|---|---|---|---|---|---|---|---|---|
| | | | | (MW) | | | | |
| **2000**<br>winter | Jan | 19 | 18 | 551 | 0 | 1 | 0 | 1 |
| winter | Dec | 15 | 18 | 614 | 15 | 0 | 0 | 0 |
| summer | July | 18 | 18 | 451 | 0 | 3 | 0 | 3 |
| summer | Aug | 8 | 18 | 464 | 7 | 0 | 0 | 0 |
| **2001**<br>winter | Jan | 16 | 18 | 530 | 12 | 0 | 0 | 0 |
| winter | Dec | 12 | 18 | 560 | 12 | 0 | 0 | 0 |
| summer | July | 10 | 16 | 497 | 11 | 0 | 0 | 0 |
| summer | Aug | 16 | 18 | 466 | 4 | 0 | 0 | 0 |
| **2002**<br>winter | Jan | 28 | 18 | 572 | 4 | 0 | 0 | 0 |
| winter | Mar | 6 | 9 | 568 | 11 | 0 | 0 | 0 |
| summer | June | 26 | 18 | 491 | 15 | 0 | 0 | 0 |
| summer | July | 24 | 17 | 515 | 22 | 0 | 0 | 0 |
| **2003**<br>winter | Nov | 6 | 18 | 553 | 16 | 0 | 0 | 0 |
| winter | Dec | 30 | 18 | 609 | 6 | 0 | 0 | 0 |
| summer | July | 30 | 17 | 526 | 13 | 0 | 0 | 0 |
| summer | Aug | 1 | 14 | 512 | 14 | 0 | 0 | 0 |
| **2004**<br>winter | Jan | 5 | 18 | 718 | 13 | 0 | 0 | 0 |
| winter | Dec | 13 | 18 | 606 | 16 | 0 | 0 | 0 |
| summer | June | 29 | 18 | 501 | 28 | 0 | 0 | 0 |
| summer | Aug | 16 | 17 | 511 | 0 | 7 | 0 | 7 |
| **2005**<br>winter | Jan | 14 | 18 | 708 | 13 | 0 | 0 | 0 |
| winter | Dec | 7 | 18 | 675 | 15 | 0 | 0 | 0 |
| summer | July | 28 | 18 | 512 | 0 | 9 | 0 | 9 |
| summer | Aug | 8 | 18 | 512 | 0 | 2 | 0 | 2 |
| **2006**<br>winter | Nov | 29 | 18 | 718 | 0 | 7 | 6 | 1 |
| winter | Dec | 18 | 18 | 647 | 5 | 0 | 0 | 0 |
| summer | June | 27 | 18 | 521 | 0 | 4 | 0 | 4 |
| summer | July | 26 | 18 | 554 | 0 | 6 | 5 | 1 |

### Table Zellstoff Celgar IR2 A20.4 – cont'd

| **Year** | Month | Day | Hour | FortisBC Peak Load | Celgar Consumption | Celgar Generation | Celgar Sales | Celgar Net Generation to FortisBC |
|---|---|---|---|---|---|---|---|---|
| | | | | **(MW)** | | | | |
| **2007** winter | Jan | 11 | 18 | 683 | 10 | 0 | 0 | 0 |
| winter | Dec | 11 | 18 | 623 | 0 | 9 | 6 | 3 |
| summer | July | 12 | 17 | 569 | 0 | 4 | 0 | 4 |
| summer | Aug | 2 | 18 | 523 | 0 | 6 | 6 | 0 |
| **2008** winter | Jan | 18 | 18 | 663 | 33 | 0 | 0 | 0 |
| winter | Dec | 20 | 18 | 746 | 2 | 0 | 0 | 0 |
| summer | July | 21 | 17 | 528 | 0 | 5 | 0 | 5 |
| summer | Aug | 7 | 17 | 537 | 0 | 5 | 5 | 0 |
| **2009** winter | Jan | 26 | 9 | 714 | 40 | 0 | 0 | 0 |
| winter | Dec | 14 | 18 | 704 | 0 | 4 | 0 | 4 |
| summer | July | 22 | 18 | 561 | 0 | 9 | 0 | 9 |
| summer | Aug | 1 | 18 | 527 | 0 | 8 | 0 | 8 |

### Table Zellstoff Celgar IR2 A20.4a – 1CP

| **Year** | **Month** | **Day** | **Hour** | **FortisBC Peak Load** | **Celgar Consumption** |
|---|---|---|---|---|---|
| | | | | **(MW)** | |
| 2000 | Dec | 15 | 18 | 614 | 15 |
| 2001 | Dec | 12 | 18 | 560 | 12 |
| 2002 | Jan | 28 | 18 | 572 | 4 |
| 2003 | Dec | 30 | 18 | 609 | 6 |
| 2004 | Jan | 5 | 18 | 718 | 13 |
| 2005 | Jan | 14 | 18 | 708 | 13 |
| 2006 | Nov | 29 | 18 | 718 | 0 |
| 2007 | Jan | 11 | 18 | 683 | 10 |
| 2008 | Dec | 20 | 18 | 746 | 2 |
| 2009 | Jan | 26 | 9 | 714 | 40 |

**Table Zellstoff Celgar IR2 A20.4b – 2CP**

| | FortisBC | Celgar |
|---|---|---|
| | MW | |
| **2000** | 520 | 5.5 |
| **2001** | 513.25 | 9.75 |
| **2002** | 536.5 | 13 |
| **2003** | 550 | 12.25 |
| **2004** | 584 | 14.25 |
| **2005** | 601.75 | 7 |
| **2006** | 610 | 1.25 |
| **2007** | 599.5 | 2.5 |
| **2008** | 618.5 | 8.75 |
| **2009** | 626.5 | 10 |

**Q20.5 Please describe fully how and why self-generation caused inaccurate data on the use of wire facilities for the Rate Schedule 33 customer.**

A20.5 FortisBC did not intend to indicate in its response to Zellstoff Celgar IR No.1 Q3.1 that self-generation caused inaccurate data on the use of wires facilities. The response indicated that self-generation caused inaccuracies in determining the System Coincidence Factor.

**21.0 Reference: Exhibit B-3-1, BCUC 38.1; Exhibit 8-3-4, ZCLP 4.1**

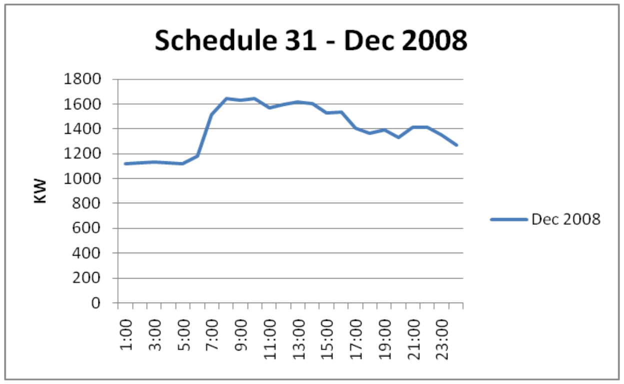
**Primary Line Losses**

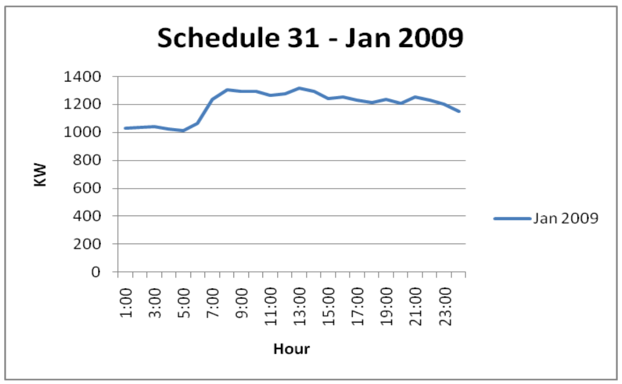
**Q21.1 For each month shown in Table BCUC A38.1 please provide a graph of the average daily consumption load pattern by hour, and the corresponding average daily system load by hour, and average Rate Schedule 31 rate class load by hour; that is; provide a comparison of the average daily "load shape" for each month for Rate Schedule 33 rate class, Rate Schedule 31 rate class, and the overall system. Also present the data in a normalized fashion that allows the shapes to be readily compared on similar scales.**

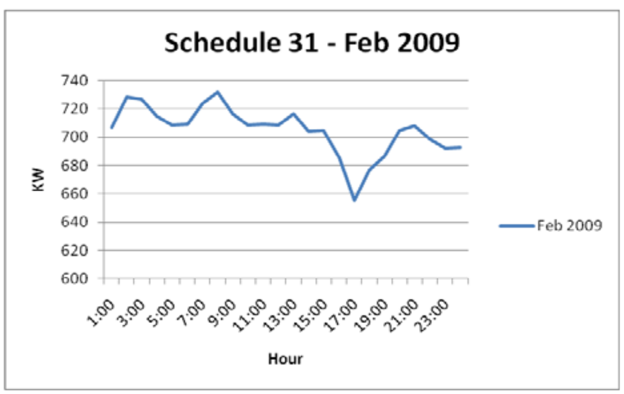
A21.1 The average daily consumption load pattern for Rate Schedule 31 is for the two customers in this class that are on interval metering.

The requested graphs are provided as Zellstoff Celgar IR2 Attachment A21.1.

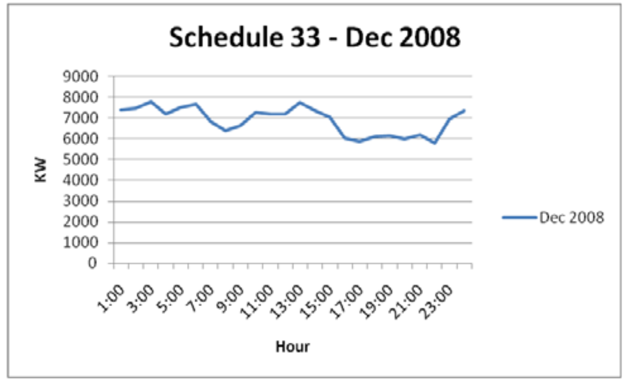
**Schedule 31 - KW**

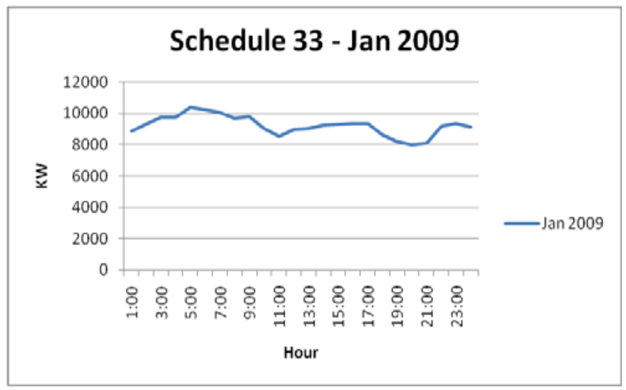


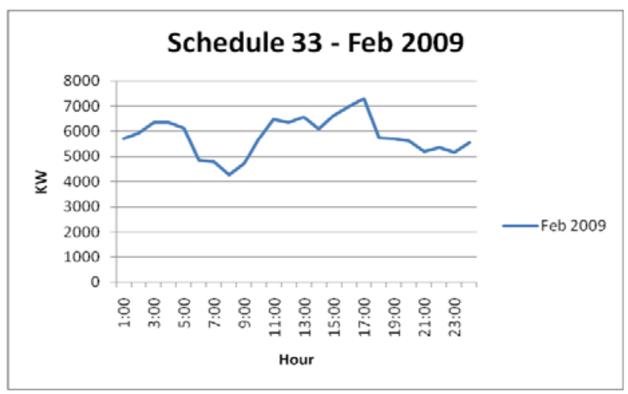



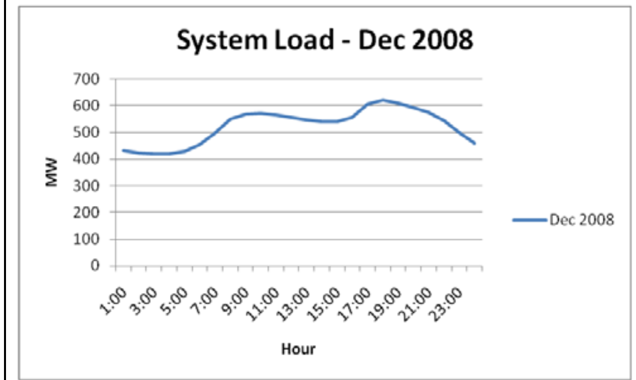

**Schedule 33 - KW**

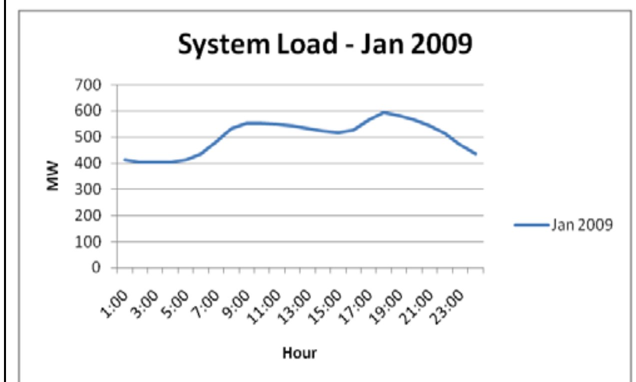


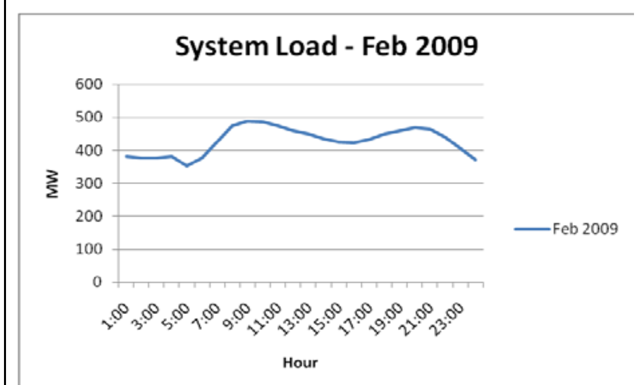




**System Load - MW**



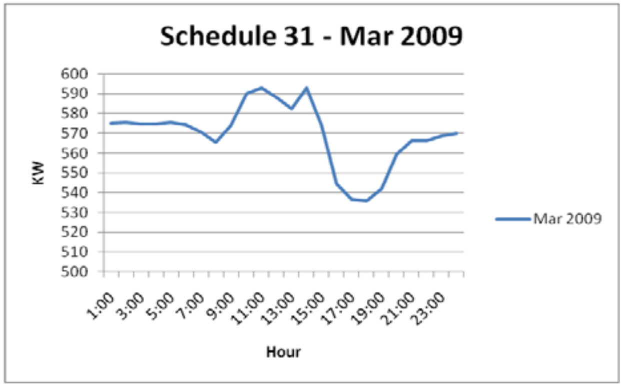



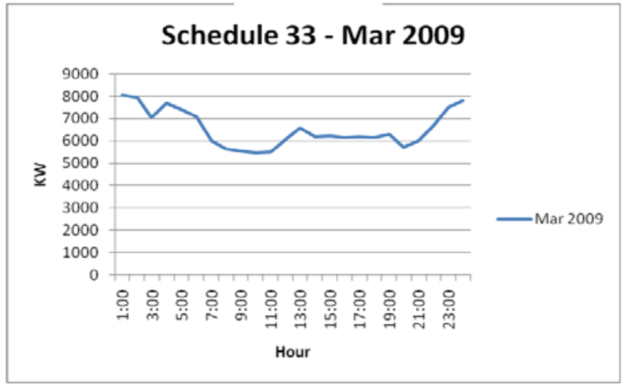



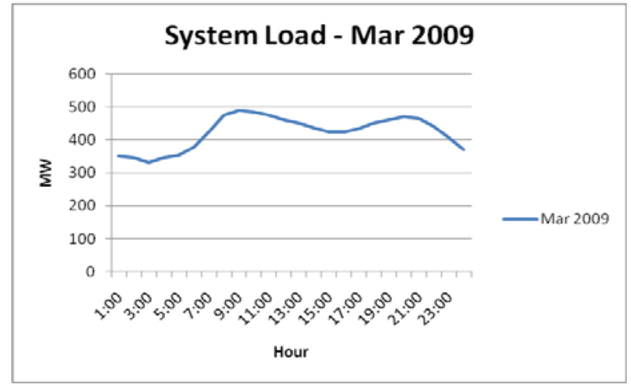
Schedule 31 - KW

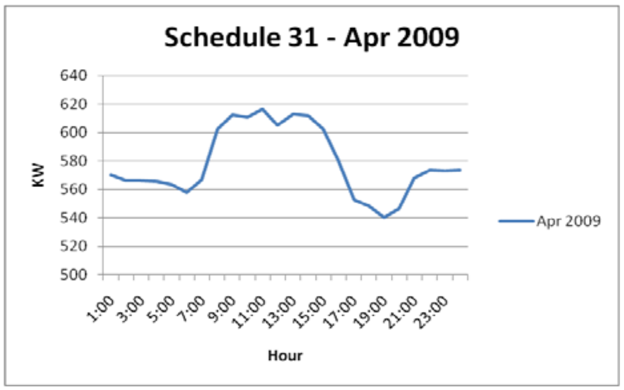
Schedule 33 - KW

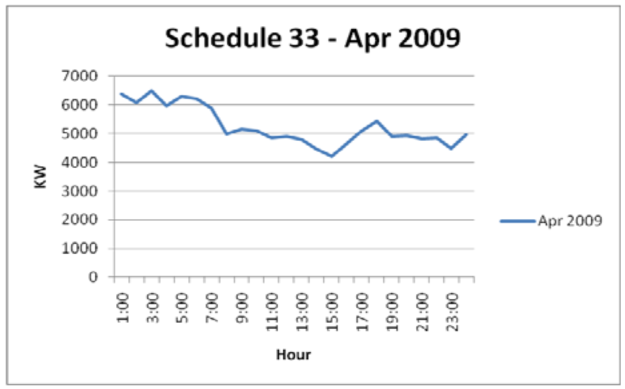
System Load - MW

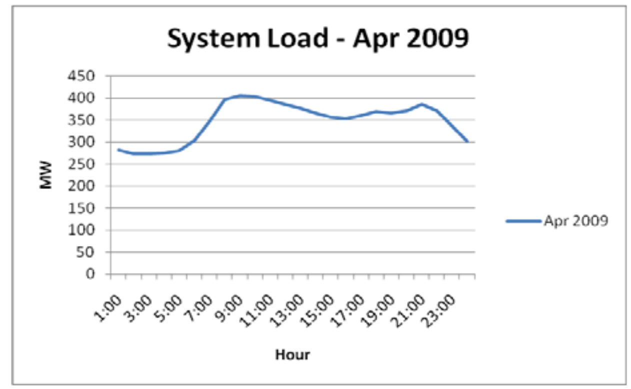


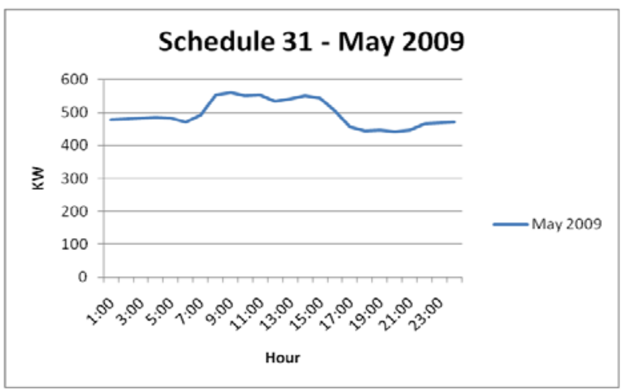



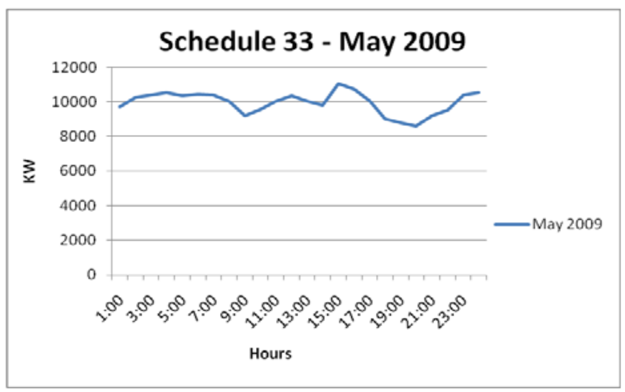



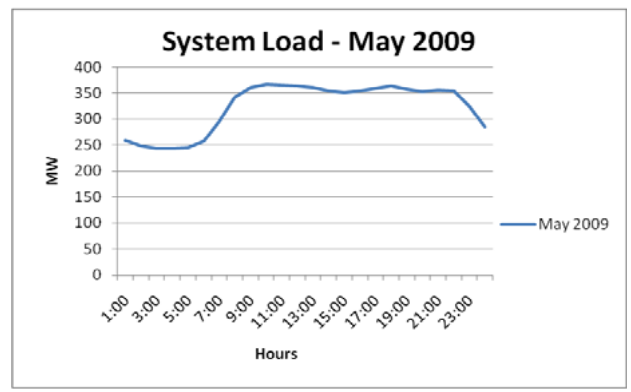



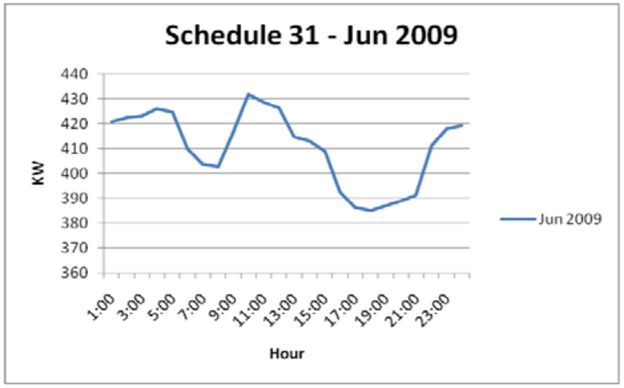



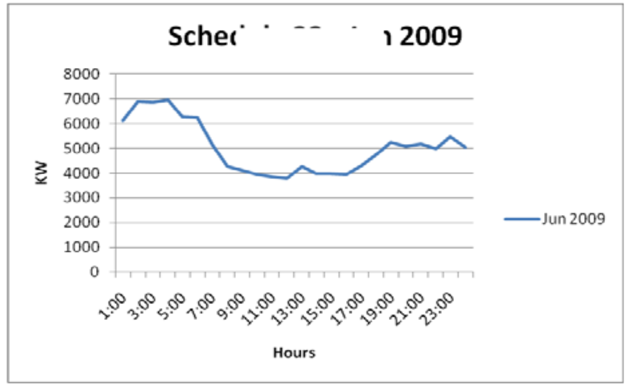



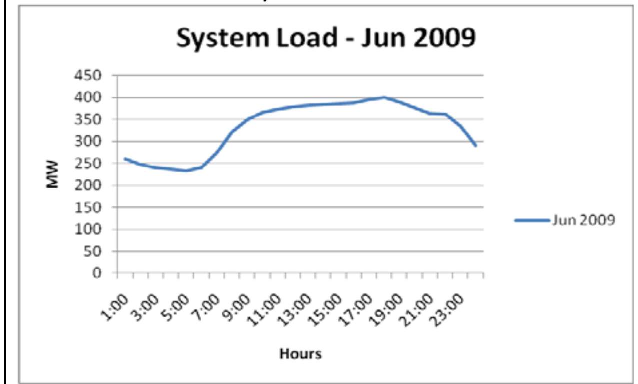
Schedule 31 - KW

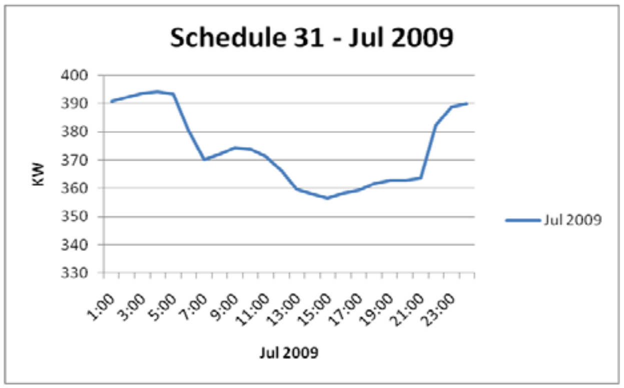
Schedule 33 - KW

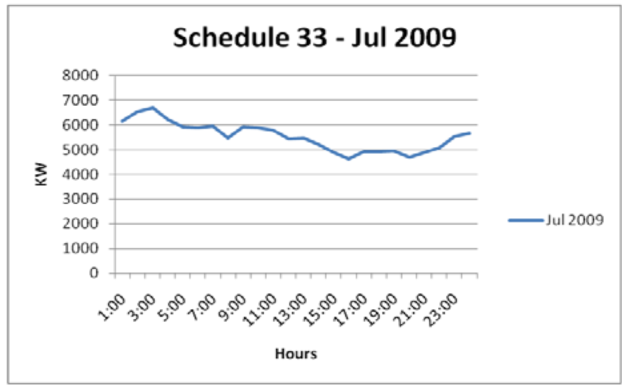
System Load - MW

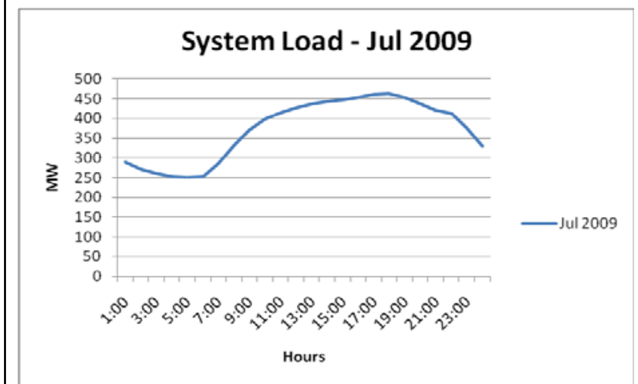


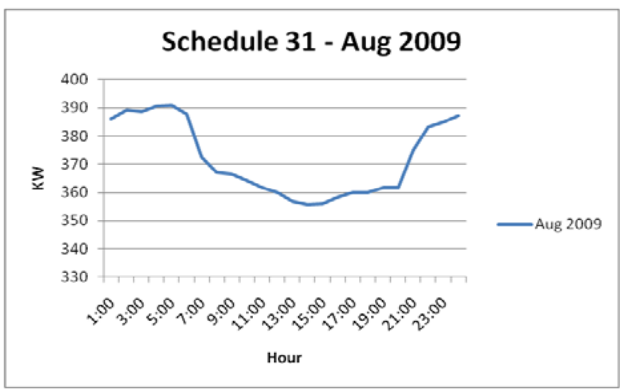



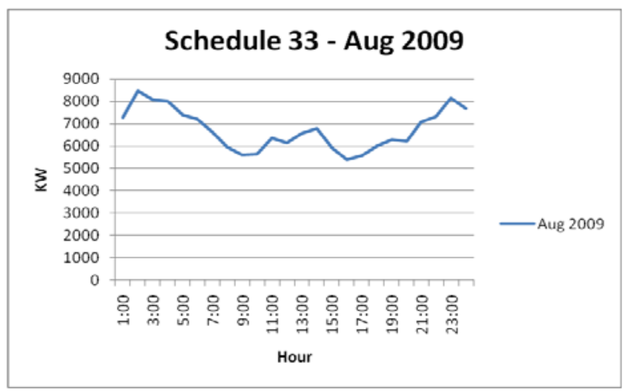



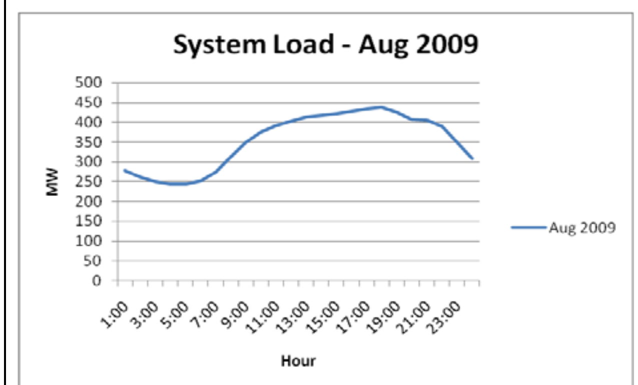



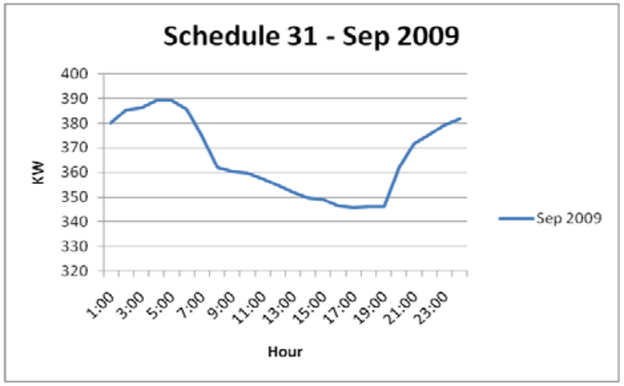



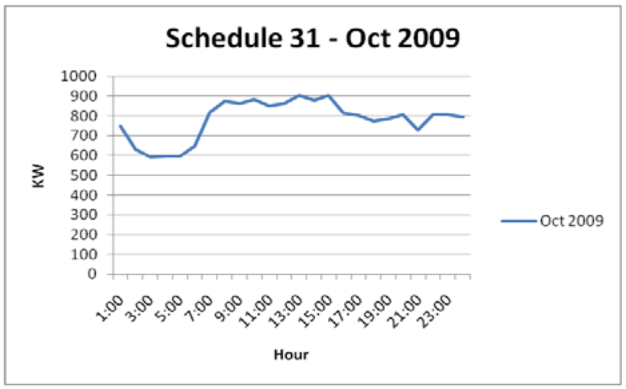



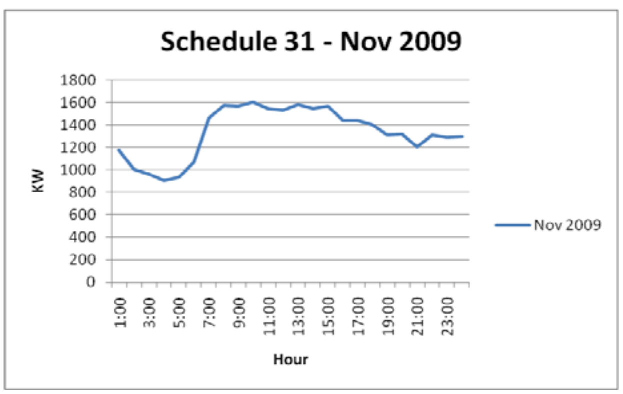



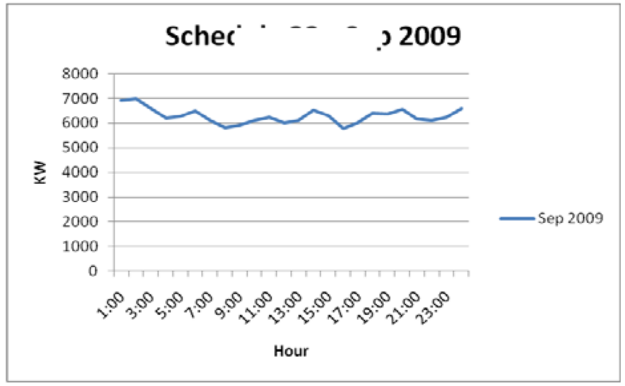
**Schedule 31 - KW**

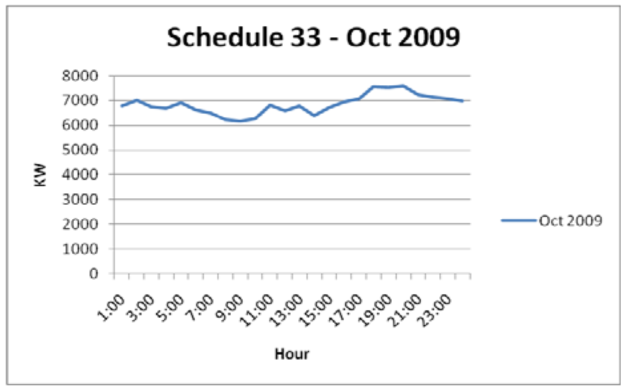


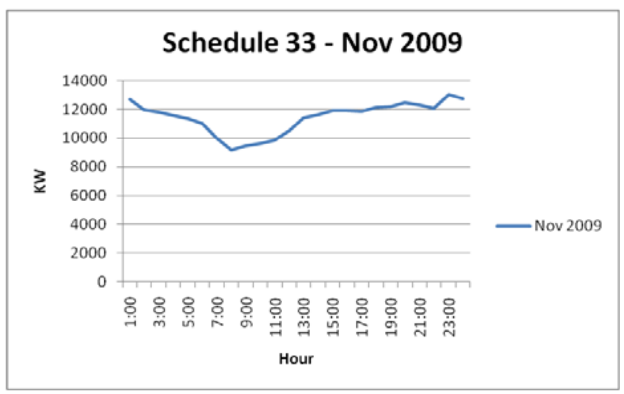



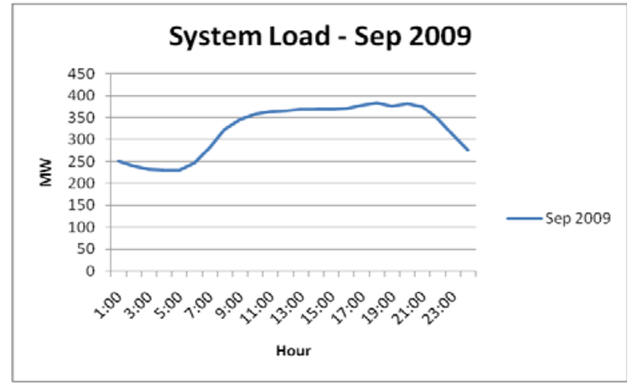

**Schedule 33 - KW**

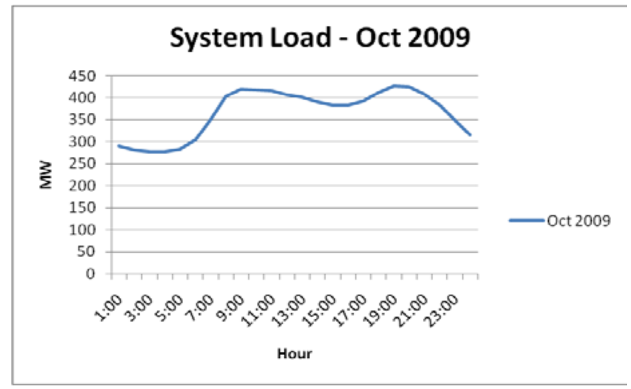


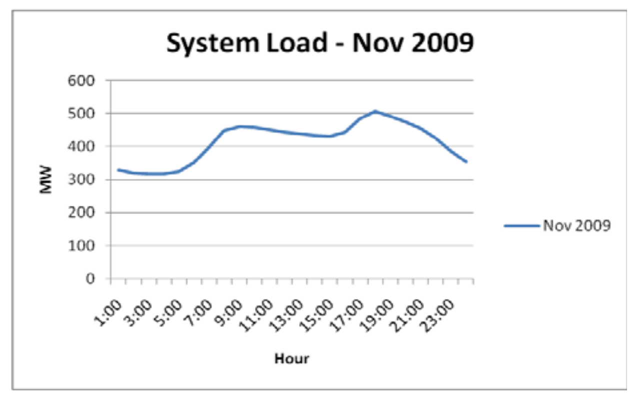




**System Load - MW**



**Q21.2 Please confirm that a load that that has lower consumption during On-peak periods as compared to Off-peak periods will contribute significantly less to system losses than a load that exhibits average load levels in both periods, or a load that has higher consumption during On-peak periods as compared to Off-peak periods.**

A21.2 In general terms, a given load will result in lower losses during Off-peak times as compared to the same load during On-peak periods.

**Q21.3 Please confirm that FortisBC's system modelling software can calculate transmission losses for any given level of system load.**

A21.3 Confirmed.

**22.0 Reference: Exhibit B-3-4, ZCLP 11.4; Exhibit 8-3-5, Interfor 2(b)**

**Celgar Facility Electricity Consumption**

**Q22.1 Please review the data in Table Zellstoff Celgar A11.4 as it does not reconcile with the billing invoices received by Celgar. Please provide a comparison table showing both the data from Table Zellstoff Celgar A 11.4, along with the electricity consumption for the same periods as reflected by the billing invoices sent to the Celgar facility. Please explain any discrepancies between the data from the billing invoices and the data from the system control interchange estimates.**

A22.1 The requested information is provided below in Table Zellstoff Celgar IR2 A22.1. Data between 2006 and 2001 matches closely with small variances due to how SCC estimates are recorded. The data for 2007 and 2008 in IR No. 1, Table Zellstoff Celgar A11.4 was energy billed including manual adjustments. These manual adjustments that convert to net load and adjust for timing differences should not have been applied in this situation.

No annual customer service data is available for 1997 to 2000. However the correct annual number for 1997 based on SCC interchange estimates should be 57,710 rather than 5,072 which was for December only. Please see Errata 4. Please also see the response to Zellstoff Celgar IR No. 2 Q22.2 below.

**Table Zellstoff Celgar IR2 A22.1**

| Year | IR No. 1, Table Zellstoff Celgar A11.4 MWh | Customer Service Billing Data MWh |
|---|---|---|
| 2008 | 13,772 | 24,662 |
| 2007 | 25,108 | 22,609 |
| 2006 | 62,694 | 62,712 |
| 2005 | 54,427 | 54,432 |
| 2004 | 59,234 | 59,220 |
| 2003 | 71,393 | 71,400 |
| 2002 | 93,833 | 93,702 |
| 2001 | 88,704 | 88,704 |
| 2000 | 30,636 | N/A |
| 1999 | 19,824 | N/A |
| 1998 | 28,217 | N/A |
| 1997 | ~~5,072~~ 57,710 | N/A |

**Q22.2 Please explain why FortisBC only has access to nine years of billing data, and explain what has happened to the billing records for the period prior to 2000.**

A22.2 FortisBC has access to limited information that is older than nine years as the Company is required to retain this data for six years. In 2000, a new billing system was installed at FortisBC which is the one still in use today. Only certain data from the old billing system was archived. However, individual account records can be restored and accessed in some occasions it is required for billing adjustment or investigation purposes.

**Q22.3 If the billing data is able to be recovered, please provide the Celgar facility billed electricity consumption from 1992 onwards.**

A22.3 FortisBC was able to restore Celgar billing data for the period of July 1998 to November 2000. However, quality checks revealed that the recovered data was incomplete for the purpose of answering this question and it has not been provided here.

**Q22.4 Please explain why FortisBC has provided "system control interchange estimates" rather than actual billed consumption.**

A22.4 As shown in Zellstoff Celgar IR No. 2 Table A22.1 above, there is close correlation between system control interchange estimates and customer service billing data. Billing data for Zellstoff Celgar is complex and difficult to correctly interpret whereas, system control interchange estimates were readily available.

**Q22.5 With regard to Table Zellstoff Celgar A11.4, did FortisBC take into account in its calculation of the table the appropriate adjustments for imports and exports at the Celgar facility?**

A22.5 The numbers provided in Table Zellstoff Celgar A11.4 were intended to be gross sales to Zellstoff Celgar and therefore no adjustment for sales to FortisBC or exports were taken into account. In addition, while it is correct that in the past FortisBC did make market purchases to service Zellstoff Celgar load, FortisBC made the purchases, not Zellstoff Celgar. Therefore, no adjustment for imports was required. Please also refer to the response to Zellstoff Celgar IR No. 2 Q22.1 above.

**Q22.6 Please provide a history of demand of Celgar as a Rate Schedule 31 Industrial customer since 1997 at the time of FortisBC system peak for the months of January, February, July, August, November and December of each year. In how many instances did Celgar's demand meet or exceed 40,000 kVA at the time of the FortisBC system peak in each of those months?**

A22.6 Table Zellstoff Celgar A22.6 below, provides the requested data in MW from FortisBC’s system interchange data. For any month in which the MW demand was close to 40, the MVA demand was calculated based on the interval data provided in the response to Zellstoff Celgar IR No. 2 A8.1. The Zellstoff Celgar demand exceeded 40 MVA on the FortisBC System Peak in a total of three months during the period from 2004 to 2009 for which FortisBC has the interval data. From the period 1997 to 2003 there was one additional event that cannot be confirmed since the MVA reading is not available, only the 39 MW reading.

**Table Zellstoff Celgar A22.6 –
Celgar Loads at Time of FortisBC System Peak (1997 – 2009)**

| Year | Month | Date of Peak | Peak Hour | Celgar Load | FortisBC System Peak | Celgar MVA Demand | Year | Month | Date of Peak | Peak Hour | Celgar Load | FortisBC System Peak | Celgar MVA Demand |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | MW | | | | | | | MW | | |
| 1997 | January | 27-Jan-97 | 18 | 35 | 637 | | 2004 | January | 5-Jan-04 | 18 | 13 | 715 | |
| | February | 7-Feb-97 | 9 | 39 | 583 | 40 est. | | February | 2-Feb-04 | 18 | 2 | 567 | |
| | July | 28-Jul-97 | 19 | 0 | 440 | | | July | 30-Jul-04 | 17 | 13 | 498 | |
| | August | 6-Aug-97 | 18 | 0 | 446 | | | August | 16-Aug-04 | 17 | -7 | 511 | |
| | November | 27-Nov-97 | 18 | 0 | 485 | | | November | 29-Nov-04 | 18 | 16 | 577 | |
| | December | 15-Dec-97 | 18 | 0 | 554 | | | December | 13-Dec-04 | 18 | 16 | 607 | |
| 1998 | January | 12-Jan-98 | 18 | 10 | 631 | | 2005 | January | 14-Jan-05 | 18 | 13 | 705 | |
| | February | 3-Feb-98 | 18 | 0 | 480 | | | February | 16-Feb-05 | 8 | 15 | 573 | |
| | July | 27-Jul-98 | 15 | 0 | 482 | | | July | 28-Jul-05 | 18 | -9 | 503 | |
| | August | 4-Aug-98 | 18 | 5 | 483 | | | August | 8-Aug-05 | 18 | -2 | 508 | |
| | November | 30-Nov-98 | 18 | 0 | 477 | | | November | 30-Nov-05 | 18 | 7 | 596 | |
| | December | 21-Dec-98 | 18 | 10 | 628 | | | December | 7-Dec-05 | 18 | 15 | 672 | |
| 1999 | January | 4-Jan-99 | 18 | 21 | 543 | | 2006 | January | 18-Jan-06 | 18 | 39 | 591 | 44 |
| | February | 11-Feb-99 | 9 | 0 | 501 | | | February | 16-Feb-06 | 19 | 20 | 614 | |
| | July | 28-Jul-99 | 18 | 0 | 453 | | | July | 26-Jul-06 | 18 | -6 | 548 | |
| | August | 3-Aug-99 | 18 | 0 | 453 | | | August | 3-Aug-06 | 18 | 38 | 482 | 38.3 |
| | November | 29-Nov-99 | 18 | 0 | 490 | | | November | 29-Nov-06 | 18 | -7 | 709 | |
| | December | 8-Dec-99 | 18 | -2 | 533 | | | December | 18-Dec-06 | 18 | 5 | 646 | |
| 2000 | January | 19-Jan-00 | 18 | -1 | 547 | | 2007 | January | 11-Jan-07 | 18 | 10 | 682 | |
| | February | 14-Feb-00 | 18 | -7 | 510 | | | February | 2-Feb-07 | 9 | -6 | 594 | |
| | July | 18-Jul-00 | 18 | -3 | 445 | | | July | 12-Jul-07 | 17 | -4 | 561 | |
| | August | 8-Aug-00 | 18 | 7 | 473 | | | August | 2-Aug-07 | 18 | -6 | 517 | |
| | November | 29-Nov-00 | 18 | -1 | 524 | | | November | 30-Nov-07 | 18 | 2 | 594 | |
| | December | 15-Dec-00 | 18 | 15 | 616 | | | December | 13-Dec-07 | 18 | 7 | 623 | |
| 2001 | January | 16-Jan-01 | 18 | 12 | 530 | | 2008 | January | 28-Jan-08 | 18 | -6 | 662 | |
| | February | 7-Feb-01 | 9 | 16 | 550 | | | February | 4-Feb-08 | 18 | -6 | 601 | |
| | July | 10-Jul-01 | 16 | 11 | 486 | | | July | 21-Jul-08 | 17 | -5 | 528 | |
| | August | 14-Aug-01 | 18 | 4 | 462 | | | August | 7-Aug-08 | 17 | -5 | 537 | |
| | November | 28-Nov-01 | 18 | 17 | 532 | | | November | 27-Nov-08 | 18 | 37 | 581 | 38.1 |
| | December | 12-Dec-01 | 18 | 12 | 569 | | | December | 20-Dec-08 | 18 | 2 | 744 | |
| 2002 | January | 28-Jan-02 | 18 | 4 | 576 | | 2009 | January | 26-Jan-09 | 9 | 40 | 714 | 41.4 |
| | February | 27-Feb-02 | 9 | 13 | 545 | | | February | 10-Feb-09 | 18 | -7 | 580 | |
| | July | 24-Jul-02 | 17 | 22 | 515 | | | July | 22-Jul-09 | 18 | -9 | 561 | |
| | August | 28-Aug-02 | 17 | 37 | 480 | | | August | 1-Aug-09 | 18 | -8 | 524 | |
| | November | 26-Nov-02 | 18 | 17 | 522 | | | November | 28-Nov-09 | 18 | 42 | 551 | 43.9 |
| | December | 19-Dec-02 | 18 | 17 | 555 | | | December | 14-Dec-09 | 18 | -4 | 703 | |
| 2003 | January | 6-Jan-03 | 18 | 35 | 540 | | | | | | | | |
| | February | 24-Feb-03 | 9 | 6 | 529 | | | | | | | | |
| | July | 30-Jul-03 | 17 | 13 | 523 | | | | | | | | |
| | August | 1-Aug-03 | 14 | 14 | 509 | | | | | | | | |
| | November | 6-Nov-03 | 18 | 16 | 547 | | | | | | | | |
| | December | 30-Dec-03 | 18 | 6 | 609 | | | | | | | | |

**23.0 Reference: Exhibit B-3-4, ZCLP 13.1, ZCLP 14.2**

**Table Zellstoff Celgar A13.1**

**Q23.1 In each of the Years 0 through 5 in Table Zellstoff Celgar A13.1, please divide "Revenues at Proposed Rates ($)" by the energy (MW.h) assumed to be consumed in each year to determine the average rate ($/MW.h). Please provide these numbers in a separate table titled "Average rate ($/MW.h) for Rate 33 Rebalancing".**

A23.1 As described in the original response to Zellstoff Celgar IR No. 1 Q13.1, no individual billing determinants were used to build the rebalancing results tables. The tables assume a flat load, and costs allocated on the same percentages across the years covered by the table. For Rate Schedule 33 energy usage in the COSA model is assumed to be 16,500 MW.h. The requested table is provided below.

**Table Zellstoff Celgar IR2 A23.1**
**Average rate ($/MW.h) for Rate 33 Rebalancing**

| | **Year 0** | **Year 1** | **Year 2** | **Year 3** | **Year 4** | **Year 5** |
|---|---|---|---|---|---|---|
| Consumption (MW.h) | 16,500 | 16,500 | 16,500 | 16,500 | 16,500 | 16,500 |
| Revenues at Proposed Rates ($) | 897,931 | 987,724 | 1,086,496 | 1,195,146 | 1,314,660 | 1,446,126 |
| $ / MW.h | 54.42 | 59.86 | 65.85 | 72.43 | 79.68 | 87.64 |

**Q23.2 In each of the Years 0 through 5 in Table Zellstoff Celgar A13.1, please divide the "Allocated Costs ($)" by the energy (MW.h) assumed to be consumed in each year to determine the average rate ($/MW.h) that FortisBC would require to fully recover the allocated costs. Please provide these numbers in a separate table titled "Average rate ($/MW.h) for Rate 33 if full rebalancing occurs in Year 0".**

A23.2 The requested table is provided below.

**Table Zellstoff Celgar IR2 A23.2**
**Average rate ($/MW.h) for Rate 33 if full rebalancing occurs in Year 0**

| | Year 0 | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 |
|---|---|---|---|---|---|---|
| Allocated Costs ($) | 3,814,638 | 4,005,370 | 4,205,638 | 4,415,920 | 4,636,716 | 4,868,552 |
| Consumption (MW.h) | 16,500 | 16,500 | 16,500 | 16,500 | 16,500 | 16,500 |
| $ / MW.h | $231.19 | $242.75 | $254.89 | $267.63 | $281.01 | $295.06 |

**Q23.3 Please provide and review the BC Hydro document titled "Quick Facts for the Year Ended March 31, 2009". (The downloadable version of this document is available by following the "Essential Facts" link at: www.bchydro.com/quickfacts or directly at www.bchydro.com/etc/medialib/internet/documents/about/company_information/quick_facts.Par.0001.File.quick_facts.pdf )**

A23.3 The requested document is provided as Zellstoff Celgar Appendix IR2 A23.3

**Q23.4 Please confirm that the following statement is made on the first page of this document under the sub-heading "Comparison statistics": "A large industrial customer, such as a pulp mill, might use 400 GWh in a year....".**

A23.4 Confirmed

**Q23.5 On page 2 of the Quick Facts document please confirm that BC Hydro states its large industrial customers generated an average revenue (or have an average "all in cost") of 3.4 cents per kilowatt-hour in 2009 and 3.5 cents per kilowatt-hour in 2008.**

A23.5 The document indicates that the average revenue per kilowatt-hour of its Large General Service Customers was of 3.4 cents per kilowatt-hour in 2009 and 3.5 cents per kilowatt-hour in 2008.

**Q23.6 In each of the two tables created above ("Average rate ($/MW.h) for Rate 33 Rebalancing" and "Average rate ($/MW.h) for Rate 33 if full rebalancing occurs in Year 0"), please add a row which shows the BC Hydro Large industrial customers average 2009 rate ("all in cost" converted to $/MW.h) and enter this number in Year 0. For Years 1 through 5, escalate this rate by FortisBC's assumed BC Hydro 3808 Rate increases.**

A23.6 The requested table follows. In responding to the request, FortisBC has escalated the BC Hydro rate by the values for Class Average Rate increases contained on page 10 of Appendix O to the BC Hydro Large General Service Rate Application currently before the BCUC as follows:

| | F2010 | F2011 | F2012 | F2013 | F2014 | F2015 |
|---|---|---|---|---|---|---|
| Annual CARC | n/a | 10.635% | 3.697% | 6.8% | 7.0% | 5.6% |

In addition, in order to provide results that are more relevant to Zelstoff-Celgar without the effect of averaging the entire BC Hydro Large Industrial number, The “all-in” cost of power developed in response to Zellstoff Celgar IR No. 2 Q25.1 has also been included in Table 23.6c.

**Table Zellstoff Celgar IR2 A23.6a**
**Average rate ($/MW.h) for Rate 33 Rebalancing**

| | Year 0 | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 |
|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 |
| Consumption (MW.h) | 16,500 | 16,500 | 16,500 | 16,500 | 16,500 | 16,500 |
| Revenues at Proposed Rates ($) | 897,931 | 987,724 | 1,086,496 | 1,195,146 | 1,314,660 | 1,446,126 |
| $ / MW.h | 54.42 | 59.86 | 65.85 | 72.43 | 79.68 | 87.64 |
| Average Rate from A23.5 | 34.00 | 37.62 | 39.01 | 41.66 | 44.58 | 47.07 |
| Difference Between BC Hydro Large Industrial Rate | 20.42 | 22.24 | 25.84 | 30.77 | 35.10 | 40.57 |

**Table Zellstoff Celgar IR2 A23.6b**
**Average rate ($/MW.h) for Rate 33 if full rebalancing occurs in Year 0**

| | Year 0 | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 |
|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 |
| Allocated Costs ($) | 3,814,638 | 4,005,370 | 4,205,638 | 4,415,920 | 4,636,716 | 4,868,552 |
| Consumption (MW.h) | 16,500 | 16,500 | 16,500 | 16,500 | 16,500 | 16,500 |
| $ / MW.h | $231.19 | $242.75 | $254.89 | $267.63 | $281.01 | $295.06 |
| Average Rate from A23.5 | 34.00 | 37.62 | 39.01 | 41.66 | 44.58 | 47.07 |
| Difference Between BC Hydro Large Industrial Rate | 197.19 | 205.13 | 215.88 | 225.97 | 236.43 | 247.99 |

It is important to note the analysis by FortisBC shows that if Zellstoff-Celgar took service under BC Hydro TOU Rate Schedule 1825 that it would pay approximately $162.10 per MWh based on the forecast energy consumption in the COSA, a peak demand in one month of 44 MVA (as occurred in January 2009), and a 75 percent demand ratchet of 33 MVA in the remaining months. FortisBC also conservatively assumed that all winter consumption would occur during the less expensive Low Load Hours. Under this more realistic scenario, the comparison between proposed FortisBC and actual BC Hydro Rate Schedule 1825 would be as follows:

**Table Zellstoff Celgar IR2 A23.6c**
**Comparison of Average rate ($/MW.h) for Proposed Rate 33 and BC Hydro 1825**

| | | Year 0 | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 |
|---|---|---|---|---|---|---|---|
| $/MW.h (from A23.1) | a | 54.42 | 59.86 | 65.85 | 72.43 | 79.68 | 87.64 |
| Average Rate from BCH 1825 ($/MWh) (from A25.1) | b | 162.10 | 179.34 | 185.97 | 198.62 | 212.52 | 224.42 |
| Difference Between Large Industrial Rates ($/MWh) | b-a | 107.68 | 119.48 | 120.12 | 126.19 | 132.84 | 136.78 |

**Q23.7 Please add a final row to each of the two tables and title this row, "Difference Between BC Hydro Large Industrial Rate" and show the difference between the average BC Hydro rate and the average FortisBC Rate 33.**

A23.7 The requested rows have been added to Tables Zellstoff Celgar IR2 A23.6a and A23.6b in the previous responses.

**24.0 Reference: Exhibit 6-3-4, ZCLP 14.1**

**Rate Schedule 33 proposed changes**

**Q24.1 The response to ZCLP 14.1 was not responsive to the question as it referred to the previous response which only showed summary information. Please provide the billing determinants and other data requested in ZCLP 14.1.**

A24.1 The response to the original information request was correct. The billing determinant information cannot be provided for the reasons stated in the response to Zellstoff Celgar IR No 1, Q13.1.

**25.0 Reference: Exhibit 6-3-4, ZCLP 14.2, ZCLP 34.1, Appendix 34.1**

**Comparable Provincial Electricity Rates**

**Q Although FortisBC is unable to confirm current cost information for a utility other than itself, please provide what FortisBC understands to be the "all-in" average cost of energy for BC Hydro's pulp and paper customers, through an analysis of BC Hydro's applicable rates provided in ZCLP 34.1, Appendix 34.1, if necessary.**

A25.1 FortisBC does not have information specific to any pulp and paper customer of BC Hydro as distinct from the Large Industrial class in aggregate. As a proxy, billing data for Zellstoff-Celgar as provided in Schedule 7.2 of the COSA was applied to the BC Hydro Rate Schedule 1825 as provided in Zellstoff Celgar Appendix A34.1 from IR No. 1. Using the 44 MVA of demand actually recorded for Zellstoff-Celgar in 2008 and applying the ratchet provisions contained in the BC Hydro Tariff, the calculation reveals an “all-in” cost of 16.21 cents per kWh. This analysis includes the assumption that Zellstoff Celgar records the peak demand of 44 MVA in January 2009. It has also been assumed that Zellstoff-Celgar would only be exposed to the Light Load Hour pricing during the winter period for all consumption above 90 percent of the Customer Baseline Load.

**26.0 Reference: Exhibit B-3-4, ZCLP 15.1, ZCLP 15.2**

**Objective of Rate Schedule 33**

**Q26.1 Regarding Rate Schedule 33, FortisBC stated that the "intention at the time was primarily to shift customer usage from on-peak to off-peak periods to reduce power purchase costs and defer system capital expenditures" and that a customer with the ability to generate all or a portion of its power requirement "hinders the ability to determine whether and to what extent peak load has been shifted or simply reduced by self generation, and whether the TOU rate has been responsible for the reduction or has simply made it economic for the self- generating customer to make investments in generation". If FortisBC's objective is to shift customer usage from on-peak to off-peak periods to reduce power purchase costs and defer system capital expenditures, please explain why FortisBC is concerned as to how the customer achieved this objective, and why FortisBC is unable to confirm that Rate Schedule 33 has had this effect, as requested in ZCLP 15.2.**

A26.1 FortisBC is not concerned with the manner in which a customer reduces on-peak consumption and confirms that Celgar has been able to reduce on-peak consumption as described in the response to Zellstoff Celgar IR No 2 Q3.4. However, FortisBC is concerned with the underrecovery of costs that the Zellstoff Celgar energy consumption pattern has created.

**27.0 Reference: Exhibit B-3-4, ZCLP 15.1, ZCLP 16.1, ZCLP 16.4**

**Objective of Rate Schedule 33 and Load Factor**

**Q27.1 Regarding Rate Schedule 33, FortisBC stated that the "intention at the time was primarily to shift customer usage from on-peak to off-peak periods to reduce power purchase costs". For a customer with a high load factor, please confirm that the effect of the intended usage shift will decrease a customer's load factor.**

A27.1 This is not confirmed. Load Factor is computed by dividing the kWh usage for the month by the product of the month's "peak" or maximum demand and the hours for the same period (730 for a month and 8,760 for a year).

Load Factor (percent) = [(Total kWh)/(# Days in Bill Cycle x 24 hrs/day)]/[Peak kW Demand]

Should a customer shift consumption as described in the previous response, and still require the peak demand in order to operate, load factor will not change. Should a portion of a customer's consumption simply disappear but still require the peak demand in order to operate, rather than shift to a different period, load factor will decrease.

**Q27.2 Please describe how customers can determine whether their usage-shifting under a time of use rate has been "too successful" and thus will be deemed to have load factors that have become unsatisfactory, and hence will be denied access to the time of use rate, which incented the unacceptable load factor.**

A27.2 The time-of-use rate does not incent an unacceptable load factor. A customer who was originally deemed to have an acceptable load factor would not normally become unacceptable unless it has also changed its consumption patterns. Customers will generally be free to operate within the selected tariff unless they have a large impact on the customer class as a whole.

**Q27.3 Please provide FortisBC's determination, definition or criteria of what constitutes a satisfactory load factor.**

A27.3 Please see the response to Zellstoff Celgar IR No. 1 Q16.1.

**28.0 Reference: Exhibit B-3-4, ZCLP 16.10**

**Effect of significant distributed generation uptake in the Residential rate class**

**Q28.1 If 50 percent of the customers in the Residential rate class install a small wind turbine and a solar panel roof or other distributed generation technology, thereby reducing the load factor of the rate class to 5 percent, would Fortis have a significant under-recovery of revenue from this rate if the next COSA was in 10 years?**

A28.1 Any movement in this direction on the part of the residential customer base would not happen overnight, nor would it happen in a vacuum. There are a number of considerations that would be incorporated into the FortisBC planning process for distribution facilities over the next 10 years including an examination of the capital requirements of the system.

There would be a significant change the amount of power that the Company would be required to purchase which would in turn change the average cost of power.

In the very unlikely event that the hypothetical case transpired, and then on top of that the unlikely case it did not significantly change the revenue requirements in terms of power and capital, and on top of that the Company ignored the issue for 10 years, then it is possible that the residential class would under-recover its costs.

However, there are too many other factors to consider that would affect the outcome, and given the Company's proposed direction in rate design it is not conceivable that it will be 10 years before a new a COSA and rate design is completed.

**29.0 Reference: Exhibit B-3-4, ZCLP 16.11**

**Effect of significant distributed generation uptake in the Residential rate class**

**"No. For TOU customers, in order to limit the short-term impacts on non-participating customers, the annual incremental customer participation in each class is limited to 5 percent per annum of the previous year's total load for that customer class."**

**Q29.1 Does FortisBC acknowledge that current rates that are designed to incent customers to conserve and reduce load factors are not entirely effective for the reason that, as load factors reduce, "all in" rates would need to rise because the "all-in" costs would need to be recovered from a smaller MW.h base.**

A29.1 Time-of-use rates are not designed to reduce load factors, but are designed to shift use to periods of lower cost energy. In the long term, the uptake of the rates is intended to provide a net benefit to ratepayers for the reasons discussed in the response to Zellstoff Celgar IR No. 2 Q2.1 above.

**30.0 Reference: Exhibit B-3-4, ZCLP 18.1, ZCLP 18.2, ZCLP 18.3, ZCLP 18.4, ZCLP 18.5**

**Distribution Customer charges**

**Q30.1 FortisBC stated that the "$304,196 referenced in the question is the amount of rate base assigned to the class, not the annual cost of service." Since there is only one customer in this rate class, please explain why it is not possible to use the annual cost of service.**

A30.1 As the number represents the allocated rate base, it is used to allocate revenue requirement items for all customers but is not directly included in the cost of service.

**Q30.2 Please provide the annual cost of service for Celgar for the functions included in the category Distribution Customer charges.**

A30.2 The cost of service related to distribution for Celgar can be found in Schedule 1.1 of the COSA and is equal to $54,287. That reflects all of the costs associated with metering, billing and customer assistance for the customer and includes O&M plus a share of return, depreciation, taxes and A&G.

**Q30.3 FortisBC stated that it "generally does not produce any advertising directed solely to Rate Schedule 33 customers or any other specific customer class". If ZCLP is the only customer in Rate Schedule 33 rate class, please explain if Celgar can elect not to contribute to funding for advertising from its Rate Class if ZCLP views advertising as a waste of money and unnecessary. Does FortisBC have the ability to reduce its advertising budget if so requested?**

A30.3 All customers share in the cost of running the electrical utility on the basis of the cost allocations derived from the COSA. Customers do not have the ability to pick and choose from among services unless they are taking service under a rate that specifically allows it. (ie, transmission customers do not have distribution costs embedded in their rates). The proper venue for the examination of utility costs and processes is the annual Revenue Requirements process during which any customer can raise any concern that may exist with an individual cost component.

**Q30.4 Please outline advertising costs for 2009 in detail, justifying each expenditure and describe why it was necessary for FortisBC, given that it is a monopoly, to undertake such costs. Please explain what benefits the Rate Schedule 33 customer received from this.**

A30.4 FortisBC provides below Table Zellstoff Celgar IR2 A30.4 outlining the 2009 advertising costs. These costs are associated with development and placement of newspaper, radio and television spots and are based on the assumption that advertising is the action of calling something to the attention of the public by paid announcements or is the business of preparing advertisements for publication or broadcast.

**Table Zellstoff Celgar IR2 A30.4**

| Type of Advertising | Cost ($) | By Category ($) | |
|---|---|---|---|
| Print Advertising | 245,457.05 | PowerSense | 51,885.44 |
| | | Customer Service | 48,875.52 |
| | | Safety | 49,030.54 |
| | | Regulatory | 30,762.63 |
| | | Provincial Applications | 13,908.90 |
| | | Fleet Sales | 4,831.40 |
| | | Human Resources | 46,162.62 |
| Ad Creative / Production | 99,841.46 | PowerSense | 83,074.54 |
| | | Customer Service | 12,617.71 |
| | | Safety | 3,571.71 |
| | | Regulatory | 525.00 |
| | | Provincial Applications | 52.50 |
| Television Advertising | 6,804.25 | PowerSense | 6,804.25 |
| Radio Advertising | 67,688.93 | PowerSense | 48,416.72 |
| | | Customer Service | 659.41 |
| | | Safety | 17,904.00 |
| | | Fleet Sales | 708.80 |
| **Total** | **419,791.69** | | |

In general, the advertising falls into seven categories with benefits to all customer groups, including Rate Schedule 33 customers, as follows:

- PowerSense – The FortisBC PowerSense program educates and informs customers about energy efficiency programs, rebates and events offered by FortisBC. Since its inception in 1989, the FortisBC PowerSense program has helped southern interior customers save over 360 million kWhs, enough energy to power over 30,000 homes each year. Minimizing energy consumption lessens the need for new generation resources, transmission and distribution lines, and substations required to safely and reliably meet customer's future electricity needs. It also reduces the need for FortisBC to purchase power at peak periods, helping keep rates lower for all of our customers. And all of these savings help the environment, creating a cleaner, more sustainable future for the communities in FortisBC's service area.

- Customer Service – Customer service advertising advises customers about significant planned power outages, capital project work and the FortisBC Community Investment program. This advertising helps to increase customer satisfaction and helps to reduce the inconvenience of unplanned outages and capital work.

- Safety – FortisBC uses advertising to promote and increase public and contractor electrical safety. In particular, FortisBC provides a Kidsmartz safety program booklet and coordinates the Cooperative Safety Program (CSP). The CSP is a partnership of 13 utilities, municipalities and organizations that share a commitment to public and workplace safety across the southern interior of B.C. The program improves public awareness of electrical and natural gas hazards, and provides information on how those hazards can be avoided. In 2009, more than $49,000 was recovered from CSP partners, reducing the FortisBC totals provided above.

- Regulatory – Notifies the public of consultation opportunities and of regulatory processes such as procedural conferences and regulatory hearings. This provides customers the opportunity to take part in processes that may impact them. In addition, FortisBC is required to advertise for some regulatory processes. During 2009, some of these processes included the COSA study and RDA, the Net Metering program application, and the 2010 Revenue Requirements application.

- Provincial Government Applications – The provincial government requires print advertising to notify the public of some permits and applications. In 2009, advertising was placed to announce new wood pole, facilities and rights-of-way pest management plans, as well as a crown land application. This advertising advises the public on the processes underway and informs them of how they can become involved.

- Fleet Sales – From time to time FortisBC advertises the sale of fleet vehicles allowing the public an opportunity to purchase these goods.

- Human resources – FortisBC uses advertising to recruit new employees, maintaining a knowledgeable workforce to provide safe, reliable electrical service to FortisBC customers.

**31.0 Reference: Exhibit B-3-4, ZCLP 26.2**

**Assignment of O&M Costs**

**Q31.1 The reference provided to ZCLP 26.2 is not responsive to the Information Request. The assertion by FortisBC that A&G amounts are classified on the same basis as the rate base for each of the three functions because the employees are more closely tied to the size of the asset value of the three functions as opposed to the O&M associated with each function is an untested assertion. The non-responsiveness of FortisBC to provide the requested data in the first round of Information Requests precludes the possibility of asking follow-on questions based on the data to test FortisBC's assertion. The cost assignment to each asset class cannot be verified. For instance, the total A&G revenue requirement is in excess of $11,000,000 (Exhibit B-l, Appendix A, Schedule 3.1) of which almost $3,000,000 is allocated to the Transmission asset class (Exhibit B-1, Appendix A, Schedule 3.2). The distribution and customer connection function may be far more labour intensive than the transmission function, hence be assigned a greater portion of A&G costs than the pro-rata portion according to rate base value.**

**Therefore, in this second round of Information Requests, please provide the data requested in ZCLP 26.2, and additionally, also provide an analysis which supports the assertion that activity levels are more closely tied to rate base values as opposed to direct O&M effort expended within each asset class.**

A31.1 The utility does not track employee hours by function, the budgeted head count by department, as provided in BCUC IR No. 1 Q54.1, was used to develop labour ratios. The detail associated with those headcounts was provided as the supporting information.

Employees that are assigned to specific functions already have their salaries show up in accounts related to that function. Only the A&G employee salaries show up in the A&G costs. The labour ratios are used because they can account for the fact that one function may be more labor intensive than another. That is why A&G is functionalized a higher amount (38%) to distribution relative to transmission (25%). Rate base values are only applied after costs are first split into the three functions according to the labour ratios.

Since the A&G employees work on issues that are unrelated to a specific function, it is impossible to determine a precise split of A&G costs per function. For example, the staff associated with the assembling the RDA does work that relates to all three functions simultaneously and cannot be separated out.

Because A&G cannot be specifically broken out, it is common to use labour ratios or all other O&M costs to functionalize the costs. Labour ratios were used in the 1997 COSA and there was no underlying reasons to make a change in the methodology for the 2007 COSA.

If O&M costs (excluding purchased power and A&G) was used to assign A&G costs rather than labour ratios, the costs for the Rate 33 class would change from $3,814,638 to $3,856,304. The revenue to cost ratios would remain unchanged at 23.3%.

**32.0 Reference: Exhibit 8-3-4, ZCLP 27.1, ZCLP 27.2, ZCLP 27.3; Exhibit B-3-3, BCMEU Attachment A6.1**

**Value assigned to the Minimum System Study**

**Q32.1 The information requested in ZCLP 27.1 should be considered in the context of a "typical" installation of a 5 MVA substation versus a 25 MVA substation. Please state the assumptions which FortisBC uses to define this "typical" installation. This information will be important if FortisBC's assertion that all substation assets are classified as 100 percent demand-related is determined not be a valid assertion.**

A32.1 FortisBC does not have costs for a “typical” 5 MVA or 25 MVA substation. These costs were not used in the COSA or minimum system study. FortisBC maintains that it is not standard utility practice to treat substations in the same manner applied to poles, conductors and transformers in the minimum system study.

**Q32.2 Please substantiate the assertion made in the response to ZCLP 27.2 that classification of substations 100 percent to demand is standard industry practice by providing references in rate design literature that support this assertion. Also provide references to support the corollary assertion that assigning some component of substation value to the Minimum System. Study as a customer related cost is inappropriate (or a practice to be avoided).**

A32.2 Reference: *Electric Utility Cost Allocation Manual*, National Association of Regulatory Utility Commissisions, January 1992, pages 89-92.

**Q32.3 For each substation identified in Exhibit B-3-3, BCMEU Attachment A6.1, please identify the demand at each substation if each customer connected to the individual substation had a demand of 1.0 kW (as requested in ZCLP 27.3). For ease of reference please provide the response as BCMEU Attachment A6.1, but simply with an additional column for the requested data.**

A32.3 Please refer to Zellstoff Celgar IR2 Attachment A32.3.

| Description | Net Book Value | Est. Replacement Cost | Installed Capacity | Demand at each substation if each customer uses 1kW |
|---|---|---|---|---|
| | ($000s) | | MVA | kW |
| **Transmission Stations (BCUC 353)** | | | | |
| A.S. Mawdsley Terminal | 4,452 | 12,000 | 160 | 0 |
| A.A. Lambert Terminal | 10,573 | 20,000 | 205 | 2319 |
| Coffee Creek Terminal | 1,785 | 10,000 | 41 | 343 |
| D.G. Bell Terminal | 7,648 | 17,000 | 232 | 4864 |
| F.A. Lee Terminal | 12,969 | 25,000 | 336 | 3243 |
| Grand Forks Terminal | 5,385 | 12,000 | 80 | 1633 |
| Oliver Terminal | 5,769 | 15,000 | 142 | 1728 |
| R.G. Anderson Terminal | 6,641 | 23,000 | 336 | 116 |
| Vaseux Lake Terminal | 18,912 | 25,000 | 500 | 0 |
| Warfield Substation | 17,167 | 25,000 | 400 | 0 |
| Utility Interconnections | 27,668 | 50,000 | n/a | 0 |
| **Total** | **118,967** | **234,000** | **2432** | **14246** |
| **Number of substations: 10** | | | | |
| | | | | |
| **Distribution Stations (BCUC 362)** | | | | |
| Arawana Substation | 5,813 | 6,000 | 10 | 53 |
| Beaver Park Substation | 528 | 6,000 | 10 | 1477 |
| Big White Substation | 8,125 | 10,000 | 40 | 2012 |
| Black Mountain Substation | 10,838 | 12,000 | 40 | 3034 |
| Blueberry Substation | 716 | 6,000 | 15 | 1921 |
| Cascade Substation | 2,235 | 7,000 | 20 | 2297 |
| Castlegar Substation | 916 | 7,000 | 15 | 2484 |
| Christina Lake Substation | 310 | 6,000 | 5 | 1394 |
| Cottonwood Substation | 4,235 | 6,000 | 10 | 19 |
| Crawford Bay Substation | 3,706 | 10,000 | 20 | 1318 |
| Creston Substation | 1,086 | 8,000 | 30 | 4344 |
| Duck Lake Substation | 3,240 | 8,000 | 28 | 1106 |
| Ellison Substation | 6,837 | 8,000 | 40 | 2400 |
| Fruitvale Substation | 599 | 6,000 | 8 | 1476 |
| Glenmerry Substation | 1,608 | 8,000 | 20 | 2862 |
| Glenmore Substation | 4,069 | 12,000 | 72 | 6835 |
| Greenwood Substation | 992 | 6,000 | 3 | 45 |
| Hearns Substation | 263 | 6,000 | 2 | 234 |
| Hedley Substation | 1,610 | 8,000 | 10 | 950 |
| Hollywood Substation | 1,386 | 12,000 | 63 | 10752 |
| Huth Substation | 1,900 | 15,000 | 44 | 1 |
| Joe Rich Substation | 1,110 | 7,000 | 20 | 498 |
| Kaleden Substation | 794 | 6,000 | 10 | 1155 |
| Kaslo Substation | 1,617 | 7,000 | 13.3 | 1006 |
| Keremeos Substation | 1,171 | 8,000 | 20 | 2907 |
| Kettle Valley Substation | 10,872 | 12,000 | 80 | 1834 |

| Description | Net Book Value | Est. Replacement Cost | Installed Capacity | Demand at each substation if each customer uses 1kW |
|---|---|---|---|---|
| | ($000s) | | MVA | kW |
| Kraft Substation | 86 | 250 | n/a | 0 |
| Misc. distribution step-down stations | 251 | 900 | < 1 | 59 |
| Nk'Mip Substation | 5,771 | 8,000 | 40 | 1687 |
| OK Mission Substation | 1,837 | 12,000 | 63.5 | 7123 |
| Okanagan Falls Substation | 734 | 6,000 | 15 | 2082 |
| Ootischenia Substation | 5,358 | 6,000 | 20 | 1966 |
| Osoyoos Substation | 3,386 | 8,000 | 35 | 3414 |
| Passmore Substation | 534 | 6,000 | 5.62 | 669 |
| Pine Street Substation | 2,743 | 8,000 | 35 | 3570 |
| Playmor Substation | 776 | 7,000 | 16 | 2502 |
| Princeton Terminal | 6,063 | 8,000 | 40 | 3791 |
| Recreation Substation | 1,198 | 8,000 | 31.5 | 1 |
| Rosemont Switching Station | 74 | 1,000 | n/a | 0 |
| Ruckles Substation | 287 | 9,000 | 26 | 469 |
| Salmo Substation | 416 | 7,000 | 13.3 | 1202 |
| Saucier Substation | 1,268 | 8,000 | 31.5 | 1 |
| Sexsmith Substation | 1,970 | 8,000 | 31.5 | 4053 |
| South Slocan Substation | 176 | 500 | n/a | 0 |
| Stoney Creek Substation | 413 | 6,000 | 10 | 2167 |
| Summerland Substation | 898 | 5,000 | 20 | 1 |
| Tarrys Substation | 268 | 6,000 | 2.5 | 11 |
| Trout Creek Substation | 534 | 6,000 | 15 | 3 |
| Valhalla Substation | 3,001 | 7,000 | 23 | 761 |
| Waneta Generating Station | 1,800 | 2,000 | n/a | 0 |
| Waterford Substation | 3,106 | 5,000 | 40 | 1 |
| West Bench Substation | 443 | 6,000 | 9 | 1547 |
| Westminster Substation | 969 | 5,000 | 31 | 1 |
| Ymir Substation | 166 | 6,000 | 1.5 | 258 |
| **Total** | **121,099** | **378,650** | **1204.22** | **91753** |
| **Number of substations: 54** | | | | |
| **Other** | **600** | **n/a** | **n/a** | |
| | | | | |
| **Mobile Substations (four units)** | **3,150** | **10,000** | **87** | |

**33.0 Reference: Exhibit B-3-4, ZCLP 31.1, ZCLP 31.2, ZCLP 31.3, ZCLP 31.4**

**Effect of Celgar taking higher consumption and/or shifting to Rate Schedule 31**

**Q33.1 It is not apparent that Table Zellstoff Celgar A31.1 is fully responsive to the information request. Therefore the information request is re-stated in an effort to provide greater clarity. Please re-calculate the COSA Revenue to Cost Ratios found in Exhibit B-1, Table 2.2 on the basis that the Celgar facility in Castlegar was able to purchase all of its electricity needs from FortisBC under Rate Schedule 33 with an annual demand of 43,000 kVA at 100 percent power factor and 95 percent load factor. Next, re-introduce Celgar into the Rate Schedule 31 rate class, and repeat the requested analysis on the basis that the Celgar facility in Castlegar was able to purchase all of its electricity needs from FortisBC under Rate Schedule 31 with an annual demand of 43,000 kVA at 100 percent power factor and 95 percent load factor. For each analysis, please provide a listing of the individual changes to each worksheet and cell in the COSA electronic model, or alternatively, provide the revised COSA electronic model so that the summarized results can be confirmed by either repeating or examining the methodology.**

A33.1 If Celgar was charged at Rate 31 and included within that rate class, the resulting revenue to cost ratio would be 116.0%. The revenue to cost ratios for all other classes would be the same as provided in the response to Zellstoff Celgar IR No. 1 Q31.1.

A spreadsheet model is provided in electronic format detailing the results for this and the other scenarios that follow. Please refer to electronic attachment Zellstoff Celgar Attachment A33.1.

**Q33.2 Please repeat the analysis and provide the information requested above for the six scenarios identified in ZCLP 31.2, ZCLP 31.3 and ZCLP 31.4. To be clear, the analyses for Celgar as a Rate Schedule 33 customer or a Rate Schedule 31 customer are considered two separate scenarios, as are each of the identified load levels.**

A33.2 The results would remain unchanged from the tables provided in Zellstoff Celgar IR No. 1 Q31.2, Q31.3 and Q31.4 for all classes other than the cases where Celgar is billed at Rate 31 and included in that rate class. With Celgar included in Rate 31, the revenue to cost ratios for the class are as follows:

| | |
|---|---|
| Zellstoff Celgar IR No. 1 Q31.2 | 115.1% |
| Zellstoff Celgar IR No. 1 Q31.3 | 111.5% |
| Zellstoff Celgar IR No. 1 Q31.4 | 104.0% |

**Q33.3 Please provide a table showing the numerical values used for the market energy and demand rates, the total incremental power supply purchase costs, and the total incremental revenues for each of the eight scenarios.**

A33.3 Please refer to the following tables:

**Table Zellstoff Celgar IR2 A33.3a**
**Market Energy and Demand Rates**

| | Energy | Demand |
|---|---|---|
| | (mills/kWh) | ($/MW-month) |
| January | 58.08 | 4,861 |
| February | 53.70 | 4,861 |
| March | 48.11 | 4,861 |
| April | 25.69 | 5,312 |
| May | 20.63 | 5,312 |
| June | 17.41 | 5,312 |
| July | 33.60 | 5,312 |
| August | 39.26 | 5,312 |
| September | 41.15 | 5,312 |
| October | 57.82 | 5,312 |
| November | 61.07 | 5,312 |
| December | 73.02 | 5,312 |

**Table Zellstoff Celgar IR2 A33.3b**
**Incremental Power supply Cost and Revenues**

| | Incremental | Incremental |
|---|---|---|
| | Power Supply Cost ($ millions) | Revenue ($ millions) |
| 33.1a (ZCLP 31.1 Load at Rate 33) | $17.6 | $16.8 |
| 33.1b (ZCLP 31.1 Load at Rate 31) | 17.6 | 15.9 |
| 33.2a (ZCLP 31.2 Load at Rate 33) | 16.3 | 15.5 |
| 33.2b (ZCLP 31.2 Load at Rate 31) | 16.3 | 14.7 |
| 33.2c (ZCLP 31.3 Load at Rate 33) | 13.2 | 12.7 |
| 33.2d (ZCLP 31.3 Load at Rate 31) | 13.2 | 12.0 |
| 33.2e (ZCLP 31.4 Load at Rate 33) | 8.8 | 8.6 |
| 33.2f (ZCLP 31.4 Load at Rate 31) | 8.8 | 8.1 |

**34.0 Reference: Exhibit B-3-4, ZCLP 32.1, ZCLP 32.2, ZCLP 32.3, ZCLP 32.4**

**Effect of Celgar taking higher consumption and/or shifting to Rate Schedule 31**

**Q34.1 Please explain why Revenue to Cost Ratios are the same for the Residential rate class and the wholesale rate classes in Tables Zellstoff Celgar A32.2(b) and A32.2(d), as well as in Tables Zellstoff Celgar A32.4(b) and A32.4(d), but are different in Table Zellstoff Celgar A32.3(b) as compared to Table Zellstoff Celgar A32.3(d). Please confirm if Table Zellstoff Celgar A32.3(d) is the correct table, or whether it is in error.**

A34.1 Table Zellstoff Celgar A32.3d has been corrected in Errata 3 as filed January 28, 2010 (Exhibit B-3-4-1).

**Q34.2 For each of the scenarios in ZCLP 32.1, ZCLP 32.2, ZCLP 32.3, and ZCLP 32.4 that requested the analysis for service taken under Rate Schedule 31, please first re-introduce Celgar into the Rate Schedule 31. rate class, and report the results for the revised Rate Schedule 31 rate class as it existed prior to the separation of the Rate Schedule 33 rate class.**

A34.2 The results are the same as provided in the response to Zellstoff Celgar IR No. 2 Q33.1 and Q33.2.

**Q34.3 For each analysis in ZCLP 32.1, ZCLP 32.2, ZCLP 32.3, and ZCLP 32.4, please provide a listing of the individual changes to each worksheet and cell in the COSA electronic model, or alternatively, provide the revised COSA electronic model so that the summarized results can be confirmed by either repeating or examining the methodology.**

A34.3 Please refer to the response to Zellstoff Celgar IR No. 2 Q33.1.

**Q34.4 Please confirm the incremental power supply purchase costs for the analysis in ZCLP 32.1, ZCLP 32.2, ZCLP 32.3, and ZCLP 32.4 were the same as described in ZCI.P 31.1.**

A34.4 The incremental power supply costs were calculated in the same manner for all of the scenarios.

**Q34.5 Please explain why Year 1 increases are as low as 2.0 percent for rate classes in an over-recovery position for the scenarios considered in ZCLP 32.1, ZCLP 32.2, ZCLP 32.3, and only go below 2.0 percent for the scenario considered in ZCLP 32.4.**

A34.5 The scenario under Zellstoff Celgar IR No. 1 Q32.4 has a lower load for rate 33 than for the other cases, and therefore the revenue from the class is lower in that case. This provides less revenue overall, resulting in a reduced ability to give reductions to those classes with a revenue to cost ratio above 105%.

**35.0 Reference: Exhibit B-3-4, ZCLP 33.1, ZCLP 33.2, ZCLP 33.3**

**Effect of Celgar taking higher consumption**

**Q35.1 Please provide a table showing the sources and costs of incremental power supply purchase for the scenarios in ZCLP 33.1, ZCLP 33.2, and ZCLP 33.3 over the power supply purchase for the base COSA scenario, including the maximization of purchases from BC Hydro if such purchases represent the lowest cost supply.**

A35.1 Please refer to the response to Zellstoff Celgar IR No. 2 Q33.3. Market prices for additional power supply were used to develop the incremental costs of power for each scenario. FortisBC did not run an optimization model for power supply under each of the scenarios requested due to the complexity associated with determining projected power supply costs.

**36.0 Reference: Exhibit B-3-3, BCMEU Attachment A6.1**

**Infrastructure Costs**

**Q36.1 Please provide a listing of the individual components over $10,000 in replacement cost that make up the $250,000 total Kraft Substation estimate replacement cost.**

A36.1 The $250,000 replacement cost estimate was intended to be a conceptual estimate only; however, it would include equipment such as the high-voltage switches, the structures to mount them on, and the communications and control equipment.

**37.0 Reference: Exhibit B-3-3, BCMEU 24.1**

**Load Growth since the 1997 COSA**

**Q37.1 Please separately identify the change in load for Large General Service - Primary (all rate schedules) and Large General Service - Transmission (all rate schedules) from Retail category as shown in Table BCMEU A24. 1.**

A37.1 Please see Table Zellstoff Celgar IR2 A37.1 below.

**Table Zellstoff Celgar IR2 A37.1**

| | 1997 COSA | 2009 COSA | % Growth |
|---|---|---|---|
| | MWh | | % |
| Wholesale | 957,815 | 981,536 | 2.5% |
| LGS - Primary | 199,855 | 150,425 | -24.7% |
| LGS - Transmission | 63,647 | 87,764 | 37.9% |
| Other Retail | 1,694,745 | 2,444,696 | 44.3% |
| Total | 2,916,062 | 3,426,323 | 17.5% |

**38.0 Reference: Exhibit B-3-8, A. Shadrack 4**

**Regionalization of Assets**

**Q38.1 Please provide the book value of Transmission Assets separated into two distinct areas, those being West Kootenay Region and Okanagan Region, for the Years 2005 to 2010 inclusive. (Format of Table provided below).**

| | West Kootenay | Okanagan |
|---|---|---|
| 2010 | | |
| 2009 | | |
| 2008 | | |
| 2007 | | |
| 2006 | | |
| 2005 | | |

A38.1 Please find the requested values below in Table Zellstoff Celgar IR2 A38.1. Note that amounts for 2010 are not yet available as the values shown are for year-end 2009.

**Table Zellstoff Celgar IR2 A38.1**
**Transmission Asset Book Values**

| | West Kootenay | Okanagan |
|---|---|---|
| 2010 | - | - |
| 2009 | $ 90,763,991 | $ 136,964,238 |
| 2008 | $ 91,922,150 | $ 134,340,930 |
| 2007 | $ 90,197,576 | $ 134,307,156 |
| 2006 | $ 86,651,633 | $ 117,464,824 |
| 2005 | $ 82,155,089 | $ 105,541,329 |

**Q38.2 Please provide the total capital cost of investments made in Transmission assets in the West Kootenay Region and the Okanagan Region, for the Years 2005 to 2010 inclusive.(Format of Table provided below).**

| | West Kootenay | Okanagan |
|---|---|---|
| 2010 | | |
| 2009 | | |
| 2008 | | |
| 2007 | | |
| 2006 | | |
| 2005 | | |

A38.2 Please find the requested values below in Table Zellstoff Celgar IR2 A38.2. Note that amounts for 2010 are not yet available as the values shown are for year-end 2009..

**Table Zellstoff Celgar IR2 A38.2**
**Transmission Asset Additions by Year**

| | West Kootenay | Okanagan |
|---|---|---|
| 2010 | - | - |
| 2009 | $ 4,306,151 | $ 7,686,599 |
| 2008 | $ 3,105,405 | $ 4,953,204 |
| 2007 | $ 6,581,556 | $ 21,119,447 |
| 2006 | $ 6,922,181 | $ 15,600,173 |
| 2005 | $ 14,407,051 | $ 50,731,107 |

**Q38.3 Please provide the number of hours per year where Celgar's customer load was 30 MW or higher for the Years 2005 to 2010.**

A38.3 The information for 2005 to 2009 is provided below in Table Zellstoff Celgar IR2 A38.3. Partial data for 2010 was not provided.

**Table Zellstoff Celgar IR2 A38.3**

| Year | # of hours with Load > 30 MW |
|---|---|
| 2005 | 152 |
| 2006 | 447 |
| 2007 | 132 |
| 2008 | 208 |
| 2009 | 111 |

**Q38.4 Please identify the number of FortisBC's Rate Schedule 31 customers that operate in the distinct region defined as the West Kootenay.**

A38.4 There are two FortisBC customers on Rate Schedule 31 which operate in the West Kootenay.

**Q38.5 Please identify the number of FortisBC's Rate Schedule 31 customers that operate in the distinct region defined as the Okanagan.**

A38.5 There is one FortisBC customer on Rate Schedule 31 which operates in the Okanagan.

**Q38.6 Please identify the number of FortisBC's Rate Schedule 33 customers that operate in the distinct region defined as the West Kootenay.**

A38.6 There is one Rate Schedule 33 customer operating in the West Kootenay.

**Q38.7 Please identify the number of FortisBC's Rate Schedule 33 customers that operate in the distinct region defined as the Okanagan.**

A38.7 There are no Rate Schedule 33 customers operating in the Okanagan.

**39.0 Reference; Exhibit B-3-8, A. Shadrack 6**

**Effect of Celgar load leaving FortisBC**

**Q39.1 Please describe and quantify the effect on rates for the remaining FortisBC customers if the Celgar load and any revenues associated with Celgar left the FortisBC system.**

A39.1 Based on the filed COSA information, the removal of all Zelstoff-Celgar revenues and associated variable costs would entail the following:

- The removal of approximately $890,000 of revenue. (Schedule 1.1)
- At a minimum, the removal of approximately $645,000 in allocated power supply costs comprised of purchased power and SCC costs. (Schedule 3.3)
- Barring any stranded asset recovery, at most $245,000 in margin that Zellstoff-Celgar is currently contributing would need to be collected from the remaining customer classes, who would also continue to pay the balance of $3.17 million of costs allocated to Zellstoff Celgar through the COSA.

This would result in a maximum one-time rate increase of 0.1 percent.

**Issue: Implications of BCUC Order No. G-48-09 and accompanying Decision**

**40.0 Reference: Exhibit B-3-4, ZCLP 29.1, Appendix A29.1**

**Decision accompanying BCUC Order No. G-48-09, p. 29**

**"What will not be permitted is the supply of embedded cost power to service the domestic load, at any time when the self-generator is selling power into the market."**

**Q40.1 Please comment on the consideration given, prior to filing the Application, to the above Commission direction.**

A40.1 FortisBC was aware of the decision referenced prior to filing the Application. Please also see the response to Zellstoff Celgar IR No. 2 Q40.2.

**Q40.2 Please identify any specific implications, if any, for the Application of the above direction from the Commission.**

A40.2 Order G-48-09 does not impact the data or assumptions used in the COSA or proposed rate design, therefore it has no material implications.

**Q40.3 Please identify any specific implications, if any, for the Application of the "net of load" concept as enunciated in the referenced Decision.**

A40.3 Please see the response to Zellstoff Celgar IR No. 2 Q40.2 above.

**Q40.4 Please comment on whether or not one of the principles of BCUC Order No. G-38-01 is that in some, albeit limited, circumstances a self-generating customer may purchase embedded cost power from BC Hydro at the same time as selling to the domestic or export market.**

A40.4 Order G-38-01 stated that B.C. Hydro is not required to supply any *increased* embedded cost power to a self-generating customer selling to the market, based on either the historical energy consumption or the historical generation of the customer.

**Q40.5 Given the above reference, does FortisBC believe that there are fundamental differences in principle between BC Hydro's obligation to serve self-generating customers and FortisBC's obligation to serve self-generating customers? Does FortisBC believe that BC Hydro's obligation to serve self generation customers and FortisBC's obligation to serve self-generation customers should follow similar principles?**

A40.5 FortisBC believes that the obligation to serve all customers follows similar principles for both FortisBC and BC Hydro. This similarity was confirmed by the Commission in its Reasons for Decision accompanying Order G-48-09 regarding BC Hydro's Application to Amend Section 2.1 of the Rate Schedule 3808 Power Purchase Agreement, which stated at page 8 that the "disposition of the BC Hydro Application in this proceeding may be seen as having precedential value for all self-generators in the province".

**41.0 Reference: Exhibit B-3-4, ZCLP 29.2, Appendix A29.2**

**BCUC Order No. G-48-09 Compliance Filing by BC Hydro**

**Q41.1 Does FortisBC have reason to expect that BC Hydro's self-generating customers listed on the first page of the compliance filing dated October 5, 2009 (ZCLP Appendix A29.2), may purchase embedded cost power from BC Hydro at the same time as selling to the domestic or export market?**

A41.1 BC Hydro's compliance filing of October 5, 2009 suggests this may occur.

**Q41.2 Does FortisBC believe that it either has or should have an obligation to serve Celgar at the same time that Celgar is selling to the domestic or export market?**

A41.2 FortisBC believes that it has an obligation to serve Celgar subject to the revised section 2.1 of the Power Purchase Agreement, which reads:

> "(a) The electricity purchased under this agreement is solely for the purpose of supplementing FortisBC's resources to enable it to meet its service area load requirements and, shall not be exported or stored, provided that nothing contained herein shall prohibit FortisBC from storing its entitlement resources in its entitlement account pursuant to the Canal Plant Agreement; and
>
> (b) shall not be sold to any FortisBC customer when such customer is selling self generated electricity which is not in excess of its load.
>
> For greater certainty, paragraph (b) above is to prevent FortisBC self-generating customers from purchasing power at regulated embedded cost rates and simultaneously selling an equivalent amount of power into available domestic and export markets."

**Q41.3 Please identify circumstances where the "net of load" concept as enunciated in the Decision accompanying BCUC Order No. G-38-01 and the mechanisms identified in the compliance filing dated October 5, 2009 (ZCLP Appendix A29.2) would be necessary if FortisBC complies with the Commission direction "[w] hat will not be permitted is the supply of embedded cost power to service the domestic load, at any time when the self-generator is selling power into the market."**

A41.3 At page 30 of the Reasons for Decision accompanying Order G-48-09, the Commission Panel stated that “self-generators should be permitted to sell any self-generated power that is in excess of the self-generator’s own “domestic” load”, with reference to the historical energy consumption or generator output of the customer, and stated that the treatment of new or incremental generation capacity would be dealt with on a case by case basis.

**42.0 Reference: Exhibit B-3-4, ZCLP 29.1, Appendix A29.1**

**Decision accompanying BCUC Order No. G-48-09, p. 31**

**"(a) The electricity purchased under this agreement is solely for the purpose of supplementing FortisBC's resources to enable it to meet its service area load requirements and, shall not be exported or stored, provided that nothing contained herein shall prohibit FortisBC from storing its entitlement resources in its entitlement account pursuant to the Canal Plant Agreement [sic]; and**

**(b) shall not be sold to any FortisBC customer when such customer is selling self generated electricity which is not in excess of its load.**

**For greater certainty, paragraph (b) above is to prevent FortisBC self-generating customers from purchasing power at regulated embedded cost rates and simultaneously selling an equivalent amount of power into available domestic and export markets."**

**Q42.1 Please comment on the consideration given, prior to filing the application, to the above revisions to the 3808 Power Purchase Agreement ("3808 PPA").**

A42.1 Please see the responses to Zellstoff Celgar IR No. 2 Q40.1 and Q40.2 above.

**Q42.2 With regard to only the provisions of the 3808 PPA between BC Hydro and FortisBC, as revised by BCUC Order No. G-48-09, please comment on whether or not, in some circumstances, FortisBC may purchase under the 3808 PPA and at the same time sell to a self-generating customer at regulated embedded cost rates at the same time as the same customer is selling into domestic and export markets. If so, please provide examples of those potential circumstances with details of coincident 3808 PPA purchases, FortisBC sales to Celgar, Celgar industrial load, and Celgar sales to domestic and export markets.**

A42.2 Order G-48-09 contemplates that new or incremental generation capacity added by a self-generator may be exported. It is possible that the customer's load could be met by a combination of existing self-generation and purchases from FortisBC, including coincident PPA purchases.

WEST KOOTENAY POWER
ENERGYONE

# GENERAL SERVICE POWER CONTRACT

Customer No.: 275331

This contract made December 20, 2000 between KPMG Inc. Trustee of the Estate of Stone Venepal (Celgar) Pulp Inc. ("the Customer") and West Kootenay Power Ltd. ("WKP") witnesses that, for and in consideration of the mutual covenants and agreements contained herein, the parties agree as follows:

1. AGREEMENT: WKP agrees to supply and the Customer agrees to take and pay for electric service to the Customer's premises located at Castlegar, British Columbia.

2. THE POINT OF DELIVERY of electricity shall be at the load side of WKP's disconnect switch near the Customer's substation located at the Customer's pulp mill. WKP's responsibility for supply of electricity shall cease at the Point of Delivery.

3. The TYPE OF SERVICE to be supplied by WKP to the Customer shall be nominally 60,000 volt, three phase 60 hertz service. The CONTRACT DEMAND is 16,000 kVA . The Customer shall not exceed the DEMAND LIMIT OF 40,000 kVA unless otherwise agreed in writing.

4. Service pursuant to this contract shall be deemed to COMMENCE on November 1, 2000 or the date when electricity is first taken by the Customer, whichever is the earlier. In the event that electricity is not available to the Customer on the above commencement date, service pursuant to this contract shall then be deemed to commence on the day that it is made available. The TERM of this contract shall be for two years, and shall continue thereafter until terminated by 12 months prior notice in writing by either party to the other.

5. The RATE to be paid by the Customer for electric service made available by WKP shall be according to

   Rate Schedule 31 as may be amended, commencing from the date as determined in clause 4.

6. A REVENUE GUARANTEE of $ nil and a SECURITY DEPOSIT of $ nil will be required from the Customer pursuant to the Terms and Conditions of West Kootenay Power Ltd.'s filed Electric Tariff before WKP provides electric service.

7. A CUSTOMER CONTRIBUTION will be required with respect to the construction and installation of supply facilities and the Customer agrees to pay, in advance, the sum of $ nil pursuant to the provisions of WKP's filed Terms and Conditions and Extension Schedule.

8. THE TERMS AND CONDITIONS OF WEST KOOTENAY POWER LTD. ATTACHED HERETO HAVE BEEN FILED WITH AND APPROVED BY THE BRITISH COLUMBIA UTILITIES COMMISSION, AND FORM PART OF THIS CONTRACT AND BY THIS REFERENCE ARE INCORPORATED HEREIN. THE TERMS AND CONDITIONS AND SCHEDULES MAY BE AMENDED FROM TIME TO TIME SUBJECT TO APPROVAL BY THE COMMISSION, AND THE CUSTOMER SHALL BE SUBJECT TO ANY SUCH AMENDMENTS AND THE TERMS AND CONDITIONS AS AMENDED SHALL BECOME PART OF THIS CONTRACT.

9. This contract for electricity service replaces all previous contracts for electric service.

10. The Customer's ADDRESS for purposes of billing and notification shall be: P.O. Box 1000, Castlegar, B.C.

11. SPECIAL PROVISIONS Electricity Supply Brokerage Agreement, Curtailment Agreement, and Technical Requirements for Parallel Generation Facilities as attached are incorporated herein.

Per: ______________________________ Per: ______________________________

Manager, Rates and Contract Administration, WKP ______________________________
Title

# TERASEN GAS INC.

## RATE SCHEDULE 22A
## TRANSPORTATION SERVICE (CLOSED)
## INLAND SERVICE AREA

**Effective November 1, 2000**

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# 1. Applicability

1.1 **Description of Applicability -** This Rate Schedule applies to the provision of firm and interruptible transportation service through one meter station (except as otherwise specified in the Transportation Agreement) to the following existing large industrial Shippers:

| **NAME OF SHIPPER** | **LOCATION OF SHIPPER** |
|---|---|
| Zellstoff Celgar Ltd. | Castlegar |
| Cominco Ltd. | Trail |
| Pope & Talbot Ltd. | Castlegar |
| Domtar Pulp and Paper Products Inc. | Kamloops |
| Weyerhaeuser Company Limited | Kamloops |
| Consumers Packaging Inc. | Lavington |
| Federated Co-operatives Limited | Canoe |
| FMC of Canada Limited | Prince George |
| Highland Valley Copper | Logan Lake |
| Moly-Cop Canada | Kamloops |
| Northwood Pulp & Timber Ltd. | Prince George |
| Tolko Industries Ltd. | Kamloops |
| Cariboo Pulp & Paper Company | Quesnel |
| Finlay Forest Industries Ltd. | Mackenzie |
| Fletcher Challenge Canada Limited | Mackenzie |
| Husky Oil Operations Ltd. Prince George Refinery | Prince George |
| Louisiana-Pacific Canada Ltd. | Chetwynd |
| Canadian Forest Products Ltd. (Canfor) Prince George Pulp | Prince George |
| Northwood Pulp and Timber Limited | Prince George |
| Quesnel River Pulp Company | Quesnel |

C

For greater certainty, firm transportation service under this Rate Schedule means the transportation service Terasen Gas is obligated to provide to a Shipper on a firm basis subject to interruption or curtailment pursuant to sections 17 (Default or Bankruptcy) and 20 (Force Majeure) of Rate Schedule 22 and the General Terms and Conditions of Terasen Gas. Interruptible transportation service under this Rate Schedule means the provision by Terasen Gas of transportation service to a Shipper which may be interrupted or curtailed by Terasen Gas pursuant to sections 4.2 (Curtailment), 17 (Default or Bankruptcy) and 20 (Force Majeure) of Rate Schedule 22 and the General Terms and Conditions of Terasen Gas.

1.2 **Transportation Agreement -** Terasen Gas will only transport Gas under this Rate Schedule pursuant to an executed Transportation Agreement under Rate Schedule 22.

1.3 **British Columbia Utilities Commission -** This Rate Schedule may be amended from time to time with the consent of the British Columbia Utilities Commission.

## 2. Definitions

2.1 **Definitions -** Except where the context requires otherwise all words and phrases defined below or in the General Terms and Conditions of Terasen Gas and used in this Rate Schedule or in a Transportation Agreement have the meanings set out below or in the General Terms and Conditions of Terasen Gas. Where any of the definitions set out below conflict with the definitions in the General Terms and Conditions of Terasen Gas, the definitions set out below govern.

(a) **Business Day -** means a Day that commences on other than a Saturday, a Sunday, or a statutory holiday in the Province of British Columbia.

(b) **EKE -** means the East Kootenay Exchange, an Interconnection Point where the Terasen Gas System interconnects with the facilities of TransCanada PipeLines Limited, B.C. System.

(c) **Firm EKE Receipt Service -** means the firm receipt service by which the Shipper provides Gas to Terasen Gas at EKE for firm transportation to a Delivery Point in the Inland Service Area, as described in section 6.1.

(d) **Interruptible EKE Receipt Service -** means the interruptible receipt service by which the Shipper provides Gas to Terasen Gas at EKE for firm transportation to a Delivery Point in the Inland Service Area or the Lower Mainland Service Area, as described in section 6.2.

(e) **Non-Bypass Shipper -** means a Shipper that receives service under Rate Schedule 23, 25 or 22A and pays rates as set out in the standard Table of Charges for the applicable Rate Schedule.

(f) **Peak Day Demand -** means the quantity of energy used for the purposes of determining the Peaking Gas and EKE Receipt Service available to a Non-Bypass Shipper, as calculated pursuant to section 5.4.

(g) **Peaking Gas -** means Gas which is provided to the Shipper by Terasen Gas in accordance with the provisions of section 5.

(h) **Peaking Gas Quantity -** means the Peaking Gas available to a Non-Bypass Shipper on a Day, determined pursuant to the provisions of section 5.5.

(i) **Replacement Gas -** means Gas which is provided to a Shipper by Terasen Gas in the event the Shipper fails to return Peaking Gas Quantity pursuant to section 5.7.

(j) **Requested Peaking Gas Quantity -** means the quantity of energy for each Day requested as Peaking Gas under this Rate Schedule.

(k) **Southern Crossing Pipeline -** means the pipeline and other facilities constructed by Terasen Gas from EKE to an interconnection with existing Terasen Gas facilities near Oliver that will enable Terasen Gas to transport Gas between EKE and the Delivery Point.

(l) **Sumas Daily Price -** means the "NW Sumas" Daily Midpoint Price as set out in Gas Daily's Daily Price Survey for Gas delivered to Northwest Pipeline Corporation at Sumas, converted to Canadian dollars using the noon exchange rate as quoted by the Bank of Canada, one business day prior to Gas flow date, for each Day. Energy units are converted from MMBtu to Gigajoule by application of a conversion factor equal to 1.055056 Gigajoule per MMBtu.

(m) **Transporter** - means, in the case of the Columbia Service Area, TransCanada PipeLines Limited, B.C. System, and in the case of the Inland Service Area and Lower Mainland Service Area, Westcoast Energy Inc., Terasen Huntingdon Inc., TransCanada PipeLines Limited, B.C. System and any other gas pipeline transportation company connected to the facilities of Terasen Gas from which Terasen Gas receives Gas for the purposes of Gas transportation or resale.

## 3. Table of Charges

3.1 **Charges -** In respect of transportation service pursuant to Rate Schedule 22A and the Transportation Agreement, the Shipper will pay to Terasen Gas all of the charges set out in the Table of Charges attached hereto. For greater certainty it is expressly confirmed that the Table of Charges attached to Rate Schedule 22 does not apply to this Rate Schedule 22A.

## 4. Terms and Conditions

4.1 **Other Terms and Conditions -** The terms and conditions set out in Rate Schedule 22 apply to and form part of this Rate Schedule, with necessary changes and bind Terasen Gas and the Shipper as if set out in this Rate Schedule, except as excluded by operation of section 4.2 (Inapplicable Terms and Conditions).

4.2 **Inapplicable Terms and Conditions -** The following terms and conditions set out in Rate Schedule 22 do not apply, and are not incorporated by reference, into this Rate Schedule and shall not be construed in any way to affect the meaning or intent of any provision this Rate Schedule:

- section 2 (Applicability)
- section 5 (Table of Charges)

If any term or provision of this Rate Schedule is inconsistent with any term or provision of Rate Schedule 22, the term or provision of this Rate Schedule will prevail.

4.3 **Shippers on Bypass Rates -** Shippers who have executed long term service agreements on rates, terms and conditions competitive with a bypass pipeline alternative remain subject to the rates, terms and conditions set out in the respective long term service agreement.

4.4 **Curtailment of Firm Service -** Subject to section 4.5 (Firm Curtailment Alternative), Terasen Gas may, in order to serve its firm Gas sales Customers, curtail firm transportation under this Rate Schedule and use the Shipper's Gas up to a maximum daily quantity of 1/2 the Firm DTQ for a maximum of 5 Days during each Contract Year. If Terasen Gas and the Shipper agree, the Shipper may, from time to time, be curtailed by less than 1/2 the Firm DTQ and may be curtailed the balance of such one Day curtailment on a subsequent Day.

4.5 **Firm Curtailment Alternative -** Where Terasen Gas determines that adequate capacity exists on the Terasen Gas System, Shipper may elect to execute an agreement with Terasen Gas that makes available to Terasen Gas peaking supplies during the period November 1 through March 31 of each Contract Year in order to avoid curtailment pursuant to section 4.4 (Curtailment of Firm Service). Peaking supplies will equal 1/2 the Firm DTQ for:

(a) a maximum of 10 Days where the Gas must be nominated by the Shipper with the Transporter in advance of the Day that the peaking supplies are required, or

(b) a maximum of 5 Days where the Shipper is able to and makes available to Terasen Gas peaking supplies on the Day that the peaking supplies are required.

The Shipper will notify Terasen Gas of its election to provide peaking supplies under option (a) or (b) above prior to the commencement of each Contract Year.

4.6 **Adjustment to Firm Curtailments -** If the Shipper has a Firm DTQ that is subject to curtailment under section 4.4 (Curtailment of Firm Service), commencing on the first Day of the Month following a Month during which the Shipper becomes subject to a demand surcharge or recalculated surcharge, firm curtailments applicable to the Shipper will be modified, subject to the determination by Terasen Gas that adequate capacity exists on its system. The adjustment will equal the lessor of the Demand Surcharge Quantity calculated in section 7.3 (Demand Surcharge) of Rate Schedule 22 and the amount otherwise subject to firm curtailment.

4.7 **Shipper's Gas -** Part of the Gas to be transported under this Rate Schedule forms an important and integral part of the Gas supply of Terasen Gas used to meet the requirements of its firm Customers. Shipper commits to deliver to Terasen Gas at the Interconnection Point Gas a quantity equal to ½ the Shipper's Firm DTQ when Terasen Gas exercises its right pursuant to section 4.4 (Curtailment of Firm Service) to curtail firm transportation and use the Shipper's Gas. It is reasonably foreseeable that Terasen Gas may be unable to meet its requirements to deliver Gas to its firm Customers if Shipper fails to meet its commitment hereunder to deliver Gas to Terasen Gas. If Shipper fails to meet its commitment to deliver Gas to Terasen Gas, Terasen Gas has the right to immediately obtain substitute supplies of Gas in quantities equivalent in energy to the Gas which Shipper fails to deliver. Shipper will reimburse Terasen Gas for all reasonable costs paid by Terasen Gas in acquiring and delivering substitute supplies of Gas, including any demand and commodity tolls incurred. Shipper will reimburse Terasen Gas for the reasonable costs paid by Terasen Gas to acquire and deliver substitute supplies upon demand by Terasen Gas at any time after such costs are actually incurred by Terasen Gas. The costs of substitute supplies that are recoverable by Terasen Gas from

Shipper shall not exceed the costs that were or would have been incurred in acquiring and delivering the lowest cost Gas which was at the time available to Terasen Gas in the Service Area in which Shipper is located and of which Terasen Gas would reasonably have been expected to have been aware, given the immediacy of the Gas needs of Terasen Gas. For the purposes of this section, the Shipper's commitment to deliver Gas to Terasen Gas shall not be lessened by any occurrence other than an event of Force Majeure on the facilities of the Transporter.

## 5. Peaking Gas Service

5.1 **Applicability -** In each Contract Year, Peaking Gas Service is available only to Non-Bypass Shippers for Gas which is delivered to a Delivery Point in the Inland Service Area, and for which the Transportation Agreement was in effect on the 1st Day of November of the subject Contract Year.

5.2 **15-Day Maximum -** A Non-Bypass Shipper may request Peaking Gas for a maximum of 15 Days during each Contract Year. Any Day for which any portion of the Shipper's Peaking Gas Quantity is requested and authorized will be considered one of the 15 Days of Peaking Gas entitlement even if the quantity of authorized Peaking Gas is not used or only partially used.

5.3 **Contract Year 2000/2001 -** Should the Southern Crossing Pipeline ("SCP") not be fully operational by the 1st Day of November 2000, the number of Days for which Peaking Gas may be requested during the Contract Year which commences on the 1st Day of November 2000 will be:

$$\frac{\text{the number of Days that SCP is operational during the 2000/2001 Contract Year} * 15}{365}$$

rounded to the nearest whole number. Peaking Gas may only be requested after the SCP has become fully operational.

5.4 **Peak Day Demand -** For purposes of determining the Peaking Gas Quantity available to a Non-Bypass Shipper on a Day, the Peak Day Demand of a Rate Schedule 22A Shipper is the DTQ set out in the Shipper's Transportation Agreement.

5.5 **Peaking Gas Quantity -** The quantity of Peaking Gas available on a Day to a Non-Bypass Shipper ("Peaking Gas Quantity") will be a percentage of that Shipper's Peak Day Demand. The Peaking Gas Quantity available to Non-Bypass Shippers for the next Contract Year will be determined by Terasen Gas, and Terasen Gas will in writing notify each Non-Bypass Shipper of that Shipper's Peaking Gas Quantity, at least 30 Days prior to the commencement of each Contract Year. The Peaking Gas Quantity available to a Non-Bypass Shipper in a Contract Year will be:

(a) $$\frac{\text{Total Non-Bypass Transport Demand}}{\text{Forecast Sales Demand} + \text{Non-Bypass Transport Demand}} = \text{Peaking Gas Factor}$$

(b) Peaking Gas Factor * SCP Peaking Gas = Non-Bypass Transport Volume

(c) $$\frac{\text{Non-Bypass Transport Volume}}{\text{Non-Bypass Transport Demand}} = \text{Peaking Gas Percentage}$$

(d) Peaking Gas Percentage * a Non-Bypass Shipper's Peak Day Demand = Peaking Gas Quantity

Where:

"Non-Bypass Transport Demand" is the aggregate Peak Day Demand of all Non-Bypass Shippers for the Contract Year commencing the next November 1; "Forecast Sales Demand" is the Terasen Gas forecast of the aggregate peak day demand for the Year commencing the next November 1 for all Gas sales Customers of Terasen Gas excluding those in the Fort Nelson Service Area; and "SCP Peaking Gas" is the quantity of peaking Gas available to Terasen Gas in the Year commencing the next November 1 due to the operation of the Southern Crossing Pipeline.

5.6 **Requested Peaking Gas Quantity -** Shipper will notify Terasen Gas of its Requested Peaking Gas Quantity pursuant to nomination procedures described in section 8.2 of Rate Schedule 22 except as otherwise described in section 5.6 (a) and 5.6 (b) below. The Requested Peaking Gas Quantity must be explicitly stated on the nomination and may be less than but may not exceed the Shipper’s Peaking Gas Quantity described in section 5.5.

(a) **Prior Day Notices of Curtailment -** On a Day when Terasen Gas has given notice of curtailment for the next or subsequent Day, a Shipper may notify Terasen Gas of its Requested Peaking Gas Quantity for the next Day up until one Hour prior to the evening nomination cycle on the Day preceding the Day for which notice of curtailment has been given.

(b) **Same Day Notices of Curtailment -** On a Day when Terasen Gas has given notice of curtailment to be effective during that Day, a Shipper may notify Terasen Gas of its Requested Peaking Gas Quantity up until one Hour after the notice of curtailment has been given by Terasen Gas; provided that Terasen Gas has usable nomination cycles available during that Day with the Transporter(s). Requests for Requested Peaking Gas Quantity received after the time when Terasen Gas has usable nomination cycles available during that Day will be authorized only on an as available basis. If notice of Requested Peaking Gas Quantity is given to Terasen Gas during the Day for which Peaking Gas is being requested then the Peaking Gas Quantity available to Shipper on that Day will be reduced consistent with the elapsed pro-rata practices of applicable Transporter(s).

(c) **Non-Curtailment Days -** On Days for which Terasen Gas has not given notice of curtailment, requests for Peaking Gas Quantity shall be made in accordance with the provisions described in section 8.2 of Rate Schedule 22.

5.7 **Return of Peaking Gas Quantity -** Terasen Gas will, within 4 business days following the date for which Peaking Gas is authorized, provide to the Shipper a statement indicating the amount of Peaking Gas authorized and used, and this will be the statement used for the purposes of tracking the authorization and use of Peaking Gas. Peaking Gas must be returned to Terasen Gas within 6 Business Days of the Day in respect of which it was authorized. Shipper must notify Terasen Gas that it is returning Peaking Gas Quantity with its nomination for Requested Quantity described in section 8.2 of Rate Schedule 22. Peaking Gas returned will be applied against the earliest Peaking Gas Quantity authorized and not yet returned. Shipper has option to elect to return Peaking Gas from the Peaking gas inventory which is kept for this purpose. If Peaking Gas is not returned to Terasen Gas within 6 Business Days, Terasen Gas will provide Shipper with an equivalent quantity of Replacement Gas. The charge for Replacement Gas will be as set out in the Table of Charges.

5.8 **Last Gas Ordered -** Peaking Gas Quantity will be considered the last Gas ordered and taken during the Day.

5.9 **Transport of Peaking Gas Quantity -** Peaking Gas Quantity will be deemed to be provided to the Shipper at the Interconnection Point, and the volumes consumed by the Shipper will be included in the Shipper's monthly transport volume for the purposes of calculating monthly transport charges.

# 6. Access to East Kootenay Exchange (EKE) Interconnection Point

## 6.1 Firm EKE Receipt Service

(a) **Applicability -** Firm receipt service access from the EKE Interconnection Point ("Firm EKE Receipt Transport") is available to Non-Bypass Shippers for Gas which is delivered to a Delivery Point in the Inland Service Area and for which the Shipper has a Transportation Agreement which is effective on the August 1st preceding the subject Contract Year ("Inland Non-Bypass Shippers").

(b) **Availability -** The total quantity of Firm EKE Receipt Service available in aggregate to Inland Non-Bypass Shippers ("EKE Transport Volume") will be determined by Terasen Gas for each Contract Year. Terasen Gas shall publish the EKE Transport Volume which is available for the next Contract Year by July 31 of each Year. The EKE Transport Volume shall be determined as follows:

$$\frac{\text{Inland Non-Bypass Transport Demand}}{\text{Forecast Inland Sales Demand} + \text{Inland Non-Bypass Transport Demand}} * \text{ITS Constraint} = \text{EKE Transport Volume}$$

Where:

"Inland Non-Bypass Transport Demand" is the aggregate Peak Day Demand of all Non-Bypass Shippers in the Inland Service Area for the Contract Year commencing the next November 1; "Forecast Inland Sales Demand" is the Terasen Gas forecast of the aggregate peak day demand for the Year commencing the next November 1 for all firm Gas sales Customers of Terasen Gas in the Inland Service Area; and "ITS Constraint" is the capacity of the Terasen Gas Interior transmission system available to flow Gas from Oliver in a northbound direction during periods of peak demand.

(c) **Election -** Annual elections for Firm EKE Receipt Service for the next Contract Year must be submitted in writing by Shippers to Terasen Gas within 5 Business Days of the date on which Terasen Gas publishes the EKE Transport Volume. The election must indicate the quantity of Firm EKE Receipt Service requested. The quantity requested must not exceed the Shipper's Peak Day Demand. Terasen Gas will pro-rate the Firm EKE Receipt Service requests based on the requested quantities if aggregate Firm EKE Receipt Service requests exceed the available EKE Transport Volume. Terasen Gas will notify Shippers of the Shippers' quantity of Firm EKE Receipt Service within 10 Business Days of the date on which Terasen Gas publishes the EKE Transport Volume.

6.2 **Interruptible EKE Receipt Service**

(a) **Applicability** - Interruptible receipt service access to the EKE Interconnection Point ("Interruptible EKE Receipt Service") is available only to Non-Bypass Shippers for which Gas is delivered to a Delivery Point in the Inland Service Area ("Eligible Interruptible Non-Bypass Shippers").

(b) **Quantity Available** - The quantity of Interruptible EKE Receipt Service available to Eligible Interruptible Non-Bypass Shippers will be determined by Terasen Gas. In determining the quantity of Interruptible EKE Receipt Service available Terasen Gas will take into account system delivery constraints including the requirement to flow Gas from the facilities of Westcoast Energy Inc. into the Inland Service Area, and the quantity of Firm EKE Receipt Service not utilized. The quantity of Interruptible EKE Receipt Service available to Eligible Interruptible Non-Bypass Shippers will be a pro-rata portion of the aggregate available demands of all firm Gas sales Customers and all firm transportation Customers in the Inland and Lower Mainland Service Areas.

(c) **Maximum Nomination** - A Shipper may not request Interruptible EKE Receipt Service in excess of the Shipper's Peak Day Demand less the Firm EKE Receipt Service of the Shipper. If Terasen Gas receives requests for Interruptible EKE Receipt Service in excess of the aggregate available Interruptible EKE Receipt Service available for the Day (as determined in 6.2 (b)), Terasen Gas will apportion the available Interruptible EKE Receipt Service on a pro-rata basis of requested Interruptible EKE Receipt Service.

# Table of Charges

| | | | Inland Service Area | |
|---|---|---|---|---|
| **Transportation** | | | | |
| **(a)** | **Basic Charge** per Month | | $ 4,810.00 | |
| **(b)** | **Delivery Charges** for firm transportation | | | |
| | (i) | per Month per Gigajoule of Firm DTQ | $ 12.401 | A |
| | (ii) | per Gigajoule of Firm MTQ | $ 0.086 | A |
| **(c)** | **Delivery Charges** per Gigajoule of Interruptible MTQ | | $ 0.985 | A |
| **(d)** | **Rider 2** per Gigajoule | | $ 0.009 | N |
| **(e)** | **Rider 3** per Gigajoule | | $ (0.007) | A/C |
| | | | | O |
| **(f)** | **Unauthorized Overrun Charges** | | | |
| | (i) | per Gigajoule charge on first 5 percent of specified quantity | Sumas Daily Price[1] | |
| | (ii) | per Gigajoule charge on all Gas over 5 percent of specified quantity | The greater of $20.00/GJ or 1.5 x the Sumas Daily Price[1] | |
| | (iii) | Demand Surcharge per Gigajoule of Demand Surcharge Quantity | $ 17.00[2] | |

| | | | Inland Service Area |
|---|---|---|---|
| **(g)** | **Charge per Gigajoule of Balancing Service provided** (over the greater of 100 Gigajoules or 20% of Rate Schedule 22 Authorized Quantity) | | |
| | (i) | between and including April 1 and October 31 | $ 0.30 |
| | (ii) | between and including November 1 and March 31 | $ 1.10 |
| **(h)** | **Charge per Gigajoule of Backstopping Gas** | | Sumas Daily Price[1] |
| **(i)** | **Replacement Gas**[3] | | Sumas Daily Price[1] Plus 20 Percent |
| **(j)** | **Administration Charge** per Month | | $ 78.00 |

**Rider 1** **Propane Surcharge -** Not applicable.

**Rider 2** **Recovery of July to December 2009 Approved Return on Equity and Capital Structure -** Applicable to Lower Mainland, Inland and Columbia Service Area Customers for the period January 1, 2010 to December 31, 2010. C

**Rider 3** **Earnings Sharing Mechanism -** Applicable to Lower Mainland, Inland and Columbia Service Area Customers for the Year ending December 31, 2010. C

**Rider 4** (Reserved for future use.) C

**Rider 5** **Revenue Stabilization Adjustment Charge -** Not applicable.

**Franchise Fee Charge** of 3.09% of the aggregate of the above charges is payable (in addition to the above charges) if the facilities to which Gas is delivered under Rate Schedule 22A are located within the boundaries of a municipality or First Nations lands (formerly, reserves within the *Indian Act*) to which Terasen Gas pays Franchise Fees.

**Permanent Rate Establishment -** Pursuant to British Columbia Utilities Commission Order No. G-158-09, Terasen Gas Inc. interim delivery rates are made permanent effective July 1, 2009. The 2009 deferred deficiency resulting from Order No. G-158-09 will be recovered by Rate Rider 2 from January 1, 2010 to December 31, 2010. C

**Notes:**

1. As defined under Section 2.1(1), the Sumas Daily Price quoted each day will apply to gas consumed on that gas day.

2. The demand surcharge is calculated in accordance with section 7.3 (Demand Surcharge) of Rate Schedule 22.

3. The Sumas Daily Price for the sixth Business Day following the Day for which the Peaking Gas was authorized plus 20 percent.

O

# TRANSPORTATION AGREEMENT FOR
# RATE SCHEDULES 22, 22A, 22B, 23, 25 AND 27

This Agreement is dated _______________, 20___, between Terasen Gas Inc. ("Terasen Gas") and ______________________________________________ (the "Shipper").

**WHEREAS:**

A. Terasen Gas owns and operates the Terasen Gas System; and

B. The Shipper has requested that Terasen Gas arrange for the transportation of Gas on a firm and/or interruptible basis through the Terasen Gas System to ____________________ located in or near ___________________________ British Columbia in accordance with a transportation Rate Schedule as set out below and the terms set out herein.

**NOW THEREFORE THIS AGREEMENT WITNESSES THAT** in consideration of the terms, conditions and limitations contained herein, the parties agree as follows:

## 1. Specific Information

| | |
|---|---|
| Applicable Rate Schedule: | ☐ 22 ☐ 22A ☐ 22B<br>☐ 23 ☐ 25 ☐ 27 |
| Type of Service: | ☐ Firm ☐ Interruptible<br>☐ Firm and Interruptible |
| Firm DTQ / DTQ: | _________________ Gigajoules per day |
| Shipper Agent and / or Group, if applicable: | ______________________________________ |
| Commencement Date: | ______________________________________ |
| Expiry Date: | ______________________________________<br>(only specify expiry date if term not automatically renewed as set out in the Automatic Renewal section of the applicable transportation Rate Schedule) |
| Delivery Point: | ______________________________________ |
| Pressure at the Delivery Point: | ______________________________________<br>(only specify where applicable as set out in the Gas Pressure section of the applicable transportation Rate Schedule) |
| Service Address: | ______________________________________ |
| Account Number: | ______________________________________ N |

Interconnection Point: The point at (________ km-post ________) where the Transporter's pipeline system in British Columbia interconnects with the Terasen Gas System

Address of Shipper for receiving notices:

________________________________ Attention: ____________________________
(name of Shipper)

________________________________ Telephone: ____________________________
(address of Shipper)

________________________________ Fax: ____________________________

________________________________ Email: ____________________________ N

________________________________

The information set out above is hereby approved by the parties and each reference in either this agreement or the applicable transportation Rate Schedule to any such information is to the information set out above.

## 2. Rate Schedule 22 / 22A / 22B / 23 / 25 / 27

2.1 **Additional Terms -** All rates, terms and conditions set out in the applicable transportation Rate Schedule (22, 22A, 22B, 23, 25, or 27) and the General Terms and Conditions of Terasen Gas, as any of them may be amended by Terasen Gas and approved from time to time by the British Columbia Utilities Commission, are in addition to the terms and conditions contained in this Transportation Agreement and form part of this Transportation Agreement and bind Terasen Gas and the Shipper as if set out in this Transportation Agreement.

2.2 **Payment of Amounts -** Without limiting the generality of the foregoing, the Shipper will pay to Terasen Gas all of the amounts set out in the applicable transportation Rate Schedule for the services provided under such Rate Schedule and this Transportation Agreement.

2.3 **Conflict** - Where anything in either the applicable transportation Rate Schedule or the General Terms and Conditions of Terasen Gas conflicts with any of the terms and conditions set out in this Transportation Agreement, this Transportation Agreement governs. Where anything in the applicable transportation Rate Schedule conflicts with any of the rates, terms and conditions set out in the General Terms and Conditions of Terasen Gas, the Rate Schedule governs.

2.4 **Member of a Group -** Where the Shipper will be a member of a Group which has a Shipper Agent acting as agent for the members of the Group, Shipper must complete Appendix "A" attached to this Transportation Agreement and Shipper thereby agrees that the terms and conditions of Appendix "A" form part of this Transportation Agreement and bind the Shipper as if set out in this Transportation Agreement.

2.5 **Acknowledgement -** The Shipper acknowledges receiving and reading a copy of the applicable transportation Rate Schedule (22, 22A, 22B, 23, 25 or 27) and the General Terms and Conditions of Terasen Gas and agrees to comply with and be bound by all terms and conditions set out therein. Without limiting the generality of the foregoing, where the transportation service is interruptible, the Shipper acknowledges that it is able to accommodate such interruption or curtailment and releases Terasen Gas from any liability for the Shipper's inability to accommodate such interruption or curtailment of transportation service.

**IN WITNESS WHEREOF** the parties hereto have executed this Transportation Agreement.

| | |
|---|---|
| TERASEN GAS INC. | ______________________ (here insert name of Shipper) |
| BY: ______________________ (Signature) | BY: ______________________ (Signature) |
| ______________________ (Title) | ______________________ (Title) |
| ______________________ (Name – Please Print) | ______________________ (Name – Please Print) |
| DATE: ______________________ | DATE: ______________________ |

# APPENDIX A

## NOTICE OF APPOINTMENT OF SHIPPER AGENT

1. ________________________________ (Shipper) hereby gives notice to Terasen Gas that
(Name of Shipper)
Shipper has appointed ______________________________ (the Shipper Agent) to act as
(Name of Shipper Agent)
agent for Shipper in all matters relating to gas supply and to transportation service on the Terasen Gas System. Shipper also gives notice to Terasen Gas that Shipper wishes to be a member of a Group.

2. Shipper acknowledges and agrees that the Shipper Agent will provide aggregate nominations for the Group to Terasen Gas.

3. Shipper acknowledges and agrees that if the Group includes a member which is a Shipper under Rate Schedule 22, 22A, or 22B then section 10 (Group Nominations and Balancing) of Rate Schedule 22 will apply to the Group on an aggregate basis, and the Group and its members will be subject to the Demand Surcharge provisions of Rate Schedule 22.

4. Shipper acknowledges and agrees that when there are constraints or limitations of Gas supply Terasen Gas will notify the Shipper Agent and it will then be the responsibility of the Shipper Agent to notify Shipper of any curtailment or interruption arising from the constraint or limitation of Gas supply.

5. Shipper acknowledges and agrees that the Shipper Agent will provide Gas supply priority schedules to Terasen Gas which will advise Terasen Gas of the allocation of Gas supply amongst members of the Group during constraints or limitations of Gas supply.

6. Shipper acknowledges and agrees that the Shipper Agent will provide Terasen Gas with information which will be used by Terasen Gas to bill Shipper for Backstopping Gas, C
Balancing Gas, unauthorized overrun charges and Demand Surcharges.

7. Shipper acknowledges that Terasen Gas will bill Shipper on the basis of information provided to Terasen Gas by the Shipper Agent. Shipper agrees that it is bound by the information supplied to Terasen Gas by the Shipper Agent and Shipper agrees that it will not dispute the information provided to Terasen Gas by the Shipper Agent. Shipper acknowledges that if the Shipper Agent fails to provide information to Terasen Gas then Terasen Gas will bill Shipper on the bases set out in section 3.7 of the standard form Shipper Agent Agreement of Terasen Gas. Shipper agrees to pay Terasen Gas as billed, and if Shipper Agent Agreement of Terasen Gas. Shipper agrees to pay Terasen Gas as billed, and if Shipper disagrees with any of the billing information used by Terasen Gas the Shipper will deal with the Shipper Agent to resolve that disagreement.

8. Shipper will use its best efforts to provide Terasen Gas with at least 30 days notice if Shipper wishes to leave the Group.

9. Shipper acknowledges and agrees that Terasen Gas may disband the Group pursuant to section 9 of the standard form Shipper Agent Agreement.

10. Shipper will indemnify and hold harmless each of Terasen Gas, its employees, contractors and agents from and against any and all adverse claims, losses, suits, actions, judgments, demands, debts, accounts, damages, costs, penalties and expenses (including all legal fees and disbursements) arising from any act or omission of the Shipper Agent related to the agency created by the Shipper Agent Agreement.

11. Shipper acknowledges receiving a copy of the standard form Shipper Agent Agreement of Terasen Gas.

____________________________________
(here insert name of Shipper)

BY: ________________________________
(Signature)

________________________________
(Title)

________________________________
(Name - Please Print)

DATE: ______________________________

# QUICK FACTS

## FOR THE YEAR ENDED MARCH 31, 2009

### Corporate Purpose

**BC Hydro's corporate purpose is to provide reliable power, at low cost, for generations.**

### Business of BC Hydro

BC Hydro is a commercial Crown corporation owned by the Province of British Columbia. BC Hydro is one of North America's leading providers of clean, renewable energy, and the largest electric utility in British Columbia, serving approximately 95 per cent of the province's population and 1.8 million customers. We are responsible for reliably generating between 43,000 and 54,000 gigawatt hours (GWh) of electricity. Electricity is delivered to customers through an interconnected system of 18,531 kilometres of transmission lines and 56,780 kilometres of distribution lines.

### 2009 Facts

- Net income was $366 million, compared with $369 million the year before, resulting on a return on equity of 11.75 per cent.
- Power Smart conservation programs delivered cumulative energy savings of 983 GWh—equivalent to powering 65,700 homes for a year.
- BC Hydro received decisions from the British Columbia Utilities Commission on our Residential Inclining Block Rate Application, which will help us meet the increasing costs of doing business, and the two-step Conservation rate, which will encourage conservation in October 2008. The Conservation Rate will benefit up to 70 per cent of our residential customers, who will pay less than under the previous "flat rate" structure.
- Water levels flowing into our reservoirs were 96 per cent of average for fiscal 2009, 18 per cent lower than the year before due to lower than average system inflows into our reservoirs. As a result, BC Hydro needed to purchase more energy from the market which is more expensive than energy generated from its system, increasing the overall cost of energy.
- Many of BC Hydro's power-generating facilities were built decades ago, and needed additional refurbishment and expansion to continue providing reliable electricity to British Columbians. BC Hydro is investing significant funds—$365 million over fiscal 2009 —to address our aging infrastructure.

### Energy Facts

#### Definitions

**power** = how much electricity is consumed by customers (or produced by power generators) at any instant in time

**energy** = how much is consumed (or produced) over a period of time

**capacity** = the maximum sustainable amount of energy that can be produced or carried at any instant. Example: a car engine's horsepower rating is its energy capacity

**Units of power**
- 1 kilowatt (kW) = 1,000 watts
- 1 megawatt (MW) = 1,000 kilowatts (or 1 million watts)
- 1 gigawatt (GW) = 1,000 megawatts (or 1 billion watts)

**Units of energy**
- 1 kilowatt hour (kWh) = 1,000 watts for 1 hour (1,000 watt hours)
- 1 megawatt hour (MWh) = 1,000 kWh
- 1 gigawatt hour (GWh) = 1,000 MWh

(Note that the abbreviations for prefixes follow metric convention, so kilo is k, while mega and giga are capitalized. The abbreviation for watt is W.)

**Power to Energy ratios – rule of thumb**
- Power to energy – for thermal electric: MW x 8 = GWh per year
- Power to energy – for large hydro: MW x 5 = GWh per year

#### Comparison statistics

- The average household in BC Hydro's service area uses 11,258 kWh per year.
- A large industrial customer, such as a pulp mill, might use 400 GWh in a year, equal to the consumption of 40,000 households.
- A typical large office building of 20–25 storeys will consume 5 GWh in a year, equal to the consumption of 500 households.
- A large "big box" retail outlet will consume 3.5 GWh per year, or roughly the equivalent of 350 households.
- A 1 MW micro hydro plant produces about 5 GWh per year of green energy.

BC hydro
FOR GENERATIONS

## Financial Information
(in millions)

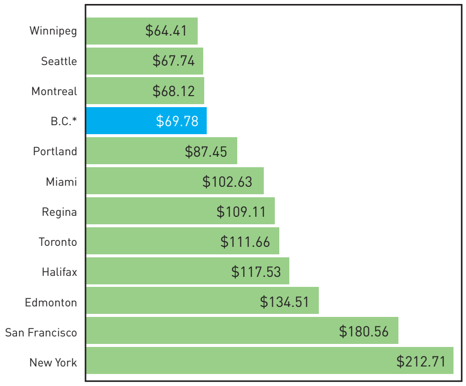
*For the years ended as at March 31*

| | 2009 | 2008 |
|---|---|---|
| Revenues | **$ 4,269** | $ 4,210 |
| Net income | **$ 366** | $ 369 |
| Property, plant and equipment and intangible assets | **$ 12,140** | $11,154 |
| Property, plant and equipment and intangible additions | **$ 1,400** | $ 1,076 |
| Net long-term debt[1] | **$ 9,135** | $ 7,519 |

[1]Consists of long-term debt, including the current portion, net of sinking funds and cash and cash equivalents.

## Residential Rates

Monthly $ Bills per 1,000 KWh




Note: All bills and average rates are in Canadian currency and exclude taxes. "B.C." refers to BC Hydro service territory. Source for rates: April 2008 Hydro Quebec Survey. The exchange rate used to convert bills in U.S. dollars into Canadian dollars is $0.9737 (CA$1 = US$0.9737), the rate in effect at noon on April 1, 2008.

## Operating Statistics

*For the years ended as at March 31*

| | 2009 | 2008 |
|---|---|---|
| Customers | | |
| Residential | **1,606,156** | 1,568,508 |
| Light industrial and commercial | **191,286** | 194,861 |
| Large industrial | **162** | 160 |
| Other | **3,434** | 3,480 |
| Trade | **290** | 257 |
| Total | **1,801,328** | 1,767,194 |
| Electricity sold *(gigawatt hours)* | | |
| Residential | **17,861** | 17,553 |
| Light industrial and commercial | **18,265** | 18,406 |
| Large industrial | **14,303** | 15,380 |
| Other | **2,083** | 1,961 |
| Total domestic | **52,512** | 53,300 |
| Trade *(electricity and gas)* | **50,799** | 51,815 |
| Total | **103,311** | 105,115 |
| Domestic Change Over Previous Year (%) | **(1.5)** | 0.7 |
| Revenues *(in millions)* | | |
| Residential | **$ 1,197** | $ 1,171 |
| Light industrial and commercial | **1,054** | 1,054 |
| Large industrial | **481** | 536 |
| Other energy sales | **82** | 183 |
| Total domestic | **2,814** | 2,944 |
| Trade | **1,455** | 1,266 |
| Total | **$ 4,269** | $ 4,210 |
| Average revenue *(per kilowatt-hour)* | | |
| Residential | **6.7¢** | 6.7¢ |
| Light industrial and commercial | **5.8** | 5.7 |
| Large industrial | **3.4** | 3.5 |
| Other | **5.3** | 6.5 |
| Trade[1] | **6.6** | 6.5 |
| Average annual kilowatt hour use per residential customer | **11,258** | 11,290 |
| Peak one-hour demand integrated system *(megawatts)* | **10,010** | 9,548 |
| Lines in service | | |
| Distribution *(kilometres)* | **56,780** | 56,297 |
| Transmission *(circuit kilometres)* | **18,531** | 18,531 |
| Number of employees[2] | **5,844** | 5,185 |

[1] The method used to calculate trade revenue per kWh is based on gross trade revenues.

[2] Includes full and part-time employees of BC Hydro and its subsidiaries.

## Generating Capacity in kW

| | Hydroelectric* | Kilowatts (kW) |
|---|---|---|
| | Aberfeldie | 25,000 |
| | Alouette | 9,000 |
| | Ash River | 28,000 |
| | Bridge River | 478,000 |
| | Cheakamus | 158,000 |
| † | Clayton Falls | 2,002 |
| | Clowhom | 33,000 |
| | Elk River | 12,000 |
| | Falls River | 7,000 |
| V | GM Shrum | 2,730,000 |
| | John Hart | 126,000 |
| | Jordan | 170,000 |
| | Kootenay Canal | 583,000 |
| | Ladore | 47,000 |
| | La Joie | 25,000 |
| R | Lake Bunzten | 72,800 |
| | Mica | 1,805,000 |
| V | Peace Canyon | 694,000 |
| R | Puntledge | 24,000 |
| V | Revelstoke | 1,980,000 |
| | Ruskin | 105,000 |
| R | Seton | 48,000 |
| | Seven Mile | 805,000 |
| R | Shuswap | 6,000 |
| | Spillimacheen | 4,000 |
| V R | Stave Falls | 91,000 |
| R | Strathcona | 64,000 |
| R | Wahleach | 65,000 |
| | Walter Hardman | 8,000 |
| | Whatshan | 54,000 |
| | | 10,258,802 |

* Maximum sustained generating capacity
R Has recreational area
V Has visitor centre
† Non-integrated area

### Thermal

| | |
|---|---|
| Burrard | 950,000 |
| Fort Nelson | 47,000 |
| Prince Rupert | 46,000 |
| | 1,040,500 |

### Diesel Generation

| | | |
|---|---|---|
| † | Ah-Sin-Heek | 6,580 |
| † | Anahim Lake | 3,650 |
| † | Atlin | 2,650 |
| † | Bella Bella | 3,300 |
| † | Dease Lake | 3,450 |
| † | Eddontenajon | 2,550 |
| † | Masset | 12,945 |
| † | Sandspit | 9,150 |
| † | Telegraph Creek | 1,800 |
| | | 46,075 |

**Total Capacity** ..........11,345,377

Generation capacity figures may vary slightly from those stated in BC Hydro's Annual Report due to recent plant upgrades/updates.

FOR GENERATIONS

BC Hydro
333 Dunsmuir Street, Vancouver
British Columbia, Canada V6B 5R3

A downloadable version of this information is available at:

bchydro.com/quickfacts

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## 1. Interfor-FortisBC- 1

**Reference:** **Information Request #1: Answer to Question 1(a) and Appendix A4b "Deposits"**

**Preamble:** **In response to Question 1 (a) FortisBC responded that its "written security deposit policy does not detail the treatment of customers above 200 kVA".**

**Requests:**

**Q1(a) Produce a copy of the written security deposit policy referenced.**

A1(a) The written security deposit referenced has been provided as Interfor Appendix A4b in response to Interfor IR No. 1 Q4b.

**Q1(b) Confirm the date that Appendix A4b was created and, if different, the date it was implemented.**

A1(b) Interfor Appendix A4b was originally created when the FortisBC Contact Centre first opened in April of 2005. There have been numerous revisions to this document, the most recent being Sept 20, 2009. This is the date of Interfor Appendix A4b.

## 2. Interfor-FortisBC - 2

**Reference: Information Request # 1: Answer to Question 1(d)**

**Preamble: In response to Question 1(d) FortisBC refused to disclose the names and usage levels of individual customers.**

**Interfor disagrees that there is any basis for refusing to provide the answer in full. In any event, and while expressly reserving its rights to seek an Order from the Commission compelling FortisBC to provide the names, Interfor submits that there should be no justification for not providing the usage levels of the 129 accounts and the amount of the security deposit(s) without naming the customers.**

**Requests:**

**Q2(a) Of the 129 accounts with demands in excess of 200 kVA as of April 2007 please indicate the usage levels of each of those accounts.**

A2(a) Please see Table Interfor IR2 A2(a) below.

## Table Interfor IR2 A2(a)

| Customer | Demand (kVA) | Customer | Demand (kVA) | Customer | Demand (kVA) | Customer | Demand (kVA) |
|---|---|---|---|---|---|---|---|
| 1 | 450.41 | 34 | 410.61 | 67 | 2690.85 | 100 | 854.50 |
| 2 | 240.98 | 35 | 1912.38 | 68 | 506.77 | 101 | 290.51 |
| 3 | 679.85 | 36 | 299.59 | 69 | 327.55 | 102 | 236.27 |
| 4 | 1175.10 | 37 | 268.28 | 70 | 757.27 | 103 | 275.24 |
| 5 | 727.20 | 38 | 620.35 | 71 | 651.67 | 104 | 254.75 |
| 6 | 602.87 | 39 | 261.00 | 72 | 246.42 | 105 | 239.35 |
| 7 | 345.25 | 40 | 1329.20 | 73 | 357.40 | 106 | 460.57 |
| 8 | 371.20 | 41 | 228.07 | 74 | 224.69 | 107 | 392.86 |
| 9 | 582.77 | 42 | 365.88 | 75 | 546.60 | 108 | 4007.67 |
| 10 | 233.61 | 43 | 519.83 | 76 | 305.00 | 109 | 353.85 |
| 11 | 2061.88 | 44 | 4977.06 | 77 | 237.00 | 110 | 316.55 |
| 12 | 60310.52 | 45 | 849.22 | 78 | 2871.23 | 111 | 270.40 |
| 13 | 265.13 | 46 | 307.00 | 79 | 419.29 | 112 | 614.02 |
| 14 | 829.48 | 47 | 308.80 | 80 | 391.56 | 113 | 255.47 |
| 15 | 385.63 | 48 | 354.50 | 81 | 398.00 | 114 | 253.65 |
| 16 | 281.08 | 49 | 266.85 | 82 | 343.41 | 115 | 517.01 |
| 17 | 226.83 | 50 | 1237.27 | 83 | 275.30 | 116 | 448.02 |
| 18 | 1025.00 | 51 | 866.01 | 84 | 328.66 | 117 | 1453.39 |
| 19 | 268.69 | 52 | 284.23 | 85 | 262.40 | 118 | 1453.39 |
| 20 | 526.24 | 53 | 316.15 | 86 | 586.70 | 119 | 250.20 |
| 21 | 1356.08 | 54 | 711.11 | 87 | 350.25 | 120 | 879.79 |
| 22 | 386.00 | 55 | 589.32 | 88 | 633.57 | 121 | 228.52 |
| 23 | 470.85 | 56 | 241.20 | 89 | 17597.56 | 122 | 562.50 |
| 24 | 296.15 | 57 | 432.00 | 90 | 7132.25 | 123 | 324.07 |
| 25 | 358.83 | 58 | 273.16 | 91 | 299.74 | 124 | 54030.69 |
| 26 | 955.97 | 59 | 265.08 | 92 | 363.27 | 125 | 353.48 |
| 27 | 598.33 | 60 | 258.11 | 93 | 607.30 | 126 | 4777.20 |
| 28 | 330.23 | 61 | 270.04 | 94 | 20390.29 | 127 | 624.48 |
| 29 | 378.92 | 62 | 268.61 | 95 | 250.40 | 128 | 2212.50 |
| 30 | 614.16 | 63 | 476.00 | 96 | 234.91 | 129 | 240.51 |
| 31 | 266.65 | 64 | 370.38 | 97 | 368.74 | | |
| 32 | 1016.57 | 65 | 293.00 | 98 | 1665.48 | | |
| 33 | 274.67 | 66 | 313.60 | 99 | 218.70 | | |

**Q2(b) Please provide the amount of the security deposit that had to be paid by the one customer referenced in A1(d)(ii) and the reason for requiring that deposit.**

A2(b) The amount of the security deposit that had to be paid by the one customer referenced in Interfor IR No. 1 A1(d)(ii) was $75.00. The reason for the deposit is unknown.

**Q2(c) How many of the 129 accounts were for customers in the wood products/lumber industry?**

A2(c) FortisBC does not keep information regarding the specific business engaged in by all of its customers. However, based on customer name, FortisBC estimates that 12 of the 129 accounts were for customers in the wood products/lumber industry.

**3. Interfor-FortisBC - 3**

**Reference: Information Request #1: Answer to Question 1(e)**

**Preamble: In response to Question 1(e) FortisBC refused to disclose the names of individual customers.**

**Interfor disagrees that there is any basis for refusing to provide the names. In any event, and while expressly reserving its rights to seek an Order from the Commission compelling FortisBC to provide the names, Interfor submits that there should be no justification for not providing the usage levels of the 16 new customers without naming the customers.**

**Requests:**

**Q3(a) Please provide the usage levels of the 10 new customers since April 1, 2007 that have been required to pay a security deposit.**

A3(a) The usage levels of the 10 new customers since April 1, 2007 that have been required to pay a security deposit are as follows:

**Table Interfor IR2 A3(a)**

| Customer | Demand (kVA) |
|---|---|
| 1 | 819.44 |
| 2 | 232.36 |
| 3 | 327.52 |
| 4 | 572.79 |
| 5 | 325.79 |
| 6 | 279.16 |
| 7 | 228.31 |
| 8 | 323.22 |
| 9 | 251.05 |
| 10 | 2253.83 |

**Q3(b) Indicate the usage levels of the 6 new customers since April 1, 2007 who were not required to pay a security deposit.**

A3(b) The usage levels of the 6 new customers since April 1, 2007 who were not required to pay a security deposit are as follows:

**Table Interfor IR2 A3(b)**

| Customer | Demand (kVA) |
|---|---|
| 1 | 282.16 |
| 2 | 446.60 |
| 3 | 364.03 |
| 4 | 562.69 |
| 5 | 283.01 |
| 6 | 239.89 |

## 4. Interfor-FortisBC - 4

**Reference: Information Request #1: Answer to Questions 1(i) and (j).**

**Preamble: In response to Questions 1 (i) and (j) FortisBC indicated that two customers had to pay a security deposit as a result of having poor payment history, but that individual negotiations occurred with each customer.**

**Requests:**

**Q4(a) Please indicate the amount of the security deposit required from each of these customers.**

A4(a) The security deposits required from each of these customers were:

**Table Interfor IR2 A4(a)**

| Customer | Deposit Amount |
|---|---|
| 1 | $ 12,000.00 |
| 2 | $ 84,500.00 |

**Q4(b) Please indicate the amount of the security deposit that would have been required had these customers been new customers with demands greater than 200 kVA.**

A4(b) FortisBC assumes that the deposit calculated in this question is based on data from the same approximate date that the deposits referenced in the response to Interfor IR No. 1 Q4(a) were originally required. Had these customers been new customers with demands greater than 200 kVA, the amount of the security deposits would have been:

**Table Interfor IR2 A4(b)**

| Customer | Deposit Amount |
|---|---|
| 1 | $ 237,858.56 |
| 2 | $ 181,770.27 |

## 5. Interfor-FortisBC - 5

**Reference: Information Request #1: Answer to Question 2(b)**

**Preamble: In response to Question 2(b) FortisBC refused to disclose the names and particulars, including the amounts of any delinquency or default on payment.**

**Interfor disagrees that there is any basis for refusing to provide the answer in full. In any event, and while expressly reserving its rights to seek an Order from the Commission compelling FortisBC to provide the answers, Interfor submits that there should be no justification for not providing the amounts of any delinquency or default on payment without naming the customers.**

**Requests:**

**Q5(c) Please provide the amount of the default for each of the four customers with demands in excess of 200 kVA that had defaulted on their accounts prior to the implementation of the policy.**

A5(c) The amount of default for all four customers with demands in excess of 200 kVA that had defaulted on their accounts prior to implementation of the policy are as follows:

**Table Interfor IR2 A5(c)**

| Customer | WO Amount | WO Type |
|---|---|---|
| 1 | $ 3,197.18 | 3rd Party Collections |
| 2 | $ 4,546.16 | 3rd Party Collections |
| 3 | $ 15,167.26 | 3rd Party Collections |
| 4 | $ 16,175.71 | Bankruptcy |

**Q5(d) Confirm the amount recovered, if any, through the referral to3rd party collections.**

A5(d) The amount recovered through the referral to 3rd party collections was $4,435.20.

**Q5(e) Provide the total amount of the debt for the account that was written off due to bankruptcy.**

A5(e) Please refer to the response to Interfor IR No. 2 Q5(c).

## 6. Interfor-FortisBC - 6

**Reference: Information Request #1: Answer to Question 2(c)**

**Preamble: In response to Question 2(c) FortisBC refused to disclose the amounts of any delinquency or default on payment.**

**Interfor disagrees that there is any basis for refusing to provide the answer. In any event, and while expressly reserving its rights to seek an Order from the Commission compelling FortisBC to provide the answers in full, Interfor submits that there should be no justification for not providing the amounts of the delinquency or default on payment without naming the customers.**

**Requests:**

**Q6(a) Please provide the amount of the default for the three customers with demands in excess of 200kVA that had defaulted on their accounts prior to the implementation of the policy.**

A6(a) FortisBC assumes this question should read "... since the implementation of the policy" rather than "… prior to the implementation of the policy" (since Q2(c) is referenced in the preamble). The default amount for the three customers with demands in excess of 200kVa that had defaulted on their accounts since the implementation of the policy are as follows:

**Table Interfor IR2 A6(a)**

| Customer | WO Amount | WO Type |
|---|---|---|
| 1 | $ 851,701.54 | Bankruptcy |
| 2 | $ 21,538.54 | 3rd Party Collections |
| 3 | $ 12,407.89 | 3rd Party Collections |

**Q6(b) Confirm the amount recovered, if any, through the referral to 3rd party collections.**

A6(b) The amount recovered through referral to third party collections was $21,538.54

**Q6(e) Provide the total amount for the debt for the account that was written off due to bankruptcy.**

A6(e) Please refer to the response to Interfor IR No. 2 Q6(a).

**7. Interfor-FortisBC -**

**Reference: Information Request #I: Answer to Question 2(d)**

**Preamble: In response to Question 2(d), FortisBC indicated that 3 of 86 customers since the implementation of the policy had been required to pay a security deposit.**

**Requests:**

**Q7(a) What was the reason for those 3 customers being required to pay a security deposit?**

A7(a) As a condition of continuing service, security deposits were required for all 3 existing customers because the customer either exhibited poor payment history or requested an increase in their demand limit.

**8. Interfor-FortisBC - 8**

**Reference: Information Request #1: Answer to Question 2(e)**

**Preamble: In response to IR 1 Question 2(c) FortisBC refused to disclose the names and particulars, including the amounts of any delinquency or default on payment and the particulars of any security deposit.**

**Interfor disagrees that there is any basis for refusing to provide the answer in full In any event, and while expressly reserving its rights to seek an Order from the Commission compelling FortisBC to provide the answers, Interfor submits that there should be no justification for not providing the amounts of the delinquency or default on payment and the particulars of any security deposit without naming the customers.**

**Requests:**

**Q8(a) With respect to the seven customers with demands in excess of 200 kVA that had defaulted on their accounts prior to the implementation of the policy, provide the amount of each of the defaults.**

A8(a) FortisBC has assumed this question should read “had defaulted on their accounts in the past 10 years” (since it references Q 2(e) in the preamble). The amount of each of the defaults for the seven customers is as follows:

**Table Interfor IR2 A8(a)**

| Customer | WO Amount |
|---|---|
| 1 | $ 21,538.54 |
| 2 | $ 16,175.71 |
| 3 | $ 15,167.26 |
| 4 | $ 12,407.89 |
| 5 | $ 3,197.18 |
| 6 | $ 4,546.16 |
| 7 | $ 851,701.54 |

**Q8(b) Provide a breakdown of the amount of the debt for each of the seven customers that FortisBC was unable to collect from and indicate for whom security deposits had been required and the amount of those security deposits, if any.**

A8(b) For each of the 7 customers, the following table shows the original amount of debt, any applicable recoveries, the outstanding balance and any security deposit(s) the customer was charged.

**Table Interfor IR2 A8(b)**

| Customer | WO Amount | Recovery | Balance | Deposit |
|---|---|---|---|---|
| 1 | $ 21,538.54 | $ 21,538.54 | $ - | $ - |
| 2 | $ 16,175.71 | $ 1,100.00 | $ 15,075.71 | $ 5,194.00 |
| 3 | $ 15,167.26 | $ - | $ 15,167.26 | $ - |
| 4 | $ 12,407.89 | $ - | $ 12,407.89 | $ - |
| 5 | $ 3,197.18 | $ - | $ 3,197.18 | $ - |
| 6 | $ 4,546.16 | $ 4,435.20 | $ 110.96 | $ - |
| 7 | $ 851,701.54 | $ - | $ 851,701.54 | $ 75,000.00 |

**9. Interfor-FortisBC - 9**

**Reference: Information Request #1: Answer to Question 2(f) and "Table Interfor A2f"**

**Q9(a) Please explain how the write-off of $3,542,021 was dealt with from an accounting perspective, with reference to financial statements and other documents.**

A9(a) All of the $3,542,021 except $709,000 of Industrial revenue has been written off to allowance for doubtful accounts. The $709,000 exception was deferred from 2008 and expensed as amortization expense in 2009 as per BCUC Orders G-147-07 and G-193-08 to recognize the uncertainty in the Forest Industry load forecast of 2008. Please also refer to the response to Interfor IR No. 2 Q9(d).

**Q9(b) Confirm the time period for "Table Interfor A2f' is *January 1, 2007* to *December 31, 2009*. If not, please revise the Table to include that time period.**

A9(b) The time period for IR No. 1, Table Interfor A2f is January 1, 2007 to December 30, 2009. December 30, 2009 reflects FortisBC's fiscal year end.

**Q9(c) Please revise "Table Interfor A21" to include the total number of customers by rate class.**

A9(c) Please see Table Interfor IR2 A9(c) below.

**Table Interfor IR2 A9(c)**

| | Revenue ($) | Write Offs ($) | WO % Revenue | Total Number of Customers[1] |
|---|---|---|---|---|
| General Service | 158,309,461 | 309,921 | 0.196% | 11,308 |
| Industrial | 46,761,361 | 873,240 | 1.867% | 33 |
| Irrigation | 7,729,936 | 6,318 | 0.082% | 1,066 |
| Lighting | 5,435,933 | 2,747 | 0.051% | 1,874 |
| Residential | 303,174,604 | 2,349,795 | 0.775% | 96,565 |
| Wholesale | 138,346,059 | - | 0.000% | 7 |
| | **659,757,354** | **3,542,021** | | **110,853** |

[1] Number of customers as at December 30, 2009.

**Q9(d) Please produce the same Table for the periods January 1, 2001 to December 31, 2003 and January 1, 2004 to December 31, 2006. Include the total number of customers by rate class and provide an explanation of how the write-offs were dealt with from an accounting perspective, with reference to financial statements and other documents.**

A9(d) For the period January 1, 2001 to June 1, 2005 customer accounts were written off directly to bad debt expense as a period expense. Beginning June 2005 the Company began accruing a provision or allowance for doubtful accounts and expensing the accrual to bad debt expense in the period. Actual customer accounts written off are booked to the allowance for doubtful accounts. Please see Tables Interfor IR2 A9(d)(i) and A9(d)(ii) below.

### Table Interfor IR2 A9(d)(i)

| | January 1, 2001 to December 31, 2003 Over 200 kVa | | | |
|---|---|---|---|---|
| | **Customers at 12/31/2003** | **Billed Amounts** | **Write Offs** | **WO % Revenue** |
| General Service | 9,585 | $99,482,000 | $258,196 | 0.26% |
| Industrial | 38 | $46,684,000 | - | 0.00% |
| Irrigation[1] | 1,263 | $8,074,000 | $3,197 | 0.04% |
| Lighting | 2,002 | $2,733,000 | $9,703 | 0.36% |
| Residential | 82,174 | $192,074,000 | $1,490,120 | 0.78% |
| Wholesale | 8 | $104,165,000 | - | 0.00% |
| **Total** | **95,070** | **$453,212,000** | **$1,761,217** | |

[1] In 2001 the Irrigation and Lighting figures were recorded as one balance. The total balance for 2001 is included as part of the Irrigation rate class.

### Table Interfor IR2 A9(d)(ii)

| | January 1, 2004 to December 31, 2006 | | | |
|---|---|---|---|---|
| | **Customers at 12/31/2006** | **Billed Amounts** | **Write Offs** | **WO % Revenue** |
| General Service | 10,285 | $125,291,000 | $295,403 | 0.24% |
| Industrial | 37 | $54,899,000 | - | 0.00% |
| Irrigation | 997 | $6,230,000 | - | 0.00% |
| Lighting | 1,905 | $4,625,000 | $25,559 | 0.55% |
| Residential | 89,181 | $240,093,000 | $2,436,796 | 1.01% |
| Wholesale | 8 | $130,225,000 | - | 0.00% |
| **Total** | **102,413** | **$561,363,000** | **$2,757,758** | |

**Q9(e) Please produce the same Table, but limited only to customers with demands greater than 200 kVA, for January 1, 2001 to December 31, 2003; January 1, 2004 to December 31, 2006; and January 1, 2007 to December 31, 2009. Include the total number of customers with demands greater than 200 kVA by rate class.**

A9(e) Please see Tables Interfor IR2 A9(e)(i), A9(e)(ii) and A9(e)(iii)below. Note, all write-offs are net of any recoveries received.

**Table Interfor IR2 A9(e)(i)**

| | **January 1, 2001 to December 31, 2003 Over 200 kVA** | | | |
|---|---|---|---|---|
| | **Customers at 12/31/2003** | **Billed Amounts** | **Write Offs** | **WO % Revenue** |
| General Service | 92 | $26,481,876 | $0 | 0.00% |
| Industrial | 31 | $43,222,996 | $3,197 | 0.01% |
| Irrigation | 0 | - | - | 0.00% |
| Lighting | 0 | - | - | 0.00% |
| Residential | 0 | - | - | 0.00% |
| Wholesale | 8 | $110,035,766 | - | 0.00% |
| **Total** | **131** | **$179,740,638** | **$3,197** | **0.00%** |

**Table Interfor IR2 A9(e)(ii)**

| | January 1, 2004 to December 31, 2006 Over 200 kVA | | | |
|---|---|---|---|---|
| | **Customers at 12/31/2006** | **Billed Amounts** | **Write Offs** | **WO % Revenue** |
| General Service | 96 | $33,398,621 | $31,457 | 0.09% |
| Industrial | 29 | $50,816,722 | - | 0.00% |
| Irrigation | 0 | - | - | 0.00% |
| Lighting | 0 | - | - | 0.00% |
| Residential | 0 | - | - | 0.00% |
| Wholesale | 8 | $137,127,625 | - | 0.00% |
| **Total** | **133** | **$221,342,968** | **$31,457** | |

**Table Interfor IR2 A9(e)(iii)**

| | January 1, 2007 to December 31, 2009 Over 200 kVA | | | |
|---|---|---|---|---|
| | **Customers at 12/31/2009** | **Billed Amounts** | **Write Offs** | **WO % Revenue** |
| General Service | 135 | $42,435,588 | $12,398 | 0.03% |
| Industrial | 20 | $32,668,765 | $851,701 | 2.61% |
| Irrigation[1] | 0 | $171,982 | - | 0.00% |
| Lighting | 0 | - | - | 0.00% |
| Residential | 0 | - | - | 0.00% |
| Wholesale | 7 | $139,960,039 | - | 0.00% |
| **Total** | **162** | **$215,236,374** | **$864,099** | |

[1] Irrigation customers over 200 KVA existed within the 3 year reporting period but not at the end of the period which is the point in time that the customer count was taken.

## 10. Interfor-FortisBC - 10

**Reference: Information Request #1: Answer to Question 3(c)**

**Preamble: In response to Question 3(c) FortisBC refused to disclose the names and respective demands.**

**Interfor disagrees that there is any basis for refusing to provide the answer in full. In any event, and while expressly reserving its rights to seek an order from the Commission compelling FortisBC to provide the answers, Interfor submits that there should be no justification for not providing the respective demands without naming the customers.**

**Requests:**

**Q10(a) Please provide the respective demands of the 162 accounts as of December 18, 2009 with demand in excess of 200 kVA.**

A10(a) The respective demands of the 162 accounts as of December 18, 2009 with demand in excess of 200 kVA are provided in Table Interfor IR2 A10(a) below.

1 **Table Interfor IR2 A10(a)**

| Customer | Demand (kVA) | Customer | Demand (kVA) | Customer | Demand (kVA) | Customer | Demand (kVA) |
|---|---|---|---|---|---|---|---|
| 1 | 432.43 | 42 | 251.88 | 83 | 3005.04 | 123 | 803.66 |
| 2 | 928.84 | 43 | 319.66 | 84 | 439.91 | 124 | 253.61 |
| 3 | 1167.29 | 44 | 973.97 | 85 | 239.03 | 125 | 378.13 |
| 4 | 616.32 | 45 | 400.31 | 86 | 730.61 | 126 | 274.36 |
| 5 | 584.17 | 46 | 1849.20 | 87 | 685.24 | 127 | 446.60 |
| 6 | 231.62 | 47 | 309.58 | 88 | 303.30 | 128 | 259.74 |
| 7 | 306.48 | 48 | 258.33 | 89 | 323.58 | 129 | 292.30 |
| 8 | 371.10 | 49 | 616.24 | 90 | 320.24 | 130 | 258.24 |
| 9 | 306.82 | 50 | 570.27 | 91 | 429.81 | 131 | 320.42 |
| 10 | 1889.17 | 51 | 245.50 | 92 | 481.81 | 132 | 434.86 |
| 11 | 47939.85 | 52 | 1291.75 | 93 | 304.77 | 133 | 388.34 |
| 12 | 224.33 | 53 | 228.07 | 94 | 286.20 | 134 | 2875.31 |
| 13 | 4184.39 | 54 | 343.57 | 95 | 1631.88 | 135 | 286.84 |
| 14 | 908.41 | 55 | 530.14 | 96 | 383.42 | 136 | 317.83 |
| 15 | 245.22 | 56 | 507.39 | 97 | 509.05 | 137 | 231.49 |
| 16 | 1120.35 | 57 | 833.54 | 98 | 289.88 | 138 | 303.98 |
| 17 | 491.04 | 58 | 284.83 | 99 | 371.46 | 139 | 702.31 |
| 18 | 298.48 | 59 | 340.14 | 100 | 318.86 | 140 | 253.49 |
| 19 | 296.79 | 60 | 295.05 | 101 | 327.45 | 141 | 245.89 |
| 20 | 289.01 | 61 | 302.51 | 102 | 281.02 | 142 | 4321.03 |
| 21 | 451.42 | 62 | 258.90 | 103 | 264.68 | 143 | 262.60 |
| 22 | 268.09 | 63 | 1232.79 | 104 | 275.68 | 144 | 535.36 |
| 23 | 441.73 | 64 | 963.33 | 105 | 221.68 | 145 | 397.16 |
| 24 | 2103.62 | 65 | 458.71 | 106 | 599.07 | 146 | 1252.38 |
| 25 | 258.32 | 66 | 380.10 | 107 | 229.84 | 147 | 247.80 |
| 26 | 369.25 | 67 | 221.36 | 108 | 261.60 | 148 | 861.11 |
| 27 | 2395.43 | 68 | 684.06 | 109 | 387.23 | 149 | 334.11 |
| 28 | 423.44 | 69 | 297.67 | 110 | 341.26 | 150 | 1748.07 |
| 29 | 333.51 | 70 | 742.66 | 111 | 672.02 | 151 | 568.45 |
| 30 | 334.93 | 71 | 433.21 | 112 | 19022.00 | 152 | 356.35 |
| 31 | 812.54 | 72 | 343.13 | 113 | 7201.33 | 153 | 54675.25 |
| 32 | 280.78 | 73 | 227.67 | 114 | 211.17 | 154 | 252.37 |
| 33 | 562.88 | 74 | 260.31 | 115 | 247.26 | 155 | 1629.33 |
| 34 | 292.08 | 75 | 229.77 | 116 | 305.92 | 156 | 847.56 |
| 35 | 368.20 | 76 | 243.23 | 117 | 552.29 | 157 | 227.96 |
| 36 | 8019.48 | 77 | 251.94 | 118 | 25438.22 | 158 | 384.18 |
| 37 | 568.20 | 78 | 338.14 | 119 | 546.41 | 159 | 592.65 |
| 38 | 620.55 | 79 | 422.92 | 120 | 238.81 | 160 | 3011.90 |
| 39 | 230.15 | 80 | 312.49 | 121 | 399.98 | 161 | 251.99 |
| 40 | 986.24 | 81 | 291.34 | 122 | 1588.11 | 162 | 241.69 |
| 41 | 350.65 | 82 | 316.91 | | | | |

**11. Interfor-FortisBC - 11**

**Reference: Information Request #1: Answer to Question 3(i)**

**Preamble: In response to Question 3(i) FortisBC had indicated that security deposits are "currently required for new general service customers with demand below 200 kVA."**

**Requests:**

**Q11(a) Why does FortisBC require security deposits from new general service customers with demand below 200 kVA?**

A11(a) FortisBC requires security deposits from general service customers below 200 kVA to reduce ratepayer exposure to bad debt risk.

**12. Interfor-FortisBC - 12**

**Reference: Information Request #1: Answer to Question 3(k)**

**Preamble: In response to Question 3(k) FortisBC had indicated that it will "continue to monitor [the] payment history" of customers prior to the implementation of the policy with demands of over 200 kVA.**

**Requests:**

**Q12(a) Please confirm what steps FortisBC has taken since implementation of the policy to monitor the credit status of existing customers. Provide specifics including dates.**

A12(a) FortisBC continues to monitor the credit status of existing customers using automated credit and collection reporting on missed payments. The Company also generates a monthly report that details the account status of specific accounts that could potentially have a higher credit risk. FortisBC does not have information regarding the date of implementation of these steps, but can confirm that the automated reporting existing prior to the implementation of the policy and that the initiation of the monthly report on specific accounts occurred after to the implementation of the policy.

**Q12(b) Does FortisBC perform random audits of customers' accounts? If so, please provide specifics including the number of audits, and the dates the audits were performed.**

A12(b) No, FortisBC does not perform random audits of customers' accounts. Please also refer to the response to Interfor IR No. 2 Q12(a).

**Q12(c) Does FortisBC randomly require customers to provide ongoing financial information confirming their credit status? If so, please provide specifics including the information required, the number of customers and the dates.**

A12(c) No, FortisBC does not randomly require customers to provide ongoing financial information confirming their credit status. Please also refer to the response to Interfor IR No. 2 Q12(a).

## 13. Interfor-Fortis - 13

**Reference: British Columbia Hydro and Power Authority's ("BC Hydro") Electric Tariff, effective April 1, 2008. https: //www.bchydro. com/etc/med i al ib/intemet/documents/appcontent/y our account/BC_Hydro Electric Tariff.Par.0001..File.policies I459.pdf**

**Requests:**

**Q13(a) Please indicate whether FortisBC agrees with the following facts:**

**Q13(a)(i) BC Hydro does not require a security deposit from new customers where the customer can establish satisfactory credit.**

A13(a)(i) FortisBC does not have knowledge of how BC Hydro applies the referenced Electric Tariff, including the establishment of "satisfactory credit".

**Q13(a)(ii) Unlike FortisBC, BC Hydro's terms and conditions do not require a mandatory security deposit for customers with contractual demand over a set limit.**

A13(a)(ii) The terms and conditions in the referenced Electric Tariff does not appear to require a mandatory security deposit from any customer, but FortisBC notes that Schedules 1255, 1256, 1265, 1266 have a special condition: "Where the Customer's demand is or is likely to be in excess of 45 kVA, then BC Hydro may require that supply to such Customer be by special contract and that such supply be subject to such special conditions as BC Hydro, in its sole discretion, considers necessary to insert in the Customer's special contract." Presumably such special conditions could include a mandatory security deposit.

**Q13(a)(iii) BC Hydro only requires security deposits where an applicant has not established credit satisfactory to BC Hydro or where an existing customer has not maintained a credit history satisfactory to BC Hydro.**

A13(a)(iii) FortisBC does not have knowledge of how BC Hydro applies the referenced Electric Tariff, including the establishment of "satisfactory credit".

**Q13(a)(iv) In circumstances where BC Hydro requires a security deposit, it allows for the return of the deposit when the customer has (1) maintained an account with BC Hydro for the immediately preceding one year; and (2) paid every amount due within one month of the billing date on every bill rendered during such period.**

A13(a)(iv) FortisBC does not have knowledge of how BC Hydro applies the referenced Electric Tariff, but acknowledges that the Tariff allows the return of a deposit.

## 14. Interfor-Fortis - 14

**Reference: EPCOR Energy Alberta Inc.'s ("EPCOR") Regulated Rate Tariff --Terms and Conditions, effective August 1, 2008. http://www.epcor.ca/SiteCollectionDocuments/Retai1%20and%2OMass%o20Market/pdfs/EEAI%20RRT%20Terms%20and%2OConditions,.pdf**

**Requests:**

**Q14(b) Please indicate whether FortisBC agrees with the following facts:**

**Q14(b)(i) EPCOR does not require a security deposit from new customers where the customer can establish satisfactory credit.**

A14(b)(i) FortisBC does not have knowledge of how EPCOR applies the referenced Regulated Rate Tariff, including the establishment of “satisfactory credit”.

**Q14(b)(ii) Unlike FortisBC, EPCOR's terms and conditions do not require a mandatory security deposit for customers with contractual demand over a set limit.**

A14(b)(ii) The referenced terms and conditions do not appear to require a mandatory security deposit for customers with contractual demand over a set limit.

**Q14(b)(iii) EPCOR may require a deposit in the following certain circumstances:**

- **if the prospective Customer making the application for service cannot demonstrate a satisfactory credit rating to EPCOR**
- **the existing customer has paid two consecutive bills late, in any twelve month period or three non-consecutive bills late in any twelve month period;**
- **the Customer has issued more than one payment that has. Been returned for non-sufficient funds in any six month period;**
- **there has been more than a 50% increase in the Customer's average monthly consumption of Energy over the prior six month period;**
- **the Customer's service was disconnected for non-payment by EPCOR;**
- **the Customer makes a request for re-connection of service after having been disconnected for non-payment by EPCOR; or**
- **the Customer making the application for service has a credit rating which is not satisfactory to EPCOR or the Customer has refused to provide credit information to EPCOR.**

A14(b)(iii) The above circumstances appear to be a paraphrasing of Section 5.1 of the EPCOR Energy Alberta Inc. Regulated Rate Tariff – Terms and Conditions, Effective August 1, 2008.

**Q14(b)(iv) EPCOR may waive the requirement for a deposit in the following circumstances:**

- **where the Customer has a previous good payment history with EPCOR;**
- **where a result satisfactory to EPCOR is obtained from an external credit check;**
- **where the Customer can demonstrate, to the satisfaction of EPCOR, a previous good payment history with another utility;**
- **where the Customer provides a co-signor who has a credit rating acceptable to EPCOR who agrees to be personally and severally responsible for payment of any and all amounts payable by the Customer under EPCOR's Terms and Conditions; or**
- **where the Customer provides to EPCOR an indemnity bond or irrevocable letter of credit from a financial institution satisfactory to EPCOR.**

A14(b)(iv) The above circumstances appear to be a paraphrasing of Section 5.2 of the EPCOR Energy Alberta Inc. Regulated Rate Tariff – Terms and Conditions, Effective August 1, 2008.

**Q14(b)(v) If a deposit is required, EPCOR will return the deposit to the customer after a satisfactory payment history over a period of 12 consecutive months.**

A14(b)(v) FortisBC does not have knowledge of how EPCOR applies the referenced Regulated Rate Tariff, including the return of deposits.

## 15. Interfor-Fortis - 15

**Reference: FortisAlberta Inc.'s ("FortisAlberta") Interim 2010 Customer Terms and Conditions, effective January 1, 2010, http://www.fortisalberta.com/data/l/rec docs/707Interim2010CustomerTermsAndConditions 2009-1Q-1.6 Appendix2.pdf**

**Requests:**

**Q15(c) Please indicate whether FortisBC agrees with the following facts:**

**Q15(c)(i) FortisAlberta does not require a security deposit from new customers where the customer can establish satisfactory credit.**

A15(c)(i) FortisBC does not agree. Unlike FortisBC, FortisAlberta is a Distribution Wire Owner only and does not operator as a retailer. As such, FortisAlberta only bills electricity Retailers directly for the use of electricity. As per Distribution Tariff Regulation A.R. 162/2003, all Retailers must provide security acceptable to FortisAlberta as per Article 6 – Prudential Requirements in our Retailer Terms and Conditions. This could be in the form of cash deposit, bond, letter of credit, bank guarantee etc. FortisAlberta requires that retailers satisfy security requirements to ensure that the Retailer is and remains of sufficient financial standing to meet its ongoing financial obligations. FortisAlberta reserves the right to re-evaluate the security requirements of a Retailer on a regular basis, and to require additional security where appropriate. Additional details can be found in section 6.0 of FortisAlberta's Interim 2010 Retailer Terms and Conditions of Distribution Access Service.

**Q15(c)(ii) Unlike FortisBC, FortisAlberta's terms and conditions do not require a mandatory security deposit for customers with contractual demand over a set limit.**

A15(c)(ii) Please refer to the response to Interfor IR No. 2 Q15(c)(i).

**Q15(c)(iii) FortisAlberta only requires a security deposit to cover cancellation costs for project design work or construction of facilities that are required to establish service.**

A15(c)(iii) FortisBC does not agree. FortisAlberta also requires a security deposit from Retailers based on the conditions described in the response to Interfor IR No. 2 Q15(c)(i) above.

## 16. Interfor-Fortis -1b

**Reference: SaskPower's Account Collection Policy, effective September 7, 2007. http://www.saskpower.com/pubs/pdf/busadminman/SP_30_Collections_Policy.pdf**

**Requests:**

**Q16(d) Please indicate whether FortisBC agrees with the following facts:**

**Q16(d)(i) SaskPower does not require a security deposit from new customers where the customer can establish satisfactory credit.**

A16(d)(i) FortisBC does not have knowledge of how SaskPower applies the referenced policy, and including the establishment of "satisfactory credit".

**Q16(d)(ii) Unlike FortisBC, SaskPower does not require a mandatory security deposit for customers with contractual demand over a set limit.**

A16(d)(ii) FortisBC does not have knowledge of how SaskPower applies the referenced policy, including whether the deposit requirements change for customers with demand over a set limit.

**Q16(d)(iii) SaskPower only requires a security deposit:**

- **prior to connecting a customer that has a current outstanding debt with SaskPower and, as a consequence, has been listed on SaskPower's Bad Debt File, including bankrupts;**
- **prior to connecting a customer whose electrical services have been disconnected or curtailed by a load limiting device for non-payment of the customer's account;**
- **prior to connecting a customer at an additional service location, when the customer is already receiving service at one location and has an existing security deposit; or**
- **from new general service customers that have no previous credit history with SaskPower and that fall into 30-day arrears within the first 12 months of their billing.**

A16(d)(iii) The above circumstances appear to be a paraphrasing of a portion of Section 4 of the SaskPower Accounts Collection Policy effective September 7, 2007.

**Q16(d)(iv) In circumstances where SaskPower requires a security deposit, the deposit will be refunded after a period of 12 months for residential or farm accounts and 24 months for general service accounts provided the account has not been in 60 day (or greater) arrears two or more times in the preceding 12 month period.**

A16(d)(iv) The above circumstances appear to be a paraphrasing of a portion of Section 4 of the SaskPower Accounts Collection Policy effective September 7, 2007.

**17. Interfor-Fortis - 17**

**Reference: Terasen Gas Inc.'s ("Terasen Gas") General Terms and Conditions, effective January 1, 2004. http://www.terasengas.com/documents/ratestariffs/Terasen_GeneralTermsandConditions.pdf**

**Requests:**

**Q17(e) Please indicate whether FortisBC agrees with the following facts:**

**Q17(e)(i) Terasen Gas does not require a security deposit from new customers where the customer can establish satisfactory credit.**

A17(e)(i) FortisBC does not agree. Terasen Gas requires all new commercial and industrial customers to provide a security deposit.

**Q17(e)(ii) Terasen Gas only requires security deposits where an applicant has not established credit satisfactory to Terasen Gas or where an existing customer has not maintained credit satisfactory to Terasen Gas.**

A17(e)(ii) FortisBC does not agree. Terasen Gas can require industrial customers on Rate Schedules 22, 23, 25 and 27 to provide a security deposit or an irrevocable letter of credit in order to ensure prompt and orderly payment as per Section 3.2 of those Rate Schedules.

## 18. Interfor-Fortis - 18

**Requests:**

**Q18(a) Since April1, 2007, how many customers have requested an increase to their demand that has resulted in them having a demand greater than 200 kVA?**

A18(a) Since April 1, 2007, no customers that had demand below 200 kVA at April 1, 2007 have requested an increase to their demand limit that has resulted in them having a demand greater than 200 kVA.

**Q18(b) How many of these customers have been required to pay a security deposit? Provide the amount of those security deposits without identifying the customer.**

A18(b) Please refer to the response to Interfor IR No. 2 Q18(b) above.

**Q18(c) What would the amount of the security deposits have been if they were new customers?**

A18(c) Please refer to the response to Interfor IR No. 2 Q18(b) above.

**In order to reduce costs and increase efficiency of the BCUC proceedings, Okanagan Environmental Industry Alliance, Natural Resource Industries and Hedley Improvement District have contributed together and are supportive of this Information Request.**

## 1.0 Energy Conservation and Efficiency in RDA

**FortisBC notes in its 2009 Rates Design Application a response to Information Request #1 (RDA IR #1 Response) OEIA/NRI/HID Q3.3[1].**

**FortisBC noted in its application:**

> ***"This RDA is a key component of FortisBC's energy conservation and efficiency strategy."[2]***

**OEIA requested in regards to this statement:**

> ***"Please indicate[d] the extent to which the conservation due to rates is expected to contribute to FortisBC's energy conservation targets."[3]***

**FortisBC replied:**

> ***"The Company has not quantified the incremental conservation due to the proposed rate changes, but has commissioned a study on the effect of time-based rates as described on page 24 of the Application (Exhibit B-1)."[4]***

**Q1.1 On page 24 of Exhibit B-1, there are 4 steps described with several mentions of "*study*". Please confirm the "*study*" as mentioned in FortisBC's answer is the study as discussed in step 1, lines 18 to 20. If not, please clarify.**

A1.1 Confirmed.

[1] Exhibit B-3-6
[2] Exhibit B-3-6, OEIA/NRI/HID IR#1 Q3.0 & Exhibit B-1, Section 2.1, Page 11, Lines 25-26
[3] Exhibit B-3-6, OEIA/NRI/HID IR#1 Q3.3
[4] Exhibit B-3-6, OEIA/NRI/HID IR#1 A3.3

**Q1.2 Please clarify if the answer provided by FortisBC describes the full extent in which rates are expected to contribute to the energy conservation targets. In other words, is the "*study during 2009 and 2010 that examines the typical effects of time-based rates on energy and demand*"[5] intended to cover the full extent to which rates are expected to contribute to the energy conservation targets? If not, please describe the full extent and other approaches.**

A1.2 The rates proposed in this Rate Design Application are expected to contribute to energy conservation targets. The referenced study will help FortisBC design time-based rates that further contribute to achieving energy conservation targets. FortisBC believes that its strategy for achieving energy conservation with rate design is well described in the Application (Exhibit B-1), and in particular in Sections 2.3 and 2.4.

[5] Exhibit B-1, Page 24, Lines 18-20

## 2.0 Conservation Potential Review

**FortisBC notes:**

***"The RDA will be an important consideration in determining the achievable potential in the 2010 Conservation Potential Review (currently under development), and the CPR in turn will be the primary reference document for the 2011 DSM plan."6***

**Q2.1 Please describe how the RDA will help determine the achievable potential in the CPR.**

A2.1 The overall achievable and cost-effective potential over the 20-year period is based on the avoided cost of electricity and not the retail rates. The rate impacts will come into play in how fast this potential can be achieved or accelerated, i.e. the ramp rates of the conservation measures.

[6] Exhibit B-3-6, OEIA/NRI/HID IR#1 Q3.0 & Exhibit B-1, Section 2.1, Page 11, Lines 25-26

**Q2.2 Please provide the Terms of References for the CPR.**

A2.2 The scope of work for the CPR is:

- Reviewing the previous DSM Study undertaken by FortisBC in the early 1990s and subsequent updates in 2000 and 2005 and have an understanding of recent utility-sponsored Conservation Demand Management (“CDM”);
- Recommending data structures for determining CDM potential within each of three sectors: residential, commercial and industrial;
- Preparing a CDM Potential Study. The Consultant shall provide analysis to calculate and report on CDM potential for each of the three sectors (residential, commercial and industrial), both conservation and demand reduction;
- Conservation with commensurate peak load impacts includes, but is not limited to, energy efficiency measures, behavioural energy savings, and Customer owned generation (COG); and
- Demand Response includes, but is not limited to, load controls, contractual DR and measures e.g. Electric Thermal Storage.

Significant aspects of the CDM Potential Study shall include:

- Identifying and cataloguing CDM technology options for residential, commercial and industrial sectors;
- Preparing technical and economic achievable CDM potential;
- Identifying program concepts, program costs and achievable CDM; and
- Preparing economic cost benefit analyses.

**Q2.3 FortisBC notes that the CPR is "*currently under development*" – when does FortisBC expect the CPR to be complete?**

A2.2 The CPR is expected to be complete in the first half of 2010.

## 3.0 Study Release

**FortisBC notes that:**

> ***"The AMI Future Program study was initiated on December 2009 and is expected to be complete by the end of March 2010."7***

**Q3.1 Will this study be released and available for public review? If so, when will it be available for public review? If not, why not.**

A3.1 FortisBC expects to include this study as part of the AMI CPCN Application submission expected in the last quarter of 2010.

**Q3.2 Please provide the Terms of Reference for this study.**

A3.2 The primary objective of the AMI Study is to provide cost and benefit analysis for future programs enabled by AMI technology. This information will be utilized in the AMI business case and the eventual reapplication for the AMI project.

In order to achieve the objective, the AMI DSM study will:

- Research and compile cost and benefit information on DSM program pilots and implemented programs related to the following:
  - Time of Use Rates
  - Critical Peak Pricing Rates
  - In-home display units (both on their own and for the purpose of supporting time-based rates)
- Compare and contrast usage and benefit results of these studies to those that can be expected by FortisBC taking into account FortisBC's service area and customer demographics.

- Provide a report summarizing both cost and benefit information for use in the AMI CPCN.

## 4.0 Factors for AMI CPCN Application

**FortisBC notes that:**

> ***"The AMI CPCN application is expected to be filed in the 4th quarter of 2010. However, this is dependent on several factors including the issuance of Smart Meter Regulations made pursuant to the Utilities Commission Act." 8***

**Q4.1 Please list and describe all the factors other than the issuance the regulations on which the AMI CPCN is dependent on.**

A4.1 FortisBC cannot predict all factors that could influence the filing of an AMI CPCN, however, some factors which could impact the filing date are:

- Regulatory schedules;
- Vendor response to the RFP; and
- The timing and extent of utility collaboration

**Q4.2 Please describe the stakeholder engagement before the AMI CPCN application is filed.**

A4.2 FortisBC has not yet finalized consultation plans for the AMI CPCN Application, however, that consultation is likely to include presentations to the DSM Advisory Committee and First Nations, as well as customer workshops in the various areas of the service territory.

[7] Exhibit B-3-6, Page 6, OEIA/NRI/HID IR#1 A5.1.1
[8] Exhibit B-3-6, Page 7, OEIA/NRI/HID IR#1 A5.1.2

**Q4.3 When the AMI CPCN application is filed please describe in detail the extent to which it may or may not include the introduction of time of use or other rate structures.**

A4.3 The AMI CPCN will include a long term plan relating to AMI-enabled technologies and programs such as conservation rates. However, since the AMI Future Program Study has not yet been completed and the AMI CPCN Application is still under development, the extent to which it will include the introduction of time based rates is not known.

## 5.0 Study Date

**FortisBC notes that:**

> ***"The results of the AMI future program study expected within the first quarter next year . . . " 9***

**Q5.1 This statement seems to contradict the information provided in OEIA/NRI/HID IR#1 A5.1.1 in which FortisBC indicated the study would be complete in March 2010[10]. Please confirm that the "*next year*" in the above statement refers to the year 2010.**

A5.1 Confirmed.

[9] Exhibit B-3-6, Page 8, OEIA/NRI/HID IR#1 A5.2
[10] Exhibit B-3-6, Page 6, OEIA/NRI/HID IR#1 A5.1.1

## 6.0 Time period up to 2013/2014

**FortisBC notes that in regards to the expected date of stage 4[11]:**

> ***"It is likely that information could be consolidated for the purposes of filing time-based rates within six months after 'Stage 3' is complete. However, the filing of any Rate Design Application would depend not only on the completion of 'Stage 3' but other factors as well."[emphasis added] 12 FortisBC indicates that Stage 3 is expected to start "during 2013"13 and to complete is "unlikely to be shorter than six months"14.***

**Q6.1 Please describe how FortisBC intends to work towards its energy conservation and efficiency targets in the time period leading up 2014 or later when time-based rates based upon AMI are expected (2014 is estimated using the following calculation: 2013 for start of Stage 3, at least 6 months for Stage 3, and then Stage 4 (RDA application) starts within six months after Stage 3, plus time for that next RDA process).**

A6.1 FortisBC has committed to work toward its energy efficiency targets through 2014 with a combination of DSM program measures (which have been enhanced in 2009 and 2010 and are expected to be further enhanced starting in 2011) and the conservation rates detailed in this Rate Design application.

**Q6.2 Please describe all the "*other factors*" that the filing of the next RDA is dependent on.**

A6.2 The "other factors" referred to in the question are unknown at this time, but could include stakeholder feedback and regulatory schedules.

[11] Exhibit B-3-6, Page 7, OEIA/NRI/HID IR#1 Q5.1.4
[12] Exhibit B-3-6, Page 7, OEIA/NRI/HID IR#1 A5.1.4
[13] Exhibit B-3-6, Page 7, OEIA/NRI/HID IR#1 A5.1.3
[14] Exhibit B-3-6, Page 7, OEIA/NRI/HID IR#1 A5.1.3

**Q6.3 Please describe what would affect the length of Stage 3.**

A6.3 The length of Stage 3 would be dependent on the number of different rate structures and supporting technologies that were being studied. It would also be dependent on the amount of interval data required to complete the study. For example, to understand the effect of education and real-time consumption on the winter peak, hourly data over the winter months must be gathered. FortisBC will consider beginning the Stage 3 study prior to the full implementation of AMI, which could also affect the completion date of Stage 3 relative to the full implementation date.

**Q6.4 Please estimate the earliest and latest expected date for the application to the BCUC of the new time-of-use rates to be used in conjunction with the AMI System, and the expected date for implementation for customers to be using the new rates.**

A6.4 The earliest expected date for the application to the BCUC of the new time-of-use rates to be used in conjunction with the AMI system is during the second quarter of 2013. Based on this, the earliest implementation date for new time-based rates would be within the fourth quarter of 2013. FortisBC has no estimate for a “latest expected date”.

**Q6.4.1 Will all customers be implemented at the same time, or will there be a certain order (residential, commercial etc.)?**

A6.4.1 It is FortisBC’s current expectation that if time based rates were implemented as mandatory rates, all customers would be implemented at the same time.

## 7.0 Statistically significant

**FortisBC notes in regards to stage 3 it:**

***"would begin once a statistically significant number of meters were installed in the field." 15***

**Q7.1 Please be specific on the meaning of "*statistically significant*"; please indicate in percentage or absolute terms, the appropriate number of meters that this refers to.**

A7.1 The number of meters required will be dependent on the planned structure of the TOU rates and what impacts are being tested. For example, if the expected response to an in-home display is large, a smaller sample size would be required than if the expected response was small. There may also be requirements to study various types of customers in each of the different areas within FortisBC's service area, which would influence the sample composition.

[15] Exhibit B-3-6, Page 7, OEIA/NRI/HID IR#1 A5.1.3

## 8.0 Time-based rate pilots

**FortisBC notes:**

> ***"At this time, FortisBC is not planning to conduct any time-based rate pilots . . . "[16]***

**Q8.1 Although FortisBC is not planning any time-based rate pilots[17], it is planning to "*model and study time based rates . . . [with] . . . a statistically significant number of meters . . . during 2013*"[18]. Could a time-based rate pilot achieve the same results, and at an earlier time frame? If so, when and how? If not, please explain.**

A8.1 FortisBC is planning on leveraging the AMI technology being installed in order to minimize the cost and to maximize flexibility of such a pilot.

A time-based rate pilot could be completed earlier if a trial AMI system was installed within various areas of the service territory to gather hourly usage data on customers. This would require an investment in both meters and infrastructure that would be incremental to the current scope of the AMI CPCN contemplated. FortisBC has investigated this option and found that it would have an incremental cost on the AMI project of $250,000 or higher depending on the number of areas that require coverage and how many different AMI systems were installed. This option would also delay the AMI CPCN filing (and therefore the physical installation and the implementation of time based rates) by 12 – 18 months. Therefore, although the pilot would be completed sooner, the implementation of time-based rates would not.

FortisBC believes that the most prudent method to study the effects of time based rates is to extrapolate the costs and benefits from studies and pilots in other jurisdictions through the AMI Future Program Study.

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16 Exhibit B-3-6, Page 8, OEIA/NRI/HID IR#1 A5.2
17 Exhibit B-3-6, Page 8, OEIA/NRI/HID IR#1 A5.2

## 9.0 Rapid Introduction

**FortisBC notes in regards to an interim rate:**

> ***"concern that the rapid introduction and subsequent change of conservation types is not in the interest of either the customers or the Company."***[19]

**Q9.1 Given that it will not be until 2014 or later for the introduction of time-based rates based on AMI[20], please explain how the introduction of an interim rate now can be considered a "*rapid introduction*".**

A9.1 FortisBC considers the implementation of an interim conservation rate in 2011 and the subsequent implementation of an entirely different rate structure in 2014 to be "rapid" for its customers for the reasons outlined on page 16 of the Application (Exhibit B-1).

**Q9.2 Given that it will not be until 2014 or later for the introduction of time-based rates based on AMI[21], please explain how the introduction of an interim rate now causes FortisBC to be concerned about "*the rapid introduction and subsequent change of conservation types is not in the interest of either the customers or the Company*".**

A9.2 Please refer to the response to OEIA IR No. 2 Q9.1 above.

**Q9.3 Please indicate the time frame that would not cause such concerns.**

A9.3 FortisBC does not have a proposal for a reasonable time between the implementation of two fundamentally different types of conservation rates.

[18] Exhibit B-3-6, Page 8, OEIA/NRI/HID IR#1 A5.2
[19] Exhibit B-3-6, Page 5, OEIA/NRI/HID IR#1 A4.3
[20] See this document, Section 0
[21] See this document, Section 0

## 10.0 Statistics for Residential Inclining Block

**FortisBC notes in response to a BCUC IR that:**

> ***"FortisBC does not have any statistics on the effectiveness of the BC Hydro including block rate with respect to reducing energy consumption. BC Hydro has been unable to confirm to FortisBC that there has been any significant impact. "[22]***

**We also note that FortisBC reported to the DSM Advisory Committee on October 27, 2009 that:**

> ***"Inclined Block rates only have about a 1-2% difference in energy savings, and are punitive to customers who have electric heat, etc."23***

**Q10.1 Please explain this apparent contradiction.**

A10.1 FortisBC does not understand where a contradiction may exist in the referenced quotes. It has no statistics or results from BC Hydro regarding inclining block rates, but estimates that results from such a rate would be 1-2 percent as indicated in the quote and in Exhibit B-1 page 22, line 25.

**Q10.2 Please provide backup material and documentation supporting 1-2% difference in energy savings and that it is "*punitive to customers who have electric heat*".**

A10.2 The logic for the referenced quotation is as follows: If consumption is only slightly reduced (due to the relatively inelastic nature of electricity consumption), but customers with consumption in the upper block are paying 17 percent more than a flat rate, then customers with consumption in the second block will be paying more than they do today. Since electric heat customers will generally have consumption in the second block, an inclining block rate can be considered punitive to them.

[22] Exhibit B-3-1, Page 9, BCUC IR#1 A6.7
[23] Exhibit B-3-6, Page 18, OEIA/NRI/HID IR#1 Attachment A9.2

**Q10.3 Please discuss the emphasis that FortisBC placed in using this 1-2% difference statistic in that "*the Company does not recommend introducing an interim rate such as an inclining block structure*"[24].**

A10.3 FortisBC does not understand this request, but confirms that it does not recommend introducing an interim residential rate such as inclining block.

**Q10.4 Please suggest at what level of energy savings difference FortisBC would reverse its recommendation.**

A10.4 The FortisBC recommendation to not implement an interim residential rate such as inclining block is not based on energy savings, but for the three reasons articulated in the Application on pages 16-17 (Exhibit B-1):

> *"Given the relatively short time period between the decision on this application and the proposed implementation of AMI, the Company does not recommend introducing an interim rate such as an inclining block structure. There are three reasons for this recommendation. First, the effective implementation of energy conservation rate structures requires that customers be provided with additional education allowing them to understand the new pricing signals. Since the Company intends to introduce time-based rates after the implementation of an AMI, customers would have to be re-educated in order to understand and adjust to the time-based pricing signals. This could cause customer confusion and stranded customer investment in conservation infrastructure. Second, certain types of energy conservation rates, inclined block in particular, require real-time energy consumption information to be available to customers for maximum effectiveness. This information will not be available until an AMI is implemented. Third, energy conservation rate structures do not directly*

[24] Exhibit B-1, Section 2.4, Page 16, Lines 18-19

*address the fundamental power supply issue at FortisBC, which is an increasing capacity constraint.*

**Q10.5 FortisBC notes it does not have statistics on BC Hydro's rates – please provides statistics on other utilities' rates.**

A10.5 FortisBC does not have statistics on other utilities' inclining block rates.

**Q10.6 Please suggest at what level of energy savings difference FortisBC would reverse its recommendation for the inclining block structure.**

A10.6 Please see the response to OEIA/NRI/HID IR No. 2 Q10.4.

## 11.0 RIB Price Signals – other rates

***FortisBC discusses in BCUC IR #1, A6.5 that: "FortisBC believes that a residential inclining block rate would have at least some impact on residential consumption in the transition period before the implementation of time-based rates." 25***

**Q11.1 Please list and describe in more detail other rates, changes to conditions associated with rates or other approaches that could be incorporated to have some impact on residential consumption in the transition period before the implementation of time-based rates.**

A11.1 The residential rates in addition to inclining block that were considered are described in Section 10.1 of the Application (Exhibit B-1), and include seasonal rates, urban/rural rates and a reduced basic charge.

[25] Exhibit B-3-1, Page 8, BCUC IR#1, A6.4

## 12.0 RIB Price Signals – second block

***FortisBC discusses in BCUC IR #1, A6.5 that: "FortisBC believes that an inclining block rate structure would only send conservation price signals to customer with consumption in the second block." 26.***

**Q12.1 Please provide any studies or documentation supported this theory.**

A12.1 The referenced assertion is based on the economic theory that demand for a product will increase as the price declines. Customers with consumption only in the first block of an inclining block rate are assumed to pay a lower overall rate per kWh than they will under a flat rate, and therefore the customer will respond by using more of the product. Conversely, those customers with consumption in the second block, who are exposed to a higher marginal price, would be expected to reduce consumption.

**Q12.2 If no specific documentation is available, please expand on why FortisBC believes in this theory.**

A12.2 Please see the response to OEIA/NRI/HID IR No. 2 Q12.1.

**Q12.3 Please provide an estimate (e.g. percentage) of FortisBC customers who would have consumption in the second block.**

A12.3 Approximately 55 percent of residential bills would have consumption in the second block based on a first block size of 1,350 kWh bi-monthly.

[26] Exhibit B-3-1, Page 8, BCUC IR#1, A6.5

## 13.0 RIB Price Signals – overall and shifting

***FortisBC discusses in BCUC IR #1, A6.5 that: "Any price signals arising out of an inclining block structure would not be time-based and therefore would not prepare customers to begin reducing power use at specific times and/or shifting their power use to off-peak period." 27.***

**Q13.1 Would FortisBC agree that reducing power use overall would also reduce power at specific times?**

A13.1 An overall reduction in power use over a certain period of time necessarily results in reduced power use in at least one time interval during that period. A time-based rate would incent customers to reduce their consumption at specific times and/or shift their power use to off-peak during that period.

**Q13.2 Please confirm that FortisBC is interested in shifting customers away from on-peak times – it does not have a desire to add power use to off-peak times, unless it is linked to the reduction in on-peak time.**

A13.2 FortisBC would not introduce a rate with the sole purpose of increasing power use during off-peak periods. Any increase in off-peak consumption resulting from a new rate would be expected only as a result of peak shifting.

[27] Exhibit B-3-1, Page 8, BCUC IR#1, A6.5

## 14.0 Energy Efficiency in Inclining Block

***FortisBC discusses in BCUC IR #1, A6.6 the reasons why inclining block rates require "real-time energy consumption information to be available to customers for maximum effectiveness" 28.***

**Q14.1 While real-time energy consumption information may provide maximum effectiveness to the rate, please discuss whether or not FortisBC believes the inclining block rate promotes energy efficiency even without the real time information.**

A14.1 Please refer to the response to BCUC IR No. 1 Q6.4.

[28] Exhibit B-3-1, Page 9, BCUC IR#1, A6.6

## 15.0 DSM targets from rates

***While "BC Hydro plans to meet their DSM targets with 1/3 from rates . . ."29. FortisBC indicates that: "the Company has not quantified the incremental conservation due to the proposed rate changes, but has commissioned a study on time-base rates . . ."30.***

**Q15.1 Does FortisBC believe that the study is needed in order to set their target for the percentage of DSM due to rates? If so, please explain why? If not, please clarify.**

A15.1 Yes, FortisBC believes that a rate conservation target can only be set once the potential benefits of time-based rates have been determined.

**Q15.2 Please explain how BC Hydro is able to set its targets, yet FortisBC is unable to do so.**

A15.2 FortisBC cannot explain how BC Hydro was able to set its targets.

**Q15.3 Please explain how FortisBC can plan to achieve its overall conservation targets without setting its targets for DSM contributed by rates.**

A15.3 FortisBC believes it can voluntarily meet the 50% target articulated in the 2007 BC Energy Plan with DSM programs only.

**Q15.4 Please indicate the timeframe for FortisBC to be able to develop its DSM target from rates.**

A15.4 FortisBC would be able to develop its DSM targets once the AMI Future Program Study is complete.

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[29] Exhibit B-3-6, Page 22, OEIA/NRI/HID IR#1, Q10
[30] Exhibit B-3-6, Page 3, OEIA/NRI/HID IR#1, A3.3 (as referenced from A10.2.1)

## 16.0 Basic Charge

**FortisBC states:**

***"With respect to the Basic Charge, Principles 3 (concerning efficient use) and 8 (concerning revenue stability) are most relevant"[31].***

**Q16.1 Please clarify: does FortisBC intend to refer to Principle 7 for revenue stability (as noted in Exhibit B-1, Section 5.0, Page 33) and not 8?**

A16.1 In its response to OEIA/NRI/HID IR No. 1 Q11.7, FortisBC intended to refer to Principle 7 – Revenue Stability. Please also see Errata 4.

**Q16.2 Please explain what is meant by revenue stability.**

A16.2 The principle of revenue stability with respect to rate design prescribes that rates should be designed to ensure that an adequate portion of the utilities fixed costs are recovered with certainty and that a steady revenue stream is available for use in operating the business. Most often, this is inherent in the adage that fixed costs should be recovered in fixed customer charges and variable costs recovered in variable customer charges.

**Q16.3 Please describe the situation and ramifications if Principle 3 (efficient use) were set to a higher priority than Principle 7 (revenue stability).**

A16.3 If Principle 3, *Price signals that encourage efficient use and discourage inefficient use (consideration of social issues including environmental and energy policy)*, was given disproportionate priority over Principle 7, revenue stability, the result could be the requirement to collect fixed costs through a variable rate component. The fluctuation in revenue may have a negative impact on the utility's ability to match revenue with costs and may result in under or over collection of revenue.

[31] Exhibit B-3-6, Page 34, OEIA/NRI/HID IR#1, A11.7

## 17.0 Interval Data for TOU

**In support of maintaining the existing TOU rates, FortisBC discusses the scarcity of interval data[32].**

**Q17.1 Does FortisBC believe that interval data is needed for changing the TOU rates? If so, please explain why and how it was possible to set up TOU rates in 1997 without interval data?**

A17.1 Interval data is not needed for changing the TOU rates, however the information available today is no better than the information available in 1997 and FortisBC saw no reason to update the rates. Once interval data is available, TOU rates can be set more precisely.

[32] Exhibit B-3-6, Page 39, OEIA/NRI/HID IR#1, A14.2.1

## 18.0 Promotion of Time-of-Use rates

**FortisBC notes:**

> ***"Greater promotion of time-of-use rates using existing metering technology could be confusing to customers as there will likely be differences between current time-based rates and future time-based rates."[33]***

**Q18.1 Does FortisBC believe that general education of the critical considerations of the FortisBC system (such as capacity constraints at certain times, and therefore the need for time-based rates) helpful for achieving conservation targets?**

A18.1 FortisBC believes that general education of the critical considerations for the electric system supply could be helpful for achieving conservation targets.

**Q18.2 In what ways does FortisBC expect current time-based rates to be different than the future time-based rates?**

A18.2 FortisBC expects that the rates could differ in the on-peak pricing differential and on-peak periods.

[33] Exhibit B-3-6, Page 38, OEIA/NRI/HID IR#1, A14.1.2

## 19.0 Increase Penetration Rates

**FortisBC notes in answer to increasing the penetration rates of TOU rates:**

> ***"Providing real-time consumption information that would allow customers to take advantage of TOU rates: and***
>
> ***Making TOU rates mandatory after the implementation of an Advanced Metering Infrastructure"[34]***

**Q19.1 Does FortisBC believe that promotion and marketing of TOU rates could increase the penetration rate of TOU rates[35]?**

A19.1 FortisBC believes that promotion and marketing of TOU rates could increase the penetration of TOU rates.

**Q19.2 Does FortisBC believe that changing the rates charged for the on-peak and off-peak rates could increase the penetration rate of TOU rates[36]? If so, please indicate how this penetration could be increased (which rates should go up or down), and please provide examples.**

A19.2 It is difficult to predict how the on-peak rate differential would affect penetration of optional TOU rates. A large on-peak pricing differential might be attractive to customers which already have relatively high off-peak consumption or which have the ability to shift their consumption to off-peak periods. A smaller differential might attract a broader range of customers to try a TOU rate since the potential bill impact would also be smaller.

[34] Exhibit B-3-6, Page 41, OEIA/NRI/HID IR#1, A14.3.2
[35] Example tariff in Exhibit B-1, Appendix B, Page 38, Schedule 2A
[36] Example tariff in Exhibit B-1, Appendix B, Page 38, Schedule 2A

**Q19.3 Does FortisBC believe that changing the time of day periods for on-peak and off-peak rates could increase the penetration rate of TOU rates[37]? If so, please indicate how this penetration could be increased (e.g. what changes in the time of day would need to be done), and please provide examples.**

A19.3 It is difficult to predict how changing the time-of-day on-peak periods would affect penetration of optional TOU rates. In a cost-based TOU rate structure, a shorter on-peak period will generally result in higher on-peak prices and a longer on-peak period will result in lower on-peak prices. The opinion of FortisBC with respect to the effect of the on-peak pricing differential on the penetration of optional TOU rates is discussed in the response to OEIA/NRI/HID IR No. 2 Q19.2.

**Q19.4 Does FortisBC believe that changing the seasonal variation the on-peak and off-peak rates could increase the penetration rate of TOU rates[38]? If so, please indicate how this penetration could be increased (e.g. what changes in season), and please provide examples.**

A19.4 It is difficult to predict how seasonally-varying rates would affect penetration of optional TOU rates. FortisBC expects that seasonally-varying rates would be attractive to customers depending on their heating and cooling choices. Higher winter prices would presumably be less desirable to those customers using electricity for heating purposes. Higher summer prices would presumably be less desirable for those using electricity for cooling (air conditioning purposes).

[37] Exhibit B-3-6, Page 41, OEIA/NRI/HID IR#1, A14.3.2
[38] Exhibit B-3-6, Page 41, OEIA/NRI/HID IR#1, A14.3.2

**Q19.5 Does FortisBC believe that changing the minimum number of consecutive months required could increase the penetration rate of TOU rates[39]? If so, please indicate how this penetration could be increased (e.g. would the number of months need to be decreased), and please provide examples.**

A19.5 FortisBC assumes that this question refers to the minimum number of consecutive months that a customer would be required to remain on an optional TOU rate once they have elected to take service under that rate. In that case, it is clearly advantageous to the customer to have a shorter minimum period for all customers since they would have an option to switch back to the default option sooner if they were paying more under the TOU rate.

**Q19.6 Has FortisBC considered changing any of items as discussed in Sections 0 to Section 0 above? If not, why not. If so, please expand what changes had been contemplated and the results.**

A19.6 FortisBC did not consider changing any of the items as discussed in Sections 19.2 to 19.5 for the reasons articulated in Section 14.1 of the Application (Exhibit B-1) as clarified in the response to OEIA/NRI/HID IR No. 1 Q14.2.2.

[39] Exhibit B-3-6, Page 41, OEIA/NRI/HID IR#1, A14.3.2

## 20.0 Rate Structure changes

**OEIA/NRI/HID requested in an Information Request:**

> ***"Please describe in detail how the rate structures could be changed (e.g. in pricing or time periods) to encourage a higher penetration rate?"[40]***

**FortisBC replied:**

> ***"FortisBC believes the best way to encourage a higher penetration rate is to make the rate mandatory. FortisBC intends to implement mandatory time based rates after the implementation of AMI."[41]***

**Q20.1 With respect, we suggest that FortisBC did not answer our question. Our question did not ask for FortisBC's interpretation of what they felt was the best way. We request that FortisBC answer again our question - please describe in detail how the rate structures could be changed (e.g. in pricing or time periods) to encourage a higher penetration rate.**

A20.1 Please see the responses to OEIA IR No. 2 Q19.1 through Q19.5.

[40] Exhibit B-3-6, Page 41, OEIA/NRI/HID IR#1, Q14.3.3
[41] Exhibit B-3-6, Page 41, OEIA/NRI/HID IR#1, A14.3.3

## 21.0 Wholesale customers

**In answer to OEIA/HRI/HID's Information Request regarding how a drop in energy rates for the wholesale customers could encourage energy efficiency and conservation, FortisBC states:**

> ***"The first step in encouraging energy efficiency and conservation in this context is the acceptance of contract demand . . . "***[42]

**Q21.1 Please describe in detail how contract demand encourages energy efficiency and conservation.**

A21.1 In order for a municipal utility to incent its direct customers to adopt conservation and demand reduction behaviours, it must provide price signals to those customers. At present, a municipal utility has no incentive to create price signals for its customers, nor to limit the amount of infrastructure it requires. Due to the fact that a municipal utility earns a margin on each additional kWh that it sells, it is itself incented to sell as much energy as it can in order to create additional revenue. The adoption of a contract demand billing component tied to a nominated capacity reservation sets a limit under which the municipal utility must operate. Properly selected, and with a financial consequence in place for under-nominating the limit or exceeding the contract, the municipal utility has an incentive in place that should translate into price signals to end use customers.

[42] Exhibit B-3-6, Page 41, OEIA/NRI/HID IR#1, Q14.3.3

**Q21.2 With respect, we suggest that FortisBC did not answer our question. Our question did not ask for FortisBC's interpretation of what they felt was the best way. We ask if FortisBC could answer again our question - please describe in detail how the rate structures could be changed (e.g. in pricing or time periods) to encourage a higher penetration rate.**

A21.2 FortisBC does not understand which question was unanswered. The footnote referenced in OEIA IR No. 2 21.0 is to OEIA IR No. 1, Q14.3.3, which is the same question as OEIA IR No. 2, Q20.1 and is answered in.OEIA IR No. 2 Q19.1 through Q19.5.

## 22.0 Peak Graphs

**FortisBC provided one graph of a Summer Peak[43] and one graph of a Winter Peak[44].**

**Q22.1 Using the Summer Peak graph shown, please discuss how the existing TOU rates could be varied in order to reduce the Summer Peak.**

A22.1 The on-peak period could be compressed to more closely capture the peak (which occurs near 18:00 hours). The loss of revenue resulting from the compressed on-peak period could be made up by raising the on-peak rate, further creating incentive for off-peak consumption.

**Q22.2 Using the Winter Peak graph shown, please discuss how the existing TOU rates could be varied in order to reduce the Winter Peak.**

A22.2 The on-peak period could be compressed to more closely capture the peak (which generally occurs near 18:00 hours). The loss of revenue resulting from the compressed on-peak period could be made up by raising the on-peak rate, further creating incentive for off-peak consumption.

[43] Exhibit B-3-9, Page 5, WAIT IR#1, A10a
[44] Exhibit B-3-9, Page 5, WAIT IR#1, A10b

**Q22.3 Please describe the reasons why the Winter Peak graph has two peaks and the Summer Peak graph has one peak.**

A22.3 The summer peak is generally driven by air conditioning load, which is prevalent in the afternoon when the temperature is highest. Winter peak is generally driven by electric heating load, which is prevalent in the morning when residential customers begin their day followed by the start of business. When residential customers leave their homes, heating is generally reduced during the day with another peak in the afternoon when people are starting to return home and many businesses continue to operate. This trend is reinforced since the outside temperatures are highest during the middle of the day and lower in the morning and evening.

## 23.0 Multiple Residential

**Q23.1 It is noted that there is no multiple residential rate tariff[45] for FortisBC (only Residential Schedules 1 and 2A). Please discuss any plans to implement Multiple Residential.**

A23.1 FortisBC assumes that a multiple residential rate tariff would allow residential customers to have both a Schedule 1 and Schedule 2A meter at a single residence. FortisBC does not have any plans to implement such a rate since it allows a customer to arbitrage the two rates and pay less without changing their electricity consumption patterns.

[45] Exhibit B-1, Appendix B, Page 3

**Q1 Our house has about 800 square feet of floor space, and between October and April we heat with wood, keeping the temperature between 15.6 C (60 F) and 21.1 C ( 70 F). This winter we spent $700 on four cords of split wood. Please provide what the equivalent cost would be if we used baseboard heaters, natural gas (not available to us), propane (used in Kaslo and Area D), oil (used in Kaslo), coal (still used in Balfour), ground source heat pumps or air sourced heat pumps.**

A1 The equivalent annual costs are shown below based on an assumption of 20 MBtu per cord used in a wood stove at 50% efficiency and there is no value associated with cleaning and other maintenance costs. FortisBC was not able to determine a retail price for coal or the seasonal efficiency of a coal furnace.

- Electric baseboard - $1000
- Natural Gas $820 - (mid-efficiency)
- Propane $1517 - (mid-efficiency)
- Fuel oil $1487 - (mid-efficiency)
- Air Source Heat Pump - $735
- Ground Source Heat Pump - $500

**Q2 FortisBC introduced a new bill in April 2007, which stated, in part:**

**"Introducing your new FortisBC energy bill. To learn about all features of your new bill, take a moment to review the enclosed insert "**

**Please provide a copy of that insert and also explain why FortisBC introduced the feature of comparing average current year kWh/Day usage on that bill with the average for the previous year.**

A2 The bill insert is provided as Shadrack IR2 Appendix A2. The comparison that is provided is current month as compared to the same timeframe in the previous year. This enhancement was intended to give customers more information about their consumption levels to help them in managing their energy costs. During the design phase of the new FortisBC energy bill, several options were presented to customer focus groups for their review and comment. This feature was well received by customers and therefore continues to be included in the revised bill design.

**Q3 FortisBC has stated that the unit cost of delivering power to residential customers is 8.9 cents per kWh (BCUC IR1, A78 and A78.1, page 134, line 2 and line 11, and Table BCUC A81.1, page 139, lines 6 - 8 ). Earlier, at A25.3 (page 40, line 12 - 15) and A25.4 (line 21) and A25.6 (page 41, line 4), FortisBC states that:**

**i) 21,000 (22%) residential customers consume below 1,000 kWh per billing period**

**ii) 23,000 (24%) consume above 3,000 kWh per billing period.**

**Using current billing rates (basic charge plus current energy charge/kWh, before taxes), those residential customers consuming below 1,000 kWh per billing period pay 10.05 cents per kWh or higher, and those consuming 3,000 kWh per billing period 8.4 cents per kWh or lower.**

**In fact FortisBC's proposed rate design continues to ensure that the more power a residential customer uses, the less he or she pays for that power, such that, at 1,906 kWh consumed over a billing period, the cost to that customer is 8.8998 cents for each kWh used, below estimated delivery cost. Please provide an explanation, economic, social and environmental, as to why FortisBC should continue delivering power to 23,000 plus (24% plus) residential customers at below cost.**

A3 A fixed period billing charge such as a customer charge causes the total cost of energy to decline as consumption rises. This is consistent with the COSA model which identifies a certain amount of cost incurred by the utility for each customer regardless of consumption level. FortisBC is currently charging a lower customer charge than the COSA model indicates, meaning that higher consumption customers are paying more than their allocated costs.

**Q4 How many of the 21,000 residential customers consuming below 1,000 kWh, in any given billing period, can FortisBC identify as room/basement suite/apartment renters, apartment/condo and small cabin owners?**

A4 FortisBC does not retain this type of information on its customers and therefore cannot identify room/basement suite/apartment renters, apartment/condo and small cabin owners within the 21,000 residential customers consuming below 1,000 kWh per billing period on average.

**Q5 If I pull into a gas station and buy 2 litres of gasoline I am not charged more than if I buy 20 litres. The price per litre is the same. Similarly if I go to the grocery store and buy ten oranges one time and two the next I am not charged more for buying two than if I buy ten. And if I go to the hardware store I am not charged more for buying more or fewer screws or nails, I am charged a single unit price.**

**In contrast, at A26.1 (page 43, lines 6 - 18) and Table BCUC A26.1 (page 44, line 1) FortisBC appears to be proposing a minimum residential bi-monthly charge of between $26.93 and $32. If the BCUC accepts Fortis's proposal, with the current rate design, a residential customer would pay 17.331 cents per kWh at 250 kWh.**

**Using the same intervals as Table BCUC A26.1, the current billings (before taxes) to residential customers are as follows:**

**100 kWh: $31.89**
**200 kWh: $39.51**
**300 kWh: $47.14**
**400 kWh: $54.77**
**500 kWh: $62.40**
**600 kWh: $70.02**
**700 kWh: $77.65**
**800 kWh: $85.28**
**1,200 kWh: $115.78**
**2,000 kWh: $176.80**
**3,000 kWh: $253.07**
**4,000 kWh: $329.34**

**In contrast, if 8.9 cents was charged for each kWh of energy used, plus a 10% return on investment, the unit cost to a residential customer would be 9.79 cents per kWh. Again, using the same intervals as Table BCUC A26.1,**

**residential customer billings (before taxes) would be as follows:**

**100 kWh: $9.79**

**200 kWh: $19.58**

**300 kWh: $29.37**

**400 kWh: $39.16**

**500 kWh: $48.95**

**600 kWh: $58.74**

**700 kWh: $68.53**

**800 kWh: $78.32**

**1,200 kWh: $117.48**

**2,000 kWh: $195.80**

**3,000 kWh: $293.70**

**4,000 kWh: $391.60**

**Please note that the cost differential for low-end users, when comparing current billing with a flat rate of 9.79 cents, ranges from a high of $22.10 at 100 kWh usage over a billing period to $6.96 at 800 kWh usage. In contrast, at 1,200 kWh, the differential is only $1.70 higher under the flat rate, $19 higher at 2,000 kWh, $58.63 at 3,000 kWh and $62.26 at 4,000 kWh.**

**Given the BC government's energy policy, please provide an explanation, economic, social and environmental, why FortisBC should continue to deliver a unit cost of power to residential customers who consume 100 kWh over a two month billing period at 31.9 cents, and at 8.2 cents (7.5% below cost) to a residential customer who uses 4,000 kWh.**

A5 Please refer to the response to Shadrack IR No. 2 Q3.

**Q6 At Andy Shadrack IR1 A4, in answer to Q4 (page 4, lines 26 - 28), Fortis BC states:**

**"From a principle perspective, Fortis BC is not proposing or supportive of moving away from postage stamp rates to regional rates at this time".**

**At Table BCMEU A45.6 (page 64, lines 8 and 9) FortisBC provides Winter Historical and Projected Load (MW) information to BCMEU.**

**Please provide the same data in the same format for the same residential sub-regions, for both winter and summer.**

A6 Table BCMEU A45.6, in the response to BCMEU IR No. 1 Q45.6, provides Winter Historical and Projected Load from FortisBC's 2009 System Development Plan Update, Appendix 1 broken down by geographic area. Summer Historical and Projected Load is provided below in Table Shadrack IR2 A6. This information is also from FortisBC's 2009 System Development Plan Update, Appendix 1, which was provided as an electronic Appendix to BCMEU IR No. 1 Q15.1a.

**Table Shadrack IR2 A6**

| | **Total System Summer Historical and Projected Load (MW)** | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **2002/3** | **2003/4** | **2004/5** | **2005/6** | **2006/7** | **2007/8** | **2008/9** | **2009/10** |
| North Okanagan | 197.36 | 208.96 | 224.28 | 220.24 | 246.26 | 255.47 | 270.90 | 300.94 |
| South Okanagan | 166.35 | 178.21 | 172.90 | 169.89 | 198.26 | 197.33 | 217.08 | 222.45 |
| Kootenay | 127.64 | 148.92 | 143.79 | 142.18 | 143.03 | 147.57 | 156.38 | 158.07 |
| Boundary | 38.59 | 41.80 | 41.75 | 42.52 | 42.42 | 44.12 | 45.22 | 45.76 |
| Total | 529.94 | 577.89 | 582.72 | 574.82 | 629.96 | 644.50 | 689.58 | 727.22 |

| | **Total Summer Historical and Projected Load (MW)** | | | |
|---|---|---|---|---|
| | **2010/11** | **2011/12** | **2012/13** | **2013/14** |
| North Okanagan | 322.82 | 343.87 | 361.83 | 373.04 |
| South Okanagan | 227.91 | 233.45 | 239.08 | 244.95 |
| Kootenay | 159.77 | 161.46 | 163.15 | 164.96 |
| Boundary | 46.31 | 46.85 | 47.41 | 48.04 |
| Total | 756.80 | 785.63 | 811.46 | 830.99 |

**Q7 At BCMEU IR1 A52.2 (page 72, lines 8 - 15) FortisBC provides a rationale as to why it opposes a single rate class for municipal electric utilities:**

***"FortisBC believes that each customer should pay its fair share of costs, and that the characteristics of the municipal utilities indicate that a separate rate for each customer class is appropriate and would prevent one unique customer from subsidizing another...Summerland currently has a revenue to cost ratio of 96.6%...if Summerland was grouped with the other municipalities, they would have a revenue to cost ratio of 80.4% and would effectively be subsidizing other municipal wholesale utilities as the rates were rebalanced*."**

**And in response to Zellstoff Celgar Limited Partnership, FortisBC provides a number of Tables: A32.1 (a) through A32.4 (d) (pages 61-76).**

**Please provide the residential customer revenue to cost ratio for the same sub-regions as provided to BCMEU in Table A45.6, namely North Okanagan, South Okanagan, Kootenay and Boundary.**

A7 FortisBC uses a postage stamp methodology where all of its service area is combined for purposes of the COSA and ratemaking. FortisBC believes this is the most appropriate approach and it has been supported by the BCUC, most recently in Order G-87-07 for the Rate Design on the Big White Supply Project. As such, FortisBC does not have the capability built into the COSA model to separate costs and revenues by region.

The municipalities served by FortisBC differ due to the fact that each operates their own electric utility, with their own facilities and costs, and take wholesale service from FortisBC.

**Q8 At Table BCUC A81.1 (page 139, lines 7 and 8) FortisBC provides the average cents per kWh by customer class, and at Zellstoff Celgar Appendix A34.1 (page 1) provides an energy rate of 8.085 cents, plus a $25.72 basic charge.**

**Please provide the same data for residential customer sub-regions as provided to BCMEU in Table A45.6, namely North Okanagan, South Okanagan, Kootenay and Boundary.**

A8 The data provided in IR No. 1, BCMEU Table A45.6 are the System Development Plan aggregate load forecasts by geographic area. This information is not available broken down by customer class due to the unavailability of interval meter data on a class by class basis.

**Q9 There are some 96,000-plus residential customers in the FortisBC residential customer class. According to Statistics Canada data some 500 persons lived in the BCH Lardeau Wholesale area at the 2001 Census, and according to the 2006 Census Grand Forks Wholesale has approximately 1,862 dwellings, Kelowna Wholesale 47,727 dwellings, Nelson Wholesale 4,427 (plus parts of Electoral Areas E and F of the RDCK), Penticton Wholesale 15,271 and Summerland Wholesale 4,726.**

**In response to the answer to Andy Shadrack IR1 at A4 (page 4, lines 23 - 28), please explain, economically, socially and environmentally, how FortisBC can then justify giving a different answer to BCMEU at A52.2 (page 72, lines 8 - 18) than they did to Mr Shadrack.**

A9 The question asked at Shadrack IR No. 1, Q4 was:

> *Q4 Given that FortisBC has previously reported that it is able to generate power along the Kootenay River cheaper than it can purchase it under various contracts and on the spot market, what is the cost differential of supplying residential power in the West Kootenay versus supplying residential power in the Okanagan?*

The question asked at BCMEU IR No. 1 Q52.2 was:

> *Q52.2Does FortisBC oppose the concept of a single rate class for municipal electric utilities? If so, why?*

With respect, the questions are markedly different and were responded to accordingly. As indicated in the response to Shadrack IR No. 1 Q4, the data is not available and there is no basis for drawing any conclusions regarding the average total cost to serve residential customers in the various regions.

By contrast, full data is available for each municipal utility that allows for a comparison of both the costs and operating characteristics of each. Based on this, FortisBC considers it appropriate to treat each as a separate rate class.

**Q10 At Table BCUC A81.1 (page 139, lines 7 and 8) FortisBC clearly demonstrates that it is prepared to design rates for wholesale customers with residential dwelling numbers as follows:**

**Lardeau Wholesale 317***
**Grand Forks Wholesale 1,862**
**Nelson Wholesale 4,427+**
**Summerland Wholesale 4,726**
**Penticton Wholesale 15, 271**
**Kelowna Wholesale 47,727**

*** In the 2006 Census, Area D, Regional District Central Kootenay, had a population of 1,525 and a total number of dwellings of 250. Extrapolating from the 2001 Cenus data, the Lardeau Wholesale area had about one-third of the Area D population, and one-third of the dwellings would be 317.**

**Please explain why, if it is discriminatory to lump Summerland Wholesale in with the other Wholesale customers under a single rate, it is not also discriminatory to lump residential customers in under one single rate instead of determining revenue cost ratios for the North Okanagan, South Okanagan, Boundary and Kootenay?**

A10 While it is possible to segment the residential class in a number of ways and derive separate revenue cost ratios based on that segmentation FortisBC continues to adhere to postage stamp principles for rate classes that contain a large number of customers. This is consistent with the majority of utilities in Canada. Where there are a small number of customers with distinctly different cost characteristics, such as the municipal utilities, this segmentation may be more practical.

**11. According to Statistics Canada, Census 2006:**

**http://www12.statcan.ca/census-recensement/2006/dp-pd/hlt/97-550/Index.cfm?TPL=P1C&Page=RETR&LANG=Eng&T=305&SR=1&S=0&O=A&RPP=9999&PR=59&CMA=0**

**the number of dwellings usually occupied varies - for example, as follows:**

**Area D, Regional District Central Kootenay 74.6%**

**Yahk 83.5%**

**Castlegar 94.9%**

**At OEIANRI and HID IR1 A11.1.2 (page 23, lines 19 and 20) FortisBC makes the claim that:**

***"...250 kWh over two months...is characteristic of an unoccupied building without electric heat..."***

**Q11i) Given the varying usual rates of occupancy stated above, please explain what factual evidence FortisBC has for the stated claim to OCEIANRI and HID above.**

A11i) FortisBC bases the referenced claim on the fact that 250 kWh over two months is less than the amount of energy used by two 100W light bulbs over the same period. FortisBC considers it unlikely that an occupied premise would consume this little energy. The "usual rates of occupancy" listed above are not inconsistent with the information provided in the response to BCOAPO IR No. 1, Q16.2, repeated here:

*Based on the most recent 12 months of billing data (Jan 1st, 2009 to Dec 31st, 2009), FortisBC has 96,532 residential accounts.*

- *1.2 percent of customer accounts (1,187 customer accounts), used less than 250 kWh during each of the 6 billing periods*
- *12.9 percent of customer accounts, (12,452 customer accounts) used less than 250 kWh for one or more of the 6 billing periods (including the 1,187 accounts above).*

**Q11ii) Further, please explain why such consumption rates could not equally come from low income renters in single rooms, apartments and small cabins, in which there are only a few lights, a small fridge, no washer, dryer or freezer, and sometimes no water heater.**

A11ii) It is possible for low consumption to result from energy conscious customers with minimal electric equipment.

**Q12 OEIANRI and HID IR1 Q16.4 (page 47, lines 1 - 4) asks FortisBC how: "...the Energy Charge at 7.627 cents/kWh for Residential and with no other charges supports the claim that the Company has proposed rate structures that encourage energy efficiency and conservation..."**

**Given cost/price evidence provided in questions 3 and 5 of this document above, please definitively explain how the introduction of AMI in 2013 and TOU in 2014 will address the price discrimination being experienced by the 21,000 FortisBC residential customers in 2010 who use less than 1,000 kWh in any given billing period.**

A12 FortisBC does not believe the 21,000 residential customers are currently experiencing price discrimination. Time-based rates can be designed to be more representative of actual costs than current rates or any other purely energy consumption-based rate. A time-based rate will continue to incent customers to reduce overall consumption, and will also incent them to reduce power at specific times. The extent to which lower consumption customers may benefit from time-based rates will therefore depend on their electricity consumption patterns.

**13. At Wait A6 (page 3, lines 12 and 13) FortisBC states that the intent of a TOU differential is to:**

**"...incent conservation, it is not necessarily cost based. The differential is intended to discourage consumption during peak periods".**

**At BCUC A7.2 (page 12, lines 7 and 8) FortisBC states:**

**"...energy shortfall associated with the peak capacity gap - currently at about 18 GWh of annual requirements - will grow to approximately 131 GWh by 2028..."**

**and at line 27 and 28 and page 13, line 1 FortisBC states:**

**"Collectively, the FortisBC Plants, the BC Hydro PPA and the Brilliant PPA provided, in 2008, about 99% of the Company's energy requirements, but only about 76% of its peak capacity requirements..."**

**Q13i) Please explain how introduction of AMI in 2013 and TOU in 2014 addresses the fact that FortisBC increasingly cannot meet non-peak capacity loads.**

A13i) As stated in Section 3.1, pages 22-24 of the Application (Exhibit B-1), FortisBC believes that time-based rates are the most effective manner of reducing both overall energy use and peak period energy use. FortisBC will also continue to enhance its energy conservation DSM programs.

**Q13ii) Further, please explain, if the objective is to "*incent conservation",* why an increasing block rate design does not give better incentive to residential consumers considering purchase of, for example, compact fluorescent bulbs and LEDs, energy efficient appliances, or switching to a solar hot water heater and/or fridge.**

A13ii) Customers will continue to be incented to reduce energy consumption through time-based rates. Enhanced DSM programs will also provide information and financial incentives to purchase the type of energy efficient equipment described above. However, it is important for FortisBC customers to also reduce their use of electricity at peak times to mitigate the capacity shortfall.

**Q13iii) Further still, how does AMI and/or TOU encourage a residential consumer to buy an energy efficient fridge, freezer, front loading washing machine or on demand water heater?**

A13iii) Please refer to the response to Shadrack IR No. 2 Q13ii.

**14. It is assumed that the cheapest source of power for FortisBC is that produced by its own Plants, then through long term purchase agreements with BC Hydro and the Brilliant Power Corporation (aka Columbia Power Corporation/Columbia Basin Trust).**

**Q14i) Is this assumption correct, and is it true that all three of these sources of power are primarily produced on the Kootenay River between Nelson and Castlegar?**

A14i) The assumption is typically correct. However, it should be noted that the power produced by BC Hydro is dispatched from the BC Hydro provincial grid which could be generated locally or elsewhere.

**Q14ii) Please explain how much of FortisBC's energy requirements and peak capacity requirements were met by FortisBC Plants in 2008 and 2009, and in which sub-regions, in accordance with Table BCMEU A45.6, North Okanagan, South Okanagan, Kootenay and Boundary, FortisBC Plants produced this power.**

A14ii) It is not possible to track what sub-region in which Company generated energy and capacity is used. FortisBC generation is located in the Kootenay region.

**Table Shadrack IR2 A14(ii)**

| | Energy from FortisBC sources (GWh) | Capacity from FortisBC sources (MW) |
|---|---|---|
| 2008 | 1608 | 198 |
| 2009 | 1585 | 194 |

**Q14iii) Further, please explain in which sub-regions, as per above, FortisBC met its own energy requirements and peak capacity with its own Plants, and what percentage of overall requirements and peak capacity were met in sub-regions where it could not meet either or both.**

A14iii) Please refer to the response to Shadrack IR No. 2 Q14ii) above.

FORTISBC

## Our Commitment

FortisBC is committed to providing safe, reliable and affordable electrical service to communities across the southern interior of British Columbia. As part of our ongoing commitment to customer service, we have designed a new bill to better serve our customers. The new bill design was created in consultation with customers from across our service area. Your new FortisBC electricity bill is easy-to-read and well organized, making it easier for you to find details about your services, charges and usage.

FORTISBC

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FortisBC is a Canadian owned electric utility operating in the southern interior of British Columbia.

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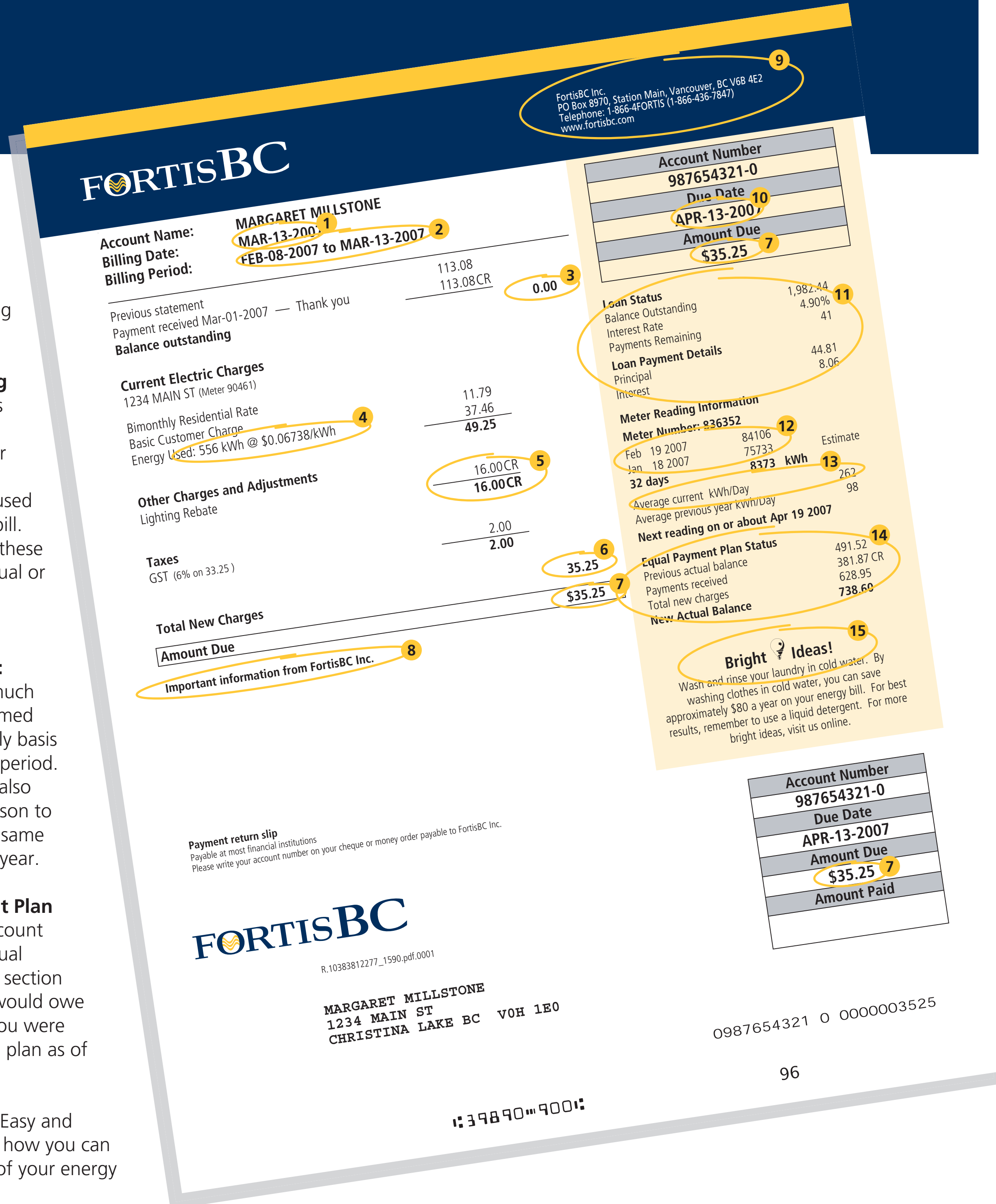


## FortisBC Has a New Look

Your new FortisBC electricity bill is easy-to-read and well organized, making it easier for you to find details about your services, charges and usage. Take a moment to familiarize yourself with the improved features of your FortisBC bill:

1 **Billing Date:** This is the date your bill was issued. Transactions after this date will appear on your next bill.

2 **Billing Period:** The period of time in which charges were billed to your account.

3 **Balance Outstanding:** This section shows the amount owing from your previous bill and any payments or adjustments since your last bill was issued.

4 **Current Electric Charges:** This section gives you an itemized list of your current charges based on FortisBC's electrical tariff. For more information on FortisBC's electrical tariff, please visit us online at www.fortisbc.com.

5 **Other Charges and Adjustments:** Any adjustments credited or debited to an account within the billing period.

6 **Total New Charges:** This is the amount of new charges for the current billing period. It does not include any balance outstanding on your account.

7 **Amount/Payment Due:** This is the balance outstanding on your account from your last bill plus new charges. If your account is set up on an equal payment plan, this is the payment amount required.

8 **Bill Messages**: Important information from FortisBC.

9 **FortisBC Contact Information:** Easy ways you can contact us for more information on your bill, energy efficiency, safety awareness, and more.

10 **Due Date:** Your bill payment is due on this date.

11 **Loan Status:** If you have a loan with FortisBC, the balance outstanding, interest rate and payments remaining will appear here.

12 **Meter Reading Information:** This section contains your current meter reading and the previous reading used to calculate your bill. It also indicates if these readings were actual or estimated.

13 **Average kWh Usage/Day:** Shows you how much energy you consumed on an average daily basis during this billing period. If available, it will also provide a comparison to your usage at the same time the previous year.

14 **Equal Payment Plan Status:** If your account is set up on an equal payment plan this section shows what you would owe or be credited if you were removed from the plan as of the billing date.

15 **Bright Ideas!:** Easy and affordable tips on how you can get the most out of your energy dollar.

**Q1 Ref. The Municipal Electrics written agreements**

**Do the written contracts allow for the Municipals, other than Nelson, to generate their own electricity? Is the new 100% contract wires demand charge designed to encourage the Municipals to install their own peaking generation?**

A1 Each wholesale agreement, other than that which is in place with the City of Nelson, allows for up to 15 MW of generation that is owned by the municipality or its direct customers. The 100 percent contract-demand based wires charge was not implemented in consideration of the promotion of customer owned generation.

**Q2 If the present contracts do not allow some Municipal Electrics to generate their own power, will FortisBC write the new agreements to allow all Municipal Electrics to generate a portion of their own power if requested?**

A2 Please see the response to Wait IR No. 2 Q1 above.

**Q3 Is the new COSA plan reasonably neutral to the FortisBC bottom line for swings in temperature related system demand and consumption changes in regards to covering power costs purchased or saved?**

A3 The new rate plan provides an improved matching of revenues and costs and reduces the risk associated with swings in temperature related changes. In several cases the change in rate structure to a higher demand charge or a reduction in the declining block rate differential provides rates that better reflect the costs. Therefore, the revenues will be more closely aligned with the costs of the system and variations will be more in line with actual cost variations due to weather.

For the industrial transmission and wholesale customers, the use of contract demand for the wires component of the costs eliminates the revenue swings associated with weather variations for that rate component. This is appropriate as the wires costs do not differ from year to year on the basis of weather variation. Power supply costs, which do vary according to weather-driven load variation, are still collected on the basis of actual loads. Revenues from these rate components will therefore move in conjunction with weather variability.

**Q4 Ref. Wait IR#1**

**On a percentage basis, do the residential customers contribute more to the peak than industrial customers where FortisBC has demand readings?**

A4 FortisBC does not have demand readings for any residential class customers at this time, therefore the peak demands were estimated as described in Appendix C of the COSA Report. For the highest system peak of the year (1CP), the residential contribution at the time of the system peak was assumed to be 313,226 kW compared to an industrial contribution of 47,831 kW (rates 30, 31 and 33 combined). This results in 44.7% for residential and 6.8% for industrial. Under the 2CP method used for allocating costs within the COSA, the residential percent is 40.6% compared to 7.2% for the industrial class. This information can be found in Schedules 6.2 and 6.3 of the COSA (Exhibit B-1).

## 1.0 Reference: Exhibit B-1, Pages 33 and 47

**FortisBC states that its “rebalancing effort” contains the following elements: “Total increase due to rebalancing and revenue requirements not to exceed 10 per cent unless the revenue requirement increase alone exceeds 10 per cent” and “Increases noted above are exclusive of BC Hydro increases that the Company may apply on a flow-through basis.”**

### Questions

**Q1.1 Please explain the source of the 10 per cent figure. Is 10 per cent a “hard and fast” rule used in rate-making to define “rate-shock?”**

A1.1 FortisBC has not considered what the threshold percentage rate increase would be to cause rate shock to customers. Consideration of any rate increase would be the subject of regulatory proceedings to investigate the nature of the cost drivers that the Company believes would have to be reviewed with the Commission and customers. The determination of whether any particular rate increase would constitute rate shock would thereby be a decision of the Commission and in the context of the current PBR Plan would also reflect stakeholder views through the Negotiated Settlement Process. Thus, the 10 percent figure is not “hard and fast” and was chosen as a number that combined with anticipated revenue requirement and rebalancing increases would bring the revenue to cost ratio of most rate classes to within the range of reasonableness within a reasonable time.

**Q1.2 The referenced provisions would seem to suggest that customers can bear greater-than-10 per cent rate increases for some reasons (rising utility costs) but not others (rebalancing).**

**Q1.2.1 Does FortisBC agree with that interpretation?**

A1.2.1 The Company could bring forward to the Commission a Revenue Requirement Application that alone required a year over year increase exceeding 10 percent, with that application subject to a full regulatory process. Therefore, subject to BCUC approval, it is possible that a rate increase could be above 10 percent. Should this happen, FortisBC would not apply a rebalancing increase in keeping with the intent of the rebalancing plan outlined in the COSA/RDA Application.

**Q1.2.2 If not, why not?**

A1.2.2 Please refer to the response to Big White IR No. 2 Q1.2.1 above.

**Q1.2.3 If so, does this suggest that Principle 1 (page 33 of Exhibit B-1) has primacy over Principle 2 or the other Principles?**

A1.2.3 The revenue requirement of the Company as mentioned in Principle 1, and as approved by the Commission will be recovered through rates as provided for by the Utilities Commission Act, Section 59. Principle 1 therefore sets a parameter within which the other principles must be balanced while setting rates.

**2.0 Reference: Exhibit B-1, Pages 33 and 46 to 49, Exhibit B-3-1, Question BCUC IR#1, Q21**

**"…the Company has chosen to recommend a 95 per cent to 105 per cent revenue-to-cost ratio range of reasonableness for all customer groups. While it may seem ideal to attempt to bring each customer class to 100 per cent, the selection of a range of reasonableness reflects the fact that, during a cost of service study, certain assumptions are necessarily made in the absence of perfect data."**

**Questions**

**Q2.1 Please reproduce Tables 8.1a and 8.1b for a case where the revenue-to-cost target is 1.0 rather than the "range of reasonableness."**

A2.1 Please see Table Big White IR2 A2.1a and A2.1b below.

**Table Big White IR2 A2.1a**
**Resulting Total Rate Increases Assuming 5% General Rate Increase and 10% Cap with Revenue to Cost Target of 1.0**

| | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 |
|---|---|---|---|---|---|
| | Total Rate % Increase | Total Rate % Increase | Total Rate % Increase | Total Rate % Increase | Total Rate % Increase |
| Residential | 6.0 | 5.8 | 5.0 | 5.0 | 5.0 |
| Small General Service | 0.0 | 0.0 | 2.1 | 5.0 | 5.0 |
| General Service | 0.0 | 0.0 | 1.5 | 0.5 | 0.5 |
| Industrial Primary | 0.0 | 0.0 | 1.5 | 0.5 | 2.2 |
| Industrial Transmission 31 | 0.0 | 0.3 | 5.0 | 5.0 | 5.0 |
| Industrial Transmission 33 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 |
| Lighting | 10.0 | 10.0 | 10.0 | 10.0 | 6.5 |
| Irrigation | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 |
| Kelowna Wholesale | 10.0 | 10.0 | 6.4 | 5.0 | 5.0 |
| Penticton Wholesale | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 |
| Summerland Wholesale | 8.7 | 5.0 | 5.0 | 5.0 | 5.0 |
| Grand Forks Wholesale | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 |
| BCH Lardeau Wholesale | 3.1 | 5.0 | 5.0 | 5.0 | 5.0 |
| BCH Yahk Wholesale | 1.4 | 5.0 | 5.0 | 5.0 | 5.0 |
| Nelson Wholesale | 10.0 | 10.0 | 10.0 | 10.0 | 9.0 |

**Table Big White IR2 A2.1b**
**Impact on Revenue to Cost Ratio over 5 Years with Revenue to Cost Target of 1.0**

| | Rebalancing Increase and 5% General Rate Increase | | | | | |
|---|---|---|---|---|---|---|
| | Initial R/C Ratio | Year 1 R/C Ratio | Year 2 R/C Ratio | Year 3 R/C Ratio | Year 4 R/C Ratio | Year 5 R/C Ratio |
| | % | | | | | |
| Residential | 98.3 | 99.3 | 100.0 | 100.0 | 100.0 | 100.0 |
| Small General Service | 113.4 | 108.0 | 102.8 | 100.0 | 100.0 | 100.0 |
| General Service | 138.9 | 132.3 | 126.0 | 121.8 | 116.6 | 111.6 |
| Industrial Primary | 122.4 | 116.6 | 111.0 | 107.3 | 102.7 | 100.0 |
| Industrial Transmission 31 | 109.9 | 104.6 | 100.0 | 100.0 | 100.0 | 100.0 |
| Industrial Transmission 33 | 23.5 | 24.7 | 25.8 | 27.1 | 28.4 | 29.7 |
| Lighting | 81.9 | 85.8 | 89.8 | 94.1 | 98.6 | 100.0 |
| Irrigation | 78.6 | 82.3 | 86.3 | 90.4 | 94.7 | 99.2 |
| Kelowna Wholesale | 89.9 | 94.2 | 98.7 | 100.0 | 100.0 | 100.0 |
| Penticton Wholesale | 78.0 | 81.7 | 85.6 | 89.7 | 94.0 | 98.4 |
| Summerland Wholesale | 96.6 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| Grand Forks Wholesale | 68.1 | 71.3 | 74.7 | 78.3 | 82.0 | 85.9 |
| BCH Lardeau Wholesale | 101.8 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| BCH Yahk Wholesale | 103.5 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| Nelson Wholesale | 80.0 | 83.8 | 87.8 | 92.0 | 96.4 | 100.0 |

**Q2.2. In making the referenced statement, does FortisBC believe that the "assumptions made in the absence of perfect data" are systematically biased in one direction or another? If so, please explain the source of the systematic bias.**

A2.2 FortisBC does not believe there is a systematic bias in one direction or another. The uncertainty surrounding load variation between customer classes without interval metering is by nature unbiased as the total load for the system is metered and therefore a known quantity. Any error in loads between classes must have an equal amount above and below the actual value so that the total adds up to the appropriate amount. Other uncertainties in the COSA include the uncertainty associated with the selection of one methodology over another and the uncertainty associated with using a forecast test year where both costs and loads can vary from actuals.

**Q2.3. Does FortisBC agree that if the data were not systematically biased in one direction or another, then targeting unity is likely to better satisfy Principle 2 (page 33 of Exhibit B-1) than would targeting some figure other than unity (i.e., .95 or 1.05)? Please explain.**

A2.3 Using a target of unity implies a level of certainty that does not exist in any COSA.

**Q2.4 Is there any Principle on page 33 that is compromised by targeting unity rather than the "range of reasonableness?" If so, please explain.**

A2.4 The use of a range of reasonableness (ROR) recognizes the inherent limitations that exist within a COSA study and is not directly part of the rate design principles discussed in the Application. The choice of the ROR may impact the degree to which the principles can be adhered to, depending on the starting ROR of a customer class. For example, a customer class that is significantly under-collecting revenues in light of its costs would see Principle 6 (Rate Stability) compromised were a more aggressive goal adopted. It could also be contended that Principle 3 (concerning efficient use of electricity) would be compromised if a customer class were to see a large drop in current rates as a result of rebalancing. For these reasons, utilities and regulators design and approve rebalancing practices that seek to balance the principles to the extent possible.

**3.0 Reference: Exhibit B-1, Pages 33 and 46 to 49**

**FortisBC states that the “rebalancing effort” contains the following elements: “If, in any year, a customer class achieves a revenue-to-cost ratio within the range of reasonableness, no further adjustments would be made in subsequent years if the ratio again fell outside of the range.”**

**Questions**

**Q3.1 Please explain the rationale behind this element.**

A3.1 During the initial term of rebalancing approved by the Commission, rebalancing adjustments will be applied as set out in the Decision that will accompany the BCUC Order. It is possible that given the variability of revenue and costs in relation to the estimates, that revenue-to-cost ratios may not reach or remain within the range of reasonableness. This could only be ascertained through an updated COSA filing, after which further adjustments can be made.

**Q3.2 Please comment on the relationship of this element to Principles 2 and 3 on page 33 of Exhibit B-1.**

A3.2 As indicated in the response to IR Q3.1 above, the rebalancing element maintains fair apportionment of costs per Principle 2 and does not create price signals that would violate Principle 3.

**4.0 Reference: Exhibit B-1, Pages 33 and 46 to 49, Exhibit B-3-1, Question BCUC IR#1, Q21**

**Table 8b of Exhibit B-1 shows that the General Service class should be expected to see less than half of its over-charge addressed during the next five years under FortisBC's rebalancing regime. Morevover, the class rates would remain more than 20 points above unity at the end of that period – a result little better than the starting point for the next worst class.**

**Questions**

**Q4.1 FortisBC claims that the "Super Group" found the Company's approach "reasonable", and notes that "there are only four customer groups that remain outside of the 95-105 per cent range at the end of five years." Table 8.1b would appear to show only three classes outside the range by the end of year 5. Is that correct?**

A4.1 Correct. Please refer to Errata 4.

**Q4.2 FortisBC identifies that four (three) customer groups remain outside of the 95-105 per cent range, but claims that "this situation cannot be remedied without introducing increases larger than 10 per cent annually for those groups."**

**Q4.2.1 Please confirm that this quote does not apply to the General Service class, as the sole customer group with rates outside the so-called range of reasonableness and whose rates subsidize other classes, rather than the other way round.**

A4.2.1 This quote does apply to the General Service class. Without applying larger increases to all or some of the other classes with revenue to cost ratios below 95 percent, the revenue to cost ratio of the General Service class cannot be lowered further.

**Q4.2.2 In making the referenced comment, did FortisBC consider the use of a deferral account mechanism to both: (a) move the General Service class closer to unity more quickly; and (b) smooth the rate impact for other classes?**

A4.2.2 FortisBC did not consider the use of a deferral mechanism in its examination of rebalancing alternatives.

**Q4.2.3 If FortisBC did consider using a deferral mechanism, please provide a full explanation of why it was rejected, including in the context of the Principles on page 33 of Exhibit B-1.**

A4.2.3 Please see the response to Big White IR No. 2 Q4.2.2 above.

**Q4.2.4 If the Commission were to instruct FortisBC to move the General Service class to unity within five years using a deferral account mechanism to protect other classes from "rate shock", how would FortisBC propose to implement that instruction? Within the answer, please provide tables similar to Tables 8.1a and 8.1b, using unity as a target, and tracking the balance and clearing of the deferral account.**

A4.2.4 FortisBC assumes that any direction from the BCUC to move the General Service class to unity would occur within a more general order to move all classes with adequate metering data within the same time frame. Using the same criteria for rate mitigation as the original rebalancing plan would require no individual class increases above 10 percent in total. Capping class rate increases while forcing the over-collecting classes to unity would result in a revenue shortfall that would need to be recovered in some manner at the end of the rebalancing period. One such scenario is contained in the table below. Practically speaking, such an approach would be fraught with implementation issues as actual rates would need to be adjusted as actual annual rate changes are incorporated and results verified through future cost of service studies. Note that some classes will still not achieve a 100% ratio.

1 **Table Big White IR2 A4.2.4**

| Class | Year 0 | Year 1 | | Year 2 | | Year 3 | | Year 4 | | Year 5 | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | R/C Ratio | Total Increase | R/C Ratio | Total Increase | R/C Ratio | Total Increase | R/C Ratio | Total Increase | R/C Ratio | Total Increase | R/C Ratio |
| | % | | | | | | | | | | |
| **Residential** | 98.3 | 5.0 | 98.3 | 5.0 | 98.3 | 5.0 | 98.3 | 5.0 | 98.3 | 5.0 | 98.3 |
| **Small General Service** | 113.4 | 1.7 | 109.8 | 2.0 | 106.7 | 3.3 | 105 | 5.0 | 105 | 5.0 | 105 |
| **General Service** | 138.9 | -1.6 | 130.2 | -1.7 | 121.9 | -1.7 | 114.2 | -1.7 | 106.9 | -1.7 | 100 |
| **ID 33** | 23.5 | 10.0 | 24.7 | 10.0 | 25.8 | 10.0 | 27.1 | 10.0 | 28.4 | 10.0 | 29.7 |
| **ID 30** | 122.4 | 0.9 | 117.6 | 0.9 | 112.9 | 0.8 | 108.4 | 0.8 | 104.1 | 0.8 | 100 |
| **ID31** | 109.9 | 3.2 | 108 | 3.1 | 106.1 | 3.0 | 104.1 | 3.0 | 102.1 | 2.8 | 100 |
| **Lighting** | 81.9 | 10.0 | 85.8 | 10.0 | 89.8 | 10.0 | 94.1 | 6.0 | 95 | 5.0 | 95 |
| **Irrigation** | 78.6 | 10.0 | 82.3 | 10.0 | 86.3 | 10.0 | 90.4 | 10.0 | 94.7 | 5.5 | 95 |
| **Kelowna** | 89.9 | 10.0 | 94.2 | 10.0 | 98.7 | 6.4 | 100 | 5.0 | 100 | 5.0 | 100 |
| **Penticton** | 78.0 | 10.0 | 81.7 | 10.0 | 85.6 | 10.0 | 89.7 | 10.0 | 84 | 10.0 | 98.4 |
| **Summerland** | 96.6 | 8.7 | 100 | 5.0 | 100 | 5.0 | 100 | 5.0 | 100 | 5.0 | 100 |
| **Grand Forks** | 68.1 | 10.0 | 71.3 | 10.0 | 74.7 | 10.0 | 78.3 | 10.0 | 82 | 10.0 | 85.9 |
| **Lardeau** | 101.8 | 5.1 | 101.9 | 4.8 | 101.7 | 4.6 | 101.3 | 4.4 | 100.8 | 4.2 | 100 |
| **Yahk** | 103.5 | 4.7 | 103.2 | 4.4 | 102.6 | 4.3 | 101.9 | 4.1 | 101 | 3.9 | 100 |
| **Nelson** | 80.0 | 10.0 | 83.8 | 10.0 | 87.8 | 10.0 | 92 | 10.0 | 96.4 | 9.0 | 100 |
| **Revenue Shortfall/ Deferral Account Balance** | | **1,145,061** | | **2,241,038** | | **3,569,597** | | **4,713,469** | | **6,082,333** | |

## Table Big White IR2 A4.2.4 cnt'd

| Class | Year 6 | | Year 7 | | Year 8 | | Year 9 | | Year 10 | | Year 11 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Total Increase | R/C Ratio | Total Increase | R/C Ratio | Total Increase | R/C Ratio | Total Increase | R/C Ratio | Total Increase | R/C Ratio | Total Increase | R/C Ratio |
| | % | | | | | | | | | | | |
| **Residential** | 0.0 | 98.3 | 0.0 | 98.3 | 0.0 | 98.3 | 0.0 | 98.3 | 0.0 | 98.3 | 0.0 | 98.3 |
| **Small General Service** | 0.0 | 105.0 | 0.0 | 105.0 | 0.0 | 105.0 | 0.0 | 105.0 | 0.0 | 105.0 | 0.0 | 105.0 |
| **General Service** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **ID 33** | 5.0 | 31.1 | 5.0 | 32.6 | 5.0 | 34.2 | 5.0 | 35.8 | 5.0 | 37.5 | 5.0 | 39.3 |
| **ID 30** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **ID31** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **Lighting** | 0.0 | 95.0 | 0.0 | 95.0 | 0.0 | 95.0 | 0.0 | 95.0 | 0.0 | 95.0 | 0.0 | 95.0 |
| **Irrigation** | 0.0 | 95.1 | 0.0 | 95.1 | 0.0 | 95.1 | 0.0 | 95.1 | 0.0 | 95.1 | 0.0 | 95.1 |
| **Kelowna** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **Penticton** | 1.7 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **Summerland** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **Grand Forks** | 5.0 | 90.0 | 5.0 | 94.3 | 5.0 | 98.8 | 1.3 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **Lardeau** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **Yahk** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **Nelson** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **Deferral Offset** | **849,051** | | **312,762** | | **344,038** | | **174,350** | | **116,450** | | **128,095** | |
| **Deferral Account Balance** | **5,233,281** | | **4,920,520** | | **4,576,482** | | **4,402,132** | | **4,285,682** | | **4,157,587** | |

## Table Big White IR2 A4.2.4 cnt'd

| Class | Year 12 | | Year 13 | | Year 14 | | Year 15 | | Year 16 | | Year 17 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Total Increase | R/C Ratio | Total Increase | R/C Ratio | Total Increase | R/C Ratio | Total Increase | R/C Ratio | Total Increase | R/C Ratio | Total Increase | R/C Ratio |
| | % | | | | | | | | | | | |
| **Residential** | 0.0 | 98.3 | 0.0 | 98.3 | 0.0 | 98.3 | 0.0 | 98.3 | 0.0 | 98.3 | 0.0 | 98.3 |
| **Small General Service** | 0.0 | 105.0 | 0.0 | 105.0 | 0.0 | 105.0 | 0.0 | 105.0 | 0.0 | 105.0 | 0.0 | 105.0 |
| **General Service** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **ID 33** | 5.0 | 41.1 | 5.0 | 43.1 | 5.0 | 45.1 | 5.0 | 47.3 | 5.0 | 49.6 | 5.0 | 51.9 |
| **ID 30** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **ID31** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **Lighting** | 0.0 | 95.0 | 0.0 | 95.0 | 0.0 | 95.0 | 0.0 | 95.0 | 0.0 | 95.0 | 0.0 | 95.0 |
| **Irrigation** | 0.0 | 95.1 | 0.0 | 95.1 | 0.0 | 95.1 | 0.0 | 95.1 | 0.0 | 95.1 | 0.0 | 95.1 |
| **Kelowna** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **Penticton** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **Summerland** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **Grand Forks** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **Lardeau** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **Yahk** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **Nelson** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **Deferral Offset** | **140,905** | | **154,995** | | **170,495** | | **187,544** | | **206,298** | | **226,928** | |
| **Deferral Account Balance** | **4,016,682** | | **3,861,687** | | **3,691,193** | | **3,503,649** | | **3,297,351** | | **3,070,422** | |

**Table Big White IR2 A4.2.4 cnt'd**

| Class | Year 18 | | Year 19 | | Year 20 | | Year 21 | | Year 22 | | Year 23 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Total Increase | R/C Ratio | Total Increase | R/C Ratio | Total Increase | R/C Ratio | Total Increase | R/C Ratio | Total Increase | R/C Ratio | Total Increase | R/C Ratio |
| | % | | | | | | | | | | | |
| **Residential** | 0.0 | 98.3 | 0.0 | 98.3 | 0.0 | 98.3 | 0.0 | 98.3 | 0.0 | 98.3 | 0.0 | 98.3 |
| **Small General Service** | 0.0 | 105.0 | 0.0 | 105.0 | 0.0 | 105.0 | 0.0 | 105.0 | 0.0 | 105.0 | 0.0 | 105.0 |
| **General Service** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **ID 33** | 5.0 | 54.4 | 5.0 | 57.0 | 5.0 | 59.7 | 5.0 | 62.5 | 5.0 | 65.5 | 5.0 | 68.6 |
| **ID 30** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **ID31** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **Lighting** | 0.0 | 95.0 | 0.0 | 95.0 | 0.0 | 95.0 | 0.0 | 95.0 | 0.0 | 95.0 | 0.0 | 95.0 |
| **Irrigation** | 0.0 | 95.1 | 0.0 | 95.1 | 0.0 | 95.1 | 0.0 | 95.1 | 0.0 | 95.1 | 0.0 | 95.1 |
| **Kelowna** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **Penticton** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **Summerland** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **Grand Forks** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **Lardeau** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **Yahk** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **Nelson** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **Deferral Offset** | **249,621** | | **274,583** | | **302,041** | | **332,246** | | **365,470** | | **402,017** | |
| **Deferral Account Balance** | **2,820,801** | | **2,546,218** | | **2,244,177** | | **1,911,931** | | **1,546,461** | | **1,144,444** | |

**Table Big White IR2 A4.2.4 cnt'd**

| Class | Year 24 | | Year 25 | | Year 26 | |
|---|---|---|---|---|---|---|
| | Total Increase | R/C Ratio | Total Increase | R/C Ratio | Total Increase | R/C Ratio |
| | % | | | | | |
| **Residential** | 0.0 | 98.3 | 0.0 | 98.3 | 0.0 | 98.3 |
| **Small General Service** | 0.0 | 105.0 | 0.0 | 105.0 | 0.0 | 105.0 |
| **General Service** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **ID 33** | 5.0 | 71.9 | 5.0 | 75.3 | 2.1 | 76.8 |
| **ID 30** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **ID31** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **Lighting** | 0.0 | 95.0 | 0.0 | 95.0 | 0.0 | 95.0 |
| **Irrigation** | 0.0 | 95.1 | 0.0 | 95.1 | 0.0 | 95.1 |
| **Kelowna** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **Penticton** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **Summerland** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **Grand Forks** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **Lardeau** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **Yahk** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **Nelson** | 0.0 | 100.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| **Deferral Offset** | **442,219** | | **486,441** | | **215,625** | |
| **Deferral Account Balance** | **702,225** | | **215,784** | | **160** | |

Using this methodology, it would take 26 years to rebalance all rate classes. In addition, there would be approximately $5.2 million (or an NPV of $2.0 million) of carrying costs associated with the deferral that would have to be collected from customers as part of the annual revenue requirement. The Company respectfully submits that this would not be a reasonable method of addressing rate rebalancing.

**5.0 Reference: Exhibit B-1, pages 33, 76 and 77; Exhibit B-3-1, Question BCUC IR#1, Question 71**

**FortisBC states that its distribution extension charges are "designed to be equitable to all customers within a rate class, and across rate classes. The charge should collect enough from a new customer to hold harmless all other customers from the incremental costs of new localized distribution poles, conductors, and transformers."**

**Questions**

**Q5.1 FortisBC's answer to the referenced information request includes a quote taken from a wholesale customer's contract. That contract requires FortisBC to upgrade its system for the customer under defined conditions. However, in that case, the cost allocation principle appears to be that the customer triggering the expense is held harmless.**

**Q5.1.1 Does FortisBC see a distinction between the principle underlying its distribution extension policy and the referenced provision of its wholesale contract? Please explain.**

A5.1.1 In the response to BCUC IR No. 1 Q71.1, FortisBC was not making a distinction between its distribution extension policy and the upgrade provisions in the wholesale contracts. The Company was making a distinction between the upgrade provisions for other customers versus those for municipal wholesale utilities.

With respect to upgrading existing facilities or adding new facilities for existing customers, the majority of the costs of upgrading FortisBC infrastructure for the municipal wholesale utilities benefit are borne by all of FortisBC's customers, but the bulk of the benefits accrue to the municipal wholesale utility. All other customers are required to make a cost-based contribution in relation to the upgrade, thereby ensuring other customers do not bear these costs.

**Q5.1.2 If there are different principles inherent in the approach used for distribution extensions and the principle used for wholesale customers, please explain why that is appropriate. In answering this question, please make reference to the rate-making principles set out on page 33 of Exhibit B-1.**

A5.1.2 FortisBC is of the opinion that the difference in principles may not be appropriate since Principle 2 (fair apportionment of costs among customers) and Principle 3 (price signals should encourage efficient energy use) could arguably be violated.