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BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-134-99

TELEPHONE: (604) 660-4700
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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

West Kootenay Power Ltd.
2000-2002 Preliminary Revenue Requirements Application
1999 Annual Review

**BEFORE:** P. Ostergaard, Chair )
L.R. Barr, Deputy Chair )
P.G. Bradley, Commissioner ) December 16, 1999
B.L. Clemenhagen, Commissioner )
K.L. Hall, Commissioner )
F.C. Leighton, Commissioner )

**O R D E R**

**WHEREAS:**

A. Commission Order No. G-123-98 approved the December 15, 1998 Settlement Agreement extending the rate adjustment mechanism (“the Incentive Mechanism”) approved by Commission Order No. G-73-96, for the year ending December 31, 1999; and

B. The terms of the Settlement Agreement required that West Kootenay Power Ltd. (“WKP”) file a multi-year rate-making proposal to commence January 2000; and

C. The Settlement Agreement included an Annual Review process, to assess WKP’s performance and to make adjustments against 1998 and 1999 Revenue Requirements; and

D. In accordance with Commission Order No. G-94-99 the Commission initiated a Negotiated Settlement Process and an Annual Review; and

E. On November 8, 1999, WKP filed its 2000-2002 Preliminary Revenue Requirements Application (“the Application”). WKP applied, pursuant to the Utilities Commission Act (“the Act”), for an Order to set rates in accordance with an amended Incentive Mechanism for the period beginning January 1, 2000 and ending December 31, 2002; and

F. A negotiated settlement was reached among the participants and circulated to all Registered Intervenors, Interested Parties and the Commission on December 2, 1999; and

…/2

G. The Commission received letters on the negotiated settlement from the City of Kelowna, Natural Resource Industries, Hedley Improvement District, the British Columbia Public Interest Advocacy Centre, and the Kootenay-Boundary Regional Association/Nelson-Creston Constituency Association – Green Party; and

H. The Commission has considered the Application and is satisfied that the negotiated settlement, attached as Appendix A hereto, is necessary and in the public interest.

**NOW THEREFORE** the Commission orders as follows:

1. The Commission approves the negotiated settlement, attached as Appendix A, in its entirety.

2 The 1998 and 1999 Revenue Requirement adjustments are approved.

3. WKP is ordered to file a Final Rate Application which reflects the terms of the negotiated settlement, effective January 1, 2000.

**DATED** at the City of Vancouver, in the Province of British Columbia, this 17th day of December 1999.

BY ORDER

*Original signed by:*

Peter Ostergaard
Chair

Attachment

WILLIAM J. GRANT
EXECUTIVE DIRECTOR,
REGULATORY AFFAIRS & PLANNING
bill.grant@bcuc.com
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~~CONFIDENTIAL~~

*VIA FACSIMILE*

November 22, 1999

Dear Participants:

Re: Proposed Settlement of Issues
West Kootenay Power Ltd.
<u>2000-2002 Revenue Requirements and Incentive Mechanism Application</u>

The purpose of this letter is to record the proposed settlements achieved with respect to the West Kootenay Power Ltd. ("WKP") 2000-2002 Revenue Requirements and Incentive Mechanism Application filed November 8, 1999. The enclosed proposed settlement remains confidential until it is submitted to the British Columbia Utilities Commission for consideration. I, therefore ask that you provide to me a communication of endorsement for the proposal by Monday, November 29, 1999. At that time, the Settlement Agreement will be made public and provided to the Commission and all interested parties.

WKP has recalculated the revenue requirements schedules to reflect the settlement adjustments. The income tax expense has increased due to the decrease in the RSA credit. In accordance with the Settlement Agreement, if the actual income taxes are different, the variance is flowed through to customers in the following year. WKP has also provided the enclosed description of the Demand Side Management Incentive Mechanism for 2000.

It is recognized by all the parties that the agreement represents a package proposal within which there has been give and take by all parties. No issue is to be severed from the proposed settlement without allowing signatories the opportunity to address other related issues in the package.

In accordance with the NSP Guidelines, the right of parties to dissent from a proposed agreement is explicitly recognized by the Commission. If a party dissents, it can submit a written argument to the Commission panel. If the Commission panel is of the view that the dissent is reasonable and material, it may request written rebuttal argument or, where the settlement review process is to occur at an oral hearing, request argument at the oral hearing. If the dissent is determined to be reasonable and material, the dissenting party retains the right to present evidence and to cross-examine, or to rebut the evidence of others if there is a written hearing.

Yours truly,

W.J. Grant

WJG/lm
Enclosure
cc: Mr. Robert H. Hobbs, Director, Regulatory and Government Affairs
West Kootenay Power Ltd.

WKP/00/02RR-IM Agrmt Ltr

# WEST KOOTENAY POWER LTD.
# REVENUE REQUIREMENTS 2000-2002 AND INCENTIVE MECHANISM REVIEW
# SETTLEMENT AGREEMENT – FINAL DRAFT
# NOVEMBER 19, 1999

CONFIDENTIAL

## 1. Limitation on Annual Rate Increase

Parties agree that the annual rate increase in each of the three years of this Settlement Agreement will be no higher than 5 percent, considered as the average of all rate classes. In the event that recovery of approved costs cannot be accommodated within that increase, WKP will propose a mechanism for managing its recovery of costs within this cap. If necessary, WKP may utilize a funding adjustment to past years' depreciation to create a Rate Stabilization Fund.

## 2. Base Costs

Base costs are accepted as proposed and will not be re-based for the test period.

## 3. Operating Expenses

The parties accept that the productivity improvement factors for Operating Expenses shall be 2, 2 and 2 percent for each of the three years of the test period.

### 3.1 Capitalized Overhead, Wheeling, and Water Fees

Parties accept the forecasts for these items as listed at Tab 2, Page 8 of the Application.

### 3.2 Extraordinary O&M

- The Wide Area Network Lease will be included in extraordinary O&M.
- The Environmental Management System will be excluded from extraordinary O&M.
- The pension adjustments as listed at Tab 2, page 13 are accepted.
- The head office lease payments in excess of $200,000 are accepted, although O&M productivity factors will apply to these expenses.
- Parties accept a mechanism to adjust rates in the year following completion of Extraordinary O&M cost accounts for variances from

forecast as a flow-through component in the annual statement of adjustments.

- Parties accept a mechanism to make adjustments to O&M costs and the related capital expenditure when a lower-cost financing alternative is available and the Commission approves the adjustment. For CPCN projects, a discounted revenue requirement comparison of the capital and O&M alternatives is required. WKP will notify the Commission of any leasing arrangements of non-CPCN projects. Projects related to the Kelowna office are to reflect any changes to existing leases and capital including any new lease costs.

### 3.3 Other Income

Parties agree that WKP, at each annual review, will declare any anticipated extraordinary income for the next year and that the declared income will be included in the determination of revenue requirements for that year.

## 4. Financing Costs

Parties accept financing costs as shown at Tab 2, page 14 of the Application.

## 5. Return on Equity

Parties accept that WKP's allowed ROE will be set 40 basis points above the ROE set by the Commission for a benchmark low-risk utility.

## 6. Amortization Expense

Parties accept that the depreciation rate for transmission and distribution assets will be extended to 50 years effective on a prospective basis from January 1, 2000. This will apply to new and existing plant.

## 7. Tax Expense

Variances from the forecast effective income tax rate will be a 100 percent flow-through to customers. Parties accept that property tax and the B.C. capital tax will be treated in the manner described at Tab 2, page 17 of the Application.

8. Base Capital

The parties accept that the productivity improvement factors for all Base Capital shall be 2, 2 and 2 percent for each of the three years of the test period.

The parties accept the forecast for all categories as listed at Tab 2, page 23 of the Application. Parties note that if Princeton Light and Power leaves the West Kootenay system, then the cost driver for Transmission and Distribution Upgrades will need to be re-based.

All parties reserve their rights to argue, at the Annual Reviews or following the three years of this Settlement Agreement, that significant changes to target costs require adjustments to base levels. In particular, capital investments in the 230 Kv system and substation upgrades may affect base capital targets.

9. Extraordinary Capital Expenditures

Parties accept the Extraordinary Capital Expenditures listed at Tab 2, page 30 of the Application (Table 8-B, Aggregate Capital Expenditures). Parties accept that the timing of these capital expenditure projects are firm for the year 2000 but the timing and amounts may be adjusted at the Annual Review for the years 2001 and 2002. WKP must demonstrate the need for any changes.

All parties are concerned that projects proceed in a timely fashion to achieve power quality and quality of service improvements at the least cost possible. Three requirements are established:

- Cost Containment: Each CPCN application (including the one filed November 10, 1999) will include proposals for standards, mechanisms and incentives for cost containment and cost-sharing as WKP believes appropriate to the individual project. Parties may argue to the Commission in favour of specific cost containment and scheduling measures.

- Timing: WKP must file CPCN applications for the upcoming year within that year or be penalized by not sharing in other financial incentives in this Settlement Agreement.

- Power Quality and Quality of Service: WKP will file a report by February 29, 2000 that will endeavour to propose a performance standard on power quality to apply in the year 2000. That report will also address the specific plans to maintain quality of service in the

Nelson/South Slocan areas. The report will be provided to participants in this process, and the Commission will solicit the views of participants on the report and the process for dealing with the report.

In addition to the forecasts listed at Tab 2, page 30, the Osoyoos Indian Band right-of-way and the CNR right-of-way will be treated as extraordinary items in the year 2000 and will be filed as CPCNs and included in the totals when approved.

10. Power Purchases

Parties accept cancellation of the Power Purchase Variance Mechanism and the Market Incentive Mechanism. Parties accept that WKP will be responsible for the power purchase variances from load variances, described as the difference between the Forecast Power Purchase Expense ("FPPE") and the Adjusted Power Purchase Expense ("APPE"). The calculation of the APPE should include the contract commitments made at the start of the year.

Parties accept the addition of a Power Purchase Price Variance ("PPPV") mechanism based on the difference between the APPE and the Actual Power Purchase Expense, as defined at Tab 4, Appendix A of the Application. Up to $1 million in PPPV, the sharing of the PPPV for any year will be 65 percent to the ratepayer and 35 percent to West Kootenay Power, and will be 75 percent to the ratepayer and 25 percent to WKP on any remaining amount.

Parties accept the year 2000 power purchase forecasts as described at Tab 4 of the Application, as amended by Section 11 of this agreement.

11. Load Forecast

Parties accept the load forecast in the application with the addition of 5 GWh to the residential forecast as suggested by WKP and accepted by the load forecast Committee.

12. Demand Side Management

Parties accept the DSM Incentive Mechanism as presented by the DSM Committee. Spending estimates for 2001 and 2002 will be as set out in the DSM business plan, but may be amended following the Annual Reviews.

13. Performance Standards

Parties accept the performance standards as described at Tab 2, page 6 of the Application, as amended by Section 9 of this Agreement.

14. Additional Items

Parties agree to a variance from Generally Accepted Accounting Principles ("GAAP") to allow post-retirement benefits to be recorded on a cash basis.

Parties accept the deferral of incremental costs for regulatory and related activities as they arise until those costs can be incorporated into rates.

Parties accept the deferral of issue costs of the Series I five-year term loan.

Parties accept the deferral of $26,500 in Y2K costs if power is uninterrupted on January 1, 2000, except for acts of God/B.C. Hydro. Other Y2K expenses incurred in 1999 are to be expensed in that year.

15. Commercial Customers

Parties agree that WKP will provide customer information and education about the demand charge component of the customer bill.

Parties agree that WKP will undertake a customer bill analysis to show the impact of the demand charge on commercial customers' electricity bills. Parties also agree that WKP will complete and deliver that analysis to the largest 20 percent of their commercial customers before the next Annual Review.

## 2. Revenue Requirements

### Table 2-A Revenue Requirements

| | | 2000 | 2001 | 2002 | Reference Tab | Reference Page |
|---|---|---|---|---|---|---|
| | | | (000's) | | | |
| 1 | POWER PURCHASES | $ 45,558 | $ 45,395 | $ 46,258 | 4 | |
| 2 | OPERATING EXPENSES | | | | 2 | 8 |
| 3 | Operating & Maintenance | 26,538 | 26,761 | 27,062 | | |
| 4 | Extraordinary O&M | 699 | 696 | 694 | | |
| 5 | Capitalized overhead | (3,353) | (3,414) | (3,465) | | |
| 6 | Wheeling | 3,592 | 4,194 | 4,251 | | |
| 7 | Water fees | 7,189 | 7,773 | 8,046 | | |
| 8 | Other income | (3,196) | (3,307) | (3,429) | | |
| 9 | | 31,468 | 32,703 | 33,160 | | |
| 10 | FINANCING COSTS | | | | 2 | 14 |
| 11 | Interest expense | 14,722 | 16,679 | 19,362 | | |
| 12 | Cost of equity | 12,425 | 13,867 | 15,556 | | |
| 13 | Amortization expense | 9,892 | 12,050 | 13,447 | | |
| 14 | AFUDC | (628) | (2,457) | (4,054) | | |
| 15 | | 36,411 | 40,139 | 44,311 | | |
| 16 | TAX EXPENSE | | | | 2 | 17 |
| 17 | Income tax | 7,615 | 8,499 | 9,535 | | |
| 18 | Property tax | 9,143 | 10,323 | 11,144 | | |
| 19 | B.C. capital tax | 892 | 902 | 978 | | |
| 20 | | 17,650 | 19,724 | 21,657 | | |
| 21 | REVENUE REQUIREMENTS | 131,088 | 137,961 | 145,385 | | |
| 22 | ADJUSTMENTS TO REVENUE REQUIREMENTS | | | | | |
| 23 | Prior Year Adjustment (Final) | (44) | | | 2 | 18 |
| 24 | Current Year Adjustment (Preliminary) | 803 | | | 2 | 19 |
| 25 | Power Purchase Adjustment | (581) | | | 2 | 20 |
| 26 | RATE STABILIZATION ACCOUNT AMORTIZATION | (300) | (300) | (600) | 7 | 3 |
| 27 | REVISED REVENUE REQUIREMENTS | $ 130,966 | $ 137,661 | $ 144,785 | | |
| 28 | | | | | | |
| 29 | REVENUE AT PRIOR YEAR RATES | $ 124,725 | $ 131,159 | $ 137,851 | | |
| 30 | | | | | | |
| 31 | REQUIRED RATE INCREASE | 5.0% | 5.0% | 5.0% | | |

## 4. Target Cost Variables

The Incentive Mechanism applies various Cost Drivers and Base Cost Escalators to the Base Cost to determine Target Costs and Revenue Requirements. Table 4-A below presents the main Cost Driver and Base Cost Escalator forecasts. Certain cost accounts make use of other drivers/escalators as described in Section 5 -5. Target *Costs.*

### Table 4-A Target Cost Variables

| | | Current Estimate Normalized | Forecast | | | |
|---|---|---|---|---|---|---|
| | | 1999 | 2000 | 2001 | 2002 | Notes |
| 1 | **Cost Drivers** | | | | | |
| 2 | Number of Direct Customers (Year-End) | 86,459 | 87,610 | 89,141 | 90,869 | 1 |
| 3 | Customer Growth (Year-End) | 1.0% | 1.3% | 1.7% | 1.9% | |
| 4 | | | | | | |
| 5 | Number of Direct Customers (Simple Average) | 86,049 | 87,035 | 88,376 | 90,005 | |
| 6 | Customer Growth (Simple Average) | 1.3% | 1.1% | 1.5% | 1.8% | |
| 7 | | | | | | |
| 8 | System Energy Sales (GW.h - Normalized) | 2,607 | 2,620 | 2,648 | 2,645 | 1 |
| 9 | Losses (GW.h - Normalized) | 327 | 330 | 333 | 333 | 1 |
| 10 | Gross Load (GW.h - Normalized) | 2,934 | 2,950 | 2,981 | 2,978 | |
| 11 | | | | | | |
| 12 | System Energy Sales Growth | 0.3% | 0.5% | 1.1% | -0.1% | |
| 13 | | | | | | |
| 14 | Peak Load (MW - Normalized) | 641 | 643 | 652 | 650 | 1 |
| 15 | | | | | | |
| 16 | Generation (GW.h) | 1,477 | 1,512 | 1,550 | 1,577 | 2 |
| 17 | Power Purchases (GW.h) | 1,457 | 1,438 | 1,431 | 1,401 | 2 |
| 18 | Gross Load (GW.h - Normalized) | 2,934 | 2,950 | 2,981 | 2,978 | |
| 19 | | | | | | |
| 20 | | | | | | |
| 21 | **Base Cost Escalators** | | | | | |
| 22 | CPI - Canada | 1.6% | 2.0% | 1.9% | 1.8% | 3 |
| 23 | | | | | | |
| 24 | CPI - British Columbia | 0.8% | 1.1% | 1.3% | 1.3% | 4 |

## 5. Target Costs

The target costs presented in this section incorporate the proposed changes outlined in Section 3.

### 5.1 Operating Expenses

**Table 5-A Operating Expenses**

| | | | Target 1999 | Current Estimate 1999 | Target 2000 | Target 2001 | Target 2002 |
|---|---|---|---|---|---|---|---|
| 1 | **Operating & Maintenance** | | | | | | |
| 2 | Cost Driver | Direct customers | 86,049 | 86,049 | 87,035 | 88,376 | 90,005 |
| 3 | Base Cost | ($ 1998) | $ 305.30 | $ 305.30 | $ 305.30 | $ 305.30 | $ 305.30 |
| 4 | Base Cost Escalator | CPI BC (Cumulative) | 1.0082 | 1.0082 | 1.0191 | 1.0327 | 1.0464 |
| 5 | Productivity Improvement Factor (Cumulative) | | 1.0000 | | 0.9800 | 0.9604 | 0.9412 |
| 6 | | | $ 26,485 | $ 27,476 | $ 26,538 | $ 26,761 | $ 27,082 |
| 7 | **Extraordinary O&M** | | | | | | |
| 8 | | | $ 385 | $ 385 | $ 699 | $ 698 | $ 694 |
| 9 | **Capitalized Overhead** | | | | | | |
| 10 | Cost Driver | Capital exp. excl. DSM | 33,509 | 33,509 | 45,158 | 76,176 | 72,759 |
| 11 | Base Cost | | 8.0% | 7.5% | 7.4% | 4.5% | 4.8% |
| 12 | Base Cost Escalator | None | n/a | | n/a | n/a | n/a |
| 13 | | | $ (2,681) | $ (2,502) | $ (3,353) | $ (3,414) | $ (3,465) |
| 14 | **Wheeling** | | | | | | |
| 15 | Cost Driver | MW Months | 2,220 | 2,220 | 2,130 | 2,421 | 2,409 |
| 16 | Base Cost | (weighted average) | $ 1,682 | $ 1,674 | $ 1,653 | $ 1,695 | $ 1,725 |
| 17 | Base Cost Escalator | BC Hydro rate | 1.0000 | | 1.0200 | 1.0220 | 1.0230 |
| 18 | | | $ 3,735 | $ 3,717 | $ 3,592 | $ 4,194 | $ 4,251 |
| 19 | **Water Fees** | | | | | | |
| 20 | Cost Driver | GW.h | 1,513 | 1,513 | 1,477 | 1,512 | 1,550 |
| 21 | Base Cost | (includes upgrade) | $ 4,866 | $ 4,857 | $ 4,772 | $ 5,030 | $ 5,074 |
| 22 | Base Cost Escalator | BC Hydro rate | 1.0000 | | 1.0200 | 1.0220 | 1.0230 |
| 23 | | | $ 7,362 | $ 7,349 | $ 7,189 | $ 7,773 | $ 8,046 |
| 24 | **Other Income** | | | | | | |
| 25 | Cost Driver | Direct customers | 86,049 | 86,049 | 87,035 | 88,376 | 90,005 |
| 26 | Base Cost | ($ 1998) | $ (35.44) | | $ (35.44) | $ (35.44) | $ (35.44) |
| 27 | Base Cost Escalator | CPI Canada (Cumulative) | 1.0160 | 1.0160 | 1.0363 | 1.0560 | 1.0750 |
| 28 | | | $ (3,098) | $ (3,265) | $ (3,196) | $ (3,307) | $ (3,429) |
| 29 | **Total Operating Expenses** | | $ 32,188 | $ 33,160 | $ 31,468 | $ 32,703 | $ 33,160 |

## Table 5-B Extraordinary O&M Costs

| | | Actual | Forecast | | |
|---|---|---|---|---|---|
| | | 1999 | 2000 | 2001 | 2002 |
| 1 | Head Office Lease Payments | $ - | $ 108 | $ 106 | $ 104 |
| 2 | Pension Expense Adjustments | | | | |
| 3 | 1999 Adjustment | 385 | 385 | 385 | 385 |
| 4 | 2000 Adjustment | - | (87) | (87) | (87) |
| 5 | Total Pension Expense | 385 | 298 | 298 | 298 |
| 6 | Wide Area Network Lease | - | 293 | 293 | 293 |
| 7 | **Total Extraordinary O&M Expenses** | **$ 385** | **$ 699** | **$ 696** | **$ 694** |

## 5.3 Financing Costs

### Table 5-C Financing Costs

| | | | Current Estimate | | Forecast | |
|---|---|---|---|---|---|---|
| | | | 1999 | 2000 | 2001 | 2002 |
| 1 | **Interest expense** | | | | | |
| 2 | Cost Driver | Weighted average debt | $ 167,713 | $ 186,275 | $ 213,332 | $ 252,264 |
| 3 | Base Cost | Weighted average cost of debt | 8.01% | 7.90% | 7.82% | 7.68% |
| 4 | | | $ 13,440 | $ 14,722 | $ 16,679 | $ 19,362 |
| 5 | **Cost of equity** | | | | | |
| 6 | Cost Driver | Simple average shareholders' equity | $ 112,567 | $ 124,253 | $ 142,221 | $ 168,176 |
| 7 | Base Cost | Return on equity (Note 1) | 9.50% | 10.00% | 9.75% | 9.25% |
| 8 | | | $ 10,694 | $ 12,425 | $ 13,867 | $ 15,556 |
| 9 | | | | | | |
| 10 | **Amortization expense** | | | | | |
| 11 | Cost Driver | Assets subject to amortization | n/a | n/a | n/a | n/a |
| 12 | Base Cost | | n/a | n/a | n/a | n/a |
| 13 | | | $ 9,629 | $ 9,892 | $ 12,050 | $ 13,447 |
| 14 | | | | | | |
| 15 | **AFUDC** | | | | | |
| 16 | Cost Driver | Capital expenditures subject to AFUDC | n/a | n/a | n/a | n/a |
| 17 | Base Cost | | 8% | 8% | 8% | 8% |
| 18 | | | $ (420) | $ (628) | $ (2,457) | $ (4,054) |
| 19 | **Total Financing Costs** | | $ 33,343 | $ 36,411 | $ 40,139 | $ 44,311 |
| 20 | | | | | | |

21 **Notes:**

22 1.) *The 1999 approved return on equity, not the actual, has been shown for the purposes of*

23 *calculating the return on capitalization for the financing cost adjustments.*

## Table 5-D Amortization Expense

| | | 1999 | 2000 | 2001 | 2002 |
|---|---|---|---|---|---|
| | | | (thousands) | | |
| 1 | **Amortization Expense** | | | | |
| 2 | Amortization of Plant & Equipment | $ 11,041 | $ 9,016 | $ 10,472 | $ 11,814 |
| 3 | Amortization of Deferred Charges | | | | |
| 4 | Previously Approved | (1,412) | 703 | 1,443 | 1,498 |
| 5 | To be Approved | | | | |
| 6 | AFUDC 1998 Final Regulatory Adj. | - | (31) | - | - |
| 7 | 1999 Revenue Requirements | - | 69 | - | - |
| 8 | WKP Transmission Access | - | 85 | 85 | 85 |
| 9 | Time of Use Marketing | - | 10 | 10 | 10 |
| 10 | Series 1 | - | 40 | 40 | 40 |
| 11 | | 9,629 | 9,892 | 12,050 | 13,447 |

## 5.4 Tax Expense

### Table 5-E Tax Expense

| | | | Current Estimate | Forecast | | |
|---|---|---|---|---|---|---|
| | | | 1999 | 2000 | 2001 | 2002 |
| 1 | **Income tax** | | | | | |
| 2 | Cost Driver | Earnings before income taxes | $ 16,512 | $ 20,041 | $ 22,365 | $ 25,091 |
| 3 | Base Cost | Effective tax rate | 33.40% | 38.00% | 38.00% | 38.00% |
| 4 | | | $ 5,515 | $ 7,615 | $ 8,499 | $ 9,535 |
| 5 | | | | | | |
| 6 | **Property tax** | | | | | |
| 7 | Cost Driver | Assessed value | $ 295,000 | $ 315,276 | $ 355,966 | $ 384,276 |
| 8 | Base Cost | Composite mill rate | 30.18 | 29.00 | 29.00 | 29.00 |
| 9 | | | $ 8,902 | $ 9,143 | $ 10,323 | $ 11,144 |
| 10 | | | | | | |
| 11 | **B.C. capital tax** | | | | | |
| 12 | Cost Driver | Total Capitalization | $ 281,417 | $ 310,631 | $ 355,553 | $ 420,440 |
| 13 | Base Cost | Effective tax rate | 0.29% | 0.29% | 0.25% | 0.23% |
| 14 | | | $ 826 | $ 892 | $ 902 | $ 978 |
| 15 | **Total Taxes** | | $ 15,243 | $ 17,650 | $ 19,724 | $ 21,657 |

## Schedule E Return on Capitalization

| | | Current Estimate | Forecast | | |
|---|---|---|---|---|---|
| | | 1999 | 2000 | 2001 | 2002 |
| 1 | EARNED RETURN | | | | |
| 2 | Interest expense | $ 13,440 | $ 14,722 | $ 16,679 | $ 19,362 |
| 3 | Cost of equity | 10,694 | 12,425 | 13,867 | 15,556 |
| 4 | | $ 24,134 | $ 27,147 | $ 30,546 | $ 34,918 |
| 5 | | | | | |
| 6 | CAPITALIZATION | | | | |
| 7 | Weighted average debt | $ 167,713 | $ 186,275 | $ 213,332 | $ 252,264 |
| 8 | Simple average shareholders' equity | 112,567 | 124,253 | 142,221 | 168,176 |
| 9 | Deferred income taxes | 1,137 | 104 | - | - |
| 10 | | $ 281,417 | $ 310,631 | $ 355,553 | $ 420,440 |
| 11 | | | | | |
| 12 | RETURN ON CAPITALIZATION | 8.58% | 8.74% | 8.59% | 8.31% |

## 6.3 Adjustments to Power Purchase Costs

### Schedule F Adjustment to 1999 Power Purchase Costs

| | | Target Cost | Current Estimate | Variance (000's) | WKP Share of Market Incentive | Adjustment to Rates |
|---|---|---|---|---|---|---|
| 1 | TARGET POWER PURCHASE EXPENSE | $ 44,574 | | | | |
| | Weather Adjustment | (342) | | | | |
| | ADJUSTED POWER PURCHASE EXPENSE | $ 44,232 | $ 43,321 | $ 911 | 330 | $ 581 |
| 2 | | | | | | |
| 3 | SHARED COMPONENT | | | | | |
| 4 | First | | | 200 | 100% | 200 |
| 5 | Next: | | | 400 | 50% | 200 |
| 6 | Next: | | | 520 | 75% | 390 |
| 7 | Over $1,800 | | | - | 100% | - |
| 8 | Total Market Incentive Variance | | | 1,120 | | 790 |
| 9 | | | | | | |
| 10 | FLOW-THROUGH COMPONENT | | | | | |
| 11 | Load Variance | | | (209) | 100% | (209) |
| 12 | | | | | | |
| 13 | TOTAL ADJUSTMENT TO RATES | | | $ 911 | | $ 581 |

## 7. Revenue Forecast Summary

The following tables are summarized from the Load and Customer Forecast at Tab 3. The methodology for forecasting customer growth, load and revenue is described in detail in the Load and Customer Forecast.

### 7.1 Sales Load

Revenue from the sale of electricity will be adjusted each year to reflect revised load forecasts and incorporated in the annual revenue requirements application.

**Table 7-A Sales Load (GW.h)**

| | | Current Estimate | Forecast | | |
|---|---|---|---|---|---|
| | | 1999 | 2000 | 2001 | 2002 |
| 1 | CUSTOMER CLASS | | | | |
| 2 | Residential | 958 | 967 | 969 | 973 |
| 3 | General Service | 480 | 485 | 492 | 502 |
| 4 | Industrial | | | | |
| 5 | Mines | 12 | 12 | 12 | - |
| 6 | Lumber | 161 | 163 | 161 | 159 |
| 7 | Sundry | 77 | 92 | 107 | 102 |
| 8 | Pulp | 12 | 12 | 12 | 12 |
| 9 | | 263 | 279 | 292 | 273 |
| 10 | Wholesale | 852 | 835 | 841 | 843 |
| 11 | Lighting | 12 | 12 | 12 | 12 |
| 12 | Irrigation | 42 | 42 | 42 | 42 |
| 13 | TOTAL SALES LOAD | 2,607 | 2,620 | 2,648 | 2,646 |

## 7.2 Revenue from Sale of Electricity

### Table 7-B Revenue from Sale of Electricity

| | | Current Estimate 1999 | Forecast 2000 | 2001 | 2002 |
|---|---|---|---|---|---|
| 1 | **CUSTOMER CLASS** | | | | |
| 2 | **Residential** | $ 53,598 | $ 53,788 | $ 53,899 | $ 54,120 |
| 3 | **General Service** | 26,498 | 26,986 | 27,376 | 27,931 |
| 4 | **Industrial** | | | | |
| 5 | **Mines** | 379 | 408 | 408 | - |
| 6 | **Lumber** | 6,791 | 6,816 | 6,732 | 6,649 |
| 7 | **Sundry** | 2,954 | 3,758 | 4,327 | 4,114 |
| 8 | **Pulp** | 1,181 | 1,092 | 1,092 | 1,092 |
| 9 | | 11,305 | 12,074 | 12,559 | 11,855 |
| 10 | **Wholesale** | 29,771 | 28,919 | 27,561 | 27,608 |
| 11 | **Lighting** | 1,333 | 1,380 | 1,380 | 1,380 |
| 12 | **Irrigation** | 1,500 | 1,454 | 1,455 | 1,456 |
| 13 | **Third Party Transmission Services** | - | 124 | 683 | 685 |
| 14 | **TOTAL SALES REVENUE** | $ 124,005 | $ 124,725 | $ 124,913 | $ 125,035 |

*Note: Revenues are forecast at rates effective January 1, 1999 and do not include restructuring accruals.*

# 8. Capital Expenditures

## 8.1 Base Capital Expenditures

### Table 8-A Base Capital Expenditures

| | | | Target | Current Estimate | Forecast | | |
|---|---|---|---|---|---|---|---|
| | | | 1999 | 1999 | 2000 | 2001 | 2002 |
| 1 | Generation | | | | | | |
| 2 | Cost Driver | Generating Plants | 4 | 4 | 4 | 4 | 4 |
| 3 | Base Cost | ($ 1998) | $ 1,275 | $ 1,275 | $ 1,275 | $ 1,275 | $ 1,275 |
| 4 | Base Cost Escalator | CPI Canada (Cumulative) | 1.0160 | 1.0160 | 1.0363 | 1.0560 | 1.0750 |
| 5 | Productivity Improvement Factor (Cumulative) | | 1.0000 | | 0.9800 | 0.9604 | 0.9412 |
| 6 | | | $ 1,296 | $ 1,345 | $ 1,295 | $ 1,293 | $ 1,290 |
| 7 | Transmission and Distribution Upgrade | | | | | | |
| 8 | Cost Driver | Peak MW (Normalized) | 641 | 641 | 643 | 652 | 650 |
| 9 | Base Cost | ($ 1998) | $ 14,224 | $ 14,224 | $ 14,224 | $ 14,224 | $ 14,224 |
| 10 | Base Cost Escalator | CPI Canada (Cumulative) | 1.0160 | 1.0160 | 1.0363 | 1.0560 | 1.0750 |
| 11 | Productivity Improvement Factor (Cumulative) | | 1.0000 | | 0.9800 | 0.9604 | 0.9412 |
| 12 | | | $ 9,263 | $ 9,522 | $ 9,288 | $ 9,405 | $ 9,354 |
| 13 | Distribution Extensions | | | | | | |
| 14 | Cost Driver | Number of New Customers | 821 | 821 | 1,151 | 1,531 | 1,728 |
| 15 | Base Cost | ($ 1998) | 846 | 846 | 1,325 | 1,325 | 1,325 |
| 16 | Base Cost Escalator | CPI Canada (Cumulative) | 1.0160 | 1.0160 | 1.0363 | 1.0560 | 1.0750 |
| 17 | Productivity Improvement Factor (Cumulative) | | 1.0000 | | 0.9800 | 0.9604 | 0.9412 |
| 18 | | | $ 705 | $ 1,301 | $ 1,549 | $ 2,057 | $ 2,317 |
| 19 | General Plant | | | | | | |
| 20 | Cost Driver | Direct customers | 86,049 | 86,049 | 87,035 | 88,376 | 90,005 |
| 21 | Base Cost | ($ 1998) | $ 44.14 | $ 44.14 | $ 44.14 | $ 44.14 | $ 44.14 |
| 22 | Base Cost Escalator | CPI Canada (Cumulative) | 1.0082 | 1.0082 | 1.0191 | 1.0327 | 1.0464 |
| 23 | Productivity Improvement Factor (Cumulative) | | 1.0000 | | 0.9800 | 0.9604 | 0.9412 |
| 24 | | | $ 3,829 | $ 4,329 | $ 3,837 | $ 3,869 | $ 3,912 |
| 25 | Total Base Capital Expenditures | | $ 15,093 | $ 16,497 | $ 15,969 | $ 16,625 | $ 16,874 |

## 8.3 Aggregate Capital Expenditures

### Table 8-B Aggregate Capital Expenditures

| | | Current Estimate | Forecast | | |
|---|---|---|---|---|---|
| | | 1999 | 2000 | 2001 | 2002 |
| 1 | Extraordinary Expenditures | | | | |
| 2 | Turbine Upgrades | 8,613 | 13,730 | 12,027 | 11,450 |
| 3 | Dam Rehabilitation Projects | 356 | - | - | - |
| 4 | 44 Line Upgrade | 2,700 | - | - | - |
| 5 | 49 Line Upgrade | 250 | - | - | - |
| 6 | Insulator Replacement Program | 1,371 | 900 | - | - |
| 7 | Okanagan-Kootenay Transmission Supply | - | 9,637 | 41,878 | 39,397 |
| 8 | Huth Substation/Subtransmission Rebuild | 600 | 2,292 | - | - |
| 9 | Joe Riche Reconductoring | 1,547 | - | - | - |
| 10 | Okanagan HV Capacitors | | - | 1,580 | - |
| 11 | 138kV Line to Big White | | - | 40 | 520 |
| 12 | Big White Substation | | - | - | 340 |
| 13 | Greenwood Substation | | 102 | 898 | - |
| 14 | Ruckles Substation | | - | - | 2,900 |
| 15 | Lee Terminal Upgrade | | - | - | 1,150 |
| 16 | CSP Transformer Replacement | | 500 | 1,000 | - |
| 17 | Customer Information System | 1,575 | 1,000 | - | - |
| 18 | Kelowna Operations Center | | 900 | 2,000 | - |
| 19 | Extraordinary Pension (Capitalized Portion) | | 128 | 128 | 128 |
| 20 | | 17,012 | 29,189 | 59,551 | 55,885 |
| 21 | Demand Side Management | | | | |
| 22 | Demand Side Management | 1,596 | 1,542 | 1,585 | 1,624 |
| 23 | DSM Tax | (728) | (704) | (723) | (741) |
| 24 | | 868 | 838 | 862 | 883 |
| 25 | **Total Extraordinary Capital Expenditures** | **17,880** | **30,027** | **60,413** | **56,768** |
| 26 | **Total Base Capital Expenditures** | **16,497** | **15,969** | **16,625** | **16,874** |
| 27 | **Total Capital Expenditures** | **$ 34,377** | **$ 45,996** | **$ 77,038** | **$ 73,642** |

# Demand Side Management Incentive Mechanism for 2000:

The 2000 DSM incentive mechanism is a shared savings mechanism (SSM). It is based on a recommendation contained in the study of DSM incentive mechanisms for WKP by David Nichols of the Tellus Institute. It may be extended to 2001 and 2002 upon consensus of the DSM Committee at the next annual review.

The SSM has been the most commonly used shareholder incentive during the 1990's. This approach will provide WKP with a share of the net benefits from its DSM activities. Benefits are defined as the value of avoided energy and capacity costs and deferred capital expenditures. All utility program costs and the customer costs of energy efficiency are deducted from the benefits to arrive at the net benefits. This mechanism sends the signal to maximize the resource savings per dollar spent on energy efficiency measures. The SSM will provide for a small share of the life-cycle benefits as a potential reward to the shareholders. It also introduces a penalty for not achieving a threshold level of net benefits.

The SSM approach requires both the power savings and the resource benefits flowing from those savings to be quantified. The benefits are calculated over the lifetimes of the DSM measures put into place. WKP will receive a share of the total net present value of these life-cycle benefits.

<u>Gross Benefit Values</u>
For 2000, the benefits are valued at 2.6¢ for each kW.h (energy savings) and $28 for each annual KW (capacity savings) and $36 for each annual KW saved from peak (deferred capital expenditures). The lifetimes of DSM measures range from 5 years to 20 years.

<u>SSM Incentive or Penalty Rates</u>
The DSM Committee modified the report recommendation by introducing different incentive or penalty levels based on WKP's performance compared to Plan Net Benefits in 2000 for each of the three sectors. The maximum incentive amount that can be earned in any sector will be based on 150% of the plan net benefits for that sector and the maximum penalty will be based on 50% of the plan net benefits:

**TABLE A for Incentives (+) or Penalties (-) at Selected Performance Levels**

| % of Plan Net Benefits | <50% | <70% | <90% | <95% | 95-100% | >100% | >110% | >120% |
|---|---|---|---|---|---|---|---|---|
| Residential | -6.0% | -4.5% | -3.0% | 0.0% | 0.0% | 3.0% | 4.5% | 6.0% |
| General Service | -4.0% | -3.0% | -2.0% | -1.0% | 0.0% | 2.0% | 3.0% | 4.0% |
| Industrial | -3.0% | -2.0% | -1.0% | -0.5% | 0.0% | 1.0% | 2.0% | 3.0% |

<u>Plan Net Benefits for 2000</u>
For purposes of the SSM, Table B is WKP's Plan Net Benefits for 2000:

**TABLE B** (with maximum and minimum values of +/- 50% of plan)

| Sector ($000) | Gross | TRC | et Benefits (NB) | Max NB | Min NB |
|---|---|---|---|---|---|
| Residential | 769 | 590 | 179 | 269 | 90 |
| General Service | 2540 | 1293 | 1247 | 1871 | 624 |
| Industrial | 483 | 243 | 240 | 360 | 120 |

This plan will form the basis for the application of incentives or penalties from Table A. For incentive purposes, WKP expenditures will be capped at 110% of the planned $1254 K for program delivery. Planning and evaluation expenditures of $288K will not form part of the incentive calculation. DSM expenditures and targets for 2001 and 2002 will be established at the WKP annual reviews proceeding each year.

23 November 1999

BCUC Log #...2142
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WEST KOOTENAY POWER
ENERGYONE

**Via Courier**

Mr. R. J. Pellatt
Commission Secretary
BC Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Pellatt:

Re: ***Response to Proposed Settlement of Issues West Kootenay Power Ltd. 2000-2002 Preliminary Revenue Requirements Settlement Agreement and Incentive Mechanism Application***

By letter dated November 22,1999, the Commission staff requested endorsement letters with respect to the Proposed Settlement of Issues.

The Company endorses the Proposed Settlement of Issues in its entirety, without exception. Item #10 contains a typo in the reference to Tab 4, Appendix A; the power purchase variance ("PPV") is the difference between the APPE and the Actual Power Purchase Expense. The reference to the Power Purchase Price Variance ("PPPV") in Tab 4, Appendix A is incorrect.

Re: ***Customer Satisfaction Survey***

Please find enclosed fifteen copies of the Customer Satisfaction Index ("CSI") results for inclusion in the 2000-2002 Preliminary Revenue Requirements Application binder at the end of Tab 6. The 1999 actual CSI for WKP is 89.8% which compares favourably to the 1997 and 1998 CSI's of 90.0%. WKP therefore has achieved a satisfactory Customer Satisfaction Index ("CSI") for 1999. Page 20 of Tab 6 has been amended to reflect the CSI results and should replace the previously filed page.

By copy of this letter, WKP's endorsement of the Proposed Settlement Agreement and a copy of the CSI results is being forwarded to participants in the negotiations.

Sincerely,

RMcKay

for Robert H. Hobbs
Director, Regulatory and
Government Affairs

cc: 2000-2002 Annual Review Participants
Enclosures (15)

## 5. *CUSTOMER SATISFACTION*

In November of each year, an independent market research firm carries out a telephone survey of 1,000 utility customers in the West Kootenay Power service area. A survey of this size provides results which are accurate ± 3.1% at the 95% confidence level.

Customers are specifically asked to rate their utility on a scale of 1-10 with regard to their satisfaction on five elements of core service.

Ratings from all 1,000 customers are then rolled together and averaged to provide an overall Customer Satisfaction Index (CSI). The five elements that of the CSI are:

1. Reliability of electric service
2. Speed of service restoration
3. Quality of service contact
4. Helping customers conserve energy
5. Price

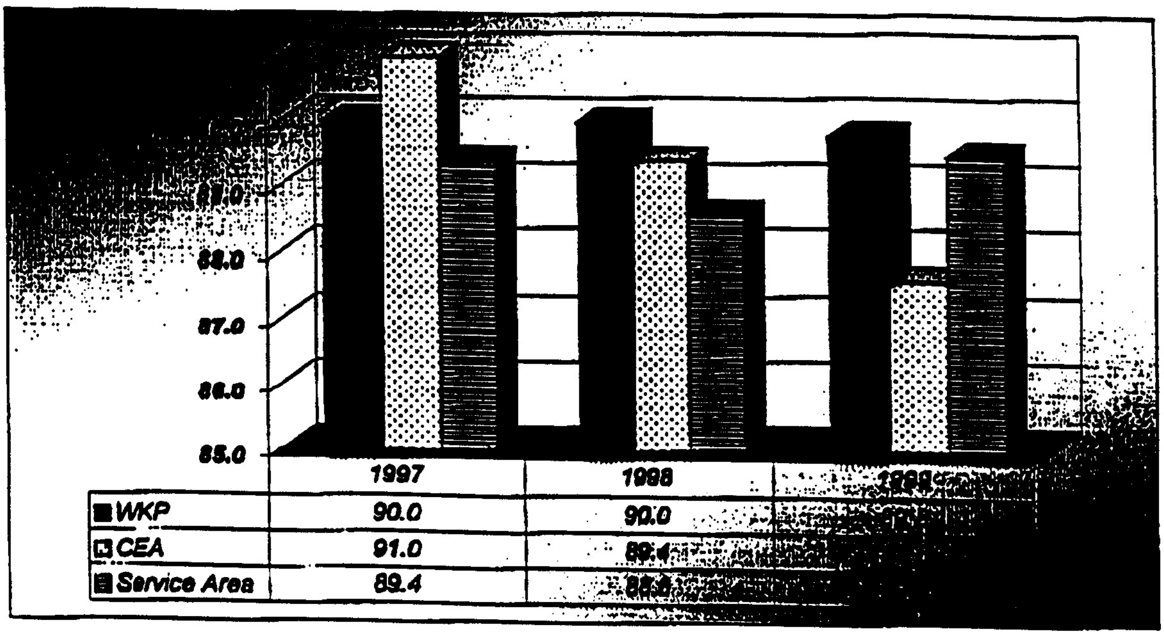
Customer perception and satisfaction are affected by changes in service delivery mechanisms, costs and reliability. The successful shift from a traditional utility to one driven by performance standards requires that the organization undertake numerous changes, while maintaining a stable CSI rating over the long-term.

Results from this year's survey and prior year comparisons are attached.

# Customer Satisfaction

## 1999 Customer Satisfaction Index

## Annual Results for 1997 to 1999




CSI = Composite Index of:
- Reliability of Electric Service
- Speed of Service Restoration
- Quality of Service Contact
- Helping Customers Conserve Energy
- Price

Note: Annual data has been presented for 1997 to 1999. The rating scales changed for the CSI for both CEA and WKP surveys in 1997. Therefore, it is not possible to calculate a three-year average for the period ending 1997 and 1998.

**Kootenay-Boundary Regional Association**
**Nelson/Creston Constituency Association**
**Green Party**
**Box 717, Nelson, British Columbia, V1L 5R4**

November 25, 1999

William Grant, Executive Director
Regulatory Affairs & Planning,
British Columbia Utilities Commission,
Sixth Floor, 900 Howe Street,
Vancouver, BC

BCUC Log #2152
RECEIVED
NOV 25 1999
Routing Confidential: letter to staff
copy to CMS

Dear Mr Grant

Thank you for faxing the letter of November 22, 1999, to my home fax at (250) 353-7350, the Kootenay-Boundary Greens really appreciate the chance to have input into this decision.

We cannot endorse the proposal of a 5% rate increase in each of the next three years at this time as we feel that to do so would be to endorse West Kootenay Power receiving a rate increase when they have as yet not demonstrated to our satisfaction that they have fixed the problem of potential power surges in the Kootenay river and Kootenay Lake portion of their transmission area.

We also want to urge the BC Utilities Commission to re-consider its requirement that West Kootenay Power customers and not shareholders should pay for damages arising out of the 1999 power surges. As a motorists, for example, each of us is expected to drive in accordance with the conditions at the time, and cannot expect other motorists to pay for our injuring their person or damaging their property when we have an accident that involves them.

We therefore find it hard to believe that West Kootenay Power does not carry some kind of accident or liability insurance from which they can draw on to pay for the damage caused to customers property and equipment. To ask customers as whole to pay for damage caused by a power failure is in our opinion a bit like saying no matter what West Kootenay Power does they are never liable for any error they might make.

One outage maybe, but we documented at the hearings in Kelowna at least three, possibly four, power outages that caused damage to property and equipment in 1999 in the Kootenay river and Kootenay Lake transmission area. West Kootenay Power shareholders must accept some culpability for this situation, and as we said at the hearings not just reap the revenue benefit of a late spring and higher flow through of water that allowed for full capacity power generation during the thunderstorm season.

In this regard, we wish to remind the Commission that the evidence clearly showed that a similar power outage in 1993 did not result in the reported $360,000 damage to approximately 450 customers that occurred in 1999. Such a decision as the one made by the Commission (to have customers be

**Office Phone/Fax: (250)354-4615**
**Home Phone/Fax: (250)353-7350**
**E-Mail: ashadra@pop.kin.bc.ca**

liable for compensation) only serves to push costs and rates up even faster than they are already moving towards BC Hydro rates.

Finally, we again wish to reiterate that West Kootenay Power should not take five months to alert all customers (via a bill stuffer) that the power outages may have caused damage to, for example, fire alarms and furnace carbon monoxide detectors. If West Kootenay Power could mail out a notice to all customers after a recent brown out in Greenwood it can afford the residents of the Kootenay river and Kootenay Lake the same courtesy and the Commission should ensure that West Kootenay Power has a consistent public notification policy.

Given the rural and scattered nature of customers the Kootenay-Boundary Greens would recommend adoption of bill stuffers rather than radio, tv and newspaper advertisements, so as to ensure that the well being and safety of all customers is protected.

When customers anecdotal comments include small fires and notation that a fire alarm quite literally blew off the wall during one of the surges in Kaslo we become alarmed about the time it has taken to get a bill stuffer out to all customers alerting them to potential safety problems. For this reason we also wish to see the claims deadline extended until after every customer has had a chance to determine if any damage has occurred to their property as a result of these power outages in the Kootenay river and Kootenay Lake transmission area.

Thanking you for your immediate attention to these matters.

Yours
(faxed direct from computer)
Andy Shadrack

Co-spokesperson Kootenay-Boundary Greens

cc Mr Robert Hobbes, Director, Regulatory and Government Affairs, West Kootenay Power

**Office Phone/Fax: (250)354-4615**
**Home Phone/Fax: (250)353-7350**
**E-Mail: ashadra@pop.kin.bc.ca**

City of Kelowna

**Works and Utilities Department**

Electrical Division
1495 Hardy Street
Kelowna, B.C. V1Y 7W9
Tel: (250) 862-5500 Option 3
Fax: (250) 762-0165

November 24, 1999

Mr. W. J. Grant
Executive Director, Regulatory Affairs & Planning
British Columbia Utilities Commission
Sixth Floor, 900 Howe Street, Box 150
Vancouver, British Columbia
V6Z 2N3

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**"CONFIDENTIAL"**

Dear Mr. Grant:

***Re: Proposed Settlement of Issues***
***West Kootenay Power Ltd.***
***<u>2000-2002 Revenue Requirements and Incentive Mechanism Application</u>***

The Interior Municipal Electrical Utilities from the City of Kelowna, City of Nelson, City of Grand Forks, City of Penticton, District of Summer and Princeton Light & Power Ltd. are jointly endorsing the Settlement Agreement (as a package) achieved with respect to the West Kootenay Power Ltd. 2000-2002 Revenue Requirements and Incentive Mechanism Application.

We fully support the Negotiated Settlement Process and recommend the conclusions arrived at on Nov. 15th, 16th & 17th, 1999, be forwarded for review by the B.C. Utilities Commission.

Respectfully submitted,

R. E. Carle, P. Mgr., C.I.M.
Electrical Manager
IMEU Chairman

FAXED 99 11 24

cc IMEU
Director of Works & Utilities

City of Kelowna

**Works and Utilities Department**

Electrical Division
1495 Hardy Street
Kelowna, B.C. V1Y 7W9
Tel: (250) 862-5500 Option 3
Fax: (250) 762-0165

November 24, 1999

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Mr. R. J. Pellatt
Commission Secretary
British Columbia Utilities Commission
Sixth Floor, 900 Howe Street, Box 150
Vancouver, British Columbia
V6Z 2N3

Dear Mr. Pellatt:

***Re: West Kootenay Power Ltd. – 1999 Annual Review***

I am writing on behalf of the Interior Municipal Electrical Utilities from the City of Kelowna, City of Nelson, City of Grand Forks, City of Penticton, District of Summerland and Princeton Light & Power Ltd. to advise the Commission we do not support a performance incentive payment to West Kootenay Power for 1999.

The IMEU believe the intent of the performance incentive is to reward the company for financial performance over the year, provided that the quality of service does not deteriorate. Unfortunately, as you are well aware, customers in the Nelson/South Slocan area experienced repeated voltage and frequency excursions over this past summer that resulted in hundreds of thousands of dollars in damage to customer equipment. These events represent a significant deterioration of the quality of service that, in our opinion, preclude any entitlement to a performance incentive.

We will have representation at the Annual Review if required on November 30, 1999. If you wish to discuss this matter further please contact my office at 1-250-862-5560, ext. 509.

Respectfully submitted,

R. E. Carle, P. Mgr., C.I.M.
Chairman, IMEU

cc Interior Municipal Electrical Utilities
West Kootenay Power

FAXED 99/11/24

# NATURAL RESOURCE INDUSTRIES

Box 19, Hedley, B.C., V0X 1K0
Fax / Phone (250)292-8692

BC Fishing Resorts and Outfitters Assn.
Council of Tourist Associations of BC
Guide Outfitting Association of BC
BC Trapping Association
National Farmers Union
Certified Organic Associations of BC
BC Wildcrafters Association

Whitewater Kayaking Association
BC Wildlife Federation
Recreational Canoeists Association
BC Federation of Fly Fishers
Steelhead Society
Outdor Recreation Council of BC
Commercial Fishing Industry Council

November 24, 1999

Mr. Robert J. Pellatt
BC Utilities Commission
900 Howe Street
Vancouver, BC, V6Z 2N3

Via Fax: (604) 660-1102

Dear Mr. Pellatt,

Re: Proposed Settlement of Issues West Kootenay Power Ltd. 2000-2002 Preliminary Revenue Requirements and Incentive Mechanism Application

Natural Resource Industries endorses the Proposed Settlement of Issues as per the November 22 letter of W.J. Grant.

Yours truly,

Richard Tarnoff

Richard Tarnoff

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# *Hedley Improvement District*

BOX 186, HEDLEY, B.C. V0X 1K0
TELEPHONE (250) 292-8637 • FAX (250) 292-8637

November 24, 1999

Mr. Robert J. Pellatt
BC Utilities Commission
900 Howe Street
Vancouver, BC, V6Z 2N3

Via Fax: (604) 660-1102

Dear Mr. Pellatt,

Re: Proposed Settlement of Issues West Kootenay Power Ltd. 2000-2002 Preliminary Revenue Requirements and Incentive Mechanism Review

Hedley Improvement District endorses the Proposed Settlement of Issues as per the November 22, 1999 letter of Mr. W.J. Grant.

Yours truly,

Richard Tarnoff

Richard Tarnoff

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The
British Columbia
Public Interest
Advocacy Centre
815 - 815 West Hastings Street
Vancouver, B.C. V6C 1B4
Tel: (604) 687-3063 Fax: (604) 682-7896
email: bcpiac@bcpiac.com
http://www.bcpiac.com

Michael P. Doherty 687-3034
R.J. Gathercole 687-3006
Sarah Khan 687-4134
Patricia MacDonald 687-3017
Susan Prosser (articled student) 687-3063
Barristers & Solicitors

**Via fax and mail: 660-1102**

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December 13, 1999

Robert J. Pellatt
Commission Secretary
BC UTILITIES COMMISSION
6th Floor - 900 Howe Street
Vancouver, BC V6Z 2V3

Dear Mr. Pellatt:

**Re: West Kootenay Power Ltd. - 2000 - 2002 Revenue Requirements**
**BCUC Order No. G-94-99**

I have now had the opportunity of consulting with my clients and am happy to advise that CAC(BC) *et al.* accepts the proposed Settlement Agreement as filed.

Yours sincerely,

BC PUBLIC INTEREST ADVOCACY CENTRE

Richard J. Gathercole
Counsel for CAC(BC) *et al.*

c: Robert Hobbs, WKP (via fax only)

RJG:ll
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