IN THE MATTER OF
the Utilities Commission Act
S.B.C. 1980, c. 60, as amended

and

IN THE MATTER OF
an Application by
West Kootenay Power Ltd.

DECISION

April 25, 1989

J.D.V. Newlands, Deputy Chairman
W.M. Swanson, Q.C., Commissioner
W.A. Best, Commissioner

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1.0 INTRODUCTION

West Kootenay Power Ltd. ("WKP"), incorporated in 1897, is a wholly-owned subsidiary of UtiliCorp British Columbia Ltd. which in turn is a wholly-owned subsidiary of UtiliCorp Inc. of Kansas City, Missouri. The shares of UtiliCorp Inc. are traded on the New York Stock Exchange. Certain preferred shares of WKP are listed on the Toronto Stock Exchange.

WKP provides electric utility service in the Southern Okanagan as well as the West Kootenay/Boundary region of British Columbia. Electricity is primarily supplied through its own generating plants on the Kootenay River, purchases from Cominco Ltd. and purchases from the British Columbia Hydro and Power Authority ("B.C. Hydro"). Minor purchases have been made from the Bonneville Power Administration ("BPA"). The quantity and nature of future power purchases is to some extent, dependent on whether or not WKP is successful in its Application to build a gas turbine facility.

The WKP system supplies approximately 60,000 direct service customers and approximately 37,000 other customers indirectly through municipal utilities in Nelson, Grand Forks, Kelowna, Penticton and the District of Summerland, and a privately-owned utility supplying Princeton and environs. Of the wholesale customers only Nelson, which supplies itself and the North Shore area, adjacent to the City, has its own generation with additional electricity purchased from WKP as and when required.

2.0 APPLICATION

WKP applied on November 28, 1988 for a rate increase of 6.7% to be applied uniformly to all classes of service, effective with consumption on and after January 1, 1989. The Applicant stated that this increase was required to recover increased power purchase and wheeling expenses, and to provide a fair return on the increased investment in plant. In addition, the Applicant sought to simplify the Residential rate, amended the Application to revise the General Service rate and sought the Commission's guidance for its Demand-Side Management ("DSM") program. The Applicant, in the 1988 Financial Plan (Exhibit 4, Tab 6, page 1), has indicated that in addition to the above increase, further increases are required in the succeeding years. These increases cumulatively totalling 34%, are forecast to be as follows:

1990	7.8%
1991	10.7%
1992	7.0%
1993	4.9%

The Commission, pursuant to Orders No. G-107-88 and G-112-88, approved an interim 6.7% increase, subject to refund, and set the Application for hearing in Rossland, B.C. on February 28, 1989.

The Application was heard in Rossland over seven days, with final argument being heard on March 8, 1989.

3.0 RATE BASE

The Application is based on a revenue deficiency of $4,562,000, caused mainly by increases in plant investment, power purchases and wheeling charges (Exhibit 1, Tab 2, page 5). The total 1989 revenue requirement increase of $7,033,000 is only partially offset by anticipated revenue increases of $2,471,000 at prevailing rates for power.

3.1 Capital Expansion Projects

The 1989 additions to plant in service have been estimated at $12,358,000, which is mainly transmission and distribution expenditures for system improvement and expansion to meet load growth (Exhibit 1, Tab 3, page 3). This amount, though $909,000 less than the 1988 expenditure, has generated 37% of the 1989 increased revenue requirement. In order to obtain a true appreciation of the relative necessity of these expenditures, the Commission requested the Applicant to categorize the individual projects as being essential, mandatory or desirable.*

Of the 24 projects listed in Exhibit 4, Tab 1, page 27, seven were declared essential, eight mandatory, six desirable, and three contained a mixture of both essential and mandatory designations. The Commission was particularly concerned about whether the essential projects would be completed in the designated time frame. The Applicant confirmed that such was expected to be the case, except possibly for the Glenmore-Rutland 138 kV transmission extension where right of way difficulties were being encountered with the City of Kelowna (T 369).

For the 1988 year, the Applicant stated that actual capital expenditures were 2.5% lower than forecast (T 393). This is a significant improvement in the Applicant's capital expenditure forecasting.

The Applicant advised that the 1989 plant additions are based on information contained in their Long Term Capital Expenditure Plan (Exhibit 1, Tab 3, page 9). The Commission acknowledges that these projects appear to be needed, but believes that sound utility practice dictates that such capital projects be examined within the broader context of an overall system development plan.

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* Essential - If these projects are not completed WKP will be unable to provide service.

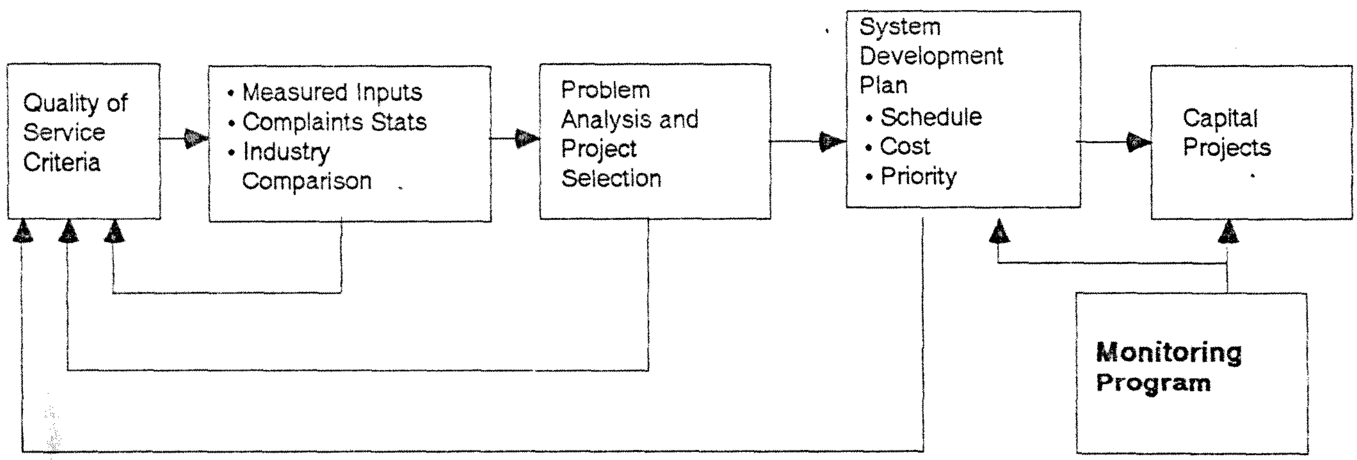
Mandatory - Projects deemed necessary to be consistent with single contingency and other operating philosophies or necessary to meet regulatory or safety requirements.

Desirable - Projects that are warranted based on being advantageous or beneficial to the Company and its customers.

As an illustration, the flow chart in Figure 3.1 provides an example of the typical process that could be adopted.

FIGURE 3.1

System Development Process



As shown, an integral component of the process is the long-term system development plan which provides for correlation of individual projects with the overall system planning objective. With the above process in mind, a capital plan can then be developed consistent with the quality of service criteria adopted.

The Commission directs the Applicant to demonstrate the existence of a process similar to that shown in Figure 3.1, produce a detailed 10-year system development plan as soon as possible and file it annually with the Commission as required by Section 51(3) of the Utilities Commission Act.

3.2 System Improvement Projects

In Volume 1, Tab 3, page 9, the Applicant's comments regarding upgrading of the existing system specified that "Major projects are identified by field personnel and a comprehensive list of these projects is submitted to the Manager of Transmission and Distribution for approval." In Exhibit 4, Tab 1, page 31, in response to an Information Request from the Commission staff, the Applicant further advised that the above stated policy applies only to transmission and distribution maintenance. With respect to capacity upgrades on the bulk transmission system, the Applicant advised that these were planned and scheduled by the System Planning and Operations Department based on system capacity, load and voltage information and the load forecast.

During cross-examination of Mr. McKay, Mr. Gathercole quoted from the previous April 3, 1987 Rate Application Decision (page 18) in which WKP policy was quoted as follows:

> "Our policy regarding investment in new or replacement plant, therefore, is that such investment should not occur until the point in time when not doing so would result in deterioration of the quality of service."

Mr. McKay advised that this policy is basically unchanged (T 43).

While advocating the prudent use of capital and resources, the Commission has reservations about the Applicant's interpretation of the "basic required quality of service" as emphasized on page 46 of the Transcript. Although no operating problems seem to be imminent, the apparent reduction in the level of distribution upgrading and maintenance activity since 1987 (Exhibit 4, Tab 1, page 32), might place the supply of some customers at risk due to the age of the equipment. The Commission also has concerns that the Applicant's capital expansion commitments could cause lengthy deferrals in upgrading and maintenance programs and suggests that the Company re-assess both its staffing and contracting out policies to ensure adequate manpower will be available to execute upgrading and maintenance programs.

3.3 Resource Planning Considerations

Exhibit 13, the 1987 Resource Study, is an analysis of supply-side and demand-side options that have been investigated and evaluated by the Applicant. In 1990, WKP will be making 10-year rolling nominations for capacity, energy and wheeling, albeit with some flexibility in the final five years. The accuracy of WKP's load/resource balance forecasting therefore becomes crucial because of the costs associated with firm B.C. Hydro purchases.

The Commission therefore recommends the Applicant review its supply-side options in light of the potential economic benefits that can be obtained by pursuing opportunities that do not appear to have been seriously considered. There should also be a projection of demand reduction quantities resulting from aggressive implementation of demand-side management (see Section 4.2.5).

Generally, the Applicant should optimize its resource planning relative to:

(a) Hydro 10-year nomination requirement.

(b) Possible supply from Independent Power Producers, co-generators or other sources not currently identified.

(c) Surplus energy storage with B.C. Hydro, BPA or others.

(d) Wheeling options.*

(e) Demand-Side Management Programs.

(f) Other Supply Options.

With respect to storage of surplus power with B.C. Hydro, the Applicant is directed to vigorously pursue this potential opportunity, and if satisfactory progress cannot be achieved, consideration be given to the complaint procedure pursuant to the Utilities Commission Act.

3.4 System Performance and Quality of Service

In assessing its quality of service performance, the Applicant examined the outage statistics and input (complaints, surveys) from its customers. When questioned by Commission Counsel (T 334) whether these two items constituted the only indicators used by the Company, Mr. McKay responded:

> "I think that they are the specific ones we rely on, comparison of outage and outage times with industry generally, and what we have had in the past and what we are doing, we're currently achieving."

A random telephone survey by Angus Reid and Associates in March/April 1988 (Exhibit 4, Tab 4) convinced the Applicant that, with few exceptions, its customers were generally satisfied with the current level of service.

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* Wheeling - The Utilities Commission Amendment Act (Bill 46), Section 85.2, provides for the transmission of a producer's electricity over the transmission system of an electric utility.

In addition, WKP stated that its outage duration statistics for 1987 compared favourably with the Canadian Electrical Association's ("C.E.A.") published statistics for Canadian utilities in 1987.

The Commission encourages WKP to continue the practice of reporting outage statistics to the C.E.A., as these comparative analyses are quite useful for assessing a utility's performance relative to others in the industry.

In cross-examination, Commission Counsel asked Mr. McKay (T 338), "What is West Kootenay doing to measure or assess how it is performing today and how it is likely to perform in the future?" The response indicated that WKP has no formalized program to monitor quality of service or system performance, but relies on the expert judgement of its individual field operating staff. Because judgment among individuals may vary quite widely without the thread of established criteria to create uniformity, some basic written criteria should be established and circulated among those individuals affected.

WKP also utilizes a Complaint Report Form to register all incoming complaints from its customers. Information adduced at the proceeding suggests that these complaints are attended to appropriately. In view of the age of some of the components on the system, the Commission believes that a more formal review of the complaint information should be instituted and integrated in a more formal manner into the process outlined in Figure 3.1.

3.5 Conclusion

The Applicant has adopted a long standing policy of deferring investment in new or replacement plant until deterioration of the quality of service is threatened. In light of such a policy, it is unlikely that the 1989 expenditure on plant expansion and upgrades would be excessive. However, often a single major expenditure might be more cost effective than a succession of smaller ones. The former may also serve to reduce the risk of a major system failure.

The Commission therefore recommends that the Applicant take cognizance of this and, using sound engineering judgement, assess the economic feasibility of continuing or deviating from its present policy. The preparation of a system development plan, complete with individual project justification, should facilitate decision making on year-to-year expenditures.

4.0 COST OF SERVICE

The major components of the Applicant's cost of service for the 1989 test year include:

	$
Power Purchases	17,342,000
Wheeling	2,245,000
Operations and Maintenance	16,268,000
Property Taxes	4,581,000
Water Fees	6,236,000
Depreciation	5,412,000

The projected 1989 expenditures show only modest increases over those of the 1988 forecast.

The Commission has considered the forecast 1989 expenses and, with the exception of an adjustment to remove an anticipated 3.5% increase from B.C. Hydro power purchase costs, accepts the Applicant's estimates.

With regard to the forecast B.C. Hydro increase, the Applicant can seek the approval of the Commission to pass this cost through, if and when incurred, pursuant to Section 67 of the Utilities Commission Act. The desire of the Applicant to avoid more than one rate increase is noted, but based on the evidence at the hearing, the anticipated increase was too speculative in nature to be acted on by the Commission.

The WKP Gas Turbine Project is the subject of a separate Commission Report being made to the Lieutenant Governor in Council. The forecast costs of this project are not included in rate base but the capital cost allowances have been used to reduce the income tax expense in this Application. WKP stated (T 24) that it has been provided for in order to avoid any uncertainty or controversy that might be present with the decision still outstanding. If the gas turbine is not approved, those deductions will not be available to the Company. However, WKP did not apply for the additional amount in this Application. The Commission agrees with WKP's treatment and, consequently, has not made an adjustment.

With regard to staff levels, the Commission concurs with the Applicant's plan to hire 13 additional people but would observe that, if anything, additional employees should be considered.

4.1 Application for Accounting Order

The Commission previously deferred the Company's December 7, 1988 Application for an accounting order concerning the disposition of certain costs to this hearing. The Application was provided at in Exhibit 4, Tab 1, page 3 and the proposed treatment was cross-examined by Commission Counsel. The Commission agrees that the costs of items 1-4 are properly included in rate base and that the five-year amortization period, while arbitrary, is reasonable.

The costs of the 500 kV substation site at Vaseaux Lake (item 5), are presently included in "Work in Progress subject to AFUDC". Mr. McKay testified (T 224) that the substation will be needed immediately if the Gas Turbine is not approved, or in about ten years if the turbine is approved. The land was obtained at this time because of the limited suitable alternatives (two or three) available. In addition, the site was the least costly and the least desirable for other purposes such as agriculture. The costs in question do not affect the Application for a rate increase and the Commission believes that they should continue to be included in Work in Progress subject to AFUDC.

The Commission is concerned that the deferred interest account rate of 9.5% is too low to properly reflect the actual cost of short-term funds to be expected over the test year. Dr. Evans testified that the Company has been able to obtain such funds at about one percentage point less than prime, and based on his advice, WKP applied (Exhibit 33) to increase the specified rate to 10.5%. The Commission accepts this rate and has adjusted the schedules accordingly.

4.2 Meeting Load Growth

The primary WKP resource is its generation entitlement under the B.C. Hydro/Cominco/WKP Canal Plant Agreement. This resource, or supply, is based upon average water flows through the four WKP plants on the Kootenay River and is essentially constant on an annual basis. The Canal Plant entitlement is not sufficient to meet WKP's loads and to balance its growing demand, WKP must purchase increasing quantities of power. The present suppliers are Cominco and B.C. Hydro. Supplies from Cominco are limited and relatively low cost and supplies from B.C. Hydro can easily meet WKP's growing power needs in the near term, but are relatively expensive. Purchases from sources other than Cominco and B.C. Hydro have not been significant to date. Purchases must be arranged or nominated well in advance of need based upon load forecasts and load/resource balance projections. An increasing portion of purchases are subject to nominations, "take-or-pay", and demand ratchet provisions of the B.C. Hydro Purchase Agreement.

In the 1989 test year, the Applicant's total load is forecast to be 2623 GW.h with a peak capacity requirement of 547 MW. This load is supplied as follows:

	Energy (GW.h)	Percent	Capacity (MW)	Percent
WKP's Entitlement	1549	59	189	35
BPA Storage	10	0	-	0
Cominco Purchase	880	34	199	36
B.C. Hydro Purchase	184	7	159	29
	2623	100	547	100

4.2.1 Forecasting

The Applicant's load forecasting has been facilitated by means of an econometric model for the residential, commercial and wholesale customer classes. The model incorporates such variables as demographics, electricity prices and elasticities, alternate energy choices, population growth, income levels and temperature variations. Industrial customers' load is determined by direct consultation with the customer regarding its end-use needs.

In its prepared testimony (Exhibit 3, Tab 2, p. 8), the Applicant advised that the:

> ". . . actual load experience for 1988 has indicated that we were above forecast for the first time in several years. The 1988 actuals adjusted for weather are running significantly above the original 1988 forecast. As a consequence, the forecast for 1989 incorporated in this Rate Application has been increased above that determined for 1989 in the 1988 twenty-year forecast."

The load forecast is the key component "driving" the load/resource balance and therefore the nominations of purchased power and wheeling. The Commission understands that the test year forecast accepted will be consistent with the updated 1989 20-year forecast. Additionally, the Commission will be closely examining variances between the actual loads and this March 1989 load forecast. The Commission directs the Applicant to file the March, 1989, 20-Year Forecast with explanatory information when it is available.

Of particular interest to the Commission will be the ability of the econometric models to forecast wholesale customers' demand. One third of the total load is represented by this wholesale group which includes residential, commercial and industrial customers.

To ensure that credits for DSM are appropriately accounted for, it is important that future load forecasts clearly differentiate between naturally occurring (price driven) conservation and the impact of the Company's strategic DSM projects.

Future forecasts should make more explicit the price assumptions, such as cross elasticities for alternative fuels and the resultant capture rates for electric space heating.

For at least the first five years of the forecast, the Applicant is directed to prepare detailed contingency plans for the high probable and the low probable forecasts. A "bracket plan" around the probable forecast, may reveal the need for aggressive pursuit of contract terms or alternative sources of supply for contingency loads in the forecast.

4.2.2 Load/Resource Balance

WKP's own generation can only supply a portion of its current load. The significant disparity in unit power costs between the Cominco purchases and the B.C. Hydro purchases forces WKP to maximize its Cominco purchases.

All B.C. Hydro firm purchases must be nominated in advance, and significant deviations in load requirements from these nominations will attract penalties as stipulated in the contracts. It is important that such penalties be kept to a minimum, therefore WKP must adopt strategies for load/resource projections that will optimize the present process.

The Commission recommends that in addition to its traditional supply sources, WKP seriously investigate supply possibilities from other power producers. WKP stated at the proceeding (T 179) that it was prepared to pay not more than its avoided cost. This price might attract other power producers. Clearly in its negotiations with all suppliers, WKP should strive to achieve the lowest cost of purchased power.

4.2.3 Power Purchases

The Applicant identifies the component cost of meeting forecast 1989 load growth at Exhibit 1, Tab 8. The increase of 116 GW.h in energy is forecast to cause a growth in purchases from B.C. Hydro of 75 GW.h costing approximately $1,924,000. Increased wheeling costs are identified as approximately $224,000. A forecast increase in capacity in the order of 35 MW is assumed by the Applicant to be met entirely by B.C. Hydro purchases at a cost of approximately $859,000. This includes the effect of a 30% ratchet provided in the Power Purchase Agreement (see the explanation of the ratchet provision below). The balance of the power purchase costs over 1988 is $362,000, bringing the aggregate increase to $3,369,000 as identified in the Applicant's Executive Summary at Exhibit 1, Tab 2. The major cause of the increase in power purchase costs is the increasing volume of purchases from B.C. Hydro.

The 1989 test year incremental revenue requirement is $7,033,000 (Exhibit 1, Tab 2, page 1). Of this sum, 48% is caused by the forecast increase in power purchase and wheeling costs. If increased revenue from load growth is deducted from the increased purchase costs, the remaining $898,000 revenue deficiency represents approximately 20% of the requested revenue increase. WKP in its forecasts utilizes all of the available firm Cominco surplus, then meets further load increments by firm purchases from B.C. Hydro or others. Average power purchases and wheeling from B.C. Hydro cost more per unit than the corresponding revenue, resulting in a negative contribution margin for each unit purchased and resold. As the Applicant's dependency upon B.C. Hydro continues to grow, so will the magnitude of the negative contribution and its proportionate share of the resulting revenue deficiency.

Effective October 1, 1990, the Applicant, under terms of its current purchase contract with B.C. Hydro, will be required to nominate for energy purchases on a ten-year rolling basis. The first five years of the nomination will be fixed, and 90% of the quantities nominated must be paid for whether they are taken or not ("take-or-pay").

The B.C. Hydro Tariff, Schedule 3807, which is found in Exhibit 1, Tab 8, page 11, shows that in January 1991, the ratchet on capacity purchases from B.C. Hydro will reach 50%.

In 1991 the Applicant will pay, in any month, the greater of:

(a) the capacity taken that month;

(b) 50% of the Capacity Nomination for that Operating Year; or

(c) 50% of the maximum capacity taken in any of the previous eleven months.

The Commission is concerned that WKP may tend to under-nominate capacity. This is risky because B.C. Hydro may become capacity short and unable to supply WKP with amounts greater than nominated. Reducing this risk is worth pursuing. As an example, WKP may wish to spread some of this risk to speculative new load or share the risk with its suppliers.

The overall cost of purchases from B.C. Hydro depends upon the Applicant's load forecasting and balancing this requirement with its identifiable resources, including purchases from Cominco, B.C. Hydro and others. To the extent that uncertainty exists in the demand forecast and in the load/resource balance projections, the Applicant faces an increasing risk in its growing dependency upon B.C. Hydro---currently the highest cost supplier. The Applicant indicated its appreciation of this at Transcript page 1007:

> ". . . that 10-year nomination requirement gives us a great deal of concern. We've got numerous areas of uncertainty that are going to have to be recognized and somehow accommodated, and as we said before, that we expect to put in a lot of work on that this year."

To illustrate the risk of either overestimating or underestimating the load forecast, assume the following "worst case" sensitivity test, applied to the 1989 Test Year: (detailed computation at Appendix "A")

(a) 1% change in energy requirement from forecast due to sales volume.

(b) Change in energy requirements is associated entirely with B.C. Hydro purchases.

(c) Peak load increases under a 1% underestimation but does not decrease under a 1% overestimation.

This sensitivity test shows that shareholders are exposed to significant losses whether the Applicant over or under estimates its load forecast, emphasizing the point that load forecasting, load/resource balance projections and purchase nominations must be carefully managed. The Commission believes that if additional resources (people and funding), are required to reduce the risks to a reasonable level, such investment should be made.

The Applicant should also aggressively explore opportunities to purchase lower cost surplus energy, and storage from B.C. Hydro, BPA and others to add greater flexibility to its resource base.

4.2.4 Wheeling

WKP's wheeling nominations with B.C. Hydro utilizing connection points at Koch Creek, Vernon and Creston, do not deviate significantly from forecast. The Commission recommends that WKP develop a plan to optimize its load/resource balance, incorporating wheeling possibilities. Further, the Commission encourages the Applicant to consider what other supply possibilities may now exist under Section 85.2 of the Utilities Commission Act.

4.2.5 Meeting Load Growth with Demand-Side Management ("DSM")

Power purchases and wheeling costs from B.C. Hydro for incremental load growth constitute a major portion of the increase in the cost of service. Considering these costs and the need for reliable load forecasting, especially as it applies to purchase nominations from B.C. Hydro, DSM has been discussed in the last Rate Decision of the Commission and has been extensively canvassed in both of the most recent WKP hearings.

The question of using DSM to meet electric load growth and mitigate resultant increases in power purchase costs were addressed by the Commission in its 1987 Rate Decision which stated, in part, on page 12:

> "[The Commission] concludes that the Applicant must include, as an essential element in its forthcoming resource study, a careful assessment of the potential for load management as an alternative to either increased generating capacity or purchased power. Accordingly, the Commission directs the Applicant to include in its resource study an explicit and meaningful analysis for each of those alternative load management techniques deemed to be practical and potentially applicable in the Applicant's operations."

The Commission notes that the Applicant's 1987 Resource Study (Exhibit 13), did address the DSM issue and that the Applicant concluded at page 41 of the Resource Study:

> "By instituting demand-side programs, the Company can reduce its revenue requirements by reducing consumption which in turn reduces the cost of purchased or generated electricity."

The Resource Study further states at page 65:

> "Three projects indicate viability. The Company intends to proceed with the Residential Weatherization Campaign and Seasonal Rates. Though Water Heater Control requires some further refining of costs (presently being pursued) it is expected the Company will proceed with this project also."

The Commission supports the Applicant's decision to adopt DSM as an element of its strategy to mitigate rising costs of power purchases to meet load growth and the Applicant's decision to select specific DSM projects for implementation. However, as evidence in this hearing indicates, WKP has not moved ahead with a sense of urgency and high priority to launch an effective DSM marketing program for the projects it has decided are cost effective, or to complete its analysis and design of other potentially beneficial projects. The Commission is concerned that further delay in the implementation of DSM will cause further, otherwise avoidable, revenue deficiencies.

Had it been possible for the Applicant's identified cost effective DSM projects to be in place at January 1, 1989, a significant reduction of the 1989 Test Year revenue deficiency would have occurred. However, the initial phases of DSM programs may have long lead-times, as the Applicant has demonstrated in Exhibit 4, Tab 5, Table 4-2, wherein the identified DSM program will gradually achieve a saving of 18 GW.h by 1992. The 18 GW.h is associated with a capacity saving of between 25 MW and 37 MW, (Exhibit 13, page 42 and Exhibit 7 [of the Gas Turbine Hearing], Tab 3, pages 1-2).

To put these savings into perspective, using 1989 rates, the capacity saving per year approximates the cost of increased capacity for 1989 ($859,000). The 18 GW.h saved per year would be worth approximately $400,000. According to the Applicant's analysis in Exhibit 4, Tab 1, page 38, the deferred transmission and distribution investment could save an additional $770,000 per year (35 mills divided by 57 mills = 61% x $1,259,000). The total saving is approximately $2 million per year.

The annual cost of these DSM programs would be about $225,000 according to the Applicant's 1987 Resource Study (Exhibit 13, page 42). The net annual savings represented by the Applicant's currently identified, cost effective DSM is therefore, approximately $1,800,000 per year. This compares with the forecast 1989 Test Year revenue deficiency of $4,562,000 and the negative contribution from load growth that is included in that number of $898,000.

The above savings reflect the limited scope that has governed the Applicant's perception of DSM. The existing proposal does not anticipate direct funding of the DSM projects for wholesale customers, for general service (commercial) customers and recognizes only a small industrial potential. The scope is also constrained by an economic test that severely limits DSM potential.

4.2.6 Demand-Side Management Issues

4.2.6.1 Marginal Cost/Marginal Revenue Spread

The Applicant demonstrated the economics of DSM within the context of its Weatherization Campaign (Exhibit 4, Tab 1, page 38 and Transcript Volume 5, pages 899-902). It should be borne in mind that the data is illustrative, and depending upon the mix of capacity and energy savings, another program would not necessarily demonstrate the same values.

With the "no-losers" test, individual DSM projects would qualify for inclusion in a DSM program provided they cost no more, on a kilowatt hour basis, than the difference between avoided cost and the existing system average cost. The purpose of this test is to ensure non-participating customers' rates will be no higher with DSM than if the DSM project was not undertaken. The adoption of this test limits DSM scope with the end result of higher revenue requirements for all customers. Moreover, with a negative contribution from load growth, the "no-losers" project cost limit should be higher than the limit set by the Applicant.

The following tabulation illustrates how the Applicant derives, and applies the "no-losers" test for the weatherization program (all figures are "levelized present value"):

	Value of purchases saved	57 mills per kW.h
	Value of deferred capital expenditures	35 mills per kW.h
	Reduced [avoided] Cost	92 mills per kW.h
Less:		
	System Average Revenue/Cost	52 mills per kW.h
	No-Losers Test/Project Cost Limit	40 mills per kW.h
	Average Weatherization DSM Program Cost	18 mills per kW.h

4.2.6.2 "No-losers" Test is Too Conservative

To the extent that incremental sales volumes are returning a negative contribution to the utility, (cost per kW.h of purchases exceed average revenues per kW.h), a reduction in sales volume caused by DSM will benefit all customers. This will be so, provided that the individual DSM program cost per kW.h does not exceed the marginal cost of purchased power.

For the DSM projects that are under analysis, the Applicant's "no-losers" test is too restrictive. The Applicant should undertake DSM projects, the costs of which are less than the marginal cost of incremental purchases from B.C. Hydro. Savings should also be recognized in the DSM project for the deferral of plant investment. If the Applicant is prepared to pay independent power producers to the extent of its marginal cost of incremental B.C. Hydro supply (T 298), it should be prepared to make at least this level of DSM investments to achieve the same result.

Broadening the criteria from "no-losers" to marginal cost of power, including a credit for deferred plant investment, will support expansion of the program into the general and industrial classes of service. It would also be worth considering a more rigorous way of estimating DSM cost limits. The marginal cost between the residential and the commercial sectors may be very different, thus creating different DSM cost limits for the two sectors respectively.

4.2.6.3 Non-participants in DSM

The Applicant expressed concern (T 50 and T 887), about investing in DSM projects that cause non-participants' rates to rise in the absence of a reduction in their energy requirement. A participant in DSM benefits in two significant ways:

(a) The utility may contribute a portion of the cost of an energy efficient improvement in the participant's building or appliances.

(b) The increased energy efficiency will result in lower use and therefore a lower energy bill than would otherwise be the case.

These benefits to participants will be reduced by the cost of carrying charges on any capital investment made by the participants in the energy efficiency upgrade. The Applicant must ensure, to the extent possible, that participants in DSM projects are aware of all costs and benefits.

Non-participants would not receive either of the above benefits accruing to participants and could experience higher rates and bills if the marginal cost test was applied. Energy displaced by DSM could have a unit cost, on average, one half the marginal costs of energy purchases and additional plant; however, the reduction in sales volume could increase average rates beyond the level of savings (see Exhibit 53, page 4).

The Commission notes that, to the extent the DSM project is cost effective, in the long-term both participants and non-participants should benefit from the DSM project. Residential DSM program design should offer a broad choice of projects so that all customers can participate in one form or another.

To facilitate a broadly based design, the Applicant is encouraged to examine various approaches to market segmentation with the purpose of identifying customer groups within the class that demonstrate similar characteristics and circumstances. Effective market segmentation will allow the Applicant to direct various projects and combinations of projects at specific market groups. Difficult problems will need to be addressed with such program design, but DSM competing at the margin with alternate resources is of such great value to the entire customer base that it should not be compromised.

4.2.6.4 DSM and the Wholesale Customer

Counsel for several of the wholesale customers argued (T 1347-1349) that the exclusion of the wholesale customers from the Applicant's DSM initiative was discriminatory. Wholesale customer demand represents one-third of the Applicant's load, therefore we can assume that one-third of the Applicant's DSM potential is within the municipal franchises. The wholesale customers have a built-in incentive to seek out DSM as a means of meeting and shaping their growing load. The Applicant's tariff for its wholesale customers contains a "demand charge" based, in part, upon peak historical demand.

This is a form of "take or pay", wherein it is to the customers' advantage to achieve the best possible load factor. Appropriate DSM investment could lower the wholesale customers' bills, while assisting WKP to reduce its relatively costly purchases from B.C. Hydro and assist B.C. Hydro with its "Power Smart" program.

The opportunities to be found in coordinating, integrating and implementing a consistent DSM strategy throughout the service area as well as within municipal franchises should result in savings for all parties. The Commission strongly endorses the close cooperation of the Applicant and its wholesale customers.

4.2.6.5 DSM as Rate Base

The Commission sees no conceptual distinction between resources that generate power and resources that conserve power. Both are assets used to meet load growth. The Applicant should, however, be mindful of the need to make appropriate judgements concerning the economic life of DSM investments. Such judgements regarding the weatherization program, water heater control and others have been made by the Applicant and are documented in the 1987 Load Resources Study at page 42. The Commission accepts the estimates of project life as the basis for determining depreciation or amortization of those projects.

In accounting for the costs of a DSM project that has a development period longer than one year, the Commission directs the Applicant to treat all expenditures in the same manner as any other rate base addition. Overhead should be capitalized and projects should be broken down into identifiable and meaningful increments to determine in-service dates and for purposes of applying AFUDC.

4.2.6.6 Shareholder Incentives

The subject of incentives to shareholders to encourage investments in DSM was discussed with the Applicant (T 916 and Exhibit 4, Tab 1, page 45). The Applicant suggested two incentives:

(a) Permitting a higher return on investment in DSM projects.

(b) Permitting a flow-through rate adjustment to automatically offset the net revenue losses (the difference between revenue loss and reduced operating costs) associated with the DSM programs.

It is clear, in the 1989 forecast, that the Applicant would generate "net revenue gains" for all the reduced sales volume supplied by B.C. Hydro. The Applicant (in Exhibit 37), demonstrated that for each kW.h sold at the margin in the 1989 Test Year, power purchase and wheeling cost 29.3 mills and would give rise to 26.1 mills of revenue (excluding Bradford Enercon), for a loss of 3.2 mills/kW.h.

The Commission is aware of attempts by other jurisdictions to encourage DSM investment with return on equity incentives. One jurisdiction has offered a 2% premium applied to DSM investments, while another jurisdiction says that a higher Return on Equity will be awarded the utilities that are diligent in pursuing DSM. The Applicant has drawn the conclusion that these jurisdictions are recognizing a higher degree of business risk in DSM than that inherent in other more tangible forms of utility investment. The Commission believes that the reduction or elimination of the negative contribution to the margin is a sufficient incentive at this time.

4.2.6.7 Conclusion

The Applicant's executive management must articulate a clear and unambiguous strategy and policy statement regarding DSM upon which its staff and external resources (if required) can develop an effective DSM marketing campaign complete with all essential elements. This requirement must be accorded high priority and be complete with all of the following essential elements: corporate policy, targets and time frames, resources (budget and head count), employee training and incentives, market research, advertising and promotion, and program feedback designed to monitor customer acceptance.

In conclusion, the Applicant is directed to move forward immediately to finalize a marketing plan and implement a promotional program for DSM projects it has accepted. The Applicant is also directed to review all potentially appropriate DSM programs using benefit/cost criteria in line with a marginal cost of incremental supply purchases, and additional transmission/distribution plant rather than a "no-losers" test.

5.0 CAPITAL STRUCTURE AND RETURN

5.1 Capital Structure

WKP forecast capital structure incorporates a common equity component of 42.4%, an increase from the 38.1% found reasonable in the Commission Decision of April 3, 1987. The majority of Intervenors took the position that the common equity component should be deemed to be 35%, a decrease of 3.1% from the previous Decision.

The Commission has reviewed the capital structures of other utility companies in Canada (Exhibit 16) as well as comparable interest coverage ratios (Exhibit 1, Tab 13, page 2, and Exhibit 20, Appendix X). It has also considered Exhibit 51, an extract from WKP's Application in March, 1988 for Commission approval of an issue of common shares. Exhibit 51 (at line 47) shows that the common equity component of 42.4% to be close to the percentage previously contemplated for the year 1989. The Applicant's most recent financial plan (Exhibit 4, Tab 6, page 1) shows the common equity component declining to 38.4% in 1992 and 34.5% in 1993.

Having regard to the foregoing, the Commission believes a common equity component of 42.4% is satisfactory at this time and permits the Applicant to maintain an interest coverage ratio in the range of 2.5 to 2.9 in order to ensure its ability to borrow funds at reasonable rates. However, the Commission does not believe the common equity component should be edging to higher levels, but as market circumstances permit, the Applicant should work expeditiously towards achieving minimum interest coverage ratio of 2.4 as shown in their financial plan for 1992/93.

5.2 Return on Common Equity

WKP applies for a rate of return on common equity of 14.1%, an increase from the currently approved rate of 13.2% (in a range from 12.75% to 13.5%) allowed in the Decision of April 3, 1987.

WKP bases the Application on the evidence of its expert witness Dr. Robert E. Evans. His opinion was based upon the Application of three well known economic tests, namely comparable earnings, discounted cash flow and equity risk premium. He concluded that the fair rate of return on a common equity capital structure of 42.4% is in the range of 14.25% to 14.75%, but focused on the lower half of that range.

The Applicant's position is that despite the advice of Dr. Evans, it is content with a lower return of 14.1% in order to ensure that the requested rate increase does not exceed 6.7%.

The industrial and municipal Intervenors based their submissions upon the evidence of their own expert witness, Dr. William R. Waters. His opinion centered upon the discounted cash flow and equity risk premium tests. He excluded any reference to the comparable earnings method for the reasons he explained. He concluded that a fair return on a deemed common equity capital structure of 35% is within the range of 12 5/8% to 12 7/8%, and that the balance of the actual common equity be deemed to be preferred at 9%. Such rates would result in a rate of return ranging from 12.0% to 12.2% on the 42.4% common equity.

There is a significant disparity of a full two percentage points between the experts. Both are well known and highly regarded economic experts, and both readily concede that there is a high degree of subjective judgement involved in arriving at an opinion of what rate of return is fair and reasonable.

This "subjectivity" (disregarding the difference in technique and data chosen) accounts for the disparity of 2%, and is underlined by the fact that each of the experts found it necessary to give his opinion within a range of percentages rather than confining it to a single specific percentage.

While the Commission appreciates the assistance of both experts for their valuable input, and has taken their opinions and analyses fully into account, it is neither obliged to adopt outright the evidence of either or to prefer the evidence of one over the other, as was urged by the Applicant and the Intervenors, respectively.

One specific item in the expert evidence became, during the hearing, the subject of some modest controversy, and this was the somewhat elusive concept of increasing what was otherwise determined as the fair rate of return by a "flotation allowance". This consists of an allowance for the raw costs of new issues of common stock in the future together with the perceived decrease in value of shares held by existing stockholders through dilution and for general market declines. Evidence was given by Mr. Brook (T 607) that WKP recovers its issue costs through its cost of service, and Dr. Evans conceded that in such circumstances it would be double counting to also include such costs in a flotation allowance in the rate of return on common equity (T 603). He calculated the amount he had allowed for issue costs at 30 basis points (T 657).

Dr. Waters' evidence (T 783) was that he does not include in his estimates a percentage for flotation allowance, although he includes "a rather small amount" to cover the potential for dilution. He said that the dilution factor, in principle, is not one that should be singled out for addition to the investors' required rate of return, except when the utility is facing a prolonged period of capital expansion and significant need for access to financial markets. It is implicit from this view that Dr. Waters' treatment of raw issue costs must be dealt with at the time of issue (save for the exceptional situation described).

The Commission is of the view that there is less risk of double counting and more certainty in valuing the amount involved if issue costs are capitalized or expensed at the time of issue rather than being built into the rate of return based upon the subjective estimates of experts. This is particularly so where no new issue of shares is contemplated. As a cautionary note, however, it is likely that an appropriate adjustment would be required where a utility has historically been allowed a flotation allowance for issue costs that have not been capitalized or expensed. In the case of WKP the amount is insignificant because public issues have not been made.

As to the fair rate of return we heard the views and opinions of a number of lay witnesses, including Mr. Norman Gabana who expressed the view that a rate of return of 14% was too high, and that he would prefer the rate of return be tied to the chartered bank prime rate plus 1 to 1.5%. Interestingly, based on the bank prime rate at the time of the hearing, that formula would result in WKP earning a rate of return higher than the 14.1% sought by it.

Taking into account all of the evidence on rate of return, the arguments of Counsel and the Intervenors, the Commission grants the Applicant the opportunity to earn a return on common equity of approximately 14.1%, in the range of 14.0% to 14.5%.

5.3 Related Matters

A number of the Intervenors raised the suggestion that the rate of return earned by the utility was a "guaranteed" return, which insulated the Applicant from the economic valley of recession and other uncontrollable business risks with which the unregulated businessman must contend on a regular basis. The argument made was that for that reason the utility should be content with and the Commission should approve a lower rate of return than the Applicant has earned in the past and lower than it now seeks.

The Commission understands these points. However, there are two other points that it cannot overlook. Firstly, the approved return is not "guaranteed". The utility is afforded only the "opportunity" to earn the rate of return. It faces the risk, for example, that its load forecasts, upon which its return depends, may be inaccurate. If the forecasts are not accurate and the return is not realized, then the shareholders will bear the shortfall. It is not recouped from future rate applications. Secondly, the utility must contend with a highly competitive capital market for its borrowings. Failure to maintain the financial integrity of utilities is as much against the interest of consumers as it is against that of investors. If its rate of return is not perceived by lenders and investors as sufficiently attractive to provide for revenues that will meet debt service requirements and provide fair returns to investors, then its borrowings must carry higher interest rates, a charge which is passed along to customers. If the rate of return is unusually low, the lenders will not lend and the investors will not buy shares, with the inevitable result that the quality of service will decline.

It is for these reasons that the principle of providing the highest quality of service at the lowest cost to the customer, is indeed consistent with a fair return to the shareholder. The Commission recognizes the delicate balance that must be struck and believes it has done so in this case.

6.0 RATE DESIGN

A number of issues with respect to rate design were raised which the Commission believes require more in-depth investigation and consideration than the general canvassing that was presented during the hearing. These are set out below.

6.1 Simplification of the Residential Rate Structure

In its Application at Exhibit 1, Tab 15, the Applicant sets out its proposal for modifying its residential rate design. The elimination of declining block rates, that is, lower rates for higher levels of consumption, and the increase in a basic or fixed charge would result in a single rate for energy that is 1% higher than the lowest energy rate in the current structure, and a 23% increase in the "basic charge" for Area II (Trail and Rossland), and a 42% increase in the "basic charge" for Area I (all other areas). The minimum charge would be 10% lower than the "basic charge", reflecting the discount for early payment. The change would affect Rate Schedules for all direct residential customers, those on electric heat and those who are not, except for employee accounts.

The change is revenue neutral within the class, with a maximum bill increase of $26 per year for customers with low consumption. The Applicant did not attempt to justify the amount of the fixed charge by relating it to customer costs, nor did it appear to consider alternative combinations of basic and energy charges.

The Applicant identified two main reasons for the change:

(a) "We would no longer have declining block residential rates which do not reflect WKP's present cost structure"; and

(b) "The proposed rates would more readily permit the introduction of seasonal rates reflecting the difference in cost of supply in summer and winter."

Mr. Shadrack, an Intervenor, analyzed the proposed changes in rate structure and argued that, although the design is simpler, the result in terms of price signals is essentially unchanged. This Intervenor believed that conservers should be rewarded for their efficiency relative to non-conservers.

Mr. Kenyon, a residential customer, and a strong advocate of energy conservation, made a written submission (Exhibit 52) advocating that the entire deficiency be recovered from increases to the demand charge and trailing block rates.

6.2 The First Step Toward Seasonal Rates

WKP intends to apply in the near future for Seasonal Rates within its residential class. The Applicant submitted Exhibit 38, "Implementation of Seasonal Rates" providing a side-by-side comparison of residential rates and cost of consumption for customers with and without electric space heat for both the summer and the winter months. On a monthly basis, winter bills could increase by as much as 14%, and summer bills could decrease by approximately 20%, excluding price effects upon demand. The Applicant assumed that the total annual residential revenue would be unchanged.

In its Resource Study, the Applicant, on pages 53 and 54, described the Seasonal Rate concept. The following points summarize that description:

(a) Power savings: 9 MW and 1 GW.h per annum.

(b) Shift both the consumption and demand components out of winter and into summer to levelize consumption on an annual basis, and thereby optimize B.C. Hydro purchases.

(c) Phase-in over a five-year period to soften the rate impact on customers.

(d) Customers who now heat with electricity will be encouraged to convert to attractive alternatives.

(e) A 100% change in price for electric heat customers is expected to have a 27% downward change in consumption by these customers.

(f) The other winter peaking class, the wholesale customers (and their residential accounts), are not included in the analysis.

Seasonal rates could cause some customers to invest in the conversion to natural gas. While some customers will choose to invest in conservation (DSM) measures, other customers may not change their behaviour, either because they are price insensitive or because they cannot afford to modify their consumption.

The Applicant provided Exhibit 35 that sets out, in approximate terms, the economic consequences upon WKP, of one of its residential customers converting from electric heat to natural gas. The Applicant would save power purchases and plant investment worth a present value of $4,500. The 10,300 kW.h saved could be utilized to meet load growth. The Applicant is forecasting that approximately 9,700 of its direct residential customers will switch heating fuels, representing 50% of the current numbers of customers served under the space heating tariff.

6.3 Equitable Treatment of Various Residential Customers

The Applicant believes that seasonal rates will motivate many of its electric heat customers to convert to alternative energy sources. Equitable treatment of these customers involves the following issues:

(a) Not all customers are served by natural gas and cannot consider this alternative. At least 30% of the Applicant's direct residential customers are in this situation.

(b) A large number of WKP's direct residential customers are already on natural gas, and the seasonal rates will impact their costs, and will continue to impact those customers who do invest in converting to natural gas.

(c) Approximately one third of all the residential customers in the service area are served indirectly through the wholesale accounts and the seasonal rates, as currently envisaged, will not be applied to them.

(d) Some customers, particularly those who rely upon baseboard heaters, would face a relatively large cost to convert to natural gas. Some customers may not be able to afford the conversion cost, notwithstanding an incentive arrangement offered by Inland Natural Gas Co. Ltd.

The Applicant does not actively promote or provide incentives for its electric heat customers to switch to natural gas. WKP believes that more appropriate price signals will motivate customers to seek out solutions that fit the individual circumstance of the customer, such as energy conservation through its DSM program. However, the Applicant did indicate a willingness to determine policies that will address the need for equitable treatment of various customer segments within the residential class.

6.4 Impact of DSM upon Various Customer Classes' Demand

Seasonal rates are properly characterized as a DSM project by the Applicant and the objectives of peak clipping and load shifting are clearly identified. What is not so clear is how the various combinations of rate design and conservation incentives will interact to affect future load growth and future prices. This problem, and the effectiveness with which the Applicant approaches it will have consequences on the success of its rate design efforts, the success of its DSM program and upon the quality of its load forecasting.

6.5 General Service Rate Restructuring

The Applicant amended its Application to change rate design by submission of Exhibit 10. This change would utilize the same basic charge as the Area I residential service, that is $8.00/month and would also reduce the number of declining blocks from five to four. This change is justified by the Applicant because it will save general service customers, who take less than 2,000 kWh/month, some $150,000 per annum in the aggregate. When questioned on this sum, the Applicant agreed that the decrease in the General Service rate, an amount not reflected in the Test Year Revenue Requirement, will offset an equal increase in revenue in the class as a result of reclassification of certain customers from Residential Service. The amount resulting from reclassification was, likewise, not reflected in the Test Year Revenue Requirement. By letter dated March 20, 1989, the Applicant withdrew this portion of its Application because, "It (now) appears likely that the additional revenue of $150,000 will not be realized . . ."

6.6 Irrigation Rates

Intervenors interested in the Irrigation Tariff of the Applicant made representations concerning the importance of the final billing cycle of the irrigation season. The matter was resolved on the record when the Applicant agreed to file for an amendment to its Tariff such that the final billing will be made on the last day of October or later. This amendment was received and has since been accepted by the Commission pursuant to Commission Order No. G-23-89.

The suggestion was also made by Mr. Lauer that the charge for off-season irrigation should be at the residential, not the general service rate. The Applicant should address this matter in a future Rate Design Application.

6.7 West Kootenays/Okanagan Valley Rate Differential

Representation was made by Mr. Cady (Regional District of Central Kootenay) and by others, that a rate differential should exist between the rates charged by the Applicant in the Okanagan Valley and those rates charged in the West Kootenay region. The basis for this view was the difference in relative growth rates in the two regions and the high incremental cost of serving new load in the Okanagan. The Trail/Rossland residential rates are lower and the Applicant proposes that this difference be removed by 1991 (T 365). Geographic distinctions versus "postage-stamp" treatment in rate design will require further consideration.

6.8 Economic Development Initiatives

The Applicant identified the following economic development initiatives (T 58-61):

(a) WKP District Supervisors and other employees are actively participating in regional committees formed by Municipalities and Regional Districts to promote economic development and the efficient use of energy.

(b) WKP has been coordinating the mailing of economic brochures from Municipalities and Regional Districts to encourage businesses to locate in the WKP service area.

(c) WKP has facilitated the "signing-up" of some new customers by allowing the connection costs to be paid over a short period of years rather than up front.

In cross-examination by Mr. Gathercole, WKP acknowledged that the above initiatives could result in an increased load and consequently an increased resource requirement. The Applicant also advised that any new load would result in expenditures by the Company that would be in excess of the revenue derived from such new load, but that reasonable growth was necessary to maintain a sound and diversified economy in the service area.

The Commission supports economic development initiatives on the part of the Applicant, and would encourage the provision of assistance to new industries that employ energy efficient processes.

In consideration of the above initiatives, where it has been determined that a tariff amendment or supplement is appropriate, the Commission requires that WKP submit an application as soon as possible.

6.9 Commission Decision - October 5, 1984

The October 5, 1984 Decision of the Commission regarding the Applicant's proposed changes to its rate design concluded that:

> "Future rate design applications must include evidence on the potential impact on consumption of any proposed rate changes." (page 8)

This conclusion was based upon the fact that the Applicant had demonstrated insufficient communication with its customers on the likely consequences of its proposed rate design. Direct communication was lacking as was sufficient theoretical support for price induced changes in consumption patterns. The possibility of fuel substitution was not adequately canvassed. In addition to the lack of sufficient market research, the Applicant's proposal suffered problems because of the following factors:

(a) The controversial "overriding policy considerations".

(b) Uncertainty of future sources and prices of power.

(c) Changes in rates were related to shifts in responsibility for costs in particular the cost of excess investment in distribution facilities.

(d) The need for of a long-range incremental cost of service study prepared by WKP.

(e) Insufficient study of winter versus summer peak.

The Commission concluded therefore, that the rate design proposals were "premature and unsupported". However, the Commission acknowledged the need to bring the residential revenues, over time, into line with costs so that appropriate price signals be given. The Commission, nonetheless, required that this and other rate design issues be reconsidered only:

> "When evidence can be produced which shows that the "historic" rates do not properly reflect costs of service, the matter of rate design can be addressed again. At such time, however, the Applicant must have better appreciation of the demands on its transmission system and its sources of power. The Commission also expects that future changes of the nature of those proposed in this proceeding would take more specific account of the impact of those changes on the utility's earnings and its customers." (pages 11-12)

6.10 Conclusion

The Commission has applied its own conditions and recommendations as set out in its October 5, 1984 Decision to the current Application. It finds that the Applicant's proposed changes to its residential and general service rate design do not adequately meet the criteria set out in that Decision. With these conditions and recommendations in mind, the Applicant must reappraise the various rate design proposals contained in its current Application. Furthermore, the Commission believes that a piecemeal approach to rate design modifications is undesirable because it does not address overlapping issues and the nature and extent thereof.

In addition to direction in its previous Decision regarding the Applicant's Rate Design, the Commission directs that other issues to be addressed are:

(a) The interaction of an aggressive DSM program with changes in rate design.

(b) Consideration of equitable treatment for residential customer class segments having varying abilities to respond to either DSM or rate design changes.

(c) Load characteristics of its various customer classes and segments.

(d) Input from wholesale customers regarding a consistent approach to seasonal rates and other DSM projects.

The Commission is concerned that the existing rates may not facilitate DSM program development. It is with a sense of urgency that the Commission directs the Applicant to provide an outline of a "Rate Design Plan" by June 30, 1989. The plan should address a rate design development initiative that begins with a cost of service study based upon the 1989 Test Year if appropriate. It should include the impacts of aggressive DSM, competing fuel choices and should reflect the impacts of alternative load growth forecasts: "Low Probable", "Probable", and "High Probable". The plan should also address the concerns of the Commission in its previous Rate Design Decision as well as those stated above.

7.0 OTHER MATTERS

7.1 UtiliCorp

Concern was expressed at the hearing with regard to the acquisition of WKP by UtiliCorp. This acquisition was approved by the Commission, with conditions, in a Decision dated June 30, 1987. Commission Counsel, commencing at Transcript pages 194 and 1304, cross-examined the Applicant's witness with specific regard to each of those conditions, and the issue raised with regard to the Applicant changing its name from West Kootenay Power and Light Company, Limited to West Kootenay Power Ltd. The Commission is satisfied that UtiliCorp is complying with the conditions and is neither directly or indirectly attempting to recover its investment, over and above the net book value, through excess plant investment or inter-corporate charges.

With specific regard to the Applicant's relationship with its parent, UtiliCorp, the Commission would encourage the Applicant to use skills and services which are available from UtiliCorp on a cost effective basis. However, as the Applicant no doubt recognizes, when goods and services are purchased from a related company, especially a parent, these transactions must stand the test of the most stringent scrutiny, both by the Commission and the public.

7.2 Hearing Costs

The Commission has considered the hearing costs incurred in this proceeding and notes further reductions have been made from those achieved in the 1986 proceeding. The costs incurred in the 1986 hearing were 50% of those incurred in the previous hearing.

With regard to the disposition of the Applicant's and Commission's costs in this proceeding, the Commission raised the matter in the 1986 hearing by directing the Applicant to consider it in this hearing.

In considering the appropriate disposition of the costs, the Commission, amongst other matters, has considered the fairness of the full recovery of the Applicant's costs while Intervenors cannot recover their costs, as well as financial incentives to further encourage expeditious hearings and the concomitant cost reductions. Accordingly, the Commission believes that an allocation of the costs should be made on the basis of what was sought by the Applicant as opposed to what was achieved.

In this proceeding the Applicant should recover its entire costs from the rate payers over a one-year period commencing January 1, 1989.

8.0 DECISION

The Commission confirms the interim increase of approximately 6.7%, applied uniformly to rates in effect at December 31, 1988.

The Commission will accept revised Rate Schedules in accordance with this Decision, supported by a reconciliation of rates, volumes and revenues.

DATED at the City of Vancouver, in the Province of British Columbia, this 25th day of April, 1989.

J.D.V. NEWLANDS, Deputy Chairman and
Chairman of the Panel

W.M. SWANSON, Q.C., Commissioner

W.A. BEST, Commissioner

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-24-89

BRITISH COLUMBIA UTILITIES COMMISSION

PROVINCE OF BRITISH COLUMBIA

BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF the Utilities Commission Act, S.B.C. 1980, c. 60, as amended

and

IN THE MATTER OF an Application by West Kootenay Power Ltd.

BEFORE:	J.D.V. Newlands, Deputy Chairman and Chairman of the Division; W.M. Swanson, Q.C., Commissioner; and W.A. Best, Commissioner	April 25, 1989

O R D E R

WHEREAS a public hearing pertaining to West Kootenay Power Ltd.'s ("WKP") Application dated November 28, 1988 for a general rate increase proceeded before the Commission at Rossland, B.C. from February 28 through March 8, 1989; and

WHEREAS pursuant to Order No. G-107-88 WKP was granted an interim, refundable rate increase of 6.7% effective January 1, 1989; and

WHEREAS the Commission has considered the Application and the evidence adduced thereon, all as set forth in a Decision issued concurrently with this Order.

NOW THEREFORE the Commission hereby orders West Kootenay Power Ltd. as follows:

1. The Rate Base and Revenue Requirement for the Test Year ended December 31, 1989 are as set out in Schedules contained in the Decision.

2. The Commission confirms as firm, the interim rates in effect on January 1, 1989.

3. The Commission will accept, subject to timely filing, amended Electric Tariff Rate Schedules which conform to the terms of the Commission's April 25, 1989 Decision.

4. West Kootenay Power Ltd. will comply with the several directions incorporated in the Commission Decision.

DATED at the City of Vancouver, in the Province of British Columbia, this 26th day of April, 1989.

BY ORDER

J.D.V. Newlands,
Deputy Chairman and
Chairman of the Division

381/39/cms

FOURTH FLOOR, 800 SMITHE STREET, VANCOUVER, B.C. V6Z 2E1 CANADA
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UTILITY RATE BASE SCHEDULE 1		1989 APPLICATION	BCUC ADJUSTMENT	No.	1989 ADJUSTED
$000'S					
PLANT IN SERVICE, opening		$187,953			$187,953
Additions to plant in service		12,358			12,358
Disposals		(634)			(634)
		---------	---------		---------
PLANT IN SERVICE, closing		199,677	0		199,677
Add: Work in progress		750			750
Plant held for future use		0			0
Preliminary investigation		75			75
Other deferred charges		1,137			1,137
Plant acquisition adjust.		11,912			11,912
		---------	---------		---------
		213,551	0		213,551
Less:					
Accum. Depreciation		(59,089)			(59,089)
Accum. Amortization		(1,408)			(1,408)
Contributions in Aid		(14,553)			(14,553)
		---------	---------		---------
NET PLANT IN SERVICE, closing		138,501	0		138,501
NET PLANT IN SERVICE, opening		133,796			133,796
		---------	---------		---------
NET PLANT IN SERVICE, mid yr.		136,148	0		136,148
WORKING CAPITAL ALLOWANCE		3,004			3,004
ADJUST. FOR MAJOR ADDITIONS		(74)			(74)
					0
		---------	---------		---------
UTILITY RATE BASE, MID YEAR		$139,078	$0		$139,078
		=========	=========		=========
RETURN ON RATE BASE		12.07%	0.07%		12.14%

SCHEDULE 1

N O T E S:

UTILITY INCOME & RETURN SCHEDULE 2		1989 APPLICATION	BCUC ADJUSTMENT	No.	1989 ADJUSTED
$000'S					
SALES VOLUME MWh		2,342,526			2,342,526
		==========	==========		==========
Avge Exist. Revenue: ¢/kWh		2.9	0.00%		2.9
Rate Increase %		6.70%	0.01%		6.71%
REVENUE					
Existing Rates		$68,084			$68,084
Interim Rates		4,563	7		4,570
Miscellaneous Revenue		0			0
		----------	----------		----------
TOTAL REVENUE		72,647	7		72,654
Less: POWER PURCHASES		17,342	(113)	[2]	17,229
WHEELING		2,245	(21)	[3]	2,224
		----------	----------		----------
GROSS MARGIN		53,060	141		53,201
% excluding Misc. Revenue		73.04%	0.19%		73.23%
OPERATING EXPENSES		31,051	48		31,099
		----------	----------		----------
Utility income before tax		22,009	93		22,102
INCOME TAX EXPENSE		5,216	2		5,218
		----------	----------		----------
EARNED RETURN		$16,793	$91		$16,884
		==========	==========		==========
RETURN ON RATE BASE		12.075%	0.07%		12.14%

SCHEDULE 2

N O T E S:

INCOME TAXES SCHEDULE 3 $000'S		1989 APPLICATION	BCUC ADJUSTMENT	No.	1989 ADJUSTED
UTILITY INCOME BEFORE TAX		$22,009	$93		$22,102
Deduct - Interest on Rate Base		(7,561)	(88)		(7,649)
		--------	--------		--------
ACCOUNTING INCOME		14,448	4		14,452
Timing Differences					
Depreciation		5,412			5,412
Amort. of Deferred Charges		251	48		299
Current WCB Reserve		787			787
Added Insurance Reserve		100			100
Previous WCB Reserve		(617)			(617)
Capital Cost Allowance		(7,043)			(7,043)
Additions to Deferred Charges		(250)	(48)		(298)
Capitalized Overhead		(913)			(913)
Other		0			0
		--------	--------		--------
		(2,273)	0		(2,273)
		--------	--------		--------
TAXABLE INCOME		$12,175	$4		$12,179
		========	========		========
Income Tax Rate - Current		42.840%	0.00%		42.84%
INCOME TAX EXPENSE		$5,216	$2		$5,218
		========	========		========

SCHEDULE 3

N O T E S:

RETURN ON CAPITAL SCHEDULE 4		1989 APPLICATION	BCUC ADJUSTMENT	No.	1989 ADJUSTED
$000'S					
DEFERRED INCOME TAXES		$9,827	$0		$9,827
Proportion		6.408%	0.00%		6.41%
Embedded Cost		.00%	0.00%		.00%
LONG-TERM DEBT		$56,283	$0		$56,283
Proportion		36.702%	0.01%		36.71%
Embedded Cost		13.169%	0.00%		13.17%
% Return		4.833%	0.00%		4.83%
$ Return		$7,412	$0		$7,412
BANK LOANS		$9,737	$0		$9,737
Proportion		6.350%	0.00%		6.35%
Embedded Cost		9.500%	1.00%	[1]	10.50%
% Return		0.603%	0.07%		0.67%
$ Return		$925	$97		$1,022
PREFERRED SHARES		$12,500	$0		$12,500
Proportion		8.151%	0.00%		8.15%
Embedded Cost		7.864%	0.00%		7.86%
% Return		0.641%	0.00%		0.64%
$ Return		$983	$0		$983
COMMON EQUITY		$65,003	($29)		$64,974
Proportion		42.389%	-0.01%		42.38%
Return on Equity		14.148%	0.00%		14.15%
% Return		5.997%	0.00%		6.00%
$ Return		$9,197	($4)		$9,192
		----------	----------		----------
TOTAL CAPITAL		$153,350	($29)		$153,321
		==========	==========		==========
RATE BASE		$139,078	$0		$139,078
		==========	==========		==========
RETURN ON RATE BASE		12.075%	0.07%		12.14%

N O T E S:

SCHEDULE 4

COMMON EQUITY SCHEDULE 5 $000'S		1989 APPLICATION	BCUC ADJUSTMENT	No.	1989 ADJUSTED
Share Capital		$31,459			$31,459
Contributed Surplus		0			0
Retained Earnings		29,810			29,810
OPENING BALANCE		61,269	0		61,269
Add: Net Income on Total Capital		10,234	(59)		10,175
Deduct:					
Preferred Dividends		(983)			(983)
Common Dividends		(4,070)			(4,070)
		66,450	(59)		66,391
Shares Issued		3,053			3,053
CLOSING BALANCE		$69,503	($59)		$69,444
COMMON EQUITY, MID-YEAR		$65,386	($29)		$65,357
Share Issue Adjustments		(383)			(383)
COMMON EQUITY, AVERAGE		$65,003	($29)		$64,974

SCHEDULE 5

N O T E S:

OPERATING EXPENSES SCHEDULE A $000'S		1989 APPLICATION	BCUC ADJUSTMENT	No.	1989 ADJUSTED
Labour		$11,154			$11,154
Material		3,587			3,587
Uncollectible Accounts		150			150
Insurance		636			636
Rental of Head Office		173			173
Amortization-Regulatory Costs		311	48	[4]	359
Amortization-Other & Invest.		75			75
Rental of Facilities		182			182
Property Tax		4,581			4,581
Water Rental Fees		6,236			6,236
Depreciation		5,226			5,226
Amortization		186			186
Other Income		(1,446)			(1,446)
TOTAL		$31,051	$48		$31,099

N O T E S:

SCHEDULE A

ADJUSTMENTS		
1. Bank Loans	$97	To adjust deferred interest account rate to 10.5%.
2. Power Purchases	$113	To remove 3.5% increase in BCH rates.
3. Wheeling	$21	To remove 3.5% increase in BCH rates.
4. Amortization-Regulatory costs	$48	To adjust BCUC costs to actual.

N O T E S:

APPENDIX "A"

Sensitivity Test Regarding Load Forecasting

A. Overestimation of Energy by 1%

(i)	Energy Requirement reduced by: 1% of 2,623 GW.h	= 26.2 GW.h
(ii)	Sales Volume reduces by: 1% of 2,343 GW.h	= 23.4 GW.h
	Lost Revenue: 23.4 GW.h times 26.1 mills *	= $610,000
	* per Exhibit 37 - excluding Bradford Enercon's new load	
(iii)	Cost reduces by: Under 90% take-or-pay with B.C. Hydro the maximum amount of energy that may not be taken is 10% of 184 GW.h or 18.4 GW.h (Exhibit 1, Tab 8, p. 11)	
	Energy not taken (above)	26.2 GW.h
Less:	10% of nomination	18.4 GW.h
	Take-or-Pay	7.8 GW.h
	Reduced Cominco purchases 7.8 GW.h @ 11.3 mills	$ 88,000
	Reduced B.C. Hydro purchase: 18.4 GW.h at 22.39 mills	$412,000
	Energy Costs Saved	$500,000
(iv)	Loss in contribution Margin: Lost Revenue	$610,000
Less:	Net Energy Costs Saved	500,000
	LOST MARGIN	$110,000

B. Underestimation of Energy by 1%

(i)	Energy Requirement	26.2 GW.h
(ii)	Sales Volume Increases by	23.4 GW.h
	Added Revenue: 23.4 GW.h times 26.1 mills	$610,000
(iii)	Costs Increase: Energy at 22.39 mills Capacity at 7.5 mills *	$783,000
	(* from Exhibit 37)	
(iv)	Lost Contribution Margin: Added Revenue	$610,000
	Increased Costs	783,000
	LOST MARGIN	$173,000

APPENDIX "B"

Summary of Commission Directions

Reference	
	Capital Expansion Projects
page 5	Demonstrate the existence of a process similar to that shown in Figure 3.1, produce a 10-year system development plan as soon as possible and file it annually with the Commission.
	Resource Planning Considerations
page 7	Pursue the potential opportunity with respect to storage of surplus power with B.C. Hydro.
	Forecasting
page 12	File the March 1989, 20-year Forecast with explanatory information when it is available.
page 13	Prepare detailed contingency plans for the high probable and the low probable forecasts.
	DSM as Rate Base
page 13	Treat all expenditures on a DSM project that has a development period longer than one year in the same manner as any other rate base addition.
	DSM Programs
page 25	Finalize a marketing plan and implement a promotional program for DSM projects the Company has accepted.
	Review all potentially appropriate DSM programs using benefit/cost criteria in line with a marginal cost test.
	Rate Design
page 37	Address further issues in the Company's rate design proposals.
page 38	Provide an outline of a "Rate Design Plan" by June 30, 1989.