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

and

IN THE MATTER OF
Applications by
Northland Utilities (B.C.) Limited,
Dawson Creek Division

DECISION

December 16, 1983

Before:

M. Taylor, Chairman;
J.D.V. Newlands, Deputy Chairman; and
N. Martin, Commissioner

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APPEARANCES

C.K. SHEARD, Esq.	Counsel for the Applicant
MR. STEINLECHNER	Appearing on his own behalf
MRS. M. LEOPPKY	Appearing on her own behalf
MR. IKERT	Appearing on his own behalf
MR. R. BOUCHARD	Appearing on behalf of the Dawson Creek & District Hospital Chapter of the Health Sciences Association
MR. NICHOLSON	Appearing on his own behalf
MR. S. WILSON	Appearing on his own behalf
MR. L. DOWD	Appearing on his own behalf
MR. P. PIPER	Appearing on his own behalf
J.J. CAMP, Esq.	Commission Counsel

J. HAGUE D. MacINNIS R. BROWNELL	Commission Staff
D. LEACH	Hearing Officer
ALLWEST REPORTING LTD.	Court Reporters

LIST OF EXHIBITS

LIST OF EXHIBITS
(cont'd)

I. BACKGROUND

Northland Utilities (B.C.) Limited (the "Applicant" or "Northland"), owns and operates a natural gas utility, Dawson Creek Division, in a service area comprised of the City of Dawson Creek, Village of Pouce Coupe, Hamlet of Rolla and areas adjacent to those communities. The Applicant is a wholly-owned subsidiary of Northwestern Utilities Limited, which company is a wholly-owned subsidiary of Canadian Utilities Limited. Ultimate control rests in the hands of ATCO Ltd.

Natural gas is supplied to Northland by Peace River Transmission Co. Ltd. ("Peace River") a company regulated by the National Energy Board. Peace River is a wholly-owned subsidiary of Inland Natural Gas Co. Ltd.

Peace River receives its natural gas from Westcoast Transmission Co. Ltd. ("Westcoast") and transmits and resells the gas to Northland under a contract which remains in effect until January 1, 1994.

II. THE APPLICATION

Northland applied on March 4, 1983 for interim and permanent rate relief to be effective from April 1, 1983. The Applicant presented forecast data for two test years, 1983 and 1984. The 9.7% increase on existing rates was based upon the 1984 test year Revenue Requirement and assumed that such an increase would not be in conflict with the Commission's view of a fair return for the year ended December 31, 1983. The Commission approved the requested increase on an interim basis subject to refund with interest at the average monthly prime rate of the Applicant's principal bank.

The Application, pursuant to Commission Order No. G-34-83, was heard in Dawson Creek, June 9, 10 and July 18, 1983. Major revisions to the Application data, giving effect to changes announced by the Applicant during the hearing, are included on the "Schedules" to the Decision.

The Applicant was represented by Mr. R.G. Lock, Vice-President and General Manager of Northwestern Utilities Limited ("Northwestern"); Mr. H.R. Lewis, Controller of Northland and Northwestern; Mr. J.A. Walker, Treasurer of Canadian Utilities Limited; Mr. J.C. Moon, Manager of Distribution for Northwestern; Mr. G.W. Richards, Manager of Economics and Special Studies, Northwestern and Mr. N. Aspeslet, Supervisor, Northland.

III. RATE BASE

Relocation of North Dawson Creek Gate Station

This project was approved by the Commission at an earlier hearing, and justified by the Applicant on the grounds of safety, system growth, and aesthetics. The cost at that time was estimated to be $220,000 with the work to be completed in the fall of 1982. In relation to the Applicant's net plant, this project is material.

The evidence at the Hearing showed the final cost for this well-defined project was $308,000, or 40% over budget. The Applicant argued that since the original quoted cost was a "conceptual" estimate, or a "rate case" estimate, its value for predicting the final cost is minimal. The Applicant further argued that had they known the project would have cost $308,000 they would still have proceeded with the work because the cost was justified on the basis of need alone. The Applicant contends therefore, that the error in estimating and other factors which led to the cost overrun should be borne by the customer in rate base.

The Commission will permit the inclusion of the full cost of this project in Rate Base. However, the Commission is compelled to express its dissatisfaction with the Applicant's use of "conceptual" estimates and will require the Applicant to provide more effective capital budgets in future.

Looping Project

With declining flows of natural gas to U.S. customers, and the idling of some of its compressors, Westcoast has reduced the delivery pressures to certain northern B.C. transmission and distribution utilities.

Historically gas has been delivered at pressures hundreds of pounds above contract pressure and like other northern B.C. utilities, the Applicant has relied upon these delivery pressures.

The Applicant presented evidence to support its position that the Company would be unable to meet its system load in peak conditions if the low delivery pressures from Westcoast were to persist into the next heating season. To overcome this situation, the Applicant proposed to construct a 168 mm loop parallel to the existing 114 mm feeder main, at an estimated cost of $200,000.

Early in the proceedings the Commission expressed concern that it was not satisfied that all reasonable alternatives had been explored to the extent that the one proposed was clearly the most practical. Furthermore, the Commission was concerned about the accuracy of the cost estimate provided by the Applicant.

As a result the Applicant explored other alternatives for assurance of gas supply, resulting in a no-cost commitment from Westcoast that its main line pressure would be sufficient during the winter 1983/84, for the Applicant to maintain supply.

The Commission recognizes the potential for a drop in pressure in the future, and that the present commitment from Westcoast Transmission could hold for one heating season only. Should the Applicant determine that the system requirements will not be met, the Applicant is requested to forward an analysis of alternatives together with supporting cost documentation for the favoured alternative. Commission approval is to be obtained prior to commitment of funds.

Implementation of Extension Policy.

The Commission is satisfied that forecast additions do meet Northland's terms and conditions thus ensuring that existing customers are not unduly subsidizing, through their gas rates, the extension of service to new customers.

Change in Accounting Treatment

The Applicant has requested a change in accounting with respect to service lines. It proposes to capitalize the total cost of service lines and treat the payment for the lines on customers' premises as a contribution. In addition, it proposes to commence amortization of customer contributions commencing in 1984. The Commission approves the proposed changes.

Cash Working Capital

The Commission directs the Applicant for purposes of its next rate case to update its lead/lag study representing current conditions.

IV. REVENUE REQUIREMENT

Sales Volume

The Commission accepts the Applicant's forecast of 1984 sales volumes. The evidence indicates that residential and commercial space and water heating comprises almost all of the forecast sales volume. The industrial load which represented 3% of the 1982 test year volume is forecast at zero for the years 1983 and 1984.

Unit operating costs of this utility continue to rise while sales per customer continue to decline. Market penetration is heavily dependent upon government subsidies which in turn depend upon an oil displacement test. With respect to the Federal Distribution System Expansion Program (D.S.E.P.) the Commission notes that no subsidies are forecast for 1983 and 1984 extensions of service. In 1982 D.S.E.P. awards to Northland amounted to $200,000.

Propane, electricity and heating oil alternatives are available. A comparison was prepared by the Applicant on the basis of 150 GJ of residential consumption per year (ref: Exhibit 6, Item 8):

Natural gas existing rates	$ 444
Natural gas proposed rates	490
Electricity	1,079
Heating oil	1,337
Propane	1,411

According to this comparison natural gas consumption, at the proposed rates, costs 37% of oil and 45% of electricity. Combined with consideration of appliance and installation costs, natural gas continues to enjoy a very favourable cost/benefit advantage in the service area . However, the evidence is that the conservation alternative is being pursued so that sales volume per customer continues to fall at about 1% per year.

Intervenors were particularly concerned by the fact that the more they conserved the more the Company needed to increase rates to cover its fixed costs with the result that the annual cost to the customer did not decrease as anticipated by the customer's conservation effort.

With respect to the foregoing the Commission is concerned about increasing unit costs and anticipates that the Applicant will, at the next proceeding, put forward evidence as to market penetration and appliance saturation. Prospects for new industrial load should also be fully examined during the next proceeding.

Operating and Maintenance Costs

Comparing the 1982 fiscal year with the 1984 test year, operating and maintenance costs per customer are forecast to increase at a compound rate of over 11% per year as shown on Appendix A. The evidence also indicates that the Operating and Maintenance cost increase represents 60% of the 1983 rate increase and 50% of the 1984 rate increase.

The Commission addressed the matter of escalating costs with some concern. The Applicant explained the rapid escalation in costs were due to two principal factors namely, wage increases due under contract and secondly, a change in the accounting method for allocating head office costs.

In late 1981 the Applicant signed a two-year agreement with the Natural Gas Employees Benefit Association. The agreement provided for a 13% increase in compensation for the thirteen occupational employees effective January 1, 1983. Although the Applicant attempted to renegotiate, the Association was not willing to adjust the 13% previously agreed to. For fiscal 1984 the Applicant has provided for an increase in remuneration that is within federal guidelines.

With respect to the allocation of head office costs the Applicant proposes a change from an allocation based upon identifiable labour costs to an allocation based upon a combination of identifiable labour cost plus other costs allocated on a customer ratio basis. After considering the evidence the Commission finds that use of identifiable labour and sales would produce the best means of allocating common head office costs. Accordingly, it directs the Applicant to use the sales proportion plus identifiable supervisory labour. The head office allocation factor would become .7% rather than the proposed 1.5%.

A cost category that represents a large measure of allocated cost is "Customer Accounting" and this is forecast by the Applicant to cost $250,000 in 1984. The forecast amount represents about $55 per customer per year or about 10% of a residential customer's annual bill. For 1984, the Company estimates a cost of $74,000 for using the parent company's computer facilities. The Applicant prepared a brief analysis of computer alternatives but the analysis did not reveal significant opportunities for improvement. The Commission finds that an expanded study of the content and alternatives to those costs comprising the $250,000 is desirable.

Costs to maintain the Customer Accounting system are therefore of significant concern to the Commission and accordingly Northland is directed to prepare a cost/benefit analysis demonstrating the "stand alone" alternative in this cost category for the Dawson Creek Division of the Company. No more than $10,000 should be spent on such a study (see adjustment (2) on Schedule II).

Capital Structure and Return on Rate Base

The mid-year capital structure and return components are set out on Schedule IV of this Decision. The capital structure presented is the estimate of the actual balance sheet amounts applicable to the Dawson Creek Division. The equity proportion for the 1984 test year is forecast to be 41.7%. The percent would have been lower but the Applicant has decided to withhold dividends for 1983 and 1984 in order to maintain a more optimal debt to equity ratio.

The Applicant has forecast an embedded cost of debt of 11.78% for 1983 and 12.07% for 1984. Canadian Utilities Limited borrows on behalf of the corporate group and long-term requirements of Northland are met by issuance of fixed rate debentures to Canadian Utilities Limited. The Commission approves the use of the forecast cost of debt in the test year.

The Applicant applied for a 16.5% return on common equity, and this request was based upon acceptance of a 4.75% risk premium. The evidence indicated that a risk premium of this magnitude would be 1.1% higher than expected for the Canadian average of publicly traded utility stocks. Another way of looking at this is to consider the argument that the Dawson Creek investment is contended to be 30% riskier than the average utility investment. In the view of the Commission the Applicant is not exposed to either business or financial risks in the order of 30% greater than average and furthermore, based on the evidence, the Commission believes the Applicant has sufficient opportunity to mitigate existing business risks.

With respect to the foregoing and in recognition of the high value of service rendered by the Applicant in its service area, the Commission hereby approves a range of return on common equity of between 15 1/4% and 15 3/4%. The rate specified on Schedule IV of this Decision is 15.5% and, together with the cost of long-term debt, results in a rate of return on rate base of 13.1% (see adjustment (3) on Schedule II).

Deficiency Rider and Unrecorded Revenue

A revenue shortfall from November 1980 to the present is believed by the Applicant to be $100,000 and is presented as the consequence of the utility not being permitted to prospectively adjust rates in order to anticipate the Federal Excise Taxes and wholesale price increase pass-throughs. The Applicant, in its 1983 through 1984 test years, has deferred $100,000 in costs, adjusted deferred tax on account of them and has included the amount in rate base. The Applicant wishes to draw down these accounts as the $100,000 is recovered through a deficiency rider that would add 4.1¢ to the price of each GJ sold from January 1, 1984 to November 30, 1985.

Costs for gas sold are recorded by Northland , on average, fifteen days sooner than are the revenues for those same gas deliveries. Taxation authorities have permitted this departure from generally accepted accounting principles. Northland makes its rates, however, in order to recover the full cost of service during a fiscal year. In this way the full costs of service for the fiscal year are recovered on the basis of billed not delivered sales. Theoretically, adjustments would be needed to recognize unit cost differences and volume differences between the first fifteen days of billings each year and the last fifteen days. Practically, the Applicant has not made these adjustments. From the start of operations to 1980, the Applicant believes that omission of the adjustments has accumulated some $249,000 revenue shortfall (Exhibit 14, Item 1).

The $249,000 shortfall is probably represented by capital debt and has grown to this level from 1956 through to 1980. Northland records its revenues when billings are made, not as gas is delivered to customers. All of Northland's costs, on the other hand, are recorded on the accrued or "as gas is delivered" basis.

The Commission stated its opinion as to whether or not a permanent shortfall occurs in its December 4, 1981 Decision:

> ". . . the Commission is of the opinion that an allowance for working capital adequately compensates the lag . . .".

The working capital allowance is based upon cost recording and can be said to be consistent with accounting for gas cost as delivered.

The revenue side is considered by way of a comparison of the difference between the number of days elapsed between delivery of service to customers and payment by the utility for gas supply and payment by customers to the utility. This leads to the conclusion that the working capital allowance concept, based upon cash receipts accounting, is independent from the manner in which revenue accounting is performed and no "shortfall" should occur because all of the cash costs of the fiscal year are included. The Commission reiterates now its previous opinion that the working capital allowance adequately compensates the utility for the carrying cost of any permanent investment in cash operating expenses paid for in advance of receipts.

The inclusion of a working capital allowance in the rate base recognizes the fact that any permanent difference between cash operating expenses paid for in advance of receipts must be made up with permanently provided capital funds. Those funds are provided by lenders or shareholders and are represented in the rate of return on rate base. The operation of the rate of return upon the working capital allowance is a perpetual annuity, the present value of which is the permanent difference.

The Applicant's view is that the Commission might want to require the customers to currently provide those funds instead. The deficiency rider would duplicate some of the effect of the working capital allowance because there would no longer be a difference between some cash operating expenses paid for and receipts.

The Commission concludes that it would be inappropriate to segregate "pass-through costs" for deficiency rider treatment while all other costs are on the working capital allowance basis. The Commission finds that the manner of revenue accounting on either an accrual (delivered) basis or on a billed basis does not affect the operation of the working capital allowance. The Commission also finds that the deferral of the "unmatched costs", the deferred tax treatment accorded them and the inclusion of those costs in rate base is inconsistent with the Company's chosen historical accounting procedures and at variance with the Commission's December 4, 1981 Decision. Those amounts are adjusted out of the revenue requirement schedules (see adjustment (1) on Schedule II. See also adjustment (1) on Schedule I).

The Commission recognizes that for financial reporting purposes other than rate-making, the Applicant may need to writeoff the deferred gas costs amount. However, those deferred costs have not been recognized as such for regulatory purposes and the Commission is satisfied that those costs are being fairly recovered in the adjusted revenue requirement.

The Commission is concerned that the act of recording revenue when billings are made rather than on the accrual basis ultimately causes the Applicant to mismatch costs and revenues and to incur additional debt. This is a consequence of the Applicant knowingly departing from the usual financial accounting model practiced in British Columbia.

The Applicant is aware of this Commission's concerns with the deficiency rider approach. Should the utility wish to advance its next rate case utilizing the accrual basis of revenue recording, that would be appropriate, provided no retroactive rate adjustment results from the change.

V. RATE DESIGN

The Applicant has proposed a restructured rate schedule for the Dawson Creek Division beginning January 1, 1984. It would take the form of one rate level across the three communities with one rate level and fixed charge applying to both "General" and "Optional" rate classes. A comparison of the existing and proposed rate structures is contained in Appendix B.

The Applicant originally proposed an amended rate schedule for the three communities in the Rate Application of June 7, 1976. The Decision of January 24,1977 which followed, recognized that a rate differential was necessary to reflect the higher costs of service to the communities of Rolla and Pouce Coupe. It was decided at that time that if this was not acknowledged in the rates, Dawson Creek would subsidize the two communities.

The evidence presented compared the rate base related costs in Dawson Creek to the communities of Rolla and Pouce Coupe. The comparison confirmed that there is a high cost of attachment of new customers in Dawson Creek which is attributed to increased construction costs and financing charges. The result is that today the rate base related costs, for the three areas, are now nearly equal.

In support of its proposal for a uniform rate the Applicant stated that the two rate classes, being "General" and "Optional", use natural gas almost exclusively for space heating and hot water heating. The resulting load factors are then approximately equal illustrating that the two customer classes are, therefore, utilizing capacity in the same manner. The Applicant also stated that fixed charges per customer for each rate class are approximately identical.

It is to be noted that Intervenors present did not object to the Applicant's proposals for an indentical rate in the three communities, a single rate level and "Fixed Charge" for "General" and "Optional" rate classes.

An adoption of one rate level for the "General" and "Optional" rate classes would essentially eliminate rate classes. The Commission therefore considers that it is important for the Applicant to continue to monitor customer loads for changing load patterns and therefore load factors which may lead to further rate revisions.

VI. DECISION

The 9.7% interim rate increase on April 1, 1983 was based upon forecast 1984 sales of 1,299,300 GJ and revenue requirements amounting to $4,110,000. The 9.7% was derived by comparing $3,747,000, the forecast 1984 revenue on existing rates, with the 1984 forecast revenue requirements. As shown on Schedule II, the final 1984 Test Year sales are forecast to be 1,290,200 GJ with revenue requirements of $4,044,000. The forecast 1984 revenue using existing rates and the revised sales would be $3,720,757. Using the final 1984 Test Year numbers, the April 1, 1983 rate increase would have been 8.7%. The Applicant is required to refund to its customers the excess revenue on 1983 sales and to provide in a timely fashion amended Tariff Rate Schedules incorporating rates reflecting the terms of this Decision applicable to 1983.

In conclusion, therefore, the Commission finds and hereby approves a uniform rate with an identical rate level and fixed charge applying to both "General" and "Optional" rate classes and across the three communities. The Commission's approval applies to consumption on and after January 1, 1984 based upon the Revenue Requirements, as adjusted, for the 1984 Test Year as shown on Schedule II and the Applicant is required to provide in a timely fashion, amended Tariff Rate Schedules incorporating rates reflecting the terms of this Decision applicable to 1984.

DATED at the City of Vancouver, in the Province of British Columbia this 16th day of December, 1983.

M. TAYLOR, Chairman

J.D.V. NEWLANDS, Deputy Chairman

N. MARTIN, Commissioner

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 Northland Utilities (B.C.) Limited

BEFORE:	M. Taylor, Chairman; J.D.V. Newlands, Deputy Chairman; and N. Martin, Commissioner	December 16, 1983

O R D E R

WHEREAS Northland Utilities (B.C.) Limited ("Northland") applied March 4, 1983 for interim rate relief represented by a 9.7% rate increase applicable uniformly to all rates classes effective April 1, 1983; and

WHEREAS Commission Order No. G-22-83 authorized the requested interim rate relief effective April 1, 1983 with the interim increase subject to refund with interest at the average monthly prime rate of the Applicant's bank; and

WHEREAS Northland applied April 6, 1983 proposing an amended Rate Design to be implemented January 1, 1984 which will result in uniform rates for all classes of customers served by Northland in the communities of Dawson Creek, Rolla and Pouce Coupe, except Special Contract customers; and

.../2

WHEREAS Commission Order No. G-34-83 established June 9, 1983 as the date of commencement for public hearing of the Application; and

WHEREAS the Application was subsequently reconvened and heard in public at Dawson Creek on July 18, 1983 in accordance with arrangements satisfactory to all interested parties; and

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

NOW THEREFORE the Commission hereby orders Northland Utilities (B.C.) Limited as follows:

1. The interim rates incorporating a 9.7% interim increase effective April 1, 1983 have been determined to be in excess of requirements as stated in the Decision of the Commission issued concurrently with this Order, and accordingly Northland is directed to file, in a timely manner, amended Tariff Rate Schedules reflecting the appropriate rates incorporating an 8.7% increase effective April 1, 1983.

2. Northland is ordered to refund to its customers of record in the period April 1, 1983 to December 31, 1983 excess revenue billed plus interest at the average monthly prime rate of Northland's principal bank during the same period. Such refunds should be remitted to the customers, or credited to customer accounts during February 1, 1984 and a record thereof should be supplied to the Commission in a timely fashion.

3. If Northland cannot, by April 30, 1984, locate a former customer who is entitled to a refund the amount shall be recorded in a liability account for a maximum of one year during which period Northland shall collect evidence supporting a reasonable effort to locate the former customer. After the expiry of a year any amounts remaining shall be recorded as miscellaneous utility income.

.../3

4. The Rate Base for the 1984 Test Year is approximately $1,607,000.

5. The total Cost of Service for the 1984 Test Year is approximately $4,044,000 on a sales volume of 1,290,200 GJ.

6. The Commission will accept for filing effective with consumption on and after January 1, 1984, subject to timely filing, amended Tariff Rate Schedules which will permit Northland to generate the annual gross revenue requirement of approximately $4,044,000 as set out in Schedule II of the Commission Decision dated December 16, 1983. The amended Tariff Rate Schedules shall be designed in accordance with the terms contained in the Commission Decision including rate uniformity and a reconciliation schedule must be filed concurrently.

7. Northland shall comply with all of the directions of the Commission to Northland contained in the Decision issued concurrently.

DATED at the City of Vancouver, in the Province of British Columbia, this 16th day of December, 1983.

BY ORDER

M. Taylor

Chairman

NORTHLAND UTILITIES (B.C.) LIMITED
DAWSON CREEK DIVISION

Utility Rate Base

1984 Test Year ($000's)

	Per Application (Exhibit 4)	Applicant's Revisions	Revised Balance	Commission Adjustments (credit)	Final Adjusted Balance
Gas Plant in service as at December 31, 1983	$3,405	(386)	3019		3019
Additions to gas plant in service (mean)	257	(146)	111		111
Gross Plant (mid-year)	$3,662	(532)	3130		3130
Less: contributions in aid of construction	897	343	554		554
	$2,765	(189)	2576		2576
Accumulated depreciation	1,079	9	1070		1070
Net Plant (mid-year)	$1,686	(180)	1506		1506
Deferred Income Tax	(123)	2	(121)	52 (1)	(69)
Working Capital Allowance					
Cash working capital	129	(2)	127		127
Other working capital items	118	-	118	(75) (1)	43
	$ 247	(2)	245	(75)	170
NET UTILITY RATE BASE INVESTMENT	$1,810	$(182)	$1630	(23)	1607

NORTHLAND UTILITIES (B.C.) LIMITED
DAWSON CREEK DIVISION

Adjusted Utility Income and Earned Return

($000)

1984 Test Year	Per Application (Exhibit 4)	Applicant's Revisions (credit)	Revised Balance	Commission Adjustments (credit)	Final Adjusted Balance
Gas Sales Volume (GJ)	1,299,300	9,100	1,290,200		1,290,200
Unit Revenue Requirement	$3.17	$.02	$3.15	$.02	$3.13
Deficiency Rider	$ .04		$ .04	$.04	-
Gas Sales Revenue (Uniform Rates)					
Dawson Creek - residential	$ 1,928	25	1,903	11	1,892
- commercial	1,933	25	1,908	11	1,897
Pouce Coupe - residential	125	2	123	1	122
- commercial	78	1	77	1	76
Rolla - residential	20		20		20
- commercial	14		14		14
Delayed payment charge	23		23		23
Deferred costs rider	50		50	50 [1]	-
TOTAL SALES REVENUE	$ 4,171	$ 53	4,118	74	4,044
Expenses					
Purchase of gas	1,858	(13)	1,845		1,845
F.E.T.	812	(4)	808		808
Deferred gas costs	50		50	(50) [1]	-
Operation & maintenance	900	(22)	878	(5) [2]	873
Property, franchise & sundry taxes	112		112		112
Depreciation	70	(4)	66		66
	$ 3,802	(43)	3,759	(55)	3,704
Net Utility income before taxes	$ 369	10	359	19	340
Deduct Income taxes:					
- payable	136	9	145	(34)	111
- deferred	(12)	4	(8)	27	19
	$ 124	13	137	(7)	130
EARNED RETURN	$ 245	23	$ 222	12 [3]	$ 210
Utility Rate Base Investment	$ 1,810		$ 1,630		$1,607
RATE OF RETURN ON DEPRECIATED RATE BASE	13.5%		13.6%		13.1%

NORTHLAND UTILITIES (B.C.) LIMITED
DAWSON CREEK DIVISION

Calculation of Income Taxes on Utility Income

1984 Test Year ($000)

	Per Application (Exhibit 4)	Applicant's Revisions (credit)	Revised Balance	Commission Adjustments (credit)	Final Adjusted Balance
Net utility income	$369	10	359	19	340
Deduct: Interest expense	116	(22)	94	(5) (3)	89
Net Income before timing differences	$253	(12)	265	14	251
Add: Timing difference adjustments	8	(6)	14	50	(36)
TAXABLE INCOME	$261	(18)	279	64	215
Income tax rate	52%		52%		52%
Income taxes					
-payable	136	9	145	(34)	111
-deferred	(12)	4	(8)	27	19
INCOME TAX EXPENSE	$124	13	137	(7)	130

SCHEDULE IV

NORTHLAND UTILITIES (B.C.) LIMITED
DAWSON CREEK DIVISION

Return on Capital

1984 Test Year ($000's)

Mid-Year Capital Structure	Revised Balance	Commission Adjustments	Final Adjusted Balance	% of Capital Structure	Embeded Cost	Cost Component
Long-term debt	$ 745		$ 745	53.8	12.07%	6.5%
Reserve for inquiries and damages	51		51	3.7	-	
Common Equity	596	7	589	42.5	15.5%	6.6%
	$1,392	$ 7	$1,385	100.00		13.1%

Notes to Schedules

Commission Adjustments

1. Eliminate effects of accounting for deferred gas costs. These costs were not recognized as requiring deferment in the December 4, 1981 Decision and are not recognized as such in this Decision.

(a) Reduce rate base by the mid-year amount of the deferred account		$ 75,000
(b) Eliminate from the 1984 opening balance of deferred tax the 1983 deferred gas cost @ 52% of $100,000		$ 52,000

From the Balance Sheet:

Deferred tax 1984 opening	$112,000	
Less: adjustment above	52,000	
Revised 1984 opening	$ 60,000	
Add: 52% of 1984 timing differences other than deferred gas costs	19,000	
Adjusted 1984 closing balance	$ 79,000	
Closing balance per Application	131,000	
Difference	$ 52,000	
(c) Eliminate the deficiency rider from revenue		$ 50,000
(d) Eliminate the deferred gas costs from cost of gas		$ 50,000

2. Adjustments to Operating and Maintenance Costs

(a) Provision for study of "Customer Accounting"	$ 10,000
(b) Provision for Commission costs of the current rate case	34,500
(c) Change H.O. costs allocation method from 1.5% of customers to .7% of sales volume	(49,500)
Net Reduction in Operating and Maintenance Costs	$(5,000)

3.	Reduce Return on Equity from 16.5% as applied for to 15.5%. A 1.0% reduction on a proportion of 42% applied to the final application rate base of $1,630,000 ...	$ 5,500
	The reduction in rate base from $1,630,000 to $1,607,000 at 16.5% ROE and a 42% proportion is ...	$ 1,500
	The reduction in earned return applicable to debt is ...	$ 5,000
	Total Adjustment to Earned Return	$12,000

APPENDIX A

NORTHLAND UTILITIES (B.C.) LIMITED
DAWSON CREEK DIVISION

Operating and Maintenance Cost Per Customer

Year	Average No. of Customers	Normalized O & M Costs	Cost	% Change
1984	4535	$873,000	$192.50	8.8%
1983	4503	$797,000	$176.99	14.0%
1982	4464	$693,000	$155.24	27.3%
1981	4434	$541,000	$121.98	14.6%
1980	4378	$466,000	$106.44	2.0%

APPENDIX B
(from Exhibit 5)

NORTHLAND UTILITIES (B.C.) LIMITED
DAWSON CREEK DIVISION

1983 Rates Prior to Interim, 1983 Actual Interim Rates and 1984 Proposed Uniform Rates

	1983 Prior to Interim Rates		1983 Actual* Interim Rates		1984 Proposed* Uniform Rates	
	Fixed Charge ($/Month)	Energy Charge $/GJ	Fixed Charge ($/Month)	Energy Charge $/GJ	Fixed Charge ($/Month)	Energy Charge $/GJ
Dawson Creek						
General Rate	2.20	2.783	2.40	3.053	3.00	3.027
Optional Rate	9.50	2.710	10.40	2.973	3.00	3.027
Break Point	1,185 GJ		1,200 GJ			
Deficiency Rider	--		--			.041
Special Contract Rate	110.00	2.645	120.00	2.902	120.00	2.957
Deficiency Rider	--		--			0.041
Pouce Coupe						
General Rate	2.20	2.970	2.40	3.258	3.00	3.027
Optional Rate	9.50	2.907	10.40	3.189	3.00	3.027
Break Point	1,390 GJ		1,390 GJ			
Deficiency Rider	--		--			0.041
Rolla						
General Rate	2.75	3.140	3.00	3.445	3.00	3.027
Deficiency Rider	--		--			0.041

A comparison of uniform and existing rates, as shown below, is based on annual consumption.

Dawson Creek	1983 Actual* Interim Rates	1984 Proposed* Uniform Rates	% Change
Residential (150 GJ)	$ 487	$ 490	0.6
Small Commercial (1000 GJ)	3,082	3,063	(0.6)
Large Commercial (5000 GJ)	14,990	15,171	1.2
Pouce Coupe			
Residential (150 GJ)	518	490	(5.4)
Small Commercial (1000 GJ)	3,287	3,063	(6.8)
Rolla			
Residential (150 GJ)	553	490	(11.4)

*Note: These prices and amounts reflect the costs in the original March 4, 1983 application. Revisions by the Applicant and by the Commission reduce the 1984 amounts by 3¢ per GJ.

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