IN THE MATTER OF

UTILITY

SYSTEM EXTENSION TESTS

DECISION

February 16, 1996

BEFORE:

Dr. Mark K. Jaccard, Chairperson
Lorna R. Barr, Deputy Chairperson
Kenneth L. Hall, P. Eng., Commissioner

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EXECUTIVE SUMMARY

On June 30, 1995 the British Columbia Utilities Commission ("Commission") issued Order No. G-50-95 requiring that the six largest regulated utilities in British Columbia - British Columbia Hydro and Power Authority, BC Gas Utility Ltd., Centra Gas British Columbia Inc., West Kootenay Power Ltd., Pacific Northern Gas Ltd., and Princeton Light and Power Company, Limited ("Utilities") - participate in a generic hearing on their policies and practices regarding their system extension tests. A system extension test is the method used by an energy utility to determine the financial and social viability, and the required customer contribution if any, of an extension to a utility's gas or electricity distribution system. The oral phase of the hearing was held from October 30 to November 9, 1995, with written final argument and replies filed by November 30, 1995.

The Commission sets May 31, 1996 as the latest date by which the Utilities shall each file, for Commission approval, a revised system extension test. The revised system extension tests will be developed in accordance with the following determinations, which are explained in detail in this Decision.

There shall be one general form of system extension test for the Utilities, although the input values and calculation details may vary. This test will be based on a discounted cash flow evaluation method that includes, to the extent feasible, all incremental costs and benefits associated with a particular system extension. As a general principle, the costs of system extensions should be allocated, as much as is feasible, to those customers who cause them.

The time frame for consideration of costs and benefits should be generally consistent with the time frame applied for other integrated resource planning analyses by the Utilities. System extensions should be evaluated from a social perspective, which applies a social discount rate, and a utility perspective, which applies a discount rate based on each utility's cost of capital.

In general, system extensions must individually pass the discounted cash flow analysis in order to proceed. However, the Commission acknowledges that exceptional circumstances may warrant aggregation of some system extensions, subject to Commission approval. The Commission will also consider specific proposals for reducing the administrative costs of dealing with many routine, short system extensions.

The costs and benefits to be considered in the system extension test include the pre-construction estimates of the following:

(1) construction costs of the system extension;

(2) associated incremental system improvement costs, where these can be identified and assessed in a cost-effective manner;

(3) associated incremental operation and maintenance costs, where these can be identified and assessed in a cost-effective manner;

(4) net costs of connection (i.e., cost of connection less connection fees);

(5) net revenues from the system extension (i.e., customer payments less revenues to provide for commodity purchases and upstream transmission charges); and

(6) consideration of incremental environmental and social externalities (for the social perspective evaluation).

The social perspective approach to assessing system extension proposals should be more detailed with respect to communities, as opposed to individual customers or small clusters of customers. In particular, if a community application for a system extension is close to passing the discounted cash flow test from the utility perspective, the utility should then assist with a preliminary comparative analysis of all feasible alternatives for meeting the community's energy service needs. Such analysis should include recognition of significant social and environmental externalities associated with each alternative, from a social perspective.

Where a utility finds that a system extension is uneconomic from its own perspective, system extension tests help determine the magnitude of the contribution in aid of construction that is required from customers for a system extension to proceed. Generally, the size of the customer contribution will be that amount that enables the system extension to just pass the discounted cash flow analysis taken from the utility perspective. However, the social perspective analysis, including consideration of externalities and using a social discount rate, may lead to modest upward or downward adjustments in the size of this contribution.

A concern was raised in the hearing that infill customers (whose connection to the system does not require a system extension) do not compensate the utility for the true costs of their connection, while new customers on system extensions would be required to do so. As a general principle, the Commission expects utility connection charges to move toward recovery of the full costs of connection and accordingly directs the Utilities to submit for approval proposals for new connection charges. In developing these charges, the Utilities should come forward with options that send an appropriate signal to consumers about the net social costs of less efficient energy use. Increasing connection charges towards reflecting full social costs will not change the amount of revenue required for a system extension, but a greater share of the revenue will be realized from the connection charge, thereby reducing the contribution in aid of construction.

In cases where a customer contribution is still required, the Commission expects that the cost would be borne by those customers benefitting from the system extension. The detailed mechanisms for determining how customer contributions would be collected are discussed in sections 7.3 to 7.5 of this Decision. The method presented by the Commission is intended to:

(1) introduce additional options for financing system extensions, thereby reducing the financing pressures on local government (i.e., use of local taxation mechanisms);

(2) reduce the incentive for prospective customers to avoid the contribution charge by not applying for connection until after the system extension has been funded and constructed;

(3) ensure that financing considerations do not, by themselves, prevent a system extension from proceeding; and

(4) ensure that those customers paying the up-front contribution are reimbursed as additional customers connect, at least for a reasonable initial period.

Finally, Chapter 9 presents guidelines to aid the Utilities in interpreting and applying the key elements of this Decision.

1.0 INTRODUCTION

1.1 Background

A generic hearing on electric or gas system extension policies of regulated utilities had been contemplated by the British Columbia Utilities Commission ("Commission") since its November 1994 Decision regarding the revenue requirements of the British Columbia Hydro and Power Authority ("B.C. Hydro"). By early 1995, the Commission had received applications from several utilities on issues related to system extensions. Several Commission Orders were issued during April 1995, informing B.C. Hydro, West Kootenay Power Ltd. ("WKP"), BC Gas Utility Ltd. ("BC Gas"), Centra Gas British Columbia Inc. ("Centra"), and Princeton Light and Power Company, Limited ("PLP") that the Commission would be deferring a decision on their applications with respect to system extension changes pending a multi-utility review of system extension policies (Exhibit 1).

On June 30, 1995 the Commission issued Order G-50-95 (Appendix A) and indicated that the five utilities listed above, in addition to Pacific Northern Gas Ltd. ("PNG"), were to participate in a generic hearing on their tests for approving system extensions. The six utilities directed to participate will be referred to hereafter in this Decision as the "Utilities". The Commission sponsored an informational workshop and pre-hearing conference for the Utilities and other interested parties on September 19, 1995. The oral phase of the hearing commenced on October 30 and ended on November 9, 1995. Written final argument and reply were filed by November 23 and November 30, 1995 respectively.

The purpose of the system extension hearing was to look broadly at the system extension policies of the Utilities to determine if opportunities existed to improve the fairness and efficiency of these policies and to make them more consistent with one another. The hearing also considered whether the system extension policies should be aligned more closely with other policies and processes in the province, such as Integrated Resource Planning ("IRP") and other social costing initiatives. It was not the intention of the Commission to focus on the specifics of any one utility's current policy or practice except in relation to a general principle or issue which should be considered more broadly.

1.2 Critical Terms

This section briefly explains some critical terms.

For the purposes of this review, a *connection* refers to the physical facilities required to connect a customer's premises to service from a utility distribution main or line, generally located in a public street, lane or road, or in a utility right-of-way. A *utility system* includes all transmission and distribution system mains or lines other than customer connections.

The term *system extensions* is a term used by both gas and electric utilities to refer to extensions to the gas or electricity distribution systems. Gas utilities also commonly refer to such system extensions as *main extensions* whereas electric utilities often refer simply to *extensions*. Since many of the basic principles for expanding utility gas or electric systems are the same, the term generally used in this Decision for either gas or electricity system extensions will be system extensions.

Expansion of the gas or electricity distribution system includes system extensions but can also include growth in the number of customers arising from infill growth. *Infill growth* refers to the addition of new customers who attach to the existing distribution system, and thus only require a connection from the street to their premises in order to receive service. Infill growth may require reinforcement of the system in order to provide adequate service, but does not require a system extension. Reinforcements of the system required for providing adequate service are termed *system improvements*. For illustrative purposes, one could view the addition of new gas or electricity extensions as accommodating dispersed growth and leading toward an extended system, while the addition of infill customers tends to create a more concentrated system.

In situations where no system extension is required, no extension policy or test is necessary to add customers. However, during the hearing, issues were raised which suggested that all new customers, those on new system extensions and infill customers, potentially cause costs to be incurred on the system. Utilities generally have *connection policies* which include the conditions of connection and charges that apply to all new customers.

1.3 Government Policy Goals

During the hearing, the Ministry of Energy, Mines and Petroleum Resources ("MEMPR") submitted a letter outlining broad energy policy goals for system extensions (Exhibit 29-A, Appendix D to this Decision). The MEMPR policy statement established eight broad goals, which the Commission has summarized as follows:

- rates which reflect costs;
- awareness of competitive forces;

- incorporation of social costs[1];
- consistency with Integrated Resource Planning;
- simplicity and transparency;
- energy efficiency;
- consistency between utilities and regions; and
- equity in contributions in aid of construction ("contributions-in-aid", "contributions") and methods of payment.

2.0 SYSTEM EXTENSION TESTS

The proposals filed by the Utilities vary substantially in both approach and level of analysis. Some of the Utilities proposed system extension tests that were essentially their existing test with perhaps some minor amendments, while other Utilities proposed significant changes.

2.1 Current Utility System Extension Tests

The existing system extension practices of the Utilities vary in the array of costs and benefits which are considered and in the complexity of the tests.

BC Gas currently uses a Discounted Cash Flow ("DCF") test methodology based on the projected 33 year revenue from a system extension compared to the necessary capital, operating and maintenance expenditures. The current test includes no upstream or system improvement ("SI") costs.

Centra Gas currently uses a one year or three year revenue requirement calculation for its system extension test, depending on which service area the proposed system extension is in.

In the PNG-West service area, system extensions of less than 30 metres are installed without reference to a system extension test. System extensions of 30m or more are subject to a 'fifth year rate of return on rate base' test which requires as a minimum that projected net revenue fully offset incremental revenue requirements in the fifth year of operation of a system extension.

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1 *Social Costs* are the total financial costs (costs for items which have prices in a functioning market) and *externalities*. *Externalities* are uncompensated effects on parties outside of a financial transaction. These are generally categorized as either social or environmental, and may be positive or negative. *Social Costing* is the inclusion of externalities in decision making and may involve full, partial, or no monetization; in the latter two cases, an alternative means of including externality considerations in decision making, such as multi-attribute trade-off analysis, would be applied.

On the PNG-NE system, the test varies according to the location and the availability of other services. Within the municipalities served by PNG, system extensions are provided without costs to the new customers (except for routine connection fees) provided that water and sewer services are available or will be provided concurrently with gas service. In areas without water and sewer services, or beyond the municipal boundaries, system extensions up to 50 metres are provided at no cost to the new customer (except for connection fees). In those areas, system extensions longer than 50 metres may be subject to a customer charge equal to the difference between the cost of the system extension and the net revenue of the first three years.

The electric utilities' tests tend to be, in general terms, a 'standard contribution approach' in which there is little recognition given to the revenues generated by new customers. Only B.C. Hydro considers revenues from new customers in any aspect of its system extension test, although it does not discount the costs or revenues.

For *economic extensions*[1] to residential customers served with single-phase service, B.C. Hydro provides each new customer with a contribution equivalent to the cost of one pole, one span of wire and ancillary equipment. For general service customers with three-phase service, the contribution from B.C. Hydro is four times the estimated annual revenue. Additionally, B.C. Hydro may contribute to *uneconomic extensions*[2] from its Uneconomic Extension Allowance fund ("UEA"), described in section 8.1.

WKP provides a maximum of $5,000 per residential customer and up to $2,000 per general service customer towards the cost of a new system extension. No contribution is provided by the utility for system extensions to new subdivisions. WKP may impose an additional monthly charge for excessively long system extensions in order to recover additional operation and maintenance costs.

PLP contributes up to $2,000, plus 50% of the remainder of the cost of a system extension for each permanent principal residence, up to a maximum utility contribution of $3,000. It will not contribute to the cost of system extensions to new residential subdivisions, nor will the utility contribute to system extensions for irrigation use. For commercial service, the utility will contribute a maximum of $2,000.

The Utilities' current system extension practices are summarized in Table 1 below.

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1 B.C. Hydro, in its tariff, defines an *economic extension* as "an extension where B.C. Hydro's normal contribution plus a customer's contribution, if required, equals the estimated cost of the extension". In effect, such extensions would not add to the costs borne by other ratepayers.

2 An *Uneconomic Extension* is defined by B.C. Hydro as "an extension required to serve at least one principal residence, a residence on a productive farm or a productive farm irrigation load and which, in the determination of B.C. Hydro, qualifies for a contribution from the Uneconomic Extension Allowance Fund".

Table 1
Current Utility System Extension Tests

Utility	Test
BC Gas	DCF Test excluding System Improvement (SI) or upstream costs
Centra Gas (CRSA)[1]	customer contribution may be required if revenues insufficient
Centra Gas (other)	one or three year revenue requirement tests for system extensions < 200 m.
PNG-West	extend if projected 5th year revenues > 5th year incremental revenue req'mnt
PNG-NE	free in municipal limits if sewer and water available, otherwise system extensions > 50 m. require charge = est. cost - 1st 3 years of revenue.
B.C. Hydro	fixed contribution or gross revenue test (4 times Estimated Annual Revenue)
WKP	fixed contribution for individual customers (not for subdivisions)
PLP	PLP contributes $2,000 plus 50% of remainder

2.2 Proposed System Extension Tests

Various proposals concerning system extension tests were made by the Utilities. Other intervenors also proposed alternative system extension tests or linked system extension tests to proposals for revised connection fee structures.

BC Gas proposed the use of a DCF test performed from the utility's perspective over a 20 year time horizon. *Discounted Cash Flow* is a method used to analyze the expected net value of a capital investment based on the incremental cash flows to the utility over some time period, adjusted at some discount rate to reflect their current value.

BC Gas also suggested that a Multiple Resource Cost ("MRC") test "... be made available to government in deciding whether public funds should be provided in support of a system extension or alternative energy forms in recognition of broader social goals." (T9: 1228). The MRC test as originally proposed by BC Gas compared the cost of gas service to an area with the cost of service with electricity, fuel oil, or propane (Exhibit 6: 95).

1 The Centra Gas Consolidated Rate Stabilization Agreement ("CRSA") applies to those areas served by Centra whose gas is supplied through the Vancouver Island Pipeline. The other (or non-CRSA) areas served by Centra include Fort. St. John, Whistler and Port Alice.

Centra proposed using a Net Present Value of Revenue Requirements ("NPVRR") test. The *Net Present Value of Revenue Requirements* shows the expected impact of a capital investment on a utility's revenue requirement based on the stream of revenues and costs expected by the utility over time and discounted to the present time period. The impact of the investment is based on the incremental addition to rate base and the returns required to service the debt and equity components of that rate base.

Centra further presented evidence to suggest that it was immaterial whether a DCF test or a NPVRR test was used, since with identical inputs both tests would yield the same investment decision. Although NPVRR includes tax impacts in the analysis, whereas DCF may not, the inclusion of taxes will not generally change the evaluation of investments.

PNG did not propose any change from its current undiscounted models, but indicated that a DCF type test would be acceptable should it be directed to adopt such a test.

WKP proposed a policy under which the utility would contribute nothing to system extensions, and would recover virtually all of its service costs in connection fees. The WKP proposal is based on the rationale that because the marginal cost to the utility of new electricity supply exceeds the marginal benefit (the customers' payment in rates), no additional customers are beneficial, and therefore each new customer would cause rates to rise (T8: 1205). WKP's position was that in this situation it should not encourage new customers by contributing to new system extensions. The WKP test could be regarded as a DCF test under the assumption that all system extensions lead to a negative return to the utility.

Neither B.C. Hydro nor PLP suggested major changes to their existing tests. B.C. Hydro submitted that it was considering the use of a net revenue test rather than a gross revenue test.

Table 2

Utilities' Proposed System Extension Tests

Utility	**Test**
BC Gas	modified DCF Test for a 20 year period and including SI costs
Centra Gas	NPV of Revenue Requirements (NPVRR) test
PNG	propose no change, but a DCF (NPVRR) test could be used
B.C. Hydro	reviewing net revenue as replacement for gross revenue test
WKP	new customers pay almost all costs
PLP	minor change to existing (PLP pays $2,000 plus 50% of remainder)

In addition to proposed tests submitted by the Utilities, two intervenors made specific proposals relating to system extension tests or customer connection charges. The intervenors were the BC Energy Coalition ("Energy Coalition") and the Renewable Energy Association of B.C. ("REA"). Their proposals are summarized below in Table 3.

The Energy Coalition proposal focused on the connection charge, which would apply to all new customers including those who would be connected to the existing gas or electricity grid, rather than focusing primarily on only those customers who would be connected to a system extension of the existing system. The Energy Coalition proposed that the customer connection charge be based on the marginal costs of service to new customers, and that these new connection charges should be complemented by a system of credits based on the efficiency ratings of the appliances installed for a new customer. The Energy Coalition also proposed that electric utilities adopt a policy which allowed 'net billing', whereby electricity purchases by consumers from utilities would be offset by surplus self-generated electricity returned to the utility by consumers.

The REA proposal might best be summarized as an extended DCF method. Under the REA mechanism a utility would offer a system extension in exchange for a one-time payment equal to the difference between the present value of the total incremental cost of supply by the system extension and the present value of prospective customer bills. However, the REA proposal differed from other DCF proposals in that it would discount the cost of the system extension at either a social or utility discount rate, while the customers' bills would be discounted at a customer's discount rate which is typically much higher. Moreover, the cost of supply would include all incremental costs including the cost of electrical energy or of wholesale gas, capacity within and upstream of the distribution system, and monetized environmental externality costs. The REA argued that its proposal would lead to: "... full-cost pricing of line extensions, elimination of cross-subsidies among customers and an open competitive market for alternatives to distribution systems." (T9: 1308).

The REA also suggested, as an interim measure, that all Utilities be required to pay for a site visit and an energy potential assessment in all situations where the cost of a system extension exceeded $10,000, in order to enable customers to compare the cost of a system extension to that of site based supply (T9: 1309).

Table 3

Intervenor Proposed System Extension Tests

Intervenor	Test
Energy Coalition	connection charge based on Long Run Marginal Costs (LRMC) and efficiency credits
REA	DCF comparing all incremental and environmental costs discounted at utility discount rate to customer bills discounted at customer discount rate

Options for system extension tests are discussed further in section 4.1.

3.0 INTER-UTILITY CONSISTENCY

The MEMPR policy letter stated that:

> " ... utility extension policies should be as consistent as possible. Consistency enables the Commission to analyze and compare similar applications, and ensures the equitable treatment of communities or individuals requesting utility service." (Appendix D).

A key question before the Commission is the extent to which consistency in utility system extension policies is possible and desirable. Both PNG and PLP indicated during the hearing that they looked forward to a Commission decision which would set out a framework or guidelines for utility system extension policies and, within that framework, each utility would work out a system extension policy adapted to its individual circumstances (PNG, T4: 577; PLP, T7: 1005). B.C. Hydro also agreed that it would be desirable to have some degree of consistency among the Utilities (T6: 852).

The Commission concurs with the provincial policy statement and has concluded that the basic method for evaluating system extension proposals should be consistent for all Utilities. Nevertheless, the Commission notes that similarity in method does not necessarily imply that either the specific values which are entered into the analysis, or the detailed calculation method, will be identical from utility to utility. Where the use of common inputs or methodologies appears to lead to improved decision making, this will be encouraged by the Commission. However, where the cost structures which underlie the production and delivery of energy differ from utility to utility, the Commission believes that there is an equally strong argument for encouraging each utility to use values appropriate to its individual circumstances.

The Commission determines that there shall be one general form of system extension test for the Utilities. However, the Commission recognizes that neither the values used as inputs into the analysis of proposed system extensions, nor the detailed calculation method, need necessarily be the same for each utility.

4.0 SYSTEM EXTENSION TEST METHODOLOGIES

4.1 Options for System Extension Tests

A key issue is to determine the appropriate system extension test. Not all Utilities in the hearing proposed an economic test that formally evaluated the relative costs and benefits of any proposed system extension. Furthermore, not all of the approaches put forward by the Utilities enabled the determination of the appropriate level of utility contribution toward a system extension. While the DCF test, or even comparisons of undiscounted costs and benefits, attempt to assist the utility in determining the optimal investment by the utility in a system extension, other types of policies simply provide a fixed or variable contribution from the utility regardless of the costs and benefits. For the purposes of the discussion, five general types of approaches that were raised in the hearing are listed below.

(1) Undiscounted Net Revenue Tests

Commonly, utilities used system extension tests that compared the net revenue to be received over a certain time period to the cost of the system extension (e.g., for gas utilities, net revenue would be essentially the gross revenue less the cost of gas). The test used by PNG for some system extensions in its NE division would fall into this category, as would B.C. Hydro's 'four times estimated annual revenue' test for three-phase general service system extensions.

(2) Tests which Adjust for the Time-Value of Money

Cost-benefit analyses commonly adjust the flows of costs and revenues to account for the time periods in which the costs are incurred or the revenues received. This is done through 'discounting' the costs and revenues. Both the DCF and NPVRR approaches use discounting to compare the costs of serving new customers with the revenues to be received over a standard time-period.

(3) Fixed Contribution Tests

Another common type of approach is one which allows for a fixed contribution to a system extension by the utility, such that all expenses above the utility's contribution limit are paid by the new customer(s).

B.C. Hydro's current policy for residential single-phase service extensions is of this type. This approach does not constitute a cost-benefit methodology, although it can be considered a system extension test insofar as the customer applying for service must agree to pay the required customer contribution.

(4) Fixed and Variable Contribution Tests

Another approach is one which bases the utility's contribution to a system extension on a formula having a fixed and a variable component. For example, PLP's current test provides for a fixed contribution of $2,000 to residential system extensions, along with a variable component based on 50% of the remainder of the cost up to a maximum contribution of $3,000. As with the fixed contribution test, this type of policy does not constitute a cost-benefit test.

(5) User-Pay Approaches

'User-pay' approaches simply require that any new customer(s) pay the full cost of connection. Such a practice is not a test in the conventional sense, but could be based on the results of an economic analysis of the utility's marginal costs (which would justify such a practice if the incremental costs to the utility in all situations equaled or exceeded the incremental revenues) or may be based on other considerations. WKP has adopted a user-pay test based on its marginal cost analysis.

A 1994 report, prepared for BC Gas by RCG/Hagler Bailly (Exhibit 11A), surveyed the system extension tests of 14 North American utilities. The report indicated that in general three approaches toward system extension tests were used:

- undiscounted comparison of revenues and costs over several years;
- discounted cash flows over several years, considering costs and revenues strictly associated with the system extension; and
- discounted cash flows over several years, considering costs and revenues associated with a system extension including incremental system reinforcement costs.

The report (p. 3-3) indicated that approximately half of the utilities surveyed used a DCF model to determine the cost effectiveness of system extensions and the level of any required customer contribution.

The DCF and the NPVRR tests can be seen as functionally the same test in that, given similar inputs, they should yield the same investment decision. In this respect, BC Gas and Centra have proposed similar tests. Although PNG did not propose a specific DCF or NPVRR test, it suggested that such a test would be acceptable.

The Commission believes that the adoption of a DCF type test or its equivalent (such as NPVRR) by all of the Utilities, whether gas or electric, would result in increased inter-utility consistency and improved decision making with respect to utility investment in system extensions. Furthermore, the Commission agrees with the position put forward by BC Gas that the term of the analysis should be consistent with other investment analysis undertaken by the utility, such as IRP, and should reflect a reasonable expectation of the economic life of the investment (T9: 1234-35).

Additionally, even where elements of natural monopoly remain, there is an argument for regulated monopolies basing investment decisions on incremental costs and revenues in order to promote economic efficiency. Although public utilities commissions have several goals, they seek competitive-like outcomes. This approach attempts to minimize the market failures of natural monopoly and ensure that consumers face price structures which reflect marginal costs, just as they would in competitive markets. In this way, regulated prices are not a barrier to economic efficiency.

The Commission directs all of the Utilities to develop a DCF based system extension test, and submit it for Commission approval no later than May 31, 1996. The costs included in the system extension test proposals should be based as much as possible on full incremental costs. Moreover, the period during which customer revenues and costs are included in the calculation of the test should be consistent with the time periods used in each utility's IRP.

4.2 Discount Rate

During the hearing, different views were expressed on the appropriate discount rate for system extension tests.

For its DCF test, BC Gas recommended the use of a real after-tax discount rate for DCF analysis, a real social discount rate (8%, the same as B.C. Hydro) for its Multiple Resource Cost test and the current five year mortgage rate less inflation for its participant test (Exhibit 6, p. 97). BC Gas also indicated that its choice of discount rate should be consistent with other investment analyses conducted by the company, stating that:

> "BC Gas believes that the capital investment analysis tools used within the Company should generally be aligned with the IRP. Accordingly, BC Gas supports the use of the same set of input assumptions for costs, revenues and utility discount rates consistent with those used in the IRP for evaluating other utility investments." (T9: 1228).

BC Gas went on to suggest that the social discount rate was appropriate from a social perspective, but argued that the utility's perspective and utility discount rate should be used.

> "If a social perspective is desired that encompasses both the utility and the ratepayers' perspectives (as in the MRC test), then a social discount rate should be applied to both revenues and costs. BC Gas believes that the appropriate perspective to consider when evaluating a utility capital investment is the impact of the investment on ratepayers. Accordingly the utility's discount rate should be used." (T10: 1439-40).

Centra proposed using the approved return on rate base, including any inflation component which may be implicitly incorporated, on a pre-tax basis (T3: 472). Evidence submitted by Centra with its proposal suggested that use of a pre-tax discount rate would be identical to that using an after-tax discount rate if certain adjustments were made in the analysis (Appendix C of Exhibit 15A).

The REA proposed that, for the purposes of calculating the size of the customer's required contribution, the revenues from the customer should be calculated at the customer's discount rate, and that a utility, in deciding whether or not to proceed with a proposed system extension, should use the social discount rate (T7: 1088, 1097). By applying a higher discount rate to the customer's bill payments over time, for the purpose of calculating the customer's contribution to the utility, the REA proposal seeks consistency from the customer's perspective in the comparison of a system extension contribution relative to an investment in a non-grid energy alternative. However, this approach would result in a utility requiring a greater contribution from the new customers on a system extension than is required to offset the utility's real financial costs. Elsewhere in this Decision the Commission shows that it is willing to have this occur in a limited way with respect to the incorporation of externality considerations. However, the Commission is less confident of the social value of having utilities require an additional contribution in this case. As with demand-side management, differences in implicit discount rates are increasingly seen as insufficient by themselves to justify transferring money to or from customers.

In the Commission's view, the considerations when determining the appropriate discount rate for system extensions differ little from other applications of the discount rate in utility decision making. Indeed, it is desirable that a consistent approach to discounting be applied both within an individual utility and among different utilities.

Furthermore, the Commission believes that a social discount rate should be used for evaluating projects from a social perspective, and that the utility's discount rate should be used when evaluating projects from a ratepayer and shareholder perspective. The requirement to accommodate both a social and a utility perspective can be achieved by engaging in two calculations: one which adopts a social cost-benefit perspective, and one which adopts a private investment perspective, with each calculation using the discount rates appropriate to its perspective. A system extension's performance with respect to both tests is important. This approach corresponds to the current approach of the Commission with respect to DSM, for example, wherein the societal cost test would apply a social discount rate while the rate impact test would apply a discount rate based on the utility's cost of capital.

An appropriate social discount rate would be the one adopted or mandated by the provincial government for public investment projects by ministries or crown corporations such as B.C. Hydro.

The Commission directs the Utilities to conduct evaluations of system extensions both from a social perspective and a utility perspective. For the social perspective, the Utilities are to apply a social discount rate and for the utility perspective, a discount rate based on the utility's cost of capital. In cases where these two analyses lead to conflicting results, additional evaluation will be required as illustrated in Chapter 6. For reasons discussed above, the Commission is not prepared at this time to adopt the REA proposal for applying the customer's discount rate for one component of the calculation.

4.3 Aggregated versus Disaggregated Information

The issue of aggregated versus individual system extension tests was well canvassed in the hearing. Both Centra and PNG proposed some level of aggregation of possible system extensions.

PNG currently does not subject system extensions shorter than 30 metres to any sort of system extension test, and during the hearing submitted that if it were to do so, the costs of such analysis would outweigh the benefits. PNG suggested that any system extension of less than 30 metres would be virtually certain to pass any test and that removing the requirement for formal analysis of such short system extensions would reduce the administrative cost without measurably increasing the risk. In essence, PNG has adopted a policy of no system extension test and zero contribution for any system extension less than 30 metres. For longer system extensions, PNG suggested that system extensions be considered under both an Individual Performance Threshold ("IPT") and an Aggregate Performance Threshold ("APT"). The IPT value would necessarily be equal to or less than the APT and the system extension proposal, in order to proceed, would be required to meet both the IPT and the APT.

Centra indicated that on Vancouver Island it allows its district sales managers to pool all system extensions less than 200 metres in length. Each district manager is required to ensure that during any year the sum of all system extensions passes the test. Centra stated that in order to reach areas of new development, where demand would be relatively high, it had to extend its system through a band of established development where the potential to capture new customers was limited, making the system extension less economically viable. Thus, the utility pooled system extensions on Vancouver Island in order to justify extending the system through established areas to areas of new development (Exhibit 15B, T3: 497-8). An additional argument raised by Centra in favour of aggregation of system extension proposals is that the practice leads to administrative efficiencies by reducing analytical work (T3: 461-64).

Alternatively, other utilities, namely WKP, PLP and BC Gas, submitted that system extension proposals should be analyzed individually, except where system extensions to contiguous areas offered operational cost savings and these savings could be realized by treating several system extensions as a group. Some intervenors took a similar position. Consumers' Association of Canada (B.C. Branch) et al. argued that aggregation of system extension proposals was a "... disguised, arbitrary manner of determining that some new customers will subsidize others they are grouped with ..." (T9: 1386). Methanex Corporation ("Methanex") also argued that system extension proposals should not be analyzed in aggregate since this would allow system extensions to proceed that were uneconomic on their own, thereby inhibiting achievement of economies of scale (T9: 1425).

In general, the Commission agrees with those parties who argued that system extension proposals should be analyzed individually. As the Commission stated in its October 25, 1993 Decision regarding the BC Gas Phase B Rate Design Application:

> "If a natural monopoly exhibits economies of scale (as they do frequently but not always), increases in output should lead to lower costs for all customers, and that is a desirable social outcome. The Utility should not be encouraged by the regulator to, in effect, include uneconomic extensions in order to prevent the realization of economies-of-scale under the auspices that somehow these economies-of-scale effects represent a subsidy from new customers to existing customers." (p. 29).

However, the Commission is aware of the need to balance goals and objectives from time to time, and notes that there may be some special circumstances where aggregation of system extension proposals are justified. In this instance, the Commission notes that utilities such as B.C. Hydro and WKP submitted that simplicity and ease of understanding were appropriate goals for a system extension policy. MEMPR also suggested that simplicity and transparency were appropriate goals, and that a system extension test "... should not create an unreasonable administrative burden for utilities." The Commission believes that one way to ease the administrative burden on utility personnel, is to permit the adoption of a simple test for those system extension proposals having a high probability of passing the test that is normally applied to more complex proposals.

The Commission is willing to consider proposals for treating short, routine system extensions in a simpler manner than longer, more complex and costly system extensions. For example, proposals might include treatment requests for short system extensions in a manner similar to a uniform connection charge. The fee for routine system extensions may vary between the Utilities depending on each utility's incremental costs of extending the system and adding new customers.

With respect to the aggregation of longer system extensions, the Commission believes that there may be situations where two or more system extensions should be reviewed in aggregate. One situation could be where the grouping of contiguous system extensions would likely lead to cost savings due to efficiencies in construction. There may also be situations where an initial system extension that is uneconomic is required prior to a subsequent further system extension which would render the aggregate result economic.

The Commission determines that, in general, aggregation of proposed system extensions should not occur. However, as noted above, there may be situations where the benefits of aggregation exceed the costs and, where this can be demonstrated, the Commission will allow it. The Commission will also consider specific proposals for dealing with routine, short system extensions when the Utilities make their individual system extension policy filings. These proposals should be based on the incremental cost of extending the system and adding new customers.

5.0 COSTS AND BENEFITS OF SYSTEM EXTENSIONS

Once the general form of the test has been decided upon, secondary but important considerations include the inputs into the test and the ways in which the test is applied. These include which costs and benefits should be used.

5.1 Direct Costs and Benefits

The usefulness of the economic analysis of proposed system extensions will depend to a large extent on the appropriateness and quality of the specific costs and benefits entered into a DCF type test. Moreover, as noted in section 4.3, the benefits of the analysis only exist to the extent that the marginal benefit of more detailed analysis exceeds the cost.

The most significant and easily attributable direct costs of a system extension are the capital costs associated with its construction. These are readily identifiable, although issues remain concerning the accuracy of construction cost estimates and whether associated costs, such as the costs of the service connection or system improvements, should be included in the calculation. These issues are discussed in subsequent sections.

5.1.1 Estimates versus Actuals for Construction Costs

When an economic feasibility test is applied to a proposed system extension, estimates of the construction costs must be used. The estimates of construction costs may be specific to the particular system extension or may be based on average costs. Evidence during the hearing suggested that some utilities use estimates based on average per unit costs while other utilities rely more heavily on site-specific cost estimates for each system extension. Even where site-specific estimates are used, the estimates must be based on historical data and the validity of the estimate will depend on both the quality of the historical data and the appropriateness of the application of that data to the specific system extension under consideration.

With respect to customer contributions, the Commission believes that it is generally preferable to base the customer contribution on the estimate of costs rather than on actual costs, because customers are expected to want certainty of the contribution amount before they decide whether or not to proceed. However, this approach brings the accuracy of the estimate into focus because of the implications for other utility customers if there is an under collection.

During the hearing, there was some discussion of the degree of accuracy of construction cost estimates compared to the actual costs of past system extensions. Information from some of the utilities indicated significant variances.

The Commission expects the Utilities to ensure that estimates are as accurate as possible without adding substantially to the administrative workload associated with estimating system extension costs. The Commission will rely on prudency reviews to examine the accuracy of system extension estimates.

5.1.2 System Improvements

Another issue was whether system improvement ("SI")[1] costs should be included. System improvements can be required by a specific system extension, by the general growth of new infill customers, or by additional demand from existing customers.

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[1] Some utilities, notably B.C. Hydro, use the terms system improvements and system reinforcements to mean different things: system improvements referring to upgrades on the distribution system and system reinforcements referring to upgrades on the transmission system. Most gas utilities use the two terms interchangeably. This Decision will use the term system improvement to mean any upgrade to the system whether it occurs on the distribution or transmission system.

BC Gas supported the use of incremental SI costs in the economic system extension test, although it submitted that some practical matters required resolution in order to do so appropriately (T9: 1238-39). As BC Gas stated in Exhibit 7:

> "Previously, the Company has been reluctant to include certain capital costs in its main extension test given the difficulty in accurately determining and allocating such costs. General system improvement costs for projects such as the Surrey-Langley Loop and the South Okanagan Natural Gas Pipeline are examples of projects that benefit both new and existing customers. However, through the Integrated Resource Planning process the Company has gained considerable experience with long run incremental cost studies and other analysis. We believe we can explore the inclusion of additional costs in the main extension test with more confidence in their accuracy."

BC Gas also argued that the inclusion of other upstream costs, as reflected in gas costs or revenues, would be inappropriate as it could lead to double charging of customers making contributions to new system extensions, and could also encourage bypass of the BC Gas distribution system.

Methanex submitted in final argument that all incremental operating and construction costs to serve new peak-day requirements should be considered, including SI and other future costs (T9: 1426).

As indicated in section 4.1, the Commission requires that the DCF test should be based as much as possible on full incremental costs. This implies that recognition of required SI costs should be included to the extent that those are required by added load from system extensions.

In general, SI costs should be allocated as fairly as possible to those who cause them so that those SI costs caused by new load on existing systems (e.g., by infill customers) should be included in the connection charge rather than the system extension test. However, the Commission recognizes that SI costs are likely to be small in most cases.

The Commission determines that SI costs shall be consistently applied, on a cost causation basis, in system extension tests and in connection fees. Each utility should include SI costs in a manner that does not make the system extension test or connection fee unnecessarily complex. Furthermore, where the utility can demonstrate that the administration costs exceed the benefits of determining and including certain cost elements, it may exclude them.

5.1.3 Calculation of Revenues

Gross revenues for an energy utility would include revenues on unit sales of energy, plus basic charges, plus any associated additional revenues such as connection fees and third-party revenues[1]. The calculation of unit sales are a function of the number of customers who attach to a new system extension and the consumption of energy by each customer.

Although there may be the opportunity to ask for and receive revenue guarantees in some situations, estimates of gross revenue in system extension tests are usually based on the number of customers who are expected to connect to the system extension over some time period and the anticipated revenue per customer. BC Gas suggested that the forecast period for customer additions should be limited to five years because of the greater forecast uncertainty for longer periods (T9: 1237-8).

All utilities recognize, to varying degrees, the revenue collected from new customers as an offset to the capital cost of the system extension. Some companies recognize that only a part of customers' gross revenue offsets a system extension, while other revenue relates to cost of the commodity, cost of upstream transmission providers, and general operating and capital costs of the whole system.

During the hearing, the Energy Coalition suggested that the margin or net revenue calculation that gas utilities typically make in system extension tests could be negative, rather than positive, if the calculation included environmental impacts and long run rather than short run marginal costs (Exhibit 12, p. 5). BC Gas suggested that an allocation of incremental maintenance and overhead costs, as well as the capital cost of the system extension, be included in a DCF calculation (T9: 1238).

The Commission now expects greater precision in the determination of the costs caused by system extensions, including related SI costs and operating and maintenance costs. It is therefore appropriate to also require greater precision in the determination of the net revenue which offsets these costs. The Commission recognizes that certain costs can either be ignored in the net revenue calculation, and included in the cost component of the DCF test, or treated as a deduction in the net revenue calculation. Typically, costs which have been treated as a deduction in the net revenue calculation are those which have been most appropriately calculated as a per unit cost, such as the cost of the commodity or of transmission.

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1 Third-party revenues in this context refers to revenues such as those paid to an electric utility by a telephone or cable television company for use of the electric company's poles.

The Commission determines that the test should consider all revenues estimated over the test period and should be based on at least the customer additions forecast for the first five years. The costs which should be deducted from gross revenue to calculate net revenue shall include the cost of commodity and upstream transmission charges.

In addition, to the extent that the Utilities can quantify incremental maintenance or overhead costs, these should also be included in the DCF test. If these costs are most easily expressed on a per unit of energy basis, they would be appropriately included in the net revenue calculation. As noted previously, where the utility can demonstrate that the administration costs exceed the benefits of determining and including certain cost elements, it may exclude them.

5.2 Externalities

Most but not all of the utilities were opposed to including social or environmental externalities in a system extension policy. They argued that, unless all regulated and unregulated energy forms were equally subject to externality regulation, then regulated energy forms would be operating under a handicap. Nevertheless, no evidence was provided to suggest that price elasticities were such that any material market distortion would result from the inclusion of social costs in utility system extension tests.

The MEMPR broad policy goals, stated that utility financial costs should not be the sole criterion in evaluating potential system extension projects, and that:

> " ... environmental and otherwise non-priced social impacts also require consideration and should be balanced against financial costs and benefits to utilities and customers served by the extension." (Appendix D).

Both the REA and the Energy Coalition supported the inclusion of externalities in system extension tests. The REA argued that this should be done through explicit monetization and charges for social and environmental impacts (T9: 1314). The Energy Coalition argued that this should be accomplished by way of a combination of cost-based fees and credits for installing efficient appliances (T9: 1339).

Another area of discussion concerning social costs or benefits involved economic development as a social objective, specifically as a key factor underlying B.C. Hydro's Uneconomic Extension Allowance policy. The UEA is discussed further in section 8.4. However, with respect to its policy for economic extensions, B.C. Hydro indicated that it was reviewing the potential to incorporate social costs, but that it did not currently intend to do so (T6: 867). Although B.C. Hydro acknowledged (Exhibit 19F, p. 2) that the Commission, in its 1994 Decision, had clarified that charges for services should reflect the full social cost, the utility indicated during the hearing that it had not complied with the Commission direction (T6: 973).

Another argument against inclusion of externalities was that it may not be possible to accurately monetize them. However, under cross-examination, B.C. Hydro acknowledged that neither the Crown Corporation Secretariat's Multiple Account Evaluation Guidelines nor the Commission's Integrated Resource Plan Guidelines required monetization of externalities in order to consider them in utility decision making (T6: 973-74).

In the Commission's view, monetization is not necessary for inclusion of social costs in a system extension test. Although consistency in the valuation of social and environmental impacts is highly desirable within each utility, among utilities, and among regulated and unregulated energy sources, an element of consistency can be achieved through various non-monetization methods, such as multi-attribute trade-off analysis ("MATA")[1], in conjunction with monitoring and coordination by the Commission or other government agencies. The Commission acknowledges that consistent application of social costing principles will take time to develop and notes that further progress on social costing is anticipated both by the Commission and by relevant government ministries.

Exhibit 6 is the document entitled <u>Alignment of the BC Gas Utility Ltd. Main Extension Test with Integrated Resource Planning</u>. This document was prepared by BC Gas in compliance with the Commission direction, in the 1993 Rate Design Phase B Decision, that BC Gas file proposals to align its system extension test with Integrated Resource Planning and standard demand-side management tests. While presenting this document in compliance with the Commission direction, BC Gas did not adopt the document as its system extension policy proposal.

The Commission appreciates BC Gas' efforts in producing this document and finds it to be helpful in assessing the alternatives for incorporating Integrated Resource Planning principles (full financial costs and externalities) in system extension tests. Table 7-1 of the document presents an evaluation of system extension test options on the basis of the following criteria:

- minimize energy service costs;
- provide equitable policy;
- maximize customer satisfaction;
- move towards sustainability;

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1 *Multi-Attribute Trade-off Analysis ("MATA")* is a method of social costing which does not require full monetization, but instead requires that various effects (financial, social, environmental, etc.) are recorded in accounts to facilitate trade-off decision making.

- maximize social and regional economic benefits; and
- provide quality shareholder returns.

Six system extension test options were considered, ranging from reliance on a Multiple Resource Cost ("MRC") test to reliance on a DCF test which included both SI costs and environmental impacts. Table 7-1 is attached to this Decision as Appendix E.

The evaluation of the various alternatives set out in Appendix E was canvassed in some detail by counsel for the REA, counsel for the Energy Coalition and by Commission counsel, especially concerning the reasons for the low rating of Option 6, a DCF test including SI costs and externalities. During the discussion, BC Gas agreed that the inclusion of SI costs and externalities in a system extension test, or the exclusion of such costs from the test, did not imply that those costs were not present, but simply reflected whether new customers or existing ratepayers would bear those costs (T3: 340). BC Gas also agreed that if it were to re-evaluate the rankings of the options in Appendix E at the time of the hearing, it might arrive at a different set of rankings.

Based on the evidence, the Commission believes that a different set of rankings than those found in Appendix E is appropriate. The Commission finds Option 6 (DCF test and SI costs and externalities) to be the most appropriate option. Elsewhere in this decision, the Commission has determined that the DCF test (or a close approximation such as NPVRR) should be used, that SI costs should be included where feasible, and that both a social and a utility discount rate should be used.

The Commission directs all of the Utilities to incorporate, to the extent that it is feasible, the consideration of externalities in their system extension tests.

For clarification, the Commission offers the following example for including externalities in system extension tests.

First, for system extension proposals to connect discreet communities, a utility would conduct a MATA process, with public consultation, to determine the least-cost (based on social costs) means of meeting the energy services of that community. This would include both a utility and a social cost evaluation, considering conventional and renewable energy alternatives. The analysis should be commensurate with the size of the investment, in much the same way that the Commission requires substantially simpler IRP processes from small utilities.

Second, for smaller system extensions, the utility would use trade-off information from its IRP and its analyses of large system extensions (if any) to guide its consideration (perhaps even implicit monetary valuation) of externalities. Because of the smaller cost and the need to make many decisions during the course of a year, some screening techniques need to be developed. For example, preliminary DCF calculations may eliminate from further analysis those system extensions which would fail by a significant margin a financial utility cost test and for which it is unlikely that customer contributions could offset high costs. Likewise, it may be possible to eliminate some system extensions at the screening level after preliminary externality valuation.

In either case, the Commission recognizes that the inclusion of externality considerations in system extension tests creates the same kinds of challenges that arise when externalities are considered in resource selection, resource dispatch and rate design.[1] Unless externalities have been completely monetized, and then incorporated in government mandated externality taxes, the inclusion of externality considerations requires methodological and empirical approximations.

6.0 COST ALLOCATION: WHO PAYS

An important aspect of a system extension test is that it determines who pays for what proportion of the total costs of a system extension. A test result which recovers less than the total cost of construction will either require a contribution-in-aid from those receiving the new service, or require a subsidy from other customers, usually in the form of an addition to the utility's rate base. Without a contribution, the total charges to the new customers served by such a system extension will not reflect the total cost of serving them, leading to possible distortions in their decision making.

One of the broad energy policy goals submitted by MEMPR (Appendix D) indicated that the prices charged for utility services should as much as possible reflect the costs of providing service. The Commission agrees with this policy goal.

Some costs may be caused by new customers on the existing electricity or gas distribution system ('infill customers') as well as new customers on new system extensions. For example, the SI costs needed to maintain minimum pressure in the gas system would be costs resulting from customer additions no matter where they have occurred.

A challenge in the evaluation of a system extension proposal is to properly allocate the costs that new customers cause on the gas or electricity system. If costs are caused by new customers on a new system extension, and if a policy is adopted which attempts to align charges and costs, then those costs should be charged to the new customers on the new system extension, perhaps through a contribution-in-aid. If

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[1] The Commission's recent Discussion and Policy Paper on Social Costing, dated February 1996, examines in detail these challenges.

certain costs are caused by new customers on both new and existing mains, then these costs should be recovered as much as possible through a connection charge which targets all new customers. Specific issues of cost collection are discussed in Chapter 7 below.

The Commission believes that, insofar as is practical, a system extension test should reflect the incremental costs and benefits resulting from the system extension being analyzed, and that the costs of the system extension should be allocated to those customers who cause them.

As discussed in section 5.2 above, consideration of social or environmental externalities in a system extension test could provide justification for system extensions which would not proceed on strictly financial terms. In such situations, there could be a rationale for a party other than new customers attaching to the new system extension to contribute to it. Alternatively, social or environmental externality costs in a system extension test could weigh against a system extension which might have proceeded had it been evaluated only on financial criteria.

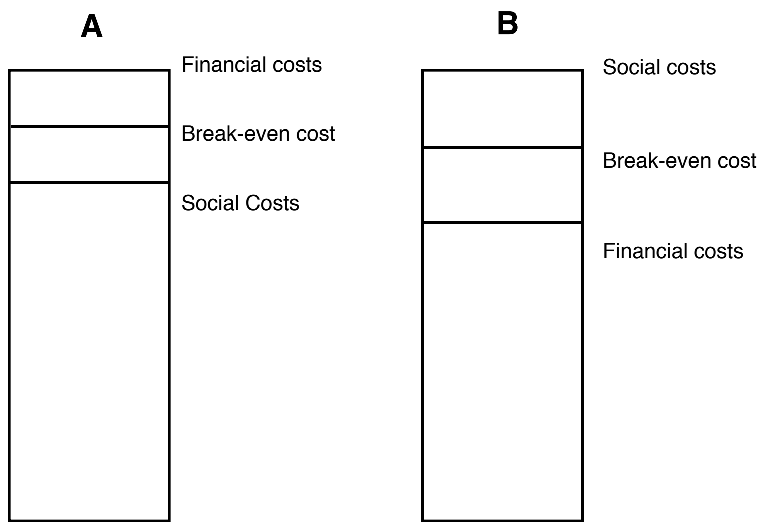
The following method is presented as an example to guide the Utilities in making these evaluations.

Figure 1 refers to two different system extensions, A and B. The revenues are presumed to be identical for each and are excluded from the analysis. Financial costs include all incremental costs for each system extension. Break-even costs are the level of financial costs that exactly offsets revenues over the test period. Social costs are financial costs plus (or minus) externality costs (or benefits).

In case A, the financial costs exceed the break-even costs. The utility would not undertake this system extension on a strictly financial cost basis without a sufficient customer contribution to offset the difference. However, a MATA process may use monetized externality values (in this case benefits) and estimate a social cost line below the break-even cost line, or may simply arrive at the judgment (without specific monetary values) that the externality benefits exceed the excess financial costs. In this case, the customer contribution may be reduced (or even set to zero) from the amount that would have been required to cover the entire difference between financial cost and break-even cost. In effect, all other customers would contribute the additional amount needed to balance financial costs and break-even costs.

There is an important qualification. The Commission agrees with the argument that utilities should not be required, on the basis of social costing, to undertake expenditures that in aggregate have onerous rate impacts. Thus, inclusion of externality considerations in system extensions, as in other utility endeavors, must include monitoring that allows each utility and the Commission to track the rate effects. This means that the size of the contribution from other customers to a particular system extension should be limited. In their system extension filings, the Utilities should propose parameters to guide this evaluation.

Figure 1



•Break-even cost is the level of costs which equals revenues from the extension over the test period.
•Social costs are financial costs plus (or minus) externalities.

In case B, the break-even costs exceed the financial costs. The utility would undertake this system extension without requiring a customer contribution. Indeed, installing this system extension benefits all customers by the difference between break-even costs (these being equivalent to revenue) and financial costs. However, a MATA evaluation may lead to the conclusion (via explicit externality monetization or judgment) that the incremental social costs exceed the break-even costs. In this case, the utility should require a customer contribution to offset the amount by which the break-even costs are exceeded. If externality values could be monetized, the size of the contribution could be determined precisely. In the absence of such values, the utility and the Commission will need to judge the magnitude of the externality effects, probably by setting a percentage 'cost adder'.[1]

The extra revenue earned by the utility in case B would be no different than the revenue currently earned when utilities make profitable system extensions; it becomes a benefit to all customers. However, there may be some concern with utilities earning extra revenue due to externality considerations and then passing

1 This would be similar to various externality adders applied by North American utilities commissions for incorporating externality considerations especially with respect to evaluating demand-side management expenditures.

this revenue on to their other customers. In the Commission's view, this revenue will not be significant and is likely to be offset by the extra subsidies required for the system extensions described in case A. In cases where utilities find that this general outcome does not occur, they should submit alternative proposals to the Commission.

In their new system extension test filings, in response to this Decision, the Utilities shall develop specific policies for inclusion of externality considerations in their calculation of the system extension's attractiveness and the size of the customer contribution if any. Where the consideration of social costs in a system extension test changes the financial test outcome from uneconomic to economic or vice versa, such system extension shall be submitted to the Commission for its review and approval prior to construction or rejection. This procedure will assist in achieving a uniform treatment of social costing criteria for the Utilities in the absence of monetization. The Commission anticipates that this procedure will only be required on an interim basis, until such time as the Utilities develop greater comfort with the application of social costing.

7.0 COST COLLECTION: HOW TO PAY

7.1 Connection Charges

Where required, costs may be recovered from new customers on system extensions through mechanisms such as contributions-in-aid, which may be paid as a lump sum or as a surcharge on customers' bills over time. Other costs may be recovered from all new customers throughout the system via connection charges. For these reasons, the Commission views the issue of connection charges and system extension tests as intimately linked.

Incremental costs to the gas or electricity system are caused by new customers attaching to system extensions, as well as by new customers attaching to the existing system, that is, infill customers. To the extent that incremental costs are common to all new customers (both infill customers and customers attaching to new system extensions) these common costs would be most fairly allocated through a connection charge which applies to both categories of new customers, rather than through a system extension test which applies only to those new customers attaching to system extensions.

The Energy Coalition focused on connection fees rather than system extension policies. Specifically, the Energy Coalition recommended a connection charge for electricity comprised of two parts: a charge tied to the cost of the actual facilities installed at the site, and a per-kilowatt charge designed to recover the marginal costs of generation and transmission above those embedded in rates. For natural gas service, the Energy Coalition recommended a cost-based charge coupled with credits for appliances or building practices which are more efficient than required by applicable codes.

BC Gas in final argument also indicated that "... consideration should be given to adjusting the service attachment policy to reflect the incremental costs imposed on the system as a result of the additional load." (T9: 1250-51). However, BC Gas argued that concept of energy efficiency credits proposed for a gas connection charge was overly complicated and could result in incorrect cost allocations among customers (T10: 1440-41).

WKP indicated that its connection fee, which increases by 50% (from $2 to $3 per ampere) above 100 amps, already provides an incentive similar to that proposed by the Energy Coalition (T8: 1217).

In the Commission's view, a connection charge designed to recover the full cost of the service connection will provide two benefits. First, it will promote more accurate (hence fairer) cost allocation between customers whose connection to the system does not require a system extension (infill customers) and customers on new system extensions. Second, to the extent that a greater share of costs are captured in the connection charge, rather than in the customer contribution on new system extensions, the policy will reduce the incentive for 'free-riders' who avoid paying a customer contribution on system extensions by waiting out the contribution period.

The Commission directs the Utilities to design, and submit to the Commission for approval, connection charges which move toward recovery of the full cost of the service connection up to but not including the meter. As noted in section 5.1.2, this should include incremental costs such as applicable SI costs. In addition, in developing new connection charges to comply with this Decision, the Commission directs the Utilities to come forward with options for connection fees that send an appropriate signal about the net social costs of less efficient energy use.

A related issue is whether the cost of the connection and the connection charge should be included in the system extension test. Some utilities, such as BC Gas, currently include connection costs and fees in the system extension test (T3: 336, 349). Of course, if the revenue received from the connection fee offsets the cost of a service connection, these two items could be netted out of the DCF test. However, evidence during the hearing indicated that for some utilities the connection fee is not sufficient to offset the cost of the service connection (T3: 336, T3: 493, T7: 1038). Therefore, the Commission finds that, until such time as there is a general correspondence between the connection cost and the connection charge, the cost of the service connection should be considered in the system extension test.

The Commission expects that the Utilities will adjust their connection charges in the direction of full-cost recovery. However, at this time the Utilities are directed to include the cost of the service connection and any revenues to be received from connection charges in their system extension test.

7.2 Contributions in Aid of Construction

If a system extension test indicates that a given system extension would create a shortfall of benefits relative to costs, that shortfall may be made up by contributions-in-aid. Generally, the goal of prices which reflect the cost of providing service suggests that any required contribution should be provided by the customers who will receive service from a system extension.

As noted in section 5.2, consideration of social or environmental externalities in a system extension test may justify system extensions which would not proceed on strictly financial terms. In these instances, the externality consideration could also provide a rationale for a party other than new customers to contribute to the system extension. For instance, there may be a justification for existing customers to contribute to a system extension through rates, or for government to contribute through a contribution-in-aid. Contributions-in-aid have the advantage of assisting system extensions explicitly, rather than implicitly.

If a contribution-in-aid is required, the Commission expects in general that it would be borne by those customers who benefit from the system extension. However, as noted above, the assessment of social costs may lead to circumstances in which government or other customers contribute.

7.3 Financing Methods for Contributions in Aid of Construction

When new customers are required to pay a contribution-in-aid for a system extension, they may desire some form of financing. Potential financing options for contributions-in-aid for a new system extension include private financing with repayment to lenders, financing by the utility with repayment through surcharges on customer bills, and financing by government with repayment through a tax or levy.

Financing of contributions by individuals through private means has been and should continue to be an acceptable option where it is available. The concern with limiting contribution financing to this type of option is that it may not be available to some, particularly low-income, customers. If financing is not available to such customers, the possibility of receiving gas or electricity service is foregone, not only for those customers, but for others who would be assessed a larger contribution in the absence of those who could not obtain financing. Therefore, other methods of financing would be beneficial.

Financing by the utility is one potential option; BC Gas proposed extending its appliance financing program to include customer contributions for system extensions (T9: 1250). Others supporting the provision of financing by the utility included WKP, PNG, and the Peace River Regional District. Under such a mechanism, the utility would bear the initial costs and be repaid through a surcharge on the bills of contributing customers. No party explicitly opposed a utility offering financing to those new customers who would be required to pay a contribution-in-aid for a system extension.

Financing by local government, with repayment through taxes or levies on properties which would be served by a system extension, has also been used. BC Gas appeared to have been particularly active in the encouragement of this method. The Regional District of Okanagan-Similkameen and the Cariboo Regional District (Okanagan-Cariboo) jointly intervened in the hearing to argue against frequent use of this mechanism (Exhibit 14, T2: 290-96). The Township of Spallumcheen also intervened because of similar concerns about local government financing of gas system extensions (Exhibit 10, T1: 123-46).

A witness for the Okanagan-Cariboo indicated that the districts had serious concerns about the use of the 'gas-by-tax' mechanism and that, while they were not asking for the tax mechanism to be ruled out completely, they were asking that it be significantly curtailed. The witness also noted potential inequities with the gas-by-tax mechanism. Depending on the voting procedure used, a system extension could be approved, and a tax levied to all property owners in an area, even though up to 49% of property owners did not want the service (T2: 288). Moreover, both the Okanagan-Cariboo and the Township of Spallumcheen argued that local governments were being used to perform administrative duties which were properly those of the Utilities. The local government intervenors clearly expressed the view that they wish to be involved significantly less in financing system extensions than they have been. However, the Okanagan-Cariboo did not request a complete prohibition of the gas-by-tax option (T2: 294-96).

BC Gas recommended that:

> " ... the Commission should not prevent those regional districts that wish to use the Gas by Taxation option for providing gas service to unserved areas in their jurisdictions from availing themselves of this financing option. BC Gas intends to provide administrative assistance to those districts experiencing difficulty managing the Gas By Taxation process." (T9: 1249).

The Commission does not prohibit the use of the gas-by-tax mechanism, although there are apparent problems associated with its use. Nor does the Commission view the BC Gas proposal to provide administrative support to local governments, in order that they may continue to

finance and administer system extensions through property taxes, as an appropriate solution. Such administrative support fails to address all of the concerns raised about local government financing.

The Commission expects that directions in this Decision, such as movement towards cost-based connection fees and longer contribution periods for customers attaching to system extensions, will reduce the need for financing by local governments. Additionally, the Utilities are directed to provide financing alternatives, such as contributions through customer bills, which will minimize the burden on local governments by further reducing the frequency of local government financing.

7.4 Time Period for Requiring New Customer Contributions

Some saw use of local government financing of system extensions as a way to circumvent the free-rider problem of residents waiting beyond the contribution period and then signing up for only the connection fee. BC Gas, which supported the use of local government financing, has one of the shortest capture periods for additional new customer contributions. Except for one trial case, BC Gas has been allowing additional new customers to sign up after only one year without contributing to the system extension costs. This would tend to make the option of waiting beyond the contribution period attractive to free-riders.

Several other utilities and intervenors suggested contribution periods ranging from five to 10 years. The requirement for BC Gas to adopt a longer contribution period would make the financing by local government less necessary.

Where customer contributions are required, the Commission directs the Utilities to develop a policy which requires at a minimum all customers who attach within the first five years to contribute to system extensions. Utilities may apply to incorporate a longer period in their system extension policies, perhaps with 'phase-out' provisions.

7.5 Contribution Determination and Policy

Prospective customers who request electricity or gas service prior to construction of a system extension may be asked to pay a contribution-in-aid if the projected revenues are not anticipated to cover the estimated costs.

As indicated earlier in this Decision, the detailed method of calculating the total contribution amount (the difference between discounted benefits and costs) is to be developed by the Utilities and submitted to the

Commission based on the general directions outlined in prior sections of this Decision. However, the Commission anticipates that no matter how precise the calculation method employed, there will be some variance between the estimated and actual difference between benefits and costs. That variance will depend on variances between:

- estimated and actual construction costs;
- estimated and actual average energy consumption (revenue) per customer;
- anticipated and actual number of customers who connect to the system, and therefore between estimated and actual total consumption (revenue); and
- anticipated and actual number of customers who connect to the system within the period requiring contributions-in-aid (contribution per customer).

Since such variances are to be expected, an issue which arises is whether customers' contributions should be adjusted once the actuals are known and if so how that adjustment should take place. In other words, under which circumstances, if any, should customers who connected to the system extension following construction but during the contribution period have some portion of their contribution refunded based on new information about the actual costs and benefits of the system extension.

The Utilities' positions varied on whether or not there should be refunds. B.C. Hydro indicated that it was not its current policy to offer refunds (T6: 905). Centra (T3: 479) and PNG (T4: 590) suggested that there should be no refunds, since the administrative burden of disbursing refunds would be too great, and that contributions in excess of those anticipated should merely be credited against rate base to the benefit of all customers. PLP supported refunds when additional new customers attached to system extensions (Exhibit 23C, p. 3).

BC Gas indicated that it currently issues refunds when contributing customers have requested a recalculation and where it is clear that more customers than anticipated have connected to the system extension. It does not issue refunds based on variances in construction costs. BC Gas was concerned that if contributions were collected based on the forecast number of customers in the first five years, the forecast contributions might not materialize. Therefore, the utility recommended the elimination of refunds except in those cases where a new system extension connected to a previous system extension less than one year old and which had included contributions in excess of $1,000 per customer (T9: 1248-49).

The Commission is of the view that the extent of the risk alluded to by BC Gas depends on the method of calculating and collecting customer contributions. During the hearing, two alternative methods were discussed (T2: 266-67), and are described below. Each method places the risk for variances on different parties.

Method 1:

- estimate the total contribution required based on anticipated costs and benefits over the system extension test period;
- calculate the contribution per customer based on the 'estimated' number of customers over the contribution period, and the total contribution;
- charge all new customers connected during the contribution period the contribution per customer;
- determine any over or under collection of contributions by the utility based on the variance in the total contribution or the number of customers; and
- return significant over collections either as a refund to the customers on the system extension, or in the rates of all customers (an under collection would not result in additional charges).

Method 2:

- estimate the total contribution required based on anticipated costs and benefits over the system extension test period;
- divide the total contribution by the 'actual' number of initial customers signing up to derive a contribution amount for each initial customer;
- as additional customers sign up within the contribution period, a new prorated contribution amount is calculated;
- charge each additional customer the appropriate contribution amount; and
- since an amount based on the cost of the system extension will have been charged to the initial customers, there would likely be an over collection of revenues as additional customers connect to the system and also pay a contribution - the over collection amount would be calculated at the end of the contribution period and refunded to customers to equalize the contribution at the adjusted amount.

In the Commission's view, an essential difference between the two methods is the allocation of the risk of under-recovery of costs if fewer than estimated customers connect to a system extension. The risk of receiving neither a contribution nor revenues from anticipated customers who did not sign up, was described by BC Gas (T2: 266). Under Method 1, if fewer than estimated customers connect to the system extension, the under-recovery of rates is borne initially by the utility and ultimately by the ratepayers. Under Method 2, there is no risk of under collection of the estimated contribution, as the first-year customers pay the total contribution. Of course, the estimated contribution itself may be incorrect and this remains a risk for the utility, albeit much smaller than under Method 1.

Although some forecasting risk is unavoidable, it may be decreased by adopting measures which discourage free-riders who may wait out the contribution period. Such measures are discussed elsewhere in this Decision and would include movement towards cost-based connection fees and a longer contribution period.

The Commission directs the Utilities to develop a policy for calculating customer contribution amounts that is consistent with Method 2 above. The policy should include methods of administering refunds for significant over-payments on the part of those customers who pay a contribution-in-aid prior to receiving gas or electricity service. Such methods should minimize administrative burden and could include mechanisms such as deferral accounts or 'deadbands' within which no refund would be required.

8.0 OTHER ISSUES

8.1 B.C. Hydro's Uneconomic Extension Allowance

The provincial government's energy policy goals for system extensions (Appendix D) state that a utility should be reasonably confident that the social benefits of a system extension exceed the social costs, relative to alternatives. Where it is demonstrated to the satisfaction of the Commission that the system extension provides net social benefits, and where such a system extension is considered to be in the public interest, the Commission should determine the appropriate allocation of costs.

B.C. Hydro's current policy includes an Uneconomic Extension Allowance ("UEA") which provides funding in addition to the funding provided for 'economic' system extensions. Funding under the UEA is limited to a total annual amount of $1.5 million.

Although B.C. Hydro provided no rationale for the actual amount in the UEA budget (T6: 952), it indicated that the UEA was seen as an instrument for fostering economic development (T6: 864). However, B.C. Hydro did not explain how it determined those system extensions that would qualify for a UEA grant. B.C. Hydro also indicated that most of its UEA system extensions were quite small, in the order of three or four customers, and that illustrating the economic development benefits was more difficult than in the case of larger system extensions. B.C. Hydro testified that any qualifying party who has applied for UEA funding in the past has received it (T6: 954).

B.C. Hydro noted that consideration of system extensions with respect to economic development entailed a high degree of subjectivity (Exhibit 19F, p. 2). During the hearing, B.C. Hydro acknowledged that this could be considered in a MATA framework, although this is not currently the utility's practice (T6: 976-78).

B.C. Hydro has not provided sufficient evidence for the social benefits of the UEA as currently structured and applied. Therefore, the Commission is not prepared to allow recovery in rates of funds allocated for system extensions in this manner. However, the Commission notes that the inclusion in a system extension test of social and environmental externalities, through monetization or a MATA method, may lead to justification of system extensions that are uneconomic on a strictly financial cost basis.

8.2 Analysis of Options for Serving Communities not Connected to the Gas or Electric Grids

For entire communities which are not connected to the electric power or gas grid, the issue arises as to whether the community is better served by a system extension or by some other type of on-site power or fuel. In these situations, there is some danger that, if a system extension is the only option considered, other potentially viable energy options may be overlooked

There was some debate during the hearing as to whether utilities were the appropriate parties to be offering analyses of the options available to communities which were without gas or electric service or both. The REA filed a study titled Review of Other Jurisdictions' and Utilities's Policies and Practices Related to Distribution Line Extensions (Exhibit 25C) which suggested that some U.S. utilities offered analysis and funding of on-site power and proposed that B.C. Hydro offer to provide funding equivalent to the UEA to allow those prospective customers to pursue site-based alternative energy (T9: 1310). The Energy Coalition supported the REA proposal (T9: 1394).

The MEMPR policy letter also indicated that utilities should be involved in the evaluation of alternatives to system extensions for both small and large projects.

> "Under the Commission's existing IRP guidelines, utilities are responsible for evaluating all potential supply and demand side resources. IRP principles should be applied consistently by utilities and should apply to small extensions and customer connections as well as to larger projects. Consideration also needs to be given to energy alternatives, including non-conventional energy options." (Appendix D).

In the Commission's view this clearly applies to evaluation of energy options for communities not connected to a gas or electricity grid.

The Commission determines that if a community application for a system extension is close to break-even with respect to the financial cost test, the utility should then assist with a preliminary comparative analysis of all feasible alternatives for meeting the community's energy service needs. Such analysis should include recognition of significant social or environmental impacts associated with each alternative. As indicated in previous sections, where the utility can demonstrate that the administration costs exceed the benefits of determining and including certain cost elements, it may exclude them.

8.3 Right-of-way Uncertainties

The In-SCHUCK-ch/N'Quatqua treaty group ("In-SHUCK-ch") suggested that the Commission direct utilities to consult with native bands prior to crossing lands that were the subject of treaty disputes. The In-SHUCK-ch stated that:

> "There needs to be some recognition that due to the treaty process there will be groups who will have control over their traditional territory within the next decade. For the sake of future relationships, it would be beneficial for the various utility companies in British Columbia to consider the First Nations people and their particular concerns starting in the present" (Exhibit 24B, p. 2).

The Commission notes that changes in title of lands through which gas or electricity lines pass may pose risks to the ratepayers or shareholders of the utility which owns the lines. Utilities and other unregulated firms typically evaluate alternatives using benefit/cost and risk analysis in situations where there are significant uncertainties.

The Commission requires the Utilities to keep themselves apprised of land ownership issues, and to consult with those affected by utility activities. Such consultation should include those contesting land titles and those who may be affected by system extensions.

8.4 Upgrades to Service

The Kispiox Band, along with some other groups from the Kispiox Valley wanted the Commission to consider the upgrade of their current power supply from single-phase to three-phase and noted that the area also wished to receive gas service. B.C. Hydro was questioned on its policy for upgrades to three-phase service.

Although the Kispiox Band discussed this issue during the hearing, the Commission is of the view that the Band's request for three-phase power is more properly addressed by filing a complaint under Section 30 of the Utilities Commission Act.

8.5 Net Metering

Net metering is a transaction involving the reciprocal flow of power between a customer and the utility. The customer generates electricity using an on-site technology, selling any excess above self-consumption to the utility. When self-generated electricity is insufficient to meet the customer's needs, the customer purchases power from the utility. In other words, the electric meter can run in either direction and it is the net reading at the end of the consumption period which determines what the customer pays (Exhibit 12A, p. 6).

The Energy Coalition recommended that:

> " ... electric utilities be directed to establish net metering policies in their respective service areas on a demonstration basis to evaluate the technical merits, system contributions and rate impacts of customer generated power." (T9: 1377).

Under the Energy Coalition's proposal, net metering would not result in a sale of power from the customer to the utility; it simply gives customers a credit on their accounts. The Energy Coalition argued that there were four main reasons for encouraging electric utilities to adopt a net metering policy:

- to make alternative technologies more accessible;
- to take advantage of the environmental benefits of alternative energy;
- to gain experience and information on self-generation; and
- to take advantage of system benefits (T9: 1353).

The Commission agrees with the general goal that every energy consumer should eventually have the right to be an energy producer, provided that their production contributes to the economic efficiency (in a full social costing sense) of the energy system. The Commission notes, however, that prior to the implementation of net metering for residential customers in British Columbia, several key issues need to be examined. These include notably: (1) implications of allowing net metering for all customers, not just residential customers; (2) determination of the appropriate value for electricity provided to the grid by net metering; and (3) potential concerns about system integrity and worker safety under net metering. The Commission also notes that the issue of net metering is somewhat peripheral to the stated list of issues for this generic system extension hearing.

The Commission is not prepared to issue any directives with respect to net metering in the context of this generic system extension hearing. The Commission is interested in exploring this concept in future proceedings, one possibility being the upcoming Industrial Service Options hearing of B.C. Hydro.

9.0 COMMISSION SYSTEM EXTENSION GUIDELINES

The following guidelines have been developed to assist the Utilities in interpreting and applying the key directions of this Decision. These guidelines are presented strictly as an aid and should not be seen as supplanting in any way the specific directions in sections 1 to 8 of this Decision.

9.1 General Principles

By May 31, 1996, the Utilities shall each file for Commission approval a revised system extension test in accordance with the principles outlined in this Decision.

There shall be one general form of system extension test common to all the Utilities.

This test will be based on a discounted cash flow calculation in which, in order for the system extension to proceed, the present value of a system extension's benefits must exceed the full incremental costs. However, neither all values used as inputs into the analysis of proposed system extensions, nor all details of the discounted cash flow calculation, need necessarily be common from utility to utility.

The costs of system extensions should be allocated, as much as is feasible, to those customers who cause them.

The time frame for consideration of costs and benefits should be generally consistent with the time frame applied for other Integrated Resource Planning analyses by the Utilities.

The costs and benefits of system extensions should be evaluated from both a social perspective and a utility perspective. The social perspective will use a social discount rate and consider externalities, while the utility perspective will use the utility cost of capital and focus on utility financial costs (sections 4.2 and 5.2).

System extensions should individually pass the system extension test, although some aggregation of system extensions may be warranted, with Commission approval. The Commission will also consider specific proposals for reducing the administrative costs of dealing with many routine, short system extensions (section 4.3).

9.2 Costs and Benefits of System Extensions

The costs and benefits to be considered in the system extension test include the pre-construction estimates of the following:

(1) construction costs of the system extension (section 5.1.1);

(2) associated incremental system improvement costs, where these can be identified and assessed in a cost-effective manner (section 5.1.2);

(3) associated incremental operation and maintenance costs, where these can be identified and assessed in a cost-effective manner (section 5.1.3);

(4) net costs of connection (i.e., cost of connection less connection fees) (section 7.1);

(5) net revenues from the system extension (i.e., customer payments less revenues to provide for commodity purchases and upstream transmission charges) (section 5.1.3); and

(6) consideration of incremental environmental and social externalities (for the social perspective evaluation), which may involve some monetization but in all likelihood may also involve some form of multi-attribute trade-off analysis (section 5.2).

9.3 Decision Criteria for System Extension Tests

In all cases, customers can attain a system extension by providing a contribution-in-aid to offset both net utility financial costs and (in special circumstances) net externality costs associated with the system extension.

If a proposed system extension passes the system extension test from both the utility and the social perspectives, the utility should proceed with the system extension without requiring a customer contribution.

If a proposed system extension is desirable from the social perspective, but fails from the utility perspective or, alternatively, if a proposed system extension is undesirable from the social perspective, but passes from the utility perspective, the contribution may be adjusted to offset in part the difference between social costs and utility costs (section 6). In either case, where the consideration of social costs alters the decision suggested by the financial test, the system extension proposal should be submitted to the Commission for its review prior to installation.

The social perspective approach to assessing system extension proposals should be more detailed with respect to communities, as opposed to individual customers or small clusters of customers. In particular, if a community application for a system extension is close to passing the discounted cash flow test from the utility perspective, the utility should then assist with a preliminary comparative analysis of all feasible alternatives for meeting the community's energy service needs. Such analysis should include recognition of significant social and environmental externalities associated with each alternative, from a social perspective. Once the analysis has been completed, the same decision criteria as outlined above apply (section 8.2).

9.4 Collection of Customer Costs (Chapter 7)

9.4.1 Connection Charges

The Utilities' connection charges should be revised if necessary in order to move toward recovery of the full costs of connection, excluding the cost of the meter. In revising their connection charges, the Utilities should come forward with options that send an appropriate signal to consumers about the net social costs of less efficient energy use.

Increasing connection charges toward reflecting full costs will not change the amount of revenue required for a system extension to proceed, but a greater share of the revenue will be realized from the connection charge, thereby reducing the contribution in aid of construction.

9.4.2 Allocation and Collection of Customer Contributions in Aid of Construction

The following general method (Method 2 in section 7.5) should be used for estimating the total required customer contribution and for allocating its costs and risks among the utility, current customers and the new customers on the system extension.

(1) Using discounted cash flow analysis, and the costs and benefits listed above, the total contribution required from customers over the system extension test period is estimated. At a minimum, all customers who attach within the first five years should pay a share of the required customer contribution.

(2) The total contribution is divided by the actual number of initial customers signing up in order to derive a contribution amount for each initial customer.

(3) As additional customers sign up within the contribution period (five years minimum), each year a new prorated contribution amount is calculated, which is charged to each additional customer.

(4) After the contribution period, a recalculation will determine what over collection, if any, was received from customers signing up at various times during the five year contribution period. Significant over collections would be refunded to customers to equalize the contribution at the adjusted amount.

Dated at the city of Vancouver, in the Province of British Columbia this 16th day of February, 1996.

Original signed by:
Dr. Mark K. Jaccard
Chairperson

Original signed by:
Lorna R. Barr
Deputy ChairChair

Original signed by:
Kenneth L. Hall, P. Eng.
Commissioner

APPEARANCES

G.A. FULTON K.M. DUKE	Commission Counsel
C.B. JOHNSON	BC Gas Utility Ltd.
R.J. McDONELL	Centra Gas British Columbia Inc.
C.P. DONOHUE	Pacific Northern Gas Ltd.
J.D. AVREN A. DOBSON	British Columbia Hydro and Power Authority
R.B. HOBBS	West Kootenay Power Ltd.
J. HALL	Princeton Light and Power Company, Limited
R.J. GATHERCOLE	Renewable Energy Association of British Columbia
C. REARDON D. FOLEY	British Columbia Energy Coalition
G. RIEGER	The Corporation of the Township of Spallumcheen
V. SUTTON B. LONG	Regional District of Okanagan-Similkameen and Cariboo Regional District
M. DOHERTY J. QUAIL	The Consumers' Association of Canada (B.C. Branch) British Columbia Old Age Pensioners' Organization Council of Senior Citizens' Organizations of B.C. Federated Anti-Poverty Groups of B.C.; Senior Citizens' Association of B.C.; West End Seniors' Network
J. YARDLEY	Peace River Regional District
D. BURSEY	Methanex Corporation
S. CLAYTON	Ministry of Energy, Mines and Petroleum Resources
D. RAWLYK	Energy Resources Management
W. KRAMPL	Energy Industry Consulting
B. WILLIAMS	Kispiox Band Council
C. HOGUE	In-SCHUCK-ch/N'Quatqua Treaty Task Group

W.J. GRANT D.W. EMES N.C.J. SMITH P.H. GRONERT J. FRASER	Commission Staff
ALLWEST COURT REPORTERS LTD.	Court Reporters & Hearing Officer

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