RESPONSE TO SOCIÉTÉ EN COMMANDITE GAZ MÉTRO (GAZ MÉTRO) TO THE INFORMATION REQUEST NO. 3 FROM EXPERT PAUL L. CHERNICK ON THE ADDITIONAL EVIDENCE OF GAZ MÉTRO

1. Source:

R-3867-2013, B-0278, Review of Methodologies for Evaluating the Profitability of System Extension Projects – Black and Veatch evidence, (Gaz Métro-7, Document 5), p. 2.

Preamble:

- "Acceptability criteria [is] IRR greater than the Prospective WACC."

Questions:

1.1. Please explain why Gaz Métro intends to use the IRR test, rather than the net present value at the WACC or other discount rate.

Réponse :

Le TRI et la VAN sont deux concepts d'évaluation d'un investissement qui sont fortement liés, le TRI étant le taux d'actualisation pour lequel une VAN est égale à 0. L'utilisation du TRI rend simple la comparaison avec le coût du capital; un TRI supérieur au coût du capital signifie que le projet est rentable économiquement (baisse des tarifs sur la période d'analyse) alors qu'un TRI inférieur signifie que le projet n'est pas rentable économiquement (hausse des tarifs sur la période d'analyse). Néanmoins, la prise de décision sur l'acceptation ou non d'un projet faite par le TRI ou la VAN est équivalente; un TRI supérieur au coût du capital implique une VAN supérieure à 0 et donc, le projet est rentable économiquement et donc accepté. Par souci de simplicité de compréhension, le TRI est l'outil utilisé par Gaz Métro pour déterminer si un projet est supérieur au coût du capital prospectif. Cette méthode a été autorisée par la Régie dans sa décision D-97-25.

1.2. Since customers will pay the net revenue requirements of the extension project, why does Gaz Métro propose to use the WACC rather than an estimate of the cost of capital to its customers?

Réponse :

Les investissements sont financés par une structure de capital autorisée par la Régie (dette et équité), le coût moyen pondéré du capital prospectif est ainsi le coût représentatif pour financer l'investissement. Cette méthode a été autorisée par la Régie dans sa décision D-97-25.

a. Please provide any available estimate of the cost of capital for any of Gaz Métro's rate classes.

Réponse :

Voir la réponse à la question précédente.

b. Please provide and available estimate of the percentage of Gaz Métro residential customers who carry a credit-card balance.

Réponse :

Gaz Métro ne dispose d'aucune information concernant le solde de cartes de crédit de sa clientèle.

2. Source:

R-3867-2013, B-0278, Review of Methodologies for Evaluating the Profitability of System Extension Projects – Black and Veatch evidence, (Gaz Métro-7, Document 5), p. 2.

Preamble:

- "[…] the cost of a distribution system project undertaken by a gas utility to replace a segment of its existing distribution mains or the cost to replace a gas service line or gas meter at a particular customer's location would not constitute an incremental cost. It is simply the cost of maintaining the existing level of output and not an incremental cost to increase the utility's output."

- "Current costs should be used to determine the directly attributable, capital-related costs to connect a new customer (e.g., main extension, service line, meter and regulator)"

Questions:

2.1. Please explain in detail how Gaz Métro reflects the costs of maintenance capital expenditures for the "directly attributable" additions over the life of the analysis.

Réponse :

Les coûts d'investissements capitalisables en maintien servent, soit à prolonger la durée de vie d'un actif, soit à le remplacer et donc, à poursuivre le service. Pour Gaz Métro, ces investissements sont considérés comme étant de l'amélioration de réseau et permettent d'assurer le maintien d'actifs sécuritaires et viables. Les investissements en amélioration de réseau ne constituent donc pas des coûts incrémentaux et ne sont donc pas considérés dans l'analyse de rentabilité tel que spécifié dans la preuve de Gaz Métro[1] et celle de l'expert[2].

2.2. Please provide any available data on the retirements and replacements of each of the following by age of the installation:

a. Mains;

b. Service lines;

c. Meters;

d. Regulators.

Réponse :

Montant des retraits en 2016 ($)					
Âge des actifs	**Entre 0 et 10 ans**	**Entre 11 et 20 ans**	**Entre 21 et 30 ans**	**Entre 31 et 40 ans**	**Total par catégorie**
Branchements acier et plastique direct	(257 817)	(622 593)	(847 218)	(1 106 940)	(2 834 568)
Conduites acier et plastique direct	(338 340)	(181 641)	(501 182)	(2 390 752)	(3 411 915)
Compteurs	(851 680)	(1 773 798)	(3 550 513)	0	(6 175 991)
Total par groupe d'âge	**(1 447 837)**	**(2 578 032)**	**(4 898 913)**	**(3 497 691)**	**(12 422 473)**

[1] B-0277, Gaz Métro-7, Document 4.

[2] B-0278, Gaz Métro-7, Document 5.

Les retraits relatifs aux régulateurs sont inclus dans ceux de branchements. Gaz Métro n'a pas de catégorie d'immobilisation distincte pour les régulateurs.

Dans la majorité des cas, un retrait est effectué suite à un projet de remplacement d'actif.

3. Source:

R-3867-2013, B-0278, Review of Methodologies for Evaluating the Profitability of System Extension Projects – Black and Veatch evidence, (Gaz Métro-7, Document 5), pp. 3 and 34.

Preamble:

- "As long as the incremental revenues from a new customer to be served by the gas utility can recover, at a minimum, the directly attributable costs of the proposed new connection to the utility's gas distribution system, any revenues above that minimum level will provide a positive contribution to the recovery of the gas utility's fixed costs that are common to the specific activities and functions of the gas utility's development efforts to add new customers and to continue to serve existing customers."

Questions:

3.1. Please explain how this statement applies if Gaz Métro needs to add upstream capacity during the analysis period to meet the combined load of this new customer, other new customers on the line extension, new customers on other line extensions, new customers along existing lines, and additional load from existing customers.

Réponse :

Black & Veatch

The statement will also apply in this situation because each of the new customers will provide a positive contribution to the recovery of Gaz Métro's fixed costs of the added upstream capacity during the analysis period, while its existing customers will also contribute to the recovery of those development costs when they are eventually reflected in Gaz Métro's rates.

3.2. If a new customer would require service-extension investment and expenses (including metering, billing, and the like) with a present value of $1 million, provide GM with revenues of $1.3 million and require a $1 million upgrade in the upstream distribution system about five years after it comes on line, would that customer be profitable to Gaz Métro?

Réponse :

Black & Veatch

The profitability of the assumed upstream distribution system project should not be evaluated solely on the basis of the profitability of a single customer. As explained in the response to FCEI question 9.1 (Gaz Métro-9, Document 11), in this type of situation, Gaz Métro would review the potential for creating future customer benefits from the upstream distribution system investment. Moreover, as explained in the responses to questions 12.1 and 12.3 below, distribution networks are complex and it is not possible to generalize the impact of network reinforcement. Some reinforcements have an impact on a small part of the network, while other reinforcements impact the entire Gaz Métro network. The inclusion of the System Incremental Capital Investment at the portfolio level is efficient because it would avoid having to develop a process and methodology to apportion the cost of the System Incremental Capital Investment to individual projects, and possibly to Gaz Métro's existing customers. This method is equitable because it recognizes the lumpy nature of the investment by aligning the number of new customers to be served and their capacity needs over the analysis time period with the investment level needed to satisfy those customer requirements rather than attributing the entire cost of the investment to the "next customer" at the margin causing the need for the investment. Finally, the inclusion of the System Incremental Capital Investment at the portfolio level is straightforward and not subject to variations in interpretation or application.

Nevertheless, in the example posed in the question which is a very rare occurrence, if the upstream distribution system investment is only to be used to serve this one customer, with no possibility of serving future customers or creating other system benefits, then this project would not be deemed to be profitable because the directly assignable costs for this customer would also include the costs of the upstream investment.

4. Source:

R-3867-2013, B-0278, Review of Methodologies for Evaluating the Profitability of System Extension Projects – Black and Veatch evidence, (Gaz Métro-7, Document 5), pp. 3 and 11.

Preamble:

- "Using LRIC costing concepts to establish *each* cost component in a gas utility's economic evaluation of system extension projects could violate the "matching principle" of utility ratemaking (i.e., a utility's revenues derived from rates must match its total cost of service or total revenue requirement approved by the regulator)."

Questions:

4.1. Please define as precisely as possible what is meant by "LRIC" in this context.

a. Does "long-run" in this context mean the average expected incremental cost to the system due to this incremental load over the analysis period?

Réponse :

Black & Veatch

Conceptually, Long-Run Incremental Cost ("LRIC") is a variant of Long-Run Marginal Cost ("LRMC") that examines changes in costs associated with a multiple unit (i.e., incremental) change in utility service or output. For both LRIC and LRMC, such costs are derived over a sufficiently long period of time in which all inputs of production are considered to be variable. As a result of using an incremental change in output, because capacity additions tend to be lumpy, LRIC may reflect more capacity additions than those required to serve the increment of load assumed for any one particular project or group of projects.

For purposes of Gaz Métro's profitability analysis, LRIC reflects the change in capital costs associated with the expansion of Gaz Métro's gas distribution system to serve new customers. These capital costs are derived based on the specific facilities required to connect the new customers to the utility's existing gas distribution system and to serve the customer's peak capacity requirements. Where this type of cost determination can be made, the LRIC amount should not be derived based on a generalized measure of the change in costs across the utility's system (i.e., as would be derived in an LRIC study) and added into the profitability analysis, irrespective of whether such facilities are actually required to serve the new customers that are being evaluated. It is not appropriate to use a generalized measure of LRIC in a profitability analysis for system extension projects because the resulting level of costs does not reflect the actual cost of the facilities required to connect the new customers to the gas utility's existing gas distribution system.

b. Does "long-run" in this context mean the average cost of replacing the entire Gaz Métro system at current prices?

Réponse :

Black & Veatch

No. Please see the response to question 4.1 above.

4.2. Please explain whether this statement is intended to suggest that using LRIC concepts in the economic evaluation of system extension projects could result in Gaz Métro receiving revenues exceeding its revenue requirement.

Réponse :

Black & Veatch

The statement is intended to suggest caution when determining the level of incremental costs that should be attributed to new customers under Gaz Métro's evaluation of the profitability of its system extension projects. For example, based on the results of an LRIC study, all new customers would be assigned the LRIC of a main extension, but only some new customers will actually require this capital investment based on where they are located in relation to the utility's existing gas distribution grid. The attribution of additional costs to these customers under this situation could create the need for a contribution from the customer, where one is not needed.

a. If so, please explain how this could occur and provide numerical examples of this effect.

Réponse :

Black & Veatch

Please see the response to question 4.2 above.

b. If not, please explain what this assertion means.

Réponse :

Black & Veatch

Please see the response to question 4.2 above.

4.3. Please explain why the word "each" is italicized in this passage on page 3.

Réponse :

Black & Veatch

The word "each" was italicized to emphasize the cautionary note indicating that the results of a LRIC study should not always be used as the basis for valuing the cost of each and every plant component required to serve new customers.

5. Source:

R-3867-2013, B-0278, Review of Methodologies for Evaluating the Profitability of System Extension Projects – Black and Veatch evidence, (Gaz Métro-7, Document 5), p. 11.

Preamble:

- "[C]aution must be exercised in order to prevent a mismatch between the embedded costs used to set rates for the utility's existing customers (which are the same rates used to derive the revenues expected from new customers) and the LRIC used to derive the profitability of serving new customers, and the level of any customer contribution required of new customers."

Questions:

5.1. Please define the "mismatch" and provide numerical examples of the problems that B&V anticipates could arise from this mismatch.

Réponse :

Black & Veatch

The "mismatch" described in the referenced document could occur If a generalized measure of LRIC is used (as derived in a LRIC study) in the gas utility's profitability analysis instead of using the actual incremental costs of connecting its new customers at the time the evaluation of the system extension project is being conducted. Under a LRIC study, the capital-related costs that are derived represent a system-wide measure of the change in costs over a long-term period caused by changes in the number of customers served and the level of capacity available to satisfy customers' demand requirements. As such, it does not necessarily reflect the actual change in costs associated with a particular system extension project or group of projects to serve new customers.

Taking the use of LRIC values to an extreme, the profitability of new customers would be evaluated using incremental revenues derived from rates based on embedded costs while the cost inputs into the gas utility's system extension profitability analysis would be valued on a LRIC basis, thereby potentially overburdening new customers with costs they are not actually causing the gas utility to incur. This situation would create a "mismatch" between the revenues and costs reflected in the profitability analysis which could create a below target financial outcome and the need for a customer contribution. This mismatch of revenues and costs would indicate the need for a customer contribution where, in reality, such a contribution would not be required if the actual capital costs of the facilities were utilized in the profitability analysis.

5.2. Please explain whether this statement implies that the Régie cannot require that Gaz Métro charge new customers more than it charges existing customers, since that would result in a "mismatch" between the costs used in setting charges for existing customers and the costs used in setting charges for new customers.

Réponse :

Black & Veatch

While Black & Veatch cannot offer a legal opinion on the ability of the Régie to undertake certain ratemaking actions, Black & Veatch's referenced statement was provided to highlight the importance of properly matching the change in rate revenues with capital-related costs actually caused by new customers within the context of Gaz Métro's analysis to evaluate the profitability of its system extension projects.

5.3. Please provide citations to any legal or other authority that B&V or Gaz Métro believe indicate that Gaz Métro cannot impose different charges on existing and new customers.

Réponse :

Black & Veatch

Please see the response to question 5.2 above.

6. Source:

R-3867-2013, B-0278, Review of Methodologies for Evaluating the Profitability of System Extension Projects – Black and Veatch evidence, (Gaz Métro-7, Document 5), p. 3 and 34.

Preamble:

- "If LRIC is used as the cost basis in a gas utility's economic evaluation of system extension projects, new customers could subsidize existing customers because the gas utility's revenue requirement and current rates are based on historical, embedded costs while the costs in the profitability model would be based on LRIC – which could be higher than the level of embedded costs underlying the gas utility's current rates."

Questions:

6.1. Please explain how this subsidization would happen.

Réponse :

Black & Veatch

Please see the response to question 5 above. In some of the LRIC studies that Black & Veatch has conducted for gas utilities, the results indicated that the gas utility's total revenue requirement based on LRIC was higher than the level of its total revenue requirement based on embedded or historical costs.

6.2. Please explain whether this subsidization would only occur if the incremental costs due to the system extension project were less than the upstream LRIC assumed in the economic evaluation.

Réponse :

Black & Veatch

This type of subsidization could occur under the conditions described in the response to question 5 above.

a. If this subsidization would only occur in other situations, please describe those situations.

Réponse :

Black & Veatch

Please see the response to question 6.2 above.

6.3. Please explain whether the incremental costs due to the system extension project could be higher than the average upstream LRIC assumed in the economic evaluation.

Réponse :

Black & Veatch

Please see the response to question 6.2 above.

a. If so, would those circumstances result in existing customers subsidizing the new customers on the service extension?

Réponse :

Black & Veatch

Please see the response to question 6.2 above.

7. Source:

R-3867-2013, B-0278, Review of Methodologies for Evaluating the Profitability of System Extension Projects – Black and Veatch evidence, (Gaz Métro-7, Document 5), p. 3 and 34.

Preamble:

- "Under this approach, the common fixed costs of providing utility service to a particular rate class are attributed to all customers within the class – not to any one customer."

Questions:

7.1. Does this statement also apply to :

a. all the new customers on a service extension?

Réponse :

Black & Veatch

Yes, if a "service extension" is defined as a single system extension project.

b. all the new customers on all service extensions in a capital plan?

Réponse :

Black & Veatch

Yes, if all the new customers on all service extensions are included in the portfolio of projects.

c. all the new customers on all service extensions over the next 40 years?

Réponse :

Black & Veatch

No. The referenced statement is applicable to a 12-month test year that would be used as the basis for a gas utility's cost of service study, class revenues and rate design.

7.2. Does B&V mean to suggest that new customers should not be charged for their contribution to adding or advancing system reinforcements that serve both new and existing customers?

Réponse :

Black & Veatch

No. The capital-related costs of system reinforcements will be included in Gaz Metro's profitability analysis conducted on a project portfolio basis and will be included in future base rates that will be charged to all customers.

a. If so, please provide the rational for prohibiting such charges.

Réponse :

Black & Veatch

Not Applicable.

b. If new customers require expensive upstream additions (i.e., additions not dedicated to the new customers) over the analysis period, but pay only the average embedded costs, could existing customers wind up subsidizing the new customers?

Réponse :

Black & Veatch

No. Please see the response to question 12 below. The profitability analysis conducted on a portfolio basis would include the cost of System Incremental Capital Investments and is targeted to have a Profitability Index (P.I.) of 1.1. If the portfolio P.I. is greater than 1.0, new customers are effectively providing more revenues than their incremental costs so there would be no subsidy from existing customers to new customers. In other words, the inclusion of the costs of additional upstream additions in future base rates will not increase the rates charged to existing customers if the portfolio P.I. is greater than 1.0 for all new projects. This outcome occurs because Gaz Métro's profitability analysis conducted on a portfolio basis is a conservative approach since it reflects the entire cost of System Incremental Capital Investments in evaluating the profitability of its new customers.

Moreover, to the extent upstream main reinforcements also provide additional capacity and operational flexibility to Gaz Métro's existing customers, attributing the entire cost of such investment to new customers should be viewed as a conservative approach to evaluating the profitability of system extension projects since a portion of those facilities will also provide benefits to Gaz Métro's existing customers.

8. Source:

R-3867-2013, B-0278, Review of Methodologies for Evaluating the Profitability of System Extension Projects – Black and Veatch evidence, (Gaz Métro-7, Document 5), p. 3 and 34.

Preamble:

- "Determination of the portion of upstream main reinforcements attributable to each new customer can be difficult since the main investment could provide future service to new customers, to all future customers, and/or to existing customers who require additional capacity over the life of the new facilities – which would be viewed as a lumpy system investment."

Questions:

8.1. Does B&V believe that values that "can be difficult" to determine should be set to zero?

Réponse :

Black & Veatch

No. The issue is not whether all or a portion of the cost of an upstream main reinforcement should be excluded from the profitability analysis, but rather at what point in time should those costs be valued and included in the analysis, and how should that be accomplished. Black & Veatch's recommendation is to include Gaz Métro's upstream main reinforcement costs in its profitability analysis on a portfolio basis rather than on an individual project basis. There is much greater certainty when calculating total upstream reinforcement costs at a portfolio level compared to at an individual project level. Therefore, inclusion of upstream reinforcement costs in the profitability analysis for an individual project adds unnecessary uncertainty and variability to the resulting calculations. This is due to the fact that any method of attributing upstream reinforcement costs to an individual project will be imperfect, and would by its very nature likely create an overstatement of the incremental investment costs required to provide the level of capacity for the new customers associated with that single project. The attribution of additional costs to these customers under this situation could create the need for a contribution from the customer, where one is not needed and therefore some projects taken individually could not meet the profitability index criteria. This situation would result in the utility foregoing an opportunity to take advantage of economies of scale and scope - missing an opportunity to decrease rates for its existing customers. As such, it is best to measure the profitability of upstream system reinforcement investments over the entire portfolio of projects rather than for each individual project.

Please, also see the response to question 9.1 in the Information Request from OC (Gaz Métro-9, Document 12).

a. If not, does B&V agree that a portion of future "upstream main reinforcements" should be attributed to load growth from new customers?

Réponse :

Black & Veatch

Please see the responses to questions 4.1 and 8.1 above.

9. Source:

R-3867-2013, B-0278, Review of Methodologies for Evaluating the Profitability of System Extension Projects – Black and Veatch evidence, (Gaz Métro-7, Document 5), p. 3 and 34.

Preamble:

(i) "The evaluation of the profitability of system extension projects to serve new customers provides the gas utility with the flexibility needed to add new customers to the gas distribution system who can recover through rates their direct incremental costs of connection (i.e., the main extension, service, meter and regulator) and to recognize that all new customers as a group contribute to the recovery of the gas utility's common fixed costs as part of an overall project portfolio."

Questions:

9.1. To the extent that a new customer, or a group of new customers, requires additional common fixed costs exceeding the average cost of service, does B&V believe that the existing customers should subsidize these new customers?

Réponse :

Black & Veatch

This question assumes that a gas utility's additional common fixed costs can be allocated to new customers or to a group of new customers. By definition, a gas utility's common fixed costs represent the costs of gas utility activities that support the provision of gas service to all customers. Additional common fixed costs are incurred to support all customers, not just to support a subset of those customers. Often the level of additional common fixed costs incurred is caused by a number of operating considerations, and not solely due to the addition of new customers. For example, a gas utility's additional investment in Information Technology (IT) systems to operate a utility's call center has more to do with the economic trade-off between labor and capital (the leveraging of technology) than to the number of customers served, or the desire to enhance customer service.

The nature of common fixed costs requires that they be allocated to entire rate classes when setting base rates and not to new and existing customers separately. Any split of common fixed costs between new and existing customers would be arbitrary and likely be a poor representation of cost causation. In the example above, it would be arbitrary to attribute to new customers only a portion of the additional IT costs for the call center since these costs are incurred on a system-wide basis to serve all customers.

As explained in the Black and Veatch report (B-0278, Gaz Métro-7, Document 5), the only capital-related costs that can be attributed to new customers on an individual project basis are those that are the direct incremental costs of connection (i.e., the main extension, service, meter and regulator), which are referred to in the Black & Veatch report as Direct Incremental Development Costs. The Indirect General Capitalized Development Costs referred to in the Black & Veatch report are costs that are incurred by Gaz Métro on annual basis and are fixed for a certain range of projects that are undertaken by year so they do not change directly based on the number of new customers connected in that year. In other words, these costs are not related to any particular single project. As a result, Black & Veatch recommends that it is reasonable and appropriate to assign these costs to new customers on a project portfolio basis only because they are indirect common costs that are incurred by Gaz Métro to support the entirety of its development activities for all new customers. The profitability analysis conducted on a portfolio basis would include these indirect general capitalized development costs and is targeted to have a Profitability Index (P.I.) of 1.1. If the portfolio P.I. is greater than 1.0, new customers are effectively providing more revenues than their incremental costs so there would be no subsidy from existing customers to new customers. In other words, the inclusion of the indirect general capitalized development costs in future base rates will not increase the rates charged to existing customers if the portfolio P.I. is greater than 1.0 for all new projects.

a. If so, please explain why.

Réponse :

Black & Veatch

See response to question 9.1 above.

b. If not, please explain how B&V and Gaz Métro would avoid that outcome.

Réponse :

Black & Veatch

See response to question 9.1 above.

10. Source:

R-3867-2013, B-0278, Review of Methodologies for Evaluating the Profitability of System Extension Projects – Black and Veatch evidence, (Gaz Métro-7, Document 5), p. 4, 35 and Table 3.

Preamble:

- "Black & Veatch recommends that Gaz Métro continue using its current valuation period of forty (40) years, which is the most common valuation period utilized by the Peer Group utilities and reflects the average life of the capital placed into service during a system extension project."

Questions:

10.1. Please provide all the data, analysis and other sources on which B&V reviewed in making this recommendation, other than the Table 3 at p. 18 and 19.

Réponse :

Black & Veatch

Black & Veatch understands that the Régie renewed the use of a 40-year valuation period by Gaz Métro in R-3173-89-E (Decision D-90-60,). In addition, during the course of its project with Gaz Métro, Black & Veatch was made aware of the average service lives of the facilities placed into service in conjunction with Gaz Métro's system extension projects, and the lives were within a reasonable range of the 40-year valuation period.

Gaz Métro

En complément, veuillez vous référer à la réponse de la question 13.1 de la Régie (Gaz Métro-9, Document 9).

10.2. Please provide any evidence available to B&V regarding the probability that a customer will continue to take service from Gaz Métro at an existing location for 40 years.

Réponse :

Black & Veatch

Black & Veatch did not evaluate the longevity of customers taking gas service from Gaz Métro.

Gaz Métro

Veuillez vous référer à la réponse à la question 7.1 de la demande de renseignements n^{o} 2 de la FCEI (B-0257, Gaz Métro-9, Document 3).

10.3. Please provide any evidence available to B&V regarding the likelihood of customers reducing their energy consumption or abandoning a location over the next 40 years.

Réponse :

Black & Veatch

Black & Veatch did not evaluate the likelihood of Gaz Métro's customers reducing their energy consumption or abandoning a location over the next 40 years, However, to the extent new customers added to Gaz Métro's gas distribution system reduce their future energy consumption in a similar manner to its existing customers, Gaz Métro's rates will increase over time to account for the lower annual volumes over which costs will be recovered, and all customers will be charged those higher rates.

10.4. Please provide any analysis that B&V has conducted regarding the amount of natural gas that Québec can utilize and still meet its obligation under Canada's and Quebec's plans for greenhouse-gas reductions.

Réponse :

Black & Veatch

Black & Veatch did not conduct any analyses regarding the amount of natural gas that Québec can utilize and still meet its obligation under Canada's and Quebec's plans for greenhouse-gas reductions.

Gaz Métro

Veuillez vous référer à la réponse à la question 7.10 de la demande de renseignements de l'expert du ROEÉ (B-0264, Gaz Métro-9, Document 6).

11. Source:

R-3867-2013, B-0278, Review of Methodologies for Evaluating the Profitability of System Extension Projects – Black and Veatch evidence, (Gaz Métro-7, Document 5), p. 4, 35 and 36.

Preamble:

- "Black & Veatch finds that the approach utilized by FortisBC, Union Gas Limited and Enbridge Gas Distribution is a reasonable and well-balanced approach. This method utilizes an individual project P.I. of 0.8 and a project portfolio P.I. of 1.1 as the appropriate profitability targets. Black & Veatch recommends that Gaz Métro adopt this type of approach."

- "[…] adopt a P.I. of 0.8 for individual projects (if further growth is anticipated) […]"

Questions:

11.1. Please explain whether the 0.8 project P.I. "target" would mean that projects would only be required to provide an IRR equal to 80% of the WACC.

Réponse :

Non, un IP cible de 0,8 ne signifie pas que le TRI exigé serait de 80 % du CCP.

a. If not, what does that the 0.8 target mean?

Réponse :

L'indice de profitabilité, que l'on appelle aussi ratio bénéfice/coût, met en relation les flux positifs d'un projet (c.-à-d. ses flux d'opération) et les flux négatifs (les coûts du projet). Un IP cible de 0,8 signifie que le rapport entre les flux d'opération (actualisés au CCP) et les coûts de projet (actualisés aussi) doit être d'au moins 0,8. Autrement dit, un IP cible de 0,8 signifie que pour chaque dollar investi, un projet doit générer minimalement 0,80 $ de valeur actuelle.

b. If the capital anticipated for a service extension were $1 million, and the present value of the operating expenses were $200,000, how much would the present value of revenues need to be for the project to pass the 0.8 P.I. threshold?

(i) Please explain why it is fair for the existing customers, and profitable new customers, to pay for this unprofitable service extension.

Réponse :

La valeur actuelle des revenus, dans l'exemple, devrait être de 1 M$.

Veuillez vous référer à la réponse à la question 3.6 de la demande de renseignements n^{o} 3 de l'ACIG (Gaz Métro-9, Document 10).

11.2. Please explain how B&V found the 0.8 project P.I. to be appropriate.

Réponse :

Black & Veatch

Black & Veatch's review of the Peer Group research noted that FortisBC, Union Gas Limited and Enbridge Gas Distribution each use the 0.8 project P.I., Black & Veatch also reviewed the additional evidence filed by Gaz Métro on January 20, 2017 in R-3867-2013. That evidence showed that the profitability of the extension projects analyzed by Gaz Métro increased an average of 4.48% (i.e., the internal rate of return or IRR increased by 4.48%). This data indicates that historically there has been an increase in the a priori profitability and the profitability actually realized. As stated in Gaz Metro's evidence, this result supports a 2% acceptable minimum threshold. This also provides strong evidence that the individual project P.I. should be set at a level below 1.00.

Using an acceptable minimum threshold IRR of 2% in a profitability analysis is equivalent to a project P.I. of 0.6, which is below the P.I. of 0.8 used in Ontario and British Columbia. Based on this evidence, Black & Veatch concluded that a conservative approach would be to utilize a P.I. of 0.8, which is the same value used by multiple gas utilities in the Peer Group.

11.3. Please provide B&V's estimate of the growth that should be anticipated "if further growth is anticipated."

Réponse :

Black & Veatch

Black & Veatch did not estimate of the growth that should be anticipated.

Gaz Métro

Veuillez vous référer à la réponse à la question 3.6 de la demande de renseignements n^{o} 3 de l'ACIG (Gaz Métro-9, Document 10).

a. Please provide the basis for that estimate.

Réponse :

Veuillez vous référer à la réponse à la question 11.3.

b. Please explain how that growth rate justifies the 0.8 P.I. threshold.

Réponse :

Veuillez vous référer à la réponse à la question 11.3.

11.4. Please explain how B&V expects that Gaz Métro would be able to determine whether further growth should be anticipated.

Réponse :

Veuillez vous référer à la réponse à la question 11.3.

a. How much further growth should be anticipated to invoke the 0.8 P.I. threshold?

Réponse :

Veuillez vous référer à la réponse à la question 11.3.

b. How would the determination of future growth reflect the costs associated with the future growth (service lines, meters, metering, billing and customer service, further main extension, etc.)?

Réponse :

À l'étape 2 de son processus de gouvernance, Gaz Métro effectue des analyses de sensibilité permettant d'évaluer combien de clients supplémentaires à ceux *a priori* identifiés seront nécessaires pour atteindre une rentabilité équivalant à un IP de 1. Gaz Métro précise que des coûts sont associés à ces clients supplémentaires.

Pour plus de détails sur le processus de gouvernance, veuillez vous référer à l'annexe Q-18.1 de la demande de renseignements n^{o} 11 de la Régie (Gaz Métro-9, Document 9).

12. Source:

R-3867-2013, B-0278, Review of Methodologies for Evaluating the Profitability of System Extension Projects – Black and Veatch evidence, (Gaz Métro-7, Document 5), p. 32, 34.

Preamble:

- p. 32 (B-0278): "**System Incremental Capital Investment** – includes the capital-related costs incurred to increase the capacity and operating flexibility of the gas distribution system caused by the addition of new customers (i.e., caused by development activities).

  These common capital-related investment costs should be assigned to those customers who created the need for the investment. This type of incremental investment could be required to serve new customers, all future customers, and/or existing customers who require additional capacity depending on the purpose of the investment and the timeframe considered in conjunction with the utility's ongoing distribution system planning activities.

  Those costs should also be considered for inclusion at the portfolio level when the profitability of all the development activities is evaluated."

- p. 34 (B-0278): "[…] the utility's fixed costs that are lumpy in nature and support gas service to both new and existing customers should not be attributed only to new customers in any one particular project, but should be attributed to all new customers on a project portfolio basis."

Questions:

12.1. Are all System Incremental Capital Investments required equally for load growth on the Gaz Métro system, or are some System Incremental Capital Investments required for load growth on some parts of the system, but not other parts?

Réponse :

Les réseaux de distribution sont complexes et il n'est pas possible de généraliser l'impact d'un renforcement réseau. En effet, certains renforcements ont un impact sur une partie restreinte du réseau tandis que d'autres renforcements impactent l'ensemble du réseau de Gaz Métro.

12.2. Please provide the System Incremental Capital Investment associated with each system extension and each annual portfolio over the last ten years.

Réponse :

Voir le tableau ci-dessous qui intègre les années à la liste de projets de renforcement fournie à la réponse à la question 1.6 de la demande de renseignements n° 2 de ROEÉ-Expert (B-0264, Gaz Métro-9, Document 6, page 3).

Classe de pression	# projet	Définition de projet	Coûts de 2004 à 2017	Années de réalisation
Distribution	1	Bouclage de la 640, Terrebonne	407 785	2002-2004
Distribution	2	Bouclage Croissant des Iles, Laval	11 809	2003-2004
Distribution	3	Bouclage Repentigny - Résidentiel	529 558	2004-2007
Distribution	4	Bouclage : Syst. Polymère Structural, Magog	42 251	2004
Distribution	5	Bouclage Beloeil - St-Jean-Baptiste	420 799	2005-2006
Distribution	6	Bouclage Bromont - Rue des Carrières	245 249	2005
Distribution	7	Bouclage Montcalm, Candiac	212 256	2005-2006
Distribution	8	Renforcement St-Sébastien	269 988	2006-2007
Distribution	9	Renforcement St-Valérien	353 127	2006-2007
Distribution	10	Bouclage réseau cl 400 de St-Jérôme	64 658	2007-2009
Distribution	11	Bouclage Boisbriand, 3825 Alfred-Laliberté	243 455	2008-2010
Distribution	12	Véolia, rue Pion, St-Hyacinthe	354 646	2011-2013
Distribution	13	Meubles Ashley, Sherbrooke	27 104	2010-2011
Distribution	14	Renforcement Asphalte générale	789 484	2010-2013
Distribution	15	Renforcement réseau, Pierrefonds	342 891	2011-2012
Distribution	16	550 McArthur, St-Laurent	64 541	2011
Distribution	17	Émile Giroux Renforcement, Qc	677 765	2012-2014
Distribution	18	UDM campus Outremont	164 057	2016
Distribution	19	Rang St-Paul, St-Rémi	569 041	2016

Classe de pression	# projet	Définition de projet	Coûts de 2004 à 2017	Années de réalisation
Distribution	20	Groupe Robin, 3riv	777 713	2015-2016
Distribution	21	Sani Estrie 405 Rudolphe Racine, Sherbrooke	246 944	2015-2016
Distribution	22	Renforcement réseau - dév région Bedford.	799 312	2014
Distribution	23	2911, av. Marie-Curie, St-Laurent	247 674	2015-2016
Distribution	24	Poste livraison St-Jérôme	661 789	2017
Distribution	25	Bouclage - Fruit D'Or	994 040	2016-2017
Distribution	26	Bouclage boul. Mercure St-Nicéphore	528 478	2015-2016
Distribution	27	99999 rue du parc industriel, Lanoraie	195 839	2017
Distribution	28	Bouclage Petites Soeurs Ste-Famille	27 454	2016
Distribution	29	Serres Marian Vinet St-Rémi	87 528	2017
Distribution	30	Boul. de Portland, Sherbrooke	318 269	2016-2017
Distribution	31	Campus Outremont UDM	102 929	2016-2017
Distribution	32	Marché aux puces / Faubourg Carignan	333 187	2016-2017
Distribution	33	NRC St-Paul d'Abbotsford	414 051	2016-2017
Distribution	35	Sherbrooke est / Georges 5	249 764	2002-2004
Distribution	36	Bouclage réseau ville de Labaie	42 343	2002-2004
Distribution	37	Bouclage auto 13 & boul. Ste-Rose	109 902	2003-2004
Distribution	38	Qc-Bouclage rue St-Jean	88 814	2004-2005
Distribution	39	Bouclage St-Valérien-de-Milton	202 142	2005-2007
Distribution	40	Bouclage de réseau - St-Lambert	155 908	2007-2009
Distribution	41	Renf. réseau PL Oka/St-Eustache	153 535	2008
Distribution	42	Renforcement réseau Guthrie Dorval	22 795	2008

Classe de pression	# projet	Définition de projet	Coûts de 2004 à 2017	Années de réalisation
Distribution	43	Bouclage Ste-marie 3 km 6'' plastiqu	348 315	2008-2009
Distribution	44	Bouclage rue des Châteaux Blainville	108 896	2009-2010
Distribution	45	Renforcement PD3087 -3090 Lachute	98 942	2010-2012
Distribution	46	QC-boucl. St-Amable (La Chevrotière-Art	38 924	2010
Distribution	47	Qc-Boucl. réseau - rue Guimont Beauport	77 175	2010-2013
Distribution	48	Qc-bouclage Pionnières-de-Beauport	27 412	2010
Distribution	49	Bouclage parc indus. Terrebonne	268 062	2011-2012
Distribution	50	Bouclage des Hêtres Shawinigan	24 945	2010
Distribution	51	Renforcement Ste-Elizabeth Laurentides	336 138	2010-2012
Distribution	52	Bouclage aut. 15/30 Delson	249 646	2010-2012
Distribution	53	Estrie-Boucl. St-Georges Drummondville	38 003	2011-2012
Alimentation	54	Rempl.supports/Revêt-Pont-Jacques Ca [1]	13 062 744	2011-2015
Distribution	55	Bouclage réseaux Vaudreuil	58 372	2012
Distribution	56	(ES) Sag-Lac-Bouclage 160m De Monfort	47 546	2013-2014
Distribution	57	ES/Ph3 Renforcement réseau Fleury et CN	194 391	2014-2015
Distribution	58	Renforcement réseau Clark-Graham	320 510	2013-2016
Distribution	59	Augmentation de pression réseau St-Clet	31 000	2013
Distribution	60	Sag-Lac Ab-reconst. ligne rég. PL4024-Chic	47 000	2013-2014

Classe de pression	# projet	Définition de projet	Coûts de 2004 à 2017	Années de réalisation
Distribution	61	Capacité hydraulique rue St-Antoine	199 978	2014-2015
Distribution	62	Renforcement réseau 32e Ave. Lachine	19 854	2014
Distribution	63	Renforcement réseau boul. Dagenais	141 762	2014
Distribution	64	Renforcement réseau rue Norman	154 241	2015
Distribution	65	Renf. du réseau boul. Tecumseh	705 664	2016
Transmission	67	Poste de compression St-Maurice[1]	31 933 122	2015-2017
Transmission	68	Poste de compression La Tuque[1]	48 763 054	2015-2017
Alimentation	69	Pétromont[1]	19 993 979	2012-2017
Total			**129 840 551**	

[1] Le coût des projets majeurs inclut les frais généraux corporatifs.

a. Identify the type, cost and timing of System Incremental Capital Investment assumed.

Réponse :

Veuillez vous référer à la réponse à la question 12.2.

b. To the extent possible, provide the derivation of the estimate of the cost of the System Incremental Capital Investment.

Réponse :

Les coûts apparaissant dans le tableau de la réponse à la question 12.2 sont des coûts réels […].

12.3. Please explain why the inclusion of the System Incremental Capital Investment only at the portfolio level would be efficient and equitable.

Réponse :

Black & Veatch

Please, also see the response to question 9.1 in the Information Request from OC (Gaz Métro-9, Document 12).

Please see the responses to question 8.1 above and to question 9.1 in the Information Request from OC (Gaz Métro-9, Document 12). The inclusion of the System Incremental Capital Investment at the portfolio level is efficient because it would avoid having to develop a process and methodology to apportion the cost of the System Incremental Capital Investment to individual projects, and possibly to Gaz Métro's existing customers. This method is equitable because it recognizes the lumpy nature of the investment by aligning the number of new customers to be served and their capacity needs over the analysis time period with the investment level needed to satisfy those customer requirements rather than attributing the entire cost of the investment to the "next customer" at the margin causing the need for the investment. Finally, the inclusion of the System Incremental Capital Investment at the portfolio level is straightforward and not subject to variations in interpretation or application. As noted at page 30 of its evidence (B-0278, Gaz Métro-7, Document 5), Black & Veatch recently conducted an electric line extension policy project where one of the focus areas specifically addressed the determination of when to attribute system reinforcement costs to a particular line extension project. The general findings were that it is quite difficult to do so, and when it was attempted, it was the basis of significant contention between new customers and the utility.

a. If the portfolio exceeds the target return, would B&V and Gaz Métro propose that existing customers subsidize the new customers who require the System Incremental Capital Investment?

(i) If so, please explain why that is equitable.

(ii) If so, please explain whether that would be the position of Gaz Métro and B&V, even if the service extension(s) that require the System Incremental Capital Investment would fail the economic test if the cost of the System Incremental Capital Investment were included in the analysis.

Réponse :

Black & Veatch

(i) Under the situation where the System Incremental Capital Investment was included in the profitability analysis, new customers would induce decreasing tolls for existing customers because the profitability analysis for the portfolio of projects resulted in a P.I. in excess of the target P.I.

(ii) Black & Veatch would not recommend to Gaz Métro that its existing customers should subsidize new customers if the results of the profitability analysis (which included the cost of its System Incremental Capital Investment) indicated a P.I. of below 1.1.

b. How would the costs of the System Incremental Capital Investment be allocated among the new customers on the service extensions in the portfolio?

(i) If the System Incremental Capital Investment results in the portfolio missing its profitability target, how would Gaz Métro decide which customers must contribute more to finance the service extensions?

Réponse :

Gaz Métro rappelle que les coûts de renforcement de réseau de distribution sont considérés dans la rentabilité globale du plan de développement. Le plan de développement comprend l'ensemble des ventes approuvées durant l'année financière.

Gaz Métro priorisera les projets de renforcement les plus porteurs et verra à s'assurer que le plan de développement atteint un indice de profitabilité supérieur ou égal à 1,1.

12.4. Please explain why B&V believes that new customers whose location does not contribute to the need for a System Incremental Capital Investment should be attributed to those customers as part of the "portfolio" of service extensions.

Réponse :

Black & Veatch

A primary basis for including the costs of the System Incremental Capital Investment in the profitability analysis at the portfolio level, and not at the individual project level, is that it is not necessary to determine which new customers create the need for the system investment. As such, all system extension projects and the associated new customers would be included in the profitability analysis for the project portfolio. Please also see the response to question 12.3 above.

13. Source:

R-3867-2013, B-0278, Review of Methodologies for Evaluating the Profitability of System Extension Projects – Black and Veatch evidence, (Gaz Métro-7, Document 5), p. 13, 14 (Section 3.2).

Preamble:

- B&V selected a peer group of five Canadian utilities and five US utilities (one of which is a holding company of six utilities).

Questions:

13.1. Please list all Canadian gas utilities.

Réponse :

Gaz Métro

Veuillez vous référer à la réponse à la question 10.1 de la demande de renseignements n° 3 de la FCEI (Gaz Métro-9, Document 11).

13.2. Please list all US gas utilities.

Réponse :

Black & Veatch

Please see the attachment to this response, "ROEE-Expert 13.2 Attachment 1.pdf" for a list of investor owned gas utilities that operate in the U.S.

13.3. Please explain why B&V selected these peers and not others.

Réponse :

Utilités canadiennes (Gaz Métro)

Veuillez vous référer à la réponse à la question 10.1 de la demande de renseignements n° 3 de la FCEI (Gaz Métro-9, Document 11).

Utilités américaines (Black & Veatch)

Please see the response to question 10 in the Information Request from FCEI (Gaz Métro-9, Document 11).

13.4. Please provide the documents on which B&V relied in describing the policies and practices of each of the members of the peer group as regards methodologies for evaluating the profitability of system extension projects.

Réponse :

Black & Veatch

The documents on which B&V relied are voluminous in nature and can, for most of them, be referred to on the internet. Given that situation, B&V refers to the attached list of the references of the said documents (ROEÉ-Expert 13.4 Attachment 1). However, B&V includes some documents in ROEÉ-Expert 13.4 Attachment 1 that cannot be consulted on the internet. B&V is willing to provide on request any document specifically identified, should it be difficult or impossible for the ROEÉ to consult on the internet.

Line No.	Name	Company Name	Ultimate Parent Company Name	State
2	Alabama Gas Corporation- AL	Alabama Gas Corporation	Spire Inc.	AL
3	Ameren Illinois Company- IL	Ameren Illinois Company	Ameren Corporation	IL
4	Virginia Gas Distribution Co.- VA	Appalachian Natural Gas Distribution Company	ANGD LLC	VA
5	Arkansas Oklahoma Gas Corp.- AR	Arkansas Oklahoma Gas Corp.	A.O.G. Corporation	AR
6	Atlanta Gas Light Company- GA	Atlanta Gas Light Company	Southern Company	GA
7	Atmos Energy Louisiana Division- LA	Atmos Energy Corporation		LA
8	Atmos Energy West Texas Division- TX	Atmos Energy Corporation		TX
9	Atmos Energy Colorado-Kansas Division- CO	Atmos Energy Corporation		CO
10	Atmos Energy Kentucky Division- KY	Atmos Energy Corporation		KY
11	Atmos Energy Mississippi Valley Gas- MS	Atmos Energy Corporation		MS
12	Atmos Energy Colorado-Kansas Division- KS	Atmos Energy Corporation		KS
13	Atmos Energy Mid-States Division- GA	Atmos Energy Corporation		GA
14	Atmos Energy Mid-States Division- IA	Atmos Energy Corporation		IA
15	Atmos Energy Mid-States Division- IL	Atmos Energy Corporation		IL
16	Atmos Energy Mid-States Division- TN	Atmos Energy Corporation		TN
17	Atmos Energy Mid-States Division- VA	Atmos Energy Corporation		VA
18	Atmos Energy Mid-Tex Division- TX	Atmos Energy Corporation		TX
19	Atmos Energy Corporation- MO	Atmos Energy Corporation		MO
20	Avista Corporation- ID	Avista Corporation		ID
21	Avista Corporation- OR	Avista Corporation		OR
22	Avista Corporation- WA	Avista Corporation		WA
23	Baltimore Gas and Electric Company- MD	Baltimore Gas and Electric Company	Exelon Corporation	MD
24	Bangor Gas Company, LLC- ME	Bangor Gas Company, LLC	Gas Natural Inc.	ME
25	Bay State Gas Company- MA	Bay State Gas Company	NiSource Inc.	MA
26	Berkshire Gas Company- MA	Berkshire Gas Company	Iberdrola, S.A.	MA
27	Black Hills Colorado Gas Utility Company, LP- CO	Black Hills Colorado Gas Utility Company, LP	Black Hills Corporation	CO
28	Black Hills Energy Arkansas, Inc.- AR	Black Hills Energy Arkansas, Inc.	Black Hills Corporation	AR
29	Black Hills Gas Distribution LLC- WY	Black Hills Gas Distribution LLC	Black Hills Corporation	WY
30	Black Hills Iowa Gas Utility Company, LLC- IA	Black Hills Iowa Gas Utility Company, LLC	Black Hills Corporation	IA
31	Black Hills Kansas Gas Utility Company, LLC- KS	Black Hills Kansas Gas Utility Company, LLC	Black Hills Corporation	KS
32	Black Hills Nebraska Gas Utility Company LLC- NE	Black Hills Nebraska Gas Utility Company LLC	Black Hills Corporation	NE
33	Black Hill Northwest Gas Utility Company, LLC d/b/	Black Hills Northwest Wyoming Gas Utility Company, LLC	Black Hills Corporation	WY
34	Bluefield Gas Company- WV	Bluefield Gas Company	ANGD LLC	WV
35	Boston Gas Company- MA	Boston Gas Company	National Grid plc	MA
36	Brainard Gas Corp.- OH	Brainard Gas Corp.	Gas Natural Inc.	OH
37	Brooklyn Union Gas Company- NY	Brooklyn Union Gas Company	National Grid plc	NY
38	Cascade Natural Gas Corporation- OR	Cascade Natural Gas Corporation	MDU Resources Group, Inc.	OR
39	Cascade Natural Gas Corporation- WA	Cascade Natural Gas Corporation	MDU Resources Group, Inc.	WA
40	CenterPoint Energy-Entex- TX	CenterPoint Energy Resources Corp.	CenterPoint Energy, Inc.	TX
41	CenterPoint Energy-Minnesota Gas- MN	CenterPoint Energy Resources Corp.	CenterPoint Energy, Inc.	MN
42	CenterPoint Energy-Arkla- AR	CenterPoint Energy Resources Corp.	CenterPoint Energy, Inc.	AR
43	CenterPoint Energy-Arkla- LA	CenterPoint Energy Resources Corp.	CenterPoint Energy, Inc.	LA
44	CenterPoint Energy-Oklahoma Gas- OK	CenterPoint Energy Resources Corp.	CenterPoint Energy, Inc.	OK
45	CenterPoint Energy-Arkla- TX	CenterPoint Energy Resources Corp.	CenterPoint Energy, Inc.	TX
46	CenterPoint Energy-Entex- LA	CenterPoint Energy Resources Corp.	CenterPoint Energy, Inc.	LA
47	CenterPoint Energy-Mississippi Gas- MS	CenterPoint Energy Resources Corp.	CenterPoint Energy, Inc.	MS
48	Central Hudson Gas & Electric Corporation- NY	Central Hudson Gas & Electric Corporation	Fortis Inc.	NY
49	Chattanooga Gas Company- TN	Chattanooga Gas Company	Southern Company	TN
50	Chesapeake Utilities-Delaware Division- DE	Chesapeake Utilities Corporation		DE
51	Chesapeake Utilities-Florida Division- FL	Chesapeake Utilities Corporation		FL
52	Chesapeake Utilities-Maryland Division- MD	Chesapeake Utilities Corporation		MD
53	Cheyenne Light, Fuel and Power Company- WY	Cheyenne Light, Fuel and Power Company	Black Hills Corporation	WY
54	Citizens Gas- IN	Citizens Energy Group		IN
55	Citizens Gas Fuel Company- MI	Citizens Gas Fuel Company	DTE Energy Company	MI
56	Colonial Gas Company- MA	Colonial Gas Company	National Grid plc	MA
57	Colorado Natural Gas, Inc.- CO	Colorado Natural Gas, Inc.	JPMorgan Chase & Co.	CO
58	Columbia Gas of Kentucky, Incorporated- KY	Columbia Gas of Kentucky, Incorporated	NiSource Inc.	KY
59	Columbia Gas of Maryland, Incorporated- MD	Columbia Gas of Maryland, Incorporated	NiSource Inc.	MD
60	Columbia Gas of Ohio, Incorporated- OH	Columbia Gas of Ohio, Incorporated	NiSource Inc.	OH
61	Columbia Gas of Pennsylvania, Inc.- PA	Columbia Gas of Pennsylvania, Inc.	NiSource Inc.	PA
62	Columbia Gas of Virginia, Incorporated- VA	Columbia Gas of Virginia, Incorporated	NiSource Inc.	VA
63	Connecticut Natural Gas Corporation- CT	Connecticut Natural Gas Corporation	Iberdrola, S.A.	CT
64	Consolidated Edison Company of New York, Inc.- N	Consolidated Edison Company of New York, Inc.	Consolidated Edison, Inc.	NY
65	Consumers Energy Company- MI	Consumers Energy Company	CMS Energy Corporation	MI
66	Corning Natural Gas Corporation- NY	Corning Natural Gas Corporation	Corning Natural Gas Holding Corporation	NY
67	Cut Bank Gas Co- MT	Cut Bank Gas Co	Gas Natural Inc.	MT
68	Delmarva Power & Light Company- DE	Delmarva Power & Light Company	Exelon Corporation	DE
69	Delta Natural Gas Company, Inc.- KY	Delta Natural Gas Company, Inc.		KY
70	DTE Gas Company- MI	DTE Gas Company	DTE Energy Company	MI
71	Duke Energy Kentucky, Inc.- KY	Duke Energy Kentucky, Inc.	Duke Energy Corporation	KY
72	Duke Energy Ohio, Inc.- OH	Duke Energy Ohio, Inc.	Duke Energy Corporation	OH
73	East Ohio Gas Company- OH	East Ohio Gas Company	Dominion Energy, Inc.	OH
74	Eastern Natural Gas Company- OH	Eastern Natural Gas Company	Utility Pipeline Ltd	OH
75	Empire District Gas Company- MO	Empire District Gas Company	Empire District Electric Company	MO
76	Energy West - Great Falls- MT	Energy West, Incorporated	Gas Natural Inc.	MT
77	Energy West - Cascade- MT	Energy West, Incorporated	Gas Natural Inc.	MT
78	ENSTAR Natural Gas Company- AK	ENSTAR Natural Gas Company	AltaGas Ltd.	AK
79	Entergy Gulf States Louisiana, L.L.C.- LA	Entergy Gulf States Louisiana, L.L.C.	Entergy Corporation	LA
80	Equitable Gas Company, LLC- PA	Equitable Gas Company, LLC	SteelRiver Infrastructure Partners, LP	PA
81	Equitable Gas Company, LLC- WV	Equitable Gas Company, LLC	SteelRiver Infrastructure Partners, LP	WV
82	Fitchburg Gas and Electric Light Company- MA	Fitchburg Gas and Electric Light Company	Unitil Corporation	MA

Line No.	Name	Company Name	Ultimate Parent Company Name	State
83	Indiantown Division- FL	Florida Public Utilities Company	Chesapeake Utilities Corporation	FL
84	Gas division- FL	Florida Public Utilities Company	Chesapeake Utilities Corporation	FL
85	Frontier Natural Gas LLC- NC	Frontier Natural Gas LLC	Gas Natural Inc.	NC
86	Molokai Gas District- HI	Gas Company, LLC	Macquarie Infrastructure Corporation	HI
87	Lanai Gas District- HI	Gas Company, LLC	Macquarie Infrastructure Corporation	HI
88	Oahu Gas District- HI	Gas Company, LLC	Macquarie Infrastructure Corporation	HI
89	Hilo Gas District- HI	Gas Company, LLC	Macquarie Infrastructure Corporation	HI
90	Maui Gas District- HI	Gas Company, LLC	Macquarie Infrastructure Corporation	HI
91	Kauai Gas District- HI	Gas Company, LLC	Macquarie Infrastructure Corporation	HI
92	Hope Gas, Inc.- WV	Hope Gas, Inc.	Dominion Energy, Inc.	WV
93	Illinois Gas Company- IL	Illinois Gas Company		IL
94	Indiana Gas Company, Inc.- IN	Indiana Gas Company, Inc.	Vectren Corporation	IN
95	Intermountain Gas Company- ID	Intermountain Gas Company	MDU Resources Group, Inc.	ID
96	Interstate Power and Light Company- IA	Interstate Power and Light Company	Alliant Energy Corporation	IA
97	Interstate Power and Light Company- MN	Interstate Power and Light Company	Alliant Energy Corporation	MN
98	Kansas Gas Service Company- KS	Kansas Gas Service Company	ONE Gas, Inc.	KS
99	KeySpan Gas East Corporation- NY	KeySpan Gas East Corporation	National Grid plc	NY
100	Laclede Gas Company- MO	Laclede Gas Company	Spire Inc.	MO
101	Liberty Utilities (EnergyNorth Natural Gas) Corp.- N	Liberty Utilities (EnergyNorth Natural Gas) Corp.	Algonquin Power & Utilities Corp.	NH
102	Liberty Utilities (EnergyNorth Natural Gas) - Keene	Liberty Utilities (EnergyNorth Natural Gas) Corp.	Algonquin Power & Utilities Corp.	NH
103	Liberty Utilities (Midstates Natural Gas) Corp- IL	Liberty Utilities (Midstates Natural Gas) Corp	Algonquin Power & Utilities Corp.	IL
104	Liberty Utilities (Midstates Natural Gas) Corp- MO	Liberty Utilities (Midstates Natural Gas) Corp	Algonquin Power & Utilities Corp.	MO
105	Liberty Utilities (Midstates Natural Gas) Corp- IA	Liberty Utilities (Midstates Natural Gas) Corp	Algonquin Power & Utilities Corp.	IA
106	Liberty Utilities (New England Natural Gas Compan	Liberty Utilities (New England Natural Gas Company) Corp.	Algonquin Power & Utilities Corp.	MA
107	Liberty Utilities (Peach State Natural Gas) Corp- GA	Liberty Utilities (Peach State Natural Gas) Corp	Algonquin Power & Utilities Corp.	GA
108	Louisville Gas and Electric Company- KY	Louisville Gas and Electric Company	PPL Corporation	KY
109	Madison Gas and Electric Company- WI	Madison Gas and Electric Company	MGE Energy, Inc.	WI
110	Maine Natural Gas- ME	Maine Natural Gas	Iberdrola, S.A.	ME
111	Great Plains Natural Gas Co- MN	MDU Resources Group, Inc.		MN
112	Great Plains Natural Gas Co- ND	MDU Resources Group, Inc.		ND
113	Montana-Dakota Utilities Co- MT	MDU Resources Group, Inc.		MT
114	Montana-Dakota Utilities Co- ND	MDU Resources Group, Inc.		ND
115	Michigan Gas Utilities Corporation- MI	Michigan Gas Utilities Corporation	WEC Energy Group, Inc.	MI
116	MidAmerican Energy Company- IA	MidAmerican Energy Company	Berkshire Hathaway Inc.	IA
117	MidAmerican Energy Company- IL	MidAmerican Energy Company	Berkshire Hathaway Inc.	IL
118	MidAmerican Energy Company- SD	MidAmerican Energy Company	Berkshire Hathaway Inc.	SD
119	Midwest Energy, Inc.- KS	Midwest Energy, Inc.		KS
120	Midwest Natural Gas Corporation- IN	Midwest Natural Gas Corporation		IN
121	Midwest Natural Gas, Inc.- WI	Midwest Natural Gas, Inc.		WI
122	Minnesota Energy Resources - PNG- MN	Minnesota Energy Resources Corporation	WEC Energy Group, Inc.	MN
123	MINNESOTA ENERGY RESOURCES- MN	Minnesota Energy Resources Corporation	WEC Energy Group, Inc.	MN
124	Missouri Gas Energy- MO	Missouri Gas Energy	Spire Inc.	MO
125	Mobile Gas Service Corporation- AL	Mobile Gas Service Corporation	Spire Inc.	AL
126	Mountaineer Gas Company- WV	Mountaineer Gas Company	Mountaineer Gas Holdings Ltd Partnership	WV
127	Mt. Carmel Public Utility Company- IL	Mt. Carmel Public Utility Company		IL
128	Narragansett Electric Company- RI	Narragansett Electric Company	National Grid plc	RI
129	National Fuel Gas Distribution Corporation- NY	National Fuel Gas Distribution Corporation	National Fuel Gas Company	NY
130	National Fuel Gas Distribution Corporation- PA	National Fuel Gas Distribution Corporation	National Fuel Gas Company	PA
131	New Jersey Natural Gas Company- NJ	New Jersey Natural Gas Company	New Jersey Resources Corporation	NJ
132	New Mexico Gas Company, Inc.- NM	New Mexico Gas Company, Inc.	Emera Incorporated	NM
133	New York State Electric & Gas Corporation- NY	New York State Electric & Gas Corporation	Iberdrola, S.A.	NY
134	Niagara Mohawk Power Corporation- NY	Niagara Mohawk Power Corporation	National Grid plc	NY
135	North Shore Gas Company- IL	North Shore Gas Company	WEC Energy Group, Inc.	IL
136	Northeast Ohio Natural Gas Corp.- OH	Northeast Ohio Natural Gas Corp.	Gas Natural Inc.	OH
137	Northern Illinois Gas Company- IL	Northern Illinois Gas Company	Southern Company	IL
138	Northern Indiana Public Service Company- IN	Northern Indiana Public Service Company	NiSource Inc.	IN
139	Northern States Power Company - MN- ND	Northern States Power Company - MN	Xcel Energy Inc.	ND
140	Northern States Power Company - MN- MN	Northern States Power Company - MN	Xcel Energy Inc.	MN
141	Northern States Power Company - WI- MI	Northern States Power Company - WI	Xcel Energy Inc.	MI
142	Northern States Power Company - WI	Northern States Power Company - WI	Xcel Energy Inc.	WI
143	Northern Utilities, Inc.- ME	Northern Utilities, Inc.	Unitil Corporation	ME
144	Northern Utilities, Inc.- NH	Northern Utilities, Inc.	Unitil Corporation	NH
145	Northwest Natural Gas Company- OR	Northwest Natural Gas Company		OR
146	Northwest Natural Gas Company- WA	Northwest Natural Gas Company		WA
147	NorthWestern Corporation- SD	NorthWestern Corporation		SD
148	NorthWestern Corporation- MT	NorthWestern Corporation		MT
149	NSTAR Gas Company- MA	NSTAR Gas Company	Eversource Energy	MA
150	Ohio Gas Company- OH	Ohio Gas Company	Nwo Resources Inc	OH
151	Ohio Valley Gas Corporation- OH	Ohio Valley Gas Corporation		OH
152	Ohio Valley Gas Inc- IN	Ohio Valley Gas Inc	Ohio Valley Gas Corporation	IN
153	Oklahoma Natural Gas Company- OK	Oklahoma Natural Gas Company	ONE Gas, Inc.	OK
154	Orange and Rockland Utilities, Inc.- NY	Orange and Rockland Utilities, Inc.	Consolidated Edison, Inc.	NY
155	Orwell Natural Gas Co.- OH	Orwell Natural Gas Co.	Gas Natural Inc.	OH
156	Orwell Natural Gas Co.- PA	Orwell Natural Gas Co.	Gas Natural Inc.	PA
157	Pacific Gas and Electric Company- CA	Pacific Gas and Electric Company	PG&E Corporation	CA
158	PECO Energy Company- PA	PECO Energy Company	Exelon Corporation	PA
159	Peoples Gas Light and Coke Company- IL	Peoples Gas Light and Coke Company	WEC Energy Group, Inc.	IL
160	Peoples Gas System- FL	Peoples Gas System	Emera Incorporated	FL
161	Peoples Gas WV, LLC- WV	Peoples Gas WV, LLC	SteelRiver Infrastructure Partners, LP	WV
162	Peoples Division- PA	Peoples Natural Gas Company LLC	SteelRiver Infrastructure Partners, LP	PA
163	Equitable Division- PA	Peoples Natural Gas Company LLC	SteelRiver Infrastructure Partners, LP	PA

Line No.	Name	Company Name	Ultimate Parent Company Name	State
164	Peoples TWP LLC- PA	Peoples TWP LLC	SteelRiver Infrastructure Partners, LP	PA
165	Philadelphia Gas Works Co.- PA	Philadelphia Gas Works Co.	Philadelphia City of	PA
166	Piedmont Natural Gas Company, Inc.- NC	Piedmont Natural Gas Company, Inc.	Duke Energy Corporation	NC
167	Piedmont Natural Gas Company, Inc.- SC	Piedmont Natural Gas Company, Inc.	Duke Energy Corporation	SC
168	Nashville Gas Company- TN	Piedmont Natural Gas Company, Inc.	Duke Energy Corporation	TN
169	Pike County Light and Power Company- PA	Pike County Light and Power Company	Corning Natural Gas Holding Corporation	PA
170	Pike Natural Gas Co- OH	Pike Natural Gas Co		OH
171	Florida City Gas- FL	Pivotal Utility Holdings, Inc.	Southern Company	FL
172	Elizabethtown Gas Company- NJ	Pivotal Utility Holdings, Inc.	Southern Company	NJ
173	Elkton Gas- MD	Pivotal Utility Holdings, Inc.	Southern Company	MD
174	Public Gas Company, Inc.- KY	Public Gas Company, Inc.	Kentucky Frontier Gas, LLC	KY
175	Public Service Company of Colorado- CO	Public Service Company of Colorado	Xcel Energy Inc.	CO
176	Public Service Company of North Carolina, Incorpor	Public Service Company of North Carolina, Incorporated	SCANA Corporation	NC
177	Public Service Electric and Gas Company- NJ	Public Service Electric and Gas Company	Public Service Enterprise Group Incorporated	NJ
178	Puget Sound Energy, Inc.- WA	Puget Sound Energy, Inc.	Puget Holdings LLC	WA
179	Questar Gas Company- ID	Questar Gas Company	Dominion Energy, Inc.	ID
180	Questar Gas Company- UT	Questar Gas Company	Dominion Energy, Inc.	UT
181	Questar Gas Company- WY	Questar Gas Company	Dominion Energy, Inc.	WY
182	Roanoke Gas Co.- VA	Roanoke Gas Company	RGC Resources, Inc.	VA
183	Roanoke Gas Company- VA	Roanoke Gas Company	RGC Resources, Inc.	VA
184	Rochester Gas and Electric Corporation- NY	Rochester Gas and Electric Corporation	Iberdrola, S.A.	NY
185	San Diego Gas & Electric Co.- CA	San Diego Gas & Electric Co.	Sempra Energy	CA
186	SEMCO Energy, Inc.- MI	SEMCO Energy, Inc.	AltaGas Ltd.	MI
187	Sierra Pacific Power Company- NV	Sierra Pacific Power Company	Berkshire Hathaway Inc.	NV
188	South Carolina Electric & Gas Co.- SC	South Carolina Electric & Gas Co.	SCANA Corporation	SC
189	South Jersey Gas Company- NJ	South Jersey Gas Company	South Jersey Industries, Inc.	NJ
190	Southern California Gas Company- CA	Southern California Gas Company	Sempra Energy	CA
191	Southern Connecticut Gas Company- CT	Southern Connecticut Gas Company	Iberdrola, S.A.	CT
192	Southern Indiana Gas and Electric Company, Inc.- I	Southern Indiana Gas and Electric Company, Inc.	Vectren Corporation	IN
193	Southwest Gas Corporation- AZ	Southwest Gas Corporation	Southwest Gas Holdings, Inc.	AZ
194	Southwest Gas Corporation- CA	Southwest Gas Corporation	Southwest Gas Holdings, Inc.	CA
195	Southwest Gas Corporation- NV	Southwest Gas Corporation	Southwest Gas Holdings, Inc.	NV
196	St. Joe Natural Gas Co, Inc.- FL	St. Joe Natural Gas Co, Inc.		FL
197	St. Lawrence Gas Company, Inc.- NY	St. Lawrence Gas Company, Inc.	Enbridge Inc.	NY
198	Summit Natural Gas of Missouri, Inc.- MO	Summit Natural Gas of Missouri, Inc.	JPMorgan Chase & Co.	MO
199	Superior Water, Light and Power Company- WI	Superior Water, Light and Power Company	ALLETE, Inc.	WI
200	Sycamore Gas Company- IN	Sycamore Gas Company	INOH Gas Inc.	IN
201	Texas Gas Service Company- TX	Texas Gas Service Company	ONE Gas, Inc.	TX
202	UGI Central Penn Gas, Inc.- MD	UGI Central Penn Gas, Inc.	UGI Corporation	MD
203	UGI Central Penn Gas, Inc.- PA	UGI Central Penn Gas, Inc.	UGI Corporation	PA
204	UGI Penn Natural Gas, Inc.- PA	UGI Penn Natural Gas, Inc.	UGI Corporation	PA
205	UGI Utilities, Inc.- PA	UGI Utilities, Inc.	UGI Corporation	PA
206	Union Electric Company- MO	Union Electric Company	Ameren Corporation	MO
207	UNS Gas, Inc.- AZ	UNS Gas, Inc.	Fortis Inc.	AZ
208	Valley Gas- PA	Valley Energy Inc.	C&T Enterprises, Inc.	PA
209	Waverly Gas Service- NY	Valley Energy Inc.	C&T Enterprises, Inc.	NY
210	Vectren Energy Delivery of Ohio, Inc.- OH	Vectren Energy Delivery of Ohio, Inc.	Vectren Corporation	OH
211	Vermont Gas Systems, Inc.- VT	Vermont Gas Systems, Inc.	Caisse de dépôt et placement du Québec	VT
212	Virginia Natural Gas, Inc.- VA	Virginia Natural Gas, Inc.	Southern Company	VA
213	Washington Gas Light Company- MD	Washington Gas Light Company	WGL Holdings, Inc.	MD
214	Washington Gas Light Company- VA	Washington Gas Light Company	WGL Holdings, Inc.	VA
215	West Yellowstone Gas- MT	West Yellowstone Gas	Gas Natural Inc.	MT
216	Willmut Gas & Oil Company- MS	Willmut Gas & Oil Company	Spire Inc.	MS
217	Wisconsin Electric Power Company- WI	Wisconsin Electric Power Company	WEC Energy Group, Inc.	WI
218	Wisconsin Gas LLC- WI	Wisconsin Gas LLC	WEC Energy Group, Inc.	WI
219	Wisconsin Power and Light Company- WI	Wisconsin Power and Light Company	Alliant Energy Corporation	WI
220	Wisconsin Public Service Corporation- MI	Wisconsin Public Service Corporation	WEC Energy Group, Inc.	MI
221	Wisconsin Public Service Corporation- WI	Wisconsin Public Service Corporation	WEC Energy Group, Inc.	WI
222	Wyoming Gas Company- WY	Wyoming Gas Company		WY
223	Yankee Gas Services Company- CT	Yankee Gas Services Company	Eversource Energy	CT

Black & Veatch Management Consulting, LLC
Review of Methodologies for Evaluating the Profitability of System Extension Projects
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Milverton, Wartburg, Rostock

Project Year ($000's)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Cash Inflow																				
Revenue	41	110	148	168	183	198	213	228	243	257	264	264	264	264	264	264	264	264	264	264
System Expansion Surcharge (SES)	143	344	422	459	486	514	542	570	598	624	637	637	637	637	637	96	-	-	-	-
Municipal Financial Support	41	41	41	41	41	41	41	41	41	41	-	-	-	-	-	-	-	-	-	-
Expenses:																				
O & M Expense	(6)	(17)	(24)	(28)	(32)	(36)	(39)	(44)	(48)	(52)	(55)	(56)	(58)	(59)	(61)	(62)	(64)	(65)	(66)	(68)
Municipal Tax	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)
Income Tax	3	(26)	(57)	(73)	(87)	(100)	(113)	(127)	(139)	(152)	(148)	(151)	(154)	(156)	(159)	(17)	6	4	2	1
Advancement Cost	(127)																			
Net Cash Inflow	16	373	452	487	512	537	563	589	616	640	619	615	611	607	603	201	127	124	121	118
Cash Outflow																				
Incremental Capital	5 033	279	113	85	71	84	77	84	78	71	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cash Outflow	5 034	280	113	86	71	84	77	84	78	71	0	0	0	0	0	0	0	0	0	0
Cumulative Net Present Value																				
Cash Inflow	16	362	761	1 170	1 580	1 988	2 396	2 802	3 205	3 604	3 971	4 318	4 646	4 956	5 249	5 342	5 398	5 450	5 499	5 543
Cash Outflow	5 034	5 300	5 403	5 476	5 535	5 601	5 658	5 717	5 770	5 815	5 815	5 815	5 815	5 815	5 815	5 816	5 816	5 816	5 816	5 816
NPV By Year	(5 017)	(4 938)	(4 641)	(4 306)	(3 955)	(3 612)	(3 262)	(2 915)	(2 564)	(2 211)	(1 844)	(1 497)	(1 169)	(859)	(566)	(473)	(417)	(365)	(317)	(272)
Project NPV @ Yr 40	73		40 Term (yrs)																	
Profitability Index																				
By Year PI	0,00	0,07	0,14	0,21	0,29	0,35	0,42	0,49	0,56	0,62	0,68	0,74	0,80	0,85	0,90	0,92	0,93	0,94	0,95	0,95
Project PI	1,01																			

Classification	Consumption (m3/year)	Annualized Dist'n Margin before SES	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Total	Ultimate Potential	Total Attachments % Potential
Residential Conversion	2,216	315	141	126	47	34	27	33	28	33	29	27	525	710	74%
Residential New	2,000	310	10	10	10	10	10	10	10	10	10	10	100	100	100%
Residential Multi Family	1,350	292	10	10	4	3	2	3	2	3	2	2	41	55	75%
Small Commercial	Wt Ave 14,631	Ave Yr 10 Dist'n Per Cust = $756	13	12	4	3	2	3	3	3	3	2	48	65	74%
Medium Commercial			5	4	2	1	1	1	1	1	1	1	18	24	75%
Large Commercial			5	1	0	0	0	0	0	0	0	0	6	6	100%
Seasonal (Grain Dryer)			1	0	0	0	0	0	0	0	0	0	1	1	100%
Total			185	163	67	51	42	50	44	50	45	42	739	961	77%

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Distribution Revenue																				
Residential	25	73	106	123	136	149	163	176	190	202	208	208	208	208	208	208	208	208	208	208
Comm/Industrial	16	37	43	45	47	48	50	52	54	55	56	56	56	56	56	56	56	56	56	56
SES, Muni Revenue																				
Volume for SES Charge 10^3 M^3	622	1 495	1 837	1 994	2 114	2 233	2 355	2 478	2 601	2 715	2 770	2 770	2 770	2 770	2 770	415	-	-	-	-
SES Revenue @ $0.23 / M^: 0,23	143	344	422	459	486	514	542	570	598	624	637	637	637	637	637	96	-	-	-	-
Muni Contribution	41	41	41	41	41	41	41	41	41	41	-	-	-	-	-	-	-	-	-	-
Calculation of Income Tax																				
Revenue	225	495	612	667	710	752	795	839	883	923	901	901	901	901	901	360	264	264	264	264
O&M Expense	(6)	(17)	(24)	(28)	(32)	(36)	(39)	(44)	(48)	(52)	(55)	(56)	(58)	(59)	(61)	(62)	(64)	(65)	(66)	(68)
Municipal Tax	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)
CCA	(151)	(301)	(295)	(283)	(271)	(259)	(249)	(239)	(229)	(220)	(209)	(196)	(184)	(173)	(163)	(153)	(144)	(135)	(127)	(120)
Taxable Income	(11)	97	214	277	328	378	428	477	526	572	558	569	580	589	598	65	(23)	(15)	(9)	(2)
Income Tax Rate	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%
Current Income Taxes	(3)	26	57	73	87	100	113	127	139	152	148	151	154	156	159	17	(6)	(4)	(2)	(1)
Inccome Tax Cash Flow	3	(26)	(57)	(73)	(87)	(100)	(113)	(127)	(139)	(152)	(148)	(151)	(154)	(156)	(159)	(17)	6	4	2	1

Milverton, Wartburg, Rostock

Project Year ($000's)	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40
Cash Inflow																				
Revenue	233	223	220	218	217	215	213	212	210	208	208	208	208	208	208	208	208	208	208	208
System Expansion Surcharge (SES)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Municipal Financial Support	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expenses:																				
O & M Expense	(64)	(58)	(57)	(57)	(58)	(58)	(59)	(59)	(60)	(61)	(61)	(62)	(63)	(64)	(65)	(66)	(66)	(66)	(66)	(66)
Municipal Tax	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)
Income Tax	6	5	4	3	2	1	1	0	(1)	(1)	(2)	(3)	(3)	(4)	(4)	(5)	(6)	(6)	(7)	(8)
Advancement Cost																				
Net Cash Inflow	96	91	88	85	82	79	76	73	70	67	66	64	63	61	60	58	57	57	56	56
Cash Outflow																				
Incremental Capital	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	(0)	(0)	(0)	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-
Cash Outflow	(0)	(0)	(0)	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-
Cumulative Net Present Value																				
Cash Inflow	5 578	5 609	5 638	5 664	5 688	5 710	5 731	5 749	5 766	5 782	5 796	5 809	5 822	5 833	5 844	5 854	5 863	5 872	5 880	5 888
Cash Outflow	5 816	5 815	5 815	5 815	5 815	5 815	5 815	5 815	5 815	5 816	5 816	5 816	5 816	5 816	5 816	5 816	5 816	5 816	5 816	5 816
NPV By Year	(238)	(207)	(178)	(152)	(127)	(105)	(85)	(66)	(49)	(34)	(19)	(6)	6	18	29	38	48	57	65	73
Project NPV @ Yr 40																				
Profitability Index																				
By Year PI	0,96	0,96	0,97	0,97	0,98	0,98	0,99	0,99	0,99	0,99	1,00	1,00	1,00	1,00	1,00	1,01	1,01	1,01	1,01	1,01
Project PI																				

	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40
Distribution Revenue																				
Residential	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208
Comm/Industrial	24	15	12	10	9	7	5	3	1	-	-	-	-	-	-	-	-	-	-	-
SES, Muni Revenue																				
Volume for SES Charge 10^3 M^3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SES Revenue @ $0.23 / M^: 0,23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Muni Contribution	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Calculation of Income Tax																				
Revenue	233	223	220	218	217	215	213	212	210	208	208	208	208	208	208	208	208	208	208	208
O&M Expense	(64)	(58)	(57)	(57)	(58)	(58)	(59)	(59)	(60)	(61)	(61)	(62)	(63)	(64)	(65)	(66)	(66)	(66)	(66)	(66)
Municipal Tax	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)
CCA	(112)	(106)	(99)	(93)	(88)	(83)	(78)	(73)	(69)	(64)	(61)	(57)	(54)	(50)	(47)	(44)	(42)	(39)	(37)	(35)
Taxable Income	(23)	(20)	(16)	(12)	(8)	(5)	(2)	(0)	2	4	7	10	12	15	17	19	21	24	26	28
Income Tax Rate	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%
Current Income Taxes	(6)	(5)	(4)	(3)	(2)	(1)	(1)	(0)	1	1	2	3	3	4	4	5	6	6	7	8
Inccome Tax Cash Flow	6	5	4	3	2	1	1	0	(1)	(1)	(2)	(3)	(3)	(4)	(4)	(5)	(6)	(6)	(7)	(8)

Lambton Shores - Kettle Point

Project Year ($000's)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Cash Inflow																				
Revenue	27	64	79	86	91	96	101	106	111	116	118	118	118	118	118	118	118	118	118	118
System Expansion Surcharge (SES)	54	126	150	162	170	178	186	194	202	210	213	213	32	-	-	-	-	-	-	-
Municipal Financial Support	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expenses:																				
O & M Expense	(4)	(11)	(13)	(15)	(16)	(18)	(19)	(21)	(22)	(24)	(25)	(25)	(26)	(26)	(27)	(28)	(28)	(29)	(29)	(30)
Municipal Tax	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)
Income Tax	(1)	(14)	(24)	(30)	(34)	(38)	(42)	(46)	(50)	(54)	(57)	(58)	(10)	(3)	(4)	(4)	(5)	(6)	(6)	(7)
Advancement Cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Cash Inflow	55	145	171	182	190	197	205	212	220	227	230	228	93	68	67	66	64	63	62	61
Cash Outflow																				
Incremental Capital	1 778	105	43	27	21	26	23	26	24	21	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cash Outflow	1 778	106	43	27	21	26	23	26	24	21	0	0	0	0	0	0	0	0	0	0
Cumulative Net Present Value																				
Cash Inflow	54	188	339	492	644	794	942	1 089	1 233	1 375	1 511	1 640	1 690	1 725	1 757	1 788	1 816	1 843	1 867	1 890
Cash Outflow	1 778	1 879	1 918	1 942	1 959	1 980	1 996	2 015	2 031	2 045	2 045	2 045	2 045	2 045	2 045	2 045	2 045	2 045	2 045	2 045
NPV By Year	(1 725)	(1 691)	(1 579)	(1 449)	(1 315)	(1 185)	(1 054)	(926)	(798)	(670)	(534)	(405)	(355)	(320)	(287)	(257)	(229)	(202)	(178)	(155)
Project NPV @ Yr 40	71		40	Term (yrs)																
Profitability Index																				
By Year PI	0,03	0,10	0,18	0,25	0,33	0,40	0,47	0,54	0,61	0,67	0,74	0,80	0,83	0,84	0,86	0,87	0,89	0,90	0,91	0,92
Project PI	1,03																			

Classification	Consumption (m3/year)	Annualized Dist'n Margin before SES	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Total	Ultimate Potential	Total Attachments % Potential
Residential Conversion - Lambton Shores	2216	315	71	63	24	17	13	16	14	16	15	13	262	380	69%
Residential Conversion - Kettle Point (Band Owned)	2216	315	32	-	-	-	-	-	-	-	-	-	32	32	100%
Residential Conversion Multi Family-Kettle Point (Band Owned)	1350	292	33	-	-	-	-	-	-	-	-	-	33	33	100%
Residential Conversion - Kettle Point (Private)	2216	315	4	4	2	1	1	1	1	1	1	1	17	45	38%
Small Commercial - Band Owned	Wt Ave 9,725	Ave Yr 10 Dist'n Per Cust = $532	5	-	-	-	-	-	-	-	-	-	5	5	100%
Small Commercial - Privately Owned			1	1	1	-	-	-	-	-	-	-	3	5	60%
Medium Commercial - Band Owned			11	-	-	-	-	-	-	-	-	-	11	11	100%
Large Commercial - Band Owned			1	-	-	-	-	-	-	-	-	-	1	1	100%
Total			158	68	27	18	14	17	15	17	16	14	364	512	71%

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Distribution Revenue																				
Residential	22	54	69	75	81	85	90	95	101	105	108	108	108	108	108	108	108	108	108	108
Comm/Industrial	5	10	10	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	27																			
SES, Muni Revenue																				
Volume for SES Charge 10^3 M^3	235	546	652	702	738	772	807	843	879	913	928	928	139	-	-	-	-	-	-	-
SES Revenue @ $0.23 / M^3 0,23	54	126	150	162	170	178	186	194	202	210	213	213	32	-	-	-	-	-	-	-
Muni Contribution	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Calculation of Income Tax																				
Revenue	81	190	229	248	261	274	287	300	314	326	332	332	150	118	118	118	118	118	118	118
O&M Expense	(4)	(11)	(13)	(15)	(16)	(18)	(19)	(21)	(22)	(24)	(25)	(25)	(26)	(26)	(27)	(28)	(28)	(29)	(29)	(30)
Municipal Tax	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)
CCA	(53)	(107)	(105)	(101)	(96)	(92)	(88)	(84)	(80)	(77)	(73)	(68)	(64)	(61)	(57)	(53)	(50)	(47)	(44)	(42)
Taxable Income	3	52	90	111	128	144	159	175	190	205	214	217	39	11	14	17	19	22	24	26
Income Tax Rate	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%
Current Income Taxes	1	14	24	30	34	38	42	46	50	54	57	58	10	3	4	4	5	6	6	7
Inccome Tax Cash Flow	(1)	(14)	(24)	(30)	(34)	(38)	(42)	(46)	(50)	(54)	(57)	(58)	(10)	(3)	(4)	(4)	(5)	(6)	(6)	(7)

Lambton Shores - Kettle Point

Project Year ($000's)	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40
Cash Inflow																				
Revenue	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108
System Expansion Surcharge (SES)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Municipal Financial Support	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expenses:																				
O & M Expense	(29)	(28)	(28)	(28)	(29)	(29)	(30)	(30)	(31)	(31)	(32)	(32)	(33)	(33)	(34)	(34)	(34)	(34)	(34)	(34)
Municipal Tax	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)
Income Tax	(5)	(6)	(6)	(7)	(7)	(8)	(8)	(8)	(9)	(9)	(9)	(9)	(9)	(10)	(10)	(10)	(10)	(10)	(11)	(11)
Advancement Cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Cash Inflow	54	54	53	52	51	50	49	48	48	47	46	46	45	44	44	43	43	43	42	42
Cash Outflow																				
Incremental Capital	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	(0)	(0)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-
Cash Outflow	(0)	(0)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-
Cumulative Net Present Value																				
Cash Inflow	1 910	1 928	1 945	1 961	1 976	1 990	2 004	2 016	2 027	2 038	2 048	2 058	2 067	2 075	2 083	2 090	2 097	2 104	2 110	2 116
Cash Outflow	2 045	2 045	2 045	2 045	2 045	2 045	2 045	2 045	2 045	2 045	2 045	2 045	2 045	2 045	2 045	2 045	2 045	2 045	2 045	2 045
NPV By Year	(135)	(117)	(100)	(84)	(69)	(55)	(41)	(29)	(17)	(7)	3	13	22	30	38	45	52	59	65	71
Project NPV @ Yr 40																				
Profitability Index																				
By Year PI	0,93	0,94	0,95	0,96	0,97	0,97	0,98	0,99	0,99	1,00	1,00	1,01	1,01	1,01	1,02	1,02	1,03	1,03	1,03	1,03
Project PI																				

	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40
Distribution Revenue																				
Residential	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108
Comm/Industrial	1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SES, Muni Revenue																				
Volume for SES Charge 10^3 M^3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SES Revenue @ $0.23 / M^3 0,23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Muni Contribution	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Calculation of Income Tax																				
Revenue	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108
O&M Expense	(29)	(28)	(28)	(28)	(29)	(29)	(30)	(30)	(31)	(31)	(32)	(32)	(33)	(33)	(34)	(34)	(34)	(34)	(34)	(34)
Municipal Tax	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)
CCA	(39)	(37)	(35)	(33)	(31)	(29)	(27)	(25)	(24)	(22)	(21)	(20)	(19)	(18)	(16)	(16)	(15)	(14)	(13)	(12)
Taxable Income	20	23	24	26	27	29	30	31	32	33	34	35	36	36	37	37	38	39	40	41
Income Tax Rate	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%
Current Income Taxes	5	6	6	7	7	8	8	8	9	9	9	9	9	10	10	10	10	10	11	11
Inccome Tax Cash Flow	(5)	(6)	(6)	(7)	(7)	(8)	(8)	(8)	(9)	(9)	(9)	(9)	(9)	(10)	(10)	(10)	(10)	(10)	(11)	(11)

Moraviantown

Project Year ($000's)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Cash Inflow																				
Revenue	4	8	9	10	10	11	11	11	12	12	12	12	12	12	12	12	12	12	12	12
System Expansion Surcharge (SES)	6	13	15	16	17	17	18	18	19	19	20	20	20	20	20	20	20	20	20	20
Municipal Financial Support	5	5	5	5	5	5	5	5	5	5	-	-	-	-	-	-	-	-	-	-
Expenses:																				
O & M Expense	(1)	(1)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Municipal Tax	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)
Income Tax	0	(1)	(2)	(2)	(3)	(3)	(3)	(4)	(4)	(4)	(3)	(3)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)
Advancement Cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Cash Inflow	6	16	18	19	19	20	20	21	21	21	18	18	17	17	17	17	17	17	16	16
Cash Outflow																				
Incremental Capital	229	8	3	3	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cash Outflow	229	8	3	3	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0
Cumulative Net Present Value																				
Cash Inflow	6	21	37	53	68	83	98	112	126	139	150	160	169	178	186	194	201	208	215	221
Cash Outflow	229	236	239	242	243	244	246	247	248	249	249	249	249	249	249	249	249	249	249	249
NPV By Year	(223)	(215)	(202)	(189)	(175)	(161)	(148)	(135)	(122)	(110)	(99)	(89)	(80)	(71)	(63)	(55)	(48)	(41)	(34)	(28)
Project NPV @ Yr 40	-		40	Term (yrs)																
Profitability Index																				
By Year PI	0,03	0,09	0,15	0,22	0,28	0,34	0,40	0,45	0,51	0,56	0,60	0,64	0,68	0,71	0,75	0,78	0,81	0,84	0,86	0,89
Project PI	1,00																			

Classification	Consumption (m3/year)	Annualized Dist'n Margin before SES	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Total	Ultimate Potential	Total Attachments % Potential
Residential Conversion	2216	315	5	5	2	2	1	1	1	1	1	1	20	53	38%
Small Commercial	Wt Ave 2,260	Ave Yr 10 Dist'n Per Cust = $321	17	-	-	-	-	-	-	-	-	-	17	17	100%
Medium Commercial			1	-	-	-	-	-	-	-	-	-	1	1	100%
Seasonal (Grain Dryer)			-	-	-	-	-	-	-	-	-	-	-	0	0%
Total			23	5	2	2	1	1	1	1	1	1	38	71	54%

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Distribution Revenue																				
Residential	1	2	3	4	5	5	5	6	6	6	6	6	6	6	6	6	6	6	6	6
Comm/Industrial	3	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
SES, Muni Revenue																				
Volume for SES Charge 10^3 M^3	26	57	65	69	73	75	77	79	82	84	85	85	85	85	85	85	85	85	85	85
SES Revenue @ $0.23 / M^3 0,23	6	13	15	16	17	17	18	18	19	19	20	20	20	20	20	20	20	20	20	20
Muni Contribution	5	5	5	5	5	5	5	5	5	5	-	-	-	-	-	-	-	-	-	-
Calculation of Income Tax																				
Revenue	15	26	29	31	32	33	34	35	35	36	32	32	32	32	32	32	32	32	32	32
O&M Expense	(1)	(1)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Municipal Tax	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)
CCA	(7)	(14)	(13)	(12)	(12)	(11)	(11)	(10)	(10)	(9)	(9)	(8)	(8)	(7)	(7)	(6)	(6)	(6)	(5)	(5)
Taxable Income	(1)	3	7	9	10	12	13	14	15	17	12	13	13	14	14	14	15	15	15	15
Income Tax Rate	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%
Current Income Taxes	(0)	1	2	2	3	3	3	4	4	4	3	3	4	4	4	4	4	4	4	4
Inccome Tax Cash Flow	0	(1)	(2)	(2)	(3)	(3)	(3)	(4)	(4)	(4)	(3)	(3)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)

Moraviantown

Project Year ($000's)	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40
Cash Inflow																				
Revenue	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
System Expansion Surcharge (SES)	15	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Municipal Financial Support	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expenses:																				
O & M Expense	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
Municipal Tax	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)
Income Tax	(2)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Advancement Cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Cash Inflow	9	6	6	6	6	6	6	6	6	6	6	6	5	5	5	5	5	5	5	5
Cash Outflow																				
Incremental Capital	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	(0)	(0)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-
Cash Outflow	(0)	(0)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-
Cumulative Net Present Value																				
Cash Inflow	224	226	228	230	232	234	235	237	238	239	240	242	243	244	245	246	246	247	248	249
Cash Outflow	249	249	249	249	249	249	249	249	249	249	249	249	249	249	249	249	249	249	249	249
NPV By Year	(25)	(23)	(21)	(19)	(17)	(15)	(14)	(12)	(11)	(10)	(8)	(7)	(6)	(5)	(4)	(3)	(2)	(2)	(1)	-
Project NPV @ Yr 40																				
Profitability Index																				
By Year PI	0,90	0,91	0,92	0,92	0,93	0,94	0,94	0,95	0,96	0,96	0,97	0,97	0,98	0,98	0,98	0,99	0,99	0,99	1,00	1,00
Project PI																				
Distribution Revenue																				
Residential	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Comm/Industrial	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SES, Muni Revenue																				
Volume for SES Charge 10^3 M^3	65	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
SES Revenue @ $0.23 / M^3 0,23	15	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Muni Contribution	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Calculation of Income Tax																				
Revenue	21	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
O&M Expense	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
Municipal Tax	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)
CCA	(5)	(4)	(4)	(4)	(4)	(3)	(3)	(3)	(3)	(3)	(3)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(1)
Taxable Income	6	3	3	3	3	3	4	4	4	4	4	4	4	5	5	5	5	5	5	5
Income Tax Rate	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%
Current Income Taxes	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Inccome Tax Cash Flow	(2)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)

Prince Township

Project Year ($000's)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Cash Inflow																					
Revenue	18	52	75	85	93	101	109	117	125	132	136	136	136	136	136	136	136	136	136	136	133
System Expansion Surcharge (SES)	22	62	88	100	109	118	127	136	145	154	158	158	158	158	158	158	158	158	158	158	156
Municipal Financial Support	12	12	12	12	12	12	12	12	12	12	-	-	-	-	-	-	-	-	-	-	-
Expenses:																					
O & M Expense	(3)	(8)	(12)	(14)	(15)	(17)	(19)	(21)	(23)	(25)	(26)	(26)	(27)	(28)	(28)	(29)	(29)	(30)	(30)	(31)	(31)
Municipal Tax	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)
Income Tax	7	7	(5)	(12)	(17)	(22)	(28)	(33)	(38)	(43)	(42)	(44)	(45)	(46)	(47)	(48)	(49)	(50)	(51)	(52)	(51)
Advancement Cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Cash Inflow	45	113	146	159	169	179	189	199	210	219	214	212	210	208	207	205	204	202	201	199	194
Cash Outflow																					
Incremental Capital	2 168	177	66	49	38	49	41	49	43	41	-	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cash Outflow	2 168	178	67	49	38	49	41	49	44	41	0	0	0	0	0	0	0	0	0	0	0
Cumulative Net Present Value																					
Cash Inflow	43	149	278	411	547	683	820	957	1 094	1 231	1 358	1 477	1 590	1 697	1 797	1 892	1 981	2 066	2 146	2 222	2 292
Cash Outflow	2 168	2 337	2 398	2 440	2 471	2 509	2 539	2 574	2 603	2 629	2 629	2 629	2 629	2 629	2 629	2 630	2 630	2 630	2 630	2 630	2 630
NPV By Year	(2 125)	(2 188)	(2 120)	(2 028)	(1 924)	(1 826)	(1 720)	(1 617)	(1 509)	(1 398)	(1 272)	(1 152)	(1 039)	(933)	(833)	(738)	(648)	(564)	(484)	(408)	(338)
Project NPV @ Yr 40	10		40 Term (yrs)																		
Profitability Index																					
By Year PI	0,02	0,06	0,12	0,17	0,22	0,27	0,32	0,37	0,42	0,47	0,52	0,56	0,60	0,65	0,68	0,72	0,75	0,79	0,82	0,84	0,87
Project PI	1,00																				

Classification	Consumption (m3/year)	Annualized Dist'n Margin before SES	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Total	Ultimate Potential	Total Attachments % Potential
Residential Conversion	2,273	460	71	64	24	17	13	17	14	17	15	14	266	370	71.89%
Residential New	2,273	460	2	2	2	2	2	2	2	2	2	2	20	20	100.00%
Small Commercial	7,640	918	3	2	-	-	-	-	-	-	-	-	5	5	100.00%
Total			76	68	26	19	15	19	16	19	17	16	291	395	73.67%

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Distribution Revenue																					
Residential	17	49	70	80	88	96	104	112	120	128	132	132	132	132	132	132	132	132	132	132	132
Comm/Industrial	1	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	2
SES, Muni Revenue																					
Volume for SES Charge 10^3 M^3	94	271	384	435	473	512	552	592	633	670	688	688	688	688	688	688	688	688	688	688	677
SES Revenue @ $0.23 / M^3 0,23	22	62	88	100	109	118	127	136	145	154	158	158	158	158	158	158	158	158	158	158	156
Muni Contribution	12	12	12	12	12	12	12	12	12	12	-	-	-	-	-	-	-	-	-	-	-
Calculation of Income Tax																					
Revenue	52	127	175	197	214	231	248	265	283	299	294	294	294	294	294	294	294	294	294	294	289
O&M Expense	(3)	(8)	(12)	(14)	(15)	(17)	(19)	(21)	(23)	(25)	(26)	(26)	(27)	(28)	(28)	(29)	(29)	(30)	(30)	(31)	(31)
Municipal Tax	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)
CCA	(65)	(131)	(131)	(127)	(122)	(117)	(113)	(108)	(105)	(101)	(96)	(90)	(85)	(80)	(75)	(71)	(66)	(62)	(59)	(55)	(52)
Taxable Income	(28)	(25)	20	45	65	84	104	124	143	161	160	165	170	175	179	183	187	190	193	196	194
Income Tax Rate	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%
Current Income Taxes	(7)	(7)	5	12	17	22	28	33	38	43	42	44	45	46	47	48	49	50	51	52	51
Inccome Tax Cash Flow	7	7	(5)	(12)	(17)	(22)	(28)	(33)	(38)	(43)	(42)	(44)	(45)	(46)	(47)	(48)	(49)	(50)	(51)	(52)	(51)

Prince Township

Project Year ($000's)	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40
Cash Inflow																			
Revenue	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132
System Expansion Surcharge (SES)	151	22	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Municipal Financial Support	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expenses:																			
O & M Expense	(31)	(32)	(32)	(33)	(33)	(34)	(34)	(35)	(35)	(36)	(36)	(37)	(38)	(38)	(39)	(39)	(39)	(39)	(39)
Municipal Tax	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)
Income Tax	(50)	(17)	(12)	(12)	(13)	(13)	(14)	(14)	(14)	(15)	(15)	(15)	(16)	(16)	(16)	(16)	(17)	(17)	(17)
Advancement Cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Cash Inflow	189	93	75	74	73	72	71	70	69	69	68	67	66	65	65	64	64	64	64
Cash Outflow																			
Incremental Capital	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-
Cash Outflow	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-
Cumulative Net Present Value																			
Cash Inflow	2 356	2 387	2 410	2 432	2 453	2 472	2 490	2 507	2 523	2 538	2 552	2 566	2 578	2 590	2 601	2 611	2 621	2 631	2 640
Cash Outflow	2 630	2 630	2 630	2 630	2 630	2 630	2 630	2 630	2 630	2 630	2 630	2 630	2 630	2 630	2 630	2 630	2 630	2 630	2 630
NPV By Year	(273)	(243)	(220)	(198)	(177)	(158)	(140)	(123)	(107)	(91)	(77)	(64)	(52)	(40)	(29)	(18)	(8)	1	10
Project NPV @ Yr 40																			
Profitability Index																			
By Year PI	0,90	0,91	0,92	0,92	0,93	0,94	0,95	0,95	0,96	0,97	0,97	0,98	0,98	0,98	0,99	0,99	1,00	1,00	1,00
Project PI																			

Distribution Revenue																			
Residential	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132
Comm/Industrial	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SES, Muni Revenue																			
Volume for SES Charge 10^3 M^3	658	98	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SES Revenue @ $0.23 / M^3 0,23	151	22	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Muni Contribution	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Calculation of Income Tax																			
Revenue	283	154	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132
O&M Expense	(31)	(32)	(32)	(33)	(33)	(34)	(34)	(35)	(35)	(36)	(36)	(37)	(38)	(38)	(39)	(39)	(39)	(39)	(39)
Municipal Tax	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)
CCA	(49)	(46)	(43)	(40)	(38)	(36)	(34)	(32)	(30)	(28)	(26)	(25)	(23)	(22)	(20)	(19)	(18)	(17)	(16)
Taxable Income	191	64	44	46	48	50	51	53	54	55	57	58	59	59	60	61	63	64	65
Income Tax Rate	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%	26,50%
Current Income Taxes	50	17	12	12	13	13	14	14	14	15	15	15	16	16	16	16	17	17	17
Inccome Tax Cash Flow	(50)	(17)	(12)	(12)	(13)	(13)	(14)	(14)	(14)	(15)	(15)	(15)	(16)	(16)	(16)	(16)	(17)	(17)	(17)

Authorized Margin Revenue Per Customer Per Month

	July	August	September	October	November	December	January	February	March	April	May	June	Annual TOTAL	PNPV PNVP (Total/7.35%)
Schedule 503 - Residential														
Basic Service Charge	$4,00	$4,00	$4,00	$4,00	$4,00	$4,00	$4,00	$4,00	$4,00	$4,00	$4,00	$4,00	$48,00	
Authorized Margin Revenue Per Customer*	$3,19	$5,12	$4,54	$10,55	$9,73	$33,87	$30,20	$31,75	$25,88	$14,79	$11,74	$9,97	$191,34	
Schedule 504 - Commercial													**$239,34**	**$3 256,34**
Basic Service Charge	$10,00	$10,00	$10,00	$10,00	$10,00	$10,00	$10,00	$10,00	$10,00	$10,00	$10,00	$10,00	$120,00	
Authorized Margin Revenue Per Customer*	$18,78	$28,63	$26,55	$47,41	$28,59	$126,89	$121,72	$130,12	$99,41	$59,31	$49,98	$50,36	$787,77	
													$907,77	**$12 350,67**

*Authorized margins are taken from the Company's Rule 21, Decoupling Mechanism , approved in Order No. 04 in UG-152286

** Please note the Residential allowance was intentionally rounded down to $3255 in Rule 8

CHESAPEAKE UTILITIES

March 1, 2017

Donna Nickerson, Secretary
Delaware Public Service Commission
861 Silver Lake Boulevard
Cannon Building
Dover, Delaware 19904

Dear Ms. Nickerson:

In compliance with the Settlement Agreement that was approved by the Public Service Commission ("Commission") by Order No. 7434 issued on September 2, 2008 in Docket No. 07-186 – Main Extension Policies, Chesapeake Utilities Corporation ("Chesapeake" or "the Company") is hereby providing Commission Staff with; 1) updated cost information relative to a typical service and meter installation to be used in the Internal Rate of Return Model ("IRRM"); and 2) updated cost information relative to the operations and maintenance expense per customer to be used in the IRRM.

The updated information relative to the cost of a typical residential service and meter installation for 2016 is $1,225 per customer. The updated information relative to the operations and maintenance expense per customer results in an increase in the three-year average from $137 per customer to $139 per customer.

As a result of discussions held with Commission Staff on the Company's Contractor Bidding Program please find attached a report summarizing Chesapeake's 2016 bidding activity.

Pursuant to 29 Del. C. Section 10002(d)(2), all of the information included in this submission has been designated as confidential commercial and financial information by Chesapeake.

Should you have any questions or comments regarding this submission, please contact me at 302.734.6797, extension 7614.

Sincerely,

Matthew M. Everngam
Sr. Regulatory Analyst

Enclosures

350 South Queen Street, Dover, Delaware 19904 | 800.427.2883 | www.chpkgas.com

TOP WORK PLACES

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2017-000XX

February 28, 2017

NORTHERN UTILITIES, INC.)
d/b/a UNITIL)
Request for Approval of Targeted)
Area Build-Out ("TAB") Program in the)
City of Sanford, Maine)

PETITION OF NORTHERN UTILITIES, INC. d/b/a UNITIL

I. INTRODUCTION

Pursuant to its Targeted Area Build-Out ("TAB") Tariff (M.P.U.C. Original Pages 161-62) and 35-A M.R.S. § 307, Northern Utilities, Inc. d/b/a Unitil ("Unitil" or the "Company") respectfully requests that the Maine Public Utilities Commission (the "Commission") authorize the Company to implement TAB surcharges in certain designated TAB areas within the City of Sanford, Maine. The TAB Tariff provides Unitil with a mechanism to build out its distribution network incrementally in certain targeted areas to serve customers who are located off of the Company's existing distribution main and would otherwise have to pay a potentially prohibitive "contribution in aid of construction" ("CIAC") to convert to natural gas. The Commission approved Unitil's TAB Tariff in an Order dated December 22, 2015 and authorized the Company to implement a pilot TAB program in the City of Saco, Maine, recognizing that the program demonstrated a novel approach to encouraging higher conversion rates to natural gas in the Company's service territory.

Using the same methodology that it used to develop the Saco TAB program, Unitil identified areas in the City of Sanford for implementation of a TAB program. The Company based its analysis upon factors including housing density, estimated customer load, and project cost estimation, and identified certain areas in Sanford with a relatively high concentration of customers that are in proximity to the Company's existing distribution system. Having identified these areas of opportunity, the Company will be able to employ a targeted approach to expand its gas distribution system incrementally and economically. In support of its Petition, the Company describes the methodology used to identify the designated TAB areas in Sanford, the manner in which the TAB program will be implemented in Sanford, and the development and estimated bill impacts of the TAB surcharges in Sanford. The Company has filed its proposed Sanford TAB Surcharge Tariff Page (Original Page 164) in connection with this Petition.

II. BACKGROUND

a. The 2015 Petition

On June 5, 2015, Unitil filed a petition requesting Commission approval of a proposed TAB program tariff designed to facilitate the build-out of the Company's distribution network in targeted areas to serve new customers who are off of the main line. As Unitil explained in its 2015 Petition, customers situated off of the main line are typically required to pay a contribution in aid of construction ("CIAC") charge before the Company can extend its main and install a new service for the customer. The CIAC is an up-front cost, often thousands of dollars, and is a significant barrier to consumer conversion to natural gas; as such, it also impedes state programs promoting conversion to natural gas. The Company designed its TAB program to eliminate the CIAC and replace it with a monthly surcharge mechanism within a specifically defined TAB geographic area. Under the program, Unitil will build out new distribution mains and services within a defined TAB area and determine, using a discounted cash flow (DCF) analysis similar to that utilized by the Company pursuant to its Main Extension Tariff, a surcharge to be assessed to customers within the area over a ten (10) year period. The intent of the TAB surcharge is to recover the costs of expansion over time from those customers that benefit from the expansion. In this way, Unitil's TAB program is consistent with its line extension policies, while also providing a reasonable solution to the conversion barrier faced by consumers that would otherwise be required to pay a potentially prohibitive up-front CIAC to convert to natural gas.

In its 2015 Petition, Unitil first sought to implement its TAB program in the City of Saco. Specifically, the Company proposed to build out new mains in four TAB areas in Saco over the course of three years (2016 – 2018). On October 30, 2015, Unitil and the Maine Office of Public Advocate ("OPA") submitted a Stipulation to the Commission recommending approval of Unitil's proposed TAB tariff and pilot TAB program in Saco. The City of Saco supported the Stipulation by letter dated November 24, 2015. In its Order dated December 22, 2015, the Commission approved the Stipulation as being reasonable and in the public interest, noting:

> The TAB surcharge is a method of amortizing the traditional CIAC in utility infrastructure build out so that an otherwise larger upfront one-time payment covering utility capital investment to build or extend gas infrastructure by the utility is spread across multiple billings of smaller amounts. Thus, the amortized amount represented by the TAB surcharge that will appear on the customer bill combines both a payment towards construction costs and a carrying charge. The pilot TAB program [in Saco] demonstrates a novel approach that may encourage a higher rate of conversion to natural gas in Unitil's service territory, and under these facts and circumstances, the Commission concludes that the TAB program is reasonable and in the public interest.

2015-00146, Order Approving Stipulation at 5 (Dec. 22, 2015). The Company's TAB tariff became effective on January 1, 2016.

b. Implementation of the Saco TAB

The implementation of Unitil's pilot TAB program in the City of Saco has, in its first year, tracked closely with Unitil's originally estimated plan. As demonstrated in Table 1 below, in 2016 Unitil contracted 82 meters versus the 53 originally planned. The number of residential R2 meters contracted was 25, which is slightly under the estimated number of 29. The number of G40 meters contracted were 50, which is above the Company's initial estimate, but only by 30 meters in terms of absolute magnitude. Unitil's conversion rates assumed in its Saco financial model were long-term conversion rates over the span of 5 years from the date of construction.[1] Thus, from the results in the first year, it appears that the Company's conversion assumptions in the model were reasonable and provide a sound basis to gauge other TAB opportunities.

Table 1

Customer Class	Meters Planned	Meters Actual
R2	29	25
G40	20	50
G41	4	6
G51	0	1
Total	53	82

The Company installed 29,457 feet of main as part of the Saco TAB in 2016, which exceeds the estimated 2016 build-out of 28,279 feet, as well as sixty one (61) service lines (compared to the thirty one (31) planned). The actual total incremental cost of installing mains in 2016 was $2,454,626 which compares favorably to planned expenditures of $2,586,050. The actual total incremental cost of installing service lines was $597,158, compared to projected expenditures of $175,690, which is consistent with the greater number of services actually installed versus planned.

III. The Sanford TAB

Unitil's TAB tariff permits the Company to designate multiple TAB areas within its service territory when TAB surcharges for those areas are authorized by the Commission. TAB Tariff at Original Page 161. Pursuant to its tariff, the Company has identified TAB areas within the City of Sanford and seeks the Commission's authorization to implement a TAB surcharge within those areas. In the sections below, the Company explains the methodology used to determine the areas in Sanford that are suitable for system expansion; the manner in which the

[1] Unitil will not have final conversion rates and timing until 5 years after all construction is completed.

TAB will be implemented in Sanford; the estimated cost to implement the TAB; the development of the TAB surcharge; the discounted cash flow (DCF) analysis utilized to determine TAB feasibility in Sanford; and estimated bill impacts of the TAB surcharge.

a. Identifying TAB Areas for Gas Expansion

Unitil identified TAB areas in Sanford using the same methodology that it used to develop the Saco TAB program. This methodology, provided as CONFIDENTIAL Exhibit Unitil-1, is based upon a detailed analysis of housing density, estimated customer load, and project cost estimation, among other factors. The Company uses the methodology to identify areas in proximity to its existing distribution system which have a relatively high concentration of customers, as such areas will have a lower construction cost per customer relative to less dense areas. In this way, the methodology enables Unitil to identify areas into which the Company might not otherwise expand under its existing mains extension policy. It is not focused on expanding natural gas service to all residents in each community served by Unitil regardless of the cost; rather, the TAB methodology employs a targeted approach to expand the Company's gas distribution system incrementally to reach the largest number of customers at the least cost in a deliberate, structured and economical manner, and with a high level of confidence that the program will be successful.

Unitil identifies candidate areas for expansion under the TAB program by using the Company's GIS system to spatially analyze publicly available data sets and develop models and tools to identify the areas of highest concentration of customers within close proximity to the Company's existing gas distribution system. Housing density and commercial business listings are critical factors in this analysis for the simple reason that it is becomes progressively more economical to install new main as the density of potential customers within proximity to the main increases. As explained more fully in subsection e below, Unitil used housing density, city assessor data and commercial business listings to identify discreet areas within the City of Sanford with relatively high housing densities, making them potential candidates for a TAB program.[2] Though these areas had been identified during the Company's initial TAB analysis, the Company determined at that time that it would be cost-prohibitive to install the mains required to get to the market area. However, the City of Sanford has since contracted for a main extension to service a new high school. This extension covers approximately one-half of the distance to get to the more densely populated areas in Sanford, and makes a TAB program to service those areas feasible.

After identifying the target areas within Sanford, Unitil developed a regression model enabling it to estimate, with a high level of accuracy, the capital cost to serve customers based upon the density of the targeted service area. The model can be used to estimate costs at the individual neighborhood level or over a much larger area. Unitil developed an estimated cost to install mains and services for the identified Sanford TAB expansion areas on a street-by-street, building-by-building basis. The Company also used information within its GIS system to estimate the number of different classes of customers (e.g., residential and commercial) within those areas. This, in turn, allowed the Company to assign an estimated load to each of these customers within the designated areas and to calculate the total estimated load (on a ccf basis) for each area.

[2] Compared to Saco, where the housing density is generally between 8 to 14 units per acre (with some areas as high as 30 units per acre), the housing density in Sanford is generally between 6-8 housing units per acre. By way of comparison, large portions of the area in direct proximity to the distribution system have housing densities below 2 to 4 units per acre.

Unitil has based its construction phasing for the Sanford TAB upon building characteristics and proximity. The Sanford build-out will differ slightly from the Saco build-out in that it is radial in design, requiring successive installation of mains.

b. The Sanford TAB Areas

Unitil's gas distribution system comprises a network of approximately 560 miles of natural gas mains that provide service to twenty-one (21) communities in Maine, including the City of Sanford. This network is subdivided into forty-six (46) separate distribution systems operating at a range of Maximum Allowable Operating Pressures ("MAOPs"), the majority of which are supplied from the Granite State Gas Transmission, Inc. (GSGT) interstate natural gas transmission pipeline system.[3] In addition to 560 miles of mains, Unitil's system in Maine includes approximately 21,300 gas services connecting approximately 32,000 customers. There are approximately 5 miles of gas mains currently installed in Sanford, the majority of which were installed in the early 2000's. This system, which extends from the Company's Route 109 regulator station,[4] consists of combination of coated steel and high-density plastic pipe and operates at an MAOP of 56 psig.

Unitil has identified three (3) TAB areas within the City of Sanford. The first area is identified as "Zone 1" and is the southern portion of the City of Sanford along Main Street (Route 109). Zone 1 begins at the location of the new Sanford High School and extends north along Main Street (Route 109) up to Winter Street and includes the area to the west and east of Main Street (Route 109). The second area, identified as "Zone 2," is located to the east of the

[3] Unitil's distribution systems in Eliot and Kittery are supplied from the Maritimes Northeast and Portland Natural Gas Transmission System interstate pipeline. The Company's Lewiston and Auburn systems are supplied by Maritimes Northeast and the Company's Lewiston liquefied natural gas (LNG) facility.

[4] Unitil has completed an engineering network analysis to size the proposed new mains and identify future improvements to the Route 109 regulator station. The engineering analysis has identified that the Route 109 station is currently operating at approximately 30 percent of its rated capacity, meaning that it has significant capacity to support expansion of the system in Sanford.

Mousam River, which flows through the city. Zone 2 extends north to the Errol Street vicinity and east to the Coolidge Street vicinity. The third area, “Zone 3,” is located north of and directly adjacent to the Zone 1 area. This area continues north on Main Street (Route 109) to the location of the existing high school.

c. Implementation of the Sanford TAB

The Company’s engineering group has developed a comprehensive design for the implementation of the TAB in Sanford in each of the above referenced construction zones. The design includes the installation of primary feeds (which will transport the majority of the gas) and secondary feeds (which will supply gas to each of the side streets in the area). Unitil anticipates that it can accomplish the proposed system build-out without the need for system reinforcements, up until the point where the load growth exceeds the existing capacity of the system. At that point in time, the Company has developed conceptual plans to modify its Route 109 regulator station to add a 95 psig regulator run, split the system and serve the Sanford area with 95 psig while continuing to serve its Wells system, which also extends from the Route 109 regulator station, with 56 psig.

Though the engineering plan anticipates a complete build-out in each proposed phase of the TAB project, the actual construction will require flexibility to coincide with the customer demand for gas on each street. For example, it may not be economic to construct a new main on a secondary side street if there is low customer interest in converting. This type of approach will promote the most cost effective build-out of the area. Unitil will only install a gas service in connection with the TAB program, including the main connection and tap, after the customer has contracted to take service from the Company within an agreed-upon date range. If the customer does not take service within the established time frame, the customer is required to fund the entire cost of the service installation.

The Sanford TAB program will be accomplished utilizing traditional open cut construction for the majority of the construction. Horizontal directional drilling is not suitable for this project due to the high population density and existing water and sewer utilities in the TAB areas. The work will be performed by New England Utility Constructors (NEUCO), a contractor with which Unitil has an existing contract. Unitil will monitor work quality through its robust quality assurance and quality control program, which includes construction inspectors that must perform daily crew inspections for all construction projects. In addition, Unitil's Manager, Gas Compliance oversees a quality audit program that includes comprehensive field audits of all construction activities. Under this program, all identified deficiencies are recorded and must be reported to Unitil's local Gas Operations Manager, Unitil's VP, Gas Operations, and various NEUCO personnel (including its President), and any necessary corrective action is immediately implemented and recorded.

Unitil will employ established procedures to monitor capital project implementation and cost control. For example, the Sanford TAB project will be part of the Company's annual Capital Budgeting Process, where each project must be fully scoped, estimated and justified. An approved capital project budget does not in itself authorize or approve spending; each project must be further authorized before any spending can occur. A construction authorization must be prepared, submitted, and approved before the commencement of work. Each project has an assigned supervisor who is directly responsible for managing the project and held directly accountable for controlling the scope and cost of the project.

d. Estimated Cost of Implementing the Sanford TAB

Detailed cost estimates in 2017 dollars for the three zones of gas main construction are provided as CONFIDENTIAL Exhibit Unitil-2. These estimates incorporate assumptions developed by the Company through field experience in Sanford. The total incremental project cost ("IPC")[5] for mains of the TAB program in Sanford is $6,635,937[6] and estimated costs for each of the zones are provided in CONFIDENTIAL Exhibit Unitil-1. The project consists of approximately 93,000 feet (~17.6 miles) of new mains installation. The proposed main installations by pipe size and zone are shown in Table 2.

Table 2

	TAB - Sanford Scope of Main Work					
	Gas Main Diameter					
	2"		4"		8"	
	Lf	Mi	Lf	mi	Lf	mi
Zone 1	17,083	3.24	6,680	1.27	11,300	2.14
Zone 2	14,255	2.70	14,740	2.79	0.00	0.00
Zone 3	22,273	4.22	0.00	0.00	6,400	1.21
Total	**53,611**	**10.16**	**21,420**	**4.06**	**17,700**	**3.35**

Unitil's engineering group designed a comprehensive and detailed three-phase installation program corresponding to the three proposed TAB zones in Sanford. The Company then developed a detailed project scope quantifying the work to be performed. It identified main footages by size and material, number of tie-ins and restoration quantities, then derived unit costs

[5] Incremental Project Cost refers to base cost plus direct overheads and is the cost used for internal rate of return calculations. This does not include general construction overheads.
[6] This number reflects annual inflation of 2.5 percent and a 10 percent contingency from the base 2017 dollars shown in Exhibit Unitil-2.

from material and contract prices coupled with historical data on replacements projects. The Company then applied the unit costs to the scope of work to develop detailed cost estimates for each of the three project phases.[7] Using the incremental project cost for each TAB zone, Unitil performed the economic feasibility analysis for the overall project.

The Company developed residential service cost estimates for both short and long side installations using typical installation parameters as a guide. These two costs were then averaged to calculate a blended cost for a typical residential service installation. The incremental project cost for a single residential service is shown in Exhibit Unitil-1. The Company calculated a blended cost for a typical commercial service installation using the same method. As the Company will only install services when customers have contracted for new service, the total cost for service installations will depend on actual conversion rates.

e. The Sanford TAB Surcharge

Unitil has calculated the Sanford TAB surcharge on a $ per ccf basis, to be in effect for a 10-year period (calendar years 2018-2027) beginning with commencement of natural gas service in Sanford. Once set, the TAB surcharge would be fixed for the entire 10 year term. The level of the surcharge is 13.14 percent applied to the distribution rates of all of the Company's rate classes according to the Company's TAB tariff. Please see Exhibit Unitil-3 for a summary of the proposed Sanford rates including the TAB surcharge. The Company has also filed its proposed Sanford TAB Surcharge Tariff Page (Original Page 164) in connection with this Petition. The Company's approach to applying its TAB Tariff to the proposed Sanford TAB areas, including calculation of the TAB surcharge, is explained below.

i. Defined expansion area

[7] Unitil estimated project costs reflect 2017 dollars. For the economic DCF analysis, these estimates are inflated 2.5 percent annually and also incorporate 10 percent contingency.

As explained above, the Company first identified the market potential in the expansion area, i.e., the number of potential customers and potential sales volume. This step involved an iterative process that balanced the cost of expanding service with the estimated new revenues to be produced from the service. The Company's objective was to make service available to as many homes and businesses as possible while keeping the costs and required surcharge as low as possible, since a high surcharge would result in less savings for customers, lower participation rates, and reduced economic benefit as fewer customers would be incented to convert.

The estimated number of customers and associated sales volume in the Sanford market area was based on a market analysis prepared by the Company's sales and marketing staff. At 100 percent conversion, the Sanford build out has a market potential of 2,122 customers that would use 2.9 million ccf per year. The market consists of 1,753 residential customers and 369 business customers, representing 83 percent and 17 percent of total customers, respectively, that use 1.3 million ccf per year and 1.6 million ccf per year, representing 45 percent and 55 percent of total sales, respectively.

The Company initially screened potential target towns suitable for a TAB with the use of residential housing density data from the U.S. Census Bureau. In this initial screening, the Company identified Sanford as a potential candidate. Then, the Company acquired parcel and assessing data directly from the City of Sanford to obtain residential and commercial unit counts. The Company estimated residential sales by applying its average residential sales per customer to the number of potential residential customers within the TAB area as derived from housing units shown in City parcel and assessing data. Similarly, the Company estimated commercial sales by applying its average commercial sales per customer to the number of potential commercial customers within the TAB area as determined by reference to a commercial list purchased by the Company, as well as City parcel and assessing data. The Company used the same commercial list and City parcel and assessing data to determine the number of potential industrial customers, and estimated industrial sales based on square footage applied to the Company's estimate of average sales per square foot.

ii. Developed construction cost estimate

As noted above, the Company developed a street-by-street cost estimate of the facility costs needed to serve the expansion area, including mains and services. The cost estimate is estimated to total $10.1 million, which consists of $6.6 million in mains and $3.5 million in services (after application of the estimated conversion rates discussed further below).

iii. Developed revenue estimate

The Company developed a revenue estimate by first applying a "conversion rate" (i.e., the number of customers who convert as a percentage of the market potential) to the market potential to estimate the number of customers who are likely to convert. The conversion rate is an important assumption informed by the Company's conversion experience to date in Saco. Because conversion in Saco has tracked closely to Unitil's original assumption, the Company used the same conversion rates for the Sanford model. The Company then applied an annual use per customer by rate class to determine annual sales volumes. Finally, the Company applied the current rates, by rate class, to determine annual revenues.

iv. Discounted Cash Flow Analysis

The Company developed a spreadsheet model (attached hereto as CONFIDENTIAL Exhibit Unitil-4) to perform the discounted cash flow analysis used to calculate the net present value ("NPV") of the Sanford build-out. The NPV calculation compares the cost of serving the area with the projected revenues from customers who would be served by the project. The cost of service is based on the estimated facilities costs to serve the TAB area, including main and service investments. The cost of service includes an estimate of the associated depreciation, property taxes, and income taxes. The discount rate for the NPV calculation is based on the Company's weighted average cost of capital. The analysis period for the NPV calculation begins with the initial main investment and ends 20 years following the final capital investment in the TAB area.

v. Calculate TAB surcharge

The TAB surcharge is based on the results of the discounted cash flow analysis. If the NPV is equal to or greater than zero, the TAB area is economically feasible to serve without a surcharge, consistent with the Company's current Main Extension policy. If the NPV is less than zero, as it is in this case, the TAB area is not economically feasible to serve without a surcharge. The TAB surcharge will be in effect for a 10 year term, and will be assessed to all new customers on a $ per ccf basis within the TAB area during the term. Once set, the TAB surcharge would be fixed for the entire 10 year term. A customer who requests service in the TAB area after the surcharge term has expired will not be assessed a TAB surcharge. A customer who requests service outside of the TAB area is subject to the Company's Service and Main Line Extensions and System Improvements terms and conditions. The calculation of the TAB surcharge for the Sanford expansion is included in Exhibit Unitil-3.

f. Unitil's Discounted Cash Flow Analysis

The discounted cash flow analysis used to calculate the economic feasibility of the Sanford expansion consists of estimated incremental revenues and estimated incremental costs directly associated with the Sanford expansion for each year of the analysis period. For comparative purposes, the spreadsheet model (CONFIDENTIAL Exhibit Unitil-4) logic is virtually identical to the model used in the Saco TAB. Furthermore, the Company utilized the same assumptions that it used in the Saco model, except for general updates to items such as property tax rates, depreciation rates, and cost of capital.

The estimate of incremental revenues is based on: (a) an estimate of the number of customers who will convert during the first five years that natural gas service is available, (b) an estimate of the annual use for each converted customer, and (c) the applicable rates for each converted customer, adjusted for future rate changes. The estimated annual use per customer is applied to the estimated number of customers to determine the estimated use per year, and applicable customer charge and consumption rates are then applied.

The estimated number of customers who will convert is based on the conversion rates discussed above, applied to the number of potential customers in the market. The estimate reflects only those customers that would convert during the first five years that natural gas service is available. The estimated annual use for each residential and commercial customer is based on the Company's average sales per customer. The estimated annual use for each industrial customer is based on an estimated use per square foot times the square footage obtained from the Company's purchased list of commercial buildings in the area.

The applicable rate is based on the most appropriate rate class for the customer. The rate applied to the first year of the analysis is based on the most recent rates filed in the Company's February 2017 Targeted Infrastructure Replacement Adjustment mechanism. Similar to the Saco TAB, the rates applied for the next seven years assume a 3 percent annual increase, consistent with the expected time remaining in the cast iron replacement program, and with the approximate magnitude of the most recent base rate increase pursuant to the Targeted

Infrastructure Replacement Adjustment tariff. Then, the rates thereafter assume a 2 percent annual increase to approximate long-term inflationary trends similar to the Saco TAB.

For the purposes of performing the discounted cash flow analysis, the Company estimated incremental cost based on: (a) an estimate of the cost of capital expenditures, (b) property taxes, (c) depreciation expense, (d) interest expense, and (e) income taxes. It calculated rate base using the plant investment in the mains and service costs described above, adjusted for accumulated depreciation of plant based on average depreciation rates and accumulated deferred income taxes based on the Internal Revenue Service ("IRS") taxable depreciation schedules and the composite federal and state tax rates. The TAB surcharge is treated not as revenue, but as an offset to rate base so that rate base is reduced by the surcharge.

The Company estimated capital expenditures by applying the methodologies described in subsection d above. Again, capital expenditures are net of the TAB surcharge, so that rate base is reduced annually by the surcharge. The Company calculated property taxes using the City of Sanford property tax rate of 2.27 percent multiplied by net plant investment (i.e., total plant investment less accumulated depreciation). It calculated depreciation expense using a weighted-average book life of 37 years for mains and services multiplied by plant investment, and determined interest expense using the weighted cost of debt of 2.98 percent multiplied by rate base. The cost of capital used in the analysis is based on the Company's actual weighted cost of capital as of December 31, 2016 and assumes an ROE of 9.75 percent similar to the Saco TAB. The Company calculated income taxes based on net income after interest payment multiplied by the composite tax rate of 39.89 percent.

The term of the financial analysis begins with the year during which initial capital investment is planned (2018) to occur in the TAB area and ends twenty (20) years after the final capital investment in the TAB area is planned to be made.

g. Estimated Bill Impacts of the TAB Surcharge

The Company prepared a bill impact analysis that compares an annual bill for each rate class based on current rates with and without the TAB surcharge for the Sanford build-out. The bill impact analysis is included in Exhibit Unitil-5. The bill impact analysis is prepared with and without the Cost of Gas Factor ("CGF"). The Exhibit shows that residential heating customers in the Sanford build-out area would experience an annual total bill approximately 7 percent higher than the Company's other customers. The delivery portion of the annual bill, which is calculated without the CGF, would be approximately 13 percent higher, consistent with the TAB surcharge level. The total bill impact to commercial and industrial customers ranges from 4-7 percent, while the delivery-only impact would be approximately 13 percent, again consistent with the TAB surcharge level.

Even with the bill impact of the TAB surcharge, the price of natural gas compares favorably to that of heating oil. The Company prepared a fuel price comparison between the natural gas price, with and without the TAB surcharge, and the heating oil price, based on an average heating oil price of $2.28 per gallon as of January 30, 2017 (source: http://maine.gov/energy/fuel_prices/index.shtml). The comparison is included in Exhibit Unitil-6. The comparison shows that the natural gas price is approximately 29 percent less than the heating oil price without the surcharge and 24 percent less with the surcharge.

h. Treatment of TAB Surcharge in a Base Rate Case

For ratemaking purposes, similar to the Saco TAB, the test year level of revenues, expenses, and plant investments (net of the TAB surcharge) attributable to the TAB area shall be included in the Company's cost of service at the time of a general base rate case proceeding. This approach is consistent with the long-term annual revenue percent increase assumptions included in the financial model, where the net present value of the project is dependent upon base rate increases over time. Furthermore, this approach is consistent with the current treatment of main and service investments, expenses, and revenues under the Company's Main Extension policy, and does not impose any incremental risk of recovery of TAB investments and expenses. Once set, the TAB surcharge remains fixed for the entire 10-year period regardless if underlying distribution rates change as a result of a base rate case filing.

IV. CONCLUSION

The Company respectfully requests that the Commission authorize the Company to implement TAB surcharges in certain designated TAB areas within the City of Sanford, Maine pursuant to the Company's previously approved TAB Tariff.

Respectfully Submitted,

Northern Utilities, Inc. d/b/a Unitil

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provided in this rebuttal testimony and the record evidence in this case are sufficient to address those concerns.

IV. RATE OF RETURN INVESTMENT CRITERIA

Q. Has Staff raised any issues in its Bench Analysis regarding the Company rate of return investment criteria?

A. Yes. Staff states that it is concerned with the Company's investment criteria and that it may not provide the Company with the proper financial incentive to expand service to new customers. Specifically, Staff requested that the Company analyze the financial incentives and whether the time periods should be adjusted of the 10 and 20 year rate of return criteria for commercial and residential customers, respectively.

Q. Can you briefly describe the Company's rate of return model and its investment criteria?

A. The Company's rate of return model assesses the future cash flows from new customers over a specified investment horizon (10 or 20 years, as the case may be). The future cash flows consist of distribution revenues, property taxes, insurance and cash income taxes. Incremental O&M costs are not included in the calculation of future cash flows. The model then discounts these future cash flows at the Company's long-term cost of capital over the specified investment horizon. If the present value of these future cash flows equals or exceeds the unloaded, incremental capital expenditure required to serve the new customer, then there is no customer contribution required. However, if the present value is less than the unloaded, incremental capital expenditure, then a customer contribution is required to make up the difference. Additionally, the Company's tariff provides for no customer contribution required for any residential service 100 feet or less, because the amount of capital spending required for a service 100 feet or less will typically pass the Customer's rate of return criteria without the need for a customer contribution.

Q. What is the Company's position with respect to its rate of return criteria?

A. In general, the Company believes its customer contribution model is relatively beneficial and incentivizes new customers, because it does not include incremental O&M costs and capital expenditures reflect unloaded, incremental spending. In addition, the Company is currently experiencing robust demand for natural gas service. As described in the rebuttal testimony of Ms. Carroll, the Company is growing at a rate well above that of its peers in the region. The Company believes that the time periods currently reflected in its rate of return criteria provide a balance of the benefits and costs of growth between existing customers, new customers and the Company.

Q. Please describe how the Company's rate of return criteria balances the benefits and risks of customer growth.

A. The Company's rate of return criteria of 10 years and 20 years for commercial and residential customers, respectively, reflects a balance between existing customers, new customers and the Company by reflecting a reasonable estimate of time to recover the investment necessary to add a new customer.

Mathematically, new customers would potentially bear less of the cost of the investment to serve them if the Company were to increase the duration of its rate of return criteria. Correspondingly, existing customers would incur less of the costs of adding a new customer if the Company were to decrease the duration of its rate of return criteria. As such, it is important to first understand the financial implications of the rate of return criteria. In Rebuttal Exhibit DLC-5, the Company has shown the annual rate of return for typical residential and commercial customers. In both cases, the usage reflects that of a typical customer, base revenue is calculated at current rates, and capital expenditures are set to the amount of investment the Company could expend on that customer and still meet its rate of return hurdle of its cost of capital by the end of the 10 or 20 years, as the case may be. The Exhibit illustrates that for both the residential and the commercial customer, the annual rate of return is sharply negative in the first few years because the Company has already spent capital at the beginning of the project, but does not recover this investment for a number of future years. Thus, we come to the conclusion that in the early years, a customer addition does not generate annual revenue that would equal its annual cost of capital. Or in other words, growth capital expenditures may not necessarily “pay” for itself at the beginning because of the very mathematical nature of internal rate of return over a specified period.

Q. So would you conclude that a longer time period for its rate of return criteria would be a financial disincentive to the Company?

A. Yes. While this conclusion may seem obvious, it is important again to look at the annual returns to the Company. By lengthening the assessment period, existing customers would be required to make up any shortfall from new customers. To the extent the Company is unable to make up this shortfall from existing customers, the Company would be dis-incentivized to add new customers, because the annual rate of returns will only become more negative in the early years requiring the Company to absorb this "gap". In the short run, the Company will be subject to the earnings attrition resulting from upfront capital spent, but then with recovery occurring over several years in the future. In the longer run, this will result in more frequent rate cases and funding from existing customers to make up this gap. This concept goes hand-in-hand with the earnings attrition issues the Company discussed earlier with the use of year-end rate base and the Company's disagreement of customer revenue annualization.

Q. So what is your conclusion of the time period used in the Company's rate of return criteria?

A. I believe that the Company's time periods of 10 years and 20 years for commercial and residential customers, respectively, presents a balanced financial incentive for existing customers, new customers and the Company. However, the Company is not opposed to evaluating this topic further but believes it should be done outside of this proceeding as the required analyses were not included in the Company's initial filing or in the Bench Analysis and are beyond the scope of the Company's rebuttal testimony.

V. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

State of Maine
Public Utilities Commission

Northern Utilities, Inc. Docket No. 2013-00133
Proposed Increase in Rates

Maine PUC Advisor's Fourteenth Set of Information Requests

Data Request EXM 14-6:

Regarding the 10 to 20 year period used for calculating the customer CIAC, considering the pros and cons as outlined in your rebuttal testimony, what was the basis for selecting the 10 and 20 year recovery period.

Response:

The establishment of the 10 and 20 year recovery periods used for calculating the customer CIAC are long standing practice reflecting a balance between new customers, existing customers and the Company which provides for a reasonable estimate of time to recover the investment necessary to add a new customer. When Unitil acquired Northern Utilities, the predecessor was using 10 year periods for both commercial and residential customers. The residential term was changed to 20 years shortly after the acquisition to recognize that residential customers are a more homogeneous group with lower risk profile and a term of 20 years was chosen consistent with Unitil's practices in other jurisdictions.

Date: October 16, 2013 **Person Responsible:** David L. Chong

State of Maine
Public Utilities Commission

Northern Utilities, Inc. Docket No. 2013-00133
Proposed Increase in Rates

Maine PUC Advisor's Fourteenth Set of Information Requests
(Testimony of James Simpson)

Data Request EXM 14-21:

Regarding footnote 5, why is the Company's CIAC not sufficient to provide recovery of growth-related costs not otherwise recovered in the revenue from the incremental sales? If the existing CIAC is, in fact, not sufficient to recover such costs, should it be revised? If so, how? If not, why not?

Response:

The currently effective CIAC ensures that over the expected recovery period, the net present value (NPV) of the expected revenue stream for each new customer (at least) recovers the net present value of the revenue requirements associated with the cost of plant additions for that new customer.

However, the revenue requirement associated with the investment to serve the new customer is greatest in the early years and decreases over time: in the first years after a customer is added, annual costs are likely to exceed revenues; in later years, revenues will exceed costs. That is, the Company's CIAC does <u>not</u> ensure annual revenue associated with a new customer will exceed annual cost in <u>each</u> year after a new customer is added. Rather, the Company's CIAC policy, which is similar to other LDC's CIAC policies that I have reviewed, ensures that total NPV revenue from a new customer is equal to or greater than total NPV cost from that new customer.

Thus, the Company's opportunity to earn a reasonable return in the next several years is hurt by the dramatic increase in actual and planned new customers during this period that the costs (revenue requirements) will exceed revenues, including any required CIAC for these customers.

Date: October 16, 2013 **Person Responsible:** James D. Simpson

Unitil
Unitil Service Corp.

December 22, 2010

BY OVERNIGHT MAIL AND E-MAIL

Bradley King, Senior Consumer Assistance Specialist
Consumer Assistance Division
#18 State House Station
Hallowell, ME 04347

Dear Mr. King:

In light of your recent requests for information in CAD Case No. 2010-30495, I am writing to provide an explanation of Northern Utilities, Inc. d/b/a Unitil ("Unitil" or "the Company") policy regarding the installation of new gas services and extensions of lines or mains for Residential, Commercial and Industrial Customers, and how the Company applies its rate-of-return criteria and project cost recovery modeling.

In calculating capital cost recovery, the Company utilizes a Rate-of-Return model (the "Model") which reflects the procedures and methods established for each of the affiliated distribution companies in the Unitil system. These procedures are formally set forth in the System Policy for Gas Services and Main Extensions. A copy is attached for your convenience. Specifically, as indicated in the Policy, Unitil utilizes existing distribution tariff rates that are currently in place. Future rate relief is not incorporated in the Model, because of the uncertainty and timing of distribution rate changes. On two specific project evaluations, Maine Public Utility Commission Staff requested that Unitil modify the methodology of its Model to incorporate rate relief for its anticipated rate case filing in 2011. Unitil agreed to do this for these specific projects at the request of the Staff. Unitil has not, however, adopted this change to its model for all projects, and believes that incorporating future anticipated rate changes is inconsistent with the rational behind the methodology it employs.

In Unitil's Policy, a number of factors are taken into account to achieve a balanced goal of system growth. These factors are intended to balance the prospective customer's desire to obtain natural gas service versus the required return necessary to not burden other ratepayers with uneconomic investments. To promote growth, the Model utilizes a plant investment approach and focuses on capital expense recovery. In Unitil's Policy, each gas utility subsidiary has a distinct Model reflecting its jurisdictional-specific set of tariff rates, depreciation rates, property tax rates, income tax rates, and capital structure. Incremental operations and maintenance and general and administrative expenses are assumed to be zero. Furthermore, the expense assumptions in the Model do not escalate over the evaluation period. To

Gary Epler
Chief Regulatory Counsel

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Hampton, NH 03842-1720

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correspond with the non-escalation of these expenses, revenue rates are maintained at existing levels.

As all assumptions in the Model are based on existing tariff rates and known and unchanging expense levels, incorporating a rate change assumption which is uncertain creates a mismatch that would adversely impact other ratepayers if the rate change is not actually authorized or achieved.

Overall, Unitil believes that its current Policy and Model are working as designed to achieve balanced system growth. For example, since August 1, 2010, Unitil has run 65 rate-of-return estimates in Maine. Of these 65 estimates, 51 resulted in new service installations, representing an approximate 80% success rate. Of the 51 new services, nine have required customer contributions. Please also note that with respect to the two projects where the model was re-run to incorporate assumptions regarding future rate relief, neither resulted in new customers.

Representatives of the Company are available to discuss this matter further at your convenience. Thank you for your attention to this matter.

Sincerely,

Gary Epler
Attorney for Northern Utilities, Inc.

Enclosure

Unitil

System Policy

Subject: System Policy - Energy Distribution Rate-of-Return Criteria and Project Cost Recovery Modeling for Gas Services and Main Extensions and Electric Services and Line Extensions **Policy Number RB, DS 4.02 (D)**

TO: **President, Chariman & Chief Executive Officer**
Senior Vice President - Operations
Senior Vice President – Customer Service & Communications
Senior Vice President & Chief Financial Officer

FROM: **M.H. Collin** **Effective**: July 1, 2009
Supersedes:

Cross-Reference Policies: RB, DS 4.01 (D) / (J)FS AC 1.04 (D) / RB EP 1.04 (D) / RB DS 1.03 (D)

APPLIES TO:
Fitchburg Gas and Electric Light Company
Northern Utilities, Inc. – New Hampshire Division
Northern Utilities, Inc. – Maine Division
Unitil Energy Systems, Inc.

PURPOSE

To define the Company policy regarding applying rate-of-return criteria and project cost recovery modeling relative to the installation of new electric or gas services and extensions of lines or mains for Residential, Commercial and Industrial Customers.

GENERAL INFORMATION

The Finance Department has developed and will maintain a Rate-of-Return model ("Model") for each Company (Fitchburg Gas and Electric Light Company d.b.a. Unitil ["FGE"]; Northern Utilities, Inc. – New Hampshire Division ["NuNH"]; Northern Utilities, Inc. – Maine Division ["NuME"]; Unitil Energy Systems, Inc. ["UES"]). The Model is to be used in conjunction with the Company's Policy Guide regarding the installation of new gas services and main extensions and also for new electric services and line extensions. The Models should be utilized whenever customer addition/expansion projects are not fully accommodated by any 'standardized allowances', surcharges, or other costing provisions identified in a related System Policy or Distribution Service Tariff. Use of the Model accomplishes several major objectives: 1) provides clear and cohesive financial analysis of the returns, capital investment, revenues and expenses associated with new customer additions; 2) ensures easy access to documented calculations and explanations; 3) provides a consistent platform for pre- and post-construction reviews; 4) documents that new customer additions and related financial contributions are not burdensome to existing customers; and 5) helps to ensure that all costs for new customer additions are includable in rate base.

The underlying rate-of-return criterion requires that each new installation project create sufficient revenues to earn the Company its after-tax weighted-average cost of capital ("WACC") to provide recovery of Incremental Project Costs (capital expenditures, net of fixed General and Engineering and Operations' ["E&O"] overhead expenses) over a period of 20 years or less for residential projects and over a period of 10 years or less for commercial and industrial projects. (The recovery periods are considered 'dynamic' in the sense of commencing after the last year of construction, which may be appropriate to larger, multi-year construction projects.) If a project yields a rate of return equal to or greater than the benchmark rate of return over the benchmark recovery period, the project passes the rate of return test and no customer contribution is required. If a project fails the rate of return test, the Model calculates a non-refundable customer contribution (Contribution in Aid to Construction) required for the project to pass the rate of return test over the recovery period.

Customer revenues used to calculate the Company's rate-of-return shall include distribution revenues only.

Each Distribution Operations Company ("DOC") will have a distinct Model reflecting its jurisdictional-specific set of tariff rates, depreciation rates, tax rates, and capital structure. However, to streamline the approval process, minimize administrative burden, and to promote growth and consistency within the service territories, certain 'standard allowances' have been established. For example, it has been determined that a 100-foot service from an existing gas main will generally have its incremental capital expenditure recovered over a 20-year period as supported by system-wide (FGE, NuNH and NuME) averages for residential heating applications and assuming normal installation conditions. Similar standard allowances have been established for electric projects, and these are denoted in the Line Extension Policy section of the electric distribution service tariffs for FGE and for UES.

Thus, for example, the DOC-specific capital recovery/customer contribution models will be utilized for gas residential heating customers with abnormal installation conditions and for all residential gas non-heating applications. A 20-year analysis/recovery period will be utilized for these situations. The individual DOC-specific capital recovery/customer contribution models will also be utilized for all non-residential gas installations, using a 10-year analysis/recovery period.

INPUTS
The capital recovery/customer contribution models require inputs for Incremental Project Costs (net of General and E&O overheads), as well as projected Annual Loads, (including Demand loads for those rate classes subject to base distribution demand-based billing). The models' interface allows for analysis of multiple customers - for instance a 50-lot residential development or a 10-store retail outlet.

OUTPUTS
The models calculate the Rate-of-Return, simple Payback Period and Present Value of net cash flows associated with the project. The models can also be used to determine the amount of customer contribution (Contribution in Aid to Construction) and/or minimum usage requirement to achieve the benchmark rate of return criterion over dynamic 10-year and 20-year periods.

Rebuttal Exhibit DLC-5

Northern Utilities, Inc. - Maine
Customer Contribution Model Payback

Typical Residential Customer		
Customer Class		R2
Number of Meters		1
Annual Usage (CCF)		716
Capital Expenditure	$	3,754
IRR on Net Cash Flow		7.19%

Typical Commercial Customer		
Customer Class		G41
Number of Meters		1
Annual Usage (CCF)		21,581
Capital Expenditure	$	35,853
IRR on Net Cash Flow		7.19%

Payback Period - 20 Years

Year	IRR
Year 1	-89.77%
Year 2	-62.81%
Year 3	-42.53%
Year 4	-29.03%
Year 5	-19.91%
Year 6	-13.55%
Year 7	-8.95%
Year 8	-5.50%
Year 9	-2.85%
Year 10	-0.77%
Year 11	0.87%
Year 12	2.20%
Year 13	3.28%
Year 14	4.17%
Year 15	4.92%
Year 16	5.54%
Year 17	6.06%
Year 18	6.51%
Year 19	6.89%
Year 20	7.19%

Payback Period - 10 Years

Year	IRR
Year 1	-85.03%
Year 2	-53.38%
Year 3	-31.92%
Year 4	-18.47%
Year 5	-9.75%
Year 6	-3.87%
Year 7	0.24%
Year 8	3.24%
Year 9	5.48%
Year 10	7.19%