RÉPONSE DE SOCIÉTÉ EN COMMANDITE GAZ MÉTRO (GAZ MÉTRO) À LA DEMANDE DE RENSEIGNEMENTS N[O] 2 D'OPTION CONSOMMATEURS (OC) À SOCIÉTÉ EN COMMANDITE GAZ MÉTRO (GM)

GAZ METRO'S PROFITABILITY ANALYSES FOR SYSTEM EXPANSION PROJECTS

1. Reference: i) Exhibit B-0277, GM-7, Doc 4, page 13, lignes 14-21.

Preamble: Gaz Metro states: "Les coûts de renforcement sont ainsi considérés globalement dans la rentabilité du plan de développement et non projet par projet."

Questions:

1.1. Please provide a detailed calculation showing how the costs of reinforcement of the distribution network are calculated for evaluating the profitability of a development plan, using a recent development plan as an example.

Réponse :

À partir de la Cause tarifaire 2007, Gaz Métro a intégré une enveloppe de renforcement du réseau de distribution au plan de développement. Gaz Métro évalue cette enveloppe globale selon une moyenne des besoins historiques. Ces besoins sont généralement associés à de multiples conduites qui dépendent de conditions de vente difficilement prévisibles. Ces besoins s'identifient en cours d'année lorsque les ventes s'effectuent. Gaz Métro bonifie néanmoins, au meilleur de ses connaissances, le montant de renforcement de l'année à venir lors de la réalisation des plans de développement à la cause tarifaire.

Basé sur la référence de la pièce B-0264, Gaz Métro-9, Document 6, page 3, Gaz Métro a réalisé environ 16 M$ de renforcement en distribution au cours des 13 dernières années. Le montant annuel moyen du renforcement en distribution est donc d'environ 1,2 M$.

Veuillez vous référer à la pièce R-3976-2016, B-0196, Gaz Métro-7, Document 2, colonne 15 afin de visualiser comment le renforcement a été intégré au plan de développement de la Cause tarifaire 2017-2018.

Certains renforcements importants sont également présentés au cas par cas à la Régie lorsque les investissements dépassent 1,5 M$ et sont généralement des projets visant les réseaux d'alimentation et de transmission tels que Pétromont (R-3833-2013 et R-3941-2015), Pont Jacques-Cartier (R-3763-2011) et Saguenay (R-3919-2015).

1.2. Please explain how reinforcement costs are estimated and calculated on a regional or service area basis for any given development plan. Explain how specific projects are identified, if at all, and explain how costs per unit of increased demand are developed, if they are developed. Provide work papers showing sample calculations.

Réponse :

Veuillez vous référer à la réponse à la question 1.1.

1.3. For how many years out (i.e. until what year in the future) is the potential for reinforcement cost calculated, and how is the cost apportioned between current and future development?

Réponse :

Veuillez vous référer à la réponse à la question 1.1.

1.4. Please identify specific near-term or intermediate-term reinforcements and their respective costs for individual very large projects at the time of their initial development, rather than including those costs in the development plan for all projects? If so, please explain how those reinforcements could be identified. If not, why not?

Réponse :

Veuillez vous référer à la réponse à la question 1.6 de la pièce B-0264, Gaz Métro-9, Document 6.

1.5. How are operations and maintenance costs associated with the reinforcement (for main inspection and main maintenance, as well as operations and maintenance of new regulating stations and compressor stations) included, if at all, in the profitability of the development plan?

Réponse:

Considérant que la preuve de la phase 3A est complète et que la Régie en a été saisie et est présentement en délibéré, Gaz Métro soumet respectueusement que les questions portant sur les dépenses d'opération déjà traitées lors de la phase 3A ne sont pas pertinentes à l'étude de la présente phase 3B.

1.5.1. If operations and maintenance costs are included, provide work papers showing sample calculations that demonstrate how those costs are calculated and included.

Réponse:

Considérant que la preuve de la phase 3A est complète et que la Régie en a été saisie et est présentement en délibéré, Gaz Métro soumet respectueusement que les questions portant sur les dépenses d'opération déjà traitées lors de la phase 3A ne sont pas pertinentes à l'étude de la présente phase 3B.

1.5.2. If operations and maintenance costs are not included, please explain why it is reasonable not to include them.

Réponse:

Considérant que la preuve de la phase 3A est complète et que la Régie en a été saisie et est présentement en délibéré, Gaz Métro soumet respectueusement que les questions portant sur les dépenses d'opération déjà traitées lors de la phase 3A ne sont pas pertinentes à l'étude de la présente phase 3B.

2. Reference: i) Exhibit B-0264, GM-9, Doc 6, GM Response to ROEE Expert Paul Chernick's No. 2 IRs in Phase 3, Question 1.6, pp. 3-5.

Question:

2.1 Please identify the length of each reinforcement project listed in this response in metres.

Response:

Classe de pression	N^bre de projets	Définition de projet	N^bre de mètres linéaires de conduite
Distribution	1	Bouclage de la 640, Terrebonne	1,956
Distribution	2	Bouclage Croissant des Iles, Laval	52
Distribution	3	Bouclage Repentigny - Résidentiel	5,207
Distribution	4	Bouclage Syst.Polymère Structural, Magog	314
Distribution	5	Bouclage Beloeil - St-Jean-Baptiste	4,120
Distribution	6	Bouclage Bromont - Rue des Carrières	1,182
Distribution	7	Bouclage Montcalm, Candiac	1,189

Classe de pression	Nbre de projets	Définition de projet	Nbre de mètres linéaires de conduite
Distribution	8	Renforcement St-Sébastien	2,204
Distribution	9	Renforcement St-Valérien	2,975
Distribution	10	Bouclage réseau cl 400 de St-Jérôme	72
Distribution	11	Bouclage Boisbriand, 3825 Alfred-Laliberté	508
Distribution	12	Véolia, rue Pion, St-Hyacinthe	1,902
Distribution	13	Meubles Ashley, Sherbrooke	69
Distribution	14	Renforcement Asphalte générale	2,300
Distribution	15	Renforment réseau, Pierrefonds	1,712
Distribution	16	550 McArthur, St-Laurent	89
Distribution	17	Émile Giroux Renforcement, Qc	2,992
Distribution	18	UDM campus Outremont	282
Distribution	19	Rang St-Paul, St-Rémi	2,862
Distribution	20	Groupe Robin, Trois-Rivières	1,897
Distribution	21	Sani Estrie, 405 Rudolphe Racine, Sherbrooke	419
Distribution	22	Renforcement réseau - dév région Bedford	900
Distribution	23	2911, avenue Marie-Curie, St-Laurent	310
Distribution	24	Poste de livraison, St-Jérôme	N/A
Distribution	25	Bouclage - Fruit D'Or	4,260
Distribution	26	Bouclage boul. Mercure, St-Nicephore	3,175
Distribution	27	99999 rue du parc industriel, Lanoraie	236
Distribution	28	Bouclage Petites Soeurs Ste-Famille	45
Distribution	29	Serres Marian Vinet St-Rémi	184
Distribution	30	Boul. de Portland, Sherbrooke	930
Distribution	31	campus Outremont UDM	348
Distribution	32	Marché aux puces / Faubourg Carignan	542
Distribution	33	NRC St-Paul d'Abbotsford	1,196
Distribution	34	Enveloppe renforcement développement	N/A
Distribution	35	Sherbrooke est / Georges V	N/A
Distribution	36	Bouclage réseau, ville de Labaie	470
Distribution	37	Bouclage auto 13 & boul. Ste-Rose	1,223
Distribution	38	Qc-Bouclage rue St-Jean	235

Classe de pression	N^{bre} de projets	Définition de projet	N^{bre} de mètres linéaires de conduite
Distribution	39	Bouclage St-Valérien-de-Milton	1,506
Distribution	40	Bouclage de réseau - St-Lambert	846
Distribution	41	Renforcement réseau PL Oka/St-Eustache	1,623
Distribution	42	Renforcement réseau Guthrie Dorval	105
Distribution	43	Bouclage Ste-Marie 3 km 6" plastique	2,010
Distribution	44	Bouclage rue des Châteaux, Blainville	782
Distribution	45	Renforcement PD3087 -3090 Lachute	679
Distribution	46	QC-bouclage St-Amable (La Chevrotière-Art)	124
Distribution	47	Qc-Boucl. réseau - rue Guimont, Beauport	349
Distribution	48	Qc-bouclage Pionnières-de-Beauport	293
Distribution	49	Bouclage parc indus., Terrebonne	1,413
Distribution	50	Bouclage des Hêtres, Shawinigan	198
Distribution	51	Renforcement Ste-Elizabeth Laurentides	2,225
Distribution	52	Bouclage aut. 15/30 Delson	88
Distribution	53	Estrie-Bouclage St-Georges Drummondville	125
Alimentation	54	Rempl.supports/Revêt-Pont-Jacques Cartier	397
Distribution	55	Bouclage réseaux Vaudreuil	94
Distribution	56	(ES)Sag-Lac-Bouclage 160m De Monfort	169
Distribution	57	ES/Ph3 Renforcement réseau Fleury et CN	311
Distribution	58	Renforcement réseau Clark-Graham	427
Distribution	59	Augmentation de pression réseau St-Clet	N/A
Distribution	60	Sag-Lac Ab-reconst ligne rég PL4024-Chic	-
Distribution	61	Capacité hydraulique rue St-Antoine	94
Distribution	62	Renforcement réseau 32e avenue Lachine	26
Distribution	63	Renforcement réseau, boul. Dagenais	316
Distribution	64	Renforcement réseau rue Norman	210
Distribution	65	Renf. du réseau boul. Tecumseh	1,197
Distribution	66	Enveloppe amélioration capacité hydraulique	N/A
Transmission	67	Poste de compression, St-Maurice	1,117
Transmission	68	Poste de compression, La Tuque	2,078
Alimentation	69	Pétromont	1,400

COST OF CAPITAL AND OTHER ECONOMIC PARAMETERS FOR EVALUATION

3. Reference: i) Exhibit B-0258, GM-9, Doc 4, GM Response to OC No. 1 IRs in Phase 3B, Question 7.2, pp. 24-27.

Questions:

3.1 Is the cost of debt of 2.82% an embedded cost or an incremental cost?

Réponse :

Le coût de la dette de 2,82 % est un coût prospectif. Il représente le coût combiné de la nouvelle dette à moyen et à long termes ainsi que de la dette à court terme (à taux variable) que devrait émettre Gaz Métro pour financer le projet.

3.2 Is the cost of debt net of the income tax deduction on debt interest?

Réponse :

Il s'agit du coût de la dette avant impôt.

3.3 In any case, please provide derivation or substantiation of the cost of debt.

Réponse :

Veuillez vous référer à l'annexe Q-3.3.

3.4 Is the cost of preferred stock of 4.44% an embedded cost or an incremental cost?

Réponse :

Le coût des actions privilégiées est aussi un coût prospectif. Il représente le coût d'une émission d'actions privilégiées en 2016-2017 que Gaz Métro devrait assumer pour financer le projet.

3.5 In any case, provide derivation or substantiation of the cost of preferred stock.

Réponse :

Le coût prospectif des actions privilégiées de 4,44 % est basé sur le rendement courant du 16 février 2016 de l'émission la plus récente de Canadian Utilities, choisie parce qu'elle se rapproche le plus de Gaz Métro de par sa cote de crédit et son industrie, parmi d'autres entreprises comparables. S&P a confirmé que les actions privilégiées de Gaz Métro, si émission il y avait, bénéficieraient d'une cote de P-2 (H), la même que Canadian Utilities.

3.6 Under item (xi), the volume of sales is identified as an item included in the analysis. Explain how the volume of sales is forecast for new residential customers and for new business customers?

Réponse :

Veuillez vous référer à la réponse à la question 14.2 de la demande de renseignements n° 9 de la Régie (B-0253, Gaz Métro-9, Document 1) et à la réponse à la question 7.6 de la demande de renseignements n° 1 d'OC (B-0258, Gaz Métro-9, Document 4).

3.7 Under item (xi), it appears that the customer charge is missing from the list of specific entries of revenue received from each project. Is this correct? If so, why is it not included?

Réponse :

Le taux du service de distribution qui est appliqué aux volumes prévus pour chaque client tient compte des frais de base applicables à ce tarif. Chaque client se voit attribuer selon son volume estimé le taux unitaire ainsi que les frais de base selon les conditions de service en vigueur.

Veuillez-vous référer à la réponse de la question 4.2 de la DDR 3 de l'ACIG (Gaz Métro-9, ddcument 10).

LONG-RUN MARGINAL OPERATION COSTS THAT ARE NOT DIRECT COSTS OF CUSTOMER CONNECTION

4. Reference: i) Exhibit B-0258, GM-9, Doc 4, GM Response to OC No. 1 IRs in Phase 3B, Question 4.4, pp. 12-13.

Questions:

4.1 Please provide the costs of operating the corporate human resources department in each year from 2012 to 2016 inclusively.

Réponse :

Le coût d'opération du département des ressources humaines, incluant salaires, avantages sociaux et autres dépenses pour les années 2012 à 2016 est présenté dans le tableau suivant.

	2012	2013	2014	2015	2016
Dépenses d'opération	8 060 533 $	8 477 995 $	8 295 062 $	8 749 968 $	8 430 851 $

4.2 What percentage of these costs is capitalized and what percentage is expensed?

Réponse :

	2012	2013	2014	2015	2016
Pourcentage capitalisé	0%	0%	0%	0%	0%

5 PROFITABILITY OF NETWORK ADDITIONS IN RECENT YEARS

References: i) Exhibit B-0258, GM-9, Doc 4, GM Response to OC No. 1 IRs in Phase 3B, Question 6.2, p. 21.

Question:

5.1 Please provide the direct cost in total for each type of project for which cumulative customers and revenues are estimated.

Réponse :

Les coûts directs représentent les coûts d'investissements excluant les frais généraux corporatifs et les frais généraux entrepreneurs.

Coûts directs prévus des extensions approuvées en 2016 *Par type*	**Coûts directs** *(000 $)*					
	An0	An1	An2	An3	An4	An5
Projet résidentiel	**2 984**	**420**	**329**	**175**	**119**	**53**
Rentable	1 406	214	124	38	57	0
SMA	1 579	206	205	137	62	53
Projet affaires	**13 663**	**229**	**48**	**9**	**21**	**0**
Rentable	6 792	175	40	1	0	0
SMA	3 448	54	7	8	21	0
SMA Parc industriel	3 185	0	0	0	0	0
SMA Repavage	237	0	0	0	0	0

MARKETING AND ADMINISTRATION OF NEW CUSTOMER CONNECTIONS

6 Reference: i) Exhibit B-0258, GM-9, Doc 4, GM Response to OC No. 1 IRs in Phase 3B, Question 4.2, pp. 11-12.
ii) Exhibit B-0264, GM-9, Doc 6, GM Response to ROEE Expert Paul Chernick's No. 2 IRs in Phase 3, Question 11.11, p. 25.
iii) Hearing Exhibit C-OC-0032 (Phase 3A)

Preamble: In Document C-OC-0032 presented in the Phase 3A hearing, on item 19 "line extension administration (pre-commitment)", the position of OC is shown as "not included but should be part of profitability analysis (Regie IR 1.3)" and the position of ROEE is shown as "figure not developed yet but should be included." These intervenors indicated that the information was relevant to a determination of profitability in Phase 3A but was not available.

Questions:

6.1 Please provide an organization chart showing those employees who are involved with the planning and marketing of new customer connections, and where they fit in the overall Gaz Metro organization. If there are separate groups serving new residential and new business connections, please identify them.

Réponse :

Considérant que la preuve de la phase 3A est complète et que la Régie en a été saisie et est présentement en délibéré, Gaz Métro soumet respectueusement que les questions portant sur les dépenses d'opération déjà traitées lors de la phase 3A ne sont pas pertinentes à l'étude de la présente phase 3B.

6.2 Please identify the cost of the planning and marketing of new customer connections by these employees (ie. those involved in the planning and marketing of new customer connections) in 2015 and 2016.

Réponse :

Considérant que la preuve de la phase 3A est complète et que la Régie en a été saisie et est présentement en délibéré, Gaz Métro soumet respectueusement que les questions portant sur les dépenses d'opération déjà traitées lors de la phase 3A ne sont pas pertinentes à l'étude de la présente phase 3B.

METHODOLOGY FOR PROFITABILITY IN OTHER PROVINCES

7 Reference: i) Exhibit B-0278, GM-7, Doc 5, pp. 29-31

Questions:

7.1 Please provide a copy of the E.B.O. 188 Final Report of the Board and the Ontario Energy Board Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario, Dated January 30, 1998.

Réponse :

Veuillez vous référer aux annexes Q-7.1a) *Final report of the Board* et Q-7.1b) *Appendix B – Guidelines for assessing and reporting on natural gas system expansion in Ontario*.

7.2 Please describe any differences in methodology of determining profitability and/or the components included in a profitability analysis between the Ontario Energy Board's report and Gaz Metro's proposal in this case, including but not limited to the concept of "tax savings" identified by the OEB.

Réponse :

Gaz Métro souligne qu'un balisage des méthodologies et des pratiques employées pour d'autres utilités gazières a été effectué dans le rapport de B&V (Gaz Métro 7, document 5). Gaz Métro a également revu à haut niveau les lignes directrices de l'OEB (voir référence à la réponse de la question 7.1.

Tout d'abord, il est à noter que les méthodes sont similaires, autant pour ce qui est des revenus et des coûts totaux considérés, qu'en regard de l'évaluation de l'indice de profitabilité.

Les principales différences notées entre les 2 méthodologies se résument aux éléments suivants :

- Les flux d'opération et les investissements (excepté l'investissement initial) sont considérés comme des flux de mi-année (OEB) versus de fin d'année (Gaz Métro) pour fin d'actualisation. À cet égard, l'approche de Gaz Métro est plus conservatrice que celle de l'OEB.

- L'économie d'impôt relative à l'amortissement fiscal est considérée comme une perpétuité pour l'OEB alors que Gaz Métro ne considère l'économie d'impôt que pour les 40 premières années. À cet égard, l'approche de Gaz Métro est plus conservatrice que celle de l'OEB.

Enfin, à noter que conformément à la décision D-97-25 de la Régie, Gaz Métro, tout comme l'OEB, utilise un taux d'actualisation dans l'évaluation de la rentabilité des projets correspondant au taux du coût moyen pondéré du capital prospectif après impôt. Toutefois, Gaz Métro a noté que le calcul de ce taux pour la cause tarifaire 2017, et depuis plusieurs années, a été fait en considérant le taux de la dette prospective avant impôt plutôt qu'après impôt, ce qui surestime légèrement le coût moyen pondéré du capital prospectif. Le calcul sera ainsi corrigé à partir du dossier tarifaire 2019.

7.3 Please describe any differences in methodology of determining profitability and/or the components included in a profitability analysis between the Fortis BC method and Gaz Metro's proposal in this case.

Réponse :

Gaz Métro souligne qu'un balisage des méthodologies et des pratiques employées pour d'autres utilités gazières a été effectué dans le rapport de B&V (Gaz Métro 7, Document 5). Gaz Métro a également revu à haut niveau le document *FortisBC Energy Inc (FEI) 2015 System Extension Application.*

Tout d'abord, il est à noter que les méthodes sont très similaires, autant pour ce qui est des revenus et des coûts totaux considérés, qu'en regard de l'évaluation de l'indice de profitabilité.

Les principales différences notées entre les 2 méthodologies se résument aux éléments suivants :

- Les « Municipal Tax » et « Property Tax » de FEI sont remplacées par la taxe sur les services publics et les redevances à la Régie de l'énergie et à la Régie du bâtiment, chez Gaz Métro.

- Les coûts de capital de FEI incluent une allocation pour fonds de roulement, alors que ceux de Gaz Métro considère des frais à l'Union des municipalités du Québec et des incitatifs commerciaux (PRC et CASEP).

- Le taux d'actualisation de FEI est le taux moyen pondéré du capital après impôt alors que celui de Gaz Métro constitue, conformément à la décision D-97-25 de la Régie, le coût moyen pondéré du capital prospectif après impôt. Toutefois, Gaz Métro a noté que le calcul de ce taux pour la cause tarifaire 2017, et depuis plusieurs années, a été fait en considérant le taux de la dette prospective avant impôt plutôt qu'après impôt, ce qui surestime légèrement le coût moyen pondéré du capital prospectif. Le calcul sera ainsi corrigé à partir du dossier tarifaire 2019.

INDIRECT COSTS

8 Reference: i) Exhibit B-0278, GM-7, Doc 5, p. 31

Questions:

8.1 Please confirm that the Capitalized General Contractors fees are paid as a percentage of the cost of each individual project, so that if a project were not completed, the capitalized general contractor's fee would be different. If you cannot confirm this point, please explain in detail.

Réponse :

Dans la méthodologie actuelle de l'évaluation de la rentabilité d'un projet de développement, Gaz Métro alloue 27,1 % de frais généraux entrepreneurs dans le calcul du coût du projet. Cette allocation spécifique à un projet sert à l'évaluation *a priori* de la rentabilité du projet de développement afin de déterminer s'il sera approuvé ou non.

Une fois le projet approuvé et réalisé, il n'y a pas d'attribution de frais généraux entrepreneurs à chacun des projets de développement dans les livres comptables de Gaz Métro. Les frais généraux entrepreneurs payés par Gaz Métro représentent un montant fixe par entrepreneur établi initialement dans le contrat général et sont capitalisés en totalité indépendamment du nombre de projets réalisés.

8.2 Please define Capitalized General Overhead Expenses, and in particular, specify if those expenses include costs such as workers' compensation insurance, employee benefits, and other costs that could be directly associated with a given worker.

Réponse :

Veuillez-vous référer à la réponse à la question 2.1 de la demande de renseignements n° 3 de la FCEI (Gaz-Métro 9 - Document 11) pour la description de la composition des frais généraux corporatifs.

Les coûts inclus dans les frais généraux corporatifs correspondent aux dépenses d'opération des centres des coûts, ce qui inclut des avantages sociaux.

SYSTEM INCREMENTAL CAPITAL INVESTMENT

9 Reference: i) Exhibit B-0278, GM-7, Doc 5, p. 32

Question:

9.1 Please explain how Black and Veatch would calculate the System Incremental Capital investment and would determine whether to assign portions of it to specific customers or at the portfolio level.

Réponse:

Gaz Métro

Gaz Métro n'a pas donné le mandat à Black and Veatch d'évaluer la projection des investissements nécessaires aux renforcements de réseau (premier volet de la question « would calculate ») et n'entendait pas le faire. Veuillez vous référer à la réponse à la question 1.1.

Black & Veatch

Black & Veatch would determine the investment-related costs of the facilities needed by Gaz Métro (as part of the reinforcement budget in its development plan) to reinforce its existing gas distribution system to enable the connection of new customers to the existing system and to increase the existing system's operational capacity and flexibility to the benefit of the new and existing customers.

System Incremental Capital Investments should be assigned to new customers in a manner that best aligns the number of customers to be served and their associated capacity needs with the investment level needed to satisfy those customer requirements. To accomplish this, it is reasonable and appropriate to assign the cost of such facilities to new customers on a portfolio basis to recognize the lumpy nature of these system investments (see also answer to question 7.2b of the ROEÉ Expert (Gaz Métro-9, Document 14). Even though gas load may grow gradually each month, capital expenditures to build upstream gas transmission or distribution projects are typically done less frequently reflecting the fact that economies of scale exist in upstream projects (i.e., it is more cost-effective on a unit basis when larger projects are undertaken compared to smaller projects).

The decision of how much investment, the location, and the timeframe for completing these types of projects is typically made by the gas utility's distribution system planning area as part of the ongoing review of its future capacity needs. Multiple factors are considered by system design and planning professionals including the current gas loads, estimates of short-term and long-term growth in load, right of ways, material costs, gas supply considerations, and modeling of current system capacity. Importantly, there is not a direct relationship between adding a single new customer or undertaking a development project and adding a unit of upstream capacity. Therefore, it is not feasible or equitable to assign a portion of the cost of these system facilities to specific customers. Please see also the response to answer to question 12.3 of the ROEÉ Expert (Gaz Métro-9, Document 14).

Calcul du coût en capital prospectif pour l'année 2017 conformément à la décision D-97-25

No de ligne						
1	**DETTE À :**	**54,00%**				
2	**25,00%**	**TAUX VARIABLE**	Pondération	Taux		
3		Titrisation	0,00%	0,00%	0,000%	
4		Papier commercial	100,00%	1,141%	1,141%	
5		Marché monétaire	0,00%	0,00%	0,000%	
6		**Rendement annuel - Taux variable :**			**1,14%**	**0,29%**
7	**10,00%**	**MOYEN TERME À TAUX FIXE**				
8		Obligation Cda 5 ans		0,85%		
9		Obligation Cda 10 ans		1,35%		
10		Moyenne des taux 5 - 10 ans :			1,10%	
11		Écart corporatif moyen :			1,42%	
12		Taux coupon :			2,52%	
13		Commission :		0,375%		
14		Frais d'émission :		0,260%		
15		Sur base annuelle :			0,08%	
16		**Rendement annuel - Moyen terme :**			**2,60%**	**0,26%**
17	**65,00%**	**LONG TERME A TAUX FIXE**				
18		Obligation Cda 10 ans :		1,35%		
19		Obligation Cda 30 ans :		1,97%		
20		Moyenne des taux 10 - 30 ans :			1,66%	
21		Écart corporatif moyen :			1,80%	
22		Taux coupon :			3,46%	
23		Commission :		0,450%		
24		Frais d'émission :		0,260%		
25		Sur base annuelle :			0,04%	
26		**Rendement annuel - Long terme :**			**3,50%**	**2,27%**
27	**TAUX PROSPECTIF DE LA DETTE :**					**2,82%**
28	**COUT EN CAPITAL PROSPECTIF :**					
29		DETTE :		54,00%	2,82%	1,52%
30		ACT. PRIVILÉGIÉES :		7,50%	4,44%	0,33%
31		ACT. ORDINAIRES :		38,50%	8,90%	3,43%
32				100,00%		
33		**COUT EN CAPITAL PROSPECTIF PONDÉRÉ :**				**5,28%**

E.B.O. 188

IN THE MATTER OF the Ontario Energy Board Act, R.S.O. 1990, c. O.13;

AND IN THE MATTER OF a hearing to inquire into, hear and determine certain matters relating to natural gas system expansion for The Consumers' Gas Company Ltd., Union Gas Limited and Centra Gas Ontario Inc.

BEFORE: G.A. Dominy
Presiding Member

R.M.R. Higgin
Member

J.B. Simon
Member

FINAL REPORT OF THE BOARD

January 30, 1998

TABLE OF CONTENTS

Appendix B: Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario

1. THE PROCEEDING

1.1 THE BACKGROUND

1.1.1 In a Notice of Public Hearing dated July 31, 1995, the Ontario Energy Board ("the Board") made provision to hold a public hearing under subsection 13(5) of the Ontario Energy Board Act ("the OEB Act", "the Act") to inquire into, hear and determine certain matters relating to the expansion of the natural gas systems of The Consumers' Gas Company Ltd. ("Consumers Gas"), Union Gas Limited ("Union") and Centra Gas Ontario Inc. ("Centra"), (collectively "the utilities"). The proceeding was given Board File No. E.B.O. 188.

1.1.2 In Procedural Order No. 1 the Board ordered the utilities to file their current policies for determining the feasibility of proposed system expansions and the application of environmental study reports.

1.1.3 The Board held an Issues Day meeting on September 11, 1995 and heard submissions on a proposed Issues List. The Board finalized the Issues List in Procedural Order No. 2 dated September 14, 1995.

1.1.4 Procedural Order No. 3, dated October 27, 1995, made provision for parties to file evidence and interrogatories on the evidence. The Order also provided for an alternative dispute resolution ("ADR") conference to be held commencing December 11, 1995 (" the first ADR Conference").

1.1.5 The Board received the *Report to The Ontario Energy Board on The Alternative Dispute Resolution Conference in E.B.O. 188 A Generic Hearing on Natural Gas System Expansion in Ontario*, on December 21, 1995 ("the first ADR Report"). There were divergent views expressed in the first ADR Report by the parties with respect to the principles involved in system expansion.

1.1.6 Having reviewed the first ADR Report, the Board issued Procedural Order No. 4 on January 11, 1996. In that Order, the Board directed that the parties choosing to file argument and reply should focus their submissions on the following issues:

> *1.1 Should financial feasibility be the only determinant for expansion or should it include, apart from security of supply and safety:*
>
> > *(1) an obligation to serve in areas where existing service is available;*
> > *(2) externalities;*
>
> *If externalities are to be included, what specific externalities, i.e. economic, social, environmental, should be considered? What tests should be applied and in what sequence?*
>
> *1.2 Given the answer to 1.1, what level of financial subsidy, if any, should be applied to system expansion;*
>
> *1.3 Should a portfolio of projects be utilized or should the utilities account for expansion on a project-by-project basis? How should the portfolio be defined?*

1.1.7 Submissions were filed on February 2, 1996 and reply submissions were filed on February 19, 1996.

1.1.8 An Interim Report of the Board ("Interim Report") was issued on August 15, 1996. In that Interim Report the Board made a determination of the issues and set out the principles that would apply to system expansion projects. The Board directed the parties to develop guidelines and policies reflecting the Board's conclusions. The Board also determined that the continuation of the proceeding should be by way of written submissions and a further ADR Settlement Conference ("the second ADR Settlement Conference").

1.1.9 A written common submission was filed by the utilities on September 30, 1996, and submissions and comments on the utilities' common submission were received from Board Staff, Consumers' Association of Canada, Canadian Industry Program for Energy Conservation, Industrial Gas Users Association/City of Kitchener, Green Energy Coalition, Northwestern Ontario Municipal Association/Federation of Northern Ontario Municipalities, Pollution Probe and Ontario Federation of Agriculture/Ontario Pipeline Landowners' Association.

1.1.10 In January 1997, the second ADR Settlement Conference was held. This resulted in the submission of:

- an ADR Agreement filed with the Board on March 14, 1997, subscribed to by the utilities and supported by a number of other parties ("ADR Agreement"), which included proposed System Expansion Guidelines;
- a dissent in the form of a document entitled "Deficiencies of the E.B.O. 188 ADR Agreement and their Rectification" dated April 1, 1997 ("Dissent Document");
- letters of comment from various parties on the ADR Agreement and Dissent Document; and
- responses (dated July 25, 1997) to a set of Board clarification questions to the utilities.

1.1.11 The parties concurring with the ADR Agreement and those substantially supporting the Dissent Document are listed in Appendix A.

1.1.12 In preparing this Final Report, the Board has considered the above documents. The resulting *Guidelines for Assessing and Reporting on Natural Gas Distribution System Expansion in Ontario (1998)* ("the Guidelines") are issued as Appendix B to this Report.

1.1.13 The following chapters set out the issues and the principles established in the Interim Report by quoting directly from that document. The positions of the parties are outlined by referencing the ADR Agreement, the Dissent Document and the various comments and clarifications made.

1.1.14 The Board’s comments and findings are structured as:

- The Portfolio Approach
- Common Methods for Financial Feasibility Analysis
- Customer Connection and Contribution Policies
- Environmental Planning Requirements for System Expansion
- Monitoring and Reporting Requirements

1.1.15 As of January 1, 1998, Union and Centra merged into a single company, Union Gas Limited. The Board’s findings in this Report and in the Guidelines are applicable to the new company and to Consumers Gas.

1.2 INTERVENTIONS

1.2.1 The following parties intervened in the proceeding:

- Canadian Association of Energy Service Companies
- City of Kitchener
- Consumers' Association of Canada
- Energy Probe
- Federation of Northern Ontario Municipalities
- Green Energy Coalition
- Grenville-Wood
- The Heating, Ventilation, Air Conditioning Contractors Coalition Inc.
- Industrial Gas Users Association
- Municipal Electric Association
- Natural Resource Gas Limited
- Northwestern Ontario Municipal Association
- Ontario Coalition Against Poverty
- Ontario Federation of Agriculture
- Ontario Hydro
- Ontario Native Alliance
- Ontario Pipeline Landowners' Association
- Ottawa-Carleton Gas Purchase Consortium

- Pollution Probe
- Power Workers' Union
- TransAlta Energy Corporation
- TransCanada PipeLines Limited
- Woodland Hills Community Inc.

Late Interventions

- The British Columbia Ministry of Energy, Mines and Petroleum Resources
- Canadian Industry Program for Energy Conservation
- Ecological Services For Planning Inc.
- F & V Energy Co-operative Inc.
- StampGas Inc.

2. THE PORTFOLIO APPROACH

2.1 INTERIM REPORT CONCLUSIONS

2.1.1 *The Board believes that utilities are in the best position to plan their distribution systems and, therefore, they should have flexibility in choosing the optimal system design for their distribution system expansions. The Board also believes that if the utilities are allowed to assess the financial viability of all potential customers as a group [using a portfolio approach] more marginal customers could be served as a result of assessing the cost of serving them together with more financially viable customers.*

2.1.2 *The Board is of the view that all distribution system expansion projects should be included in a utility's portfolio. This includes projects being developed for security of supply and system reinforcement reasons. The Board will be prepared on an exception basis to consider a utility's submissions as to why a proposed project should not be included in the portfolio but treated separately.*

2.1.3 *The Board believes that the issue of the timing of projects can be mitigated by the use of a rolling P.I. [Profitability Index] or benefit to cost ratio in the portfolio. The Board finds that using a rolling P.I. such as the approach used by Union will allow more opportunity for new projects to be added to the portfolio in a more timely fashion and that this is in the public interest. Union's rolling P.I. is a weighted average calculation of the cumulative net present value ("NPV") inflows divided by the cumulative NPV outflows during the preceding 12 months.*

2.1.4 *The Board expects the utilities to develop common policies on calculating rolling P.I.s. The forecast rolling P.I.s at a given point in time will be compared to the actuals in each utility's rates case to determine if any action needs to be taken with regard to forecast variances.*

2.1.5 *The Board recognizes that subsidization can be measured at both the project and portfolio level. An overall rolling portfolio P.I. of 1.0 means that existing customers will not suffer a rate increase over the long term as a result of distribution system expansion. The Board is therefore of the view that an overall portfolio P.I. of 1.0 <u>or better</u> (emphasis added) is in the public interest. Using this approach will obviate the need for the intense scrutiny of the financial viability of each project; will ensure that existing ratepayers are not negatively impacted by new projects (given the Board's proviso above on the sharing of risks); and assist communities to obtain gas service where otherwise it would not be financially feasible on a stand-alone basis.*

2.1.6 *However, at the present time the utilities calculate the DCF [“discounted cash flow”] for proposed projects over long periods of time. The P.I. or benefit to cost ratio is based on this calculation. In the early years, the costs shown in the calculation generally exceed the revenues and there is a greater impact on rates than in the later years when revenues generally exceed costs. The Board is concerned that even if a utility demonstrates that its portfolio of distribution system projects shows a P.I. of at least 1.0 the impact on rates in a given year may be undue. For this reason, the Board expects the utilities to demonstrate in their rates cases that the short-term rate impact of the cumulative effect of the portfolios will not cause an undue burden on existing ratepayers.*

2.1.7 *The Board has considered whether or not it should impose a minimum threshold P.I. for projects to be included in the portfolios. The Board is concerned that the utilities may proceed with a number of projects with low P.I.s even though the P.I.s of the portfolios remain at 1.0 or greater. The cumulative impact of these projects may result in economic inefficiencies that outweigh the public benefit of the portfolio approach. From time to time, the Board will review the project specific data to monitor the operation of the portfolios in order to determine whether the cumulative* *economic inefficiency of proceeding with financially unfeasible projects outweighs the public interest in using the portfolio approach.*

2.2 POSITIONS OF THE PARTIES

2.2.1 The ADR Agreement proposed that each utility group all proposed new distribution customers and new facilities to serve them, for a particular test year into one portfolio (the "Investment Portfolio"). The Investment Portfolio would be designed to achieve a NPV of zero or greater (including normalized reinforcement costs).

2.2.2 The ADR Agreement proposed that each utility also maintain a rolling 12 month distribution expansion portfolio (the "Rolling Project Portfolio"). The cumulative result of project-specific discounted cash flow ("DCF") analyses from the past 12 months would be calculated monthly. The costs and revenues associated with serving customers on existing mains would not be included. The Rolling Project Portfolio would be used as a management tool by the utilities to decide on appropriate distribution capital expenditures.

2.2.3 The Dissent Document listed three concerns with the Investment Portfolio proposed in the ADR Agreement:

i. service lines off existing mains are included;
ii. security of supply projects are not included; and
iii. reinforcement costs have been normalized rather than using forecast actual costs.

2.3 BOARD'S COMMENTS AND FINDINGS

Investment Portfolio

2.3.1 The Board accepts the ADR Agreement proposal that each utility would group into one portfolio, the Investment Portfolio, all proposed new distribution customer attachments and facilities for a particular test year. The Investment Portfolio would be designed to achieve a positive NPV (greater than zero) in the test year (including normalized reinforcement costs).

2.3.2 The Board considers that a primary purpose of the Investment Portfolio analysis is to provide the Board with sufficient evidence to decide whether a utility's test year system expansion plan will result in undue rate impacts.

2.3.3 The Board understands that the ADR Agreement's proposed Investment Portfolio contains the capital costs of facilities for all new customers added during a test year. The analysis of system expansion financial feasibility includes revenues and operation and maintenance ("O&M") costs associated with these new customers over horizons as proposed up to 40 years. The utilities propose to include an allowance for reinforcement costs to supply the new projects on a normalized basis.

2.3.4 Since the Investment Portfolio analysis is intended to predict the financial and rate impacts of test year incremental system expansion capital expenditures and associated revenues and expenses, it is inappropriate to include historic capital expenditures or revenues from attachments in prior periods.

2.3.5 The Board accepts the difficulty in isolating test year customers attaching to new mains only (versus those attaching to mains built in prior years). However, as specified in the Guidelines attached as Appendix B, an estimate of the NPV without attachments to prior expansions will be required. This will enable the Board to better monitor the overall economic feasibility of such projects.

2.3.6 The Board's interpretation of the Investment Portfolio analysis and its associated rate impacts was assisted by reference to Consumers Gas' interrogatory response [Exhibit I, Tab 7, Schedule 8] in the E.B.R.O. 495 Consumers Gas 1998 rates case. The Board directs the utilities to file future impact analyses in a similar form (see paragraph 6.3.4).

2.3.7 The Board sought further explanation for the proposed treatment of reinforcement costs in the Investment Portfolio in its letter of July 4, 1997 to the utilities. The utilities responded that "normalized" reinforcement costs were categorized into "special" reinforcement and "normal" reinforcement. The costs of the former are those associated with specific major reinforcements of the system and are amortized over a period of 10-20 years. The normal reinforcement costs are the residual of the total identified reinforcement costs after the special reinforcement costs are deducted. The historical average for the special and normal reinforcement costs will then be used as the normalized amount to be included in the portfolio analysis as a percentage of the total capital expenditure in the year.

2.3.8 The Board finds the proposed treatment of reinforcement costs to be included in the Investment Portfolio as proposed in the ADR Agreement appropriate for overall portfolio analysis purposes. Union currently includes an allowance related to the carrying costs for advancement of reinforcement expenditures resulting from a new project and the Board finds this approach to be appropriate.

2.3.9 The Board does not agree that a design target of zero NPV and a P.I. of 1.0 is appropriate given the forecast risks inherent in the Investment Portfolio analysis. As the Investment Portfolio NPV approaches zero the marginal projects will be those with long cash flow break-even periods. Such projects require subsidy for long periods and hence increase short term rate impacts disproportionately.

2.3.10 In addition, the Board notes that the Investment Portfolio includes the costs and revenues associated with attaching customers to existing mains (i.e. mains constructed prior to any given test year). These projects by their nature will be more profitable for the utilities, since the costs of the mains are not included in the Investment Portfolio calculation. The Board concludes that the Investment Portfolio should be designed to achieve a positive NPV including a safety margin (for example, corresponding to a P.I. of 1.10). The Board believes that a portfolio designed in this way will minimize the forecast risks and hence more likely achieve the desired results of no undue rate impacts.

Rolling Project Portfolio

2.3.11 The Board also accepts the ADR Agreement proposal to maintain a Rolling Project Portfolio. The Rolling Project Portfolio provides an ongoing method of determining the financial feasibility and rate impact of expansion projects over a previous 12 month period. The Rolling Project Portfolio excludes the costs and revenues associated with new customers attaching to mains built prior to the last 12 month period. The Rolling Project Portfolio also provides a basis to compare a utility's Investment Portfolio with actual system expansion. Union has used a Rolling Project Portfolio approach for some time and has filed rate impacts from significant individual projects in its rates cases (e.g. E.B.R.O. 493/494 Exhibit B1, Tab 4, Appendices C and D).

2.3.12 As noted above the Board finds the proposed treatment for reinforcement costs to be included in the Rolling Project Portfolio to be appropriate.

2.3.13 The Board finds the Rolling Project Portfolio as proposed by the utilities to be a useful management tool. This Portfolio provides a mechanism for facilitating review of the financial status of overall distribution system expansion at the time that individual major projects are before the Board for either franchise and certificate approval, or for approval of leave to construct and also for monitoring purposes.

2.3.14 The Board has previously expressed its position that inclusion in the Investment Portfolio, of revenues and costs for infill customers connecting to existing mains may provide a mismatch between periodic costs and revenue. The Board notes that the Rolling Project Portfolio, which is the utilities' primary management tool, does not include such infill customers. Therefore, the Board finds that the Rolling Project Portfolio does provide appropriate matching and that an NPV of zero (or greater) is appropriate.

3. COMMON METHODS FOR FINANCIAL FEASIBILITY ANALYSIS

3.1 INTERIM REPORT CONCLUSIONS

3.1.1 *The Board believes that a further review of the methodology to be used by the utilities in assessing the project and portfolio financial feasibility is necessary. Among the factors to be considered are the period for new attachments and the time period over which the DCF analysis is calculated. The Board expects utilities to develop common methods for the Stage I Financial Feasibility test that will be used to show whether or not each utility's portfolio of distribution system expansion projects is profitable.*

3.2 POSITIONS OF THE PARTIES

3.2.1 The ADR Agreement set the following parameters for the DCF analysis:

(a) Customer Attachment Horizon

A maximum 10 year forecast horizon will be utilized. For customer attachment periods of greater than 10 years an explanation of the extension of the period will be provided to the Board.

(b) Customer Revenue Horizon

The maximum customer revenue horizon shall be 40 years from the in-service date of the initial mains, except for large volume customers where the maximum shall be 20 years from the customers' initial service.

(c) Discount Rate

The Utilities' incremental after-tax cost of capital will be used for the discount rate. This will be based on the prospective capital mix, debt and preference share costs, and the latest Board approved equity return levels.

(d) Discounting

Discounting will reflect the true timing of expenditures. Up-front capital expenditures will be discounted at the beginning of the project year and capital expended throughout the year will be mid-year discounted, as will revenue, gas related costs, and operating and maintenance expenditures.

(e) Operating and Maintenance Expenditures

The incremental costs directly associated with the attachment of new customers to the system will be included in the operating and maintenance expenditures.

(f) Gas Costs

In the near term, the weighted average cost of gas ("WACOG") will continue to be the proxy for gas costs (gas costs shall be WACOG less the commodity portion of the gas costs). This approach may not be appropriate in the case of projects for large customers, where a specific gas cost forecast may be required.

3.2.2 The parties to the Dissent Document submitted the ADR Agreement was deficient in that the utilities had not agreed on a common method for calculating their P.I.s; that a 40 year revenue horizon may result in existing customers paying undue rate increases; and that 40 years is inappropriate in the absence of shareholder responsibility for forecast variations.

3.2.3 The Dissent Document also stated that the utilities were understating the costs in the financial feasibility analysis, since they are not using incremental costs for gas storage and transportation services, but have proposed that gas costs be WACOG less the commodity portion of gas costs.

3.2.4 The Dissent Document proposed:

- a customer attachment horizon no longer than 5 years (unless there is a specific contract);
- a maximum time period for the DCF calculation of 20 years from the in-service date of the initial main for large volume customers and between 20 and 30 years for small volume customers;
- customer use volumes representing the best estimates of the gas consumption for new customers; and
- the inclusion of incremental costs associated with gas storage and TransCanada PipeLines Limited transmission.

3.3 BOARD'S COMMENTS AND FINDINGS

3.3.1 The Board notes that the utilities have undertaken to apply consistent business principles for the development of the elements of the financial feasibility test. These elements include: customer attachment horizon, customer revenue horizon, discount rate and timing, operating and maintenance expenditures, and weighted average gas costs.

3.3.2 The Board notes that the proposed customer attachment forecast horizon of 10 years is a maximum and adopts this as part of the Guidelines in Appendix B.

3.3.3 The Board is concerned that a customer revenue horizon of 40 years will encourage inclusion of projects with very long cash flow break-even periods and hence high levels of subsidy in the early years. The Board has addressed this issue as part of the design targets for the Investment Portfolio.

3.3.4 The Board concludes that, although theoretically correct, the inclusion of forecast incremental costs for the transportation and storage of gas will add unnecessary complexity to the DCF calculations for distribution system expansion projects.

3.3.5 The Board finds however that the methodology should include a standard test or measure to assess short term rate impacts at the Portfolio level. This would be similar to the Rate Impact Measure ("RIM") Test used to evaluate Demand Side Management ("DSM") programs, with the objective of allowing comparisons from year to year and, to a degree, among the separate portfolios of the utilities.

3.3.6 The Board accepts that the DCF calculation will be based on a set of common elements as proposed in the ADR Agreement. These common elements will be reflected in the DCF analysis for the Investment Portfolio and the Rolling Project Portfolio filed by each of the utilities in its rates cases, the details of which are set out in Appendix B.

4. CUSTOMER CONNECTION AND CONTRIBUTION POLICIES

4.1 INTERIM REPORT CONCLUSIONS

4.1.1 *In the last few years, the Board has approved contributions in aid of construction in the form of periodic contribution charges for residential and small commercial customers in order to improve the profitability of projects when the P.I. or benefit to cost ratio is less than 1.0.*

4.1.2 *The Board notes that accidents of timing and geography can ... lead to inequitable situations where some ratepayers in similar situations may not have to pay a contribution while others are required to pay contributions.*

4.1.3 *The Board realizes that customers have indicated their willingness to contribute towards the cost of projects that are not financially feasible in order to obtain gas service. The Board also notes that there may be communities that would be so costly to serve and the P.I. so low that they are unlikely ever to be included in the portfolio. The Board accepts that in these special circumstances a contribution in aid of construction from a community would be acceptable on a case by case basis, but the Board will not expect the utilities to require contributions from all projects which do not meet a threshold P.I. of 1.0. In light of these considerations, the Board expects the utilities to prepare common guidelines on the treatment of customers currently paying periodic contribution charges.*

4.1.4 *The Board will review in the next phase of this proceeding the utilities' policies on requiring contributions in aid of construction where dedicated facilities are being constructed primarily for a single customer. In this regard the Board is interested in a policy that deals with all customer classes and expects the utilities to prepare a policy that is common among the utilities.*

4.2 POSITIONS OF THE PARTIES

4.2.1 The ADR Agreement states that the utilities will accept contributions in aid of construction for communities or projects that would otherwise not likely be included in the portfolio.

4.2.2 The ADR Agreement also proposed that existing contractual arrangements for the collection of contributions continue with the exception of Consumers Gas' projects for which contributions would be adjusted to achieve a P.I. of 0.8.

4.2.3 The ADR Agreement did not propose a definition to be used in determining when a facility is to be considered "dedicated".

4.2.4 The Dissent Document does not address the issue of customer contribution policies.

4.3 BOARD'S COMMENTS AND FINDINGS

4.3.1 The Board notes that the utilities wish to retain the ability to accept contributions in aid of construction for communities or projects that would not otherwise be included in the portfolio. However, no cost limits or P.I. thresholds have been recommended by the parties to assist the utilities in making such decisions. As stated in the Interim Report, the Board believes that the utilities should continue to make decisions on contributions in an even handed manner.

4.3.2 The Board recognizes that Union and Centra have been applying a P.I. threshold of 0.8 for the collection of customer contributions for new community attachments. The Board also notes that the utilities proposed this level as the basis for determining the treatment of customers currently paying periodic contributions. In order to ensure fairness and equity in the application and design of contribution requirements, the Board finds that all projects must achieve a minimum threshold P.I. of 0.8 for inclusion in a utility's Rolling Project Portfolio.

4.3.3 The Board directs the utilities to prepare and maintain a common set of Board-approved customer connection policies that shall, as a minimum, include:

i. the circumstances under which customers will be required to pay for all, or part, of their service line connection, including the specific criteria and the quantum of, or formula for calculating, the total or excess service line fees and other charges; and

ii. the circumstances where the use of a proposed facility will be dominated by one or more large volume customers for which the utilities will retain the option of collecting contributions in aid of construction. The contribution amounts will be consistent with the cost allocation for such mains and accordingly based on the peak day demand and the cost allocators used by each of the utilities.

4.3.4 The Board agrees with the parties that the common criteria for contributions in aid of construction should apply to all customer classes. If there is a reasonable expectation of further expansion, the contribution in aid of construction is expected to take into account the future load growth potential and timing of any such expansion.

4.3.5 The Board expects the utilities to bring forward common proposals for customer connection and contribution policies for Board approval. These proposals will be reviewed in each of the utilities' rate cases.

5. ENVIRONMENTAL PLANNING REQUIREMENTS FOR SYSTEM EXPANSION

5.1 INTERIM REPORT CONCLUSIONS

5.1.1 *The Board requires that for all distribution projects, the utilities prepare a display of alternatives (routes and sites) which would show the various trade-offs between customer attachments and environmental, social and financial costs. The Board expects the utilities to prepare common guidelines on how to conduct and document the evaluation of their route selection and to apply these to all expansion projects.*

5.1.2 *The Board also expects the utilities to appropriately apply the [Board's] Environmental Guidelines for Locating, Constructing and Operating Hydrocarbon Pipelines in the Province of Ontario, Fourth Edition, 1995 ("the Environmental Guidelines") to all distribution system projects whether or not they involve a facilities application to the Board. The Board believes that the type and level of detail of the environmental investigations conducted by the utilities should be determined on the basis of environmental significance, and not on whether or not a particular application comes before the Board, whether a proposed pipeline is a distribution or transmission line, or whether or not the line will be located in a town. The utilities should conduct and document the necessary investigation and develop mitigation measures where significant environmental features are encountered. It is expected that the utilities will not require additional resources to undertake these investigations.*

5.1.3 *The utilities will have to confirm in their rates cases that all proposed projects meet the guidelines on route selection and the Environmental Guidelines and if not, why not. In addition, for facilities applications, the Board expects the utilities to file the project specific route selection display and environmental report. The Board expects that the utilities may incorporate the route selection evaluation into their environmental report.*

5.1.4 *The requirements to conduct and document the evaluation of the route selection and to apply the Environmental Guidelines to all distribution projects will be incorporated in the Environmental Guidelines.*

5.1.5 *In facilities applications the utilities will also have to continue to satisfy the Board on the design and construction practices and costs for the project. In addition, the Board will have to be satisfied that landowner concerns have been met and that any necessary permits have been obtained.*

5.2 POSITIONS OF THE PARTIES

5.2.1 The ADR Agreement proposed that whenever a need for gas is identified, and a reasonable source is available, an evaluation would be done on whether this need could be accommodated. Full information on service alternatives would be gathered, including potential customers served, the running line location, construction costs and environmental and socio-economic concerns.

5.2.2 In selecting a preferred route, the ADR Agreement stated that standard environmental guidelines will be used for dealing with most environmental features. Significant environmental features (those not covered by the utilities' standard environmental guidelines) will require separate evaluation and may require public meetings and agency consultation.

5.2.3 The ADR Agreement proposed that costs of avoiding significant environmental features or mitigating significant environmental impacts will be included in the cost and benefit analysis for the project. For projects with similar economic benefits, routes that avoid significant environmental features will be preferred. Generally, routes with the greatest economic benefits overall will be preferred, subject to the environmental considerations described above.

5.2.4 The parties to the Dissent Document submitted that the ADR Agreement is not consistent with the Board's Interim Report because:

i. the utilities have not yet developed common guidelines on how to conduct and document the evaluation of their route selection; and

ii. according to the ADR Agreement, the utilities can select a route that will cause significant harm to the local environment if the route's economic benefits exceed its costs to the environment.

5.2.5 The parties to the Dissent Document proposed that the utilities be required to prepare and apply common guidelines on how to conduct and document the evaluation of their route selections to all expansion projects.

5.2.6 Energy Probe, the Green Energy Coalition, and Pollution Probe proposed that the utilities should be required to adopt as a principle that there should be "no net loss" of local environmental resources as a result of their system expansion activities. Where a utility is unable to offset the environmental impacts of its system expansion activities, the utility should make best efforts to create an offsetting environmental resource to meet the "no net loss" principle.

5.3 BOARD'S COMMENTS AND FINDINGS

5.3.1 The Board notes that a move to a portfolio planning and management approach may result in less public scrutiny of the financial and economic evaluation of individual system expansion projects. However this does not imply that there should be any decrease in the necessary level of environmental assessment of projects by the utilities, or the documentation of this work, as these matters will continue to be reviewed by the Board.

5.3.2 The planning principles described in the Board's Environmental Guidelines shall also apply to distribution expansion projects undertaken by the utilities. The level of detail required, the degree of public consultation and the level of alternative route/site evaluation should be determined by the utilities in a manner consistent with the Environmental Guidelines based on a review of the environmental (biophysical and socio-economic) significance of features potentially impacted by a proposed project. Environmental significance is to be determined based on the expected impacts of a particular project, not on whether the feature is covered by the utility's environmental guidelines.

5.3.3 To assist in determining what level of planning, investigation and reporting is necessary, the Board finds that the utilities shall jointly develop a common set of environmental screening criteria to determine if significant environmental features may be impacted during the construction or the operation of the facility. Corresponding planning, documentation, and reporting requirements are to be jointly developed and applied by each utility depending on the impacts expected as determined through the screening process. The criteria and corresponding requirements can be in the form of a checklist. The Board will review the screening criteria and the corresponding planning, documentation and reporting requirements for inclusion in the Environmental Guidelines. The Board expects the utilities to submit this material to the Board by June 1, 1998.

5.3.4 Once the study area for the project is determined, a regional officer of the utility who is familiar with the study area and has been trained in environmental matters shall identify potential impacts through the screening process and determine the level of planning required. Depending on the significance of the potential impacts anticipated, the decision on the level of planning may involve additional environmental specialists of the utility, external consultants and other affected parties.

5.3.5 Depending on the level of significance of the environmental feature(s) encountered, the planning may involve alternative routing/siting considerations, detailed mitigation requirements and/or public and/or agency review. It is expected that the criteria and requirements will be updated from time to time by the utilities in consultation with other interested parties and reviewed by the Board for inclusion in updated Board Environmental Guidelines.

5.3.6 Where alternative routes or sites are investigated, the Board expects that the preferred alternative will be chosen based on an optimization of the particular environmental, social and financial criteria for the project. Decisions on the relative importance of these criteria are to be made based on the specific environmental features encountered and their significance, rather than deciding in advance that financial criteria have priority.

5.3.7 In those cases where the significance of environmental features may be in question or the planning requirements are not clear, the utilities are expected to consult with environmental specialists, Board Staff and affected parties. The Board expects that as experience is gained, consultation will be necessary only in unusual cases. In all cases however, it is expected that provincial and local agency requirements (permits, licences) shall be obtained where necessary and that the utilities will apply their standard guidelines, drawings, and specifications.

5.3.8 The Board finds that further examination of the "no net loss" principle is unnecessary in this proceeding in light of the Board's specified environmental planning requirements.

6. MONITORING AND REPORTING REQUIREMENTS

6.1 INTERIM REPORT CONCLUSIONS

6.1.1 *The Board also expects the utilities to develop proposals on the appropriate method to use to monitor the variation between forecast and actual profitability of their distribution system expansion portfolios.*

6.1.2 *Despite the advantages of a portfolio approach, the Board is of the view that certain containment practices should be put in place in order to ensure that:*

- *ratepayers are protected from financially risky decisions on expansion by the utilities;*
- *the utilities make decisions on which projects should proceed in an even-handed manner;*
- *the cumulative impact on rates is not undue in any given year;*
- *the continued expansion of natural gas service is in the overall public interest; and*
- *the economic inefficiencies implicit in including projects with negative P.I.s do not outweigh the public interest benefits of the portfolio approach.*

6.1.3 *Utility shareholders will be held responsible for any significant variation in the forecast of customer attachments, volumes and costs from the aggregate portfolio. The Board expects the utilities to make proposals in the next phase of this proceeding on how variances from the aggregate forecast should be treated in order to* *appropriately share the risk between ratepayers and shareholders. In considering how the risk should be shared, the utilities may want to review their policies on obtaining financial assurances from new large volume customers.*

6.1.4 *The Board also expects the utilities to develop proposals on the appropriate method to use to monitor the variation between forecast and actual profitability of their distribution system expansion portfolios.*

6.1.5 *However, the Board finds that it is in the public interest to require the utilities to demonstrate that it continues to be in the overall public interest to expand the natural gas distribution systems from an aggregate economic, social and environmental point of view. Therefore, the Board will require utilities to file the results of a societal cost test ["SCT"] of their overall portfolios of distribution system expansion when seeking approval of their portfolios. The societal cost test could include monetized, non-monetized and qualitative components. To this end, the Board requests the utilities to develop a common evaluation method, that would be cost-effective, that would adequately characterize performance, and that would be relatively straightforward to apply.*

6.1.6 *The Board expects the utilities to develop common reporting requirements so that the utilities' forecast P.I.s, customer attachments, volumes and costs can be compared to actuals on a portfolio basis and, if need be, on a project specific basis. This information shall be put on the record in the rates cases to serve as a benchmark.*

6.1.7 *The Board expects that under the portfolio approach the Stage I financial feasibility P.I. will be calculated for each proposed project as well as for the portfolio of infill projects. For the purposes of calculating the P.I. of the infill portfolio, infill projects are defined as the extension of mains and service attachments in existing service areas, but does not include service lines to individual customers off existing mains.*

6.1.8 *All the P.I.s of the proposed projects and the infill portfolio will be aggregated to calculate the overall portfolio P.I. at a given time for each utility.*

6.2 POSITIONS OF THE PARTIES

6.2.1 The ADR Agreement proposed that the utilities file Test Year and Historic Year information as part of their rates cases. This information would include the capital amounts, profitability and rate impacts of the Investment Portfolio and the Rolling Project Portfolio; actual expenditures on reinforcement costs; and specific customer attachment information on a set of randomly selected projects.

6.2.2 The ADR Agreement also proposed that each utility file in its rate case a projected NPV of the results of a SCT for the Investment Portfolio for the test year. The results would be presented both with and without monetized externality costs and benefits.

6.2.3 The parties to the Dissent Document submitted that the ADR Agreement fails to meet the Board's direction in the Interim Decision because:

- the ADR Agreement does not require the utilities to report the P.I.s of their Investment Portfolios or any individual project within their Investment Portfolios;

- the ADR Agreement does not require the utilities to report the forecast aggregate NPV and P.I. of the test year's projects that have negative P.I.s (information necessary to address the Board's concern with respect to economic efficiency); and

- the ADR Agreement does not require the utilities to put on the record in their rates cases project specific P.I.s, customer attachments, volumes and cost data so that project specific information can serve as a benchmark for monitoring performance on an on-going basis.

6.2.4 The parties to the Dissent Document further submitted that the ADR Agreement fell short because:

- there is no commitment to provide a comparison of actual and forecast volumes;

- there is no commitment to provide a comparison of actual and forecast capital expenditures for the Investment Portfolio; and

- the utilities are only committed to providing a comparison of their actual and forecast customer attachments for the first three years of a project's life, which does not cover the remaining 7 years in a project's 10 year customer attachment forecast period.

The parties to the Dissent Document proposed that the utilities should be required to file portfolio and project specific information for the historic, bridge and test years.

6.3 BOARD'S COMMENTS AND FINDINGS

6.3.1 The Board believes that the principles outlined in the Interim Report should form the basis of the monitoring and reporting requirements.

Rate Case Review

6.3.2 The Board directs that the utilities file, in their respective rates cases, a forecast NPV and P.I. of the test year Investment Portfolio. In subsequent rates cases, each utility will report to the Board on the actual results of the Investment Portfolio.

6.3.3 The actual results of the Investment Portfolio will present the NPV and the P.I. taking into account the capital spent, the number of customers attached and the revenues received from the customers attached in the most recent historical year for which there is full data. Volume usage for larger commercial and industrial customers will be individually estimated to more closely reflect actual annual volumes.

6.3.4 Each utility will, in its rates case, provide an analysis of the estimated rate impact of its Investment Portfolio in the first five years of service. As referred to earlier, the Board found the material filed by Consumers Gas in E.B.R.O. 495 at Exhibit I, Tab 7, Schedule 8, to be a good example of the information necessary, but would be further assisted if the impacts were broken down by rate class. The Board directs that such a breakdown be included in the required impact analysis.

6.3.5 As noted earlier, the Board also wishes the utilities to use a standard rate impact test or measure similar to the R.I.M. test used to assess DSM program impacts. This measure should present the following information in aggregate and by rate class:

- impact of the Investment Portfolio cash flow on the test year revenue deficiency; and
- the ratio of incremental revenues to costs in the test year and subsequent three years.

6.3.6 The Board notes that in recent rates cases both Centra and Consumers Gas have significantly overspent their Board-approved capital budgets, particularly in the bridge year. In its E.B.R.O. 493/494 Decision the Board set out the criteria of *affordability* and *rate stability* as key factors affecting the capital budget and additions to rate base, which the Board will consider in assessing prudence of expenditures.

6.3.7 The Board notes that the addition of capital for assets such as Information Technology and Customer Information Systems may have significant impacts on both the level of capital expenditure and year to year additions to rate base. The Board in its E.B.R.O. 493/494 Decision suggested that affordability criteria be applied to develop ceilings for capital expenditures and rate stability criteria be used to manage the scheduling of expenditures on more discretionary projects in conjunction with system expansion projects. In addition, in E.B.R.O. 495 the Board expressed its concern about the upward pressure on rates resulting from continual system expansion, and concluded that, for ratemaking purposes, expenditures above overall Board-approved levels in various categories (“envelopes”) of the capital budget could not automatically be included in the Company’s proposed rate base for the next fiscal year. In addition, the Board cautioned that the Company would be required to prove the reasonableness of its capital expenditures within each envelope, even if the expenditures were at or below the Board approved level.

6.3.8 The Board expects that the concerns raised in these recent rate cases regarding affordability and rate stability will be addressed in the utilities’ plans under the portfolio approach.

6.3.9 The Board will treat variances between actual and forecast portfolio NPVs in the same manner as for other forecast test year variables. The utilities will provide explanations of the reasons for the variations and the corrective actions taken or proposed. The Board will judge the degree to which the cost impacts should be apportioned between the shareholder and the ratepayers.

6.3.10 The Board agrees with the ADR proposal for portfolio level SCT analysis, monitoring and reporting, using a test that is consistent with the treatment of the SCT for DSM.

Ongoing Monitoring and Reporting

6.3.11 The Board notes that the primary purposes of the Guidelines in Appendix B are to streamline the process of approval of system expansion projects and achieve a commonality of approach between the utilities, while ensuring that ratepayers are protected against the impacts of either over-aggressive, or financially inappropriate, system expansion by the utilities.

6.3.12 The Board believes that the achievement of these objectives requires periodic standardized reporting to the Board, as well as the filing of information in rate cases in order to allow the prudence of the utilities' actions and rate impacts to be reviewed. These reviews should appropriately be rate focussed with account taken of both short-term and long-term costs and benefits to ratepayers.

6.3.13 The Board considers that, in general, the ADR Agreement proposals in the section *Monitoring the Performance of the Portfolios/Short Term Rate Impacts*, provide a reasonable point of departure and that experience should show whether the content and timing of the monitoring and reporting requirements are adequate. The Board will require filing of the P.I.s of the portfolios as well as the NPVs. The adjusted monitoring requirements are included in the Guidelines in Appendix B.

6.3.14 The Board emphasizes that the utilities must maintain clear records at a project specific level that will allow for inspection and/or reporting of individual projects as may be deemed necessary from time to time.

6.3.15 The Board will require quarterly filing of the monthly reports on the Rolling Project Portfolio and total capital expenditures in order to monitor performance.

6.3.16 The approach to environmental planning outlined above should simplify the documentation requirements. The sampling process and reporting required in the Guidelines will ensure consistency across projects and between utilities and ensure compliance with the Board's environmental planning requirements.

7. COMPLETION OF THE PROCEEDING AND COSTS

7.1 COMPLETION OF THE PROCEEDING

7.1.1 The Board has reviewed the letters of comment setting out the positions of various parties on the ADR Agreement and the Dissent Document. The Board is of the view that it would not be in the public interest at this stage to hold additional hearings on this matter. Rather, the Board believes that the public interest is better served by proceeding with the implementation of the Guidelines included in Appendix B of this Report.

7.1.2 The Board directs that the Guidelines shall be implemented as soon as possible, but no later than the 1999 fiscal year for each of the utilities. The Guidelines will be subject to future review by the Board in the light of experience gained in their application.

7.2 COSTS

7.2.1 In the Board's Interim Decision of August 15, 1996 the parties to the proceeding were directed to submit cost claims for that phase of the proceeding. The Board made an interim cost award to those parties requesting one.

7.2.2 The Board directs all parties who wish to do so, to submit their final claim for costs with the Board and a copy to each of the utilities, taking into account the interim cost award (if applicable) by February 20, 1998. Comments from the utilities are to be filed by March 2, 1998 and reply by parties by March 16, 1998. The Board will issue its Cost Award Decision and Order in this proceeding in due course.

7.2.3 The Board directs the utilities to pay the Board's costs of, and incidental to the proceeding upon receipt of the Board's invoice.

7.2.4 The Board directs that all costs be apportioned on a 50:50 basis between Consumers Gas and Union/Centra Gas.

DATED AT TORONTO January 30, 1998.

G.A. Dominy
Vice Chair and Presiding Member

R.M.R. Higgin
Member

J. B. Simon
Member

Was Appendix, preliminary page 2 247

APPENDIXB ONTARIO ENERGY BOARD GUIDELINES FOR ASSESSING AND REPORTING ON NATURAL GAS SYSTEM EXPANSION IN ONTARIO

1998 248

Was Appendix, preliminary page 3 249

CONTENTS

Was Appendix, page 1 258

I. OVERVIEW - PURPOSE AND OBJECTIVE OF THE GUIDELINES

The Ontario Energy Board ("OEB", "Board") Guidelines for Assessing and Reporting on Natural Gas System Expansion In Ontario ("The Guidelines") provide a common analysis and reporting framework to be applied by regulated Ontario Local Distribution Companies - Union Gas Limited and The Consumers' Gas Company Ltd. ("the utilities") to natural gas distribution system expansion. The principles upon which the Guidelines are based reflect the Board's conclusions in its Distribution System Expansion Reports under Board File No. E.B.O. 188. (Interim Report[12JM1-0:1] dated August 15, 1996; Final Report[1] dated January 30, 1998). 259

Portfolio Approach 260

The main change from prior policy and practice is the use of a portfolio approach, as opposed to a project-by-project approach, to the planning, analysis, management and reporting of distribution system expansion projects. The intent of the portfolio approach is to provide the utilities a greater degree of flexibility in determining which projects to undertake, while the Board retains overall regulatory control to ensure no undue cross subsidy or rate impacts result from distribution system expansion. 261

Financial Feasibility Analyses 262

The Guidelines provide the utilities with direction with respect to the structure of their system expansion portfolios and the methods for conducting financial feasibility analyses at both the individual project level and the portfolio level. The Guidelines standardize the elements to be used in the discounted cash flow ("DCF") analysis as well as establish the parameters for the costs and revenues that are the inputs to that analysis. 263

Reporting 264

The Guidelines establish a mechanism to evaluate the performance of each of the utilities' distribution expansion activities on a portfolio basis and on an individual project basis. The Guidelines also outline reporting requirements for system expansion plans and post expansion impacts. The forecast rate impacts of a utility's expansion plans will be presented in rates case filings on a prospective test year basis. 265

These reporting requirements are intended to provide the Board and interested parties with sufficient information to monitor the utilities' expansion activities and their associated rate impacts. The performance of the utilities related to implementation of these Guidelines will be evaluated as part of each utility's rates case. 266

Customer Connection Policies Was Appendix, page 2 267

Part of the utilities' management of distribution system expansion will be the provision of common customer connection policies. These will include policies relating to service line fees, customer contributions to otherwise financially unfeasible projects and for projects dominated by one or more large volume customers. 268

Environmental Considerations 269

To ensure that the utilities plan and construct system expansion facilities in an environmentally acceptable manner, the Guidelines also address the routing and environmental planning, documentation and reporting requirements for distribution expansion projects. 270

Was Appendix, page 3

1. SYSTEM EXPANSION PORTFOLIOS 271

1.1 Investment Portfolio 272

Each of the utilities will group into a portfolio (the "Investment Portfolio") the costs and revenues 273
associated with all new distribution customers who are forecast to attach in a particular test year (including new customers attaching to existing mains). The Investment Portfolio is to include a forecast of normalized system reinforcement costs.

The Investment Portfolio will be designed to achieve a profitability index ("PI") *greater* than 1.0. 274

1.2 Rolling Project Portfolio 275

Each of the utilities will maintain a rolling 12 month distribution expansion portfolio (the "Rolling 276
Project Portfolio") updated monthly, as an ongoing management tool for estimation of the future impacts of capital expenditures associated with distribution system expansion. The Rolling Project Portfolio will exclude those customers requiring only a service lateral from an existing main.

The utilities will calculate monthly the cumulative result of project-specific DCF analyses from the 277
past twelve months for the Rolling Project Portfolio. It will include all future customer attachments, revenues and costs on the basis of the life cycle of each of the projects making up the Portfolio.

2. STANDARD TEST FOR FINANCIAL FEASIBILITY 278

The standard test for determining the financial feasibility at both the project and the portfolio level 279
will be a DCF analysis, as set out below.

2.1 DCF Calculation and Common Elements 280

The DCF calculation for a Portfolio will be based on a set of common elements. For <u>revenue forecasting</u>, the common elements will be as follows: 281

(a) for the Rolling Project Portfolio, total forecasted customer attachments over the Customer Attachment Horizon for each project; 282

(b) for the Investment Portfolio, a forecast of all customers to be added in the Test Year; 283

(c) an estimate of average use per added customer which reflects the mix of customers to be added; 284

(d) a factor which reflects the timing of forecasted customer additions; and 285

Was Appendix, page 4

(e) rates derived from the existing rate schedules for the particular utility, net of the gas commodity component. 286

For <u>capital costs</u>, the common elements will be as follows: 287

(a) an estimate of all costs directly associated with the attachment of the forecast customer additions, including costs of distribution mains, services, customer stations, distribution stations, land and land rights; 288

(b) an estimate of incremental overheads applicable to distribution expansion at the portfolio level; and 289

(c) an estimate of the normalized system reinforcement costs. 290

For <u>expense forecasting</u>, the common elements will be as follows: 291

(a) gas costs as used in revenue forecasts (excluding commodity costs); 292

(b) incremental operating and maintenance costs; 293

(c) income and capital taxes based on tax rates underpinning the existing rate schedules; and 294

(d) municipal property taxes based on projected levels. 295

2.2 Specific Parameters 296

Specific parameters of the common elements include the following: 297

(a) a 10 year customer attachment horizon;. 298

(b) a customer revenue horizon of 40 years from the in service date of the initial mains (20 years for large volume customers); 299

(c) a discount rate equal to the incremental after-tax cost of capital based on the prospective capital mix, debt and preference share cost rates, and the latest approved rate of return on common equity; 300

(d) discounting reflecting the true timing of expenditures. Up-front capital expenditures will be discounted at the beginning of the project year and capital expended throughout the year will be mid-year discounted, as will revenue, gas costs, and operating and maintenance expenditures; and 301

(e) gas costs based on the weighted average cost of gas ("WACOG") excluding commodity costs. 302

Was Appendix, page 5

3. MONITORING PORTFOLIO PERFORMANCE AND SHORT-TERM RATE IMPACTS 303

3.1 Rates Case Filings 304

The following information will be filed in each rates case: 305

Test Year 306

(a) the Investment Portfolio, including NPV, the total capital in the portfolio and the portfolio PI; 307

(b) an estimate of the aggregate NPV of all new facilities requiring a new franchise and/or certificate of public convenience and necessity and of all "infills" (i.e. main extensions and service attachments in existing service areas excluding service lines to customers off existing mains) based on extrapolated historical data; 308

(c) an estimate of the Test Year rate impacts of the Investment Portfolio based on the: 309

(i) contribution to annual revenue requirement; 310

(ii) Rate Impact Measure presented as the ratio of added revenue to costs for each customer class; and 311

(iii) class-specific estimated percent rate and annual average bill increases. 312

(d) estimates of the NPV and the benefit-cost ratio for the Investment Portfolio using a Societal Cost Test ("SCT"), defined in the Report of the Board, E.B.O. 169 III, as an evaluation of the costs and/or benefits accruing to society as a whole, due to an activity. The SCT analysis should be consistent with that used for the utilities' DSM programs. The benefit-cost ratio shall be presented with and without monetized externalities. 313

Historic Year: 314

(a) the Historic Year Investment Portfolio, including the NPV, total capital in the portfolio, and the portfolio PI; 315

(b) the aggregate NPV, the total capital, and the portfolio PI for: 316

(i) the Rolling Project Portfolio at the end of the historic year; 317

(ii) all completed projects with negative NPVs; 318

(iii) all completed projects with positive NPVs; 319

(c) upon the request of the Board, a list of the projected results of individual extensions included in the Rolling Project Portfolio; 320

(d) actual expenditures on reinforcement projects; and 321

Was Appendix, page 6 322

(e) the rate impact of the Historic Year Investment Portfolio reflecting actual capital expenditures and customer related data.

3.2 Ongoing Monitoring Information 323

The utilities shall establish a process to allow the Board to monitor the performance of their distribution system expansion project portfolios including financial and environmental requirements. 324

A. Financial Monitoring 325

In consultation with Board Staff, the utilities shall select projects from their Rolling Project Portfolios on an annual basis and shall file the following with respect to the sample: 326

(a) the cumulative number of customers attached at the end of the 3rd full year and the associated revenues and costs; and 327

(b) the corresponding year 3 customer attachment forecasts and associated revenues and costs. 328

B. Environmental Monitoring 329

In consultation with Board Staff, the utilities shall select a set of completed projects and file data on those projects on an annual basis as described below. The projects chosen should be selected in a random, stratified manner, reflecting the range of environmental impacts encountered in the time period and the various levels of environmental planning, documentation and reporting required. The selection should be reviewed by an independent auditing group within the utility, which group shall include (a) trained environmental auditor(s). The utility shall file the following with respect to each sample: 330

1. a description of how the project complied with the Board-approved environmental screening, planning, documentation and reporting requirements; 331

2. a table of significant features, how they were avoided or mitigated, and resulting impacts; 332

3. a table displaying the concerns raised by affected parties including member ministries of the Ontario Pipeline Coordination Committee, how they were addressed, and reasons for any outstanding concerns; 333

4. issues of significance arising from any post-construction monitoring; 334

5. where alternatives were investigated, a display of alternatives (routes/sites) which show the various trade-offs between customer attachments, and environmental, social and financial costs and a discussion of how the preferred alternative was chosen; 335

Was Appendix, page 7

6. evidence that all necessary approvals (permits, licences) were obtained; and 336

7. forecast versus actual costs of the environmental planning. 337

3.3 Risks of Non-performance 338

In the event that the actual results of the Investment Portfolio do not produce a positive NPV or a PI of at least 1.0, the following will occur: 339

(a) the utility will be required to provide a complete variance explanation in its rates case and the Board will determine whether or not an acceptable explanation has been provided; and 340

(b) the implications of a negative NPV or PI less than 1.0 will be determined by the Board on a case by case basis. 341

4. CUSTOMER CONNECTION AND CONTRIBUTION POLICIES 342

The utilities will maintain a clear set of common Board-approved Customer Connection and Con- 343
tribution in Aid Policies.

The criteria for contributions in aid of construction for service lines and mains will apply to all 344
customer classes. If there is a reasonable expectation of further expansion, the contribution in aid of construction will take into account the future load growth potential and timing of any such expansion.

The Customer Connection and Contribution in Aid Policies shall, as a minimum, include the fol- 345
lowing:

- Requirements for payment for all, or part, of a customer service line connection, including 346
  the specific criteria and the quantum of, or formula for calculating, the total or excess service line fees and other charges.
- Requirements for contributions in aid of construction for connection of individual custom- 347
  ers, subdivisions or communities requiring main extensions that would not otherwise be included in the Investment or Rolling Project Portfolios.
- Requirements for contributions in aid of construction for expansion projects dominated by 348
  one or more large volume customers.

5. ENVIRONMENTAL REQUIREMENTS FOR DISTRIBUTION FOR SYSTEM EXPANSION PROJECTS 349

The planning principles described in the Board's "Environmental Guidelines for the Location, 350
Construction, and Operation of Hydrocarbon Pipelines and Facilities In Ontario (1995)" shall also apply to distribution expansion projects undertaken by the utilities. The level of detail required, the degree of public consultation and the level of alternative route/site evaluation should be determined based on a review of the environmental (biophysical and socio-economic) significance of features potentially impacted by a proposed project.

Was Appendix, page 8 351
The utilities shall apply environmental screening criteria to determine when significant features may be impacted during the construction or the operation of the facility. Corresponding planning, documentation, and reporting requirements are to be applied depending on the impacts expected as determined through the screening process.

Once the study area for the project is determined, a regional officer of the utility who is familiar 352
with the study area and has been trained in environmental matters, shall identify potential impacts through the screening process and determine the level of planning required. Depending on the

significance of the potential impacts anticipated, the planning requirements may involve environmental specialists of the utility, external consultants or other affected parties.

353

All provincial and local agency requirements (permits, licences) shall be obtained where necessary and the utilities shall apply their standard guidelines, drawings, and specifications.

354

6. DOCUMENTATION, RECORD KEEPING AND REPORTING

355

The utilities will maintain documentation for all projects which are to be included in the Rolling Project Portfolio. A record of the DCF analysis conducted for each project in the Rolling Project Portfolio shall be available for review upon request of the Board. The performance tracking of individual projects shall be as described in Section 3 of these Guidelines.

356

The utilities will maintain a record of the environmental planning, documentation and reporting requirements associated with all projects and Environmental Reports for those projects deemed to have significant environmental impacts.

357

For all expansion projects in the Rolling Project Portfolio with a capital cost greater than $500,000 ("major projects") the utilities shall file the NPV and DCF analysis in each rate case and shall keep a record of forecast and actual customer attachments for a period of three years after construction is completed. In addition, the utilities shall also file in each rate case, the NPV and DCF analysis for all major projects planned for the test year. Upon request of the Board, the utilities shall file forecast and actual customer attachments for major projects.

358

The utilities shall file quarterly with the Board Secretary, the updated monthly Rolling Project Portfolio results immediately upon completing the calculations.

Was Appendix, schedule page 1 359

SCHEDULE1 DISCOUNTED CASH FLOW METHODOLOGY

360

<u>Net Present Value ("NPV")</u> = *Present Value ("PV") of Operating Cash Flow + PV of CCA Tax Shield - PV of Capital*

<u>Profitability Index ("PI")</u> = *<u>PV of Operating Cash Flow + PV of CCA Tax Shield</u>*

(PV of Capital)

361

1. <u>PV of Operating Cash Flow</u> = *PV of Net Operating Cash (before taxes) - PV of Taxes*

a)	PV of Net Operating Cash	=	PV of Net Operating Cash Discounted at the Company's discount rate for the customer revenue horizon. Mid-year discounting is applied.
	Net Operating Cash	=	*(Annual Gas Revenue - Annual Gas Costs - Annual O&M)*
	Annual Gas Revenue	=	*Customer Additions * Consumption Estimates per Customer * Revenue Rate per* m^3
	Annual Gas Cost	=	*Customer Additions * Consumption Estimates per Customer * Gas Costs per* m^3 *net of commodity costs*
	Annual O&M	=	*Customer Additions * Annual Marginal O&M Cost/customer*

b)	PV of Taxes	=	PV of Municipal Taxes + PV of Capital Taxes + PV of Income Taxes (before Interest tax shield)
	Annual Municipal Tax	=	*Municipal Tax Rate * (Total Capital Cost)*
	Total Capital Cost	=	*(Mains Investment + Customer Related Investment + Overheads at portfolio level)*
	Annual Capital Taxes	=	*(Capital Tax Rate) * (Closing Undepreciated Capital Cost Balance)*
	Annual Capital Tax	=	*(Capital Tax Rate) * (Net Operating Cash - Annual Municipal Tax - Annual Capital Tax)*

The Capital Tax Rate is a combination of the Provincial Capital Tax Rate and the Large Corporation Tax (Grossed up for income tax effect where appropriate).

Note: Above is discounted, using mid-year discounting, over the customer revenue horizon. 363

364

2. <u>PV of Capital</u> = *PV of (Total Annual Capital Expenditures - Annual Contributions)*

a) PV of Total Annual Capital Expenditures

Total Annual Capital Expenditures over the customer's revenue horizon discounted to time zero

Total Annual Capital Expenditure = *(Mains Investment + Customer Specific Capital + Overheads at the Portfolio level)*

Was Appendix, schedule page 3 365

b) Annual Contributions

Annual Contributions = *Cash payments (or principal portions of payments over time) received as Contributions in Aid of Construction*

Note: Above is discounted to the beginning of year one over the customer addition horizon. 366

367

3. <u>PV of CCA Tax Shield</u>

PV of the CCA Tax Shield on [Total Annual Capital]

The PV of the perpetual tax shield may be calculated as:

PV at time zero of :

$$\frac{[(\text{Income Tax Rate}) * (\text{CCA Rate}) * \text{Annual Total Capital}]}{(\text{CCA Rate} + \text{Discount Rate})}$$

or,

Calculated annually and present valued in the PV of Taxes calculation.

Note: An adjustment is added to account for the $^{1}/_{2}$ year CCA rule. 368

369

4. <u>Discount Rate</u>

PV is calculated with an incremental, after-tax discount rate.