BALISAGE DES MÉTHODES DE CALCUL DU TEST DU COÛT TOTAL EN RESSOURCES (TCTR)

TABLE DES MATIÈRES

LEXIQUE DES ABRÉVIATIONS

AEÉ :	Agence de l'efficacité énergétique
BCUC :	British Columbia Utilities Commission
CPUC :	California Public Utilities Commission
Gaz Métro :	Société en commandite Gaz Métro
GES :	Gaz à effet de serre
HQD :	Hydro-Québec Distribution
MPUB:	Manitoba Public Utilities Board
NTG :	Net to gross ratio
OEB :	Ontario Energy Board
PEEENT :	Plan d'ensemble en efficacité énergétique et nouvelles technologies
PGEÉ :	Plan global en efficacité énergétique
Régie :	Régie de l'énergie
SPM :	Standard Practice Manual
TCTR :	Test du coût total des ressources
TRC :	Total resource cost
WACC :	Weighted average cost of capital

1 MISE EN CONTEXTE

Dans sa décision D-2011-048[1], la Régie a permis la mise en place d'un groupe de travail pour l'étude du dossier tarifaire 2012 de Gaz Métro. Au terme de ses travaux, le groupe de travail a formulé des demandes à la Régie.

Une des demandes du groupe de travail à la Régie visait à autoriser Gaz Métro à réaliser un balisage des méthodologies de calcul du TCTR. Plus précisément, le groupe de travail s'est entendu sur le texte suivant :

> *«La Régie a approuvé par la décision D-2010-091 une méthode révisée par Gaz Métro pour le calcul du test du coût total des ressources (TCTR). Le Groupe de travail souhaite souligner que la California Public Utility Commission (CPUC) a adopté en 2007 une révision à sa méthodologie du calcul du TCTR[2]. Le Groupe de Travail s'entend pour que Gaz Métro réalise pendant l'exercice 2011-2012 un balisage des méthodologies actuelles de calcul du TCTR, incluant celle suggérée par le CPUC, et de proposer, le cas échéant, des modifications au calcul dans le cadre du PGEÉ de la Cause tarifaire 2013.*
>
> *Le Groupe de travail demande à la Régie d'autoriser Gaz Métro à réaliser le balisage des méthodologies de calcul du TCTR proposé.»*[3]

Dans sa décision D-2011-182[4], la Régie précisait que :

> *« Par ailleurs, tenant compte des amendements apportés par la California Public Utilities Commission (CPUC) à sa méthodologie de calcul du test du coût total en ressources (TCTR), la Régie autorise Gaz Métro à baliser, en 2012, les méthodologies actuelles de calcul du TCTR, incluant celle de la CPUC, et de proposer, le cas échéant, des modifications au calcul de ce test dans le cadre du PGEÉ 2013 ».*

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[1] Paragraphe 10.

[2] California Public Utility Commission, Decision 07-09-043 : Interim Opinion on Phase 1 Issues Shareholder Risk-Reward Incentive Mechanism for Energy Efficiency Programs, Section 10.2, September 20,2007

[3] Cause tarifaire 2012, R-3752-2011, B-0122 - Gaz Métro – 2, Document 3, page 2.

[4] Paragraphe 27

Considérant cette décision de la Régie, Gaz Métro a entrepris des travaux visant à procéder à un balisage des différentes méthodologies utilisées par des distributeurs réglementés impliqués en efficacité énergétique.

Les objectifs de ce document sont donc de :

- présenter les méthodologies de calculs du TCTR utilisées :
  - Par Gaz Métro;
  - Par les autres distributeurs réglementés au Québec;
  - Par d'autres distributeurs réglementés ailleurs au Canada;
  - Par la CPUC.
- présenter les aspects communs et les particularités des méthodologies observées;
- tirer des conclusions suite à l'analyse des résultats du balisage.

À partir des résultats de ce balisage, Gaz Métro émet ses recommandations à la Régie dans le document B-0156 - Gaz Métro – 09 document 1.

2 MÉTHODOLOGIE UTILISÉE POUR LA RÉALISATION DU BALISAGE

Gaz Métro a procédé à une recherche documentaire à l'aide des moteurs de recherche des différents sites internet suivants :

- Organismes canadiens et distributeurs d'énergie :
  - OEB ;
  - MPUB ;
  - BCUC ;
  - Office de l'efficacité énergétique du Canada (OEEC);
  - Régie ;
  - Manitoba Hydro ;
  - Hydro Québec ;
  - Gazifère ;

- Union Gas ;
- Enbridge ;
- BC Hydro ;
- Ministry of Energy and Mines.

- Organismes américains :
  - Consortium for Energy Efficiency (CEE) ;
  - California Measurement Advisory Council (CALMAC) ;
  - California Public Utilities Commission (CPUC) ;
  - Pennsylvania Public Utility Commission (PUC) ;
  - United States Environmental Protection Agency (EPA) ;
  - American Council for an Energy Efficient Economy (ACEEE) ;
  - Energy center of Wisconsin ;
  - Public Utilities Commission of Ohio ;
  - Northwest Natural Gas Company ;
  - San Diego Gas and Electric.

La collecte de données dans les moteurs de recherche à été effectuée avec les mots-clés suivants :

- TCTR ;
- TRC equation ;
- Free-ridership ;
- Distorsion effects ;
- Free drivers ;
- Avoided costs ;
- Measure benefits ;
- NTG ratio ;

- Program administrative cost ;
- Participant cost net.

Outre cette collecte d'information à partir des moteurs de recherche, plusieurs échanges et discussions ont eu lieu entre Gaz Métro et les autres distributeurs réglementés au Canada faisant partie du présent balisage afin de s'assurer d'obtenir les informations les plus précises possible et de bien comprendre les particularités relatives à chacun.

La recherche documentaire effectuée sur différents sites internet ainsi que les multiples discussions et rencontres réalisées dans le cadre du balisage sur les principes de base du calcul du test du coût total en ressources ont permis d'amasser une quantité importante d'information. Les prochaines sections présentent les différentes méthodologies utilisées par des distributeurs réglementés impliqués en efficacité énergétique. Pour chacun, un tableau synthèse de la méthode de calcul utilisée a été produit afin de permettre de comparer plus facilement les méthodes entre elles et d'être en mesure de tirer des conclusions.

Gaz Métro souligne que la recherche n'a pas permis de mettre la main sur un balisage déjà effectué auprès des différents distributeurs réglementés au Canada. Gaz Métro en vient à la conclusion que cet exercice constitue une première au Canada qui pourra servir de référence à d'autres distributeurs.

3 PRINCIPES DE BASE DU CALCUL DU TEST DU COÛT TOTAL EN RESSOURCES

Le TCTR est l'un des nombreux tests de rentabilité applicables aux programmes d'efficacité énergétique. Dans sa décision D-2009-046[5], la Régie demandait à l'AEÉ d'utiliser le TCTR comme critère de rentabilité principal pour tous ses programmes et ceux des distributeurs inclus dans le PEEÉNT.

De façon simple, le TCTR met en relation les bénéfices et les coûts générés par un programme d'efficacité énergétique.

TCTR = Bénéfices - Coûts

[5] D-2009-046, page 66.

Les bénéfices sont calculés à partir des éléments suivants :

- le nombre de participants;
- les économies d'énergie unitaires attribuables au programme;
- les coûts évités du distributeur.

Les coûts sont constitués de deux types de coûts spécifiques :

- les coûts des participants;
- les coûts du programme.

Le résultat du TCTR est calculé en considérant la valeur actualisée, selon un taux d'actualisation réel défini, des bénéfices et des coûts sur la durée de vie de la mesure d'efficacité énergétique promue par le programme.

Ces principes de base sont généralement reconnus, documentés et partagés par les distributeurs réglementés et acceptés par les offices de réglementation en Amérique du Nord. Si ce n'était que sur cette base, aucun balisage ne serait nécessaire, puisque ce n'est pas à ce niveau qu'il peut se retrouver avec des différences entre les méthodologies de calculs utilisées par des distributeurs réglementés aux fins de l'évaluation de la rentabilité des programmes d'efficacité énergétique.

Les différences entre les méthodologies sont plus subtiles et font référence à des détails de calcul attribuables à une ou plusieurs des composantes du calcul des bénéfices ou des coûts. L'application des effets de distorsion, par exemple l'effet d'opportunisme, aux bénéfices ou aux coûts considérés peut être la source de différences observées d'un distributeur à l'autre. Il en est de même sur plusieurs autres éléments spécifiques de la méthode de calcul.

Le présent balisage des méthodologies de calcul mettra donc davantage d'emphase sur les éléments plus spécifiques de la méthode de calcul en considérant que les aspects méthodologiques de base sont communs.

4 MÉTHODE DE CALCUL UTILISÉE PAR GAZ MÉTRO

En 2010, Gaz Métro a révisé sa méthodologie de calcul du TCTR. La méthode révisée a été détaillée à la Régie en demande de renseignements[6] puis approuvée par cette dernière dans la décision D-2010-091[7].

La méthodologie de calcul du TCTR par Gaz Métro peut être présentée de la manière suivante.

Les bénéfices considèrent les éléments suivants :

- Les participants nets : Les participants nets sont obtenus à partir des participants bruts auxquels on ajoute l'effet d'entraînement et on soustrait l'effet d'opportunisme. Les effets d'entraînement et d'opportunisme sont évalués régulièrement selon une méthodologie approuvée par la Régie et propre à chaque programme[8].
- Les économies unitaires : Les économies attribuables à une mesure d'efficacité énergétique encouragée par un programme du PGEÉ de Gaz Métro.
- Les économies attribuables à l'effet de bénévolat : L'effet de bénévolat est ajouté aux économies totales. L'effet de bénévolat est évalué régulièrement selon une méthodologie approuvée par la Régie et propre à chaque programme[9].
- Coûts évités : Les coûts évités sont présentés annuellement à la Régie et la méthode de calcul est revue régulièrement[10]. Les coûts évités considèrent le taux d'inflation prévu pour prendre en compte l'augmentation des coûts sur la durée de vie de la mesure.
- Taux d'actualisation réel: Le taux d'actualisation utilisé correspond au taux du coût du capital prospectif autorisé par la Régie dans le dossier tarifaire précédent. Le taux du coût du capital prospectif utilisé est réduit du taux d'inflation prévu pour obtenir un taux d'actualisation réel[11].

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[6] Rapport annuel au 30 septembre 2009, R-3717-2009, Gaz Métro – 12, Document 3.3
[7] D-2010-091, page 19.
[8] Rapport de la Régie sur le suivi 2011 des évaluations des programmes du PGEÉ et du FEÉ de Gaz Métro
[9] Rapport de la Régie sur le suivi 2011 des évaluations des programmes du PGEÉ et du FEÉ de Gaz Métro
[10] Cause tarifaire 2012, R-3752-2011, B-0156 - Gaz Métro 9, Document 1, pages 13-14.
[11] D-2011-182, page 20.

- Durée de vie de la mesure : La durée de vie utilisée est propre à chaque programme selon son cas type. Les durées de vie sont présentées annuellement à la Régie[12].

Les coûts considèrent les éléments suivants :

- Les coûts pour les participants :
  - Les participants nets : Les participants nets sont obtenus à partir des participants bruts auxquels on soustrait l'effet d'opportunisme;
  - La mise de fonds du participant : La mise de fonds correspond au surcoût complet du participant pour faire l'acquisition de la mesure d'efficacité énergétique. La mise de fonds du participant n'est pas réduite du montant de l'aide financière.
- Les coûts du programme[13] :
  - Le budget de développement et de formation;
  - Le budget de commercialisation;
  - Le budget de suivi et d'évaluation;
  - Le budget de support et de frais administratifs.

Le tableau suivant présente la synthèse des éléments considérés par la méthodologie de calcul utilisée par Gaz Métro.

[12] Cause tarifaire 2012, R-3752-2011, B-0244 - Gaz Métro 9, Document 2, page 15
[13] Cause tarifaire 2012, R-3752-2011, B-0244 - Gaz Métro 9, Document 2

Tableau 1

	Valeur actuelle nette des <u>bénéfices</u>	
A	**Participants nets**	
	Participants bruts en nombre	√
-	Effet d'opportunisme en %	√
+	Effet d'entraînement en %	√
B	**Économies annuelles**	
A	Participants nets en nombre	√
*	Économies unitaires en m^3	√
+	Effet de bénévolat en m^3	√
C	**Taux d'actualisation réel**	
	Coût de capital prospectif autorisé par la Régie (t-1)	√
-	% inflation	√
D	**Coûts évités totaux**	
B	Économies annuelles	√
*	Coûts évités pour $1m^3$	√
*	(1 + % inflation) sur la durée de vie de l'appareil	√

	Valeur actuelle nette des <u>coûts</u>	
E	**Coût des participants**	
	Participants bruts en nombre	√
-	Effet d'opportunisme en %	√
*	Mise de fond du participant	√
C	Taux d'actualisation réel	√
F	**Coût du programme**	
	Développement et formation	√
+	Commercialisation	√
+	Suivi et évaluation	√
+	Support et administration	√
C	Taux d'actualisation réel	√

5 MÉTHODES DE CALCULS UTILISÉES PAR LES AUTRES DISTRIBUTEURS RÉGLEMENTÉS AU QUÉBEC

MÉTHODE UTILISÉE PAR GAZIFÈRE

La méthodologie de calcul du TCTR par Gazifère peut être présentée de la manière suivante.

Les bénéfices considèrent les éléments suivants :

- <u>Les participants nets</u> : Les participants nets sont obtenus à partir des participants bruts auxquels on ajoute l'effet de bénévolat et on soustrait l'effet d'opportunisme. Les effets de bénévolat et d'opportunisme sont évalués régulièrement selon une méthodologie approuvée par la Régie et propre à chaque programme.
- <u>Les économies unitaires</u> : Les économies attribuables à une mesure d'efficacité énergétique encouragée par un programme du PGEÉ de Gazifère.
- <u>Coûts évités</u> : Les coûts évités sont présentés annuellement à la Régie et la méthode de calcul est revue régulièrement. Les coûts évités sont calculés sur la durée de vie de la mesure à laquelle un effet de persistance est appliqué pour chaque programme. L'effet de persistance est un facteur correcteur qui tient compte de la période réelle où la mesure demeure en place chez le client.

- Taux d'actualisation réel : Le taux d'actualisation utilisé correspond au taux du coût du capital pondéré prévu au dossier tarifaire[14]. Le taux du coût du capital pondéré utilisé est réduit du taux d'inflation prévu pour obtenir un taux d'actualisation réel.

Les coûts considèrent les éléments suivants :

- Les coûts pour les participants :
  - Les participants nets : Les participants nets sont obtenus à partir des participants bruts auxquels on soustrait l'effet d'opportunisme.
  - La mise de fonds du participant : La mise de fonds correspond au surcoût complet du participant pour faire l'acquisition de la mesure d'efficacité énergétique. La mise de fonds du participant n'est pas réduite du montant de l'aide financière.
- Les coûts du programme :
  - Le budget de développement et de formation
  - Le budget de commercialisation
  - Le budget de suivi et d'évaluation
  - Le budget de support et de frais administratifs.

Le tableau suivant présente la synthèse des éléments considérés par la méthodologie de calcul utilisée par Gazifère.

[14] Cause tarifaire 2012, R-3752-2011, B-0156 - Gaz Métro 9, Document 1, page 16, ligne 18-19, note de bas de page #5.

Tableau 2

Valeur actuelle nette des bénéfices		
A	**Participants nets**	
	Participants bruts en nombre	√
-	Effet d'opportunisme en %	√
+	Effet de bénévolat en %	√
B	**Économies annuelles**	
A	Participants nets en nombre	√
*	Économies unitaires en m^3	√
C	**Taux d'actualisation réel**	
	Coût de capital pondéré en attente d'approbation par la Régie	√
-	% inflation	√
D	**Coûts évités totaux**	
B	Économies annuelles	√
*	Coûts évités pour $1m^3$	√
*	(1 + % inflation) sur la durée de vie de l'appareil ajusté pour tenir compte de la persistance	√

Valeur actuelle nette des coûts		
E	**Coût des participants**	
	Participants bruts en nombre	√
-	Effet d'opportunisme en %	√
*	Mise de fond du participant	√
C	Taux d'actualisation réel	√
F	**Coût du programme**	
	Développement et formation	√
+	Commercialisation	√
+	Suivi et évaluation	√
+	Support et administration	√
C	Taux d'actualisation réel	√

MÉTHODE UTILISÉE PAR HYDRO-QUÉBEC

La recherche documentaire effectuée a permis de déterminer les principales composantes utilisées par HQD dans sa méthodologie de calcul du TCTR.

En effet, dans son dossier tarifaire 2012-2013, HQD demandait à la Régie d'accepter une proposition de modification au calcul du TCTR afin de retirer les coûts relatifs aux opportunistes, des coûts des participants. HQD précisait que :

> *« … Test du TCTR = Coûts évités – (coûts des mesures + coûts de commercialisation) ≥ 0*
>
> *Au niveau des coûts évités par la mesure, seuls les gains énergétiques obtenus grâce aux clients non-opportunistes et bénévoles sont comptabilisés. Les économies d'énergie réalisées par les clients opportunistes sont déjà exclues des gains énergétiques, car le Distributeur ne peut pas se les créditer. Elles ne nécessitent donc aucune modification.*
>
> *Au chapitre des coûts de programme et plus précisément des coûts de la mesure elle-même (équipement et implantation), ceux supportés par l'ensemble des clients participant au programme (non-opportunistes, opportunistes et bénévoles) étaient comptabilisés. Or, cette démarche surestimait le coût de la mesure, car elle comptabilisait des dépenses qui auraient été réalisées par les clients opportunistes même en l'absence du programme. Par conséquent, ces dépenses sont désormais retirées du coût de la mesure. Autrement dit, le*

coût de la mesure ne tient dorénavant compte que des dépenses associées aux clients non-opportunistes et bénévoles (c.-à-d., ceux réellement influencés par le programme). »[15]

Dans sa décision déposée le 8 mars 2012, la Régie considère que la proposition d'Hydro-Québec ne peut être retenue[16] car celle-ci n'a pas procédé à un balisage exhaustif à cet égard auprès d'autres entités responsables de livraison de programmes d'efficacité énergétique. Conséquemment, la méthodologie actuelle a été maintenue.

Gaz Métro a également procédé à des validations auprès d'HQD afin de s'assurer de bien rapporter la méthodologie de calcul utilisée par ce distributeur.

Ainsi, les bénéfices considèrent les éléments suivants :

- <u>Les participants nets</u> : Les participants nets sont obtenus à partir des participants bruts auxquels on ajoute l'effet d'entraînement et on soustrait l'effet d'opportunisme. Les effets d'entraînement et d'opportunisme sont évalués régulièrement selon une méthodologie approuvée par la Régie et propre à chaque programme.
- <u>Les économies unitaires</u> : Les économies attribuables à une mesure d'efficacité énergétique encouragée par un programme du PGEÉ d'Hydro-Québec.
- <u>Les économies attribuables à l'effet de bénévolat</u> : L'effet de bénévolat est ajouté aux économies totales. L'effet de bénévolat est évalué régulièrement selon une méthodologie approuvée par la Régie et propre à chaque programme.
- <u>Coûts évités</u> : Les coûts évités sont augmentés par l'annuité croissante à l'inflation sur la durée de vie de la mesure.
- <u>Taux d'actualisation réel</u>: Le taux d'actualisation utilisé correspond au taux du coût du capital prospectif autorisé par la Régie dans le dossier tarifaire précédent. Pour obtenir un taux d'actualisation, HQD utilise le taux du coût du capital prospectif nominal selon l'équation suivante : (1+ taux actualisation nominal) / (1+ taux d'inflation).

[15] Demande R-3776-2011, B-0045 - HQD-8, Document 8 Annexes, page 44.
[16] D-2012-024, R-3776-2011, page 129

- Durée de vie de la mesure : La durée de vie utilisée est propre à chaque programme selon son cas type. Les durées de vie sont présentées annuellement à la Régie.

Les coûts considèrent les éléments suivants :

- Les coûts pour les participants :
  - Les participants bruts : Les participants considérés sont les participants bruts ainsi que les bénévoles.
  - La mise de fonds du participant : La mise de fonds correspond au surcoût complet du participant pour faire l'acquisition de la mesure d'efficacité énergétique. La mise de fonds du participant n'est pas réduite du montant de l'aide financière.
- Les coûts du programme :
  - Le budget de planification et conception
  - Le budget de développement et de formation
  - Le budget de commercialisation
  - Le budget de suivi et d'évaluation.

Ainsi, aux fins de comparaison, le tableau suivant présente la méthodologie utilisée par Hydro-Québec.

Tableau 3

Valeur actuelle nette des bénéfices		
A	**Participants nets**	
	Participants bruts en nombre	√
-	Effet d'opportunisme en %	√
+	Effet d'entraînement en %	√
B	**Économies annuelles**	
A	Participants nets en nombre	√
*	Économies unitaires en kWh	√
+	Effet de bénévolat	√
C	**Taux d'actualisation réel**	
	Coût de capital prospectif autorisé par la Régie (t-1)	√
/	% inflation	√
	(1+ taux nominal) / (1+ inflation)	
D	**Coûts évités totaux**	
B	Économies annuelles	√
*	Coûts évités pour 1kWh	√
*	Annuité croissante à l'inflation sur la durée de vie de l'appareil	√

Valeur actuelle nette des coûts		
E	**Coût des participants**	
	Participants bruts en nombre	√
+	Effet de bénévolat	√
*	Mise de fond du participant	√
C	Taux d'actualisation réel	√
F	**Coût du programme**	
	Planification	√
+	Conception	√
+	Développement	√
+	Commercialisation	√
+	Exploitation	√
+	Suivi et évaluation	√
C	Taux d'actualisation réel	√

6 MÉTHODE UTILISÉE PAR D'AUTRES DISTRIBUTEURS RÉGLEMENTÉS AU CANADA

MÉTHODE UTILISÉE EN ONTARIO

En 2011, la Commission de l'énergie de l'Ontario (OEB) a rendu publics les résultats de travaux effectués sur plusieurs années afin de régler différents enjeux liés aux activités des distributeurs gaziers en lien avec l'efficacité énergétique.[17] L'OEB a ainsi défini la méthodologie et les paramètres de calcul à considérer par les distributeurs pour le calcul du TCTR.

La méthodologie approuvée vise donc les deux distributeurs gaziers, soit *Union Gas Limited* (Union) et *Enbridge Gas Distribution Inc* (Enbridge).

Au lieu de présenter les résultats du TCTR sous forme de différence entre les bénéfices et les coûts d'un programme, la méthode utilisée présente les résultats sous la forme d'un ratio. Ainsi, un ratio supérieur ou égal à 1 indique une rentabilité positive alors qu'un ratio inférieur à 1 présente une rentabilité négative.

[17] Ontario Energy Board, Demand side management guidelines for natural gas utilities, EB-2008-0346

$$\text{TRC Ratio} = \frac{PV_{Benefits}}{PV_{Costs}}$$

Where:

$$PV_{Benefits} = \sum_{t=1}^{N} \frac{Benefits_t}{(1+d)^{t-1}}$$

$$PV_{Costs} = \sum_{t=1}^{N} \frac{Costs_t}{(1+d)^{t-1}}$$ [18]

Ce document décrit les composantes liées aux bénéfices et aux coûts de façon détaillée.

Les bénéfices sont présentés comme étant les coûts évités. Le document fait référence aux coûts évités totaux en considérant :

- Les coûts évités du distributeur[19] : Selon la structure de coût de chaque distributeur.
- Les économies prévues pour le programme[20] : On sous-entend que les économies prévues sont obtenues par la multiplication du nombre de participants prévus par les économies unitaires du programme.
- Les effets de distorsion : Les effets de distorsion suivants sont considérés :
  - Effet d'opportunisme : Effet à la baisse sur les bénéfices.
  - Effet de bénévolat[21] : Effet à la hausse sur les bénéfices.
  - Effet d'entraînement[22] : Effet à la hausse sur les bénéfices.
  - Effet de persistance[23] : Effet à la baisse sur les bénéfices.

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[18] http://www.oeb.gov.on.ca/OEB/_Documents/EB-2008-0346/DSM_Guidelines_for_Natural_Gas_Utilities_20110630.pdf, page 16
[19] http://www.oeb.gov.on.ca/OEB/_Documents/EB-2008-0346/DSM_Guidelines_for_Natural_Gas_Utilities_20110630.pdf, page 20
[20] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2008-0346/DSM_Guidelines_for_Natural_Gas_Utilities_20110630.pdf, page 17
[21] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2008-0346/DSM_Guidelines_for_Natural_Gas_Utilities_20110630.pdf, page 22
[22] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2008-0346/DSM_Guidelines_for_Natural_Gas_Utilities_20110630.pdf, page 23
[23] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2008-0346/DSM_Guidelines_for_Natural_Gas_Utilities_20110630.pdf, page 24

- Taux d'actualisation [24]: Le taux d'actualisation correspond au taux du coût moyen pondéré du capital WACC autorisé qui est réduit du taux d'inflation prévu pour obtenir un taux d'actualisation réel.
- Durée de vie de la mesure[25] : Nombre d'années durant lesquelles des économies sont anticipées ou que des surcoûts sont anticipés, selon le plus élevé des deux.

Ainsi, les bénéfices peuvent se calculer par la valeur actuelle nette des coûts évités totaux (considérant les coûts évités du distributeur, les économies prévues pour le programme en considérant les effets de distorsion présentés) sur la durée de vie de la mesure.

Les coûts considèrent les éléments suivants :

- Les coûts pour les participants :
  - Coût net des équipements[26] : On fait référence au surcoût d'un équipement efficace par rapport à un équipement standard.
  - Les effets de distorsion[27] décrits au niveau des bénéfices doivent également s'appliquer au niveau des coûts. On précise toutefois que les coûts nets des équipements associés aux opportunistes devraient être exclus. À l'inverse, les coûts nets des équipements des bénévoles devraient être inclus.
- Les coûts du programme
  - Conception et lancement
  - Promotion
  - Opérations
  - Évaluation, mesurage et vérification
  - Administration

[24] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2008-0346/DSM_Guidelines_for_Natural_Gas_Utilities_20110630.pdf, page 21
[25] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2008-0346/DSM_Guidelines_for_Natural_Gas_Utilities_20110630.pdf, page 17
[26] http://www.oeb.gov.on.ca/OEB/_Documents/EB-2008-0346/DSM_Guidelines_for_Natural_Gas_Utilities_20110630.pdf, page 12
[27] http://www.oeb.gov.on.ca/OEB/_Documents/EB-2008-0346/DSM_Guidelines_for_Natural_Gas_Utilities_20110630.pdf, page 13

- o Les effets de distorsion[28] : Les coûts du programme liés aux opportunistes doivent faire partie des coûts.

Ainsi, aux fins de comparaison, le tableau suivant présente la méthodologie utilisée en Ontario.

Tableau 4

		Valeur actuelle nette des bénéfices	
A		**Participants nets**	
		Participants bruts en nombre	√
	-	Effet d'opportunisme en %	√
	+	Effet d'entraînement en %	√
B		**Économies annuelles**	
	A	Participants nets en nombre	√
	*	Économies unitaires en m^3	√
	+	Effet de bénévolat en m^3	√
C		**Taux d'actualisation réel**	
		Coût moyen pondéré du capital (WACC)	√
	-	% inflation	√
D		**Coûts évités totaux**	
	B	Économies annuelles	√
	*	Coûts évités pour $1m^3$	√
	*	(1 + % inflation) sur la durée de vie de l'appareil ajusté pour tenir compte de la persistance	√

		Valeur actuelle nette des coûts	
E		**Coût des participants**	
		Participants bruts en nombre	√
	-	Effet d'opportunisme en %	√
	+	Effet de bénévolat	√
	*	Mise de fond du participant	√
	C	Taux d'actualisation réel	√
F		**Coût du programme**	
		Développement et lancement	√
	+	Promotion	√
	+	Opérations	√
	+	Évaluation, mesurage et vérification	√
	+	Administration	√
	C	Taux d'actualisation réel	√

AUTRES DISTRIBUTEURS CANADIENS

6.1 Fortis BC (Terasen gas)

En 2009, la BCUC rendait une décision[29] qui visait, entre autres, la méthode de calcul du TCTR à appliquer par Terasen Gas, aujourd'hui Fortis BC, en Colombie Britannique.

Ce document décrit les composantes liées aux bénéfices et aux coûts.

Tout comme en Ontario, au lieu de présenter les résultats du TCTR sous forme de différence entre les bénéfices et les coûts d'un programme, la méthode utilisée présente les résultats sous la forme d'un ratio. Ainsi un ratio supérieur ou égal à 1 indique une rentabilité positive alors qu'un ratio inférieur à 1 présente une rentabilité négative[30].

[28] http://www.oeb.gov.on.ca/OEB/_Documents/EB-2008-0346/DSM_Guidelines_for_Natural_Gas_Utilities_20110630.pdf, page 13
[29] British Columbia Utilities Commission,Terasen Gas Inc Terasen Gas (Vancouver Island) Inc and Energy Efficiency And Conservation Application Decision, April 16, 2009.
[30] http://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/TGI-TGVI_EnergyEfficiencyConservation.pdf, page 33

Les bénéfices sont présentés comme étant les coûts évités. Le document fait référence aux coûts évités totaux en considérant :

- Les coûts évités du distributeur[31] : Selon la structure de coût du distributeur.
- Les économies prévues pour le programme[32] : On sous-entend que les économies prévues sont obtenues par la multiplication du nombre de participants prévus par les économies unitaires du programme.
- Les effets de distorsion : Les effets de distorsion suivants sont considérés.
    - Effet d'opportunisme : Effet à la baisse sur les bénéfices;
    - Effet de bénévolat : Le distributeur est en attente d'une décision de la BCUC relativement à l'incorporation de l'effet de bénévolat au calcul du TCTR.[33]
- Taux d'actualisation : Le taux d'actualisation correspond au taux du coût moyen pondéré du capital (WACC) autorisé qui est réduit du taux d'inflation prévu pour obtenir un taux d'actualisation réel[34].
- Durée de vie de la mesure : La durée de vie utilisée est propre à chaque programme selon son cas type.
- Ainsi, les bénéfices peuvent se calculer par la valeur actuelle nette des coûts évités totaux (considérant les coûts évités du distributeur, les économies prévues pour le programme en considérant les effets de distorsion présentés) sur la durée de vie de la mesure.

Les coûts considèrent les éléments suivants :

- Les coûts pour les participants :
    - Coût net des participants[35] fait référence au surcoût d'un équipement efficace par rapport à un équipement standard.

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[31] http://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/TGI-TGVI_EnergyEfficiencyConservation.pdf, page 33

[32] http://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/TGI-TGVI_EnergyEfficiencyConservation.pdf, page 33

[33] http://www.bcuc.com/Documents/Arguments/2011/DOC_29217_12-02-2011_FEU-Final-Submission.pdf, page 183

[34] Information obtenue après de Fortis BC

1 - Les participants nets sont obtenus à partir des participants bruts auxquels on
2 soustrait l'effet d'opportunisme.

3 - <u>Les coûts du programme</u>

4 - Support et administration
5 - Communication et recherche
6 - Suivi et évaluation

7 Ainsi, pour fins de comparaison, le tableau suivant présente la méthodologie utilisée par Fortis
8 BC.

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[35] http://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/TGI-TGVI_EnergyEfficiencyConservation.pdf, page 33

Tableau 5

		Valeur actuelle nette des <u>bénéfices</u>	
A	**Participants nets**		
		Participants bruts en nombre	√
	-	Effet d'opportunisme en %	√
B	**Économies annuelles**		
	A	Participants nets en nombre	√
	*	Économies unitaires en m^3	√
C	**Taux d'actualisation réel**		
		Coût moyen pondéré du capital (WACC)	√
	-	% inflation	√
D	**Coûts évités totaux**		
	B	Économies annuelles	√
	*	Coûts évités pour $1m^3$	√
	*	(1 + % inflation) sur la durée de vie de l'appareil	√

		Valeur actuelle nette des <u>coûts</u>	
E	**Coût des participants**		
		Participants bruts en nombre	√
	-	Effet d'opportunisme en %	√
	*	Mise de fond du participant	√
	C	Taux d'actualisation réel	√
F	**Coût du programme**		
		Communication et recherche	√
	+	Support et administration	√
	+	Suivi et évaluation	√
	C	Taux d'actualisation réel	√

6.2 Atco Gas

Aucune documentation précise décrivant la méthode de calcul du TCTR n'a été trouvée lors du balisage. La seule information disponible précisait que ce distributeur utilisait le TCTR comme principal test de rentabilité pour ses programmes d'efficacité énergétique[36].

6.3 Sask Energy

Le balisage n'a pas permis de déterminer la méthodologie de calcul du TCTR. Il faut préciser que Sask Energy est une société de la couronne en Saskatchewan. Selon une étude réalisée en 2005[37], Sask Energy évalue ses programmes résidentiels sur la base de la satisfaction des participants et elle utilise le test du participant pour évaluer les bénéfices et les coûts.

6.4 Manitoba Hydro

En 2009, Manitoba Hydro décrivait sa méthode de calcul du TCTR dans son document intitulé «2009 Power Smart Plan».[38]

[36] http://www.cga.ca/pdfs/DSM2010update.pdf, page 11

[37] http://indeco.com/www.nsf/788895c29ec2338d85256a3300690fcc/988fa970427dc91f8525707e005fdc74/$FILE/Canadian%20natural%20gas%20distribution%20utilities'%20best%20practices%20in%20DSM.pdf, page 8

[38] 2009 Power Smart Plan, Manitoba Hydro Power Smart, July 2009.

Au lieu de présenter les résultats du TCTR sous forme de différence entre les bénéfices et les coûts d'un programme, la méthode utilisée présente les résultats sous la forme d'un ratio. Ainsi, un ratio supérieur ou égal à 1 indique une rentabilité positive alors qu'un ratio inférieur à 1 présente une rentabilité négative.

$$\textbf{TRC} = \frac{\textbf{PV (Marginal Benefits)}}{\textbf{PV (Total Program Admin Costs + Incremental Product Costs)}}$$ [39]

Les bénéfices intitulés « *Marginal Benefits* » considèrent les éléments suivants :

- Les participants nets : Les participants nets sont obtenus à partir des participants bruts auxquels on ajoute les effets de bénévolat et d'entraînement pour ensuite soustraire l'effet d'opportunisme.
- Les économies unitaires : Les économies attribuables à une mesure d'efficacité énergétique encouragée par un programme.
- Coûts évités : Les coûts évités intègrent la valeur de réduction des gaz à effet de serre et considèrent l'effet du taux d'inflation sur la durée de vie de la mesure à laquelle un effet de persistance est appliqué pour chaque programme.
- Taux d'actualisation réel: Le taux d'actualisation utilisé correspond au taux du coût du capital prospectif autorisé par la Manitoba Public Utilities Board dans le dossier tarifaire précédent. Pour obtenir un taux d'actualisation réel, Manitoba Hydro utilise le taux du coût du capital prospectif nominal selon l'équation suivante : (1+ taux actualisation nominal) / (1+ taux d'inflation).
- Durée de vie de la mesure : La durée de vie utilisée est propre à chaque programme selon son cas type et est ajustée pour tenir compte de l'effet de persistance.

Les coûts intitulés *« Total Program Admin Cost + Incremental Product Cost »* considèrent les éléments suivants :

[39] http://www.hydro.mb.ca/regulatory_affairs/electric/gra_2010_2012/Appendix_9_1.pdf, page 22

- Les coûts pour les participants :
  - Les participants nets : Les participants nets sont obtenus à partir des participants bruts auxquels on soustrait l'effet d'opportunisme.
  - La mise de fonds du participant : La mise de fonds correspond au surcoût du participant pour faire l'acquisition de la mesure d'efficacité énergétique. La mise de fonds du participant n'est pas réduite du montant de l'aide financière.
- Les coûts du programme :
  - Le budget de développement
  - Le budget de commercialisation
  - Le budget de suivi et d'évaluation
  - Le budget de support et de frais administratifs.

Le tableau suivant présente la synthèse des éléments considérés par la méthodologie de calcul utilisée par Manitoba Hydro.

Tableau 7

	Valeur actuelle nette des bénéfices	
A	**Participants nets**	
	Participants bruts en nombre	√
-	Effet d'opportunisme en %	√
+	Effet de bénévolat en %	√
+	Effet d'entraînement en %	√
B	**Économies annuelles**	
A	Participants nets en nombre	√
*	Économies unitaires en m^3	√
C	**Taux d'actualisation réel**	
	Coût de capital prospectif autorisé par la MPUB (t-1)	√
/	% inflation	√
	(1+ taux nominal) / (1+ inflation)	
D	**Coûts évités totaux**	
B	Économies annuelles	√
*	Coûts évités pour $1m^3$	√
+	Valeur réduction des gaz à effet de serre	√
*	(1 + % inflation) sur la durée de vie de l'appareil ajusté pour tenir compte de la persistance	√

	Valeur actuelle nette des coûts	
E	**Coût des participants**	
	Participants bruts en nombre	√
-	Effet d'opportunisme en %	√
*	Mise de fond du participant	√
C	Taux d'actualisation réel	√
F	**Coût du programme**	
	Développement	√
+	Commercialisation	√
+	Suivi et évaluation	√
+	Support et administration	√
C	Taux d'actualisation réel	√

7 MÉTHODE UTILISÉE PAR LA CALIFORNIE

En 2001, la California Public Utility Commission (CPUC) a publié un document[40], le ***«Standard Practice Manual»*** (SPM) dans lequel elle redéfinit sa méthodologie du calcul du TCTR datant de 1983. Ce document identifie les composantes qui doivent faire partie intégrante des coûts et des bénéfices afin d'obtenir un calcul du coût total en ressources des plus complets et précis possible.

Le TCTR met en relation les bénéfices et les coûts générés par un programme d'efficacité énergétique[41].

Les résultats peuvent être présentés sous différentes formes. La première présente les résultats du TCTR sous forme de différence entre les bénéfices et les coûts d'un programme alors qu'une autre méthode présente les résultats sous la forme d'un ratio. Ainsi, un ratio supérieur ou égal à 1 indique une rentabilité positive et un ratio inférieur à 1 présente une rentabilité négative.

[40] California Standard Practice Manual, Economic Analysis of Demand-Side Programs and Projects, October 2001
[41] http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF, page 18

Les bénéfices sont déterminés à partir des éléments suivants[42] :

- le nombre de participants;
- les coûts évités du distributeur;
- les économies d'énergie unitaires attribuables au programme.

Les coûts sont déterminés à partir des éléments suivants[43] :

- les coûts des participants;
- les coûts du programme.

Le taux d'actualisation ainsi que la durée de vie de la mesure sont pris en compte, tant au niveau des bénéfices que des coûts. La méthodologie propose également de tenir compte de divers effets de distorsion et d'autres éléments considérés comme des bénéfices non énergétiques[44].

Les principes de cette méthodologie sont maintenant utilisés par la très grande majorité des utilités publiques en Amérique du Nord.

En 2007, la CPUC a apporté une précision à sa méthodologie de calcul du TCTR[45].

En effet, la CPUC admet que la formule actuelle introduit un biais dans le calcul des coûts au niveau de l'application du «NTG ratio». Le «NTG ratio», ou «net-to-gross ratio» se définit comme étant la proportion des participants qui n'est pas opportuniste. Par exemple, un «NTG ratio» de 80 % indique que 20 % des participants sont opportunistes. Cette formule permet d'établir les participants nets, et ce, tant au niveau des bénéfices que des coûts. Il s'agit en fait du calcul des participants nets.Le biais a été observé par la CPUC en comparant les deux types d'approches qui sont actuellement utilisées pour commercialiser un programme en Californie[46].

Les deux types d'approches se déclinent de la façon suivante :

[42] http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF, page 18
[43] http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF, page 18
[44] http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF, page 20
[45] Decision 07-09-043 September 20, 2007,Before the Public Utilities Commission of the State of California, Interim Opinion on Phase 1 Issues: Shareholder Risk/Reward Incentive Mechanism for Energy Efficiency Programs..,
[46] http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/73172.pdf, page 158

- Rabais versé directement au client (*rebate programs*[47]): Cette approche consiste à verser un rabais au client suite à la mise en place d'une mesure d'efficacité énergétique. Le client est conscient de l'aide financière ou du rabais obtenu, soit en argent ou en réduction sur sa facture.
- Réduction du coût d'acquisition à la source (direct install[48]): Le client bénéficie directement d'un rabais à la source lors de l'achat d'un équipement. Le rabais est versé directement au détaillant par le distributeur réglementé. Ainsi, le prix affiché considère déjà le rabais, sans que le client soit au courant qu'il bénéficie d'une aide financière ou d'un rabais quelconque.

En fonction de l'approche commerciale utilisée, les coûts nets considérés aux fins du calcul du TCTR pouvaient varier pour un même programme, ce qui ne semblait pas logique pour la CPUC.

En ce qui concerne l'approche où le rabais est versé directement au client *(rebate program)*, la méthode de calcul en vigueur permettait de retirer les surcoûts complets attribuables aux opportunistes des coûts des participants. Ainsi, il en résultait des coûts des participants nets de l'effet d'opportunisme.

En ce qui concerne maintenant l'approche où le rabais était déjà intégré au coût d'acquisition à la source *(direct install)*, la méthode de calcul en vigueur ne permettait pas de retirer les coûts attribuables aux opportunistes. En étant *a priori* intégrés au prix de la mesure, les rabais, qui réduisaient *a priori* le surcoût pour les participants, étaient associés à des coûts de programmes et non pas aux coûts des participants. Comme la méthode en place permettait de considérer l'effet d'opportunisme uniquement au niveau des coûts des participants[49] et non pas au niveau des coûts de programme, il n'était donc pas possible de retirer les coûts attribuables aux opportunistes. Ainsi, les rabais intégrés *a priori* au prix de la mesure pour les opportunistes

[47] http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/73172.pdf, page 158
[48] http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/73172.pdf, page 158
[49] http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/73172.pdf, page 160

faisaient partie des coûts du programme[50]. Cela créait un écart au niveau des coûts qui se traduisait par un écart de rentabilité entre les deux approches commerciales.

L'approche où le rabais est versé directement au client (*rebate program*) était alors avantagée et présentait un écart favorable du résultat du TCTR par rapport à l'autre approche (*direct install*).

Afin de corriger cette iniquité, la CPUC a proposé d'ajouter un paramètre (**(1.0-NTG)*INC**) à l'équation permettant d'ajouter les aides financières versées aux participants opportunistes aux coûts des programmes[51].

TRC Costs = PRC + NTG*PC + UIC + (1.0-NTG)*INC, where:

PRC = program administrator program costs
PC = participant device costs (*before* INC is received)
UIC = (for fuel substitution programs) utility increase supply costs
NTG = net-to-gross ratio
INC = incentive costs, restricted to include only dollar benefits such as rebates or rate incentives (bill credits).

Cette nouvelle équation assure des résultats de calcul identiques, peu importe l'approche commerciale utilisée.

La CPUC a publié un document dans lequel elle fait la démonstration de l'applicabilité de la nouvelle formule pour les deux types d'approches[52]. Voici un tableau synthèse qui reprend l'essentiel de la démonstration détaillée par la CPUC. La première partie du tableau présente les informations utiles au calcul du TCTR selon les deux approches. La partie centrale présente les différentes composantes des bénéfices et des coûts selon les deux approches. Finalement, la partie inférieure du tableau illustre les résultats du TCTR. La zone surlignée présente l'effet de la modification de la méthode pour l'approche « *Rebate program* ».

Tableau 8

[50] http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/73172.pdf, page 159
[51] http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/73172.pdf, page 160
[52] http://docs.cpuc.ca.gov/published/Graphics/77641.PDF, attachement 3, page 15

Informations de base communes :					
A	Participants bruts en nombre	4	D	Mise de fond du participant	2 000 $
B	Effet d'opportuniste (25 %)	1	E	Coûts évités totaux	3 000 $
C	Participants nets	3	F	Aide financière (Rebate program)	1 000 $
			G	Aide financière (Direct install)	1 000 $
			H	Coût du programme (administration)	100 $

Rebate program		Direct install	
Calcul des bénéfices		**Calcul des bénéfices**	
Bénéfices = C x E		Bénéfices = C x E	
3 x 3 000 $ =	9 000 $	3 x 3 000 $ =	9 000 $
Coûts des participants		**Coûts des participants**	
Coût NET des participants = C x D		Coût NET des participants = C x (D - G)	
3 x 2 000 $ =	6 000 $	3 x (2 000 $ - 1 000 $) =	3 000 $
Coûts du programme		**Coûts du programme**	
Formule actuelle			
Coût NET du programme = A x H		Coût NET du programme = (A x H) + (A x G)	
4 x 100 $ =	400 $	(4 x 100 $) + (4 x 1 000 $) =	4 400 $
Formule proposée			
Coût NET du programme = (A x H) + (B x F)			
(4 x 100 $) + (1 x 1 000 $) =	1 400 $		

Calcul du TCTR			
Formule actuelle		**Formule actuelle**	
TRC = Bénéfices / Coûts		TRC = Bénéfices / Coûts	
9 000 $ / (400 $ + 6 000 $) =	1,41	9 000 $ / (4 400 $ + 3 000 $) =	1,22
Formule proposée			
TRC = Bénéfices / Coûts			
9 000 $ / (1 400 $ + 6 000 $) =	1,22		

En appliquant la modification proposée, le résultat du calcul du TCTR est le même, peu importe l'approche commerciale utilisée.

En conclusion, la CPUC a proposé de déposer la nouvelle formule sur son site internet sous le terme «***2007 SPM Clarification***», accompagnée de la plus récente version du SPM (2001). La CPUC a également demandé que toutes les utilités sous sa juridiction appliquent la nouvelle formule proposée dans leur futur calcul du TCTR[53].

En considérant la modification de 2007, le tableau suivant présente la synthèse des éléments considérés par la méthodologie de calcul de la CPUC.

Tableau 9

[53] http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/73172.pdf, page 162

	Valeur actuelle nette des <u>bénéfices</u>	
A	**Participants nets**	
	Participants bruts en nombre	√
-	Effet d'opportunisme en %	√
+	Effet de bénévolat en %	√
+	Effet d'entraînement en %	√
B	**Économies annuelles**	
A	Participants nets en nombre	√
*	Économies unitaires en m^3	√
C	**Taux d'actualisation réel**	√
D	**Coûts évités totaux**	
B	Économies annuelles	√
*	Coûts évités pour $1m^3$	√
+	Bénéfices non-énergétiques	√
*	(1 + % inflation) sur la durée de vie de l'appareil ajusté pour tenir compte de la persistance	√

	Valeur actuelle nette des <u>coûts</u>	
E	**Coût des participants**	
	Participants bruts en nombre	√
-	Effet d'opportunisme en %	√
*	Mise de fond du participant	√
C	Taux d'actualisation réel	√
F	**Coût du programme**	
	Développement et formation	√
+	Commercialisation	√
+	Suivi et évaluation	√
+	Support et administration	√
+	Aide financière des opportunistes	√
C	Taux d'actualisation réel	√

8 AUTRES ÉLÉMENTS DU BALISAGE

Le balisage a également permis de constater que plusieurs utilités publiques évaluent actuellement la possibilité d'ajouter différentes composantes supplémentaires au niveau des bénéfices[54]. La CPUC propose une liste d'éléments ou externalités qui sont actuellement utilisés dans le «test du coût social» et qui pourraient être considérés également dans le calcul du TCTR. Certaines juridictions incorporent un ou plusieurs de ces éléments.

Également, la CPUC et d'autres organismes proposent d'évaluer les bénéfices, autres que ceux reliés aux économies d'énergies réalisées par les participants. Ces bénéfices peuvent inclure des externalités sociales comme le confort[55], la santé et la sécurité. Par contre, le développement de méthodologie peut être complexe et couteux.

En ce qui concerne les externalités environnementales, le 15 décembre 2011, le gouvernement du Québec adoptait le Règlement concernant le système de plafonnement et d'échange de droits d'émission de GES. Le Règlement prévoit que les coûts d'acquisition minimaux des droits d'émission, dans le cadre d'une vente aux enchères sous l'égide du gouvernement, pourraient varier entre 10 $/tonne et 50 $/tonne selon le mode d'acquisition.

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[54] http://www.nhpci.org/images/TRC.pdf, page 8-9
[55] http://www.nhpci.org/images/TRC.pdf, page 9

Les volumes économisés avec les mesures d'efficacité énergétique mises en place par les émetteurs assujettis au règlement réduiront d'autant les droits d'émission nécessaires pour respecter leurs plafonds annuels ou pour couvrir leurs émissions de GES selon le cas.

9 SYNTHÈSE

Le tableau consolidé suivant présente la synthèse des paramètres de calcul observés auprès de 7 distributeurs au Canada ainsi que la CPUC. Pour faciliter la comparaison, Gaz Métro a ajouté la proportion des paramètres utilisés pour chacune des grandes composantes du calcul. Ainsi, une proportion de 100 % indique que tous les participants au balisage utilisent le même paramètre de calcul alors qu'une proportion de 13 %, indique que seulement 1 participant sur 8 utilise le paramètre de calcul.

Tableau 10

		Gaz Métro	Gazifère	Hydro-Québec	Enbridge	Union Gas	Fortis	Manitoba Hydro	CPUC	Proportion
	Valeur actuelle nette des bénéfices									
A	**Participants nets**									
	Participants bruts en nombre	√	√	√	√	√	√	√	√	100%
-	Effet d'opportunisme en %	√	√	√	√	√	√	√	√	100%
+	Effet de bénévolat en %	√	√	√	√	√		√	√	88%
+	Effet d'entraînement en %	√		√	√	√		√	√	75%
B	**Économies annuelles**									
A	Participants nets en nombre	√	√	√	√	√	√	√	√	100%
*	Économies unitaires	√	√	√	√	√	√	√	√	100%
C	**Taux d'actualisation réel**									
	Coût de capital prospectif autorisé par la Régie ou WACC	√	√	√	√	√	√	√	√	100%
-	% inflation	√	√		√	√	√		√	75%
/	% inflation (1+ taux nominal) / (1+ inflation)			√				√		25%
D	**Coûts évités totaux**									
B	Économies annuelles	√	√	√	√	√	√	√	√	100%
*	Coûts évités	√	√	√	√	√	√	√	√	100%
+	Valeur réduction des gaz à effet de serre							√	√	25%
*	(1 + % inflation)	√		√	√	√	√	√	√	88%
	sur la durée de vie de l'appareil	√	√	√	√	√	√	√	√	100%
	Ajustement pour considérer l'effet de persistance		√		√	√		√	√	63%
	Valeur actuelle nette des coûts									
E	**Coût des participants**									
	Participants bruts en nombre	√	√	√	√	√	√	√	√	100%
-	Effet d'opportunisme en %	√	√		√	√	√	√	√	88%
+	Effet de bénévolat			√	√	√				38%
*	Mise de fond du participant	√	√	√	√	√	√	√	√	100%
C	Taux d'actualisation réel	√	√	√	√	√	√	√	√	100%
F	**Coût du programme**									
	Développement	√	√	√	√	√	√	√	√	100%
+	Commercialisation	√	√	√	√	√	√	√	√	100%
+	Suivi et évaluation	√	√	√	√	√	√	√	√	100%
+	Support et administration	√	√	√	√	√	√	√	√	100%
+	Aides financières des opportunistes								√	13%
C	Taux d'actualisation réel	√	√	√	√	√	√	√	√	100%

Voici quelques constats sur les différentes composantes.

<u>Bénéfices :</u>

<u>Participants nets :</u> Tous les distributeurs ainsi que la CPUC considèrent l'effet d'opportuniste et 7 d'entre eux considèrent également l'effet de bénévolat. Le 8e distributeur est en attente d'une décision de la BCUC. L'effet d'entraînement est également pris en compte dans le calcul dans une proportion de 75 %.

Il est important de noter que l'effet de bénévolat est appliqué de deux façons distinctes. Il est pris en compte en pourcentage dans l'établissement du calcul des participants nets ou ajouté en volume dans le calcul des économies annuelles. Les deux méthodes utilisées génèrent les mêmes résultats.

<u>Les économies unitaires :</u> Tous les distributeurs comptabilisent les économies attribuables à une mesure d'efficacité énergétique encouragée par un programme. Tel que décrit

précédemment, deux distributeurs considèrent l'effet de bénévolat au niveau des économies de façon positive.

Taux d'actualisation réel : Tous les distributeurs appliquent un taux d'actualisation réel qui tient compte également du taux d'inflation.

Coûts évités : La majorité des distributeurs utilisent des coûts évités qui sont augmentés du taux d'inflation prévu pour considérer l'augmentation des coûts sur la durée de vie de la mesure, seule Gazifère ne tient pas compte du taux d'inflation. Soixante-trois pour cent appliquent un effet de persistance pour chaque programme. Manitoba Hydro attribue également une valeur positive relativement à la réduction des gaz à effet de serre.

Coûts :

Coûts des participants : Suite à la récente décision de la Régie[56], Hydro-Québec est le seul distributeur qui comptabilise les coûts des participants opportunistes. Les autres participants au balisage considèrent les participants nets de l'effet d'opportunisme. De plus, l'effet de bénévolat est pris en compte par deux utilités.

Mise de fonds du participant : L'ensemble des distributeurs utilise le surcoût complet du participant pour faire l'acquisition de la mesure d'efficacité énergétique.

Coûts du programme : À quelques détails prêts, l'ensemble des distributeurs utilise les mêmes paramètres dans l'établissement des coûts des programmes, seul le libellé varie. La CPUC est la seule entité qui propose d'ajouter les aides financières des opportunistes au coût du programme.

10 CONCLUSIONS

Afin de répondre à la demande de la Régie, Gaz Métro a réalisé un balisage des différentes méthodologies utilisées par des distributeurs réglementés impliqués en efficacité énergétique.

Le balisage a permis de détailler les méthodes et les paramètres utilisés par les principaux distributeurs gaziers canadiens, Hydro-Québec et en Californie afin de permettre à la Régie de les comparer entre elles, d'identifier les similitudes et les particularités observées.

[56] D-2012-024, R-3776-2011, page 129

Gaz Métro observe de très grandes similitudes entre les méthodes et paramètres utilisés d'un distributeur à l'autre. La méthode de calcul et les paramètres utilisés par Gaz Métro se comparent très bien à la pratique généralisée au Canada.

Gaz Métro demande à la Régie de prendre acte du balisage des méthodes de calcul du test du coût total en ressources effectué.

The spillover effects are associated with customers that adopt energy efficiency measures because they are influenced by a utility's program-related information and marketing efforts, but do not actually participate in the program. Accordingly, there are no Program Costs associated with the spillover effects.[11] If the spillover effects are considered and adequately supported (see section 7.1 for details), then programs that have high spillover rates will be more cost effective (as measured by the TRC test) since they do not have Program Costs while they do generate benefits.

Program Cost estimates should be based on the best available information known to the natural gas utilities at the relevant time.

5.1.3 TRC Test Calculation

For screening purposes, the TRC test should be performed at the program level only.

At the program level, the TRC test takes into account the following:

- Avoided Costs;
- Net Equipment and Program Costs; and
- Adjustments to account for free ridership, spillover effects, and persistence of savings and costs, as applicable.

The results of the TRC test can be expressed as a ratio of the present value ("PV") of the benefits to the PV of the costs. For example, the PV of the benefits consists of the sum of the discounted benefits accruing for as long as the DSM program's savings persist. The PV of the benefits therefore expresses the stream of benefits as a single "current year" value.

If the ratio of the PV of benefits to the PV of the costs (the "TRC ratio") exceeds 1.0, the DSM program is considered cost effective from a societal perspective as it implies that the benefits exceed the costs. If, on the contrary, the TRC ratio for a program falls below 1.0, the program would be screened out and no longer considered for inclusion as part of the DSM portfolio.[12]

The TRC threshold test should be 1.0 for all programs amenable to this screening test, except for low-income programs. To recognize that low-income natural gas DSM programs may result in important benefits not captured by the TRC test, these programs should be screened using a lower threshold value of 0.70 instead.[13]

[11] An alternative way to explain this is that all Program Costs are allocated to program participants (including free riders) and there are no additional Program Costs generated by the spillover effect.
[12] An alternative way to consider the cost-effectiveness of a program under a TRC ratio threshold of 1.0 is to determine whether the TRC net savings are greater than 0. The TRC net savings are equal to the PV of benefits less the PV of costs.
[13] These various benefits not captured by the traditional net TRC savings measure may include reduction in arrears management costs, increased home comfort, improved safety and health of residents, avoided homelessness and dislocation, and reductions in school dropouts from low-income families.

6.1.3 Use of Input Assumptions

The natural gas utilities should design and screen DSM programs using the best available information known to them at the relevant time. The natural gas utilities should continuously monitor new information and determine whether the design, delivery and set of DSM programs offered need to be adjusted based on that information.

The evaluation of the achieved results for the purpose of determining the lost revenue adjustment mechanism ("LRAM") amounts and the incentive amounts should be based on the best available information which, in this case, refers to the updated input assumptions resulting from the evaluation and audit process of the same program year. For example, the LRAM and incentive amounts for the 2012 program year should be based on the updated input assumptions resulting from the evaluation and audit of the 2012 results. The updates to the input assumptions resulting from the evaluation and audit of the 2012 results would likely be completed in the second half of 2013.

Where feasible and economically practical, the preference to determine LRAM and incentive amounts should be to use measured actual results, instead of input assumptions. For example, it may be feasible and economically practical to measure the natural gas savings of weatherization programs based on the results of the pre- and post-energy audits conducted by certified energy auditors on a custom basis, as opposed to input assumptions associated with the individual measures installed.

6.2 Avoided Costs

As described earlier, assumptions relating to the societal benefit of not having to provide an extra unit of supply of natural gas, or other resources (e.g., electricity, heating fuel oil, propane or water) are referred to as "avoided costs".

Avoided costs should be based on long-term estimates and include:

- Avoided supply-side costs, such as capital, operating and commodity costs.
  - Commodity costs include those for natural gas and, if applicable, for other resources such as electricity, water, heating fuel oil and propane.
- Avoided demand-side costs, such as the impact on customer equipment and operating costs.
- The following avoided upstream costs directly incurred by the natural gas utility: storage costs, transportation tolls and demand charges.
  - For simplicity, other avoided upstream costs (such as avoided costs of upstream pipeline companies and natural gas producers) should be excluded from the avoided cost calculations.

Each natural gas utility should calculate all avoided costs to reflect their specific cost structure as well as the characteristics of their franchise area. In order to ensure consistency, the natural gas utilities should use a common methodology to determine

The TRC ratio is expressed mathematically below:

$$TRC\ Ratio = \frac{PV_{Benefits}}{PV_{Costs}}$$

Where:

$$PV_{Benefits} = \sum_{t=1}^{N} \frac{Benefits_t}{(1+d)^{t-1}}$$

$$PV_{Costs} = \sum_{t=1}^{N} \frac{Costs_t}{(1+d)^{t-1}}$$

And where,

$Benefits_t = AC_t$

$Costs_t = NEC_t + PC_t$

And,

AC_t = Avoided costs in year t (see section 6.2)
Avoided costs should be calculated using the input assumptions, savings estimates, and adjustment factors based on the best available information known to the natural gas utilities at the relevant time, as further described in section 6.1 and 7.

NEC_t = Net Equipment Cost in year t (see section 5.1.1)
Net Equipment Costs should be calculated using cost estimates and adjustment factors based on the best available information known to the natural gas utilities at the relevant time, as further described in sections 5.1.1 and 7.

PC_t = Program Costs in year t (see section 5.1.2)
Program Costs should be calculated using cost estimates and adjustment factors based on the best available information known to the natural gas utilities at the relevant time, as further described in sections 5.1.2 and 7.

N = Number of years that the savings are expected to persist or that the incremental costs are expected to be incurred, whichever is greater. (see section 7.3)

D = Discount rate (see section 6.2.2)

The four adjustment factors that are the topic of this section are free ridership, spillover effects, attribution and persistence.

As indicated in section 6.1.3, the natural gas utilities should design and screen DSM programs using the best available information known to them at the relevant time, including information on adjustment factors. The natural gas utilities should continuously monitor new information and determine whether the design, delivery and set of DSM programs offered need to be adjusted based on that information.

The evaluation of the achieved results for the purpose of determining the LRAM amounts and the incentive amounts should be based on the best available information which, in this case, refers to the updated adjustment factors resulting from the evaluation and audit process of the same program year. For example, the LRAM and incentive amounts for the 2012 program year should be based on the updated adjustment factors resulting from the evaluation and audit of the results of the 2012 program year.

7.1 Free Ridership and Spillover Effects

A free rider is a "program participant who would have installed a measure on his or her own initiative even without the program."[17] In contrast, spillover effects refer to customers that adopt energy efficiency measures because they are influenced by a utility's program-related information and marketing efforts, but do not actually participate in the program.

All adjustment factors considered, including free ridership and spillover effects, should be assessed for reasonableness prior to the implementation of the multi-year plan and annually thereafter, as part of each natural gas utility's ongoing program evaluation and audit process. The natural gas utilities should always provide information on free ridership for all their applicable programs. In contrast, the natural gas utilities have the option to request the inclusion of spillover effects for any of their programs.

Any request for the Board to consider the spillover effects, needs to be supported by comprehensive and convincing empirical evidence, which clearly quantify the spillover effects that of a specific program has had on program savings and the natural gas utilities' revenue.

For their custom projects, the natural gas utilities should propose common free ridership rates and spillover effects, if applicable, that are differentiated appropriately by market segment and technologies.

[17] Violette, Daniel M. (1995) *Evaluation, Verification, and Performance Measurement of Energy Efficiency Programs.* Report prepared for the International Energy Agency.

7.2 Attribution

Attribution relates to whether the effects observed after the implementation of a natural gas utility's DSM activity can be attributed to that activity or at least partly result from the activities of others.

Given the potential for greater coordination and even integration of certain natural gas DSM programs with electricity CDM programs provided by rate-regulated electricity distributors, the guidance on attribution is divided into two categories: attribution between rate-regulated natural gas utilities and rate-regulated electricity distributors, and attribution between rate-regulated natural gas utilities and other parties (e.g., non-rate-regulated entities such as agencies and various levels of government, non-rate-regulated private companies, etc.).

The natural gas utilities are encouraged to develop partnerships that result in economies of scale and economies of scope that benefit ratepayers.

7.2.1 Attribution Between Rate-Regulated Natural Gas Utilities and Rate-Regulated Electricity Distributors

For electricity CDM and natural gas DSM programs jointly delivered with rate-regulated electricity distributors, all the natural gas savings should be attributed to rate-regulated natural gas utilities and vice versa for electricity savings. This represents a continuation of the simplified approach adopted in the 2006 Generic Proceeding.

7.2.2 Attribution Between Rate-Regulated Natural Gas Utilities and Other Parties

Attribution of savings between rate-regulated natural gas utilities and other parties (e.g., governments, non-rate-regulated private sector, etc.) should be based primarily on the shares established in a partnership agreement reached prior to the program's launch.

Where the natural gas utilities' allocated share in the partnership agreement is more than 20% of the share that would have been allocated based on a "percentage of total dollars spent" basis, an explanation for the difference should be provided.[18] The natural gas utilities also need to file expected spending for each of the partners before the program is launched and the actual amount spent by each partner within each program year. As partnerships do not always evolve as originally planned, this additional information will help the Board and stakeholders to assess the reasonableness of the shares allocated in the partnership agreement reached prior to the program's launch and the actual contribution the natural gas utilities made to the program.

[18] For example, if the partnership agreement allocates a share of 50% to the gas utility, but the actual share of "dollars spent" by the utility is 30% or less, an explanation should be provided to justify why the 50% share is more reflective of the gas utility's actual contribution.

In the absence of a partnership agreement on the sharing of the savings resulting from the program, the attribution should be based on the percentage of total dollars spent by the natural gas utilities.

The share allocated to the natural gas utilities will be used to determine the credited achievement for each of the relevant metrics used to evaluate the program. For instance, if a natural gas utility's allocated share is 30%, then 30% of the natural gas savings associated with the program will be counted towards the natural gas savings target.

7.3 Persistence

Persistence of DSM savings can take into account how long a DSM measure is kept in place relative to its useful life, the net impact of the DSM measure relative to the base case scenario, and the impact of technical degradation. For example, if an energy efficient measure with a useful life of 15 years is removed after only two years, most of the savings expected to result from that installation will not materialize. As for technical degradation, it refers to the potential for the DSM measure's performance to decrease as it gets closer to the end of its useful life (e.g., the achieved efficiency level of a natural gas furnace may decrease as it ages).

Another aspect that can be considered as part of the persistence factor is whether a program participant would have implemented the DSM measure on its own in the future (e.g., in two years time), but their implementation date was accelerated by the program offering. In this case, the savings resulting from the DSM program would only accrue for up to the period by which the adoption was accelerated (e.g., two years), instead of the entire useful life of the measure.

More generally, an important consideration when assessing the persistence of savings is the fact that some energy efficient equipment have a much longer life than the base case equipment. For example, if an efficient natural gas furnace (model A) with a 25-year useful life is used to replace a homeowner's furnace (model B) with a remaining useful life of 5 years, an assumption must be made with regard to what would have happened under the base case. Would the average homeowner have opted to replace its furnace for a more efficient furnace (model C) on its own in five years from now? If so, estimated savings for the first five years should be based on the savings of model A compared to model B, but the savings over the next 20 years should be calculated by comparing model A to model C.

Another important consideration in assessing the persistence of savings is the potential changes in usage pattern. For example, large custom commercial and industrial DSM projects with expected useful life of 20 years or more may not fully materialize if the business benefiting from the custom measure operates at lower levels or closes down its processes within that time period. Given the natural gas utilities' 15 years of experience delivering natural gas DSM programs in Ontario, the natural gas utilities should undertake an assessment of the historical persistence of savings of custom DSM their utility specific avoided costs. The natural gas utilities should also coordinate the timing for selecting commodity costs so that they are comparable.[15]

The estimation of natural gas avoided costs should consider whether different estimates are warranted for each customer class, sector (e.g., residential, commercial, and industrial), and/or the load characteristics (e.g., baseload versus weather sensitive).

In determining their utility specific avoided costs, the natural gas utilities should consider, among other information available, the avoided costs used by the OPA to assess the cost effectiveness of electricity CDM programs.[16]

6.2.1 Updating of Avoided Costs

The natural gas utilities should submit avoided costs for approval as part of their multi-year DSM plan, with the commodity costs to be updated annually (i.e., for natural gas and, if applicable, for other resources such as electricity, water, heating fuel oil and propane) but all other avoided costs (e.g., avoided distribution system costs such as pipes, storage, etc.) to remain fixed for the duration of the plan. As avoided costs should be based on long-term projections, it is expected that updating the remaining component of the avoided costs (i.e., other than the commodity costs) on a multi-year cycle should not cause benefits to be significantly under or overstated.

If an extension to the term of the plan is considered, as discussed in section 2, an updating of all the avoided costs should also be considered.

6.2.2 Discount Rate

For the purpose of the TRC test, the total avoided costs resulting over the life of the DSM measures need to be discounted to a present value. The natural gas utilities should continue using a discount rate that is equal to their Board approved weighted average cost of capital ("WACC")..

7. Adjustment Factors for Screening and Result Evaluation

The assumptions described in section 6 enable the calculation of savings accruing from specific measures or programs. Adjustment to those results must be considered to take into account the extent to which the natural gas utilities contributed to their achievement and the extent to which the savings are expected to persist. This exercise is done through the use of adjustment factors.

[15] Commodity costs include those for natural gas and, if applicable, for other resources such as electricity, water, heating fuel oil and propane.

[16] The avoided cost assumptions currently used by the OPA are provided in the *OPA conservation and Demand Management Cost Effectiveness Guide*, dated October 15, 2010.

The TRC ratio is expressed mathematically below:

$$TRC\ Ratio = \frac{PV_{Benefits}}{PV_{Costs}}$$

Where:

$$PV_{Benefits} = \sum_{t=1}^{N} \frac{Benefits_t}{(1+d)^{t-1}}$$

$$PV_{Costs} = \sum_{t=1}^{N} \frac{Costs_t}{(1+d)^{t-1}}$$

And where,

$Benefits_t = AC_t$

$Costs_t = NEC_t + PC_t$

And,

AC_t	=	Avoided costs in year t (see section 6.2) Avoided costs should be calculated using the input assumptions, savings estimates, and adjustment factors based on the best available information known to the natural gas utilities at the relevant time, as further described in section 6.1 and 7.
NEC_t	=	Net Equipment Cost in year t (see section 5.1.1) Net Equipment Costs should be calculated using cost estimates and adjustment factors based on the best available information known to the natural gas utilities at the relevant time, as further described in sections 5.1.1 and 7.
PC_t	=	Program Costs in year t (see section 5.1.2) Program Costs should be calculated using cost estimates and adjustment factors based on the best available information known to the natural gas utilities at the relevant time, as further described in sections 5.1.2 and 7.
N	=	Number of years that the savings are expected to persist or that the incremental costs are expected to be incurred, whichever is greater. (see section 7.3)
D	=	Discount rate (see section 6.2.2)

5.1 Screening Test

The purpose of screening natural gas DSM programs is to determine whether or not they should be considered any further for inclusion in the DSM portfolio. Some programs, such as market transformation, R&D and pilot programs are not typically amenable to a mechanistic screening approach and, as set out in sections 5.3 and 5.4, should be reviewed on a case-by-case basis instead. Among those programs amenable to a mechanistic screening approach, the natural gas utilities may only apply for approval of programs that are cost effective as determined by the TRC test.

The TRC test measures the benefits and costs of DSM programs for as long as those benefits and costs persist. Under this test, benefits are driven by avoided resource costs, which are based on the marginal costs avoided by not producing and delivering the next unit of natural gas to the customer. Those marginal costs avoided include the natural gas commodity costs (both system and customer) and distribution costs (e.g., pipes, storage, etc.). The marginal costs also include the benefits of other resources saved such as electricity, water, propane and heating fuel oil, as applicable. Avoided costs are further described in section 6.2.

The costs considered in the TRC test are the Net Equipment and Program Costs associated with delivering the DSM program to the marketplace. Net Equipment and Program Costs are further explained in sections 5.1.1 and 5.1.2 below.

5.1.1 Net Equipment Costs

Net Equipment Costs relates to the costs of the more efficient equipment relative to the base case scenario. They include capital, cost of removal less salvage value (e.g., in the case of a replacement), installation, operating and maintenance ("O&M"), and/or fuel costs (e.g., electricity) associated with the more efficient equipment. As the TRC test assesses the benefits and costs of DSM programs from a societal perspective, it is does not differentiate between who (natural gas utility, customer, or third party) pays the cost of the equipment.

Net Equipment Costs can be either the cost difference between the more efficient equipment and a base measure (a.k.a., incremental cost) or the full cost of the more efficient equipment. When the investment decision is a replacement, the Net Equipment Costs will typically be incremental. For example, if a DSM program results in a high efficiency natural gas furnace being purchased instead of a standard model, the Net Equipment Costs would be incremental: they would be the cost differential between the two options. In contrast, retrofit and discretionary investments are typically associated with the full cost of the equipment. For example, if a DSM program results in a retrofit to improve the energy efficiency of an industrial process and, in the absence of such DSM program, the status quo would have been maintained, then the Net Equipment Costs will be the full cost of the equipment. As these examples illustrate, Net Equipment Costs depend not only on the equipment costs but also on the costs that would have been incurred under the base case (i.e., in the absence of the DSM program).

A third type of equipment cost is the cost of the equipment that is assigned to a project when a replacement decision is "advanced" because of a natural gas utility's DSM programming efforts. Advanced replacements occur when an older, but still working lower efficiency technology, is replaced with a more efficient piece of equipment. In these cases, the natural gas utilities should adjust both the equipment life and the project cost to reflect the advancement. This adjustment is akin to a net present value estimate.

O&M costs associated with the more efficient equipment are often not incremental (i.e., they would have been incurred under the base case anyway). However, there are some exceptions where the incremental O&M costs are significant and these should be appropriately accounted for in the Net Equipment Costs. As a general rule, cost differential from the base case should be considered as part of the Net Equipment Costs for as long as they persist.

Free ridership and spillover effects, if applicable, should also be taken into account when calculating the Net Equipment Costs. As further explained in section 7.1, a free rider is a "program participant who would have installed a measure on his or her own initiative even without the program."[7] In contrast, spillover effects refer to customers that adopt energy efficiency measures because they are influenced by a utility's program-related information and marketing efforts, but do not actually participate in the program.
Net Equipment Costs associated with free riders are excluded from the TRC test.[8] However, as discussed in the section 5.1.2, all Program Costs associated with free riders should be included in the TRC analysis.

Spillover effects are essentially the mirror image of free ridership. Net Equipment Costs associated with spillover effects are included in the TRC test.[9] However, as discussed in the section 5.1.2, there are no Program Costs associated with spillover effects.

Information sources for equipment costs vary. For residential equipment, retail store prices are appropriate sources of information for many technologies including appliances and "do-it-yourself" water heater or thermal envelope upgrades. It is common practice to specify an average price based on a sample of retail prices. For utility direct/install programs, it is appropriate to use the cost to the utility of bulk purchase of the equipment. For commercial and industrial equipment, cost data can be more complicated to acquire due to limited access and confidentiality concerns. For larger "custom" projects, invoices or purchase orders may be necessary to support the

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[7] Violette, Daniel M. (1995) *Evaluation, Verification, and Performance Measurement of Energy Efficiency Programs.* Report prepared for the International Energy Agency.
[8] Eto, J, (1998) *Guidelines for assessing the Value and Cost-effectiveness of Regional Market Transformation Initiatives.* Northeast Energy Efficiency Partnership, Inc.
[9] Ibid.

would have been incurred under the base case (i.e., in the absence of the DSM program).

A third type of equipment cost is the cost of the equipment that is assigned to a project when a replacement decision is "advanced" because of a natural gas utility's DSM programming efforts. Advanced replacements occur when an older, but still working lower efficiency technology, is replaced with a more efficient piece of equipment. In these cases, the natural gas utilities should adjust both the equipment life and the project cost to reflect the advancement. This adjustment is akin to a net present value estimate.

O&M costs associated with the more efficient equipment are often not incremental (i.e., they would have been incurred under the base case anyway). However, there are some exceptions where the incremental O&M costs are significant and these should be appropriately accounted for in the Net Equipment Costs. As a general rule, cost differential from the base case should be considered as part of the Net Equipment Costs for as long as they persist.

Free ridership and spillover effects, if applicable, should also be taken into account when calculating the Net Equipment Costs. As further explained in section 7.1, a free rider is a "program participant who would have installed a measure on his or her own initiative even without the program."[7] In contrast, spillover effects refer to customers that adopt energy efficiency measures because they are influenced by a utility's program-related information and marketing efforts, but do not actually participate in the program.
Net Equipment Costs associated with free riders are excluded from the TRC test.[8] However, as discussed in the section 5.1.2, all Program Costs associated with free riders should be included in the TRC analysis.

Spillover effects are essentially the mirror image of free ridership. Net Equipment Costs associated with spillover effects are included in the TRC test.[9] However, as discussed in the section 5.1.2, there are no Program Costs associated with spillover effects.

Information sources for equipment costs vary. For residential equipment, retail store prices are appropriate sources of information for many technologies including appliances and "do-it-yourself" water heater or thermal envelope upgrades. It is common practice to specify an average price based on a sample of retail prices. For utility direct/install programs, it is appropriate to use the cost to the utility of bulk purchase of the equipment. For commercial and industrial equipment, cost data can be more complicated to acquire due to limited access and confidentiality concerns. For larger "custom" projects, invoices or purchase orders may be necessary to support the

[7] Violette, Daniel M. (1995) *Evaluation, Verification, and Performance Measurement of Energy Efficiency Programs.* Report prepared for the International Energy Agency.
[8] Eto, J, (1998) *Guidelines for assessing the Value and Cost-effectiveness of Regional Market Transformation Initiatives.* Northeast Energy Efficiency Partnership, Inc.
[9] Ibid.

Total Resource Cost Test

Terasen proposes that the benefit-cost tests be used to evaluate its programs as outlined in the "California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects", which is included in Exhibit B-1 as Appendix 12 ("the California Standard Practice Manual"). (Exhibit B-1, p. 82)

The California Standard Practice Manual describes the Total Resource Cost Test as a cost-effectiveness test which "measures the net cost of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs." (Exhibit B-1, Appendix 12, p. 18)

The "benefits" portion of the TRC test is made up of the avoided supply costs, valued at their marginal cost, for periods when a load reduction results. These costs are "calculated using net program savings, savings net of changes in energy use that would have happened in the absence of the program. For fuel substitution programs, benefits include the avoided device costs and avoided supply costs for the energy, using equipment not chosen by the program participant." (Exhibit B-1, Appendix 12, p. 18)

The "costs" portion of the TRC test is made up of the program costs paid by the utility and the participants plus any increase in supply costs for periods when load is increased. This is a broad category, and includes all equipment costs, installation, operation and maintenance costs, cost of removal (less any salvage value), and administration costs, regardless of who pays, less any tax credits. For fuel substitution programs, costs also include any increase in the supply costs of the utility providing the chosen fuel. (Exhibit B-1, Appendix 12, p. 18)

The benefit-cost ratio is the ratio of discounted total program benefits to discounted total program costs over a specified period of time. A benefit-cost ratio greater than one indicates the program is beneficial, on the basis of the TRC test. (Exhibit B-1, Appendix 12, p. 19)

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effective as prescribed by the DSM Regulation. While the DSM Regulation imposes some parameters regarding cost-effectiveness, the Commission retains discretion with respect to how to measure cost-effectiveness. The FEU submit that in exercising this discretion, the Commission should be guided by industry standards, the unique context of the FEU in the province of B.C., as compared to electric utilities, and British Columbia's energy objectives. These considerations support:

- the continued use of the portfolio approach for determining cost-effectiveness;
- the adoption of the Societal Cost Test (SCT) instead of the TRC test; and
- the incorporation of spillover effects.

(a) Portfolio Approach Remains Appropriate

444. In the 2008 EEC Application, the Commission determined that cost-effectiveness of EEC should be assessed at the portfolio level, such that the overall portfolio including all EEC-funded activity should have a benefit-cost result of 1.0 or greater. The Commission directed FEI and FEVI to provide information in annual reporting as to why individual programs and measures with a benefit-cost result of less than 1.0 should continue, including information on any other goals supported by the program or measure.[690] The portfolio approach was also approved as part of the Negotiated Settlement Agreements for FEI and FEVI's 2010 and 2011 revenue requirements.[691] The FEU submit that there are several reasons, discussed below, to maintain the portfolio approach going forward.

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[690] Order G-36-09, Reasons for Decision, p. 32: "The Commission Panel accepts the portfolio level approach based on achieving a portfolio TRC level, discussed below, of 1.0 or greater, provided that program areas, initiatives of measure with an individual TRC of less than 1.0 are proactively designed or sufficiently support social or environmental objectives. The Commission Panel directs that Terasen include in its annual EEC Report to the Commission the results of the RIM, UC, TRC and Participant tests for each proposed DSM in its portfolio, and provide justification for continuing with any measures or groups of measures which have a TRC of less than 1.0."

[691] Order G-141-09 and G-140-09. See Exhibit B-9, BCUC IR 1.205.1.

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ATCO's and SaskEnergy's DSM is treated as 'regulated DSM'. Since the Nova Scotia natural gas market is relatively immature, Heritage Gas does not offer DSM programs. Table 3 summarizes the DSM regulatory environment of these companies.

Table 3: Regulatory environment of natural gas companies conducting DSM in Canada

LDC	DSM approval agency	DSM since
ATCO	Alberta Utilities Commission[1]	2001
Enbridge	Ontario Energy Board	1995
Gaz Métro	Régie de l'énergie Québec	1999
Gazifère	Régie de l'énergie Québec	1999
Heritage Gas	N/A	--
Manitoba Hydro	Manitoba Public Utilities Board	2005
SaskEnergy	Crown Investment Corporation	2001
Terasen	British Columbia Utilities Commission	1997
Union	Ontario Energy Board	1997

1. As of January 1, 2008. Formerly Alberta Energy Utilities Board.

The DSM regulatory environment influences the primary drivers for DSM, the programs that are selected for implementation and the preferred outcome of DSM activities. In jurisdictions with DSM regulated by an arms-length agency, the primary driver for DSM tends to be achieving cost effective energy savings. The Total Resource Cost (TRC) test is the principal test used to screen programs and to calculate total societal benefits from the programs. Other tests used by Gaz Métro, Gazifère, Manitoba Hydro, SaskEnergy and Terasen include the Participant Cost Test, the Rate Impact Measure Test and the Utility Cost Test, although no formal pass or fail criteria for these tests are used. SaskEnergy also uses the input from its Industry Dialogue Table.

Overall, natural gas DSM in Canada continues to be a maturing enterprise. All companies included in this report have continued to expand DSM program offerings and increase associated budget, in some cases significantly. As seen in Table 3 above, some utilities have over a decade of experience delivering DSM programs while others have less. Additionally, some companies have focused their efforts on a small number of programs while others have developed a broad range of programs covering all sectors (discussed in more detail below and in the next section).

A brief description of each LDC's DSM program follows.

ATCO

ATCO's Energy Management Services department was formed in 2001, as a customer service and retention initiative in response to high energy prices. Soon after formation, ATCO adopted the brand of EnergySense™ for its energy conservation and efficiency programs. ATCO offers three areas of service within EnergySense™: (1) education and outreach, (2) residential assessment, and (3) commercial assessment.

DSM activities are not approved by an 'arms-length' regulator, as in Ontario, BC and Quebec, it is still considered 'regulated DSM' for the purposes of this study. Atco's EnergySense program is the only example of non-regulated DSM in this study, as it is conducted as a quasi 'non-utility' program. Table 2 summarizes the DSM regulatory environment of these companies.

Table 2 Regulatory environment of natural gas companies conducting DSM in Canada

LDC	DSM approval agency	DSM since
Atco	n/a	2002
Enbridge	Ontario Energy Board	1995
Gaz Métro	Régie de l'énergie Québec	1999
Manitoba Hydro	Manitoba Public Utilities Board	n/a
SaskEnergy	Crown Investment Corporation	2001
Terasen	British Columbia Utilities Commission	1997
Union	Ontario Energy Board	1997

The DSM regulatory environment influences the primary drivers for DSM, the programs that are selected for implementation and the preferred outcome of DSM activities. In jurisdictions with DSM regulated by an arms-length agency, the primary driver for DSM tends to be achieving cost effective energy savings. The Total Resource Cost (TRC) test is used to screen programs and to calculate total societal benefits from the programs. At SaskEnergy, on the other hand, the primary driver for its DSM program is residential customer satisfaction and retention. As such, programs are screened based on the cost and benefits to individual program participants (i.e. the Participant Cost Test).

Overall, natural gas DSM in Canada is a maturing enterprise. As seen in the Table 2 above, some utilities have a decade of experience delivering DSM programs while others have only a few years of experience. Additionally, some companies have focused their efforts to a single program or to a single customer sector, while others have developed a broad range of programs covering all sectors over time (discussed in more detail in section 2.3).

A brief description of each LDC's DSM program follows.

Where:

- *For electricity, the Marginal Benefits includes the revenue realized by Manitoba Hydro from conserved electricity being sold in the export market, the avoided cost of new infrastructure (e.g. electric transmission facilities) and measurable non-energy benefits (e.g. water savings);*

- *For natural gas, the Marginal Benefits includes Manitoba Hydro's avoided cost of purchasing natural gas, avoided transportation costs, the value of reduced greenhouse gas emissions (GHGs) and measurable non-energy benefits (e.g. water savings);*

- *Incremental Product Costs includes the total incremental cost associated with implementing an energy efficient opportunity. It is the difference in costs between the energy efficient technology and the standard technology that would have been installed in the absence of the program. Any maintenance cost differences associated with the technology options is also considered as part of the incremental cost.*

b) Total Resource Cost Test

The Total Resource Cost (TRC) test is used to assess the benefits associated with an energy efficient program. This benefit/cost ratio is a detailed assessment to determine whether the benefits that are associated with an energy efficient program are greater than the costs. This assessment is undertaken irrespective of who realizes the benefits and who pays the costs with any economic transfers between the Corporation and the participating customer being excluded.

In general, if program offers greater benefits relative to costs, then a program for pursuing the opportunity should be considered, however Manitoba Hydro will also consider supporting certain programs where the benefits are less than the costs. In the latter case, the rationale driving the support will be driven by other qualitative factors such as supporting emerging technologies (e.g. solar panels) or targeting low participation market sectors (e.g. lower income). The Total Resource Cost test is defined as follows:

$$\textbf{TRC} = \frac{\textbf{PV (Marginal Benefits)}}{\textbf{PV (Total Program Admin Costs + Incremental Product Costs)}}$$

Where:

- *For electricity, the Marginal Benefits includes the revenue realized by Manitoba Hydro from conserved electricity being sold in the export market,*

Chapter 4

Total Resource Cost Test[6]

Definition

The Total Resource Cost Test measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs.

The test is applicable to conservation, load management, and fuel substitution programs. For fuel substitution programs, the test measures the net effect of the impacts from the fuel not chosen versus the impacts from the fuel that is chosen as a result of the program. TRC test results for fuel substitution programs should be viewed as a measure of the economic efficiency implications of the total energy supply system (gas and electric).

A variant on the TRC test is the Societal Test. The Societal Test differs from the TRC test in that it includes the effects of externalities (e.g.,, environmental, national security), excludes tax credit benefits, and uses a different (societal) discount rate.

Benefits and Costs: This test represents the combination of the effects of a program on both the customers participating and those not participating in a program. In a sense, it is the summation of the benefit and cost terms in the Participant and the Ratepayer Impact Measure tests, where the revenue (bill) change and the incentive terms intuitively cancel (except for the differences in net and gross savings).

The benefits calculated in the Total Resource Cost Test are the avoided supply costs, the reduction in transmission, distribution, generation, and capacity costs valued at marginal cost for the periods when there is a load reduction. The avoided supply costs should be calculated using net program savings, savings net of changes in energy use that would have happened in the absence of the program. For fuel substitution programs, benefits include the avoided device costs and avoided supply costs for the energy, using equipment not chosen by the program participant.

The costs in this test are the program costs paid by both the utility and the participants plus the increase in supply costs for the periods in which load is increased. Thus all equipment costs, installation, operation and maintenance, cost of removal (less salvage value), and administration costs, no matter who pays for them, are included in this test. Any tax credits are considered a reduction to costs in this test. For fuel substitution programs, the costs also include the increase in supply costs for the utility providing the fuel that is chosen as a result of the program.

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by no means exhaustive list of 'externalities and their components' is given below (Refer to the Limitations section for elaboration.) These values are also referred to as 'adders' designed to capture or internalize such externalities. The list of potential adders would include for example:

1. The benefit of avoided environmental damage: The CPUC policy specifies two 'adders' to internalize environmental externalities, one for electricity use and one for natural gas use. Both are statewide average values. These adders are intended to help distinguish between cost-effective and non cost-effective energy-efficiency programs. They apply to an average supply mix and would not be useful in distinguishing among competing supply options. The CPUC electricity environmental adder is intended to account for the environmental damage from air pollutant emissions from power plants. The CPUC-adopted adder is intended to cover the human and material damage from sulfur oxides (SOX), nitrogen oxides (NOX), volatile organic compounds (VOC, sometimes called reactive organic gases or ROG), particulate matter at or below 10 micron diameter (PM10), and carbon. The adder for natural gas is intended to account for air pollutant emissions from the direct combustion of the gas. In the CPUC policy guidance, the adders are included in the tabulation of the benefits of energy efficiency programs. They represent reduced environmental damage from displaced electricity generation and avoided gas combustion. The environmental damage is the result of the net change in pollutant emissions in the air basins, or regions, in which there is an impact. This change is the result of direct changes in powerplant or natural gas combustion emission resulting from the efficiency measures, and changes in emissions from other sources, that result from those direct changes in emissions.

2. The benefit of avoided transmission and distribution costs – energy efficiency measures that reduce the growth in peak demand would decrease the required rate of expansion to the transmission and distribution network, eliminating costs of constructing and maintaining new or upgraded lines.

3. The benefit of avoided generation costs – energy efficiency measures reduce consumption and hence avoid the need for generation. This would include avoided energy costs, capacity costs and T&D line

4. The benefit of increased system reliability: The reductions in demand and peak loads from customers opting for self generation, provide reliability benefits to the distribution system in the forms of:
    a. Avoided costs of supply disruptions
    b. Benefits to the economy of damage and control costs avoided by customers and industries in the digital economy that need greater than 99.9 level of reliable electricity service from the central grid
    c. Marginally decreased System Operator's costs to maintain a percentage reserve of electricity supply above the instantaneous demand
    d. Benefits to customers and the public of avoiding blackouts.

have identical total costs and benefits."[241] Our determinations in D.92-12-050 were designed to achieve that specific objective, based on the record in that proceeding. However, in 1992 we did not consider how applying the NTG ratio to individual components of "participant costs" could impact the cost-effectiveness of different program delivery approaches (e.g., direct install versus rebate programs), that is, how such application could unduly advantage one approach over the other. It was not until the post-2005 portfolio plans were being developed and evaluated that Energy Division and its consultants brought these implications and questions concerning the 1998 SPM Correction Memo to our attention. Therefore, it is appropriate and important that we fully examine and resolve this issue in the context of post-2005 energy efficiency portfolio development and evaluation, and we do so today.

Without further clarification, the mathematical formulation of the 1988 SPM Correction Memo appears to create a free rider cost advantage to rebate programs relative to direct install programs, which should not occur if all else is equal. This is because this memo first displays the equation for TRC costs, which included at that time a "participant cost" (PC_t) term,[242] and then "suggest[s] renaming the participant cost as PCN to designate 'Participant cost—net'." (See Attachment 9.) That particular PC_t term has always been defined in the SPM as participant costs *before* receiving the dollar rebate incentive (cash rebate or bill credit) discussed above, which is represented as the "INC" term in SPM

241 D.92-12-050, 47 CPUC 2d, p. 73.

242 *Standard Practice Manual: Economic Analysis of Demand-Side Management Programs* (*1987 SPM*), December 1987, p. 29.

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prohibits applying the NTG ratio to the administrative cost component of TRC costs, since these are costs unrelated to participant expenditures.[245]

This means, all other things being equal, the 1988 SPM Correction Memo formulation would assign more costs to a direct install program than to a customer rebate program that is identical except for the delivery approach. As we stated in D.06-06-063, this type of inconsistency in cost-effectiveness results makes no sense, and is inconsistent with the intent of the TRC discussed above.[246] It is not even clear that this was the intent of the authors of the 1988 memo, since the formula did not actually present a full restatement of all the equations (benefit and cost side) of the TRC test with explicit NTG ratios applied.

To clarify how the NTG ratio should in fact be applied, a transfer incentive (INC) recapture quantity will be added to the TRC cost equation presented in the 1988 SPM Correction Memo as follows:

TRC Costs = PRC + NTG*PC + UIC + (1.0-NTG)*INC, where:

PRC = program administrator program costs
PC = participant device costs (*before* INC is received)
UIC = (for fuel substitution programs) utility increase supply costs
NTG = net-to-gross ratio
INC = incentive costs, restricted to include only dollar benefits such as rebates or rate incentives (bill credits).

Adding this term to the TRC cost formulation will ensure that the removal of free rider costs does not also remove program costs that become ratepayer

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245 The 1988 SPM Correction Memo utilizes the "UC" (for "utility administrative costs") term, which as been subsequently renamed "PRC" ("program administrator program costs") in more recent versions of the SPM. Therefore, we use the current PRC term in today's clarification.

246 See D.06-06-063, p. 72.

equations.[243] Therefore, the 1988 SPM Correction Memo could be interpreted to mean that the NTG ratio is applied to the participants' out-of-pocket costs (after receiving a rebate incentive) as well as to the rebate incentive paid, up to the full cost of the measure or device.

This result means, as currently formulated in that memo, removal from TRC costs of all revenue requirements associated with paying free riders a rebate incentive. However, an equivalent financial incentive to the customer offered under a direct install program would not be removed. In other words, if instead of offering a cash rebate to the customer, the utility directly installs that same measure and requires a customer co-payment (such that the out-of-pocket cost to the customer is the same under either approach), the financial incentive to free rider participants would be *included* in the costs. This is because all of the direct install costs would appear in the "program administrative cost" (PRC) term.[244] As indicated in Attachment 9, the 1988 SPM Correction Memo specifically

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[243] See *1987 SPM*, p. Appendix C, p. C-6; See also 2001 SPM at p. 11, footnote 3, and p. 32.

[244] See D.06-06-063, pp. 71-72 and Ordering Paragraph 15. The utilities recently filed a joint petition to modify D.06-06-063 with regard to our orders that certain costs be included in the administrative cost component of the TRC, and not be considered transfer payments. (See *Joint Petition of PG&E, SDG&E, and SCE for Modification of D.06-06*-063, May 31, 2007 in R.04-04-025 and also served on the parties to this rulemaking.) We do not address this issue in today's decision. Instead, we focus on how the NTG should be applied to TRC cost components within the context of the SPM and our determinations to date on the application of the TRC and PAC tests to various energy efficiency delivery approaches. Until further order by the Commission, our determinations in D.06-06-063 and the 2006 ALJ Compliance Ruling on how costs are to be accounted for under these tests remain unchanged.

prohibits applying the NTG ratio to the administrative cost component of TRC costs, since these are costs unrelated to participant expenditures.[245]

This means, all other things being equal, the 1988 SPM Correction Memo formulation would assign more costs to a direct install program than to a customer rebate program that is identical except for the delivery approach. As we stated in D.06-06-063, this type of inconsistency in cost-effectiveness results makes no sense, and is inconsistent with the intent of the TRC discussed above.[246] It is not even clear that this was the intent of the authors of the 1988 memo, since the formula did not actually present a full restatement of all the equations (benefit and cost side) of the TRC test with explicit NTG ratios applied.

To clarify how the NTG ratio should in fact be applied, a transfer incentive (INC) recapture quantity will be added to the TRC cost equation presented in the 1988 SPM Correction Memo as follows:

TRC Costs = PRC + NTG*PC + UIC + (1.0-NTG)*INC, where:

PRC = program administrator program costs
PC = participant device costs (*before* INC is received)
UIC = (for fuel substitution programs) utility increase supply costs
NTG = net-to-gross ratio
INC = incentive costs, restricted to include only dollar benefits such as rebates or rate incentives (bill credits).

Adding this term to the TRC cost formulation will ensure that the removal of free rider costs does not also remove program costs that become ratepayer

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245 The 1988 SPM Correction Memo utilizes the "UC" (for "utility administrative costs") term, which as been subsequently renamed "PRC" ("program administrator program costs") in more recent versions of the SPM. Therefore, we use the current PRC term in today's clarification.

246 See D.06-06-063, p. 72.

1. Rebate Program

4	participants	$2,000	measure cost
1	free rider	$3,000	measure benefit per measure
0.75	NTG	$1,000	rebate per measure
		$100.0	admin cost per measure
	TRC benefits=	4 participants x 3,000 x 0.75 NTG	

1988 SPM Correction Memo:

Program Net Costs = 4 participants x 100 admin costs per measure
Participant Net Costs =4 participants x 2,000 measure cost x 0.75 NTG

Adopted Clarification:

Program Net Costs = 4 participants x 100 admin costs/measure + 4 participants x (1-0.75)x $1,000 rebate per measure
Participant Net Costs=4 participants x 2,000 measure cost x 0.75 NTG

Methodology	**TRC Benefit**	**Program Net Costs**	**Participant Net Costs**	**TRC Cost**	**TRC**
1988 SPM Correction Memo:	$9,000	$400	$6,000	$ 6,400	**1.41**
Adopted Clarification	$9,000	$1,400	$6,000	$7,400	**1.22**

2. Direct Install

4	participants	$2,000	measure cost
1	freerider	$3,000	measure benefit per measure
0.75	NTG	$1,000	Direct program paid cost per measure
		$100.0	admin cost per measure

TRC benefits=4 participants x 3,000 x 0.75 NTG
Program Net Costs= 4 participants x 100 admin costs/measure + 4 participants x 1,000 direct program paid cost/measure
Participant Net Costs = 4 participants x 0.75 NTG x (2,000 measure cost - 1,000 direct program paid cost per measure)

Methodology	**TRC Benefit**	**Program Net Costs**	**Participant Net Costs**	**TRC Cost**	**TRC**
Per D.06-06-063	$9,000	$4,400	$3,000	$7,400	**1.22**

the SPM. The utilities shall take steps immediately to ensure that all future cost-effectiveness calculations apply the NTG ratio as directed by this decision. This includes the accomplishments reported for 2006-2008 energy efficiency portfolios, effective immediately.

As directed in the 2006 ALJ Compliance Ruling, Energy Division shall confer with Energy and Environmental Economics ("E3") and other technical expertise, as staff deems appropriate, to explore whether the naming of input values in the E3 calculator should be modified to better capture the SPM cost definitions and calculation methods, including the NTG ratio adjustments we clarify today. In addition, Energy Division may directly manage the development of the E3 calculator in the future, at its discretion, as part of this Commission's overall quality assurance responsibilities for post-2005 energy efficiency.[250]

11. Performance-Based Incentives for Emerging Technologies and Information Programs

PG&E proposes separate performance-based incentives for emerging technologies and education and training programs, in recognition of the essential role they play in the total portfolio of programs. NRDC supports PG&E's proposal in order to provide some earnings potential to balance the inclusion of these program costs in the PEB.

For the Emerging Technologies Program, PG&E proposes that shareholder earnings equal to five percent (5%) of Emerging Technology expenditures be awarded based on two performance thresholds. The first would be a "product introduction" threshold, which is met if the utility successfully moves a total of seven new technologies or products into the resource programs to generate

[250] See D.05-01-055, Section 5.3.3.

Best practices: Applications of the TRC should use only the incremental cost of a project or measure, with "incremental costs" defined as the difference between the cost of an average-efficiency measure that the homeowner would have installed in the absence of a program, and the cost of a high-efficiency measure that the homeowner installs in response to programmatic incentives.

4. <u>Discount rate</u>

In calculating the TRC test, costs and benefits are presented in terms of their net present value (NPV) – their value taking into account the opportunity cost of money, or discount rate. Because costs are incurred up front, while savings are realized over an extended period of time, higher discount rates typically result in the program scoring lower on the test. The discount rate can have a substantial impact on test outcomes, and also decrease the value of the effective useful life (EUL) of measures with long life-spans, as discussed below.

In theory, the discount rate to be used depends on the specific test and stakeholder interests. The Participant test, for example, should theoretically use a rate equivalent to an average of consumer loan rates for similar products. For the Societal test, a "societal" rate comprised of a blend Treasury bill rates is commonly employed. The discount rate used in the TRC test varies considerably; some states use a societal discount rate, while others employ the weighted average cost of capital (WACC) for the utility. However, because the TRC is explicitly designed to measure the societal impact of a program – as opposed to helping a utility weigh investment options – the societal discount rate represents a more appropriate choice from a methodological perspective.

Some observers have argued that, as a result of climate change, the value of avoided CO_2 emissions is likely to be higher in the future rather than lower, suggesting that the most appropriate discount rate would be negative, to reflect the fact that the value of the savings grows over time, rather than decreasing, as is the case with most other investments (Hall et al. 2008). While this approach is logically sound, commissions may be unwilling to adopt a practice as unorthodox as a negative discount rate in the short term.

Best practices: Use a societal discount rate as a ceiling for TRC testing, with an option for jurisdictions to use an even lower rate to reflect the increasing value of avoided carbon emissions over time.

5. <u>Value other avoided externalities</u>

The California Public Utilities Commission identifies several avoided externalities, including NO_x (nitrous oxide), SO_x (sulfur oxides), and/or VOC (volatile organic compounds) emissions, and includes an imputed value for these savings and/or avoided externalities as an "adder" (i.e. a multiplier) to the energy savings in the Societal test. These and similar avoided externalities have since been incorporated into applications of the TRC test in a number of jurisdictions. Given the widespread preference for the TRC over the Societal test, there is a strong rationale for including at least the most easily and accurately quantifiable savings and avoided non-energy costs as an enhancement to the TRC.

Best practices: The value of non-energy savings and avoided externalities (e.g. NO_x*,* SO_x*, VOCs, etc.) should be included in TRC testing. Use of a standard "adder" to energy costs represents a reasonable methodology for approximating the impact of these avoided externalities.*

6. Non-Energy Benefits

Non-energy benefits (NEBs) are the benefits other than energy savings that homeowners realize as a result of participating in an energy efficiency program. They may include comfort, health and safety, aesthetics, and other general quality of life issues, as well as financial savings such that result from causes other than increases in energy efficiency, such as savings on water costs resulting from the installation of a high-efficiency dishwasher or washing machine. These benefits can be substantial: an Oak Ridge National Laboratory study found that non-energy benefits such as comfort slightly outweighed the value of energy benefits for Weatherization program clients (see Schweitzer and Tonn, 2002). The data suggests that these benefits, particularly comfort, are frequently the primary motivator for consumers who implement energy efficiency upgrades. Other social non-energy benefits include local job creation and economic development.

Methods have been developed to quantify the value of these benefits, but they are generally complex and expensive to administer, and there is no widespread consensus regarding which are the most appropriate. As a result, many states have not incorporated NEBs into the TRC, and those that do tend to use conservative estimates for valuing NEBs (Amann 2006: iii). The evidence for the significance of NEBs is so compelling, however, that failure to consider them substantially reduces the ability of the TRC to perform its stated goal of providing an accurate assessment of the costs and benefits of a program. Without consideration of NEBs the test is effectively asymmetrical: it captures the full value of participant costs, but not benefits.

In theory, the value of the NEBs can be considered a benefit for the purposes of applying the TRC test. Given that these benefits fall outside the scope of the utility commission's jurisdiction, however, a more appropriate methodology is to reduce participant costs by the estimated value of NEBs. A simpler method is to determine the average value of NEBs associated with a program and discount participant costs by a percentage that reflects the ratio of the average NEB value to energy savings. Average NEB value could be determined at a national or regional level through well-designed survey research in a cost-effective fashion for use in multiple TRC tests. (See Amann 2006: 13.)

Best practices: For whole-house programs, discount participant costs by a percentage that reflects the average value of NEBs relative to energy savings, using national or over the Societal test, there is a strong rationale for including at least the most easily and accurately quantifiable savings and avoided non-energy costs as an enhancement to the TRC.

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