MÉTHODE D'ÉVALUATION DE LA DEMANDE CONTINUE EN JOURNÉE DE POINTE

(Suivi D-2013-179)

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INTRODUCTION

À la Cause tarifaire 2014, Société en commandite Gaz Métro (« Gaz Métro ») a fait la démonstration que la consommation de la clientèle aux tarifs D_3 et D_4 est influencée par la température[1]. Gaz Métro avait donc proposé de modifier la méthode d'évaluation de la demande continue en journée de pointe relativement à cette clientèle.

Dans sa décision D-2013-179, la Régie de l'énergie (« Régie ») a convenu que la méthode actuelle d'évaluation de la demande en journée de pointe, utilisant le maximum de la demande quotidienne moyenne de chacun des mois de décembre à mars pour les clients aux tarifs D_3 et D_4, n'est pas parfaite et peut sous-estimer la prévision de la journée de pointe.

Toutefois, la Régie s'est questionnée sur certains aspects de la méthode proposée : la proportion des volumes consommés par les clients avec un coefficient d'utilisation de 60 % (qu'elle identifie comme des clients à profil stable), les niveaux des coefficients de corrélation, le facteur d'ajustement pour tenir compte de l'écart entre la prévision de volume de l'année témoin et la consommation réelle de l'année historique utilisée en référence dans la régression et le fait que la méthode proposée mène à une coïncidence partielle.

À ces égards, la Régie ordonnait :

> ***« [29] Pour l'ensemble de ces motifs, la Régie rejette la modification à la méthode de prévision de la journée de pointe proposée par Gaz Métro. Elle demande au Distributeur de revoir la méthode de prévision dans son ensemble pour corriger, entre autres, la prévision de la journée de pointe de la clientèle aux tarifs D_3 et D_4 et de déposer à la Régie une proposition d'ici six mois. Elle juge que le Distributeur devra, d'ici là, appliquer la méthode actuelle. »***

Le présent document vise à répondre à la demande de la Régie.

Les différentes analyses sont effectuées en fonction de la demande projetée et des paramètres de la Cause tarifaire 2014.

[1] R-3837-2013, Gaz Métro-2, Document 1, section 9.1.2.

1. MÉTHODES D'ÉVALUATION DE LA DEMANDE EN JOURNÉE DE POINTE

1.1. Gaz Métro

La méthode actuelle d'évaluation de la demande continue en journée de pointe approuvée par la Régie dans sa décision D-2009-156 et mise en place à la Cause tarifaire 2011 se résume comme suit :

a) Une régression linéaire est appliquée à la demande quotidienne réelle observée *a posteriori* pour la période de l'hiver de la dernière année financière disponible pour la clientèle aux tarifs D_1 et D_3 à lecture mensuelle. La formule de régression développée est la suivante :

$$C_t = A_t + \beta_1 DJ_t + \beta_2 DJ_{t-1} + \beta_3 (DJ_t \times V_t)$$

Où :

C = Consommation du jour t
A_t = $\alpha_0 + \alpha_{1 à 6}\text{Jour} + \alpha_{7 à 17}\text{Mois} + \alpha_{18}\text{Jour\_férié}$ du jour t
i.e facteur base selon le jour, le mois et jour férié ou non du jour t
β_1 = Facteur calorifique par degré-jour du jour t
β_2 = Facteur calorifique par degré-jour du jour précédent au jour t (i.e. t-1)
β_3 = Facteur calorifique par "degré-jour x vent"
DJ_t = Degrés-jours au jour t
DJ_{t-1} = Degrés-jours au jour t-1
V_t = Vitesse moyenne du vent au jour t

Les DJ sont établis en base 13°C.

Le facteur de base de la clientèle aux tarifs D_1 et D_3 à lecture mensuelle pour une journée donnée correspond à la somme des paramètres : Constante, Jour de la semaine, Férié et Mois – selon les caractéristiques propres à la journée. Les paramètres DJ_t et DJ_{t-1} captent l'effet de la température et le paramètre DJ_t x V_t capte l'effet croisé du vent et de la température.

Il est à noter que la formule de régression est similaire à celle utilisée dans le calcul de la normalisation des revenus.

b) Pour définir les valeurs d'évaluation de la journée de pointe, les paramètres DJ_t, DJ_{t-1} et DJ_tXV_t de la régression linéaire sont appliqués aux différentes combinaisons des variables climatiques réchauffées[2] pour chaque journée des 20 dernières années. La combinaison DJ_t, DJ_{t-1} et DJ_tXV_t générant le volume maximal établit les valeurs d'évaluation de la journée de pointe.

Pour 2014, la combinaison de la journée de pointe est observée le 15 janvier 2004 avec les variables suivantes :

	Variables réelles	Variables réchauffées en 2014
DJ_t	37,25	36,80
DJ_{t-1}	39,93	39,48
DJ_tXV_t	1 283,86	1 268,33

c) La demande de la journée de pointe est estimée par une extrapolation des facteurs climatiques de la régression selon les variables de la journée de pointe établies préalablement, à laquelle est ajouté le facteur de base calculé selon les paramètres : Constante, Jour de semaine, Férié et mois générant le volume quotidien maximal ;

d) Un facteur d'ajustement est requis pour refléter la demande prévue au dossier tarifaire puisque la demande utilisée au calcul de la régression est celle de la dernière année historique disponible. Cet ajustement est établi en comparant la demande mensuelle prévue au dossier tarifaire à la demande découlant de l'application de la régression linéaire aux variables normales du dossier tarifaire. Cet ajustement est ensuite appliqué aux facteurs de la régression. On obtient ainsi des paramètres qui reflètent la demande de la clientèle aux tarifs D_1 et D_3 à lecture mensuelle au dossier tarifaire ;

e) Le facteur de base ajusté est ensuite majoré par le maximum de la demande quotidienne moyenne de chacun des mois de décembre à mars de la clientèle aux tarifs D_3 et D_4. Les volumes de ces clients sont considérés comme de la consommation de base, non assujettie aux facteurs calorifiques et vent.

En complément d'information, il est important de souligner que le volume quotidien des outils d'approvisionnement est défini comme le maximum entre la demande continue en journée de

[2] DJ réchauffés selon la méthode Ouranos développée initialement pour Hydro-Québec Distribution (B-0037, R-3644-2007, HQD-15, document 1.1, Annexe A)

pointe et les outils quotidiens d'approvisionnement requis pour répondre à la demande saisonnière de l'ensemble de la clientèle en hiver extrême.

1.2. Autres distributeurs

Dans son dossier EB-2013-0109, Union Gas a déposé un rapport[3] préparé par Sussex Economic Advisors, LLC (Sussex) dans lequel un balisage portant sur la prévision de la demande de la journée de pointe de plusieurs distributeurs a été réalisé (Appendix C). Ce balisage a porté spécifiquement sur la méthode d'établissement des DJ de la journée de pointe, le calcul de la demande de la journée de pointe et le calcul du facteur d'ajustement de la demande de pointe.

Le rapport est présenté à l'annexe 1. Les résultats de ce balisage sont présentés aux pages 22 et 23 du rapport et se résument comme suit :

a) Méthode d'établissement des DJ de la journée de pointe
Deux approches sont principalement utilisées par les distributeurs.

La première approche considère la journée la plus froide d'un certain nombre d'années d'historique. Les distributeurs consultés utilisent, de façon générale, une période historique de 30 à 40 ans ou la journée la plus froide historiquement observée. Seule Gaz Métro est moins conservatrice en utilisant une période de 20 ans.

La seconde approche se base sur une approche probabiliste. Les DJ de la journée de pointe sont déterminés selon des probabilités d'occurrence de 1 sur 5 ans à 1 sur 90 ans avec des données historiques de 10 à 50 ans. La méthode de Monte Carlo est également utilisée par certains distributeurs pour modéliser les bases de données.

Il ressort du balisage que la première approche est utilisée par 12 distributeurs et la deuxième par 7 distributeurs.

Le balisage ne précise pas si la notion de réchauffement climatique est utilisée par les autres distributeurs comme le fait Gaz Métro. Après vérification auprès du consultant,

[3] EB-2013-0109, Exhibit C, Tab 2 du 8 mai 2013.

il précise qu'aucun distributeur n'a fait référence à un réchauffement des DJ. Seule Gaz Métro est moins conservatrice en utilisant des DJ réchauffés.

b) Méthode d'établissement de la demande continue en journée de pointe
La majorité des distributeurs détermine une formule de régression sur les volumes quotidiens historiques les plus récents selon les DJ réels. La demande de la journée de pointe est calculée par une extrapolation au DJ de la journée de pointe.

c) Facteur d'ajustement de la demande de pointe
La majorité des distributeurs applique le facteur de croissance de la demande projetée à la demande de la journée de pointe.

De façon plus spécifique, les méthodes des distributeurs ontariens Union Gas et Enbridge Gas Distribution, distributeurs qui évoluent dans des contextes similaires à celui de Gaz Métro tant au niveau de la clientèle desservie que des conditions climatiques, sont les suivantes :

Union Gas

Union Gas dessert des clients dans deux régions géographiques différentes. La région Nord débute à l'est de la frontière du Manitoba, traverse la province de l'Ontario d'est en ouest en passant par Toronto et inclut la région de Cornwall. La région Sud est à l'est de Windsor dans le sud de l'Ontario. Cette région est moins étendue et est contiguë aux installations de stockage et de transmission de Union Gas et du carrefour de Dawn.

La méthode d'établissement de la demande de la journée de pointe est établie distinctement pour les régions Nord et Sud.

La région Nord est composée de 6 zones d'approvisionnement. Une demande de la journée de pointe est établie pour chacune de ces zones. La somme des demandes des 6 zones constitue la demande de la journée de pointe de la région Nord.

La demande de la journée de pointe de chacune des 6 zones d'approvisionnement est établie comme suit :

1. Pour certaines catégories tarifaires, une régression selon la variable explicative DJ est réalisée sur les volumes de l'hiver précédent, les volumes des fins de semaine et des

jours fériés sont exclus. Pour d'autres catégories de clients, des données contractuelles sont utilisées.

2. La journée de pointe correspond aux DJ de la journée la plus froide observée. Pour les deux zones les plus apparentées à celles de Gaz Métro, les DJ sont les suivants.

Tableau 1

Régions	Base 18°C	Base 13°C
Union EDA (Kingston)	47,1	42,1
Union NDA (Sudbury)	51,9	46,9

3. La demande de la journée de pointe est établie par une extrapolation de la régression à la journée de pointe.

4. Le facteur de croissance de la demande projetée au dossier est finalement appliqué à la demande de la journée de pointe estimée.

Pour la région Sud, la même méthodologie d'établissement de la demande de la journée de pointe est appliquée. La demande de la journée de pointe est extrapolée à 43,1 DJ en base 18°C ou 38,1 DJ en base 13°C selon l'historique des observations relevées à l'aéroport de London.

<u>Enbridge Gas Distribution</u>

Enbridge dessert des clients dans trois régions géographiques différentes : « Central Region » (Toronto), Eastern Region (Ottawa) et Niagara Region.

Pour chaque région, Enbridge évalue les DJ de la journée de pointe en fonction d'une distribution Log-normale sur des données développées avec la méthode de Monte-Carlo, considérant une probabilité d'occurrence de 1 sur 5 ans. Selon cette méthode, pour les deux zones les plus apparentées à celles de Gaz Métro, la journée de pointe pour 2014[4] est établie comme suit :

[4] Décision de l'Ontario Energy Board du 15 octobre 2012 dans le dossier EB-2011-0354, Exhibit N1, Tab 1, Schedule 1, page 22.

Tableau 2

Régions	Base 18°C	Base 13°C
Central Region (Toronto)	41,4	36,4
Eastern Region (Ottawa)	48,2	43,2

Cette journée de pointe ainsi que les 17 journées les plus froides (pointes multiples) sont réparties sur l'hiver pour établir la demande quotidienne projetée de l'année témoin et le plan d'approvisionnement pour répondre à cette demande.

1.3. Conclusions

En comparant les méthodes d'évaluation de la demande continue en journée de pointe, Gaz Métro tire les conclusions suivantes :

<u>Modèle de régression</u>

Le modèle de régression utilisé par Gaz Métro et défini par la formule :

$$C_t = A_t + \beta_1 DJ_t + \beta_2 DJ_{t-1} + \beta_3 (DJ_t \ x \ V_t)$$

est un modèle plus élaboré comparativement aux modèles de régression des autres distributeurs. En effet, le modèle de régression de Gaz Métro comporte un plus grand nombre de variables explicatives que les modèles de régression de la majorité des autres distributeurs n'utilisant que les DJ.

De plus, lors de son développement, ce modèle a démontré une meilleure performance comparativement à plusieurs variantes analysées. Plus particulièrement, pour la détermination de la demande de la journée de pointe, ce modèle a démontré une meilleure performance que le modèle utilisé avant 2011, établi uniquement en fonction des DJ normaux et des volumes mensuels projetés. Cette meilleure performance découle non seulement d'une meilleure capacité explicative du modèle, mais aussi de l'utilisation de données réelles quotidiennes et donc plus précises.

Selon Gaz Métro, les résultats produits par le modèle sont jugés adéquats. Les figures 5, 6 et 7 présentées à la section 4 illustrent clairement la performance du modèle. Les volumes projetés et les volumes historiques sont relativement juxtaposés.

Paramètres de la journée de pointe

Gaz Métro établit les paramètres de la journée de pointe selon un historique des 20 dernières années en considérant des DJ normaux réchauffés.

La journée de pointe de Gaz Métro est établie pour l'ensemble de son territoire et définie en base 13°C. Elle correspond à la journée du 15 janvier 2004 et se définit par les variables suivantes :

	Variables réelles	Variables réchauffées en 2014
DJ_t	37,25	36,80
DJ_{t-1}	39,93	39,48
$DJ_t x V_t$	1 283,86	1 268,33

En base 13, la journée de pointe de Union Gas est de 42,1 DJ dans la zone Union EDA et de 46,9 DJ dans la zone Union NDA. Celle de la zone Est (Ottawa) de Enbridge est de 43,2 DJ.

La journée de pointe de Gaz Métro est inférieure à celle des distributeurs ontariens, malgré le fait que son territoire se situe au nord des zones EDA et NDA de Union Gas et de la zone Est d'Enbridge, et donc sujet à des conditions hivernales plus ardues.

Selon le balisage réalisé par Sussex, la majorité des distributeurs qui, comme Gaz Métro, établissent leur journée de pointe selon la journée la plus froide observée, utilise un historique de plus de 25 ans avec certains distributeurs, dont Union Gas, qui utilisent la journée la plus froide jamais observée.

De plus, la méthode de normalisation de Gaz Métro, qui a inspiré la méthode d'établissement de la demande continue en journée de pointe, utilise un historique de données d'octobre 1970 à ce jour. Cette méthode repose sur la méthode développée par Hydro-Québec Distribution en collaboration avec le groupe de recherche Ouranos et utilisée pour estimer la demande électrique de pointe.[5] Dans ses grandes lignes, cette méthode consiste à ajuster les températures de la période de référence (octobre 1970- à ce jour) afin de considérer l'impact du réchauffement climatique sur cette période. Elle permet de conserver un maximum d'informations puisque même les années les plus anciennes demeurent pertinentes et ne

[5] B-0037, R-3644-2007, HQD-15, document 1.1, Annexe A

risquent pas de biaiser la normale. En d'autres termes, toutes les données historiques sont actualisées à l'année de référence.

Facteur d'ajustement

Tout comme Gaz Métro, plusieurs distributeurs utilisent un facteur d'ajustement pour tenir compte, dans l'établissement de la demande de la journée de pointe, de la variation de la demande de l'année témoin par rapport à l'année historique. Ce type d'ajustement est requis et résulte de l'utilisation d'une extrapolation sur des données historiques dont le résultat ne peut coïncider parfaitement à la prévision de l'année témoin.

2. PROBLÉMATIQUES

La méthode actuelle d'évaluation de la demande en journée de pointe présente des traitements différents pour la clientèle aux tarifs D_3 à lecture quotidienne et D_4 (volume quotidien moyen) comparativement à la clientèle aux tarifs D_1 et D_3 à lecture mensuelle (régression). Un des constats de la journée historique du 23 janvier 2013 est que la méthode appliquée à la clientèle aux tarifs D_3 à lecture quotidienne et D_4 sous-estime l'apport à la pointe de ces clients.

En effet, à travers les analyses réalisées dans son dossier tarifaire 2014[6], présentées à l'annexe 2, Gaz Métro a constaté l'inexactitude de l'hypothèse voulant que les clients aux tarifs D_3 et D_4 consomment selon un profil uniforme au cours du mois, sans influence de la température. L'analyse des consommations du mois de janvier 2013 a démontré que pour des mêmes jours de la semaine ou pour des jours fériés, le volume de gaz naturel consommé a tendance à augmenter avec les degrés-jours.

De plus, des régressions linéaires sur les consommations observées pour la clientèle aux tarifs D_3 et D_4 à lecture quotidienne pour les hivers 2009 à 2012 ont été réalisées. Les résultats ont démontré clairement que la consommation de cette clientèle est influencée par la température.

[6] R-3738-2013, Gaz Métro 2, Document 1, section 9.2.1

Gaz Métro a alors proposé de modifier la méthode d'évaluation de la demande continue en journée de pointe relativement à la clientèle aux tarifs D_3 et D_4. Cette modification consistait à appliquer la méthode pour les clients des tarifs D_1 et D_3 à lecture mensuelle.

Au paragraphe 26 de sa décision D-2013-179, la Régie convient que la méthode actuelle d'évaluation de la demande en journée de pointe, utilisant la demande mensuelle moyenne des clients aux tarifs D_3 et D_4, n'est pas parfaite et peut sous-estimer la prévision de la demande en journée de pointe. La Régie n'a pas exclu que des besoins de pointe supplémentaires puissent exister.

D'ailleurs, même si la méthode proposée d'évaluation de la demande en journée de pointe n'a pas été approuvée, la Régie a approuvé le maintien des outils d'approvisionnement découlant de l'application de cette méthode.

Pour compléter l'information, Gaz Métro a effectué des analyses similaires à celles présentées à la Cause tarifaire 2014 et relatives aux observations durant le dernier hiver.

2.1. Approvisionnement pour l'hiver 2013-2014

À la suite de la révision de la projection de la demande pour l'hiver 2013-2014, Gaz Métro a modifié sa structure d'approvisionnement. Ainsi, la vente *a priori* d'une capacité de 264 10^3m^3/jour (10 000 GJ/jour), projetée à la Cause tarifaire 2014, n'a pas été effectuée. De plus, Gaz Métro évaluait un manque d'outils d'approvisionnement de 70 10^3m^3/jour (2 642 GJ/jour) pour sécuriser les approvisionnements.

Le tableau suivant présente la demande de pointe et les outils d'approvisionnement évalués à la Cause tarifaire 2014 et à la révision budgétaire précédant le début de la saison hivernale.

Tableau 3

		Dépôt CT-2014 10^3m^3/jour	Plan 2-10 10^3m^3/jour
1	**Demande de la journée de pointe (Méthode proposée)**	**31 521**	**31 536**
2	FTLH primaire	8 586	8 586
3	FTLH secondaire	396	396
4	Transport par échange	1 031	1 031
5	Réceptions en franchise	11	21
6	Clients fournissant leur transport +biogaz	1 065	735
7	FTSH (Dawn / EDA)	2 903	2 903
8	Transport par échange (Dawn-EDA)	2 164	2 164
9	FTSH (Parkway / EDA)	1 715	1 715
10	STS (Parkway / EDA & NDA)	5 705	5 705
11	Pointe-du-Lac	1 196	1 196
12	St-Flavien	1 294	1 285
13	LSR	5 729	5 729
14	**Approvisionnement disponible**	**31 794**	**31 466**
15	Vente transport	-264	0
16	**Total approvisionnement**	**31 531**	**31 466**

2.2. Analyse de la journée de pointe 2013-2014

La journée la plus froide de l'hiver 2013-2014 a été le 2 janvier 2014 avec

DJ_t 37,20
DJ_{t-1} 36,30
$DJ_t x V_t$ 881,88

Or, étant une journée fériée, la consommation de pointe de la demande continue n'a pas été observée. Celle-ci s'est plutôt produite le 21 janvier 2014 avec

DJ_t 35,97
DJ_{t-1} 32,05
$DJ_t x V_t$ 259,81

Un volume de 29 171 10^3m^3 a été observé pour la clientèle continue.

La demande totale de la journée du 21 janvier 2014 ainsi que les outils d'approvisionnement utilisés sont présentés au tableau suivant.

Tableau 4

	Journée du 21 janvier 2014	10^3m^3/jour
1	**Demande**	**30 723**
2	Continue	29 171
3	Interruptible (Retraits interdits + GAI)	1 428
4	Autre (Biogaz + Linepack)	124
5	**Approvisionnement**	**30 723**
6	FTLH primaire	8 586
7	FTLH secondaire	396
8	Transport par échange	1 031
9	Réceptions en franchise	21
10	Clients fournissant leur transport +biogaz	766
11	Gaz d'appoint concurrence	36
12	Gaz d'appoint interruption	1 484
13	FTSH (Dawn / EDA)	2 903
14	Transport par échange (Dawn-EDA)	2 164
15	FTSH (Parkway / EDA)	1 715
16	STS (Parkway / EDA & NDA)	5 705
17	Pointe-du-Lac	1 184
18	St-Flavien	1 516
19	LSR	3 119
20	Écart de nomination	96

La capacité maximale de vaporisation à l'usine LSR étant de 5 729 10^3m^3, il restait donc un excédent de capacité de 2 610 10^3m^3 pour répondre à une demande supérieure à celle du 21 janvier 2014.

Si la journée de pointe avait été observée, la demande continue aurait été approximativement de 32 628 10^3m^3, soit 3 457 10^3m^3 de plus que la demande continue observée pour cette journée spécifique. Cette valeur est établie en appliquant les variables volumétriques définies à la Cause tarifaire 2014 aux unités manquantes de chaque paramètre.

Tableau 5

Paramètre de régression		Paramètres de pointe CT 2014	Paramètres réels 2014-01-21	Variation des paramètres	Ajustement de volume	Volume de pointe
					10^3m^3/jour	10^3m^3/jour
Consommation continue maximale réelle observée						**29 171**
Ajustement de volume						
DJ t (10^3m^3/DJ)	327,69	36,80	35,97	0,83	272	
DJ t-1 (10^3m^3/DJ)	88,61	39,48	32,05	7,43	658	
DJ t x V t (10^3m^3/DJxkm/h)	2,51	1 268,33	259,81	1 008,52	2 527	
Total					**3 457**	
Demande continue projetée pour la journée de pointe						**32 628**

Ainsi, en date du 20 janvier, si une journée de pointe avait été projetée pour le 21 janvier, un manque d'outils de 847 10^3m^3 (2 610 10^3m^3 – 3 457 10^3m^3) aurait été constaté, toutes choses étant égales par ailleurs. Gaz Métro aurait eu alors besoin de contracter des outils additionnels pour répondre à la demande.

À elle seule, cette analyse démontre que les outils détenus par Gaz Métro et reflétant la méthode proposée d'évaluation de la demande en journée de pointe étaient requis et même inférieurs au besoin pour assurer la sécurité d'approvisionnement. La méthode actuelle ne génère donc pas une projection de demande continue en journée de pointe représentative des besoins de la clientèle.

2.3. Analyse de l'hiver 2013-2014

Le tableau suivant compare les DJ normaux aux DJ réellement observés.

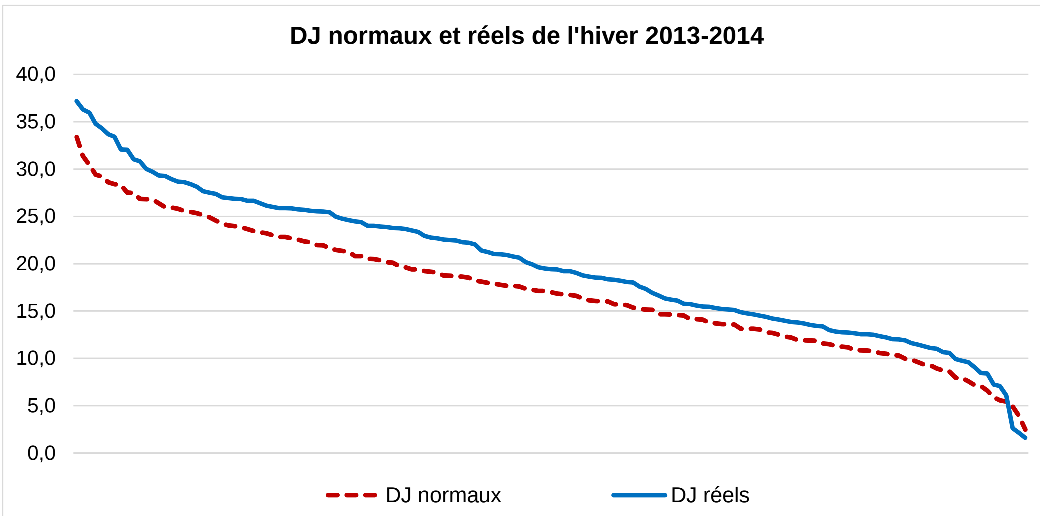
Tableau 6

	Degrés-jours hiver 2014		
	Normaux	**Réels**	**Variation**
Novembre	320,7	373,3	16,4%
Décembre	570,0	677,9	18,9%
Janvier	683,5	720,0	5,3%
Février	570,9	616,2	7,9%
Mars	453,6	600,8	32,5%
TOTAL	**2 598,7**	**2 988,2**	**15,0%**

Il est à noter que le mois de janvier 2014, avec des DJ légèrement supérieurs à la normale, a été particulier. En effet, le mois a connu des extrêmes de températures chaudes (6 jours en dessous de 15 DJ comparativement à 3 à la normale) et froides (7 jours au-dessus de 30 DJ, comparativement à 3 à la normale).

Le graphique suivant présente les DJ quotidiens normaux et réels en ordre décroissant.

Figure 1



Ce graphique illustre bien que les DJ réels sont supérieurs aux DJ normaux pour l'ensemble de la période d'hiver à l'exception de quelques jours plus chauds observés en janvier. D'ailleurs, l'hiver 2013-2014 a été l'hiver le plus froid depuis 1970 (sur la base des DJ réchauffés). Le tableau suivant présente les cinq années les plus froides.

Tableau 7

	Novembre	Décembre	Janvier	Février	Mars	Total
2013-2014	373,3	677,9	720,0	616,2	600,8	2 988,2
1993-1994	345,9	567,5	906,8	667,9	463,0	2 951,0
2002-2003	371,7	536,2	780,6	661,8	506,0	2 856,2
1995-1996	409,2	650,8	720,3	595,7	474,8	2 850,8
1991-1992	307,1	610,0	711,9	629,3	539,4	2 797,7

Le tableau suivant présente sommairement les approvisionnements utilisés du 1er novembre au 31 mars comparativement à la projection à la Cause tarifaire 2014.

Tableau 8

DEMANDE ET SOURCES D'APPROVISIONNEMENT GAZIER POUR L'HIVER 2013-2014

		Projection CT-2014 (10^6m^3) (1)	Résultats réels** (10^6m^3) (2)	Écarts (10^6m^3) (3)
	DEMANDE			
1	Continu	2 811	3 089	278
2	Interruptible	378	375	-2
3	Client biogaz en réseau dédié	13	11	-2
4	Gaz d'appoint concurrence	17	9	-8
5	*Sous-total ventes*	*3 220*	*3 485*	*265*
6	Gaz perdu, usage de la compagnie et autres	47	90	44
7	Ventes GNL	5	7	2
8	Sous-total demande avant injections	3 272	3 583	311
	INVENTAIRES injections			
9	Union Gas	43	33	-10
10	LSR *	10	11	0
11	Pointe-du-Lac *	16	44	28
12	St-Flavien *	10	4	-6
13	Échanges de gaz	0	0	0
14	Sous-total injections et échanges	79	92	13
15	**TOTAL DEMANDE**	**3 350**	**3 674**	**324**
	APPROVISIONNEMENT			
16	FT - Empress - GMI	1 257	1 296	40
17	Cessions d'optimisation	60	60	0
18	Transport par échange (Emp - GMI)	156	160	4
19	Transport fourni par les clients	149	100	-48
20	Gaz d'appoint	17	59	41
21	*Sous-total transports*	*1 638*	*1 675*	*37*
22	Cessions / ventes de transport FTLH	0	0	0
23	FTLH non utilisé	0	-1	-1
24	Achats dans le territoire	2	3	2
25	Achats Dawn (GR)	1 214	1 381	167
26	Biogaz	13	11	-2
27	Autres réceptions	0	26	26
28	Sous-total appro. avant retraits	2 866	3 095	229
	INVENTAIRES retraits			
29	Union Gas	294	299	5
30	LSR *	10	38	27
31	Pointe-du-Lac *	17	49	32
32	St-Flavien *	120	115	-5
33	Échanges de gaz	0	0	0
34	Sous-total retraits et échanges	441	500	59
35	**TOTAL APPROVISIONNEMENT**	**3 308**	**3 595**	**288**
	INTERRUPTIONS			
36	Interruptions brutes estimées	-43	-79	-36
37	Dépannage, gaz d'appoint pour éviter une journée d'interruption et retrait interdit		39	39
38	**INTERRUPTIONS NETTES ESTIMÉES**	**-43**	**-40**	2

* Un pouvoir calorifique de 37,89 a été utilisé alors que le pouvoir calorifique a été de 37,76 MJ/m³ du 1er novembre 2013 au 31 mars 2014.

** Les résultats réels présentés sont provisoires et sont sujets à révision à la fermeture de l'année.

Les résultats montrent l'augmentation de l'utilisation de l'ensemble des outils et une augmentation des interruptions brutes.

Il est à noter que la baisse des retraits au site de St-Flavien découle, entre autres, de l'arrêt des retraits durant la période chaude de janvier. De plus, des retraits en avril ont également été effectués.

Le tableau suivant présente la comparaison des niveaux d'inventaires au 31 mars prévus à la Cause tarifaire 2014 et ceux atteints au site d'Union Gas et à l'usine LSR.

Tableau 9

($10^6 m^3$)	Capacité maximale	Inventaires au 31 mars 2014	
		Projection CT-2014	Résultats réels
Union Gas	344	45	31
Usine LSR (DAQ)	52	49	25

Le nombre de jours d'interruption a frôlé, et même atteint dans certains cas, les maximums fixés à la Cause tarifaire 2014, comme le démontre le tableau suivant :

Tableau 10

Palier tarifaire	Cause tarifaire 2014		Réel
	Prévu	Maximum	
Volet A			
505	8	48	42
506	10	52	44
507	13	62	49
508	15	62	56
509	28	76	56
Volet B			
535	4	20	20
536	4	20	20
537	9	30	29
538	9	30	29
539	9	30	29

Considérant le contexte de l'hiver 2013-2014 avec des prix des énergies alternatives très élevés combinés à une rareté du transport et des prix du gaz naturel également élevés, les clients interruptibles ont eu à supporter des coûts énergétiques excédant de façon importante leur budget énergétique. À cet effet, plusieurs clients ont signifié leur intention de migrer en partie ou en totalité au service continu.

Gaz Métro a effectué une analyse sommaire de l'impact sur le plan d'approvisionnement d'une décision de la Régie qui ne lui aurait pas permis de conserver les capacités additionnelles reliées à la proposition de modification au calcul de la journée de pointe. Cette baisse de 1 206 10^3m^3/jour (45 700 GJ/jour) des capacités de transport FTLH aurait entraîné 25 jours d'interruption additionnels, abstraction faite des jours maximums d'interruption. Gaz Métro n'aurait donc pas été en mesure de faire face à ses obligations envers ses clients. De plus, des retraits additionnels à l'usine LSR de 21,7 10^6m^3 auraient été requis amenant le niveau d'inventaire au 31 mars à 2,9 10^6m^3, soit à un niveau inférieur au niveau minimum sécuritaire de 7,7 10^6m^3. Il est à noter que cette analyse ne considère pas le fait que la baisse des capacités de transport entraînerait une diminution des cyclages au site d'entreposage de Pointe-du-Lac. Le niveau d'inventaire serait alors inférieur réduisant ainsi la capacité de retrait disponible et, potentiellement, une plus grande utilisation de l'usine LSR.

L'analyse des résultats de l'hiver 2013-2014 démontre que l'ensemble des outils, incluant les outils additionnels de 1 206 10^3m^3/jour (45 700 GJ/jour) reliés à la proposition de modification au calcul de la journée de pointe, combinés à des niveaux d'interruption maximum ou très élevés ont été requis pour alimenter la clientèle continue.

2.4. Analyse de la consommation de la clientèle aux tarifs D_3-D_4 à lecture quotidienne

Le tableau suivant présente les consommations quotidiennes de janvier 2014 de la clientèle aux tarifs D_3 et D_4 à lecture quotidienne.

Tableau 11

Consommation Janvier 2014 Clientèle D_3-D_4 à lecture quotidienne				
Jour	**Date**	**DJ**	**Volume** 10³m³	
lundi	20	32,1	7 798	
lundi	27	28,6	7 579	
lundi	13	22,0	6 867	
lundi	6	9,6	6 990	
mardi	21	36,0	8 019	
mardi	7	27,7	7 342	
mardi	28	26,1	7 582	
mardi	14	12,5	6 740	
mercredi	1	36,3	6 548	*
mercredi	22	34,3	7 834	
mercredi	29	24,5	7 415	
mercredi	8	23,9	7 371	
mercredi	15	13,8	7 165	
jeudi	2	37,2	7 002	*
jeudi	23	33,7	7 771	
jeudi	9	24,0	7 513	
jeudi	30	18,1	7 466	
jeudi	16	15,7	7 236	
vendredi	3	34,8	6 947	*
vendredi	24	25,7	7 407	
vendredi	10	18,5	7 176	
vendredi	31	18,4	7 175	
vendredi	17	15,2	7 222	
samedi	25	25,4	7 139	
samedi	4	24,8	6 853	
samedi	18	15,3	6 809	
samedi	11	9,9	6 745	
dimanche	26	28,9	7 375	
dimanche	19	20,2	7 270	
dimanche	5	14,8	6 689	
dimanche	12	12,0	6 748	

* : Impact des jours fériés

Ce tableau démontre que la consommation de cette clientèle est influencée par la température.

Les régressions linéaires sur les consommations des hivers 2012-2013 et 2013-2014 de cette clientèle génèrent les variables suivantes :

Tableau 12

Hiver 2013

Paramètres	**(10^3m^3)**	**Paramètres**	**(10^3m^3)**	**Paramètres**	**(10^3m^3 /unité)**
Base	**5 095**	Novembre	0	DJ (t)	**23**
		Décembre	176	DJ (t-1)	**10**
Dimanche	46	Janvier	**310**	DJ(t) x Vent (t)	**0**
Lundi	200	Février	244		
Mardi	193	Mars	58		
Mercredi	**267**			R^2	68,8%
Jeudi	249				
Vendredi	203				
Samedi	0				
Ferié	-921				

Tableau 13

Hiver 2014

Paramètres	**(10^3m^3)**	**Paramètres**	**(10^3m^3)**	**Paramètres**	**(10^3m^3 /unité)**
Base	**6 061**	Novembre	0	DJ (t)	**29**
		Décembre	189	DJ (t-1)	**7**
Dimanche	-33	Janvier	349	DJ(t) x Vent (t)	**0**
Lundi	59	Février	**394**		
Mardi	109	Mars	205		
Mercredi	**191**			R^2	61,9%
Jeudi	176				
Vendredi	130				
Samedi	0				
Ferié	-878				

Les paramètres DJ_t et DJ_{t-1} n'étant pas nuls confirment que la consommation de la clientèle aux tarifs D_3 et D_4 à lecture quotidienne est influencée par les conditions climatiques.

2.5. Conclusion sur la problématique

Les différentes analyses présentées ci-dessus confirment que les consommations de la clientèle continue aux tarifs D_3 et D_4 sont influencées par la température et que les outils d'approvisionnement définis en fonction de ces hypothèses étaient effectivement requis pour répondre aux besoins en cas d'hiver extrême et inférieurs au besoin pour une journée de pointe.

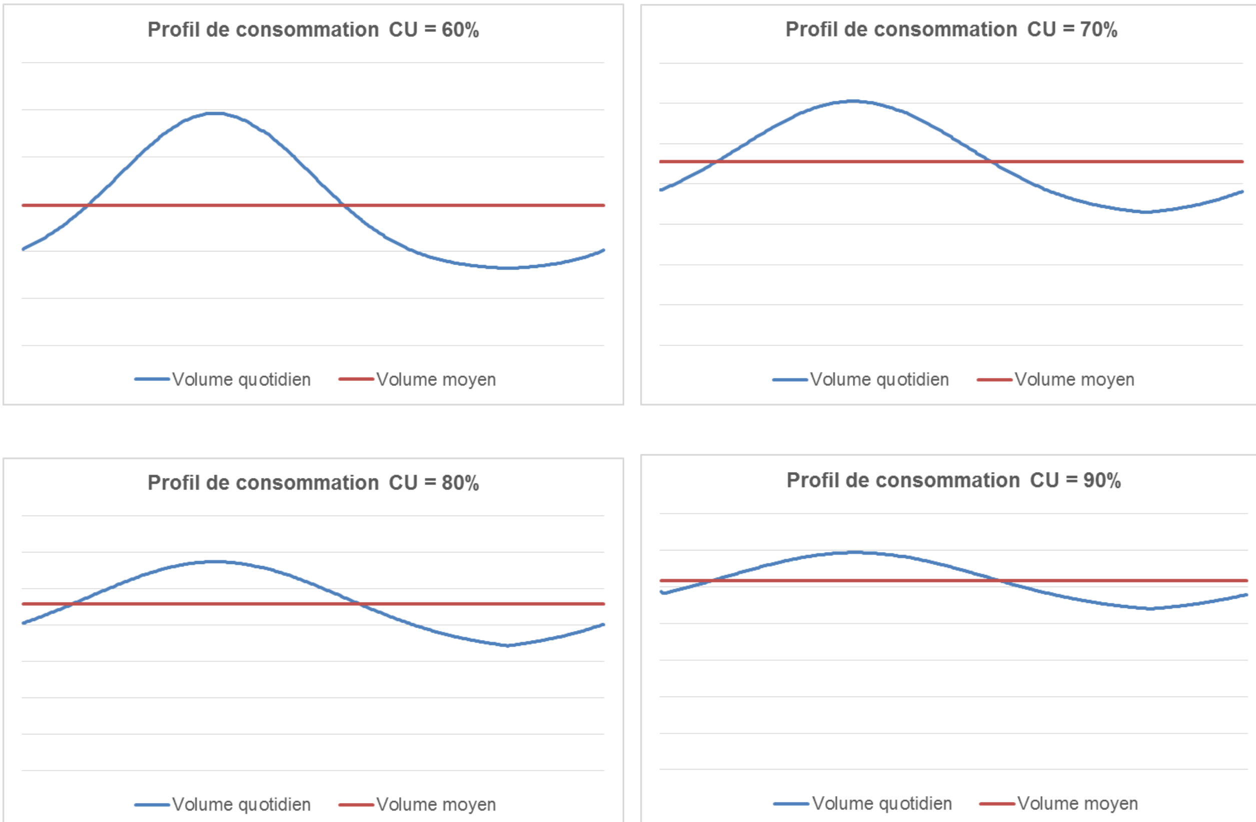
Une méthode de calcul de la journée de pointe qui ne prendrait pas en compte l'impact des conditions climatiques sur la consommation de la clientèle aux tarifs D_3 et D_4 entraînerait un niveau d'approvisionnement qui ne saurait assurer la sécurité d'approvisionnement autant pour répondre à la journée de pointe qu'aux besoins d'un hiver extrême.

3. ANALYSE DES PROFILS DE CONSOMMATION

Le coefficient d'utilisation (CU) est un indicateur de la stabilité de consommation d'un client. Comme indiqué aux définitions des *Conditions de service et Tarif*, le CU est défini comme étant le *« ratio de la consommation journalière moyenne annuelle avec la consommation journalière de pointe ».* Le CU est généralement pris en compte dans l'établissement de structures tarifaires.

Les graphiques suivants présentent des profils de consommation dont le CU est de 60, 70, 80 et 90 %.

Figure 2



Durant la période d'hiver, tous ces profils présentent des volumes de consommation plus élevés que le volume moyen annuel et impliquent donc un apport à la journée de pointe. À volume égal, plus le profil tend à être stable, c.-à-d. le CU augmente, plus l'apport à la pointe diminue. Selon une perspective d'approvisionnement gazier, un profil est qualifié de « stable » lorsque le CU est de 100 % et l'apport à la pointe est alors constant.

Aux services de distribution à débit stable D_3 et D_4, il existe deux catégories de clients : les clients qui retirent du gaz naturel uniquement sous les tarifs D_3 ou D_4 (clients continus purs) et des clients qui retirent du gaz naturel à la fois sous les tarifs D_3 ou D_4 et sous le tarif interruptible D_5. Dans ce dernier cas, les clients sont dits en combinaison tarifaire D_3-D_5 ou D_4-D_5. Les sections suivantes présentent l'analyse des profils de consommation de ces deux catégories de clients.

3.1. Profil de consommation des clients en combinaison tarifaire D_3-D_5 et D_4-D_5

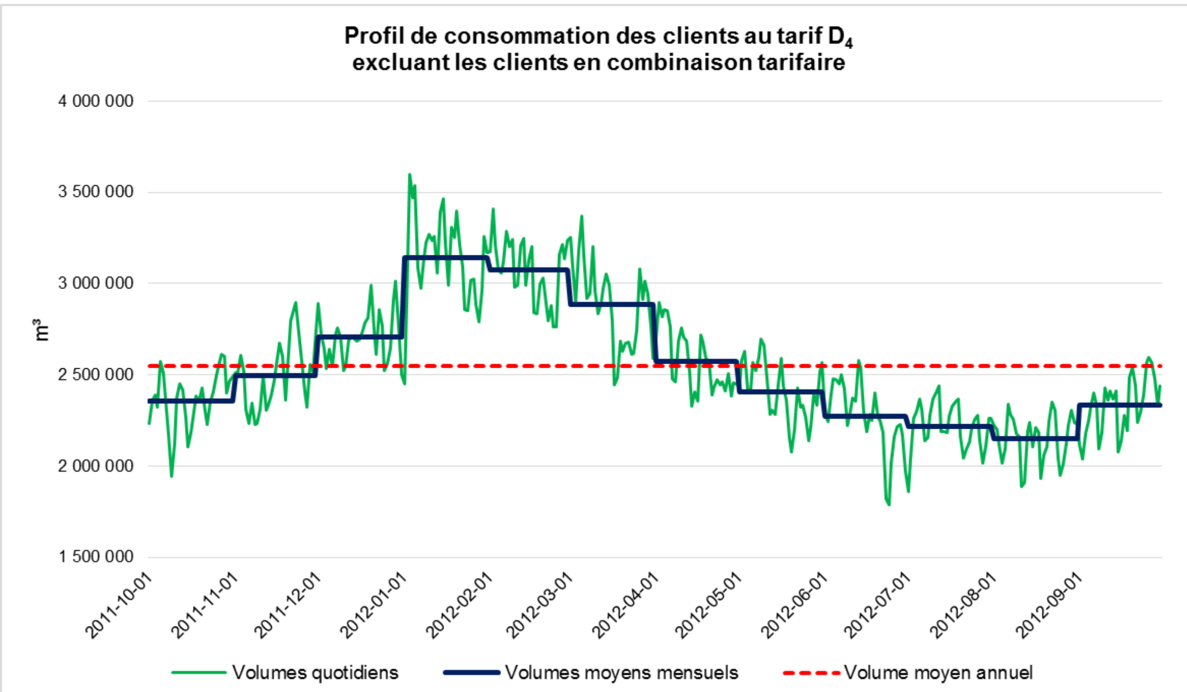
Les volumes retirés par les clients en combinaison tarifaire ne sont pas mesurés distinctement au service à débit stable et au service interruptible. Les volumes quotidiens retirés jusqu'à concurrence du volume souscrit sont attribués au service à débit stable et ceux au-delà du volume souscrit sont attribués au service interruptible.

Ainsi, en journée de pointe, les volumes au service continu des clients en combinaison tarifaire sont établis au total des volumes souscrits et ne sont donc pas influencés par la température. Pour ces clients, les volumes influencés par la température sont au service interruptible.

3.2. Profil de consommation des clients au tarif D_4 sans combinaison tarifaire

Le graphique suivant présente le profil de consommation des clients au tarif D_4, excluant les clients en combinaison tarifaire, pour la période du 1er octobre 2011 au 30 septembre 2012.

Figure 3

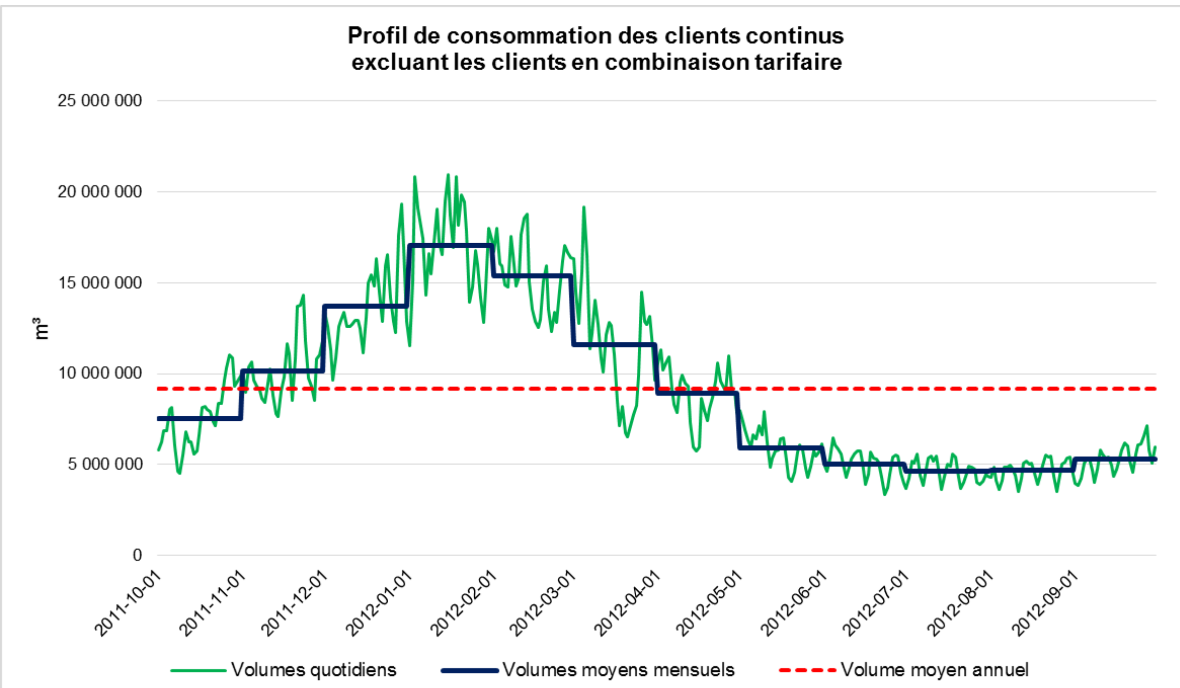


Le graphique montre clairement que la consommation de cette clientèle est influencée par la température. D'ailleurs, des pointes de consommation supérieures aux volumes moyens mensuels sont observées durant la période d'hiver. Le CU de ce profil s'établit à 71 %.

3.3. Profil de consommation des clients continus D_1-D_3-D_4 excluant les clients en combinaison tarifaire

Le profil de consommation de l'ensemble de la clientèle continue, excluant les clients en combinaison tarifaire, présente une pointe de consommation durant la période d'hiver. Pour la période du 1er octobre 2011 au 30 septembre 2012, le CU de ce profil s'établit à 44 %. Le graphique suivant présente le profil de consommation de cette clientèle.

Figure 4



4. OPTIONS ANALYSÉES

Les options analysées par Gaz Métro pour l'établissement de la journée de pointe reflètent la méthode d'évaluation de la journée de pointe de la clientèle au tarif D_1 approuvée par la Régie dans sa décision D-2009-156.

Gaz Métro juge que le modèle considérant une régression en fonction des DJ de la journée et de la journée précédente et un effet croisé du vent est satisfaisant et propose de maintenir son application dans toutes les options analysées.

Toutefois, Gaz Métro propose d'utiliser la période d'évaluation depuis octobre 1970 pour établir les variables climatiques réchauffées définissant la journée de pointe historique ainsi que l'hiver extrême. Comme mentionné à la section 1.3, l'application de la formule d'Ouranos permet de considérer l'impact du réchauffement climatique sur la période analysée et de conserver un maximum d'informations puisque même les années les plus anciennes demeurent pertinentes et ne risquent pas de biaiser la normale. Cette approche vient reproduire la période d'évaluation utilisée dans la méthode de normalisation des revenus de Gaz Métro ainsi que la période d'évaluation utilisée par Hydro-Québec Distribution dans la détermination de sa demande électrique de pointe.

Considérant l'historique des conditions climatiques depuis octobre 1970 réchauffées jusqu'en 2014, la journée de pointe correspondrait à la journée du 3 janvier 1981 et s'établirait à :

	Variables réelles	Variables réchauffées en 2014
DJ_t	45,15	43,66
DJ_{t-1}	34,03	32,55
$DJ_t x V_t$	623,23	602,77

Il est à noter que l'utilisation des données historiques depuis octobre 1970 ne modifie pas l'année de référence de l'hiver extrême. Ainsi, pour la Cause tarifaire 2015, l'hiver extrême demeure l'année 1993-1994, l'hiver 2013-2014 n'étant pas considéré dans la période de référence pour cette cause.

Les sections suivantes présentent les différentes options analysées.

4.1. Régression globale – Clients continus aux tarifs D_1, D_3 et D_4

Pour assurer une coïncidence totale[7] de la demande continue en journée de pointe, cette option consiste à effectuer une régression sur les volumes historiques de l'ensemble de la clientèle continue, incluant la portion continue des clients en combinaison tarifaire.

Les résultats de la régression linéaire sur les consommations observées durant l'hiver 2011-2012 sont les suivants :

[7] Décision D-2013-179, paragraphe 25.

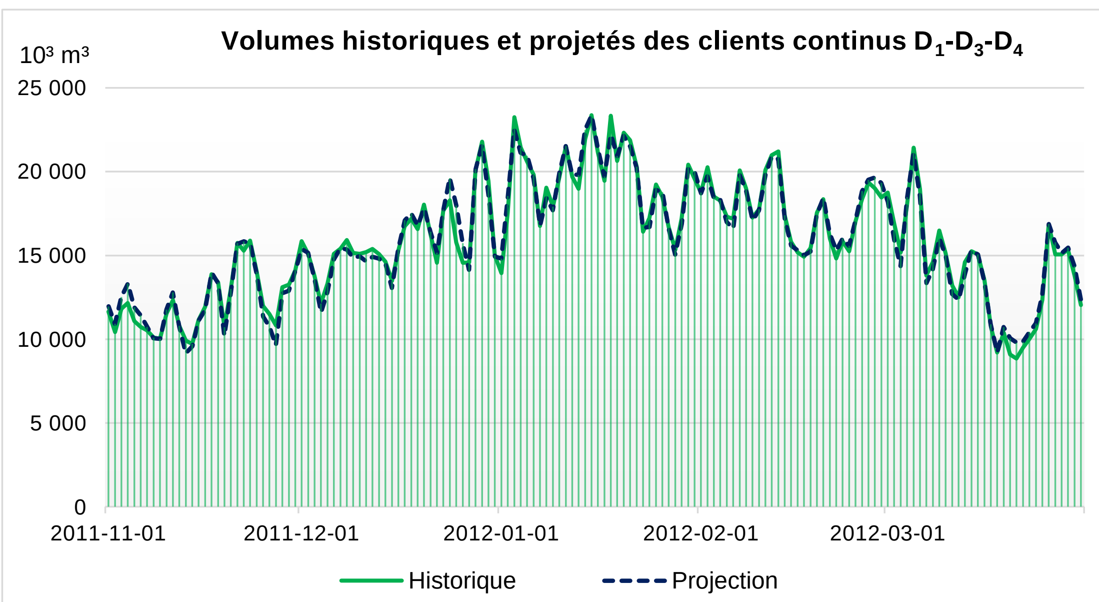
Tableau 14

Clients continus D_1-D_3-D_4

Paramètres	**(10^3m^3)**	**Paramètres**	**(10^3m^3)**	**Paramètres**	**(10^3m^3 /unité)**
Base	**7 161**	Novembre	0	DJ (t)	**329**
		Décembre	377	DJ (t-1)	**91**
Dimanche	623	Janvier	**1 438**	DJ(t) x Vent (t)	**3**
Lundi	1 937	Février	1 143		
Mardi	1 916	Mars	549		
Mercredi	**1 960**			R^2	98,0%
Jeudi	1 913				
Vendredi	1 131				
Samedi	0				
Ferié	-1 023				

Le facteur de corrélation de la régression est de 98,0 %. Le graphique suivant permet de constater la forte corrélation entre les volumes historiques et les volumes projetés selon la régression établie ci-dessus.

Figure 5



L'établissement de la journée de pointe se détaille comme suit :

Tableau 15

	Budget 2014 - Régression globale D_1-D_3-D_4				
		Décembre	Janvier	Février	Mars
	Demande normale projetée (10³m³)				
1	Clients continus D_1-D_3-D_4	581 621	660 681	579 343	542 252
2	Autres	4 548	5 186	4 570	4 295
3	Client biogaz en réseau dédié	2 100	2 700	2 600	2 800
4	Année de régression	2011-2012			
5	Paramètres de régression continus purs (10³m³/unité)	Décembre	Janvier	Février	Mars
6	Base	9 498	10 558	10 263	9 669
7	DJ t	329	329	329	329
8	DJ t-1	91	91	91	91
9	DJ t x V t	3	3	3	3
10	Paramètres journée de pointe				
11	DJ t	43,66			
12	DJ t-1	32,55			
13	DJ t x V t	602,77			
	Calcul de la demande en journée de pointe (10³m³)				
14	Pointe selon formule de régression	28 317	29 377	29 082	28 488
15	Ajustement pour la demande 2014	1,101	1,101	1,101	1,101
16	Pointe clients continus purs et Autres	31 185	32 353	32 028	31 374
17	Volumes souscrits clients en combinaison tarifaire	0	0	0	0
18	Client biogaz en réseau dédié	68	87	93	90
19	Journée de pointe = maximum	31 253	**32 440**	32 121	31 464
20	**Pointe selon méthode actuelle**		**29 995**		
21	Variation		2 445		

Le facteur d’ajustement requis pour ramener la demande estimée par la régression au niveau de la demande prévue au dossier tarifaire est de 1,101, soit une majoration de 10,1% (Tableau 15, l.15).

4.2. Régression globale excluant les clients en combinaison tarifaire

Cette option consiste à effectuer une régression sur les volumes historiques de l’ensemble de la clientèle continue en excluant les volumes au service continu des clients en combinaison tarifaire puisque les consommations de ces derniers ne sont pas influencées par la température.

Les résultats de la régression linéaire sur les consommations observées durant l’hiver 2011-2012 sont les suivants :

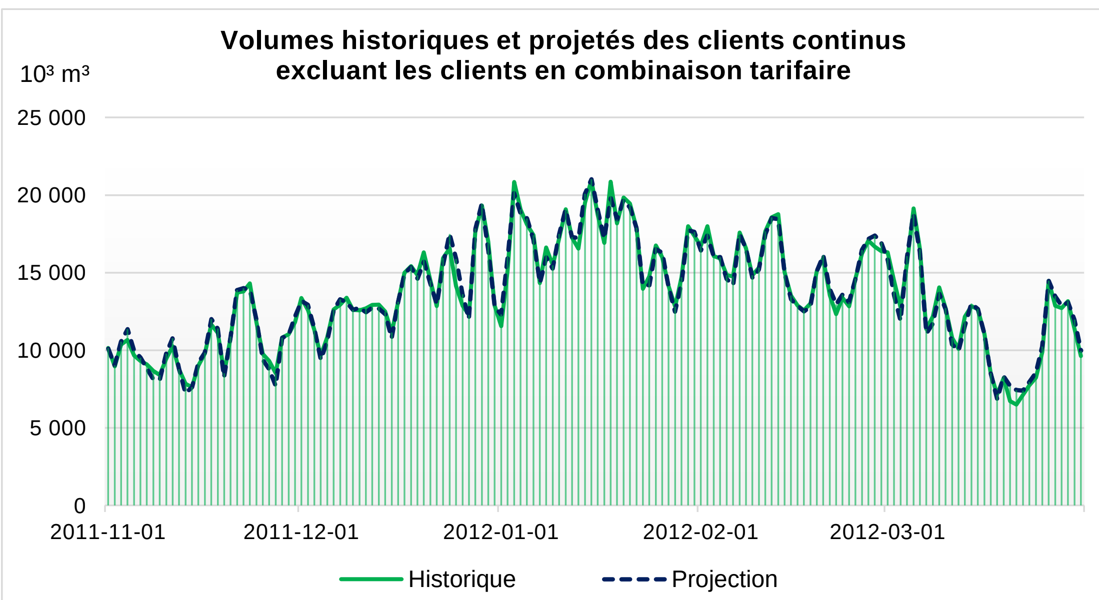
Tableau 16

Clients continus excluant les clients en combinaison tarifaire

Paramètres	**(10³m³)**	**Paramètres**	**(10³m³)**	**Paramètres**	**(10³m³ /unité)**
Base	**5 170**	Novembre	0	DJ (t)	**335**
		Décembre	69	DJ (t-1)	**96**
Dimanche	647	Janvier	**861**	DJ(t) x Vent (t)	**2**
Lundi	1 970	Février	637		
Mardi	1 981	Mars	98		
Mercredi	**2 032**			R^2	98,6%
Jeudi	1 904				
Vendredi	1 099				
Samedi	0				
Ferié	-977				

Le facteur de corrélation de la régression est de 98,6 %. Le graphique suivant permet de constater la forte corrélation entre les volumes historiques et les volumes projetés selon la régression établie ci-dessus.

Figure 6



Pour les clients en combinaison tarifaire, les volumes retirés jusqu'à concurrence du volume souscrit sont attribués au service continu. Toutefois, lors d'une journée d'interruption, ces clients peuvent difficilement limiter leur volume retiré au niveau de leur volume souscrit en service continu. Une marge de manœuvre de 2 % a été prévue à cet effet et est libellée à l'article 16.4.2.6 des *Conditions de Service et Tarif*. Ainsi, l'apport à la pointe de cette clientèle est établi par la somme des volumes souscrits, comme prévus au dossier tarifaire, majorés de 2 %.

L'établissement de la journée de pointe se détaille comme suit :

Tableau 17

	Budget 2014 - Régression globale excluant les clients en combinaison tarifaire				
		Décembre	Janvier	Février	Mars
	Demande normale projetée (10^3m^3)				
1	Clients continus purs	497 324	574 057	500 833	456 191
2	Clients continus en combinaison tarifaire	84 297	86 624	78 510	86 061
3	Autres	4 548	5 186	4 570	4 295
4	Client biogaz en réseau dédié	2 100	2 700	2 600	2 800
5	Année de régression	2011-2012			
6	Paramètres de régression continus purs (10^3m^3/unité)	Décembre	Janvier	Février	Mars
7	Base	7 271	8 063	7 839	7 299
8	DJ t	335	335	335	335
9	DJ t-1	96	96	96	96
10	DJ t x V t	2	2	2	2
11	Paramètres journée de pointe				
12	DJ t	43,66			
13	DJ t-1	32,55			
14	DJ t x V t	602,77			
	Calcul de la demande en journée de pointe (10^3m^3)				
15	Pointe selon formule de régression	26 291	27 083	26 859	26 320
16	Ajustement pour la demande 2014	1,083	1,083	1,083	1,083
17	Pointe clients continus purs et Autres	28 469	29 326	29 083	28 499
18	Volumes souscrits clients en combinaison tarifaire	2 962	2 962	2 962	2 962
19	Client biogaz en réseau dédié	68	87	93	90
20	Journée de pointe = maximum	31 499	**32 375**	32 138	31 552
21	**Pointe selon méthode actuelle**		**29 995**		
22	Variation		2 380		

Le facteur d'ajustement requis pour ramener la demande estimée par la régression au niveau de la demande prévue au dossier tarifaire est de 1,083, soit une majoration de 8,3 % (Tableau 17, l.16).

Cette option présente une coïncidence totale de la pointe. En effet, lors de la journée de pointe, la clientèle interruptible est interrompue et les clients en combinaison tarifaire consommeraient un volume maximal égal à la somme des volumes souscrits majorés de 2 %.

4.3. Régression globale excluant les clients en combinaison tarifaire et les grands clients

Gaz Métro a constaté que le profil de consommation de grands clients aux paliers 4.9 et 4.10 du tarif D_4 influence grandement l’apport à la journée de pointe. En effet, des variations du niveau et/ou du profil de consommation à travers les années peuvent générer des impacts considérables sur les résultats de la régression et sur le niveau du facteur d’ajustement requis pour tenir compte de l’écart entre la prévision de volume de l’année témoin et la consommation réelle de l’année historique.

Ainsi, une régression excluant les volumes des clients en combinaison tarifaire et des clients aux paliers 4.9 et 4.10 qui ne sont pas en combinaison tarifaire a été effectuée sur les volumes de l’hiver 2011-2012. Dans les faits, tous les clients au palier 4.9 sont actuellement en combinaison tarifaire. Ainsi, seuls les deux clients au palier 4.10 ont été exclus de la régression.

Les résultats de la régression sont les suivants :

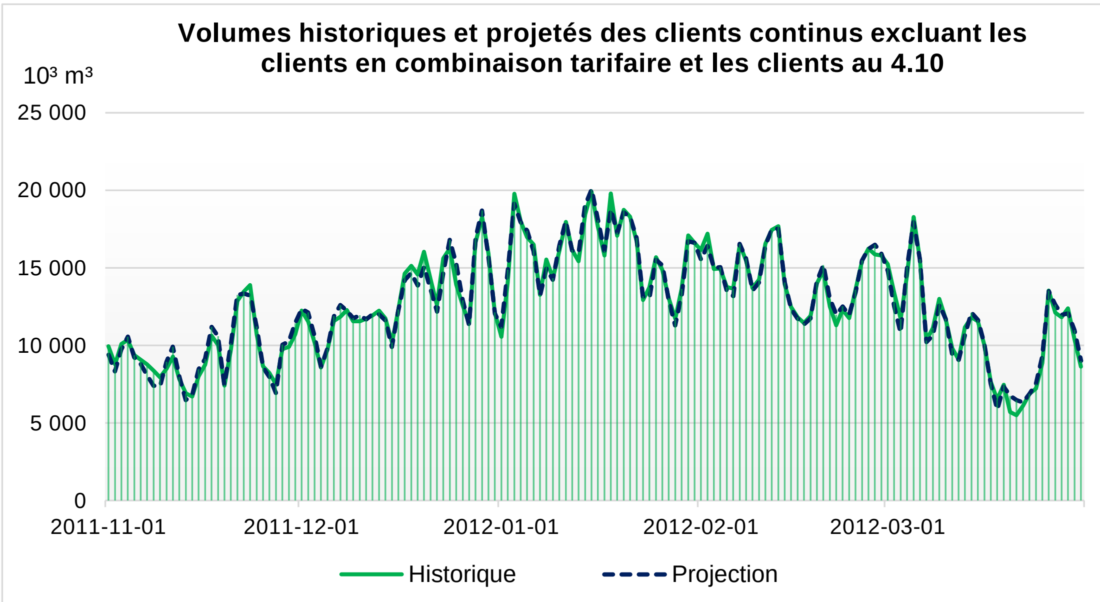
Tableau 18

Clients continus excluant les clients en combinaison tarifaire et les clients au 4.10

Paramètres	**(10^3m^3)**	**Paramètres**	**(10^3m^3)**	**Paramètres**	**(10^3m^3 /unité)**
Base	**4 307**	Novembre	0	DJ (t)	**343**
		Décembre	28	DJ (t-1)	**100**
Dimanche	703	Janvier	**498**	DJ(t) x Vent (t)	**2**
Lundi	2 048	Février	330		
Mardi	2 092	Mars	-111		
Mercredi	**2 140**			R^2	98,3%
Jeudi	1 901				
Vendredi	1 084				
Samedi	0				
Ferié	-963				

Le facteur de corrélation de la régression est de 98,3 %, légèrement inférieur au facteur de la régression précédente. Le graphique suivant permet de constater que cette régression entraîne également une forte corrélation entre les volumes historiques et les volumes projetés.

Figure 7



Comme dans l'option précédente, l'apport à la pointe les clients en combinaison tarifaire est établi par la somme de leurs volumes souscrits prévus au dossier tarifaire majorés de 2 %.

L'importance des volumes des clients sans combinaison tarifaire au palier 4.10 sur l'établissement de la journée de pointe amène Gaz Métro à fixer l'apport à la pointe de chaque client au maximum des volumes retirés historiques observés, ajusté, le cas échéant, pour refléter le profil de consommation projeté au dossier tarifaire.

L'établissement de la journée de pointe se détaille comme suit :

Tableau 19

	Budget 2014 - Régression globale excluant les clients en combinaison tarifaire et les clients au 4.10				
		Décembre	Janvier	Février	Mars
	Demande normale projetée (10^3m^3)				
1	Clients continus purs excluant 4.10	448 296	524 510	455 607	407 577
2	Clients continus en combinaison tarifaire	84 297	86 624	78 510	86 061
3	Clients 4.10	49 028	49 547	45 226	48 614
4	Autres	4 548	5 186	4 570	4 295
5	Client biogaz en réseau dédié	2 100	2 700	2 600	2 800
6	Année de régression	2011-2012			
7	Paramètres de régression continus purs (10^3m^3/unité)	Décembre	Janvier	Février	Mars
8	Base	6 475	6 945	6 777	6 336
9	DJ t	343	343	343	343
10	DJ t-1	100	100	100	100
11	DJ t x V t	2	2	2	2
12	Paramètres journée de pointe				
13	DJ t	43,66			
14	DJ t-1	32,55			
15	DJ t x V t	602,77			
	Calcul de la demande en journée de pointe (10^3m^3)				
16	Pointe selon formule de régression	25 719	26 189	26 021	25 580
17	Ajustement pour la demande 2014	1,038	1,038	1,038	1,038
18	Pointe clients continus purs et Autres	26 708	27 196	27 022	26 563
19	Volumes souscrits clients en combinaison tarifaire	2 962	2 962	2 962	2 962
20	Volumes maximums observés des clients au 4.10	1 922	1 922	1 922	1 922
21	Client biogaz en réseau dédié	68	87	93	90
22	Journée de pointe = maximum	31 660	**32 167**	31 998	31 538
23	**Pointe selon méthode actuelle**		**29 995**		
24	Variation		2 171		

Le facteur d'ajustement requis pour ramener la demande estimée par la régression au niveau de la demande prévue au dossier tarifaire est de 1,038, soit une majoration de 3,8 % (Tableau 19, l.17), légèrement inférieur aux facteurs d'ajustement des deux régressions précédentes.

Cette option ne présente pas une coïncidence totale de la pointe. En effet, les volumes maximums observés des clients au palier 4.10 ne correspondent pas nécessairement aux volumes que ces clients consommeraient lors de la journée de pointe identifiée pour les autres clients.

5. PROPOSITION DE GAZ MÉTRO

Les trois options analysées reposent sur la même méthode d'évaluation de la demande en journée de pointe. Seuls les volumes à la base de l'établissement de la régression sont différents. À l'option 1, la régression tient compte des volumes de l'ensemble de la clientèle continue. À l'option 2, les volumes des clients en combinaison tarifaire ne sont pas pris en compte dans la régression. Finalement, à l'option 3, les volumes des clients en combinaison tarifaire ainsi que ceux des clients aux paliers 4.9 et 4.10 du tarif à débit stable ne sont pas pris en compte dans la régression – pour 2014 uniquement les clients au palier 4.10, ceux au 4.9 étant en combinaison tarifaire.

Le tableau suivant présente un sommaire des résultats de ces trois options.

Tableau 20

	Demande de la journée de pointe (10^3 m^3)	Facteur de correlation	Facteur d'ajustement	Coïncidence de la pointe
Option 1	32 440	98,0%	10,1%	Totale
Option 2	32 375	98,6%	8,3%	Totale
Option 3	32 167	98,3%	3,8%	Partielle

Dans les trois options, les facteurs de corrélation sont du même ordre. Les options 1 et 2 mènent à une coïncidence totale de la pointe. Cependant, Gaz Métro ne retient pas l'option 1 car la régression tient compte des volumes des clients en combinaison tarifaire alors qu'ils ne sont pas influencés par la température.

L'option 3 permet de traiter spécifiquement les grands clients dont les variations de volumes, année après année, ont des impacts considérables sur l'établissement de la demande de pointe. Cette option présente, d'ailleurs, le plus petit facteur d'ajustement, signifiant que la régression représente mieux la clientèle visée. Gaz Métro ne retient toutefois pas cette option car elle ne présente pas une coïncidence totale de la pointe. Cet élément a été identifié par la Régie comme un point important dans l'évaluation de la demande en journée de pointe.

Gaz Métro propose d'établir la demande de la journée de pointe selon l'option 2 (régression globale excluant les clients en combinaison tarifaire). Cette option présente des résultats probants en termes de facteur de corrélation et de coïncidence de la pointe.

CONCLUSION

À la suite de la demande de la Régie, Gaz Métro a effectué différentes analyses afin de revoir en profondeur sa méthode d'évaluation de la demande en journée de pointe.

Elle a initialement consulté un balisage réalisé par Sussex pour Union Gas en avril 2013 et comparé sa méthode d'évaluation de la demande de la journée de pointe à celle des autres distributeurs, incluant une comparaison plus détaillée avec les distributeurs ontariens ayant des conditions climatiques similaires. Cette analyse montre que la méthode de Gaz Métro est élaborée et que les conditions climatiques de la journée de pointe en fonction des DJ historiques depuis 1970 et réchauffés, sont similaires à celles de ses voisins, voire même inférieures considérant le fait que le territoire de Gaz Métro se situe plus au nord.

Des analyses spécifiques de la demande et des approvisionnements observés pour l'hiver 2013-2014 ont été effectuées et viennent confirmer que la consommation de la clientèle aux tarifs D_3 et D_4 est influencée par la température, comme soulevée à la Cause tarifaire 2014. De plus, les approvisionnements détenus par Gaz Métro, établis en fonction d'une méthode de pointe similaire à celle proposée à la section 5, ont permis de répondre à la demande d'un hiver extrême. Quant à la demande continue en journée de pointe, si celle-ci avait été observée en 2013-2014, les approvisionnements auraient été insuffisants.

L'analyse des profils de consommation a permis de cibler une partie des consommations de la clientèle continue qui n'est pas, ou peu, influencée par la température.

Gaz Métro a ensuite analysé trois options qui consistent à appliquer le modèle actuel de régression sur la clientèle continue, mais qui tiennent compte de différentes combinaisons de volumes des clients continus.

En considérant les éléments identifiés par la Régie, soit :

- l'analyse des clients à profil stable;
- les niveaux des coefficients de corrélation des régressions;
- le facteur d'ajustement pour tenir compte de l'écart entre la prévision de volume de l'année témoin et la consommation réelle de l'année historique utilisée en référence dans la régression; et

- la coïncidence totale de la journée de pointe pour l'ensemble de la clientèle,

Gaz Métro demande à la Régie :

1. **d'approuver le maintien de l'application du modèle considérant une régression en fonction des DJ de la journée et de la journée précédente et un effet croisé du vent ;**

2. **d'approuver la méthode proposée d'évaluation de la demande de la journée de pointe qui consiste à effectuer une régression sur les volumes historiques de l'ensemble de la clientèle continue en excluant les volumes au service continu des clients en combinaison tarifaire en fonction du dernier hiver disponible;**

3. **d'approuver l'utilisation de la période d'évaluation depuis octobre 1970 pour établir les variables climatiques réchauffées définissant la journée de pointe historique ainsi que l'hiver extrême ;**

4. **d'approuver l'application d'un facteur d'ajustement à la demande projetée en journée de pointe de la clientèle continue excluant les clients en combinaison tarifaire de façon à refléter la demande projetée de l'année témoin; et**

5. **d'approuver la fixation de la demande en journée de pointe des clients en combinaison tarifaire à la somme des volumes souscrits majorés de 2 %.**

Gaz Métro précise que la méthode d'évaluation de la journée de pointe proposée dans ce document sera utilisée dans le plan d'approvisionnement de la présente cause tarifaire.

ANNEXES

Annexe 1 : Rapport de Sussex Economics Advisors – Union Gas – Gas Supply Planning Review EB-2013-0109 (2013-05-08), Exhibit C, Tab 2

Annexe 2 : R-3837-2013, Gaz Métro-2, Document 1, section 9.1.2, pages 83 à 88

Filed: 2013-05-08
EB-2013-0109
Exhibit C
Tab 2

SUSSEX ECONOMIC ADVISORS

Union Gas

Gas Supply Planning Review

April, 2013

Prepared by

Sussex Economic Advisors, LLC

Executive Summary

Sussex Economic Advisors, LLC ("Sussex") was retained by Union Gas ("Union" or the "Company") to review their gas supply planning practices. Specifically, pursuant to an Ontario Energy Board Decision ("OEB") and Order in EB-2011-0210, Sussex reviewed the following Union gas supply planning activities:

- Guiding Principles
- Design Day Demand Forecast
- Implementation of the Plan
- Contracting/Transportation Path Decision Process

In addition to the above issues outlined by the OEB, Sussex also reviewed the Union approach with respect to extracting value from gas supply assets (i.e., upstream transportation capacity contracts).

The Sussex approach, with respect to this assignment, consisted of on-site meetings with various Union departments involved in the development and implementation of the gas supply plan and associated inputs; a review of gas supply planning documentation (e.g., Excel spreadsheets and SENDOUT model runs) and a benchmarking analysis comprised of over 20 local distribution companies ("LDCs") located in Canada and the U.S.

The following is a summary of our major conclusions and recommendations, which are discussed in detail herein.

Conclusions

- The Union primary gas supply planning principles of reliability and cost are reasonable, similar to other LDCs, and are reflected in the gas supply plan.
- The Union approach regarding design day demand forecasting (i.e., extreme cold weather conditions and a firm customer usage factor per degree day) is appropriate, similar to other LDCs, and reflected in the gas supply plan.
- The design day demand forecasting approach for Union North and Union South is consistent and aligned. Sussex recognizes that the Union North forecasted design day demand becomes a direct input into the gas supply design day plan, while the Union South forecasted design day demand is an input into the storage and transmission

system plan; however, the process used to develop the Union North and Union South design day demand forecast is similar.

- The Union gas supply portfolio for Union North and Union South reflects the circumstances of each area; specifically, Union North is comprised of a non-contiguous service territory with the TransCanada ("TCPL") Mainline providing the physical connections across the service territory. Conversely, Union South is a contiguous service territory with access to significant underground storage, transmission assets, as well as the Dawn Hub. Because of the differing circumstances, Union North relies on the TCPL Mainline services to meet the gas supply planning principles; while Union South uses underground storage and access to various natural gas supply transportation paths to meet the gas supply planning principles. The resultant gas supply portfolios for Union North and Union South are reasonable and appropriately sized.
- The Union approach to decontracting/recontracting is comprised of data gathering, quantitative and qualitative analysis, and documentation. This approach is consistent with the contract evaluation approach used by other LDCs, is similar to the Union Incremental Transportation Contracting Analysis,[1] and is reasonable.
- With respect to whether Union is using the transportation portion of the gas supply portfolio to favor transportation paths in which Union or the parent may have an interest, Sussex understands that Union contracts with St. Clair Pipelines LP (an affiliate) for certain capacity that is used for overall security of supply. Sussex further understands that the St. Clair Pipeline LP agreements (St. Clair Pipeline and Bluewater Pipeline) are the only capacity contracts Union has with an affiliate. Therefore, given the role of St. Clair Pipeline LP in the Union gas supply portfolio (i.e., security of supply) Sussex understands that the Union capacity agreement with St. Clair Pipeline LP has not been subjected to or included in any Union transportation path analysis.
- On the broader issue of whether Union could use the transportation portfolio to favor transportation paths in which Union or the parent may have an interest, Sussex recommends Union utilize the Incremental Transportation Contracting Analysis framework (i.e., description of path, rationale for including path in the portfolio, benefit analysis with a discussion of how the path conforms to the gas supply planning

1 As outlined in the EB-2005-0520 Settlement Agreement, Union utilizes an Incremental Transportation Contracting Analysis for any new or extensions to existing upstream transportation agreements with a term of one year or greater.

principles, and landed cost analysis) augmented by our recommendations for all contracting decisions, regardless of whether that contract decision is for decontracting, recontracting or incremental capacity. This approach would be applied irrespective of the entity owning the upstream pipeline/project, and as a result would provide sufficient analysis and documentation as to why Union pursued a certain strategy regarding a transportation path decision.

- Finally, while there are various alternatives used by LDCs to extract value from gas supply portfolio assets, the current approach utilized by Union leverages the core competencies of the Gas Supply and Storage & Transmission groups, is consistent with other approaches used by LDCs (e.g., asset management arrangements), and is reasonable.

Recommendations

- Regarding the design day demand forecasting process, Sussex recommends:
  - In general, Union should increase the level of documentation across departments with respect to the demand forecasting and gas supply planning processes.
  - The design day demand forecasting team (which is a cross-functional undertaking) should develop an annual review process regarding the weather and consumption data from the prior year; performance of the trend line; and any changes in the process or data, responsibilities/people, events/business conditions that could impact the process/results.
  - Review and evaluate whether different data sets, regarding the design day demand forecast should be analyzed (e.g., multiple winter periods, subsets of multiple winter periods).[2]
  - For Union South, the coldest observed temperature should be used to develop the design day weather standard. This would result in Union North and Union South having a consistent and similar approach regarding design day weather standards. If this recommendation is adopted for Union South, the design day weather standard would be 43.1 degree days rather than the current value of 44 degree days.

[2] It is important to note that Sussex is not recommending a change in the methodology rather Union should have a process in place to annually evaluate different data periods to assess whether a change in methodology should be investigated.

- Regarding the development of the gas supply plan, Sussex recommends:
    - Union should develop a gas supply plan memorandum that includes the following: (i) summary of the current natural gas market situation; (ii) the results of the design day demand forecast with a discussion of the underpinning assumptions; (iii) an overview of the current gas supply portfolio; and (iv) identification of near term portfolio decisions and a description of how the Union strategy for the specific portfolio decision conforms to the gas supply planning principles.
    - The Union gas supply plan should include a summary of major upstream pipeline regulatory filings and/or recent regulatory orders (e.g., RH-003-2011); physical infrastructure projects that will likely impact Union; and implications associated with gas supply basins as a high level discussion of these regulatory and market drivers in the Union gas supply plan will provide market context for Union's stakeholders.
- Regarding Union's contracting practices, Sussex recommends:
    - Union should continue to use known information (e.g., current approved tolls) in the contracting decision process to reduce the subjectivity of the analysis; however, Union should develop scenarios around the base case.
    - Union should provide documentation supporting the choice of alternatives analyzed and not analyzed (e.g., Path A was not reviewed as there is no capacity available on that pipeline). The documentation requirements are similar to the practices described in the Union Incremental Transportation Contracting Analysis as augmented by the Sussex recommendations.
    - Review and evaluate whether the SENDOUT model could be used to augment the landed cost analysis. Although the landed cost analysis is a straightforward analysis for pipeline options that will be dispatched at 100% load factor; the exercise of modeling contract options in SENDOUT may, in of itself, be a useful process, as the attributes of the path need to be understood in order to be modeled.
    - The Sussex recommendations with respect to contracting decisions apply to all Union contract/transportation path decisions regardless of the entity owning the upstream pipeline/project.
    - Union should establish a process to review the cost of service, rate level, and rate design for St. Clair Pipeline and Bluewater Pipeline. Specifically, every three

years or pursuant to a significant National Energy Board ("NEB") filing by either St. Clair Pipeline or Bluewater Pipeline, Union should undertake a review of the current pipeline situation and, depending on the outcome of that review, initiate negotiations with the pipeline or submit a complaint to the NEB.

Introduction

Sussex Economic Advisors LLC ("Sussex")[3] was retained by Union Gas ("Union" or the "Company") to review their Gas Supply Planning functions pursuant to an Ontario Energy Board ("OEB") Decision and Order in EB-2011-0210; and to review Union's approach with respect to the management of gas supply transportation/capacity contracts.

Specifically, in the EB-2011-0210 Decision and Order the OEB provided the following direction to the Company: "Accordingly, the Board orders Union, prior to its next rates proceeding (cost of service or incentive regulation), to file with the Board an expert, independent review of its gas supply plan, its gas supply planning process and gas supply planning methodology."[4] In addition, the OEB outlined eleven specific elements[5] that should be included in the independent review; eight of those elements[6] are addressed by Sussex herein.

This report is organized and presented in the same sequence as the typical gas supply planning process. In general, an LDC gas supply planning and portfolio management process follows a logical sequence of activities, primarily: (i) development and communication of gas supply planning objectives and principles; (ii) forecast of natural gas demand for certain time periods including peak demand under design weather conditions; (iii) plan and implement a gas supply strategy (e.g., level and type of resources to meet the forecasted demand) while adhering to the stated gas supply planning objectives and principles; and (iv) on-going management of the gas supply portfolio assets.

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3 Sussex Economic Advisors, LLC is a management and economic advisory firm providing consulting services to regulated industries such as natural gas, electricity, water, and thermal energy distribution. The firm's Partners have held senior positions in utility companies, competitive energy suppliers, management consulting firms and business focused academic institutions. Our Consulting Staff, Executive Advisors, and Affiliated Experts have substantial experience and training in matters relating to regulatory strategy and policy development, natural gas infrastructure development and open season processes, gas supply planning and capacity portfolio optimizing, energy market analysis and assessments, financial and economic analysis, rate proceedings and regulatory compliance, due diligence and valuation, and management reviews and audits. Sussex has a substantial list of clients including natural gas distribution companies, electric utilities, combination utilities, electric transmission providers, natural gas pipeline companies, municipal utilities, and non-regulated energy market participants. Summary biographies for the Sussex project team assigned to the Union gas supply planning project are provided in Appendix A.

4 Ontario Energy Board, EB-2011-0210 Decision and Order, P. 40

5 Ibid, P. 41

6 The remaining elements are addressed in a separate report issued by another consulting firm.

The following chart lists the primary LDC gas supply planning activities and identifies the section where Sussex addresses certain of the elements outlined by the OEB in the EB-2011-0210 Decision and Order:

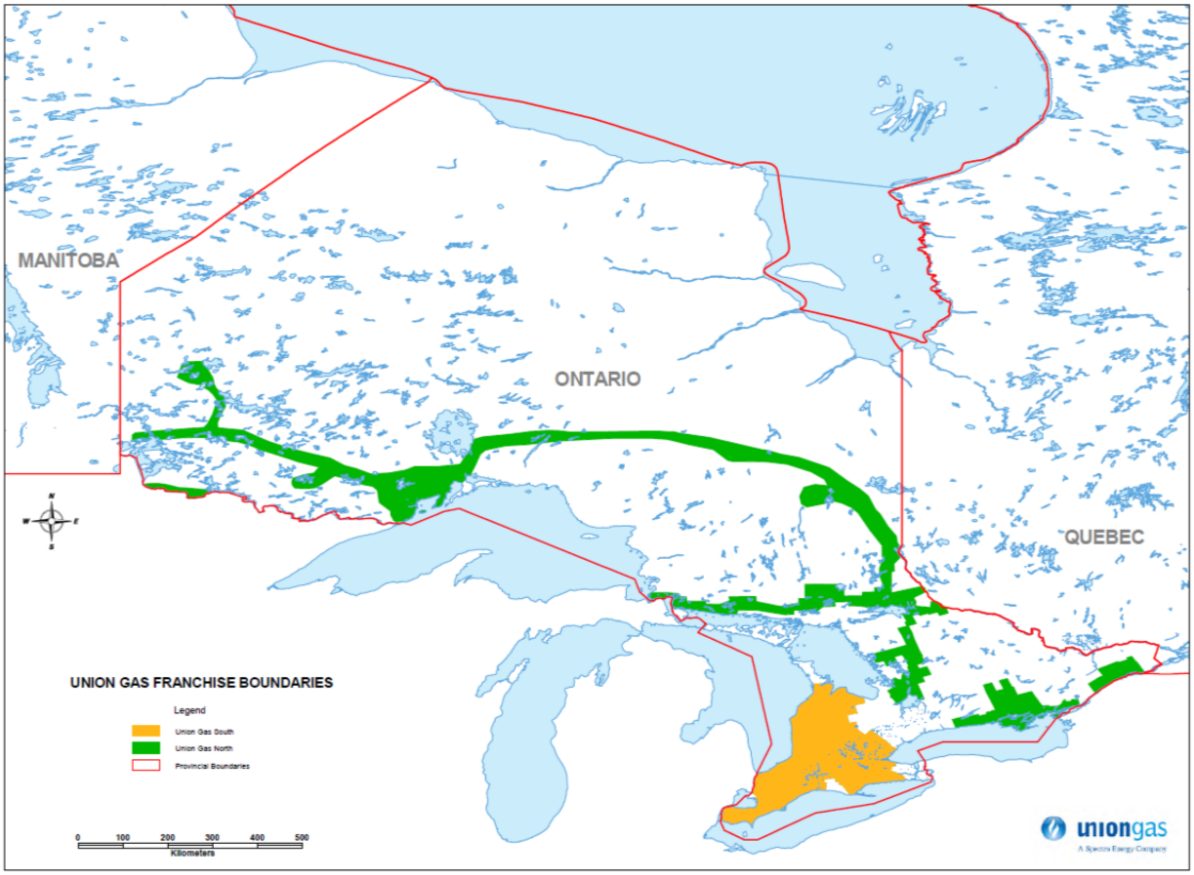
Gas Supply Planning Activity	EB-2011-0210 Report Elements
Develop Gas Supply Planning Principles	1. Verify that Union's gas supply planning process, methodology, and plan reflects appropriate planning principles, including a reference to cost.
Design Day Demand Forecast	3. Determine whether Union's differing peak-day methodologies in the North and South Delivery Areas are appropriate, and if not, recommend alternative approaches. 4. Recommend whether the two approaches should be aligned. 5. Compare the methodology of determining the peak design day, based on the coldest day in the last 50 years, with other heat-sensitive distributors in North America.
Develop Gas Supply Plan	2. Determine if the planning principles are objectively applied and result in a gas supply plan that is "right sized". 6. Determine whether the peak day in the North and South Delivery Areas are appropriately/consistently reflected in the gas supply plan, and if not, recommend remedial action.
On-going Management	7. Determine whether Union is conducting sufficient due diligence with respect to the cost benefit analysis associated with decontracting a particular gas transportation route and recontracting on an alternative route, and recommend remedial action, if required. 8. Determine whether Union is using the transportation portion of the gas supply portfolio to favor the transportation paths of entities in which Union or its parent has (or will have in the future) an economic interest, and recommend remedial action, if required.

Prior to the evaluation of the Union gas supply planning process, the report includes a brief overview of the Company and certain Union gas supply planning geographical areas to provide necessary background information, context, and perspective. In addition, the report briefly outlines our approach and analysis regarding the Union gas supply planning process.

Union Gas Overview

Union provides natural gas service to almost 1.4 million customers in over 400 communities across northern, southwestern and eastern Ontario. In addition, Union provides third party storage and transmission service to a variety of customers located in Ontario, Quebec, the U.S. Northeast and other geographic locations. The Union storage, transmission and distribution network has an annual throughput of about 1,300 PJ of which approximately 500 PJ is distributed within the Union service territory. Natural gas consumption in the Union service territory has been growing at approximately 1% per year and the customer base is predominantly residential and small commercial customers (i.e., end users that do not have alternative fuel capability and the associated consumption is very weather sensitive).

From a gas supply planning perspective, the Union service territory has two distinct geographic regions, Union North and Union South. Union North comprises the Union service territory from the Manitoba border running east and south through Ontario and includes the Cornwall region just east of the Greater Toronto Area ("GTA"), while Union South consists of the region east of Windsor in southwest Ontario running northeast to London and including the area just west of the GTA and down to the Hamilton Region. Union South represents approximately 75% of the total number of Union distribution customers and is experiencing higher growth than Union North. The following map depicts the general geographical location of Union North and Union South:



As illustrated by the above map, Union North is a geographically dispersed non-contiguous service area where the TransCanada ("TCPL") Mainline provides the sole feed of natural gas and physically connects the various service regions. Conversely, the Union South service territory is contiguous and the Company has a significant asset position in this region including on-system underground storage, transmission infrastructure and direct access to the Dawn Natural Gas Trading Hub ("Dawn Hub"). As discussed in more detail herein, the Union North and Union South distinctions (e.g., contiguous v. non-contiguous service territories and the availability of Union gas supply assets) frame the gas supply planning process for the Company.

Sussex Project Approach

To evaluate the Union gas supply planning process, Sussex utilized various data gathering approaches including:

- On-site meetings with representatives from applicable Union departments[7] involved in: (i) the preparation of the design day demand forecast; (ii) the development of the gas supply plan; and (iii) the implementation and management of the gas supply plan.
- Reviewing various Union gas supply planning documents, spreadsheets, SENDOUT model runs, and other relevant material (e.g., EB-2011-0210 submissions and transcripts).
- Conducting an LDC benchmarking analysis, which consisted of a review of certain Canadian and U.S. LDC gas supply plan materials.

In addition to our research and analysis the Sussex observations, conclusions and recommendations regarding the Union gas supply planning process are also based on the collective gas supply planning experience and judgment of the Sussex project team.

As discussed above, the Sussex analysis regarding the Union gas supply plan is organized in a similar manner to how an LDC would generally develop a gas supply plan and manage the resultant portfolio. Specifically, an LDC gas supply plan and portfolio management process follows a logical sequence of steps and is comprised of four major activities:

1. Develop and communicate the gas supply planning objectives and principles.
2. Prepare a design day demand forecast, which guides the level of resource requirements.
3. Develop the gas supply plan within the stated objective and principles.
4. On-going management of the gas supply portfolio.

While these four activities are comprised of various tasks and analyses, they are generally representative of the gas supply planning approach utilized by LDCs. However, the individual LDC gas supply plan will reflect the unique circumstances and situation of that LDC. It is important to note that as market circumstances and regulatory requirements change the LDC approach regarding the four major gas supply planning activities would also change.

[7] Sussex met with several Union departments and areas including: Gas Supply Acquisitions, Gas Supply Planning, Transportation Acquisition, Capacity Management & Utilization, Storage & Transportation Sales, Gas Control, Storage Planning, Distribution Planning, System Planning, Finance, and Regulatory Affairs.

Gas Supply Plan Review – Principles

The first activity in a gas supply planning process is to develop and communicate the gas supply plan objectives and principles. These objectives and principles provide the framework and structure for the remaining three activities (i.e., design day demand forecast, gas supply portfolio development, and management of the gas supply plan and associated resources). As part of our review of the Union gas supply planning principles, Sussex addresses the first element from the OEB Decision and Order in EB-2011-0210, specifically:

- Verify that Union's gas supply planning process, methodology and plan reflects appropriate planning principles, including a reference to cost.

The Sussex analysis regarding the first gas supply planning activity (i.e., principles and objectives) is comprised of three steps: (i) document the current Union gas supply planning principles; (ii) evaluate the Union gas supply plan principles; and (iii) compare the Union gas supply principles to other LDCs.

In terms of the first step (i.e., documentation), the Union gas supply planning principles were defined in EB-2011-0210 as follows: "the Gas Supply Planning Process is guided by a set of principles that are intended to ensure that customers receive secure, diverse gas supply at prudently incurred cost. These principles are:

1. Ensure secure and reliable gas supply to Union's service territory;
2. Minimize risk by diversifying contract terms, supply basins and upstream pipelines;
3. Encourage new sources of supply as well as new infrastructure to Union's service territory;
4. Meet planned peak-day and seasonal gas delivery requirements; and
5. Deliver gas to various receipt points on Union's system to maintain system integrity.[8]

In addition, the Union Gas Supply planning principles were further discussed in the EB-2011-0210 proceeding. Specifically, Union provided the following context regarding gas supply planning principles: "Gas Supply is guided by a number of key principles. These principles ensure that Union's customers receive a secure and reliable gas supply at a prudently and

8 EB-2011-0210, Exhibit D1, Tab 1, P. 2 of 16.

reasonably incurred cost. These long-standing principles are filed in our current evidence…and the OEB has actually endorsed these in some of those past proceedings."[9]

Although Union lists five gas supply planning principles, the discussion during the EB-2011-0210 proceeding narrows the focus of the principles to the major drivers of an LDC portfolio (i.e., reliability and cost). The remaining Union gas supply planning principles provide guidance on how to achieve reliability from a demand perspective (e.g., meet the design day demand and support system integrity through gas supply deliveries); and from a gas supply perspective (e.g., diversity of gas supply basins and pipeline delivery paths, and encouraging new sources of gas supply/infrastructure).

The reliability of service to firm customers, who are high priority end users (e.g., home heating residential customers or small to medium commercial customers such as hospitals and private businesses), is the primary objective of an LDC's design day gas supply portfolio. This primary objective of reliable service under extreme cold weather conditions is balanced with the cost of the gas supply portfolio needed to provide that service. LDCs typically balance the objectives of reliability and reasonable cost by developing a diversified and flexible asset portfolio that can respond to not only on-system demand fluctuations but also upstream gas supply/capacity issues or opportunities. Although the concept of gas supply diversity can have different meanings and be accomplished using various approaches, the development of shale gas basins, particularly in the market area, has placed an added emphasis on portfolio diversity/flexibility in the furtherance of the primary gas supply planning objectives (i.e., reliability and reasonable cost).

Regarding the second step (i.e., evaluate the Union gas supply planning principles), the Union gas supply planning principles recognize not only the need for reliable service (i.e., provide service during extreme cold weather conditions), which is of particular importance given Union's customer segment profile (i.e., residential and small commercial customers), but also how to achieve the stated goal of reliability at a reasonable cost (i.e., through diversification of delivery paths and sources, contract for a variety of pipeline services, staggered contract termination dates, and meeting the supply requirements[10] of the geographically diverse Union service

9 OEB, EB-2011-0210 Hearing Transcripts, July 13, 2012, Volume 3, P. 6-7.

10 The gas supply requirements of the diverse Union system include providing sufficient pipeline capacity and supply to support on-system demand and pressure needs.

territory). In addition, the Union gas supply planning principles recognize the importance of new natural gas supply sources and infrastructure to the Union service area as the continued viability of the Dawn Hub and the utilization of the Union storage and transmission assets provide benefits to the Union distribution customers as well as the broader market that utilizes those resources.

The third step in the Sussex analysis of the Union gas supply planning principles was to review the gas supply planning principles of other LDCs. Although gas supply planning principles will likely reflect the circumstances of the individual LDC, the following excerpts from certain LDC planning documents provide insight to LDC gas supply planning principles:

- "The NSTAR Gas resource planning process is designed to ensure a reliable energy supply for its customers with a minimum impact on the environment and at the lowest cost taking into consideration important non-price factors such as reliability, flexibility and diversity."[11]
- "The Company's forecast methodology supports its supply planning goals of ensuring that: (1) its resource portfolio maintains sufficient supply deliverability to meet customer requirements on the coldest planning day ("design day"); and (2) it maintains sufficient supplies under contract and in storage (underground storage, LNG and propane) to meet customers' requirements over the coldest planning year ("design year")."[12]
- "Cascade's resource planning continues to focus on ensuring that the Company can meet the needs of our firm gas sales customers in a way that minimizes costs over the long term…Integrated Resource Plan provides the strategic direction guiding the Company's long-term resource acquisition process."[13]
- "Pursuit of a best-cost portfolio allows CMA to provide its customers with reliable service at a reasonable cost. The Company's overall portfolio objective is supported by a number of specific resource planning objectives, which are summarized as follows: (1) reduce portfolio costs; (2) maintain portfolio security/reliability (which includes enhancing diversity across pipelines and supply basins); (3) provide contract flexibility; and (4) acquire viable resources."[14]

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[11] NSTAR Gas Company, 2012 Forecast and Supply Plan filed February 10, 2012, P. 7.

[12] Long-Range Resource and Requirements Plan of Boston Gas Company and Colonial Gas Company for the forecast period 2012/13 to 2013/17 filed February 21, 2013, P. 6.

[13] Cascade Natural Gas Corporation, 2012 Integrated Resource Plan filed December 14, 2012, PP. 5 and 9.

[14] Columbia Gas of Massachusetts, 2011 Forecast and Supply Plan filed September 19, 2011, P. 59.

- "In its GCR plan, the Company takes into consideration the importance of taking actions to assure that our customers receive reliable and reasonably priced natural gas supplies for their needs. The Company utilizes a consistent planning methodology with defined risk parameters to assure customers service is not unreasonably jeopardized."[15]

As illustrated by the gas supply planning objectives and principles of the various LDCs reviewed, the Union gas supply planning principles address similar themes (i.e., reliability and cost); outline approaches to achieve these objectives (e.g., gas supply and pipeline diversity, and support new sources of supply and infrastructure); and, based on the experience and judgment of the Sussex project team, are reasonable.

[15] Consumers Energy Company, Gas Cost Recovery Plan, Direct Testimony of Michael A. McKimmy filed December 27, 2012, P. 3.

Gas Supply Plan Review – Design Day

Once the gas supply planning principles have been established, the next activity in the LDC gas supply planning process is the development of the design day demand forecast for firm customers. As part of the Union design day demand forecast review, Sussex will address Elements three, four and five from the OEB Decision and Order in EB-2011-0210, specifically:

- Determine if Union's differing peak-day methodologies in the North and South Delivery Areas are appropriate, and if not, recommend alternative approaches.
- Recommend whether the two approaches should be aligned.
- Compare the methodology of determining the peak design day, based on the coldest day in the last 50 years, with other heat-sensitive distributors in North America.

The Sussex analysis, with respect to the process utilized by Union to forecast design day demand, consists of five steps: (i) general definition, purpose and approach regarding LDC design day forecasts; (ii) summary of the current approach utilized by Union to forecast design day demand for Union North and Union South; (iii) benchmark the Union design day demand forecast process to the design day demand forecasting process used by other LDCs; (iv) Sussex observations and conclusions regarding the appropriateness of the Union design day demand forecasting process and address the issue of Union North and Union South forecast alignment; and (v) Sussex process recommendations.

With respect to the first step (i.e., general definition, purpose and approach regarding LDC design day demand forecasts), Sussex provides a brief overview of the role and importance of design day demand forecasting in the development of the LDC gas supply portfolio followed by a summary of the components of an LDC design day demand forecast.

In general, an LDC develops a gas supply portfolio to meet design day demand, which is the forecasted demand for firm customers during an extreme cold weather day. The following representative excerpts from other LDC planning documents with respect to design day demand not only provide similar definitions of design/peak day demand but also underline the importance of design/peak day demand in the LDC's gas supply/infrastructure plan:

- "Peak demand, or the maximum gas that our customers require at a single point in time, drives infrastructure investment because we must build to that demand even if it is a relatively infrequent occurrence to ensure reliable gas service when it is most needed."[16]

- "The purpose of a design day standard is to establish the amount of system-wide throughput (interstate pipeline and underground-storage capacity plus local supplemental capacity) that is required to maintain the integrity of the distribution system."[17]
- "[Design day demand is] the greatest total natural gas demand forecasted in a 24-hour period used as a basis for planning peak capacity requirements."[18]
- "The primary objective of the design peak day forecast is to ensure sufficient supply under extreme and potentially dangerously cold conditions."[19]
- "Gas system design criteria are used to size pipeline, storage, and contractual commitments to maintain gas system reliability. Standard practice in the gas utility industry is to correlate peak day demand with certain operating conditions, most notably ambient temperature."[20]

There are generally two main drivers regarding an LDC design day demand forecast: (i) the weather standard (i.e., what is the expected degree day that will be utilized in the design day demand forecast); and (ii) the calculated firm customer use per degree day factor. The LDC design day demand forecast is the result of applying the calculated firm customer use per degree day factor to the design day weather standard resulting in an estimate of firm customer consumption under extreme cold weather conditions. The forecast of design day demand is of particular importance to LDCs that have a high concentration of residential and small commercial customers that rely on the LDC for heating requirements as these segments will have significant usage under extreme cold weather conditions and no alternative fuel capability.

The second step in the Sussex analysis was to document the current approach utilized by Union to forecast the design day demand for Union North and Union South.

16 Consolidated Edison, Gas Long Range Plan 2010-2030, December 2010, P. 33.
17 Long-Range Resource and Requirements Plan of Boston Gas Company and Colonial Gas Company for the forecast period 2012/13 to 2013/17 filed February 21, 2013, P. 25.
18 Cascade Natural Gas Corporation, 2012 Integrated Resource Plan filed December 14, 2012, P. 148.
19 Consumers Energy Company, Gas Cost Recovery Plan, Direct Testimony of Jonathon J. Guscinski filed December 27, 2012, P. 3.
20 Enbridge Gas Distribution Rate Application, EB-2011-0354, Exhibit D2, Tab 4, Schedule 1, P.1.

Union North – Design Day Demand Forecast Process

The Union approach to forecasting design day demand for Union North is similar to the general LDC design day forecasting approach outlined above (i.e., develop a design day weather standard and a calculated firm customer use per degree day factor). In terms of the design day weather standard for Union North, the Company utilizes a coldest observed methodology (i.e., the design day weather standard is the actual coldest temperature observed over a period of time). Specifically, for the development of the design day demand requirements for the gas supply plan, the thirteen Union North temperature zones used by the Union Distribution Planning group are aggregated into six gas supply planning areas. The following chart illustrates the mapping of the thirteen temperature zones into the six gas supply planning areas (when multiple temperature zones are mapped into one gas supply planning area, Sussex has underlined which temperature zone weather is utilized for gas supply planning purposes):

Distribution Planning Temperature Zone		Gas Supply Planning Areas
Fort Frances	→	Manitoba Delivery Area
Kenora <u>ThunderBay</u>	→	Western Delivery Area
Kapuskasing Timmins Earlton <u>Sudbury</u> NorthBay	→	Northern Delivery Area
Sault Ste. Marie	→	Sault Ste. Marie Delivery Area
Muskoka/Gravenhurst	→	North Central Delivery Area
Trenton <u>Kingston</u> Cornwall	→	Eastern Delivery Area

As shown by the above chart, there are certain gas supply planning areas that are comprised of one temperature zone (e.g., the Manitoba, Sault Ste. Marie, and North Central Delivery Areas); and there are other gas supply planning areas that are comprised of several temperature zones (e.g., the Western, Northern and Eastern Delivery Areas).

For each of the six gas supply planning areas and the associated temperature zone (e.g., Western Delivery Area and Thunder Bay temperature zone), Union uses the coldest observed temperature in that area/zone as the design day weather standard. The following table summarizes the design day weather standard by area/zone and to provide context Sussex has included other extreme cold temperature observations for each area/zone:

HIGHEST DAILY DEGREE DAYS

	THUNDER BAY		FORT FRANCES		S.S. MARIE		MUSKOKA		SUDBURY		KINGSTON	
Temperature Zone	3		1		8		10		7		12	
Gas Supply Zone	WDA		MDA		SSMDA		NCDA		NDA		EDA	
Design Day	1/29/1951	51.6	2/1/1996	54.7	1/15/1994	48.2	1/15/1994	49.0	1/3/1981	51.9	1/3/1981	47.1
	2/1/1996	51.6										
# Within 2 Degree Days	5		2		3		7		3		2	
	1/16/2005	51.0	1/18/1994	53.5	1/3/1981	47.6	1/20/1942	48.9	1/15/1994	51.8	1/9/1947	45.5
	1/9/1982	51.0	1/16/2005	52.8	2/1/1962	47.2	1/23/1976	48.3	1/8/1968	50.9	1/9/1968	45.5
	1/19/1985	50.7			2/17/1979	46.6	2/15/1943	48.1	1/18/1982	50.3		
	1/4/1968	50.1					1/3/1981	48.0				
	1/14/1972	50.0					2/11/1979	47.7				
							1/8/1968	47.5				
							1/18/1997	47.5				

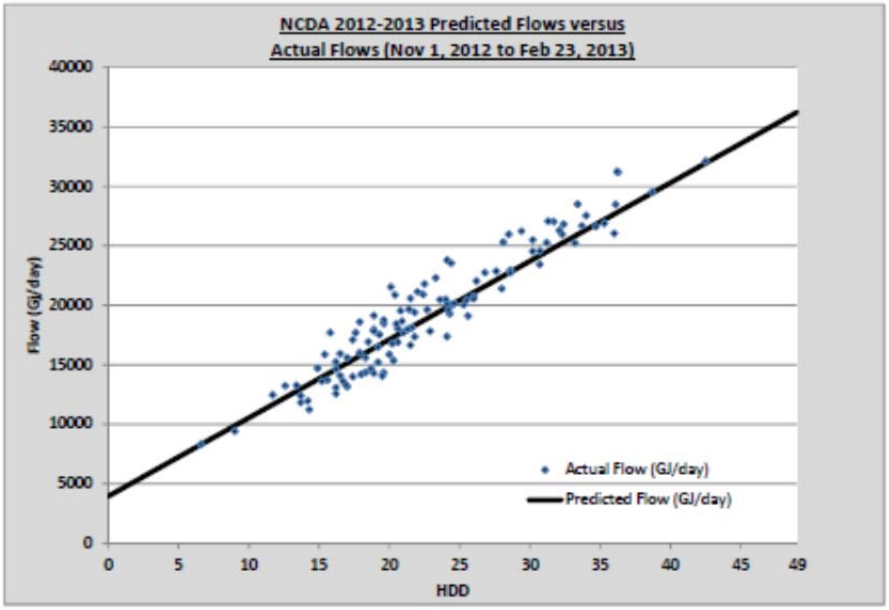
Source: Union Gas

As indicated by the above table, each gas supply planning area has observations that are within two degree days of the coldest observed temperature/degree day indicating that the coldest observed temperature/degree day is not an outlier relative to the data set.

The second component of the Union North design day demand forecast is the calculation of the firm customer use per degree day factor.[21] Specifically, the Company develops a trend line using the daily firm customer consumption from the prior winter and the associated daily degree day data. Stated differently, for each of the six gas supply planning areas Union calculates daily firm customer demand for the prior winter period (interruptible and T-service consumption and weekend/holiday data are removed from the series) and, in conjunction with daily degree day data, a trend line is developed.

Next, Union extrapolates the calculated trend line to the coldest observed temperature resulting in the estimated design day demand for each gas supply planning area. Please find below an illustrative example of the degree day data and trend line calculation developed by Union for the North Central Delivery Area ("NCDA"):

[21] Please note that the calculated firm customer use per degree day factor is for certain customer segments (e.g., general service) while for other customers Union may use a contracted amount.



Based on the design day weather standard of 49 degree days for the NCDA, the expected design day demand is just under 40 TJ.

Finally, the design day demand is increased by the winter season growth factor developed by the Union Demand Forecasting group. By way of example, if the design day demand estimate for the NCDA is 40 TJ and the Demand Forecasting group is projecting a 1% winter season growth factor the forecasted design day demand for the NCDA is 40.4 TJ.

The following table provides the Union 2012/2013 design day demand forecast[22] for the gas supply zones in Union North:

Supply Zone	**TJ/Day**
Manitoba Delivery Area ("MDA")	14
Western Delivery Area ("WDA")	85
Northern Delivery Area ("NDA")	284
Sault STE. Marie Delivery Area ("SSMDA")	115
North Central Delivery Area ("NCDA")	40
Eastern Delivery Area ("EDA")	251
Total	789

22 The design day demand forecast includes T-service firm contract demand, Bundled Firm Service demand, and T-service storage redelivery demands.

As illustrated by the above table, the projected design day demand for Union North is approximately 789 TJ, with the NDA and EDA gas supply zones representing almost 70% of the projected Union North design day demand.

Union South – Design Day Demand Forecast Process

The Union approach to forecasting design day demand for Union South is similar to not only the general LDC approach but also to the Company approach utilized for Union North. Specifically, for Union South the Company utilizes a coldest observed approach as the design day weather standard and a calculated firm customer use per degree day factor.

In terms of the design day weather standard, Union currently uses weather information for the London Airport as the temperature data for Union South. The following table is a summary of the coldest observed temperatures at the London Airport from 1953 to 2013:

Date	**Degree Day**
10-Jan-82	43.1
18-Jan-94	42.8
19-Jan-94	42.6
20-Jan-85	42.1
15-Jan-72	41.4

Although the coldest observed weather is 43.1 degree days, Union utilizes a 44 degree day for the design day weather standard for Union South. While the documentation associated with the 44 degree day is not informative regarding its relationship to the coldest observed temperature, it is our understanding that the 44 degree day was established based on a review of the coldest temperatures observed. Similar to Union North, there are several degree day observations within one or two degree days of the coldest observed (i.e., the 43.1 degree day) indicating that the coldest observed temperature is not an outlier relative to the overall data series.

The next component of the Union South design day demand forecast is the development of the trend line (i.e., the daily firm customer load relative to daily degree days).[23] Similar to Union North, the Company collects the daily consumption from the prior winter; removes interruptible load and holiday/weekend observations; and, in conjunction with the daily degree day observations calculates a trend line. The trend line is then extrapolated to the design day weather standard and the design day demand forecast is estimated. Finally, the design day demand forecast is increased based on the Union South growth forecast developed by the Demand Forecasting group.

The following table is a summary of the Union design day demand forecast for Union South:[24]

Supply Zone	**TJ/Day**
Dawn to Parkway (D-P) System (Incl. D-P fuel)	1,662
Dawn to Sarnia Industrial System	417
Dawn to Panhandle System	439
Dawn to Low Pressure Market (Sarnia N&S and London Lines)	31
Dawn Fuel (Incl. 'Company Used' gas)	34
Total	**2,583**

As illustrated by the above table, the design day demand forecast for Union South is approximately 2,583 TJ.

However, unlike Union North the design day demand estimate is not communicated to Gas Supply. Rather it is one of the inputs to the storage and transmission system planning model. As discussed above, Union South, unlike Union North, is a contiguous service territory with significant on-system assets such as underground storage facilities, transmission lines and the Dawn Hub. As a result of these physical assets, the design day demand forecast is utilized by Union as part of an integrated physical natural gas delivery plan that includes: storage volumes required to meet a Union South design day on February 28, natural gas supply delivery requirements at Dawn and Parkway for Union and other third parties; and potential Union South winter peaking requirements on the Dawn to Parkway transmission system.

[23] Please note that the calculated firm customer use per degree day factor is for certain customer segments (e.g., general service) while for other customer segments Union may use a contracted amount.

[24] The design day demand forecast includes system sales, Bundled Direct Purchase, T-service and unbundled customers.

The third step in the Sussex design day demand analysis is to review the results of the benchmarking analysis regarding LDC design day demand forecasting. Specifically, Sussex reviewed design day demand forecasts for 21 companies representing 64 separate business units or planning regions located in Canada or the northeast, mid-west and western United States.[25] With respect to the design day demand forecasting process, Sussex focused our benchmarking analysis on weather standards utilized (e.g., coldest observed temperature for the design day); the calculation of design day demand (e.g., trend line) and the growth factor calculation.

In terms of the weather standard, there are two main approaches utilized by LDCs for determining design day weather. The first approach is to use the coldest observed temperature over a certain period of time while the second approach is to use probability (i.e., frequency of occurrence). If the coldest observed approach is utilized, the time period of the data series is usually thirty to forty years. Some utilities, however, relied on historical weather data stretching much further back. For example, ConEd of New York relies upon a peak day which was experienced in 1934.[26] If the probability approach was utilized, the frequency of occurrence ranged from one in five years to one in ninety years and the underlying data series ranged from ten to over fifty years.[27] Overall, twelve of the companies reviewed use coldest observed, seven use frequency of occurrence and two rely on other methodologies.[28]

In addition to the design day weather standard, the Sussex benchmarking analysis also reviewed the process utilized by various LDCs to calculate design day demand per degree day and the approach used to project design day demand growth. While the LDCs reviewed may have different equation components regarding design day demand per degree day the vast majority utilize a regression analysis whereby historical daily consumption and degree days are

25 The benchmarking analysis is attached as Appendix C.

26 Based on discussions with ConEd of New York.

27 For example, NSTAR Gas Company reviewed ten years of historical weather data. *See*, NSTAR Gas Company, 2012 Forecast and Supply Plan filed February 10, 2012, P. 58. Additionally, Enbridge Gas Distribution reviewed over fifty years of historical weather data (January 1953 to September 2010 for the Central and Eastern divisions). *See*, Enbridge Gas Distribution, Rate Application filed January 1, 2012, Exhibit D1, Tab 2, Schedule 3, P. 8. The remaining companies (for which the length of the dataset was reported) fell within a range of 34 to 43 years.

28 Other methodologies include: (1) a Monte Carlo analysis to determine normal weather and then use two standard deviations (assuming a normal distribution) to determine the design day and (2) a form of cost benefit analysis.

evaluated and a trend line is developed. Regarding the design day demand growth factor, the majority of the LDCs reviewed, utilize the annual demand growth developed as part of the LDC corporate demand projections and apply that same factor to the design day demand forecast.

The fourth step in the Sussex review of the Union design day forecast process consists of certain observations and conclusions based on our review of the Union approach, the LDC benchmarking analysis and the collective experience and judgment of the Sussex project team, specifically:

- The approach utilized by Union to forecast design day demand for Union North and Union South is consistent (i.e., aligned) and includes similar steps: (i) use of the coldest observed as the weather planning standard; (ii) develop a trend line using the most recent daily winter data and degree days; and (iii) extrapolate the trend line to the weather planning standard to determine design day load.
- The approach used by Union for design day demand forecasting is similar to the LDCs reviewed in the benchmarking analysis (i.e., develop a weather standard, calculate use per degree day, and project design day demand based on the combination).
- The use of the coldest temperature observed is reasonable as Union has experienced weather close to the coldest observed in all the gas supply planning areas; and it is consistent with the practice of the LDCs in the Sussex benchmarking analysis. The following table is a summary of the design day weather standard used by the LDCs in the Sussex benchmarking analysis.

Peak Day Planning Approach	Number of Companies Utilizing Approach
Coldest Day Observed	12
Frequency of Occurrence	7
Other	2

- Sussex recognizes that the Union North design day demand becomes a direct input to the gas supply design day plan, while the Union South design day demand is an input to the storage and transmission system plan; however, the process used to develop the Union North and Union South design day demand forecast is consistent and aligned.
- Overall, the Union methodology for forecasting design day demand is appropriate; and, the Company approach with respect to forecasting design day demand for Union North and Union South is consistent and aligned.

Lastly, based on our review of the Union design day demand forecast process, the LDC benchmarking analysis and the experience of the project team, Sussex has the following process recommendations:

- While the design day demand planning process is well documented within each Union department/group, the process should be documented across the departments/groups; specifically, Union should develop a high level flow chart that outlines the information flow needed to develop the design day demand forecast and associated departmental/group responsibilities.
- Prior to the start of the annual gas supply planning process, the departments/groups involved in peak day demand estimation should meet and kick off the design day demand process with: (i) a review of the results from the prior year (e.g., coldest degree day observations, associated demand on those days; performance of the trend line); (ii) any changes in the process, data, responsibilities/people, events/business conditions that could impact the process/results; (iii) schedule for completion; and (iv) communication of final work product.
- Once the design day demand forecast is completed a de-brief meeting should be held to discuss process changes or issues that need to be addressed.
- As part of the design day demand forecasting process, Union should review and evaluate whether different data sets, with regard to the design day demand forecast, should be analyzed (e.g., multiple winter periods, or subsets of multiple winter periods); it is important to note that Sussex is not recommending a change in the methodology being utilized, rather Union should have a process in place to annually evaluate different data sets and/or time periods to assess whether a change in methodology should be investigated.
- Finally, Union South should utilize the actual coldest observed temperature (i.e., 43.1 degree days) and not the current value of 44 degree days in the calculation of the Union South design day demand. The use of the actual coldest observed temperature for Union South would result in a consistent approach for determining the design day weather standard for both Union North and Union South.

Gas Supply Plan Review – Develop Gas Supply Plan

After the preparation of the design day demand forecast the next activity in an LDC gas supply planning process is the development of a gas supply plan that is consistent with the first two activities (i.e., gas supply planning principles and the design day demand forecast). Specifically, the LDC in this activity will develop a gas supply plan that conforms to the gas supply planning objectives and principles while meeting the forecasted design day demand. In this section, Sussex will address Elements two and six from the OEB Decision and Order in EB-2011-0210:

- Determine if the planning principles are objectively applied and the result is a gas supply plan that is "right sized".
- Determine whether the peak day in the North and South Delivery Areas are appropriately reflected in the gas supply plan, and if not, recommend remedial action.

The Sussex analysis of the Union gas supply plan development consists of the following steps: (i) an overview of the current gas supply portfolios for Union North and Union South and the major considerations in the development of the respective portfolios; (ii) our observations and conclusions regarding the Union gas supply plan development; and (iii) the Sussex recommendations.

The Union North gas supply portfolio primarily consists of Western Canadian Sedimentary Basin ("WCSB") gas supply and TCPL Mainline transportation contracts. Union augments this primary source of gas supply with a limited volume from MichCon that is transported on Great Lakes Gas Transmission to the TCPL Mainline; and underground storage transported on Union transmission to the TCPL Mainline at Parkway for redelivery on the TCPL Mainline to Union North.

In terms of TCPL Mainline services,[29] Union contracts for long haul long term firm transport on the TCPL Mainline (Mainline LTFT);[30] and, as a result, Union has access to certain TCPL

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[29] Please see Appendix B for a summary of certain TCPL Mainline service offerings.

[30] TCPL Mainline offers long term (i.e., 365 days or greater) and short term (i.e., less than 365 days) transportation service.

Mainline LTFT transportation service attributes (FT-RAM)[31] and other TCPL Mainline service offerings (e.g., storage transportation service ("STS")). The TCPL Mainline LTFT service provides Union with a firm right to renew thus ensuring that Union North customers will have access to firm capacity at NEB approved tolls from the only pipeline option to feed the service territory. Under the TCPL Mainline LTFT terms of service, Union also has the option of in-path deliveries thus enabling Union to provide service under extreme weather conditions, at no additional cost, to delivery areas that are upstream of the primary delivery area in the specific TCPL Mainline LTFT contract.

Another aspect of the TCPL Mainline LTFT service is the ability of the customer (e.g., Union) to contract for STS.[32] The main benefit of the LTFT and STS service combination is described by TCPL as follows: "Allows a Firm Transportation (FT) contract holder, in combination with their STS contract to meet seasonal market and storage requirements and still keep a high load factor. Offers numerous flexibility features including guaranteed renewal rights, additional nomination windows to better balance daily gas supply and consumption, and RAM credits to maximize the value of the contract."[33]

Sussex understands that Union utilizes the TCPL Mainline LTFT to meet the demand requirements of Union North and when the demand is less than the Union North Mainline LTFT capacity, Union, using the STS service, injects those volumes to storage. In the winter period, Union is able to withdraw the previously injected gas supply from STS to meet winter seasonal demand requirements. Not only does the TCPL Mainline LTFT and STS service combination allow for high utilization of the Union North LTFT capacity (e.g., where feasible Union plans for 100% contract utilization for nine to ten months per year), but it also provides customers with a potential natural gas price benefit (i.e., a physical hedge). Stated differently, Union is able to purchase natural gas in the summer period, inject into storage, then withdraw that natural gas priced at summer price indices to serve winter peak season load.

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31 FT-RAM is currently an attribute of the long term long haul service that provides Union with several benefits including reduced interruptible transportation costs and increased market value of unutilized capacity.

32 To be eligible for STS service, the TCPL Mainline customer must have a long haul LTFT contract to a market point.

33 TransCanada Mainline website.

STS also provides Union North with additional nomination flexibility as this service has four additional nomination windows with two of those nomination windows during the night, which facilitates daily load balancing and minimization of balancing costs.[34] Finally, STS service can be pooled across certain Northern delivery areas thus adding flexibility to the Union North portfolio; in other words the STS contracted capacity by delivery area (e.g., NDA) can be shared across certain delivery areas (e.g., NDA and NCDA) thus providing inter-delivery area flexibility.

In addition to reviewing the Union gas supply portfolio developed to meet Union North requirements, Sussex also reviewed whether the Company had contracted for an appropriate level of resources to meet the forecasted design day demand requirements. Specifically, for the six gas supply delivery areas, Sussex reviewed the Union North level of gas supply assets planned to meet the forecasted design day demand. The following table is a summary of the design day demand forecast and the associated portfolio to meet the individual gas supply planning areas in Union North:

[34] Sussex understands that Union has estimated approximately $5 to $7.5 million of avoided load balancing cost for the 2011/2012 period as a result of STS.

Winter 2012/2013 Northern Firm Design Day Demand in TJ's/Day

	Delivery Area						
	MDA	WDA	SSMDA	NDA	NCDA	EDA	Total
Design Day - Degree Day	54.7	51.6	48.2	51.9	49.0	47.1	
Design Day Demand by Delivery Area	14	85	115	284	40	251	789
Composed of:							
T-Service Firm Contract Demand	9	10	80	126	3	98	326
Union Responsible							
Bundled Firm Service Demand	5	75	34	149	37	154	454
T-Service Storage Redelivery Demand	-	-	-	9	-	-	9
Firm Demand - Union Responsible	5	75	34	158	37	154	463
Capacity & Supply to meet Firm Demand - Union Responsible							
Upstream Transportation - Capacity							
TCPL L/H from Empress	4	37	8	49	9	59	166
Supply - Upstream Transportation							
Union	3	27	4	34	5	42	115
Direct Purchase	1	10	4	15	4	17	51
	4	37	8	49	9	59	166
Redelivery from Storage							
TCPL STS Withdrawals - contracted	-	31	35	48	14	69	197
TCPL STS Withdrawals - pooled	-	-	(9)	3	14	(9)	-
TCPL STS Withdrawals - flowed		31	26	52	28	60	197
TCPL S/H from Parkway	-	-	-	-	-	35	35
		31	26	52	28	95	232
Supply from Upstream Transport & Storage	5	68	34	101	37	154	398
Firm Demand	**5**	**75**	**34**	**158**	**37**	**154**	**463**
Supply from Upstream Transport & Storage	**5**	**68**	**34**	**101**	**37**	**154**	**398**
Excess/(shortfall) by Delivery Area	**(1)**	**(7)**		**(57)**			**(65)**
Excess/(shortfall) by delivery area	**(1)**	**(7)**		**(57)**			**(65)**
Supply from Other Sources							
Diversions - from Union South transport portfolio							
TCPL Empress - Union CDA	1	7	-	57	-	-	65
Excess/(shortfall) by Delivery Area	-	-	-	-	-	-	-

As illustrated by the above table, the design day demand for Union North is approximately 789 TJ[35] of which 41% or 326 TJ is associated with T-Service Firm Contract Demand[36] and approximately 59% or 463 TJ is attributed to Bundled Firm Service demand or T-Service storage redelivery demand.

To meet the forecasted design day demand associated with Union firm gas supply requirements (i.e., 463 TJ), the Union portfolio is comprised of: 36% TCPL Mainline long haul capacity; 43%

[35] This value is the same estimate developed and reported in the Gas Supply Review – Design Day Demand section for Union North.

[36] T-Service customers are typically large industrial customers that hold their own contract for upstream pipeline capacity, but Union provides a storage service to these customers.

from redelivery of STS volumes; 8% from a short haul service on the TCPL Mainline; and 13% from a diversion of a TCPL Mainline contract that is primarily used to deliver gas supply to Union South.

The Union South gas supply portfolio, unlike Union North, has access to diverse supply basins and/or market area hubs such as the WCSB, Gulf of Mexico, Rockies, Marcellus/Utica shale, Chicago Hub, and Dawn Hub. As a result, Union South has various pipeline options including the following contracted delivery paths:

- TCPL Mainline ➔ Parkway
- Trunkline ➔ Panhandle ➔ Ojibway
- Alliance Pipeline ➔ Vector Pipeline ➔ Dawn
- Chicago Hub ➔ Vector Pipeline ➔ Dawn
- Panhandle Eastern Pipe Line ➔ Ojibway
- Niagara ➔ TCPL Mainline ➔ Kirkwall

In addition to the various pipeline delivery options and paths, Union South has access to significant on-system underground storage and associated transmission facilities as well as the Dawn Hub. With respect to pipeline services for Union South, the Company has a variety of contracts including TCPL Mainline LTFT to the CDA, TCPL Mainline short-haul transportation services as well as firm service on other upstream pipelines including Alliance, Vector and Panhandle Eastern. Given the significant underground natural gas storage volume and the direct access to the Dawn Hub, the Union South upstream pipeline contracts are utilized at 100% load factor (i.e., no unabsorbed demand charges on a planned basis).

Similar to the analysis of Union North, please find below a summary of Union South design day demand, and the resources utilized to serve that demand:

Union South Design Day Demand* and Resources (TJ/day)	
Union South Demand	2,583
Supply	
Storage at Dawn	1,238
Non-obligated (e.g., Power Plants)	197
TCPL Empress to CDA	70
Trunkline	21
Panhandle	26
TCPL Niagara	21
Ontario Parkway	522
Alliance/Vector	85
Vector	85
Ontario Dawn	288
Customer Supplied Fuel	30
Total Supply	**2,583**
*Includes system sales, Bundled Direct Purchase, T-service, Unbundled	

As illustrated by the above table, the forecasted design day demand for Union South is approximately 2,583 TJ (which includes system sales, bundled direct purchase, T-service and unbundled customers). The forecasted design day demand volume (i.e., 2,583 TJ) is provided as an input to the Union storage and transmission system plan; and the resultant plan is developed based on pipeline capacity, delivered gas supplies, and storage volume.[37]

To meet the forecasted design day demand, Union has approximately 50% of the volume being delivered from Dawn Storage; while the other 50% is comprised of upstream pipeline capacity or delivered volumes.

Based on our analysis and evaluation regarding the development of the gas supply plan, Sussex has the following observations and conclusions:

[37] The 2,583 TJ value is the same estimate developed and reported in the Gas Supply Review – Design Day Demand section for Union South; and General Service represents approximately 55% of the 2,583 TJ, while contract customers reflect about 45%.

- The Union gas supply plan for Union North and Union South appropriately reflects the forecasted design day demand for each area. Stated differently, the forecasted design day requirements as discussed above in the Gas Supply Plan Review – Design Day section are included and appropriately reflected in the development of the Union Gas Supply Plan.
- The Union gas supply plan is developed for each region based on the specific circumstances and situation for Union North and Union South. Union North, given its reliance on the TCPL Mainline has sufficient capacity under contract to serve the design day demand and incorporates the flexibility of the diverse TCPL Mainline service offerings to provide natural gas storage benefits to Union North. The gas supply plan developed for Union South appropriately leverages the physical on-system storage and transmission assets as well as access to Dawn Hub, thus allowing the upstream pipeline capacity for Union South to be utilized at 100% load factor on a planned basis.
- Although Union North and Union South portfolios are developed to meet the requirements of each region there are certain assets that can provide service to both delivery areas:
    - The Union South portfolio has long haul long term firm capacity on the TCPL Mainline (Empress to CDA), which can provide gas supply to Union South or to "with-in" path delivery areas in Union North.
    - Union North has access to Union storage and transmission assets as there is approximately 290 TJ/day withdrawn at Dawn to meet the Union North design day demand.

Finally, Sussex has developed the following recommendations regarding the Union gas supply plan development.

- Gas Supply Plan Memorandum
    - Once the gas supply plan has been developed (i.e., the models have been updated and the new results calculated), Union should develop a summary memorandum that provides a narrative discussion regarding: (i) general market conditions and drivers with respect to natural gas demand and supply; (ii) the results and process used to develop the Union North and Union South design day demand forecasts; (iii) the assumptions underpinning the results; (iv) an overview of the current Union gas supply portfolio for Union North and Union South; (v) identification of near term portfolio decisions; and (vi) describe how the

Union strategy regarding the identified portfolio decisions conforms to the gas supply planning principles.

- The gas supply plan narrative should be circulated and reviewed both within the gas supply area but also in certain supporting departments such as Storage Planning, Distribution Planning, and Regulatory.

- Regulatory and Market Implications
  - The Union gas supply plan should also provide a summary of major upstream pipeline regulatory filings and/or recent regulatory orders (e.g., RH-003-2011) that may influence Union gas supply decisions. Stated differently, the results of major regulatory changes that will influence upstream pipeline services and costs should be included and discussed in the Union gas supply plan.
  - The Union gas supply plan should provide a summary of physical infrastructure projects or gas supply/pipeline options that may impact the Union gas supply plan. While the potential infrastructure projects will have specific regulatory processes, discussing these projects and gas supply drivers at a high level in the Union gas supply plan will provide market context for Union stakeholders.
  - The Union gas supply plan should include research and analysis regarding the gas supply portfolio implications associated with gas supply basin trends and evaluate potential impacts on the Union gas supply portfolio. The additional narrative would allow the Union stakeholders to better understand the rationale underpinning certain gas supply strategies.

Gas Supply Plan Review – Contracting

The last activity in the gas supply planning process is the on-going management of the gas supply portfolio (e.g., contracting decision analysis). As part of our review of the Union gas supply contracting/transportation path practices, Sussex addresses Elements seven and eight from the OEB Decision and Order in EB-2011-0210:

- Determine whether Union is conducting sufficient due diligence with respect to the cost benefit analysis associated with decontracting a particular gas transportation route and recontracting on an alternative route and recommended remedial action, if required.
- Determine whether Union is using the transportation portion of the gas supply portfolio to favor the transportation paths of entities in which Union or its parent has (or will have in the future) an economic interest, and recommend remedial action if required.

When an LDC is analyzing a transportation contracting decision, and assuming that the volume required has not changed, there are three general options that are evaluated:

- Recontract for the same path
- Recontract for a different path on the same pipeline
- Recontract on a different pipeline/path

The LDC contract analysis generally includes: (i) data gathering; (ii) quantitative modeling of the options; (iii) evaluating qualitative factors; and (iv) documenting the decision analysis and process. The Sussex analysis of the Union contracting practices evaluates the Union approach with respect to transportation contracting based on the typical LDC approach (i.e., data gathering, modeling, documentation).

Regarding the first step (i.e., data gathering), the Union Gas Supply Group is active in various information gathering activities including: attending energy conferences, market participant meetings, access to industry publications and data, and contracting for third party consulting reports. The Union gas supply group also conducts requests for proposals associated with natural gas purchases thus acquiring market information and price signals. In addition, Union has an active regulatory group that is involved in upstream pipeline regulatory proceedings, thus providing gas supply with current pipeline filings and submissions.

With respect to the second step (i.e., quantitative modeling), Union utilizes two approaches to evaluate contracts/transportation path decisions. First, Union uses a landed cost analysis to evaluate the delivered cost of transportation path options. In a landed cost analysis, Union identifies the various components of each path; develops cost/price assumptions for the various components; and calculates a delivered cost of transporting natural gas from the transportation path gas supply source to the Union market area. The following example illustrates the landed cost approach:

1	2	3	4		3 + 4
Path	**Gas Supply Basin**	**Gas Supply Cost**	**Pipeline 1**	**Pipeline 2**	**Total**
A	Rockies	Henry Hub + x	$D	N/A	Henry Hub + x + $D = A Total
B	Gulf of Mexico	Henry Hub + y	$E	$F	Henry Hub + y + $E + $F = B Total

As shown by the above table, Path A consists of a Rockies gas supply priced at Henry Hub plus a basis of x and is transported on Pipeline 1 for a landed cost comprised of the gas supply cost and the toll for Pipeline 1. Path B consists of a Gulf of Mexico gas supply transported on both Pipeline 1 and 2 for a landed cost of gas supply cost plus transport on Pipeline 1 and 2.

The landed cost approach assumes that the pipeline components are costed at 100% load factor (i.e., the transportation path is used every day at full volume). This type of analysis allows the alternative paths to be evaluated in a straight forward and transparent manner.

In addition to the landed cost analysis, Union may also utilize the SENDOUT model to evaluate a transportation path that is not expected to be utilized at 100% load factor. The SENDOUT model, which is an optimization tool, allows Union to evaluate how alternative transportation paths influence the overall gas supply portfolio. Using an optimization model, such as SENDOUT, allows Union to evaluate the total cost of the portfolio as the model considers the inter-relationships of the numerous contract parameters of the individual resources. Specifically, Union has modeled the gas supply portfolio in SENDOUT and has included the following inputs: maximum daily quantity ("MDQ"), tolls and fuel rates, and demand estimates.

With respect to the third step (i.e., evaluate qualitative factors), Union considers various qualitative factors in contracting decisions such as supply basin diversity, contract terms, and pipeline diversity. These qualitative factors are discussed in more detail below when Sussex reviews the Union Incremental Transportation Contracting Analysis.

Regarding the fourth step (i.e., documentation), Sussex reviewed documentation associated with certain Union gas supply contracting/transportation decisions including:

- Alliance Pipeline renewal decision
- 2011-2012 system and supply plan proposed transportation additions
- SSMDA via MichCon proposed transportation additions
- CTHI/CPMI capacity renewal – Union MDA

Sussex reviewed the Union management presentations for each of the identified decisions to verify that sufficient information had been gathered regarding each decision; alternative options had been identified and modeled; and the decisions were documented. The following table is a summary of our findings:

Decision	Data Gathering	Quantitative Analysis	Documentation
Alliance Renewal	Included Alliance depreciation surcharge, tolls and used ICF gas price forecast	Landed cost approach as path flows at 100% load factor	Management Presentation
Proposed 2011-2012 Transport Additions	Included gas price forecast from ICE, toll and fuel information	Landed cost analysis as path would flow at 100% load factor	Management Presentation
SSMDA via MichCon	Included gas price forecast from ICE, tolls and fuel	Landed cost and annual cost comparison	Management Presentation
Union MDA/CTHI/CPMI	Focused on volume as no other pipeline alternative is available	Focus of analysis was on MDQ level; demand data reviewed	Management Presentation

As illustrated by the above table, the Union contracting decisions reviewed by Sussex addressed issues typically covered by an LDC contract analysis (i.e., data gathering, modeling, and documentation).

In addition to the contracting decisions summarized in the matrix above, Sussex reviewed the process used by Union to evaluate new or incremental capacity contracts. Specifically, for new or incremental transportation paths Union uses the Incremental Transportation Contracting

Analysis, which was first outlined in EB-2005-0520. As part of the Incremental Transportation Capacity Analysis Union utilizes the following evaluation process:

- Description of the new or incremental transportation path;
- Provide written rationale describing why Union is entering into this new transportation path;
- Describe all relevant transportation contract parameters including: provider, term, price and receipt/delivery points;
- Quantitative comparison of the landed cost to alternatives; and
- Quantitative and/or qualitative consideration of additional factors considered relevant by Union, including: security of supply, supply basin diversity, contract term diversity, pipeline operator diversity, terms and conditions and demand charge/commodity charge structure.

The process outlined for Incremental Transportation Capacity Analysis is consistent with the LDC process described above (i.e., data gathering, quantitative modeling, qualitative considerations and documentation).

With respect to whether Union is using the transportation portion of the gas supply portfolio to favor transportation paths in which Union or the parent may have an interest, Sussex understands that Union contracts with St. Clair Pipelines LP (an affiliate) for certain capacity that is used for overall security of supply. Sussex further understands the St. Clair Pipeline LP agreements (St. Clair Pipeline and Bluewater Pipeline) are the only capacity contracts Union has with an affiliate. Therefore, given the role of St. Clair Pipeline LP in the Union gas supply portfolio (i.e., security of supply) Sussex understand the Union capacity agreement with St. Clair Pipeline LP has not been subjected to or included in any Union transportation path analysis.

On the broader issue of whether Union could use the transportation portfolio to favor transportation paths in which Union or the parent may have an interest, Sussex recommends Union utilize the Incremental Transportation Contracting Analysis framework augmented by our recommendations for all contracting decisions, regardless of whether that contract decision is for decontracting, recontracting or incremental capacity. This approach would be applied irrespective of the entity owning the upstream pipeline/project, and as a result would provide sufficient analysis and documentation as to why Union pursued a certain strategy regarding a transportation path decision.

Sussex has the following additional recommendations regarding the Union contract/transportation path evaluation process:

- It is important for Union to continue to use known information (e.g., current approved tolls) to reduce the subjectivity of the analysis; however, a range of inputs should also be considered to increase the robustness of the analysis. Stated differently, Union should develop scenarios around the base case.
- Union should provide documentation supporting the choice of alternatives analyzed and not analyzed (e.g., Path A was not reviewed as there is no capacity available on that pipeline). The documentation requirements are similar to general LDC contracting practices and the Union Incremental Transportation Contracting Analysis process discussed above.
- Review and evaluate whether the SENDOUT model could be used to augment the landed cost analysis. Sussex appreciates that the landed cost analysis at 100% load factor is more straightforward analysis for pipeline options that will be dispatched at maximum capacity value every day; however, the exercise of modeling the contract option in SENDOUT may, in of itself, be a useful process, as the attributes of the path need to be understood in order to be modeled.
- The Sussex recommendations with respect to contracting decisions apply to all Union contract/transportation path decisions regardless of the entity owning the upstream pipeline/project.
- Union should establish a process to review the cost of service, rate level, and rate design for St. Clair Pipeline and Bluewater Pipeline. Specifically, every three years or pursuant to a significant NEB filing by either St. Clair Pipeline or Bluewater Pipeline, Union should undertake a review of the current pipeline situation and, depending on the outcome of that review, initiate negotiations with the pipeline or submit a complaint to the NEB.
- Finally, although the OEB Decision and Order in EB-2011-0210 did not address whether an LDC contracting analysis should consider the broader implications of that contract decision on third parties, Sussex recommends that if Union attempts to incorporate such an analysis the focus of that broader evaluation should be directional impact assessments and not detailed quantification of costs and benefits. Specifically, given the supply/market footprint and diverse service areas of the infrastructure that provides natural gas to Union and the various downstream customer segments, a detailed cost

and benefit analysis will need to rely on many assumptions associated with markets and regulatory activities that may be difficult to estimate and the result from such an analysis may or may not inform the contract decision for Union and its customers.

Gas Supply Plan Review – Organization

In addition to the gas supply plan elements identified by the OEB in EB-2011-0210, Sussex also reviewed the Union practices associated with gas supply portfolio asset optimization. Specifically, once a gas supply plan has been developed and the contracts/assets are in place for a certain period of time (e.g., season or multi-year), LDCs will typically identify and undertake activities and opportunities to leverage the assets that are not being used to serve firm customers (i.e., asset optimization).

The process or range of activities utilized by an LDC to extract value from the gas supply portfolio can range from the straight forward (i.e., daily assignment of transportation contracts) to the more complicated (i.e., structured products to serve the need of a particular market participant). As expected, the value derived from an LDC gas supply portfolio will be related to the level of activity and products/services provided to the market.

In general, there are three options used by LDCs to extract value from gas supply assets: (i) LDC managed activity; (ii) third party asset manager; and (iii) non-regulated affiliated asset manager.

When a third-party or a non-regulated affiliated asset manager is utilized to extract value from the LDC portfolio, the LDC assigns an asset or a portfolio of assets to the asset manager and in return, the LDC receives a payment based on the activity of the asset manager. There are various payment structures for asset management arrangements, including:

- The asset manager pays a fixed fee for the use of the LDC's assets;
- The asset manager provides an upfront payment and shares any additional value with the LDC at a pre-arranged percentage; or
- The asset manager shares the value earned with the LDC based on a pre-arranged percentage.

The value received by the LDC under an asset management arrangement could vary significantly based on: (i) the competitiveness of the marketplace with respect to asset managers; (ii) the timing of the transaction and whether the forward natural gas prices and/or basis is trending up or down; and (iii) the assets provided by the LDC to the asset manager (i.e., one path on a specific pipeline or various assets such as transportation on several pipelines and underground storage).

In addition to the variability in the value derived from asset management arrangements, this approach may also results in a decrease of "in-house" knowledge and expertise, thus impacting the overall capability of the LDC. Stated differently, the "out-sourcing" of the value extraction activities could reduce the expertise and knowledge of the "in-house" LDC personnel.

The other option with respect to asset management is for the LDC to perform these activities "in-house" and compete with other market participants such as energy marketing companies. Under this approach, the LDC is active in the market and has direct participation resulting in market insights and information; however, the LDC may lack the scale and scope of other energy market participants as those firms may have more innovative deal structures or greater incentives to extract value. For example, a non-regulated energy marketing company has an incentive to develop innovative and creative products and services to grow revenue, margins and profit; and as a result of this financial incentive, the energy marketer is more likely to maximize the value of the LDC assets as compared to general LDC activity. In addition, the energy marketer is able to add assets to existing or expected positions and thereby bundle the combined or integrated assets to extract more value.

The Union approach to extracting value from the gas supply portfolio is a hybrid of the two approaches and leverages the Union assets and positions. Specifically, Union has storage and transmission assets that are offered to market participants by the Storage and Transmission Sales Group ('S&T") at various time periods (e.g., daily, seasonal or multi-year); and as such, the S&T sales group is in the energy marketplace on a continuous basis. By including the gas supply assets with the S&T existing positions, Union is able to provide market participants with structured products that optimize the assets on an integrated basis; and provide value that would likely not be extracted had the gas supply assets been managed on a standalone basis. The S&T Group essentially operates as an asset manager within the regulated organization.

The attributes of the Union approach include:

- The gas supply group is focused on developing a portfolio that meets the forecasted demand over not just the upcoming year but over the long term. As such, the gas supply group is focused on medium and long-term portfolio decisions that meet the gas supply planning principles, not on short term value extraction.

- The S&T sales group, on the other hand, is focused on near term asset utilization and optimization (i.e., extracting the most value from the current asset positions).
- As both functions are within the utility, the OEB has the ability to review transactions and activity in a fairly detailed and transparent process.
- Union, as an active market participant, provides structured services to the marketplace thus providing another alternative to meet the needs of market participants (i.e., Union is able to structure products and services for a variety of market participants including: end users, retail energy marketers and wholesale market participants).
- The incentive for S&T to extract value from the gas supply portfolio assets create a healthy tension between S&T (i.e., market driven) and the Union Gas Control group (i.e., reliability and system integrity driven).
- Changing market dynamics may result in new products and structures that will continuously require risk/reward evaluation, thus requiring the need for Union to continue to develop quantitative analytical skills and analysis.

In summary, while there are various alternatives used by LDCs to extract value from the gas supply portfolio assets the main differences in approach are: “in-house” v. “out-sourced” and value drivers (e.g., incentives). The current approach utilized by Union to extract value leverages the core competencies of Gas Supply and S&T, is consistent with other approaches used by LDCs (e.g., asset management arrangements), and, based on the experience of the Sussex project team, is reasonable.

Sussex Team Bios

James M. Stephens, Partner

Mr. Stephens has twenty-five years of experience in the energy industry and he has held senior management positions at consulting firms, energy marketing companies and natural gas utilities. Most recently, Mr. Stephens served as Senior Vice President for Concentric Energy Advisors, Inc. He has assisted numerous clients with regulatory policy strategy/tactics and energy market analyses/assessments including: the analysis of regional energy market dynamics and the associated drivers for new natural gas infrastructure (e.g., pipeline expansions); the evaluation of new markets/opportunities (e.g., distributed LNG); market entry/exit strategies (e.g., service territory or product/service expansions); market implications of new energy infrastructure (e.g., LNG facilities and pipelines); integrated resource plans (e.g., natural gas demand forecasting and resource portfolio analysis); natural gas supply portfolio evaluation and optimization (e.g., asset management agreements); and management prudence (e.g., implementation of risk management/portfolio strategies). In addition to his consulting experience, Mr. Stephens served as the President of a retail energy marketing firm where he was responsible for all aspects of business unit management including front, mid and back office functions. Mr. Stephens was also responsible for the Gas Supply Procurement and Portfolio Optimization function for a local distribution company. Mr. Stephens holds a B.S. in Management and an M.B.A. with a concentration in Operations Management from Bentley College.

Peter Newman, Executive Advisor

Mr. Newman, who is an Executive Advisor with Sussex, has over thirty-five years of experience in various natural gas supply management roles for WE Energies. Specifically, Mr. Newman was responsible for managing all the natural gas supply functions including: long term supply planning and acquisition; natural gas purchasing strategies and execution; capacity portfolio optimization; development and implementation of risk management objectives and policies; and management of the gas control function. In addition, Mr. Newman participated in numerous Federal Energy Regulatory Commission proceedings with respect to natural gas pipeline expansions, rate proceedings, new services and other regulatory issues. Mr. Newman was also a key member of the management team that developed and built the Guardian Pipeline and, in that role, Mr. Newman contributed to a variety of activities, including: market development and project management, developing and implementing the open season process, market assessment, regulatory strategy and proceedings, capacity marketing and tariff development. Mr. Newman is an engineering graduate of the University of Wisconsin-Platteville.

Jim Voss, Executive Advisor

Mr. Voss, who is an Executive Advisor with Sussex, has twenty-five years of experience in the natural gas industry having held management positions at major Midwestern LDCs as well as unregulated energy marketing firms. He has extensive background and knowledge of gas trading and asset optimization, nominating and scheduling operations, pipeline-LDC system interfaces, gas supply portfolio planning, and related Federal and State regulatory oversight. Mr. Voss is a graduate of the University of Wisconsin-Madison with a Masters in Finance from the University of Wisconsin-Milwaukee.

Adam Perry, Managing Consultant

Mr. Perry's experience in the energy industry is wide-ranging, including work related to regulatory proceedings, rate design, cost of service, cost of capital and financial valuations. His regulatory work has involved development of minimum filing requirements, demand forecasts, return on equity analyses, class cost of service and allocation factor analyses, and market-based rates evaluations. In addition, Mr. Perry has developed expert testimony, prepared financial models for valuation purposes, and performed regulatory and market research. Mr. Perry holds a B.S. in Economics from Northeastern University, where he graduated magna cum laude and was a member of the Omicron Delta Epsilon Society.

TCPL Mainline Services

Service	Description	Access	Toll / Price	Toll Type	Renewal Rights	Key Features and Benefits
FT Firm Transportation	• Firm service with a primary receipt point and primary delivery point • Term: minimum of 1 year; no maximum	• Open Season • Awarded based on term x toll	• 100% load factor FT toll • Empress to Union-EDA o Demand: $63.84842/GJ/ month or $2.099/GJ/day o Commodity: $0.14377/GJ	• Monthly demand and commodity	• Renewal minimum 1 year • 6 months notice required	• Will build for service • Secure and reliable daily deliveries • Guaranteed renewal rights • Alternate Receipt Point and Diversion rights • Shifts (i.e., temporary receipt and/or delivery points) – minimum duration of 3 months • Assignment rights • RAM credits on long-haul and linked short-haul
STFT Short Term Firm Transportation	• A short term firm service with a primary receipt point and primary delivery point • Term: specified number of days not less than 7 consecutive days, monthly periods, or	• Open Season • Shippers bid quantity, price and term • Awarded based on aggregate revenue	• Biddable • Bid floor price = 100% load factor FT toll • No maximum • Toll is fixed for the term of the contract • Empress to Union-EDA o STFT Minimum Toll: $2.2429/GJ	• Bid price daily demand equivalent	• n/a	• Will not build for service • Fills short term and seasonal transportation needs on a firm basis; has the same reliability as FT service • No Alternate Receipt Point and Diversion rights • No Shifts • No Assignment rights • No RAM • Receipts allowed from certain delivery areas

Service	Description	Access	Toll / Price	Toll Type	Renewal Rights	Key Features and Benefits
	combination of consecutive monthly periods (i.e., Block Periods) up to 1 year less 1 day					
STS Storage Transportation Service	• Firm service allowing for injections and withdrawals at storage locations • Requires the STS contract holder to also hold a long-haul FT contract to their market point • Term: minimum of 1 year; no maximum	• Open Season • Awarded based on term x toll • Must also hold a long-haul FT contract to the market point	• STS toll	• Monthly demand and commodity	• Renewal minimum 1 year • 6 months notice required	• Will build for service • Guaranteed renewal rights • No Alternate Receipt Point and Diversion rights • No Shifts • No Assignments • STS RAM credits (seasonal) • Ability to convert to STS-L • Additional Nomination Windows to balance daily gas supply and consumption

Sources: TCPL Mainline Customer Express website (http://www.transcanada.com/customerexpress/2773.html) and Company Tariff

Company	Division	State / Province	Number of Customers	Annual Sales / Throughput (Dth)	Peak Day Send-Out (Dth)	Peak Day Planning Approach	Peak Day Consumption Estimation Process
Enbridge Gas Distribution	Central	Ontario					
Enbridge Gas Distribution	Eastern	Ontario					
Enbridge Gas Distribution	Niagara	Ontario					
Enbridge Gas Distribution	TOTAL	Ontario	1,957,733	404,670,766	3,506,040	Multi-Peak Design Criteria, which, in addition to incorporating the single peak day weather criteria, include statistical conditions about weather applied to other days in the winter season. Relies upon probability of occurrence to determine the peak days.	Peak day demand is derived from the HDDs for peak day, and potentially other weather variables, assumed within the Design Criteria. However, the Company's current Design Criteria does not include weather variables other than HDDs.
Centra Gas Manitoba	TOTAL	Manitoba	266,699	65,898,545	456,184	Coldest winter day experienced	
FortisBC	Columbia	British Columbia			26,539		
FortisBC	Coastal	British Columbia			860,618		
FortisBC	Ft. Nelson	British Columbia			5,687		
FortisBC	Inland	British Columbia			275,815		
FortisBC	Whistler	British Columbia			6,635		
FortisBC	TOTAL	British Columbia	841,000	108,430,263	1,175,293	Probability of occurrence	Usage per degree day.
Gaz Métro	Quebec	Quebec			1,261,561	Coldest day in last 20 years	
NSTAR	Cambridge	Massachusetts	52,032	9,485,379			
NSTAR	Framingham	Massachusetts	63,282	10,925,112			
NSTAR	New Bedford	Massachusetts	63,636	7,820,545			
NSTAR	Worcester	Massachusetts	89,472	13,402,977			
NSTAR	TOTAL	Massachusetts	268,422	41,634,013	412,000	Probability of occurrence	Develop NSTAR Gas Forecast Sendout/EDD Factors by Division and Month factors for each division.
National Grid	Boston Gas	Massachusetts	606,159	81,629,143	954,000		
National Grid	Essex Gas	Massachusetts	50,835	6,460,769	71,000		
National Grid	Colonial Gas - Lowell	Massachusetts	88,911	12,359,614	149,000		
National Grid	Colonial Gas - Cape Cod	Massachusetts	105,795	10,360,869	114,000		
National Grid	TOTAL	Massachusetts	851,700	110,810,395	1,107,897	Probability of occurrence	The Company developed the reference year sendout using regression equations of its Primary Firm Load Sendout (those sales classes for which the Company must plan its interstate pipeline capacity portfolio) based on the prior April to March time period. The level of the Company's sendout in the reference year served as the "springboard" to which incremental sendout was added. Using the design day weather planning standard, the Company determined the design day sendout requirement.
Bay State Gas d/b/a Columbia Gas of MA	Brockton	Massachusetts	147,028	20,581,514	241,320		

Company	Division	State / Province	Number of Customers	Annual Sales / Throughput (Dth)	Peak Day Send-Out (Dth)	Peak Day Planning Approach	Peak Day Consumption Estimation Process
Bay State Gas d/b/a Columbia Gas of MA	Lawrence	Massachusetts	45,807	6,763,865	72,676		
Bay State Gas d/b/a Columbia Gas of MA	Springfield	Massachusetts	101,001	12,854,268	136,374		
Bay State Gas d/b/a Columbia Gas of MA	TOTAL	Massachusetts	293,836	40,199,647		Probability of occurrence	Forecast design day demand for each division is derived from a daily demand model that uses data for all days in April 2010 through March 2011 with 10 or more EDDs.
Southern Connecticut Gas	TOTAL	Connecticut	165,000	28,939,000	281,255	Coldest day in last 30 years	SCG uses a multiple regression model for determining peak day gas requirements (design day sendout). The model utilizes daily weather information, lagged daily weather information, and firm sendout for SCG's service area. The assumed design day and lagged EDD variables used to calculated the design day sendout are 68 EDDs and 60 EDDs, respectively.
Connecticut Natural Gas	Hartford	Connecticut			277,611		
Connecticut Natural Gas	Greenwich	Connecticut			39,182		
Connecticut Natural Gas	TOTAL	Connecticut	155,000	31,148,000	316,793	Coldest day in last 30 years	CNG uses a multiple regression model for determining peak day gas requirements (design day sendout). The model utilizes daily weather information, lagged daily weather information, and firm send out for each of CNG's service areas (Hartford and Greenwich).
Yankee Gas	TOTAL	Connecticut	209,952	47,571,000	396,494	Coldest day in last 30 years	Based on the highest heating degree day occurrence (75 EHDD) in the Reference Case, Design Weather Forecast.
National Grid	Narragansett Electric Company	Rhode Island	250,000	34,023,000	308,000	First, the Company performed a Monte Carlo analysis of normal weather conditions. Design Day = Normal Day + 2 standard deviations. Second, the Company performed a cost/benefit analysis.	The Company developed the reference year sendout using regression equations based on the prior April to March time period. The level of the Company's sendout in the reference year served as the "springboard" to which incremental sendout was added. Using the design day weather planning standard, the Company determined the design day sendout requirement.
National Grid	Brooklyn Union Gas (Long Island)	New York	553,000		949,942		
National Grid	Brooklyn Union Gas (New York City)	New York	1,200,000		1,399,830		

Company	Division	State / Province	Number of Customers	Annual Sales / Throughput (Dth)	Peak Day Send-Out (Dth)	Peak Day Planning Approach	Peak Day Consumption Estimation Process
National Grid	TOTAL	New York	1,753,000			Coldest day observed	The Company developed the reference year sendout using regression equations based on the prior April to March time period. The level of the Company's sendout in the reference year served as the "springboard" to which incremental sendout was added. Using the design day weather planning standard, the Company determined the design day sendout requirement.
National Grid	Niagara Mohawk	New York	588,452	145,128,000		Coldest day observed	The Company developed the reference year sendout using regression equations of its Primary Firm Load Sendout (those sales classes for which the Company must plan its interstate pipeline capacity portfolio) based on the prior April to March time period. The level of the Company's sendout in the reference year served as the "springboard" to which incremental sendout was added. Using the design day weather planning standard, the Company determined the design day sendout requirement. This regression equation captures the observed characteristics of the Company's sendout requirements. The observed characteristics include the following: (1) sendout requirements are directly related to HDD; (2) sendout requirements are affected by HDDs that occur over a multiday period; and (3) sendout requirements differ by day of the week.
Consolidated Edison	ConEd of New York	New York	1,101,100	247,000,000	1,090,909	Coldest day observed	Peak day consumption for firm customers is calculated by determining the previous winter's peak, by regressing each day's firm consumption from November 15 through March 15, excluding weekends and holidays to a 0 degree day.
Northern Utilities	Maine	Maine	26,500	9,025,493	52,353		
Northern Utilities	New Hampshire	New Hampshire	28,000	7,333,889	52,778		
Northern Utilities	TOTAL	Total System	54,500	16,359,382		Probability of occurrence. The 20 year average and standard deviation of the peak day was calculated and used to calculate the Design Day EDD associated with a 1-in-33 year probability of occurrence.	To determine the Planning Load associated with Design Day weather in each Division, a daily Design Day model was developed for each Division. Similar to the daily Planning Load model developed for Normal Year and Design Year, the dependent variable was historical daily Planning Load for the period May 1, 2009 through March 31, 2011 by Division and the independent variables included weather and other variables (e.g., day of the week). The preliminary Design Day Planning Load was then calibrated using the adjustment factors associated with Design Year January for each forecast year for the Base Case, High Growth, and Low Growth scenarios.
National Grid	EnergyNorth Natural Gas	New Hampshire	87,000	12,782,786	138,401	Monte Carlo analysis of average daily temperature as the variable to be modeled and HDD, which is a linear transformation of average daily temperature (Determines Normal Day/Year). Design Day/Year = Normal Day/Year + 2 Standard Deviations.	The Company developed the reference year sendout using regression equations based on the prior April to March time period. The level of the Company's sendout in the reference year served as the "springboard" to which incremental sendout was added. Using the design day weather planning standard, the Company determined the design day sendout requirement.
Michigan Consolidated Gas	Detroit/Ann Arbor	Michigan			1,383,000		
Michigan Consolidated Gas	Grand Rapids	Michigan			557,000		
Michigan Consolidated Gas	Upper Peninsula	Michigan			86,000		
Michigan Consolidated Gas	Traverse City	Michigan			120,000		
Michigan Consolidated Gas	Alpena	Michigan			94,000		
Michigan Consolidated Gas	TOTAL	Michigan	1,213,521	151,500,000	2,240,000	MichCon plans for an end-of-month peak day based on the coldest historical temperatures from the 22nd of that month to the 7th of the following month. It is possible for an end of March peak day temperature to occur through the end of the first week in April when storage balances are at their minimums.	MichCon serves its peak day requirements around critical end-of-month demand. MichCon's peak day demand model examines the design weather at sixteen different locations and condenses them down to five primary demand locations. End-of-month peak demand in January, February, and March 2013 at these five primary demand locations are calculated using statewide weather.

Company	Division	State / Province	Number of Customers	Annual Sales / Throughput (Dth)	Peak Day Send-Out (Dth)	Peak Day Planning Approach	Peak Day Consumption Estimation Process
Consumers Energy	TOTAL	Michigan	1,713,239	287,142,000	3,437,000	Coldest day since 1960	There are three primary steps in the peak day forecast development methodology. In step 1 of the design peak day sendout forecast method, the linear regression of city gate sendouts versus Wind Adjusted Weighted Degree Day ("WAWDD") is performed. Then an adjustment is used to implement allowance for potential variance in design peak day sendouts by calculating the 4% probability line. The city gate sendout represented by this 4% probability line at 80 WAWDD is then used in later steps instead of the city gate sendout represented by the linear regression line. In the second step, historical results of step 1 are directly compared using linear regression to historical weather adjusted system sendouts for the winter time period of January alone, due to it having the strongest correlation of the four selected winter time periods evaluated. This linear regression equation is then used to estimate non-electric 80 WAWDD design peak day sendouts for the five year planning period based on the gas sendout forecasts for January in the Corporate Gas Deliveries forecast with the addition of fuel use and system loss. After the additions in step 3, the estimated future 80 WAWDD peak day loads reflect the total peak day load connected to the Consumers gas transmission system. Estimates for future 65 WAWDD peak day and 50 WAWDD peak day loads can be determined by adjusting the results of step 2 downward with the appropriate weather sensitivity factor and then continuing with step 3 as normal. The Company also implements a floor mechanism which does not allow the design peak day sendout to go below the 80 WAWDD result from the most recent winter in the first forecast Plan year.
Cascade Natural Gas	Aberdeen	Washington	6,400	925,818	8,093		
Cascade Natural Gas	Bellingham	Washington	45,377	4,083,168	67,781		
Cascade Natural Gas	Bremerton	Washington	30,602	2,781,927	34,624		
Cascade Natural Gas	Kennewick	Washington	23,371	2,352,617	36,887		
Cascade Natural Gas	Longview	Washington	3,745	643,646	7,956		
Cascade Natural Gas	Moses Lake	Washington	2,505	391,348	7,736		
Cascade Natural Gas	Mount Vernon	Washington	40,297	3,733,543	48,805		
Cascade Natural Gas	Sunnyside	Washington	6,668	877,714	9,802		
Cascade Natural Gas	Walla Walla	Washington	11,663	993,260	15,804		
Cascade Natural Gas	Wenatchee	Washington	2,303	555,619	5,920		
Cascade Natural Gas	Yakima	Washington	22,631	2,639,888	30,276		
Cascade Natural Gas	Baker	Oregon	3,854	367,694	2,622		
Cascade Natural Gas	Bend	Oregon	43,648	4,630,960	56,796		
Cascade Natural Gas	Ontario	Oregon	4,474	448,181	3,043		
Cascade Natural Gas	Pendleton	Oregon	12,412	1,213,757	19,696		
Cascade Natural Gas	TOTAL	Total System	259,950	26,639,139	355,841	Coldest day in last 30 years	The peak day forecast is developed by adjusting the therm usage on the coldest day in recent history (January 5, 2004 at 56 HDD) upwards to an estimate of what therm usage would have been had that day been 61 HDD (December 21, 1990, the coldest day in the last 30 years). The therm usage is then applied to each district and escalated into the future at the forecast therm usage annual growth rate.
NW Natural	Albany	Oregon	40,191				
NW Natural	Astoria	Oregon	12,281				
NW Natural	Dalles	Oregon	5,476				
NW Natural	Eugene & Coos Bay	Oregon	39,882				
NW Natural	Lincoln City & Newport	Oregon	10,097				
NW Natural	Portland	Oregon	413,232				
NW Natural	Salem	Oregon	87,994				
NW Natural	Vancouver & Dalles	Washington	68,301				

Company	Division	State / Province	Number of Customers	Annual Sales / Throughput (Dth)	Peak Day Send-Out (Dth)	Peak Day Planning Approach	Peak Day Consumption Estimation Process
NW Natural	TOTAL	Total System	677,454		697,970	Coldest day in last 25 years	Daily use is separated into two components, base load and heat load. The base load component is assumed to be constant throughout the year and is independent of ambient temperatures. Base load represents demand for uses such as water heating and cooking. Heat load represents demand for space heating. Base load is calculated by performing a linear regression with daily use per customer as a function of HDDs, using customer usage data from the summer months of July, August, and September. For the non-summer months, the base load value is subtracted from the daily customer use data and the heat load factors are calculated. Peak day load is calculated by inputting the peak day HDDs in the two equations and adding the results together.
Pacific Gas & Electric	TOTAL	California	4,520,000		2,842,000	Probability of occurrence	The Abnormal Peak Day ("APD") core forecast is developed using the observed relationship between historical daily weather and core usage data. This relationship is then used to forecast the core load under APD conditions.

Company	Division	State / Province	Growth Rates for Peak Day Load	Planning Factors/Processes	Objective of Plan
Enbridge Gas Distribution	Central	Ontario			
Enbridge Gas Distribution	Eastern	Ontario			
Enbridge Gas Distribution	Niagara	Ontario			
Enbridge Gas Distribution	TOTAL	Ontario			
Centra Gas Manitoba	TOTAL	Manitoba			
FortisBC	Columbia	British Columbia			
FortisBC	Coastal	British Columbia			
FortisBC	Ft. Nelson	British Columbia			
FortisBC	Inland	British Columbia			
FortisBC	Whistler	British Columbia			
FortisBC	TOTAL	British Columbia	Growth rate based on underlying econometric models.	The objectives of the Annual Contracting Plan are: (1) To contract for resources which ensure an appropriate balance of cost minimization, security, diversity and reliability of gas supply in order to meet the core customer design peak day and annual requirements. (2) To develop a portfolio mix which incorporates flexibility in the contracting of resources based on short term and long term planning, and evolving market dynamics.	
Gaz Métro	Quebec	Quebec			
NSTAR	Cambridge	Massachusetts			
NSTAR	Framingham	Massachusetts			
NSTAR	New Bedford	Massachusetts			
NSTAR	Worcester	Massachusetts			
NSTAR	TOTAL	Massachusetts		In addition to conducting a review of the historical frequency of occurrence associated with the five coldest winter periods and peak days for each division, the Company also reviewed recent changes in the natural gas industry that may affect the Company's selection of its design-planning standards. These factors include: (a) regulatory unbundling; (b) liquidity in market centers downstream of traditional production areas; and (c) the role of gas marketers.	The NSTAR Gas resource planning process is designed to ensure a reliable energy supply for its customers with a minimum impact on the environment and at the lowest cost, taking into consideration important non-price factors such as reliability, flexibility, and diversity.
National Grid	Boston Gas	Massachusetts			
National Grid	Essex Gas	Massachusetts			
National Grid	Colonial Gas - Lowell	Massachusetts			
National Grid	Colonial Gas - Cape Cod	Massachusetts			
National Grid	TOTAL	Massachusetts	Growth rate based on underlying econometric models.	The Department assesses the two major aspects of every gas company's supply plan: adequacy and cost; and the supply planning process. The Department's review of reliability, is included in the Department's consideration of adequacy. A supply planning process is critical in enabling a utility company to formulate a resource plan that achieves an adequate, least-cost, and low environmental impact supply for its customers. An appropriate supply planning process provides a gas company with an organized method of analyzing options, making decisions, and re-evaluating decisions in light of changed circumstances.	The Company's forecast methodology supports its supply planning goals of ensuring that: (1) its resource portfolio maintains sufficient supply deliverability to meet customer requirements on the coldest planning day ("design day"); and (2) it maintains sufficient supplies under contract and in storage (underground storage, LNG and propane) to meet customers requirements over the coldest planning year ("design year").
Bay State Gas d/b/a Columbia Gas of MA	Brockton	Massachusetts			

Company	Division	State / Province	Growth Rates for Peak Day Load	Planning Factors/Processes	Objective of Plan
Bay State Gas d/b/a Columbia Gas of MA	Lawrence	Massachusetts			
Bay State Gas d/b/a Columbia Gas of MA	Springfield	Massachusetts			
Bay State Gas d/b/a Columbia Gas of MA	TOTAL	Massachusetts	Based on the assumptions that design day occurred on a day in January, the design day planning load requirements were calculated as part of the design year planning load requirements.		The F&SP details CMA's resource planning process and presents the Company's resource strategies based on its current forecast of customer requirements and present market conditions. The plan demonstrates that CMA's planning standards are appropriate and its resource strategies are in the best interests of its customers and result in a reliable, best-cost, long-range supply and capacity portfolio to meet the Company's forecasted firm demand. CMA's decision-making process requires the Company to establish appropriate goals and objectives. The primary goal of CMA's planning process is to acquire and manage all available resources in a manner that achieves a best-cost resource portfolio for its customers. A best-cost portfolio appropriately balances lower costs with other important non-cost criteria such as reliability, viability and flexibility. Pursuit of a best-cost portfolio allows CMA to provide its customers with reliable service at a reasonable cost. The Company's overall portfolio objective is supported by a number of specific resource planning objectives, which are summarized as follows: (1) reduce portfolio costs; (2) maintain portfolio security/reliability (which includes enhancing diversity across pipelines and supply basins); (3) provide contract flexibility; and (4) acquire viable resources.
Southern Connecticut Gas	TOTAL	Connecticut	Peak day demand projections are based upon the current base case scenario.		To describe its planning process to regulators, customers, and other interested parties. The Forecast is constantly changing as the industry and the markets change, and the report represents a single view of that Forecast at a particular point in time. Numerous scenarios continue to evolve from the Forecast and are used in the decision-making process.
Connecticut Natural Gas	Hartford	Connecticut			
Connecticut Natural Gas	Greenwich	Connecticut			
Connecticut Natural Gas	TOTAL	Connecticut	Peak day demand projections are based upon the current base case scenario.		To describe its planning process to regulators, customers, and other interested parties. The Forecast is constantly changing as the industry and the markets change, and the report represents a single view of that Forecast at a particular point in time. Numerous scenarios continue to evolve from the Forecast and are used in the decision-making process.
Yankee Gas	TOTAL	Connecticut	Peak day demand projections are based upon the current base case scenario.		
National Grid	Narragansett Electric Company	Rhode Island	Growth rate based on underlying econometric models.		This Supply Plan is designed to demonstrate that the Company's gas-resource planning process has resulted in a reliable resource portfolio to meet the combined forecasted needs of the Company's Rhode Island customers at least cost and to ensure that the Company maintains sufficient supply deliverability in its resource portfolio to meet customer requirements on the coldest planning day ("design day") and that it maintains sufficient supply under contract and in storage (underground storage, LNG and propane) to meet customers requirements over the coldest planning year ("design year").
National Grid	Brooklyn Union Gas (Long Island)	New York			
National Grid	Brooklyn Union Gas (New York City)	New York			

Company	Division	State / Province	Growth Rates for Peak Day Load	Planning Factors/Processes	Objective of Plan
National Grid	TOTAL	New York	Growth rate based on underlying econometric models.		
National Grid	Niagara Mohawk	New York	Growth rate based on underlying econometric models.		
Consolidated Edison	ConEd of New York	New York	Growth is based on forecasts for economic growth, transfers from interruptible to firm service, fuel switching and energy efficiency.		The gas forecast drives the timing and magnitude of the required investment in transmission and distribution infrastructure. Con Edison currently develops 10-year load forecasts to ensure that transmission and distribution infrastructure is adequate to support the economic growth of NYC and Westchester County. To develop the 20-year forecast for the Gas Long Range Plan, the existing forecast was extended based on a number of key driver sensitivities.
Northern Utilities	Maine	Maine			
Northern Utilities	New Hampshire	New Hampshire			
Northern Utilities	TOTAL	Total System	The preliminary Design Day Planning Load was calibrated using the adjustment factors associated with Design Year January for each forecast year for the Base Case, High Growth, and Low Growth scenarios.		The IRP is provided to explain the planning processes Northern uses to develop an adequate, reliable and economic portfolio and to allow the Public Utilities Commissions of Maine and New Hampshire to evaluate the reasonableness of those planning processes. The IRP relates solely to Northern's planning and contracting activities in support of the gas supply portfolio used to supply customers in the two states.
National Grid	EnergyNorth Natural Gas	New Hampshire	Growth rate based on underlying econometric models.	The Company's planning process ensures that it maintains a reliable resource portfolio and energy supply to meet the forecasted needs of its customers at the lowest possible cost.	The filing of IRPs helps promote communication between the utility and the Commission regarding the utility's supply needs and gas resource decisions. Integrated resource planning helps the Commission assess a utility's comprehensive supply-side and demand-side resources and the utility's ability to satisfy customer's short-term and long-term energy needs at the lowest overall cost consistent with maintaining supply reliability.
Michigan Consolidated Gas	Detroit/Ann Arbor	Michigan			
Michigan Consolidated Gas	Grand Rapids	Michigan			
Michigan Consolidated Gas	Upper Peninsula	Michigan			
Michigan Consolidated Gas	Traverse City	Michigan			
Michigan Consolidated Gas	Alpena	Michigan			
Michigan Consolidated Gas	TOTAL	Michigan			

Company	Division	State / Province	Growth Rates for Peak Day Load	Planning Factors/Processes	Objective of Plan
Consumers Energy	TOTAL	Michigan	Growth is based on gas sendout forecasts for January in the Corporate Gas Deliveries forecast with the addition of fuel use and system loss.	In its Gas Cost Recovery ("GCR") Plan, the Company takes into consideration the importance of taking actions to assure that our customers receive reliable and reasonably priced natural gas supplies for their needs. The Company utilizes a consistent planning methodology with defined risk parameters to assure customers service is not unreasonably jeopardized.	The primary objective of the design peak day forecast is to ensure sufficient supply under extreme and potentially dangerously cold conditions.
Cascade Natural Gas	Aberdeen	Washington			
Cascade Natural Gas	Bellingham	Washington			
Cascade Natural Gas	Bremerton	Washington			
Cascade Natural Gas	Kennewick	Washington			
Cascade Natural Gas	Longview	Washington			
Cascade Natural Gas	Moses Lake	Washington			
Cascade Natural Gas	Mount Vernon	Washington			
Cascade Natural Gas	Sunnyside	Washington			
Cascade Natural Gas	Walla Walla	Washington			
Cascade Natural Gas	Wenatchee	Washington			
Cascade Natural Gas	Yakima	Washington			
Cascade Natural Gas	Baker	Oregon			
Cascade Natural Gas	Bend	Oregon			
Cascade Natural Gas	Ontario	Oregon			
Cascade Natural Gas	Pendleton	Oregon			
Cascade Natural Gas	TOTAL	Total System	The underlying peak day forecast is calculated as the peak day therm usage applied to each district and escalated into the future at the forecast therm usage annual growth rate. This method rests on the assumption that core market load shape does not significantly change throughout the forecast horizon.	The plan provides a method for evaluating resources in terms of their costs and risk. Cascade's service territory covers about 32,000 square miles and extends over 700 highway miles from end to end, encompassing a diverse economic base as well as varying climatological areas. Cascade serves 96 communities throughout Washington and Oregon consisting of about 260,000 customers. All of the communities Cascade serves are small cities and towns. This makes Cascade unique in the gas distribution business in the Pacific Northwest.	The primary purpose of Cascade's long-term resource planning process has been, and continues to be, to inform and guide the Company's resource acquisition processes. In addition, to minimize costs over the long term for the Company's firm gas sales customers.
NW Natural	Albany	Oregon			
NW Natural	Astoria	Oregon			
NW Natural	Dalles	Oregon			
NW Natural	Eugene & Coos Bay	Oregon			
NW Natural	Lincoln City & Newport	Oregon			
NW Natural	Portland	Oregon			
NW Natural	Salem	Oregon			
NW Natural	Vancouver & Dalles	Washington			

Company	Division	State / Province	Growth Rates for Peak Day Load	Planning Factors/Processes	Objective of Plan
NW Natural	TOTAL	Total System	Forecast peak day demand relies upon the base case customer forecast, usage factors, and the design weather pattern.	The Company continues to use the same region-specific forecasts in its 2013 IRP as it used in past IRPs. The regions are defined as Vancouver & The Dalles (Washington), Albany, Astoria, Eugene & Coos Bay, The Dalles (Oregon), Lincoln City & Newport, Portland, and Salem. Each region is distinguished by unique weather, usage patterns, customer growth and resource availability. These eight regions also define the separate demand points along with supplies and distribution system connections.	The IRP defines the mix of natural gas supply and demand side measures designated to meet expected future demand and reliability requirements at the lowest reasonable cost to the utility and its ratepayers. Peak day demand is the primary driver of the resource plan. High peaking demand puts a premium on storage, while large base line volumes may drive more pipeline capacity. Meeting peak day load is of primary consideration for the IRP.
Pacific Gas & Electric	TOTAL	California	Growth rate based on underlying econometric models.		The 2012 California Gas Report presents a comprehensive outlook for natural gas requirements and supplies for California through the year 2030. The projections in the California Gas Report are for long-term planning and do not necessarily reflect the day-to-day operational plans of the utilities.

Company	Division	State / Province	Design Day	Design Day (HDD or EDD?)	Design Day Probability	Definition of Peak Day	Optimization Software Used	Source
Enbridge Gas Distribution	Central	Ontario	41.4	HDD (°C)	1:5			Settlement decision in Enbridge Gas Distribution Rate Case (EB-2011-0354), see also application at Exhibit D1, Tab 2, Schedule 3
Enbridge Gas Distribution	Eastern	Ontario	48.2	HDD (°C)	1:5			Settlement decision in Enbridge Gas Distribution Rate Case (EB-2011-0354), see also application at Exhibit D1, Tab 2, Schedule 3
Enbridge Gas Distribution	Niagara	Ontario	38.8	HDD (°C)	1:5			Settlement decision in Enbridge Gas Distribution Rate Case (EB-2011-0354), see also application at Exhibit D1, Tab 2, Schedule 3
Enbridge Gas Distribution	TOTAL	Ontario					SENDOUT	Settlement decision in Enbridge Gas Distribution Rate Case (EB-2011-0354), see also application at Exhibit D1, Tab 2, Schedule 3
Centra Gas Manitoba	TOTAL	Manitoba	56.0	HDD (°C)				Centra Gas Manitoba 2013/14 General Rate Application, Transcript of Centra Gas Manitoba Transportation and Portfolio Application
FortisBC	Columbia	British Columbia						FortisBC Executive Summary to 2012/13 Annual Contracting Plan (Confidential)
FortisBC	Coastal	British Columbia						FortisBC Executive Summary to 2012/13 Annual Contracting Plan (Confidential)
FortisBC	Ft. Nelson	British Columbia						FortisBC Executive Summary to 2012/13 Annual Contracting Plan (Confidential)
FortisBC	Inland	British Columbia						FortisBC Executive Summary to 2012/13 Annual Contracting Plan (Confidential)
FortisBC	Whistler	British Columbia						FortisBC Executive Summary to 2012/13 Annual Contracting Plan (Confidential)
FortisBC	TOTAL	British Columbia			1:20	The maximum forecasted consumption or demand of gas over a 24 hour period that can be expected.		FortisBC Executive Summary to 2012/13 Annual Contracting Plan (Confidential), Commercial Energy Consumers Association of BC Information Request 11.3
Gaz Métro	Quebec	Quebec	46.0	HDD (°C)				Peak Gas Day Analysis, May 2005
NSTAR	Cambridge	Massachusetts	80.0	EDD (°F)	1:50			NSTAR Gas 2012 Forecast and Supply Plan
NSTAR	Framingham	Massachusetts	85.0	EDD (°F)	1:50			NSTAR Gas 2012 Forecast and Supply Plan
NSTAR	New Bedford	Massachusetts	74.0	EDD (°F)	1:50			NSTAR Gas 2012 Forecast and Supply Plan
NSTAR	Worcester	Massachusetts	85.0	EDD (°F)	1:50			NSTAR Gas 2012 Forecast and Supply Plan
NSTAR	TOTAL	Massachusetts				The design day represents the single highest EDD the Company's resource portfolio must be structured to meet.	SENDOUT	
National Grid	Boston Gas	Massachusetts						Boston Gas and Colonial Gas 2013 Long-Range Resource and Requirements Plan
National Grid	Essex Gas	Massachusetts						Boston Gas and Colonial Gas 2013 Long-Range Resource and Requirements Plan
National Grid	Colonial Gas - Lowell	Massachusetts						Boston Gas and Colonial Gas 2013 Long-Range Resource and Requirements Plan
National Grid	Colonial Gas - Cape Cod	Massachusetts						Boston Gas and Colonial Gas 2013 Long-Range Resource and Requirements Plan
National Grid	TOTAL	Massachusetts	77.6	EDD (°F)	1:35.9	The purpose of a design day standard is to establish the amount of system-wide throughput (interstate pipeline and underground-storage capacity plus local supplemental capacity) that is required to maintain the integrity of the distribution system. In this filing, the Company defines its design day standard at 77.6 EDD with a probability of occurrence of once in 35.90 years, as a result of its on-going review of planning standards.	SENDOUT	Boston Gas and Colonial Gas 2013 Long-Range Resource and Requirements Plan, Final Order of the DPU dated May 7, 2012, Discussions with Company
Bay State Gas d/b/a Columbia Gas of MA	Brockton	Massachusetts	79.5	EDD (°F)	1:33			Bay State Gas Company 2011 Long Range Integrated Forecast and System Gas Supply Resource Plan

Company	Division	State / Province	Design Day	Design Day (HDD or EDD?)	Design Day Probability	Definition of Peak Day	Optimization Software Used	Source
Bay State Gas d/b/a Columbia Gas of MA	Lawrence	Massachusetts	80.5	EDD (^oF)	1:33			Bay State Gas Company 2011 Long Range Integrated Forecast and System Gas Supply Resource Plan
Bay State Gas d/b/a Columbia Gas of MA	Springfield	Massachusetts	78.6	EDD (^oF)	1:33			Bay State Gas Company 2011 Long Range Integrated Forecast and System Gas Supply Resource Plan
Bay State Gas d/b/a Columbia Gas of MA	TOTAL	Massachusetts				The design day standard represents extreme winter weather conditions that have a statistically defined probability of occurring on a very infrequent basis; the design day standard is used to assess the Company's plans to provide reliable service under extremely cold weather conditions.	SENDOUT	Bay State Gas Company 2011 Long Range Integrated Forecast and System Gas Supply Resource Plan
Southern Connecticut Gas	TOTAL	Connecticut	68.0	EDD (^oF)			SENDOUT	SCG 2012 Biennial Forecast Demand & Supply, CT General Statutes (Title 16, Chapter 277, Section 16-32f), Company website
Connecticut Natural Gas	Hartford	Connecticut	75.0	EDD (^oF)				CNG 2012 Biennial Forecast Demand & Supply, CT General Statutes (Title 16, Chapter 277, Section 16-32f)
Connecticut Natural Gas	Greenwich	Connecticut	68.0	EDD (^oF)				CNG 2012 Biennial Forecast Demand & Supply, CT General Statutes (Title 16, Chapter 277, Section 16-32f)
Connecticut Natural Gas	TOTAL	Connecticut					SENDOUT	CNG 2012 Biennial Forecast Demand & Supply, CT General Statutes (Title 16, Chapter 277, Section 16-32f), Company website
Yankee Gas	TOTAL	Connecticut	75.0	EDD (^oF)			SENDOUT	Yankee Gas 2012 Biennial Forecast Demand & Supply, CT General Statutes (Title 16, Chapter 277, Section 16-32f)
National Grid	Narragansett Electric Company	Rhode Island	66.0	HDD (^oF)	1:40.69		SENDOUT	2011/12 to 2015/16 Long-Term Gas Supply Plan
National Grid	Brooklyn Union Gas (Long Island)	New York						Downstate Service Territory Technical Conference January 9, 2013
National Grid	Brooklyn Union Gas (New York City)	New York						Downstate Service Territory Technical Conference January 9, 2013

Company	Division	State / Province	Design Day	Design Day (HDD or EDD?)	Design Day Probability	Definition of Peak Day	Optimization Software Used	Source
National Grid	TOTAL	New York						Discussions with Company
National Grid	Niagara Mohawk	New York	74.0	HDD (°F)				Upstate Service Territory Technical Conference January 9, 2013, Gas Sales Forecast - Witness A. Leo Silvestrini - 12-G-0202, Discussions with Company
Consolidated Edison	ConEd of New York	New York	65.0	HDD (°F)		Peak demand, or the maximum quantity of natural gas that our firm customers require at a single point in time, drives infrastructure investment because our system must be able to meet that demand even if it is a relatively infrequent occurrence. In our service territory, these peak demand periods occur only during the coldest winter days, often for only several hours over the span of a few days.		Technical Conference January 9, 2013, ICF Assessment of NYC Natural Gas Market Fundamentals and Life Cycle Fuel Emissions, ConEd Integrated Long-Range Plan 2012, ConEd Gas Long Range Plan 2010-2030 December 2010, Discussions with Company
Northern Utilities	Maine	Maine	78.9	EDD (°F)	1:33			Northern Utilities 2011 Integrated Resource Plan
Northern Utilities	New Hampshire	New Hampshire	80.5	EDD (°F)	1:33			Northern Utilities 2011 Integrated Resource Plan
Northern Utilities	TOTAL	Total System				The Design Day planning standard represents extreme weather conditions on a single day that has a statistically defined probability of occurring on a very infrequent basis.	SENDOUT	Northern Utilities 2011 Integrated Resource Plan
National Grid	EnergyNorth Natural Gas	New Hampshire	72.3	HDD (°F)		Design day is an extreme weather event for which the Company must maintain adequate resources. The design day standard determines the most cost-effective amount of daily transportation capacity (both interstate and supplemental). The design day standard is based on the statistical distribution of the coldest day of each calendar year.	SENDOUT	National Grid NH 2010 Integrated Resource Plan, New Hampshire Public Utilities Commission Order No. 25,317, January 11, 2012
Michigan Consolidated Gas	Detroit/Ann Arbor	Michigan	69.0	HDD (°F)				MichCon Gas Cost Recovery Plan
Michigan Consolidated Gas	Grand Rapids	Michigan	72.0	HDD (°F)				MichCon Gas Cost Recovery Plan
Michigan Consolidated Gas	Upper Peninsula	Michigan		HDD (°F)				MichCon Gas Cost Recovery Plan
Michigan Consolidated Gas	Traverse City	Michigan	76.0	HDD (°F)				MichCon Gas Cost Recovery Plan
Michigan Consolidated Gas	Alpena	Michigan	75.0	HDD (°F)				MichCon Gas Cost Recovery Plan
Michigan Consolidated Gas	TOTAL	Michigan				The coldest mean average temperature MichCon can expect at each location as of January, February and March.		MichCon Gas Cost Recovery Plan

Company	Division	State / Province	Design Day	Design Day (HDD or EDD?)	Design Day Probability	Definition of Peak Day	Optimization Software Used	Source
Consumers Energy	TOTAL	Michigan	80.0	HDD (°F) (Adjusted upward by 4 HDD due to wind)			SENDOUT	Consumers Energy Gas Cost Recovery Plan
Cascade Natural Gas	Aberdeen	Washington						Cascade Natural Gas Corporation 2012 Integrated Resource Plan
Cascade Natural Gas	Bellingham	Washington						Cascade Natural Gas Corporation 2012 Integrated Resource Plan
Cascade Natural Gas	Bremerton	Washington						Cascade Natural Gas Corporation 2012 Integrated Resource Plan
Cascade Natural Gas	Kennewick	Washington						Cascade Natural Gas Corporation 2012 Integrated Resource Plan
Cascade Natural Gas	Longview	Washington						Cascade Natural Gas Corporation 2012 Integrated Resource Plan
Cascade Natural Gas	Moses Lake	Washington						Cascade Natural Gas Corporation 2012 Integrated Resource Plan
Cascade Natural Gas	Mount Vernon	Washington						Cascade Natural Gas Corporation 2012 Integrated Resource Plan
Cascade Natural Gas	Sunnyside	Washington						Cascade Natural Gas Corporation 2012 Integrated Resource Plan
Cascade Natural Gas	Walla Walla	Washington						Cascade Natural Gas Corporation 2012 Integrated Resource Plan
Cascade Natural Gas	Wenatchee	Washington						Cascade Natural Gas Corporation 2012 Integrated Resource Plan
Cascade Natural Gas	Yakima	Washington						Cascade Natural Gas Corporation 2012 Integrated Resource Plan
Cascade Natural Gas	Baker	Oregon						Cascade Natural Gas Corporation 2012 Integrated Resource Plan
Cascade Natural Gas	Bend	Oregon						Cascade Natural Gas Corporation 2012 Integrated Resource Plan
Cascade Natural Gas	Ontario	Oregon						Cascade Natural Gas Corporation 2012 Integrated Resource Plan
Cascade Natural Gas	Pendleton	Oregon						Cascade Natural Gas Corporation 2012 Integrated Resource Plan
Cascade Natural Gas	TOTAL	Total System	61.0	HDD (°F)		The greatest total natural gas demand forecasted in a 24-hour period used as a basis for planning peak capacity requirements.	SENDOUT	Cascade Natural Gas Corporation 2012 Integrated Resource Plan
NW Natural	Albany	Oregon	54.5	HDD (°F)				2013 Integrated Resource Plan
NW Natural	Astoria	Oregon	50.0	HDD (°F)				2013 Integrated Resource Plan
NW Natural	Dalles	Oregon	62.0	HDD (°F)				2013 Integrated Resource Plan
NW Natural	Eugene & Coos Bay	Oregon	52.2	HDD (°F)				2013 Integrated Resource Plan
NW Natural	Lincoln City & Newport	Oregon	48.5	HDD (°F)				2013 Integrated Resource Plan
NW Natural	Portland	Oregon	53.0	HDD (°F)				2013 Integrated Resource Plan
NW Natural	Salem	Oregon	54.0	HDD (°F)				2013 Integrated Resource Plan
NW Natural	Vancouver & Dalles	Washington	54.7	HDD (°F)				2013 Integrated Resource Plan

9.1. Planification pour l'année 2013-2014

9.1.1. Demande et sources d'approvisionnement gazier

L'annexe 5 présente la planification annuelle pour l'année 2014.

Hiver

La demande totale s'élève à 3 350 10^6m^3 pour la période d'hiver. L'approvisionnement pour répondre à la demande totale avant interruption se chiffre à 3 308 10^6m^3, incluant les retraits des inventaires. Ainsi, un volume d'interruption de 43 10^6m^3 est requis pour répondre à la demande d'hiver durant les mois d'épaulement.

Été

Durant l'été, la demande totale prévue s'élève à 2 900 10^6m^3. L'approvisionnement défini pour répondre à cette demande considère les différentes capacités de transport disponibles, les volumes d'achat de gaz naturel à Dawn ainsi que les retraits des sites d'entreposage.

Il est à noter qu'aucune capacité de transport FTLH non utilisée n'est prévue. Étant donné que la structure d'approvisionnement requiert des achats à Dawn en été et que la quantité prévue est significative, c'est cette quantité d'achats qui fluctuera. En effet, d'un point de vue opérationnel, Gaz Métro utilisera la totalité de son transport FTLH (après la vente des capacités excédentaires projetées) et modulera les achats « spot » à Dawn, le cas échéant.

9.1.2. Modification à la méthode d'évaluation de la demande continue en journée de pointe

Gaz Métro propose de modifier la méthode d'évaluation de la demande continue en journée de pointe relativement à la clientèle aux tarifs D_3 et D_4.

Actuellement, la contribution de cette clientèle à la journée de pointe est déterminée en utilisant le maximum des volumes moyens des mois de décembre à mars, tel que projeté pour l'année financière considérée. Cette approche suppose que les clients aux tarifs D_3 et D_4 consomment selon un profil uniforme au cours du mois, sans influence de la température.

Or, cette hypothèse s'avère inexacte. Dans les faits, la consommation de cette clientèle est influencée par la température.

Gaz Métro a pu observer cet impact de la température sur la clientèle du tarif D_4 au cours du mois de janvier 2013, plus spécifiquement le 23 janvier, journée où Gaz Métro a desservi le volume de gaz naturel le plus élevé de son histoire, toute clientèle confondue. Les conditions climatiques de cette journée (DJ_t 36,7, $DJ_{(t-1)}$ 34,6 et DJ x V 756.02) étaient inférieures aux paramètres de la journée de pointe (DJ_t 36,85, $DJ_{(t-1)}$ 39,5 et DJ x V 1272,35). Toutefois, lors de la planification de cette journée, Gaz Métro ne détenait pas les approvisionnements pour répondre à la demande projetée de la clientèle continue. Le tableau suivant présente la planification effectuée le 22 janvier et le constat de la journée du 23 janvier.

Demande et approvisionnement 23 janvier 2013

	Planification 22 janvier	**Réel fin de journée**
Degrés jours (t)	37	36,7
Degrés jours (t-1)	34	34,6
DJ x Vent	666	756,02
Demande franchise		
Continue	30 083	28 956
Interruptible (GAI *)	2 963	2 418
Total de la demande	**33 046**	**31 375**
Outils d'approvisionnment en franchise		
FTLH	4 363	4 363
FTSH	4 355	4 355
STS	5 705	5 705
Marché secondaire	4 572	4 985
Transport fourni par les clients	2 172	2 114
Gaz d'appoint (GAC)	115	115
Gaz d'appoint (GAI)	2 963 *	2 587
Retrait LSR	5 698	4 573
Retrait Pointe-du-Lac	932	1 039
Retrait St-Flavien	1 478	1 416
Linepack et écart de nominations	0	122
Total des approvisionnements	**32 354**	**31 375**
Excédent (déficience)	**-692**	**1 134**

*Livraisons observées le 22 janvier 2013

Il est à noter que le 23 janvier était la septième journée consécutive d'une vague de froid où tous les clients étaient interrompus. Un effritement des outils était entamé.

En fonction de la planification effectuée le 22 janvier, Gaz Métro ne détenait pas les outils pour répondre à la demande, il manquait 692 10^3m^3 d'approvisionnement. Elle avait décidé de contracter 1 056 10^3m^3/jour (40 000 GJ/jour) pour une période de sept jours, soit la déficience d'approvisionnement plus une marge équivalente au besoin pour un degré-jour. Dans les faits, elle n'a été en mesure de contracter que 413 10^3m^3/jour pour la période visée, laissant ainsi une déficience projetée de 279 10^3m^3 pour la journée du 23 janvier.

De plus, plusieurs clients interrompus qui désiraient contracter du gaz d'appoint pour éviter une interruption (GAI) n'ont pu le faire, la capacité n'étant pas disponible, amenant une incertitude additionnelle quant au respect de l'interruption demandée par Gaz Métro.

Le 23 janvier, à 09 h 00, la projection des degrés-jours pour la journée gazière du 23 janvier était passée à 38 DJ. Selon la règle du pouce d'une consommation de 528 10^3m^3/DJ (20 000 GJ/DJ), la déficience d'approvisionnement passait à 807 10^3m^3, après ajout de capacité. Gaz Métro s'enlignait donc pour être en situation de déficience auprès de TCPL et entraîner des frais de LBA « Load Balancing Agreement ».

La température de la journée a finalement été légèrement inférieure à la projection initiale. Le constat des approvisionnements était qu'il restait 1 134 10^3m^3 d'outil à l'usine LSR, mais les clients en GAI ont livré 169 10^3m^3 de gaz naturel de plus que le volume total consommé de la clientèle interruptible. Sur une base nette, Gaz Métro avait donc une marge de 965 10^3m^3, soit les approvisionnements pour 1,8 DJ.

À la suite de ces événements, Gaz Métro a analysé de façon plus spécifique la consommation des clients du tarif D_4 en fonction des degrés-jours observés. Le tableau suivant présente les résultats regroupés par journée.

Consommation Janvier 2013 - Tarif D4			
Jour	**Date**	**DJ**	**Volume** 10^3m^3
lundi	21	31,4	6 659
lundi	28	21,9	6 505
lundi	07	21,7	6 385
lundi	14	13,5	5 639
mardi	22	34,6	6 858
mardi	15	15,7	5 948
mardi	08	14,7	6 175
mardi	29	13,6	6 301
mercredi	23	36,6	6 822
mercredi	16	15,2	6 181
mercredi	09	11,2	5 859
mercredi	30	7,1	5 940
jeudi	24	32,2	6 951
jeudi	17	30,7	6 615
jeudi	03	27,1	6 294
jeudi	31	22,1	6 343
jeudi	10	14,0	6 141
vendredi	25	30,4	6 621
vendredi	18	23,1	6 493
vendredi	04	15,7	6 127
vendredi	11	11,8	6 037
samedi	26	28,0	6 362
samedi	05	23,0	6 225
samedi	19	14,2	6 099
samedi	12	9,8	5 722
dimanche	27	26,3	6 500
dimanche	20	25,9	6 323
dimanche	06	23,2	6 165
dimanche	13	8,8	5 671
férié	02	32,6	5 946
férié	01	27,6	4 867

Cette analyse démontre que pour des mêmes jours de la semaine ou pour des jours fériés, le volume de gaz consommé a tendance à augmenter avec les degrés-jours.

Pour compléter l’analyse, des régressions linéaires sur les consommations observées pour la clientèle aux tarifs D_3 et D_4 à lecture quotidienne pour les hivers 2009 à 2012 ont été réalisées. Les résultats sont les suivants :

Hiver 2009

Paramètre	$10^3 m^3$	Paramètre	$10^3 m^3$	Paramètre	$10^3 m^3$/unité
Constante	3 152	Novembre	0	DJ (t)	23
		Décembre	-37	DJ (t-1)	9
Dimanche	67	Janvier	286	DJ x V	0,1
Lundi	297	Février	468		
Mardi	323	Mars	370		
Mercredi	266				
Jeudi	306				
Vendredi	148				
Samedi	0				

Hiver 2010

Paramètre	$10^3 m^3$	Paramètre	$10^3 m^3$	Paramètre	$10^3 m^3$/unité
Constante	3 860	Novembre	0	DJ (t)	22
		Décembre	11	DJ (t-1)	3
Dimanche	79	Janvier	132	DJ x V	-0,1
Lundi	305	Février	209		
Mardi	208	Mars	150		
Mercredi	201				
Jeudi	256				
Vendredi	192				
Samedi	0				

Hiver 2011

Paramètre	$10^3 m^3$	Paramètre	$10^3 m^3$	Paramètre	$10^3 m^3$/unité
Constante	3 560	Novembre	0	DJ (t)	19
		Décembre	4	DJ (t-1)	7
Dimanche	46	Janvier	210	DJ x V	0,3
Lundi	145	Février	194		
Mardi	206	Mars	223		
Mercredi	237				
Jeudi	222				
Vendredi	114				
Samedi	0				

Hiver 2012

Paramètre	$10^3 m^3$	Paramètre	$10^3 m^3$	Paramètre	$10^3 m^3$/unité
Constante	4 061	Novembre	0	DJ (t)	20
		Décembre	295	DJ (t-1)	0
Dimanche	56	Janvier	827	DJ x V	0,4
Lundi	200	Février	774		
Mardi	159	Mars	760		
Mercredi	192				
Jeudi	300				
Vendredi	185				
Samedi	0				

Les résultats démontrent clairement que la consommation de cette clientèle est influencée par la température. Les valeurs de 19 à 23 10^3m^3/DJ peuvent sembler non significatives, mais lorsque celles-ci s'appliquent à 40 DJ, cela représente une fluctuation variant de 760 à 920 10^3m^3, ce qui devient alors significatif.

Ces diverses observations viennent appuyer l'hypothèse que la consommation de la clientèle aux tarifs D_3 et D_4 est influencée par la température.

En conséquence, Gaz Métro demande à la Régie d'approuver la modification à la méthode d'évaluation de la journée de pointe de la clientèle aux tarifs D_3 et D_4 qui consiste à appliquer la méthode déjà en place pour la clientèle au tarif D_1 et approuvée par la Régie dans sa décision D-2009-156.

Le plan d'approvisionnement 2014-2016 a été établi en considérant la modification à la méthode d'évaluation de la journée de pointe pour la clientèle aux tarifs D_3 et D_4.

L'annexe 10, lignes 80 à 107, présente le détail de la projection de la demande continue en journée de pointe pour la Cause tarifaire 2014 en fonction de la nouvelle méthode.

9.1.3. Établissement de la journée de pointe

La combinaison représentant la journée de pointe estimée historique des 20 dernières années pour la demande continue est identifiée en appliquant les facteurs de la régression linéaire (ci-après décrite) aux combinaisons « degrés-jours et vent » réels réchauffés des 20 dernières années, évalués en base 13°C, distinctement pour :

- la clientèle au tarif D_1 et D_3 à lecture mensuelle ; et
- la clientèle aux tarifs D_3 et D_4 à lecture quotidienne.

La régression linéaire est établie en considérant les facteurs calorifiques (DJ_t et DJ_{t-1}), le facteur croisé de la température et du vent (DJ x V) et le facteur de base maximal journalier et mensuel, sous la base de référence 13°C, en fonction des volumes quotidiens réels observés du 1er novembre 2011 au 31 mars 2012. Un facteur d'ajustement est par la suite appliqué pour refléter la demande de la Cause tarifaire 2014.

Le Tableau 28 présente les résultats de la régression ainsi que les combinaisons des cinq journées historiquement les plus froides des 20 dernières années ; la journée du