Études, analyses et rapports pour la détermination du Facteur X déposés dans le cadre de l'établissement du mécanisme de réglementation incitative du Transporteur

Table des matières

Liste des figures

1. Demande de la Régie

Dans sa décision D-2018-001[1], la Régie ordonne au Transporteur de déposer les études, analyses et rapports dont il dispose, notamment toutes les mises à jour ou études supplémentaires à celles déposées par le Distributeur[2], afin d'éclairer la Régie quant à la détermination du Facteur X pour le Transporteur en phase 3 de la demande relative à l'établissement du mécanisme de réglementation incitative (« MRI »).

En suivi, le Transporteur décrit son contexte d'affaires et expose le cadre d'analyse qui pourra permettre à la Régie d'exercer son jugement afin de fixer un Facteur X qui soit approprié pour le Transporteur.

À la section 2, le Transporteur fait état de son contexte général et rappelle les particularités de son réseau et les principaux enjeux qui lui sont associés.

À la section 3, il explique plus en détails sa stratégie d'efficience et les éléments à prendre en considération pour l'apprécier ainsi que la mesure de celle-ci.

À la section 4, il résume l'analyse de ses experts Concentric Energy Advisors (« Concentric »), présentée à l'annexe B, portant sur l'identification et l'analyse des études, méthodologies et autres informations pertinentes à l'établissement d'un Facteur X pour le Transporteur.

En conclusion, le Transporteur résume les particularités de son réseau et de ses activités en rappelant les principaux enjeux auxquels il doit faire face, lesquels enjeux doivent impérativement être pris en considération pour l'établissement de son Facteur X.

Les hyperliens pour accéder aux documents suivants sont présentés à l'annexe A :

- Pièces portant sur l'efficience du Transporteur déposées de 2007 à 2017 dans le cadre de ses dossiers tarifaires ;
- Pièces portant sur les charges d'exploitation du Transporteur déposées de 2007 à 2017 dans le cadre de ses dossiers tarifaires ;
- Pièces portant sur le balisage du Transporteur déposées de 2008 à 2017 dans le cadre de ses dossiers tarifaires ;
- Pièces portant sur le modèle de gestion des actifs (« MGA ») du Transporteur déposées en 2016 et 2017 dans le cadre de ses dossiers tarifaires.

L'information présentée dans le présent document permet de constater que l'efficience du Transporteur est globale, soit tant au niveau des investissements que des charges d'exploitation. De plus, la stratégie du Transporteur lui permet de demeurer parmi les entreprises les plus performantes de l'industrie au Canada, livrant une bonne fiabilité à moindre coût, et cela, malgré les facteurs propres à son contexte (décrits aux sections

[1] Décision D-2018-001, paragraphe 110 et page 89.
[2] Suivi de la décision D-2017-043, pièce A-0161.

suivantes) qui exercent une pression sur ses coûts. Le Transporteur entend persévérer dans cette voie et le MRI doit lui permettre de maintenir cette bonne performance.

Conformément à l'article 48.1 de la *Loi sur la Régie de l'énergie*[3] (« la Loi »), la réalisation des gains d'efficience exigée dans le cadre du MRI du Transporteur devra lui permettre de poursuivre les objectifs suivants :

- l'amélioration continue de la performance et de la qualité du service ;
- une réduction des coûts profitable à la fois aux consommateurs et au Transporteur ;
- l'allégement du processus par lequel sont fixés ou modifiés les tarifs du Transporteur applicables à un consommateur ou à une catégorie de consommateurs.

Dans le contexte actuel de vieillissement des actifs, le Transporteur se doit donc d'assurer le maintien de la sécurité, de la fiabilité et de la disponibilité de son réseau. Le Transporteur entend poursuivre ses efforts d'efficience en ce sens.

2. Contexte du Transporteur

Le Transporteur maintient son engagement à assurer la sécurité du public et de ses employés, à fournir un service fiable et à maximiser la disponibilité de son réseau, tout en faisant preuve de prudence pour le réaliser, et ce au meilleur coût pour ses clients. Faisant face à un réseau de transport vieillissant requérant à la fois des investissements en pérennité et une intensification des interventions en maintenance, le Transporteur s'appuie notamment sur son MGA et d'autres mesures d'efficience déjà en place pour réaliser cette optimisation. La Régie est bien au fait de ces initiatives.

Une telle démarche nécessite une stratégie d'efficience permettant l'optimisation de l'ensemble des interventions sur le réseau de transport, aussi bien aux investissements qu'en maintenance.

Le parc d'actifs du Transporteur est actuellement composé de plus de 700 000 équipements répartis dans plus de 520 postes électriques et de plus de 34 200 km de lignes. Ce parc, dont plus de 75 % des équipements est en deuxième moitié de vie, a une valeur nette de l'ordre de 21 G$.

Le Transporteur rappelle les particularités de son réseau caractérisé par son étendue, son degré d'automatisme et sa complexité. De fait, plusieurs particularités le distinguent des réseaux typiques du continent nord-américain. L'une d'elles consiste en la polarisation des charges et de la production aux extrémités sud et nord du réseau respectivement. La grande distance entre la production et les charges implique le recours à plusieurs paliers de conversion de tension, un plus grand nombre d'équipements et des conditions d'exploitation et de maintenance exigeantes. Ces caractéristiques exercent une pression élevée sur les probabilités de bris et de défaillances, dont les conséquences peuvent notamment être

[3] Loi sur la Régie de l'énergie (RLRQ, c. R-6.01), chapitre IV - Tarification, article 48.1.

aggravées en raison d'autres particularités propres à l'utilisation du réseau, soit la pointe hivernale et le taux élevé d'utilisation du réseau.

Un autre facteur de risque opérationnel non négligeable résulte de la hausse de l'âge moyen de ses infrastructures de transport d'électricité, qui génère un risque accru de défaillance, et ce, malgré un programme d'investissements en pérennité et une stratégie de maintenance ciblée.

De plus, le réseau du Transporteur traverse des zones aux conditions climatiques difficiles qui le rendent plus exposé à des événements liés au climat. Ces conditions peuvent aussi rendre plus difficile et onéreux l'accès au réseau afin d'accomplir les activités de dépannage et de maintenance.

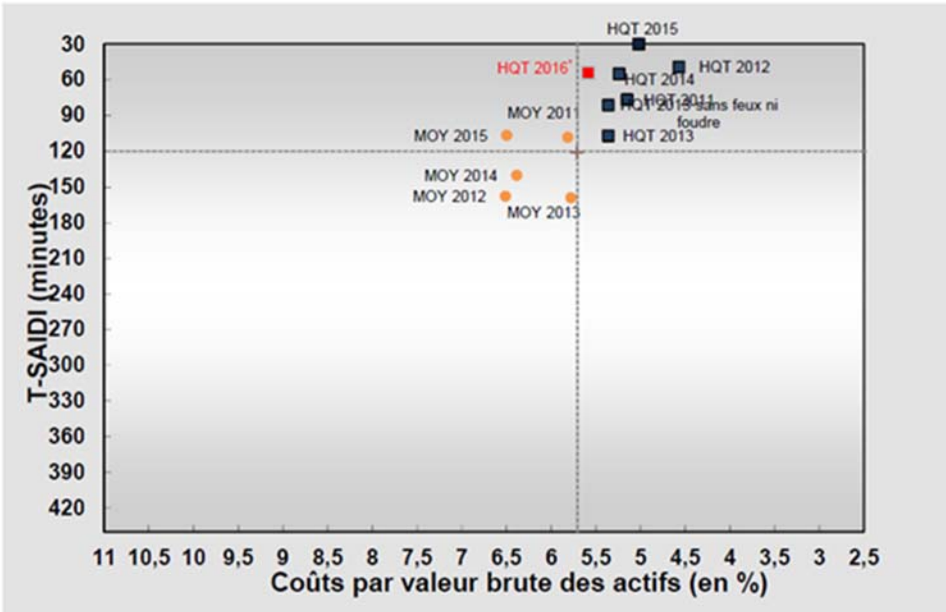
Ces particularités précitées doivent être prises en considération, notamment dans des comparaisons avec les rares transporteurs soumis à un MRI afin que la détermination du Facteur X soit adaptée à la situation globale du Transporteur.

3. L'efficience du Transporteur

Dans un contexte de vieillissement des actifs, le Transporteur se doit d'assurer le maintien de la sécurité, de la fiabilité et de la disponibilité de son réseau. Les initiatives d'efficience mises en place par le Transporteur procurent des gains aux niveaux des charges nettes d'exploitation (« CNE ») et des investissements. L'indicateur composite est un indicateur global de choix pour apprécier l'efficience du Transporteur. En effet, cet indicateur met en relation les coûts totaux (CNE et investissements) avec la fiabilité du service et compare la performance du Transporteur à celle d'autres entreprises d'électricité canadiennes qui participent aux travaux du Best Practice Working Group (« BPWG ») de l'Association canadienne de l'électricité (« ACÉ »).

À la lumière des résultats présentés dans la figure 1 ci-dessous, qui est reproduite chaque année dans la pièce HQT-3, Document 1 des dossiers tarifaires du Transporteur, on constate que le Transporteur demeure parmi les entreprises les plus performantes au sein des entreprises de comparaison, livrant une bonne fiabilité à moindre coût.

Figure 1
Indicateur composite[4]



Le MGA constitue le principal vecteur d'efficience du Transporteur. En effet, en arrimant les stratégies de pérennité[5] et de maintenance, il permet, sur le cycle de vie de l'actif, de déterminer l'intervention la plus appropriée compte tenu de l'état de l'actif individuel et de l'ensemble du parc, du niveau de fiabilité visé, de la capacité de réalisation et des coûts. Ainsi, par cet arbitrage annuel systématique, le Transporteur est en mesure de proposer des scénarios d'investissements et de maintenance qui assurent la fiabilité du réseau au moindre coût dans une perspective pluriannuelle. Le scénario retenu consiste en un accroissement de la maintenance et un remplacement des équipements à un rythme justifié par un équilibre entre le contrôle du risque et un coût moindre.

En plus de l'arbitrage systématique, le MGA intègre les gains d'efficience qui découlent de l'amélioration des façons de faire. En effet, lorsque la mise en œuvre de pistes d'efficience résulte, par exemple, en la réduction de la durée d'une gamme opératoire, ou une réduction des coûts liés à l'acquisition de biens ou services, ces nouvelles façons de faire sont intégrées dans les paramètres du MGA. Ceci permet aussi de déterminer les niveaux d'investissements et de maintenance requis pour assurer le niveau de fiabilité visé. Les gains issus de cette optimisation des coûts bénéficient à la clientèle du Transporteur.

Le Facteur X à venir devra donc considérer cette réalité pour tenir compte des orientations du MGA et ne pas enrayer la mise en œuvre des stratégies de pérennité et de maintenance du Transporteur.

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4 Dossier R-4012-2017, HQT-3, Document 1, page 7.
5 Dossier R-3670-2008, HQT-2, Document 1.

3.1. L’efficience aux charges nettes d’exploitation

Considérant la décision D-2018-001 de la Régie, les CNE constituent la principale portion des revenus requis sujet au Facteur X dans le cadre du MRI du Transporteur. Elles représentent environ 25 % des revenus requis du Transporteur. L’efficience aux CNE pour le Transporteur vise entre autres à accroître le temps à pied d’œuvre des ressources, à améliorer son organisation du travail pour absorber la croissance des besoins en maintenance et réduire les coûts d’acquisition de biens et de services.

Entre 2008 et 2017, grâce à l’amélioration de ses pratiques d’affaires, le Transporteur a été en mesure de générer de l’efficience à hauteur de 161 M$[6]. Depuis 2008, le Transporteur a poursuivi plusieurs pistes d’améliorations génératrices d’efficience. À titre d’exemples, le Transporteur réfère à l’évaluation de la stratégie de maintenance pour les disjoncteurs/réenclencheurs, la révision du cycle d’entretien des systèmes de refroidissement des salles de commande, le déploiement du programme d’Optimisation des systèmes de maintenance (« OSM »), la planification opérationnelle consolidée (« POC »), la création du Centre de gestion des activités de transport (« CGAT »), la gestion de l’organisation du travail (logistique, vacances, modulation saisonnière, temporaires vs permanents) ainsi que les divers ajustements organisationnels dont le but a été de doter l’organisation de la robustesse « système » et organisationnelle nécessaire pour faire face aux défis de son environnement. Plusieurs exemples d’améliorations des façons de faire sont présentés dans les pièces HQT-3, Document 1 soumises au fil des ans dans le cadre des dossiers tarifaires du Transporteur et référencées à l’annexe A du présent document.

Considérant sa stratégie de pérennité et afin d’assurer la fiabilité de son réseau, le Transporteur se doit de mettre à niveau la maintenance des équipements. Toutefois, en raison du nombre d’équipements en deuxième moitié de vie, la portée des CNE allouées à la maintenance se trouve restreinte. De plus, les efforts d’efficience, lorsqu’ils se matérialisent, offrent plutôt au Transporteur la possibilité de réaliser davantage de travaux. Évidemment, la capacité de réaliser davantage de travaux se traduit, entre autres, par une consommation accrue de pièces qui peut aussi influencer à la hausse les coûts totaux. En d’autres termes, dans le contexte actuel, l’efficience aux CNE ne se traduit pas nécessairement par une baisse du coût global, mais bien par une augmentation du volume de travaux à réaliser pour maintenir la fiabilité du réseau.

Ainsi, depuis 2014, notamment avec l’intensification des travaux de maintenance, le Transporteur présente un bilan de CNE défavorable, démontrant le défi auquel il fait face pour dégager des gains d’efficience aux CNE qui se traduisent réellement par une diminution de celles-ci.

Le Facteur X à venir devra donc considérer cette réalité pour ne pas enrayer la mise en œuvre des stratégies de pérennité et de maintenance du Transporteur.

[6] R-3897-2014 - Phase 1, HQTD-8, Document 1, pages 19- 20, R5.1.

3.2. L'efficience aux investissements

Les coûts associés aux investissements constituent environ 75 % des revenus requis du Transporteur. Ainsi, la mitigation de la progression des revenus requis est en partie attribuable à l'efficience réalisée aux investissements.

Le Transporteur rappelle qu'au fil des années, il a poursuivi ses efforts pour livrer davantage d'efficience dans ses projets d'investissements, et ce, au bénéfice de sa clientèle. La planification intégrée[7] (ex. : coûts évités au poste Anne-Hébert[8]), les plans d'évolution des réseaux sous régionaux (ex. : réseaux sous régionaux Saint-Jérôme Nord et Québec[9]), la gestion par programme (ex. : remplacement des disjoncteurs PK) et la transposition des meilleures pratiques constituent quelques exemples d'efficience réalisée aux investissements.

Le Transporteur poursuit ses actions en vue de dégager davantage d'efficience dans ses projets d'investissement, comme il en fait mention à chaque année dans ses demandes tarifaires, dont notamment la démarche d'amélioration de projets, l'innovation technologique et la réingénierie de la chaîne d'approvisionnement. Parmi les autres pistes, le Transporteur souligne l'usage optimal de sa main d'œuvre, à savoir la vérification pré-opérationnelle, la mise en route des automatismes ainsi que les stratégies de mise en route et de mise en service.

Considérant que sa force de travail est mixte, c'est-à-dire intervenant autant pour effectuer la maintenance des installations que dans le cadre de la réalisation de ses projets d'investissement, le Transporteur souligne l'enjeu que peut occasionner une efficience aux investissements. En effet, lorsque le Transporteur se montre efficient pour ses activités financées aux investissements, il risque d'exercer une pression à la hausse sur ses CNE en raison de la baisse de prestations pouvant découler de l'efficience aux investissements.

De plus, le Transporteur souligne que les gains d'efficience dans ses projets d'investissement profitent essentiellement à sa clientèle. Le Transporteur soumet qu'il serait souhaitable que le futur régime réglementaire prévoit des incitatifs lui permettant aussi de bénéficier des améliorations dans la réalisation de ses projets d'investissement.

4. Rapport des experts de concentric pour l'établissement d'un Facteur X pour le Transporteur

Le Transporteur a retenu les services d'experts de Concentric pour identifier et analyser les études, méthodologies et autres informations pertinentes à l'établissement d'un Facteur X dans le cadre de son MRI. Les constatations préliminaires de Concentric sont présentées à l'annexe B.

[7] Dossier R-3706-2009, HQT-3, Document 1, pages 13-18.
[8] Dossier R-3669-2008, HQT-3, Document 1, page 11.
[9] Dossier R-3738-2010, HQT-3, Document 1, pages 13-14.

Il appert du rapport de Concentric que la nature des activités des transporteurs électriques crée un profil d'exploitation et de coûts moins homogène[10]. Ce constat pose donc des défis pour l'analyse comparative de la productivité de l'industrie pour le transport d'électricité.

Les organismes de réglementation ont ainsi établi une vaste gamme d'objectifs de rendement pour les services de transport d'électricité. L'analyse de Concentric illustre cette variabilité dans les approches adoptées et les types spécifiques d'objectifs fixés pour les différents programmes.

Concentric observe une tendance à la baisse au fil du temps de la productivité pour les distributeurs électriques. Quoique fondée sur un plus petit échantillon d'études disponibles, une tendance similaire est également observée pour les services de transport.

Finalement, il est important de noter que lorsque ces facteurs de productivité sont mesurés, ils ne tiennent généralement pas compte de la fiabilité. Considérant l'exigence de l'article 48.1 de la Loi pour l'amélioration continue de la performance et de la qualité du service, le cadre approuvé par la Régie doit permettre au Transporteur d'obtenir des revenus suffisants pour atteindre cet objectif.

5. Conclusion

À la lumière des éléments de contexte présentés dans les sections précédentes, il est important de retenir que :

- L'efficience du Transporteur ne peut être appréciée uniquement du point de vue des CNE ou des investissements, mais bien comme un tout découlant de son MGA ainsi que de l'ensemble de ses activités.
- L'indicateur composite qui mesure le coût total par rapport à la fiabilité livrée témoigne du bien-fondé des stratégies du Transporteur et de son efficience à ce jour. À cet égard, le Transporteur présente une performance qui le situe années après années parmi les meilleurs au sein des entreprises de comparaison. Le Transporteur souhaite poursuivre dans cette même voie. Cette approche correspond aux objectifs de l'article 48.1 de la Loi.
- Le Transporteur remet les gains réalisés de sa bonne performance pour la réalisation des projets d'investissements à sa clientèle, même si pour certaines activités, cette efficience peut générer une pression sur les CNE. Le Transporteur soumet que cet élément doit être pris en considération dans la détermination d'un Facteur X applicable à son contexte.

[10] Davantage de données sont disponibles pour des groupes comparables au niveau de la distribution en raison du plus grand nombre de distributeurs dans une région donnée.

- Le contexte actuel du réseau (réseau vieillissant, forte proportion des équipements en deuxième moitié de vie et sollicitation accrue du réseau) présente des défis importants pour le Transporteur. Il a entre autres été démontré en preuve[11] que la maintenance requise pour un réseau vieillissant est plus onéreuse. Cette situation a contribué au bilan défavorable des CNE depuis 2014. De plus, considérant les besoins importants du réseau, l'efficience réalisée par le Transporteur ne se traduit pas nécessairement par une baisse des CNE, mais lui offre aussi la possibilité de faire davantage de maintenance pour assurer la fiabilité du réseau.
- Bien que le niveau de maintenance dicté par le MGA tienne compte de la fiabilité du réseau et de sa réalisation au moindre coût, il exercera assurément une pression sur les charges visées par la formule d'indexation. Le Transporteur est donc d'avis que cet élément doit être pris en considération dans la détermination d'un Facteur X applicable à son contexte.

Dans le cadre de sa demande tarifaire 2019, le Transporteur procédera à la mise à jour des études, analyses et rapports existants, le cas échéant, et présentera son positionnement quant à la détermination du Facteur X à utiliser pour son MRI.

[11] Dossier R-3981-2016, pièce HQT-3, Document 1.1 révisé.

Annexe A

Références (hyperliens) aux documents du Transporteur

Documents sur l'efficience

- R-3640-2007 : Efficience du Transporteur
- R-3669-2008 : Efficience
- R-3706-2009 : Efficience, performance et balisage
- R-3738-2010 : Efficience
- R-3777-2011 : Efficience
- R-3823-2012 : Efficience
- R-3903-2014 : Efficience
- R-3934-2015 : Efficience
- R-3981-2016 : Efficience
- R-4012-2017 : Efficience

Documents sur les charges d'exploitation

- R-3640-2007 : Charges brutes directes
- R-3669-2008 : Charges brutes directes
- R-3706-2009 : Charges nettes d'exploitation
- R-3738-2010 : Charges nettes d'exploitation
- R-3777-2011 : Charges nettes d'exploitation
- R-3823-2012 : Charges nettes d'exploitation
- R-3903-2014 : Charges nettes d'exploitation
- R-3934-2015 : Charges nettes d'exploitation
- R-3981-2016 : Charges nettes d'exploitation
- R-4012-2017 : Charges nettes d'exploitation autres que services partagés
- R-4012-2017 : Charges nettes d'exploitation - Contexte et approche globale paramétrique
- R-4012-2017 : Coûts de maintenance

Documents sur le balisage

- R-3669-2008 : Balisage
- R-3706-2009 : Efficience, performance et balisage
- R-3738-2010 : Balisage
- R-3777-2011 : Balisage
- R-3823-2012 : Balisage
- R-3903-2014 : Balisage
- R-3934-2015 : Balisage
- R-3981-2016 : Balisage
- R-4012-2017 : Balisage

Documents sur le modèle de gestion des actifs (« MGA »)

- R-3981-2016 : Modèle de gestion des actifs
- R-3981-2016 : Modèle de gestion des actifs (présentation Panel 2)
- R-4012-2017 : Modèle de gestion des actifs (hypothèses techniques)
- R-4012-2017 : Modèle de gestion des actifs (Roland Berger)
- R-4012-2017 : Analyse coûts-bénéfices de la maintenance additionnelle (présentation du Transporteur)
- R-4012-2017 : Analyse coûts-bénéfices de la maintenance additionnelle (Roland Berger)
- R-4012-2017 : Analyse coûts-bénéfices de la maintenance additionnelle (présentation Panel 3)
- R-4012-2017 : Analyse coûts-bénéfices de la maintenance additionnelle (Roland Berger Panel 3)

ANNEXE B

RAPPORT DE CONCENTRIC

PERFORMANCE BASED REGULATION:
PRODUCTIVITY FACTOR RESEARCH FOR HQT

PREPARED FOR:
HYDRO-QUÉBEC TRANSÉNERGIE

R-3897-2014

BEFORE THE: RÉGIE DE L'ÉNERGIE

APRIL 4TH, 2018

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Section 1:
Introduction

The Régie determined in D-2018-001 that it would rely on its informed judgment to set an appropriate productivity factor for HQT in Phase III of this proceeding. To inform its judgment, the Régie has requested that the Transmission Carrier ("the Carrier") file all studies, analyses, and reports available to it by March 31st, 2018.[1] There are multiple methodologies to help inform X for distribution utilities, ranging from observing past productivity gains to industry benchmarking studies to complex productivity studies. The challenge in this case is to identify and determine the appropriate analyses and methodologies to be used for informing X for transmission utilities. This report focuses on research and methodologies relevant to transmission utilities, and other information to support the Régie's determination of HQT's X factor. Concentric's recommendation for a specific X factor for HQT's first generation mécanisme de réglementation incitative ("MRI") will be submitted in August consistent with the Régie's schedule for this proceeding.

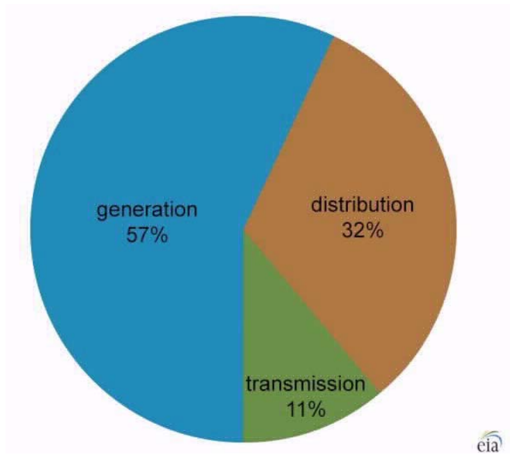
In developing this research, we recognize that the recommended X factor for HQT in combination with the other elements of its rate plan must meet the requirements of Article 48.1:

1) continuous improvement of performance and service quality;
2) cost reduction that is beneficial to both consumers and the distributor or carrier;
3) streamlining of the process by which the Régie fixes or modifies the rates the electric power carrier and electric power distributor charge consumers or a class of consumers.

Through this research, Concentric has determined that traditional approaches to performance-based regulation ("PBR") adopted for distributors have been more selectively adopted for the regulation of transmission companies. This is likely attributable to several factors. Transmission, as a share of the customer's final bill, is typically the smallest cost component, in contrast to generation and distribution. The perceived gains are therefore deemed to be smaller. For example, as seen in Figure 1 below, in the U.S. transmission accounts for 11% of average price of electricity. In Québec, transmission accounts for 25% of the average price of electricity for consumers. Also, the capital intensive and project specific nature of transmission creates a less homogeneous operating and cost profile. This poses challenges in terms of creating peer groups for cost benchmarking and industry productivity analysis.

[1] D-2018-001, R-3897-2014 Phase 1, at para. 106-110.

Figure 1: Major Components of the U.S. Average Price of Electricity, 2016[2]



Finally, larger sets of peer group data are more readily available for distribution companies due to the greater number of distributors in a given geography. These factors have not, however, stopped regulators from establishing performance based regulatory frameworks for transmission utilities. But these programs are more custom in their approach, and international in their examples.

As discussed in the sections that follow, regulators have established a wide range of performance goals for electric transmission utilities. This research illustrates variability in the approaches taken and the specific types of targets set for these programs.

Concentric has also observed that the trend in distribution utility industry productivity is declining over time, as evidenced by trends in the most recent studies and resulting PBR plans for electric distributors in North America. We have seen evidence of a similar trend, albeit based on a smaller sample of available studies, for transmission utilities.

[2] U.S, Energy Information Administration, *Annual Energy Outlook 2017.* January 2017, Reference Case, Table 8: Electrical supply, disposition, prices, and emissions.

Section 2:
Approach to Research

Concentric's research focuses on models of performance-based ratemaking for electric transmission, and the use of productivity or benchmarking studies supporting the development of these programs. For initial direction, we examined the 2015 Elenchus Report [3] conducted for the Régie and the studies identified by PEG in Phase I of this proceeding. We also conducted an independent review of the literature to identify other pertinent examples.

In addition to a review of transmission related productivity and benchmarking analyses, Concentric focused on how specific jurisdictions are regulating transmission companies under incentive or performance-based regimes. In the sections that follow, Concentric presents the broad parameters for how transmission companies are regulated under performance or formula-based plans in North America and internationally. This research is not exhaustive, but representative of programs we have identified in North America, Europe, and Australia/New Zealand.

Our research indicates that PBR applied to transmission is not uniform. Regulators place an emphasis on cost control but also use reliability and performance to create incentives for transmission owners. Because transmission service providers are less commonly regulated under performance-based regulation, transmission-specific productivity research is more limited.

3 Elenchus Research Associates, Inc., Performance Based Regulation: A Review of Design Options as Background for the Review of PBR for Hydro Québec Distribution and Transmission Divisions. January 2015.

Section 3:
E3GRID Benchmarking Study

The 2012 E3GRID2012 study examined a sample of 21 transmission system operators ("TSOs") across Europe between 2007 and 2011.

Table 1: Participating TSOs in E3grid2012[4]

	TSO	Regulator	Country	Line km
1	50Hertz	Bundesnetzagentur	Germany	10,000
2	ADMIE	Regulatory Authority for Energy	Greece	11,000
3	Amprion	Bundesnetzagentur	Germany	11,000
4	APG	E-Control	Austria	6,971
5	CEPS	ERU	Czech Republic	5,728
6	CREOS	ILR	Luxembourg	9,300
7	Elering	Konkurentsiamet	Estland	5,406
8	Energinet.DK	DERA	Denmark	4,200
9	Fingrid	EMU	Finland	14,400
10	National Grid	OFGEM	UK	7,200
11	PSE Operator	URE	Poland	14,195
12	REE	CNE	Spain	43,793
13	REN	ERSE	Portugal	8,400
14	RTE	CRE	France	105,000
15	SHETL	OFGEM	UK	345
16	SPTL	OFGEM	UK	4,000
17	Statnett	NVE	Norway	11,000
18	venska Kraftnät	Energy Markets Inspectorate	Sweden	15,000
19	TenneT DE	Bundesnetzagentur	Germany	11,100
20	TenneT NL	ACM	Netherlands	10,118
21	TransnetBW	Bundesnetzagentur	Germany	3,200

For perspective on the sample, HQT has approximately 34,500 km of transmission lines, which would make it the third largest if placed in the context of this European sample.

The purpose of the study was to benchmark the overall cost efficiency of European transmission operators. For European regulators, an international benchmark provides information about exogenous vs. endogenous cost drivers, and therefore useful information about managerial efficiency. As the authors note, "[t]his can be used to assess the current and

[4] Frontier Economics, Ltd, E3Grid2012 – European TSO Benchmarking Study. July 2013, p. 17.

past relative cost efficiency, which may inform tariff reviews under both high- and low powered regulatory regimes."[5]

Cost efficiency was measured for grid construction, maintenance and administrative support. The study used data envelopment analysis ("DEA"), the same method used in the prior study conducted in 2009. DEA involves using data received by the operators to generate an artificial optimal frontier. Operators are benchmarked against the optimal frontier. One potential drawback of the DEA approach is the tendency to rank a disproportionately large share of operators as being optimally efficient if the data set is not robust enough. DEA is a non-parametric analysis, meaning it does not assume a clear relationship between costs and cost drivers.

The benchmarking study was based on total expenditures (capital expenditure + operating expenditures). The model includes three output factors used to later create the efficiency scores:

- Normalised Grid – weighs the assets in use by cost, allowing the model to account for the different operating environments.
- Densely populated area – The size in square kilometers of an area with 500 or more inhabitants.
- Value of weighted angular towers – Weighs the number of angular towers in use by the normalized grid of overhead lines by voltage level. This parameter indicates "a complex operating environment where routing of lines is not always straight which leads to higher specific cost of assets."[6]

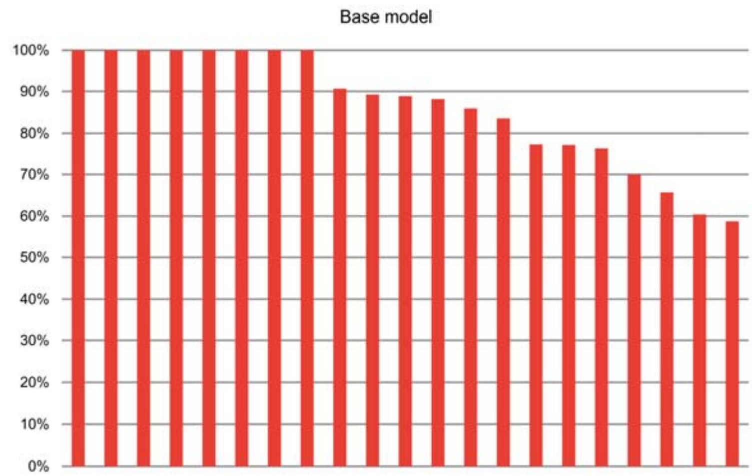
Companies were permitted to submit adjustment costs, which were removed from the rate base and therefore affected capital expenditures. These costs included:

- Structural claims – Higher costs due to terrain and other environmental factors.
- Individual claims – Unique claims for each ISO.

Our research on Norway (see Section 7) indicates that the NVE uses these results over a five-year period to establish performance targets for Statnett. Concentric has not investigated how other regulators utilize the benchmarking results.

[5] Frontier Economics, Ltd, E3Grid2012 – European TSO Benchmarking Study. July 2013, p. 15.
[6] Frontier Economics, Ltd, E3Grid2012 – European TSO Benchmarking Study. July 2013, p. 4.

Figure 2: E3grid2012 base model results



The final report was issued on July 25th, 2013. The result of the analysis was an average efficiency of 86% and a minimum efficiency of 59% (excluding outliers). Eight companies scored 100%. The results can be seen above.[7] Efficiency is based upon how the operators performed in comparison to the optimal frontier. A score of 100% means that the operators met the optimal frontier.

The study authors summarize their findings as "the average results for all TSOs indicate a positive efficiency change of +2.4%, i.e. the inefficient companies improve their position against the efficiency frontier, and a regress of the efficiency frontier of -1.0%. A split of the TSOs into three groups indicated that the change in the efficiency frontier for continental Europe and UK tends to be in a similar range (-0.8% and -1.1%), while Scandinavia indicates a higher regress of -1.9%."[8] The analysis accounted for time by including a factor of expected technological growth.

[7] Frontier Economics, Ltd, E3Grid2012 – European TSO Benchmarking Study. July 2013, p. 9.
[8] Frontier Economics, Ltd, E3Grid2012 – European TSO Benchmarking Study. July 2013, p. 13.

Section 4:
United Kingdom: RIIO

In the United Kingdom the regulatory organization responsible for energy utilities is Ofgem (Office of Gas and Electricity Markets). Transmission rate adjustments are made based on performance and follow the RIIO (Revenue = Incentives + Innovation + Outputs) price control model. This model is the first transmission control model of RIIO, known as RIIO-T1. The framework is "designed to promote smarter gas and electricity networks for a low carbon future"[9]. RIIO-T1 took effect on April 1st, 2013 and lasts until March 31st, 2021. There are three onshore electric transmission companies ("TOs") in the U.K.:

- National Grid Electricity Transmission plc ("NGET")
- SP Transmission Ltd ("SPTL")
- Scottish Hydro Electric Transmission plc ("SHE Transmission")

The RIIO framework places significant emphasis on outputs, or performance targets that are linked to revenue. Companies must deliver these outputs either annually or on an 8-year basis. The allowed revenue is set based on a forecast of total expenditures with incentives linked to outputs and the quality of the forecast. For example, National Grid Electricity Transmission's output incentive parameters are provided in the following table:

[9] Ofgem, RIIO-T1 network price control, https://www.ofgem.gov.uk/network-regulation-riio-model/current-network-price-controls-riio-1/riio-t1-network-price-control. Accessed March 27, 2018.

Table 2: NGET's outputs and incentive parameters for RIIO-T1[10]

Category	Output	Incentive
Safety	Compliance with safety obligations set by the Health and Safety Executive (HSE).	Statutory requirements. No financial incentive.
	Supported by measures of asset health, condition and criticality with agreed targets and impacts on RIIO-T2 funding.	A penalty/reward of 2.5% of the value of any over/under delivery of network replacement outputs.
Reliability	Primary output based on Energy Not Supplied (ENS).	Incentive rate of £16,000/MWh[27] which is based on an estimate of the value of lost load (VoLL).[28] A collar on financial penalties limiting the maximum penalty to 3% of allowed revenues.
Availability	Prepare and maintain a Network Access Policy (NAP).	Reputational incentive. Potential financial incentives if relevant during development and update of NAP.
Customer Satisfaction	Develop customer/stakeholder satisfaction survey.	Up to +/-1% of allowed revenue.
	Effective stakeholder engagement.	Up to 0.5% of allowed revenue via a discretionary reward scheme.
Connections	To meet existing legal requirements.	General enforcement policy.
Environmental	SF_6 – Baseline target calculated annually with best practice 0.5% leakage rate for new assets installed.	Differences to baseline subject to a reward/penalty based on the non-traded carbon price for carbon equivalent emissions.
	Losses – Publish overall strategy for transmission losses and annual progress in implementation and impact on transmission losses.	Reputational incentive.
	Business Carbon Footprint (BCF) – Publish BCF accounts at business level annually over RIIO-T1.	Reputational incentive.
	EDR Scheme – measures to focus on aspects of the roles of the TOs and SO not explicitly captured in RIIO-T1 incentives.	Positive reward available if achieve leadership performance across different scorecard activities.
	Visual amenity – to efficiently meet planning requirements for new infrastructure and deliver visual amenity outputs by mitigating impacts of existing infrastructure when it is located in designated areas.	Reputational incentive in the context of its performance in the utilisation of two mechanisms: (1) baseline and uncertainty mechanism funding for additional cost of mitigation technologies required for development consent (2) initial expenditure cap of £500m to reduce the impact of existing infrastructure in designated areas.
Wider works (new investment)	Baseline wider works outputs of approximately 7,250MW of additional transmission transfer capacity funded baseline funding. Best view wider works outputs (approximately another 22,150MW) are to be funded through flexible baseline (with volume driver to adjust allowances if delivery turns out to be different) and SWW arrangements for potentially a further 7,900MW of transmission capacity).	NGET's scheduled baseline and SWW outputs will be subject to timely delivery standards. For best view wider works (ie non SWW), NGET required to meet NDP criteria and take forward timing and phasing of WW outputs that are in best interests of consumers.

[10] Ofgem, Final Proposals for National Grid Electricity Transmission and National Grid Gas. December 17, 2012, p. 22-23.

There are also a number of “uncertainty mechanisms” that allow a transmission owner to adjust its revenues and manage the myriad of uncertainties that it may face over the 8-year control period. One key uncertainty mechanism is the “efficiency incentive rate” which determines the percentage of under or overspend against the price controls that a company is allowed to keep or absorb. Any deviation outside of this dead-band is collected from, or passed back to, customers.[11]

[11] Ofgem, Final Proposals for National Grid Electricity Transmission and National Grid Gas. December 17, 2012, p. 31.

Table 3: NGET Uncertainty Mechanisms[12]

Uncertainty	Mechanism
Volume of new generation connections	Volume driver to adjust baseline expenditure each year for deviations in generation capacity connections from annual baseline profile, including RPEs adjustment.
New demand connections	Volume driver for demand related infrastructure backed by commercial agreements to adjust baseline revenues as delivered infrastructure deviates from baseline profile of investment, including RPE adjustment.
Wider reinforcement works	Volume driver based on delivered wider works outputs (additional transfer capability) that meet NDP criteria and funded using boundary specific unit costs and delivered outputs. SWW (within period determination) mechanism for large reinforcements of greater than £500m or projects not meeting NDP criteria.
Planning requirements to mitigate impacts of new transmission infrastructure on visual amenity	Volume driver to adjust revenues for cost of mitigation measures required to gain planning consent.
Funding for the delivery of outputs in RIIO-T2	Volume drivers will calculate the funding adjustment for activity in RIIO-T1 related to outputs NGET will deliver in the first two years of RIIO-T2. It will be based on the unit cost allowances agreed for RIIO-T1, pro rated using the spend profile that is part of the volume drivers.
Licence fees, business rates, Inter-TSO scheme payment	Annual pass through.
Financial distress	Disapplication of the price control where outside the company's control.
Material pre-defined events	Reopener for enhancement of physical security, innovation roll-out. Potential reopener for costs related to delivering EMR measures, pre-construction costs for the east coast integrated network.
RPI Inflation (TO and SO)	Indexation of allowed revenues.
Financial (TO and SO)	A number of mechanisms in relation to the financial arrangements. These cover: • cost of debt • tax legislation • pension deficit repair. These are discussed in more detail in the Finance Supporting Document.
Mid-period review (TO and SO)	The areas of uncertainty identified by NGET which we would propose to consider as part of the mid-period review are: • GB or EU market change – cost associated with new market facilitation roles/functions stemming from GB or EU legislation. • Flood and erosion protection - in the event that the Government requires NGET to contribute to flood protection or erosion schemes.

[12] Ofgem, Final Proposals for National Grid Electricity Transmission and National Grid Gas. December 17, 2012, p. 31-32.

Companies are required to file on an annual basis an updated Price Control Financial Model ("PCFM") which is used to alter the Opening Base Revenue Allowances during RIIO-T1. The PCFM consists of three adjustment categories:

- "Legacy price control adjustments – the close out of schemes and mechanisms from preceding Price Control Periods;
- Financial adjustments covering tax, pension and cost of debt issues; and
- Adjustments relating to actual and allowed Totex[13] expenditure and the Totex Incentive Mechanism."[14]

The annual increase added to the Opening Base Revenue Allowances is called the MOD. The values of the PCFM and in the MOD are calculated in 2009-10 prices. Companies are required to submit changes to the PCFM by September 30th of each year, and their proposed changes by October 31st. Decisions on revised values are returned to the companies by November 30th of each year.

Annual reporting is an important component of the RIIO price control model as it allows Ofgem to see how TOs have performed against the outputs and allowances that the price control established.[15]

There are inflationary elements within the RIIO approach, but it is fundamentally a building-block model based on a forecast of costs with an emphasis on performance against a broad array of outputs.

[13] Total Expenditures.
[14] Ofgem, ET1 Price Control Financial Handbook. February 1, 2013, p. 9.
[15] Ofgem, RIIO ET-1 Annual Report. December 19, 2017, p. 8.

Section 5:
Australia: AER

In Australia, energy utilities are regulated by the Australian Energy Regulator ("AER") under the National Electricity Rules ("NER"). There are seven electric transmission entities, or transmission network service providers ("TNSPs") in Australia:

- Ausnet
- Directlink
- ElectraNet
- Murraylink
- PowerLink
- TasNetworks
- TransGrid

A. AER Maximum Allowed Revenue Determination

The AER regulates TNSP revenues through a periodic revenue determination review which typically occurs every five years. Revenues are determined according to the process outlined below, or what the AER calls a "propose-respond" framework.[16]

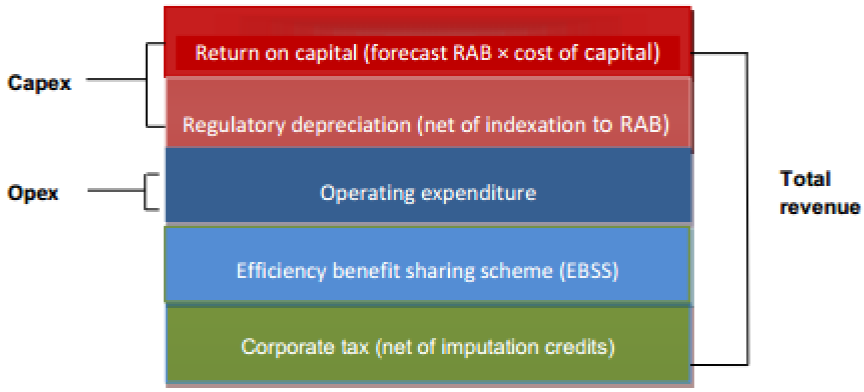
[16] AER, Annual Benchmarking Report, Electricity transmission network service providers. November 2017, p. 17.

Figure 3: AER Revenue Determination Process for TNSPs[17]

Box 3: Three stages of the revenue determination process

1. Network business submit a network expenditure proposal to the AER for a coming regulatory control period, including forecast costs for each of the building blocks of their network expenditure [*AER Figure 1 – the building block includes both CAPEX and OPEX. The EBSS building block is intrinsically linked to the forecasting of OPEX only*[18]]. The proposals include data and information to support estimates of needed expenditure.

AER Figure 1: The Building Block approach for determining total revenue



2. The AER assess the proposal against relevant criteria and tests in the NER and using the assessment methods and tools developed as part of our Better Regulation Guidelines. Network efficiency benchmarking is one of these assessment tools (see below).
3. Where a network business' proposed expenditure for a building block meets the criteria and tests specified under the NER, the AER accepts the proposal. Where the AER is not satisfied that the relevant regulatory criteria and tests are met, the AER cannot accept the proposal and must estimate an amount it believes reasonably reflect the regulatory requirements. Benchmarking can also inform these AER estimates. The AER must also explain its reasons for each of its constituent decisions. [*References omitted.*]

These seven companies must then report to the AER on an annual basis to adjust rates. Generally, the Maximum Allowed Revenue ("MAR") for each regulatory year during the regulatory control period is calculated as:

The MAR is calculated as follows: [19]

[17] AER, Annual Benchmarking Report, Electricity transmission network service providers. November 2017, p. 18.
[18] AER, Efficiency Benefit Sharing Scheme. November 2013, p. 4.
[19] AER Final Electricity Transmission Network Service Provider Service Target Performance Incentive Scheme, Version 5, October 2015, p. 39.

MAR_t = AR_t + *financial incentive*$_{ct}$ + other adjustments

where: AR = allowed revenue

AR_t = AR_{t-1} *(1 + Δ CPI) *(1-X_t)

Δ CPI is the annual percentage change in the most recently published *Consumer Price Index All Groups, Weighted Average of Eight Capital Cities* as specified in the *TNSP's transmission determination*

X_t is the X factor specified in the *TNSP's transmission determination*.

While the revenue determination takes the general form of CPI-X, the X itself, as illustrated above, is set as more of a "smoothing factor" aligned with the approved revenue path, with significant differences between companies and by year. X Factors established in recent years for the seven TNSPs are listed in the following table.

Table 4: AER TNSP X Factors 2009-2022[20]

Provider	AusNet*	ElectraNet	Directlink	MurrayLink	Powerlink	TasNetworks	TransGrid
2017 Revenue (CAD $M)	$522.2	$327.6	$13.5	$13.4	$1,016.7	$1.7	$714.1
Line km	6,573	5,527	63	180	14,310	3,503	12,893
2009-10						N/A	
2010-11						-5.53%	-4.10%
2011-12						-5.53%	-4.10%
2012-13					N/A	-5.53%	-4.10%
2013-14		N/A		N/A	-3.02%	-5.53%	-4.10%
2014-15	N/A	-2.69%		1.20%	-3.02%	N/A	N/A
2015-16	3.24%	-2.69%	N/A	1.20%	-3.02%	9.81%	15.03%
2016-17	3.24%	-2.69%	0.00%	1.20%	-3.02%	2.00%	3.00%
2017-18	N/A	-2.69%	0.00%	1.20%	N/A	2.00%	3.00%
2018-19	1.12%		0.00%		0.15%	2.00%	
2019-20	1.12%		0.00%		0.15%		
2020-21	1.12%				0.15%		

The large uptick in X factor observed for TasNetworks and TransGrid after 2014-2015 is primarily due to the fact that both companies rebased their plans in that year and faced

[20] Data obtained from individual company orders at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements?f[0]=field_accc_aer_segment%3A9&f[1]=field_accc_aer_sector%3A4. Accessed March 14, 2018.

certain adjustments, including changes to the return on capital.[21,22] As will be described below, the X factor represents the real rate of change from one year to the next given the AER's final determinations on building block expenditures, and therefore acts as a smoothing factor.

Taking a specific company example, the AER provides its final determination on Powerlink's MAR as:

[21] AER, Final Decision, TasNetworks Transmission Determination, Overview. April 2015, p. 10.

[22] For example, the AER notes for TasNetworks that "[w]e have set the 2014–15 MAR equal to TasNetworks' targeted revenue ($186.9 million) for 2014–15. We note that TasNetworks applied a lower revenue than the placeholder MAR of $205.1 million for 2014–15 pricing purposes. The MAR for 2014–15 ($186.9 million) is around 26.4 per cent lower than the approved MAR ($247.9 million) in the final year of the 2009–14 regulatory control period (2013–14) in real terms, or 24.6 per cent lower in nominal terms." AER, Final Decision, TasNetworks Transmission Determination, Overview. April 2015, p. 10.

Table 5: AER's final decision on Powerlink's revenues ($million, nominal)[23]

	2017–18	2018–19	2019–20	2020–21	2021–22	Total
Return on capital	425.5	430.4	434.2	437.3	440.5	2168.0
Regulatory depreciation[a]	88.9	113.3	131.0	143.1	150.2	626.6
Operating expenditure[b]	201.7	205.8	209.8	214.2	219.3	1050.7
Revenue adjustments[c]	–0.8	–7.1	–3.2	3.0	0.0	–8.1
Net tax allowance	17.1	19.4	22.7	24.3	24.5	108.0
Annual building block revenue requirement (unsmoothed)	732.4	761.8	794.6	821.9	834.5	3945.2
Annual expected MAR (smoothed)	**752.7**	**770.0**	**787.6**	**805.7**	**824.2**	**3940.2**[d]
X factor[e]	n/a[f]	0.15%	0.15%	0.15%	0.15%	n/a

Source: AER analysis.

(a) Regulatory depreciation is straight-line depreciation net of the inflation indexation on the opening RAB.

(b) Operating expenditure includes debt raising costs.

(c) Includes efficiency benefit sharing scheme amounts.

(d) The estimated total revenue cap is equal to the total annual expected MAR.

(e) The X factors will be revised to reflect the annual return on debt update. Under the CPI–X framework, the X factor measures the real rate of change in annual expected revenue from one year to the next. A negative X factor represents a real increase in revenue. Conversely, a positive X factor represents a real decrease in revenue.

(f) Powerlink is not required to apply an X factor for 2017–18 because we set the 2017–18 MAR in this decision. The MAR for 2017–18 is around 27.9 per cent lower than the approved MAR for 2016–17 in real terms, or 26.1 per cent lower in nominal terms.

Here, the X factor is described as the real rate of change in annual expected revenue from one year to the next. A negative X factor represents a real increase in revenue. Conversely, a positive X factor represents a real decrease in revenue.

The AER summarizes:

> We use an expected inflation rate in our post-tax revenue model ("PTRM") to calculate the expected MAR (as shown in Table 5) in nominal dollar terms. Therefore, the calculation of the actual annual MAR will require an adjustment for actual inflation. The MAR is also subject to adjustments for updating the return on debt annually, a revenue increment or decrement determined in accordance with the STPIS, and any approved pass through amounts. This section sets out the method of this annual adjustment process.

[23] AER, Powerlink transmission determination 2017-22. April 2017, p. 16.

We determine that the method for calculating Powerlink's MAR for each year of the 2017–22 period will be the sum of its allowed revenue ("AR") for that year and adjustments arising from the Service Target Performance Incentive Scheme ("STPIS") and any approved pass through amounts.

We determine the 2017–18 AR of $753.6 million for Powerlink. Powerlink then applies an annual adjustment to determine its AR for each subsequent year of the 2017–22 period, based on the previous year's AR and using the CPI–X methodology. That is, the subsequent year's AR is determined by adjusting the previous year's AR for actual inflation and the X factor determined after the annual return on debt update:

$$AR_t = AR_{t}\text{-}1 \times (1 + \Delta CPI) \times (1 - X_t)$$

Where:

AR	the allowed revenue
t	time period/financial year (for t = 2, (2018–19), 3 (2019-20), 4 (2020–21), 5 (2021–22))
ΔCPI	the annual percentage change in the Australian Bureau of Statistics' (ABS) consumer price index (CPI) all groups, weighted average of eight capital cities from December in year t – 2 to December in year t – 1[24]
X	the smoothing factor determined in accordance with the PTRM as approved in the AER's final decision, and annually revised for the return on debt update in accordance with the formula specified in the return on debt appendix calculated for the relevant year.

The MAR is determined annually in accordance with the NER by adding to (or deducting from) the AR:

- Service target performance incentive scheme revenue increment (or revenue decrement)[25]
- Approved pass through amounts.[26]

The annual MAR is established according to the following formula:

[24] Per the AER "In the transmission determination for Powerlink's 2012–17 regulatory control period, the CPI required for the annual MAR adjustment process reflects the March quarter CPI, which is typically published by the ABS in late April each year. For this transmission determination we require Powerlink to use the December quarter of the previous calendar year CPI for the annual MAR adjustment for its 2017–22 regulatory control period. December quarter CPI is typically released by the ABS towards the end of January of the following year. As the same set of CPIs will be used for the RAB roll forward at the next reset for Powerlink in 2022, this change will allow us to update the actual CPI for RAB roll forward purposes well before the publication date of the AER's final decision at the next reset. We note that there will be an overlapping issue of the March quarter CPI when the transition to the December quarter CPI occurs (this will be in the year 2017–18 for Powerlink). This is because the CPI for March quarter 2017 will be reflected in both 2016–17 and 2017–18. However, we consider this is only a transitional issue and does not have a material impact on the revenue to be recovered by Powerlink."
[25] NER, clauses 6A.7.4.
[26] NER, clauses 6A.7.2 and 6A.7.3.

MAR_t = (allowed revenue) + (performance incentive) + (pass through)

$$= AR_t + \left(\frac{\left(AR_{t-1} + AR_{t-2}\right)}{2} \times S_{ct} \right) + P_t$$

Where:

MAR	the maximum allowed revenue
AR	the allowed revenue
S	the revenue increment or decrement determined in accordance with the STPIS
P	the pass-through amount (positive or negative) that the AER has determined in accordance with clauses 6A.7.2 and 6A.7.3 of the NER
t	time period/financial year (for *t* = 2 (2018–19), 3 (2019–20), 4 (2020–21), 5 (2021–22))
ct	time period/calendar year (for *t* = 2 (2017), 3 (2018), 4 (2019), 5 (2020))

Under the NER, a TNSP may also adjust the MAR for under or over-recovery amounts.[27] That is, the revenue amounts recovered higher or lower than the approved MAR for each year would be included in the subsequent year's MAR. In the case of an under-recovery, the amount would be added to the future year's MAR. In the case of an over-recovery, the amount would be subtracted from the future year's MAR.[28]

B. Service Target Performance Incentive Scheme

There is a financial incentive component to the AER's TNSPs revenue adjustments, which are based on performance through a program called the Service Target Performance Incentive Scheme (STPIS).

There are three components to the scheme: the service component, the market impact component, and the network capability component. These components apply to all of the transmission providers, except for Directlink and Murraylink which are not required to file the network capability component. The STPIS is in effect, unless otherwise stated, from January 1st to December 31st of the regulatory control period.[29]

The Service Standards Factor (S-factor), the percentage change companies are permitted to make to their maximum allowed revenue, is calculated annually for each provider. Adjustments do not account for performance outside of the relevant time period. The providers must submit the following estimates for each of the components:

[27] NER, clauses 6A.23.3(c)(2)(iii) and 6A.24.4(c).
[28] AER, Powerlink transmission determination 2017-22, April 2017, p. 6-8.
[29] AER, Electricity transmission network service provider, Service target performance incentive scheme. October 2015, p. 4.

- Service Component
    - Performance target – must be set equal to the average performance over the past 5 years, unless otherwise specified.
    - Performance floor
    - Performance cap
- Market Impact Component
    - Performance target – Calculated by looking at prior performance and adjusting account for unplanned outages. The target must be set to a minimum of 100 counts.
    - Unplanned outage event limit – Maximum of 17% of the performance target.
    - Dollar per dispatch interval incentive – 1% of the maximum allowed return for the first year of the control period, divided by the performance target.
- Network Capability Component
    - Basis for the limit for each injection point and transmission circuit.
    - Descriptions and data on the priority projects to improve limits that will be undertaken during the regulatory control period.

Using the submitted estimates, the providers use the formulas provided in the STPIS to generate S-factors for each component. The providers then submit the required data and S-factors to the AER. The AER has the authority to determine if the company-provided estimates and S-factors are accurate, and if not, is permitted to submit its own. The table below shows the maximum increase to revenue that transmission providers are allowed to receive in a year.

Table 6: Maximum Permitted Change to Maximum Allowed Revenue[30]

Component	Max Change to Maximum Allowed Revenue Over Prior Year
Service	+/- 1.25%
Market Impact	+/- 1%
Network Capability	+/- 1.5%

C. AER Transmission Utility Performance Benchmarking

The AER has also benchmarked transmission utility performance in recent years. Concentric examined the transmission network service provider benchmarking reports from 2017, 2016, and 2015. These benchmarking reports were conducted by the AER and are used as one of the tools to set the maximum revenues TNSPs can recover from customers.

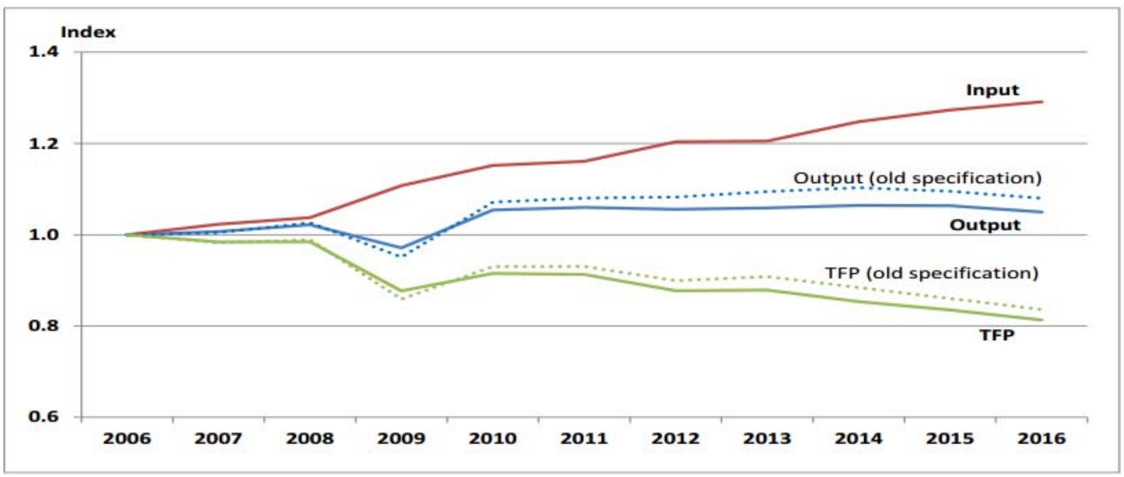
[30] AER, Electricity transmission network service provider, Service target performance incentive scheme. October 2015, p. 7, 10, 16,

In 2017, the AER updated the output specifications from previous benchmarking reviews. The primary changes included:

- Substitution of the end–user numbers output measure for the voltage–weighted connections output measure,
- Introduction of a cap on the weighting given to the reliability output measure (energy not supplied or ENS),
- Updating of cost share weights for outputs other than reliability.

The AER presented the results for both old and new output specifications to demonstrate their impact on results over time. The figure below shows change in total industry inputs, outputs, and total factor productivity for the period 2006-2016. As can be seen in the figure, input indices have held a positive trajectory while output indices have shown a decline. The resulting TFP indices have generally been declining over this time period.

Figure 4: AER Transmission Benchmarking Results: Industry Input, Output, and TFP Indices, 2006-2016[31]



The primary results of this analysis are summarized by the AER:

- As can be seen in Figure 4, industry-wide TFP continued to decline over 2016 decreasing by 2.7 per cent. This is the third consecutive year of declining TNSP productivity – TFP decreased by 2.9 percent over 2014 and 2.2 per cent over 2015. It is also a faster rate of decline than the long-term industry rate of a -2.1 per cent average annual decrease over 2006-16.
- The long term decrease in TFP – by 19 per cent over the last 11 years – has been driven by network inputs growing at a faster rate than outputs. Total inputs increased 29 per cent over 2006-16 while total outputs grew by only five per cent.[32]

The AER also describes the reasons behind this decline in TFP, with the primary drivers of decreased TFP for 2016 being:

[31] AER, Annual Benchmarking Report, Electricity transmission network service providers. November 2017, p. 6.
[32] AER, Annual Benchmarking Report, Electricity transmission network service providers. November 2017, p. 7.

- Decrease in network reliability (energy not supplied or ENS), which contributed -1.4 percentage points to the rate of TFP decline;
- Growth in capital inputs (transformers and overhead lines) which contributed -0.5 percentage points each; and
- Growth in OPEX spending which contributed a further -0.4 percentage point to the rate of TFP decline.[33]

The AER ranks each TNSP by their multilateral total factor productivity score. Because transmission benchmarking is relatively new, and the models have various limitations in accurately comparing across different operating circumstances, the authors caution against heavy reliance on the TNSP productivity comparisons.[34] A range of supporting benchmarks is also provided individually for each TNSP, including a capital multilateral partial productivity index and an OPEX multilateral partial productivity index. The capital MPFP results have declined for each TNSP since 2006, while the OPEX MPFP results has been more variable.

The limitations of transmission benchmarking are discussed in general terms by the AER. Of note, the AER recognizes that each TNSP operates in different environments under different circumstances. Therefore, each TNSP's costs, cost structure, and performance may be impacted differently. Additionally, the small number of TNSPs make comparisons at the aggregate level more difficult.

Lastly, the AER examines partial performance indicators (PPI) for each TNSP. They note that PPIs represent the input costs used to produce various outputs and provide "a general indication of comparative performance in delivering one type of output. However, PPIs do not take interrelationships between outputs into account. Therefore, PPIs are most useful when used in conjunction with other benchmarking techniques (such as MTFP)."[35] The PPIs discussed by the AER include total cost per end user, and total cost per km of transmission circuit length, total cost per MVA of non-coincident maximum demand, and total cost per MWh of energy transported.

The tables below list the input and output contributions of each TNSP to the overall industry measure of TFP, as well as the S_factors approved for each TNSP in recent years. As can be seen in Table 7, the average annual change in TFP from 2015 to 2016 was -2.7%, and -2.1% from 2006-2016.

[33] AER, Annual Benchmarking Report, Electricity transmission network service providers. November 2017, p. 7.
[34] AER, Annual Benchmarking Report, Electricity transmission network service providers. November 2017, p. 30.
[35] AER, Annual Benchmarking Report, Electricity transmission network service providers. November 2017, p. 49.

Table 7: Input and Output Contributions to TFP growth rates, by TNSP, 2006-2016[36]

	2006-2016					2015 to 2016				
	Av annual change in TFP (%)	Transformer contribution to TFP (ppts)	Overhead lines contribution to TFP (ppts)	Opex contribution to TFP (ppts)	Energy not supplied (ENS) contribution (ppts)	Av annual change in TFP (%)	Transformer contribution to TFP (ppts)	Overhead lines contribution to TFP (ppts)	Opex contribution to TFP (ppts)	Energy not supplied (ENS) contribution (ppts)
Industry	**-2.1**	**-1.5**	**-0.6**	**-0.3**	**-0.3**	**-2.7**	**-0.5**	**-0.5**	**-0.4**	**-1.4**
AusNet (Vic)	0.3	-0.5	0.0	-0.1	-1.0	-1.1	0.3	0.3	-0.8	-2.0
ElectraNet (SA)	-2.5	-1.1	-0.1	-0.7	-0.8	-7.8	-1.1	0.0	-1.4	-8.3
PowerLink (QLD)	-2.4	-2.1	-1.1	-0.8	0.3	-0.1	-1.4	0.4	-0.3	1.4
TasNetworks (Tas)	-0.1	-1.2	-0.3	0.6	0.5	-3.6	-0.1	0.0	-1.4	0.4
TransGrid (NSW)	-3.1	-1.8	-0.8	0.0	-0.6	-3.7	0.0	-1.6	0.3	-2.0

Notes: Results use the new benchmarking model specification adopted in this year's report. The three inputs and one output used in the table were chosen as they were the four largest negative contributors to the average annual TFP growth rate of - 2.1 per cent over 2006-16. TFP results for an individual TNSP here can differ from MTFP results in table 1 as the two measures are based on different statistical techniques. Appendix A of the 2017 Economic Insights Report contains an explanation for these differences. In this report MTFP results are primarily used to measure the relative productivity performance of TNSPs while TFP results are primarily used to measure the change in productivity over time at the industry level or for a given TNSP and to decompose changes in productivity into its constituent input and output drivers.

[36] AER, Annual Benchmarking Report, Electricity transmission network service providers. November 2017, p. 34.

Table 8: Australian TNSP s Factors, 2014-2016[37]

Network	Component	Start Date*	End Date	Proposed S Factor	Endorsed S Factor
AusNet	Service	1/1/2016	12/31/2016	0.32%	0.32%
AusNet	Market Impact	1/1/2016	12/31/2016	0.00%	0.00%
AusNet	Network Capability	1/1/2016	12/31/2016	N/A	1.50%
AusNet	Service	1/1/2015	12/31/2015	0.11%	0.11%
AusNet	Market Impact	1/1/2015	12/31/2015	0.91%	0.33%
AusNet	Network Capability	1/1/2015	12/31/2015	1.50%	1.50%
AusNet	Service	1/1/2015	3/31/2015	0.95%	0.95%
AusNet	Market Impact	4/1/2014	12/31/2014	1.85%	1.70%
AusNet	Service	4/1/2014	12/31/2014	0.28%	0.24%
AusNet	Market Impact	4/1/2014	12/31/2014	1.09%	1.06%
AusNet	Network Capability	4/1/2014	12/31/2014	0.00%	0.00%
DirectLink	Service	1/1/2016	12/31/2016	-1.00%	-1.00%
DirectLink	Market Impact	1/1/2016	12/31/2016	0.74%	0.23%
DirectLink	Service	1/1/2015	6/30/2015	-0.76%	-0.76%
DirectLink	Service	7/1/2015	12/31/2015	-0.20%	-0.60%
DirectLink	Market Impact	11/5/2015	12/31/2015	0.00%	0.29%
DirectLink	Service	1/1/2014	12/31/2014	-1.00%	-1.00%
ElectraNet	Service	1/1/2016	12/31/2016	-0.02%	-0.02%
ElectraNet	Market Impact	1/1/2016	12/31/2016	0.00%	0.00%
ElectraNet	Network Capability	1/1/2016	12/31/2016	1.50%	1.50%
ElectraNet	Service	1/1/2016	12/31/2016	0.31%	0.23%
ElectraNet	Market Impact	1/1/2016	12/31/2016	0.00%	0.00%
ElectraNet	Network Capability 6 months pro rated	1/1/2016	12/31/2016	1.50%	1.50%
ElectraNet	Service	1/1/2014	12/31/2014	0.72%	0.63%
ElectraNet	Market Impact	1/1/2014	12/31/2014	1.88%	1.88%
MurrayLink	Service	1/1/2016	12/31/2016	-0.94%	-1.00%
MurrayLink	Market Impact	1/1/2016	12/31/2016	0.00%	0.00%
MurrayLink	Service	1/1/2015	12/31/2015	0.17%	0.15%
MurrayLink	Market Impact	1/1/2015	12/31/2015	0.62%	0.61%
MurrayLink	Service	1/1/2014	12/31/2014	-0.33%	-0.33%
MurrayLink	Market Impact	1/1/2014	12/31/2014	1.54%	1.54%
PowerLink	Service	1/1/2016	12/31/2016	0.47%	0.47%
PowerLink	Market Impact	1/1/2016	12/31/2016	1.94%	1.94%
PowerLink	Network Capability	1/1/2016	12/31/2016	N/A	N/A
PowerLink	Service	1/1/2015	12/31/2015	0.28%	0.28%
PowerLink	Market Impact	1/1/2015	12/31/2015	1.91%	1.91%
PowerLink	Network Capability	1/1/2015	12/31/2015	N/A	N/A

[37] AER, Compliance Reporting, https://www.aer.gov.au/networks-pipelines/compliance-reporting?f[0]=field_accc_aer_sector%3A4&f[1]=field_accc_aer_report_type%3A319. Accessed March 14, 2018.

Network	Component	Start Date*	End Date	Proposed S Factor	Endorsed S Factor
PowerLink	Service	1/1/2014	12/31/2014	0.49%	0.46%
PowerLink	Market Impact	1/1/2014	12/31/2014	0.00%	0.00%
TasNetworks	Service	1/1/2016	12/31/2016	0.67%	0.67%
TasNetworks	Market Impact	1/1/2016	12/31/2016	0.00%	0.00%
TasNetworks	Network Capability	1/1/2016	12/31/2016	1.50%	1.50%
TasNetworks	Service	1/1/2015	6/30/2015	0.74%	0.74%
TasNetworks	Service	7/1/2015	12/31/2015	0.45%	0.45%
TasNetworks	Market Impact	1/1/2015	12/31/2015	1.01%	1.01%
TasNetworks	Network Capability	1/1/2015	12/31/2015	1.50%	1.50%
TasNetworks	Service	1/1/2014	12/31/2014	0.82%	0.77%
TasNetworks	Market Impact	7/1/2014	12/31/2014	0.00%	0.00%
TasNetworks	Network Capability	7/1/2014	12/31/2014	1.50%	1.50%
TransGrid	Service	1/1/2016	12/31/2016	0.65%	0.65%
TransGrid	Market Impact	1/1/2016	12/31/2016	0.00%	0.00%
TransGrid	Network Capability	1/1/2016	12/31/2016	1.50%	1.50%
TransGrid	Service	1/1/2015	6/30/2015	-0.18%	-0.18%
TransGrid	Service	7/1/2015	12/31/2015	0.29%	0.29%
TransGrid	Market Impact	1/1/2015	12/31/2015	0.00%	0.00%
TransGrid	Network Capability	1/1/2015	12/31/2015	1.50%	1.50%
TransGrid	Service	1/1/2014	12/31/2014	-0.43%	-0.43%
TransGrid	Market Impact	1/1/2014	6/30/2014	1.88%	1.87%
TransGrid	Market Impact	7/1/2014	12/31/2014	0.41%	0.20%
TransGrid	Network Capability	7/1/2014	12/31/2014	1.50%	1.50%

Section 6:
New Zealand

In New Zealand, the Commerce Commission ("NZCC") is responsible for regulating the country's transmission provider, Transpower. In 2008 legislation was introduced which shifted the regulatory regime from one where Transpower's rates were set via a settlement agreement to one where Transpower is subject to an "individual price-quality path" (IPP). The IPP establishes a building-block framework with various input methodologies ("IM") under which Transpower forecasts it operating and capital expenditures.[38] The maximum revenue that Transpower may recover for each pricing year in the regulatory period, net of the sum of pass-through costs and the sum of recoverable costs, is the forecast maximum allowable revenue ("MAR").[39]

Transpower is currently operating under an IPP that applies for 2015-2020. This regime governs its MAR, expenditures, and service quality standards. The operating expense building block has an "incremental rolling incentive scheme" whereby differences between allowed controllable Opex and actual controllable Opex between term years. The incremental adjustment term is determined by applying the inflation rate to the results of the following formula:

(allowed controllable opex$_{t-1}$ - actual controllable opex$_{t-1}$) - (allowed controllable Opex$_{t-2}$ - actual controllable opex$_{t-2}$),

Where:

$t-1$ means the final disclosure year commencing in the preceding regulatory period;

$t-2$ means the penultimate disclosure year commencing in the preceding regulatory period.[40]

Once the adjustment term is determined, it is notionally carried forward by applying the inflation rate. In each of the subsequent years into which an amount has been carried, a net balance must be determined by addition of any incremental changes carried forward into that year from a preceding regulatory period; and any incremental adjustment term carried into that term year.[41]

Transpower is also subject to input methodologies related to cost allocation, asset valuation, treatment of taxes, and cost of capital.

[38] Brattle Group, Framework for assessing capex and OPEX forecasts as part of a "building blocks" approach to revenue/price determinations. June 2012, p. 33.
[39] NZCC, Transpower Individual Price Quality Path Determination 2015, December 22, 2017, p. 13.
[40] NZCC, Transpower Input Methodologies Determination, June 29, 2012, p. 37.
[41] NZCC, Transpower Input Methodologies Determination, June 29, 2012, p. 38.

Section 7:
Norway

In Norway, the Norwegian Water Resources and Energy Directorate (NVE) is the national regulator and is responsible for all distribution system operators as well as the country's Transmission System Operator, Statnett. While there are 156 distribution system operators, and 20 transmission owners who own minor parts of the transmission network, Statnett is the country's primary transmission system operator.

Incentive regulation in Norway has evolved over more than two decades. The 1999 Regulation No. 302 formed the framework under which the NVE regulates natural monopolies. Regulation No. 302 is "intended to ensure that power is transmitted at the correct price and quality of supply and that the network is utilized and developed safely and in a way that efficiently promotes the interests of society."[42]

The efficiency requirements outlined in Regulation No. 302 stated a general efficiency requirement of 1.5%, and an individual efficiency requirement differential among each network company on the basis of individual considerations or comparative efficiencies.[43]

The revenue cap was to be determined on the basis of the initial values less efficiency requirements, with an annual adjustment for inflation, calculation of the return on network capital on the basis of the reference interest rate, calculation of network losses, and an increment for cost connected with new investment.

Today, Statnett is operating under its 4th PBR term for the years 2013-2018. The current generation has seen further evolution of the regime. NVE still regulates Statnett using an incentive-based revenue cap model. The revenue cap is set annually, based on a formula of 40 percent cost recovery and 60 percent cost normalization resulting from benchmarking models. The revenue cap is calculated based on expected total costs using inflated cost data on a two-year lag.[44] Once the revenue cap is determined, rates are set based on a forecast of throughput. The variance between the allowed revenue and the actual revenue in any year is captured in a variance account and returned to customers in later years.[45]

The NVE's approach to setting efficiency targets has evolved in its more than 20-year history. The NVE now benchmarks Statnett against other European TSOs in the e3grid study described in Section 3. Benchmarking is based on five-year average data rather than a single year.[46]

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[42] NVE, Regulation No. 302. March 1999, Section 1-1, p. 1.
[43] NVE, Regulation No. 302. March 1999, Section 8-2, p. 14.
[44] NVE, Revenue regulation, published November 25, 2015. https://www.nve.no/energy-market-and-regulation/revenue-regulation/. Accessed March 27, 2018.
[45] Elenchus Research Associates, Inc., Performance Based Regulation: A Review of Design Options as Background for the Review of PBR for Hydro Québec Distribution and Transmission Divisions. January 2015, p. 74.
[46] Elenchus Research Associates, Inc., Performance Based Regulation: A Review of Design Options as Background for the Review of PBR for Hydro Québec Distribution and Transmission Divisions. January 2015, p. 73.

As discussed by Elenchus, the benchmarking studies in the initial regimes were used to establish allowed costs for each utility. The benchmarking results were adjusted for inflation since the allowed costs were based on historic cost data to set allowed revenue. "Extreme over- and under-earning is restricted as the regime includes a minimum (2%) and a maximum (15%) permitted return on capital. Returns outside this collar triggered a rate adjustment."[47]

The 4th generation regime includes further adjustments to the weighted average cost of capital, adjustments for merger related activity, and allowances for costs related to participation in research, development, and pilot projects.[48]

[47] Elenchus Research Associates, Inc., Performance Based Regulation: A Review of Design Options as Background for the Review of PBR for Hydro Québec Distribution and Transmission Divisions. January 2015, p. 71.
[48] Elenchus Research Associates, Inc., Performance Based Regulation: A Review of Design Options as Background for the Review of PBR for Hydro Québec Distribution and Transmission Divisions. January 2015, p. 73.

Section 8:
FERC

A. FERC Performance Based Regulation

The Federal Energy Regulatory Commission (FERC, or the Commission) is responsible for ensuring that the rates, terms and conditions of service for wholesale sales and transmission of electric energy in interstate commerce are just, reasonable, and not unduly discriminatory or preferential.

In Order No. 679, FERC looked for comments on ways performance-based ratemaking (PBR) might apply to for-profit Transcos and traditional public utilities, and not-for-profit Transcos and public utility ISOs and RTOs. According to FERC:

"However, citing to current market structure, most commenters expressed a general lack of enthusiasm for PBR, and none held out any expectation that PBR would have a significant role to play in providing consumer benefits. Chief among the obstacles cited to implementing PBR is a difficulty in determining appropriate performance measures or benchmarks."[49]

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"Some commenters oppose PBR because they believe it could deter investment in transmission facilities, contrary to the main objective of the proposed rulemaking."[50]

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"Few commenters see any realistic role for PBR as a means of inducing cost saving behavior on the part of non-profit entities, although some, such as Ameren, believe that the Commission's oversight is inadequate.."[51]

——

"Industrial consumers, in particular, express the view that PBR has no role to play in the non-profit area and, furthermore, that PBR should not be applied to the profit area unless a proven model would make pricing under PBR as transparent as pricing under conventional ratemaking."[52]

FERC concluded:

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[49] Docket No. RM06-4-000, Order No. 679, Promoting Transmission Investment Through Pricing Reform. July 20, 2006, p. 139.

[50] Docket No. RM06-4-000, Order No. 679, Promoting Transmission Investment Through Pricing Reform. July 20, 2006, p. 140.

[51] Docket No. RM06-4-000, Order No. 679, Promoting Transmission Investment Through Pricing Reform. July 20, 2006, p. 141.

[52] Docket No. RM06-4-000, Order No. 679, Promoting Transmission Investment Through Pricing Reform. July 20, 2006, p. 141.

> "The overwhelming view on PBR from all segments of the industry is "not at this time" and "not given the current industry structure." Although there is general support for our earlier principles, we acknowledge, as commenters stress, that our voluntary program has not resulted in any PBR proposals being filed with the Commission. The consensus appears to be that the current state of the industry structure – a multitude of transmission-owning entities, many that do not directly control their transmission assets and operate in diverse geographical regions with very different customer densities, system ages and configurations – makes the determination of generally applicable performance benchmarks unworkable."[53]

FERC noted in its 2006 Order that it intended to continue to work with the industry to encourage development of PBR proposal, but to date Concentric is not aware of any that have been filed.[54]

B. Formula Based Rates

It has been the Commission's policy to permit utilities to establish rates through "formulas". The use of the term formula applies to the process rather than a specific formula, per se. FERC recognized that the integrity and transparency of formula rates and formula rate protocols are critically important in ensuring just and reasonable rates, and especially so given that more utilities are using formula rates to recover the cost of their transmission investments. Formula rates provide a mechanism for transmission owners to set a yearly (12-month period defined by the formula rate filer) revenue requirement. This enables transmission owners to recover costs in as close to real time as possible. Under a formula rate, a transmission owner files a yearly projected revenue requirement, which is then collected from customers over the upcoming year. After the year ends, the company must file a true-up comparison between the estimate it collected (revenues) and the actual amount spent. If too much has been collected, ratepayers will receive a refund in a subsequent year. If not enough has been collected, ratepayers will pay the balance due in a subsequent year.

Sections 205 and 206 of the Federal Power Act deal with the authority of the FERC over a public utility's rates, terms and conditions for transmitting or selling electric energy in interstate commerce. The rates, terms and conditions are required to be just and reasonable and not unduly discriminatory or preferential; otherwise, they are deemed unlawful. This is generally referred to as the "just and reasonable" standard. Section 205, in most cases the utility's burden of proof, requires that the entity proposing of a revision demonstrate that the proposed rate, term or condition is just and reasonable. Section 206, usually the customer, consumer advocate or FERC's burden of proof, requires that the entity proposing of a revision meet a higher burden of proof. The entity must demonstrate not only that the proposed

[53] Docket No. RM06-4-000, Order No. 679, Promoting Transmission Investment Through Pricing Reform. July 20, 2006, paragraphs 265-272, p. 143.
[54] Docket No. RM06-4-000, Order No. 679, Promoting Transmission Investment Through Pricing Reform, July 20, 2006, paragraphs 265-272, p. 143.

change is just and reasonable, but also that the existing provisions are unjust and unreasonable.

The formula rate is the transmission owner's FERC-approved, filed rate. Formula rates produce an annual revenue requirement, which can change from year to year. This obviates the need for transmission owners to file traditional rate cases at set intervals and attempts to prevent regulatory lag. The annual formula rate filings are informational only and deemed to be just and reasonable unless an interested party raises a challenge to the revenue requirement as filed. FERC does not audit, review or approve annual formula rate filings. FERC relies on the transmission system customers, market monitor, state regulatory bodies and other interested parties to review each annual revenue requirement, raise any disputes directly with the transmission owner and attempt to settle any dispute with the transmission owner. If there is no resolution, then the interested party can formally challenge the formula rate annual update with the Commission. The challenge of the formula rate is done under Section 206 of the Federal Power Act.

Regarding formula rates, the Commission has stated that "the formula itself is the rate, not the particular components of the formula."[55] Thus, periodic adjustments, typically performed on an annual basis, made in accordance with the Commission approved formula do not constitute changes in the rate itself and accordingly do not require Section 205 filings.[56] Because the formula rates for transmission service presently on file with the Commission do not typically require transmission owners to make a Section 205 filing to update their annual transmission revenue requirement, safeguards (protocols) were needed to be put in place to ensure that the input data is the correct data, that calculations are performed consistent with the formula, that the costs to be recovered in the formula rate are reasonable and were prudently incurred, and that the rates are just and reasonable.[57]

The safeguard that has often been employed is "formula rate protocols". The reason for including formula rate protocols in formula rates for transmission service is to provide the parties paying such rates specific procedures for notice and review of, and challenges to, the transmission owner's annual updates. Such formula rate protocols, to fulfill this purpose, should afford adequate transparency to affected customers, state regulators or other interested parties, as well as provide mechanisms for resolving potential disputes; they can be an important tool in ensuring just and reasonable rates.[58]

American Electric Power ("AEP") is an example of a FERC regulated utility that has utilized the Formula Rate structure to recover operating costs and investment costs. AEP's East

[55] *Ocean State Power II*, 69 FERC, Docket No. ER91-576-001. November 2, 1994, p. 15.
[56] *Ala. Power Co. v. FERC*, 993 F.2d 1557, 1567-68 (D.C. Cir. 1993). May 28, 1993, p. 8.
[57] *Idaho Power Co.,* 115 FERC ¶ 61,281, 29. May 31, 2006, Paragraph 29, p. 10; *Midwest Indep. Transmission Sys. Operator, Inc.*, 139 FERC ¶ 61,127. May 17, 2012 at Paragraph 9, p. 5. (*MISO*); *The Empire Dist. Elec. Co.*, 148 FERC 61,030. July 17, 2014, Paragraph 3 p. 1-2 (*Empire District*).
[58] *MISO*, 139 FERC ¶ 61,127. May 17, 2012, Paragraph 10, p. 6.

Companies[59] Formula Rate and protocols are reflected in Attachment H-14 of the PJM OATT. AEP provides a forward-looking formula rate, an annual true-up of that rate, and customer protocols governing such annual updates.[60] AEP's formula rate contains three cost-of-service provisions: (1) a historic cost-of service, (2) a projected cost-of-service, and (3) a true-up cost-of-service, including protocols for updating the formula rate. AEP recalculates the revenue requirement under the formula rate with historical data, using FERC Form No. 1 cost data as well as data from its accounting ledgers.

For each subsequent year, the historical cost of-service data is based on the prior year's expenses and plant in service. For the projected cost-of-service, AEP calculates adjustments to recognize transmission plant additions and associated depreciation for new plant that have gone into service or are expected to go into service in the current calendar year to produce an estimate of the cost-of-service for that year. The only elements in AEP's Formula Rate that are projected are those related to transmission plant in service additions and depreciation expense on new and existing plant in service. The true-up cost-of-service uses the prior year actual cost-of-service, and the difference between the collected cost-of-service and the true-up cost-of-service will be collected (or refunded) with the projected cost-of-service when AEP makes its annual update.

In contrast to I-X type rate programs, FERC's formula rates do not incorporate a specific I or X factor. Instead, the transmission company provides a forecast cost of service based off its prior year FERC Form 1 actual costs. FERC's standard is whether the forecast was reasonable when made. When actuals are filed in the company's FERC Form 1 following the close of the rate year, any differences are trued-up and recovered/refunded in a subsequent rate period. Formula Rates include a Carry Charge (interest) calculated on the recorded differences in its True-Up in an attempt to address the regulatory timing lag.

Below is the AEP Formula Rate for rates effective January 1, 2017. Line 12 shows that AEP includes the prior year's True-up as well as reductions for and prior period revenue requirements (including interest/carry charges) in Line 13. The revenue requirements for Network Service, Point-to-Point Service as well as PJM Regional Service are all broken out separately to ensure no cross-subsidization amongst the different customer classes.

[59] Ohio Power Company, Wheeling Power Company, Appalachian Power, Indiana Michigan Power, Kentucky Power, Kingsport Power Company.

[60] American Electric Power Service Corporation, 113 FERC ¶ 61,294. December 20, 2015, p. 2. American Electric Power Service Corporation, 115 FERC ¶ 61,114. April 26, 2006, p. 2.

Table 9: AEP Transmission Formula Rate Revenue Requirement[61]

AEP EAST Companies Transmission Formula Rate Revenue Requirement
Utilizing Projected or FERC Form 1 Data
For rates effective January 1, 2017

AEP Zone Transmission Service Revenue Requirement

Line No.			AEP Annual Revenue Requirement
A.	**Network Service**		
1	REVENUE REQUIREMENT (w/o incentives)	(TCOS Ln 1)	$890,241,963
2	LESS: REVENUE CREDITS	(TCOS Ln 2)	$23,314,038
3	CURRENT YEAR ZONE 1 AEP NETWORK SERVICE REVENUE REQUIREMENT	(TCOS Ln 3)	$866,927,926
4	LESS: REVENUE REQUIREMENTS INCLUDED IN LINE 1 FOR:		
5	RTEP UPGRADES (W/O INCENTIVES)	(TCOS Ln 5)	$42,321,233
6	OTHER ZONAL UPGRADES (W/O INCENTIVES)	(Worksheet J)	$0
7	SUBTOTAL		$42,321,233
8	EXISTING ZONAL ATRR (W/O INCENTIVES)	(Ln 3 - Ln 7)	$824,606,693
9	INCENTIVE REVENUE REQUIREMENT FOR ZONAL PROJECTS	(Worksheet J)	$0
10	EXISTING ZONAL ATRR (W/INCENTIVES)	(Ln 8 + Ln 9)	$824,606,693
11	PRIOR YEAR TRUE-UP (including interest)		($2,744,531)
12	INTEREST ON PRIOR YEAR TRUE UP		$0
13a	Reduction in the 2015 Annual Transmission Revenue Requirement (inc. interest)		($4,500,000)
13	**EXISTING ZONAL ATRR FOR PJM OATT**	(Ln 10 + Ln 11 + Ln 12 + Ln 13a)	**$817,362,162**
B.	**Point-to-Point Service**		
14	2017 AEP East Zone Network Service Peak Load (1 CP)		22,475.7
15	Annual Point-to-Point Rate in $/MW - Year	(Ln 13 / Ln 14)	$36,366.48
16	Monthly Point-to-Point Rate in $/MW - Month	(Ln 15 / 12)	$3,030.54
17	Weekly Point-to-Point Rate in $/MW - Weekly	(Ln 15 / 52)	$699.36
18	Daily On-Peak Point-to-Point Rate in $/MW - Day	(Ln 15 / 260)	$139.87
19	Daily Off-Peak Point-to-Point Rate in $/MW - Day	(Ln 15 / 365)	$99.63
20	Hourly On-Peak Point-to-Point Rate in $/MW - Hour	(Ln 15 / 4160)	$8.74
21	Hourly Off-Peak Point-to-Point Rate in $/MW - Hour	(Ln 15 / 8760)	$4.15
C.	**PJM Regional Service**		
22	RTEP UPGRADE ATRR W/O INCENTIVES	(Ln 7)	42,321,233
23	ADDITIONAL ATRR FOR FERC-APPROVED INCENTIVES ON RTEP	(Worksheet J)	-
24	TRUE-UP ADJUSTMENT INCLUDING INTEREST		1,470,439
26a	ADJUSTMENT Schedule 12		-
25	**RTEP ATRR FOR PJM COLLECTION UNDER SCHEDULE 12**		**$ 43,791,672**

In 2014, AEP filed two Section 205 filings with FERC to update its post-retirement benefits other than pensions ("PBOP" or "OPEB") and another to implement a PJM depreciation expense adjustment.[62] These filings were completed in accordance with the Formula Rate Protocols established in FERC Docket No. ER08-1329-000. The two changes to the Formula Rate inputs were defined in the Formula Rate Protocols and required a Section 205 filing from AEP. Otherwise, the annual true-up and rates for the upcoming year are informational only. The Formula Rate Protocols explains the process for any party to informally and formally dispute the annual filing at FERC.[63]

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61 AEP, ATRR Summary of AEP Operating Companies https://www.aep.com/about/codeofconduct/OASIS/TariffFilings/. Accessed March 27, 2018.

62 Quadrennial PBOP Update-Docket No. ER14-1375-000, PJM Depreciation Expense Change-Docket No. ER14-1408-000.

63 PJM Open Access Transmission Tariff. Docket ER10-2710-000 Attachment H-14, September 17, 2010.

Section 9:
Decline In X Factors Over Time

Concentric has previously presented productivity data, analyses, and findings for the electric distribution utility industry.[64] These findings have shown lower TFP growth resulting from the noted reduction in electricity consumption growth and, consequently, lower output growth.

TFP is a measure of the change in the outputs delivered by the utility (or industry) relative to the inputs required to deliver those outputs. However, it is important to note that a negative TFP growth rate does not necessarily indicate declining efficiency at either the industry or the utility level. The TFP trend equals the Output Quantity Index trend minus the Input Quantity Index trend. Negative TFP trends do indicate that measured outputs are growing slower than inputs.

A. CANADIAN AND U.S TRENDS IN PRODUCTIVITY

The Canadian and U.S. governments also track trends in productivity. In Canada, trends are tracked for the broader business sector, and specific to utilities. In the U.S., a utility specific measure is not available, but the broader business sector is tracked. The data in Table 10 show what has historically been a productivity differential between the Canadian and U.S. business sectors that has narrowed over the past several years, with overall business productivity at 0.4 and 0.5% respectively. The Canadian business sector has actually seen an increase in productivity in the near-term compared to the longer-term average. As seen in the evidence submitted in the Alberta and Ontario evidence, the pattern of declining productivity growth in the utility sector has been exhibited more broadly across the Canadian utility sector, as illustrated in the multifactor productivity data provided by Statistics Canada. The longer-term utility productivity growth of -1.1% declined to -2.1% over the most recent five-year period.

[64] Concentric Energy Advisors, Performance Based Regulation: Productivity Factor for HQD, June 29, 2017.

Table 10: Canada and US Multifactor Productivity Trends

	Statistics Canada[65]	*Statistics Canada*[66]	*Bureau of Labor Statistics*[67]
	Utility Sector Multifactor Productivity	Business Sector Multifactor Productivity	Non-Farm Private Business Multifactor Productivity
2000	2.4%	2.1%	1.6%
2001	-7.9%	0.1%	0.5%
2002	7.8%	1.3%	2.2%
2003	-3.0%	-0.7%	2.3%
2004	-3.0%	-0.3%	2.6%
2005	2.8%	0.0%	1.5%
2006	-3.1%	-0.8%	0.4%
2007	4.2%	-1.1%	0.5%
2008	0.5%	-2.3%	-1.3%
2009	-6.7%	-2.6%	-0.4%
2010	-1.5%	1.8%	2.9%
2011	-1.0%	1.5%	0.3%
2012	-2.4%	-0.6%	0.9%
2013	-3.1%	0.9%	0.2%
2014	-1.9%	1.3%	0.7%
2015	-2.1%	-1.0%	0.6%
2000-2015	-1.1%	0.0%	1.0%
2011-2015	-2.1%	0.4%	0.5%

These broad trends in business and utility-sector productivity in Canada are generally consistent with the trends evidenced in Australia's transmission networks.

[65] Statistics Canada. Table 383-0021 - Multifactor productivity, value-added, capital input and labour input in the aggregate business sector and major sub-sectors, by North American Industry Classification System (NAICS), annual (index, 2007=100 unless otherwise noted), CANSIM (database). (Accessed: June 2016).

[66] Statistics Canada. Table 383-0021 - Multifactor productivity, value-added, capital input and labour input in the aggregate business sector and major sub-sectors, by North American Industry Classification System (NAICS), annual (index, 2007=100 unless otherwise noted), CANSIM (database). (Accessed: June 2016).

[67] Bureau of Labor Statistics, Office of Productivity and Technology, Division of Major Sector Productivity. *Net Multifactor Productivity and Costs, Private Non-Farm Business Sector*. March 30, 2017.

Section 10:
Conclusions

Several examples of performance-based regulatory models for transmission companies have been identified in our research. The programs identified illustrate the practical need for customization of these approaches, even more so than for gas or electric distributors. Transmission companies exhibit a high degree of differentiation due to the varied sizes and configuration of their networks, geographies and loads served. Regulatory approaches range from modifications of cost-of-service to extended multi-year rate plans linked to performance targets. It is important to note that where productivity factors are measured and applied, these factors typically do not account for reliability. Considering the requirement of Article 48.1 for ongoing improvement in performance and service quality, the framework approved by the Régie must allow sufficient revenues for HQT to meet this objective.

The following are generalized conclusions from our prior and current research to assist the Régie with consideration of its approach to Phase III for HQT.

1. Cost of service regulation remains the standard for transmission companies in North America, but PBR programs for transmission companies have been developed internationally, and some have operated for multiple generations.

2. Approaches to transmission PBR vary considerably and exhibit a greater degree of company specific customization than typical utility distribution programs and retain some link to cost-of-service.

3. The goal of cost control and efficiency found in distribution PBR programs is present in transmission programs, but closely aligned with reliability as a central tenet.

4. The goal of regulatory efficiency with transmission can be served with multi-year rate plans, or formula-based rates, such as that adopted by FERC.

5. The broad array of productivity studies (and specifically total factor productivity studies) utilized in distribution programs to set revenue path trajectories are lacking for transmission companies. This is likely attributable to the lack of data on comparable peer groups.

6. In the place of TFP studies, benchmarking and peer cost analysis are more prevalent, and utilized to set custom revenue paths.

7. While limited productivity studies are available, the declines in productivity evidenced in North American distribution utility studies are similarly evidenced based on increasing input costs and flat-to-declining outputs (e.g., Australia).

8. The one example we have identified of a partial productivity factor measured for transmission companies is in Australia, where the average contribution of OPEX to total factor productivity was estimated at -0.3% over the 2006-2016 period. Total factor productivity declined at -2.1% over this same 10-year period.