COÛTS ÉVITÉS

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1. COÛTS ÉVITÉS SUR LE RÉSEAU INTÉGRÉ

1.1. Coût évité de fourniture – transport

1.1.1. Signal de coût évité de l'énergie

Le bilan offre - demande en énergie du Distributeur présente d'importants surplus.

Pour la période d'hiver, le signal de coût évité reflète le coût des achats sur les marchés de court terme alors que pour la période d'été, il correspond au prix de l'électricité patrimoniale.

- 2017 à 2026 inclusivement :
  - le signal de coût évité pour la période hivernale (décembre à mars) est de 6,3 ¢/kWh ($ 2016), indexé à l'inflation ;
  - le signal de coût évité pour la période estivale (avril à novembre) est de 2,8 ¢/kWh ($ 2016), indexé à l'inflation.

1.1.2. Signal de coût évité de la puissance

Le bilan offre - demande du Distributeur présente des déficits en puissance. Pour les deux premiers hivers, le signal de coût évité correspond au coût moyen d'approvisionnement sur les marchés de court terme. À partir de l'hiver 2018-2019, le signal de coût évité reflète le coût moyen de la puissance des soumissions retenues dans le cadre de l'appel d'offres de long terme A/O 2015-01.

- Pour les hivers 2016-2017 et 2017-2018, le signal de coût évité est de 20 $/kW-hiver ($ 2016, indexé à l'inflation) ;
- À compter de l'hiver 2018-2019, le signal de coût évité est de 108 $/kW-an ($ 2016, indexé à l'inflation).

Dans sa décision D-2016-033[1], la Régie fixait le signal de prix à 53 $/kW-hiver à compter de l'hiver 2018-2019. Toutefois, le Distributeur réitère respectueusement sa proposition d'établir le signal de coût évité selon l'approche proposée dans le cadre du dossier R-3933-2015. Le Distributeur rappelle en effet que la valorisation d'un nouvel équipement en dehors de la période d'hiver n'est plus possible dans le contexte actuel, rendant ainsi irréaliste l'hypothèse d'un équipement dédié à 50 % aux besoins du Québec.

Tout d'abord, toutes les capacités de transport ferme sur les interconnexions à partir du Québec sont réservées à très long terme, rendant donc impossible la revente de puissance et de l'énergie y étant associée durant les mois d'avril à novembre. Afin d'illustrer cette nouvelle réalité, le Distributeur souligne que les interconnexions vers l'état de New York et ceux de la Nouvelle-Angleterre sont réservées jusqu'en 2044.

[1] Décision D-2016-033, paragraphe 273.

De plus, un équipement situé à l'extérieur de la zone d'équilibrage du Québec qui transiterait par une interconnexion existante cannibaliserait la capacité d'importation du Distributeur en pointe, n'amenant ainsi aucune contribution additionnelle au bilan en puissance.

Enfin, le fait que l'A/O 2015-01 ait porté sur une période annuelle plutôt qu'hivernale n'a aucunement biaisé le résultat des soumissions reçues. En effet, l'impossibilité de pouvoir valoriser la puissance sur les marchés externes, compte tenu de l'absence de disponibilités sur les interconnexions, a inévitablement contraint les soumissionnaires à élaborer leurs propositions en comptant uniquement sur le rendement procuré par l'entente avec le Distributeur pour rentabiliser leurs investissements.

1.1.3. Différenciation pointe et hors pointe

Selon la méthodologie de la moyenne mobile sur 5 ans[2], l'écart des prix DAM, New York – Zone M (IMPORT) entre les heures de pointe et celles hors pointe est de 11,60 $/MWh (ou 1,2 ¢/kWh), comme présenté au tableau 1.

TABLEAU 1 :
COMPARAISON DES PRIX DAM, NEW YORK – ZONE M (IMPORT)
HEURES DE POINTE ET HEURES HORS POINTE (ANNUEL)

	2011	2012	2013	2014	2015	Moyenne 2011-2015
$ CAN / MWh						
Pointe	41,40	30,55	42,26	61,64	39,36	43,04
Hors-pointe	34,88	25,49	31,62	39,77	25,46	31,44
Écart	6,53	5,06	10,63	21,87	13,90	**11,60**
Écart %	19%	20%	34%	55%	55%	37%

1.2. Coût évité de transport de la charge locale et de la distribution

Le Distributeur propose de maintenir les indicateurs des coûts évités pour la charge locale et la distribution tels qu'ils ont été présentés dans le dossier R-3677-2008. Exprimés en $ 2017, le coût évité de la charge locale est de 48,1 $/kW-an et celui de la distribution de 17,4 $/kW-an.

1.3. Répartition du coût évité par usages et catégories de clients

La répartition du coût évité par usages et catégories de clients est présentée, sur une base annuelle, à l'annexe A.

[2] Décision D-2011-028, paragraphe 69.

Tel qu'il a été précisé aux sections 1.1.1 et 1.1.3, le coût évité de la fourniture est différent selon la saison (hiver, été) et entre les périodes de pointe et hors pointe. Ce coût évité est calculé par usages et catégories de clients, en tenant compte de la répartition de ceux-ci selon quatre périodes (pointe d'hiver, hors pointe d'hiver, pointe d'été, hors pointe d'été), ainsi qu'en appliquant les pertes en énergie associées aux catégories de clients.

Compte tenu de la structure actuelle, le coût évité d'un usage tel que la climatisation, qui n'est présent qu'en période d'été, est significativement plus bas que celui d'un usage présent toute l'année ou, encore, en grande partie en hiver. Ainsi, en 2017, pour un client résidentiel, le coût évité pour l'usage de climatisation est de 3,22 ¢/kWh, tandis qu'il est de 8,31 ¢/kWh pour le chauffage des locaux.

2. COÛTS ÉVITÉS DES RÉSEAUX AUTONOMES

2.1. Objectif des coûts évités et suivi de la décision D-2015-018

Le coût évité est un indicateur qui mesure le coût d'une variation à la marge de la demande à partir d'une situation d'équilibre offre - demande. Ce coût est principalement utilisé pour évaluer la rentabilité des interventions en efficacité énergétique et du PUEÉ. En revanche, les projets spéciaux qui sont de nature à modifier le plan d'équipement spécifique à un réseau font davantage l'objet d'une analyse économique détaillée.

En réponse à la demande de la Régie dans sa décision D-2015-018[3], le Distributeur a confié un mandat à une firme d'experts (ICF International). Le mandat consistait, d'une part, à effectuer un balisage sur les méthodes utilisées par d'autres juridictions nord-américaines pour établir les coûts évités dans les réseaux non reliés et, d'autre part, à proposer une méthode visant à déterminer les coûts évités en énergie et en puissance pour les réseaux autonomes au Québec.

Les principales conclusions du rapport sont présentées dans les sections suivantes et le rapport final de l'étude d'ICF International est déposé à l'annexe B.

2.2. Coût évité de l'énergie

D'après le balisage présenté dans le rapport d'ICF International, la méthode utilisée par le Distributeur pour établir ses coûts évités en énergie est reconnue et similaire à celle utilisée dans les juridictions nord-américaines examinées.

Le Distributeur reconduit donc la méthode utilisée dans le dossier R-3933-2015 pour l'établissement de ses coûts évités en énergie.

Le coût évité de l'énergie, exprimé en ¢/kWh, est constitué :

- du coût de combustible (incluant le transport et la distribution) ;

[3] Décision D-2015-018, paragraphes 464 et 465.

- du taux de rendement moyen de la centrale (exprimé en kWh/litre) ;
- des coûts variables d'exploitation et d'entretien ;
- des pertes sur le réseau ;
- des coûts liés aux émissions de gaz à effet de serre.

À partir de ces variables, lesquelles sont mises à jour chaque année, une annuité croissante, indexée à l'inflation (exprimée en $ 2016), est calculée.

Comparativement au dossier R-3933-2015, les coûts évités sont plus élevés, et ce, malgré la baisse à court terme des prix des combustibles. En effet, cette faible baisse est compensée par la mise à jour des paramètres économiques (notamment le taux d'actualisation et le taux de change) ainsi que par l'augmentation des coûts liés aux droits des émissions de gaz à effet de serre (SPEDE[4]).

Pour le réseau de Schefferville, le coût évité de l'énergie est basé sur les paramètres du contrat avec NALCOR.

2.3. Coût évité de la puissance

Au regard du balisage réalisé par ICF international, seuls le Yukon et le Distributeur calculent des coûts évités en puissance et ils utilisent la même méthode pour le faire, soit celle de l'équipement générique. Le Distributeur note également que, d'après le balisage, il est le seul à publier ses coûts évités chaque année.

Toutefois, la firme d'experts propose une autre méthode pour calculer les coûts évités en puissance. La méthode proposée est basée sur le report de l'investissement d'un équipement dans le temps. Selon le Distributeur, cette méthode ne permet de répondre ni à ses besoins ni aux exigences de la Régie, c'est-à-dire obtenir un signal stable et cohérent afin de faciliter la planification des investissements à moyen et long termes[5]. D'ailleurs, cette méthode n'est présentement pas utilisée par d'autres juridictions pour calculer les coûts évités en puissance en réseau non relié.

En effet, cette méthode proposée engendre une forte volatilité des coûts évités d'une année sur l'autre, sans pour autant apporter plus de précision et de robustesse dans son application. Or, les problèmes découlant de cette volatilité avaient déjà été soulevés par la Régie dans le passé[6].

De plus, dans sa décision D-2015-018[7], la Régie soulignait sa préoccupation face à ce qu'elle estimait être une sous-estimation du coût évité en puissance des réseaux autonomes. Or, selon la méthode basée sur le report de l'investissement, les coûts évités en puissance seraient systématiquement plus faibles que ceux découlant de la méthode actuelle du Distributeur.

[4] Système de plafonnement et d'échange de droits d'émission de gaz à effet de serre du Québec.
[5] Décisions D-2012-024, paragraphes 95 et 96 et D-2015-018, paragraphe 463.
[6] Ibidem.
[7] Décision D-2015-018, paragraphe 458.

Par conséquent, le Distributeur maintient sa méthode adoptée depuis le dossier R-3814-2012, laquelle repose sur le coût d'un équipement générique de production, pour déterminer ses coûts évités en puissance. Cette méthode présente l'avantage de déterminer un coût évité stable, permettant ainsi une planification des investissements à moyen et long termes.

Ainsi, pour chaque territoire, les coûts évités de la puissance exprimés en $/kW-an restent identiques à ceux du dossier R-3933-2015. Seuls les paramètres économiques sont mis à jour. Pour l'ensemble des réseaux du Nunavik, le coût évité en puissance demeure à 900 $/kW-an. Il correspond à celui d'un équipement générique pour un groupe alimenté au diesel. Il en est de même pour les réseaux de la Basse-Côte-Nord et de la Haute-Mauricie, où le coût évité de la puissance est de 765 $/kW-an, soit 15 % de moins que celui du Nunavik compte tenu des coûts de transport plus faibles.

Aux Îles-de-la-Madeleine, le coût évité en puissance est de 200 $/kW-an. Il correspond au coût d'un équipement générique pour un groupe alimenté au mazout lourd.

Quant au réseau de Schefferville, le coût évité en puissance correspond à la mise en place d'un groupe électrogène, soit 145 $/kW-an.

2.4. Coûts évités des réseaux autonomes

Le tableau 2 présente le détail des coûts évités de chacun des réseaux.

TABLEAU 2 :
COÛTS ÉVITÉS PAR RÉSEAUX AUTONOMES – ANNUITÉ CROISSANTE EXPRIMÉE EN ¢/KWH DE 2016

	Coût évité en énergie ¢/kWh	Coût évité en puissance $/kW-an	Facteur d'utilisation	Coût évité en puissance ¢/kWh	Coût évité total ¢/kWh
Îles-de-la-Madeleine					
Cap-aux-Meules	22,79	200	54%	4,26	27,05
Nunavik					
Akulivik	51,19	900	57%	17,98	69,17
Aupaluk	50,50	900	57%	17,91	68,41
Inukjuak	48,09	900	63%	16,36	64,46
Ivujivik	54,03	900	59%	17,55	71,58
Kangiqsualujjuaq	57,41	900	58%	17,84	75,25
Kangiqsujuaq	53,92	900	61%	16,72	70,64
Kangirsuk	53,27	900	59%	17,35	70,62
Kuujjuaq	52,09	900	62%	16,64	68,72
Kuujjuarapik	50,09	900	65%	15,76	65,86
Puvirnituk	48,94	900	65%	15,81	64,76
Quaqtaq	57,18	900	61%	16,91	74,09
Salluit	49,27	900	63%	16,38	65,65
Tasiujaq	56,14	900	60%	17,16	73,30
Umiujaq	52,57	900	58%	17,67	70,24
Basse-Côte-Nord					
La Romaine	35,67	765	45%	19,34	55,01
Port Menier	35,39	765	45%	19,32	54,71
Haute Mauricie					
Clova	42,08	765	42%	20,55	62,64
Opitciwan	36,11	765	48%	18,21	54,33
Schefferville	2,41	145	51%	3,24	5,66

ANNEXE A :

COÛTS ÉVITÉS PAR USAGES ET PAR CATÉGORIES DE CLIENTS

TABLEAU A-1 : COÛT ÉVITÉ PAR USAGES – CLIENTS AU TARIF D EN ¢/KWH DE 2017

	Annuité constante[1] (10 ans)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Chauffage de l'eau	**7,42**	**5,92**	**6,03**	**7,40**	**7,55**	**7,69**	**7,84**	**7,99**	**8,15**	**8,31**	**8,47**
Fourniture - Transport	6,21	4,81	4,90	6,25	6,37	6,49	6,62	6,74	6,87	7,01	7,14
Transport - Charge locale	0,88	0,81	0,83	0,85	0,86	0,88	0,90	0,92	0,94	0,95	0,97
Distribution	0,32	0,29	0,30	0,31	0,31	0,32	0,33	0,33	0,34	0,35	0,35
Chauffage des locaux	**10,92**	**8,32**	**8,49**	**11,00**	**11,22**	**11,44**	**11,67**	**11,90**	**12,14**	**12,38**	**12,63**
Fourniture - Transport	8,43	6,02	6,14	8,60	8,77	8,95	9,13	9,31	9,49	9,68	9,88
Transport - Charge locale	1,83	1,69	1,72	1,76	1,79	1,83	1,87	1,90	1,94	1,98	2,02
Distribution	0,66	0,61	0,62	0,64	0,65	0,66	0,68	0,69	0,70	0,72	0,73
Tous les usages	**8,84**	**6,91**	**7,04**	**8,85**	**9,03**	**9,20**	**9,38**	**9,57**	**9,76**	**9,95**	**10,14**
Fourniture - Transport	7,09	5,29	5,40	7,18	7,31	7,46	7,60	7,75	7,90	8,06	8,21
Transport - Charge locale	1,29	1,18	1,21	1,23	1,26	1,28	1,31	1,33	1,36	1,39	1,42
Distribution	0,47	0,43	0,44	0,45	0,46	0,46	0,47	0,48	0,49	0,50	0,51

[1] Note : Le taux d'actualisation nominal utilisé est de 5,248 %.

TABLEAU A-2 : COÛT ÉVITÉ PAR USAGES – CLIENTS AU TARIF G EN ¢/KWH DE 2017

	Annuité constante[1] (10 ans)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Chauffage des locaux	**10,86**	**8,19**	**8,36**	**10,96**	**11,18**	**11,40**	**11,63**	**11,86**	**12,10**	**12,34**	**12,59**
Fourniture - Transport	8,63	6,14	6,26	8,82	9,00	9,18	9,36	9,55	9,74	9,93	10,13
Transport - Charge locale	1,64	1,51	1,54	1,57	1,60	1,63	1,67	1,70	1,73	1,77	1,80
Distribution	0,59	0,55	0,56	0,57	0,58	0,59	0,60	0,61	0,63	0,64	0,65
Tous les usages (sans chauffe)	**7,93**	**6,27**	**6,39**	**7,92**	**8,08**	**8,24**	**8,40**	**8,56**	**8,73**	**8,90**	**9,07**
Fourniture - Transport	6,52	4,98	5,07	6,58	6,71	6,84	6,97	7,10	7,24	7,38	7,52
Transport - Charge locale	1,03	0,95	0,97	0,99	1,01	1,03	1,05	1,07	1,09	1,11	1,14
Distribution	0,37	0,34	0,35	0,36	0,36	0,37	0,38	0,39	0,39	0,40	0,41
Tous les usages	**7,91**	**6,25**	**6,37**	**7,90**	**8,06**	**8,22**	**8,38**	**8,54**	**8,71**	**8,88**	**9,05**
Fourniture - Transport	6,50	4,96	5,05	6,56	6,69	6,82	6,95	7,08	7,22	7,36	7,50
Transport - Charge locale	1,03	0,95	0,97	0,99	1,01	1,03	1,05	1,07	1,09	1,11	1,14
Distribution	0,37	0,34	0,35	0,36	0,36	0,37	0,38	0,39	0,39	0,40	0,41

[1] Note : Le taux d'actualisation nominal utilisé est de 5,248 %.

TABLEAU A-3 : COÛT ÉVITÉ PAR USAGES – CLIENTS AU TARIF M EN ¢/KWH DE 2017

	Annuité constante[1] (10 ans)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Chauffage des locaux	**10,90**	**8,23**	**8,39**	**10,99**	**11,21**	**11,43**	**11,66**	**11,89**	**12,13**	**12,37**	**12,62**
Fourniture - Transport	8,62	6,13	6,25	8,81	8,98	9,16	9,34	9,53	9,72	9,91	10,11
Transport - Charge locale	1,67	1,54	1,57	1,60	1,64	1,67	1,70	1,74	1,77	1,81	1,84
Distribution	0,61	0,56	0,57	0,58	0,59	0,60	0,62	0,63	0,64	0,65	0,67
Tous les usages (sans chauffe)	**7,16**	**5,71**	**5,82**	**7,14**	**7,28**	**7,42**	**7,57**	**7,71**	**7,86**	**8,02**	**8,17**
Fourniture - Transport	6,07	4,70	4,79	6,09	6,21	6,33	6,46	6,58	6,71	6,84	6,97
Transport - Charge locale	0,80	0,74	0,75	0,77	0,78	0,80	0,82	0,83	0,85	0,87	0,88
Distribution	0,29	0,27	0,27	0,28	0,28	0,29	0,30	0,30	0,31	0,31	0,32
Tous les usages	**7,16**	**5,71**	**5,82**	**7,14**	**7,28**	**7,42**	**7,57**	**7,71**	**7,86**	**8,02**	**8,17**
Fourniture - Transport	6,07	4,70	4,79	6,10	6,21	6,33	6,46	6,58	6,71	6,84	6,97
Transport - Charge locale	0,80	0,74	0,75	0,77	0,78	0,80	0,82	0,83	0,85	0,87	0,88
Distribution	0,29	0,27	0,27	0,28	0,28	0,29	0,30	0,30	0,31	0,31	0,32
Hors pointe	**3,57**	**3,28**	**3,33**	**3,44**	**3,50**	**3,57**	**3,63**	**3,70**	**3,76**	**3,83**	**3,90**
Fourniture - Transport	3,57	3,28	3,33	3,44	3,50	3,57	3,63	3,70	3,76	3,83	3,90
Transport - Charge locale	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Distribution	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00

[1] Note : Le taux d'actualisation nominal utilisé est de 5,248 %.

TABLEAU A-4 : COÛT ÉVITÉ PAR USAGES – CLIENTS AU TARIF LG EN ¢/KWH DE 2017

	Annuité constante[1] (10 ans)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Tous les usages	**6,40**	**4,94**	**5,04**	**6,43**	**6,55**	**6,68**	**6,81**	**6,94**	**7,08**	**7,22**	**7,36**
Fourniture - Transport	6,23	4,79	4,88	6,27	6,39	6,51	6,64	6,77	6,90	7,03	7,17
Transport - Charge locale	0,17	0,16	0,16	0,16	0,17	0,17	0,17	0,18	0,18	0,19	0,19
Distribution	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00

[1] Note : Le taux d'actualisation nominal utilisé est de 5,248 %.

TABLEAU A-5 : COÛT ÉVITÉ PAR USAGES – CLIENTS AU TARIF L EN ¢/KWH DE 2017

	Annuité constante[1] (10 ans)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Tous les usages	**5,87**	**4,62**	**4,71**	**5,88**	**5,99**	**6,11**	**6,23**	**6,35**	**6,47**	**6,59**	**6,72**
Fourniture - Transport	5,75	4,51	4,59	5,76	5,87	5,98	6,10	6,22	6,34	6,46	6,59
Transport - Charge locale	0,12	0,11	0,12	0,12	0,12	0,12	0,13	0,13	0,13	0,13	0,14
Distribution	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00

[1] Note : Le taux d'actualisation nominal utilisé est de 5,248 %.

ANNEXE B :

RAPPORT DE BALISAGE RELATIF AUX COÛTS ÉVITÉS EN RÉSEAUX AUTONOMES

Methodology for calculating avoided costs in non-integrated areas

Final report

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Acronyms

Alaska EA	Alaska Energy Authority
AEA	Arctic Energy Alliance
AEO	Annual Energy Outlook
IEA	International Energy Agency
ATCO	ATCO Electric Yukon
AVEC	Alaska Village Electric Cooperative
BC Hydro	BC Hydro and Power Authority
BC	British Columbia
BCN	Basse Côte-Nord
OEB	Ontario Energy Board
C&T	Cap & Trade
COGUA	Canadian Off Grid Utility Association
CPUC	California Public Utilities Commission
EIA	Energy Information Agency
FERC	Federal Energy Regulatory Commission
H1RCI	Hydro One Remote Communities Inc.
HQD	Hydro-Québec Distribution
HM	Haute Mauricie
ICF	ICF International
IDLM	Îles-de-la-Madeleine
IESO	Independent Electricity System Operator
INAC	Indigenous and Northern Affairs Canada
LBNL	Lawrence Berkeley National Laboratory
NAPEE	National Action Plan for Energy Efficiency
NIA	Non-integrated area
NL Hydro	Newfoundland and Labrador Hydro
NPV	Net present value
NRCan	Natural Resources Canada
NREL	National Renewable Energy Laboratory
NTPC	Northwest Territories Power Corporation
NUL	Northland Utilities Limited
NWT	Northwest Territories
NYMEX	New York Mercantile Exchange
PURPA	Public Utility Regulatory Policies Act
PV	Photovoltaic
QEC	Qulliq Energy Corporation
REF	Renewable Energy Fund
WCI	Western Climate Initiative
WTI	West Texas Intermediate
YEC	Yukon Energy Corporation
YoY	Year-over-Year

Introduction

Hydro-Québec Distribution (HQD) retained ICF International (ICF) to recommend an avoided-cost calculation method for non-integrated areas (NIAs[1]). This report answers questions raised by the Régie de l'énergie (Régie) in its decision D-2015-018 about the methodology HQD uses to calculate its avoided costs of energy and capacity. ICF will serve as an independent expert and suggest a methodology that reflects industry best practices in North America.

ICF proposed to conduct a scan of avoided-cost calculation practices in relevant jurisdictions in North America to identify best practices. The team assessed the methodology used in Newfoundland and Labrador, Ontario, Nunavut, Northwest Territories, Yukon, British Columbia and Alaska[2]. ICF selected these jurisdictions because of the large number of NIAs in these jurisdictions and their similarities with the NIAs of Quebec.

ICF reviewed relevant professional and academic literature on avoided cost in NIAs and conducted interviews with utility staff and demand-side management (DSM) program administration staff in July, August, and September 2015. ICF proposed a methodology to HQD based on the research and interviews conducted. ICF then applied this methodology by producing calculation examples based on filed and/or publically-available data on Quebec NIAs.

Objectives

The purpose of this study is to recommend a methodology for calculating avoided costs in Quebec's NIAs. In Quebec, avoided costs are used to support decision making regarding expenses in DSM programs and in development projects that may alter HQD's capital expenditure requirements. For development projects led and financed by independent developers, avoided costs are used as a maximum threshold in power purchase price negociation. Examples of such development projects could include renewable energy projects like wind power projects, solar photovoltaic (PV) projects or small hydropower (small hydro) projects, as well as projects involving liquefied natural gas-fired generation or interconnection of a NIA to the integrated-area system.

Regulatory context

HQD started calculating and filing avoided costs for NIAs with the Régie in its 2006-2007 rate application, and has since been filing avoided costs on an annual basis. Since the inception of avoided cost determination for the NIAs, the Régie has provided direction for HQD's avoided cost methodology. Despite the use and proposal of several alternative calculations by HQD, the Régie continues to seek changes to the HQD methods. As a result, HQD has sought ICF's independent review of methodologies used elsewhere to determine best practices for NIAs.

[1] Namely: Îles de la Madeleine (IDLM): Cap-aux-Meules; Nunavik : Akulivik, Aupaluk, Inukjuak, Ivujivik, Kangiqsualujjuaq, Kangiqsujuaq, Kangirsuk, Kuujjuaq, Kuujjuarapik, Puvirnituq, Quaqtaq, Salluit, Tasiujaq, and Umiujaq; Basse Côte-Nord (BCN): La Romaine and Port-Menier; Haute Mauricie (HM): Clova and Opitciwan; and Schefferville.

[2] The selected sample, with the addition of Quebec, represents the vast majority (98%) of installed capacity in NIAs in Canada (Arriaga, 2015, p. 39). Quebec stands out as the jurisdiction with the most installed capacity in NIAs in Canada, with a total of 175 MW (26% of total). Alaska was added because of its leadership in the area of renewable energy generation in its NIAs.

In addition to our best practice review, ICF has reviewed all of the Régie's decisions wherein guidance was provided regarding avoided costs as well as completed an inventory of key guidance made by the Régie to date, as described below:

A. In 2009-2010, the Régie expressed a preference for avoided cost figures that are specific to each NIA (D-2009-016, R-3677-2008, page 114.)

B. In 2012-2013, the Régie observed large year-over-year (YoY) fluctuations of avoided cost figures for each NIA. These fluctuations were due to variations in the demand forecast which, in turn, caused variations in HQD's capital expenditure plan, both in terms of the installation time and size of new generators. The Régie required that HQD propose an approach to reduce these fluctuations (D-2012-024, R-3776-2011, page 33.)

C. In 2015-2016, the Régie suggested that using the same avoided cost figures for DSM measures and other types of investment may not be appropriate. The Régie showed openness to integrating nuances in the methodology based on the type of project as long as the methodology, its nuances and its main parameters are clearly laid out. (D-2015-018, R-3905-2014, page 116.)

D. Again in 2015-2016, the Régie sought to know whether the marginal approach used by HQD ($ per kW of new generator capacity being installed) is valid in NIAs, considering that generator capacity increments have a high nominal value relative to the size of each of the isolated power systems and are infrequent[3] (i.e. they are "lumpy") (D-2015-018, R-3905-2014, page 116.)

E. Furthermore in 2015-2016, the Régie suggested that an expert consider and evaluate a methodology based on extrapolation of the historical cost of service figures, netting ou fixed operation and maintenance costs (D-2015-018, R-3905-2014, page 116.)

In assessing the methodologies used in other jurisdictions and in selecting a preferred approach for HQD, ICF also addresses the key concerns of the Régie listed above. The methodology that ICF has proposed attempts to balance the guidance of the Régie, the difficulty in data collection and load forecasting by HQD, the needs of the NIA systems, and the best practices in avoided cost calculation identified in North America.

The remainder of this document contains two Chapters. Chapter 1 provides a detailed description of the inventory of methodologies and practices for avoided cost determination in several jurisdictions across North America. It also provides an assessment of the methodologies and the rationale for the selection of the preferred approach. Chapter 2 provides a discussion of ICF's recommended approach and the results of implementing this approach using illustrative data examples.

[3] "les ajouts de puissance se font donc par incréments de capacités importantes, à l'échelle de ces réseaux, et espacés dans le temps." (Régie de l'énergie, 2015)

1. Jurisdictional scan

In conducting the jurisdictional scan, ICF developed an observational framework to assess the avoided cost calculation practices that are used in NIAs. This chapter sets out this framework, describes the observations ICF made regarding each jurisdiction, and includes ICF's conclusions based on these observations.

1.1 Observational framework

The jurisdictional scan and recommended methodology should consider the general features of similarly situated NIAs and the ways in which other jurisdictions use avoided cost for capital planning purposes and resource evaluation specifically to serve these NIAs. The steps followed in the jurisdictional scan include:

- Identify similarly situated NIAs which utilize avoided cost
- Survey the avoided cost methodology
- Identify pros and cons of each methodology

This chapter provides background on the avoided cost concept with particular relevance to NIAs. It also provides the conclusions of the NIA avoided cost methodology review. Finally, ICF presents recommendations based on the overall survey and an analysis of pros and cons for common NIA approaches.

1.1.1 Typical uses of avoided cost and application in NIAs

Avoided costs of electricity are a measure of the reduction in cost to electricity ratepayers that is caused by a certain set of alternative actions that differ from a set of *reference* or *expected* actions. This alternative scenario may be a portfolio of DSM programs or a variety of investment projects. The level of avoided cost is meant to be a threshold at which the alternative scenario is at par with the reference scenario in terms of average total cost of electricity. In this report, ICF considered this definition to be a best practice and adopted this definition for use in this report.

The concept of avoided cost originated from the Public Utility Regulatory Policies Act (PURPA) in the United States in 1978 when power markets in most states were regulated and when most utilities were still vertically integrated. Avoided cost rates were meant to be the price at which a regulated utility could purchase electricity from non-regulated electricity generators, while not affecting the utility's regulated rates. If the regulated utility purchased electricity at a rate equivalent to the avoided cost, the regulated rates would remain the same; no adjustment to rates would be necessary. If the utility pursued an alternative scenario for which the cost was higher than the avoided cost, this scenario would have an upward impact on a regulated utility's revenue requirements; and if the utility pursued an alternative scenario for which the cost was lower than the avoided cost, this scenario would have a downward impact on the revenue requirements. In both cases an adjustment to rates would be necessary. Since 1978, the uses of the concept of avoided costs have multiplied, but the definition of avoided costs has not changed.

While avoided cost definitions and applications have varied as the industry has developed, they remain fundamentally associated with the opportunity cost of new regulated generation resources. Nowadays, while assessments of avoided cost are still applicable to generation resources to an extent, the most common application of electricity avoided cost is in the assessment of DSM resources.

DSM program administrators and utilities in NIAs in North America use avoided costs for one and sometimes both of the following purposes:

- To design, prioritize and assess DSM programs using cost-effectiveness tests standardized according to the practices originally articulated by the California Public Utilities Commission (CPUC, 2001), such as the total resource cost test and the rate-impact measure test that are used in Quebec.
- To be used as part of the negotiation of a power purchase agreement with an independent power producer (private or community). In power purchase agreement negotiations, avoided costs can be used as a piece of information for determining the impact of the power purchase on revenue requirements, or in helping to set boundaries around what is an acceptable purchase price.

Utilities, such as BC Hydro and Power Authority (BC Hydro), Newfoundland and Labrador Hydro (NL Hydro) use the avoided cost as a price cap when negotiating a power purchase price with independent project developers. Hydro One Remote Community Inc. (H1RCI) in Ontario uses the avoided cost as the power purchase price as part of its standing offer program. As in the original PURPA design, the avoided price, therefore, provides a transparency to potential independent power producers who are able to assess their project against a readily-available price from the utility.

In general, utility avoided costs have several components including: electric energy (kWh), roughly the short-run variable costs of generation; capacity (kW), considered the contribution to enhancement of the utility's system reliability; and transmission and distribution, equivalent to the costs associated with maintenance and operation of the T&D system serving the area (see section 1.1.3). In cases of deferred investment, the avoided costs include not only the capital cost of a new resource, but also the financing, corporate income tax (when applicable), and regulated rate of return, i.e. the revenue requirements. Costs are avoided when alternative actions offset operational expenditures or reduce the planned capital expenditures. Both DSM and investment projects may have an impact on planned capital expenditures.

Application of Avoided Costs in the HQD NIAs

HQD calculates and publishes avoided cost figures to be used for evaluating DSM resources. In the 2015-2016 rate filing decision, the Régie suggested that using the same avoided cost rates for DSM measures and other types of investment may not be appropriate (D-2015-018, R-3905-2014, page 116.) While avoided-cost calculations must reflect the impact on revenue requirements in any case, the details of the methodology must be nuanced. This is because DSM programs do not impact revenue requirements in the same way as investment projects: they affect different components of cost of service. Therefore, while fundamental components of avoided costs are the same across investment project and DSM program comparisons, full avoided costs will vary depending on the application.

1.1.2 General features of NIAs

The majority of utilities serving NIAs throughout Canada are regulated utilities, which means that their electricity generation and distribution rates are regulated by an economic regulatory body or “regulator” like the Régie[4]. Most of them are Crown corporations, with the exception of one regulated investor-owned utility in Yukon and two in the Northwest Territories. In the NIAs of Alaska, electricity is generated and distributed by individual local power authorities.

Retail electricity prices are not representative of the actual cost of electric service in diesel-powered NIAs. There are two main reasons for this: cross-subsidization through rate design, and direct subsidization by territorial/provincial and federal governments. As a result, in these NIAs, both the cost of service and the avoided costs are very different than retail rates. Cross-subsidies generally benefit residential NIA customers, who pay less than the cost of service.

According to the International Energy Agency (IEA-RETD 2012, 50), NIAs in Canada and Alaska fall into the “remote areas with long winters” category. These communities are subject to the vagaries of the weather, limiting their access to fuel for long periods in winter. There are also few available methods of transportation for the fuel. These fuel costs are directly affected as a result. Deliveries to NIAs are made by road transport, all-season road, ice road, rail, boat or plane (Arriaga, 2015, p. 40).

In some communities, primarily in Newfoundland and Labrador, Nunavut, and Alaska, and in some of Quebec’s NIAs, diesel is transported by boat. As a result, diesel can only be delivered during short periods of the year when the coastal waters are ice-free. These communities therefore require a large fleet of tanks to store enough fuel for the winter months. The substantial cost of storing the fuel in tanks has to be added to the cost of the diesel.

The most expensive method of fuel transportation is by plane. It is the only possible method of transportation in some communities in Nunavut, in many communities in Northwest Ontario and in Old Crow, Yukon. It is in these NIAs, with only plane transport of fuel being possible, where the highest avoided costs are typically found. There are no NIAs in Quebec that rely exclusively on plane transport.

Comparison to HQD NIAs

Utilities serving the NIAs examined in a number of Northen jurisdictions (e.g. in Nunavut, Northwest Territories, Yukon and Alaska) are highly dependent on fossil fuels; their cost of service is strongly tied to global oil prices. Often, when prices go up quickly and unexpectedly, their customers have to absorb the sudden increase in their electricity rates. In contrast, Quebec NIA customers are less affected by these fluctuations because Quebec NIAs are included in the same rate base as the integrated area and 99% of the provincial power supply comes from sources other than fossil fuels. The customers in the NIAs benefit from the greater supply diversity of HQD.

[4] However, there are notable exceptions. In Ontario, a large proportion of NIAs is served by a power authority separate from the Crown utility. These local power authorities often reside within a band council or municipality. The same situation applies to British Columbia and Alaska. In Canada, local power authorities are supported and funded by Indigenous and Northern Affairs Canada (INAC).

1.1.3 Components of avoided cost in NIAs

DSM programs and investment projects have the potential to offset one or many components of cost of service. For instance, the components usually associated with avoided costs are fuel, fuel transportation and storage, maintenance, generator wear-and-tear and replacement, and the cost of additional generator capacity. ICF used a systematic approach during the jurisdictional scan by identifying and describing which components were accounted for in the avoided cost in each of the jurisdictions.

ICF divided the avoided cost into two categories: operational expenditures and capital expenditures. All components researched are included in the following categories:

(A) Avoided operational expenditures

- **Fuel:** Fuel is an avoided cost in the NIAs of every jurisdiction and the approach to calculating it is the same throughout. The avoided cost of fuel is the price paid for the fuel (e.g., in $/litre) divided by the power plant’s annual average energy conversion efficiency (in kWh/litre).
- **Fuel transportation and storage:** In some NIAs, the cost of transportation and storage is included in the fuel price, while elsewhere it is borne by the electric utility and has to be added to the price.
- **Maintenance:** Maintenance costs include labour and physical resource costs incurred to ensure that NIA power plants and distribution systems operate properly.
- **Greenhouse gases:** The avoided costs include greenhouse gas (GHG) emission allowances only in provinces with a carbon pricing system, such as Quebec and British Columbia.
- **Hedge of fossil fuel prices:** A hedge against fossil fuel prices is a value assigned to the risk of fossil fuel price fluctuation, especially sudden price increases. Including a hedging component in the avoided cost is a recommended practice in jurisdictions that are highly dependent on fossil fuels for power generation. DSM and renewable energy resources have the attribute of reducing electric utilities’ exposure to fuel price volatility (Bolinger & Wiser, 2008; Wu & Huang, 2014).

(B) Avoided capital expenditures

- **Capacity installation to support growth in demand:** Electric utilities are responsible for forecasting electricity demand and deciding when to install one or more new generators to maintain supply reliability when demand is on the rise.
- **End-of-useful-life generator replacement:** Generators typically have to be replaced after 100,000 hours of operation, which is usually equivalent to 15 years of useful life. With certain alternative technologies, generators could potentially be set to standby or be shut down for multiple hours, thereby prolonging their useful life and postponing their replacement.
- **Investment in fuel tanks:** Some NIAs require large fuel tanks to ensure that their electricity supply will be reliable for several months without replenishment. The NIAs that most need

them are those where fuel is delivered seasonally by boat during the summer, when the water (sea or river) is not ice covered, or those where fuel is delivered only by ice road during the winter.

Avoided operational expenditures are often grouped together and referred to as **avoided energy cost**. This grouping is convenient because all of these costs can be turned into a simple $ per kWh rate and then summed together. Avoided capacity installation due to demand growth is often referred to as **avoided capacity cost**. Avoided capacity cost can be turned into a marginal rate, in $ per kW per year. Other avoided capital expenditures are generally not turned into a rate, and are instead included in cost-benefit analyses as a present worth.

Depending on the nature of the alternative scenario, avoided cost may need to be adjusted to account for **distribution network losses**. Distribution losses represent the energy lost in the distribution system between the point of power generation and the point of electricity consumption. Distribution losses must be added for technological solutions implemented at the customer's end, such as DSM and self-generation (or distributed energy). Distribution losses must be added to both the avoided costs of energy and the avoided costs of capacity (Liu et al., 2015, p. 6; NAPEE, 2007, p. 3.2; Woolf, Malone, Schwartz, & Shenot, 2013, p. 41).

In the integrated area, it is common practice to include an avoided cost of **transmission and distribution infrastructure**. ICF observed that this was not the case in the NIAs because transmission and infrastructure system investments represent significantly lower capital expenditures than power generation capacity, and therefore, are typically ignored.

ICF used the list of components of avoided cost described above to document observations on best practices of avoided costs in NIAs.

1.2 Key observations of the jurisdictional scan

This section presents a high-level summary of observations made as a result of the jurisdictional scan. At the beginning of our research, we found that no other jurisdictions are as diligent as Quebec in calculating, filing and substantiating, on an annual basis, official avoided costs. While other jurisdictions do use avoided costs for DSM evaluation and power purchase price negotiation, these avoided costs are developed on an ad-hoc basis, are not systematically filed with the regulator, and often are not subjected to any particular public and/or regulatory scrutiny.

Furthermore, there are no textbooks or reference guides laying out approaches specifically applicable to NIAs. This section presents a review of several cost-benefit or economic analyses of DSM programs and alternative energy projects, as observed across the jurisdictions ICF reviewed.

1.2.1 Two main methodological approaches

One key observation from the jurisdictional scan is that, with the exception of Yukon and Quebec, no jurisdictions account for avoided capacity cost to evaluate DSM in their NIAs. Therefore, in order to draw conclusions regarding possible approaches to avoided capacity cost in NIAs, ICF decided to expand the research horizon and look at all economic analyses that compare an alternate solution (DSM or investment projects) with business as usual.

Through the jurisdictional scan, ICF observed two main families of methods to determine avoided costs:

- The **Levelized cost (LC)** method. The levelized cost of capacity divides the capital expenditure associated with the purchase of a generator by the capacity rating of the generator and annualizes the result over the book life of the generator. The rate obtained is in $/kW-year. That rate may be turned into an average cost per kWh by dividing by the expected annual throughput of the generator. When capacity and energy costs are blended together, they become the levelized cost of energy (LCOE). Two variations of this methodology were used by HQD, the first in its 2010-2011 rate filing and the second in its 2013-2014 rate filing, "*méthode de l'équipement générique*" (R-3708-2009) and "*méthode de l'équipement générique de production*" (R-3814-2012), respectively. The latter is the method used by HQD for the 2013-2014 filing through to and including the 2016-2017 filing. It was calculated based on a proxy generator, applied to most of the NIAs, and held constant.

  The LC method is used in Quebec and in Yukon to calculate avoided capacity cost for evaluating DSM in NIAs.

  In Yukon, the avoided capacity cost is a flat 2 c./kWh, which represents the avoided cost of one marginal kW installed in the Yukon integrated system. The Yukon integrated system is the largest NIA in Canada, with a peak demand of approximately 84 MW. Because it is so large, ICF believes that Yukon cannot be used as a reference point with regard to the approach to estimating avoided capacity cost because investment decision will follow a pattern that is more similar to the North American integrated area than to other NIAs. Capacity investment is more flexible in the Yukon integrated system (i.e. less lumpy).

- The **Differential of revenue requirements (DRR)** method, also known as the "present worth" method. The DRR method calculates the difference between the present value of revenue requirements under a reference scenario, and the present value under an alternative scenario (example: a reference scenario *without DSM* and an alternative scenario *with DSM*). Revenue requirements are the sum of operational expenditures, and amortized capital expenditures. The DRR method applies to any capital expenditure, not only capacity cost. A variation of this methodology was used by HQD in its 2006-2007 rate filing and referred to as "*méthode du différentiel de parc*" (R-3584-2005). After this filing, HDQ replaced the DRR with the LC method.

  Ontario (i.e. H1RCI) used the DRR method to determine the avoided capacity cost for the purpose of evaluating DSM programs (Navigant, 2005). However, H1RCI has since decided not to include avoided capacity cost to simplify their calculations, and because it did not make a significant difference with regard to the cost-effectiveness of their DSM program (i.e. the program is cost-effective without the inclusion of avoided capacity cost).

Since ICF found few occurrences of avoided capacity cost determination for DSM, we broadened the scope of our research and included all economic analyses of any alternative energy scenarios in NIAs. With a broader scope, ICF found occurences of the use of the DRR method in Newfoundland and Labrador, where it was used to value the deferral of investment in a new fuel storage tank attributed to a DSM program in the costal NIA of Rigolet. It was also used in the Northwest Territories and British Columbia to value alternative energy projects, solar PV and small hydro, respectively, as documented in the next section.

The Yukon Energy Corporation (YEC) used both the LC method and the DRR method in its latest 20-year integrated electric resource plan, published in 2011. The LC method was used to do a preliminary screening of energy resources. The DRR method was then used to study particular scenarios.

Both in the LC method and in the DRR method, energy costs and capacity costs may be added up to form a single average value in cents per kWh. Energy and capacity costs can also be used independently. The avoided cost of energy is calculated the same way in both methods. The difference in results only lies in the approach to calculating the avoided capacity cost.

1.2.2 Summary of the jurisdictional scan

Table 1 and Table 2 summarize our findings for each cost component of our observational framework for DSM programs and for investment projects, respectively. It became clear early on in the research stage of this study that DSM programs do not offset the same cost of service components as investment projects. ICF therefore decided to differentiate DSM programs from investment projects in the analysis. A detailed description of the components for each jurisdiction is presented in Appendix A.

Table 1 Summary of avoided cost components – DSM programs

	Operational expenditures Also referred to as avoided energy cost					Capital expenditures			
						Avoided capacity cost			
Jurisdiction	Fuel	Transportation and storage	Maintenance	Greenhouse gases	Hedge of fossil fuel prices	Capacity installation	End-of-life replacement	Invest. in fuel tanks	Distribution losses
Newfoundland and Labrador	**Incl.**	**Incl.**	No	No	No	**Some-times**	**Some-times**	**Some-times**	**Incl.**
Quebec	**Incl.**	**Incl.**	**Incl.**	**Incl.**	No	**Incl.**	No	No	**Energy only**
Ontario	**Incl.**	**Incl.**	No	No	No	No	No	No	**Incl.**
Northwest Territories (NWT)	Not applicable – None of the DSM programs in the NWT are subject to cost-effectiveness tests that use avoided cost.								
Yukon	**Incl.**	**Incl.**	**Incl.**	No	No	**Incl.**	**Incl.**	No	**Incl.**

Jurisdiction	Operational expenditures Also referred to as avoided energy cost					Capital expenditures			
						Avoided capacity cost			
	Fuel	Transportation and storage	Maintenance	Greenhouse gases	Hedge of fossil fuel prices	Capacity installation	End-of-life replacement	Invest. in fuel tanks	Distribution losses
British Columbia (BC)	Not applicable – BC Hydro shut down its DSM program aimed specifically at its NIAs before 2013.								
Alaska	Not applicable – The Alaska Energy Authority does not use avoided cost to assess the cost-effectiveness of its DSM projects and programs. Furthermore, there are few utility-administered DSM program activity in Alaska (ACEEE, 2015).								

Four of the jurisdictions reviewed use avoided cost for DSM program evaluation. Of these four, two use the LC method to calculate the avoided cost of capacity: Quebec (R-3708-2009 and R-3814-2012) and Yukon. In order to calculate the levelized cost, ATCO Electric Yukon and the Yukon Energy Corporation, the two regulated utilities in Yukon, estimate a generic cost of generator capacity based on their engineers' experience: $1,000 per kW for diesel generators. The value obtained is 2 c./kWh. If inputs were identical (they are not), the Yukon utilities' method would yield the same result as HQD's "*méthode de l'équipement générique de production*". This value, 2 c./kWh, represents the avoidance of all capital expenditures, namely new capacity installation and end-of-life generator replacement (ICF Marbek, 2012, p. 53, 2013, p. 6; YEC, 2011, p. 79). However, in its 2011-2030 resource plan, YEC used the LC to complete a preliminary screening of the different supply- and demand-side resources, and then used the DRR method in its detailed analysis of the main scenarios being considered (YEC, 2011).

NL Hydro in Newfoundland and Labrador used the DRR method to perform the valuation of the deferral of the installation of a fuel tank in Rigolet, a town on the North Coast of Labrador, to demonstrate that more aggressive DSM measures (targeted DSM) were justified. Rigolet thereby took priority over other NIAs. NL Hydro, rather than the fuel supplier, is owner of the fuel storage facilities in Rigolet. If this had not been the case, the deferral would have been of no benefit to NL Hydro. NL Hydro did not convert the benefit generated by deferring the installation of a new tank in Rigolet into a *marginal* figure (i.e., into $/kWh). Instead, NL Hydro inserted the total benefit, in $, directly into its cost-effectiveness tests.

Although the situation has never arisen, NL Hydro advised that it would agree to carry out the same valuation, using the same approach, for the deferral of installation of additional production capacity. NL Hydro would also be willing to value the deferral of end-of-life generator replacement for a project that would allow the generators to be completely turned off for multiple hours, as might be the case with some small hydro projects.

In 2005 in Ontario, H1RCI hired Navigant Consulting to determine its avoided costs in NIAs in preparation for the potential launch of its DSM program (Navigant, 2005). Although H1RCI no longer uses Navigant's method in its entirety, it is one of the most complete methods seen during the jurisdictional scan. Navigant used the DRR method to determine the avoided cost of capacity. H1RCI no longer uses this method because its DSM program is modest; its total budget is about $300,000 per year. Therefore, H1RCI considers that the budget envelope does not warrant the effort of gathering and analyzing data needed to use the method developed by Navigant. Moreover, to date, the avoided energy costs alone have sufficed to demonstrate the cost-effectiveness of its DSM program.

Table 2 presents the results for investment projects.

Table 2 Summary of avoided cost components – Investment projects

Jurisdiction	Operational expenditures Also referred to as avoided energy cost					Capital expenditures			
						Avoided capacity cost			
	Fuel	Transportation and storage	Maintenance	Greenhouse gases	Hedge of fossil fuel prices	Capacity installation	End-of-life replacement	Invest. in fuel tanks	Distribution losses
Newfoundland and Labrador	**Incl.**	**Incl.**	No	No	No	**Some-times**	No	**Some -times**	No
Quebec	Not applicable. HQD does not use avoided cost for power purchase price negotiation.								
Ontario	**Incl.**	**Incl.**	No	No	No	No	No	No	No
Northwest Territories (NWT)	**Incl.**	**Incl.**	**Incl.**	No	No	No	No	No	No
Yukon	**Incl.**	**Incl.**	**Incl.**	No	No	**May-be**	**May-be**	No	No
British Columbia (BC)	**Incl.**	**Incl.**	**Some -times**	**Incl.**	No	**Some -times**	**Some -times**	No	No
Alaska	**Incl.**	**Incl.**	**Incl.**	**Incl.**	No	**May-be**	No	**May-be**	No

Utilities across all scanned jurisdictions use avoided costs to evaluate alternative-energy projects and/or to negotiate a power purchase price with independent power producers in the NIAs. However, none include distribution losses in their avoided cost[5]. This is one fundamental distinction between the avoided cost due to DSM, which includes distribution losses, and avoided cost due to alternative energy investment projects, which does not.

Utilities in Newfoundland and Labrador, Yukon, BC and Alaska agreed that most alternate-energy investment projects do not allow the offsetting of capacity cost. However, these utilities applied several nuances to the avoided costs for investment depending on the technology employed. ICF sought to capture these nuances in our recommendations, as detailed in Section 2.3. ICF was informed that certain projects that use storage technology may in the future allow some capacity to be offset, but that none of these projects had been realized in NIAs as yet.

[5] With the exception of behind-the-meter self-generation projects.

There was also agreement among these utilities that certain small hydro projects may allow deferring new capacity installation and end-of-life replacement of generators. For instance, BC Hydro used the DRR method to determine the avoided cost associated with purchasing electricity from hydropower developers. BC Hydro offers developers of small hydro project a series of payments equal to the avoided operation and maintenance costs, as well as the avoided cost of capacity and end-of-life generator replacement. These payments are computed based on the avoidance of operation and maintenance costs for each hour that a power plant is on standby and based on the deferral of the installation of new generators at the end of the expected effective useful of life of these gensets, which is also measured in hours of operations.

In the NWT, the Northwest Territories Power Corporation (NTPC) used the DRR method to assess the Colville Lake solar PV-diesel, which was to be funded primarily by the NTPC rate base. The project underwent an economic evaluation that was submitted to the regulator before it approved the project (NTPC, 2014, 2015). Despite involving battery energy storage, NTPC decided not to claim avoided capacity cost. NTPC hopes that the Colville Lake pilot project will demonstrate the feasibility of using battery storage to curtail some peak demand.

Alaska is a leader in renewable energy in northern NIAs. Numerous renewable energy projects have been developed in Alaska since the late 1990s, especially wind-diesel projects. To date, Alaska has completed 23 wind-diesel projects. Three projects are under construction as of the time of writing of this report; approximately 30 projects are in the design stage (Alaska EA, 2015b). The organization that is currently at the helm of renewable energy development in Alaska is the Alaska Energy Authority (Alaska EA). The Alaska EA is a state agency whose operating funds come primarily from the state and federal governments. Alaska EA manages the Renewable Energy Fund (REF) through which it distributes funds in support of renewable energy projects. One of the criteria used by the Alaska EA to allocate REF grants is the result of a project-by-project economic analysis. The standard economic analysis accepted by the Alaska EA does not currently include avoided capacity cost (Alaska EA, 2015a).

The Alaska EA, just like BC Hydro and NL Hydro, indicated that it would be amenable to incorporating avoided capacity cost if two conditions were met: (i) if the host NIA for the project were in need of new capacity in the short term (2 to 5 years ahead), and (ii) if provided it were demonstrated that the technological solution could reliably provide capacity during on-peak emergency events. The current position of the Alaska EA is that wind power cannot deliver such capacity. To date, the specific situation in which these two conditions would be met, has not arisen.

The challenges regarding the planning of capital expenditures in the NIAs, and, in particular, planning the addition of new capacity, were a recurring theme during the jurisdictional scan. This is one important reason why many utilities in NIAs are reluctant to use avoided capacity cost in their economic analysis. Due to the significance of these challenges, a more thorough discussion is provided in Section 1.2.3.

1.2.3 Challenges with capital expenditure planning in NIAs

Utilities are responsible for forecasting electricity demand and deciding when to install additional capacity. All of the utilities reviewed in this study have to justify their investment decisions to their respective regulators. To that end, they use the N-1 supply reliability rule to decide when to install new capacity[6]. Under the N-1 rule, the remaining generators must be able to provide the required capacity when the thermal power plant's most powerful generator is shut down either for maintenance or due to failure.

All of the utilities plan capacity additions to their NIAs in the short term, i.e., only a few years in advance. In Newfoundland and Labrador, for example, even if a long-range 20-year capital expenditure plan provides a high level forecast, capacity additions are only scheduled no more than five years in advance. Other utilities plan this type of investment two or three years in advance. All of the utilities included in the jurisdictional scan have difficulty planning further into the future because of the variability in peak demand from one year to the next.

Forecasting electricity demand is a particular challenge in NIAs, primarily because of the small number of customers, but also because of uncertainty about the future development of northern communities, whose economies depend on natural resource exploitation, which in turn depends on global prices for those resources. Utilities want to avoid investing to install extra capacity in a community only to have the community's population decline due to the closure of a neighbouring mine, for example. One of the utilities, BC Hydro, mentioned that this is even more relevant when committing to a long-term electricity purchase agreement (20 to 40 years) with a small hydro producer because a hydropower plant cannot be moved. In comparison, diesel generators are easier to move.

Additionally, much of the load growth in many communities is driven primarily by government funding, and through the development of larger community infrastructure projects such as schools, water treatments plant and housing projects, all of which have unpredictable funding patterns. Multiple utilities reported observing stagnation or even a decrease in electricity demand in some NIAs, with residents moving to larger towns.

The jurisdictional scan revealed that the level of development of avoided-cost calculation practices is relatively incipient in most NIAs. This also contributes to the focus on avoided energy cost, which is simple to calculate, and the disregard for the avoided capacity cost, which is more challenging to compute and is rather imprecise due to the volatility of demand.

Avoided-cost calculation practices are relatively underdeveloped by most electric utilities in remote areas because they do not have access to the same resources, such as human resources and expertise, as those in the integrated system. Compared to that of integrated-area utilities, their smaller rate base limits their ability to spend resources to conduct studies. The relatively small size of their DSM programs also limits spending on analysis. This comment was made a number of times during interviews, in particular by BC Hydro, H1RCI (Ontario) and QEC (Nunavut). ICF's observations suggest that this also applies to the other jurisdictions, with the exception of the Yukon[7].

[6] There are some differences, but the rules are very similar. For example, in Quebec a factor of 90% is applied to the N-1 rule.

[7] The comment does not necessarily apply to Yukon. Firstly, because ATCO Yukon is one of the largest utilities in Canada, a part of the ATCO holding company in Alberta. Secondly, both Yukon utilities (YEC and ATCO) are required to submit significant analysis to the regulator despite the relatively small size of the DSM portfolio of programs offered.

1.3 Benefits and drawbacks of common approaches to avoided costs for NIAs

ICF's analysis relies upon the observation of a large number of economic analyses of DSM programs and projects across NIAs. This thorough research zeroed in on two main families of economic analyses: the LC method and the DRR method. The LC method is the average fixed cost of a generator (i.e. estimated cost of generator divided by its capacity rating, in $/kW) which is then annualized ($/kW-year). One of its variations, the *proxy* LC method, uses the estimated investment cost of an archetype generator also known as proxy plant, pro-forma plant or generic equipment.

The DRR method is the difference between a *reference* capital expenditure plan and an *alternative* capital expenditure plan, both discounted to current days. It also uses the estimated investment cost of generators, provided that generators are appropriately sized for each of the NIAs.

Based on ICF's jurisdictional scan, a pros & cons analysis was performed, as displayed in Table 3. As indicated in Table 3, there is a large degree of consensus over how to compute the avoided cost of energy. The method was consistent across most of the jurisdictions targeted by the study. Avoided energy costs are calculated using the same approach whether the LC method or the DRR method is used. In contrast, the avoided cost of capacity varies.

Table 3 Comparison of the levelized cost method and the DRR method

Compo-nent	App-roach	Benefits	Drawbacks	Implications
Energy	**DRR** and **LC**	There is no distinction between the DRR and the LC method on avoided energy cost. Both methods use the same formula and result in the same numbers. The only nuances from one jurisdiction to another are whether variable maintenance, environmental compliance cost (such as GHG allowances), distribution losses, etc. are included or not.		
Capacity	**DRR**	▪ Uses planned capital expenditures sized according to the need for reserve margin in size (kW) and timing (year) for each NIA ▪ Provides differentiation of NIA-specific value of resources. ▪ Captures value of both deferral and avoidance based on timing; ▪ Is not affected by economies of scale	▪ Data requirements higher, though not prohibitive. ▪ Higher level of YoY fluctuations than the LC method (if using a *proxy LC*).	*Result: Investment reflects need.* Accurate reflection of avoided capacity value regardless of the level of the NIA reserve margin. Captures real value of specific NIA based on that NIA's conditions.

Compo-nent	App-roach	Benefits	Drawbacks	Implications
	LC	▪ Ease of calculation ▪ Data requirements low	▪ Uses generic cost data and assumes full levelized cost can be avoided during all time periods ▪ Is challenging to estimate in the presence of economies of scale ▪ Does not accurately reflect deferral versus avoided value.	*Result: Over-investment in DSM and other alternative energy.* Likely to overstate capacity value in periods of higher reserve margins. More accurate in periods of low reserves.

The strength of the differential of revenue requirements (DRR) method is that it is meant to measure the real-world impacts on revenue requirements of the alternative course of action, and thereby the impact on electricity rates, which is typically what energy regulators want to see in the results of an economic analysis. This should result in more accurate estimate of avoided costs. The DRR method allows electricity supply planners to gain an appreciation of the value of DSM considering both the all-in cost of the fossil-fuel resource and the timeline of when new fossil fuel-fired generation capacity will be needed.

A weakness of the DRR method, in particular in the NIAs, is that it must rely on a long-term capital expenditure plan and on long-term demand growth forecast. Demand forecasts in NIAs are subject to a large degree of uncertainty since each individual NIA is a small demand centre with a small population of customers; as a result, the way in which demand evolves in an NIA is more volatile than demand in integrated-area systems. The disconnection of a few customers or the start of a few new construction projects can be enough to create large upward or downward fluctuations in relation to any given NIA's previous year's demand. There are two implications to this uncertain load forecast. First, many utilities in NIAs generally prefer not to have long-term capital expenditure plans, and they prefer to make short term decisions about new capacity installation. Second, even where a capital expenditure plan exists, it is to be expected that this plan will have many discrepancies from one year to the next as the result of demand volatility, which in turn will result in YoY variations in the avoided capacity cost results.

The strength of the LC method is that it may not require a capital expenditure plan or any form of demand growth forecast. The proxy LC method, for example, relies on an archetype generator that is sized without having to determine the *magnitude* of the capacity need (kW). Furthermore, the LC method assumes that the investment cost needed to obtain a resource is incurred immediately without having to determine the *timing* of the capacity need (year of installation). The average fixed cost, in $/kW, the capital expenditure, is then annualized to enable comparison with operational expenditures, $/kW-yr. Capital and operational expenditures can then be used separately. When combined, the result is known as a levelized cost of energy (LCOE). The LCOE is essentially a measure of the average all-in cost of procuring electricity through diesel generators, regardless of whether or when a new generator is actually needed.

Using LC indicators is useful to inform long-term planning decisions by pointing to which of multiple resource options are the cheapest. LCs are easy to calculate and easy to compare and thus they allow planners to do a preliminary screening of the best portfolio of resources. Making a decision exclusively on LC for various alternatives would be most appropriate if there were no pre-existing installed capacity. Indeed, that is not the case, and thus this is a key caveat with the use of the LC.

The proxy LC method as currently used by HQD carries the intrinsic assumption that capacity is to be procured immediately, regardless of whether it is needed or not[8]. It may fluctuate less from one year to another because it is a universal and constant value, but it is less accurate because it carries an upward bias in periods of higher reserve margins (excess capacity) which are prevalent in the NIAs due to the lumpiness of capacity investment.

In most instances, the LC method is only a crude approximation for calculating avoided costs. The proxy LC method does not capture the nuances of a small electric system. Typically, the avoided costs in an integrated area will be attributable to changes in a large number of new generating unit projects every year (e.g. project delays, reduction in of project sizes, avoidance of certain projects). This does not apply to a small system such as a NIA, however, where timing of capacity installation (i.e. deferral) is the reason why revenue requirements are impacted by DSM. As a result, the LC method does not accurately value the impact of capital expense deferral on revenue requirements in NIAs.

The most critical caveat of using the LC of a diesel generator as the avoided capacity cost is that the LC will not allow distinguishing whether the generator is actually needed or not and the timing of when it is needed. Whenever a utility procures a resource before it is truly needed, it automatically causes an undue upward impact on revenue requirements. In other words, for any utility, any organization, or any person, buying something one does not need is invariably more expensive than not buying it. Spending on DSM when it is not needed can be a wasteful use of ratepayer monies just as much as not pursuing DSM when needed. As a result the LC method will have an upward bias on the avoided capacity cost by assuming that capacity must be installed immediately. It gives the signal to planners to pursue more DSM than needed. Regulatory bodies in North America typically seek to avoid such bias.

Quebec's NIAs have two main elements that are important in assessing the two methodologies:

1. The price of generation infrastructure is regulated, and
2. The generation capacity investments in NIAs are "lumpy", as pointed out by the Régie.

From an economic analysis perspective, the avoided cost of generation infrastructure in the NIAs should be handled in the same manner as avoided cost of local distribution infrastructure (e.g. transformer substations) owned by regulated distribution companies in the integrated area. While supply-side investments in general tend to be lumpy, transmission and distribution investments are more so given the longevity of these resources and the economies of scale in developing the infrastructure.

The impact to small systems becomes even more pronounced as annual decisions for new resource additions drastically affect forward planning needs. Under such lumpy investment

[8] The LC could also potentially be calculated for each NIA instead of using the same LC across all NIAs and discounted to account for the installation year. However, it would still assume the avoidance of an annuity rather than valuing investment deferral. In addition, the use of the capacity rating of the generator as the denominator in the formula exacerbates the YoY fluctuations of the avoided cost figures due to the presence of economies of scale.

planning, the value of a one-year deferral is achieved only if enough load reduction is achieved to defer a project for a year. No additional savings are achieved until enough DSM is implemented for a two-year deferral, and so on. A LC method applies the value of deferral regardless of whether a deferral is possible or needed. In contrast, the DRR method recognizes the *timing* directly.

1.4 Recommendation and rationale for the choice of the DRR method

ICF observed, through the jurisdictional scan, that no other jurisdictions other than Quebec and Yukon[9] include avoided capacity cost as part of their avoided costs for evaluating DSM. Despite the fact that avoided capacity cost is rarely used to evaluate DSM programs in NIAs, ICF believes that HQD should set the bar higher than the practice observed in other jurisdictions by seeking to estimate and include avoided capacity cost. Ignoring the avoided capacity cost due to DSM would undervalue DSM in the NIAs, thereby leading to underspending on DSM and overspending in the NIAs.

In comparing the LC with the DRR option, and consistent with the best practice in the rest of North America, ICF recommends the use of the DRR method to determine the avoided cost in the NIAs. In the preceding section, we discussed the pros and cons of each method. In this section we discuss the rationale for our choice.

The DRR methodology calculates the present value of the difference in total generation costs with and without a load increment. This methodology, while more data intensive than a LC approach, has the advantages of:

- Reflecting the actual conditions of each NIA,
- Capturing the true value of deferral based on the timing of the resource need and the timing of availability of alternate options, and
- Reflecting avoided capacity costs accurately regardless of the reserve margin situation in each of the NIAs.

As currently estimated, the HDQ uses a universal LC of capacity across all NIAs (i.e. a proxy LC) and does not reflect the level of reserve margin for each individual NIA. The DRR approach relies on a more specific characterization of each NIA. This will yield a different value for each NIA, which will provide an accurate reflection of the location-specific value of DSM. It will provide the ability to optimize the scheduling of DSM expenses.

Due to such advantages, ICF believes that the DRR methodology will provide the best reflection of actual NIA needs and hence will help determining the right amount of spending on DSM or on alternate investment projects. Using the LC method to estimate the avoided capacity cost is more likely to lead to overspending in DSM; just like ignoring the avoided capacity cost would lead to underspending in DSM.

In addition, the accommodations made to the DRR method, as described in detail later in this chapter, will allow the method to be applied with a level of effort and an amount of information that are commensurate with the DSM expenditures anticipated in HQD's NIAs, while delivering a more accurate cost signal than the LC method.

[9] Yukon includes an avoided capacity cost of 2 c./kWh in its avoided cost of diesel generation.

In assessing the two methods, ICF has addressed the Régie's goals:

- The recommended DRR approach allows for avoided cost figures that can be allocated specifically to each NIA through application of the same methodology. In particular, this allows the level of reserve margin of individual NIAs to be directly recognized.
- ICF has recommended that the application of the DRR approach be applied in such a way as to minimize YoY fluctuations in avoided cost. To some extent, however, some variations are to be anticipated due to the natural fluctuations of demand in the NIA, which have a direct impact on the NIAs' demand outlook and in turn on the result of any accurate avoided cost methodology.
- ICF proposes to vary the application of the DRR for DSM and alternative investment projects, reflecting the alternate implications to revenue requirements.

The Régie also suggested that an independent expert should consider and evaluate a methodology for calculating avoided cost based on extrapolation of historical cost of service. Under this approach, the total cost of service would have to be stripped from all of the expenditures that cannot be offset by DSM or investment projects (e.g. customer service, billing and general administration). The cost of service could also be stripped from the cost of energy, which would be handled separately. What would remain is essentially the amortized past investment in generation capacity plus the cost of capital[10], which is equivalent to the sum of annuities for all past investments in generation facilities. The sum of annuities is divided by the historical kWh annual production. Consequently, provided that our interpretation of the Régie's suggestion is correct, this approach is a variation under the LC method.

We see value to the suggestion made by the Régie. The Régie's suggested a variation to the LC method, which would have the advantage of providing grounds to estimate the size of the generators that would be installed in the NIAs based on historical trend. The generator sizing would be based on the actual sizes that were selected and installed for each NIA in the past.

The sizing of generators that will be installed is important under the LC method in the NIAs. This is because the avoided capacity cost is sensitive to the sizing decision. The kW rating of the generator has an influence on the result because a degree of economies of scale exists in NIAs. The existence of economies of scale means that the average fixed cost of a generator (i.e. the cost divided by kW rating, resulting in a $/kW value) is higher for a small piece of equipment compared to a larger one. With the LC method, oversizing the generator has a downward impact on the result thereby such oversizing would result in lowering the cost signal used for DSM planning purposes. Under the *proxy* LC method in the NIAs, it is of importance for the utility to demonstrate that the kW rating used for the proxy generators is representative of the generators that will be installed in all the NIAs in the planning horizon.

The variation of the LC method suggested by the Régie would provide the correct order of magnitude in terms of the size of generators adapted to each of the NIAs because it is based on actual generators that were installed in these NIAs.

[10] The cost of capital includes interest payments and regulated return on equity. Corporate income taxes do not need to be incorporated in the calculation in Quebec because HQD is a crown corporation that does not pay income tax.

The Régie's suggestion, however, would not seek to reflect the real-world avoided cost due to the pursuance of an alternative set of actions. In this, the Régie's suggestion would not be consistent with the best-practice North American definition of avoided costs used in this report. There are two main reasons for this. First, the costs incurred as a result of past investment decisions can no longer be changed. Therefore, using the *historical* cost of service of capacity is inappropriate to evaluate *future* alternative actions. Second, just like the proxy LC method, the Régie's suggested variation of the LC method uses the *avoidance* of capacity rather than *deferral* of capacity. In small systems such as the NIAs, the investments in additional capacity are lumpy, and thereby investments are *deferred* rather than *avoided*. The lumpiness of capacity investment needs to be factored into the approach to estimating the impact of DSM on revenue requirements.

Table 4 is a summary of the discussions above. It expands on Table 3 by providing more details about the benefits of the proposed method. It presents the accomodations that ICF suggests in response to the trade-offs being made that choosing the DRR method entails and that we will elaborate upon in Section 2.2.2.

Table 4 Benefits and trade-offs of the proposed DRR method

<table>
<tr><th colspan="2">Advantages</th></tr>
<tr><td colspan="2"> Uses planned capital expenditures that are commensurate with the need for reserve margin in size (kW) and timing of installation (Year) for each NIA: The results of the DRR method are an accurate reflection of capital expenditures that will be required in the future, and that may be avoided or deferred if selecting a diffent course of action.
Provides differentiation of NIA-specific value of resources: The DRR method, as detailed in Chapter 2, will produce avoided capacity cost figures specific to each NIA, which provides valuable information in optimal scheduling DSM expenses in the NIAs to the benefit of all ratepayers.
Captures value of both deferral and avoidance based on timing: Accurately reflects the fact that incoming capacity cost will be lower in the NIAs that dispose of a sufficient level of reserve margin in the foreseeable future. Also, it can value the deferral of capital expenditure in addition to avoidance of the capital expenditure. Deferral is more representative of what will happen in reality in the NIAs.
Is not affected by economies of scale: The DRR method, detailed in Chapter 2, does not use the generator kW rating to determine annual marginal avoided cost of capacity (i.e. it does not use the average fixed cost). The result is thereby less sensitive to the sizing decision, which will lead to a lower level of YoY fluctuations.
Avoided capacity cost will be nil in some of the the NIAs: The avoided capacity cost in NIAs that have no need for additional reserve margin within the planning horizon will have a value of $0/kW-yr. This is valuable information rather than being a flaw of the DRR method. It gives an accurate cost signal to HQD, which should react by scheduling DSM interventions where the level of avoided cost is higher. </td></tr>
<tr><th>Trade-offs</th><th>Response to the trade-offs</th></tr>
<tr><td>Data requirements higher: Ideally the method would require a 15-year load forecast and a 15-year capital expenditure plan for each one of the NIAs to identify incoming shortages in reserve margin, and size of generators to be added in response to these shortages.</td><td>In the absence of a formal capital expenditure plan, in section 2.2, ICF will suggest an approach to quickly and mechanically determine the installation year and sizing of generators for the purpose avoided cost determination.</td></tr>
<tr><td>Higher level of YoY fluctuations than the <u>proxy</u> LC method: The avoided capacity cost will still fluctuate because the results depend on the peak load forecast and the installation year, which fluctuate from one year to another.</td><td> First, the results of the proposed DRR method will have a lower level of YoY fluctuations than the version of the LC method used by HQD from the 2010-2011 rate filing to the 2012-2013 rate filing (R-3708-2009 and R-3814-2012) because the proposed DRR method does not use the average fixed cost as a marginal cost.
Second, as described in Section 2.2.2, ICF recommends calculating a weighted average of the NIA-specific avoided capacity cost figures for each region, which will further dampen the YoY fluctuations. </td></tr>
</table>

The DRR method is more accurate, better suited for the NIAs and will result in a cost signal that will allow DSM planners to optimize DSM spending. While it is true that the DRR is marginally more difficult to calculate than the proxy LC method, it does not make the method impractical or prohibitive. ICF recommends the DRR method because it strikes the right balance between accuracy, complexity and level of effort.

We appreciate that the Régie wanted an approach that reduces the YoY fluctuations of avoided capacity cost resulting from to the method that was used until 2011 (D-2012-024, R-3776-2011, page 33.) While cognizant of this requirement, we propose a method that puts accuracy on an equal footing with stability. The use of the proxy LC had nearly eliminated fluctuations. The proposed variation of the DRR method will show a higher fluctuation in the cost signal than the proxy LC method, but it will also be more accurate. The higher level of fluctuations will be an inconvenience to capital expenditure planners, but that inconvenience will be outweighed by the higher accuracy of the cost signal delivered by the proposed method. While medium- and long-term capital expenditure planning would be easier if financial indicators were perfectly stable, planners already have to cope with a number of indicators that fluctuate every year, such as oil prices and commodity prices. Using currency exchange rates as an example, planners, typically, would prefer using the most up to date and accurate outlook of exchange rates, despite exchange rates outlooks showing a degree of variation over the years. The same preference applies to the use of fluctuating avoided capacity cost.

The next Chapter presents more details on the DRR method and our recommendation on how to mitigate the variability of the DRR method.

2. Recommended methodology

This chapter describes the DRR method recommended by ICF based on the results of the jurisdictional scan, and based on ICF's experience as professionals involved in the calculation of avoided cost across North America.

2.1 Description of the differential of revenue requirements (DRR) method

The DRR method essentially consists of calculating the present value (PV) of the revenue requirements under a reference capital expenditure plan (e.g. a capital expenditure plan without DSM), and the PV of the revenue requirements under an alternative capital expenditure plan (e.g. with DSM). The value of the alternative is thereby the difference between both scenarios.

Under the DRR method, investments in new generation infrastructure are typically assumed to be deferred rather than avoided entirely as a result of DSM, which is consistent with what happens to the revenue requirements in the NIAs. Postponing the increment in revenue requirements caused by a new investment is good for ratepayers due to the concept of the time value of money, which is appreciated by the discount rate used to calculate the PVs.

At a high level, the calculation under the DRR method is spelled out in Equation 1.

Equation 1 $$PW = \sum_{t=0}^{n} \frac{K_t}{(1+r)^t} - \sum_{t=0}^{n} \frac{K'_t}{(1+r)^t}$$

Where:
- PW is the present worth of the benefit accrued by ratepayers due to the deferral of capital expenditure(s), such as the investment in additional generation capacity.
- $\mathrm{K_t}$ is capital expenditure in year t, according to the reference capital expenditure plan
- $\mathrm{K'_t}$ is the capital expenditure in year t, according to the alternate capital expenditure plan
- n is the planning horizon in years
- r is the discount rate (real)

The DRR method, in general, and this equation, in particular, represents the least biased approach to determining the avoided cost of capacity in Quebec's NIAs. Equation 1 can be simplified in a number of ways to make calculation less work intensive, as presented in Section 2.2.2.

2.2 Adaptation of the DRR method to DSM programs for HQD NIAs

ICF recommends differentiating the DRR application for the avoided cost calculations between DSM and investment alternatives. There are fundamental differences between DSM and investment projects that have key implications on what costs are being avoided. Under the DRR methodology, scenarios considering the implication of alternatives are compared against the "reference" scenario, which is a base case absent that alternative. As such, the alternative scenario should reflect the implications of that alternative based on the contributions of the specific alternative. As each component (energy, capacity, etc.) is affected differently by a DSM or investment project, the DRR methodology should be adaptable to capture each component's costs and benefits. This is why the DRR method needs to be adapted to DSM programs, as presented in this section, and to investment projects, as will be presented in Section 2.3.

These nuances are captured in detailed calculations described in the sections below.

2.2.1 Avoided cost components for DSM programs

Table 6 provides a summary of the proposed avoided cost methodology by component as applied to DSM programs in Quebec's NIAs. Substantiation for each of the components is provided in the table, from left to right.

Table 5 Summary of cost components for DSM program

	Operational expenditures & Avoided cost of energy					Capital expenditures			
						Avoided cost of capacity			
	Fuel	Transportation and storage	Maintenance	Greenhouse gases	Hedge of fossil fuel prices	Capacity installation	End-of-life replacement	Investment in fuel tanks	Distribution losses
DSM programs	**Yes**, included. Fuel price divided by fuel conversion efficiency.		**Yes**, included.	**Yes**	**No**	**Yes**, included. Calculated using the DRR method.	**No**	**No**	**Yes**

Avoided cost of fuel, transport and storage: The avoided cost of fuel is the fuel price divided by the fuel conversion efficiency of the thermal generation plant for each NIA. The fuel conversion efficiency can be an annual average. When transport and storage are the responsibility of fuel suppliers as they are in Quebec, these costs are included in the fuel price. The utility must ensure that fluctuations in the cost of fuel as well as the cost of transport and storage are all contained in the forecast used to compute the avoided cost.

Avoided cost of maintenance: The avoided cost of maintenance of thermal generation plants must be estimated on a marginal basis, in a conservative manner and for each NIA. A large share of the maintenance expenditures of thermal plants in NIAs is a fixed annual cost. If the thermal plants vary, maintenance expenditures vary mostly based on the number of hours of operation of the generators and not based on their actual throughput. Utilities should obtain an estimate from their engineering department of the marginal cost of maintenance per unit of production. Moreover, engineering departments should be careful to provide specific figures for each NIA. In terms of consumption, larger NIAs will typically have lower average cost of maintenance per unit of production due to economies of scale.

ICF has not found any compelling evidence to make a rigorous estimate of the marginal cost of maintenance per kWh in the NIAs in Quebec. ICF recommends a conservative approach, using 2 c./kWh as an early estimate for all of the NIAs. This is higher than the value used by Navigant in Ontario (0.5 c./kWh) (Navigant, 2005, p. 4), but lower than the value suggested in Yukon (2.5 c./kWh) (YEC, 2011, p. 79). In the NWT, the Colville Lake project economic analysis did not include enough details in order to make a comparison. In all other jurisdictions reviewed, the utilities did not attribute a value to the avoided cost of maintenance so long as generators remained in operation.

Avoided cost of greenhouse gas (GHG) emissions: The avoided cost of GHG emissions must be accounted for. Wherever a carbon pricing scheme exists as it does in Quebec, carbon allowances are part of the cost of service. In Quebec, the avoided cost of GHG emissions is already included in the price of fuel in all of the NIAs except for the Cap-aux-Meules plant in the Îles-de-la-Madeleine, where it must be added in.

Hedge of fossil fuel prices: ICF does not recommend valuing and including the hedge of fossil fuel prices in the avoided cost of energy used. This is due to the fact that all of the revenue requirements from electricity supply in Quebec NIAs are blended for the Quebec integrated area and combined together in the same revenue requirements. Furthermore, with 99% of electricity being generated from hydropower, wind power and biomass in Quebec (Whitmore & Pineau, 2016, p. 13), HQD's electricity supply already largely comes from non-fuel resources. Consequently, HQD's revenue requirements as a whole have little exposure to fuel price volatility and, in turn, the hedge of fossil fuel prices induced by DSM is of little value to Quebec ratepayers. The hedge of fossil fuel prices would benefit ratepayers in remote communities located in other jurisdictions, such as Nunavut, NWT and Alaska, where fuel price has a larger relative impact on their revenue requirements.

Avoided capacity cost (Capacity installation): As observed during the jurisdictional scan, few utilities in the NIAs include avoided capacity cost in their evaluation of DSM measures and programs. The only two jurisdictions that do include avoided capacity cost are Yukon (which values capacity at an average of 2 c./kWh) and Quebec.

ICF appreciates the challenges experienced in most jurisdictions and the reasons why avoided capacity cost is rarely included. The challenges consist of gathering data, finding the resources and time to perform the calculation, and dealing with the level of uncertainty of the result due to the fluctuations of demand in remote communities. In addition, as identified by the Régie, the resulting avoided costs for capacity are likely to be highly variable from period to period due to the lumpy cycle of investments, as well as to the effects that small perturbations in load or supply have on the expected investment timing. These variations, while accurate reflections of the results using the best available data, may be difficult to utilize for decision making purposes on a regular basis given the level of detail needed to understand the rationale for the movement in each period.

Nevertheless, we believe that ignoring the avoided capacity cost potentially underestimates the value of DSM and alternate resources. DSM programs do restrain demand because they typically entail a variety and large number of individual DSM measures which, when combined together as diversified savings, reduce the peak demand of NIAs.

Therefore, ICF's recommendation is the use of avoided cost of capacity in economic analysis of DSM programs in Quebec's NIAs. Furthermore, ICF recommends the use of the DRR method to determine the avoided cost of capacity.

End-of-life replacement of the generators: ICF recommends not including end-of-life replacement of generators in the avoided cost of capacity for DSM because DSM will not reduce the runtime of generators and thereby will not prolong their effective useful lifetime.

Investment in fuel tanks: Similarly, ICF recommends not including the deferral of investment in fuel tanks as an avoided cost because the expenditures associated with fuel storage are passed to HQD through the price of fuel.

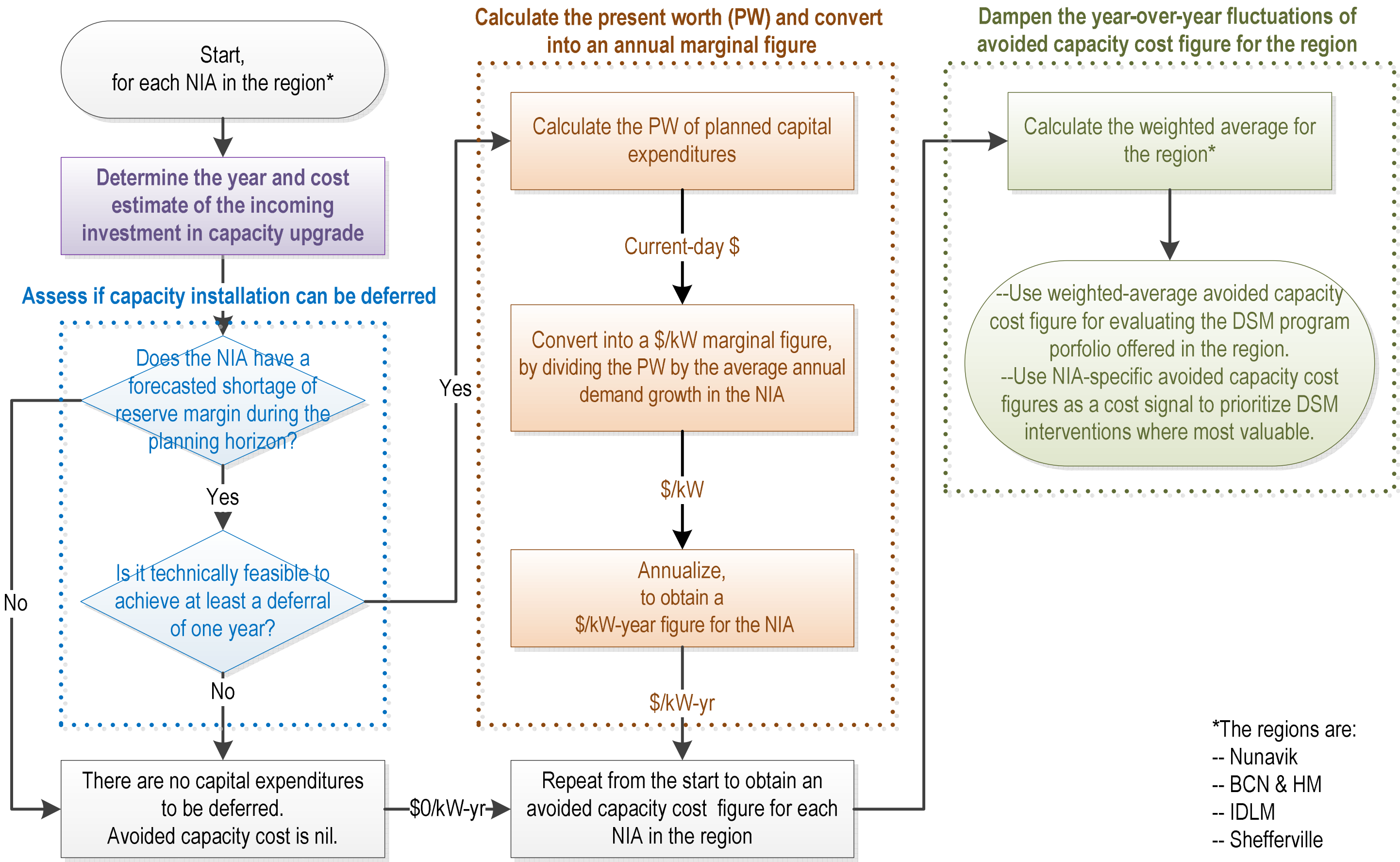
Distribution network losses: Both avoided energy cost and avoided capacity cost caused by DSM must be adjusted to account for losses in electric lines and transformers between the source and the use.

2.2.2 Details of the methodology to determine avoided capacity cost

As discussed above, the general formulation for DRR is to calculate the difference in capital expenditures between two scenarios on a present value basis: a *reference scenario* and an *alternative scenario*. The primary result is a present worth (or a net present value) in current dollars. Though the DRR approach provides the best estimation available for avoided costs, for practical purposes, the data intensity of the DRR methodology may occasionally outweigh the practical use of it under resource constraints as it did in 2005 when HQD used it in its rate filing ("méthode du différentiel de parc", R-3584-2005).

As such, ICF adapted the DRR method to better allow the practical application by HQD, while complying with the guidance provided by the Régie in its rate filing decisions. The proposed method is illustrated at a high level in Figure 1.

Figure 1 Proposed methodology as a decision tree, for a given region



The steps shown in Figure 1 will be described in detail in the next pages.

Determination of year and cost estimate of the next capacity upgrade

The use of Equation 1 requires knowing when capital expenditures related to capacity upgrade are expected to be incurred and how much will need to be invested. The standard practice would be to retrieve those estimates from the capital expenditure plan prepared by the utility's own engineering department. The utility's own engineering department typically makes cost estimates based on an intimate knowledge of each power plant, budgetary estimates made in collaboration with suppliers, and similar projects in the recent past.

In the absence of a capital expenditure plan, the following approach could be used to determine the avoided capacity cost:

1. Use the demand forecast for each NIA and the reserve margin for each NIA under the (N-1)*90% criterion to determine when the NIA will see a shortage of reserve margin. This is when capital expenditures should be incurred.

2. Decide on a kW rating for the new generator to be added, and select the generator from the manufacturer's catalogue.

   ICF suggests assuming that the size of the additional generator to be installed will systematically match the size of the smallest generator of the generator fleet in each NIA. To start with, installing a smaller generator would not be realistic, from an engineering standpoint, because the new generator would risk creating instability in the operation fleet. Furthermore, assuming the smallest generator that is technically feasible is a conservative assumption.

   ICF suggests assuming that the generator to be installed in response to a deficit will be a "mobile generator" rather than permanent equipment. We are assuming that mobile generators are more expensive by a small margin. Our rationale is based on the principle of "investment flexibility" offered by DSM. Investment flexibility is defined as the ability to procure capacity as much as needed and when it is needed; it is the opposite of "lumpy". The use of a mobile generator to make a cost estimate will reflect the flexibility of DSM.

3. Make capital cost estimates based on the latest generators that were purchased and installed by HQD, adjusted to account for the capacity of the mobile generator in each NIA.

Assessment if capacity installation can be deferred

In order to assess whether there is investment to defer and if it is feasible to defer investment by at least one year, ICF used the following conditions. All conditions must be met in order to consider that a certain level of deferral is achievable.

- **Incoming shortage in reserve margin, within the planning horizon:** Capacity cost can only be avoided or deferred if capacity addition is anticipated in the foreseeable future. If the NIA has a large reserve margin, spending on DSM to shave off the demand will not avoid capacity cost. ICF recommends using a planning horizon that matches the effective useful life of the generators, i.e. 15 years for diesel generators. However, due to the size of each system, the level of uncertainity surrounding the load forecast is relatively high and thereby a shorter planning horizon is more appropriate to the NIAs.

- **Technical feasibility of achieving a deferral of at least one year:** The standard practice would be for HQD supply planning staff to collaborate with DSM staff to determine whether it is technically feasible to defer capacity investment by at least one year for each of the NIA. If not feasible, then there is no capital expenditure to be avoided and the avoided capacity cost is thereby nil. When the shortage in the NIA is coming the next year or after, a deferral is technically feasible if DSM can offset the demand by at least one year's worth of average demand growth between now and the incoming shortage. When a NIA is already in a situation of shortage, which is more challenging, DSM would need to curtail peak demand by at least the deficit plus one year's worth of demand growth.

HQD needs a simpler approach than the standard practice in order to provide a cost signal to DSM staff without necessarily having to involve them each time the avoided costs need to be updated. Thereby, ICF proposes using two simple conditions:

- If the NIA is already in a situation of shortage of reserve margin, systematically assume that the deferral is no longer technically feasible.
- If the NIA has an incoming shortage next year or any year through to the end of the planning horizon, then systematically assume that the deferral is technically feasible.

ICF reviewed the results of the 2013-2017 DSM potential study, *"Potentiel technico-économique d'efficacité énergétique dans les réseaux autonomes*" (Technosim inc., 2013), to assess whether the second condition is realistic. ICF established that there is enough DSM potential in HQD's NIA to defer capacity installation. We saw that if only 20% of the economic potential was achievable in each NIA, the level of DSM potential uncovered in the potential study would be sufficient to defer capacity installation by at least one year in all of the NIAs. In the absence of a different indication from HQD's DSM staff, we believe that 20% is a reasonable threshold to establish feasibility.

In order to come to this conclusion, the results of the 2013-2017 DSM potential study were broken down in five zones: Nunavik, Basse Côte-Nord (BCN), Haute-Mauricie (HM), Îles-de-la-Madeleine (IDLM), and Shefferville (Technosim inc., 2013, pp. 8–9)[11]. The impact was attributed to each of the NIAs within each of the regions using the individual NIA peak demand as the weighting factor. Energy efficiency potential was converted into peak-coincident curtailment in kW using an average coincidence factor (i.e. *facteur d'utilisation*) of 70% for the mix of efficiency measures available, which is a conservative assumption. Energy efficiency potential (in Table 1 of the Technosim report) and DR potential (in Table 5) results were summed up to obtain the total economic potential per NIA. The results suggest that the DSM potential is sufficient to achieve a one-year deferral or more in all of the NIAs.

- **Pace of the DSM deployment:** The pace of DSM deployment is a consideration when assessing the technical feasibility of achieving a deferral. However, HQD has access to a number of DSM approaches that could be deployed quickly to achieve curtailment in time to avoid a deficit. We see at least two different options available to HQD to achieve significant, measureable and fast DSM impact:

  - **Targetted direct install approach:** HQD could use a direct install approach and target specific NIAs that are in need of capacity in the next few years. Provided that the avoided cost of capacity justifies the expenses, HQD could achieve significant impact within a year by dispatching teams of installers to offer LED lamps, energy efficient appliances (freezers, for instance) and three-element water heaters (where applicable) free of charge.

[11] R-3854-2013, HQD-9, document 2

- **Interruptible-rate DR program:** HQD could quickly gain access to additional reserve margin through enrolling commercial and institutional customers who own and maintain back-up diesel generators in their building or facility. Hydro-Sherbrooke, for instance, runs a similar program (Hydro-Sherbrooke, 2016). In its latest rate filing, HQD mentioned being interested in such a program for the NIAs in Nunavik (R-3933-2015, HQD-10, Document 1, page 22).

In conclusion, because the two aforementioned delivery options are available to HQD, ICF recommends systematically assuming that DSM deployment can technically be fast enough to achieve a deferral, even when the deficit is foreseen in the next coming year.

Calculation of the present worth and conversion into an annual marginal figure

ICF recommends the following simple approach to converting the present worth (PW) resulting from Equation 1 into an *annual marginal value*, $/kW-yr, in the NIAs.

In its decision following the 2015-2016 rate filing, the Régie questioned the soundness of using a marginal avoided capacity cost in the NIAs due to the fact that capacity installation is a rare but discrete event and has a high nominal value relative to the installed capacity of each of the NIAs (D-2015-018, R-3905-2014, page 116,) i.e. the investment is “lumpy.”

The nature of the investment in the NIA does not preclude using a marginal value. The “lumpiness” of the investment in the NIAs has, however, an impact on how the marginal value is to be obtained. In the integrated areas, the marginal value is typically obtained using the average fixed cost (cost of a generator divided by kW rating). This approach is appropriate for the integrated area, but not for the NIAs. Capacity addition differs in two ways in the NIAs as compared with the integrated area that make the use of average fixed cost, in general (and the LC method in particular), less accurate.

- First, in the NIAs, diesel generators show a degree of economies of scale. In the North American integrated area, that is no longer the case. For instance, the average fixed cost of a 300-MW gas-fired plant will be similar to the average fixed cost of a 500-MW plant. The sizing of the proxy plant has therefore less influence on the final result in the integrated area than it does in the NIAs.

- Second, in the NIAs, generation capacity is typically being *deferred* as a result of DSM instead of being *avoided*. In most of the North American integrated area, new capacity is added every year in a constant series of projects. As a result of DSM, projects will be smaller (example: 300 MW instead of 500 MW), some projects will be delayed and some projects will be cancelled all together. In the thermal integrated areas, system operators typically seek to add capacity on an as needed basis year over year. In a NIA, capacity addition is less frequent than in the integrated area; the kW rating of the new generator is not dependent on the load forecast but on factors such as economies of scale, fleet operational efficiency, the N-1 reliability rule and the sizes available in the manufacturers' catalogue. As such, in the NIAs, there is less relationship between the kW offset achieved through the DSM program and the number of new kWs being installed in the system. The generators being installed for any given NIA will be approximately the same size, but they will be installed a number of years later.

Consequently, the use of the average fixed cost to estimate marginal cost is not appropriate in the NIAs and would lead to underestimation of the marginal cost.

As such, ICF recommends a different approach to convert the PW into a marginal value rather than the approach used in the proxy LC method. The equations that ICF is proposing will use the average annual demand growth instead of the capacity rating as the denominator. This method was utilized by one of the surveyed jurisdictions for its capacity avoided cost (in Ontario on behalf of H1RCI[12]).

This approach is also often utilized in practice in multiple jurisdictions for *distribution* system investments which also experience the same lumpy investment problem (e.g. overloaded transformer substations).[13] Other attributes of distribution systems which are shared with the NIAs are that the infrastructure is owned by a regulated utility and there is presence of economies of scale. In addition, in both cases (distribution systems and remote NIAs), the capacity addition contemplated will be postponed rather than avoided. The direct relation between DSM impact and avoided capacity cost is the length of the deferral rather than how many kW are forgone.

The approach relies on using the average annual demand growth between current days and the year of the incoming shortage in reserve margin, in kW, as the denominator in place of the kW rating of the generator. The average annual demand has a direct relation with DSM impact because the annual demand growth represents the level impact that is required to defer the next investment by one year.

[12] The method was later abandoned due to lack of resources to update the numbers. See Appendix A for details, the paragraphs about Ontario.
[13] This approach is applicable to avoided cost of local distribution capacity described in a best-practice guidebook developed as part of the National Action Plan for Energy Efficiency (NAPEE) project (NAPEE, 2007, p. 3.11).

The approach has three steps. For the first step, ICF presents two alternative equations depending on the availability of data.

Step 1 – Calculate the present worth of planned capital expenditures

Equation 2 is essentially a simplification of Equation 1 (See Section 2.1), which calculates the annual difference between two scenarios and determines the present value.

Equation 2

$$PW = \sum_{t=0}^{n} \frac{K_t}{(1+r)^{t}} - \sum_{t=0}^{n} \frac{K_t}{(1+r)^{t+\Delta t}}$$

Where:

- **PW** is the present worth of the benefit accrued by ratepayers due to the deferral of capital expenditure(s), such as the investment in additional generation capacity, in $ discounted to current days.
- K_t is the capital expenditure for capacity installation[14] in the reference scenario in year t
- **Δt** is deferral time.

If substituting the capital expenditure plan *without DSM* in Equation 2 for a capital expenditure plan *with DSM*, the equation becomes as follows.

Equation 3

$$PW = \sum_{t=0}^{n} \frac{K'_t}{(1+r)^{t-\Delta t}} - \sum_{t=0}^{n} \frac{K'_t}{(1+r)^{t}}$$

Where:

- K'_t capital expenditure in year t, according to a capital expenditure plan *with DSM*

Equation 3 is simply the equivalent of assuming that in the absence of DSM, the capital expenditure would have been incurred Δt year *before* the year when the deficit is foreseen to take place under the capital expenditure plan with DSM. The result from Equation 3 and that from Equation 2 can be used interchangeably in the following Step 2 and Step 3 depending on the forecast availability.

Step 2 – Convert into a $/kW marginal value

Equation 4 is then applied to determine the per unit capacity value of the present worth assuming a single period deferral.

Equation 4

$$\$/\text{kW marginal cost} = \frac{PW\ with\ \Delta t=1}{deferral\ kW\ needed\ to\ achieve\ \Delta t=1}$$

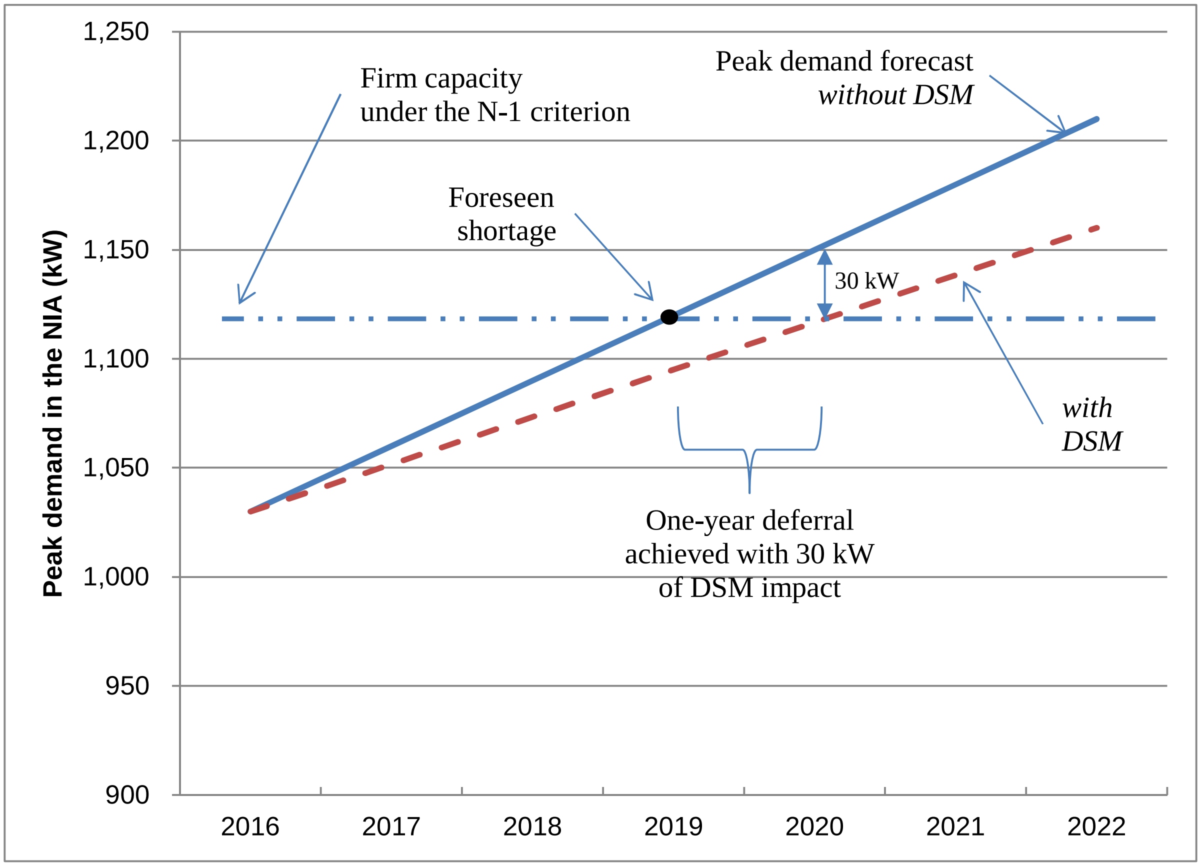
Where:

- ***PW with Δt=1*** is the result of Equation 3 when the deferral is set to one year
- ***Deferral kW needed to achieve Δt=1*** is the amount of load reduction required to defer the investment by one year. Typically, this is equivalent to the average YoY peak load increase in the system.

[14] The capital expenditures being considered in Equation 2 are only the capital expenditures that are incurred to add generation capacity to cope with the growth in demand. Capital expenditures added as a result of end-of-life replacement should not be considered because DSM would have no influence on them, as substantiated and documented through the jurisdictional scan.

Equation 4 is best explained through an example. Figure 2 shows the YoY peak demand in a small system with an average peak demand growth of 30 kW, a maximum peak demand allowed under the N-1 reliability criterion of 1,120 kW and a deficit occurring in 2019.

Figure 2 Example of one-year deferral



Source: Adapted from Navigant (2005)

What Figure 2 seeks to illustrate is that if the utility were able to reduce the peak demand by 30 kW through deploying DSM measures in 2016, 2017 and 2018, then the deficit would occur one year later, thereby allowing the utility to defer the investment by one year. A DSM impact equivalent to one times the average annual peak demand growth is thereby worth an investment deferral of one year; the installation is postponed from 2019 to 2020.

As seen in Equation 4, the capacity rating of the generator to be installed in 2019 (or 2020) is irrelevant to the calculation, only the deferral kW needed to achieve a 1-year deferral is relevant.

Step 3 – Annualize

The third and last step involved in obtaining an annual marginal avoided capacity value is shown in Equation 5. Equation 5 is an annualization formula.

Equation 5 $$\textbf{Annual marginal value (\$/kW-yr)} = \textbf{Marginal cost (\$/kW)} \times \frac{r(1+r)^n}{(1+r)^n-1}$$

Capacity avoided cost caveats

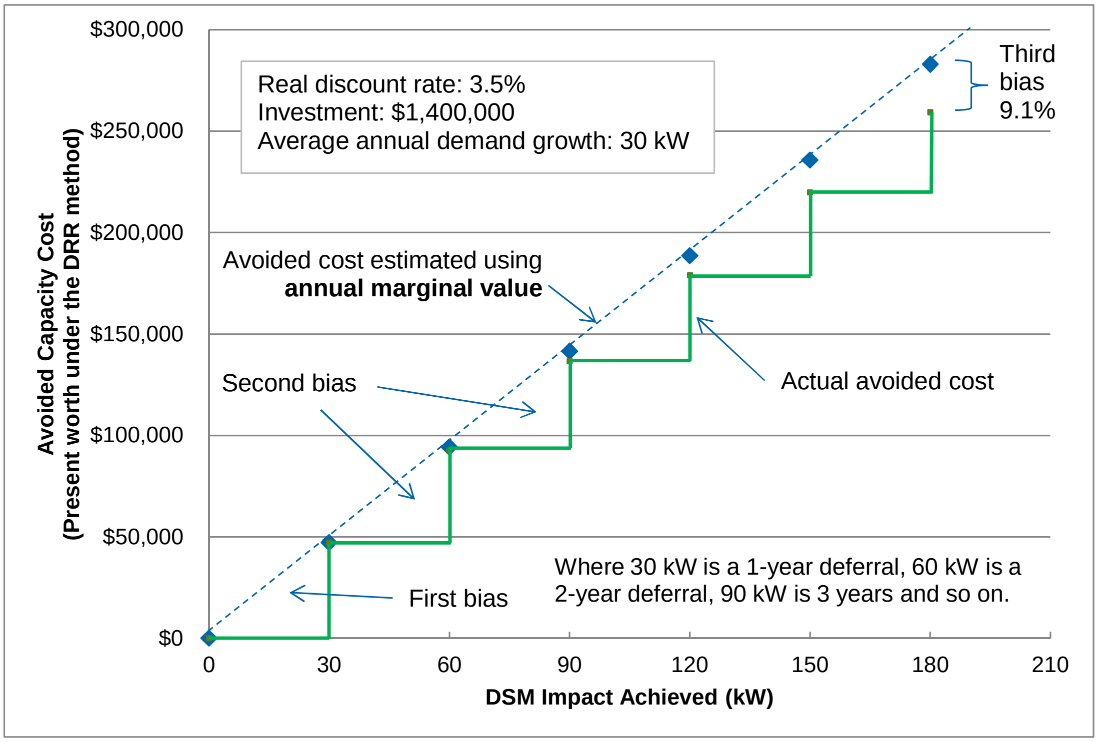
We have identified three caveats associated with using the present worth turned into an annual marginal value:

- First, the method will lead to an overvaluation of avoided capacity cost if DSM programs cannot achieve at least a deferral of one year. In this case, the true avoided cost to the ratepayers should be nil.
- Second, the model proposed assumes linearity of the investment schedule, when in fact it is a yearly step function because decision to incur a capital expenditure typically occurs once per year for the next year.
- Third, the method will lead to a small bias in the result if the deferral happened to be more than one year. For instance, using a 3.5% real discount rate, if the deferral happened to be 6 years rather than 1 year, the bias would be 9.1%, as shown in Figure 3[15].

[15] DSM typically allows for the deferral of a few years. A six-year deferral or above, for instance, is unlikely.

The three caveats are illustrated in Figure 3.

Figure 3 Example illustrating the caveats related with using a $/kW marginal cost



Source: Adapted from NAPEE (2007)

The one bias that can and should be controlled is the first of the three biases: when it is already too late to achieve any deferral at all. In Figure 3, this is the bias that would happen if the DSM impact achieved during the DSM deployment period was less than 30 kW. The best practice is to verify the feasibility of deferring the investment by one year, which is what we recommended on page 31.

Dampening of the YoY fluctuations of avoided capacity cost figure for the region

In its 2012-2013 decision (D-2012-024, R-3776-2011), the Régie observed large fluctuations of the avoided cost figures from one year to another for each of the NIAs that came as a result of the use of the method proposed by HQD two years before, in the 2010-2011 rate filing (R-3708-2009). The Régie required that HQD propose a new approach to reduce these fluctuations as compared with the method that was used at the time. In particular, the Régie wanted the variations related to the avoided cost of capacity to be dampened (D-2012-024, R-3776-2011, page 33.)

ICF's recommended method will *reduce* the fluctuations as compared to the method used in the the 2010-2011 rate filing, but will not *cancel out* the fluctuation entirely. It is normal to see fluctuations of avoided capacity costs in the NIAs because NIAs are small load centres with relatively few customers compared to the integrated area. In NIAs, the change in load of a single institutional customer, for example, can have a significant impact on the need for a new capacity in the capital expenditure plan from one year to the next. NIAs will therefore naturally experience larger swings in demand than the integrated area (as a percentage of the load); this makes demand forecasting more uncertain. It is also desirable to see these swings because they give an indication to the DSM planners of where and when DSM is most needed.

The recommended methodology addresses the requirement of the Régie in the following manner:

- ***The approach proposed by ICF to calculate the annual marginal figure of avoided capacity cost will reduce the fluctuations compared with the approach used by HQD in its 2010-2011 rate filing (R-3708-2009), "méthode de l'équipement générique".***

  The YoY fluctuations observed when using the 2010-2011 method were due to three factors: peak load growth forecast, size of the new generator, and upgrade year[16]. The first of the three, YoY changes in peak load forecast, actually induced the discrepancies in both the installation year and kW rating of the selected generator.

  With the suggested method, the DRR method, ICF proposes: (i) systematically using a generator sized to match the smallest generator of the fleet (same size from one year to another), and (ii) using the average annual growth of the peak demand as the denominator instead of kW rating, which is relatively stable. The 2010-2011 method used kW rating as the denominator, and that kW rating was fluctuating from one year to the next. In the proposed method, the size of the generator is no longer a factor that causes fluctuations. We suspect this factor to have been a significant cause of fluctuations from the 2010-2011 rate filing to the 2012-2013 rate filing[17] because of the presence of economies of scale in the NIAs; i.e. the average fixed cost declines quickly as the selected generator becomes larger.

  YoY fluctuations will still be observed in the NIA-specific figures, however, mainly as a result of the change in the installation year. A sharp increase (from zero to non-zero) will be experienced when the installation year will enter the planning horizon[18]. A mild increase will be experienced as time passes, because the incoming shortage will progressively come closer to current days as demand grows. A sharp decrease (from a non-zero to zero) will be experienced when the avoided capacity cost becomes "unfeasible" from a technical standpoint in a NIA becasuse a shortage in reserve margin is incurred[19].

[16] "La variation des coûts évités en puissance par réseau autonome s'explique par la conjugaison de trois facteurs: la croissance de la demande en puissance, la taille des groupes, et l'année où les ajouts sont requis." (R-3708-2009, HQD-2, Document 5, page 11)

[17] ICF suggests, in the future, demonstrating this statement empirically. The demonstration would require three contiguous years of peak load forecast with a level of resolution of at least 10 kW.

[18] The installation year may swing in and out of the planning horizon as a result of variations in the load forecast, which is characteristic of small load centres. ICF suggests extending the time horizon for this particular NIA from the moment that a deficit first enters the time horizon in order to avoid the "flickering" of the avoided capacity cost for this one NIA.

[19] ICF suggests that the status of "technically unfeasible" would remain indefinitely once a first shortage of reserve margin has been incurred to avoid the "flickering" of the avoided capacity cost for this one NIA. For example, if the shortage were to resorb on the next year due to load fluctuations that are characteristic to small load centres, the avoided cost would remain nil.

- **ICF recommends calculating the avoided cost of energy and of capacity for each NIA, and then computing the weighted average of the results by region (Nunavik, BCN, HM, Îles-de-la-Madeleine and Shefferville) to evaluate DSM programs[20].**

  Calculating the weighted average will mitigate fluctuations through aggregation of the small load centres without losing the key information provided by the individual NIA avoided cost. Aggregation will decrease the level of uncertainty because errors will cancel each other out, therefore improving the level of precision.

  Furthermore, using a weighted average to evaluate a DSM program is consistent with the standard practices of DSM program design. Typically, DSM programs must be offered to all of the utility's customers on an equal and fair basis. Only in rare events can a utility offer preferential treatment to some customers over others. Over the years, HQD will likely have to deploy the same DSM offerings to all of the NIAs. Consequently, the use of a weighted average remains an *accurate* measure of the avoided cost caused by DSM programs delivered to all of the NIAs of a certain region.

ICF sought to meet the Régie's requirements by reducing the level of fluctuation as compared with the method used in the 2010-2011 rate filing. However, the recommended method does not cancel out fluctuation entirely. Developing a practical and rigorous methodology is a balancing act between different considerations. ICF chose to favor the accuracy and alignment of the method with North American best practices over stabilizing the avoided cost values through the use of a universal, constant LC value. Such a LC value would both introduce biases in the results, and provide less information for the DSM planners.

The weighted-average avoided capacity cost, which will be more stable, can be used to design and evaluate the DSM program portfolio by region. The NIA-specific avoided capacity cost, which will be less stable yet more accurate, will provide effective cost signals so that the DSM implementers can schedule their actions and target the NIAs where the DSM impact will be most beneficial in terms of avoided cost, which in turn will be to the benefit of all ratepayers.

[20] The recommended weighting factor of the avoided energy cost should be energy consumption as per the most recent financial year, and for avoided capacity cost should be peak demand as per the most recent financial year.

2.2.3 Examples of calculation

ICF presents three examples of calculation for the archetype (yet fictitious) NIAs of Lorem, Ipsum and Dolor (respectively).

Example 1: NIA of Lorem

With a shortage in reserve margin in 10 years.

Avoided energy cost in Lorem

The avoided energy cost in Lorem is calculated as follows. The procedure is straightforward, and was presented in Section 2.2.1.

Box 1

Price of diesel (c./Litre)	155	
Thermal efficiency (kWh/Litre)	3.71	(archetype)
Avoided diesel cost (c./kWh)	41.8	
Avoided maintenance cost (c./kWh)	2.0	(see section 2.2.1 for substantiation)
Avoided carbon (c./kWh)	0.0	(because included in price of diesel)
Avoided cost of energy without Tx (c./kWh)	43.8	
Distribution losses, Tx :	2.0%	(assumption, as a % of production)
Avoided cost of energy with Tx (c./kWh)	44.7	

The avoided energy cost in Lorem is 44.7 c./kWh.

Avoided capacity cost in Lorem

First, we determined the year and cost estimate of the next capacity installation. The box below presents the description of the diesel plant in the archetype NIA.

Box 2

Installed capacity (kW):	7,275	(archetype)
Description of installed generators:	5 x 1,455 kW	(archetype)
Firm capacity (kW):	5,238	(archetype, under the (N - 1)*90% rule)

Using the peak load forecast for the archetype NIA, it becomes relatively simple to identify the timing of the incoming shortage as shown below.

Box 3

|<-------------------- Planning Horizon = 15 years ------------->|

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Load forecast in kW (archetype)	4,430	4,350	4,410	4,500	4,610	4,720	4,830	4,940	5,050	5,150	**5,260**	5,360	5,450	5,550	5,650	5,740	5,830	5,920	6,010	6,100	6,180

Shortage in reserve margin: 2026

As a simple rule, the method suggests the next generator to be installed to be a mobile generator with a capacity rating equivalent to that of the smallest generator installed in Lorem. According to the recommended method, HQD's engineering department would then make a capital budget estimate for this size of a generator, as presented below.

Box 4

kW rating of mobile generator to be installed:	1,455	(data used as example from NL Hydro (2011))
Capital budget ($,000, real 2016 $):	$2,195	(ibid)

We assumed a capital budget of $2,195,000 (real 2016 $). This number was the capital budget made by NL Hydro's engineering department for an isolated NIA along the cost of Labrador (NL Hydro, 2011). The generation capacity increase project in Lorem would be scheduled in 2026 in time for the incoming shortage.

Second, we assess if capacity increase can be deferred through DSM. Lorem does not currently have a shortage of reserve margin, thereby the installation may be deferred provided that the level of DSM potential is sufficient, which is demonstrated below.

Box 5

Potential attributed to Lorem through proration (kW):	1,171	(using peak load at current time, in 2016)
Average annual load growth until shortage (kW):	83	(between now and 2026)
Annual load growth as % of economic potential:	7.1%	

For example, technical feasibility is proven because the average annual load growth (i.e. average YoY forecasted peak demand increment) represents 7.1% of the 5-year DSM economic potential, which is achievable. The average annual load growth is the minimum level of impact required to defer the capital investment by one year. In the absence of a better rule from HQD's DSM staff, ICF recommends considering an impact below 20% of the economic potential to be achievable (Technosim inc., 2013).

Third, we calculate the present worth of deferral, and convert it into an annual marginal figure.

Box 6

Real discount rate, r :	3.5%	(assumption)
Year of investment, t :	10	(shortage year, 2026, minus current time, 2016)
Present worth of 1-year deferral ($'000):	$54	(using capital budget above, Δt = 1, and Equation 3)
$/kW marginal value without Tx:	$656	(using average annual load growth in and Eq. 4)
$/kW-yr annual marginal value without Tx:	$57	(planning horizon n=15, and Equation 5)
Distribution losses, Tx :	2.0%	(assumption, as % of production)
Avoided capacity cost of DSM in Lorem ($/kW-yr):	$58	

The use of Equation 3, Equation 4 and Equation 5 results in $58/kW-yr. For instance, if HQD was able to curtail 166 kW of peak demand (2 x 83 kW, which is the impact level needed to achieve a deferral of two years) through DSM measures with an effective useful lifetime of 15 years and implemented immediately, the avoided capacity cost would be $111,148 in real 2016 $.

The avoided energy cost is 44.7 c./kWh. If the avoided capacity cost was distributed evenly through the yearly sales it would be equivalent to 1.1 c./kWh, assuming the load factor in Lorem is 62%. Once blended together, the avoided energy cost and avoided capacity cost are totalling 45.7 c./kWh[21]. When practical, it is more accurate to use the avoided energy cost in c./kWh and avoided capacity cost in $/kW-yr separately than blended.

Example 2: NIA of Ipsum

With a shortage in reserve margin in 2 years.

Avoided energy cost in Ipsum

The avoided energy cost in Ipsum is calculated as follows.

Box 7

Price of diesel (c./Litre)	93	
Thermal efficiency (kWh/Litre)	3.08	(archetype)
Avoided diesel cost (c./kWh)	30.2	
Avoided maintenance cost (c./kWh)	2.0	(see section 2.2.1 for substantiation)
Avoided carbon (c./kWh)	0.0	(because included in price of diesel)
Avoided cost of energy without Tx (c./kWh)	32.2	
Distribution losses, Tx :	2.0%	(assumption, as a % of production)
Avoided cost of energy with Tx (c./kWh)	32.9	

The avoided energy cost in Ipsum is 32.9 c./kWh.

Avoided capacity cost in Ipsum

First, we determine the year and cost estimate of the next capacity installation.

Box 8

Installed capacity (kW):	1,547	(archetype)
Description of installed generators:	1 x 365 kW, 2 x 591 kW	(archetype)
Firm capacity (kW):	860	(archetype, under the (N - 1)*90% rule)

We identify the incoming shortage in reserve margin.

Box 9

|<-------------------- Planning Horizon = 15 years ------------->|

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Load forecast in kW (archetype)	840	850	**870**	900	920	940	960	980	1,000	1,010	1,030	1,050	1,060	1,080	1,090	1,110	1,120	1,130	1,150	1,160	1,170

Shortage in reserve margin: 2018

[21] Figures do not add up due to rounding.

We found a similar project in Old Crow, a fly-in community in Yukon served by ATCO. We used ATCO's capital budget as in Business Case #10, page 2, of their 2013-2015 General Rate Application (2013).

Box 10

kW rating of mobile generator to be installed:	365	(ATCO Electric Yukon, 2013)
Capital budget ($,000, real 2016 $):	$500	(ibid)

Second, we assess if capacity increase can be deferred through DSM in Ipsum.

Box 11

Potential attributed to Ipsum through proration (kW):	368	(using peak load at current time, in 2016)
Average annual load growth until shortage (kW):	15	(between now and 2018)
Annual load growth as % of economic potential:	4.1%	

The impact needed to achieve a deferral of at least one year, 15 kW, represents 4.1%, of the economic potential. Since below 20%, this impact is deemed achievable. The time window between now and the shortage, two years, is relatively short to deploy DSM, but we believe that HQD has a number of fast-deployment options at its disposal such as direct install and interruptible-rate so HQD planning staff should assume the deferral to be achievable. The DSM staff will be responsible for determining whether achieving an impact of 15 kW is technically feasible in Ipsum.

Third, we calculate the present worth of deferral, and convert it into an annual marginal figure.

Box 12

Real discount rate, r :	3.5%	(assumption)
Year of investment, t :	2	(shortage year, 2018, minus current time, 2016)
Present worth of 1-year deferral ($'000):	$16	(using capital budget above, Δt = 1, and Equation 3)
$/kW marginal value without Tx:	$1,089	(using average annual load growth and Eq. 4)
$/kW-yr annual marginal value without Tx:	$95	(planning horizon n=15, and Equation 5)
Distribution losses, Tx :	2.0%	(assumption, as % of production)
Avoided capacity cost of DSM in Ipsum ($/kW-yr):	$96	

The avoided capacity cost is $96/kW-yr in Ipsum. If the avoided capacity cost was distributed evenly through the yearly sales it would be equivalent to 1.8 c./kWh, assuming the load factor in Ipsum is 62%.

Example 3: NIA of Dolor

No shortage in reserve margin expected during the next 30 years.

Avoided energy cost in Dolor

The avoided energy cost in Dolor is calculated as follows. The Dolor power station uses heavy oil instead of diesel.

Box 13

Price of heavy oil (c./Litre)	53	
Thermal efficiency (kWh/Litre)	4.70	(archetype)
Avoided fuel cost (c./kWh)	11.3	
Avoided maintenance cost (c./kWh)	2.0	(see section 2.2.1 for substantiation)
Avoided carbon (c./kWh)	1.0	(The Dolor power station is a large emitter)
Avoided cost of energy without Tx (c./kWh)	14.3	
Distribution losses, Tx :	2.0%	(assumption, as a % of production)
Avoided cost of energy with Tx (c./kWh)	14.6	

The avoided energy cost in Dolor is 14.6 c./kWh. The avoided energy cost in Dolor includes an avoided carbon cost explicitly as opposed to including the cost in the fuel price. This is so because the Dolor power station is a large emitter and thus may sell carbon allowance or have to purchase carbon allowances in the Western Climate Initiative.

Avoided capacity cost in Dolor

We determined the year and cost estimate of the next capacity installation.

Box 14

Installed capacity (kW):	70,000	(archetype)
Description of installed generators:	14,000 kW x 5	(archetype)
Firm capacity (kW):	50,400	(archetype, under the (N - 1)*90% rule)

The planning horizon was extended to 25 years in Dolor because the heavy oil-fired steam turbines used in Dolor have a longer effective useful life than the diesel generators used in other NIAs.

Box 15

| Start <-------------------- Planning Horizon = 25 years -------------Continued

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Load forecast in kW (archetype)	41,300	41,700	42,000	42,300	42,500	42,800	43,000	43,200	43,500	43,600	43,700	43,800	43,800	43,800	43,800	43,800	43,700	43,700	43,600	43,500	43,400

------------->End |

2037	2038	2039	2040	2041	2042	2043	2044	2045
43,300	43,200	43,100	42,900	42,800	42,700	42,600	42,400	42,300

The current load forecast in Dolor suggests that no additional reserve margin will be needed within the next 29 years. No shortage is thereby expected during the planning horizon. Since there is no anticipated cost associated with acquiring more capacity in Dolor, there cannot be any capacity cost being avoided or deferred. The avoided capacity cost in Dolor is $0/kW-yr.

The avoided capacity cost is nil because there is no need for capacity in Dolor. Offsetting peak demand growth through DSM is thereby of no value. The avoided cost in Dolor is 14.6 c./kWh, which is the avoided energy cost.

2.3 Adaptation of the DRR method to investment projects

Section 2.3 presents the adaptation of the DRR method to investment projects. As for DSM programs, there is a need to create categories of investment projects because they do not avoid the same cost components. The treatment of avoided cost of capacity, for instance, is the main difference.

Technologies like solar PV or wind power should not be attributed an avoided capacity cost because electricity production cannot be relied on to generate electricity at the exact moment when an emergency situation will arise. These technologies offer non-firm capacity, which in NIAs cannot be attributed any value.

Some other alternative investment projects, however, may be able to guarantee some capacity during on-peak emergency events. Investment projects that can claim some firm capacity should be attributed avoided capacity cost. Investment projects capable of guaranteeing some firm capacity are likely to be projects that include a form of energy storage, e.g. wind power with battery storage, PV with battery storage or battery storage on its own for optimizing diesel plant operation.

Finally, certain alternative investment projects may be able to entirely substitute for the power plant, supply the entire demand and allow the power plant to go into standby mode. These projects should be handled differently than the other investment projects. Such projects could include, for example, certain small hydro projects, projects for interconnection with the integrated area, and certain liquefied natural gas projects (such as in Inuvik, NWT, and that of Whitehorse, Yukon, referred to earlier in this report).

2.3.1 Avoided cost components for investment projects

The nuances of the DRR method based on the type of project and technology being assessed are summarized in Table 6. Selected cost components are commented on below the table.

Table 6 Summary of cost components for investment projects

<table>
<tr><th rowspan="3"></th><th colspan="5" rowspan="2">Operational expenditures & Avoided cost of energy</th><th colspan="3">Capital expenditures</th><th rowspan="3">Distribution losses</th></tr>
<tr><th colspan="2">Avoided cost of capacity</th><th rowspan="2">Investment in fuel tanks</th></tr>
<tr><th>Fuel</th><th>Transportation and storage</th><th>Maintenance</th><th>Greenhouse gases</th><th>Hedge of fossil fuel prices</th><th>Capacity installation</th><th>End-of-life replacement</th></tr>
<tr><td>Non-firm capacity technologies</td><td colspan="2" rowspan="3">Yes, included.
Fuel price divided by fuel conversion efficiency.</td><td rowspan="2">Yes, included.
Same as for DSM.</td><td rowspan="3">Yes</td><td rowspan="3">No</td><td>No</td><td>No</td><td>No</td><td>No</td></tr>
<tr><td>Projects with some firm capacity</td><td>Yes, included.
Calculated using the DRR method, and assuming that the firm capacity can be guaranteed by the developer.</td><td>No</td><td>No</td><td>No</td></tr>
<tr><td>Projects capable of fully offsetting thermal generation</td><td>Yes, included.
Based on number of hours of operation.</td><td colspan="2">Yes, included.
Calculated using the DRR method on a project-by-project basis, assuming deferral of capital investment due to capacity addition or obsolescence of generators (whichever comes first).</td><td>No</td><td>No</td></tr>
</table>

Application of DRR methodology for intermittent generation

The **avoided energy cost** for all investment projects should be determined with the same approach as that of DSM programs, as described in Section 2.2.1. The three types of investment projects should be attributed avoided energy cost. An **avoided capacity cost** should be calculated on a case-by-case basis based on the type of investment project as follows: non-firm capacity technologies, projects with some firm capacity and projects capable of fully offsetting thermal generation as described below.

Projects with *some* firm capacity will be attributed an avoided cost to the extent that they are able to guarantee a certain number kW during on-peak emergency events. For instance, a 100-kW wind power project with a capacity factor of 20% in the winter may have battery storage that can guarantee 5 kW. The avoided energy cost would be 175,200 kWh multiplied by the avoided energy cost in cent per kWh. The avoided capacity cost would be 5 kW multiplied by the avoided capacity cost.

Distribution network losses should not be included in the avoided cost because losses are incurred between the new resource and the customers in the same way they are incurred between the generators and the customers[22].

For example, the avoided energy cost of a utility-scale solar PV project in the NIA of Ipsum (See page 43) should be 32.2 c./kWh instead of 32.9 c./kWh. If the same solar PV had a battery bank and was able to provide some firm capacity, the firm capacity should be valued at $95/kW-yr instead of $96/kW-yr.

For investment projects, ICF recommends that the avoided cost should be calculated specifically for each NIA. ICF does not see any justification to use a weighted average by region because these projects are most likely to be large (relative to the size of the NIA), discrete in time, deployed in only one NIA at a time rather than spread equally between NIAs.

Adaptation to projects capable of fully offsetting thermal generation

Projects capable of fully offsetting thermal generation should be able to claim both an avoided energy cost and an avoided capacity cost as a result of load growth and as a result of end-of-life replacement. This is due to the fact that thermal generators would remain on standby and their useful lifetime would be extended.

Such projects should be evaluated on a case-by-case basis. The utility will need to produce a detailed *reference* capital expenditure plan, and a detailed *alternate* capital expenditure plan. The avoided cost will then be determined using the DRR method, based on Equation 1. Each capital expenditure should be noted at full value in the predicted year when it is to be incurred and then discounted to current days. Both capital expenditure plans should account for capacity installations due to forecasted load growth and due to end-of-life replacement. The proposed approach is the same approach used by BC Hydro to value the avoided capacity cost for small hydro projects.

Projects capable of fully offsetting thermal generation should account for avoided maintenance costs in a different way than what is already included in the avoided cost of energy, as described in 2.1.1. ICF recommends making estimates with regard to the avoided cost of maintenance on a project-by-project basis, and the avoided maintenance should be measured in $ per day of standby mode instead of $ per kWh. If early estimates of avoided maintenance are needed, HQD or the project developers could use the following standard assumptions used by the Alaska EA : from $9.61 to $11.86 (USD) of avoided cost per hour of standby mode, based on the capacity of the generator (Alaska EA, 2015a).

[22] This statement does not apply to distributed-energy projects (i.e. generation *behind* the meter). Distributed energy projects should be attributed an avoided cost of distribution network losses.

2.3.2 Example of calculations

ICF presents one example of calculation of avoided cost of capacity for a stand-alone investment project in the archetype NIA of Ipsum (Same as page 43).

Example 4: NIA of Ipsum, Stand-alone investment project

For a small hydro project with a steady capacity of 1,500 that can allow the Ipsum diesel plant to be on standby for most of the year.

Avoided energy cost in Ipsum, for Stand-alone investment project

The avoided energy cost in Ipsum is calculated as follows.

Box 16

Price of diesel (c./Litre)	93	(based on IEA price forecast)
Thermal efficiency (kWh/Litre)	3.08	(archetype)
Avoided diesel cost (c./kWh)	30.2	
Avoided carbon (c./kWh)	0.0	(because included in price of diesel)
Avoided cost of energy without Tx (c./kWh)	30.2	

The avoided energy cost in Ipsum is 30.2 c./kWh. The distribution network losses are not included. The avoided cost of maintenance is valued by hour instead of by kWh, as explained below.

Avoided capacity cost in Ipsum, for Stand-alone investment project

As a reminder, the Ipsum diesel plant is described in the table below.

Box 17

Installed capacity (kW)	1,547
Description:	1 x 365, 2 x 591 kW
Firm Capacity, (N - 1)*90% rule	860

We developed two strawman capital expenditure plans shown on next page for both the reference scenario and for the investment project scenario. We used a 40-year planning horizon because this is the effective useful life of a typical small hydro project.

These are two strawman capital expenditure plans, reference and alternative, developed by ICF for illustrative purposes.

Box 18

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Planning horizon:		| Start	-----------	-----------	-----------	-----------	-----------	-----------	-----------	-----------	-----------	-----------	-----------	-----------	-----------	-----------	-----------	-----------	-----------	-----------
Capacity balance																				
Peak demand forecast in Ipsum	840	850	870	900	920	940	960	980	1,000	1,010	1,030	1,050	1,060	1,080	1,090	1,110	1,120	1,130	1,150	1,160
Reference capital expenditures																				
Capacity addition		$0	$500	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
End-of-life replacement of 365-kW generator		$0	$0	$0	$0	$0	$500	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
End-of-life replacement of 591-kW generator		$0	$0	$0	$0	$0	$0	$0	$0	$600	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
End-of-life replacement of the 2nd 591-kW generator		$0	$0	$0	$0	$600	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total - Reference CapEx		$0	$500	$0	$0	$600	$500	$0	$0	$600	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Alternative capital expenditures. Assuming a small hydro project capable of delivering 1,500-kW of steady capacity. The firm capacity under (N-1)*90% criterion would become 1,392 kW.																				
Capacity addition		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
End-of-life replacement of 365-kW generator		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
End-of-life replacement of 591-kW generator		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
End-of-life replacement of the 2nd 591-kW generator		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total - Alternative CapEx		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056
Planning horizon:	-----------	-----------	-----------	-----------	-----------	-----------	-----------	-----------	-----------	-----------	-----------	-----------	-----------	-----------	-----------	-----------	-----------	-----------	-----------	-----------	---- End |
Capacity balance																					
Peak demand forecast in Ipsum	1,170	1,180	1,190	1,200	1,210	1,220	1,230	1,240	1,250	1,260	1,270	1,280	1,290	1,300	1,310	1,320	1,330	1,340	1,350	1,360	1,370
Reference capital expenditures																					
Capacity addition	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
End-of-life replacement of 365-kW generator	$0	$500	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$500	$0	$0	$0	$0
End-of-life replacement of 591-kW generator	$0	$0	$0	$0	$600	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$600	$0
End-of-life replacement of the 2nd 591-kW generator	$600	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$600	$0	$0	$0	$0	$0
Total - Reference CapEx	$600	$500	$0	$0	$600	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$600	$500	$0	$0	$600	$0
Alternative capital expenditures. Assuming a small hydro project capable of delivering 1,500-kW of steady capacity. The firm capacity under (N-1)*90% criterion would become 1,392 kW.																					
Capacity addition	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
End-of-life replacement of 365-kW generator	$0	$0	$0	$0	$0	$0	$0	$0	$500	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
End-of-life replacement of 591-kW generator	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$600	$0	$0	$0
End-of-life replacement of the 2nd 591-kW generator	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$600	$0	$0	$0	$0	$0	$0	$0	$0
Total - Alternative CapEx	$0	$0	$0	$0	$0	$0	$0	$0	$500	$0	$0	$0	$600	$0	$0	$0	$0	$600	$0	$0	$0

The avoided cost of capacity simply becomes the differential of revenue requirements turned into an hourly fee, as shown below. The table shows an example of avoided cost of maintenance, also as an hourly fee as per the assumption used by the Alaska EA (2015a).

Box 19

Present value of reference capital expenditures ($'000):	$2,626
Present value of alternative capital expenditures ($'000):	$558
Present worth of alternative ($'000):	$2,068
Levelized number of hours of operation in 40 yr	187,070
Present worth of "sustaining capital" as a hourly fee ($/h)*:	$11.05
Other avoided maintenance cost per hour of standby*:	$11.86

* for each hour that the thermal plant will be on standby.

Appendix A: Detailed observation by jurisdiction

The following are ICF's observations by jurisdiction:

Newfoundland and Labrador

NL Hydro (Newfoundland and Labrador Hydro) is a regulated utility responsible for electric service in the coastal and insular non-integrated areas of Newfoundland and Labrador. Similarly to many of Quebec's NIAs, in some Newfoundland and Labrador NIAs, diesel fuel is delivered by boat, and delivery is only possible during the three to four months of the year when the coastal waters are ice free.

NL Hydro administers the TakeCharge DSM program, which offers some incentives and measures designed especially for NIAs. It uses avoided cost to assess the cost-effectiveness of its programs through standardized cost-effectiveness tests (NL Hydro & NP, 2013).

NL Hydro also has an official independent producer policy based on the principle of "shared savings" and, as a result, avoided cost is a key benchmark in establishing the price of electricity purchased from independent producers. For example, NL Hydro entered into a power purchase agreement with a private producer for a 390-kW wind-diesel project on Ramea Island. The purchase price negotiation was thus directly linked with avoided cost.

Table 7 summarizes the avoided costs included in the calculations in Newfoundland and Labrador. The terms used in the table are defined in Section 1.1.4.

Table 7 Summary of avoided costs – Newfoundland and Labrador

	Operational expenditures					Capital expenditures			Distribution losses
	Fuel	Transportation and storage	Maintenance	Greenhouse gases	Hedge of fossil fuel prices	Capacity installation	End-of-life replacement	Invest. in fuel tanks	
DSM programs	**Incl.**	**Incl.**	No	No	No	**Some-times**	**Some-times**	**Some-times**	**Incl.**
Investment projects	**Incl.**	**Incl.**	No	No	No	**Some-times**	No	**Some-times**	No

Fuel: For the avoided cost of fuel, NL Hydro uses an annual average efficiency and price specific to each NIA. It also forecasts how efficient each power plant will be in future years. This forecast improves based on investments and improvements in its power plants.

Like all the other electric utilities, NL Hydro uses each power plant's annual average efficiency to compute an average avoided cost.

Annual average efficiency is a simplification unanimously accepted for NIAs for the calculation of avoided cost of energy. In reality, power plant performance varies from hour to hour depending on the level of the demand. The use of an average efficiency is an acceptable approximation in NIAs because electric utilities design fossil fuel-fired power plants to perform optimally and consistently for the majority of the hours of operation each year. The utilities achieve this by installing modern generators that offer relatively stable optimal performance within a range from 50% to 100% of their nominal capacity and by installing several different sizes of generators to optimize performance along the entire demand duration curve. NIA operators use annual average fuel efficiency rather than using the results hourly marginal production cost simulation, which would typically be the approach for a price-regulated integrated-area system.

Transportation and storage: In Newfoundland and Labrador, the price of transportation is always included in fuel suppliers' prices. As for storage, NL Hydro owns the fuel tanks in some of its NIAs in order to get a lower fuel price and so the cost of storage must be treated as "investment in fuel tanks" for these NIAs, which is a capital expenditure. In other NIAs where the storage tanks are owned by the suppliers, the cost of fuel storage is intrinsically part of the price of the diesel. Some of the NIAs have a secondary supply of fuel. When the diesel plant gets low on fuel, a tank wagon delivers fuel from the secondary supply.

Maintenance: Similar to the electric utilities in Ontario and British Columbia, NL Hydro prefer not to include avoided costs of maintenance because their power plants have to continue operating despite DSM programs and despite the addition of a number of alternative sources of power such as wind and solar PV. According to NL Hydro and the utilities in Ontario and British Columbia, the maintenance costs for diesel generators is proportional to the number of hours each generator is in operation. As long as the plant is operating, the number of employees on site or paid hours remains the same, the amount of replacement parts and other supplies required does not change and thereby there is actually no cost being avoided.

Investment in fuel tanks: NL Hydro used the DRR method to value the deferral of the installation of a tank in Rigolet, a town on the North Coast of Labrador, to demonstrate that more aggressive demand-side management measures were appropriate in Rigolet than in the other non-integrated areas under its control.

The avoided cost of investment in a fuel tank was relevant to NL Hydro generally and Rigolet specifically because all of the following conditions were met: Rigolet, being remote, requires large tanks and cannot increase the frequency of replenishments because its waters are ice covered in winter; the tanks there are owned by the electric utility; there were short- or medium-term plans to add a tank; and NL Hydro's demand-side management measures had a large enough impact to warrant deferring the investment for a year or more.

NL Hydro did not convert the benefit generated by deferring the installation of a new tank in Rigolet into a *marginal* figure (i.e., into $/kWh). Instead, NL Hydro inserted the total benefit, in $, directly into its cost-effectiveness tests.

New capacity installation: Although the situation has never arisen, NL Hydro would agree to carry out the same valuation for the deferral of installation of additional production capacity. NL Hydro would also be willing to value the deferral of end-of-life generator replacement for a project that would allow the generators to be completely shut down for multiple hours, as might be the case with some small hydro projects. NL Hydro would agree to value the deferral of an investment only if the investment were expected within the next five years as part of its capital expenditure plan and if it were shown that the proposed technological solution would allow the investment to be deferred by a year or more.

NL Hydro would consider valuing the deferral of capacity installation only if installation is planned in the short term. NL Hydro maintains that capacity installation planned beyond a five-year horizon is too uncertain to be taken into account. Similar statements were made by the electric utilities of the Northwest Territories and British Columbia, as well as the Alaska Energy Authority (Alaska EA). The other utilities mentioned horizons of less than five years. The British Columbia electric utility and Alaska EA also indicate that few NIAs in their jurisdictions are seeing growth in demand that would warrant the installation of new capacity.

Distribution losses: In Newfoundland and Labrador, like in all the other jurisdictions, distribution losses have to be added to avoided costs in order to assess the cost-effectiveness of DSM programs and self-generation.

In order to encourage investment projects, NL Hydro has a “shared savings” power purchasing policy for independent producers, meaning that NL Hydro offers to pay a price equivalent to mid-way between the average production cost of the proposed solution and its own avoided cost of fuel. Each year, the independent producer has to provide NL Hydro with its accounting records in order to determine its average production cost for that year. NL Hydro also calculates the fuel costs that would have been incurred if the same amount of electricity had been generated by its thermal power plant. The final purchase price is determined annually at the end of the year. Note that, according to “shared savings” policy, NL Hydro limits the purchase price to no more than 90% of the avoided fuel costs; so the mid-way price cannot be higher than this.

NL Hydro has entered into a power purchase agreement with Frontier Power Systems, a private producer, for a 390-kW wind-diesel project on Ramea Island, an island with a population of approximately 700 off the coast of Newfoundland with a peak demand of 1,200 kW (F Katiraei, Abbey, Bailey, & Pelland, 2006; Farid Katiraei & Abbey, 2007). However, NL Hydro made an exception to its shared savings policy for Frontier Power Systems because this was an innovative project involving research and development costs. As a result of this exception, the price for the independent producer in Ramea amounted to 100% of the avoided costs[23]. For this producer, NL Hydro also offered to use a constant generator efficiency (the efficiency from before their installation of the wind turbines) to calculate the avoided costs. NL Hydro actually observed that the generators’ average efficiency decreased by a small margin after the turbines were installed because the generators were operating outside their optimal performance range for a longer period each year. This additional cost was absorbed by its rate base.

NL Hydro did not consider the avoided cost *of capacity* for the Ramea wind project. Like all of the electric utilities interviewed, NL Hydro does not consider wind power to be a source of power that provides firm capacity. As a result, installation of wind turbines, regardless of their number and individual capacity, cannot justify deferring the installation of additional thermal capacity. The same comment was made regarding solar PV projects. Both solar PV and wind power are considered to be intermittent power sources. Only firm-capacity solution, such as some small-hydro projects, may be able to deliver firm capacity under the N–1 reliability criteria, according to NL Hydro and most of the other utilities.

[23] Note that the independent producer also received financial support from Technology Early Action Measure (TEAM), a federal research program (Farid Katiraei & Abbey, 2007).

In this, the NIAs differ from the integrated system. In the integrated system, a capacity credit can be allocated to non-firm technologies by assessing the likelihood of coincidence between the intermittent generation and peak demand. This coincidence can be explained in part by the geographic distribution of wind turbines in the integrated system. In a NIA, however, wind turbines cannot be spread out the same way. Furthermore, the integrated system operators have access to other backup solutions that NIA operators do not have access to, such as interties with other balancing areas. As a result, all of the NIA utilities that were consulted are absolutely positive that intermittent power sources like wind power and solar PV cannot contribute to the reliability of supply.

The utilities included in the jurisdictional scan know that some technologies, such as energy storage or direct load control technologies, could make it possible to provide firm capacity. For example, Nalcor, NL Hydro's parent company, has carried out a pilot electrolizer and hydrogen storage project on Ramea Island (Nalcor Energy, 2010). NL Hydro and the other utilities are keen to see the results of this pilot project and of other energy storage pilot projects in other jurisdictions. To date they have not seen any proposals for investment projects involving an energy storage solution that was economically viable without considerable financial support from research funds or government incentives.

Ontario

In Ontario, Hydro One Remote Communities Inc.(H1RCI), a division of Hydro One, oversees half of all NIAs. H1RCI is a regulated utility with majority ownership by government, whose operation is managed independently from that of Hydro One. H1RCI is regulated directly by the Ontario Energy Board (OEB) in the same way Ontario's local distribution utilities are. The other half of the NIAs is served by independent authorities that are directly linked with a band council.

H1RCI developed and now administers a DSM program for its NIAs and uses avoided cost in its cost-effectiveness tests. H1RCI also created and now administers the Renewable Energy Innovation Diesel Emission Reduction (REINDEER) program, an incentive program for independent power producers. The REINDEER program has made it possible to develop seven solar PV projects, most between 10 and 20 kW. The largest project is 110 kW. Two more solar PV projects are in development.

Under legal agreements signed with the Department of Indigenous Affairs and Northern Development Canada, investment related to load growth in power plants and diesel gensets in H1RCI's NIAs are funded by INAC and are not included in H1RCI's rate base. HIRCI does not have visibility to these costs. As a result, most capital expenditures in H1RCI's NIAs are excluded from its avoided costs.

Table 1 Summary of avoided costs – Ontario

	Operational expenditures					Capital expenditures			
	Fuel	Transportation and storage	Maintenance	Greenhouse gases	Hedging	Capacity installation	End-of-life replacement	Invest. in fuel tanks	Distribution loss
DSM programs	**Incl.**	**Incl.**	No	No	No	No	No	No	**Incl.**
Investment projects	**Incl.**	**Incl.**	No	No	No	No	No	No	No

Fuel, transportation and storage: For the avoided cost of fuel, H1RCI uses a specific annual average efficiency for each NIA. For DSM programs, H1RCI uses the fuel price forecasting model developed by Navigant Consulting (2005) described below. Fuel transportation costs are included in the suppliers' prices. Costs associated with operations and maintenance, generation repairs, replacements and H1RCI-owned storage are not included. Where H1RCI enters into purchase agreements with local first nation band councils, the first nation's storage costs are also included. H1RCI oversees NIAs that have access to an all-season road, some NIAs accessible only by plane or ice road, and one NIA with water access. The avoided cost of fuel therefore varies tremendously from one NIA to the next, i.e. from 26.0 c./kWh to 70.6 c./kWh.

In 2005, H1RCI in Ontario hired Navigant Consulting to determine its avoided costs in NIAs in preparation for the potential launch of its DSM program (Navigant, 2005). Although H1RCI no longer uses Navigant's method in its entirety, it is one of the most complete methods seen during the jurisdictional scan and it is worth describing it in detail.

The method suggested by Navigant had the following features:

- Fuel expenses included refining, transportation, storage and distribution loss; an average efficiency was used for all of H1RCI's NIAs;
- Fuel prices were determined using the NYMEX futures prices for WTI (West Texas Intermediate) crude oil. The price of crude oil is available for the five years following the analysis. It was pegged to inflation from the sixth year. The cost of diesel was determined using a model based on the historical correlation between crude and diesel. The costs of storage and transportation, from the port of New York to the NIA, were then added. Since these were futures, the hedging value was naturally included in the avoided cost of fuel;
- Since the cost of transportation also depends on the cost of fuel, the latter cost was adjusted based on forecasted crude oil prices;

- Navigant included maintenance expenses based on the assumption that the variable portion of its expenses represents 0.5 c./kWh, which was estimated by applying a working assumption used in Alaska; and
- Navigant included an avoided cost of installed capacity in $/kW-year using the method of differential of revenue requirements.

The method of differential of revenue requirements is the same as what was used by NL Hydro to value the deferral of the investment in fuel storage tanks. The method consists of calculating the difference between the present value of forecasted revenue requirements without DSM and that with DSM. The net present value was then converted into a marginal value, in $/kW-yr, by dividing it by the impact needed to defer investment by one year in kW and then by annualizing the result of the division. A number of with-DSM scenarios were ran to test the sensitivity of the method. The method was proven to be robust because of the low level of discrepancy that was found between a moderate DSM scenario and a more aggressive scenario.

H1RCI no longer uses the Navigant method in its entirety. Its DSM program for NIAs, which has since been launched, is modest. The total budget is in the order of approximately $300,000 per year. Therefore, H1RCI considers that the budget envelope does not warrant the ongoing effort of gathering and analyzing data needed to use the method developed by Navigant. H1RCI uses only the avoided costs of fuel and fuel transportation. So far, the avoided cost of fuel and transportation has been enough to prove that its program is cost-effective.

H1RCI also administers the REINDEER program, which regulates and provides incentives for power generation by independent producers using renewable energy technologies (H1RCI, 2015). The REINDEER program has two streams: the “feed-in tariff” stream and the “net metering” stream. The first stream offers producers an official purchase price that is the same for all producers, published annually by H1RCI and equivalent to the avoided cost of fuel in each NIA. The second stream is only for producers that install the technology in a customer's building for self-generation purposes. Through the second stream, H1RCI offers to purchase surplus electricity (i.e. electricity not consumed by the building) from producers at the retail electricity price. The amount of surplus electricity that H1RCI committed to purchase is limited to 50% of the electricity consumed by the building.[24]

All seven projects that have joined the program to date did so through the “net metering” stream and all of them involved installing PV panels on institutional buildings. Institutional buildings form a separate rate class in Ontario’s NIAs, the *government* general service rate class. By design, their retail rate is higher than the cost of service and, therefore, much higher than the avoided costs. For example, the retail rates for institutional buildings in fly-in communities is over 95 c./kWh. It is, therefore, more cost-effective for renewable energy producers to take advantage of the retail price paid by institutional buildings by opting for self-generation and subscribing to the “net metering” component of the REINDEER program[25]. Producers have installed solar panels on schools, water treatment plants, band council administrative buildings and community centres. Since the power purchase price is higher than the avoided costs, the purchase of surplus power from self-generation by the utility could lead to an increase in revenue requirements. The regulator has tolerated this increase in revenue requirements because electricity consumers in Ontario have a statutory right to net metering which was guaranteed by the Green Energy Act.

[24] H1RCI’s non-integrated areas are not eligible for the IESO microFIT program.
[25] Producers have also taken advantage of provincial and federal government subsidies for their projects.

H1RCI publishes its avoided cost of diesel annually (2015). Any independent producer that would be interested in part in the “feed-in tariff” stream of the REINDEER program, if the event was to arise, would automatically be given a power purchase price equivalent to the avoided cost for that year. H1RCI does not make any long-term forecasts of the avoided cost of energy. The avoided cost of diesel values are the moving average of the avoided costs for the last three years (H1RCI, 2015). An independent developer wishing to propose a renewable energy project to H1RCI through the “feed-in-tariff” stream therefore has to make its own diesel price forecasts for the purposes of cost-effectiveness and risk analysis. By using a moving average for the last three years, H1RCI provides independent producers with a certain hedge against the price of diesel, which allows both H1RCI and the independent producer to share the risk of fuel price increases and decreases.

Nunavut

Despite the fact that Nunavut was consulted as part of this jurisdictional scan, it is premature to report any observations on this jurisdiction. Qulliq Energy Corporation, Nunavut’s electric utility, is in a development phase in terms of its economic analysis practices and has yet to deal with the concept of avoided costs.

Northwest Territories

There are two large legacy off-grid hydroelectric power systems in the Northwest Territories (NWT), the one in Yellowknife, to the north of Great Slave Lake, and the one in Hay River, to the south of the same lake. One distinctive feature of the NWT is that three-quarters of its electricity supply and demand is concentrated around its two largest communities and two large hydroelectric power systems. The other quarter comes from stand alone diesel plants spread across a million square kilometers and two small solar arrays. The town of Inuvik has the third largest stand-alone plant in the NWT, and it generates electricity using diesel and liquefied natural gas.

The economic analysis carried out in the two large off-grid hydroelectric power systems in the NWT is similar to the analysis in an integrated system due to the low cost of legacy electricity, the sufficient installed capacity (95% of the year)[26] and the breadth of their transmission and distribution systems, which all offer more renewable energy resource options than in other NIAs.

In the NWT, Northwest Territories Power Corporation (NTPC) oversees generation in both hydroelectric systems. NTPC is a regulated government-owned utility. Two private regulated utilities oversee distribution: Northland Utilities (Yellowknife) Limited and Northland Utilities (NWT) Limited (NUL-Yellowknife and NUL-NWT, respectively). NTPC oversees generation and distribution in 80 percent of the off-grid thermal power systems in the NWT, and NUL-NWT oversees thermal generation in the last 20 percent of the NIAs.

NTPC administers the PowerWise program, a DSM program that consists primarily of information and education initiatives, which is why NTPC has not put it through any cost-effectiveness tests.

[26] Note that the NWT recently had two consecutive years of unusually low rainfall that resulted in abnormally high diesel use for electricity generation in the two large off-grid hydroelectric power systems.

The Arctic Energy Alliance (AEA) is an independent, non-profit organization whose operating funds are provided by the territorial government. It administers DSM and renewable energy incentive programs as well as information programs. It does not use avoided costs to design or assess its programs.

Neither NTPC nor the AEA have a specific framework policy for independent power producers. The electric utilities negotiate a purchase price with independent producers on a case-by-case basis. The NWT still went ahead with three solar PV-diesel projects that were substantial given the size of the communities. NTPC developed a 104-kW solar PV project in Fort Simpson, a community of 1,250. Last year, it completed building a 135-kW solar PV project with electricity storage via battery bank in Colville Lake, a community of 160. NTPC has also just signed a Power Purchase Agreement with a community producer to buy the electricity from a 35-kW solar project in Lutsel K'e, a community of 350. The Government of the NWT played an important role in all three of the above projects by providing financial support.

Table 8 Summary of avoided costs – Northwest Territories

	Operational expenditures					Capital expenditures			Distribution losses
	Fuel	Transportation and storage	Maintenance	Greenhouse gases	Hedge of fossil fuel prices	Capacity installation	End-of-life replacement	Invest. in fuel tanks	
DSM programs	Not applicable – None of the DSM programs in the NWT are subject to cost-effectiveness tests that use avoided cost.								
Investment projects	**Incl.**	**Incl.**	**Incl.**	No	No	No	No	No	No

The Colville Lake solar PV-diesel project was developed by NTPC and funded primarily by the NTPC rate base. As a result, the project underwent an economic evaluation that was submitted to the regulator before it approved the project. It is a public document and representative of the practices surrounding the economic evaluation of investment projects in the NWT (NTPC, 2014, 2015).

Since no independent producer was involved in the Colville Lake project, the electric utility did not perform any marginal avoided-cost calculations (in c./kWh) for purchase price negotiation purposes. The economic analysis nevertheless has certain features typical of avoided-cost calculation methods. For example, the economic analysis of the Colville Lake project was a DRR analysis, meaning that NTPC calculated the present value of the revenue requirements for the project to refurbish the power plant for a "diesel only" scenario (a complete refurbishment was needed in any event) and that for a "solar PV-diesel" scenario in order to compare them. The analysis revealed that the Colville Lake solar PV project will have an upward impact on the utility's revenue requirements. In other words, if NTPC had presented its economic analysis in terms of marginal figures (in c./kWh for instance), the study would have shown that the average production cost using solar PV is greater than the marginal avoided of thermal generation.

The regulator approved the project all the same, since it was an innovative project and will have other benefits for the Colville Lake community (which were not monetized). NTPC predicts that the project could potentially be replicated at a lower cost in other communities when the technology is better known and understood.

Fuel, transportation and storage: NTPC published a reference avoided cost of thermal generation value for planning purposes. This value is based on an average efficiency and price for all NIAs (NT Energy, 2013). NTPC forecasts the price of fuel over the short term (three years) using the most recent price of its main fuel supplier, the Petroleum Products Division (PPD) (NTPC, 2012, p. 3.10)[27]. NUL also uses its fuel suppliers' most recent price (NUL, 2013, p. 4.1).

Maintenance: NTPC used an avoided cost of maintenance of 9.8 c./kWh for the Colville Lake solar PV project[28]. For the Lutsel K'e community solar PV project, an NTPC representative stated that the savings on maintenance costs were also added to the avoided cost of fuel during the purchase price negotiations[29].

New capacity installation: The Colville Lake solar PV project did not warrant a reduction in or the deferral of installed capacity (NTPC, 2014). NTPC also did not value capacity installation deferral in the price negotiated with the community producer of the Lutsel K'e solar PV project.

End-of-life generator replacement: Research conducted by Usher and Martel in the NWT in collaboration with the NTPC (1994), based on computer-assisted simulations, suggested that the solar PV projects in the NIAs areas of the NWT would reduce the number of times the generators had to be shut down and started up, which would reduce wear and increase the number of years of useful life. Each stop-start cycle was assigned an equivalent number of hours of operation. This method, however, is no longer used by NTPC.

On the contrary, now NTPC, similar to other electric utilities including British Columbia's and NL Hydro, asserts that intermittent power projects may increase the number of stop-start cycles of its diesel generators. The inclusion of electricity storage solutions could change this. Nevertheless, NTPC indicated that pilot projects will have to be conducted to demonstrate the benefits of energy storage for the useful life of generators before they can be valued. The Colville Lake solar PV project, which includes a battery bank, is one of such pilots and could provide answers in this regard. Nevertheless, in the interest of accuracy and for lack of tangible proof, NTPC decided not to value the deferral of generator replacement in the economic analysis submitted to its regulator (NTPC, 2015).

Yukon

The Yukon has one large legacy off-grid hydroelectric power system across the territory, the "Yukon Integrated System," which is not interconnected with the continental integrated system but is the largest NIA in Canada. The Yukon Integrated System extends from Whitehorse to

[27] Transportation and storage are partially subsidized due to the costs incurred by the PPD, a division of the NWT government, not all of which are passed on to consumers (GNWT, 2013, p. 57).
[28] (\$0.042 million – \$0.031 million) * 1,000,000 / (112 MWh * 1,000) * 100 = 9.8 c./kWh (NTPC, 2014, p. 25)
[29] It was impossible to obtain a description of how the latter were determined since the purchase agreement between NTPC and the community of Lutsel K'e is confidential.

Dawson City, connecting most towns. There are only four small and medium remote diesel-powered NIAs in the territory. Yukon Energy Corporation (YEC), a regulated government-owned utility, oversees generation in the Yukon Integrated System. A private regulated utility oversees distribution within the territorial integrated system: ATCO Electric Yukon (ATCO), formerly Yukon Electrical*.* ATCO oversees generation and distribution in the diesel-powered NIAs.

YEC and ATCO jointly administer the InCharge DSM incentive program. They use the avoided cost of energy as well as standardized cost-effectiveness tests (ICF Marbek, 2013, p. 11). The Energy Branch of the Yukon government (formerly the Yukon Energy Solution Centre) administers the Good Energy program, which includes DSM and renewable energy incentives, as well as information and education activities. The Energy Branch is not required to use standardized cost-effectiveness tests. However, the Energy Branch has recently adopted and applied standardized cost-effectiveness tests to Yukon programs in 2014 to ensure compliance with industry best practices.

In October 2015, The Yukon's territorial government approved a policy to regulate and encourage power generation by independent producers using renewable energies (Government of Yukon, 2015). The government continues to negotiate a standard offer program (similar to the standard-offer stream of the REINDEER program in Ontario), but this policy now offers certainty for private sector and First Nations partners to explore energy options. A standard offer program is anticipated in 2016 that will include the avoided cost of liquefied natural gas (marginal electricity generation in the Yukon integrated system is the liquefied natural gas plant in Whitehorse) and will update the current estimate of the avoided cost of electricity. The current estimated avoided cost of electricity, as offered through through the existing micro-generation program and predicated on diesel, is $0.21/kWh.

Despite the independent producer policy being incomplete, the Yukon has a few sizable investment projects at the development stage. First, a community developer is working on an 300-kW solar PV-diesel project in Old Crow, a community of 250 in the northern part of the territory that is accessible only by air. The community developer will have to negotiate a purchase price with ATCO in the near future. Then there are other projects at the design stage in the Yukon, such as a wind-diesel-heating project in Burwash Landing/Destruction Bay, and some small hydro and deep geothermal energy projects in Watson Lake. Most First Nations in Yukon, such as those of Old Crow and Burwash Landing/Destruction Bay, are investigating their renewable energy options and are in some stage of pre-feasibility investigations.

Every five years, YEC draws up an integrated electric resource plan on a 20-year horizon. Avoided costs are one of the outputs of this planning exercise. The most recent exercise was completed and the report published in 2011 (YEC, 2011). The next plan is in progress and will be completed in 2016. The five-year-old avoided costs will therefore be updated shortly.

Table 9 Summary of avoided costs – Yukon

	Operational expenditures					Capital expenditures			Distribution losses
	Fuel	Transportation and storage	Maintenance	Greenhouse gases	Hedge of fossil fuel prices	Capacity installation	End-of-life replacement	Invest. in fuel tanks	
DSM programs	**Incl.**	**Incl.**	**Incl.**	No	No	**Incl.**	**Incl.**	No	**Incl.**
Investment projects	**Incl.**	**Incl.**	**Incl.**	No	No	**Maybe**	**Maybe**	No	No

The approach taken by YEC, ATCO and the Energy Branch in assessing its DSM programs is based on the levelized cost of energy. Avoided costs, i.e., the levelized cost of electricity, are included in the reports by YEC (2011, p. 79) and ICF Marbek (2012, p. 53, 2013, p. 6). The levelized cost of energy is the cost of electricity generation adjusted to a uniform basis of calculation, generally $/kWh, that includes all operational expenditures and capital expenditures.

Fuel: The levelized cost of energy includes the cost of fuel. The costs used in 2010-2011 were the prices of YEC and ATCO's diesel suppliers at the time.

Transportation and storage: The cost of transportation in the Yukon varies a great deal depending on the method of transportation and storage. For example, the levelized cost of energy in Old Crow, a remote community in the northern part of the territory accessible only by plane, is 64 c./kWh. For small and medium NIAs accessible by all-season road, the levelized cost is 30 c./kWh (ICF Marbek, 2012, p. 53).

Maintenance: The avoided operation and maintenance costs included in the levelized cost of diesel generation total 3 c./kWh for old generators and 2 c./kWh for new generators. YEC used the average (YEC, 2011, p. 79).

Capacity installation and end-of-life replacement: In order to calculate the levelized cost, ATCO and YEC estimate a typical cost of diesel generator capacity based on their engineers' experience, $1,000 per kW for diesel generators. They then estimate the energy supplied each year using a typical utilization factor for the territory's non-integrated areas. The capital cost is divided by the sum of the discounted kWh supplied during the useful life of a generator (15 years). The value obtained is 2 c./kWh. With identical inputs, this method yields the same result as HQD's generic equipment method. This value, 2 c./kWh, represents the avoidance of all capital expenditures, namely new capacity installation and end-of-life generator replacement.

On the issue of DSM, the avoided costs that YEC and ATCO use to assess the cost-effectiveness of their InCharge DSM program is a weighted average of several new resources that were planned to be installed in the near term resources in the Yukon Integrated System; namely diesel, liquefied natural gas, improvements to existing hydroelectric plants, wind and biomass (ICF Marbek, 2013, p. 6).

The avoided costs used to assess the cost-effectiveness of the DSM programs are less than the avoided cost of diesel generation because the levelized cost of liquefied natural gas-fired generation was far less than that of diesel-fired generation. At the time the avoided costs were calculated, liquefied natural gas was going to represent a large percentage of the new generation capacity that was to be installed in the territory, while other technologies (wind, biomass) were going to represent a smaller percentage.

YEC and ATCO did not use avoided costs specific to the territory's small and medium NIAs in assessing the cost-effectiveness of their DSM program. Small and medium off-grid thermal power systems are simply eligible for the same program with the same incentive levels, the assumption being that if the program is cost-effective in the territory's integrated system, then it will also be cost-effective in its small and medium NIAs, where the cost of electricity generation is higher.

With respect to investment projects, the Yukon's independent power generation policy indicates that there will be three streams of projects: a "Standing Offer"stream for small project that will be eligible for predetermined feed-in tariffs through, a "Call-for-Power" stream for large projects based on tendering processes that YEC will launch on an as-needed basis to meet future demand, and "Unsollicited Proposal" stream for large projects developed by communities and First Nations (Government of Yukon, 2015). As for very small self-generation projects, the Yukon has had a "microgeneration" policy since 2013 (Government of Yukon, 2013) that is similar to a net metering program.

British Columbia

Most NIAs in British Columbia (BC) are administered by independent authorities with support from INAC, much like a number of NIAs in Ontario. BC Hydro and Power Authority (BC Hydro) oversees the electric service of only 14 NIAs.

BC Hydro no longer has a DSM program that is specifically designed for NIAs. The program was shut down over three years ago. BC Hydro NIA customers are eligible for the Power Smart program, the same program as the one offered to all of its other clients.

BC Hydro applies a "reasonable return on investment" policy in negotiating with independent developers of small hydro projects and uses avoided costs as a maximum purchase price threshold. With this policy as a guide, BC Hydro has purchased power from independent small hydro producers in Bella Bella, Sandspit and Dease Lake. These projects were built over 15 years ago. A community producer in Atlin recently entered into a power purchase agreement with BC Hydro at a price equal to the avoided cost of fuel for a small hydro project. The Atlin project is a flagship project and is often held up as an example of a successful investment project in partnership with First Nations.

A community/First Nations developer of a small hydro project in BC negotiated a purchase price with BC Hydro in the last 5 years. According to BC Hydro, this particular negotiation is most representative of the approach BC Hydro will take to independent power production going forward. However, the future of the project stays unclear as the developer continues to gather all the necessary financial resources.

Table 10 Summary of avoided costs – British Columbia

	Operational expenditures					Capital expenditures			
	Fuel	Transportation and storage	Maintenance	Greenhouse gases	Hedge of fossil fuel prices	Capacity installation	End-of-life replacement	Invest. in fuel tanks	Distribution losses
DSM programs	Not applicable – BC Hydro shut down its DSM program aimed specifically at non-integrated areas over three years ago.								
Investment projects	**Incl.**	**Incl.**	**Some-times**	**Incl.**	No	**Some -times**	**Some-times**	No	No

Fuel, transportation and storage (Energy Payment): BC Hydro forecasts the price of diesel in its NIAs based on the prices of its local diesel suppliers, which include transportation costs. BC Hydro then uses historical price information to create a diesel price trend based on the last 10 years of data. Power purchase agreements negotiated with independent producers on this basis have the current price set on the trend line, and are then pegged to inflation, annually, going forward. In this the EPA price is set looking backward, using real data. BC Hydro then compares this backward-looking price point, but tagged to inflation going forward, to the trend in the price of crude oil as forecast by the Energy Information Administration (EIA) in the United States.

Maintenance and end-of-life generator replacement (Capacity Payment when project can load follow): BC Hydro and the community producer of the small hydro project negotiated a series of extra payments equal to the avoided operation and maintenance costs, as well as the avoided cost of capacity and end-of-life generator replacement. In order to receive the payments, the community producer has to be able to completely replace the power produced by the generators, allowing the generators to be shut down and left in standby mode, and supply the NIA entirely alone, including the instananeous fluctuations in demand. The payments are calculated based on the number of hours per year for which the power plant is shut down. They would be reduced if, for any reason, BC Hydro had to start up its power plant.

These payments are computed based on the avoidance of operation and maintenance costs for each hour that a power plant is turned off and based on the deferral of the installation of new gensets at the end of the expected effective useful of life of these gensets (which is measured in hours of operations). BC Hydro valued the deferral capital expenditures using the DRR method.[30]

In an ideal project scenario, the project would be much lower than the avoided fuel and operation and maintenance costs, so these payments streams would be much lower than the theoretical maximum payments. In the example cited, the project costs were above the theoretical maxium, requiring the developer to make up the difference with grant funding.

[30] According to BC Hydro, most renewable projects (e.g. windpower or solar PV) would not be able to follow the load, and therefore only the energy payment would be applicable.

Similarly to H1RCI in Ontario, BC Hydro does not believe there are any avoided operation and maintenance costs unless investment projects allow generators to be shut down. In BC Hydro's view, intermittent power sources such as wind and solar PV do not allow to shut down the diesel gensets. Furthermore, potentially the increased ramping due to additional renewables could increase maintenance. Electricity storage solutions may be able to solve this in the future. However, no project developer to date has submitted an economically viable project to BC Hydro that included an electricity storage solution.

Greenhouse gases: BC Hydro has to include the BC carbon tax in its avoided costs.

New capacity installation: BC Hydro is seeing low demand growth in most of its NIAs. In BC Hydro's view, there is therefore no need to value the deferral of additional capacity installation in the short and medium term.

For investment projects, BC Hydro applies a so-called "reasonable return on investment" negotiation policy to independent producers in NIAs. It is similar to NL Hydro's policy. Avoided costs are used to determine the maximum purchase price; it forms a "price cap". Much like NL Hydro, BC Hydro asks developers to engage in open-book negotiations, i.e. the developers ought to share all their cost estimates and cash flow analysis with BC Hydro. BC Hydro is willing to purchase power at the developers' average production cost with a reasonable return on investment. According to BC Hydro, the independent producer's reasonable return is generally 2 to 5% higher than BC Hydro's own regulated return to account for the greater level of risk that will be incurred by independent producer. The independent producers' cost estimates and accounting records are to be checked by third-party technical experts. This way, BC Hydro ensures to ratepayers that the independent producers cannot artificially overestimate the proposed average production cost in order to bolster its profit margins. Only in the case when the project costs reach the price cap would the maximum EPA price (including capacity payments) be realized.

Alaska

The Alaska Energy Authority (Alaska EA) is a state agency whose operating funds come primarily from the state and federal governments. It manages a large number of energy programs including administering a Renewable Energy Fund grant program, efficiency and conservation programs, an electric subsidy program called the Power Cost equalization program, and upgrades and maintenance of rural diesel powerhouses and bulk fuel facilities.

The Alaska EA administers a DSM information program, a DSM audit program for non-residential buildings and a DSM support program for small municipalities. The Alaska Housing Finance Corporation and Alaska Native Tribal Health Consortium also administer certain other DSM programs related to housing and water/sanitation systems respectively. Their operating funds come from the state budget and federal government. In addition, ther are limited utility-administered DSM programs in Alaska. Avoided cost is not used for DSM-related economic analysis in state of Alaska programs; retail electricity prices are used instead.

Numerous renewable energy projects have been developed in Alaska since the late 1990s, especially wind-diesel projects. To date, Alaska has completed 23 wind-diesel projects. Three projects are under construction and approximately 30 projects are at the design stage (Alaska EA, 2015b).

Financial support from the federal and state governments has contributed significantly to wind-diesel project development in Alaska. The first wind-diesel projects in the late 1990s, in Kotzebue and Wales, were financed largely using federal funds from the Department of Energy. Later, between 2004 and 2008, five projects were funded by the Denali Commission, a federal infrastructure funding agency for remote Alaska communities. In 2008, new wind-diesel projects began receiving financial support from the Alaska EA's Renewable Energy Fund (REF) program, created and funded by the state government to reduce reliance on diesel (Fay, Keith, & Schwörer, 2010, p. 5). Other renewable energy technologies, such as small hydro, biomass and two solar projects also receive financial support from the REF.

Alaska has no specific policy for independent producers because most electricity service in its NIAs is overseen by the communities' local governments. Electricity service in remote communities is provided largely by unregulated community utilities that operate with technical support from the Alaska EA or Alaska Village Electric Cooperative (AVEC). This model is similar to the "independent authorities" of Ontario and BC. It is these community utilities that apply to the REF program and develop the wind-diesel projects. As a result, only three wind-diesel projects have been developed by independent producers in Alaska.

State funding for renewable energies is now administered primarily through the Alaska EA's REF. REF funds are allocated through an annual application process. The project file submitted by a community must include a cost-benefit analysis of its project using a template provided by the Alaska EA (2015a). Avoided diesel consumption is the main benefit assessed for power generation projects. The outcome of the renewable energy project cost-benefit analysis is one of the assessment criteria for selecting projects and determining the level of financial support. Other criteria include the cost of service in the community, technical feasibility, and other benefits for the community and project management.

Table 11 Summary of avoided costs – Alaska

	Operational expenditures					Capital expenditures			
	Fuel	Transportation and storage	Maintenance	Greenhouse gases	Hedge of fossil fuel prices	Capacity installation	End-of-life replacement	Invest. in fuel tanks	Distribution losses
DSM programs	Not applicable – The Alaska EA does not use avoided cost to assess the cost-effectiveness of its DSM projects and programs. There is no utility-administered DSM program in Alaska.								
Investment projects	**Incl.**	**Incl.**	**Incl.**	**Incl.**	No	**Maybe**	No	**Maybe**	No

Fuel, transportation and storage: The Alaska EA has established a correlation model to arrive at the price of fuel, purchased from local suppliers, based on crude oil price forecasts. The Alaska EA's model is the most robust correlation model seen during the jurisdictional scan (Pride, Snodgrass, & Scott, 2015). It was established through a multifactorial regression analysis. Pride et al. developed a correlation formula for each of the following fuel transportation methods: all-season road, air, boat via coastal waters that freeze in winter, and boat via waters that are ice free all year. The correlation model makes it possible to accurately predict future diesel prices based on the specific transportation and storage costs of each NIA.

Maintenance: Under the Alaska EA's economic evaluation model, developers can claim maintenance cost savings only if the technology makes it possible to completely shut down the diesel generators, as in the case of small hydro projects. The maintenance savings estimation method recommended by the Alaska EA uses the number of hours for which the power plant will be inactive instead of the electricity the investment project is expected to generate.

Greenhouse gases: Although Alaska does not subscribe to any carbon pricing system, the Alaska EA uses a shadow carbon price in its economic analysis. It also allows developers to include other monetized externalities as benefits.

Capacity installation and end-of-life replacement: According to the Alaska EA, wind-diesel and solar PV-diesel projects cannot replace the installed capacity of thermal power plants in NIAs. The Alaska EA’s evaluation template does not consider the deferral of capacity installation (2015a). An independent economic evaluation of the many wind projects implemented to date in Alaska, by the University of Alaska, did not include avoided cost of capacity and of other capital expenditures in its valuation model (Fay et al., 2010).

The Alaska EA would be willing to assist project developers in valuing the deferral of capacity installation under the following circumstances: if the NIA had a short-term need to install more capacity and if the project provided a firm-capacity supply solution like some small hydro projects would. The Alaska EA has never found itself in a situation where it was appropriate to value the deferral of capacity installation for a renewable energy project.

The Alaska EA is closely monitoring the few projects that include electricity storage, but at this point has yet to value the avoidance of installed capacity or the deferral of end-of-life replacement for an energy storage project.

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