Brief

The Transmission Provider's Transmission Network Upgrades Policy
R-3888-2014

Union des consommateurs

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December 5, 2014

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The Union des Consommateurs, *Strength of a Network*

The Union des consommateurs (UC) is a not-for-profit organization made up of nine family economics cooperative associations (ACEF), the Association des consommateurs pour la qualité dans la construction [consumer association for construction quality] (ACQC) and individual members. UC's mission is to represent and defend the interests of consumers, particularly those of low-income households. UC focuses on activities related to the values its members hold dear: solidarity, equity and social justice and better economic, social, political and environmental living conditions for consumers.

By virtue of its structure, UC can look at big picture consumer issues, while developing specific expertise in certain areas, notably via its research into the new problems that face consumers. Its work is province-wide in scope and is supported and legitimized by the field work and grounding of member associations in their communities.

UC is active primarily in the provincial arena, representing consumer interests before various political and regulatory bodies, as well as in public and in its collective initiatives. Among its most important areas of research, action and representation are family budgeting and debt, energy, issues related to telephones, radio communications, cable television and the information highway, health, agri-food and biotechnologies, financial products and services, and social and fiscal policies.

Lastly, in a context of market globalization, UC is working in conjunction with a number of consumer groups in English Canada and abroad. It is a member of Consumers International (CI), an organization recognized by the United Nations, among others.

For over 40 years, family economics cooperative associations have worked tirelessly with low-income individuals in Quebec. Since their inception, they have demanded better social and fiscal policies and offered services directly to families, including personalized budget counselling.

1 Upgrades Policy for Native Load: an Exception in North America

1.1 The "higher of" rule applied to native load

The Transmission Provider's current upgrades policy applies a portion of the capital expenditures that would otherwise be included in the assets of the Transmission Provider to native load.

> A similar concept is also well entrenched in North American upgrade policies. That is the "higher of" concept, long established by FERC, whereby upgrades to the system made for third parties do not affect native load customers, while allowing the requestors to pay a fair price for the upgrades and use of the existing transmission network. The concept relies on three principles set out by the FERC:
>
> > First, the native load customers of the utility providing transmission service should be held harmless. Second, transmission customers should be charged the lowest reasonable cost-based rate for third party firm transmission service. Third, the pricing should prevent the collection of monopoly rents by the transmission owner and promote efficient transmission decisions.[1]

The Transmission Provider's application of the "higher of" rule or rate neutrality to native load is not followed elsewhere in North America.[2]

> "Tariff neutrality" refers to a policy implemented by the Régie in 2002 (Decision D-2002-95). The Régie defined tariff neutrality as a limit on the amount that HQT could add to rate base in providing new transmission services, for all transmission customers—above which customers would provide a direct contribution for the upgrade. It is my understanding that the Régie's stated purpose behind its current tariff neutrality test is to treat the native load and point to-point customers the same way by subjecting both groups to the same HQT allowance. The current policy is unique among the Régie's regulatory peers; it is also a method that no longer suits HQT's current context as it subjects native load upgrades to a benchmark that is based on historical average cost. Regulatory precedent in other Canadian and US jurisdictions calls for the use of the prudent investment test to assure that the investments made on behalf of native load are reasonable.[3] [emphasis ours]

It is therefore important to note from the outset that, as it is constrained to the same rate neutrality treatment as point-to-point customers, the Transmission Provider's native load does not see the same benefit as its North American counterparts. Yet, the transmission network is there for point-to-point customers because of native load and "the required upgrades to serve native load allow the Distributor to fulfill its service obligation."[4]

[1] Northeast Utilities Service Company, Opinion 364-A, 58 FERC ¶61,070 (1992).
[2] R-3669-2008, Phase 1, HQT-15, Document 1, page 15 and R-3738-2010, HQT-10, Document 3, page 13.
[3] R-3738-2010, HQT-10, Document 5, page 17.
[4] R-3738-2010, HQT-13, Document 11.1, page 18.

Lastly, UC points out that at the very least we must recognize equivalent if not favourable treatment for native load "based on the principle that native load… is ultimately responsible for the entire transmission revenue requirement."[5]

UC notes, however, that regulatory history has clearly been unfavourable to native load.

1.2 Concern about double application

The Transmission Provider proposes that the Distributor's resource projects arising from calls for tenders, exempt purchases and other purchase programs be included in the project aggregation used for the annual calculation of the Distributor's contribution.[6]

The Transmission Provider's proposal stems directly from the position taken by the Régie in a previous decision:

> [110] Further, this exercise must also take into account the methodology for examining applications for authorization of capital projects submitted to the Régie. In particular, projects to connect generating stations, on the one hand, and load integration or interconnection projects, on the other, are generally distinct projects and, accordingly, are subject to separate review by the Régie. The result is a <u>double application of the maximum allowance for the same production transiting through the network</u>.
>
> [111] To remedy that situation, a number of options may be considered, including:
>
> - Application of the maximum allowance only for connection of generating stations;
> - Application of the maximum allowance only for load integration or interconnection;
> - Application of a percentage of the maximum allowance for connection of generating stations and a percentage for load integration or interconnection. For example, the proportion could be 50-50 or could be determined using an as-yet undefined weighting distribution.
>
> [112] The Régie concludes that it is necessary to re-examine the methodology in Attachment J to the Transmission Tariff to ensure that the target objective is achieved, i.e. that the various upgrades to the network for native load and those for point-to-point service have no upward impact on the Transmission Provider's rates.[7] [emphasis ours]

However, the question of double application is unique in North America, as the Transmission Provider's expert specifies.

> Please specify how this matter of double application of the maximum allowance, raised by the Régie, is treated elsewhere in North America.
>
> Response
> The "double application" raised by the Régie is not an issue raised in jurisdictions in the U.S. and therefore Ms. Chang is not aware of any jurisdiction dealing with this issue.[8]

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[5] R-3738-2010, HQT-13, Document 11.1, page 16.
[6] HQT-1, Document 1, page 14.
[7] D-2009-071, page 28.
[8] HQT-4, Document 7, page 5.

> Please indicate how frequently native load is treated the same as point-to-point customers. If need be, provide examples of jurisdictions where this practice is used.
>
> Response
> As explained in Ms. Chang's testimony, FERC's primary policy objective at the time of restructuring was to ensure that transmission providers offered non-discriminatory open access to the transmission network while protecting existing transmission users from costs imposed by customers requesting transmission service that involve network upgrades. FERC's policy is to strike a proper balance of protecting load and point-to-point customers. In that sense, HQT's proposed network upgrade policy is also intended to strike the balance between protecting native load and point-to-point customers….[9]

Clearly, not only is subjecting native load to the rate neutrality test by the Transmission Provider an exception in North America, under its current upgrades policy, but the Transmission Provider's proposed changes aggravate the situation by allocating only the unused portion of the aggregated maximum allowances as a contribution to the Distributor's resource projects, dependant on the vicissitudes of projects conducted each year to maintain the network and meet growth in demand.

UC argues that the Transmission Provider's proposal is not based on any recognized principle. When compared with what goes on in other jurisdictions, it essentially relies on minimizing the transmission cost of point-to-point customers to the detriment of native load customers.

> Include all of the Distributor's projects in the annual aggregation of projects used to calculate the "annual aggregation (loads and resources)" contribution, i.e. add resource projects to the aggregation currently used for native load growth projects in order to limit the total capital costs borne by the Transmission Provider to the maximum allowance based on forecasted 20-year growth in satellite substations and customers connected directly to the transmission system.[10]

UC argues that this proposal discriminates against native load and should be rejected by the Régie.

1.3 Project categories and cost-sharing

The Transmission Provider's proposal to recognize only the unused portion of the maximum allowance recognized for the Distributor's other projects as a specific contribution to the cost of native load resource projects is an extreme proposal that supposes that the Transmission Provider's current upgrades policy actually assigns a double allocation to native load, which in UC's opinion is far from being demonstrated.

Indeed, there is no direct link between demand growth projects and the Distributor's resource projects.

[9] HQT-4, Document 5, page 19.
[10] HQT-1, Document 1, page 17.

> The Transmission Provider cannot establish a direct link between the commissioning of a resource project and that of a satellite substation project, for the reasons cited in previous dockets, notably R-3669-2008 and R-3738-2010:
>
>> In the case of native load, the Distributor must serve a large variety of loads with different delivery features from a portfolio of resources that also have different features. Further, the Distributor can never directly identify a specific resource that serves a specific load.[11]

Further, the Transmission Provider's projects, while often fulfilling multiple objectives, meet or will in future meet the needs of multiple customers. Yet an arbitrary and static breakdown of an evolving business reality determines whether or not the Transmission Provider's main customer, which is not an intervenor in this docket, will receive an allowance from the Transmission Provider for its resource projects.

In its decision D-2014-117, the Régie indicates:

> [57] The Régie considers it appropriate to deal with cost-sharing for projects that belong to more than one capital expenditure category in this proceeding, particularly in the context of integrated capital expenditure planning, under which this situation may become increasingly common.
>
> [58] The Régie directs the Transmission Provider to file additional evidence describing the cost-sharing methodology and criteria that it intends to apply to projects that belong to both the "demand growth" category and to capital expenditure categories that do not generate revenues.[12]

According to the Transmission Provider, categorization of capital projects is based on the project objectives. Depending on those objectives, the Transmission Provider uses four investment categories recognized by the Régie, i.e. in order, "customer demand growth," "asset maintenance," "maintenance and improvement of service quality" and "compliance with requirements."[13] However, only native load demand growth projects are covered by the proposed methodology in the upgrades policy. Now, when we're dealing with large-scale projects, assigning costs based on the different investment categories by the Transmission Provider becomes difficult.

> However, to optimize each of its initiatives, the Transmission Provider carries out many large-scale projects whose main components simultaneously pursue multiple objectives in an integrated fashion (“integrated multiple-objective projects”). For example, entire facilities and sometimes entire sub-systems are sometimes fully replaced to achieve objectives of durability, growth and service quality improvement. The allocation of project costs to the various relevant categories is more complicated in those cases.[14]

The literature on the subject does in fact indicate that it can often be difficult to arrive at a fair and equitable allocation of costs to various investment categories.

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[11] HQT-4, Document 1, page 17.
[12] D-2014-117, page 15.
[13] HQT-3, Document 1, page 19.
[14] HQT-3, Document 1, page 20.

Another practical difficulty with traditional distinctions between "reliability" and "economic" upgrades is the fact that almost all transmission projects in effect serve both purposes. At any point in time – and even more so over time – almost any project will lower the risks of interruptions by some degree, and almost every upgrade justified for reliability concerns will inevitably yield at least some economic benefits as well.

Furthermore, because transmission exhibits large economies of scale and high transaction costs – that is to say, as a general proposition larger capacity projects have much lower permegawatt ("MW") costs – it usually makes sense to accommodate both reliability and economic opportunities within a single project rather than piece-meal. Finally, because transmission assets are extremely long-lived, lines that are unnecessary for meeting forecasted peak demand today will become part of the portfolio of assets maintaining supply demand balance far into the future.[15] [emphasis ours]

The Transmission Provider was asked how the multiple objectives of investment projects were taken into account or whether it was possible that such projects would benefit other customers in the future. UC notes the difficulty, perhaps even the impossibility, of assigning a fair proportion of project costs to the current and future customers that will benefit.

According to the Transmission Provider, could a project associated with native load growth (other than a resource project) be considered a network durability project after the fact?

Response
The categorization of a project is generally established at the preliminary stage and is not changed after the fact. As indicated in Exhibit HQT-3, Document 1, section 7.2, this categorization is done as a function of the project objectives.[16]

Please explain why it is not possible or reasonable to require future beneficiaries of current period investments, funded in part by current period customer contributions, to contribute to the cost of the upgrade when they obtain the benefit therefrom.

Response
As indicated in Exhibit HQT-3, Document 1, pages 24 and 25, some network upgrades provide direct or indirect benefits to existing or future users other than the requester that triggered the expenditure. It is however reasonable to think that those users would be inclined to challenge any attempt to make them pay a share of the cost of upgrades that are not required for their own transmission or generating station connection needs, on the grounds that they were not involved in the decision to make such network upgrades.

Thus, where transmission capacity is available, the Transmission Provider would not reasonably allocate a portion of the cost of upgrades triggered by a previous request, on

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[15] On Allocating the Costs of New Transmission Investment: Practice and Principles, A White Paper Prepared by The Blue Ribbon Panel on Cost Allocation for WIRES, the Working group for Investment in Reliable and Economic Electric Systems, September 2007, pages 14 and 15. http://www.hks.harvard.edu/hepg/Papers/Rapp_5-07_v4.pdf (consulted November 20, 2014).
[16] HQT-4, Document 7, page 5.

the basis that a requester today benefits from a transmission service with no network upgrade.

Even if a requester agreed to pay a higher cost for the benefit it is receiving today, the Transmission Provider should be able to identify which past upgrades are the reason for this available capacity and make the appropriate assumptions for bringing the cost incurred to a present value.[17]

From the standpoint where to meet native load power needs in winter only (four months a year), a new resource was connected to the Transmission Provider's network, how would the resource project be rolled into the aggregation of projects used to perform the annual calculation of the Distributor's contribution if the resource project is a point-to-point service customer the rest of the year?

Response

In the example presented by the intervenor, it is possible that a portion of the project costs could be rolled into the Distributor's project aggregation, pro-rated for the production used to meet native load requirements, based on the proposed stages, in order to determine the cost of resource projects that are eligible to be rolled into the aggregation.[18] [emphasis ours]

Already, the cost-sharing among current and future beneficiaries of a project is sparking discussion. In the Transmission Provider's application for authorization of the 735 kV project in Chamouchouane – Bout-de-l'Île, the matching of the project and the needs met is a huge grey area, as shown in the following excerpts.

As required for a structural addition such as a new 735 kV line, the Transporter considered, for the purposes of assessing the respective strengths of the solutions considered, the estimated potential needs that match the most probable conditions for development of the network, based on projects with the greatest potential for completion at the time, without losing sight of the fact that needs could evolve differently.

The project is therefore not intended to meet potential needs. The Transmission Provider reiterates in that respect that it cannot be specific about such needs at this point and that they could evolve in a variety of ways, as explained in response to question 2.4 of Information Request #2 from the Régie.[19]

… the Transmission Provider reiterates that it cannot know, except for the projects already recommended or in process at the time of the study, what specific needs will materialize later, in terms of load, production, commissioning and geographic location.[20]

Reading between the lines, a number of intervenors are wondering about the true purpose of the new transmission line; perhaps by postponing the investment it will be easier to match it to the right requestor?[21] [emphasis ours]

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[17] HQT-4, Document 3, page 18.
[18] HQT-4, Document 7, page 4.
[19] R-3887-2014, HQT-6, Document 1, page 19.
[20] R-3887-2014, HQT-3, Document 1, page 7.

UC feels that the Transmission Provider's proposed upgrades policy should make it possible to arrive at a more precise match between the various customers, current and future, benefitting from an investment project. By analogy, taking the context of the network distribution extension, the Distributor's service conditions explicitly provide for such situations in order to repay a customer for a portion of the costs that it paid to extending the network when the line is used by a new customer.[22]

Indeed, in all of the cases in which multiple objectives are pursued on one of the Transmission Provider's investment projects, the allocation of costs to the various project categories and customers runs the risk of being extended to the residual amount that may be allocated to resource projects. For instance, when the Transmission Provider receives concomitant requests from different customers and decides to combine their respective needs to identify a comprehensive technical solution, it assigns the transmission services customers a portion of the costs of the comprehensive technical solution selected based on the chronological sequence of their requests, to a maximum of the amount of the technical solution developed for them initially and up to the full value of the common objective assigned to them.[23]

UC wonders what means there are or will be to ensure that the "chronological sequence of requests" is not and will not be used by the Transmission Provider's main customers, the Distributor and the Generator, to force one or the other to pay a larger share of the investments.

Table 1 illustrates two annual breakdowns or cost-sharing arrangements on one 100 MW project, given a maximum allowance of $500 million. In the first case, the project is totally associated with native load. There is a difference of $45 million that allows the entire $15 million cost of the resource project to be rolled in.

Table 1
Impact of Cost-Sharing by Objectives

	MW	Allowance $/kW	Allowance $M	Cost $M	Difference $M
Share 1 (100%)	100	500	50	5	45
Demand growth project					
Resource project	10			30	
Total demand/resource				15	
Share 2 (50%)	50	500	25	2.5	22.5
Demand growth project					
Resource project	10			30	
Total demand/resource				-7.5	

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21 R-3887-2014,C-A HQ-ARQ-0018, page 7.
22 See Appendix 2.
23 HQT-4, Document 3, page 15.

In the second case, only half of the project is associated with native load. The difference of $22.5 million does not allow the entire cost of the resource project to be rolled in and an additional contribution of $7.5 million would be required from the Distributor.

Since cost-sharing among the Transmission Provider's various customers will have an impact on the amounts available to roll into native load resource projects, UC argues that ultimately, for the years in which significant costs to roll in resource projects will arise for native load, it would be in the Distributor's interest to be allocated a major proportion of the projects that meet the demand from a number of customers and of which the actual costs are below the overall allowance.

In UC's view, the Transmission Provider's current proposal is in this respect illogical and unfair and should be rejected out of hand by the Régie.

1.4 Resource projects and government energy policy

The Transmission Provider's proposal will apply only for the Distributor's upcoming resource projects, except for the projects arising out of the Distributor's three calls for tenders for wind energy, because in the decisions regarding these projects, the Régie has reserved its decisions concerning the calculation of the Distributor's contribution.[24]

Over the timeframe of the Distributor's 2013-2024 supply plan, the resource project transmission network upgrades that will be carried out to serve the native load will consist essentially of wind power projects ordered by the government[25] while the Distributor has an energy surplus.

> The combined effect of decreased requirements and increased supply is a larger energy surplus than anticipated three years ago. The surplus stands at 75.0 TWh for 2014–2023, even after application of the management methods [..][26]

UC has previously questioned the Transmission Provider on this subject:

> When integrating the 450 MW of new wind power projects that are the subject of Order in Council 1149-2013, does the Transmission Provider plan any particular calculation of the "annual aggregation (loads and resources)" given that these wind power projects will not serve the load growth in light of the Distributor's supplies and consequently will not have any "counterpart" that would have led to a double application of the maximum allowance for the same energy transmitted over the system?
>
> See the response to question 5.1 in the Régie's Information Request #1 in exhibit HQT-4, Document 1. In addition, the Transmission Provider reiterates that the installed power

[24] D-2007-141, page 26, D-2011-166, pages 8 and 9, D-2014-045, page 23.
[25] For example, see Orders in Council D-1149-2013 and D-1150-2013 for a call for tenders for an additional 450 MW of wind energy.
[26] R-3864-2013, HQD-1, document 1, page 6.

> of the Distributor's resource projects is used solely for the purpose of establishing the costs that are eligible to be rolled into the aggregation of the Distributor's projects.[27]

The integration of the wind power projects into the Transmission Provider's network is the result of the Québec government's 2006-2015 energy strategy.

> Wind energy development is thus a sound investment in terms of energy, the economy and the environment. The 4,000 MW objective is ambitious but achievable, given Québec's potential and the progress made in production technology. The investments made will benefit the resource regions directly. The priority placed by the Government on wind energy is a concrete illustration of the move towards sustainable development.[28]

Without this Energy Strategy, there would not have been any wind power projects to integrate into the Transmission Provider's network, because they most likely would not have qualified in a supply call for tenders from the Distributor, because they would have been too costly. The Transmission Provider has already underscored the impact of this strategy on the transmission requirements to be met.

> Thus, in the current state of the transmission network, projects intended to integrate even minimal growth entail costly integration solutions whose economic feasibility might be facilitated, depending on the circumstances, through the achievement of economies of scale. In addition, the Transmission Provider must deal with some powerful vectors of change in transmission requirements. One of these is the start of a period of rapid growth in customers' transmission requirements. <u>Another is the growing integration of new renewable energy sources with special characteristics, in particular to meet the targets established by the Québec government in the implementation of its energy strategy, which present the Transmission Provider with some major integration and network management challenges.</u>[29] (footnote omitted; underscore ours)

UC cannot help drawing a parallel between the Transmission Provider's proposal and one aspect of FERC Order No. 1000 concerning the type of treatment that must be given to "public policy" projects.

> In reaching this conclusion, the Commission has balanced competing interests of various segments of the industry and designed a package of reforms that, in our view, will support the development of those transmission facilities identified by each transmission planning region as necessary to satisfy reliability standards, reduce congestion, and <u>allow for consideration of transmission needs driven by public policy requirements established by state or federal laws or regulations</u> (Public Policy Requirements). By "state or federal laws or regulations," we mean enacted statutes (i.e.,

[27] HQT-4, document 7, page 5.

[28] http://www.mern.gouv.qc.ca/english/publications/energy/strategy/energy-strategy-2006-2015.pdf, page 29 (English version consulted January 24, 2015 for this translation).

[29] R-3738-2010, HQT-10, document 3, page 7.

passed by the legislature and signed by the executive) and regulations promulgated by a relevant jurisdiction, whether within a state or at the federal level.[30]

Order No. 1000 opens the door to using different calculation or allocation methods for different kinds of projects.

> The costs must be allocated ―in a manner that is at least roughly commensurate with estimated benefits.‖ The benefits include reliability, production cost savings, congestion relief, and meeting public policy requirements.
>
> Different cost allocation methods can be used for different types of transmission projects. For example, the transmission entity has the option, but not the requirement, to establish different cost allocation mechanisms in their tariff for projects designed for reliability versus projects associated with public policy requirements.[31] (underscore ours)

Although the Régie is not bound by FERC's orders, the implications of Order No. 1000 for cost allocation are interesting in the current context, where the Transmission Provider is eliminating in advance the opportunity for the Distributor's resource projects to take full advantage of the maximum allowance.

UC understands that one of the objectives of FERC Order No. 1000 is to encourage the integration of renewable energy projects. UC also submits that the Transmission Provider's proposal, as regards the integration of the Distributor's government-required resource projects, goes in a direction diametrically opposite to FERC's.

In UC's view, government requirements could be taken into account by an adjustment of the discount rate used to calculate the maximum allowance. For example, the use of a rate lower than the average prospective capital cost rate[32] used by the Transmission Provider for projects resulting from government orders would increase the maximum allowance and make all of the Transmission Provider's customers support the cost of the government policies.

To illustrate this principle, Table 2 shows the impact of a 0.5% decrease in the average prospective capital cost used to calculate the maximum allowance, for cost-recovery timeframes of 20 and 40 years.

[30] Federal Energy Regulatory Commission, Docket No. RM10-23-000; Order No. 1000, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, page 8.

[31] http://www.nera.com/content/dam/nera/publications/archive2/PUBEnergyCommittees0512.pdf (consulted November 13, 2014)

[32] For example, a lower discount rate would assign greater value to the future revenues associated with wind power projects resulting from calls for tenders ordered by the government.

Table 2
Maximum allowance for projects resulting from government requirements (2014)

	Timeframe	
	20 years	**40 years**
Average prospective capital cost - 0.5% (5.166%)	**625**	**819**
Average prospective capital cost (5.666%)	**598**	**772**

If the Régie decides to reject the Transmission Provider's current proposal on the upgrades policy as previously recommended, then UC invites the Régie to include in its decision a provision inspired by FERC Order No. 1000 that would allow, prospectively, the application of a special maximum allowance for native load resource projects associated with a government requirement.

In the next section, UC submits its recommendations in the event that the Régie instead accepts the underlying principle of the Transmission Provider's proposal: rolling the costs of native load resource projects into the aggregation of its network growth and maintenance projects.

2. Methodology for the upgrades policy

2.1 Number of years used to calculate the maximum allowance

The allowance calculated by the Transmission Provider ensures tariff neutrality in light of the additional revenues generated over a period of 20 years. Even if "it should also be noted that native load, which grows gradually over the timeframe factored into the maximum allowance, in fact persists well beyond the 20-year period used to establish this allowance."[33]

> For example, in some circumstances, a 40-year period might seem appropriate, in particular for the native load whose expected presence is long term, or for a point-to-point transmission customer that wanted to sign transmission agreements for long terms (over 20 years). In such cases, the coverage of the costs by the client that requested the upgrade requires that client to have a long-term presence on the network.[34] (underscore ours)

On the basis of a 20-year period applied to ensure tariff neutrality under the applicable transmission tariff, the Transmission Provider estimates that with the upgrades policy that it is proposing with regard to native load resource projects, the Distributor would have an additional contribution estimated at $441.1 million, plus operating and maintenance expenses.[35]

UC has estimated, in a summary fashion and to the best of its knowledge, for each year since 2006, the maximum allowance for the native load specific to the expected growth based on a 40-year period on the basis of the associated financial parameters.[36] Table 3 shows the calculation for the year 2006. The allowance for each of the subsequent years has been calculated in a similar manner.

[33] HQT-1, document 1, page 15
[34] HQT-4, document 1, page 8
[35] HQT-1, document 1, (revised October 31) page 15.
[36] UC has, however, used for the entire period a straight-line amortization of the investment.

Table 3
Calculation of the maximum allowance with a 40-year useful life (year 2006)

Maximum allowance for the year 2006								
Investment ($/kW)						631		
Weighted average prospective capital cost[1]						6.800%		
Annual operations and maintenance[2]						1.100%		
Tax on capital[3]				2005		0.60%		
				2006		0.53%		
				2007		0.49%		
				2008		0.36%		
				2009		0.29%		
Tax on utilities[4]						0.55%		
Number of years						40		
Year	Net assets[4]	Amortiza-tion	Cost of capital	Sub-total	Operations and maintenance	Tax on utilities	Tax on capital	Annual cost
	($)	($)	($)	($)	($)	($)	($)	($/kW)
2005	615	16	43	59	7	3	4	72.90
2006	600	16	42	58	7	3	3	71.21
2007	584	16	41	57	7	3	3	69.73
2008	568	16	40	55	7	3	2	67.74
2009	552	16	39	54	7	3	2	66.12
2010	537	16	38	53	7	3	2	64.92
2011	521	16	36	52	7	3	2	63.71
2012	505	16	35	51	7	3	2	62.50
2013	489	16	34	50	7	3	1	61.30
2014	473	16	33	49	7	3	1	60.09
2015	458	16	32	48	7	3	1	58.89
2016	442	16	31	47	7	3	1	57.68
2017	426	16	30	46	7	2	1	56.48
2018	410	16	29	45	7	2	1	55.27
2019	395	16	28	44	7	2	1	54.06
2020	379	16	27	43	7	2	1	52.86
2021	363	16	26	42	7	2	1	51.65
2022	347	16	25	40	7	2	1	50.45
2023	331	16	24	39	7	2	1	49.24
2024	316	16	23	38	7	2	1	48.04
2025	300	16	21	37	7	2	1	46.83
2026	284	16	20	36	7	2	1	45.63
2027	268	16	19	35	7	2	1	44.42
2028	252	16	18	34	7	1	1	43.21
2029	237	16	17	33	7	1	1	42.01
2030	221	16	16	32	7	1	1	40.80
2031	205	16	15	31	7	1	1	39.60
2032	189	16	14	30	7	1	1	38.39
2033	174	16	13	29	7	1	1	37.19
2034	158	16	12	28	7	1	1	35.98
2035	142	16	11	27	7	1	0	34.77
2036	126	16	10	25	7	1	0	33.57
2037	110	16	9	24	7	1	0	32.36
2038	95	16	8	23	7	1	0	31.16
2039	79	16	6	22	7	1	0	29.95
2040	63	16	5	21	7	0	0	28.75
2041	47	16	4	20	7	0	0	27.54
2042	32	16	3	19	7	0	0	26.34
2043	16	16	2	18	7	0	0	25.13
2044	0	16	1	17	7	0	0	23.92
Present value				631				
[1]Weighted average prospective capital cost as per Decision D-2005-63								
[2] Operating and maintenance expenses estimated at 15% of investment								
[3 and 4] Taxes on utilities and taxes on capital as shown in exhibit HQT-4, document 1 page 38 (R3549-2004)								

Table 6 presents the maximum allowances for the years in the 2006-2014 timeframe.

Table 4
Maximum allowance for 20-year and 40-year periods

	Maximum allowance ($/kW)	
	20 years	40 years (UC estimate)
D-2006-066	560	631
D-2007-008	570	648
D-2008-019	574	653
D-2009-015	622	717
D-2010-032	596	767
D-2011-039	566	725
D-2012-059	571	736
D-2014-035	598	771

Note: UC's estimate takes into account the weighted average prospective capital cost, the transmission tariff and the taxes on capital through 2010 associated with each decision. In addition, the annual operating and maintenance costs are calculated from the weighted average prospective capital cost and the 40-year period to obtain a discounted present value of 15%. For all years, the investment has been amortized on a straight-line basis.

On the basis of these new maximum allowances, the cumulative difference for the Distributor would change from -$444.1 M to +$17 M,[37] plus operating and maintenance expenses.

Because for regulatory purposes, the useful life of transmission facilities can be up to 40 years for substations and up to 50 years for lines,[38] and given that the native load will generate revenues well beyond the 20-year timeframe, UC recommends that the Régie use a 40-year timeframe in calculating the maximum allowance for native load projects.

2.2 Operating and maintenance costs

Under its current upgrades policy, in calculating the maximum allowance that can be granted for an investment project carried out to meet a client's growth needs, the Transmission Provider assumes that operating and maintenance costs will equal 15% of the investment. The Transmission Provider is proposing the *status quo* with regard to this parameter, on the basis of actual costs in 2012.

> For 2012, the operating and maintenance costs are $9.11/kW ($380.2 M / 41,744 MW), which equals 1.6% of capital cost on an annual basis. The data used to illustrate this percentage are the direct operating and maintenance costs and total forecast transmission demand. Calculated from present value over 20 years using a [weighted average prospective capital cost] of 5.698% for 2012, these costs equal 19% of the

[37] Difference between the figure of $272 M calculated in Appendix 1 and the projected amounts of $289.4 M shown in Docket R-3823-2012, Exhibit HQT-12, document 2, page 13 for 2013 and 2014. As indicated in Appendix 1, the cumulative difference is the result of a simplified calculation.
[38] HQT-3, document 1, page 10.

capital cost. Consequently, the Transmission Provider proposes holding the rate for operating and maintenance costs at 15% of capital cost.[39]

But UC submits that the operating and maintenance costs actually incurred for aging facilities cannot be compared with the future costs for a new facility. The fact is that the Transmission Provider's aging network requires substantial, recurring maintenance work.

> This is what I was trying to describe a moment ago, by showing the trend for 2015 and subsequent years in terms either of investments or of the maintenance that is going to be done because the network is aging. Now we know that there is going to be pressure on the loads because of aging, as well as because of the ongoing activities that are going to be carried out.[40] (underscore ours)

However, the Transmission Provider indicates that it is trying to improve its asset-management methods, as it has stated in its current tariff application.

> If the forecasts for the years 2014 and 2015 prove accurate, the Transmission Provider will have realized recurrent cumulative net operating expense gains of $120.4 M, which will have allowed it to limit the growth in these expenses by about 14% since 2008. At the end of major changes since 2012, the gains covering the 2013-2015 timeframe of the present application total $27.5 M in a complex, demanding operational context that involves major appropriation challenges. This performance reflects an active management of the Transmission Provider's work force and its business practices.[41] (underscore ours)
>
> The asset management strategy anticipates increasing aging of the network and an increased risk of equipment breakdowns. The success of this strategy will depend on controlling the risks associated with this increase, which will result in an increase in maintenance time and costs, placing additional pressure on the Transmission Provider's net operating expenses. Once the implementation challenges have been met, any gain in productivity resulting from the organization of the Transmission Provider's activities will enable it to carry out a growing number of systematic, conditional, corrective and targeted maintenance operations.[42] (underscore ours)

In other words, UC submits that when it comes to operating and maintenance expenses, the past is no guarantee of the future.

To illustrate this point, UC has calculated what the maximum allowances would have been since 2006 if operating and maintenance costs had been estimated at 10% of capital costs.[43] Table 5 shows the calculation for 2006. The allowance for each of the subsequent years was calculated in a similar fashion.

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[39] HQT-3, document 1, pages 10 and 11.
[40] R-3903-2014, NS of November 24, 2014, page 72
[41] R-3903-2014, HQT-3, document 3, pages 7 and 8.
[42] R-3903-2014, HQT-3, document 1, page 16.
[43] The figure of 10% was chosen solely to provide a scenario that contrasts with the current situation.

Table 5

Calculation of the maximum allowance using an operating and maintenance cost of 10% with a useful life of 40 years (year 2006)

Maximum allowance for the year 2006								
Investment ($/kW)						652		
Weighted average prospective capital cost[1]						6.800%		
Annual operations and maintenance[2]						0.73%		
Tax on capital[3]				2005		0.60%		
				2006		0.53%		
				2007		0.49%		
				2008		0.36%		
				2009		0.29%		
Tax on utilities[4]						0.55%		
Number of years						40		
Year	Net assets[4] ($)	Amortiza-tion ($)	Cost of capital ($)	Sub-total ($)	Operations and maintenance ($)	Tax on utilities ($)	Tax on capital ($)	Annual cost ($/kW)
2005	636	16	44	61	5	4	4	72.90
2006	619	16	43	60	5	3	3	71.16
2007	603	16	42	58	5	3	3	69.63
2008	587	16	41	57	5	3	2	67.57
2009	570	16	40	56	5	3	2	65.90
2010	554	16	39	55	5	3	2	64.65
2011	538	16	38	54	5	3	2	63.41
2012	522	16	37	53	5	3	2	62.16
2013	505	16	35	52	5	3	2	60.92
2014	489	16	34	51	5	3	1	59.67
2015	473	16	33	50	5	3	1	58.43
2016	456	16	32	48	5	3	1	57.18
2017	440	16	31	47	5	3	1	55.94
2018	424	16	30	46	5	2	1	54.69
2019	407	16	29	45	5	2	1	53.45
2020	391	16	28	44	5	2	1	52.20
2021	375	16	27	43	5	2	1	50.96
2022	359	16	25	42	5	2	1	49.71
2023	342	16	24	41	5	2	1	48.47
2024	326	16	23	40	5	2	1	47.22
2025	310	16	22	38	5	2	1	45.98
2026	293	16	21	37	5	2	1	44.73
2027	277	16	20	36	5	2	1	43.49
2028	261	16	19	35	5	2	1	42.24
2029	244	16	18	34	5	1	1	41.00
2030	228	16	17	33	5	1	1	39.75
2031	212	16	16	32	5	1	1	38.51
2032	196	16	14	31	5	1	1	37.26
2033	179	16	13	30	5	1	1	36.02
2034	163	16	12	28	5	1	1	34.77
2035	147	16	11	27	5	1	0	33.53
2036	130	16	10	26	5	1	0	32.28
2037	114	16	9	25	5	1	0	31.04
2038	98	16	8	24	5	1	0	29.79
2039	81	16	7	23	5	1	0	28.54
2040	65	16	6	22	5	0	0	27.30
2041	49	16	4	21	5	0	0	26.05
2042	33	16	3	20	5	0	0	24.81
2043	16	16	2	19	5	0	0	23.56
2044	0	16	1	17	5	0	0	22.32
Present value				652				
[1]Weighted average prospective capital cost as per Decision D-2005-63								
[2] Operating and maintenance expenses estimated at 10% of investment								
3 and 4 Taxes on utilities and taxes on capital as shown in exhibit HQT-4. document 1 page 38 (R3549-2004)								

Table 6 presents the maximum allowances thus calculated for the years in the 2006-2014 timeframe.

Table 6

Maximum allowance according to the percentage of capital cost used to estimate operating and maintenance costs (40-year period)

	Maximum allowance ($/kW)	
	Operations and maintenance 15%	Operations and maintenance 10%
2006	631	652
2007	648	669
2008	653	675
2009	717	741
2010	767	793
2011	725	750
2012	736	762
2014	771	798

Note: UC's estimate takes into account the weighted average prospective capital cost, the transmission tariff and the taxes on capital through 2010 associated with each decision. In addition, the annual operating and maintenance costs are calculated from the weighted average prospective capital cost and the 40-year period to obtain a discounted present value of 15% or 10%, as the case may be.

In addition, on the basis of these new maximum allowances, the cumulative difference for the Distributor over 40 years would change from a positive figure of $17 M to a positive figure of $98 M.[44]

If the Régie decides to approve the network upgrades policy proposed by the Transmission Provider, which harshly penalizes the native load, then UC recommends that at the very least, it use a 40-year timeframe and an operating and maintenance cost of less than 15% in calculating the maximum allowance for native load projects.

In UC's view, this approach would at least have the merit of attenuating the impact of the proposed upgrades policy for native load resource projects in light of the exceptionally unfavourable treatment that the native load receives, compared with the way that native loads are treated elsewhere in North America.

[44] Difference between the estimated amount of $191 M shown in Appendix 3 and the projected amounts of $289.4 M shown in Docket R-3823-2012, Exhibit HQT-12, document 2, page 13 for 2013 and 2014. As indicated in Appendix 3, the cumulative difference is the result of a simplified calculation.

Appendix 1: Estimate of the Distributor's required contribution (40-year timeframe)

Year	2006	2007	2008	2009	2010	2011	2012	2013	2014
Total growth over 40 years, in MW - Loads	865	106	369	460	429	229	230	551	190
HQT maximum allowance in $M - Loads	546	69	241	330	329	166	169	406	147
Total HQT investment in $M - Loads	143	58	140	173	170	126	105	296	389
Total HQT investment in $M - Resources	26	18	62	122	22	214	210	231	169
Annual difference	377	-7	39	35	137	-174	-146	-121	-411
Cumulative difference	377	370	409	444	581	407	261	140	-272

The estimate of HQT's maximum allowance in millions of dollars for each year has been calculated by taking the update of the additional megawatts for each year that appears in Appendix 1 of HQT-1, document 1 and multiplying it by the 40-year maximum allowance calculated by UC and presented in Table 4. For example, for 2006, the maximum allowance is:

864.7 MW * $631/kW = $546.

This is a simplified estimate, but it can nevertheless be regarded as a good order of magnitude.

UC's calculation cannot take into account, for example, the details provided by the Distributor on the annual assessments:

> For the load growth, the aggregation pertains to the determinations of the contribution required from the Distributor, which were filed with the rate applications addressed in the Régie's decisions. For satellite substation projects, the Transmission Provider applies the maximum allowance in effect in the year of commissioning, <u>which is the year in which the project is included in the aggregation</u>. The Transmission Provider also notes that for the projects done to supply load for Distributor customers connected directly to the system, it applies the maximum allowance in effect <u>when the internal connection agreement is executed</u> with the Distributor.
>
> If load for a Distributor customer is requested for a period of less than 20 years, the Transmission Provider applies an allowance lower than the maximum allowance, as set out in section E of Attachment J to HQT's OATT.
>
> With respect to the integration of wind farms within the transmission system, the portion of costs of projects that may be included in the project aggregation, and which thus may potentially be covered by the maximum amounts for satellite substations and customers connected directly to the system, is determined based on the maximum allowance that was in effect in HQT's OATT as of the date of execution of the administrative agreement with the Distributor, as the Régie wishes.[45] (underscore ours)

[45] HQT-4, document 3, page 12.

Appendix 2: Refund of Contribution in Case of Additions or Joint Use

DIVISION 5 – REFUND OF CONTRIBUTION IN CASE OF ADDITIONS OR JOINT USE

Conditions for refund

16.12 For the five (5) years following the date on which the contribution agreement is signed, connection of a new permanent electrical installation to the portion of the power line for which the applicant has paid a contribution gives rise to a refund determined on the basis of the amount allocated in respect of the use that is to be made of the new installation in accordance with the Electricity Rates in force on the date of connection of the addition. Such amount is paid to the applicant during the period of five (5) years, if he so requests, or at the end of the period of five (5) years.

The allowed amount for non-domestic use or for a farm is determined on the basis of the estimated annual average billing demand for the new installation, expressed in kW, multiplied by the *"amount allocated for non-domestic use"* established in the Electricity Rates.

Refund for additions requiring power line extension

16.13 Refunds are reduced by the cost of any extension of the power line required to supply electricity to the electrical installation that is added.

Refunds are applied first to the applicant who paid for the extension or modification of the portion of the power line where the new installation is connected. If the contribution paid by such applicant has been refunded in full, the balance refundable is applied to the applicant who paid for the portion immediately prior to that section. This rule applies until any balance refundable has been exhausted.

Joint-use credit

16.14 The applicant is entitled to an adjustment of the amount of his contribution if, at the time of the initial installation or during the term of his contribution agreement, the Hydro-Québec poles that were included in the cost of work are used by an enterprise with which Hydro-Québec shares the cost and ownership of the poles. Such adjustment is based

(1) on the *"joint-use credit"* established in the Electricity Rates where the cost of work is calculated from per-metre prices; or

(2) in other cases, on the amount estimated by Hydro-Québec.

The total amount of the credit may not exceed the balance of the refundable contribution paid by the applicant.

Conditions of Electricity Service, Effective April 1, 2014 and approved by the Régie de l'énergie in Decision D -2014-052.

Appendix 3: Estimate of the Distributor's required contribution (40-year timeframe and operating expenses at 10%)

Year	2006	2007	2008	2009	2010	2011	2012	2013	2014
Total growth over 40 years, in MW - Loads	865	106	369	460	429	229	230	551	190
HQT maximum allowance in $M - Loads	564	71	249	341	340	172	175	420	152
Total HQT investment in $M - Loads	143	58	140	173	170	126	105	296	389
Total HQT investment in $M - Resources	26	18	62	122	22	214	210	231	169
Annual difference	395	-5	47	46	148	-168	-140	-107	-406
Cumulative difference	395	390	437	483	631	463	323	215	-191

The estimate of HQT's maximum allowance in millions of dollars for each year has been calculated by taking the update of the additional megawatts for each year that appears in Appendix 1 of HQT-1, document 1 and multiplying it by the 40-year maximum allowance calculated by UC and presented in Table 3. For example, for 2006, the maximum allowance is:

864.7 MW * $652/kW = $564.

This is a simplified estimate, but it can nevertheless be regarded as a good order of magnitude.

> For the load growth, the aggregation pertains to the determinations of the contribution required from the Distributor, which were filed with the rate applications addressed in the Régie's decisions. For satellite substation projects, the Transmission Provider applies the maximum allowance in effect in the year of commissioning, which is the year in which the project is included in the aggregation. The Transmission Provider also notes that for the projects done to supply load for Distributor customers connected directly to the system, it applies the maximum allowance in effect when the internal connection agreement is executed with the Distributor.
>
> If load for a Distributor customer is requested for a period of less than 20 years, the Transmission Provider applies an allowance lower than the maximum allowance, as set out in section E of Attachment J to HQT's OATT.
>
> With respect to the integration of wind farms within the transmission system, the portion of costs of projects that may be included in the project aggregation, and which thus may potentially be covered by the maximum amounts for satellite substations and customers connected directly to the system, is determined based on the maximum allowance that was in effect in HQT's OATT as of the date of execution of the administrative agreement with the Distributor, as the Régie wishes.[46] (underscore ours)

[46] HQT-4, document 3, page 12.