BC hydro
FOR GENERATIONS

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Via email: scott.barillaro@gov.bc.ca

April 19, 2013

Mr. W. S. Barillaro, B.A, B.Mus, MPA
Director, Transmission and Industrial Electricity Policy
Electricity Policy
Ministry of Energy, Mines and Natural Gas
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Victoria, BC V8T 4J1

Dear Mr. Barillaro:

RE: Industrial Electricity Policy Review

BC Hydro writes to enclose its response to participant comment papers as part of the Industrial Electricity Policy Review.

Yours sincerely,

Janet Fraser
Chief Regulatory Officer

mb/ma

Enclosure (1)

Industrial Electricity Policy Review

BC Hydro Response to Participant Comment Papers

Industrial Electricity Policy Review Task Force

April 19, 2013

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Introduction

BC Hydro writes to provide its comments on submissions made to the Task Force by other participants in the Industrial Electricity Policy Review. Those comments were dated on or about March 28, 2013.

BC Hydro's comments will follow the same general structure as our initial comments. That is, Part I will provide umbrella comments dealing with the Task Force's Terms of Reference (**ToR**) and, by extension, the nature of its review and the scope of recommendations it can most usefully provide to the Province.

Part II of this submission will deal with the matters directly raised by the initial Task Force Issue Papers and, in turn, responded to by the various participants. BC Hydro has not organized its comments to speak directly to submissions of the individual participants. This reflects two considerations: (1) our belief that many of the responses delve into matters well beyond the scope of the ToR; and (2) where comments were within the scope of the review, many were encouraging the Task Force to engage in the detail of rate or program design. BC Hydro believes that such work can only be effectively explored within a formal and evidence-led regulatory process.

Part I - Role of the Task Force

There are a number of important issues before the Task Force. Some of those issues have prompted fundamental – but quite clear – differences between commenters. Other matters that were raised as potential questions by the Task Force Issue Papers adduced a strong consistency of views. The Task Force has a firm foundation from the comments now before it and from its ToR, to provide its own perspectives on critical issues within existing or proposed programs and rates. In particular, the Task Force's perspectives are clearly being sought on matters such as the possible gaming that arises from an all-or-nothing line between large and small customers in Tariff Supplement No. 6 (**TS No. 6**) and the appropriate principles surrounding retail access.

As BC Hydro described in its initial comments, the Task Force is being asked by the Province for a menu of regulatory alternatives that will inform it about the trade-offs and implications of various policy alternatives. In particular, the recommendations of the Task Force will inform the Province about which actions it might prefer, depending upon which of the three key objectives set out in the ToR (conservation, economic development, and current environmental policy) the Province decides is paramount.

Notwithstanding the importance of the recommendations being sought from the Task Force, BC Hydro does not understand that the Province has asked the Task Force to rank its policy objectives. Moreover, BC Hydro does not understand that the Task Force has been asked to replace the regulatory process by actually designing and setting rates however much the comments of some participants seem to be urging that role on the Task Force.

BC Hydro makes these observations because it believes that there are significant risks and pitfalls associated with engaging in rate and program design work in the absence of a full evidentiary record subject to cross-examination in a public process with broad representation of affected interests. In regard to the latter point, BC Hydro notes the complete absence of participation by representatives of residential customers and the participation of only one representative of commercial customers. Given that decreased revenues from one class of customers must be made up by increased revenues from others, and the challenges in designing rates that are truly revenue neutral, it is particularly important to avoid narrowly-focused recommendations whose impacts on other customer classes may not be readily apparent.

The breadth of comments received by the Task Force demonstrate two important things: (1) that there is a wide range of opinion on the matters in question, covering a broad spectrum of possible outcomes; and (2) the Task Force has been presented with these ideas without the benefit of any real evidence, and with no process from which to adduce any evidence or to test it.

In short, the Task Force cannot possibly know if the proposed ideas will work for their intended purpose – even if it were within the Task Force's mandate to determine what the governing purpose of BC Hydro's rates and programs should be. Moreover, the Task Force will have had little opportunity to explore and evaluate the enormous potential for unintended consequences that can accompany many of the matters under consideration here.

As such, even if the Task Force felt that its mandate did allow it to set about designing rates and programs as other commenters have urged, the sheer impracticality of undertaking that exercise without the full benefit of evidence and critical examination should remind the Task Force to: (1) show dereference to the role of the Heritage Contract framework in cementing the high-level allocation decisions; and (2) acknowledge the substantive and procedural expertise of the BCUC in its traditional role of setting rates. For reference, BC Hydro set out in detail in its initial comments important context on both the existing regulatory structure and on the Heritage Contract Inquiry.

In order to better understand the range of alternative approaches to the key issues under examination in this review, BC Hydro has prepared an inter-jurisdictional review, which appears as Appendix A to these comments. BC Hydro's survey considers how a number of Canadian and US jurisdictions have dealt with large load interconnections and retail access policies. Examination of Appendix A reveals two important points: (1) there is no one-size-fits-all approach to these issues, and each jurisdiction tailors its approach to suit its specific objectives and circumstances; and (2) a high-level review raises as many questions as it answers – reinforcing why a careful evidence-based process must underpin any decision-making.

An example is useful here. Within its comments, the Association of Major Power Customers (**AMPC**) expresses frustration that BC Hydro has suspended its Retail Access Program (**RAP**) and calls for a new pilot to be instituted as soon as possible. In saying this, AMPC acknowledges the need for rules governing the "terms on which customers may depart from, or return to, embedded cost service." AMPC cites Oregon as an example that such an approach is viable.

AMPC is fair and correct to advise taking a close look at Oregon. Morgan Stanley Capital Group also suggests that Oregon's adoption of retail access provides a model for B.C. An examination shows that the Portland General Electric (Portland) retail access program, for example, contains exactly the sorts of protections that BC Hydro was worried were absent from its program. Specifically, the Portland RAP features a "transition adjustment" that charges (or credits) customers for the difference between the regulated utility rate and the forecast value of "freed up" energy from customers choosing retail access.

Examining these critical features is possible in a detailed regulatory process. It is not possible in a process where letters and comments stand effectively uncontested, each as credible as the next. The limited examination of submissions that characterizes this inquiry should be carefully borne in mind as the Task Force formulates its recommendations.

The foregoing commentary is not meant to detract from the importance of and the challenges inherent in the Task Force's responsibilities. Clearly and transparently identifying the trade-offs between potentially conflicting Provincial policy objectives is a challenging exercise; clearly and transparently identifying the changes that might be required to advance one or more of those objectives is technically challenging. Meeting these responsibilities will require the Task Force to look at the overall regulatory framework and policy objectives, as opposed to looking at specific rate design and program proposals.

Part II - Specific Issues

Extension Policies

Several commenters raise the importance of a consistent and predictable extension policy. Several commenters also note that such extension rules should capture the full financial obligation of the new customer, including both generation and transmission. BC Hydro agrees with these points, and also makes the following observations.

The BC Hydro system is characterized by two features that are relatively unusual (although not unique):

- First, as a large province with relatively long radial lines, attaching new loads can trigger very significant costs even before the customer reaches the BC Hydro system. In addition, even the first point of interconnection with the BC Hydro system can be remote and radial, adding to System Reinforcement costs. Simply, there is more potential for very large incremental costs when a new customer connects to B.C.'s radial system than when a similar customer hooks up to a tightly looped grid in, for example, the U.S. northeast.
- Second, BC Hydro's embedded cost of generation is well below the long-term marginal cost of new supply. So all new customers (residential, commercial, and those taking service at transmission voltage) impose generation-related costs on existing customers in a way that new customers would not in jurisdictions where the average and marginal costs of generation are similar, or where the price relationship is the reverse of BC Hydro's.

These features make it relatively unsurprising that BC Hydro's extension policy for new industrial loads varies in some important way from those in some other jurisdictions, for example by including generation costs for large new loads.

Certainly the second point, above, argues strongly against AMPC's assertion that generation costs "are not relevant to a contribution policy unless that generation is local and can economically substitute for more expensive transmission additions." Clearly, very large customers could appropriate hundreds of millions of dollars per year of system value if they held no responsibility for paying the marginal cost of new generation that they trigger. BC Hydro believes that, at some load size, no single customer should be able to diminish B.C.'s competitiveness by imposing such a large rate impact on other customers.

This observation raises another subject that was common in many of the submissions: the 150 MVA threshold. In particular, many comments focused on the fact that it was both arbitrary and subject to gaming.

As noted in its initial comments, BC Hydro supports some distinction between large and smaller customers, and generally supports the notion in TS No. 6 that the substance of such distinction should be responsibility for generation and bulk transmission upgrades. Nevertheless, BC Hydro has said that it supports investigation into the 150 MVA threshold level.

BC Hydro notes that some commenters suggested abandoning the 150 MVA cut off altogether. This, of course, would have an even greater effect (because it would exclude both bulk transmission and generation costs) than AMPC's suggestion of failing to consider any generation costs in the extension policy. As such, the proposal to abandon the threshold is flawed for the same reasons.

Other commenters, such as Canadian Association of Petroleum Producers (**CAPP**), suggest that if the threshold is intended to protect ratepayers from the cost of very large new customers, then the threshold should be abandoned, and payments for new generation should be mandated by Government on an exception-basis. While attractive at some level, the Task Force should think carefully about the impact that such an approach would have on investment transparency and fairness.

Some commenters, such as Clean Energy B.C. (**CEBC**) go so far as to suggest a full rolling-in approach for all new generation and transmission costs (with even the suggestion of a volume discount for very large customers). BC Hydro believes that such an extraordinary approach would certainly fail to balance the fundamental objective of keeping B.C.'s electricity rates competitive and at a level that is viable for existing customers.

This question of balance is critical. BC Hydro understands the desire of CEBC (and others) to see a strong and continued commitment to clean energy mandates. BC Hydro shares those objectives. However, the cost challenges of committing to significant clean energy development, with the attendant effects on B.C.'s economic competiveness, should not be minimized. BC Hydro believes strongly, and many commenters agreed, that it is critical for B.C. to remain a low-cost jurisdiction for electricity. BC Hydro suggests that the Task Force should retain a keen focus on costs as it develops its recommendations.

The matter of gaming is also worth further discussion. A certain amount of gaming is inevitable whenever there is a threshold in a tariff or program, and (to some extent), it is simply a cost that must be balanced against the value of having the threshold itself. However, this does not mean that the gaming cannot be mitigated.

One reason why the gaming risk is so troubling in respect of TS No. 6 is that the consequence of being slightly over the 150 MVA threshold is so profound. In fact, the cost consequence of being over the threshold has caused the cancellation of several proposed projects that BC Hydro is aware of. BC Hydro urges the Task Force to explore ways to introduce more graduated impacts around the threshold level, and have it act as less of a cliff. Notions of paying for the advancement costs of generation rather than the full cost may be worth considering.

As a final observation on extension policies, BC Hydro notes that AMPC has suggested abandoning the existing extension policies, and using its supplied "step-by-step" development guide to create a new one. FortisBC also appears to suggest a quite specific amendment to the nature of the revenue test employed by TS No. 6.

BC Hydro urges the Task Force to consider these ideas as illustrations of the dangers that arise from contemplating detailed solutions without evidentiary discipline. For example, the breadth and depth of issues surrounding a sound extension policy are not raised in AMPC's discussion of its suggested model.

The Task Force should, in BC Hydro's view, recommend that the legislative framework regarding TS No. 6 – specifically, the restrictions on its modification contained in Heritage Contract Special Direction #2 – be altered sufficiently such that the BCUC, in a normal rate-making process can: (1) establish a new threshold or framework to delineate smaller customers from very large ones; and (2) make changes to the tariff respecting the allocation of costs between new and existing ratepayers. The Task Force can suggest, as well, how the Province may wish to guide or direct the BCUC's work in furtherance of Government's policy preferences related to economic development, conservation, and existing environmental policies.

Retail Access Program (RAP)

BC Hydro's initial submission to the Task Force made two substantial points about retail access. First, it is essential that any RAP be designed around a "No Harm" principle that protects non-participating customers. Second, BC Hydro stated its belief that it would likely be infeasible to design a RAP that maintained a No Harm principle while still delivering material value to participating customers.

In BC Hydro's view, no other commenters provided a comprehensive perspective on the issue. The sole opponent of reintroducing retail access – The B.C. Sustainable Energy Association – seemed to argue against a RAP on the basis that departing customers would be crowding out BC Hydro's access to low cost power. This concern alone should not be determinative, and is provided without evidence of this effect actually occurring.

On the other side of the issue, the remaining commenters (who were universally in favour of retail access) focused on the potential benefit to participants. There is very little acknowledgment even of the potential for harm to other ratepayers, let alone any attempt to quantify or justify the damage.

Proponents of retail access also failed to focus on environmental concerns in their responses. As BC Hydro emphasized in its initial comments:(1) environmental policies that are applied selectively (to BC Hydro only) or inconsistently (across competing jurisdictions) provide additional incentives for retail access; (2) retail access allows the costs of environmental policies to be avoided for some consumers, undermining the environmental policies and imposing costs on other consumers; and (3) it is likely to be very challenging to write rules to prevent customers from circumventing these costs.

These concerns arise particularly with environmental policies that impact resource choice at the margin (such as the clean energy target and the carbon tax).

To be fair, AMPC does focus somewhat on the protection of remaining customers (though not environmental bypass), but then concludes that a pilot program is a suitable answer to the issue. AMPC does not explain the questions the pilot is intended to inform, leaving instead the impression that the purpose is to mitigate or reduce harm by constraining participation volumes. But the No Harm principle should mean what it says. Ratepayers should not be asked to accept some harm so that select industrial customers can appropriate some value for the period of the pilot particularly when, as noted earlier, the majority of those ratepayers are not represented in this review.

As there were no comments in this review process from parties representing commercial or residential ratepayers, the best stand in for their views is the concern expressed by BC Hydro: that in BC Hydro's current circumstances it can imagine no program that would meet the needs of participants and would also protect non-participants.

With the record of comments before it, BC Hydro respectfully submits that the Task Force should not recommend reinstating BC Hydro's previous RAP, nor should it attempt to design a new one in this process, as there simply is insufficient evidence before us to support those actions.

The Task Force should be especially wary of arguments that it is only being asked to do what is already being done elsewhere. As raised earlier, and as shown in Appendix A, the programs that AMPC and others are pointing to have important protections within them, and exist in jurisdictions with different cost, supply, and demand profiles than exist in B.C.

BC Hydro urges the Task Force to conclude that retail access is not appropriate for B.C. at this time, and to recommend that Government should cause the cancelation of the suspended program without replacement. Failing that, the Task Force should recommend an evidentiary process, informed by one or more of the Provincial policy objectives, where important principles and program design elements can be carefully canvassed with the broader participation of all affected customer classes.

Transmission Stepped Rates (TSR)

BC Hydro's initial comments on the TSR were that the rate reflected a careful balance of objectives derived through the initial Stepped Rate Inquiry and through an ongoing program of BCUC-approved improvements. BC Hydro suggested that the Task Force may wish to comment on the policy implications of the current TSR vis-à-vis the three policy objectives in the ToR, but that the Task Force should resist any temptation to begin redesigning the rate itself.

This perspective was largely echoed by the other commenters. Where suggestions for change were raised, they mostly had to do with modifications designed to improve the strength of the rate in achieving one of the objectives over another. For example, Catalyst Paper made the observation that a high Tier 2 rate was a disincentive for restarting idle equipment. CAPP observed that infrequently adjusted CBLs imposed a cost on load growth by oil and gas producers. CAPP also agreed that Tier 1 could not go too low without triggering gaming. BCSEA provided a non-specific concern that the TSR's conservation effect was too weak or, at least, hard to demonstrate.

Another common theme among commenters was that none of these issues warranted a fundamental reworking of the rate design. Instead, all seemed to favour a continuation of the regulatory work that had improved the rate so far, with an effort to improve it further. This work, commenters urge, should be the job of the BCUC. Indeed it is in front of the BCUC where the more detailed rate amendments proposed by FortisBC should be considered.

Implicit in the comments, though, was a trade-off between conservation and economic activity. While it is clear that it is B.C.'s low overall rate structure (and, generally attractive extension policies) that draw new industry to the province and keep existing industry here, the marginal behaviour of those firms (investing in growth, investing in conservation, or just shrinking production) is affected by the marginal price signals in the TSR.

BC Hydro urges the Task Force to think about both the theory of how those marginal price signals in the TSR affect economic growth and conservation, and the actual behaviour of real firms (which make decisions at the margin based on their real price elasticities, not the conceptual and aggregate shape of a notional demand curve). This should provide the Province with a useful menu of options concerning how Government may wish to amend the TSR if it favours one policy outcome over another.

The Task Force should recommend to Government that, if necessary, the BCUC be instructed to undertake a narrow and focused review of the TSR to accomplish specific objectives that the Government may select based from the Task Force's advice.

Postage Stamp Rates

BC Hydro's initial submission urged the Task Force not to tamper with the established principle of using postage stamp rates. All other commenters communicated the same perspective in their responses.

In light of this, the Task Force may wish to urge the Province to embed the postage stamp rate approach with greater clarity than currently exists, likely by directing the BCUC not to accept rate complaints, or otherwise initiate processes that seek to vary from the postage stamp regime. This could usefully prevent the BCUC from being drawn into an unhelpful and expensive proceeding on this matter at some future date.

End-Use Rates

BC Hydro's initial comments on end-use rates noted that they can be an effective policy tool, but that they must be applied in a manner consistent with legal and rate-making constraints. In particular, BC Hydro stated that end-use rates that are not consistent with the *Utilities Commission Act* (**UCA**) and accepted rate design criteria (Bonbright), and which by implication are intended to serve policy objectives beyond the scope of the BCUC's jurisdiction, should continue to be the subject of Government direction.

BCSEA appeared to agree with these remarks, allowing that there is some room for policy-driven end-use rates in certain (undefined) circumstances. CEBC also left room for this view, although they were not specific as to how and when such rates should emerge.

Other commenters were more absolute, rejecting end-use rates which effected a cross-subsidy by diverging from a cost-of-service foundation (AMPC effectively defined end-use rates this way, declining to refer to rates that collect their full cost of service as "end-use" rates).

These comments were instructive in both the narrow and general cases. Commenters clearly endorse preserving cost-based rates and leaving these rates in the jurisdiction of the BCUC. Some commenters, including BC Hydro, contemplated the existence of rates that were not consistent with the UCA and Bonbright, and suggested that those rates should always emerge from Government.

BC Hydro urges the Task Force to reinforce this bifurcated rate-making model in its recommendations to Government. That is, the Task Force should advise Government to retain the existing legal and regulatory framework that: (1) prevents the BCUC from adopting end-use rates that do not collect their cost of service or do not conform to prescribed rate setting standards; and (2) preserve avenues, such as section 3 of the UCA, for Government to instruct that such rates be created to support public policy. The Task Force may also wish to seek input on principles to govern when it might be appropriate for Government to make such directions.

BC hydro

Industrial Electricity Policy Review
BC Hydro Response to Participant Comment Papers
Industrial Electricity Policy Review Task Force

Appendix A

Large Load Interconnection and Retail Access Policies - March 29, 2013

Large Load Interconnection and Retail Access Policies

March 29, 2013

Energy+Environmental Economics

Large Load Interconnection and Retail Access Policies

March 29, 2013

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1. Large Load Interconnection Policies

Cost allocation policies deal with large load interconnections were surveyed in twelve jurisdictions. From this survey, three basic categories of cost allocation policies were identified. First, large load interconnections costs, even for direct assignment facilities, can be included in the general rate base and recovered through system transmission charges. This is the policy in ERCOT, which does not impose any direct costs on interconnecting load customers. Second, interconnection costs may be distributed through revenue tests or cost allocation formulas which seek to keep other customers financially whole. Alberta, Ontario, New Brunswick, and Quebec use a revenue test or investment formula to cap the value of interconnection costs that enter the rate base, leaving the interconnecting customer responsible for the remainder. Third, interconnection costs may be assessed solely to the interconnecting customer, net of a free-footage allowance or limited financial cap. This puts a hard cap on the inclusion of load interconnection costs in the transmission rate base, which is the policy in Nova Scotia and California. Finally, in Saskatchewan, customers are assessed the costs for interconnection on a per-kilometer basis and cost incremental to this charge are added to system rate base.

Table 1 Large Load Cost Allocation

Jurisdiction	Cost allocation between		Sources
	Requesting party	System Rate Base	
Alberta	Requesting load customer pays for any cost beyond standard facility cost allowance as calculated by investment formula, plus any cost for optional facilities beyond one line and one transformer. Costs are assessed through transmission rates.	Cost for one line and one transformer enter the rate base, up to standard facility cost allowance calculated using investment formula.	2011 AESO Tariff

BC Hydro	Direct assignment costs are the responsibility of the connecting load. Contributions towards network upgrades are calculated through a utility net revenue test.	Contributions towards network upgrades are calculated through a utility net revenue test.	Personal communication
Bonneville Power Administration (BPA)	If line is to single load customer, full cost for sole use interconnection facilities is directly assigned to load customer. If a line is needed to connect the transmission system to two large load customers, the line is considered a network facility, and the customers either pay nothing (if Network Integration Customers of BPA), or the customers provide the upfront investment for the facilities but are reimbursed with transmission service credits.	If the line serves a single large load customer, none of the cost enters the transmission rate base. If a new line will serve two or more large load customers, the line will be considered a network facility, and will charged to the rate base up front (if the load customers take Network Integration service from BPA) or be paid for by the rate base as the load customer's initial payment is reimburse through bill credits (if the load customers take Point-to-point service).	**Line and Load Interconnection Procedures** Personal communication
California	Customer is considered retail load and is subject to Utility Distribution Company tariff even if connecting at the transmission level. Under these tariffs, customer pays all interconnection costs beyond a "free footage" allowance identified in utility's tariff.	The Utility Distribution Company connecting the customer provides a "free footage" allowance identified in retail load tariff. The cost of network upgrades is paid through transmission access charges assessed through the CAISO, not individual utility rates. Transmission access charges are based on transmission owner revenue requirements.	Personal communication
Manitoba	Allocation is less clear cut for large loads than for generators. Typically, a portion but not all of the costs are directly assigned to requesting party.	A portion of interconnection costs for large loads are typically added to rate base and recovered through general rates. If the total interconnection cost is small, the transmission owner may roll-in the full cost in the rate base.	Personal communication
Midwest ISO	MISO does not oversee cost allocation for loads. Instead these determinations are handled between the individual transmission owner and	MISO does not oversee cost allocation for loads. Instead these determinations are handled between the individual transmission owner	

	the requesting load customer.	and the requesting load customer.	
New Brunswick	Load customers on an OATT tariff pay for interconnection costs in excess of incremental revenues transmission owner will receive from customer's added transmission service usage.	Revenue test is used to allocate all load interconnection cost to rate base for load customers on OATT tariff. Costs up to the incremental revenues from the additional load will enter the rate base.	**NBSO OATT Attachment K**
Nova Scotia	For a customer connected at a transmission voltage, the full cost for sole use interconnection facilities is directly assigned to requesting load.	None of the costs for sole use interconnection facilities enters the rate base.	Personal communication
Ontario	New customers connecting to the IESO grid may design, construct, pay for, and own new transmission connection facilities or opt for a pool-funded option. If a customer opts for pool funding, the customer is responsible for a customer contribution that keeps the pool harmless. The cost is calculated as the present value of projected capital costs and on-going maintenance and the present value of the projected incremental revenue for transmission services. The project costs shall include, in addition to direct assignment facilities, network facility advancement costs of replacing existing transmission system elements before the end of their useful life and incremental costs of upgrading reinforcing or upgrading other transmission system elements. If new customers enter the system after the construction of transmission system elements, the initial contributor may be entitled to a rebate for the shared portion of the new transmission facilities.	For a load customer, a revenue test is used to cap the portion of the interconnection facility costs that enter the rate base.	**Transmission System Code**
PJM	PJM does not oversee cost allocation for loads. Instead these determinations are handled by the individual transmission owners.	PJM does not oversee cost allocation for loads. Instead these determinations are handled by the individual transmission owner.	

Quebec	The load customer pays nothing if the cost is less than C$570,000 per MW of contracted capacity for both sole use facilities and network upgrade costs. Beyond C$570,000/MW, Hydro Quebec Distribution pays any remaining costs and contracts with the customer for service.	Up to C$570,000 per MW of load's contracted capacity for both sole use facilities and network upgrade costs is added to rate base. The system contribution is an investment to gain long term commitment from load customer to purchase transmission service of equal or greater value. Beyond C$570,000/MW, no further costs are added to Transenergie Hydro Quebec rate base. Hydro Quebec Distribution incurs the additional fees.	Personal communication
Saskatchewan (SaskPower)	Costs for interconnection facilities are assessed on a per-kilometer basis for a particular transmission voltage. Incremental costs above SaskPower's preferred method of service are additionally assessed to the customer.	Costs net of the per-kilometer charge are included in system rate base. Additionally, network upgrades are included in the rate base unless the customer requests a specific supply voltage that results in additional network upgrade costs.	Personal communication
Texas (ERCOT)	Load customer bears none of the direct cost for facilities providing standard reliability, unless customer decides to speed project completion by building own interconnection and bypassing approval process.	Full cost of for approved interconnections facilities enter rate base.	ERCOT Standard Generator Interconnection Agreement (also applies to loads) PUCT Substantive Rules, Chapter 25

Table 2 Large Load Interconnection Cost Allocation Breakdown

Jurisdiction	**Basic Transmission Extension:** Customer connection facilities that could include short line extensions, step-up transformer, etc. Sometimes defined by "free-footage	**Transmission Extension:** Extraordinary direct assignment customer connection facilities that may include items like long line extensions.	**Network Facilities:** System upgrades or facilities used to support load or generation interconnection that are not direct-assignment

	allowances."		facilities
Alberta	System rate base	Customer	System rate base
BC Hydro	Customer	Customer	Cost share between customer and system rate base based on revenue test
Bonneville Power Administration (BPA)	Customer	Customer	System rate base
California	System rate base	Customer	System rate base.
Manitoba	System rate base	Customer	System rate base
Midwest ISO	-	-	-
New Brunswick	Cost share between customer and system rate base based on revenue test	Cost share between customer and system rate base based on revenue test	Cost share between customer and system rate base based on revenue test
Nova Scotia	Customer	Customer	Customer

Ontario	Cost share between customer and system rate base based on revenue test	Cost share between customer and system rate base based on revenue test	Cost share between customer and system rate base based on revenue test
PJM	-	-	-
Quebec	System rate base	System rate base	System rate base
Saskatchewan (SaskPower)	Costs assessed to customer on a per-kilometer basis. Additional costs are added to system rate base.	If a customer requests a method of service that incurs additional costs above SaskPower's method of service, incremental costs are assessed to the customer. Otherwise, costs incremental to the per-kilometer charge are added to system rate base.	If the customer requests a specific supply voltage that results in additional network upgrade costs, these costs are assessed to the customer. Otherwise, network upgrades are added to system rate base.
Texas (ERCOT)	System rate base	System rate base	System rate base

2. Retail Access Policies

Retail access policies were surveyed in seventeen utilities across North America. These utilities provide a cross-section of retail access under different ownership types, regulatory structures, and resource portfolios. From this sample, E3 identified three key criteria of retail access policy: eligibility-what types of customers, if any, are eligible for retail access; commitment periods-how long customers must be on either bundled service or unbundled electric service; and exit fees-how much customers have to pay when leaving bundled service.

Eligibility

Of the twelve utilities in which we found retail access, half had policies restricting the customers who could elect for retail access. This restriction was either by customer type (i.e. large industrial or commercial) or a limit based on a % of utility customers or utility sales. Utilities which provided retail access options to all customer types without restriction also tended to be those utilities with the least restrictive policies in terms of exit fees or commitment periods.

Exit Fees

In administering retail access, we found that all utilities followed the basic tenets of cost recovery, no matter the specific structure of their retail access policies. To prevent stranded costs, utilities may assess exit fees to departing load customers in the form of an NPV lump sum payment or retail access rate surcharge. These exit fees are consistently calculated as the anticipated rate revenue of the departing customer net of the market value of the "freed up" energy or capacity. Customers are additionally responsible for any non-bypassable charges like previous market restructuring stranded costs or environmental initiatives.

Those utilities that not assess exit fees are not necessarily at risk of stranded generation costs. First, customer generation charges may be explicitly indexed to the market or through short-term competitive auction supply contracts. This limits the horizon over which supply decisions need to be made, limiting utility risk. Second, a lack of retail customer switching may preclude the necessity to establish exit fees. Utilities with low-cost hydroelectricity may have retail access policies but not have established exit fee or commitment period policies due to the lack of customers electing unbundled service from competitive providers.

Commitment Periods

In attempting to avoid stranded costs, utilities may additionally require customers to elect either bundled or retail access service for a minimum commitment period. Portland General Electric (PGE) requires that customers who elect to leave bundled service inform PGE two years in advance if they plan to return in order to account for them in resource planning. Consumer Energy requires that customers returning to bundled service without a 12-month commitment receive power supply charges indexed to Midwest ISO LMPs and capacity prices. This allows utilities to make power purchase or investment decisions based on some certainty of subscription, lessening the risk of uneconomic investments.

Table 3 Retail Access Summary Table

Utility	ISO/RTO	Retail Access	Commitment Periods	Exit Fees	Sources
BC Hydro	-	• Suspended	-	-	• BCUC Order G-39-12

Commonwealth Edison	PJM	• Yes	• No minimum stay requirement	• No assessed exit fees • Supply prices set by competitive auction; no embedded cost ratemaking.	• Open Access Switching Rules
Consolidated Edison of New York	NYISO	• Yes	• No minimum stay requirement	• No assessed exit fees. Customers still responsible for non-bypassable system benefits charge and renewable portfolio standard charge. • Supply charges indexed to market (Market Supply Charge)	• Retail Access Tariff
Consumers Energy	MISO	• Limited (10% of utility's retail sales)	• Two options: Option 1 is return to Company Full Service, which requires a 12-month commitment. Option 2 is a short-term commitment.	• No exit fees are assessed. Option 2 returning customers receive power supply charges indexed to MISO LMP's along with market capacity costs, applicable transmission charges, and the market settlement fee	• Open Access Details • Customer Choice Tariff • Additional Retail Open Access Tariff Details
Duke Ohio	PJM	• Yes	• No minimum stay requirement	• No assessed exit fees • Supply prices set by competitive auction; no embedded cost ratemaking.	• Customer Choice Handbook • Customer Choice Enrollment and Participation Guidelines

ENMAX	AESO	• Yes	• No minimum stay requirement	• No assessed exit fees	
Hydro-Quebec	-	• Limited (Large Industrial)	• No minimum stay requirement	• No evidence of exit fees or customers leaving standard-offer service.	• RÉGIE DE L'ÉNERGIE ACT
Manitoba Hydro	-	• No (wholesale open access only)	• No minimum stay requirement	• No evidence of exit fees	
Maritime Electric Company Limited (Prince Edward Island)	-	• No (wholesale open access only)	• No minimum stay requirement	• No evidence of exit fees	
New Brunswick Power	NBSO	• Limited (large industrial)	• No minimum stay requirement	• No determination of exit fees has been necessary since restructuring in 2004.	• 2011 State of the Market Report • New Brunswick Energy Policy Report
Newfoundland and Labrador Hydro	-	• No	-	-	
Nova Scotia Power Incorporated	NBSO	• No (wholesale open access only)	-	• Nova Scotia Power's request for stranded cost recovery from departing municipal loads was rejected in 2012	
Ontario Hydro	IESO	• Yes	• No minimum stay requirement	• Customers who opt for electricity retailers or market wholesale prices must pay the Global Adjustment Charge, which accounts for the difference between wholesale energy prices and the price paid to regulated and contracted generators as well as costs for conservation and demand side management. • Large-customer (>5 MW	• Global Adjustment Charge Reg. 1038

				demand) global adjustment charges will be assessed based on coincident peak demand with system load	
Pacific Power	-	• Limited (commercial)	• 1 yr. direct access • 3 yrs. direct access	• Transition adjustments are charged to customers based on the difference between the regulated rate and forecasted valued of "freed up" energy from customers choosing direct access; can be a credit or charge on a monthly bill	• Direct Access Booklet • 2012 Transition Adjustments • Oregon Direct Access Law
Portland General Electric	-	• Limited (Commercial)	• Minimum 5 years (Customers who choose the minimum 5-year cost of service departure must indicate to PGE two years prior to returning to cost of service in order to account for them in resource planning) Direct Access • 3 year direct access • 1-year direct access	• Transition adjustments are charged to customers based on the difference between the regulated rate and forecasted valued of "freed up" energy from customers choosing direct access; can be a credit or charge on a monthly bill	• 2012 Transition Adjustments • Pricing Facts
Public Service of New Hampshire	ISONE	• Yes	• No minimum stay requirement	• No assessed exit fees. Customers still responsible for some non-bypassable charges including stranded cost recovery charges assessed through delivery charges.	• Summary of Rates
SaskPower	-	• No (wholesale	• No minimum stay	• Wholesale exit fees are based on $/MW and	• SaskPower Stranded

		open access only)	requirement	account for the ability of SaskPower to market the released capacity and energy. • $/MW is based on the cost of all "load at risk" so that a "first-off" incentive is not created.	Cost Methodology
Southern California Edison	CAISO	• Limited (10% of utility commercial accounts)	• Minimum stay of 18 months on bundled service. • 6 months of notice is required to switch from bundled service to direct access	• Customers are still assessed non-bypassable charges for nuclear decommissioning, public purpose programs, and a competitive transition charge from market restructuring. Additionally, an "indifference amount" is calculated based on the cost of an IOU's portfolio and the market price benchmark value of that portfolio. This can be a charge or a credit to a departing direct access customer.	• Direct Access-Rule 22 • Schedule DL-NBC (Departing Load Non-Bypassable Charges) • CPUC Decision on Direct Access