EB-2018-0028

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act*, 1998, S.O. 1998, c. 15 (Schedule B);

AND IN THE MATTER OF an application to the Ontario Energy Board by Energy+ Inc. pursuant to Section 78 of the *Ontario Energy Board Act* for approval of its proposed distribution rates and other charges, effective January 1, 2019.
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COMPENDIUM OF THE SCHOOL ENERGY COALITION
(TMMC Panel)

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Chapter 5

5. Direct Allocation

Directions on the direct allocation method to be used in the cost allocation filings are presented in this Chapter.

5.1 Background

As an initial step in a cost allocation study, a distributor should identify any significant distribution facilities that are dedicated exclusively to only one customer rate classification. The costs of such a facility, and the associated O&M expenses, should then be directly allocated to the customer classification that it is exclusively dedicated to. To prepare and review proposed direct allocations will take time and effort and therefore it is not encouraged for items that a distributor considers insignificant.

Direct allocations may not prove that common in practice, as more than one customer classification may make use of the facilities in question.

A stakeholder has asked for clarification of how to apply direct allocation where the customer in question has access to other parts of the system for additional reliability. For instance, there may be a situation where a facility (most likely a conductor) is directly assignable to a large customer as the feeder provides service to only the large customer under normal circumstances; however, under emergency circumstances there is access to back-up service provided through other facilities on the distributor's integrated system. Under this situation, it is appropriate to charge this large customer for a share of the facilities providing this redundancy or back-up, along with the full cost of the directly assignable facilities. If this situation arises, the distributor should provide a full explanation and documentation of how the directly assignable facilities, as well as the appropriate assignment of back-up facilities, are allocated to the large customer. The large customer's NCP should be used as the default allocator in these situations, but an alternative allocator may be used if supported by an adequate justification and supporting documentation (including a summary of the difference arising from use of the alternative allocator).

The consultations for this project indicated direct allocation should be explored in the following circumstances:

- A Transformer Station owned by a distributor that is 100% dedicated to customer(s) in the same rate classification.
- A feeder that is 100% dedicated to customer(s) in the same classification.
- Costs directly associated with load displacement generation assets.

Some stakeholders suggested that direct allocation be permitted in circumstances where less than exclusive (i.e. “predominant”) use of certain facilities or services are made by a single rate classification. This argument has been rejected because using more than one facility to serve a customer’s distribution requirements necessarily means other distribution facilities are used to provide a portion of the service to the customer. The vagaries associated with equitably quantifying the cost causality responsibility of these other non-directly assignable facilities leads the Board to favour the more well-established 100% (i.e. exclusive use) test for direct allocation. The 100% use test can also be applied more clearly and consistently.

It was suggested that where there are any assets that are “predominantly”, i.e. at least 90%, but not exclusively dedicated to one customer classification, distributors should disclose this in their filings so ratepayers can further question their allocation in future rate cases. However, as the Board believes that the 100% use test better reflects cost causality and standard cost allocation practice, the additional information sought will not ultimately prove helpful and therefore this item will not be included in the filing questions.

Where the prescribed test for direct allocation cannot be met, a distributor will still be required to consider whether distribution assets should be broken out into bulk, primary and secondary (discussed below) to more accurately allocate costs of facilities to rate classifications based on how they use various parts of the distribution system.

5.2 Direction – Direct Allocation Methodology

Direct allocation must be applied if, and only if, 100% of the use of a clearly identifiable and significant distribution facility can be tracked directly to a single rate classification.

If a distributor proposes to use direct allocation, it must support its filing with the following:

i) A summary of supporting accounting records for the specific facility in question.

ii) A single line diagram/schematic indicating the facility concerned, the customers served, and any other facilities serving the same customers.

iii) If direct assignment is applied to a customer that also receives back-up service, the filing must include an explanation and supporting documentation on how an appropriate share of back-up serve was determined and allocated. Additional justification and supporting analysis is also required if an allocator other than the customer's NCP is used.

If costs or assets are directly allocated, the direct allocation should capture all the associated accounts; for example, in the case of assets, the gross value, accumulated depreciation and depreciation expense, and any contributed capital.

Direct allocation must also be used where identifiable O&M activities can be directly allocated to one customer classification, and where supporting documentation in terms of sub-account records and explanations as to the related activities can be provided.

When direct allocation is used, the distributor should consider whether it needs to adjust the appropriate allocation factors so that the rate classification to which costs for a specific function are directly allocated is not allocated further costs related to that function, except where there are joint costs that apply to the customer classification. For example, if a customer classification has all its assets and O&M costs directly allocated to the classification, then the load data used to allocate “common” assets and O&M costs should exclude the load data associated with this customer classification. There may be other instances in which no adjustment is needed. The Filing Summary should address whether or not an adjustment was considered appropriate by the distributor and confirm it was undertaken where warranted.

The filing model will allow a distributor to define which costs in the trial balance that supports the 2006 approved rates should be directly allocated to a specific rate classification.

TREATMENT OF BULK vs. RTSRs

SIMPLIFIED EXAMPLE

ASSUMPTIONS:

- Two customers classes – Customer Class A consists of customers served at secondary voltage while Customer Class B consists of those customers served at primary voltage.
- However, at the primary distribution level, both customer classes have the same load profile and therefore the same demand allocators for Bulk Facilities.
- Total revenue requirement associated with Bulk Facilities (>50 kV) - $2,000
- Total cost associated with RTSR-Transformation Connection (HON-TX owned) - $8,000
- For Customer Class A: 50% of the load is served by Bulk Facilities and 50% by HON-Tx owned Transformation.
- For Customer Class B: 100% of the load is served by HON-Tx owned Transformation Connection.

SCENARIO ONE

- Bulk costs and RTSR-related costs both allocated to customer classes based on total load in each **class:**

Customer Class	**Bulk Facilities**	**RTSR**	**Total**
- Customer A	$1,000	$4,000	$5,000
- Customer B	$1,000	$4,000	$5,000
Total	$2,000	$8,000	$10,000

SCENARIO TWO

- Bulk costs only attributed to those using the facilities. RTSR-related costs allocated to all customer classes based on total load for each class.

Customer Class	**Bulk Facilities**	**RTSR**	**Total**
- Customer A	$2,000	$4,000	$6,000
- Customer B	-	$4,000	$4,000
Total	$2,000	$8,000	$10,000

SCENARIO THREE

- Bulk costs and RTSR-related cost both attributed based on use of related assets.

Customer Class	**Bulk Facilities**	**RTSR**	**Total**
- Customer A	$2,000	$2,667	$4,667
- Customer B	-	$5,333	$5,333
Total	$2,000	$8,000	$10,000

VECC-TCQ - 70

Issue: 3.2 **Are the proposed cost allocation methodology, allocations, and revenue-to-cost ratios appropriate?**

Reference: Settlement Proposal, Cost Allocation Model, Tabs 14 and E4

Preamble: A portion of E+'s primary and secondary distribution system is underground and a portion of it is overhead.

a) Is it reasonable to view the use of underground primary distribution assets (i.e., Accounts 1840 and 1845) versus overhead primary distribution assets (i.e., Accounts 1830 and 1835) as alternative means of providing Energy+'s customers with primary distribution service? If not, why not?

RESPONSE

No. While it is Energy+'s view that It is reasonable to view the use of underground primary distribution assets (i.e Accounts 1840 and 1845) versus overhead primary distribution assets (ie. Accounts 1830 and 1835) as a technical alternative means of providing Energy+'s customers with primary distribution service. However, it is not a financially feasible alternative especially for main primary lines.

Underground primary distribution assets are used to provide primary distribution service to Energy+ customers in local areas (i.e. Residential subdivisions, takeoffs from a pole line to a three phase padmount transformer). These underground primary lines are mainly 200 Ampere capacity.

For main primary (600 Ampere) capacity lines, primary distribution service is mainly provided overhead. The cost of underground main primary feeders would typically be 8 to 10 times more than the cost of an equivalent capacity overhead line. The underground line requires trenching, restoration for property, switching units to allow connection of customers and larger conductors due to lower ampacity of buried conductors versus overhead.

Even 200A underground primary lines cost several times more 200A overhead primary lines. Energy+ owns kilometers of lines. Most underground primary lines are only installed with significant customer capital contribution. Otherwise, there would be a large rate impact to existing customers.

11.0 Reference: TMMC Updated Evidence, p. 12
Energy+ Response to VECC TCQ 67

Preamble: The updated evidence states: "I did not allocate any >50 kV (Bulk) distribution costs to TMMC and to the other Large Use customer in Schedule JP-11."

11.1 For purposes of JP-11 were the allocation factors used to allocate >50 kV (Bulk) distribution cost to the other customer classes adjusted to remove the load not served by >50 kV facilities owned by Energy+ (per VECC TCQ 67 c)? If not, why not?

11.2 With respect to Energy+'s response to VECC TCQ 67 b), since customers served from >50 KV facilities owned by Energy+ do not use the Hydro One-owned transformers, should they be excluded from the allocation of the Hydro One charges related to these transformers for purposes of determining/applying the Retail Transmission Service Rates?

Responses:

11.1 Yes. In the Two Large Use Classes/Direct Assignment study presented in Schedule JP-11, the >50 kV facilities owned by Energy+ were allocated in the same manner as Energy+ is proposing in its cost allocation study, with the exception that none of these facilities were allocated to either Large Use customer class.

11.2 Mr. Pollock has not formulated an opinion on how Hydro One charges should be allocated to customer classes.

15.0 Reference: TMMC Updated Evidence, page 28 (lines 10-17)
TMMC Updated Evidence, page 29 (lines 15-20)

15.1 It is noted that the costs of primary poles, towers and fixtures (USoA #1830-4) are allocated across all rate classes including the TMMC Large Use rate class using the 4NCP allocation factor. Given this common treatment, please explain why in the derivation of the Standby Rate applicable to TMMC the poles, towers and fixtures costs allocated to the TMMC Large Use class are considered to be a shared facility cost and used to derive the daily volumetric rate (per page 28). However, in the derivation of the Standby Rate applicable to the GS 50-999 kW class they are considered to be a local distribution facility cost (as opposed to a shared facility cost) and used to derive the contract volumetric rate.

Response:

15.1 The identity of local and shared distribution facilities, and the corresponding costs, can only be determined from a specific analysis. Mr. Pollock has conducted a specific analysis for TMMC. That analysis identified all directly assigned facilities as local facilities and all allocated facilities (*i.e.,* the primary poles supporting Feeders M24 and M30) as shared facilities.

The very same analysis should be conducted for other customer classes. As stated in Mr. Pollock's Updated Evidence, the illustration presented in Schedule JP-15 assumed that all primary and secondary facilities were local and the >50 kV facilities were shared. A more in-depth analysis could reveal that some of the primary facilities are shared, rather than local, facilities. Mr. Pollock has not conducted this analysis for any customer class other than TMMC.

Alternatively, generic estimates may be used. For example, in New York, the New York State Public Service Commission has used the following assumptions to define the percentage of "local" and "shared" distribution costs in designing cost-based rates for Standby Distribution service.

Percent of Local vs. Shared Distribution Facilities

Function	Secondary Customers	Primary Customers	≥138 kV Customers
Secondary	75%/25%		
Primary	25%/75%	75%/25%	100%/0%
Substation	0%/100%	50%/50%	100%/0%
Transmission	0%/100%	0%/100%	25%/75%

Ontario Energy Board | Commission de l'énergie de l'Ontario

February 21, 2019

Staff Report to the Board

Rate Design for Commercial and Industrial Electricity Customers

Rates to Support an Evolving Energy Sector

EB-2015-0043

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The design of the CRCs would achieve the following objectives as set out by the OEB in its May 2015 letter:

D.4 – Proposed Capacity Reserve Charges for Customers with Generation

Many GS≥50kW, Intermediate and Large customers will consider distributed energy resources as a way to lower their costs. The OEB Strategic Blueprint speaks to enabling innovation that enhances consumer choice and control. Staff have developed a proposal to enable customer choice while meeting the general rate policy of ensuring fairness in the recovery of costs to maintain a reliable distribution system. The intention is to ensure that distribution systems' pricing is not a barrier to customer innovation while ensuring that the costs of the system are fairly recovered from those who are using it. These changes will only affect those customers who have behind the meter generation.

Under the current rules, the following scenario has happened in more than one distribution service area. A customer in the large class of a distributor without a standby class who is already a load decides to install distributed generation for essentially all its load. Its transmission cost is billed based on gross load (i.e. the delivered load plus its self-provided load) as per the transmission rate order. It has reduced its monthly demand significantly except for the one month during which it services the generator where its demand on the distribution system is for its full load. Over the course of the year, the customer pays the fixed Monthly Service Charge and likely very else for distribution. As a result the distributor under-recovers for that class until it reviews the allocation of cost for all classes and resets rates.

Since total costs have likely not gone down, due to the long-term nature of distribution system investments, and therefore the revenue requirement for the distributor has not gone down, those costs are reallocated to other classes when rates are reset. The amount that those other classes have to pay goes up and the demand charges in all classes (including the large class) go up. Meanwhile, the distributor must continue keep the full capacity reserved for the customer's once a year servicing and the customer has no incentive to keep its once a year demand in off-peak times.

The OEB commissioned work by Navigant[28] that shows that relatively low penetrations of load reductions can have significant effects on distributor revenue.

Table 4: Distributor Revenue Impact of Reducing Demand using Current Tariffs

LDC	GS < 50	GS >= 50	Large
Entegrus	-4.5%	-8.8%	NA
Hydro One (Rural)	-7.9%	-9.7%	NA
Hydro One (Urban)	-7.3%	-9.6%	NA
Orangeville	-5.4%	NA	NA
PowerStream	-5.7%	-9.3%	-7.0%
Toronto Hydro	-6.2%	-9.8%	NA

Table 5: Distributor Revenue Impact of Reducing Demand Using Proposed Tariffs for GS < 50kW

LDC	GS<10	GS 10 - 50
Entegrus	0.0%	-6.6%
Hydro One (Rural)	0.0%	-9.2%
Hydro One (Urban)	0.0%	-8.7%
Orangeville	0.0%	-7.7%
PowerStream	0.0%	-7.5%
Toronto Hydro	0.0%	-8.1%

Source: Navigant Analysis

By implementing a Capacity Reserve Charge (CRC), charges that fluctuated with standby charges will become a fixed charge based on the amount of generation installed. This leads to a more cost reflective recovery of costs from these customers who are expecting the system to be there on demand.

Staff have provided some illustrative graphs to try to show the difference between standby charges, contract demand with penalties, and the proposed emergency backup service. Figures 10, 11 and 12 below provide a comparison of the way that standby, contract demand and capacity reserve charges would work. These graphs are to demonstrate and contrast the concepts and do not represent any particular jurisdiction. The grey bars are the underlying distribution charge based on measured demand. The orange bars represent extra charges based on the operation of the installed generation.

[28] See tables 6 and 8 in Appendix B.

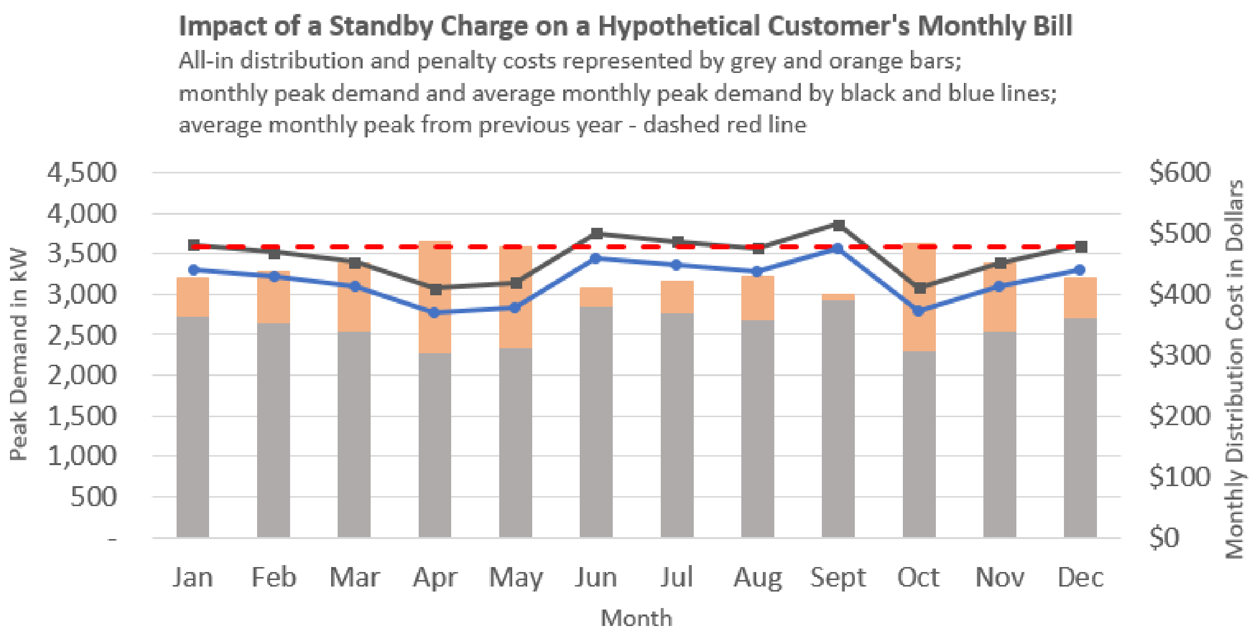

Figure 10: Sample of Standby Charge

For standby charges, there is a fluctuating charge to account for the amount of generation provided on-site. The grey bars are underlying demand charge and the orange bars are a standby charge meant to recover the distribution costs of "standing by" ready to supply the balance of the load being provided by the generator.

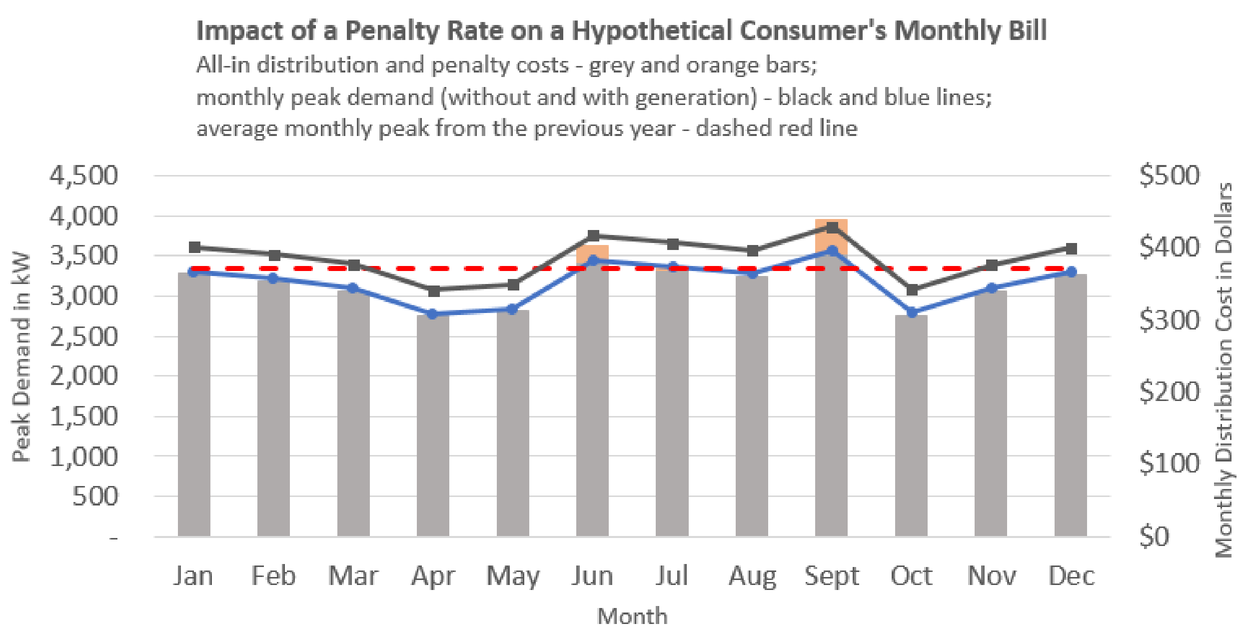

Figure 11: Sample of Contract Demand with Penalty Rate

For a contract demand, there is a penalty charge for demand above the contracted amount. The grey bars are the normal demand charge and the orange bars are penalty charges for going over the contracted demand. The penalty charge is at a significantly higher rate than the normal demand charge.

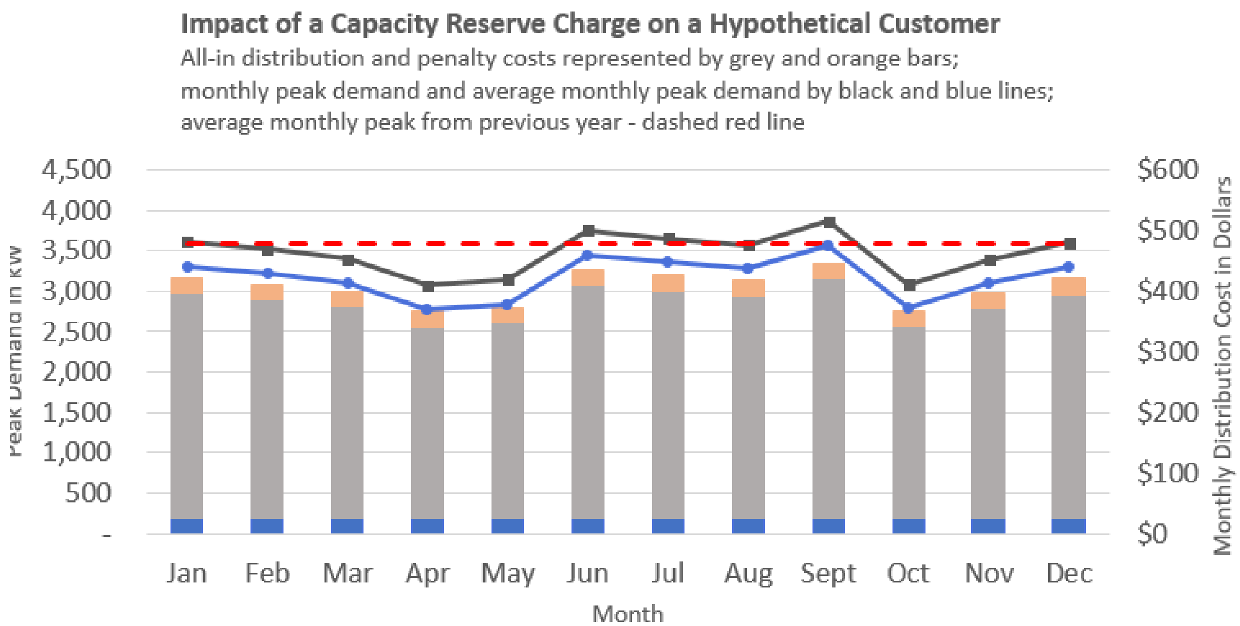

Figure 12: Sample of a Capacity Reserve Charge

For the Capacity Reserve Charge, the blue bars are the Monthly Service Charge, the grey bars are the demand charge for the class and the orange bars are the CRC. The CRC is a fixed monthly amount that represents a payment for capacity being held in the system that the customer will not otherwise be paying over the course of the year. Staff now recommend that it be based on the faceplate rating and the capacity factor of the of the generator and the underlying demand rate of the class.

The CRC payment is intended to compensate for capacity being held for the customer in the system. It should represent that value as closely as possible without either avoided costs that will end up being shifted to other customers or being a windfall for the distributor and skew the economic decisions of the customers.

Staff's initial proposal for a CRC was to set a fixed factor intended to prevent distributors from over-collecting. The work by Navigant suggested that this factor would be 90%. Staff proposed that this factor would decrease over time as a generator proved reliable service to the distributor, and the need for back-up capacity lessened. Staff's thinking was that this would provide an incentive for the operators to maintain their installation and would allow distributors to reduce the capacity held in the system for that connection.

Staff took these ideas to customers with existing onsite and load displacement generators, such as the Ontario Power Plant Administrators Association, Canadian Manufacturers & Exporters and the Association of Major Power Consumers in Ontario They pointed out that running a generator flat out to replace all load is typically not how they operate. They described other factors that influence how the customer runs its load displacement generator.

- Resource limited: Solar or wind or other renewable generators are often intermittent based on fuel availability.
- Emissions-limited: Emergency generators with a Certificate of Approval from the Ministry of Energy are limited to the number of hours they can run based on emissions. These generators may be running otherwise required tests of equipment in hours to participate in the ICI program.
- Requirements limited: Combined heat and power (CHP) plants may be heat following rather than having the goal of optimizing electricity output.
- System operations limited: Physical plant operators pointed out that their distributor will sometimes request that they not run for operational purposes of the host system.

Based on this feedback and further analysis of the system data, staff have revised the proposal for calculation of the CRC. The high level concept of the CRC remains the same. However, staff are now recommending that the proposed calculation reflect the expectation that generation is displacing load based on using a capacity factor. A capacity factor (CF) is the ratio of a generator's actual output over a period of time, to its potential output if it were possible for it to operator at full nameplate capacity continuously over the same period of time. Capacity factor is specific to the technology and more specifically to how the generator is run. For examples of potential capacity factors, see Table 6.

The CRC would be a fixed payment that is made monthly in addition to the variable charge for the metered maximum demand in the billing period. Unlike traditional standby charges that attempt to reach a contracted level every month, the CRC should recover the capacity payment on average over the year. By including capacity factor, the CRC would take into account the expectation that the customer will reach and pay for full or partial load at some point in the billing cycle.

Renewable energy generation is also referred to as intermittent generation since it depends on immediate fuel. At some point in each month or billing period, the sun will not shine or the wind will not blow during a customer's peak load. It is likely that the distributor will provide full service almost every month for renewable generation. The customer will pay the full distribution bill for its full demand load. The capacity factor for renewable plus storage installations would be higher. If the customer has its own storage, it is able to store power during times of generation excess and use this during periods when the renewable fuel source is not available. And if there was not enough of its own generation, it could store power from the grid to use when the renewable fuel source is not available. A customer with renewable generation plus storage would be able to manage to avoid drawing its full power from the grid and the capacity factor is higher.

Staff recommend that the only type of Capacity Reserve Charge available to GS ≥50kW customers is for full Emergency backup service.

Emergency backup service (EBS) is a full emergency service that is instantaneously (or nearly instantaneously) available if the customer's generator fails for any reason. Since the distributor must maintain full capacity for this customer including like-for-like asset replacement, the distributor should charge a capacity reserve charge that is based on the normal demand charge for the class and the full value (faceplate rating) of the generator and projected or historic levels of capacity factor.

EBS = Faceplate capacity rating x Demand rate of class x Capacity Factor

Some customers keep a generator on premises to provide their own emergency backup generation in the case of grid failure. Hospitals or large commercial buildings will sometimes do this in addition to manufacturers who want to ensure that they are not subject to a lengthy service disruption. These generators often use diesel for fuel and are subject to environmental restrictions and certification to limit their emissions.

Some customers are using these backup generators to participate in the Industrial Conservation Initiative (ICI) program. The ICI program allows participants to reduce their global adjustment costs and help the provincial system defer the need for investments in new electricity infrastructure that would otherwise be needed. These emission limited generators have a very low capacity factor and would pay a very low capacity reserve charge since the customer is expected to draw full load almost every month.

In staff's previous proposal, installations like renewable energy and emissions-limited generators would have had to be exempted. Under the new proposal, the capacity factor should account for the expected level of charge for load.

The IESO included standard capacity factors in Feed In Tariff (FIT) contracts to recognize expected output. The IESO also uses capacity factors in their planning for the same reason. Table 2 is some typical capacity factors. Staff expects to be able to add to and refine this table before implementation. In addition, staff expects that for Large customers, especially those with existing installations, the Capacity Factor can be agreed between the customer and the distributor and potentially adjusted periodically.

Table 6: Samples of Capacity Factors for Technologies Based on IESO System Planning

Type	Installation	Capacity Factor
Solar	Rooftop – fixed	10
	Ground mounted – fixed	20
	With storage	50
Wind	Fixed	30
	Orienting	35
	With storage	50
Bioenergy	Standard	40
	With storage	50
CHP	Heat following	50
	Full operation	65
Fossil	Certificate of approval limited	15

Implications of the proposed approach

The CRC should make the distributor indifferent to the installation of distributed generation in the service area and so enable customers to install new technology.

Customers should be able to decide on installing generators based on the commodity savings and other factors relevant to their business (e.g. control of generation, power quality, reliability of supply, or non-economic factors like support for green energy). Their decision will not disadvantage other customers through cost shifting.

D.5 – Implementation Issues for Capacity Reserve Charges

Since the new CRC charges only affect customers that are making a change and adding distributed generation, the OEB expects that these can be implemented immediately subject only to appropriate changes in distributor CIS systems. Some customers have existing generators and may or may not be paying standby charges to their distributor. Staff proposes that any current standby charges would be converted to CRC at a distributor's next rate case.

Staff further proposes that any existing generators not currently subject to standby charges begin to pay CRC on a phased-in basis. Existing installations represent an investment by the customer based on the previous rules. At the same time, any existing installation has, from an accounting perspective, depreciated over time with a concurrent increase in return. Staff therefore proposes that the applicable amount of the CRC applied every year increase by 10% of the total. i.e. reach 100% of the CRC in 10 years. This would be in line with depreciation levels for a major asset so that the CRC is implemented only as an existing installation depreciates.

D.6 – Specific Service Options for Large Customers

Large customers are very sophisticated about their energy use. They often have someone whose responsibility is planning for energy use and how to minimize costs. Staff are proposing that they have more choice[29] with regard to their level of service and consequently the amount that they pay for it. This will allow them to make decisions that support their business and respond to the circumstances around them.

At the same time, their decisions can have immediate effect on the operation of the distribution system that ultimately affect the costs allocated and charged to other customers. Their business decisions must not be allowed to disadvantage other customers.

Their decisions should be coordinated with distribution system planning to ensure that distributors can take advantage of opportunities for cost containment and are not surprised by customer actions. Distribution companies will need to discuss with each

[29] In conjunction with the levels used in regional planning, staff are suggesting that these options only apply to Large class customers, those over 5MW of demand.

customer what level of service is required and how it will be accomplished. These customers are few in number and more individual attention is warranted.
In addition to the Emergency backup service (EBS) available to GS ≥ 50kW customers, staff recommend that Large customers be able to choose Maintenance service or paying a Bypass charge.

Maintenance service (MS) would be negotiated with the distributor to provide full load at off-peak times at the distributor's discretion. Since the additional cost to the distributor is low for maintenance service, the charge should be lower than EBS. However, since the customer is abandoning load, there should be some form of recalculated economic test as an exit payment. It would include the net book value of dedicated assets and some upstream assets as well as the cost of the load limiter. The cost of removing and reinstalling the load limiter would be charged whenever the customer requires the service. Under this model, the customer is taking the risk of poor performance of the generator and that it will not be able to supply the load.

MS = Faceplate capacity rating x Demand rate of class x Maintenance Factor

> Where Maintenance Factor is negotiated with the distributor such as between 25% and 50%. For the purposes of comments, assume that the OEB chooses 30% as the Maintenance Factor.

Bypass is when a customer is essentially taking most or all load off the system. There would be a calculation of the value of abandoned assets so that the remaining costs of assets built to serve the customer (in particular feeder lines, controls, and protection systems) are not passed to the remaining customers.

Bypass could be full for disconnection or partial where some load remains on the system. There will be an economic evaluation to determine the payment owing for the value of the abandoned assets to calculate a full or partial bypass charge.

Full Bypass charge = Net Book Value of abandoned assets and system costs based on the load being abandoned

Partial bypass is when the customer wants to permanently remove their load from grid service but maintain a connection to the grid. The customer may choose to reduce their load to some minimum and protect the rest with emergency backup or maintenance levels of service from the distributor. The customer should pay out the net book value (NBV) of connection assets built to serve them, offset by the expected continuing revenue stream which may only be the Monthly Service Charge or may include some load and/or level of Capacity Reserve Charge.

During the OEB's consultation on the Regional Planning and Cost Responsibility Review[30] (Cost Responsibility consultation) which was recently completed, a number of stakeholders requested clarification in relation to how a bypass compensation charge in that consultation would work with the capacity reserve charge (CRC) being considered in this consultation.

The primary stakeholder concern was the potential for a customer being required to pay both charges to compensate the distributor for the same bypassed capacity (i.e., charged twice). In its Revised Notice of Proposal[31] related to the Cost Responsibility consultation, the OEB noted that clarification was not possible at that time, since both bypass compensation and the CRC were at the proposal stage[32]. As a consequence, in that Notice, the OEB indicated it would address the relationship between the two charges, as part of this policy consultation process, once the Cost Responsibility consultation was concluded.

OEB staff notes that bypass compensation is broader in scope than the CRC. Unlike the CRC, it is not limited to cases of bypass involving embedded generation. For example, a bypass compensation charge would be applied where bypass is achieved through wires reconfiguration, such as a customer that shifts existing load from the distributor's facilities (e.g., transformation station) to its own duplicative facilities that the customer later constructed.

Where embedded generation is involved, renewable generation is also exempt from the requirement to provide bypass compensation. As a result, the comments requesting clarification appear to be limited to one bypass scenario in relation to where both charges could potentially be applied. That scenario involves the customer installing behind-the-meter non-renewable generation (e.g., natural gas CHP). OEB staff further notes that, as reflected in the final DSC amendments in the Cost Responsibility consultation[33], for distribution-connected customers, bypass compensation will also be limited to large consumers which the OEB concluded will be those with a non-coincident peak demand of 5 MW and above (i.e., large user rate class for distribution charges). In contrast, the currently contemplated threshold for the CRC is much lower as it would be

[30] EB-2016-0003
[31] Notice of Revised Proposal
[32] Ibid, p. 23
[33] Notice of Amendments to Facilitate Regional Planning

applicable to customers over 50 kW. However, under the CRC proposal, bypass options will only be available to Large customer classes.

Bypass compensation is now required for both *full* and *partial* bypass within the distribution system. The potential where bypass compensation and the CRC could be applicable is related to partial bypass. Under a full bypass scenario, the customer fully disconnects from the distributor's system. That would not occur under any CRC scenario since the customer is maintaining its connection to reserve capacity on the system, so they can use it as needed.

Based on the above, the only scenario where both charges could be applied is therefore where a large customer (over 5 MW) has embedded non-renewable generation to supply some of its load. Key differences on the implementation side are bypass compensation is a *one-time charge* – calculated based on the remaining net book value (NBV) of the bypassed asset(s) – due to a customer *permanently* removing its load from the distributor's system. In contrast, the CRC is an *ongoing charge* and the customer is *not permanently* removing a certain amount of load from the system. Instead, they are reserving capacity for when they need it from time to time.

Under the staff proposal for the CRC, the stakeholder concern noted above will never be realized. That is, there will never be a case where a customer would be charged both the CRC and bypass compensation in relation to the same capacity. A key reason for that is it will be based on *customer choice*; i.e., not determined by the distributor which charge is applied.

Paying bypass compensation may be the lower cost option for a customer over the longer term, but they would be assuming the risk of no longer being able to rely on the system to supply all of their electricity needs. In contrast, the customer would be able to continue to rely on the system when they need it if they opt to pay the CRC for the capacity they reserve, so it is like an insurance policy.

To use an analogy, the customer's decision is similar in nature to a customer deciding on whether they want to purchase and own their water heater (after they have rented it for some time) or continue to rent and pay an ongoing monthly charge. If they choose to pay the remaining NBV and own it, they assume the risk to repair and/or replace the water heater, whereas if they continue to rent, the risk remains with the company to service the water heater and/or replace it.

A hypothetical example is set out below based on a customer that has existing demand of 100 kW and they install gas-fired embedded generation that can supply 20% of their load.

Total existing customer demand	100 kW	
Demand supplied by new LDG gas generation	20 kW	BC or CRC applies
Demand remaining on distribution system	80 kW	Unaffected

In the example above, under staff's recommendation, if the customer opted to pay bypass compensation, the capacity allocated to them would be limited to 80 kW. On the other hand, if they opted to pay the CRC, they would still have access to the full 100 kW, but they would pay the CRC in relation to 20 kW in order to pay for services received from the distributor, including maintaining capacity on the distribution system that is reserved for them. OEB staff notes this is only an example, as the customer could opt to reserve less than 20 kW.

D.7 – Implementation Issues for Large Customer Options

Treatment of Demand Overages

One implementation issue for maintenance and bypass is how to ensure that customers do not access emergency backup service without paying for it. There could be some penalty imposed for customers who are only paying for the limited service but whose generator fails and end up using full emergency backup. This could be a physical limitation or financial penalties.

One possibility for a customer that remains connected to the grid is that the distributor installs a load limiter at the customer's service to ensure that it does not draw more than the agreed amount. Under this model, the customer is taking the risk of poor performance of the generator and that it will not be able to self-supply the load. A distributor who has limited capacity on a line or faces an end-of-life replacement decision many need to physically limit the demand that a customer can draw. In this case, a customer who discovers that it actually needs full emergency backup could end up paying significant fees to install and then reverse load limiters. The distributor may make decisions based on an expectation of the customer's reduced load that then needs to be served again.

Another way of dealing with overages is to apply penalty rates to any demand over the agreed load. Network providers in the UK apply excess capacity charges[34] to demand over the agreed supply capacity. The penalties try to discourage companies from exceeding their agreed supply capacity to assist the distribution network operators with balancing network usage. The penalty rate depends on the specific distributor but ranges from 15% to 106%[35] above the base demand rate.

When penalty charges apply, a customer is taking a business risk of overage charges but not an operational risk of not having enough service. A distributor with excess capacity may prefer to allow a customer to draw over the agreed demand and incur penalties that would offset charges for other customers rather than install more equipment to have a physical limitation. The application of penalties would prevent customers from trying to game the system by choosing a lower level of service and using the higher level.

Links to Distribution System Planning

For Large customers, economic tests could be done on an individual basis. These calculation could include credit for system benefits specific to the generator and location. However, the distributor should not continue on with business as usual planning models. The distributor should assume some risk of load change.

In consultation, customers noted that installation of a large distributed generator is not a momentary decision. Developing the business case, the dedication of capital, and construction is likely a 7 year program.

The OEB began asking distributors for specific, 5-year system planning information in 2009. The filing requirements for those plans have increased in detail since then. Distributors are also expected to find out their customers experience and expectations for service level and quality. OEB expects distributors to involve customers in planning. For larger customers, this could be discussing replacement plans as dedicated assets reach their end of life. Without evidence that these kinds of consultation have taken place, the distributor would not be entitled to include those assets in the economic evaluation of NBV.

[34] Distribution Connection and Use of System Agreement (DCUSA) DCP161 - Excess capacity charges | Ofgem
[35] Professional Cost Management Group summary of excess capacity charges

Implications of Maintenance Service and Bypass

Staff believe that the proposal addresses the objectives of the project.

- It addresses concerns of distributors and customers that the level of change in the sector is already overwhelming in that it maintains the status quo for underlying rate and only applies to advanced customer installing or operating distributed generation.
- It allows for customer choice in the level of service provided by the distributor of full emergency backup service, maintenance service, or full or partial bypass.
- Customers can choose to install distributed generation to lower their bills through savings on commodity. However, they will not avoid paying for the capacity maintained in the system and thereby shift costs to other customers.
- It enables technology implementation by making the distributor indifferent to customer installation of distributed generation.