# APPENDIX D: COMMENTS OF PAPER EXCELLENCE AND RESPONSE OF ELENCHUS AND SASKPOWER

Paper Excellence ("PE") submitted a letter providing its comments on the proposed CRS rate. The letter contained a number of requests for comments of the consultant (Elenchus). The requests for comment are listed below. Responses are provided in this appendix.

1. *Can the consultant provide some comments on generation costs relative to the industrial rate?*
2. *Can the consultant comment on the proposed rate design relative to some of the other Bonbright principles, namely:*

   *1. Price signals that encourage efficient use – how is the installation of generation different from reducing purchases through the implementation of other demand side management (DSM) initiatives?*

   *2. Rate stability – does the rate as proposed represent rate shock relative to the present industrial rates? [we have attached a spreadsheet to analyze some scenarios, please review and confirm that our interpretation and analysis represents the intent of the rate]*

   *3. Avoidance of undue discrimination – does the rate as proposed create discrimination within the customer class based on the definition of self-generation and the threshold to trigger the rate.*

   *4. Practical and cost effective to manage –*

   *a. how is the threshold ratio determined, generation capacity relative to historical purchases? Actual generation vs actual purchases?*

   *b. What happens when a customer drops below the threshold?*

   *c. Will the threshold calculation be adjusted to reflect one time impacts (e.g., major maintenance, market curtailments, force majeure events, etc.)*
3. *Can the consultant comment on the number of jurisdictions in Canada where industrials are selling energy back to the utility/grid?*
4. *Can the consultant comment on the determination of peak demand in other jurisdictions?*
5. *Can the consultant review our analysis to confirm our interpretation of the rate schedule?*

6. *Can the consultant comment on the application of a similar [to BC] energy only product for SaskPower?*

1. *Can the consultant provide some comments on generation costs relative to the industrial rate?*

Please refer to Appendix C of the Elenchus Report, Table 9. Scenario 1 in Table 1 shows the revenue-to-cost ratio for the E22 class is 0.995 for a customer with no self-generation. The revenue-to-cost ratio for the E23 is 1.026 and E24 ratio is 1.003 for customers with no self-generation. The revenue-cost-ratio is based on the most recent update of SaskPower's costs allocation model. The costs include transmission as well as generation costs. The revenue, costs caused, and R/C Ratio of an average customer in each class are provided below.

| Rate Code | Revenue | Costs Caused | R/C Ratio |
|---|---|---|---|
| E22 | $1,426,958 | $1,434,764 | 0.995 |
| E23 | $4,592,346 | $4,477,637 | 1.026 |
| E24 | $8,430,272 | $8,409,193 | 1.003 |

As described in Elenchus' CRS Report, SaskPower uses a Bary Method adjustment that shifts a portion of demand-related costs to be recovered through energy charges. This adjustment is detailed in Appendix C of the Elenchus Report (see table 15). The current energy charge for an E24 customer is $61.09/MWh and SaskPower's generation costs are $41.37/MWh.

2. *Can the consultant comment on the proposed rate design relative to some of the other Bonbright principles, namely:*

   (1) *Price signals that encourage efficient use – how is the installation of generation different from reducing purchases through the implementation of other demand side management (DSM) initiatives?*

   (2) *Rate stability – does the rate as proposed represent rate shock relative to the present industrial rates? [we have attached a spreadsheet to analyze some scenarios, please review and confirm that our interpretation and analysis represents the intent of the rate]*

   (3) *Avoidance of undue discrimination – does the rate as proposed create discrimination within the customer class based on the definition of self-generation and the threshold to trigger the rate.*

   (4) *Practical and cost effective to manage –*

      a. *how is the threshold ratio determined, generation capacity relative to historical purchases? Actual generation vs actual purchases?*

      b. *What happens when a customer drops below the threshold?*

      c. *Will the threshold calculation be adjusted to reflect one time impacts (e.g., major maintenance, market curtailments, force majeure events, etc.)*

***RESPONSE***

Elenchus interprets PE's comment as referring to the ten "attributes of a sound rate structure" that are identified at page 383-384 of Bonbright, James C., Albert L Danielsen and David R Kamerschen, Principles of Public Utility Rates, Second Edition (1988), Public Utilities Reports, Inc. ("Bonbright") rather than the eight principles listed at page 291 in the first edition of that seminal work.

PE's comments state that "[T]he report focusses on the principles of cost recovery and the fair apportionment of costs." Elenchus does not agree with this characterization. Elenchus' analysis considered all ten of the Bonbright principles, although this report was not structured to explicitly address each principle in a systematic way. Elenchus notes below how the assessment of the CRS rates took into account each of the four principles identified in the EM comments.

***Price signals that encourage efficient use:*** Elenchus interprets this point to encompass Bonbright's attributes #4, static efficiency, and #8, dynamic efficiency. As Bonbright's full discussion of the issues, particularly in Part Four, The Rate Structure, makes clear, static and dynamic efficiency would most effectively be achieved by adopting rates that correspond to short-term and long-term marginal costs, respectively. Since a public utility such as SaskPower would either over-recover or under-recovery (generally the latter) if tariffs were based on marginal costs, regulators across Canada and elsewhere have adopted fully allocated (or distributed) costs as the basis for rate setting. See Bonbright, chapter 19 for a discussion of this approach. In the Elenchus report, this point is made in section 4.1, page 16, where it states:

> *The "correct" price signal for customers maintaining their connection to the grid would be based on marginal costs (as in competitive markets) rather than fully allocated costs (FAC). This approach would require pricing flexibility and either the ability to price discriminate or bundle regulated and competitive services as a means of recovering the utility's revenue requirement fully. These options raise concerns about anti-competitive practices. The solution is difficult.*

The approach taken by Elenchus in the report is consistent with accepted regulatory practice in Canada and internationally. Elenchus has attempted to point out that further rate evolution will become necessary in the coming years and decades as the traditional practice of basing rates on fully allocated costs becomes more difficult to sustain.

***Rate stability;*** This issue is typically addressed by SaskPower and other electric utilities by phasing in significant rate changes. Elenchus takes it for granted that SaskPower will not implement a rate change that results in unacceptable rate shock. The Bonbright principles do not imply that rate shock should be avoided by maintaining a rate that is misaligned with costs any longer than is necessary to mitigate rate shock.

***Avoidance of undue discrimination:*** The refinements to the CRS rates as proposed by SaskPower contained in the Elenchus report are intended to address both the unintended incentive for customers to "game the system" and to ensure that the rates for all customer classes are designed to ensure that there is no undue discrimination (as defined by Bonbright attributes #6 and #7). Elenchus notes that this concern would be most effectively addressed by billing using coincident peak demand, rather than non-coincident peak demand, as the billing determinant for demand-related costs. Given the practical difficulties of billing on the basis of coincident peak demand, Elenchus notes that various "next best alternatives" have been adopted by utilities. For example, the Bary correction has been used by SaskPower; however, that has resulted in the unintended incentives discussed in the Elenchus report. An alternative used in some other jurisdictions is to bill based on multiple coincident peaks (for example, the "high five" approach used for large industrial customers in Ontario).

***Practical and cost effective to manage:*** The Bonbright attributes include two "Practical-related Attributes: "9. The related practical attributes of simplicity, certainty, convenience of payment, economy of collection, understandability, public acceptability, and feasibility of application" and "10: Freedom form controversy as to proper interpretation." It is in recognition of the types of questions raised by PE that Elenchus commented in section

2.1 on Applicability that “[T]he self-generation threshold in other jurisdictions is lower than 50%, most often it is 15%.” In retrospect, the view of Elenchus on this point lacked clarity.

Elenchus recommends that the threshold should be eliminated, provided that the rules related to nomination of Reservation Capacity (see the discussion on page 9-10 of the Elenchus report) are modified to address the identified concerns related to the incentive to game the system by nominating less capacity than is actually required in order to avoid paying for rates that reflect actual causal costs.

3. *Can the consultant comment on the number of jurisdictions in Canada where industrials are selling energy back to the utility/grid?*

It is a standard practice in all jurisdictions for industrial customers with generation assets to sell energy to a utility or into the grid. Power sold to the utility is generally contracted as a power purchase agreement (“PPA”) that is entered into by the utility as an integral part of its supply planning.

Elenchus notes that Ontario and Alberta have very different electricity systems than other provinces. These provinces operate a real-time wholesale electricity market in which all participants including industrial customers with generation assets, competitively sell output at their marginal cost on a short-term (5-minute) basis. The other provinces are served primarily by vertically integrated utilities.

| Province | Industrial load sells power to grid |
|---|---|
| British Columbia | ✓ |
| Alberta | ✓ |
| Saskatchewan | ✓ |
| Manitoba | ✓ |
| Ontario | ✓ |
| Quebec | ✓ |
| New Brunswick | ✓ |
| Nova Scotia | ✓ |
| Newfoundland and Labrador | ✓ |

**British Columbia**: BC Hydro has signed more than 100 power purchase agreements (PPAs) with a range of generators. A number of these generators, predominantly cogeneration and biomass facilities, are located within industrial load customers.

https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/independent-power-producers-calls-for-power/independent-power-producers/ipp-supply-list-in-operation.pdf

**Alberta**: Many large industrial customers, particularly in the oil sands and mining sectors, have installed cogeneration generators. These assets often sell excess energy into the real-time wholesale energy market.

http://ets.aeso.ca/ets_web/ip/Market/Reports/CSDReportServlet

**Saskatchewan:** SaskPower has a number of Power Purchase Agreements (PPAs) with Independent Power Producers (IPPs), made up largely of natural gas and wind generation.

https://www.saskpower.com/Our-Power-Future/Powering-2030/Creating-A-Cleaner-Power-Future

**Manitoba**: Manitoba Hydro allows alternative energy technologies to sell excess energy back to the utility at a pre-established non-utility generation price.

https://www.hydro.mb.ca/accounts_and_services/generating_your_own_electricity/

**Ontario**: Ontario has undertaken multiple procurements for combined heat and power (CHP) plants. These assets are often located at industrial facilities. Nearly all these power purchase agreements (PPAs) are for terms of 20 years. Many industrial facilities also participate in the Industrial Conservation Initiative (ICI) – a peak shaving program offered to large loads. As a result of the ICI, many industrial loads have installed some form of behind-the-meter generation. The Market Surveillance Panel recently completed a comprehensive and critical analysis of this program.

https://www.oeb.ca/sites/default/files/msp-ICI-report-20181218.pdf

http://www.ieso.ca/en/Sector-Participants/Energy-Procurement-Programs-and-Contracts/Combined-Heat-and-Power

And as an example:

https://www.power-technology.com/projects/thorald/

**Quebec**: Hydro Quebec has signed a number of long-term PPAs with cogeneration facilities, many of which are located within industrial facilities. A list is available at:

http://www.hydroquebec.com/electricity-purchases-quebec/electricity-contracts.html

Also see:

https://renewablesnow.com/news/innovente-buys-5-mw-cogeneration-plant-in-canada-14608/

**New Brunswick**: NB Power has a few PPAs with industrial facilities with installed cogeneration plants. Two examples are:

https://www.twinriverspaper.com/operations/edmundston-pulp-mill/, and https://www.tcenergy.com/siteassets/pdfs/power/grandview-cogeneration-plant/tc-power-grandview-fact-sheet.pdf

**Nova Scotia**: Nova Scotia signed several long-term PPAs with generators – wind and biomass, among others – at industrial facilities.

https://energy.novascotia.ca/sites/default/files/files/Copy%20of%20DRAFT%20Comfit%20Status%20as%20of%20May%202019.pdf

**Newfoundland and Labrador**: Nalcor energy has signed a limited number of long-term PPAs, with a portion of these assets located within industrial facilities. See page 52 at:

https://www.gov.nl.ca/nr/files/publications-energy-review-of-nl-electricty-system.pdf

4. *Can the consultant comment on the determination of peak demand in other jurisdictions?*

Recorded demand for customers in rate classes analogous to the Power Class within other jurisdictions are typically determined by actual measured non-coincident peak demand. Many jurisdictions measure and bill based on kW instead of kVA. The use of demand ratchets varies by jurisdiction. As is the case with SaskPower, for purposes of allocating costs to customer classes, typically the coincident peak demand of the classes is used as the allocator of demand-related costs.

With respect to capacity reservation service, most utilities surveyed by Elenchus in other jurisdictions use a similar “reservation capacity” measure for backup/standby service rate designs. The same reservation capacity is used in each month until a customer can demonstrate that it can reduce demand during backup/standby service periods. Reservation capacity is used by utility planners to maintain the customer’s identified backup/standby capacity so some utilities impose punitive charges for exceeding reservation capacity in order to incentivize customers to provide the appropriate level of reservation capacity commiserate with its maximum demand. Reservation capacity is usually provided by the customer; however, in some cases it is determined by the utility. Some utilities use a customer’s recorded demand before generation is installed as the reservation capacity. An increase to reservation capacity when actual demand exceeds the current reservation capacity is a common feature of backup/standby service rate designs.

5. *Can the consultant review our analysis to confirm our interpretation of the rate schedule?*

Paper Excellence's interpretation of the CRS rate schedule (N24) is correct.

The CRS on-peak energy charge is listed as $36.16/MW but should be $39.16/MW within the spreadsheet. The all-in CRS charge is described as $93.14/MWh in the preamble to the question but the all-in charge, including carbon tax, is $95.13/MWh. The calculation is revised to $96.47/MWh with the on-peak charge correction. Elenchus considers these to be typos rather than misinterpretations of the schedule.

The spreadsheet calculations for the standard Power Service (E84 & E24) rates are correct assuming the customer does not self-generate or take capacity reservation service during "planned maintenance" days and the customer reaches its maximum demand in each month, including the "100% Self Generation" scenario (which could more accurately be labelled "95% Self Generation"). A customer's average monthly billing demand is typically lower than its annual maximum demand and it can be expected to be even lower for self-generating customers. A typical standard Power Class customer with the characteristics of the hypothetical customer within the spreadsheet would have lower average monthly demand, and therefore lower total demand charges and total bills, than what is calculated in the spreadsheet. Please see Table 18 of Appendix C for Elenchus' derivation of rates and costs caused by the hypothetical customer provided in the spreadsheet.

6. *Can the consultant comment on the application of a similar [to BC] energy only product for SaskPower?*

For background, this rate was first introduced in 1991 and has been in place since.

The main difference between the RS 1880 referenced in this IR and what SaskPower is proposing is that RS 1880 is an interruptible service and, as such, has no associated demand charge. There is a small administrative charge ($150) per incident, but the customer is charged only for energy consumed due to it being an interruptible service. As it's an interruptible service, BC Hydro does not need to consider it in its capacity forecasts or requirements.

- See page 402: https://sitecstatement.files.wordpress.com/2016/05/bc-hydro-2015-2015-rate-design-application-appendix-c-5a-p-107.pdf
- See page 29: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-filings/tsr/0-2019-04-15-bchydro-order-request-rs1828.pdf
- See page 65: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-matters/2015-03-13-bch-rda-wksp5-tsr1-pfb.pdf

Elenchus does not consider a rate similar to BC Hydro's RS 1880 to be applicable to the current SaskPower circumstances. In particular, interruptible rates such as BC Hydro's RS 1880 are general introduced at a time when the utility is faced with expensive capacity upgrades to meet expected peak demand requirements. The interruptible rate is economically justified when the lost revenue resulting from the introduction of the interruptible rate is less than the avoided cost that result from the reduction in peak demand when the peak is shaved by replacing firm service with interruptible service.