ADC
Alberta Direct Connect
Consumer Association

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ADC Proposal: AESO Tariff – Mitigation Alternatives – Firm / Non-Firm Tariff

There are 3 distinct types of load users of the transmission system: Firm load, standby load, and interruptible load. Each of these requires a different level and type of service from the Alberta grid. The current 12 CP tariff has specifically been designed to act as a proxy for standby service and provide a price signal for loads to interrupt during system peaks.

The ADC remains of the view that the current tariff design is preferrable; however, recognizes that there could be improvements introduced so that the tariff can remain stable for the long term. An area that ADC has been concerned about is charging CP in the shoulder months where there is no system benefit. This has a productivity impact on energy intensive trade exposed industry who must respond to all coincide peaks in order to remain competitive in Alberta.

The ADC proposes a tariff mitigation option that allows customers to select a firm and non-firm portion of their capacity requirement where the firm portion is charged on a fixed rate per MW and the non-firm portion is charged on a CP basis.

Our proposal simplifies the tariff for all firm loads – a fixed cost per MW of firm capacity requirement. For interruptible and standby loads, it still provides a CP price signal for a proposed 6 months of the year with charges assigned to the contribution to the 4 highest 15-minute intervals in each of the months. This creates a 24 CP tariff. The CP rate proposal is structured such that if a load were not able to respond to the coincident peak they would end up paying more than if they elected firm service. This provides a strong financial incentive for interruptible loads to respond to peaks without being directed to curtail by the AESO.

ADC submits that this proposal provides a long term tariff option that will keep interruptible loads in Alberta, will provide the appropriate price signals to maintain existing and encourage the development of new on site generation where it is the most efficient decision from an energy and transmission infrastructure perspective, and provide billing determinant stability for all Albertans. The ADC also submits that the proposal is consistent with the tariff objectives:

Efficient Price Signals

The regulatory history of the DTS tariff has established in principle that the transmission tariff should send a price signal to minimize future transmission build. This has been accomplished through the CP methodology. The CP rate design has 2 important outcomes:

1. Price responsive / interruptible load respond to system peaks which results in:

- Less generation required to serve the peak load, which means less transmission infrastructure is ultimately needed to serve the peak system load. Alberta has approximately 400 MW of price responsive load. *The CP tariff design has helped keep these energy intensive and trade exposed industries viable in Alberta.*
- Improved grid reliability at times of system stress.

2. To act as proxy for a standby tariff to recognize the benefits of generation development at Industrial sites. The benefits of industrial generation development include:
- Efficient use of existing transmission infrastructure
- Reduces system losses
- More competitive electric energy markets
- More reliable grid
- Reduces grid intensity – environmental benefits

Cost Responsibility

Not all customers require the same level of reliability. This naturally leads to a different tariff for firm and non-firm load or Standby service.
- Firm: requires firm service at all times, regardless of time of day or price signal.
- Non-Firm: Certain customers have a portion of their load requirement that does not require service at all times. A good example is electricity intensive loads that will self-interrupt to remain competitive in Alberta. These loads have invested in storage/generation/production modifications to get off the grid when other customers need grid supply the most.
- Standby: Does not require firm service and uses the grid as backup to on-site generation. Site capacity has been built and established through the DTS contract. These customers have less reliance on the bulk transmission grid.

Minimal Disruption

Minimal disruption is required in order to protect and improve Alberta's economic outlook.

The following sets out the ADC's proposal for mitigation using a rate structure alternative that recognizes the different reliability needs of the grid and sets out billing determinants for Firm and Non-Firm service.

Firm / Non-Firm Rate Proposal

The proposal includes 3 billing categories:

1. Site Capacity: This billing element recovers the local/regional interconnection costs. Similar to the current tariff, the greater of 90% of DTS contract capacity or NCP is used as the billing determinant for the POD and Regional charges. DOS could continue to be used for short term requirements.

2. Firm Capacity: This billing determinant is used to allocate the Bulk system charges to firm service loads. This value is nominated by the DFO or Direct Connect customer.

3. Non-Firm Capacity: This billing determinant is used to allocate the Bulk system charges to price responsive loads and standby customers. It would apply to all load above the nominated firm capacity.

Other costs such as ancillary services/ voltage support would remain the same as today.

Billing Determinants:

For the purpose of exploring the concept, we have used the 2018 revenue requirement for Bulk and Regional Interconnection Costs of $1,557,500,000. This would need to be updated for the current revenue requirement for further analysis and rate impact modelling. The revenue requirement would be recovered in 3 cost categories:

> **1. Site Capacity Charge:** This charge would recover ~ 25% of the revenue requirement as a demand charge based on 90% contract capacity or monthly non coincident peak (NCP). This capacity charge would have no ratchet and no energy component. This billing determinant would be set at ~$3,250/MW (similar to the current Regional costs if energy and capacity costs are combined).
>
> > Billing determinants: 160,561 MW-Months (~13,380 MW) (as per 2018 filing)
> > Revenue generated: $521,000,000
> >
> > Rate: $3,250/MW/month

The next 2 rate components would need to recover the remaining revenue requirement balance of just over $1,036,000,000.

Propose the Firm capacity rate to be set so that it recovers the entire balance and reduced with a rider (new Rider G) by revenues collected from the non-firm cost category.

> **2. Firm Capacity:** recovers the bulk revenue requirement less the revenue received from the non – firm capacity charges.
>
> > Billing Determinants: 110,000 MW – Months (~9,200 MW)
> > Revenue Requirement: $1,036,000,000 (less non-firm revenue contribution - Rider G)

Rate: $9500/MW/Month less Rider G

Rider G: credit applied to firm capacity $/MW based on non-firm capacity revenue.

3. Non-Firm Capacity: contributes to the bulk revenue requirement, which can be avoided if the non – firm load responds to the CP price signal.

The CP signal is proposed to change from 12 CP to a 24 CP model, but with 4 CP's in the 6 months that the peak matters most. In each of the months of Nov, Dec, Jan, Feb, July, Aug, the peak 4 - 15 min intervals would attract a CP charge for non-firm capacity that was taking grid power at the time.

Billing Determinants: estimated at 30,000 MW – Months (~ 2,500 MW of Standby & PRL)
Rate: $12,000 * 12 CP = $144,000/MW year converted to 24 CP is $144,000/24 CP = $6,000 / MW / CP

Rider G - Revenue contribution: Depends on when the Non-firm load uses the system and if they are successful at responding. If they are not successful, they would pay a premium to the firm service, for example:

10 MW of Firm = 10MW x $9500 X 12 = $1,140,000
10 MW of non-firm = 10 MW X $6000 X 24 = $1,440,000

A DFO/DC customer would not select the non – firm rate if they had no ability to respond as they would end up paying a premium.

Terms and Conditions

There may need to be additional terms and conditions around the election of the firm/ non-firm levels. An example is that there is an allowance for POD's to nominate firm/non-firm capacity once per calendar year so it is set for 12 consecutive months.

The concept is illustrated through the following examples:

1. Firm DFO site with 50 MW DTS contract capacity and 48 MW NCP:

50 MW Firm

Site Capacity Charge: 48 MW X $3,250 X 12 = $1,872,000

Firm Capacity Charge: 48 MW X $9,500 X 12 = $5,472,000

Total Annual: $7,344,000

2. Firm & non-firm DFO/DC site with 50 MW DTS capacity, NCP 48 MW, 20 MW firm, 30 MW non-firm.

a. avoided CP 80% of the time

Site Capacity Charge: 48 MW X $3250 X 12 = $1,872,000

Firm Capacity Charge: 20 MW X $9,500 X 12 = $2,280,000

Non-Firm Capacity Charge: 30 MW X $6,000 X 24 CP X 20% = $864,000 (With 80% avoidance)

Total Annual: $5,016,000

b. avoided CP 0% of the time

Site Capacity Charge: 48 MW X $3250 X 12 = $1,872,000

Firm Capacity Charge: 20 MW X $9,500 X 12 = $2,280,000

Non-Firm Capacity Charge: 30 MW X $6,000 X 24 CP X 100% = $4,320,000 (With 0% avoidance)

Total Annual: $8,472,000. (by not avoiding CP, non-firm becomes a premium to firm service)

3. ISD – Cogen Site with 50 MW DTS Capacity (90% is 45MW), NCP 0 MW, 0 MW firm, 50 MW non-Firm

a. avoided CP 95% of the time.

Site Capacity Charge: 45 MW X $3,250 X 12 = $1,755,000

Firm Capacity Charge: 0 MW X $3500 X 12 = $0

Non- Firm Capacity Charge: 50 MW X $6,000 X 24 CP X 5% = $360,000 (95% avoidance)

Total Annual: $2,115,000

b. avoided CP 0% of the time.

50 MW non-Firm

Site Capacity Charge: 45 MW X $3,250 X 12 = $1,755,000

Firm Capacity Charge: 0 MW X $3500 X 12 = $0

Non- Firm Capacity Charge: 50 MW X $6,000 X 24 CP X 100% = $7,200,000 (0% avoidance)

Total Annual: $8,955,000 (by not avoiding CP, non-firm becomes a premium to firm service)

Rider G: In the case of 2a and 3a, the total non-firm capacity cost recovery of $360,000 + $864,000 = $1,224,000 would be returned as Rider G. In the case of 2b and 3b, the total non-firm capacity cost recovery of $4,320,000 + $7,200,000 = $11,520,000 would be returned as Rider G. This rider amount would go to reduce the firm capacity charge.

The ADC has performed some initial rate impact analysis and while most interruptible and standby customer would see rate increases it is at a manageable level.

The ADC wishes to explore this rate mitigation option further with the AESO to update the potential rates to reflect the current revenue requirement.