Capacity Market Cost Allocation – initial discussion
Depal Consulting Limited
July 25, 2017
Cost Recovery Discussion Agenda

- Key principles (cost recovery/ equity)
- Review of other markets
- Alternatives (Demand/ Energy)
  - Billing determinants and Ratchet
- Pros and cons of alternatives
- Evaluation of AESO SAM position (demand at times of system stress and coincident peaks)
- Required data/ next steps
AESO’s SAM Discussion

- AESO’s system stress not always at system peak
- Cost allocation should align with the performance measure timeline to ensure price incentives for behavior are aligned

Options:
- Fraction of load over Summer and Winter Coincident peaks
- Weighting of fraction of load at coincident peaks plus fraction of load at times of system stress
- Total energy on month of year basis

- Customers can financially hedge these costs
- No Customers can avoid system costs
AESO’s SAM starting point for Cost allocation

- Capacity costs will be considered separately from wires and AS
- Cost allocation will consider energy usage at system stress performance periods and coincident peaks
- Customers can hedge capacity costs through financial methods
Key Rate Making Principles

Bonbright’s Principles

- Effective – Recovery variable costs in variable charge, ensure capital attraction and certainty
- Stability – revenue stability for Utility, rate stability for consumer
- Static Efficiency – Maximize the use of the system, correct price signals
- Appropriately priced – Cost/ Causeation
- Fair – Intergenerational equity
- No undue discrimination – treats customers equally
- Practical and simple
Cost Recovery in Other capacity markets

- Determining capacity obligations (Web – Direct Energy)

  - Generally speaking, capacity obligations are determined by a customer's peak load contribution (PLC) or peak monthly demand during a certain timeframe. The timeframe for determining this peak is calculated differently in each ISO/RTO and in the case where a customer is taking supply from an LSE, their host utility is responsible for providing the PLC to suppliers.

  - MISO: In this market, a consumer's peak demand is based on the highest hourly demand during the month and can therefore vary each billing cycle.

  - NYISO and ISO-NE: In this market, a consumer's PLC is determined by the customer's usage during the "peak hour from the previous year." The peak hour is the hour during which the usage was the highest across the RTO, as published by the RTO. Once a customer's PLC is established, it is set for the plan year. The plan year is May 1-April 30* in NYISO and June 1-May 31* in ISO-NE.

  - PJM: In this market, a customer's PLC is determined by their usage during the “five peak hours” (totaled and averaged) from the previous year. The five peak hours are the hours during which the usage was the highest across the RTO, as published by the RTO. Once a customer's PLC is established, it is set for the plan year, which is June 1-May 31*. 
General process – other markets

1. LSE Requests capacity volume
2. ISO Buys capacity
3. ISO allocates cost
4. LSE Bills Customers
AESO Proposed Process

- AESO forecasts peak load plus reserve
- AESO buys capacity
- AESO allocates cost to market participants
  - Energy
  - Peak demand
  - Coincident peak

or
Alternate AESO Process

1. **AESO** forecasts Peak load plus reserve
2. **AESO Buys** capacity
3. **AESO allocates cost to Market Participants based upon MP commitments**
4. Charge for MP use beyond capacity commitment and charge for new customers

MP commits to required capacity
Allocation Alternatives

- Peak at times of system stress
- Coincident Peak
- Use combination of system stress and coincident peak
- Peak from previous year
- Monthly peak
- Five peak hours from previous year
- Energy
Other considerations

- Duration of billing determinant
  - Month/ year

- Ratchet use

- Alignment and consideration for Government initiatives such as energy efficiency under the Climate Leadership plan
Key Issues to determine appropriate allocation method

- Is it important to send a price signal in the allocation methodology if end use customers can participate through demand response and energy efficiency?

- How does the AESO forecast load? Is the charge fixed in the current year? If the charge is relatively fixed how should that influence the cost allocation methodology?

- Is a customer in a better position than the AESO to determine the amount of its required capacity? If the Customer requests the capacity amount, should the Customer not be billed on that amount?

- Does the time of system stress correlate strongly with the coincident peak? Is the AESO buying for system stress or for peak load which will cover all times of system stress? What does the data and process say about the cost allocation methodology?

- How can the capacity charge be easily flowed through to retail customers (like pool price)?

- Should the charge be fixed in the current year (since the AESO purchased capacity prior to the current year)?
# Pros and Cons – Coincident Peak

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<tr>
<th>Pros</th>
<th>Cons</th>
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<tr>
<td>Easy to measure</td>
<td>Some will likely pay no capacity charge</td>
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<td>Likely to be at least partially</td>
<td>Difficult to change once implemented if it influences</td>
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<td>correlated to times of system stress</td>
<td>investment decisions</td>
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<td>Stronger incentive to put in cogen</td>
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<tr>
<td>May drive reduced peak demand, lower</td>
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<td>overall capacity cost</td>
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## Pros and Cons – Peak Demand

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<tr>
<td>Easy to measure</td>
<td>Does not consider system stress events</td>
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<tr>
<td>Likely to be at least partially correlated to times of system stress</td>
<td>If based upon current year peak, not considered in AESO forecast</td>
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<td>Likely that all MP’s will pay some form of charge</td>
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<td>May drive reduced peak demand, lower overall capacity cost</td>
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## Pros and Cons – Energy

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<tr>
<td>Easy to measure</td>
<td>Will not directly drive reduced peak demand</td>
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<tr>
<td>Heavy system users pay more</td>
<td>Cost causation link not as strong as peak demand</td>
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<td>May still incent cogen</td>
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## Pros and Cons – AESO SAM

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<td>CP Easy to measure, times of system stress a new billing determinant (more difficult)</td>
<td>Some will likely pay no capacity charge if CP based</td>
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<td>Incents reduced peak usage and reduced usage at times of system stress</td>
<td>Times of system stress are infrequent, therefore likely not a strong billing determinant</td>
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<td>Stronger incentive to put in cogen</td>
<td>Uncertain how to incorporate times of system stress</td>
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<td>May drive reduced peak demand, lower overall capacity cost</td>
<td>Using multiple price signals may be impractical</td>
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Key Data to help evaluate

- How will the AESO determine demand and then buy capacity
  - Customers should be charged based upon its share of the AESO purchase
  - Determine amount purchased based upon previous year?

- Historical times of system stress
  - Correlation with monthly peak
  - How many hours for each event