CONE TWG Feedback/Discussion

Technical Working Group Meeting #3
May 4, 2018

Alberta Merchant Generation Cost of Capital

To inform the discussion concerning the Alberta-specific cost of capital for merchant generation, we provide additional detail into the components (i.e., capital structure, cost of debt, cost of equity) for the range we are considering for estimating the Cost of New Entry in Alberta

- Relying on the best publicly-available market data remains the starting point for our approach to analyzing merchant generation cost of capital in Alberta
- Investment in a smaller market like Alberta's that is undergoing changes in its market design increases the risk of a new generation resource relative to existing, larger markets, such as PJM
- We find that the upper end of the weighted average cost of capital range shown during the previous meeting is appropriate (8.0 – 8.5%) for narrowing the focus of the merchant generation cost of capital in Alberta

Alberta Cost of Capital Components

- Overall after-tax cost of capital (ATWACC) is at the high end of IPP fairness opinions
- For the same debt fraction (65%), the Alberta-specific cost of equity for IPPs of 13.4% - 14.8% is higher than PJM's (12.8%) due to relative size of the market and changes in market design
  - Merchant generation cost of capital assumes no contracts (higher return)
  - Cost of debt is based on non-investment grade debt and varies with debt fraction
- Merchant generation risk premium in Alberta is higher than in U.S. markets

Illustrative Breakdown of Merchant Generation Cost of Capital

	Brattle Recommendation for Merchant Generation Cost of Capital					Allowed Cost of Equity for Regulated Utilities		
	Alberta				PJM	Alberta (AUC)	Alberta (Brattle)	U.S. Avg
After-Tax Cost of Capital	**8.0%**	**8.0%**	**8.5%**	**8.5%**	**7.5%**			
Debt Fraction	50%	65%	50%	65%	65%	63%	60%	51%
Income Tax Rate	27%	27%	27%	27%	29%			
Cost of Debt	6.0%	7.0%	6.0%	7.0%	6.5%			
Cost of Equity	11.6%	13.4%	12.6%	14.8%	12.8%	8.5%	10.0%	9.8%

Sources: PJM: 2018 PJM CONE Study, p. 36; Alberta (AUC): AUC Decision 20622-D01-2016; Alberta (Brattle): Villadsen Testimony in AUC Proceeding 22570 (2018 GCOC Proceeding); U.S. Avg: SNL.
Note: After-Tax Cost of Capital = (1 – Debt Fraction) * Cost of Equity + Debt Fraction * Cost of Debt * (1 – Income Tax Rate)

Stakeholder Feedback/Discussion from TWG #2

Question	Comments
ATWACC	Do you think the range of cost of capital (ATWACC) presented is reasonable? -A fairly even dispersal of comments from Working Group -Too low (6 respondents) -Reasonable/reasonable at high end of range (4 respondents) -No specific response (6 respondents) **AESO seeking feedback from the "no specific response" participants**
Reference Technology	Can you support the screened reference technologies and the proposed specifications to be used to estimate costs for building and operation of the reference plant? -Can Alberta absorb a larger asset into the system -Is a frame turbine an appropriate technology -Least expensive from a capital cost perspective may not be an ideal fit for the Alberta market -Consider including a reciprocating engine configuration

Energy and Ancillary Service Offset for net-Cone Technical Working Group Meeting #3 May 4, 2018

Navigating Uncertainty

Key Messages for Proposed Methodology

- A **key element** for creating the demand curve is net-CONE - the Cost of New Entry ("CONE") less the margins achieved **within a year** from Energy and Ancillary Services
- Numerous historic and future market fundamentals will lead to **significant uncertainty** in the Energy and AS market, consequently **impacting** net-CONE
- To manage the risk associated to uncertainty, a new stand-alone entrant may follow a **revenue certainty approach** for assessing Energy and AS using the **forward market** to **lock in a commodity margin**
- Energy and AS offsets will be developed for a **stand-alone generator** participating as a **price-taker** (at variable cost)
- Given the **limited volume opportunity and price uncertainty** pertaining to Ancillary Services **post Hydro PPA combined with a lack of forward pricing mechanism**, the new entrant is presumed to participate in the **energy market only (no AS)**

Future Energy & AS Market Uncertainty

Numerous factors including but not limited to the following had and will have significant impacts to prices

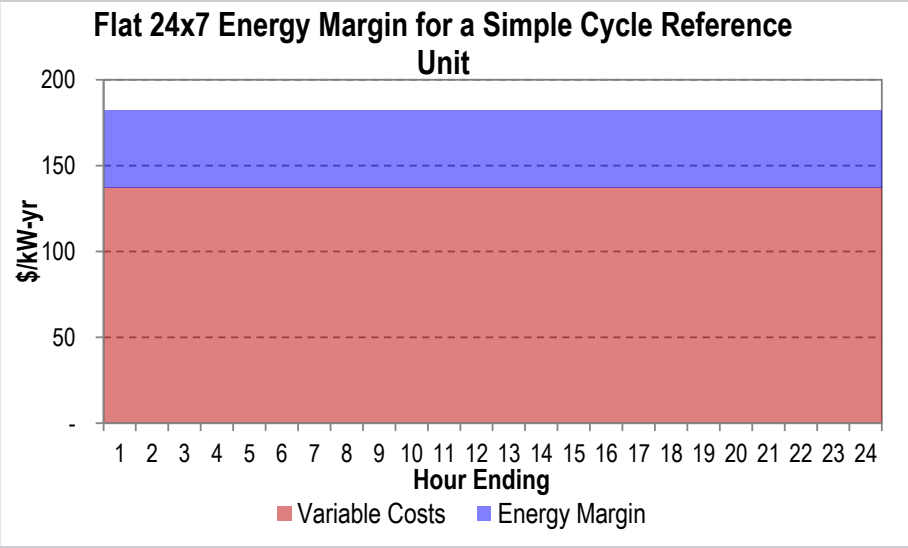
Energy & AS Offset Calculation Methodologies to Account for Uncertainty

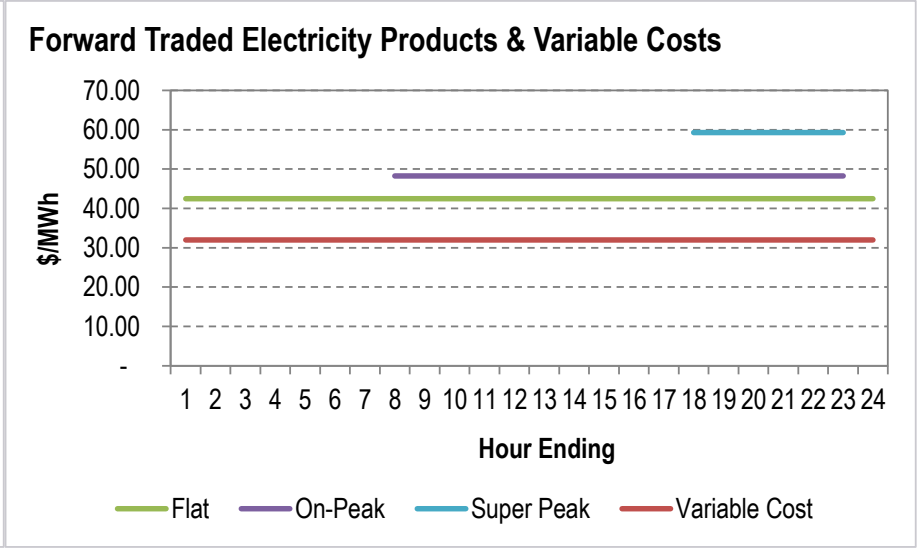
- Formulaic Approach
  - Base future key inputs on historic results adjusted to the future
    - Capacity factor, captured energy price (ie, spark spread) and AS price
- Simulation Approach
  - Develop a forward looking outlook incorporating a Monte Carlo production model
    - Significant number of assumptions (ie, offer strategy, fleet composition)
- Revenue Certainty Approach (Forward Markets)
  - Assume generator will “lock in” a positive cash-flow via a spark spread in the forward market
    - Sell financial power and buy financial gas

Methodology Pros and Cons (Initial Auctions)

Methodology	Pros	Cons	Rank
Formulaic	-Replicability	-Many key historic elements not aligned with the future market	3
Simulation	-Allows for an 8760 Monte Carlo assessment of future assumptions -Provides generator cash-flows for new assets	-Significant number of inputs and assumptions (earlier slide) -Highly sensitive to assumptions -Risk a detailed regulatory review -Highest internal/external effort	2
Revenue Certainty	-Replicability -Developer can financially hedge -Forward market takes into account the collective wisdom of market participants -Structured to manage future market uncertainty -Leverage gas market liquidity	-Limited liquidity in the forward power market	1

Revenue Certainty Comparative/Example: Flat Product (All-hours)





Year	Power ($/MWh)	Natural Gas ($/GJ)	Implied Market Heat Rate (GJ/MWh)	Spark Spread SC ($/MWh)	SC Net CONE ($/kw-yr)	CC Spark Spread ($/MWh)	CC Net CONE ($/kw-yr)
2021	42.50	1.86	22.9	11.3	45.19	25.7	49.57
2022	43.50	1.95	22.4	11.4	51.43	26.1	52.97
2023	45.75	2.09	21.94	12.3	32.41	27.3	33.95

- Note: Spark Spread = Energy less Variable Cost = (Power Price less (Fuel + Carbon + Variable O&M + Losses))
- Carbon price is based on Alberta's *Carbon Competitiveness Incentive Regulation* with $50/tonne carbon cost assumption

Ancillary Services

- The Hydro PPA currently accounts for a significant share of active reserves
- Assumption is that volumes sold by hydro will continue
- There is significant uncertainty as to how the hydro assets will participate in the future Ancillary Services market
- As a result, it is prudent that a stand-alone generator that wants revenue certainty:
  - will not participate in the Ancillary Services market due to lack of pricing certainty and inability to hedge
  - focus on energy as cashflow can be hedged
- Further investigation on-going

Active Operating Reserve Procurements by Generation Technology

Reserve Type	Year	Coal	Cogen	CC	SC	Hydro	Other	Tie	Load
Regulating Reserve	2013	12.7%	12.4%	17.0%	0.0%	57.9%	.	.	.
	2014	20.3%	10.5%	12.3%	0.0%	56.9%	.	.	.
	2015	18.4%	9.5%	13.0%	0.2%	58.9%	.	.	.
	2016	1.4%	12.4%	25.2%	0.1%	60.9%	.	.	.
	2017	2.8%	9.2%	25.2%	0.2%	62.6%	.	.	.
Spinning Reserve	2013	10.3%	23.4%	8.8%	1.7%	52.4%	.	3.4%	.
	2014	9.0%	24.8%	10.7%	1.1%	51.1%	.	3.3%	.
	2015	8.5%	22.1%	13.7%	0.5%	54.5%	.	0.6%	.
	2016	12.1%	22.8%	10.3%	1.3%	53.4%	.	0.1%	.
	2017	5.5%	29.2%	10.9%	0.5%	51.0%	3.0%	.	.
Supplemental Reserve	2013	4.2%	11.6%	3.3%	26.6%	40.8%		0.9%	12.6%
	2014	1.8%	15.2%	4.5%	21.8%	34.3%		1.3%	21.0%
	2015	1.0%	10.3%	3.7%	26.5%	35.7%		0.3%	22.6%
	2016	1.2%	13.0%	5.6%	38.7%	27.6%		.	13.9%
	2017	0.0%	17.4%	6.7%	38.8%	27.8%	2.4%	.	6.9%

Recommendation for Initial Auction(s)

- To develop the net-CONE, the Energy and AS off-set will:
  - Have the reference technology as a stand-alone asset
  - Participate in the energy and not the ancillary service market
  - Be set with the revenue certainty approach for first auction(s)
  - Incorporate the forward product that provides the largest Energy and AS off-set
    - Results in lowest net-CONE
    - Financial product could be baseload (7X24) or a peak product (ie, 7X16, vs 7X6, etc)
      - *Liquidity reduces as product moves away from baseload*
      - *Generation will be tied to running only to meet financial product requirements*
      - *7X24 is 7 days per week and 24 hours per day*

Risk Identification and Mitigation: Potential for Forward Market Manipulation

- Further out terms can be less liquid and more susceptible to market participants bids and offers
- Generation participants may by incented to undertake a strategy to lower forward prices and consequently increase net-CONE

Mitigation

- AESO/MSA – Develop and implement a confidential period of time (ie, 30+ days) to create an average spark spread based on financial power and financial gas
- MSA – Monitor activities and changes in the forward market
- Generators – Potentially self-mitigating as attempting to reduce longer dated products will also negatively lower nearer term products that they may want to hedge

Questions?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