Briefing on generator contingency and remedial action scheme modeling

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General Session
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Agenda

1. Extend remedial action scheme contingency model
2. Virtual supply/demand impact on remedial action scheme constraint
3. Congestion revenue rights market generator distribution factor calculation methodology

Modeling remedial action schemes that drop load or reconfigure the transmission system

EXTEND REMEDIAL ACTION SCHEME CONTINGENCY MODELING

Extend remedial action scheme contingency model

- If a remedial action scheme is programmed to drop load, this load drop will be modeled with the contingency.
  - Results in a different MW quantity spread to the system in the contingency
  - Loss of 1,000 MW of generation and 500 MW of load will result in modeling the pick-up effect of 500 MW of generation on the transmission system
  - Loss of 1,000 MW of load and 500 MW of generation will result in modeling the pick-up effect of 500 MW of load on the transmission system

- If a remedial action scheme is programmed to reconfigure the transmission system (switch lines in or out), this will be modeled with the contingency.
  - Results in different shift factors to use in the contingency case

Virtual supply/demand impact on remedial action scheme constraints

IMPACT OF VIRTUAL SUPPLY/DEMAND

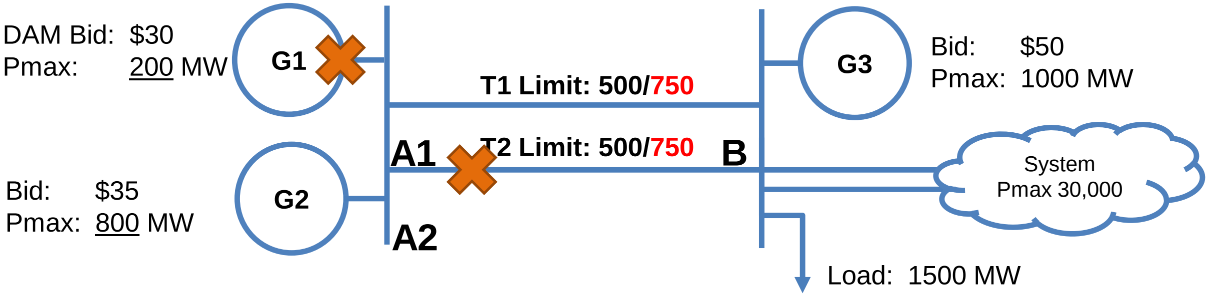
Impact of virtual supply/demand

- Virtual supply at generator contingency nodes will be treated the same as physical supply

- Enforce the contingency constraint regardless of amount of supply bid-in at the location
  - Zero MW of virtual/physical supply bids will simply lead to a zero MW pick-up by the rest of the system and no impact on constraints

- In the day-ahead market, generator contingency node is charged for the congestion it causes: applies to both virtual and physical

Virtual supply at RAS node in day-ahead



DAM

Virtual @A1 Bids $30

Physical @A1 no bid

Contingency:		**Normal**		**Loss of T2 & G1**			
Monitored:		AB Flow < 1000 MW		AB Flow < 750 MW **(binds)**			
AB Flow:		944.97 MW		750 MW			
Generator (i)	**λ^0**	**$SF^0_{i,AB}$**	**μ^0_{BA}**	**$GFF^{G1}_{i,AB}$**	**μ^{G1}_{AB}**	**LMP**	**Award**
Virtual @ A1	$50	1	$0	0.02515723	$15	$49.62	200
Physical @ A1	$50	1	$0	0.02515723	$15	$49.62	0
G2	$50	1	$0	1	$15	$35	744.97
G3	$50	0	$0	0	$15	$50	555.03

RTM

No physical bids @A1

Contingency:		**Normal**		**Loss of T2 & G1**			
Monitored:		AB Flow < 1000 MW		AB Flow < 750 MW **(binds)**			
AB Flow:		750 MW		750 MW			
Generator (i)	**λ^0**	**$SF^0_{i,AB}$**	**μ^0_{BA}**	**$GFF^{G1}_{i,AB}$**	**μ^{G1}_{AB}**	**LMP**	**Award**
Virtual @ A1	$50	1	$0	0.02515723	$15	$49.62	0
Physical @ A1	$50	1	$0	0.02515723	$15	$49.62	0
G2	$50	1	$0	1	$15	$35	750
G3	$50	0	$0	0	$15	$50	750

Congestion revenue rights market generator distribution factor calculation methodology

CRRM GDF METHODOLOGY

CRRM GDF methodology

- Generation distribution factor impacts where the system picks up the lost generation

- CRRM can only model one per <u>time of use</u> per <u>month</u> per resource per contingency

- Day ahead market will have different GDFs per <u>hour</u> per resource per contingency

- Potential for revenue imbalance
  - CRRM GDFs should as accurate as possible

- Proposed to use monthly average GDF per resource per contingency

CRRM GDF methodology

$$GDF_{o_g,i} = \begin{cases} -1 & i = o_g \\ 0 & i \notin S_{FR} \wedge i \neq o_g \\ \left(\frac{1}{N}\right) \cdot \sum_{t \in H} \left(\frac{u_{i,t} \cdot G_{i,max,t}}{\sum_{i \in S_{FR}, i \neq o_g} \left(u_{i,t} \cdot G_{i,max,t} \right)} \right) & i \in S_{FR} \wedge i \neq o_g \end{cases}$$

Where,

- *H is the set of hours in the season (or month) in the time period of interest (e.g. peak or off-peak),*
- *N is the number of hours in H*
- *t is the hour within H*
- $u_{i,t}$ *is the unit commitment status in hour t*

CRRM GDF methodology

Calculation accuracy

- Analyzed January 2016 through January 2017
- Calculated monthly CRR GDFs for 2016 based on 2015 data
- Calculated actual 2016 GDFs per hour in the day-ahead market
  - 94.7% of day-ahead market hours had GDFs within 0.005 of CRRM GDF
  - 97.3% of day-ahead market hours had GDFs within 0.01 of CRRM GDF
  - 99% of day-ahead market hours had GDFs within 0.02 of CRRM GDF

CRRM GDF methodology

Impact on revenue imbalance

- Analyzed January 2016 through January 2017
- Calculated monthly CRR GDFs for 2016 based on 2015 data
- Calculated actual 2016 GDFs per hour in the day-ahead market
- Used day-ahead market shift factors and GDFs to estimate potential revenue imbalance due to differences between CRRM and day-ahead market
  - $199,352 deficit over the year
  - 39% of observations positively impacted imbalance account
  - 45% of observations negatively impacted imbalance account
  - 16% of observations had no impact on the imbalance account

MSC THOUGHTS

MSC thoughts

Given this information:

1. ISO proposes to model remedial action schemes that are programmed to drop load and/or reconfigure the transmission system.

2. ISO proposes to continue to treat virtual supply/demand the same as physical supply/demand.

3. ISO proposes to utilize a monthly average generation distribution factor in the congestion revenue rights market.

QUESTIONS

Bonus reading materials

APPENDIX

Congestion revenue rights enhancements

Proposal to enhance CRR market

Constraint

Flow Constraints for each constraint, *g*	$\sum_{i=1}^{N} X_i \cdot GFF_{i,g} \leq hourlyTTC_g$	$GFF_{i,g}$ is the generator flow factor (calculated as the aggregate impact on the constraint from the locations where the injection is distributed) for the i^{th} control variable on the g^{th} generator/RAS constraint. $HourlyTTC_g$ is the limit for the g^{th} constraint. X_i is the MW quantity of CRRs awarded.

GFF

$$GFF_{i,g} = SF_{i,g} \qquad \forall i \neq o_g$$

$$GFF_{i,g} = \sum_{\substack{i=1 \\ i \neq o_g}}^{N} SF_{i,g}\, GDF_{o_g,i} \qquad i = o_g$$

Proposal to enhance CRR market

GDF

$$GDF_{o_g,i} = \begin{cases} -1 & i = o_g \\ 0 & i \notin S_{FR} \wedge i \neq o_g \\ \left(\frac{1}{N}\right) \cdot \sum_{t \in H} \left(\frac{u_{i,t} \cdot G_{i,max,t}}{\sum_{i \in S_{FR}, i \neq o_g} \left(u_{i,t} \cdot G_{i,max,t}\right)} \right) & i \in S_{FR} \wedge i \neq o_g \end{cases}$$

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