Generator Contingency and Remedial Action Scheme Modeling

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Market Surveillance Committee Meeting
General Session
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Agenda

1. Background on the interconnection process and remedial action schemes

2. Walk through energy pricing examples

3. Real-time settlement of day-ahead positions

4. Congestion revenue rights market enhancements

Background on the interconnection process and remedial action scheme installations

RAS BACKGROUND

Background on interconnection process & RAS

- Interconnection customer asks to interconnect
- ISO/PTO planning groups decide to require RAS or transmission installation based on:
  - reliability studies
  - deliverability studies
  - fixed infrastructure cost
- Decision not based on expected energy market prices
- Costs reimbursed to interconnection customer through TAC
- RAS is installed infrastructure

Energy prices with remedial action schemes modeled in the market

ENERGY PRICES

Energy prices with RAS modeled in the market

- The market should appropriately price each resource's contribution to congestion
- May result in a RAS resource receiving a higher LMP than non-RAS resource at same bus.
  - As shown through example, this is correct: each resource is charged the shadow price for congestion it actually contributes to.

Energy prices with RAS modeled in the market

We will walk through four examples to show pricing effects:

1. **No constraint binding**
   - Same LMP at all nodes

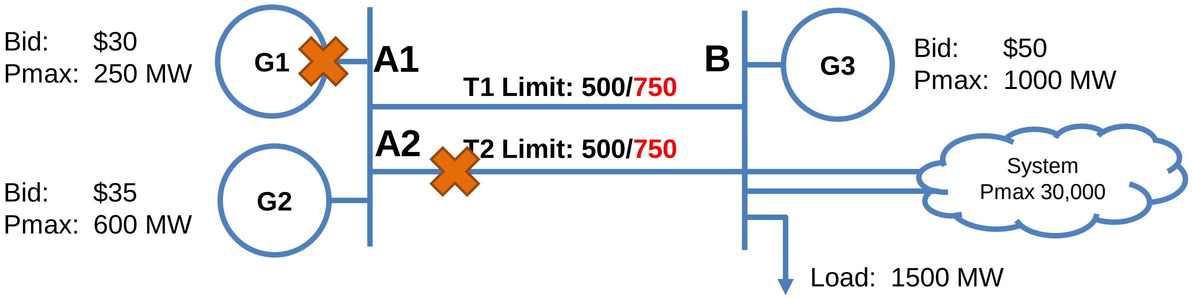
2. **Post-contingency constraint binding**
   - Higher LMP at RAS resource node

3. **Base case constraint binding (non-RAS marginal)**
   - Same LMP at Non-RAS and RAS nodes

4. **Both constraints binding (RAS marginal)**
   - LMP equals bid-cost at all nodes

Energy prices with RAS modeled in the market

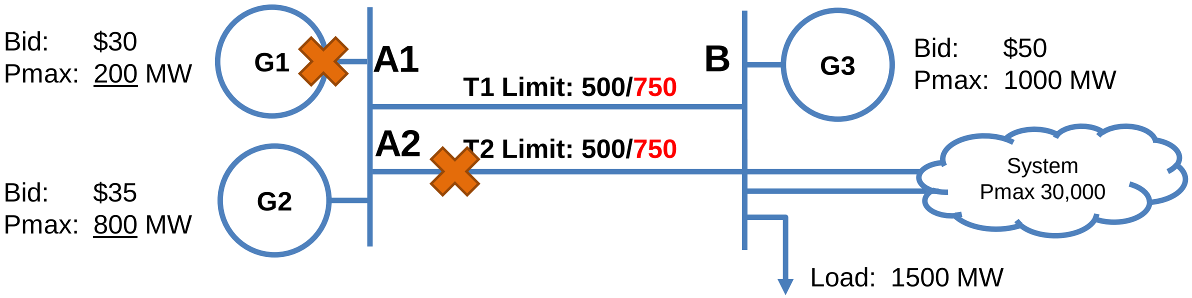
No constraint binding



Contingency:		**Normal**		**Loss of T2 & G1**			
Monitored:		AB Flow < 1000 MW		AB Flow < 750 MW			
AB Flow:		850 MW		604.75 MW			
Generator (i)	**λ^0**	**$SF^0_{i,AB}$**	**μ^0_{BA}**	**$GFF^{G1}_{i,AB}$**	**μ^{G1}_{AB}**	**LMP**	**Award**
G1	$50	1	$0	0.01898734	$0	$50	250
G2	$50	1	$0	0	$0	$50	600
G3	$50	0	$0	1	$0	$50	1000

Energy prices with RAS modeled in the market

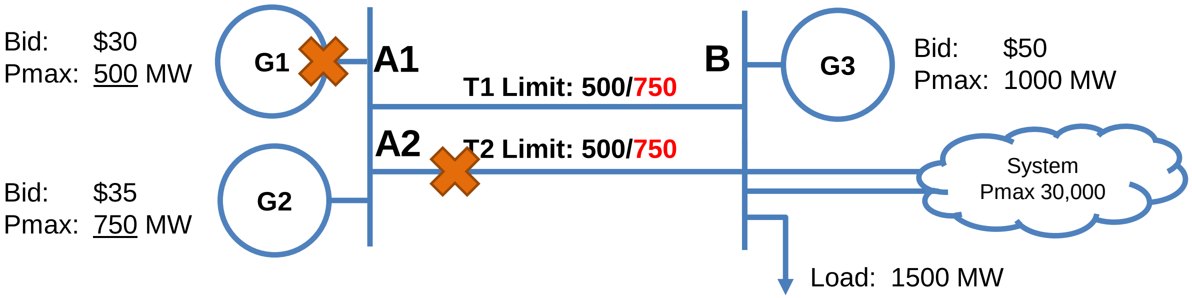
Post-contingency constraint binding



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**
G1	$50	1	$0	0.02515723	$15	$49.62	200
G2	$50	1	$0	0	$15	$35	744.97
G3	$50	0	$0	1	$15	$50	555.03

Energy prices with RAS modeled in the market

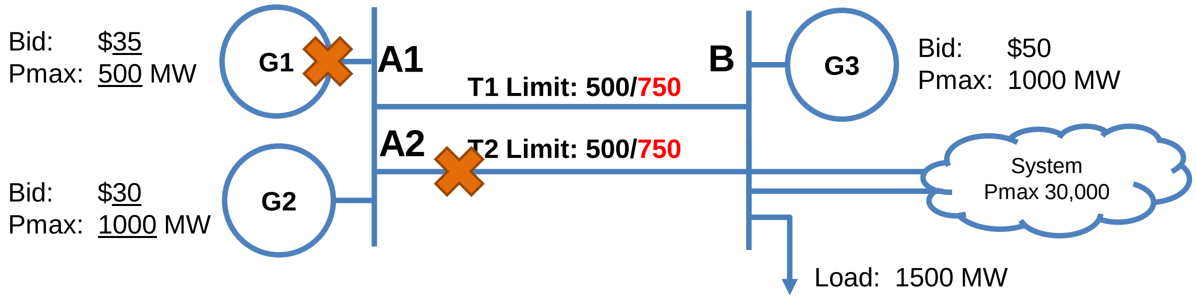
Base case constraint binding (non-RAS marginal)



Contingency:		Normal		Loss of T2 & G1			
Monitored:		AB Flow < 1000 MW **(binds)**		AB Flow < 750 MW			
AB Flow:		1000 MW		511.81 MW			
Generator (i)	**λ^0**	**$SF^0_{i,AB}$**	**μ^0_{BA}**	**$GFF^{G1}_{i,AB}$**	**μ^{G1}_{AB}**	**LMP**	**Award**
G1	$50	1	$15	0.02362205	$0	$35	500
G2	$50	1	$15	0	$0	$35	500
G3	$50	0	$15	1	$0	$50	500

Energy prices with RAS modeled in the market

Both constraints binding (RAS marginal)



Contingency:		**Normal**		**Loss of T2 & G1**			
Monitored:		AB Flow < 1000 MW **(binds)**		AB Flow < 750 MW **(binds)**			
AB Flow:		1000 MW		750 MW			
Generator (i)	**λ^0**	**$SF^0_{i,AB}$**	**μ^0_{BA}**	**$GFF^{G1}_{i,AB}$**	**μ^{G1}_{AB}**	**LMP**	**Award**
G1	\$50	1	\$14.84	0.03125	\$5.16	\$35	258.06
G2	\$50	1	\$14.84	0	\$5.16	\$30	741.94
G3	\$50	0	\$14.84	1	\$5.16	\$50	500

Real-time settlement of day-ahead positions

REAL-TIME SETTLEMENT

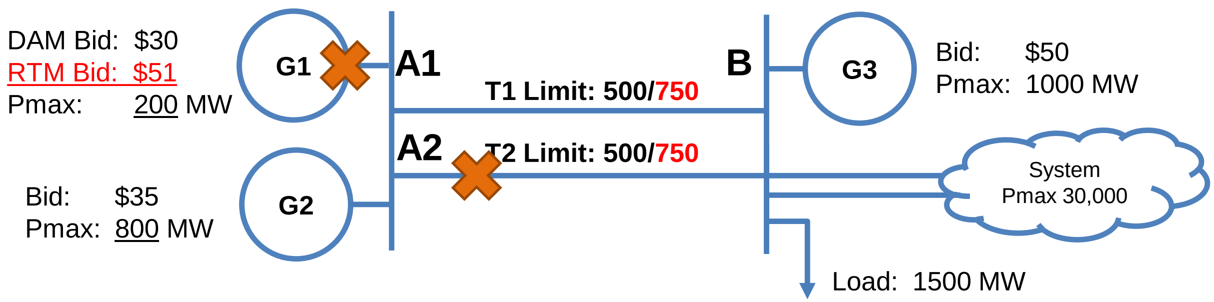
Real-time settlement of day-ahead positions

- What if the RAS resource raises its bid to $51 in the real-time market?

- What if the RAS resource suffers a forced outage in the real-time market?

- Is the RAS node (A1) settled at $35 or $49.62 in RTM?
  - If settled at $35, RAS resource keeps $15
  - If settled at $49.62, RAS resource nets $0

Real-time settlement of day-ahead positions



DAM
G1 Bids $30

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**
G1	$50	1	$0	0.02515723	$15	$49.62	200
G2	$50	1	$0	0	$15	$35	744.97
G3	$50	0	$0	1	$15	$50	555.03

RTM
G1 Bids $51

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**
G1	$50	1	$0	0.02515723	$15	$49.62	0
G2	$50	1	$0	0	$15	$35	750
G3	$50	0	$0	1	$15	$50	750

Examine potential impacts of alternate approaches to modeling in the CRR market

PROPOSED CRR SOLUTIONS

Proposed CRR Solutions

If the DAM SCED is changed but the CRR SFT is not changed, we run the risk of exacerbating revenue inadequacy.

1. **Proposal offers an optimal solution**

   - Directly model the new constraint in the CRR model the same as the market model
   - As it relates to the generator/RAS contingency constraints, ensures revenue adequacy

2. **Proposal offers an alternate solution**

   - Do a historical study to determine the maximum amount of transmission we would have needed to reserve on each constraint per month.
   - Withhold this quantity from the CRR market going forward
   - May be overly conservative
   - May not fully mitigate risk of revenue inadequacy

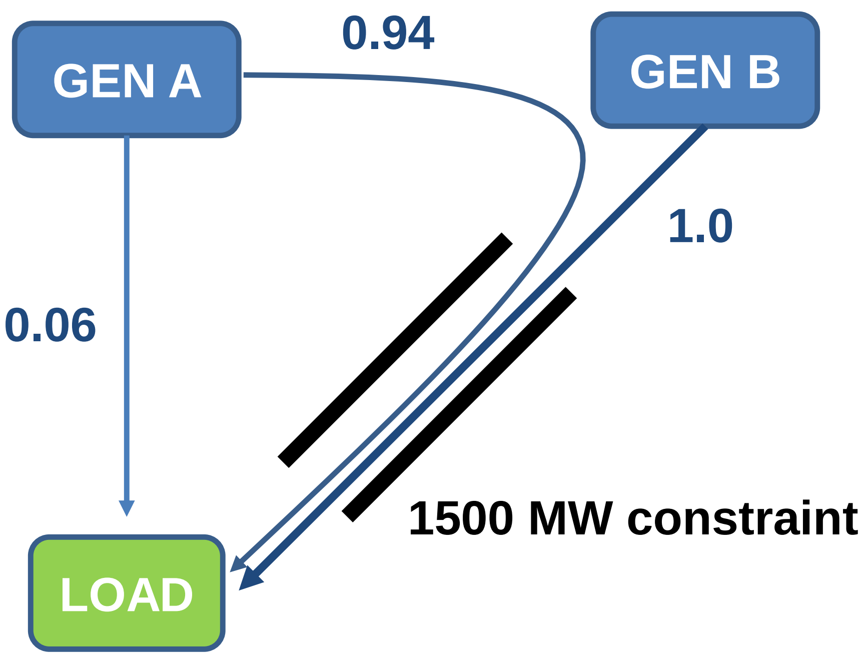
Why are we here?

- We started evaluating this as a revenue inadequacy issue
- The alternative solutions accomplish revenue adequacy
- We realized that modeling these constraints in the CRR market certain ways may lead to equity issues

    Constraining the CRRs using all alternative solutions may lead to an outcome that penalizes the wrong participants.

Representation of day-ahead market model

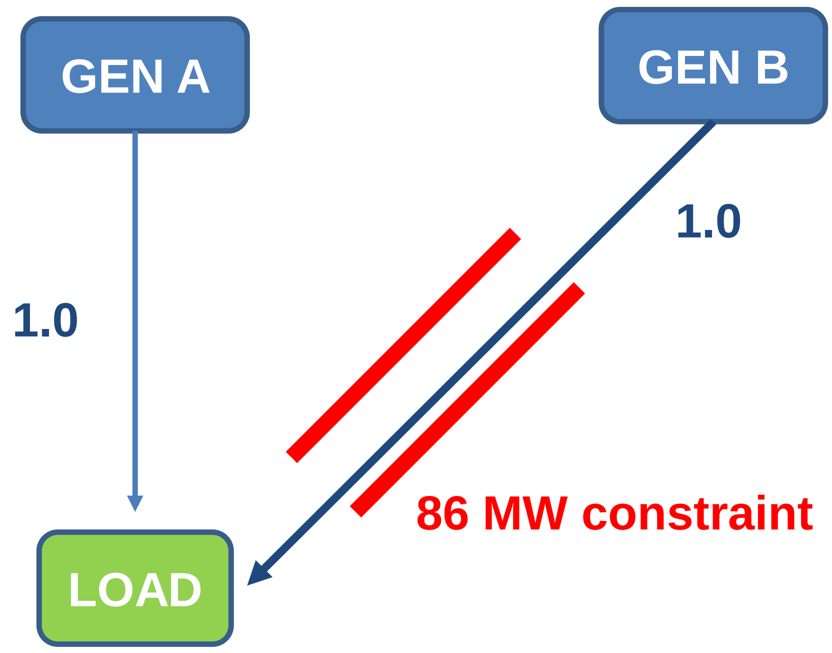
Day-ahead market (using GCARM)



- Both GEN A and GEN B compete for 1500 MW of transmission
- Optimal CRR solution models this exactly the same way.

Representation of alternate CRR solution

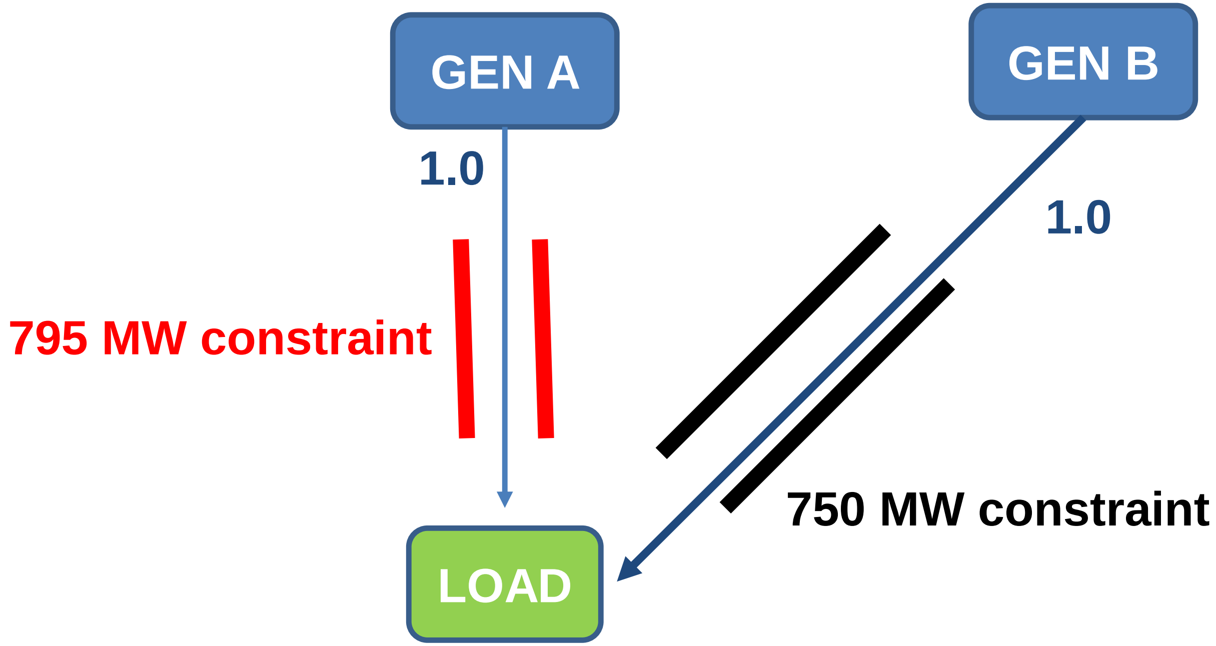
Alternate CRR solution (limit B->A flow)



- GEN A does not compete for transmission, unconstrained.
- GEN B very constrained.

Representation of alternate CRR solution

Maybe apply a nodal constraint! (limit A1 injections)



- Both GEN A and GEN B are constrained in different ways.
- GEN B is not competing with anyone on the transmission path
- **GEN A needs up to 1500 MW CRRs to hedge, but can't bid against GEN B to get them**

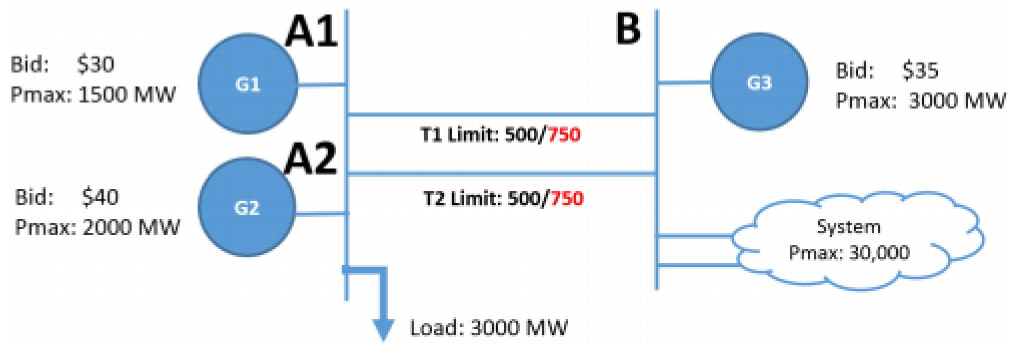
END

Bonus reading materials

APPENDIX

Congestion revenue rights market enhancements

Day-ahead market result

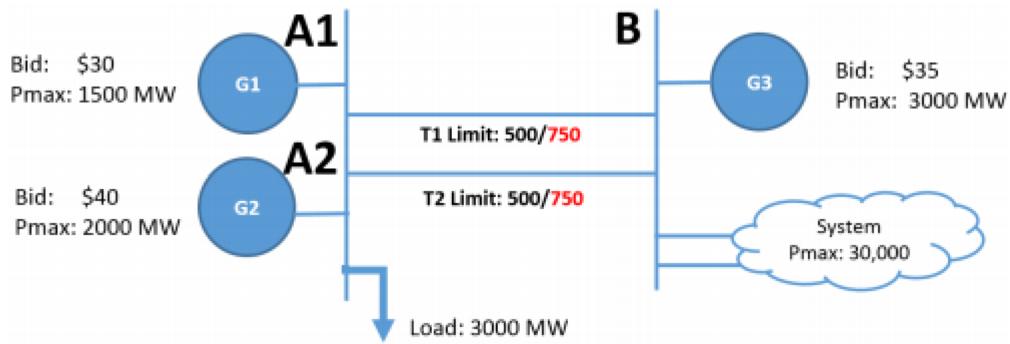


Contingency:		Normal		Loss of T1		Loss of G1		Loss of G2		Loss of G3			
Monitored:				BAFlow<1000		BAFlow<1500 (binds)		BAFlow<1500		BAFlow<1500			
Generator (i)	λ^0	$SF^0_{i,BA}$	μ^0_{BA}	$SF^{T1}_{i,BA}$	μ^{T1}_{BA}	$GFF^{G1}_{i,BA}$	μ^{G1}_{BA}	$GFF^{G2}_{i,BA}$	μ^{G2}_{BA}	$GFF^{G3}_{i,BA}$	μ^{G3}_{BA}	LMP	Award
G1	$40	0	$0	0	$0	0.942857	$5	0	$0	0	$0	$35.29	1500
G2	$40	0	$0	0	$0	0	$5	0.956522	$0	0	$0	$40	1414
G3	$40	1	$0	1	$0	1	$5	1	$0	0.895522	$0	$35	86

Generator	Energy Bid	Energy Award	LMP
G1	$30	1500	$35.29
G2	$40	1414	$40
G3	$35	86	$35

Congestion revenue rights enhancements

Day-ahead market result



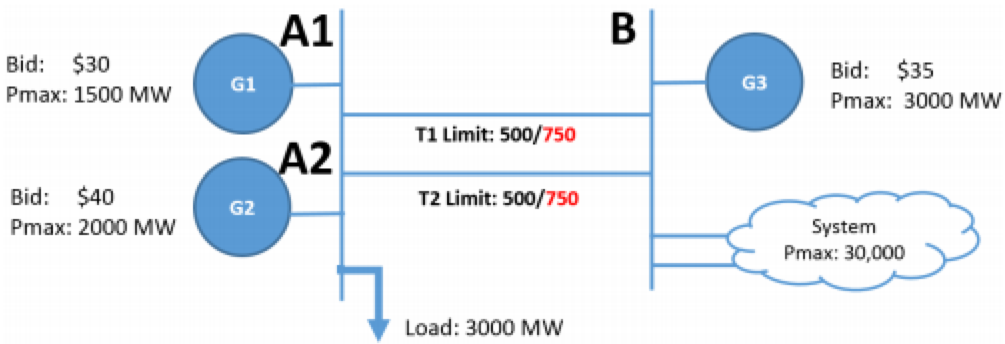
DAM collects congestion revenues:
1,500 MW x $4.71 +
1,414 MW x $0 +
86 MW x $5
= **$7,495**

Contingency:		Normal		Loss of T1		Loss of G1		Loss of G2		Loss of G3			
Monitored:				BAFlow<1000		BAFlow<1500 **(binds)**		BAFlow<1500		BAFlow<1500			
Generator (i)	**λ^0**	**$SF^0_{i,BA}$**	**μ^0_{BA}**	**$SF^{T1}_{i,BA}$**	**μ^{T1}_{BA}**	**$GFF^{G1}_{i,BA}$**	**μ^{G1}_{BA}**	**$GFF^{G2}_{i,BA}$**	**μ^{G2}_{BA}**	**$GFF^{G3}_{i,BA}$**	**μ^{G3}_{BA}**	**LMP**	**Award**
G1	$40	0	$0	0	$0	0.942857	$5	0	$0	0	$0	$35.29	1500
G2	$40	0	$0	0	$0	0	$5	0.956522	$0	0	$0	$40	1414
G3	$40	1	$0	1	$0	1	$5	1	$0	0.895522	$0	$35	86

Generator	Energy Bid	Energy Award	LMP
G1	$30	1500	$35.29
G2	$40	1414	$40
G3	$35	86	$35

Congestion revenue rights enhancements

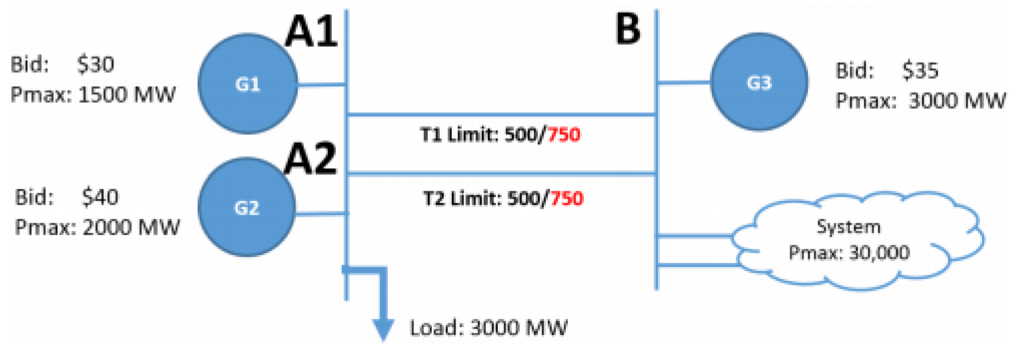
CRR market **without** generator contingencies



Contingency:		Normal	Loss of T1	Loss of G1	Loss of G2	Loss of G3	
Monitored Element:		BAFlow<1000	BAFlow<750 **(binds)**	BAFlow<1500	BAFlow<1500	BAFlow<1500	
Generator (i)	**Ask**	**$SF^{0}_{i,BA}$**	**$SF^{T1}_{i,BA}$**	**$GFF^{G1}_{i,BA}$**	**$GFF^{G2}_{i,BA}$**	**$GFF^{G3}_{i,BA}$**	**Award**
G1	1500 G1->L	0	0	Not Enforced	Not Enforced	Not Enforced	1500
G2	1500 G2->L	0	0	Not Enforced	Not Enforced	Not Enforced	750
G3	3000 G3->L	1	1	Not Enforced	Not Enforced	Not Enforced	750

Congestion revenue rights enhancements

CRR market **without** generator contingencies



CRRs payout:
1,500 MW x $4.71 +
750MW x $0 +
750 MW x $5
= **$10,815**

Contingency:		Normal	Loss of T1	Loss of G1	Loss of G2	Loss of G3	
Monitored Element:		BAFlow<1000	BAFlow<750 **(binds)**	BAFlow<1500	BAFlow<1500	BAFlow<1500	
Generator (i)	**Ask**	$SF^{0}_{i,BA}$	$SF^{T1}_{i,BA}$	$GFF^{G1}_{i,BA}$	$GFF^{G2}_{i,BA}$	$GFF^{G3}_{i,BA}$	**Award**
G1	1500 G1->L	0	0	Not Enforced	Not Enforced	Not Enforced	1500
G2	1500 G2->L	0	0	Not Enforced	Not Enforced	Not Enforced	750
G3	3000 G3->L	1	1	Not Enforced	Not Enforced	Not Enforced	750

$7,495 in day-ahead market collections minus $10,815 in disbursements equals a $3,320 shortfall
CRR balancing account short by **$3,320**

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

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

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

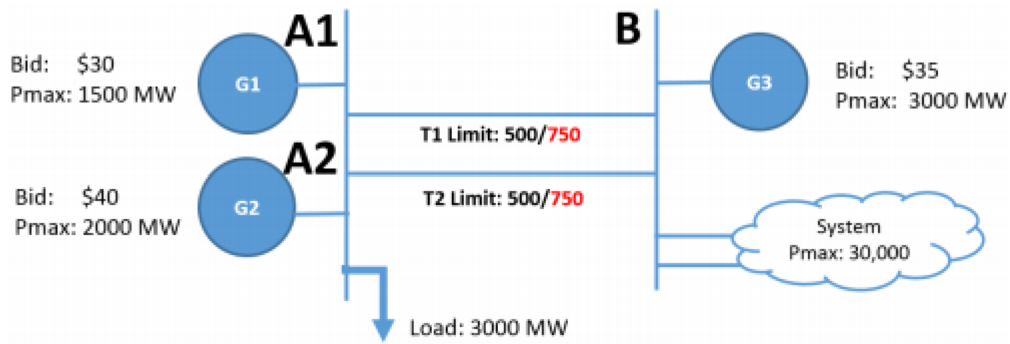
GDF

$$GDF_{season,month,time,g} = \frac{GenerationOutput_{season,month,time,g}}{\sum_{i=1}^{G} GenerationOutput_{season,month,time,i}}$$

$$Where\ G\ is\ the\ set\ of\ all\ frequence\ response\ capable\ generators$$

Congestion revenue rights enhancements

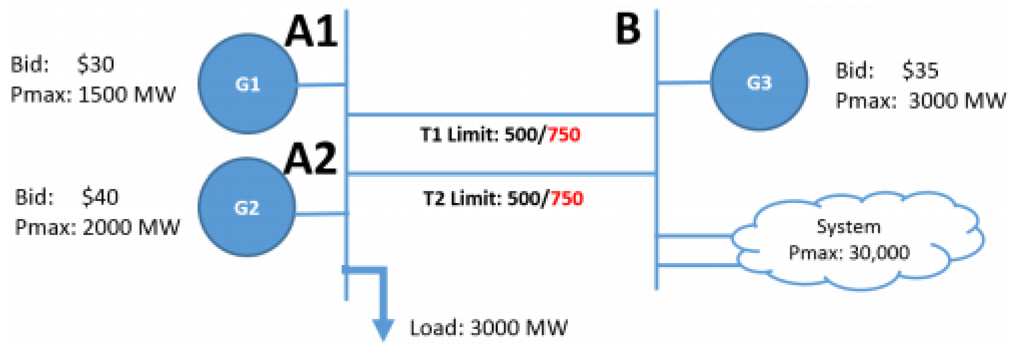
CRR market **with** generator contingencies



Contingency:		Normal	Loss of T1	Loss of G1	Loss of G2	Loss of G3	
Monitored:		BAFlow<1000	BAFlow<750	BAFlow<1500 **(binds)**	BAFlow<1500	BAFlow<1500	
Generator (i)	**Ask**	**$SF^{0}_{i,BA}$**	**$SF^{T1}_{i,BA}$**	**$GFF^{G1}_{i,BA}$**	**$GFF^{G2}_{i,BA}$**	**$GFF^{G3}_{i,BA}$**	**Award**
G1	1500 G1->L	0	0	0.942857	0	0	1500
G2	1500 G2->L	0	0	0	0.956522	0	1414
G3	3000 G3->L	1	1	1	1	0.895522	86

Congestion revenue rights enhancements

CRR market **with** generator contingencies



CRRs payout:
1,500 MW x $4.71 +
1,414 MW x $0 +
86 MW x $5
= **$7,495**

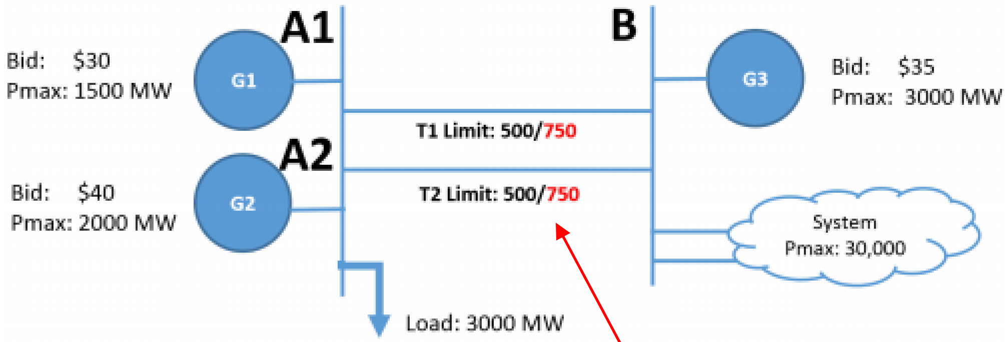
Contingency:		Normal	Loss of T1	Loss of G1	Loss of G2	Loss of G3	
Monitored:		BAFlow<1000	BAFlow<750	BAFlow<1500 **(binds)**	BAFlow<1500	BAFlow<1500	
Generator (i)	**Ask**	**$SF^{0}_{I,BA}$**	**$SF^{T1}_{I,BA}$**	**$GFF^{G1}_{I,BA}$**	**$GFF^{G2}_{I,BA}$**	**$GFF^{G3}_{I,BA}$**	**Award**
G1	1500 G1->L	0	0	0.942857	0	0	1500
G2	1500 G2->L	0	0	0	0.956522	0	1414
G3	3000 G3->L	1	1	1	1	0.895522	86

$7,495 in day-ahead market collections minus $7,495 in disbursements equals a $0 shortfall
CRR balancing account neutral

Congestion revenue rights enhancements

Alternative solution

- Do a historical study on binding generator contingency constraints
- Withhold transmission capacity from the auction



Historical study shows we needed to withhold a maximum of 1,414 MW of transmission
-> set limit to 86 MW