A Market-based Approach to Power System Expansion Planning

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АГЕНТСТВО
ПО ПРОГНОЗИРОВАНИЮ
БАЛАНСОВ В ЭЛЕКТРОЭНЕРГЕТИКЕ

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Outline

- Revisiting of the generation capacity expansion planning process
- Stochastic Reliability Pricing Model: proposed design and key economic properties
- Conclusions

High Level Schematic of the Generation Expansion Planning Process

Resource Adequacy Criteria

- Probabilistic criteria expressed in terms of Loss of Load Probability (LOLP) or Loss of Load Expectation (LOLE). Measured in [days/10 years], [hours/10 years]
- Some countries use Expected Unserved Energy (EUE) measured in MWh or in per cent of total energy consumption
- Determined via specialized probabilistic studies using Monte-Carlo simulations or algorithms based on convolution of probability distribution functions

Planning Reserve Margin

- Defined as the level of installed capacity in excess of peak demand required to maintain the required reserve adequacy criteria
- Determined by iteratively running resource adequacy studies until the required level of LOLE or other indicator is satisfied

Selection of Generation Mix

- Integrated Resource Planning:
  - Stakeholder process
  - Long-term optimization software
  - Capacity expansion scenarios are driven by reserve margin requirements
- Capacity Markets (ISO-NE, NYISO, PJM, Russian Federation)
  - Auction-based mechanism
  - Optimization-based market engine
  - Procured levels of reserves based on reserve margin requirements

The time has come to revisit the foundations of this approach

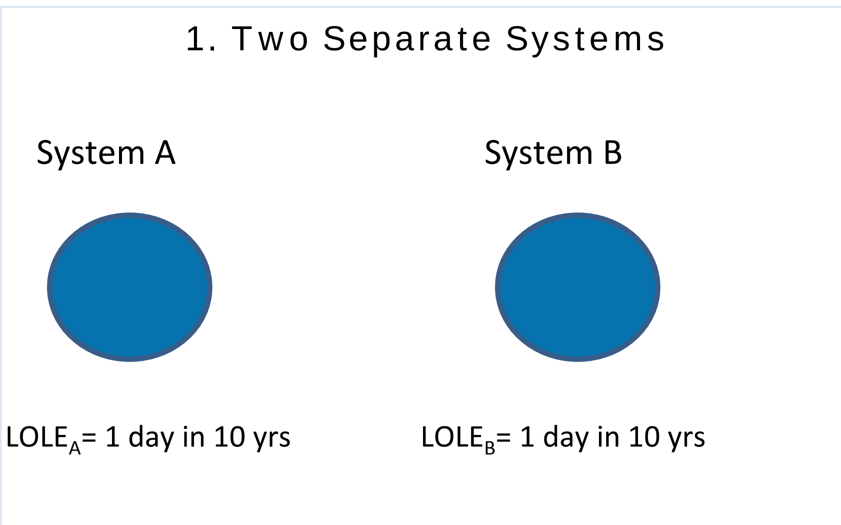
- Relevant technological advancements of the last two decades:
  - Increased computational and algorithmic power allows to address more complex and computationally intensive problems
  - Advancement in metering technologies and development of customer information systems geared toward SmartGrid – improved information on the economics of electricity use
  - Growing penetration of variable resources and energy limited resources, among them resources in the form of demand response, create significant challenges to old concepts
- Institutional advancements
  - Emerging competitive market mechanisms for energy, capacity and ancillary services, virtual power plants auctions, energy procurement auctions, derivative mechanisms (FTRs, virtual bidding)
  - Development of sophisticated market infrastructure supporting optimal operation of electricity markets over large footprints
  - Active participation of demand response in markets for energy, ancillary services, capacity
  - Emergence of highly sophisticated market participants
- Theoretical advancements
  - Theory of spot pricing of electricity, nodal economic theory of power systems
  - Use of auction theory and applications in design and operation of various power markets

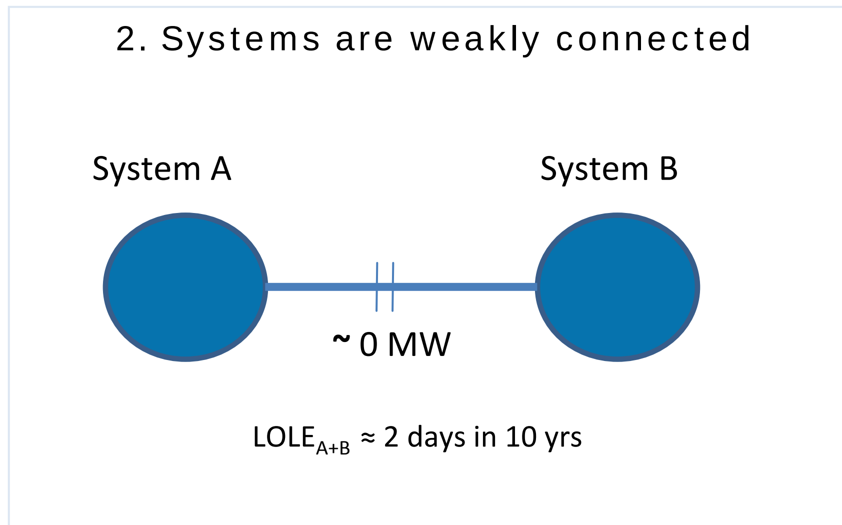
“If it is not broken, don’t fix it…” But what if it is?

- Issue 1. Resource adequacy criteria do not fully reflect the economics of service interruption
- Issue 2. Resource adequacy criteria in the form of LOLE are inadequate indicators of optimal investment in transmission-constrained systems
- Issue 3. Local capacity requirements used in practice for transmission-constrained systems are not based on a sound economic theory and do not appear optimal

Issue 1. LOLE does not fully reflect the economics of service interruptions

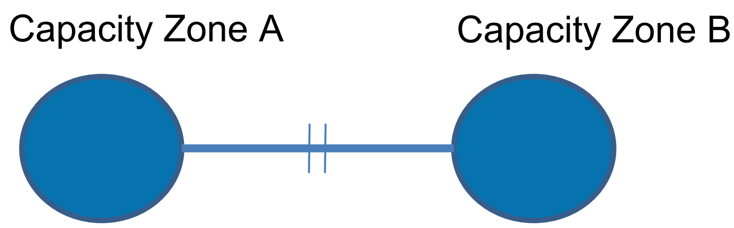
- **LOLE reflects the average frequency of the loss of load in the system as a whole**
- **LOLE does not reflect the frequency of interruption of individual end users or groups of end users**
- **LOLE does not take into account:**
  - size of the system
  - depth of interruption
  - number, fraction, categories of end users being interrupted

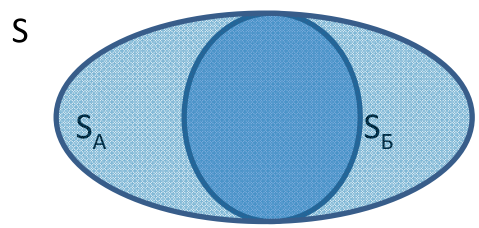




In the second case the frequency of interruption of individual end users is practically the same as in the first case but the LOLE no longer meets the 1 day in 10 years standard

Issue 2: In a transmission-constrained system LOLE does not drive optimal investment decisions





S – set of events of capacity shortage in the system

S_A – set of events in which capacity shortage can be resolved by shedding load in Zone A

S_B – set of events in which capacity shortage can be resolved by shedding load in Zone B

<u>In the absence of transmission constraints</u>

LOLE (hours/yr) = P [S] x 8760 = ∂EUE/∂L,
P [S] – probability of all events in S
<u>Optimal capacity addition rule</u>:

LOLE x VOLL = ∂EUE/∂L x VOLL ≥ CRR
CRR – annualized capacity revenue requirement

<u>In a constrained system</u> LOLE does not drive the optimal capacity addition rule:

<u>Optimal capacity addition rule for Zone A</u>
P [S_A] x 8760 x VOLL = $\partial EUE/\partial L_A$ x VOLL ≥ CRR_A

<u>Optimal capacity addition rule for Zone B</u>
P [S_B] x 8760 x VOLL = $\partial EUE/\partial L_B$ x VOLL ≥ CRR_B

The right indicators are $\partial EUE/\partial L_A$ and $\partial EUE/\partial L_B$

The relationship LOLE = ∂EUE/∂L only holds for an unconstrained system

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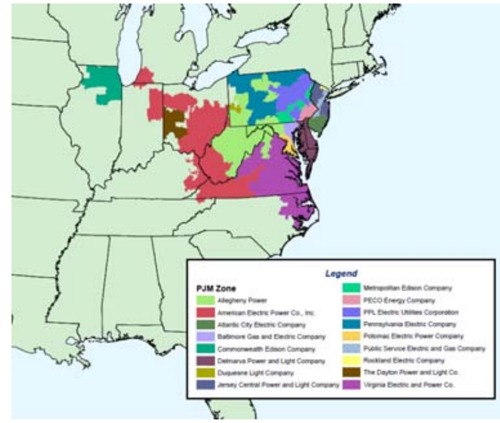
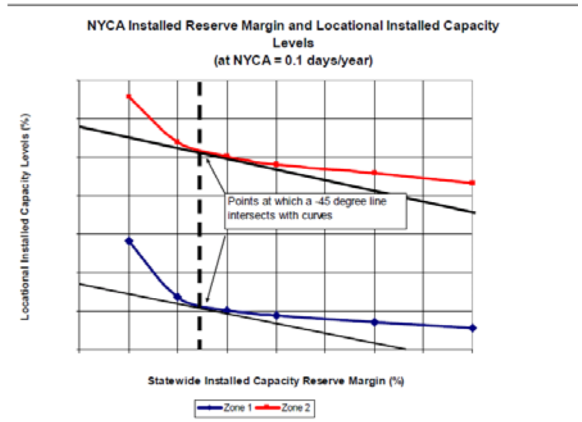
Issue 3. How installed capacity requirements are set

- Example 1: PJM
  - Sets system-wide LOLE requirement of 1 day in 10 years and local LDA requirements at 1 day in 25 years
  - Effectively determines installed capacity requirements by zone on the basis of 1 day in 25 years LOLE criteria (subject to 100% availability of imports)



- Example 2: NYISO
  - Sets up system-wide LOLE requirement of 1 day in 10 years. Upstate/downstate split in capacity requirements are set on the relative trade-off basis: increasing downstate reserve margin by 1% while reducing system reserve margin by 1% must preserve the LOLE of 1 day in 10 yrs



Neither of these methods appears optimal

Proposed Approach: Stochastic Reliability Pricing Model

- Market-based: optimal generation mix is selected through a capacity procurement auction conducted on a regular basis (e.g. annually)
- Planning horizon: one- or multi-year
- Footprint: an RTO but preferably all interconnected RTOs
- Market engine:
  - Uses full transmission model and factors in security constraints;
  - Models generator availability as stochastic processes;
  - Models demand as stochastic processes;
  - Does not require regional reserve margins as an input;
  - Explicitly incorporates expected value of unserved energy **E**(VUE) into the auctioneer's objective function
- Auction outcome:
  - Optimal selection of the resource mix
  - Locational capacity prices for resources
  - Locational capacity prices for loads

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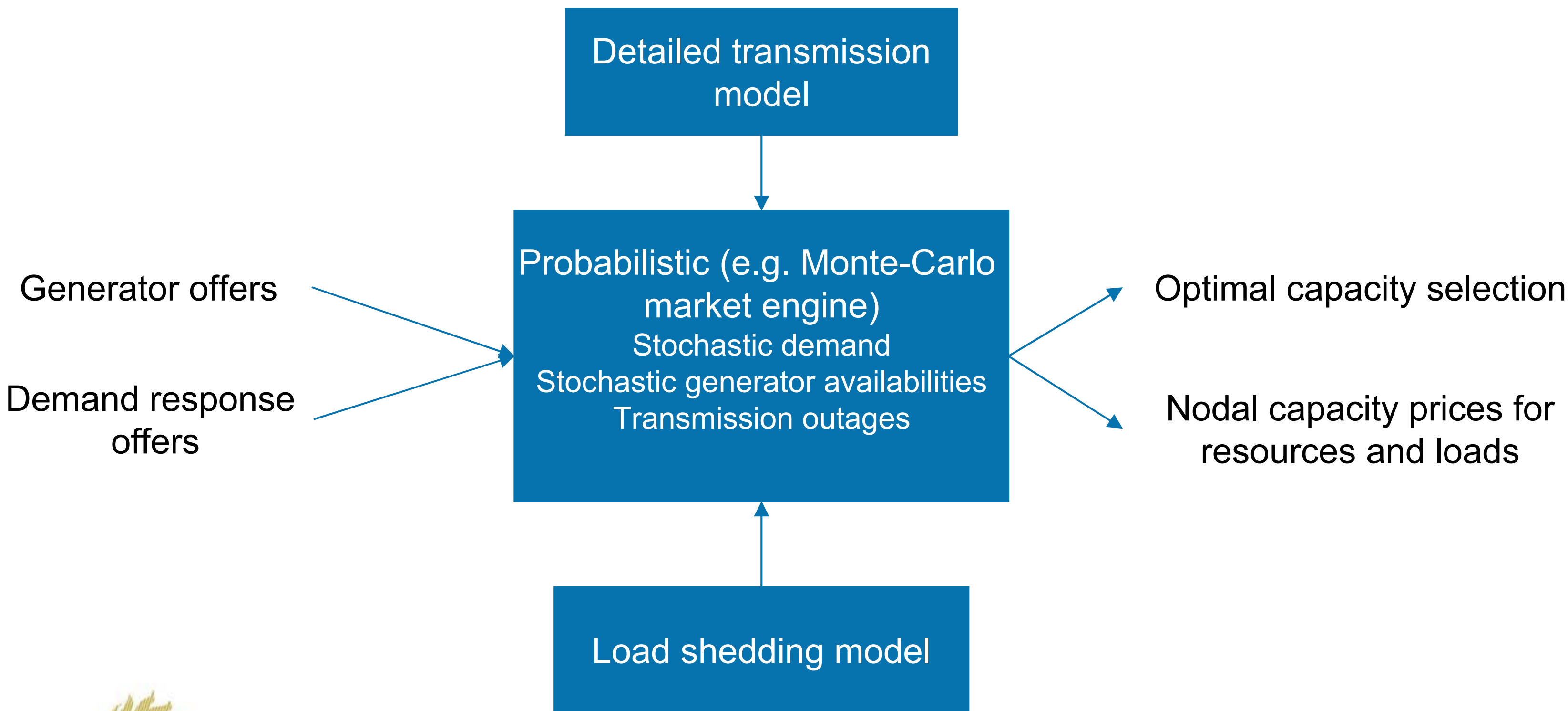
Schematic of the Market Engine

Auctioneer's Objective Function: **min [**(Gen Cost @CRR) + (DR Cost @CRR) + **E**(VUE)**]**
Planning horizon: one- or multi-year



Market Engine Inputs

Inputs	Explanation/source
• Detailed transmission model	• Transmission topology which may be changing over planning horizon by incorporating planned projects and a pre-determined set of flowgates
• Transmission outages	• Based on historical statistics or engineering estimates
• Generator offers	• Price/quantity pairs: CRRs and installed capacity for existing and new capacities
• Stochastic generator availabilities	• Based on historical statistics or engineering estimates
• Stochastic demand	• Stochastic variations around demand forecasts developed by LSEs or System Operator
• Demand response offers	• Price/quantity pairs: CRRs and levels of demand reduction below forward contracts to purchase power
• Load shedding model	• Locational levels of load shedding potential and associated VOLLs set administratively and/or specified by large buyers

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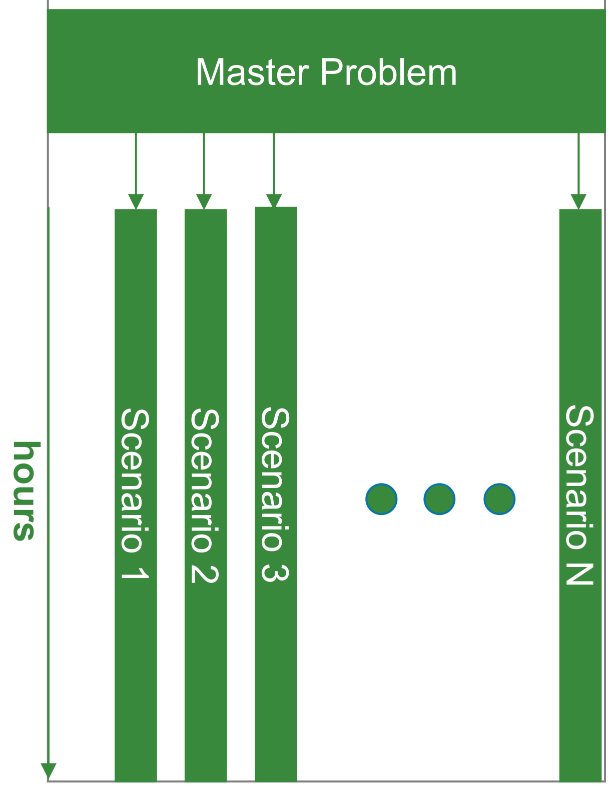
Auctioneer’s Optimization Problem

Problem Structure	Comments
	• LP problem for capacity selection which is fixed over time and across stochastic scenarios • One LP sub-problem for each stochastic scenario/hour (assuming no inter-temporal constraints) • The sub-problem is “security constrained optimal dispatch” with all selected resources being committed, zero resource costs and positive costs of load shedding (reliability dispatch) • Objective function is VUE = VOLL x UE • Each scenario/hour yields nodal prices – Locational Stochastic Reliability Price (LSRP) • No load shedding anywhere → LSRP = 0 • Load shedding somewhere, no transmission congestion → LSRP = VOLL (if VOLL is uniform) • Load shedding + transmission congestion → LSRP vary by location

Resource Capacity Price (RCP)

$$RCP_j = \mathbf{E}\sum_t \overline{S}_j(t,\omega)\max\left(0, LSRP_j(t,\omega)\right) - \mathbf{E}\sum_t \underline{S}_j(t,\omega)\max\left(0, -LSRP_j(t,\omega)\right)$$

- Resource capacity price is the difference between the reliability value of the option to use 1 MW of capacity when it is needed and the reliability cost of the obligation to use 1 MW of capacity when it is not needed

$\overline{S}_j(t,\omega)$ and $\underline{S}_j(t,\omega)$ - p.u. maximum resource availability and low bound operational limitation, respectively

- LSRPs and resource availabilities are negatively correlated! Existing practice of relying on historically estimated UCAP and multiplying it by capacity price is biased and may inadequately compensate generators in the capacity market
- Ultimately, the resource offer is
  - Accepted fully if offer price is below RCP_j
  - Rejected fully if offer price is above RCP_j
  - Accepted partially (marginal) if offer price is equal to RCP_j
- In the auction settlement, resources are paid RCPs for each MW of accepted installed capacity

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Load Capacity Prices (LCP) and the Overall Settlement

$$LCP_j = \mathbf{E}\sum_t LSRP_j(t,\omega)\left[\frac{L_j(t,\omega) - u_j(t,\omega)}{D_j}\right]$$

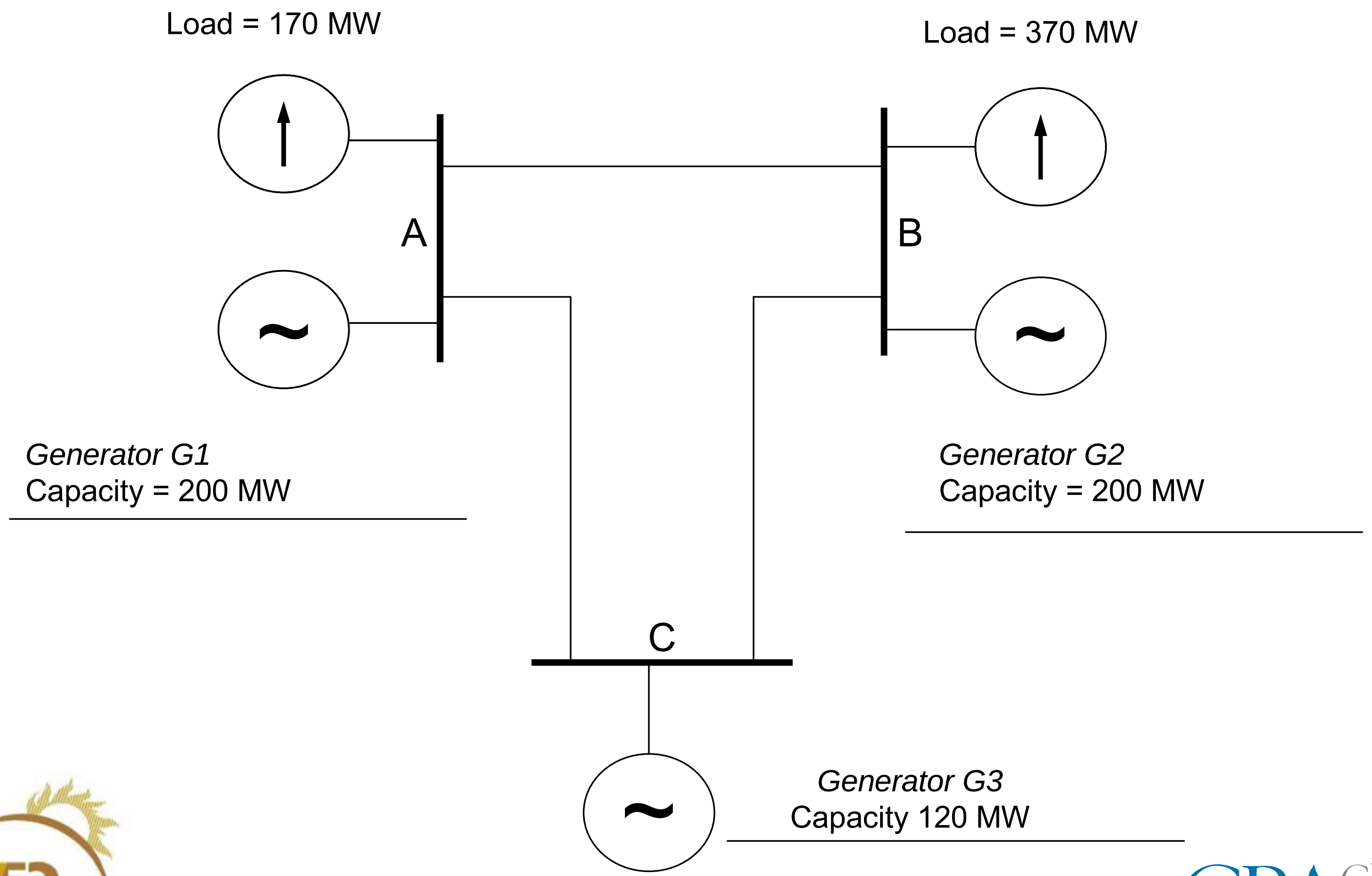
- Load payment depends on served load simulated in each scenario: *a load pays for reliability only to the extent it is not interrupted at the time when others are*
- Depending on consumption patterns and/or level of interruption loads at the same location may pay different capacity prices
- Prices are defined per unit of projected peak demand
- Projected peaks are used as a billing determinants in the auction settlement

$$\sum_j D_j LCP_j = \sum_j X_j RCP_j + \text{CongRent}, \quad \text{CongRent} \geq 0$$

- Congestion rent equals the expected value of total congestion costs of reliability dispatch and is never negative
- The Auctioneer is never revenue deficient

LSRPs, RCPs and LCPs are primarily driven by the economics of service interruptions

To illustrate this, we consider several examples using a three-node system with all lines having identical impedance. By design, the system is short: total demand is 540 MW, total available capacity is 520 MW. In all examples flow on the line B-C is limited



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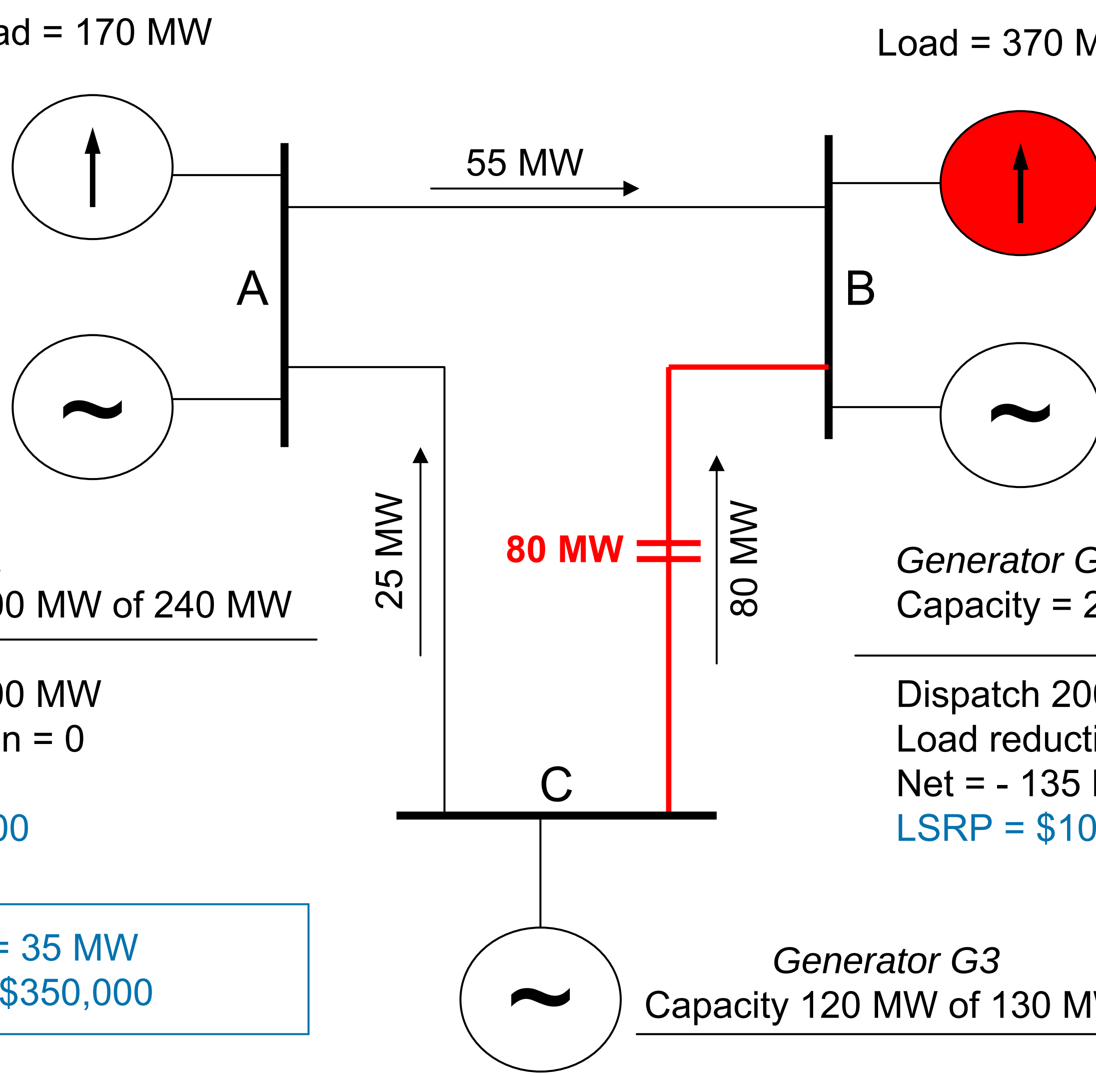
Summary of Examples

	LSRP
• For simplicity, we assume a single VOLL of \$10,000/MWh at all locations	
• Example 1. Although the system is only short for 20 MW, transmission constraint on a flow from C to B forces shedding of 35 MW of load at B. As a result, LSRPs at all nodes are different, but non-negative and do not exceed VOLL	A \$5,000 B \$10,000 C \$0
• Example 2. Similar to Example 1, but load reduction at B is limited. As a result, prices at all nodes double and at node B price is twice the VOLL	A \$10,000 B \$20,000 C \$0
• Example 3. Similar to Example 2, but transfer limit from C to B is reduced to 40 MW and load reduction at B above limit is priced at 3 x VOLL As a result, LSRP at B goes up to 3 x VOLL, while generation at C is forced to zero, resulting in a negative price of – VOLL at that node. • Example 4. Same as Example 3, but generator at C is required to operate above 10 MW. LSRPs are the same as in Example 3 but a case like that reduces RCP for generator C	A \$10,000 B \$30,000 C -\$10,000

Example 1

VOLL = $10,000



Generator G1
Capacity = 200 MW of 240 MW

Dispatch = 200 MW
Load reduction = 0
Net = 30 MW
LSRP = $5,000

Generator G2
Capacity = 200 MW of 220 MW

Dispatch 200 MW
Load reduction 35 MW
Net = - 135 MW
LSRP = $10,000

UE = 35 MW
VUE $350,000

Generator G3
Capacity 120 MW of 130 MW

Dispatch 105 MW
LSRP = $0

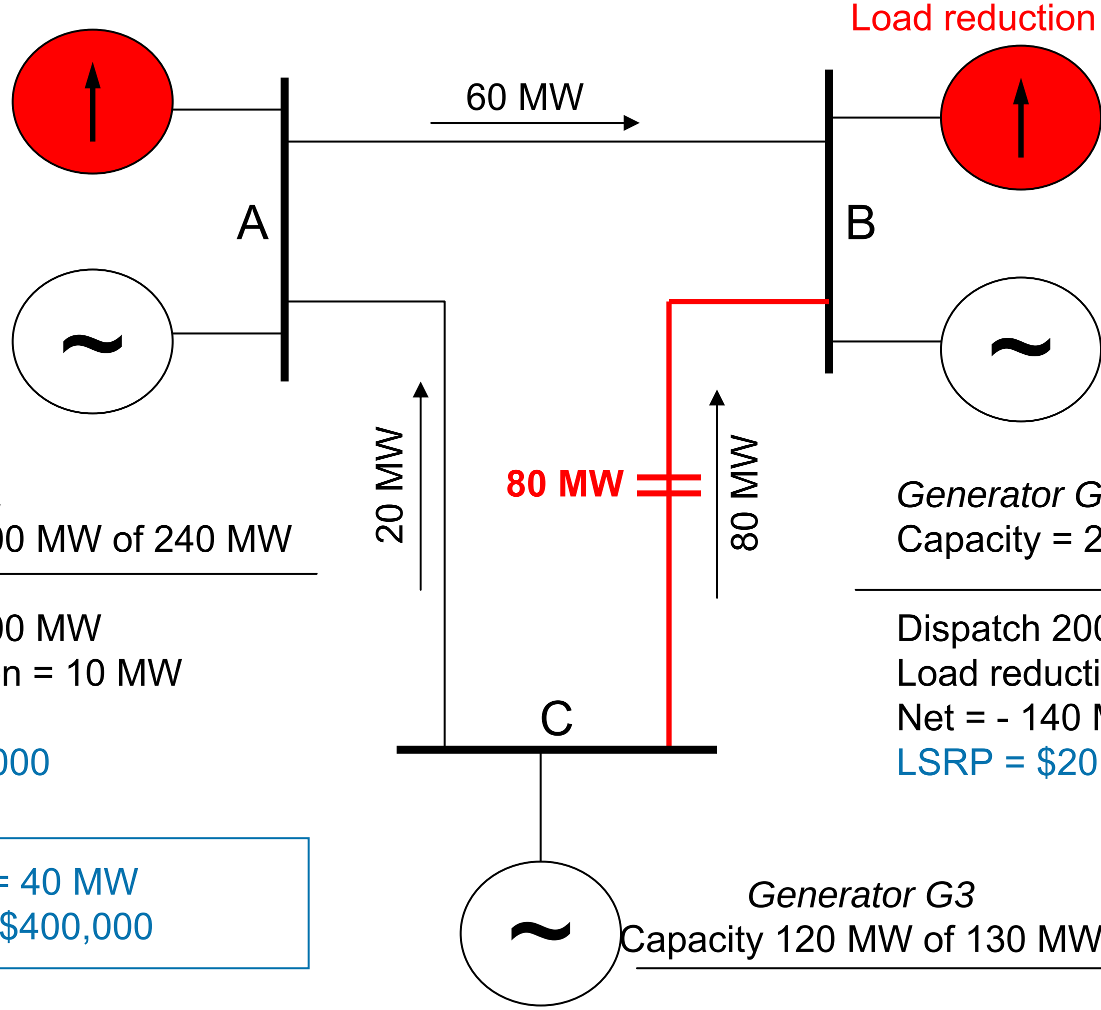
Example 2

VOLL = $10,000

Load = 170 MW

Load = 370 MW

Load reduction ≤ 30 MW



Generator G1
Capacity = 200 MW of 240 MW

Dispatch = 200 MW
Load reduction = 10 MW
Net = 40 MW
LSRP = $10,000

Generator G2
Capacity = 200 MW of 220 MW

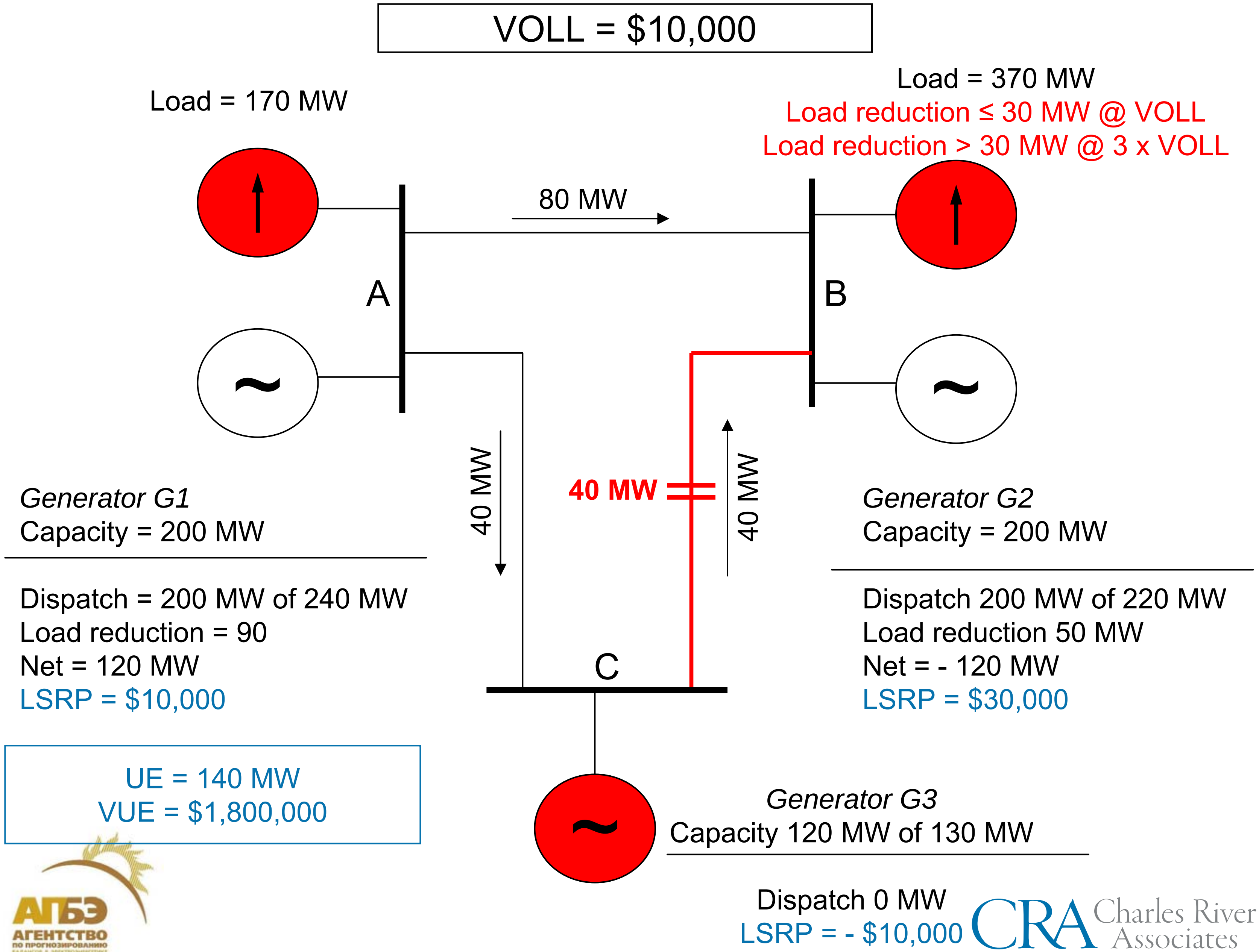
Dispatch 200 MW
Load reduction 30 MW
Net = - 140 MW
LSRP = $20,000

UE = 40 MW
VUE $400,000

Generator G3
Capacity 120 MW of 130 MW

Dispatch 100 MW
LSRP = $0

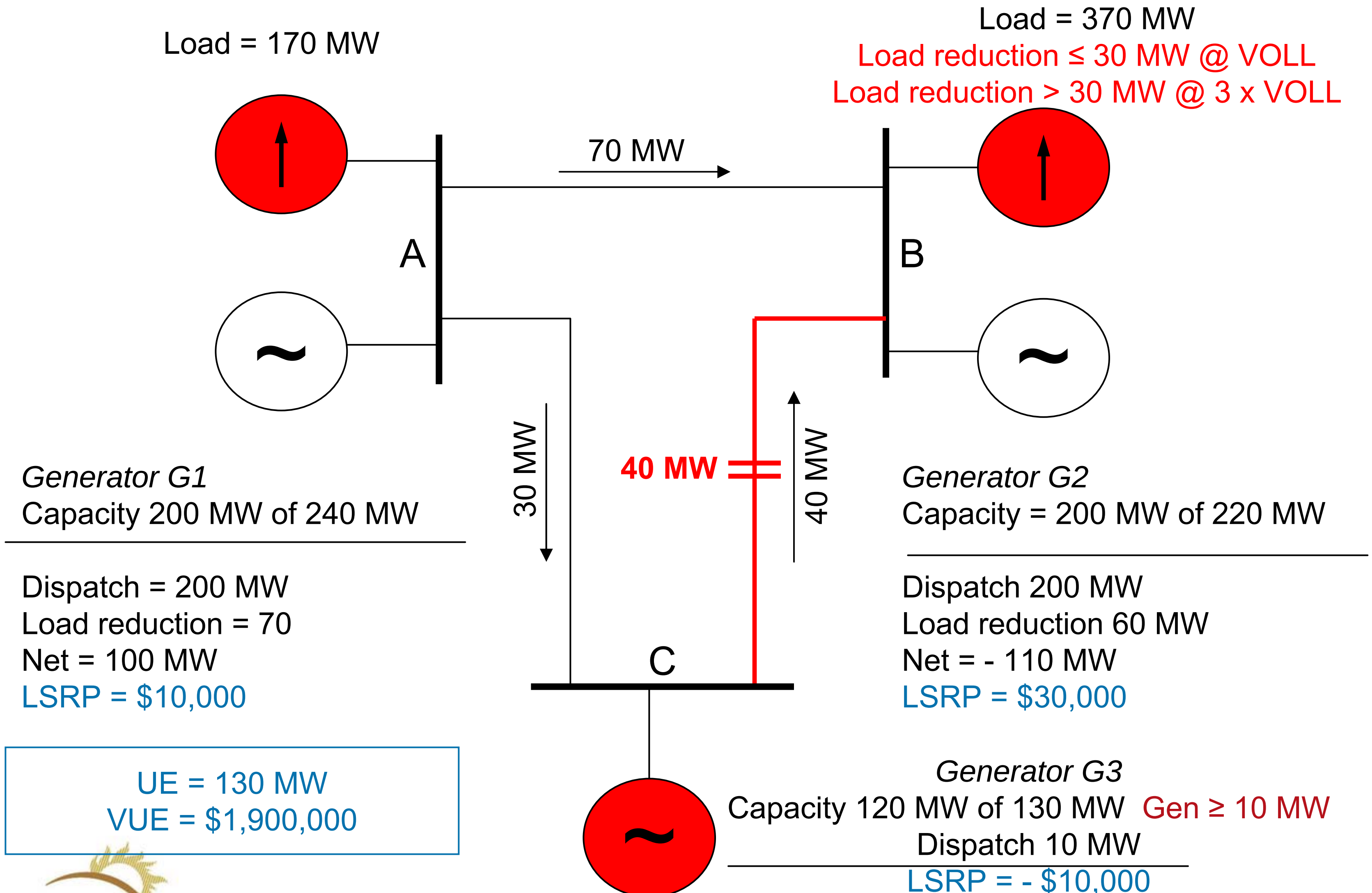
Example 3



VOLL = $10,000
Load = 170 MW
Load = 370 MW
Load reduction ≤ 30 MW @ VOLL
Load reduction > 30 MW @ 3 x VOLL
80 MW
A
B
40 MW
40 MW
40 MW
C
Generator G1
Capacity = 200 MW
Dispatch = 200 MW of 240 MW
Load reduction = 90
Net = 120 MW
LSRP = $10,000
Generator G2
Capacity = 200 MW
Dispatch 200 MW of 220 MW
Load reduction 50 MW
Net = - 120 MW
LSRP = $30,000
UE = 140 MW
VUE = $1,800,000
Generator G3
Capacity 120 MW of 130 MW
Dispatch 0 MW
LSRP = - $10,000

Example 4

VOLL = $10,000



UE = 130 MW
VUE = $1,900,000

Market Outcome Example

- Examples 1 – 4 are the only instances of service interruption
- Each instance of interruption has a duration of 1 hour
- Each instance of interruption has a probability of 0.1 per year

Summary of Scenario Outcomes

	Probability	Bus A	Bus B	Bus C
Generator capacities		240	220	130
Load capacity requirements		170	370	0
LRSPs by Scenario				
Example 1	0.1	5,000	10,000	0
Example 2	0.1	10,000	20,000	0
Example 3	0.1	10,000	30,000	(10,000)
Example 4	0.1	10,000	30,000	(10,000)
Loads Servable by Scenario				
Example 1	0.1	170	335	NA
Example 2	0.1	160	340	NA
Example 3	0.1	80	320	NA
Example 4	0.1	100	310	NA
Generator Availabilities by Scenario				
Example 1	0.1	83%	91%	92%
Example 2	0.1	83%	91%	92%
Example 3	0.1	83%	91%	92%
Example 4	0.1	83%	91%	92%
Generator low bound limitations				
Example 1	0.1	0.0%	0.0%	0.0%
Example 2	0.1	0.0%	0.0%	0.0%
Example 3	0.1	0.0%	0.0%	0.0%
Example 4	0.1	0.0%	0.0%	7.7%

Market Settlement

	Bus A	Bus B	Bus C	System
Mean LSRP ($/MW-yr)	3,500	9,000	(2,000)	
Load Capacity Price ($/MW-yr)	2,500	7,851		
Resource Capacity Price ($/MW-yr)	2,917	8,182	(76.92)	
Load Payments ($)	425,000	2,905,000	-	3,330,000
Generator Receipts ($)	700,000	1,800,000	(10,000)	2,490,000
Congestion Rent ($)				840,000

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Conclusions

- Technological, theoretical and institutional advancements of the last two decades create the need and opportunity to revisit certain foundations underlying the current practice of capacity expansion decisions in the power industry
- The concepts of Loss of Load Expectation and Planning Reserve Margins, while being useful indicators of resource adequacy, are not suitable for making optimal investment decisions in complex transmission-constrained systems
- The proposed approach to explicitly incorporate the resource adequacy assessment into the design of capacity auction overcomes existing methodological difficulties and promises a more efficient selection of generation and demand-side resources than current designs
- If implemented, this approach will:
  - Yield location-specific capacity prices consistent with actual transmission topology and limitations and helping resource developers make better siting decisions;
  - Adequately reflect stochastic and temporal properties of resource availabilities into their compensation in the capacity market – particularly important for variable resources and demand response;
  - Adequately compensate contribution of resources to system reliability based on their location on the grid and availability at the time of need;
  - Provide fair reliability pricing for loads consistent with their impact on system reliability at the time of resource scarcity;
  - Create the means for the demand-side to more fully participate in the capacity market not only in the form of demand-response but by explicitly incorporating into the market model the economics of service interruptions

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