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Demand Response (DR) : Assessing DR in Energy Markets

Presented at:

9th Annual Electric Market Forecasting Conference

Sponsored by: EPIS, Inc.

Omni Tucson Resort
Tucson, Arizona
October 18-20, 2006

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Today's DSM Environment

- EE and DR are now being considered in regions that have not previously aggressively pursued these options.
  - Managing price and volumetric risks now seen as a major issue.
  - Integrated utilities now looking at these options as "tariffed programs."
  - Concern over a new regime of rising fuel costs (gas, oil and coal).
  - AND a desire to provide customers with ways to manage energy costs.
- Linking wholesale and retail markets through appropriate pricing seen as important for the industry.
  - Leads to more pricing-types of solutions.
  - Reflected in Energy Policy Act (EPAct) in the U.S.
- EE and DR becoming viewed as integrated solution, i.e., part of the same spectrum of services.
  - But some EE supporters resist DR investments and EE/DR integration.
  - Overall, more DR now being considered than in the last DSM "boom" of the 1980s to early 1990s.

Today's DSM Environment (cont.)

- More states spending substantive amounts on DSM (EE, DR and Pricing).
- More states and utilities actively supporting new DR:
  - System-reliability based DR – interruptible customers tied to notification.
  - Price-based DR - customers make choices in response to price signals.
- Incentives for DSM investment returning after nearly disappearing in many regions (restructuring one reason for demise of incentives).
- Renewables (particularly wind) increasingly seen as viable alternatives (but, planners are assuming small amounts (e.g., 5%) of the wind capacity being used as the estimate available on peak).
- Resource planning now seen as a process for procuring lowest cost resources **AND** as a process for managing price and quantity risks.
  - DSM options are being viewed as a "resource" that diversifies the portfolio and provides a physical hedge against different uncertainties.

Importance of DSM Pricing Options

- Developing initiatives that allow customers to respond to prices (directly or to good proxies) is critical for the industry.
- It can be argued that industry change/restructuring has actually reduced the price responsiveness of demand.
  - Non-market, flat prices continued as part of standard offer or default supply services.
  - A freeze on electric tariffs including tariffed load management programs.
  - Few innovative offerings from competitive providers, given existing regulated rates.
- If the industry does not price what is scarce -- on-peak electricity use -- how can we:
  - Have efficient resource allocation in markets?
  - Incent innovation – get technology companies to invest in energy management technologies?
  - Improve productivity in one of the most capital intensive industries?

Prominent Commentators

In listening to the debate on DR and its role in future resource plans, some comments that seem to characterize the discussion are:

- An Energy Trading Company CEO – *"I suppose you think that, on our board, half the directors do all the work and the other half do nothing. As a matter of fact, the reverse is true."*
- Dan Quayle (former Vice President):
  - *"I believe we are on an irreversible trend toward more freedom and democracy - but that could change."*
  - *"We are ready for any unforeseen event that may or may not occur."*
  - *"I stand by all my misstatements."*
- Gerald Ford (former U.S. President) – *"Things are more like they are now than they have ever been."*
- Richard Nixon (former U.S. President) – *"I was not lying. I just said things that later on seemed untrue."*

The myths and facts about DR as a resource often get intertwined.

DSM & Pricing: Back to the Bottom Line

- If we don't set prices at appropriate levels, how will we determine which investments are cost-effective?
- If we don't "price what's scarce" (e.g., peak-period commodity), how do we incent appropriate practices and innovation?
- If we don't price what's scarce, how do we improve resource allocation and load factors in a very capital-intensive industry?
- *Issues:*
  - Uncertainties from restructuring & bifurcation of incentives to implement DSM/DR across the different restructured industry entities discouraged investment in DSM/DR infrastructure.
  - Wholesale competition has been encouraged, but it can be argued that price elasticity and demand response capabilities have actually decreased in recent years.
  - This creates a disconnect between wholesale and retail markets.

Robust Planning with EE and DR

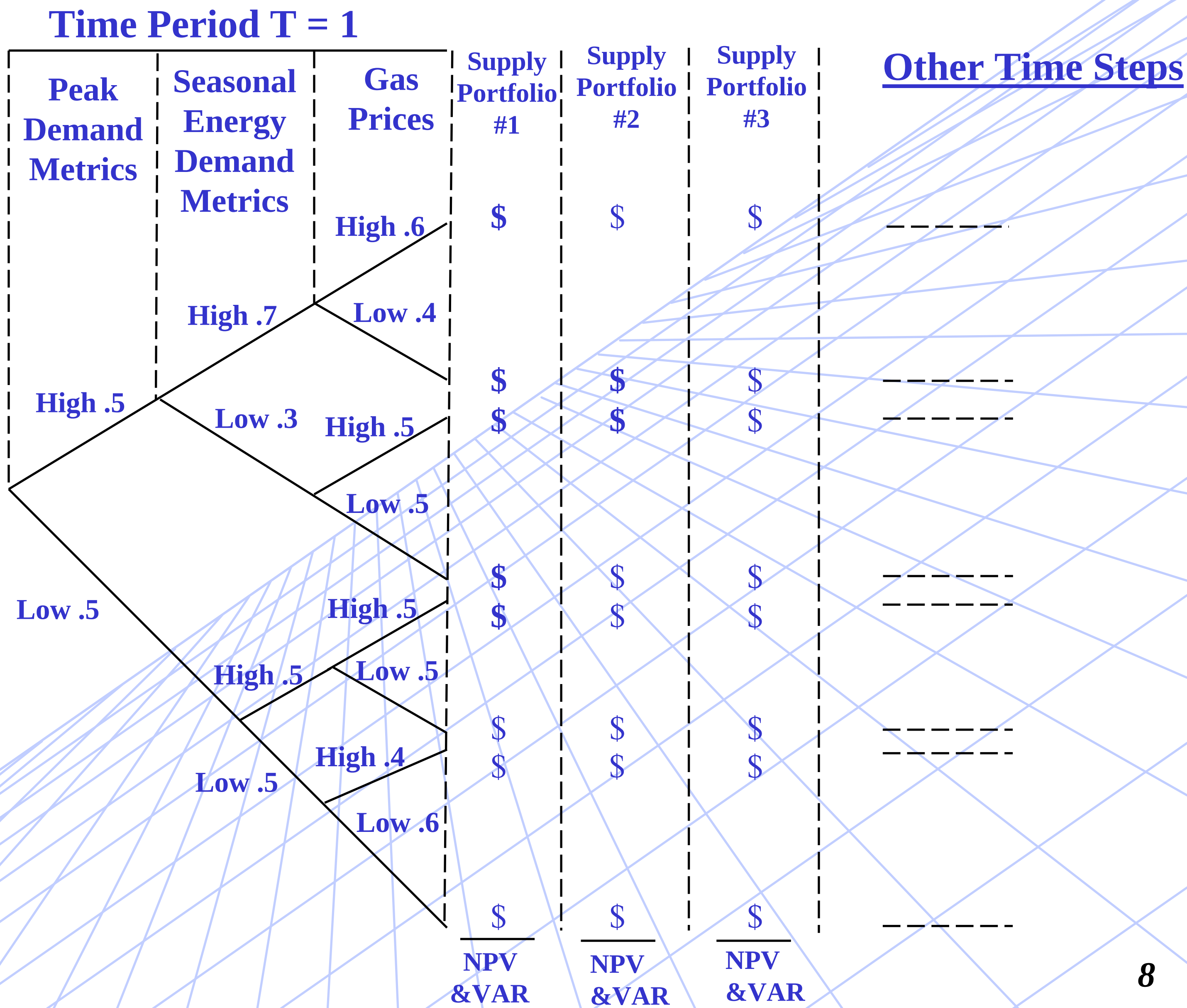
- New perspectives are needed to better represent key inputs to resource planning both on the supply-side and demand-side:
  - Represent uncertainty in key inputs that influence system costs using distributions.
  - Examine correlations across inputs (e.g., oil & gas fuel costs, hydro availability) and over time for a single input (e.g., peak demand).
  - Represent these uncertainties appropriately (e.g., using Monte Carlo model with multiple futures drawn) and each "future" assessed in resource planning.
  - Appropriate characterize resources – both supply-side and demand-side (i.e., energy efficiency, event-based DR, and pricing options) in terms of what they can they deliver and at what price?.
- Incorporate "time steps" and "value of information" to assess the value of flexibility contained in different plans.
- There is a need to work with distributions of outcomes for planning activities – **LET'S LOOK AT SOME CONCEPTUAL EXAMPLES….**

Simplified Example -- Decision Tree

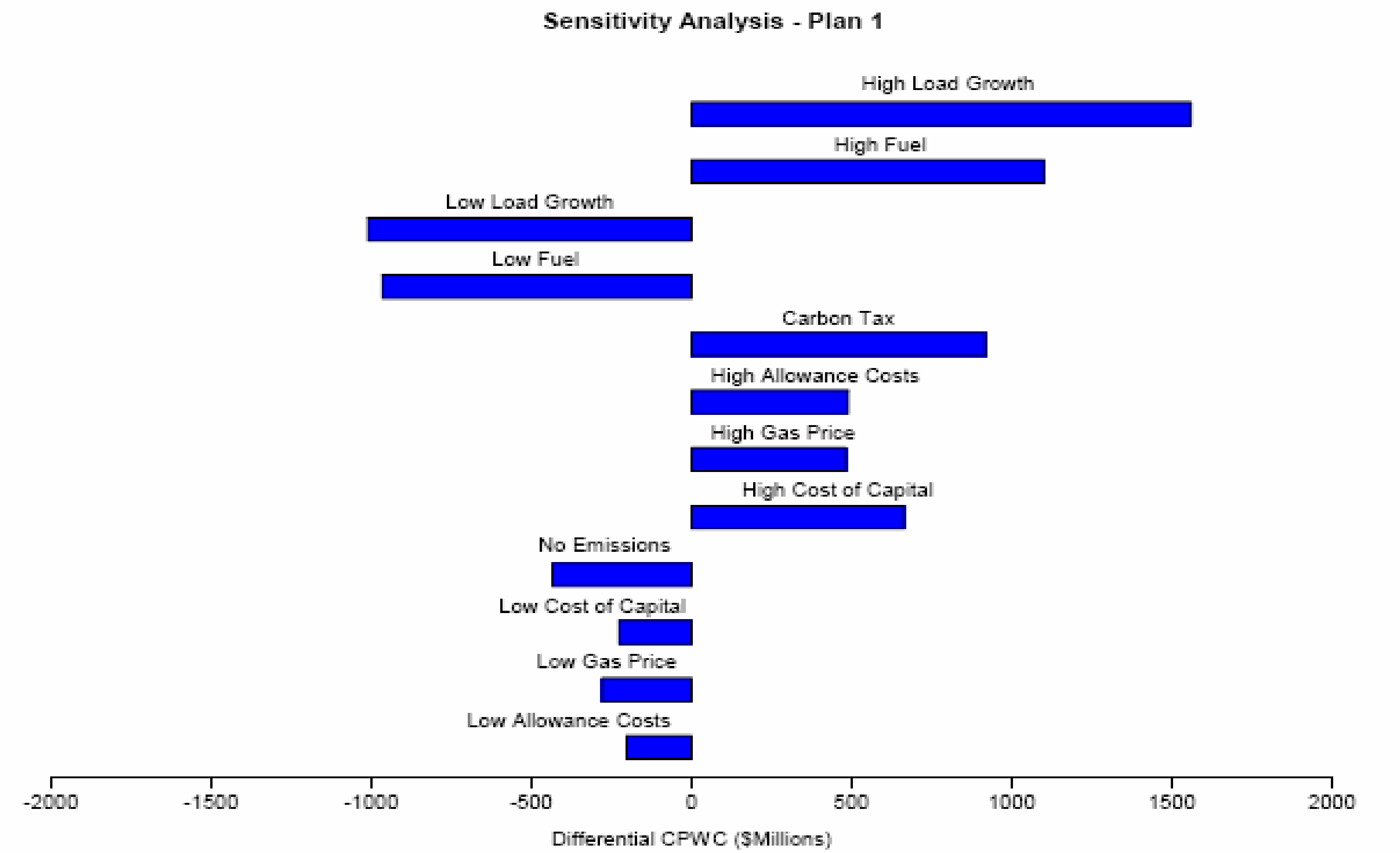
Objective:
Minimize Revenue Requirements over 10 years.

Time Step:
One-year steps over a 10-year period.

Proxy Example:
Real application would include distributions instead of single probability nodes.



Tornado Diagrams – An Example



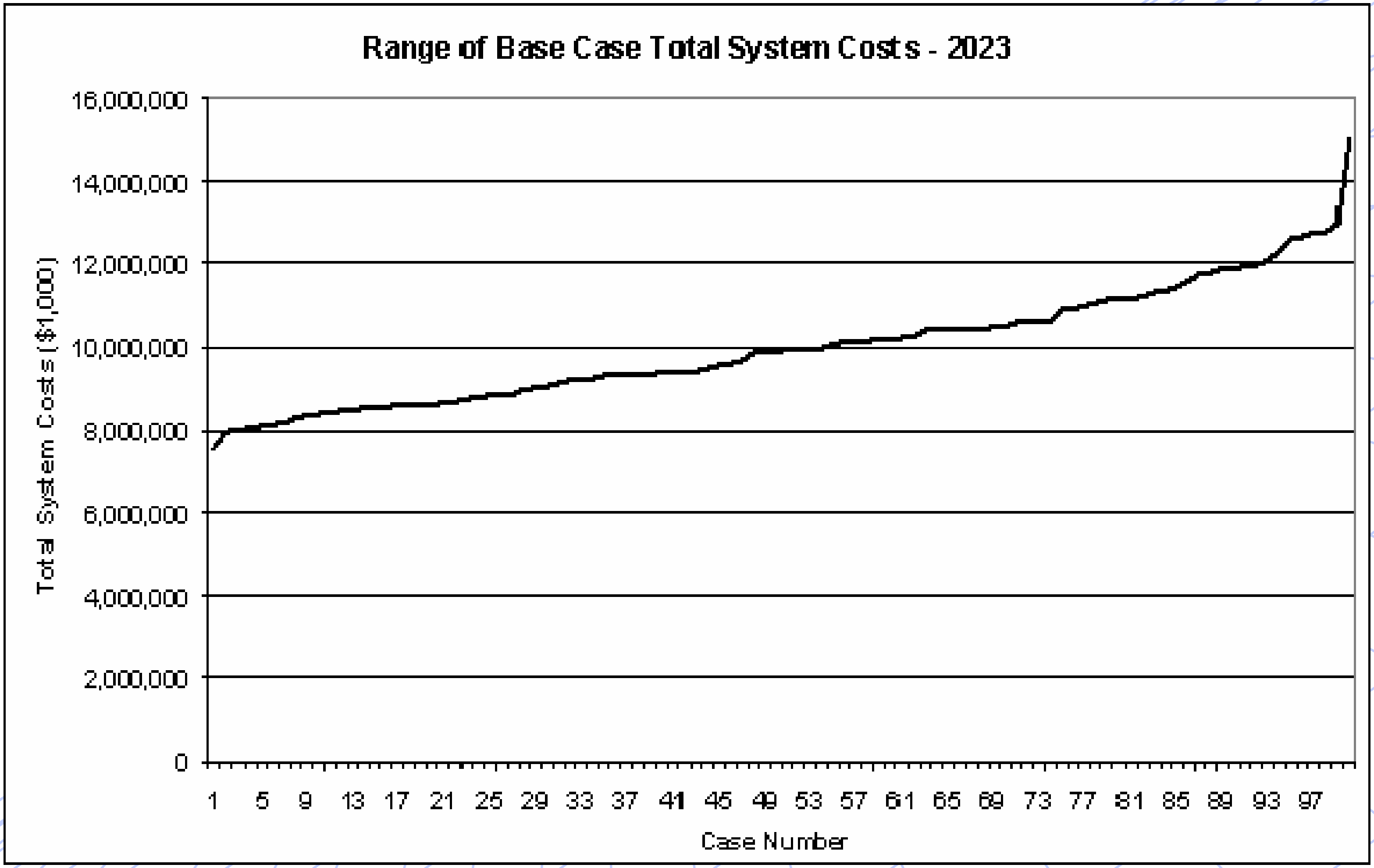
An adverse outcome of 1) high load growth, 2) high fuel prices and 3) a carbon tax would increase cumulative expected net present value costs of this plan by about $4 Billion over the “expected” $10 billion system NPV or a 40% increase in plan costs.

Modeling Methodology - Inputs

- 100 cases were created as data inputs to the market planning model; values were calculated with Monte Carlo methods to capture an appropriate range of possible futures.
- A number of pivot factors were identified and the uncertainty around these factors was dimensioned:
  - Fuel prices – natural gas, residual oil, distillate oil, and coal
  - Peak demand
  - Energy demand
  - Unit outages (four stress cases were introduced with ranges of capacity being off line -- up to 12% of generation)
  - Tie line capacities
- Data sets for four demand response programs were developed as inputs to the model

System Cost Range for the Base Case with Uncertainty Bounded

Range based on market simulation model -- one year out of 18



Ranges of System Costs by Year

- Generally, a 100% increase from low to high in system costs over time.

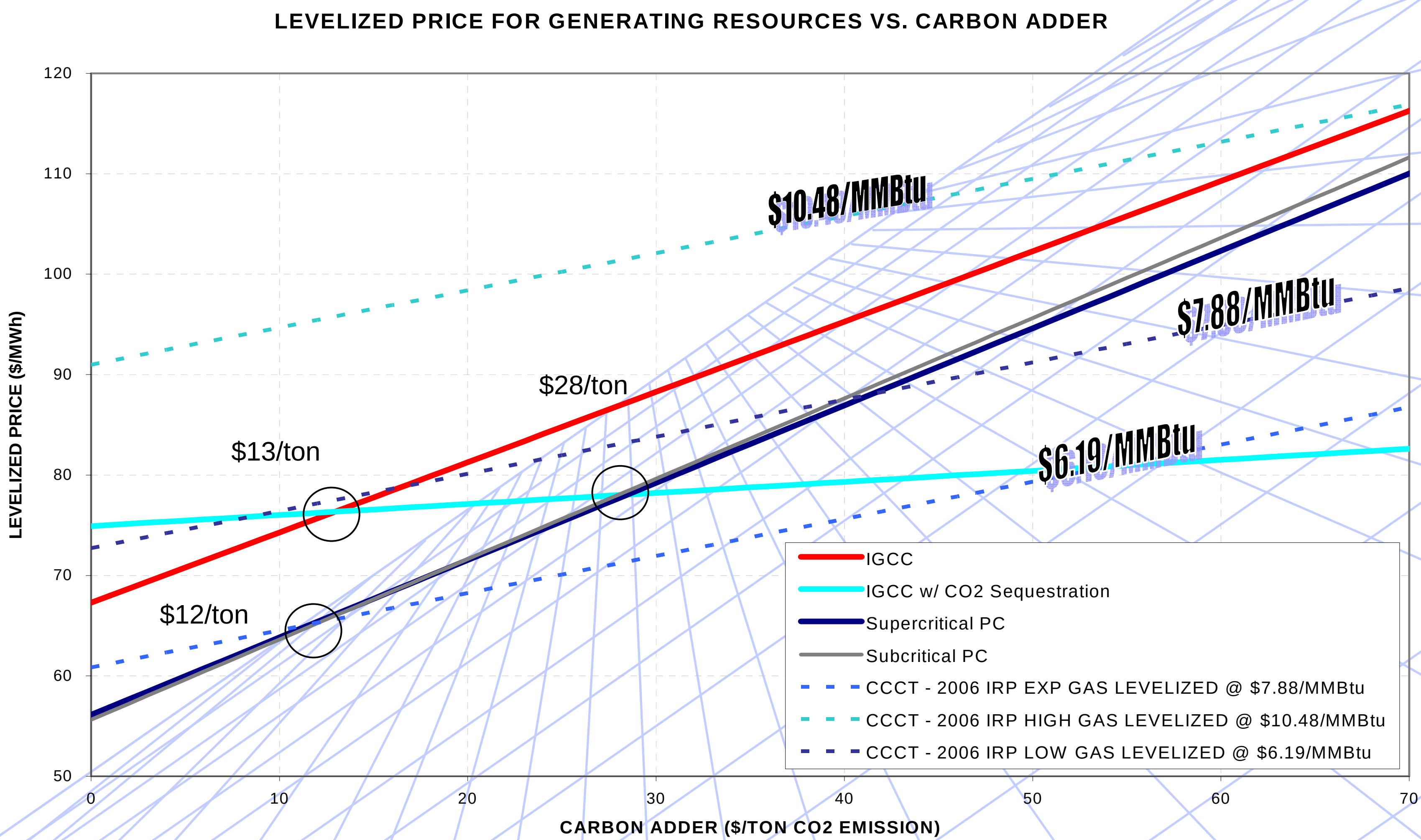
Ranges of System Costs for Select Years

Range of Total System Costs for Selected Years - Base Case
($ Billions)

Year	2010	2012	2015	2018	2020	2023
Maximum	7.7	8.2	10.2	10.3	12.4	15.0
Minimum	3.5	3.8	5.1	5.6	6.5	7.5
Range	4.2	4.5	5.1	4.6	5.9	7.5
Ratio	118.5%	118.8%	101.7%	82.2%	89.9%	99.3%

Generation Costs vs. Carbon Adder

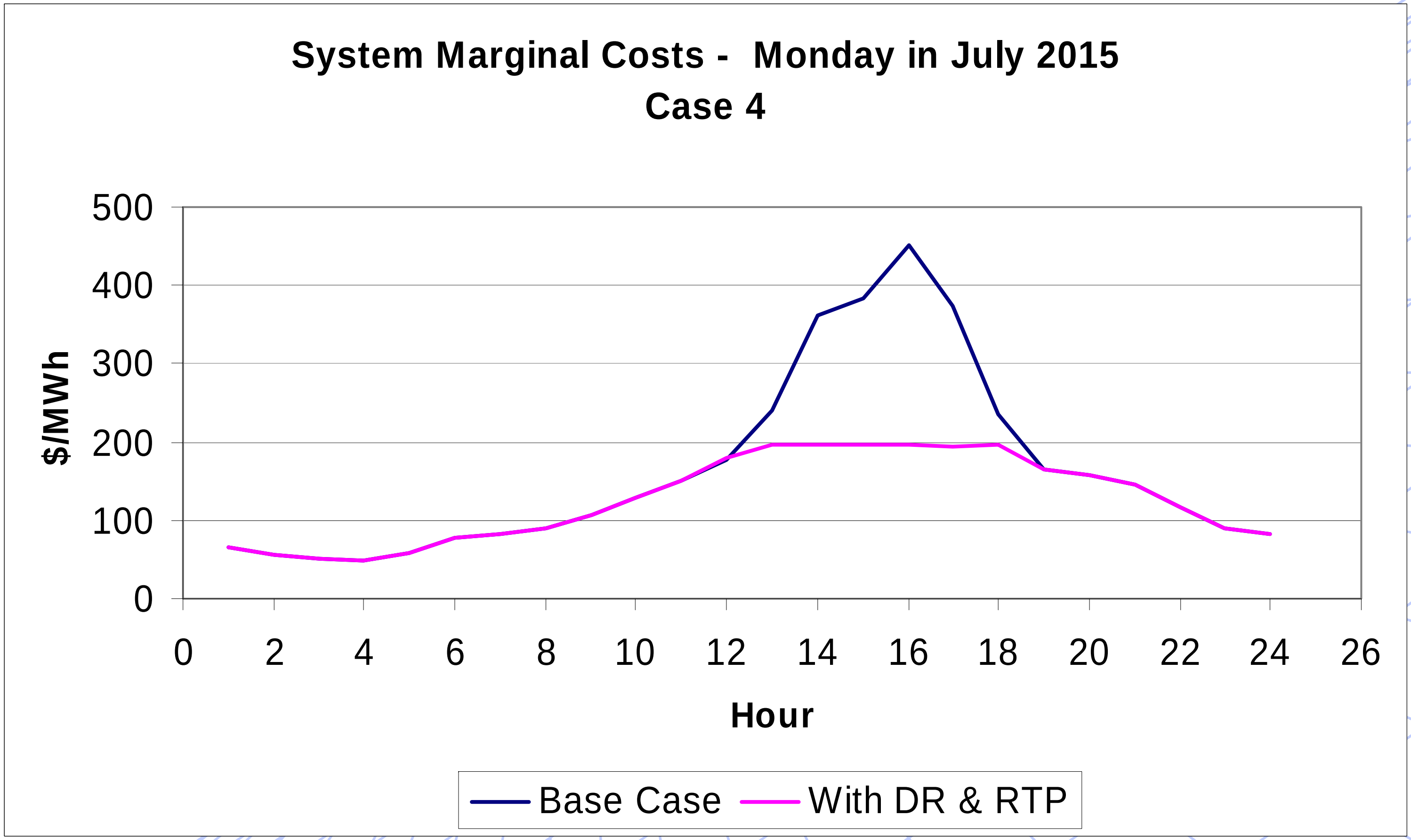
(from Idaho Power 2006 IRP: contact Karl Bokenkamp)



Demand-Side Resource Programs

- Five DR programs were modeled for a mid-Atlantic market:
  - 1) large customer interruptible,
  - 2) mass market direct load control,
  - 3) dispatchable purchase transaction (day-ahead bid program),
  - 4) time of use with event-based Critical Peak Pricing (CPP) and
  - 5) Real-time pricing variants (the only non-event based program).
- The MW capacities of the programs were calculated to start at a low value in 2005, grow at a quick rate in the first ten years to a level of about 4% of peak demand, and thereafter grow at a slightly higher rate than the peak demand.
- DR costs, economics, availability and capacity data were developed as inputs to the resource planning model based on specific product designs.

System Marginal Cost – Stress Case



- $24.5 Million saved on this one day and $45.2 million saved in this week.

Changes in Risk Profiles

- The addition of DR changed the risk profile associated with the planning scenarios.
- Results for three DR scenarios are shown below for value at risk (VAR) at 90th percentile (VAR90) and 95th percentile (VAR95).

BEFORE RIGHT SIZING:

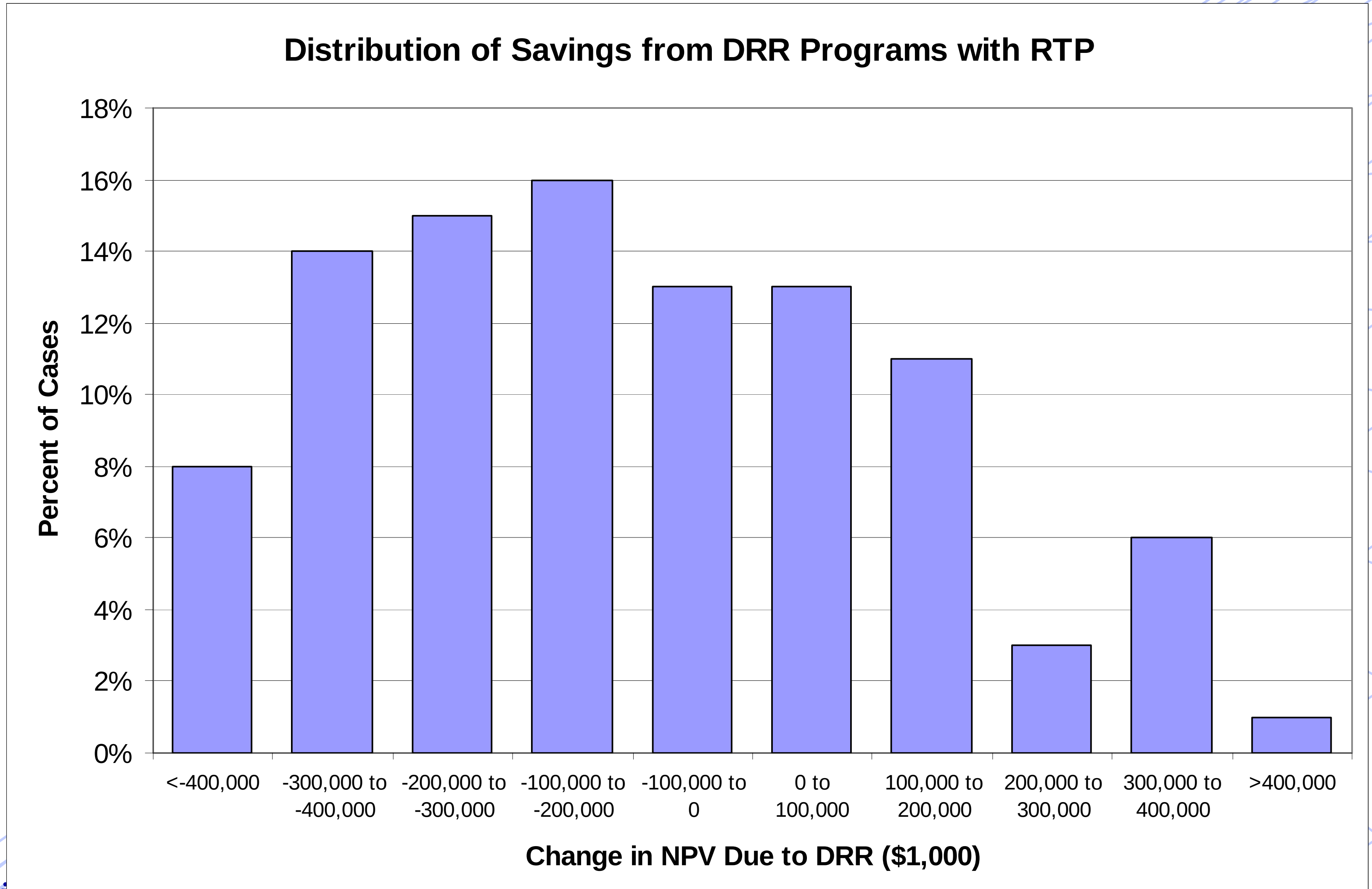
Risk Metrics – Reduction in System Costs at Risk ($M)		
	VAR 90	VAR 95
Callable DRR	238	213
Callable DRR with Critical Peak Pricing	924	966
Callable DRR with Real Time Pricing	2,673	2,766

AFTER RIGHT SIZING (Revision to the January 2006 report):

Risk Metrics – Reduction in System Costs at Risk ($M)		
	VAR 90	VAR 95
Callable DRR	1,071	1,096
Callable DRR with Critical Peak Pricing	1,786	1,828
Callable DRR with Real Time Pricing	3,535	3,628

Frequency Distribution of Changes in System Cost NPV from DR

(Savings in 65% of the cases, higher costs in 35% of the cases)

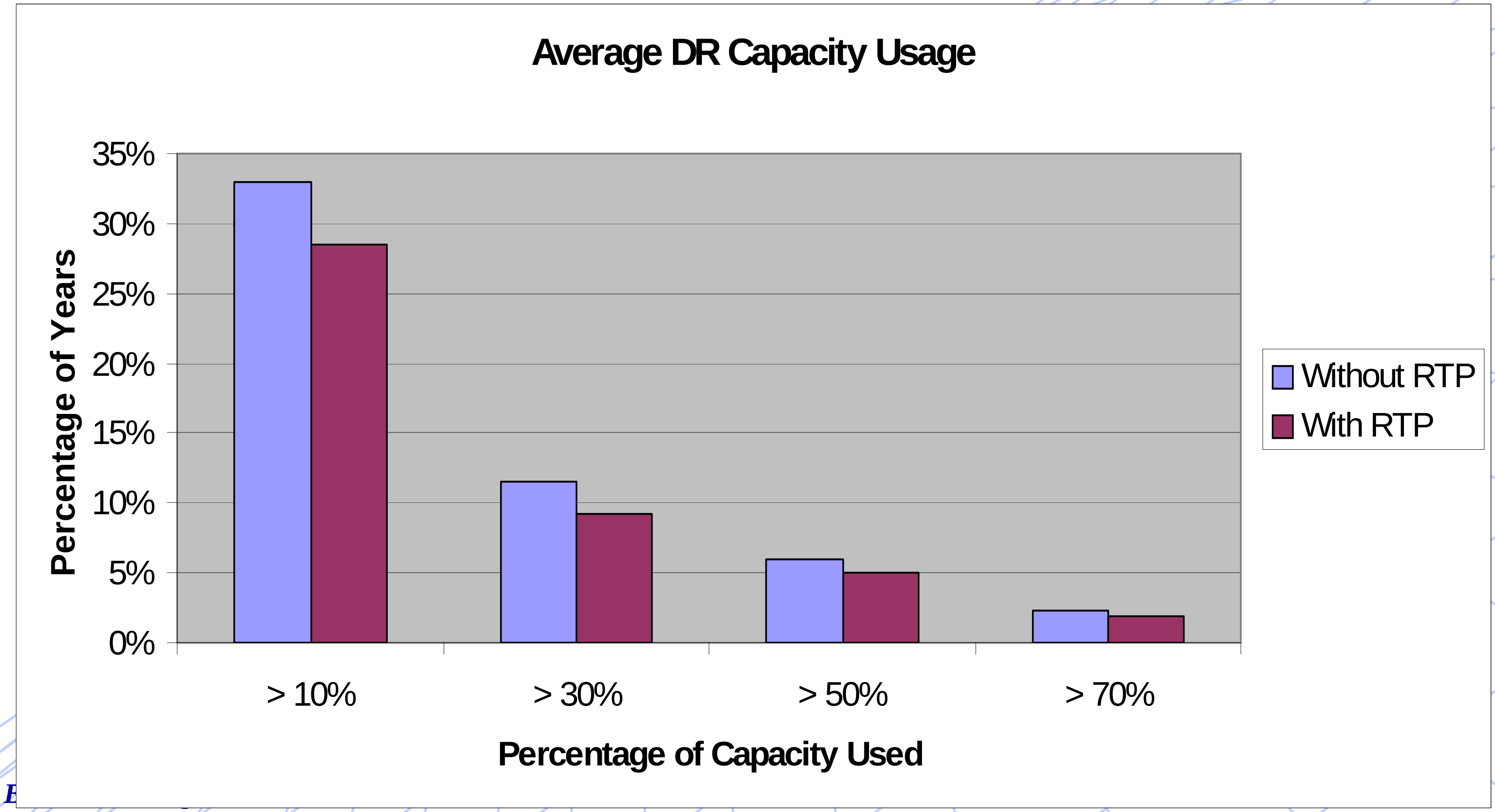


Use of Event-Based DR Resources in this Case Study

- Small amounts of event-based DR are used in most years, large amounts are used infrequently – about once every four to five years to mitigate costs of low-probability / high consequence events.
- Magnitudes and growth in DR over time was fixed, and called upon only when economic.
- Given DR can be ramped up as needed, DR products can be sized to fit system needs.
  - The scenario examined in the January 2006 analysis turned out to represent an "overbuild of DR" for this system, i.e., the same benefits could have been obtained with a smaller amount of DR.
- A more efficient DR product design could further increase net benefits of DR (this change was reflected on slide 15).

Effect of RTP on Event-Based DR Programs – A portfolio works!

- Adding non-event based pricing (RTP) meant the three callable programs were used less—**BUT, impact not as significant as might be expected:**



Customer Preferences and Risk Management

- Is managing future risks an obligation of regulators, energy companies and resource planners?
- Are customers willing to pay a bit more on average for more predictable prices and less price volatility in the future?
- How is this taken into account today?
- With economic EE and DR you not only pay less now, but you also get a reduction in risk (i.e., free insurance) – IF:
  - Adverse events happen.
  - Energy prices increase at the same time weather becomes extreme.
  - AND, there are system constraints (transmission or forced outages).
  - There are often positive correlations among the above factors resulting in 1 in 10 year events seemingly happening every 4 to 5 years.
  - Literature on underestimation of extreme events in planning is growing.

Considerations for the Future

- Developing DSM or the demand-side of the electric market is important for market for efficiency.
  - Require quality in demand-side resource acquisition – it can be difficult;
  - But, building an IGCC coal plant with supporting infrastructure on time and on budget is also difficult.
- Building demand-side infrastructure is important – this involves practices (building and specification), availability of efficient equipment, skilled practitioners, as well as verification and evaluation.
- Price signals (or proxies) providing an incentive to manage what is scarce AND enabling customer response to those signals is needed.
- Is there a rationale that justifies not moving in this direction?
- DSM provides flexibility and balances out supply-side risks.
- Bottom Line -- *Energy needs will be met at a lower overall cost and with lower price volatility.*

2nd Example – NWPCC Power Plan

- Northwest Power and Conservation Council (NWPCC) worked to expand resources considered in its regional plan, e.g., recognize DR Benefits:
  - 5th *DRAFT* Power Plan first to treat DR as a resource
  - Contributes to improved reliability and prevent outages;
  - Mitigates the risk of high market prices;
  - Helps stabilize electricity prices; and,
  - Reduces both cost and risk compared to developing new generation
- Modeling demand response (NWPPC).
  - A Monte Carlo simulation is run for all scenarios producing a cost distribution for each plan.
  - Model allows for 1,000 futures for each plan and multiple plans are analyzed to assess cost and risk differentials..
  - Risk management focuses on a type of Value At Risk (VAR), i.e., the average value for the worst 10% of the outcomes.

NWPPC Comments:

- "Planning for the future requires assessing risk. This involves characterizing the key uncertainties the power system faces."
- "Can planners, through experience, analysis, and informed judgment, develop reasonable characterizations of future uncertainty that will help illuminate resource choices for the region? The Council believes the answer is 'yes'."
- Key uncertainties considered include:
  - Hydro availability
  - Load uncertainty
  - Plant availability
  - Fuel prices
  - Environmental regulation
  - Net imports, i.e., outside market resource development and sales/purchases.
  - Stress tests of extreme circumstances were included – "various sources of risk conspire to produce particularly harsh futures…"

NWPPC Predicted Value of DR

- According to the model simulations:
  - DR is used in 89% of the years in the study.
  - Less than 1% of DR capacity is used in 79% of these years.
  - Less than 10% of DR capacity is used in 90% of these years.
  - Only a few years show DR used to near full capacity.
- Overall value:
  - Without DR, the expected net present value increase in system costs is $100 million, while system risk increases by $500 million.
  - For constant levels of risk, the loss of DR increases expected costs by about $300 to $500 million.
  - Without DR, risks increase in the range of $400 million to $1 billion at given levels of expected cost.
- NWPCC recommendations
  - Develop 500 MW of DR over the next five years; and,
  - Develop up to 2,000 MW of DR over the 20-year period.

Where do we go from here?

- Traditional utility decision making processes were designed in a more stable and forgiving environment than will likely exist in the future.
- Many current analyses are still based on single-point “most-likely” estimates with sensitivity analyses used to assess uncertainty -- often without considering the correlations across key factors.
- These measures can omit those low-probability, high-consequence events that can doom a company – even though they are known to occur several times during a 20 year planning horizon.\[1]
- In most cases, uncertainties are not explicitly identified, and management of risk not linked to the dimensioning of uncertainty.
- **BOTTOM LINE** – Planning should address uncertainty in a manner that dimensions risk and allows for the assessment of risk management options. First cut results – this favors the diversity offered by EE and DR.

1/ From Fayne, H. et al.,“By Executive Decision” Public Utilities Fortnightly, October 25, 2005 under “why historical decision frameworks failed.”

References

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