Are DR Programs Worth Doing? Cost-Effectiveness Evaluations of Demand Response Resources in California

November 16, 2011

Dr. Bruce Perlstein
Director, Energy
Navigant Consulting, Inc.

Need More Reliable Estimates of DR Load Impacts and Cost Effectiveness

- **Due to:**
  - **hard economic times,**
  - **explosive growth of DR programs (e.g., California PUC-mandated Smart Meter-enabled default dynamic pricing for all non-residential customers, and possibly residential customers, of each IOU); and,**
  - **doubts about methods IOUs were using to estimate per customer DR load impacts, forecast future DR program enrollments, and evaluate the cost effectiveness of those programs,**

  recognition of need to more accurately estimate load impacts and cost effectiveness of DR programs.

- **After authorizing IOUs to implement nation's largest Smart Meter deployment program, in 2007 California PUC opened proceeding to establish standard protocols for:**
  - **developing *ex post* estimates of prior year DR load impacts, and *ex ante* estimates of monthly DR load impact capacity that would be available in each of next 5-10 years, if DR events occurred on monthly peak load days under standardized set of event day conditions;[1] and,**
  - **evaluating cost effectiveness of DR programs, based in part on *ex ante* estimates of each program's load impacts if DR events occurred on monthly peak load days under standardized set of event day conditions.**

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[1] ***Ex ante*** **load impact estimates used to determine DR contributions to meeting each IOU's monthly Resource Adequacy capacity requirements in following year, and when and how much new generation capacity each IOU will be authorized to procure or construct over the next several years.**

How Do California IOUs Determine Whether DR Program is Cost Effective?

- **CPUC adopted DR load impact evaluation protocols in 2008[1] and DR cost-effectiveness evaluation protocols in 2010[3].**
- **Cost effectiveness protocols based largely on Total Resource Cost (TRC) test defined in California's 2001 Standard Practice Manual for Economic Evaluations of Demand Side Resources, after also taking into account:[1]**
  - **uncertainty associated with dispatchable DR resources;**
  - **using dispatchable DR resources for system reliability (i.e., DR as reliability insurance policy) vs. meeting demand at lower cost (i.e., economic dispatch of both supply- and demand-side resources)**
  - **Under TRC test, a DR resource is cost effective if present value of its future benefits to all ratepayers, exceeds present value of its future costs to all ratepayers:**
    - **TRC test = PV (Future Benefits) / PV (Future Costs); OR,**

      = PV (Future Benefits) Minus PV (Future Costs)
- **Cost effectiveness protocols require each IOU to evaluate cost effectiveness of each of its DR resource individually (i.e., DR program-specific), as well as cost effectiveness of all of its DR programs combined (i.e., DR portfolio),**

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[1] California PUC Decision 08-04-050, (April 24, 2008).

[2] California PUC Decision 10-12-024 (December 2010).

[3] Each IOU must also report the results of the Ratepayer Impact Measure (RIM) test, the Program Administrator (PA) test, and the Participant test for each of its DR resources, and for all of that IOU's DR resources combined.

Consistency in Cost Effectiveness Evaluations

- **In order to decide if a DR program is cost effective in integrated resource planning, should use same methods used to estimate cost-effectiveness of supply- side resources.**

- **Therefore, in comparing DR resources to supply-side resources in integrated resource planning, also should use consistent set of capacity, energy, and environmental impact cost estimates for both supply- and demand-side resources.**
- **However, under California's "Loading Order Preference" policy:**
  - **In resource planning, IOUs must add *cost effective* Energy Efficiency (EE), Demand Response (DR), and Renewable resources (in that order) before adding any cost effective conventional generation resources.**
- **DR cost effectiveness protocols therefore require each IOU to assume each DR program will always avoid need for "new" CT generation capacity, even in years in which no "new" CT generation capacity will be needed to meet that IOU's monthly Resource Adequacy requirement (defined as capacity needed to meet forecasted monthly peak load plus 15% capacity resource planning reserve margin) .[1]**

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[1] **Each IOU must meet both system-wide RA requirements based on forecasts of monthly peak loads within its service area under 1-in-2 weather conditions, and local RA requirements based on forecasts of monthly peak loads under 1-in-10 weather conditions within certain California ISO-designated transmission-constrained load pockets within its service area.**

Benefits Provided by DR Resources

- **Benefits provided by DR resources are capacity, energy, and environmental impact compliance costs that would be avoided by using DR resource rather than supply side alternative.**
- **Avoided Generation Capacity Costs**
  - **Based on forecasts of market prices of additional generation capacity each IOU would need, in absence of dispatchable DR resources, to meet monthly peak load day Resource Adequacy capacity requirements in each year;**
  - **Adjusted upward for T&D line losses and 15% RA capacity planning reserve margin avoided by customer meter-level demand reductions that would occur during DR program "events"**
- **Avoided T&D Capacity Costs**
  - **Based on estimates of future T&D capacity investments that would be deferred due to location-specific demand reduction capacity available from certain types of DR resources (not covered in this presentation).**

Benefits Provided by DR Resources (cont’d)

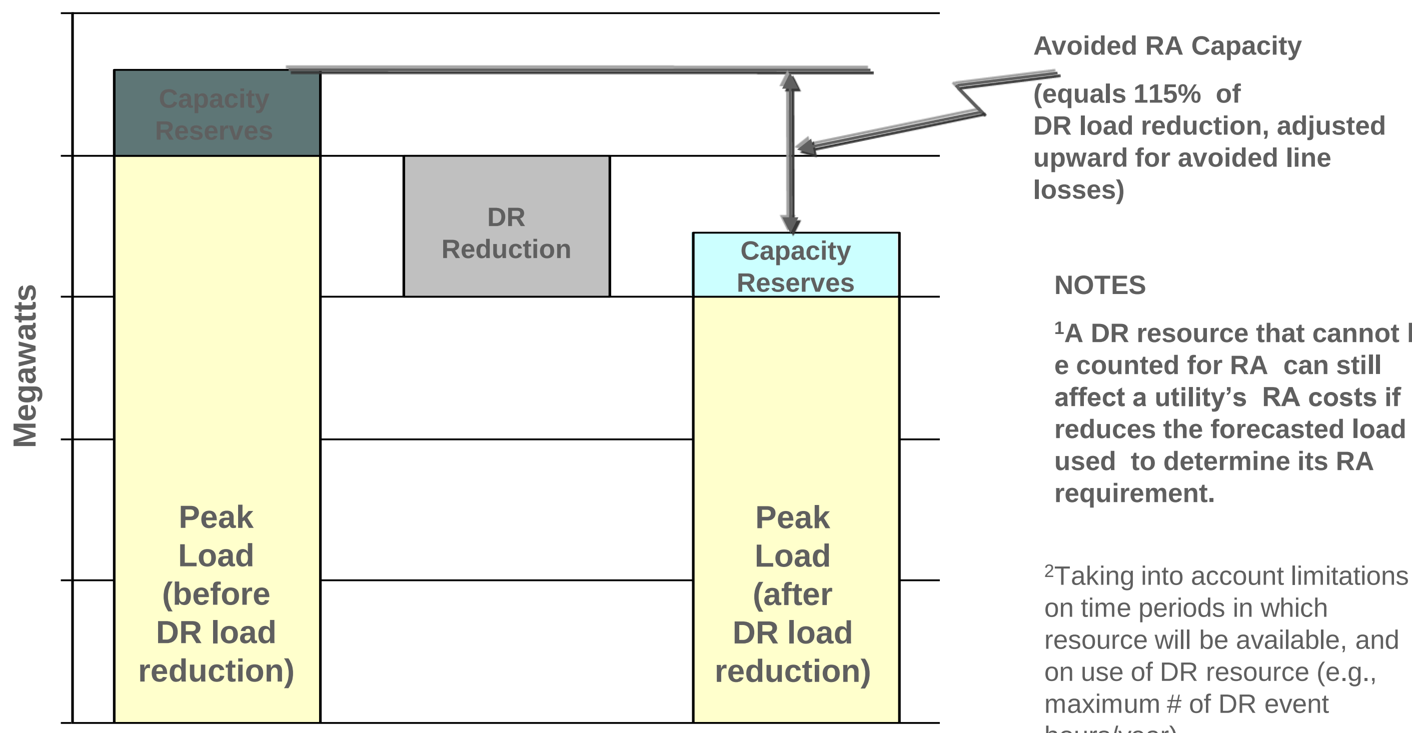
- <u>Avoided Energy Costs</u>
  - Wholesale energy costs (based on forecasts of wholesale market energy prices) that would be avoided on each monthly peak load day by dispatching DR capacity;
  - Adjusted upward for T&D line losses avoided by customer meter-level reductions in demand that would occur during DR program “events”.
- <u>Avoided Environmental Impact Compliance Costs</u>
  - Based on forecasts of future Greenhouse Gas (GHG) emission allowance costs and criteria pollutant emission compliance costs that would avoided on each monthly peak load day by demand reductions during DR program “events”
- <u>Ancillary Services Benefits</u>
  - Difference between market value of ancillary services that DR resources would provide, and market value of ancillary services that would have been provided by avoided generation capacity (not covered in this presentation)

Benefits Provided by DR Resources (cont'd)

- Market Structure Benefits
  - Change, if any, between energy costs at market prices that would occur in presence of DR resources, and energy costs at market prices that would occur in presence of additional generation capacity avoided by those DR resources.
    - **Speculative, and hard to estimate.**
    - **Therefore, cost effectiveness protocols do not require IOUs to use estimates of possible energy market price effects in evaluating DR cost effectiveness.**
  - Difference in value, if any, between reliability of system in presence of DR resources, and reliability of system in presence of generation capacity that will be avoided by those DR resources.
    - **Capacity planning reserve margin CPUC already requires IOUs to maintain is implicitly based on specific reliability (i.e., loss of load probability) target.**
    - **Therefore, cost effectiveness protocols do not require IOUs to use estimates of possible DR reliability benefits in evaluating cost effectiveness of DR resources.**

Generation Capacity Avoided by DR Resources

Portion of generation capacity needed to meet each IOU's monthly RA capacity requirement[1] that will be avoided by DR resource is based on demand reduction that will be available from DR I each hour of each monthly peak load day,[2] adjusted for T&D line losses and CPUC-established resource capacity planning reserve margin that would be avoided by dispatching DR programs on that day



NOTES

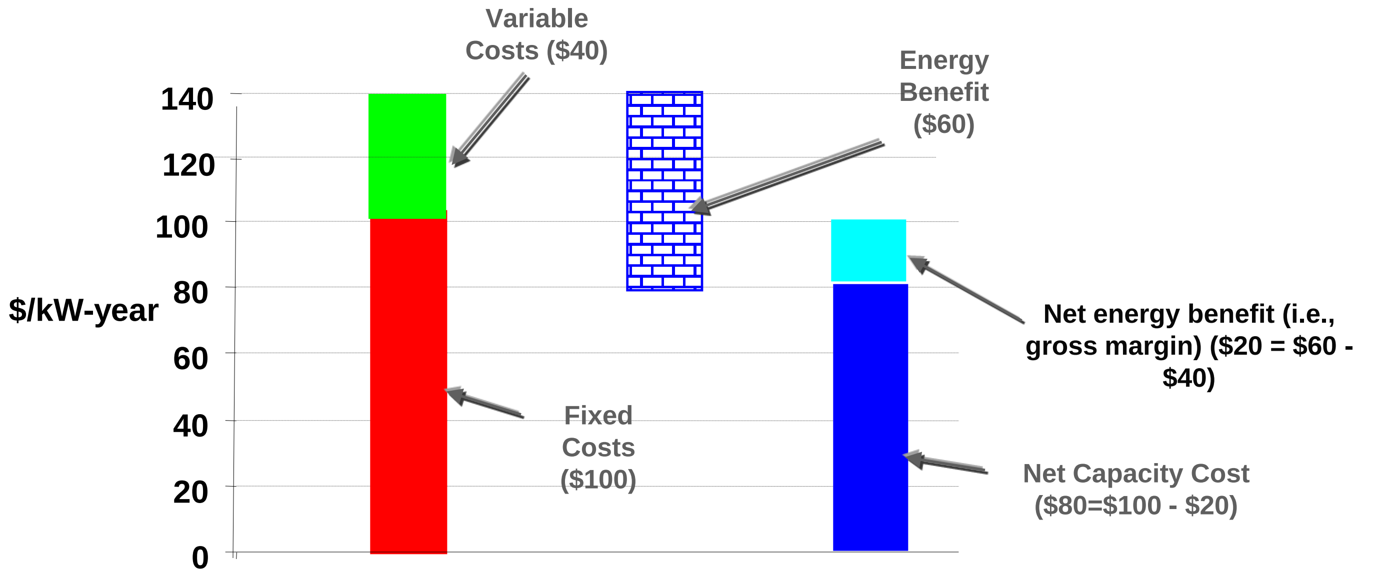
[1]A DR resource that cannot b e counted for RA can still affect a utility's RA costs if reduces the forecasted load used to determine its RA requirement.

[2]Taking into account limitations on time periods in which resource will be available, and on use of DR resource (e.g., maximum # of DR event hours/year)

Forecasts of Annual Generation Capacity Market Prices Based on Forecasts of Annual Net Capacity Costs of New CT

- Because California does not have public market for generation capacity, must estimate future annual generation capacity prices.
- DR resources avoid peaking generation resources. Peaking generation resources provide energy benefits and generation capacity benefits
- Peaking generation resources have fixed and variable costs
- At market price equilibrium:
  - Annual Energy Benefit = Annual Revenues at Market Prices from Energy Sales
  - Annual Net Energy Benefits = Annual Revenues at Market Prices from Energy Sales MINUS Annual Variable Production Costs (Fuel and Variable O&M) = Gross Margins
  - Annual Net Capacity Cost = Annual Going Forward Fixed Costs MINUS Annual Net Energy Benefits (i.e., Gross Margins)

Hypothetical Example (assuming $60/MWh Wholesale Market Energy Price)



Forecasting Annual Market Prices of New Generation Capacity

In order to estimate generation capacity costs that will be avoided by DR resources, begin by estimating future annual market prices of new CT capacity

- **Annual market price of new CT generation capacity ($/kW-year) = first year (real) economic carrying charge ($/kW-year) for present value of net capacity costs of a new CT over its expected operating life (e.g., 20 years).**
- **Present value of net capacity cost of a new CT equals:**
  - **Present value of total fixed costs [1] of new CT over its expected operating life; MINUS,**
  - **Present value of gross margins [2] new CT would earn over its operating life by selling energy whenever wholesale market price of energy exceeds variable (fuel and O&M) costs that would be incurred in generating that energy**

[1] Includes fixed O&M, insurance ,property taxes, fixed costs of environmental compliance, debt service (interest plus repayment of principal), state and local income taxes, and recovery of and return on equity invested in new CT capacity.

[2] Gross margin equals revenue from selling energy at wholesale market prices, minus variable (fuel, O&M, and environmental compliance) costs incurred in generating energy.

Future Annual Market Price of New CT Generation Capacity (cont'd)

– <u>Example</u>: Annual market price of new CT capacity in 2011 = annual economic carrying charge in 2011 for the stream of annual net capacity costs (over its operating life) of new CT coming in line in 2011

- First year annual economic carrying charge for stream of future annual net capacity costs of new CT is annual amount which, if escalated at rate of inflation, results in stream of amounts whose present value equals the present value of those future annual net capacity costs:

$$\sum_{t=1}^{20}\left[\frac{(\text{Annual Real Economic Carrying Charge})\times(!.00+\text{i})^{t}}{(1.00+r)^{t}}\right]=\sum_{t=1}^{20}\frac{(\text{Net Capacity Cost})_{t}}{(1.00+\text{r})^{t}}$$

where:

i = annual inflation rate

r = annual discount rate

t = subscript denoting year (e.g., t = 1 to 20)

Factors Affecting Hourly Gross Margins of New CT in California

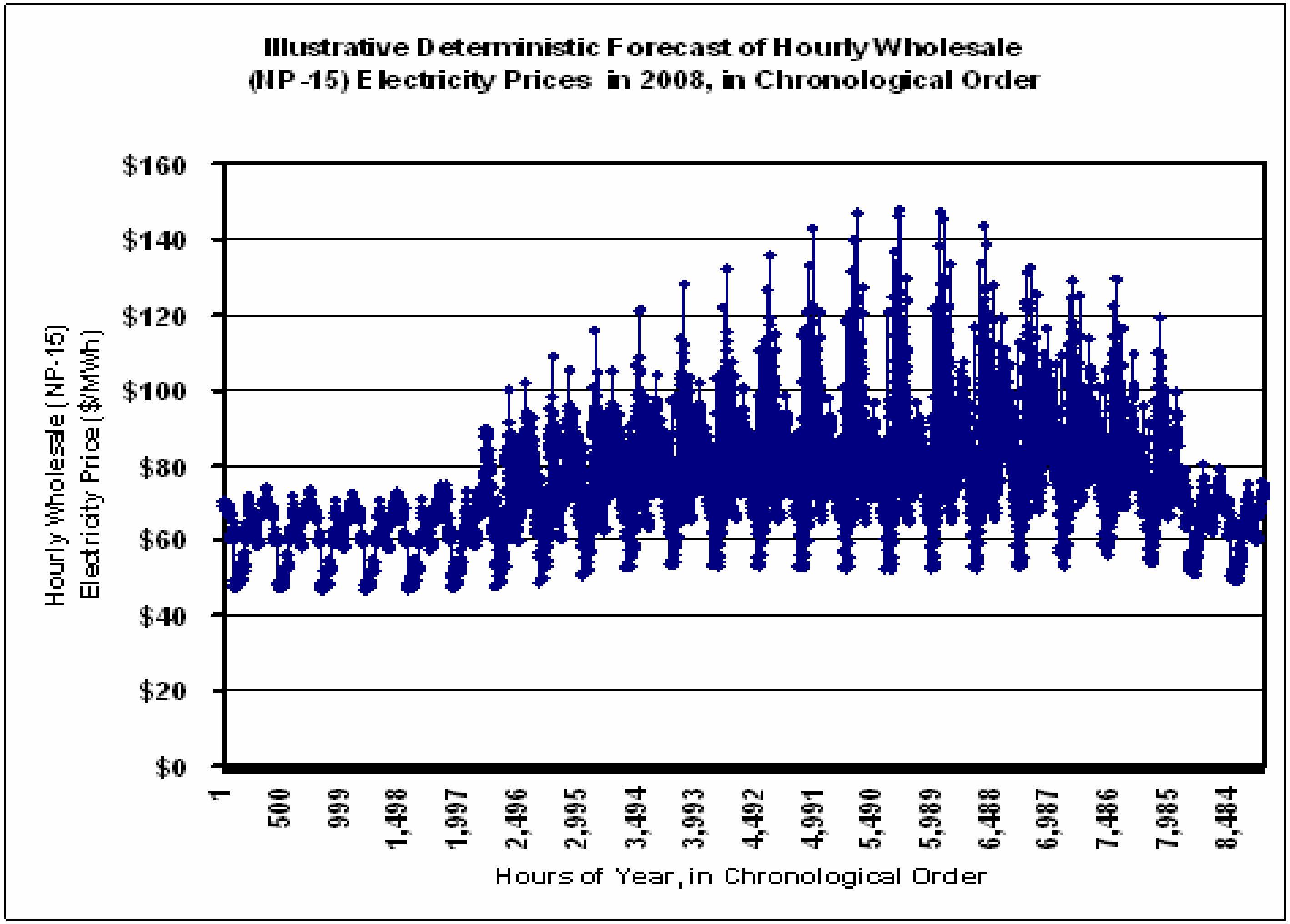
- Natural gas fired capacity is on the margin in most hours in California
- Gross margin that new natural gas-fired CT achieves in a given hour depends on:
  - CT's heat rate (i.e., Btu/kWh)
  - CT's capacity (MW)
  - Natural gas price ($/Btu) for that hour
  - Wholesale market price of electricity ($/MWh) for that hour
  - Variable O&M cost ($/kWh)

  Gross Margin = {Electricity Price ($/kWh) – [(Heat Rate (Btu/kWh) x Natural Gas Price ($/Btu)) – Variable O&M ($/kWh)]} x [CT Capacity (in MW) x 1000 kW/MW)
- CT's heat rate and variable O&M cost/kWh do not vary that much over time (aside from escalation in O&M costs and gradual decline in plant's efficiency (i.e., heat rate))
- Natural gas prices are volatile, and therefore cannot be forecasted with 100% accuracy
- Wholesale electricity prices are even more volatile, and are even harder to accurately predict than natural gas prices

Protocols Require Use of Deterministic Forecasts of Wholesale Energy Prices and Natural Gas Prices to Estimate New CT's Future Gross Margins

- Because natural gas fired generation is usually on the margin in most hours in California, CPUC-adopted DR cost effectiveness evaluation protocols require IOUs to use deterministic forecasts of future natural gas prices and wholesale energy prices to estimate future gross margins of new CT.
  - ➢ **However, there is a great deal of uncertainty in future natural gas and wholesale electric prices. Also, there is a significant correlation between variations in natural gas prices and variations in wholesale electricity prices in California markets.**
  - ➢ **Using deterministic price forecasts underestimates gross margins a new CT will earn, because those forecasts do not take into account uncertainty/volatility of and correlations between natural gas and electricity prices.**

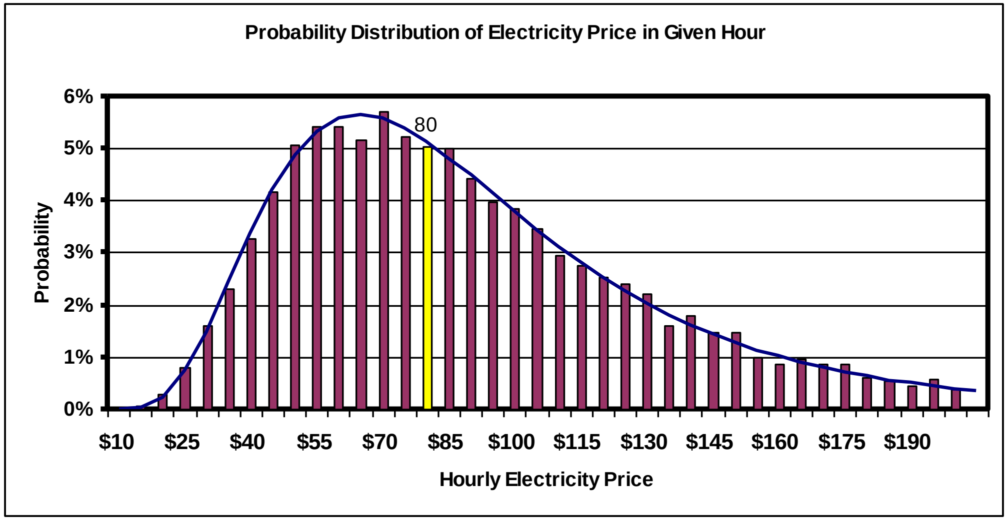
Wholesale Electricity Prices Are Highly Variable
(Minute to Minute, Hour to Hour, Day to Day, Month to Month)



For Internal Purposes, Two California IOUs Use Stochastric Methods to Estimate Future Gross Margins of New CT

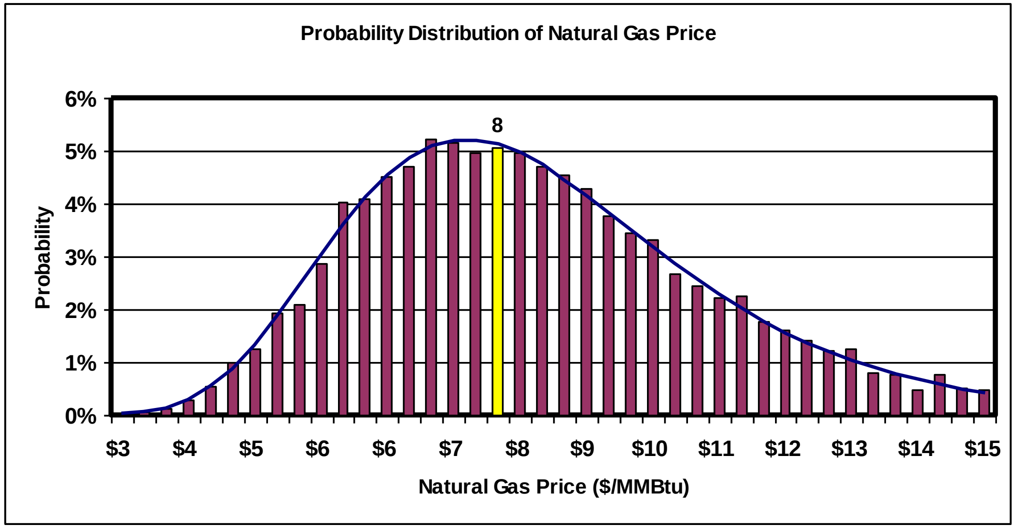
- For internal purposes, PG&E obtains more accurate estimates of hourly gross margins a CT will earn, by treating dispatch decision as a series of hourly call options, whose values can be estimated by using an hourly "spark spread" call option model.
- That model takes into account the uncertainty/volatility of and correlations between natural gas and wholesale electricity prices.
- Many others use spark spread call option models to value generation capacity (e.g., valuation experts, investment banks, etc.).
- SCE accomplishes same thing by instead using stochastic (Monte Carlo simulation-based) production cost modeling.
- CPUC decided not to adopt these stochastic methods because they are based on each IOU's confidential forecasts of wholesale energy and natural gas prices, their volatilities, and correlations.

Example: Hourly Spark-Spread Call Option Model



- Although expected electricity price in this hour is $80/MWh, the actual price could be roughly $15/MWh to over $200/MWh
- Need to take account of the probabilities of all of these possible hourly prices.

- Although expected natural gas price is $8/MMBtu, the actual price could be $3/MMBtu to over $15/MMBtu
- Need to take account of the probabilities of all of these possible natural gas prices.
- Also need to take into account the extent of the correlation between natural gas prices and hourly electricity prices.

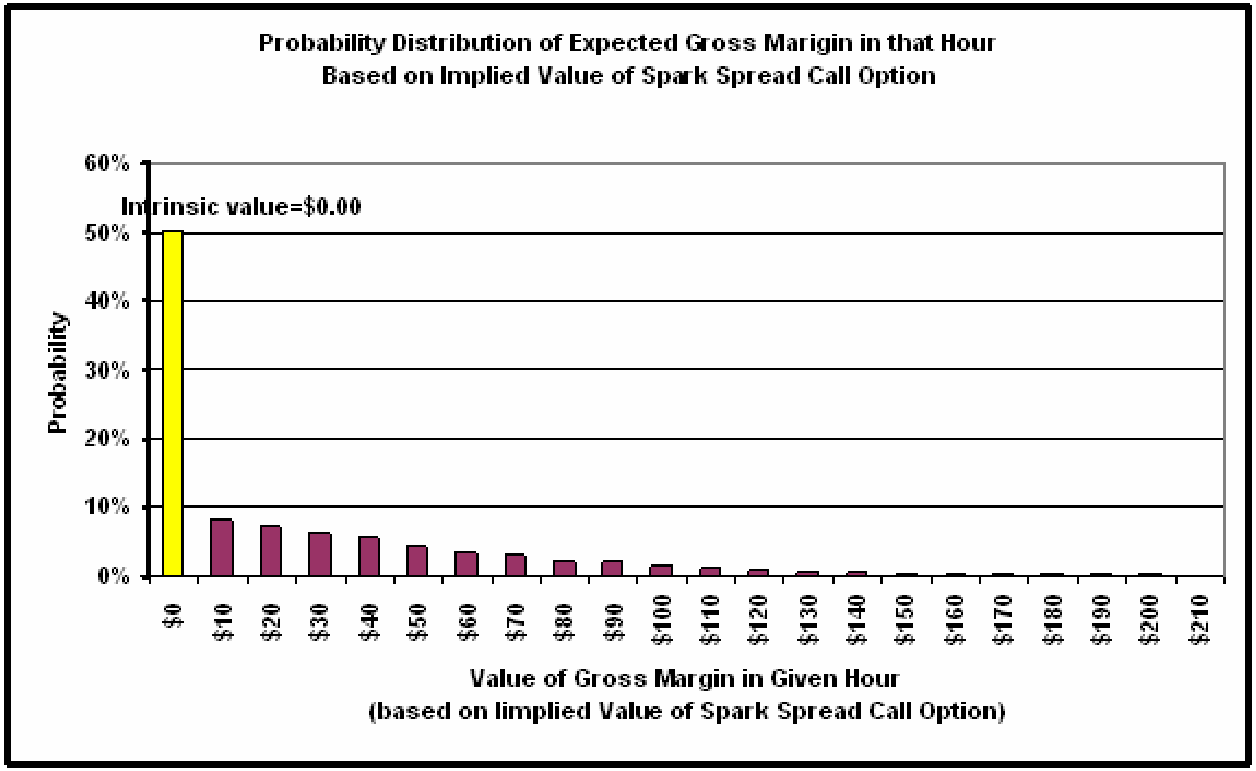


Example: Hourly Spark-Spread Call Option Model (cont'd)

• At an expected wholesale price of $80/MWh and a $8/MMBtu natural gas price, a CT with a 10,000 Btu/kWh unit heat rate (ignoring variable O&M), the deterministic ("intrinsic value") estimate of its gross margin in that hour is $0.00.

• However, that deterministic estimate does not take into account the "extrinsic" value of the gross margins due to the uncertainty of and correlations between future power and natural gas prices.

• A spark spread call option model takes into account both the "intrinsic" value and the "extrinsic" value of the plant's future gross margins .

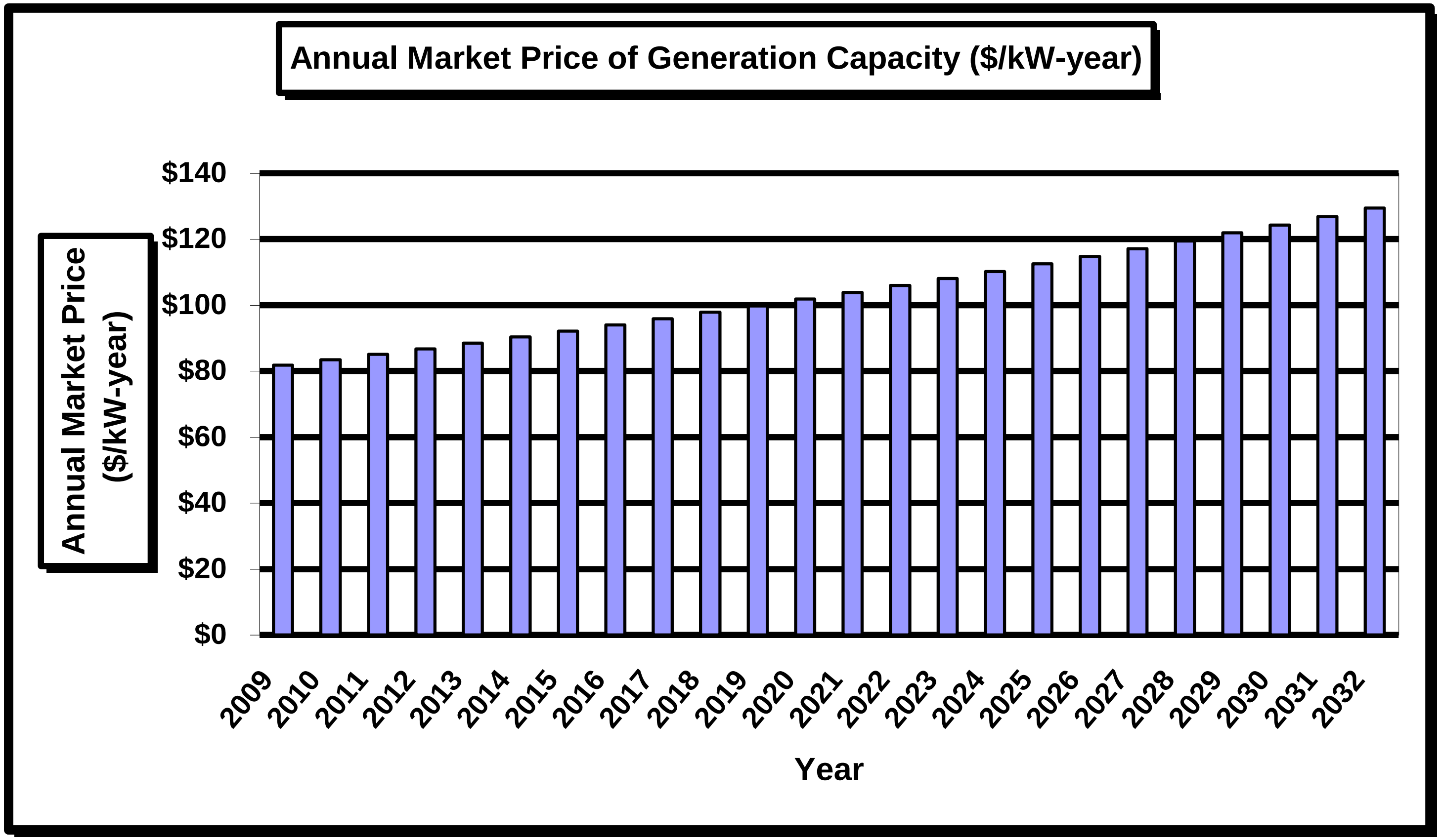


Example: Hourly Spark-Spread Call Option Model (cont'd)

- In this example, a deterministic model would estimate the CT would earn a zero gross margin for this hour, and therefore would not be dispatched.
- However, due to the volatility of and correlations between natural gas prices and hourly electricity prices, the value of the option to dispatch the plant in that hour is actually $11.45/MWh, which is a better estimate of the plant's expected gross margin in that hour.

[1]	Electricity Price	P	$80.00	$/MWh
[2]	Expected Natural Gas Price	G	$8.00	$/MMBtu
[3]	Plant Heat Rate	hr	10	MWh/MMBtu
[4]	Variable O&M	vom	$0.00	$/MWh
[5]	Volatilitility of Electricity Price		50%	
[6]	Volatility of Natural Gas Price		30%	
[7]	Time to Operation Hour		1	year(s)
[8]	Correlation between Natural Gas and Electricity Prices		0.7	
[9]	Deterministic Estimate of Hourly Gross Margin ("intrinsic value")	= [1] - ([2] x [3])	$0.00	
[10]	Spark Spread Call Option Model Estimate of Hourly Gross Margin		$11.45	
[11]	Gross Margin Not Captured by Determinist\ic Estimate ("extrinsic value")	= [10] - [9]	$11.45	

Illustrative Forecasts of Annual Market Price of New CT Capacity



Forecasted Annual Generation Capacity Market Prices Adjusted for Avoided T&D Line Losses & Avoided Capacity Reserve Margin

Illustrative *Forecasts*

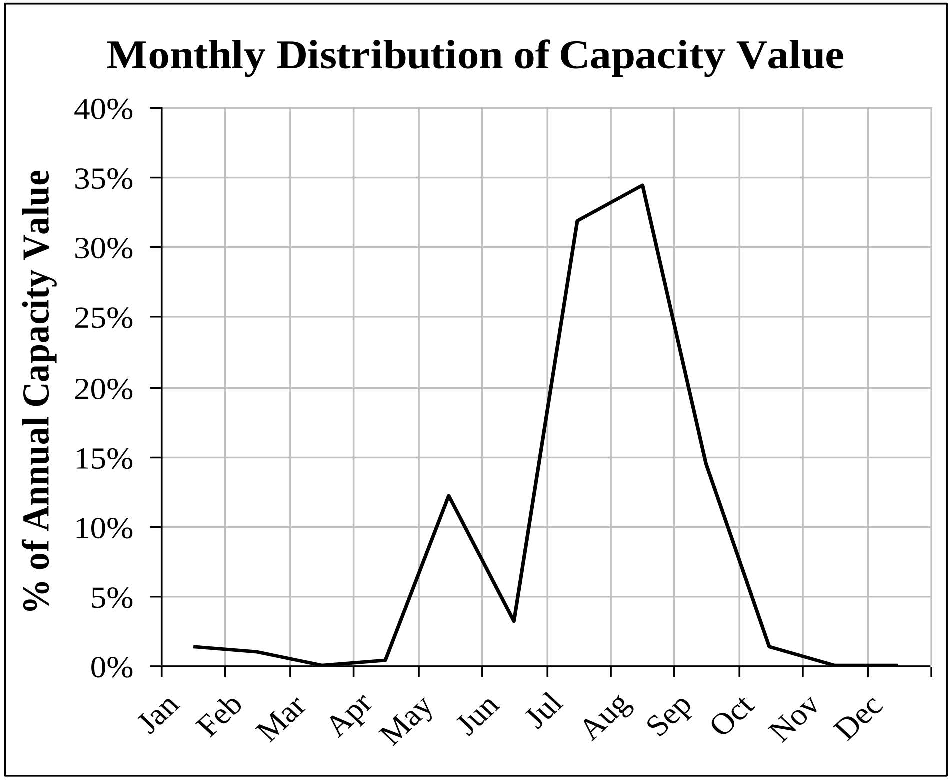
Illustrative Forecasts of Annual Market Price of Generation Capacity ($/kW-year), Before and After Adjusting for Avoided Line Losses and Avoided 15% RA Reserve Margin			
Year	Forecasted Annual Market Price of Generation Capacity	Annual Market Price, Adjusted for Avoided Line Losses	Annual Market Price, Adjusted for Avoided Line Losses & Avoided 15% RA Reserve Margin
	($/kW-year)	($/kW-year)	($/kW-year)
		(1)/(1.00 - 0.0763)	(2) x 1.15
	(1)	(2)	(3)
2009	$81.74	$88.50	$101.77
2010	$83.39	$90.29	$103.83
2011	$85.06	$92.09	$105.90
2012	$86.76	$93.93	$108.02
2013	$88.51	$95.83	$110.20
2014	$90.31	$97.78	$112.44
2015	$92.14	$99.76	$114.72
2016	$94.01	$101.77	$117.04
2017	$95.91	$103.84	$119.41
2018	$97.83	$105.91	$121.80
2019	$99.78	$108.03	$124.23
2020	$101.81	$110.22	$126.76
2021	$103.89	$112.48	$129.35
2022	$105.97	$114.73	$131.94

Allocation of Annual Market Value of Generation Capacity Among Certain Hours Within Each Year

- In order to estimate the future hourly market value of generation capacity in each year, Cost Effectiveness Protocols require each IOU to allocate forecasted annual market price of generation capacity in each year among the 250 hours in which the highest loads occurred in a recent four year time period (2006 through 2009).
- **That method is somewhat unreliable, because it does not take into account <u>changes over time</u> in the hourly <u>need</u> for capacity, as reflected in estimates of hourly loss of load probabilities in each year.**

Market Value of Peaking Generation Capacity Varies Over Course of Year

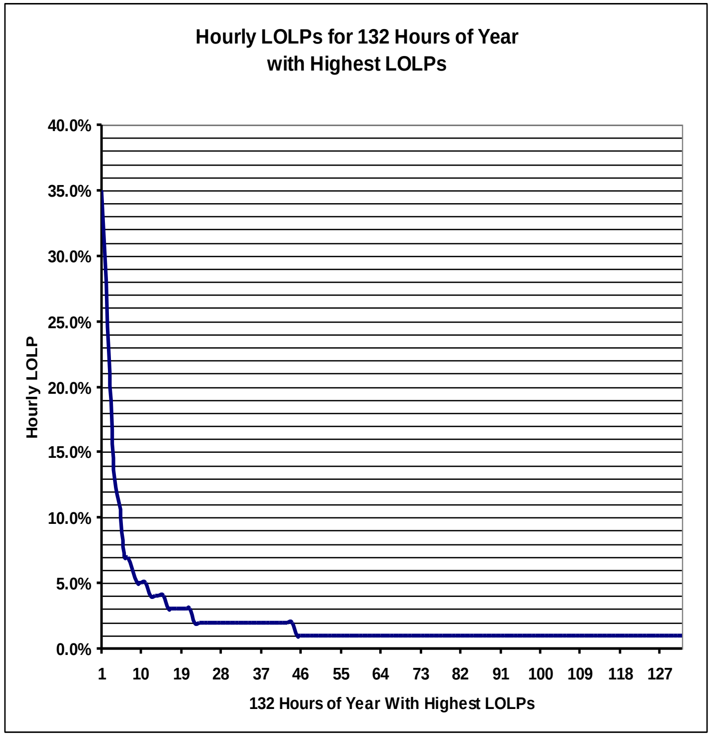
Differences between loss of load probability in each hour of the year reflects fact that need for peaking capacity varies from moment to moment, hour to hour, day-to-day, & month to month

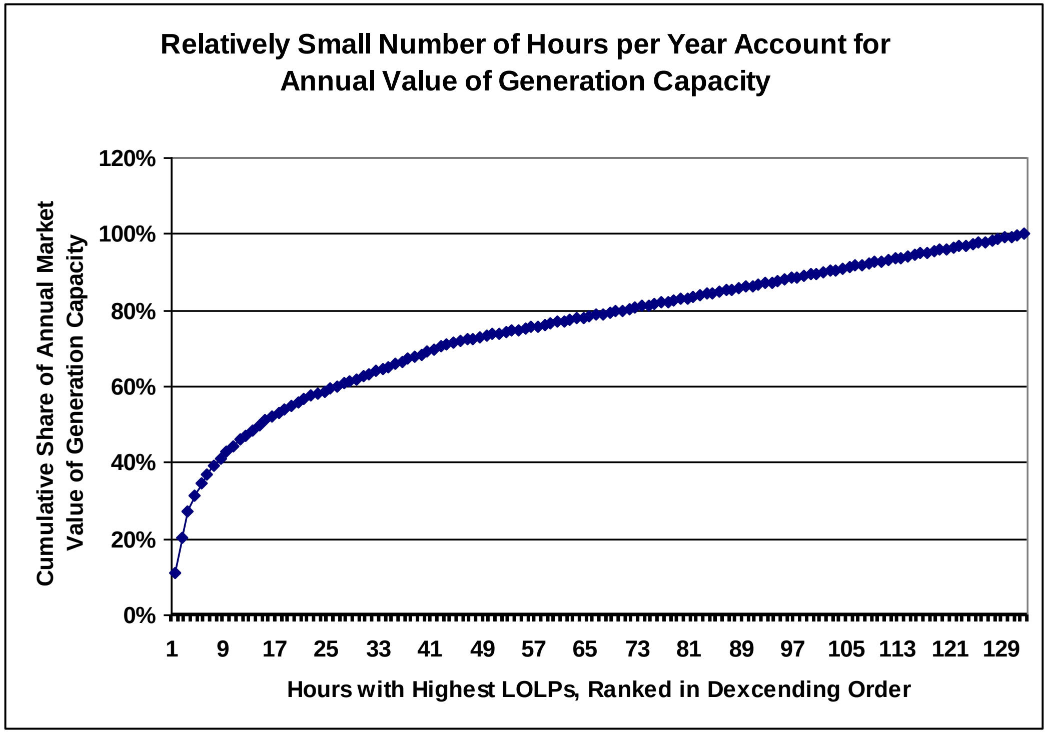


- **At times that demand exceeds capacity, some demand is not met, resulting in "loss of load".**
- **Demand that is not expected to be met is "expected unserved energy" (i.e., LOLE)**
- **Probability of unserved energy in given hour = hourly loss of load probability (i.e., LOLP)**
- **Hourly need for peaking generation capacity is proportional to hourly LOLPs**
- **Therefore, for internal purposes, at least one and perhaps two of California's three IOUs allocate forecasted annual market value of capacity among the hours/months of that year in proportion to hourly LOLPs**
- **Based on the LOLPs it estimated in 2006, for example, PG&E allocates roughly 80-90% of annual value of generation capacity to peak demand hours in summer months**

Small Number of Hours Currently Account for Bulk of Annual Market Value of Generation Capacity

Because there are only a relatively small number of hours a year in which probability of loss of load is greater than zero, those few hours account for virtually all of the annual market value of peaking generation capacity.





Growing Reliance on Renewables Likely to Increase Market Value of Avoiding Generation Capacity in Non-Summer Season Peak Load Hours

- Under California's Renewables Portfolio Standard adopted in 2006, by 2010 each IOU had to obtain 20% of energy it sold to retail customers in prior year from renewable resources
- More recent legislation requires each IOU to obtain 33% of energy it sold to retail customers in prior year by 2033.
- Wind and solar will account for most of new renewable capacity in California
- Due to growing reliance on "intermittent" wind and solar generation, each IOU will need more "back-up" fast start generation capacity in non-peak hours and non-summer season months, which account for bulk of expected renewable integration costs.
- That will change relative need for capacity in different hours, which would be reflected in updated estimates of hourly loss of load probabilities, and therefore.
    - increase generation capacity costs avoided by DR resources available in non-summer season peak hours, as well as summer season peak hours; and,
    - reduce generation capacity costs avoided by DR resources available only in summer season peak hours.

Adjustments to Generation Capacity Costs Avoided by Specific DR Resources

- DR programs that can be dispatched with less advance notice are more valuable than those that require more advance notice (e.g., day ahead vs. hour ahead vs. ten minutes advance notice).
  - **Therefore, DR cost effectiveness protocols require IOUs to adjust estimates of generation capacity costs DR resource will avoid, by multiplying by percentage of 250 highest CAISO peak load hours in 2006 through 2009 that were forecast within the minimum amount of advance notice required to call an event under that DR program.**
- Dispatchable DR programs that can be "triggered" under a greater variety and/or more frequently occurring conditions are more valuable than DR resources programs that can be triggered under fewer and/or less common conditions.
  - **Therefore, DR cost effectiveness protocols require IOUs to adjust estimate of generation capacity costs DR resource will avoid, by multiplying by percentage of 250 highest CAISO peak load hours in 2006 through 2009 in which an event could have been called based on that DR program's "triggers".**
- Dispatchable DR resources that are available in more hours, days, and/or months are more valuable than those that are less available.
  - **Therefore, DR cost effectiveness protocols require IOUs to adjust estimate of generation capacity costs DR resource will avoid, by multiplying by percentage of 250 highest CAISO peak load hours in 2006 through 2009 in which that DR Program would have been available.**

Avoided Energy Costs

Value of energy avoided by most dispatchable DR programs is relatively small

- **Value of energy at any given time is determined by wholesale energy market price for that time period, not a specific utility's power production costs.**
- **A dispatchable DR program "event" can only be called when the "trigger" for that program is exceeded (e.g., temperature > "X" degrees, system demand > "Y" MW, electricity market price > $ "Z"/MWh", system conditions require dispatch of units with heat rate exceeding "X" Btu/kWh, etc.)**
- **However, "calling" a DR program event will avoid energy costs only when wholesale market price of electricity ($/MWh) is above amount program participants would be paid ($/MWh) for reducing demand during that event (i.e., program's "strike price").**
- **Due to their triggers, "strike prices", and/or use only to avoid or during California ISO emergencies, most dispatchable DR resources avoid energy in only a few hours each year.**
- **As a result, avoided energy costs usually account for only small share of benefits provided by DR resources.**

Estimating Energy Costs Avoided by DR Resources

- **DR cost effectiveness protocols require IOUs to use deterministic forecasts of monthly average peak and off-peak energy prices to estimate energy costs that will be avoided by each DR resource.**
- **Those deterministic energy price forecasts are based on publicly available forward summer <u>monthly</u> on peak electricity prices, derived from broker's quotes which go out approximately seven years, including interpolated values.**
- **For each month in later years, monthly on peak electricity prices are derived by applying heat rate in corresponding month from last year covered by our internal forecasts, to forecasted natural gas price for that month.**
- **Average peak and off-peak hour prices for each month are derived by applying relative hourly "price shape" that occurred in the first year of the California ISO's new wholesale energy market.[1]**
- **Because energy prices in DR event hours are likely to be higher than monthly average on peak prices, DR cost effectiveness protocols require IOUs to adjust estimates of energy costs avoided by a DR program, by multiplying by ratio of expected average energy prices during DR calls to average on-peak energy prices.**

[1] As noted earlier, for internal purposes, one IOU derives estimates of future <u>hourly</u> electricity prices from these forecasted monthly electricity prices, by using model that captures expected variability of loads over each month and year of forecast period (based on load growth and seasonal factors), while retaining a realistic load shape over each day and from day to day within each week (based on day-of-the-week factors, temperature scenarios, and diurnal variations). Model that derives these hourly prices, based on these factors, is based on reasonable assumption that hourly prices are driven by hourly loads.

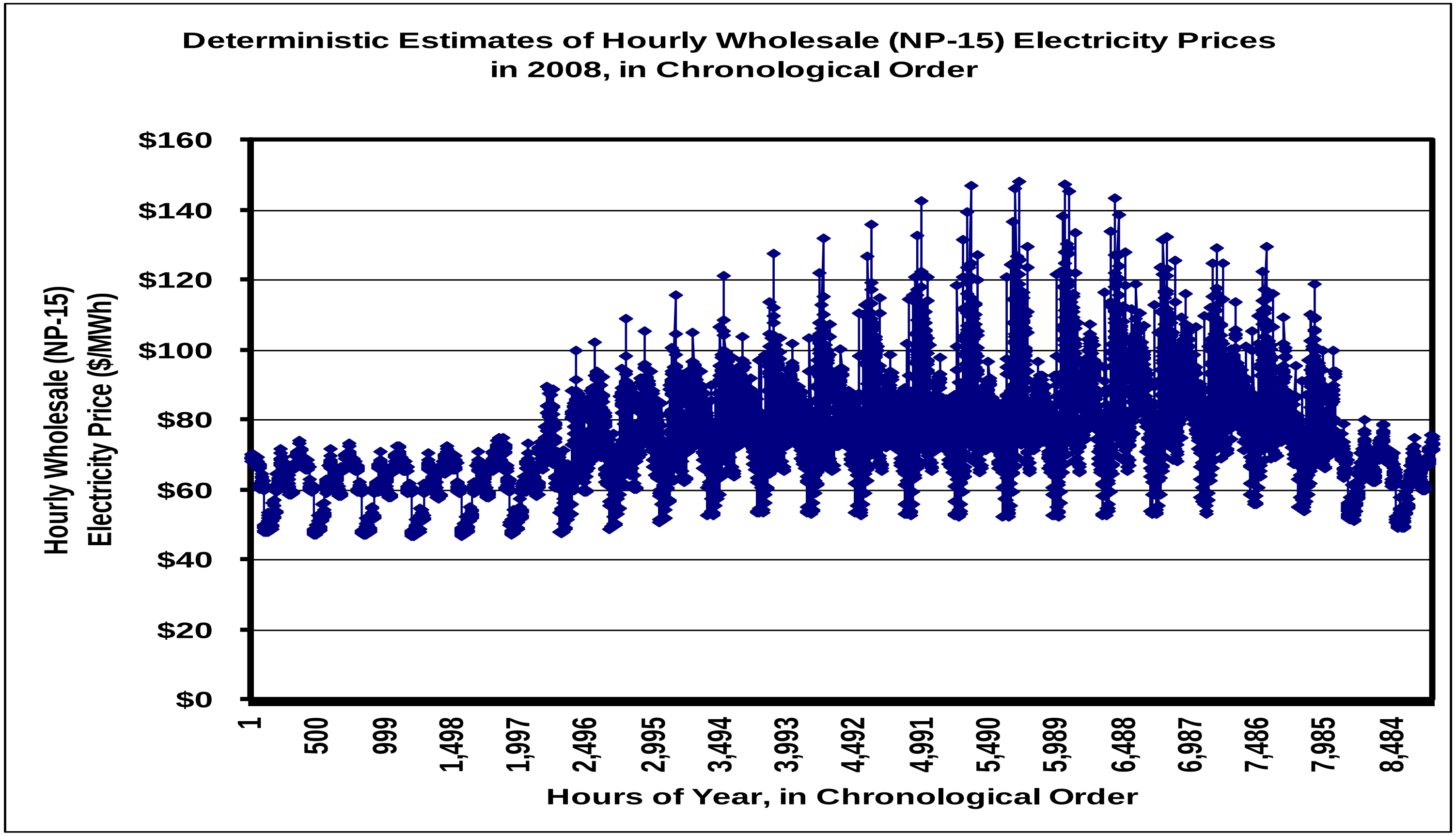
Illustrative Forecast of Wholesale Electricity Prices

Forecasts of Monthly Wholesale Power Prices for Delivery in NP-15 [1]			
	Average of Hourly Prices ($/MWh)		
			All
	Peak	Off Peak	Hours
Month	**Period Hrs**	**Period Hrs**	**Combined**
January	$86.75	$71.50	$80.03
February	$83.50	$69.50	$77.55
March	$79.00	$63.50	$72.18
April	$72.00	$50.50	$62.92
May	$74.00	$51.50	$64.08
June	$79.00	$55.50	$68.56
July	$98.50	$63.07	$82.88
August	$101.75	$69.19	$87.39
Septembe	$95.12	$65.73	$82.06
November	$76.50	$61.46	$70.19
December	$84.55	$69.20	$77.38
January	$92.24	$72.99	$83.76

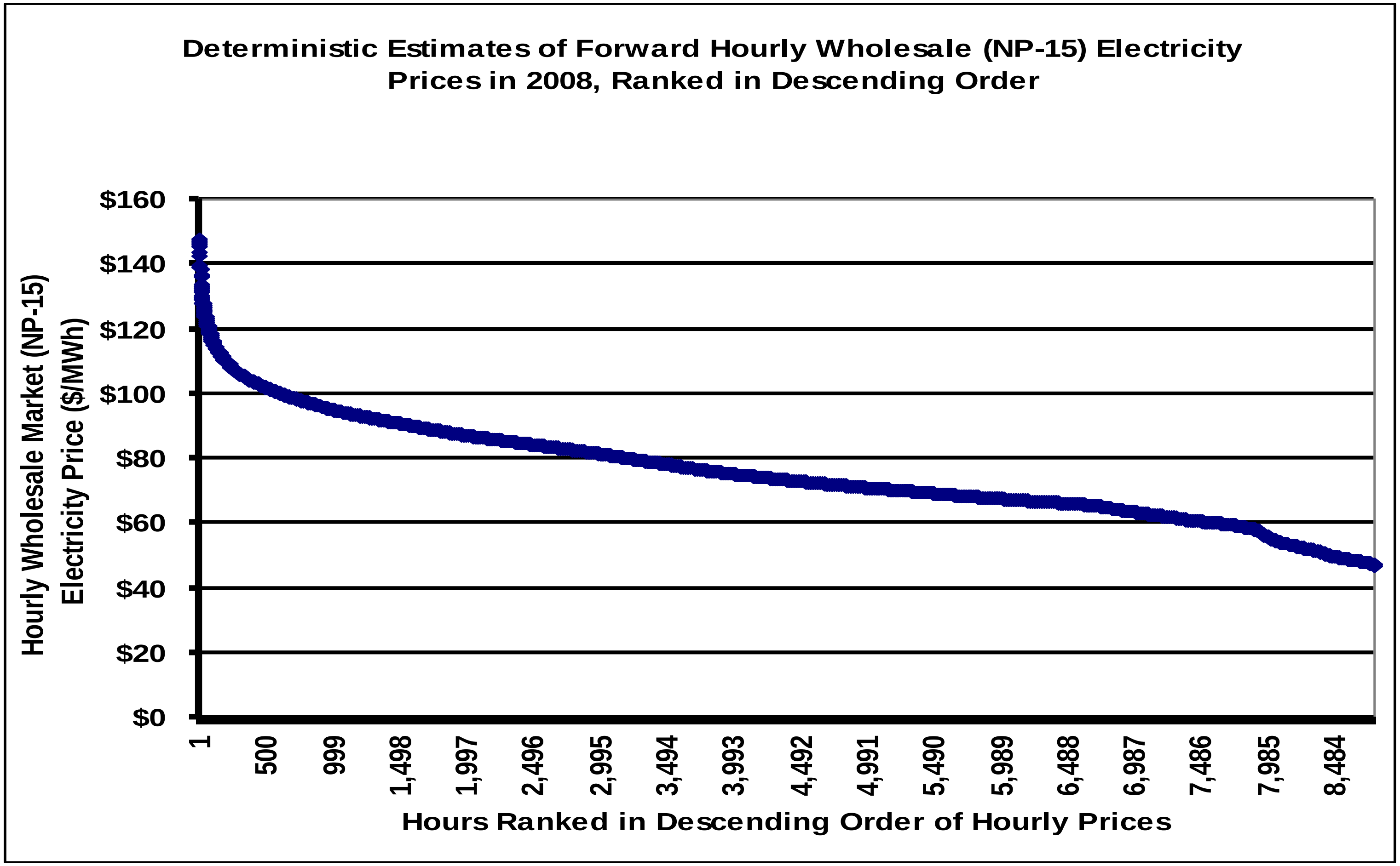
- Average peak and off-peak energy prices vary from season to season, and month to month.
- However, month to month changes in these average prices are much smaller than variation in prices from hour to hour within each time period.
- DR programs usually avoid energy costs only in hours when electricity prices are relatively high.
- Therefore, using average prices for specific time periods (e.g., July peak period hours) understates energy costs avoided by most DR programs
- ***Hourly* energy prices provide much more accurate estimates of avoided energy costs than *average* of hourly energy prices.**

Large Hourly, Daily, and Monthly Variations in Wholesale Electricity Prices

Hourly Electricity Prices Are Highly Volatile[1]

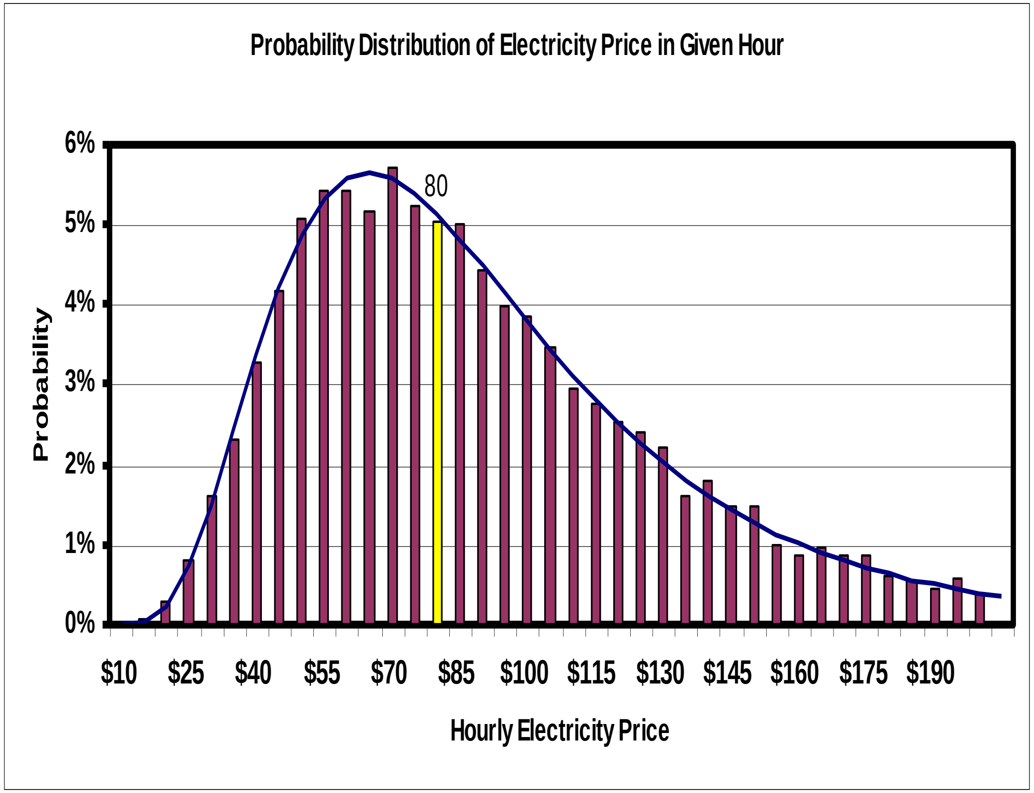


Most Event-Based DR Resources Avoid Energy Costs in Relatively Small Number of Hours with Relatively High Electricity Prices



Method Protocols Uses to Estimate Avoided Energy Costs Does Not Take into Account Uncertainty in Hourly Electricity Prices

- **Protocol's use of deterministic forecast of electricity price in a given hour (e.g., $80/MWh) to estimate energy costs DR would avoid in that hour fails to take into account uncertainty of electricity prices in that hour**



- **Therefore, PG&E formerly used spark spread call option model to estimate energy costs that use of DR program would avoided each hour, because that model takes into account the probabilities of all the electricity prices that might occur in that hour**

Method Protocols Uses to Estimate Avoided Energy Costs Does Not Take into Account Uncertainty in Hourly Electricity Prices (cont'd)

- Under that previous method:

  Avoided Energy Cost in Given Hour =

  [Call Option Value in that Hour -

  (Strike Price * Probability of Exercising Call Option in that Hour)]

- Probability of being able to use event-based DR in a given hour to avoid energy costs depends upon:
  - Limitations on specific time periods (season, months, days, hours) in which event-based DR resource is available
  - Limitations on DR program events (e.g., no more than "X" events/year, an event cannot last more than "Y" hours, events can be called on no more than "Z" consecutive days, etc.).

Method Protocols Uses to Estimate Avoided Energy Costs Does Not Take into Account Uncertainty in Hourly Electricity Prices (cont'd)

- **If event-based DR resource is available in hour in which an event could be called, whether it will be called depends on:**
  - **probability that event trigger(s) will be "met" in that hour;**
  - **probability that market price of electricity in that hour will exceed DR program "strike price";**
  - **value of call option in that hour, which in turn depends in part upon probability distribution of amount, if any, by which market price of electricity in that hour will exceed DR program "strike price";**
  - **expectations of need/ability to call more events in future; and,**
  - **expectations of value of calling more events in future**
- ***Therefore, PG&E previously used a probabilistic mixed integer linear program to choose set of hours in which use of DR program was expected to have highest call option value, which implicitly assumed DR resources would be dispatched with perfect foresight (and therefore somewhat overstated avoided energy costs).***

Value of Avoided GHG Emissions[1]

GHG emission allowance costs (starting in 2012 under California's new "cap & trade" GHG emission allowance market) and criteria pollutant compliance costs avoided by most event-based DR resources are relatively small because DR events occur in relatively small number of hours

- **In hours when DR events occur, DR avoids emissions that would otherwise have been produced in those hours by supply-side alternatives**
- **However, DR resources usually avoid very small volumes of emissions, because DR events usually reduce demand in only a few hours per year**
- **Example: GHG emission allowance costs avoided by DR program that reduces demand in in 100 hours/year:**

$$\frac{\text{(\# of program hours per year) x (avoided emission rate in lbs per MWh) x (emissions value \$ per ton)}}{\text{(2000 lbs per ton) x (1000 kW per MW)}}$$

– $= \frac{(100) \times (1200) \times (\$9.26)}{(2000) \times (1000)}$ ← CPUC estimated value/ton for 2006 GHG emission allowance[2]

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– **= ~ $0.56/kW-year**

[1] Avoided criteria pollutant emission compliance costs are captured in avoided supply-side generation capacity and energy costs (e.g., by including cost of emission control equipment and cost of NOx and PM-10 emission permits in new CT's fixed and variable costs and forecasted wholesale market energy prices).

[2] Escalated in future years, until replaced by actual forward emission allowance market prices.

Questions

Bruce Perlstein, Ph.D.

Director, Energy
Navigant Consulting, Inc.

Office: (415) 356-7189
Cell: (415) 307-0292

Bruce.Perlstein@navigant.com