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Incorporating Distributed Generation Into Hawaii's Utility Planning and Regulatory Processes

Why is distributed generation a disruptive technology?

- Disruptive technological changes occur when a new technology outstrips the current boundaries of cost, performance, and value compared to the incumbent process for delivering a product or service
- The centralized grid based generation is 75 year old technology that still delivers energy (kWh), but no longer provides the power quality, reliability and security that the society requires
- Distributed generation is disruptive because
  - Placing energy services closer to load provides superior power quality and reliability that defines customer service in the digital age
  - Distributed system architecture is more adaptive and resilient, and more secure in the face of terrorist threats
  - Distributed resources can create more utility system value in constrained urban or remote rural areas
  - Distributed resources enable elastic demand response, which makes central peaking and combined cycle units uneconomic, and hard to finance in a competitive wholesale market

The Distributed Utility Revolution

- The shift to distributed generation is rapidly accelerating
  – US new units mainly at 1940s scale (1-10 MW)
  – Will soon be at 1920s scale (10-100 kW)

- DG and renewables costs continue to decline
  – Wind is already competitive with gas plants
  – Fuel cells continue to decline

- The important federal and state rules for market access, interconnection, and net metering are being now being resolved and implemented (now in 29 US states, including Hawaii)

- DG is the largest strategic threat to traditional utilities
  – Eliminating energy peak prices makes fossil peak units and even combined cycles are far more risky investment
  – Distribution companies can not provide reliable power with traditional centralized grid and can not afford "stranded wires" and lost revenues from customers leaving the system

In *Small is Profitable*, RMI found that 207 distinctly distributed benefits can collectively increase the economic value of distributed resources

The benefits fall into four categories:

- Financial Risk Management: ~2–4×
- Electrical Engineering – grid side benefits: ~2–3×
- Power Quality and Reliability: often around ~2×
- Environmental Quality

- *Capturing* many benefits depends on Federal and State policy reform

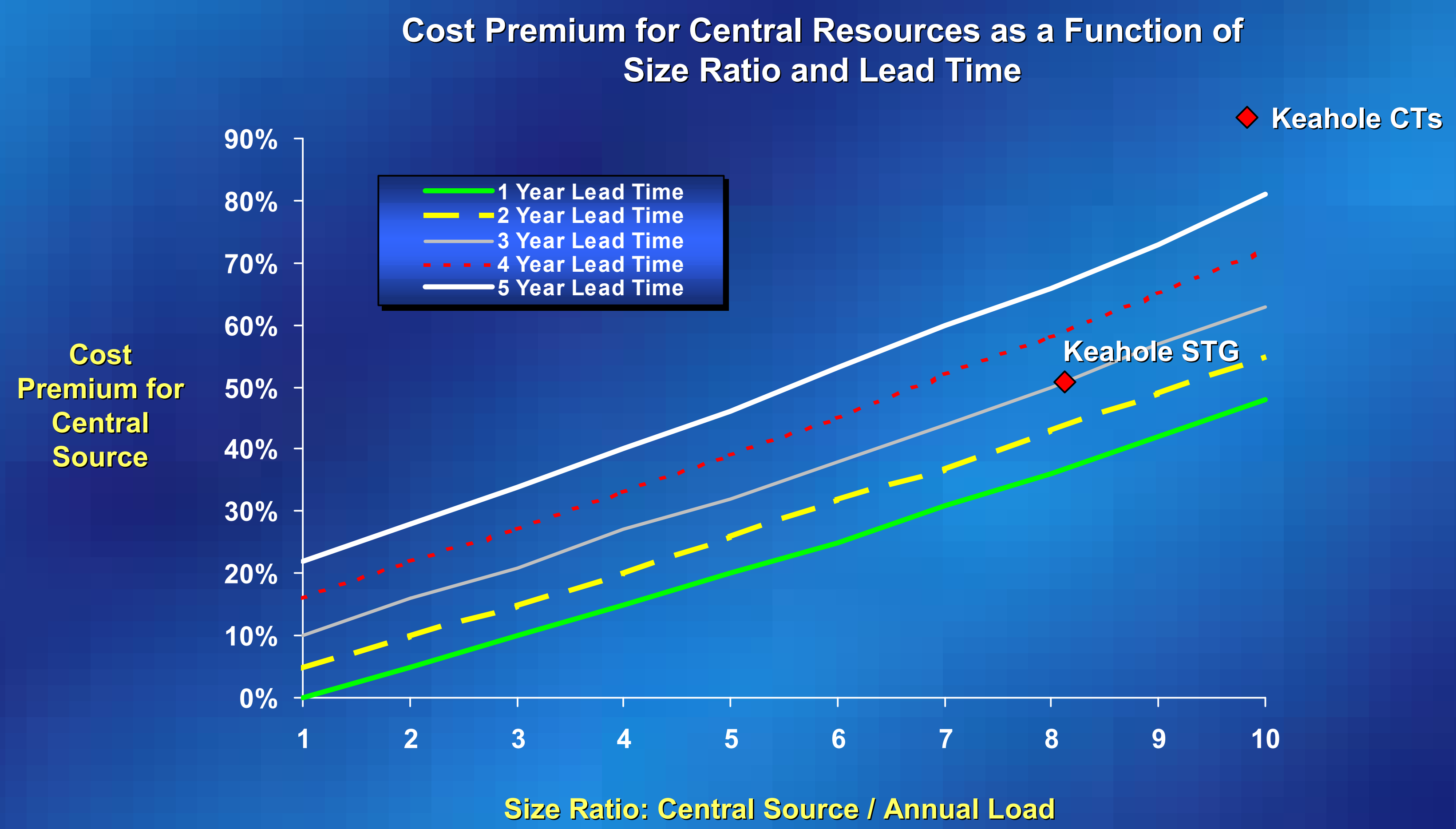
From utility's perspective, Distributed Resources could provide seven major sources of value

- **Lower Supply Costs** – Capacity and Reserves
  - Load management should reduce utility's system peak, thus utility's will have lower capacity requirements including reserve margin adjustment
- **Lower Supply Cost: Energy** – The cost of supply will be reduced because:
  - Negawatts shape load to lower supply portfolio management costs
  - Load Management shifts load to lower cost energy time periods
  - Transmission Congestion Credits (TCC) may be created
- **Risk Management** – Power markets can be "tamed" if 2-3% of total load is shifted to demand response
- **Ancillary Services Value** – Distributed can provide a variety of ancillary services if the utility is able to control them
- **MDCC Value** – The Utility should be able to avoid Marginal Distribution Capacity Costs if distributed resources are implemented on a concentrated basis that defers investment
- **Planning Flexibility Value** – Larger resources have greater risk of over capacity compared with smaller, more modular resource
- **Option Value** – Because of potential for staged investment, DR programs can be used as an option to manage the risk from future power market price spikes or load growth uncertainty

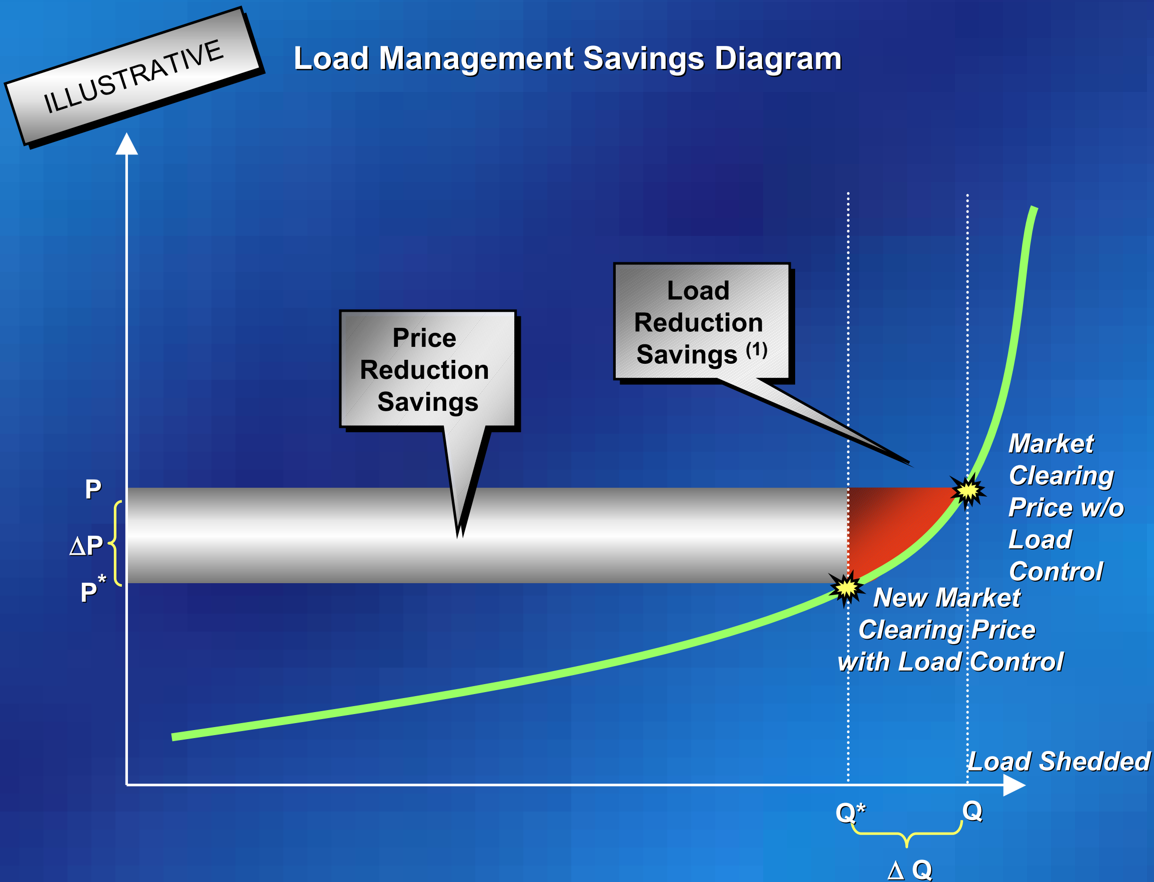
Financial Risk: Minimizing Regrets and Taming the Power Markets

- **Reducing Overshoot Risk** – Large central power plants with long lead times bear a 20-50% cost premium due to their risk. By contrast, Distributed Resources have:
  - Short lead times, cutting financial, forecasting, and obsolescence risks
  - Smaller modules reduce overshoot and "lumpiness" risks
- **Taming the Power Markets** – Distributed resources create a demand response to high prices from generators, causing spot market prices to drop 30-40% ($300-$500/MWh)
  - 500 MW of demand response would have saved California ratepayers $1 Billion dollars during the 2000 Energy Crisis
  - Not surprisingly, California is planning for 3 GW of demand response
- **Renewables Act as a Hedge on Oil and Gas Prices** – Large scale wind power now costs 2.5 cents/kWh, and can be delivered as "firm" power at 4 to 5 cents/kWh
  - Equivalent to a 15-year gas contract of $2.50-$4/Mmbtu or oil at $20/bbl – cheaper than the market

Present value financial advantage of a distributed energy resource compared to a central source depends on the lead time and size/load ratio



The real value of demand response is lowering the peak market price

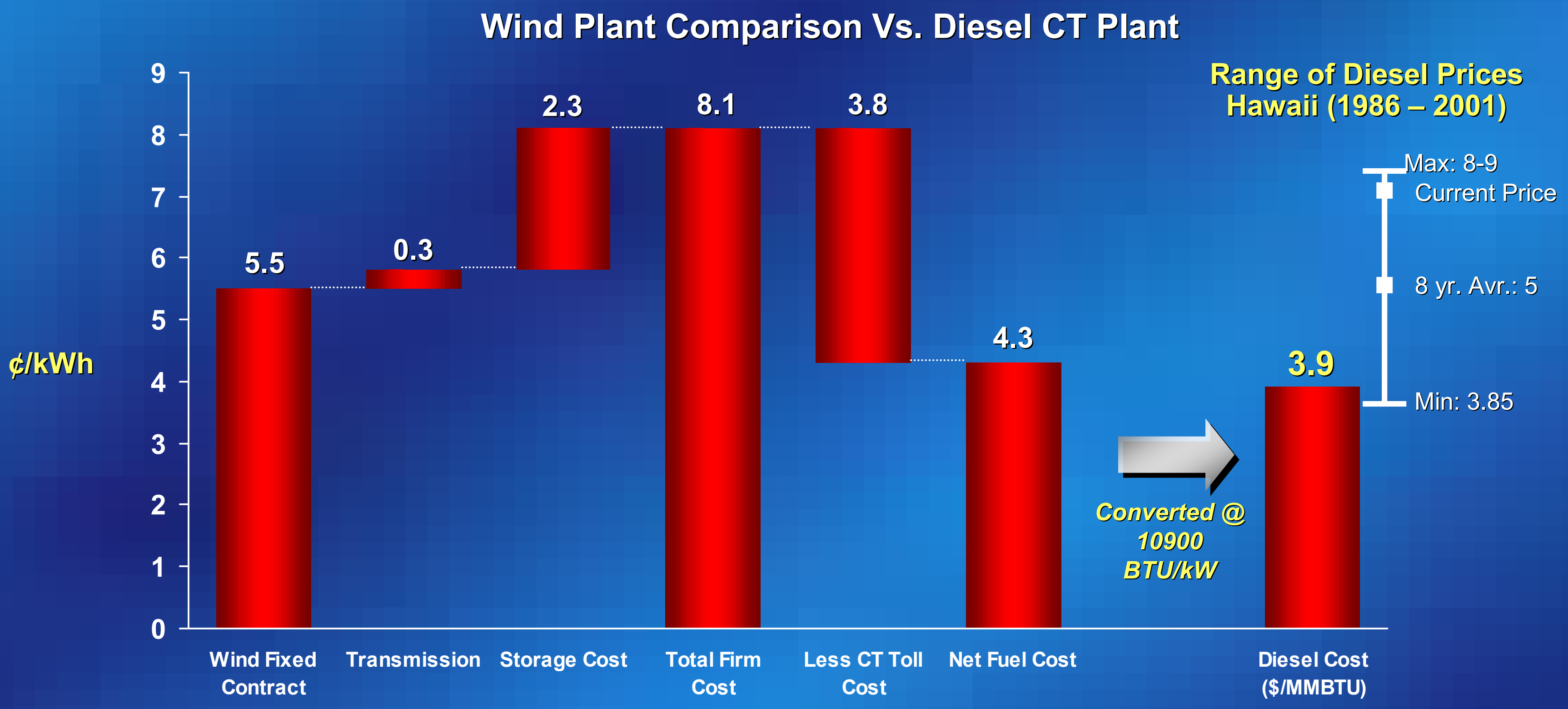


Power Market Impacts

- When a large buyer (default supplier or LSE) reduces the amount of power purchased in the wholesale market, it reduces the spot price for energy or ancillary services
- The first 5-8% of demand reduction will reduce peak energy prices by $300-$600/MWh price reduction, since supplier elasticity is an 8-10% change in price for each 1% change in quantity
- The price reduction savings impact all power contracts that are linked (exposed) the the spot market price
- Traders could also use negawatts to short the power markets

Notes: Load Reduction Savings includes the wholesale savings - the revenue that would have been generated for that hour

Firming wind power with storage would give us a means to address risk preferences regarding fossil fuels



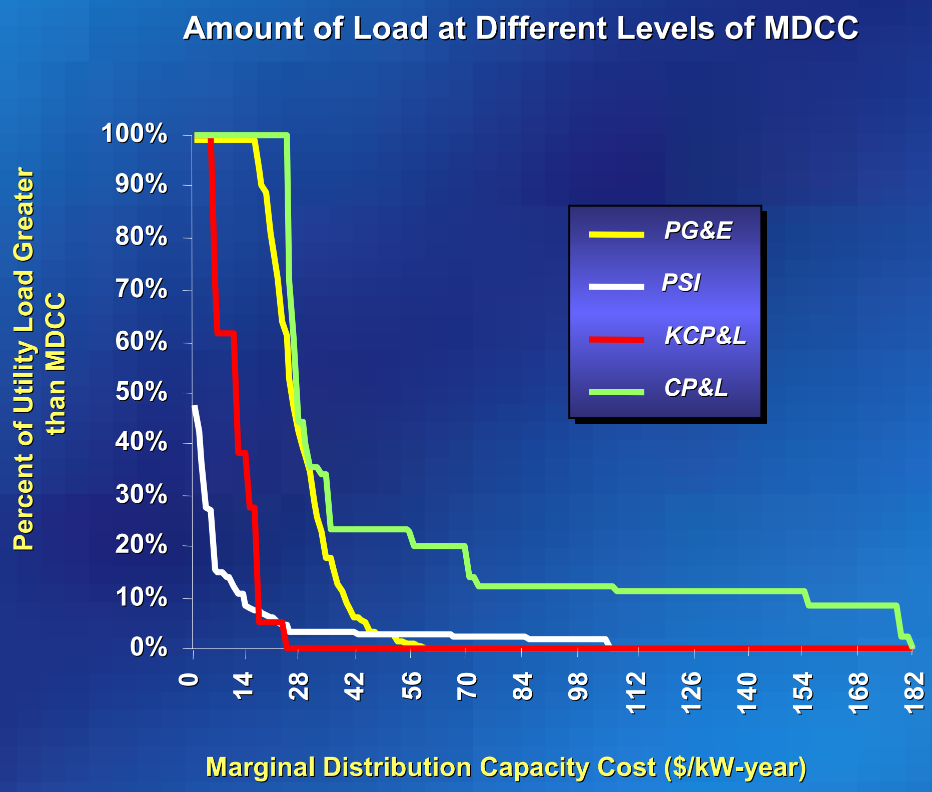
… which is better: $20/bbl for 15 years or the floating price of oil?

Note: Wind plant: capacity @36%, storage @30% of power output, pumped hydro storage costs of $2,100/kW, fixed O&M price of $36.7/kW-yr, power cost of 5.5 c/kWh and transmission charges of 0.3c/kWh. CT plant: capital cost of $1,612/kW, 55% capacity factor, 10970 BTU/kW heat rate and $23.60/kW-yr of O&M charges

Remember the grid: deferred T&D and ancillary services can equal 30-40% of the total benefit

- 50% of utility capital goes into the distribution or "wires" side of the business
- In congested or constrained distribution, DG operation can defer new distribution system upgrades, so long as the total amount of DG equals the capacity of the planned addition
- When controlled by the utility, DG operation can provide much needed power to weak points in the grid, which has a number of electrical engineering benefits:
  - Improve voltage levels at the feeder ends
  - Eliminate the need for capacitor banks
  - Provide reactive power (VAR) compensation
- DG can improve the efficiency of utility assets, and lower line losses
  - Reduce feeder loading and delay replacement
  - Reduce line losses and transmission system load

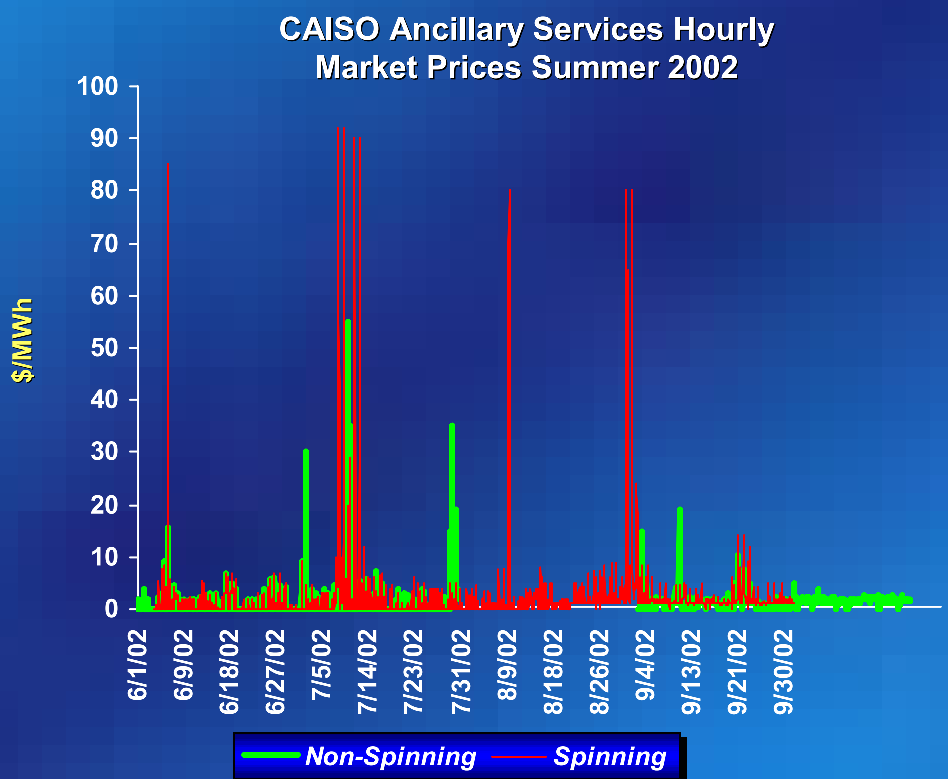
Deferral value, based on marginal distribution capacity cost



Deferral Value Issues

- The deferral value depends on the marginal distribution capacity cost, which varies by location and time
- The MDCC value can range from zero to over $100/kW-yr, average:$10-$40/kW-yr. PG&E estimate of T&D benefit from small DR is between $2-5//kW-yr
- By concentrating DR in high cost areas, a utility can offset their revenue loss in cost savings through deferral of capacity Deferral opportunities are concentrated in areas with planned T&D expansion
- To achieve deferral value, DR must displace the area load growth for at least one year. Minimum DR capacity is typically in the range of 500-2,500 kW
- DR capacity must be available at times of area peak load to defer capacity costs

Demand response should be able to bid into the ancillary services markets



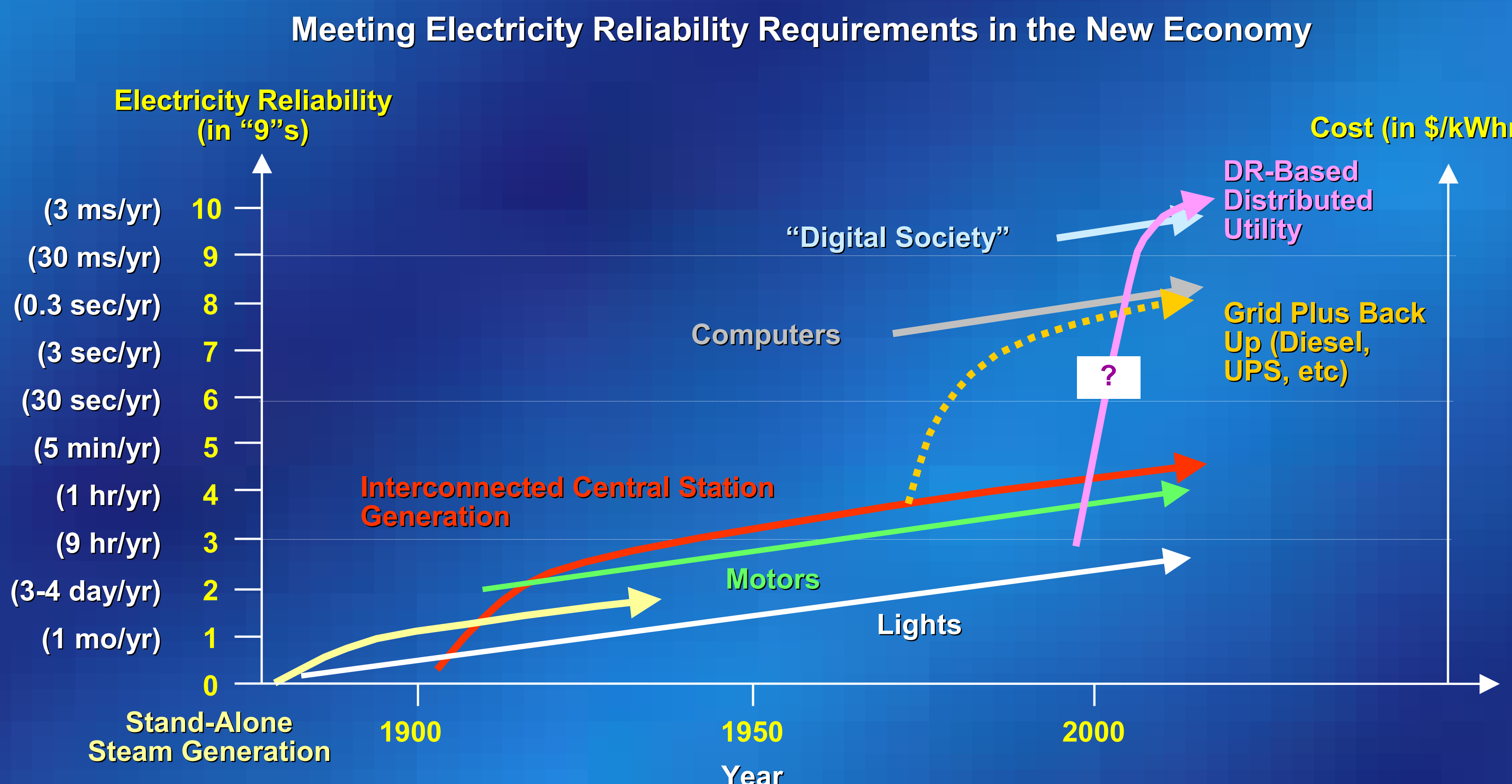
Note: Prices sum the Ten Minute Spinning Reserve, Ten Minute Non-spinning Reserve, Thirty Minute Operating Reserve and the Automatic Generation Control markets

Source: CAISO, Oasis

Ancillary Services Issues

- Eligibility of Demand Response for the wholesale ancillary services market is resolved at both the federal (FERC) and regional ISOs
- >1 MW load reduction generally required to participate in ancillary services market, which would exclude residential
- Load management is clearly technically capable to provide spinning reserve and voltage regulation
- Negawatts, like megawatts, should be able to bid into the capacity OR the ancillary services markets
- Ancillary services markets tend to spike with capacity deficiencies, and therefore this increases the upside for LSEs
- DR should be able to realize $30 – $50/kW-yr from ancillary services

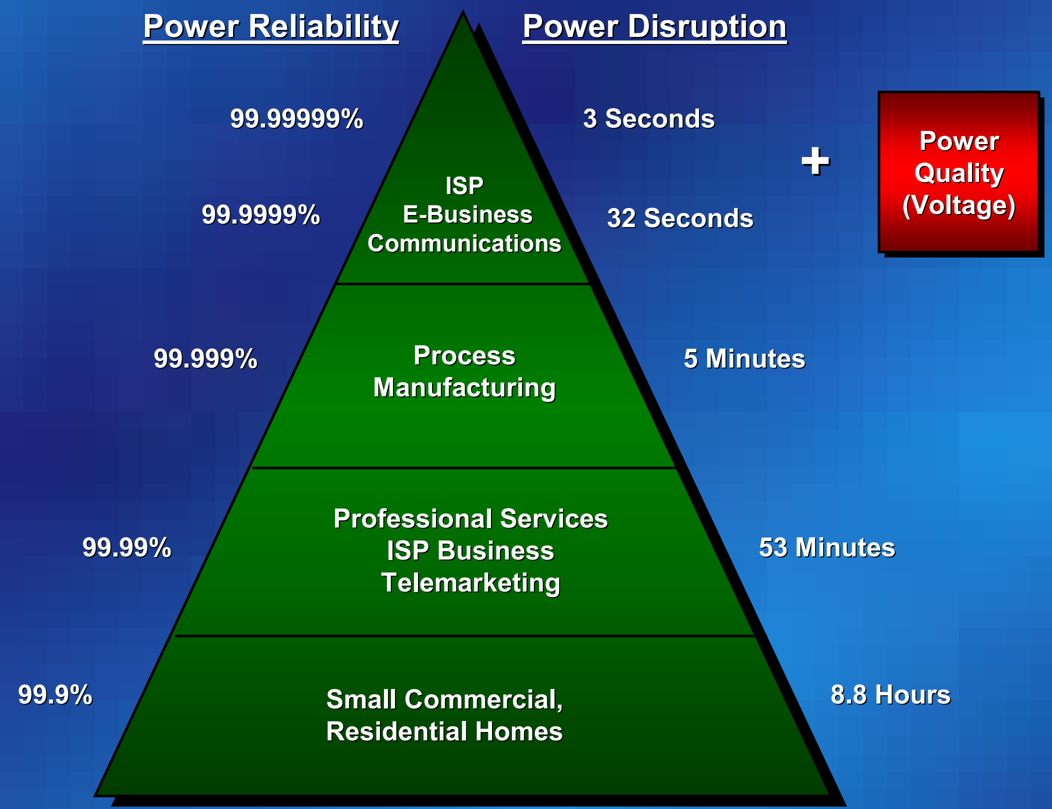
From the customer perspective, distributed generation – meeting reliability and power quality needs



Source: Workshop Proceedings, Power Electronics for Distributed Energy Resources, October 26-27, 2000

Reliability economics can support on-site capacity costs of $2000-$3,000/kW for "6-Nines" of reliability, but only if there are expected concerns with grid supplied power

Reliability Economics



Interruption Cost

- On Line Retailer– $1-60MM/hr
- Brokerage – $6MM/hr
- Credit Card – $2-$3 MM/hr
- Banking – $1.6MM/hr

- HP Fabrication – $30MM Loss Per Episode (20 Minutes)
- Mobil Refining – $10MM Loss Per Episode (30 Minutes)

- ISP: $25,000/hr
- Airline reservations $90,000/hr
- Cellular Communication $40,000/hr

- Small business $7,500/day
- Grocery store $50,000-$80,000/day

Source: EPRI, Contingency Planning & Management

When the total benefits from distributed generation are considered, many technologies are current cost effective

	Utility	Customer
Capacity & Energy	$100-$200/kW-year	
T&D Deferral Value	$15-$100/kW-year	
Generation Risk Premium	$25-$100/kW-year	
Engineering & Ancillary Costs	$30-$150/kW-year	
Environmental	?	
Net Metered Rate Savings Less Opex		$140-$650/kW-year
Thermal Value		$50-$100/kW-year
Customer Reliability		$25-250/kW-year
Total	**$170-550/kW-year**	**$215-$1,000/kW-year**

This corresponds to a capital cost of $4,000-$7,500/kW in constrained, high rate areas

Cost values for representative "high-cost" distribution planning areas, which are generally the most attractive to site DG sources
Capital charge rate of 13% used to convert $/kW-yr to capital cost.

There is enough DG to meet load growth for the next 5-10 years with *no new central* generation

- Based on the thermal energy needs, resort hotels, military bases, hospitals and colleges are prime candidates for distributed combined heat and power
- The technical/economic potential in commercial within Hawaii could be as high as 700-800 MW
  - CHP in resort hotel segment alone could meet new load growth for 5-7 years
  - Military DG could meet 2-4 years of new load growth
- So how do we capture this market?

New business models are needed for DG to reach its potential— let's innovate!

- Customers are ultimately buying energy services and insurance against reliability failures, but:
  - Facility managers have limited capital budgets
  - Customers are shocked by the high cost of physical reliability insurance
- Leasing models for DG solve these issues
  - Customer pays for DG from lower total energy bill, no upfront capital
  - Essential discount rate arbitrage
- HEI's proposed cogeneration tariff program is an innovative experiment in this new business model and the playing field must be fair regarding
  - Network information and location specific marginal value
  - Interconnection costs and timing
  - Backup charges
  - Avoided system costs paid by the utility
  - Sharing of value between the utility and its ratepayers
- With a fair playing field, competitors can offer similar approaches for not just CHP, but solar, fuel cells and other

Incorporating DG into Hawaii's Integrated Resource Planning process

- Utilities MUST understand both their generation and distribution system costs, and how these vary by area and time
- DG resources should include all DG resources, not just the ones that the utility has a commercial interest in
  - CHP, Solar PV & thermal electric, small scale hydro, landfill gas, ocean energy and fuel cells
  - Demand response in commercial and residential
- Adjustment for risks
  - Financial risks of overshoot
  - Fuels volatility risk
- Reliability benefits should be based cost effectively minimizing total unserved energy (in theory). In practice, the IRP should value the improvement in LOLP that DG provides to the system

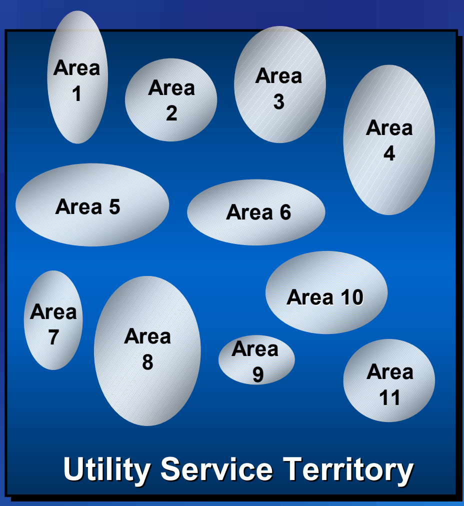
IRP must get the metrics right

- Lower customer bills should be the objective, not rates
  - The exposure of customers to fuel prices matters
  - The total price of power, including generation, fuel and transmission must be considered at realistic oil prices
- Energy security in power should be measured by
  - The risk that the planned resource won't get built on time (a function of size and lead time)
  - The dependence of the system on a single fuel (oil)
- CHP is NOT a renewable resource, since it does not hedge fossil fuel risk to the ratepayers

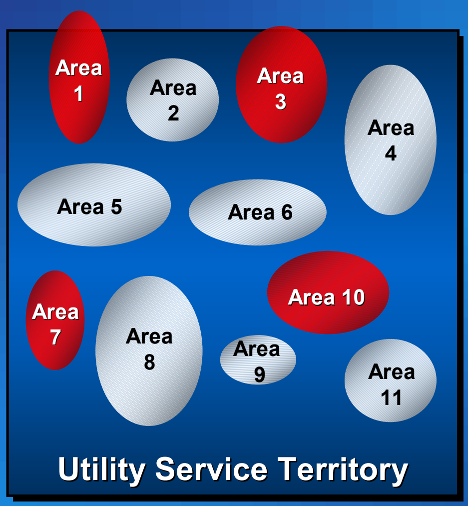
The Area and Time Specific approach to avoided costs is quite different than the current IRP approach

Conventional Approach
‣ Based on system level costs ‣ Each area looks the same!

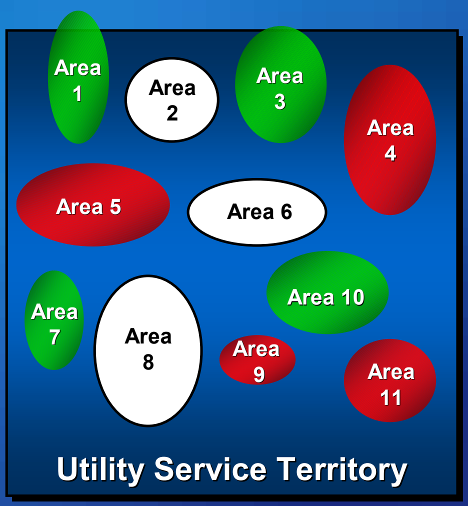
Distributed Generation or Targeted DSM
‣ Based on area- and time-specific costs ‣ High-cost (red) areas move around in time!



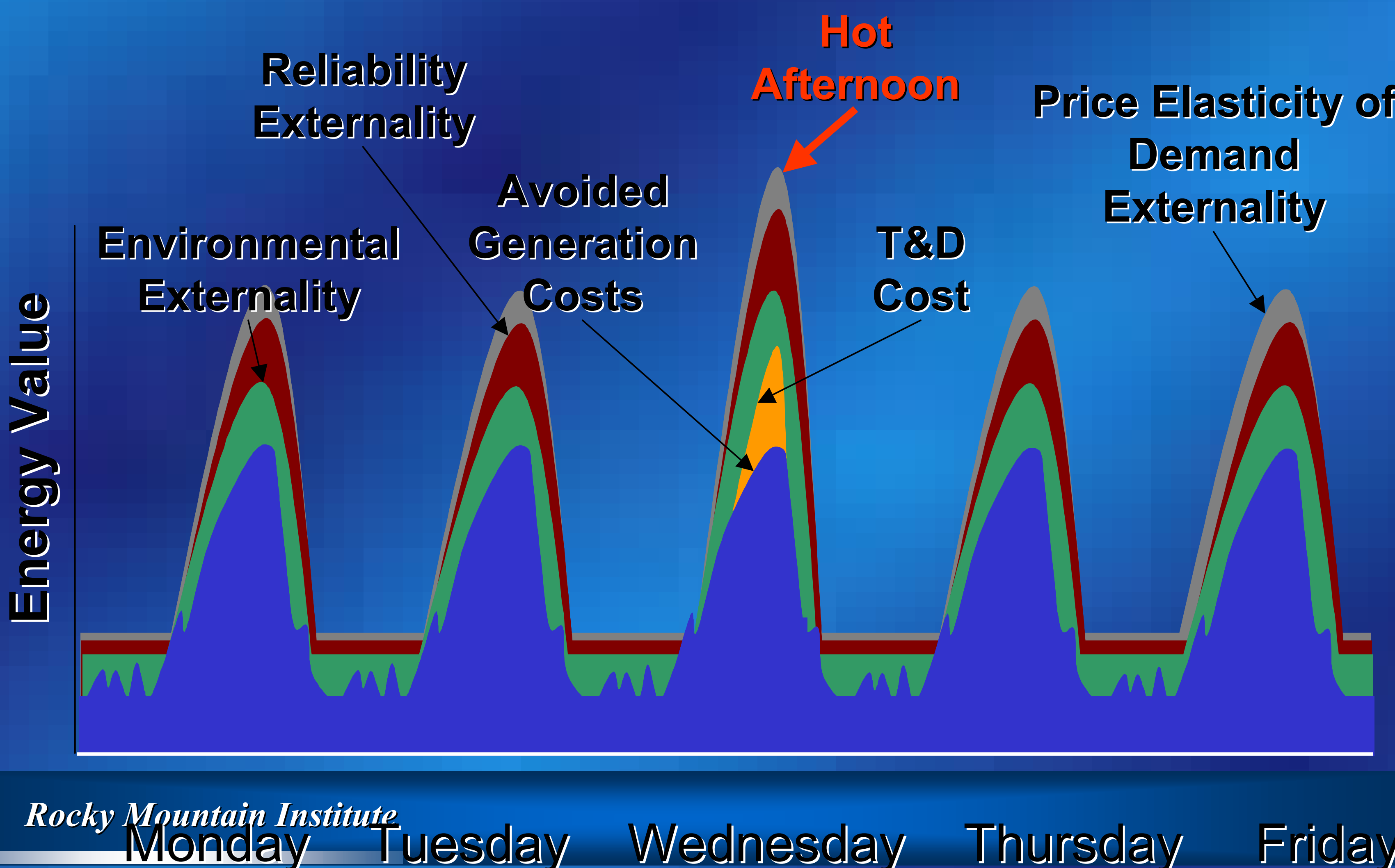
High Cost Areas – Year 1



High Cost Areas – Year 5



California has adopted the Area and Time Dependent Valuation for avoided costs



Barriers to DG in Hawaii

- Traditional utility regulation
  - Incentive to sell more kwh, not conserve or lose customers
  - Fuel costs are pass through, so why invest in hedging?
  - Institutional capabilities of PUC, CA to manage innovative regulatory approaches
- Uneven Playing Field
  - Interconnection delays and backup charges
  - Asymmetry between utility and its customer or competitors
- Standards, codes, permitting and zoning

We need a new regulatory compact to provide financial security to the utility…

- Eliminate disincentives to efficiency and distributed resources with revenue recovery mechanism or rate base adders…
- Revenue caps with lower bills, but increase rates… can we tolerate fluctuation of 1-2%/year given that we already accept far greater volatility due to oil prices?
- Allow innovative programs that expand distributed resources to flourish and build the regulatory capabilities to manage them
- Create positive incentives to promote economic efficiency and distributed resources based on a share of the total resource benefits the program creates to the system
  - Tariffs are fine, but not fancy formulations that obscure the real rate of return
  - Why wouldn't we give the utility $2-3 for every barrel of oil saved?
  - Incorporate environmental externalities

… and level the playing field

- Standard Interconnection protocols and equally rapid interconnection approvals
- Back-up charges that reflect the costs of providing reliability services that apply to all distribution resources
- Clearly defined avoided costs based on the system economics
  - Generation capacity
  - Energy based on peak, mid peak, and off peak
  - Transmission system losses
  - Avoid distribution capacity costs
- Make system information available to all competitors via IRP
- Green Pricing Option – let consumers choose to express their preference for premium green power

Hawaii Could be a Role Model

- Energy security matters
- High energy and distribution cost
- Reliability challenges
- Complete portfolio of renewable resources and thermal loads for DG
- New interest from all stakeholders in solutions
- System microcosm