Demand Response & Load Management Study

Overview of Research and Determinations

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Resource Acquisition

Topics for Discussion

- Reasons behind the Demand Response ("DR") Study
- DR Study overview
  - Quantitative evaluation approach
  - DR programs reviewed
  - Residential Survey results
  - Preliminary findings and results
  - C&I RFP Update
- Practical Application of DR

Purpose of the Study

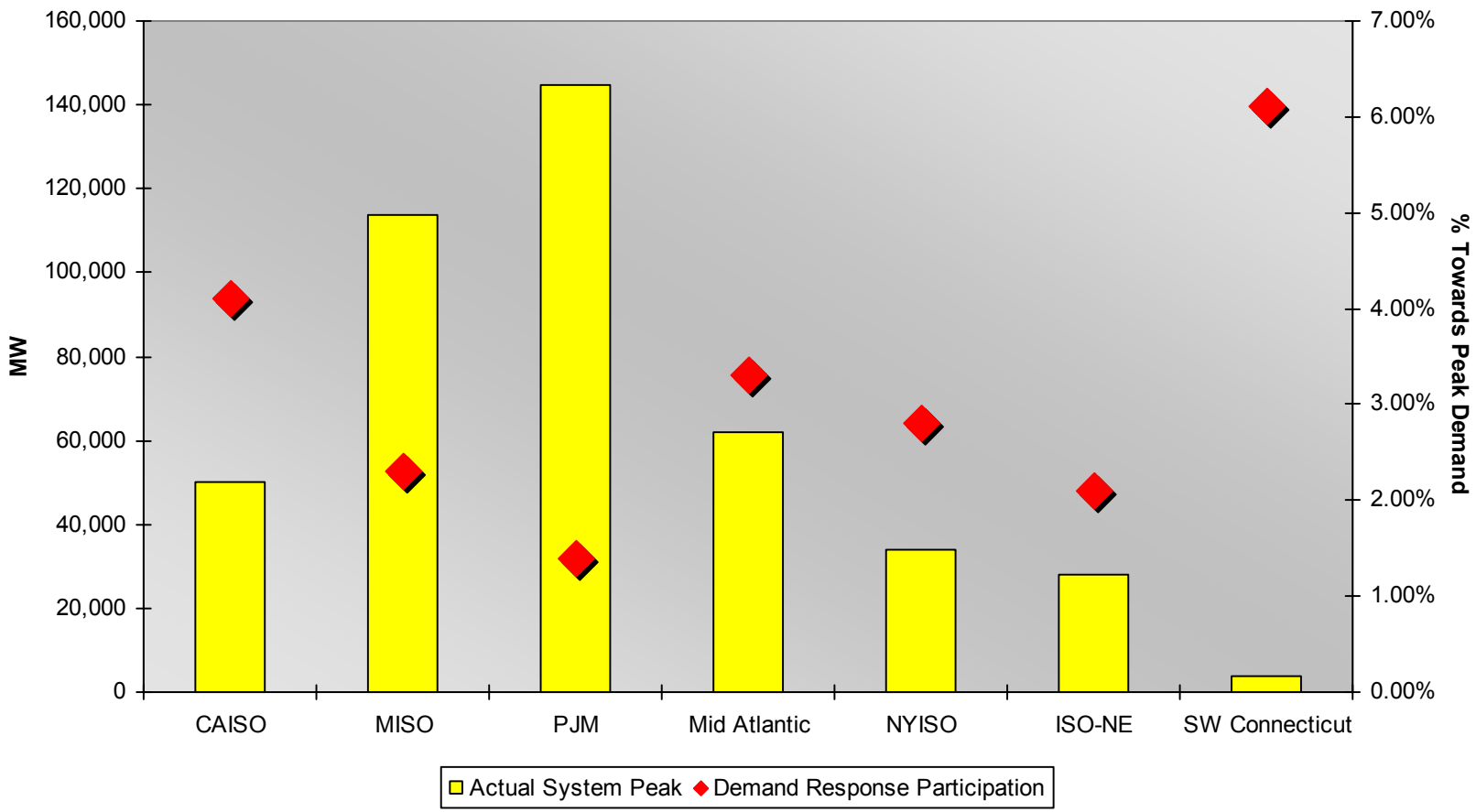
- Preliminary review of the varying Demand Response programs that APS could implement
- Determines which ones make the most economic sense for APS and its customers
- Discussed internally since 2006 and subsequently required pursuant to ACC Decision No. 69663
  - Due to be filed by June 28, 2008
  - In addition, APS must also file one or more cost-effective programs for implementation
- Leveraged the experience of Summit Blue Consulting to research and analyze the different Demand Response programs available

What is Demand Response?

- Demand Response programs are mechanisms designed to provide incentives to customers to reduce their load in response to prices, market conditions, or threats to system reliability
  - ACC Decision No. 69663 at pp. 97-98 (June 28, 2007)
- Unlike Energy Efficiency, DR does not cause a permanent reduction in consumption

	Goals
Energy Efficiency	Permanent reduction in energy consumption Reduced peak capacity need
Demand Response	Reduce/shift consumption at times of system peak Some programs may result in net reduction in consumption

Summer 2006 DR Participation at time of System Peaks – RTOs/ISOs



Federal Energy Regulatory Commission, *2007 Assessment of Demand Response and Advanced Metering*, Derived from Table D-1 (September 2007).

Elements of the Study

- Executive Summary
- Overview/Objectives
- APS Situation Assessment
  - Load Shape / Demand Characteristics
  - Supply-side Resources
  - Base Case Forecast
  - Other Relevant Factors
  - Potential for DR on the APS System
- Evaluation Overview
  - Formulas
  - Estimated Emissions Impact
  - Items to Note
- Programs Details
  - Overview
  - Current Programs in Other Jurisdictions
  - Applicability to APS
  - Benefit/Cost and Emissions Impact Results (if applicable)
  - Recommendations
- Glossary
- References

Economic Test Overview – 3 Tests Utilized

- G = Generation Avoided Cost (Capacity & Energy)
- T = Transmission/Distribution Avoided Cost
- E = Environmental Benefits
- R = Rebate/Incentive Payments
- PC_C = Program Costs to Customer
- PC_U = Program Costs to Utility

- Total Resource Cost Test ("TRCT")
  - $B_{TRCT} = G + T$
  - $C_{TRCT} = PC_C + PC_U$
  - $BCR_{TRCT} = B_{TRCT} / C_{TRCT}$
- Societal Cost Test = TRCT + Environmental Benefits
  - Quantified but not monetized

- Program Administrator Test
  - $B_{PACT} = G + T$
  - $C_{PACT} = PC_U + R$
  - $BCR_{PACT} = B_{PACT} / C_{PACT}$

Estimated Emissions Impact Calculation

- Goal – estimate the net emissions decrease/(increase) due to APS exercising certain DR programs
- On-peak assumption – Combustion Turbine is the unit "on the margin"
- Off-peak assumption – Combined Cycle is the unit "on the margin"
  - Based upon production simulations and the type of units likely to be running
- Example:
  - DR program provides for a 4 hour on-peak reduction in cooling demand, resulting in 400 MWh of reduced consumption after accounting for pre/post cooling ("Snapback Effect")
  - Estimated Emissions Impact = Avoided emissions from 400 MWh of equivalent run time from a CT unit

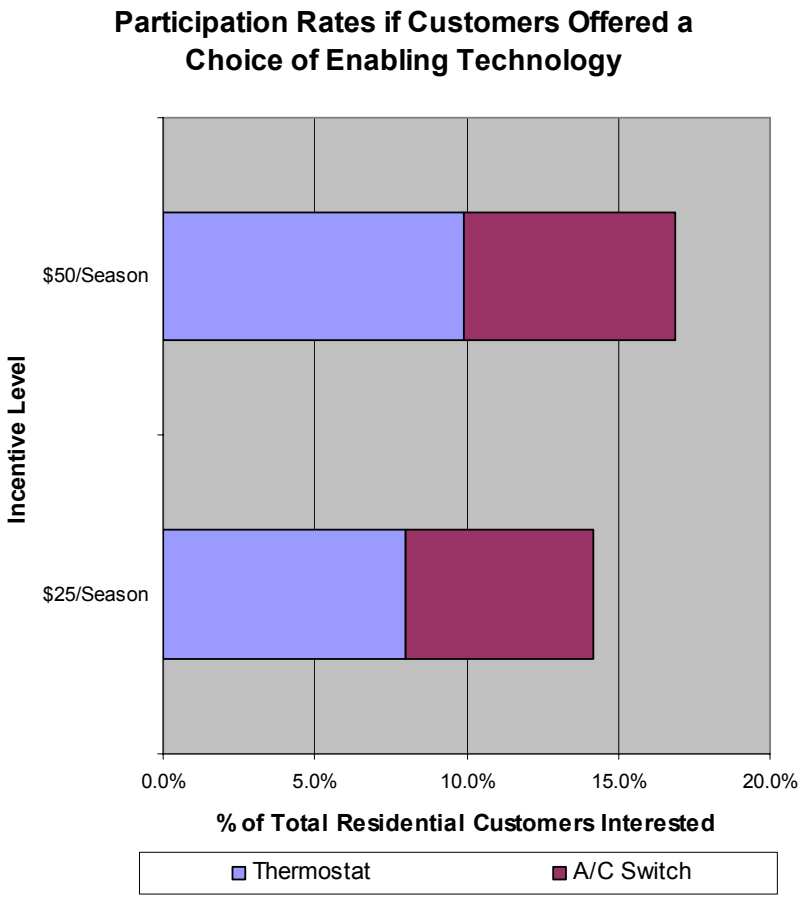
Programs Reviewed

Direct Load Control ●Residential A/C Cycling ●Residential Misc. Load Control ●C&I Load Control	**Customer Load Response** ●Curtailable/Interruptible Rates ●Demand Bidding/Buyback ●Standby Generation ●Plug-in Vehicles
Scheduled Load Management ●Thermal Energy Storage ●Scheduled Water Pumping ●Battery Storage	**Time-Differentiated Rates** ●Time-of-Use Rates ●Critical Peak Pricing ●Real-Time Pricing

Residential Survey Overview

- 1,000 residential low country customers owning single family homes
  - Evenly split between five rate plans
- The programs were described as running on no more than 20 summer afternoons (June – Sept) from 3-7pm
  - Free Thermostats – raise temperature no more than 4 degrees
  - A/C Switches – cycle 12 minutes out of every half hour (40% cycling strategy)

Results of the Residential Survey



- 14-17% of all residential customers expressed an interest in allowing APS to remotely cycle their A/C unit via either a thermostat or an A/C switch (depending on incentive level)
  - Equates to 25-30% of Low Country Single-Family Homeowners
  - If APS offered only one enabling technology:
    - Free thermostat – 11-13% total participation
    - A/C switch – 11-12% total participation

Quantitative Results

Program	Reduction per Participant	Estimated Number of Participants	Estimated MW Reduction	PAC Test	TRCT	CO_2 Decrease/ (Increase) in tons	NO_x Decrease/ (Increase) in lbs	PM10 Decrease/ (Increase) in lbs
A/C DLC - 40% Cycling - Base Case	1.04 kW	65,000	68 MW	0.89	1.32	7,487	2,271	160
A/C DLC - 40% Cycling - Survey Results @ $25 Incentive	1.04 kW	127,800	133 MW	1.03	1.59	14,721	4,465	314
A/C DLC - 40% Cycling - Survey Results @ $50 Incentive	1.04 kW	153,000	159 MW	0.79	1.60	17,624	5,345	376
A/C+WH DLC - 40% Cycling - Base Case	1.28 kW	65,000 A/C 26,000 WH	74 MW	0.86	1.35	8,178	2,480	174
Small Scale TES	10 kW	Studied on a "per participant" basis		2.29	0.70	53	32	0
Large Scale TES	200 kW			3.42	1.10	795	476	3
Standby Generation - $3.50/gallon Diesel	1,750 kW	29	50 MW	1.04	1.04	(10,855)	(406,493)	N/A
Standby Generation - $4.50/gallon Diesel	1,750 kW	29	50 MW	0.97	0.97	(10,855)	(406,493)	N/A

- Increasing the incentive from $25 per season to $50 per season for residential DLC participants has a no impact on the TRCT results, but a negative impact on the PAC Test results
  - Program assumes that the DR program is available 100 hours per year, and APS exercises 50% of the time
- The size of the TES unit can dictate whether or not it is cost effective for the consumer
  - Program assumes customer pays for the TES technology and APS provides a rebate for 50% of the costs
- The cost of diesel fuel dictates whether or not a Standby Generator program is cost effective from an economic screening standpoint
  - Because the program is capacity-based in nature, the cost of diesel fuel would not significantly change dispatch decisions if a program were implemented
- Most programs provide a net environmental benefit
  - Standby Generation is the exception, as the load responsibility is shifting from an APS-owned CT to a customer-owned diesel-powered generator

APS

Preliminary Findings

- Programs for consideration:
  - C&I DLC
  - Residential DLC
  - Residential Super-Peak Rate
  - Commercial/Industrial/Irrigation Critical Peak Pricing pilot program
- Programs that need additional evaluation:
  - Scheduled Water Pumping
  - Standby Generation
  - Thermal Energy Storage

Preliminary Findings (cont'd)

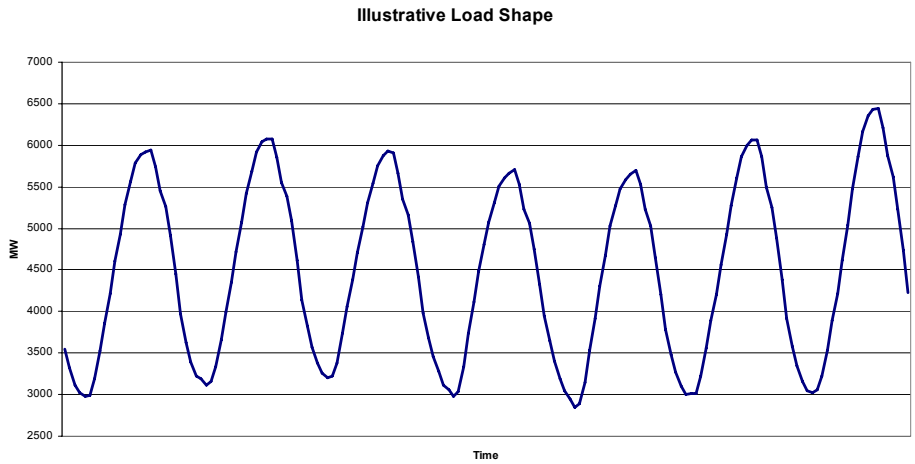
- Programs to be monitored but not pursued at this time:
  - Battery Storage
  - Demand Bidding/Buyback
  - Plug-in Vehicles
  - Curtailable/Interruptible Rates
  - Real-Time Pricing

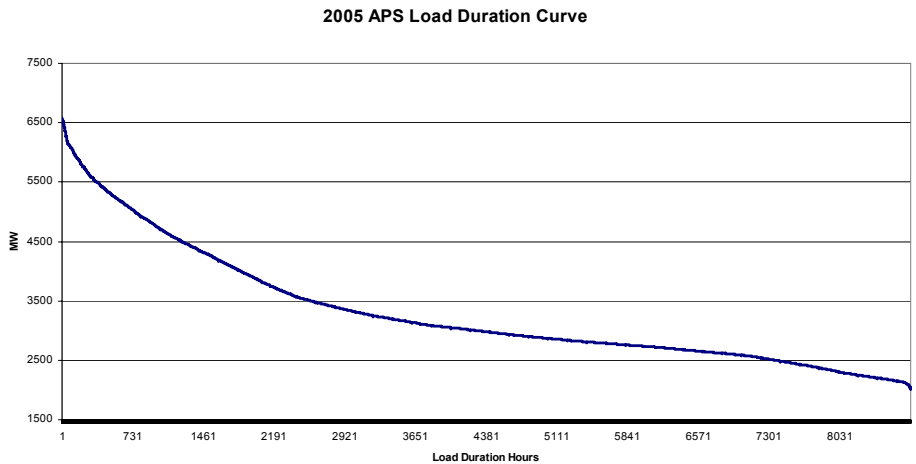
C&I Load Management RFP

- Targeted RFP issued on 10/25/07
- Similar to a capacity call option contract
- Proposals submitted in December 2007
  - Ramping to as much as 200 MW over 5 years
  - Program availability between 11am – 7pm
  - Maximum callable hour limit up to 100 hours per season
- Compared to a conventional supply-side resource
- Multiple companies with Benefit/Cost ratios >1.0 were short-listed
  - Contract negotiations on-going

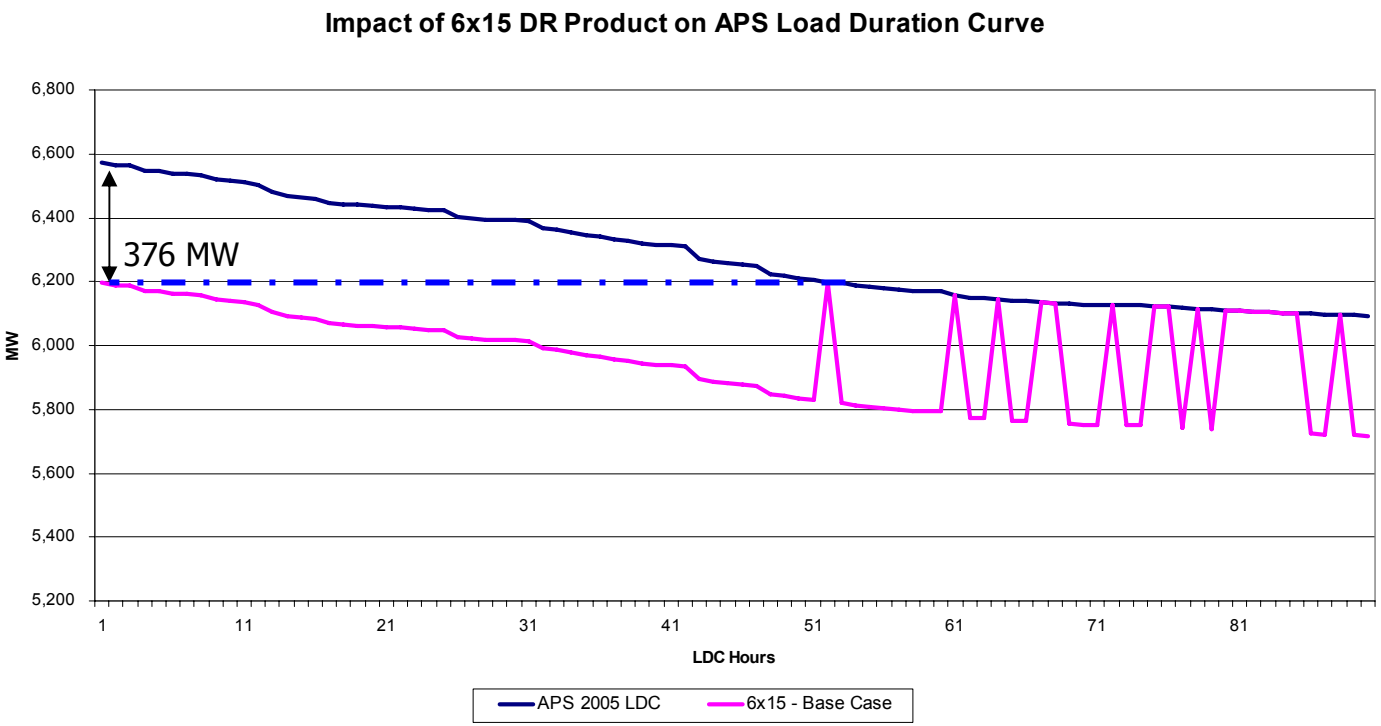
Potential for Demand Response on the APS System

- Analyze the potential impacts of different DR strategies on APS system loads
- Data and assumptions
  - Summer only (Jun-Sept), max 90 hours
  - Four scenarios
    - 4x23 – four hour event, 23 highest peak load days
    - 5x18 – five hour event, 18 highest peak load days
    - 6x15 – six hour event, 15 highest peak load days
    - 7x13 – seven hour event, 13 highest peak load days
  - Analyses performed on actual APS historical data from 2002-2007
- Sensitivity #1 – 50% Snapback effect
- Sensitivity #2 – Missing 4th highest peak load day
- Applies to callable DR programs only



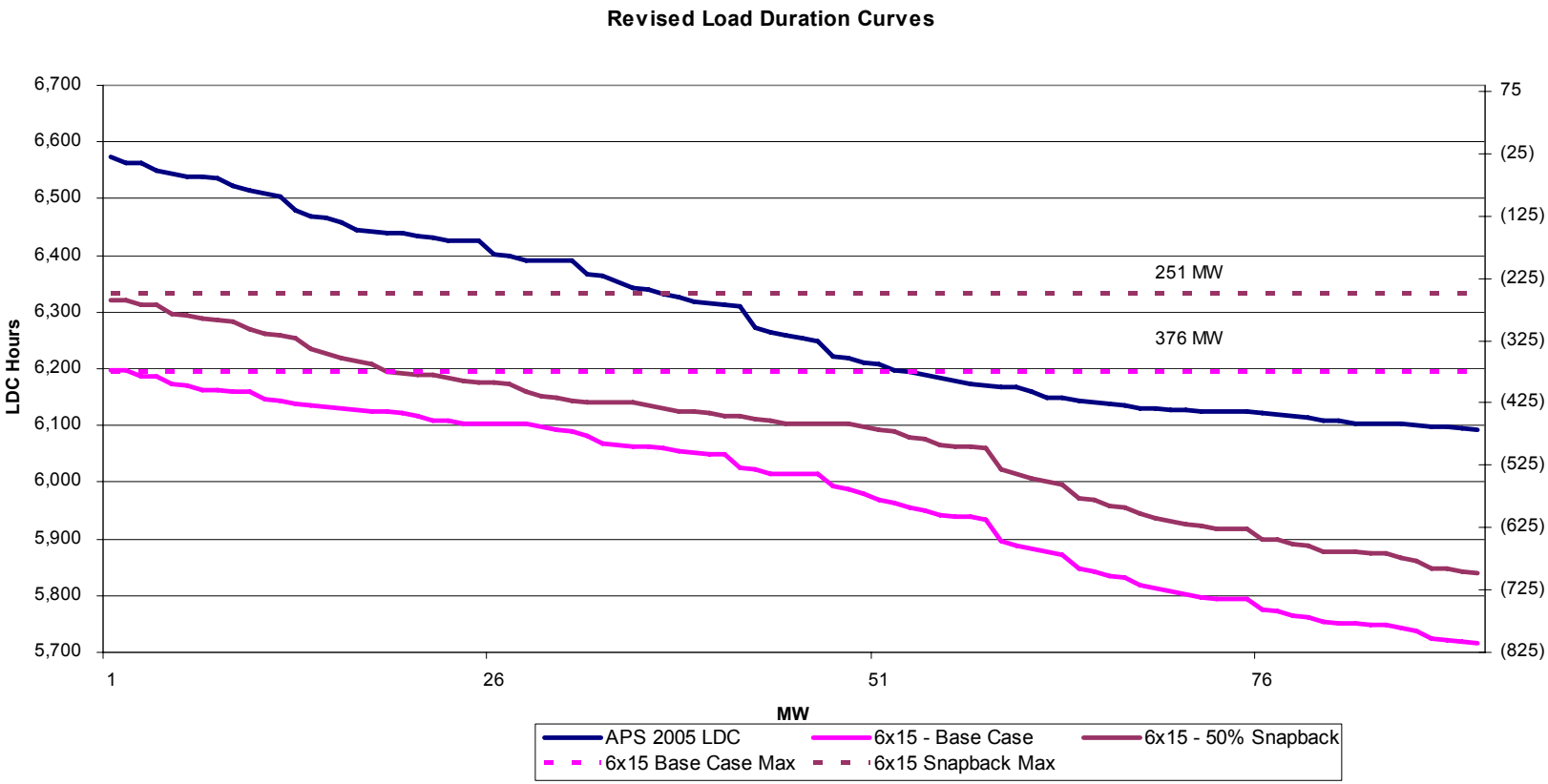


DR Potential – Results



- 52nd highest LDC hour is the new system peak, even though 90 hours of DR were purchased
  - 74 total hours out of the top 90 were effectively captured by this strategy
  - 376 MW reduction
    - Delta between 1st and 90th hour of the 2005 LDC is 481 MW

DR Potential – Results (cont'd)



- Snapback Effect sets a new peak hour outside of the targeted window, resulting in 125 MW less in experienced load reduction
- MW amount varies by scenario

DR Potential – Results (cont'd)

Summary of DR Potential Levels as a Percentage of Peak Demand		
Base Case	*4x23*	4.4%
	5x18	5.2%
	6x15	6.8%
	7x13	6.6%
	AVG	5.7%
50% Snapback	*4x23*	2.9%
	5x18	3.5%
	6x15	5.0%
	7x13	5.6%
	AVG	4.3%
Missing 4th Peak Day	*4x23*	1.9%
	5x18	1.9%
	6x15	1.9%
	7x13	1.9%
	AVG	1.9%
Missing 4th Peak Day - 50% Snapback	*4x23*	1.9%
	5x18	1.9%
	6x15	1.9%
	7x13	1.9%
	AVG	1.9%

- Longer durations (6 hours per event vs. 4 hours per event) tend to result in larger MW potentials
  - This implies that customers would be required to reduce load for longer periods of time on event days, which may limit the appeal of a DR program
- A Snapback assumption of 50% greatly reduces the maximum DR potential in most cases
- Failing to call on the DR resource on the 4th highest peak load day results in a fraction of the projected potential for the entire year (59 MW vs. 376 MW for 2005 6x15 scenario)
- Callable DR resources provide value to APS
  - Must understand the inherent limitations to maximize their value

Questions?