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Arizona Corporation Commission
DOCKETED
JUN 27 2008
DOCKETED BY

June 27, 2008

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Re: DEMAND RESPONSE AND LOAD MANAGEMENT STUDY & PROGRAMS
DOCKET NOs: E-01345A-05-0816, E-01345A-05-0826, and E-01345A-05-0827

Dear Sir or Madam:

Pursuant to Decision No. 69663 (June 28, 2007), Arizona Public Service Company ("APS" or "Company") was required to conduct a study to identify Demand Response ("DR") programs that would be most beneficial to the APS electric system, and to file for approval of one or more cost effective DR or Load Management programs that the Company believes would be most beneficial to the APS electric system and its customers. Enclosed as Attachment I is the Demand Response & Load Management Study ("DR Study"), which includes the technology assessment, cost-benefit analyses, and identification of potential DR programs that may be feasible for APS and its customers.

The DR Study evaluated an array of thirteen programs and concluded that there are a number of potential programs that may be beneficial for APS and it customers, including time-differentiated rates and several direct load-control programs. APS is well into the process of developing its first direct load-control program, a Commercial & Industrial ("C&I") Load Management Program. A summary of that program is provided below, and Attachment II describes the efforts that the Company is currently considering in more detail. The Company is also considering a residential direct load control program, and will continue to investigate the efficacy of stand-by generation and thermal energy storage[1] for future DR programs.

Finally, in its recent rate case filing[2], the Company has filed for Commission approval of two DR pricing programs, including a new Super Peak Time of Use ("Super Peak TOU") rate for residential customers, which provides higher peak price signals during the highest summer peak hours, and a Critical Peak Pricing ("CPP") pilot program for general service customers, where during a limited number of critical hours on critical days, the customer under this rate schedule is charged a higher price that is intended to reflect the high cost of power during peak times. The proposed residential Super Peak TOU has a super peak price for the most consumption intensive summer hours. The higher price would apply every non-holiday weekday from 3:00 p.m. to 6:00 p.m. during the months of June, July and August. The summer off-peak price is discounted to offset the higher super-peak price. The Company believes that the proposed Super Peak TOU would provide a significant price signal to its customers during critical hours and could result in a sustained reduction in load during the Company's periods of highest demand.

In the rate case filing the Company has also proposed a CPP pilot program for general service customers, which is the customer class that the Company believes are in the best position to reduce a substantial amount of load during a limited number of critical hours per year. The proposed rate would be available to medium, large and extra large general service and water pumping customers.[3] Eligible customers would have to be capable of reducing use during critical periods by a minimum of 200

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[1] These potential programs are discussed in detail the DR Study (Attachment I).
[2] Docket No. E-01345A-08-0172.
[3] Those customers served on Rate Schedules E-32M, E-32L, E-32TOU M, E-32TOU L, E-34, E-35 and E-221.

kilowatts and would need interval metering. Under the proposed CPP Rate Schedule, APS would notify the customer one day in advance of a "critical event", which could be called for any non-holiday weekday, June through September. Critical events would be limited to eighteen days per year, for a period of five hours per day. A critical event could be triggered by severe weather, high load, high wholesale prices, or a major generation or transmission outage, as determined by the Company. The customer would be charged an additional critical peak price for consumption during each critical hour, and would be compensated through a discount based on the customer's monthly kilowatt hour consumption. To test the concept of CPP and the customers' ability to reduce load during summer business hours, the Company is proposing that the program be limited to one hundred participants for a two-year trial period.

As described in more detail in Attachment II, APS is in the process of developing a C&I DR load management program that has the potential to be cost effective and give customers additional flexibility. The DR resource could serve to reduce operational and economic risk through portfolio diversification, while providing customers with a financial incentive to manage electricity usage, which could result in lower electric bills. The Company is currently in negotiations with a "short-list" of DR vendors that have responded to the Company's Request for Proposal dated October, 2007. APS anticipates that contract negotiations will end soon. Assuming those discussions are successful, the Company will supplement this filing with specific information, including program parameters and costs. The Company is optimistic that the result will be a viable C&I DR program that is cost-effective and benefits both customers and the APS electric system.

If you have any questions please contact Jeff Johnson at 250-2661.

Sincerely,

Barbara Klemstine

Attachments

Cc: Brian Bozzo
Terri Ford

ATTACHMENT I

ARIZONA PUBLIC SERVICE COMPANY

DEMAND RESPONSE & LOAD MANAGEMENT PROGRAM STUDY

BENEFIT-COST ANALYSIS AND PROGRAM RECOMMENDATIONS

FILED IN COMPLIANCE WITH ARIZONA CORPORATION COMMISSION DECISION NO. 69663

JUNE 2008

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1. EXECUTIVE SUMMARY

Arizona Public Service Company conducted this Demand Response & Load Management Program Study of the various Demand Response and Load Management programs and technologies currently in existence or development to assess whether they are suited to the needs of APS and its customers. This Study considers the technical applicability of the various Demand Response programs and the value of the programs, but not all aspects associated with program success, including utility cost recovery and incentives. At the highest level, the assessment concluded that several programs warrant immediate pursuit, including residential air conditioning cycling, Commercial & Industrial load control, and certain retail tariffs. Other possible opportunities that require further study include: Scheduled Water Pumping, Thermal Energy Storage, and Standby Generation.

Thirteen programs and technologies were reviewed and assessed. For the programs that showed a potential for incorporation at APS, the Total Resource Cost Test and the Program Administrator Test were calculated to assist in determining their anticipated economic value at this time (with the exception of the rate proposals, which are cost-justified in a separate proceeding). In addition, estimates of the potential impact on environmental emissions were calculated to support Societal Cost Test results. The following table provides a high-level summary of the results of the Study:

Program/Technology	Recommendation
Residential A/C Cycling	Potentially economic and attractive to customers. Plan to pursue a program.
Residential Misc. Load Control	Allow water heaters and other appliances to be considered as part of an A/C Cycling program.
Commercial & Industrial Load Control	Potentially economic and attractive to customers. Currently in negotiations with vendors.
Thermal Energy Storage	Possible program, requiring additional research and technology assessment.
Scheduled Water Pumping	Potential opportunity to increase customer participation on Time-of-Use water pumping rates.
Battery Storage	Not pursuing a program at this time. Will continue to test the technology and monitor the advancements, and will reconsider adoption in the future.
Curtailable/Interruptible Load	Not pursuing at this time – less optimal than other Commercial & Industrial programs being offered.
Demand Bidding/Buyback	Not pursuing at this time – less optimal than other Commercial & Industrial programs being offered.
Standby Generation	Possible program in the future, requiring further study of costs, operational considerations, and emissions impacts.
Vehicle-to-Grid Technology	Not pursuing at this time due to the infancy of the technology. Will monitor the technology advancements, and reconsider adoption in the future.
Residential Super Peak Rate	Filed for approval in the recent general rate case filing (Docket No. E-01345A-08-0172).
Critical Peak Pricing Pilot Program	Filed for approval in the recent general rate case filing (Docket No. E-01345A-08-0172).
Real-Time Pricing	Not pursuing at this time – more suited for utilities with highly liquid and transparent hourly market prices.

The Study includes an analysis of the potential amount of Demand Response that could be effectively utilized on the APS system. The results of this work indicate that Demand Response resources that are callable in nature (i.e., not scheduled in advance) may offset up to approximately 2 – 5% of APS' system load prior to accounting for any customer behavioral considerations. APS views the Commercial & Industrial load control program as adding a valuable summer season resource that is comparable in nature to a wholesale call option contract. A similar program focused on residential air conditioning load (and, potentially, water heaters or other appliances) would also provide summer season value. APS supports approval of the two new conservation Time-of-Use rate proposals currently before the Commission in Docket No. E-01345A-08-0172. APS will further study Scheduled Water Pumping Time-of-Use rate participation, Thermal Energy Storage and Standby Generation. Finally, APS will continue to monitor the developments in Battery Storage and Vehicle-to-Grid technology and identify opportunities for further development.

2. INTRODUCTION

2.1 OVERVIEW OF THE STUDY

APS initiated this Study as part of its resource planning and procurement process, with the intent of determining the preferred Demand Response ("DR") programs and their fit within the broader system portfolio. In APS's most recent general rate case decision, the ACC included a requirement for APS to file this Study within one year of the final order, or June 28, 2008. Decision No. 69663, states:

> Arizona Public Service Company shall conduct a study to identify what types of Demand Response and Load Management programs would be most beneficial to APS' system, relying on a cost-benefit analysis based on the Societal Cost Test and shall file the study with the Commission's Docket Control[.][1]

This Study uses the definitions for Demand Response and Load Management ("LM") found in Decision No. 69663, which states:

> 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....Load Management is a utility's deliberate action to reduce peak demand or improve system operating efficiency.[2]

The Study provides an overview of the various types of DR and LM initiatives in existence today. These include: Direct Load Control; Scheduled Load Control; Customer Load Response; and Time-Differentiated Rates. Each of these is described in additional detail based upon the specific program options available to APS, and reviewed for their pertinence and applicability to the APS system. Specifically, the Study analyzes how and under what circumstances each program could be integrated at APS, and whether or not there is a net benefit to customers from its existence.

2.2 OBJECTIVES OF THE STUDY

APS has identified three main objectives for this Study: (1) to identify the potential amount of achievable load available for reduction on a cost effective basis; (2) to identify specific DR and LM programs that could provide tangible cost-effective benefits to APS and its customers; and (3) to provide specific recommendations for the next steps to be taken for each program. This Study does not provide justification for specific program parameters; details of the implementation for any specific program would be dealt with at such time as APS files said program for Commission approval.

[1] Decision No. 69663 (June 28, 2007) issued in Docket No. E-01345A-05-0816 at p. 154.

[2] *Id.* at pp. 97-98.

2.3 STUDY DEVELOPMENT

APS lead the development of this Study with the assistance of several experts. To facilitate the research of this Study, APS enlisted Summit Blue Consulting to review programs under development across the country. Summit Blue has worked with APS on several issues in the past related to DSM. In support of this Study, Summit Blue provided APS with detailed information on programs in existence at other utilities where possible, and summary information when detailed information could not be obtained. Summit Blue referred to utility filings and other industry publications, and conducted phone surveys in certain circumstances. Based on this research, Summit Blue provided APS with program parameters and estimated costs for use in calculating the Benefit-Cost Ratios discussed in this Study. In addition to the work done by Summit Blue, APS is also an Executive Level member of the Demand Response Coordinating Committee ("DRCC"). The DRCC was formed in 2004 to increase the knowledge base on DR programs, and to facilitate the exchange of information and expertise among industry participants and policy makers.[3]

[3] For more information, please see http://www.demandresponsecommittee.org/.

3. APS SITUATION ASSESSMENT

3.1 OVERVIEW OF APS SITUATION ASSESSMENT

This section of the Study will describe the current load and resource balance on the APS system. To properly analyze the impact of each potential program, it is important to first describe the base case against which the impacts of each program will be measured. This section will provide an overview of APS's long-term load forecast and projected supply-side shortfall. In addition, there is a detailed discussion of how a typical callable DR resource could be utilized on the APS system, taking into consideration some of the inherent limitations that such programs carry. This set of analyses provides some context and real-world application for the programs to be described later in this Study.

3.2 APS LOAD SHAPE AND DEMAND CHARACTERISTICS

APS serves more than one million residential and non-residential customers, and achieved a peak demand of over 7,100 MW in the summer of 2007. The APS service territory is characterized by high population and load growth. Since 1995, the state of Arizona's population has grown at over three times the national average. Between 2008 and 2027, the number of APS customers is projected to increase by approximately 730,000 customers, which would be an increase of over 66% from present customer levels. In addition, electricity consumption per customer has risen in the last several decades. Average electricity use per customer has increased by 1.3% per year since 1980.

The following graph depicts APS's load shape on the annual peak system demand day of August 13, 2007. As can be seen, load increased by over 3,100 MW, an increase of nearly 80%, over a twelve-hour period from five o'clock in the morning to five o'clock in the evening. During this time, APS load grew by an average of 264 MW per hour. From the peak hour to the end of the day, load drops off by over 2,100 MW, or an average of 309 MW per hour.

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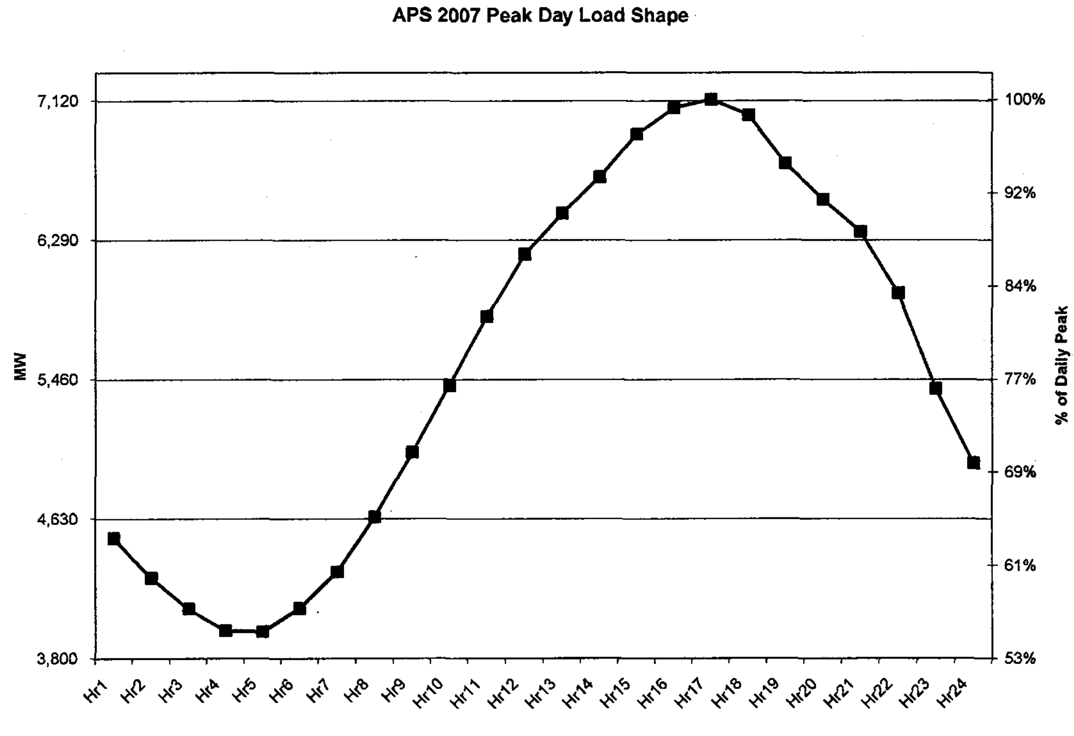

Figure 1

The APS service territory can be divided generally into two regions based on different climate conditions: the Low Country and the High Country. The Low Country includes Phoenix, Casa Grande, Yuma, and other desert-area locations. The High Country includes Prescott, Payson, Flagstaff, and other areas with higher elevation. In March 2007, ICF International prepared a detailed study about the APS customer base and its associated energy usage characteristics for both of these areas.[4] For residential customers, annual energy usage is strikingly different between these two regions. Based upon the data collected in the APS Baseline Study, central air conditioning ("A/C") energy usage makes up 42% of the average Low Country household's annual energy usage.[5] For High Country households, central A/C makes up only 15% of annual energy usage (heating is the top consumption category in the High Country at 21%).[6] Overall, central A/C accounts for 35% of all residential annual energy consumption for APS.[7]

[4] ICF International, et al., *Arizona Public Service: Energy Efficiency Baseline Study*, (March 9, 2007) ("APS Baseline Study"), filed in Docket No. E-01345A-05-0182 (April 12, 2007).

[5] *Derived from* APS Baseline Study, Table 1-2 Residential Energy by Building Vintage, Sub-Climate, and End Use Segment.

[6] *Id.*

[7] *Id.*

For non-residential customers, the APS Baseline Study compiled both energy and demand data. HVAC load comprised 44% of the total non-residential peak demand, and was the largest single end use category for the majority of building types (see table below):[8]

Non-Residential Building Type and End Use Segmentation (Peak MW)

Building Type	HVAC	Interior Lighting	Exterior Lighting	Refrigeration	Motors	Office Equipement (PC)	Office Equipment (Non-PC)	Other	Total
Grocery - Large	1.0%	0.7%	0.0%	1.5%	0.1%	0.1%	0.1%	0.1%	**3.6%**
Grocery - Small	1.0%	0.2%	0.0%	0.3%	0.1%	0.1%	0.1%	0.1%	**1.7%**
Healthcare - Inpatient	3.8%	2.2%	0.1%	0.0%	0.2%	0.2%	0.2%	0.2%	**6.9%**
Hotel/Resort	2.1%	0.9%	0.2%	0.0%	0.1%	0.1%	0.1%	0.1%	**3.6%**
Office - Large	5.9%	3.5%	0.4%	0.0%	1.0%	1.0%	1.0%	1.0%	**13.7%**
Office - Small	7.7%	3.9%	0.0%	0.0%	0.3%	0.3%	0.3%	0.3%	**12.8%**
Retail - Large	6.9%	4.7%	0.3%	0.0%	0.6%	0.6%	0.6%	0.6%	**14.1%**
Retail - Small	5.0%	3.2%	0.0%	0.0%	0.2%	0.2%	0.2%	0.2%	**9.1%**
School - Primary/Secondary	3.5%	0.7%	0.0%	0.0%	0.3%	0.3%	0.3%	0.5%	**5.5%**
School - College/University	2.2%	1.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.2%	**3.8%**
Restaurant	3.7%	1.0%	0.1%	0.7%	0.2%	0.2%	0.2%	1.0%	**7.0%**
Industrial	1.7%	1.1%	0.1%	0.0%	9.1%	0.0%	0.0%	6.1%	**18.2%**
Total	**44.5%**	**23.2%**	**1.3%**	**2.5%**	**12.1%**	**3.0%**	**3.0%**	**10.3%**	**100.0%**

Figure 2

3.3 SUPPLY-SIDE RESOURCES

APS meets its load obligation through a mix of utility-owned generation and market purchases. The utility-owned generation is fueled primarily by uranium, coal, and natural gas units, with a small amount of utility-owned solar generation. The Company has also entered into both conventional and renewable energy PPAs. For the summer of 2008, APS-owned generating capacity totals 6,283 MW, with an additional 1,978 MW of capacity via purchased power contracts. A summary of these resources is provided in the following table:

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[8] *See* APS Baseline Study, Table 5-2 Non-Residential Building Type and End Use Segmentation (Peak MW).

2008 Company-Owned Generation:	
Existing:	Capacity (MW)
Nuclear	1,147
Coal	1,750
Gas Combined Cycles	1,862
Gas/Oil CTs and Steam	1,518
Renewable	6
Total Company-Owned Generation	**6,283**
2008 Purchased Power Contracts:	
Conventional:	
Purchases/Exchanges/Tolling	1,864
Renewable:	
Wind (nameplate)	90
Geothermal	10
Biomass	14
Total Purchased Power Contracts	**1,978**
Total Resources	**8,261**

Figure 3

3.4 APS BASE CASE LOAD AND RESOURCE BALANCE FORECAST[9]

APS has sufficient resources to meet its current needs but will require additional resources to meet future load growth and replace expiring long-term power contracts. As shown in the chart below, by 2015 APS will need almost 2,000 MW of new resources to meet projected customer needs, and approximately 6,500 MW in total additional resources by 2022.

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[9] This information is consistent with what was filed in the APS Resource Alternatives filing on January 7, 2008 (Docket No. E-01345A-08-0010).

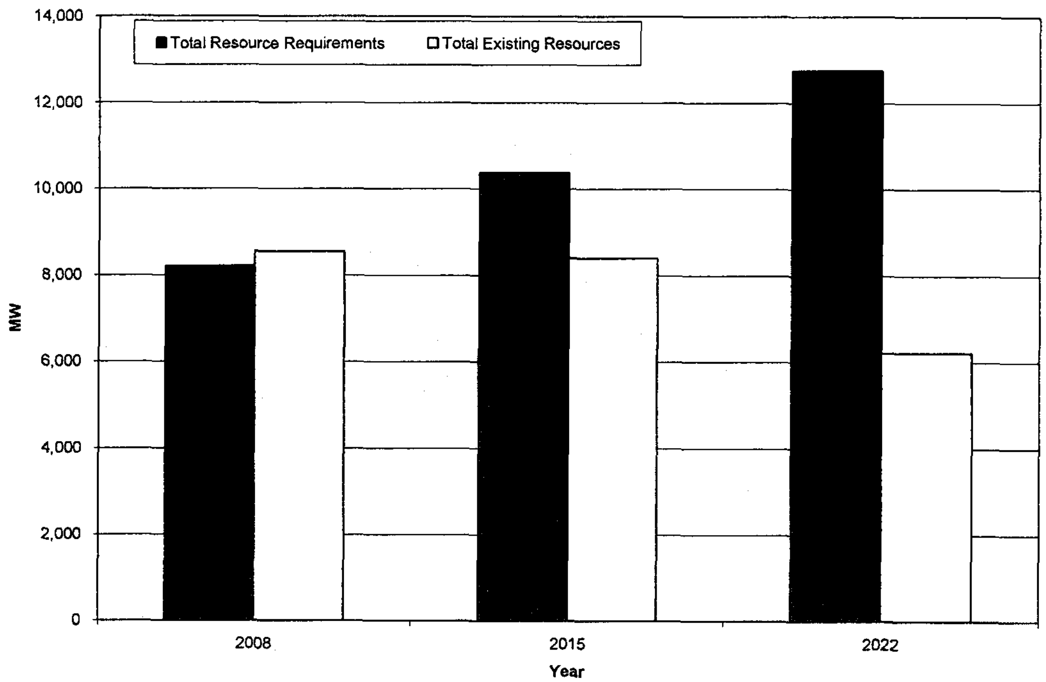

Figure 4

On a seasonal basis, APS load requirements are forecasted to grow at a much more rapid pace during the summer months than in all other months. In fact, as can be seen in the chart below, the summer peak demand will increase at almost twice the rate as the peak demand during the non-summer season.

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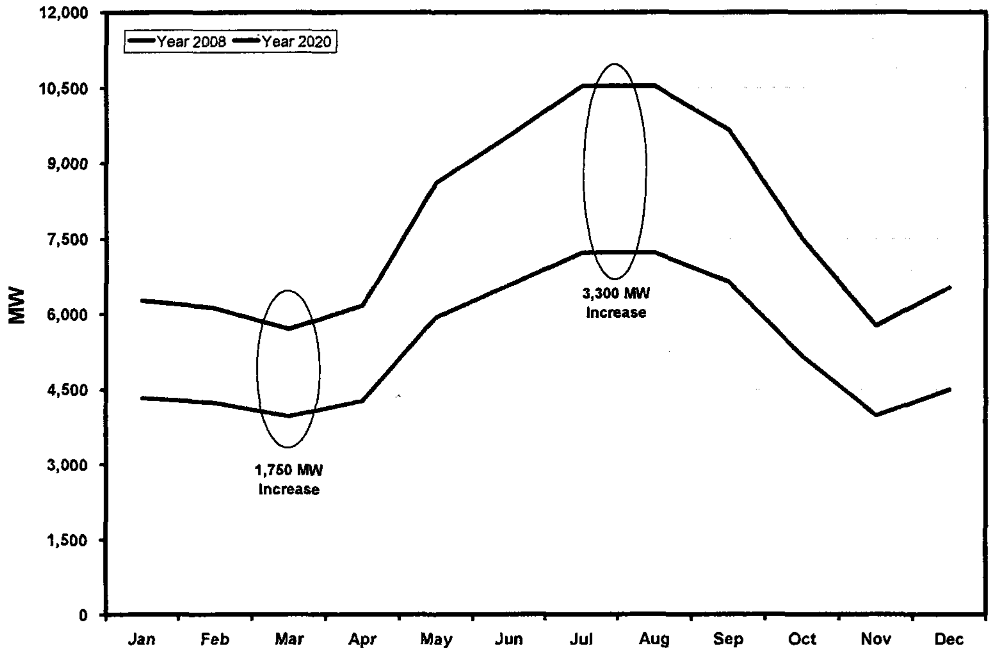

Figure 5

3.5 OTHER RELEVANT FACTORS

3.5.1 APS TRANSMISSION SYSTEM AND FUTURE PLANS

APS owns and operates an extensive transmission system, which has two main functions. The first involves the movement of power from remotely-located generation sources to the primary load pockets (such as the metropolitan Phoenix area). The second function is to provide a means to distribute the power within the load pockets.

The four primary transmission import paths that APS relies upon to bring remotely located resources to the metropolitan Phoenix area are: transmission lines from Four Corners to Cholla, and then from Cholla to both Pinnacle Peak and Saguaro; transmission lines from the Palo Verde hub (west of Phoenix) into the metropolitan Phoenix area, including Palo Verde to Westwing (two lines), Hassayampa to Jojoba to Kyrene, and Palo Verde to Rudd; a 500 kV transmission line that runs from the Mead substation to the Westwing substation; and, from the Navajo Generating Station in northern Arizona to the Westwing substation.

The Company has a number of major transmission system projects planned for the future. The 2007-2016 APS Ten-Year Plan describes planned transmission lines of 115 kV or higher that APS may construct or participate in over the next ten years. The company plans to add an expected 2,000 MW of additional EHV scheduling capability in the 10-year period, which will require an estimated $1 billion in additional transmission investment. These projects are planned to increase the Phoenix import capability by 4,170 MW, and the Yuma import capability by 310 MW.

Any DR resources that could be located within the metropolitan Phoenix area would have the ability to lessen the constraints on the APS transmission system due to reduced load-serving requirements.

3.5.2 ENERGY EFFICIENCY EFFORTS

APS currently has several DSM programs whose primary objective is to reduce the amount of energy that APS customers would otherwise consume absent these programs. These programs provide a tool to help manage electric bills, as well as provide environmental benefits to Arizona by installing energy efficient measures in customers' homes and businesses and to reduce the future energy requirements from supply side resources. In 2005, APS increased DSM expenditures to $48 million over the three-year period of 2005-2007.[10] The programs implemented since April 2005 have achieved a lifetime energy savings of more than 3,275,000 MWh, and have reduced peak demand by an estimated 64 MW. Even though DR programs and DSM programs have different objectives in that DR shifts load while DSM reduces energy consumption, there is an overlap in the minds of customers and there is a potential to market them together for the benefit of APS customers.

3.5.3 CURRENT TIME-OF-USE RATES

APS currently has several time-differentiated pricing programs, which include TOU rates for Residential, General Service, Irrigation, and Extra-Large General Service customers. These TOU rates provide higher prices during peak periods and lower prices during off-peak periods, with a goal of incenting customers to shift their energy consumption patterns to time periods where it is less expensive for APS to supply the power. APS currently has the highest customer participation in the nation for residential TOU rates, with over 453,000 participants in four rate plans, or approximately 46% of total Residential customers as of December 2007. In addition, over 34% of the Company's Extra-Large customers and 54% of the associated load are served on TOU rates. Participation for Small and Medium General Service customers is relatively low.

3.5.4 APS ADVANCED METERING INFRASTRUCTURE INITIATIVE

Remote meter reading emerged from the need for utilities to reduce or eliminate the escalating costs and safety exposures of performing the manual meter reading function. Early efforts consisted of simply metering and communications enhancements that automated the monthly gathering of energy consumption information. Through the years the utility industry has added additional functionality to these meters, allowing the support of Time-of-Use and demand rate schedules. APS has been researching remote meter reading solutions for many years. Until relatively recently, most systems were designed to support basic energy-only rates, and did not provide Time-of-Use functionality with a demand component. APS began an AMI pilot program in 2004, testing new advanced metering technologies in over 900 locations. As a result of the pilot, APS has begun a full-scale company-wide initiative to transition to AMI in the next several years.

[10] Decision No. 67744 (April 7, 2005) issued in Docket No. E-01345A-03-0437.

At APS, AMI provides the metering and communications capability necessary to support a wide variety of rate and associated customer options. Providing the latest in metering technology allows the Company to provide enhanced customer service and continue to bill our customers accurately and in a timely manner. The AMI meters used by the Company are fully functional, multi-feature, residential/small commercial meters capable of registering, storing, and displaying metered billing data. These meters are based on the Hub and Client system. Client meters utilize unlicensed spread spectrum radios in the 900 MHz Band to communicate bi-directionally to upstream Hub meters. Unlike the Client meters, Hub meters also have a cellular communication component allowing them to communicate bi-directionally with APS via public cellular networks. Both Hub and Client meters are located on customer premises.

As of March 2008, the Company's total installed AMI meter base has climbed to over 110,000. The deployment has been focused on high density residential areas. This focus has provided significant value in the reduction of manual connect and disconnect orders, and substantially lowered the costs resulting from the high customer turnover rate in multi-unit residential housing complexes in the Phoenix area. APS also has successfully installed AMI meters in twenty-two different cities and towns within its service territory, including Yuma, Prescott Valley, and Flagstaff. During the six-month period ending in March 2008, the AMI system remotely processed over 38,000 service orders without a field visit. The current deployment strategy has maintained the Client to Hub ratio at approximately 38:1, meaning that there are approximately 38 Client meters for each installed Hub meter. The Company is currently installing over 7,000 AMI meters per month. APS is moving towards installing AMI meters in more single-family homes. Current estimates are that AMI meters will be fully deployed in the metropolitan Phoenix area by the end of 2011.

AMI is not a prerequisite to DR; however, AMI technology has the potential to integrate with a DR initiative and provide a strong backbone for measurement and verification procedures. APS views AMI as being a positive initiative to undertake, and, once in place, it will provide the Company with a powerful analytical platform. APS will have the ability to create custom applications to analyze customer usage trends and target specific programs to certain load shape types. Until AMI is available on a wide scale in the APS service territory, the Company will rely on already-installed IDR meters or industry standard statistical samplings to infer any load reductions experienced due to DR programs in place.

3.6 DERIVING THE POTENTIAL FOR DEMAND RESPONSE ON THE APS SYSTEM

To analyze the potential impacts of DR resources on the APS System, the Company undertook an internal review of different DR load level and dispatch scenarios. The point of this exercise was two-fold: first, to determine the potential for capacity reductions under a variety of DR parameters, and second, to identify the different parameters that may be best suited for APS.

For this analysis, APS reviewed a June through September peak demand window during which DR events would likely be called. During those 4 months, a total of 90 hours of curtailments would be called, or roughly 1% of all the hours in the year. In order to call a total of 90 hours, four separate scenarios were utilized: the top 4 hours per day for the highest 23 peak days in the season ("4x23"); the top 5 hours per day for the highest 18 peak days in the season ("5x18"); the top 6 hours per day for the highest 15 peak days in the season ("6x15"); and the top 7 hours per day for the highest 13 peak days in the season ("7x13"). APS historical actual hourly system loads from 2002-2007 were analyzed.

For this analysis, APS selected the highest peak days in each year for each scenario (on a real-time basis, picking the exact peak days would be a critical and challenging component that drives the success of the program). For the 6x15 case, this would be the 15 days with the highest peak demand each year. On each of those days, the DR event would be simulated on the 6-hour block of time around the peak hour, thereby capturing the 6 highest load hours of that peak day. The size of the DR resource dispatched would be varied until the point at which adding additional DR would not result in further decreases to the net peak demand. This optimization of DR was developed by analyzing the LDC[11] for the base case against the new LDC created by the DR dispatch. APS would look to see how many of the top 90 load hours were captured with the particular DR scenario (i.e., the DR strategy captured those hours for load reduction), and also how many continuous hours were captured. The potential level of DR for that case was determined to be the delta between the base case peak demand and the new peak demand created after deploying a particular DR strategy. Next, the analysis would be rerun under the assumption that APS would fail to dispatch the DR resource on the fourth highest peak day. This sensitivity was run to see the impact of imperfect scheduling, which simulates the reality of dispatch decisions in the real time (i.e.., it is impossible to know until after the fact whether or not certain resource decisions were optimal, and extremely difficult for system operators to predict the best days to exercise the DR resource given the limited number of hours available to be called). Finally, another set of analyses were performed based on a certain level of Snapback occurring due to the dispatch of the DR resource.[12] This simulates consumer activities, such as pre-cooling, load shifting, etc.[13] All of the above analyses were repeated for all four DR scenarios and for all years mentioned previously.

The graph below provides an example of the 6x15 DR strategy impact on the 2005 LDC:

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[11] A Load Duration Curve sorts a utility's load not based on chronological order, but from highest load level to lowest load level.

[12] "Snapback" is a term that refers to the amount of energy that was not consumed during the DR event that will still be consumed immediately before or after the event. For example, in an A/C Cycling scenario, Snapback could be from either pre-cooling before the DR event or from the additional A/C unit runtime after the conclusion of an event needed to restore the space to a preferred temperature level. The Snapback effect is what distinguishes DR from DSM, where energy is permanently reduced. For this portion of the Study, a 50% Snapback assumption was incorporated, split evenly before and after the event. This is relatively conservative, as APS has received an estimated Snapback level of approximately 70% in a competitively bid DR RFP. Higher Snapback levels would require APS to shift additional energy to hours outside the DR event window, which would cause poorer results in this set of analyses.

[13] The Snapback assumption used in this analysis was 50% of the energy not consumed during the event would be shifted to hours preceding and following the event. For example, the 6x15 case shifted the energy to the 3 hours prior to and 3 hours following the event.

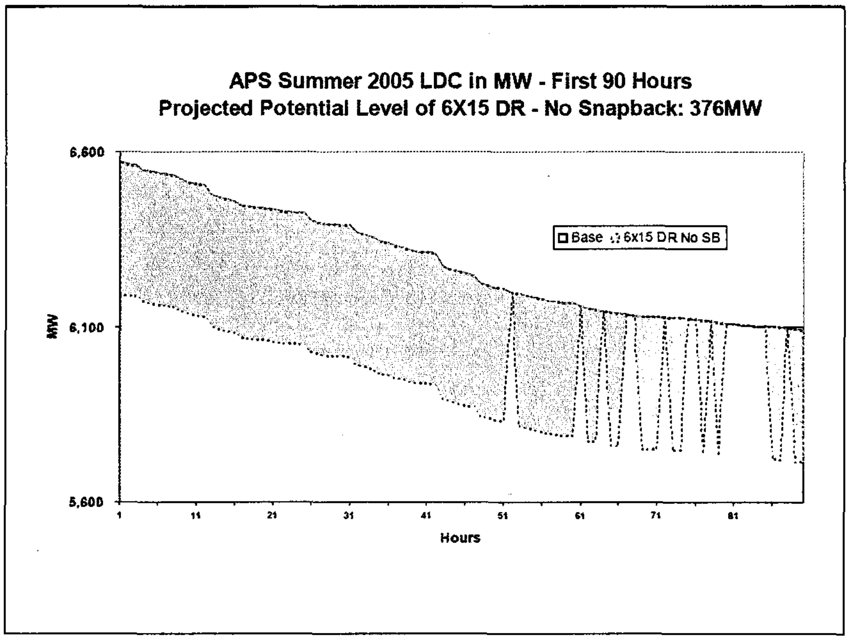

Figure 6

The top line is the first 90 hours of the LDC for the 2005 APS retail and wholesale customer base. The dotted line below it represents the LDC after accounting for the dispatch of DR. The hours in which the bottom line reverts back to the APS LDC represent the peak hours that were not impacted by the 6x15 scenario. For the first 51 hours of the LDC, the 6x15 DR strategy captured all of the top load hours; however, the 52nd hour fell outside of the 6x15 window. This occurred because the 52nd highest peak hour fell outside of the range captured by targeting the 6 highest hours on the top 15 load days. Therefore, the load differential between the load level in that 52nd hour of the LDC and the actual peak demand that year, 376 MW, represents the potential level of DR resources in 2005, in that additional DR capacity would not lower the net system peak because of the inability to reduce the 52nd hour.

The Snapback sensitivity analysis showed that the DR program benefits would be dramatically reduced if customers shifted their energy usage to periods before and after the DR event window:

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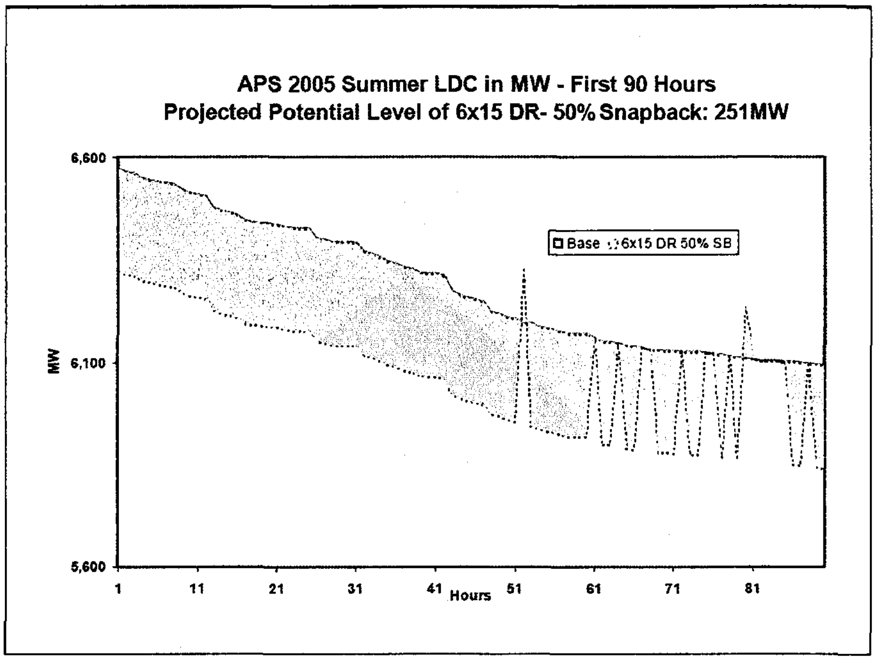

Figure 7

As seen above, the impact of a portion of the reduced energy during the DR event being shifted to hours outside of the DR event window resulted in a decrease in program effectiveness from 376 MW to 251 MW. Specifically, the 52nd hour that is missed in the 6x15 scenario has a portion of the event energy shifted to it, resulting in higher load that hour than was previously experienced.

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The potential level of DR benefit is dramatically reduced when running the sensitivity case where APS does not schedule the DR resource on the fourth highest peak day of 2005. As shown below, the potential reduction in peak demand using the 6x15 block assumption is reduced from 376 MW to 59 MW when the 4th highest peak day is missed:

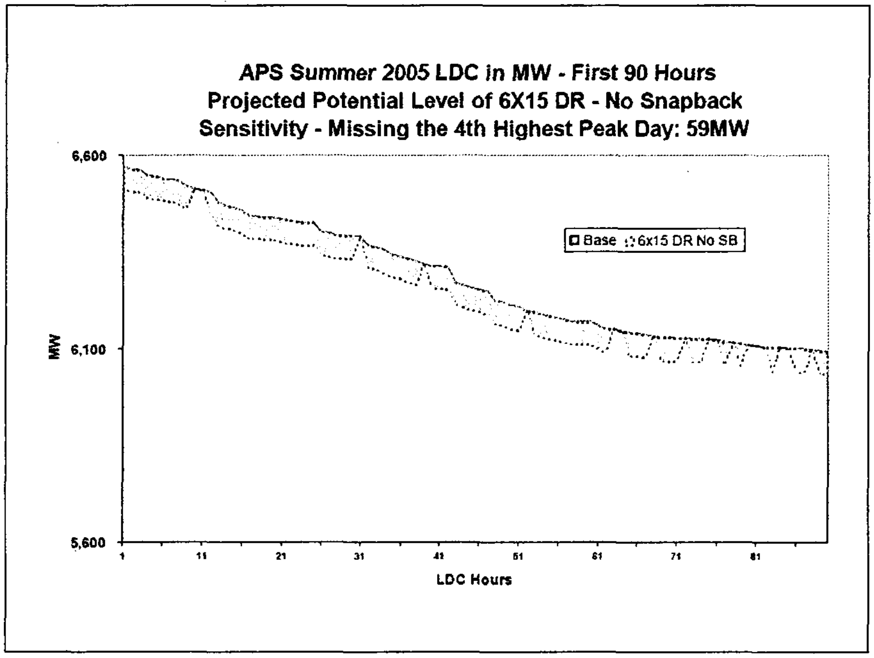

Figure 8

The results of the 2005 6x15 analyses are as follows:

Potential 2005 DR Impacts with 6x15 Disptatch	
Scenario	**MW Impact**
6x15 Base Case	376
With 50% Snapback	251
Missing 4th Peak Day	59

Figure 9

The table on the following page shows the results of each sensitivity for each of the previous six years:

PROJECTED POTENTIAL IMPACTS OF DEMAND RESPONSE SCENARIOS

	SUMMER 2002 - 5490 MW PEAK								SUMMER 2003 - 5969 MW PEAK							
	With No Snapback				With 50% Snapback				With No Snapback				With 50% Snapback			
Hours/Event X Days/Year*	4X23	5X18	6X15	7X13	4X23	5X18	6X15	7X13	4X23	5X18	6X15	7X13	4X23	5X18	6X15	7X13
# Hours Impacted (Hits)	73	73	70	64	73	73	70	64	71	75	72	71	71	75	72	71
# Continuous Hits	10	24	49	45	10	24	49	45	23	35	44	51	23	35	44	51
Optimum DR Potential in MW	175	235	346	336	116	157	300	311	228	312	352	385	152	208	234	371
% of Annual Peak Demand	*3.2%*	*4.3%*	*6.3%*	*6.1%*	*2.1%*	*2.9%*	*5.5%*	*5.7%*	*3.8%*	*5.2%*	*5.9%*	*6.4%*	*2.5%*	*3.5%*	*3.9%*	*6.2%*
Sensitivity:																
If Missing 4th Peak Load Day																
# Hours Impacted (Hits)	70	70	67	61	70	70	67	61	67	72	69	67	67	72	69	67
# Continuous Hits	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Optimum DR Potential in MW	138	138	138	138	116	138	138	138	53	53	53	53	53	53	53	53
% of Annual Peak Demand	*2.5%*	*2.5%*	*2.5%*	*2.5%*	*2.1%*	*2.5%*	*2.5%*	*2.5%*	*0.9%*	*0.9%*	*0.9%*	*0.9%*	*0.9%*	*0.9%*	*0.9%*	*0.9%*

	SUMMER 2004 - 6018 MW PEAK								SUMMER 2005 - 6573 MW PEAK							
	With No Snapback				With 50% Snapback				With No Snapback				With 50% Snapback			
Hours/Event X Days/Year*	4X23	5X18	6X15	7X13	4X23	5X18	6X15	7X13	4X23	5X18	6X15	7X13	4X23	5X18	6X15	7X13
# Hours Impacted (Hits)	68	72	73	70	68	72	73	70	71	74	74	70	71	74	74	70
# Continuous Hits	21	25	64	54	21	25	64	54	31	43	51	57	31	43	51	57
Optimum DR Potential in MW	278	317	525	486	185	211	353	353	205	308	376	403	136	205	251	341
% of Annual Peak Demand	*4.6%*	*5.3%*	*8.7%*	*8.1%*	*3.1%*	*3.5%*	*5.9%*	*5.9%*	*3.1%*	*4.7%*	*5.7%*	*6.1%*	*2.1%*	*3.1%*	*3.8%*	*5.2%*
Sensitivity:																
If Missing 4th Peak Load Day																
# Hours Impacted (Hits)	64	69	69	66	64	69	69	66	67	71	72	68	67	71	72	68
# Continuous Hits	7	7	7	7	7	7	7	7	9	9	9	9	9	9	9	9
Optimum DR Potential in MW	158	158	158	158	158	158	158	158	59	59	59	59	59	59	59	59
% of Annual Peak Demand	*2.6%*	*2.6%*	*2.6%*	*2.6%*	*2.6%*	*2.6%*	*2.6%*	*2.6%*	*0.9%*	*0.9%*	*0.9%*	*0.9%*	*0.9%*	*0.9%*	*0.9%*	*0.9%*

	SUMMER 2006 - 7220 MW PEAK								SUMMER 2007 - 7127 MW PEAK							
	With No Snapback				With 50% Snapback				With No Snapback				With 50% Snapback			
Hours/Event X Days/Year*	4X23	5X18	6X15	7X13	4X23	5X18	6X15	7X13	4X23	5X18	6X15	7X13	4X23	5X18	6X15	7X13
# Hours Impacted (Hits)	65	74	76	73	65	74	76	73	79	73	66	59	79	73	66	59
# Continuous Hits	21	27	63	51	21	27	63	51	58	50	40	33	58	50	40	33
Optimum DR Potential in MW	504	544	763	702	336	362	543	568	328	305	250	213	218	218	250	213
% of Annual Peak Demand	*7.0%*	*7.5%*	*10.6%*	*9.7%*	*4.7%*	*5.0%*	*7.5%*	*7.9%*	*4.6%*	*4.3%*	*3.5%*	*3.0%*	*3.1%*	*3.1%*	*3.5%*	*3.0%*
Sensitivity:																
If Missing 4th Peak Load Day																
# Hours Impacted (Hits)	61	69	73	70	61	69	73	70	76	72	64	58	76	72	64	58
# Continuous Hits	7	7	7	7	7	7	7	7	5	5	5	5	5	5	5	5
Optimum DR Potential in MW	248	248	248	248	248	248	248	248	86	86	86	86	86	86	86	86
% of Annual Peak Demand	*3.4%*	*3.4%*	*3.4%*	*3.4%*	*3.4%*	*3.4%*	*3.4%*	*3.4%*	*1.2%*	*1.2%*	*1.2%*	*1.2%*	*1.2%*	*1.2%*	*1.2%*	*1.2%*

*** Assume 1 event per day.**

Figure 10

The overall percentages of peak demand for each case and in summary are:

Summary of Projected Optimal Level of Callable Demand Response as a Percentage of Peak Demand

		2002	2003	2004	2005	2006	2007	
	Peak Demand	5,490	5,969	6,018	6,573	7,220	7,127	**AVG**
Base Case	*4x23*	3.2%	3.8%	4.6%	3.1%	7.0%	4.6%	4.4%
	5x18	4.3%	5.2%	5.3%	4.7%	7.5%	4.3%	5.2%
	6x15	6.3%	5.9%	8.7%	5.7%	10.6%	3.5%	6.8%
	7x13	6.1%	6.4%	8.1%	6.1%	9.7%	3.0%	6.6%
	AVG	5.0%	5.3%	6.7%	4.9%	8.7%	3.8%	5.7%
50% Snapback	*4x23*	2.1%	2.5%	3.1%	2.1%	4.7%	3.1%	2.9%
	5x18	2.9%	3.5%	3.5%	3.1%	5.0%	3.1%	3.5%
	6x15	5.5%	3.9%	5.9%	3.8%	7.5%	3.5%	5.0%
	7x13	5.7%	6.2%	5.9%	5.2%	7.9%	3.0%	5.6%
	AVG	4.0%	4.0%	4.6%	3.5%	6.3%	3.2%	4.3%
Missing 4th Peak Day	*4x23*	2.5%	0.9%	2.6%	0.9%	3.4%	1.2%	1.9%
	5x18	2.5%	0.9%	2.6%	0.9%	3.4%	1.2%	1.9%
	6x15	2.5%	0.9%	2.6%	0.9%	3.4%	1.2%	1.9%
	7x13	2.5%	0.9%	2.6%	0.9%	3.4%	1.2%	1.9%
	AVG	2.5%	0.9%	2.6%	0.9%	3.4%	1.2%	1.9%
Missing 4th Peak Day - 50% Snapback	*4x23*	2.1%	0.9%	2.6%	0.9%	3.4%	1.2%	1.9%
	5x18	2.5%	0.9%	2.6%	0.9%	3.4%	1.2%	1.9%
	6x15	2.5%	0.9%	2.6%	0.9%	3.4%	1.2%	1.9%
	7x13	2.5%	0.9%	2.6%	0.9%	3.4%	1.2%	1.9%
	AVG	2.4%	0.9%	2.6%	0.9%	3.4%	1.2%	1.9%

Figure 11

The analysis of this six-year study period indicates that the Snapback assumption has a material impact on the potential level of DR. The impact of missing the fourth highest load day has an even more dramatic impact on the level of DR that would be achieved. The analysis also indicates that longer DR dispatch windows (i.e. six or seven hours) achieve a greater benefit that smaller windows (not counting any negative customer impressions of longer event times). In general, it can be derived from this data that APS could expect that approximately 2 – 5% of peak demand can be met by callable DR programs. A DR resource portfolio equaling 2 – 5% of APS peak demand would equate to approximately 140 – 350 MW of peak load.

This level of DR is consistent with actual results in other markets. In the "Assessment of Demand Response and Advanced Metering: 2007" FERC cited DR participation ranges from 1.4 – 6.1% of peak demand for various RTO/ISO markets in 2006.[14] These results have been achieved in regions with different weather conditions, customer density and make-up, and market structures. For comparative purposes, this would translate into 100 – 440 MW for APS (based on a 2006 peak demand of 7,220 MW).

[14] Federal Energy Regulatory Commission, "Assessment of Demand Response and Advanced Metering: 2007" (September 2007) at Table B-1.

4. OVERVIEW OF DEMAND RESPONSE EVALUATION

4.1 TOTAL RESOURCE COST TEST & SOCIETAL COST TEST

4.1.1 OVERVIEW

The Societal Cost Test ("SCT") is a variant of a more broadly used economic test called the Total Resource Cost Test ("TRCT"), and is the test which APS uses to analyze DSM programs prior to implementation. The TRCT compares the supply and demand side costs of a specific program, and attempts to quantify the effects of a program on both participants and non-participants, under the assumption that by some customers participating in a DR or LM program, all customers receive some measurable benefit. Benefits included in the TRCT are the avoided costs for generation and transmission energy and capacity, and any potential tax credits. The costs included in the TRCT are program administrator costs (costs the utility incurs), participant costs, and increased supply costs for the utility that may result from Snapback or load shifting. Finally, a discount rate is used to calculate a NPV for the program. Based on informal discussions with fifteen utilities in the Western Interconnection, APS has determined that the TRCT is the predominant economic test in the region, with thirteen companies using it.

The SCT varies from the TRCT in that it attempts to extend this quantification to society as a whole, rather than just the customers for a given utility. To do this, the SCT includes the effects of externalities, such as reduced emissions. The SCT also excludes tax credit benefits, as it is assumed that those benefits are naturally offset by society as a whole. APS will quantify externalities pursuant to the SCT; however, only emissions that have established monetary values will be monetized in the Study. Due to the uncertainty of future Greenhouse Gas legislation (both from a timing and magnitude standpoint), emissions such as CO_2 will be quantified but not monetized. For the purposes of the analyses performed, the TRCT results provided in this Study plus the net impact on emissions over the life of each potential program (net of any Snapback or load shifting) equals the SCT results for that potential program.

4.1.2 VARIABLES & FORMULA

G = Generation Avoided Cost (Capacity & Energy)
T = Transmission/Distribution Avoided Cost
E = Environmental Benefits (SO_2, CO_2, NO_x, etc)
PC_C = Program Costs to Customer (Purchase, Installation, O&M)
PC_U = Program Costs to Utility (Program Planning, Marketing, O&M)
B_{TRCT} = Benefits of the Program
C_{TRCT} = Costs of the Program
BCR_{TRCT} = Benefit-Cost Ratio

$$B_{TRCT} = G + T + E$$

$$C_{TRCT} = PC_C + PC_U$$

$$BCR_{TRCT} = B_{TRCT} / C_{TRCT}$$

4.2 PROGRAM ADMINISTRATOR TEST

4.2.1 OVERVIEW

In addition to the Societal Cost Test being performed pursuant to ACC Decision No. 69663,[15] APS has also calculated the Benefit-Cost Ratio for the programs based on the Program Administrator Test ("PAC Test"). This test shows the pure cost of each program to APS, without taking into consideration any of the net societal benefits from the program. This is generally consistent with long-term resource acquisition analyses and was conducted purely to supplement the discussion of the SCT results.

4.2.2 VARIABLES & FORMULA

G = Generation Avoided Cost (Capacity & Energy)
T = Transmission/Distribution Avoided Cost
PC_U = Program Costs to Utility (Program Planning, Marketing, O&M)
R = Rebate Incentive Payments
B_{PAT} = Benefits of the Program
C_{PAT} = Costs of the Program
BCR_{PAT} = Benefit-Cost Ratio

$$B_{PAT} = G + T$$

$$C_{PAT} = PC_U + R$$

$$BCR_{PAT} = B_{PAT} / C_{PAT}$$

4.3 ESTIMATION OF EMISSIONS IMPACTS

For the technologies that were specifically studied and a Benefit-Cost Ratio calculated, APS also estimated the impacts of those DR programs on the emission levels of certain pollutants that would otherwise have been produced to meet load. For the Standby Generation program and the residential Direct Load Control programs, the demand reductions resulting from calling the program were measured against the same amount of generation from one of APS's simple cycle CT units, as a CT is typically "on the margin", or the unit most likely utilized, during summer afternoons. For the Thermal Energy Storage program, a CT unit was used for the estimated on-peak run times, and generation from a combined cycle unit was used during the off-peak time frame for the increased usage from charging the storage units overnight, when such a unit is on the margin. The estimated emissions impacts are provided in pounds avoided over the life of the program, with the exception of carbon dioxide, which is reported in tons avoided over the life of the program. If a value appears as a negative, that would indicate that the program would result in a net increase in that particular pollutant. Except for the Standby Generation program, any emissions impacts should be minimal in nature, as these are demand-based programs that do not inherently reduce total energy on the system.

[15] *See* p. 154.

4.4 GENERATION AVOIDED COST CALCULATION

The main benefit achieved via a DR program is avoided capacity costs, specifically in the highest demand hours of a given year. To estimate the capacity value a callable DR resource could provide, APS calculated an Effective Load Carrying Capability ("ELCC"). ELCC is a measure of the contribution of a generating resource to an electric system based on its impacts on the system's overall reliability. The value of this contribution to system reliability represents the capacity value of that resource. The ELCC measure of a resource is often compared to that of a reference unit, such as a CT, to determine the capacity equivalence that provides the same level of reliability for the system.

APS used three load forecasts for the 2008 – 2012 time period, each based on historical load shapes from 2004, 2005, and 2006, respectively. The reference unit to which the DR resources were compared was a Combustion Turbine unit. APS ran the reliability analysis model for the base resource plan, and then redid the analysis by adding the CT unit at 5 MW increments. A five year average (2008 – 2012) of the resulting Loss of Load Expectations was calculated. After this occurred, callable DR contracts were substituted for the CT unit to simulate their impact to the system. The capacity equivalence value of a DR resource equals the MW capacity of a CT unit that provides the same level of reliability for the system. In general, the results of this set of analyses indicated that a DR resource provides roughly 70-80% of the capacity value of a CT unit.[16] For comparative purposes, a wind generator typically provides roughly 20% of the capacity value of a CT.

4.5 PROGRAMS REVIEWED

APS commissioned the consulting firm Summit Blue to compile information on DR technologies and programs from various other utilities across the country. In each subsection of this Study, an overview of the information gathered for selected programs is given to provide a framework for how each type of DR technology can be incorporated at APS. In addition, Summit Blue analyzed this data and provided their recommended values for certain key cost and benefit components so that APS would be able to adequately complete a TRCT for the residential programs described.

4.6 OTHER CONSIDERATIONS

The exact amount of demand reduction that APS could achieve is a factor of customer awareness, customer acceptance and willingness to participate, customer classes targeted, and program load reduction characteristics.

The interplay between these programs and customers' already-conditioned behavior on the APS TOU rates is unknown at this time. APS has a very high TOU participation rate, and these rates have been in existence for many years. It is possible that customers have already altered their respective energy consumption patterns to account for these TOU rates, and additional reductions would be limited. Furthermore, there may be situations where a customer must be on a certain rate plan in order to participate in a DR program. For example, it may make sense for a Residential customer to be on the 7pm – noon rate plan rather than the 9pm – 9am rate plan based on the DR program's parameters. This analysis has yet to be performed.

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[16] Actual capacity value for a specific DR resource would vary based on customer behavior, technology characteristics, and/or contractual parameters.

In general, all programs have been studied as if they were being rolled out to all eligible customers (based on an expected participation rate) as opposed to a pilot program. This simplified assumption should provide more favorable results, as the administrative and any other fixed costs can be spread over more participants; however, in some circumstances, it may be best to perform specific pilot programs prior to final implementation in order to verify that the program(s) selected perform as expected in this climate.

The dollar figures stated for Avoided Capacity, Avoided Energy, DLC Technology, Program Costs, and Rebates/Incentives are all stated in 2009 dollars.

All Benefit-Cost Ratios derived in this Study are based upon cost and participation data estimated from Summit Blue's research on other programs, or, in the case of Standby Generation, from internal data gathering performed. APS utilized many of the variables gathered, such as internal program administration costs, as proxy values for all programs studied. These values will provide gauges for the likely success and cost-effectiveness of the potential programs, but are not necessarily indicative of what APS would ultimately experience after implementing the programs. For any program that the Company chose to implement, more exact figures would be prepared and presented to the Commission prior to implementation.

Benefit-Cost Ratios greater than 1 indicate that the program would provide a net benefit (either to Society or to the Program Administrator) over the life of the program if it were implemented. The Benefit-Cost analyses do not take into account program parameters such as performance incentives or net-lost revenues. These items must be addressed as part of the final program development and approval process.

While there are many program parameters, designs, incentive levels and implementation strategies discussed in this document, APS is not presupposing any specific model at this time. This Study is meant to be an assessment of the technologies and programs available. Any specific program blueprint will be filed with the Commission for approval at such time as APS deems it viable and appropriate.

5. DIRECT LOAD CONTROL

5.1 OVERVIEW OF DIRECT LOAD CONTROL

DLC programs have typically been mass-market programs directed at residential and small commercial (< 100 kW peak demand) air conditioning, lighting, and other appliance load. There is an emerging trend to target commercial buildings with more complex systems in what has become known as Auto-DR. Increased use and functionality of an EMCS at commercial sites and an increased interest by commercial customers in participating in these programs is driving growth in commercial curtailment in response to a signal from the utility.

The common factor in DLC programs is that they are actuated directly by the utility (or a third party contracted to act on the utility's behalf) and require the installation of control and communications infrastructure to facilitate the control process. Customer equipment can be remotely controlled by the utility during events based on previously-defined triggers (such as temperature, market price thresholds, or system emergencies) or based upon the utility's need for additional capacity resources. During such an event, the utility has the ability to either turn off specific equipment or prevent it from turning on. Customers participating in these types of programs typically enter into agreements that specify the frequency (maximum number of events or hours of control per year), notification requirements (minimum hours before the event), and duration (maximum hours per event), as well as the incentive payments for participation. Incentives can come in two forms: fixed payment(s) for participating in the program, and variable payments based on the number of events and estimated load reduction. In addition, the hardware installed at each location is often included in lieu of or in addition to the fixed payment(s). Depending upon the type of equipment installed, the customer may have some ability to override the impacts of an event on their equipment once it has been called.

5.2 RESIDENTIAL A/C CYCLING

5.2.1 OVERVIEW OF RESIDENTIAL A/C CYCLING

A/C Cycling is the most common form of an incentive-based DLC program, in terms of the number of utilities using it and the number of customers enrolled nationwide. The utility is able to reduce customer loads via an enabling technology, such as a communicating load switch or a thermostat. Thermostats can either be one-way or two-way communications capable. The basic difference in program operation is that switches utilize a duty cycling strategy, where A/C equipment is turned off remotely for a percentage of each hour (50% cycling is a common strategy), while thermostat programs may utilize either cycling or employ a temperature offset strategy during the control period. For either strategy, consideration of whether to allow user override is an important factor. A range of other issues are involved in choosing the appropriate technology for a given program, including the selection of the communications medium (private radio frequency, commercial paging, etc.) and length of control period. Installed hardware costs range from about $180 for a simple switch (including labor) to $450 for a two-way communicating thermostat. While two-way thermostats allow the utility to confirm signal receipt, improve reliability of curtailments, and identify malfunctioning units, they tend to be used in fewer new applications. Utilities are opting for one-way systems that are cheaper and capable of integrating via a wireless home-area-network to existing or planned AMI systems.

5.2.2 CURRENT PROGRAMS IN OTHER JURISDICTIONS

Direct Load Control of air conditioners and other appliances is the most common form of non price-based DR programs in terms of the number of utilities using it and the number of customers enrolled. The recent DR Report issued by the FERC[17] indicates that 234 entities (including municipal utilities, cooperatives, and related entities) offer DLC programs in the United States. These programs are primarily targeted at residential customers, although 33% also had at least one Commercial DLC offering.[18] Summit Blue recently concluded a review that focused specifically on Residential A/C programs, and identified 54 such programs that used a variety of different enabling technologies: six thermostat programs, twelve thermostat pilot programs, thirty-two switch programs, and four combination switch and thermostat programs. Summit Blue was able to compile detailed information on 15 of these programs:

Program Design Parameters	Range	Average	Median
Total Current Participants	11,000 - 300,000	79,139	63,000
Participation Rate (of total customers)	1% - 27%	13%	10%
Participation Rate (of eligible customers)	7% - 40%	24%	20%
Cycling/Control Strategy	33% - 100%	50%	50%
Avg Annual Days of Control	1 - 23	9.2	7.5
Avg Hours per Day of Control	2.5 - 6	4.4	4
Avg Event Participation	60% - 100%	78%	80%
Total Program Impacts (MW)	12 - 370	79	53
Program Impacts per Customer (kW)	0.4 - 1.3	0.9	1.0
Technology Used	Radio, Pagers (one-way and two-way), and Transmitters		

Figure 12

5.2.3 APPLICABILITY TO APS

As depicted earlier, air conditioning is the primary end use consumer of electricity in the average Low Country household. Based on this information, APS contracted with a third party research firm in early 2008 to conduct a telephonic survey of 1,000 residential single-family homeowners in the metropolitan Phoenix area to determine their appetite for a residential A/C Cycling program. The survey tested the two primary technologies for implementing a residential program: communicable thermostats and switches. An equal number of customers were asked about each technology. Customers were informed that the programs would run from June to September, and APS would initiate them on no more than 20 weekday afternoons between 3-7pm. For the thermostat program, APS would remotely raise the temperature by up to 4 degrees during this timeframe. For the switch program, APS would remotely cycle the A/C unit 12 minutes out of every half hour, or a 40% cycling strategy. The programs and incentive levels were presented as follows:

[17] Assessment of Demand Response & Advanced Metering: Staff Report, Docket No. AD06-2, August 2006 ("2006 FERC Report") at p. 46.

[18] *Id.* at p. 63.

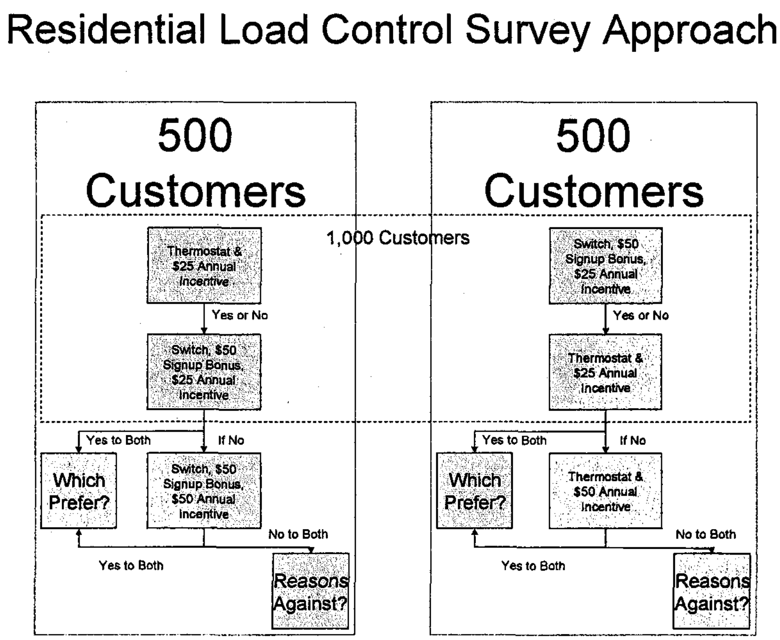

Figure 13

The survey intended to identify which technology customers preferred. To do this, each customer was queried on both, regardless of their response to the first one presented. APS also probed the reasons for or against selection of the technologies presented. Based on the responses provided during the survey, the following results can be determined:

	% of Customers that would Participate	
Interest if <u>Only One</u> DR Program Is Offered...Assuming 100% of Homeowners Are Aware of the DR Program	**% of Low Country Homeowners**	***Est. % of All Residential Customers***
FREE THERMOSTAT and the $25 thank you rebate	19.3%	10.8%
Additional % of customers that would be willing to participate in the FREE THERMOSTAT program with a $50 thank you rebate	4.6%	2.6%
Total who might participate in the FREE THERMOSTAT program and a $50 thank you rebate (sum of potential participants at $25 and $50 rebate levels)	23.9%	13.4%
AC SWITCH for a one-time $50 sign up bonus with a $25 thank you rebate	19.0%	10.6%
Additional % of customers that would consider participation in the AC SWITCH program for a $50 sign up bonus with a $50 thank you rebate	2.9%	1.6%
Total who might participate in the AC SWITCH program for a $50 thank you rebate (sum of potential participants at $25 and $50 rebate levels)	21.9%	12.3%

	% of Customers that would Participate	
Interest if Both DR Programs Are Offered...Assuming 100% of Homeowners Are Aware of the DR Programs	**% of Low Country Homeowners**	***Est. % of All Residential Customers***
Percentage preferring the FREE THERMOSTAT with a $25 thank you rebate	14.3%	8.0%
Additional % of customers willing to participate in the FREE THERMOSTAT program with a $50 thank you rebate (vs. $25)	3.4%	1.9%
Subtotal	17.7%	9.9%
Percentage preferring the AC SWITCH for a one-time $50 sign up bonus with a $25 thank you rebate	11.1%	6.2%
Additional % of customers willing to participate in the AC SWITCH program for a $50 sign up bonus with a $50 thank you rebate (vs. $25)	1.5%	.8%
Subtotal	12.6%	7%
Homeowners that said they would consider participating in one DR program (if both technologies are available)	30.3%	16.8%

The survey results indicate that, if offered a DR program focused on A/C Cycling, approximately 17% of all residential customers would be interested. This is based on offering customers the option to choose technologies, and providing a $50 incentive each season. In terms of the target market for such a program, approximately 25% of Low Country single-family homeowners expressed interest in either program at the $25 incentive level, and approximately 30% of those same customers expressed an interest in either program at the $50 incentive level.[19] These results indicate that there is sufficient interest on the part of APS's Residential customers to warrant further investigating a Residential A/C Cycling program.[20]

5.2.4 BENEFIT-COST TEST RESULTS

APS performed three variations of potential Residential A/C Cycling programs under both the TRCT and the PAC Test. The first variation was based on input provided by Summit Blue related to expected participation rates and other data points. Summit Blue based their guidance on research around other utility programs and what APS could reasonably expect to incur in terms of costs and participation levels. This variation assumed APS would utilize thermostats to remotely control A/C usage. Customers would receive an incentive of $30 per season for participating. The second and third variations utilized customer participation and incentive levels gleaned from the Residential survey that was discussed above.[21] For these variations, APS would

[19] As the tables indicate, the participation levels are contingent upon 100% customer awareness of the programs. Should customer program awareness only reach 50%, the Company could only expect to achieve half of the penetration values depicted above. For purposes of the benefit-cost analyses, APS is assuming 100% customer awareness.

[20] Caution should be used when setting expectations for actual customer participation based on research results. Customer actions are typically less likely than stated intentions. For purposes of this Study, however, the results from the survey are being utilized.

[21] APS studied all variations based on 100 hours of program availability per summer season.

offer customers the option of choosing either the thermostat or the switch (plus a $50 sign-up bonus), and then studied the $25 and $50 incentive levels. In all cases, APS assumed a reduction per customer of 1.04 kW (based on a 40% cycling strategy).[22] Finally, Summit Blue provided APS with expected levels of attrition (4% per year), event participation rate[23] (90% per year for the first three years, then diminishing by 1% each year thereafter), term (15 years), and ramp rate (5 years to full capacity).[24] Snapback (70% of event energy reductions) was derived from a bid received during a competitive solicitation specific to APS load.[25] The results are as follows:

Results Based on a 40% Cycling Strategy

		Variation 1	Variation 2		Variation 3	
		Thermostat	Thermostat	Switch	Thermostat	Switch
	Participants	65,000	72,000	55,800	89,100	63,900
	Expected Reduction (kW) per Customer	1.04	1.04	1.04	1.04	1.04
	Total Program Size (MW)	67.60	74.88	58.03	92.66	66.46
	Technology Cost per Unit (including installation)	$325	$325	$175	$325	$175
	Program Development Costs	$150,000	$150,000	$150,000	$150,000	$150,000
	Annual Program O&M Costs	$175,000	$175,000	$175,000	$175,000	$175,000
	One-time Rebate (per participant)	$0	$0	$50	$0	$50
	Annual Incentives per Customer	$30	$25	$25	$50	$50
	Benefits					
(1)	Avoided Capacity	$35.5 M	$69.8 M		$83.6 M	
(2)	Avoided Energy	$1.6 M	$3.2 M		$3.8 M	
	Costs					
(3)	Technology	$24.9 M	$39.3 M		$47.3 M	
(4)	Program Costs	$3.3 M	$6.5 M		$7.3 M	
(5)	Rebates/Incentives	$13.5 M	$25.0 M		$56.2 M	
	PAC Test					
(6)	Benefits (1+2)	$37.1 M	$73.0 M		$87.4 M	
(7)	Costs (3+4+5)	$41.7 M	$70.8 M		$110.8 M	
(8)	Benefit-Cost Ratio (6/7)	0.89	1.03		0.79	
	Total Resource Cost Test					
(9)	Benefits (1+2)	$37.1 M	$73.0 M		$87.4 M	
(10)	Costs (3+4)	$28.2 M	$45.8 M		$54.6 M	
(11)	Benefit-Cost Ratio (9/10)	1.32	1.59		1.60	

Note 1 Thermostat and Switch values for Variation 2 and Variation 3 are additive in nature
Note 2 Technology costs include both capital and O&M
Note 3 PAC Test costs assume APS pays for all technology
Note 4 Programs analyzed over a 15 year life
Note 5 Total Resource Cost Test plus the emissions information to follow equals the Societal Cost Test

Figure 14

Each program variation analyzed has a TRCT Benefit-Cost Ratio above 1, meaning that they would be considered to have a net benefit to society; however, only one of the programs provides a Benefit-Cost Ratio above 1 for the PAC Test, indicating that the other variations have a net cost

[22] APS assumed a 40% cycling strategy as a conservative estimate to minimize the impact of the reduced run-time of the A/C unit on each customer. The industry norm is 50% and is studied further below. The kW reduction value was derived from an industry norm of 1 kW per household at 50% cycling, with an adjustment for APS Low Country customers having 1.3 A/C units per household on average.

[23] The event participation rate figure is an estimate by Summit Blue indicating that a certain percentage of customers will not participate in each event, and that a small portion of equipment failures would occur for each event. An example of an equipment failure would be the inability to reach a thermostat or switch over the paging network on a given day.

[24] The values provided by Summit Blue for attrition, event participation rate, term, and ramp rate are consistent for all residential DLC programs described herein.

[25] For purposes of the residential DLC programs, APS assumed a call window of 4 hours with demand reduction, and 2 hours of Snapback, one hour prior to and one hour following the event. For each of the Snapback hours, the load was increased by 35% of the net energy reduction during the event for a total of 70%. This implies a net energy savings of 30% when an event is called.

to APS. One of the main drivers for these results is the cycling strategy of 40%.[26] To study the impact of the cycling strategy on the Benefit-Cost Ratio for each test, a 50% cycling strategy was also analyzed.[27] As can be seen below, by raising the cycling strategy to 50%, which is common among most utilities nationwide, the Benefit-Cost Ratios are very positively impacted. Still, however, Variation 3 (which utilizes the penetration rates based on a $50 annual incentive) has a Benefit-Cost Ratio for the PAC Test slightly below 1. In all cases, the TRCT is improved. The other data point worth noting is that, for both the 40% and 50% cycling strategy cases, the two variations based on the residential survey (Variations 2 and 3) have virtually identical TRCT Benefit-Cost Ratio results. This indicates that the incremental penetration rate gained by increasing the incentive level from $25 to $50 does not positively impact the Benefit-Cost Ratio; however, it does raise the overall peak demand impact of the program.

Results Based on a 50% Cycling Strategy

		Variation 1	Variation 2		Variation 3	
		Thermostat	*Thermostat*	*Switch*	*Thermostat*	*Switch*
	Participants	65,000	72,000	55,800	89,100	63,900
	Expected Reduction (kW) per Customer	1.3	1.3	1.3	1.3	1.3
	Total Program Size (MW)	84.50	93.60	72.54	115.83	83.07
	Technology Cost per Unit (including installation)	$325	$325	$175	$325	$175
	Program Development Costs	$150,000	$150,000	$150,000	$150,000	$150,000
	Annual Program O&M Costs	$175,000	$175,000	$175,000	$175,000	$175,000
	One-time Rebate (per participant)	$0	$0	$50	$0	$50
	Annual Incentives per Customer	$30	$25	$25	$50	$50
	Benefits					
(1)	Avoided Capacity	$44.4 M	$87.3 M		$104.5 M	
(2)	Avoided Energy	$2.0 M	$4.0 M		$4.8 M	
	Costs					
(3)	Technology	$24.9 M	$39.3 M		$47.3 M	
(4)	Program Costs	$3.3 M	$6.5 M		$7.3 M	
(5)	Rebates/Incentives	$13.5 M	$25.0 M		$56.2 M	
	PAC Test					
(6)	Benefits (1+2)	$46.4 M	$91.3 M		$109.3 M	
(7)	Costs (3+4+5)	$41.7 M	$70.8 M		$110.8 M	
(8)	Benefit-Cost Ratio (6/7)	1.11	1.29		0.99	
	Total Resource Cost Test					
(9)	Benefits (1+2)	$46.4 M	$91.3 M		$109.3 M	
(10)	Costs (3+4)	$28.2 M	$45.8 M		$54.6 M	
(11)	Benefit-Cost Ratio (9/10)	1.65	1.99		2.00	

Note 1 Thermostat and Switch values for Variation 2 and Variation 3 are additive in nature
Note 2 Technology costs include both capital and O&M
Note 3 PAC Test costs assume APS pays for all technology
Note 4 Programs analyzed over a 15 year life
Note 5 Total Resource Cost Test plus the emissions information to follow equals the Societal Cost Test

Figure 15

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[26] A 40% cycling strategy implies that the A/C unit would be remotely cycled off for twelve minutes out of every half hour.

[27] A 50% cycling strategy would raise the expected impact for each customer from 1.04 kW to 1.3 kW.

5.2.5 ESTIMATED EMISSIONS IMPACTS

The A/C Cycling program variations analyzed above all result in net lower emissions over the life of the programs.

	Life-Cycle Avoided Emissions Based on a 40% Cycling Strategy					
Scenario	**CO_2**	**CO**	**NO_x**	**PM10**	**SO_2**	**Hg**
	tons	lbs	lbs	lbs	lbs	lbs
A/C Cycling - Variation 1	7,487	601	2,271	160	74	0.03
A/C Cycling - Variation 2	14,721	1,183	4,465	314	145	0.06
A/C Cycling - Variation 3	17,624	1,416	5,345	376	173	0.07

Figure 16

5.2.6 RECOMMENDATIONS

After reviewing the interest of APS homeowners and the corresponding Benefit-Cost ratios derived from research conducted related to this Study, it is recommended that APS pursue a Residential A/C Cycling program.

5.3 RESIDENTIAL MISCELLANEOUS LOAD CONTROL

5.3.1 OVERVIEW OF RESIDENTIAL MISCELLANEOUS LOAD CONTROL

Miscellaneous load control programs are similar in nature to the A/C Cycling program listed above; however, they would incorporate other appliances or equipment. For example, load control devices could be placed on water heaters, pool pumps, or electric heating. These programs are often combined with the A/C Cycling programs in what amounts to a multi-end-use DLC program.

5.3.2 CURRENT PROGRAMS IN OTHER JURISDICTIONS

Hawaiian Electric Company ("HECO") has one of the few water heating-only DLC programs offered by an investor owned utility, called the *Energy Scout*. HECO's $3 per month water heater DLC incentive is roughly double the $18 average incremental water heater annual incentive offered by the other utilities whose DLC programs incorporate water heaters. HECO's program started in 2005, but they have already enrolled 15% of eligible customers. HECO installs a free "ENERGYSCOUT" near the customer's water heater. During system emergencies, the ENERGYSCOUT temporarily turns off the electricity to the water heater. Hot water in the tank would still be accessible, and the water heater typically would not be interrupted for more than one hour at a time.[28]

A number of smaller water heater pilot efforts have been initiated around the country as well. Rural cooperatives in particular have embraced water heater control as a means of engaging customers in helping to reduce peak system loads. Control periods vary dramatically from one

[28] *See* http://www.heco.com/vcmcontent/FileScan/PDFConvert/scoutsignup.pdf.

program to another. An electric cooperative in the Western United States experimented with 2-hour, 4-hour, and 5-hour control, both in the morning and evening. The length of the control period did not significantly alter the demand savings; however, the time of day the event was called did have an impact, with the early morning hours providing more kW reductions than other time periods.[29]

Electric space heating DLC programs are rare. Portland General Electric ("Portland") conducted a small pilot program in 2003 that included 77 participants. The control technology was programmable thermostats which controlled participants' space heating use for two hours per day. The average demand savings was 0.73 kW per participant from 4pm to 6pm, and 0.48 kW from 6pm to 8pm. Portland terminated the program at the conclusion of the pilot period due to a poor Benefit-Cost Ratio.[30] Florida Power & Light ("FP&L") has the nation's largest Residential DLC program with roughly 800,000 participants, and includes water heating, residential heating, and pool pumps, in addition to A/C Cycling, in its *On Call* program.[31]

5.3.3 APPLICABILITY TO APS

A water heater-specific program does not specifically fit APS's needs. The APS system is most constrained in summer months in the Phoenix Valley and Yuma. During the periods of extreme temperatures that coincide with system peak (typically between 4-5pm), it is unlikely that water heaters, typically located in garages, require long run times to maintain their preset temperature levels. During winter months, when water heaters would necessarily run more often, APS would assign much less value for such a resource; indeed, the avoided capacity cost would be negligible. If APS were to initiate a Residential A/C Cycling program, however, the incorporation of water heater cycling could provide additional kW impacts for marginal cost increases. For this reason, a combined A/C and Water Heater Cycling program has been analyzed.

Residential customers with pools in their yards provide another dimension to DLC. In the residential survey conducted earlier this year, APS also queried customers on whether or not they had pools, and if so, whether or not they were on timers. Almost one out of three Low Country homeowners indicated they had a swimming pool, and 95% of these indicated their pool pumps were on a timer. Clearly, the high participation on residential TOU rates has led to customers seeking ways to schedule high energy consuming loads on their own and there is no justification or need for APS to focus on pool pump timers.

5.3.4 BENEFIT-COST TEST RESULTS

As was the case previously, the program costs and associated load impacts were provided by Summit Blue. Two variations to a combined A/C plus water heater program were analyzed: one based on a 40% cycling methodology and one based on a 50% cycling methodology. In each case, the results were compared to and incremental from the base case A/C only program using

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[29] Summit Blue Consulting, based on a water heater program evaluation conducted for an electric cooperative in the Western United States.

[30] Portland General Electric Co., *Direct Load Control Pilot for Electric Space Heat: Pilot Evaluation and Impact Measurement,* Revised October 22, 2004.

[31] *See* https://app.fpl.com/secure/forms/oncall.shtml.

the variables provided by Summit Blue.[32] It was assumed that any customer participating in the A/C program that had an electric water heater would also allow the Company to remotely control that appliance as well. Based on internal research numbers, this would amount to approximately 40% of the expected participants (26,000 of the 65,000 A/C cycling participants would also have their water heaters cycled). The results are as follows:

		AC Only	AC + WH	AC Only	AC + WH
		40% Cycling Strategy		50% Cycling Strategy	
	Participants	65,000	26,000	65,000	26,000
	Expected Reduction (kW) per Customer	1.04	0.24	1.3	0.3
	Total Program Size (MW)	67.60	6.24	84.50	7.8
	Technology Cost per Unit (including installation)	$325	$60	$325	$60
	Program Development Costs	$150,000	$25,000	$150,000	$25,000
	Annual Program O&M Costs	$175,000	$0	$175,000	$0
	One-time Rebate (per participant)	$0	$0	$0	$0
	Annual Incentives per Customer	$30	$20	$30	$20
	Benefits				
(1)	Avoided Capacity	$35.5 M	$38.8 M	$44.4 M	$48.5 M
(2)	Avoided Energy	$1.6 M	$1.8 M	$2.0 M	$2.2 M
	Costs				
(3)	Technology	$24.9 M	$26.7 M	$24.9 M	$26.7 M
(4)	Program Costs	$3.3 M	$3.3 M	$3.3 M	$3.3 M
(5)	Rebates/Incentives	$13.5 M	$17.1 M	$13.5 M	$17.1 M
	PAC Test				
(6)	Benefits (1+2)	$37.1 M	$40.6 M	$46.4 M	$50.7 M
(7)	Costs (3+4+5)	$41.7 M	$47.1 M	$41.7 M	$47.1 M
(8)	Benefit-Cost Ratio (6/7)	0.89	0.86	1.11	1.08
	Total Resource Cost Test				
(9)	Benefits (1+2)	$37.1 M	$40.6 M	$46.4 M	$50.7 M
(10)	Costs (3+4)	$28.2 M	$30.0 M	$28.2 M	$30.0 M
(11)	Benefit-Cost Ratio (9/10)	1.32	1.35	1.65	1.69

Note 1 Technology costs include both capital and O&M
Note 2 PAC Test costs assume APS pays for all technology
Note 3 Programs analyzed over a 15 year life
Note 4 Costs and expected reductions for AC + WH program are incremental to AC Only program
Note 5 Total Resource Cost Test plus the emissions information to follow equals the Societal Cost Test

Figure 17

The A/C plus water heater programs provide an incrementally better TRCT Benefit-Cost Ratio; however, in both cases the PAC Test Benefit-Cost Ratio is marginally worse. This is likely due to the small load reduction (0.24 kW for the 40% cycling strategy and 0.30 kW for the 50% cycling strategy) expected from the water heaters compared to the necessary incentive of $20.

5.3.5 ESTIMATED EMISSIONS IMPACTS

A combined A/C and water heater cycling program as analyzed above would result in net lower emissions on the APS system over the life of the program.

[32] It is expected that the results from the other variations depicted in the A/C Cycling section would provide comparable results.

	Life-Cycle Avoided Emissions Based on a 40% Cycling Strategy					
Scenario	CO_2	CO	NO_x	PM10	SO_2	Hg
	tons	lbs	lbs	lbs	lbs	lbs
A/C & WH Cycling	8,178	657	2,480	174	80	0.03

Figure 18

5.3.6 RECOMMENDATIONS

Based on the numbers above, it appears a properly structured incremental water heater program could provide a net benefit to the APS system if done in tandem with an A/C Cycling program. Therefore, it is recommended that any A/C Cycling program provide flexibility to consider the addition of a water heater or other incremental appliance.

5.4 COMMERCIAL & INDUSTRIAL DLC

5.4.1 OVERVIEW OF COMMERCIAL & INDUSTRIAL DLC

C&I DLC programs are similar in nature to the Miscellaneous Load Control discussed above in that there are multiple end-use applications at C&I customer properties that can be tapped into for load reductions. Some large commercial facilities are already equipped with EMCS that monitor and control HVAC systems, lighting, and other building functions. Auto-DR is designed to link facility EMCS with external utility-generated price or emergency signals. The signals initiate pre-programmed, customer-defined strategies to shift, reduce or shed load for brief periods of time. Pre-defining and automating the customer response through the customer's EMCS can substantially reduce cost and complexity while providing a more reliable load reduction. Increasingly, third-party aggregators are being used to coordinate customer participation and install turnkey solutions where EMCS are not available.

5.4.2 CURRENT PROGRAMS IN OTHER JURISDICTIONS

Many different types of C&I DR programs are offered throughout the United States by varying entities, including Independent System Operators, utilities, and third-party aggregators. The aggregators, as mentioned above, offer turn-key solutions for utilities by securing a portfolio-based load curtailment capability from a mix of customers, often from different industries with varying consumption patterns. The utilities then treat DR as a resource and call upon it when needed. For example, Pacific Gas & Electric ("PG&E") recently signed five agreements with DR aggregators who collectively committed to provide load curtailments of at least 35 MW in August 2007, ramping up to as much as 149 MW from 2009 to 2011.[33]

Load impacts from C&I DR programs can vary widely depending on the types of customers participating in the program. LBNL performed interviews with various entities to assess the state of DR in 2006. Overall, the respondents felt that the reliability-based DR resources, of which

[33] Pacific Gas and Electric Company, *Application for Approval of Demand Response Agreements, Prepared Testimony*, February 28, 2007; California Public Utilities Commission, Order Approving the Applications of Pacific Gas and Electric Company and Southern California Edison Company for Approval of Demand Response Agreements, Decision 07-05-029, May 3, 2007.

DLC is a part, performed well. System operators and aggregators planned on load reductions of less than 100% of enrolled loads; results met or exceeded expectations, with some programs realizing load responses of 80% or more of enrolled resources.[34]

Preliminary results from an LBNL/PG&E pilot Auto-DR program using critical peak prices showed that participants were able to achieve 14% demand savings on average. Most of the customers involved controlled their HVAC system as part of the Auto-DR solution, while a few customers controlled their lighting and a small number controlled other equipment such as non-critical processes. Many different sectors were involved in the study. A previous LBNL study found that savings per square foot varied widely, but that many facilities were able to reduce loads by approximately 0.5 watts per square foot, or 50 kW for a 100,000 square foot building.[35]

5.4.3 APPLICABILITY TO APS

In spring 2007, APS commissioned Summit Blue to do a preliminary review of the different forms of DR that could be pursued by the Company. Based on the nature of the APS system and its customer base, Summit Blue recommended that the Company move forward with a C&I DR program. In October 2007, APS issued a targeted RFP for C&I DR and LM via a third-party aggregator. The RFP specified the scope and parameters for the DR proposals, as described below:

- Turn-key proposal where the respondent would be responsible for customer marketing, recruiting, and services; communication protocols; product installation, operations and maintenance; and measurement and verification.
- Minimum load management size: 10 MW. The proposals sought required availability during the summer months of May through September; APS did entertain proposals for other durations. Load reductions are required to be in effect no later than 24 hours after APS notification of a demand reduction event.
- Operation must begin no later than May 1, 2010, and can ramp up over time.
- Respondent must provide on-going real-time data on availability and event performance to APS.
- Any customer in Respondent's offering must be an APS C&I customer physically located within either the Greater Phoenix Metropolitan load area or the Yuma load area.

The Company received proposals in December 2007 from multiple vendors. There was wide variation in the proposals received, including phased-in capacity, with a range of 2 – 40 MW in 2009, and increasing to a maximum of approximately 200 MW by 2013. The number of anticipated customers participating in the programs varied widely, from 100 to over 10,000. Proposed contract durations ranged from 5 – 15 years. The proposals included maximum callable hour limits between 40 – 100 hours during peak load times.

5.4.4 BENEFIT-COST TEST RESULTS

Based upon the responses provided, APS calculated Benefit-Cost Ratios for the PAC Test of between 0.4 and 1.1. Due to the nature of the bids, APS was unable to calculate a TRCT Benefit-

[34] The Summer of 2006: A Milestone in the Ongoing Maturation of Demand Response, LBNL, N. Hopper *et al.*, May 2007.

[35] *Findings from the 2004 Fully Automated Demand Response Tests in Large Facilities*, M.A. Piette *et al.*, September 2005.

Cost Ratio for each proposal, as the exact amount of rebates and incentives being passed along to customers were not known; however, it can be surmised that the results of a TRCT for each proposal would be greater than the results for the PAC Test. Because there were bids submitted that passed the PAC Test, the Company felt comfortable with moving forward in the negotiations process with a short-list of vendors.

5.4.5 RECOMMENDATIONS

Currently, the Company has on-going contract negotiations with the short-list of vendors. The Company's emphasis in these negotiations – pursuant to Decision No. 69663 – is to develop a cost-effective program that is most beneficial to both customers and the APS electric system. As a result, the Company is rigorously negotiating for clear measurement, verification and performance requirements, including customer service metrics. APS anticipates that contract negotiations will end in the near future. If successful, the Company will file with the Commission specific information, including program parameters and costs. The Company is optimistic that the result will be a viable C&I DR program that is cost-effective and benefits both customers and the APS electric system.

6. SCHEDULED LOAD MANAGEMENT

6.1 OVERVIEW OF SCHEDULED LOAD MANAGEMENT

SLM is a class of programs that require pre-planned load reductions on behalf of the customer. Customers agree to and schedule load reductions at pre-determined times and in pre-determined amounts. These programs are codified as contractual obligations which specify, well in advance, the specific days, times, or situations when load reductions are to be scheduled. Due to this advance notice, utilities do not typically have the ability to call on this load for curtailment purposes on short notice. Based on this, some researchers view SLM as an energy efficiency strategy rather than a DR program.[36]

6.2 THERMAL ENERGY STORAGE

6.2.1 OVERVIEW OF THERMAL ENERGY STORAGE

TES programs typically assist customers in acquiring and installing ice or chilled water storage systems that are used to shift air conditioning load to off-peak hours on a daily basis. This is accomplished by using the existing chiller equipment to either make ice or chilled water in the off-peak hours, and then using this thermal energy to cool the customer site during the on-peak hours in lieu of running the chillers. This effectively shifts the cooling load for a building to the nighttime hours when it is less expensive for the utility to generate electricity. TES is most applicable to large commercial facilities or to district cooling systems and are fixed assets that do not require ongoing program interaction once installed and operating. One example is the district cooling system installed at Chase Field, which services much of downtown Phoenix.[37] Smaller systems applicable to residential and small commercial customers are becoming increasingly available. In some circumstances, siting storage equipment is often a barrier to installation at existing facilities.

6.2.2 CURRENT PROGRAMS IN OTHER JURISDICTIONS

Few investor-owned utilities are presently offering TES programs to their customers. Xcel Energy, in Minnesota, has offered customer incentives for TES systems in one form or another for 20 years as part of its Custom Solutions energy efficiency program. For these, the utility offers rebates of up to $200/kW reduced. This program has resulted in less than fifty total TES systems being installed in the Xcel service area.[38]

In several jurisdictions in California, the Ice Bear system is being installed with some success.[39] Ice Bear is an ISAC system designed for use with 5-20 ton rooftop or split system A/C. Ice Bear

[36] *See* "Demand Response: An Introduction" by the Rocky Mountain Institute (April 30, 2006) at pp. 6-7.

[37] For more information, *see* http://www.apses.com/district_energy.aspx.

[38] *Derived from*: Summit Blue interview with Xcel Energy, February 2007; Xcel Energy 2005-2006 CIP Filing; Xcel Energy 2005 CIP Status Report.

[39] Ice Bear is produced by Ice Energy. More information can be found at www.ice-energy.com. As of June 2008, their products are only available for commercial customers in California, Nevada, Hawaii, and Colorado.

and an air-cooled condenser make ice during the off-peak period. During peak hours, Ice Bear functions as the condenser, circulating ice-condensed refrigerant with a 100-watt refrigerant pump. Unlike more complex TES systems, the Ice Bear system can be installed by a certified HVAC contractor, thus reducing costs. Some examples of the application of Ice Bear technology in California include:

- In 2004, the City of Anaheim installed California's first Ice Bear system in a city fire station. The unit achieves a 95% reduction in peak demand and a 5% overall reduction in energy consumption.[40] Ice Bear is currently the only product approved for a TES incentive program offered by Anaheim.
- In December 2006, PG&E, Southern California Edison ("SCE"), and San Diego Gas & Electric ("SDG&E") contracted with Ice Energy within the Emerging Technology program. SDG&E arranged for eight pilot installations. PG&E offers upfront rebates, annual incentives, and TOU rates in its Shift and Save program, which includes technologies like Ice Bear. SCE proposes for 2008 a permanent load shifting program that includes ISAC systems like Ice Bear.

According to Ice Energy's website, as well as a presentation given by them to the DRCC, a system that would be installed to avoid 10 kW of A/C load has an installed cost of $15,000, has a peak itself of only 0.3 kW, and has a 15- to 30-year design life.

6.2.3 APPLICABILITY TO APS

In 1985, APS began its STEP program to encourage thermal energy installations in its service territory. At that time, only a few small TES systems were in place. Because of the limited number of existing systems, the relatively new technology required, and the benefit of shifting HVAC load from peak to off-peak, APS decided to pursue an aggressive marketing campaign to encourage TES systems. Features of the original program were two special time-of-day rates, financial incentives, and technical assistance to prospective clients. Incentives were paid based on the kW shifted at the time of the customer's peak. Other technical requirements were fairly liberal, since thermal storage was still a new technology and little operating information was available. The incentive rates were $250/kW for the first 500 kW shifted and $115/kW for all kW shifted thereafter. During this timeframe, other utilities were offering incentives ranging from $60 to $425/kW shifted. By January 1990, a total of eighteen TES systems were operating under the STEP program. APS had paid cash incentives of approximately $2 million for an average of $235/kW shifted. Most customers saw less-than-anticipated savings, but did realize excellent system availability.

As of the end of 1994, thirty six installations had been performed, with the last installation providing just over 2 MW in demand reduction. In 1995, STEP ceased to exist as a stand-alone program, as the Company began focusing on other energy efficiency efforts.

6.2.4 BENEFIT-COST TEST RESULTS

Cost and participation levels for a TES program were difficult to obtain. Summit Blue determined, based on the research they performed on behalf of APS, that there may be less than 100 currently eligible customers who would participate in a TES program. This is due to TES

[40] *See* http://www.anaheim.net/utilities/news/article.asp?id=739. 95% reduction applies to the reduced A/C load.

making better economic sense on a new-build facility where the HVAC system could be underbuilt to save on costs. In addition, there are severe space restrictions for most TES systems that would further limit the number of customers who could install TES. For this reason, APS has chosen to analyze TES applications on a customer-by-customer basis. The assumption here is that APS would incorporate a TES rebate program as part of its ongoing energy efficiency and customer service program offerings. If a customer installed a TES system, an APS representative or contractor would calculate the net capacity reduction from the technology, and the customer would be given a rebate check from APS. By making this assumption, APS can study a TES program based solely on the cost of the technology, without layering in any estimates on internal fixed costs to implement a larger scale program. Finally, APS analyzed these as if there was no net change in the energy consumption for the customer. There is no firm empirical evidence pointing to net savings or net additional energy consumption. While the City of Anaheim did note approximately 5% net energy savings, Xcel Energy's experience in Minnesota is just the opposite.

		Small-Scale TES	Large-Scale TES
	Participants	1	1
	Expected Reduction (kW) per Customer	10	200
	Total Program Size (MW)	0.01	0.20
	Technology Cost per Unit (including installation)	$15,000	$160,000
	Program Development Costs	$0	$0
	Ongoing Program O&M Costs	$0	$0
	One-time Rebate	$7,500	$80,000
	Benefits		
(1)	Avoided Capacity	$9,221	$184,419
(2)	Avoided Energy	$3,456	$69,128
	Costs		
(3)	Technology	$21,604	$230,447
(4)	Program Costs	$0	$0
(5)	Rebates/Incentives	$6,953	$74,163
	PAC Test		
(6)	Benefits (1+2)	$12,677	$253,547
(7)	Costs (4+5)	$6,953	$74,163
(8)	Benefit-Cost Ratio (6/7)	1.82	3.42
	Total Resource Cost Test		
(9)	Benefits (1+2)	$12,677	$253,547
(10)	Costs (3+4)	$21,604	$230,447
(11)	Benefit-Cost Ratio (9/10)	0.59	1.10

Note 1 Technology costs include both capital and O&M

Note 2 PAC Test costs assume Customer pays for all technology

Note 3 Programs analyzed over a 15 year life

Note 4 Total Resource Cost Test plus the emissions information to follow equals the Societal Cost Test

Note 5 All Benefit and Cost figures are based on a NPV to 2009 dollars

Figure 19

The small-scale TES, which provides a load shift of approximately 10 kW per customer, has a TRCT Benefit-Cost Ratio well below 1. This is caused by the high technology cost for a relatively small amount of capacity savings. The large-scale TES, which has an expected demand reduction of 200 kW, has a TRCT Benefit-Cost Ratio of 1.1.[41] In both cases, the PAC Test results are very favorable. For the PAC Tests, APS would incur only half of the technology costs in the form of rebates to the customers, whereas in the TRCT the full value of the technology is accounted for.[42]

6.2.5 ESTIMATED EMISSIONS IMPACTS

Both TES applications analyzed above would result in net lower emissions for all pollutants except CO. This is likely the result of the increased off-peak consumption needed to charge the TES units.

Scenario	Life-Cycle Avoided Emissions					
	CO_2	CO	NO_x	PM10	SO_2	Hg
	tons	lbs	lbs	lbs	lbs	lbs
Small-Scale TES (1 part.)	40	(3)	24	0	0	0.00
Large-Scale TES (1 part.)	795	(66)	476	3	8	0.00

Figure 20

6.2.6 RECOMMENDATIONS

On its surface, TES seems to be a very good fit in Arizona. As mentioned earlier, approximately 44.5% of peak demand requirements for C&I customers is HVAC load. However, there is some concern that TES systems would have to be built for greater capacity than needed in the Phoenix market to account for the higher ambient temperatures that the unit would have to battle while making chilled water or ice.

Because of the seemingly natural fit of TES on the APS system and the potential for bill savings that could offset some of the long-term costs of the program for customers, the Company is looking into the feasibility of installing TES units on one or more new and existing Company facilities over the next several years. By doing this, APS could test the performance of TES in the desert climate and could gather better data on potential bill savings. If it is determined that this technology can function well and provide savings, a Societal Cost Test will be revisited and the viability on the APS system will be determined.

6.3 SCHEDULED WATER PUMPING

6.3.1 OVERVIEW OF SCHEDULED WATER PUMPING

Scheduled Water Pumping programs involve any agreement, described above, for a pre-planned load reduction, where the utility and its customer agree in advance to specific, modified pumping

[41] The installed cost for a large-scale TES system of $800/kW was taken from *Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources: Appendices,* Prepared for PacifiCorp by Quantec, LLC, in collaboration with Summit Blue Consulting and Nexant, Inc. (July 11, 2007) at Table B.12.

[42] It is important to note that neither of the tests performed above account for potential rate savings from installing a TES unit.

schedules to shift pumping demand away from on-peak time periods. The downside to such programs is that they may not coincide with time periods when the utility system needs the load reduction, either for economic or reliability purposes.

6.3.2 CURRENT PROGRAMS IN OTHER JURISDICTIONS

There are two large Scheduled Water Pumping programs in Idaho, conducted by PacifiCorp and Idaho Power. These programs are very similar in most respects. Both programs started at roughly the same time (2003 or 2004), and offer similar customer incentives of between $5.50 and $13 per kW reduced per year, depending on the frequency of load reductions. Both programs have achieved very similar participation rates of 24-25% of eligible customers, and use automatic timers to reduce loads at pre-set times that customers agree to when they sign up for the program each year. For the Idaho utilities, administration of the programs has been relatively easy; however, recruitment has proven difficult.[43] SCE has a similar agricultural and interruptible program that pays an incentive of approximately 1 cent/kWh, rather than a demand-based incentive.[44] Given the nature of agricultural industries using irrigation, owners and farmers are often different entities, and the farmer who agrees to limit watering may be at a different site in subsequent years. This can lead to annual re-recruitment efforts.

6.3.3 APPLICABILITY TO APS

APS currently has two programs in place via its Commission-approved Time-of-Use and Time-of-Week rate options for its Water Pumping Service, Rate Schedule E-221.[45] These options provide an incentive to customers to shift usage to specific time frames.

The Time-of-Week rate option allows for the customer to negotiate a specific "Control Period" that covers a thirteen-hour period from 9am to 10pm for one day during the week (Monday to Friday). During the Control Period, customers are rewarded for limiting power consumption. If the measured kWh during the Control Period is 2 kWh per kW or less, the customer receives a discount of $0.00693 per kWh for all usage during that billing period; however, if the measured kWh is greater than 8 kWh per kW, they are assessed a penalty of $0.00347 per kWh for all usage during the billing period.

The Time-of-Use rate, E-221-8T, creates a customer-specific on-peak period covering a consecutive 8-hour period between 9am and 10pm each and every day, mutually negotiated by the customer and APS. This rate puts a heavy emphasis on the demand component of the customer's bill. Compared to the flat $1.660 per kW found under E-221 (both standard and Time-of-Week options), E-221-8T charges $3.950 per on-peak kW and $2.360 per off-peak kW. The usage charges for the time periods ($0.08454 and $0.04547, respectfully) are discounted from the standard rates.[46]

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[43] Summit Blue interview with Idaho Power, April 3, 2007.

[44] Flex Your Power Now, *California Demand Response Programs*, Table of Programs (updated June 23, 2006).

[45] As these rates are cost-justified and inherently designed to be revenue neutral, no benefit/cost analysis is being performed. All rates discussed are those currently in effect.

[46] The standard energy charge is a combination of the following: $0.10311 per kWh for the first 240 kWh, plus $0.0701 per kWh for the next 275 kWh per kW, plus $0.05755 per kWh for all additional kWh.

When comparing the two rate options that promote scheduled shifting of consumption to the standard plan, it is apparent that the average customer saves money if they are capable of shifting usage. Customers on these TOU options have responded to the embedded price signals and managed to save on their bills compared to the standard rate.

6.3.4 RECOMMENDATIONS

While it appears that there is economic justification for customers to switch onto one of the above-mentioned rate options, the actual participation for these rates is less than 5% combined. Therefore, APS recommends investigating the reasons why irrigation and water pumping customers have not switched to the TOU rate options. Concurrent to this Study, APS is also considering a water pumping test and repair pilot program for irrigation customers that would be rolled out later this year. The main purpose of this pilot program is to help customers identify (test) and ultimately achieve (repair) electric savings on their water pumping systems. If pursued, this would provide a good forum to discuss with these customers their awareness level related to the TOU rate options. If possible, the Company would then identify those customers currently on the standard plan who are capable of and would benefit from switching to a TOU option, and migrate them away from the standard plan.

6.4 BATTERY STORAGE

6.4.1 OVERVIEW OF BATTERY STORAGE

Battery Storage, often referred to as Energy Storage, provides an electrically rechargeable storage technology that can be cycled on a regular basis for long periods of time. Battery Storage applications are used frequently for power quality and reliability purposes and provide "ride-throughs" during outages or other system disturbances. Battery Storage can also be used in conjunction with renewable energy resources to better help intermittent resources, such as solar photovoltaic and wind, to align their output with utility peak demand requirements.[47] There are many different types of Battery Storage technologies, each with characteristics that could translate into customer-owned DR capacity. Three of the main technologies are discussed below.

6.4.1.1 LEAD-ACID BATTERIES

Lead-Acid Batteries are the oldest rechargeable battery technology, invented in 1859. They have relatively low energy-to-weight and energy-to-volume ratios, but do provide high surges of power. The expected lifetime for these batteries degrades significantly with operating temperature, as depicted in the following graph:[48]

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[47] *See* http://electricitystorage.org/technologies_applications.htm.

[48] *The EPRI-DOE Handbook of Energy Storage for Transmission and Distribution Applications (2003),* originally from *Stationary Battery Guide: Design, Application, and Maintenance, Revision 2 of TR-100248,EPRI, Palo Alto, CA: 2002, 1006757* ("EPRI-DOE Handbook").

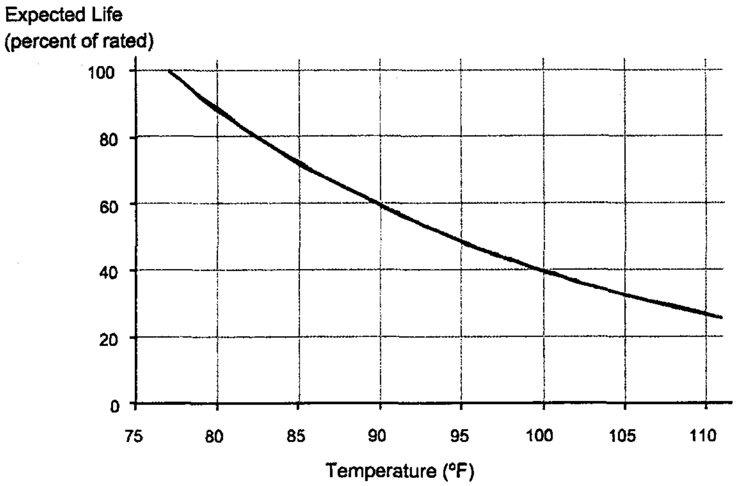

Figure 21

In addition, Lead-Acid Batteries have short lifetimes if used for deep cycling (approximately 500 cycles at an 80% depth of discharge).

Gaia Power Technologies produces an 11 kW Lead-Acid Power Tower, which can be built with 10 to 30 kWh of storage capacity. Both the NYSERDA and the CEC are funding projects using this technology.[49]

6.4.1.2 FLOW BATTERIES

A Flow Battery is a rechargeable battery in which liquid electrolyte is pumped through a power cell that converts the chemical energy in the electrolyte into electrical energy. Flow batteries have a smaller energy and power density than other more traditional rechargeable batteries. Three types of Flow Batteries are currently in production: Zinc Bromide (ZnBr), Vanadium Redox, and Polysulfide Bromide (PSB).

The CEC has partnered with the Sacramento Municipal Utility District ("SMUD") to install a 20 kW/180 kWh vanadium redox battery from VRB Power Systems Inc. This battery will be used for six hours of load shifting and an additional three hours of back-up power. The total cost for the system was $300,000 with an estimated lifetime of 10,000 cycles, an equipment cost of $450-700 per kWh (for sizes greater than 500 kW with 8 hours of storage), and a roundtrip efficiency of 65-75%.[50]

The CEC has also partnered with PG&E to install a 2 MW/2 MWh utility-sited peak shaving system using Zinc Bromide technology from ZBB Energy.[51] The system will be comprised of four 500 kW/500 kWh Zinc Bromide batteries, each containing ten 50

[49] *See,* http://www.gaiapowertechnologies.com/news.html *and* http://www.gaiapowertechnologies.com/news/CaliforniaEnergyCircuit.pdf.

[50] *See* http://www.vrbpower.com/technology/faqs.html for additional specifications.

[51] *See* http://www.zbbenergy.com/pdf/ZBB_Brochure.pdf.

kWh modules. The EPRI-DOE Handbook estimates a 2006 price of $162,500 for a 250 kW/500 kWh module (manufactured by ZBB Energy), including the battery control and management system, DC circuit breaker, exterior enclosures, environmental controls, and technical support for system integration, installation, and startup. Lifetimes of 1,500 cycles or more are expected, and have been confirmed by initial projects.

6.4.1.3 SODIUM SULFUR

Sodium Sulfur (NaS) batteries use molten sulfur and molten sodium as electrodes, separated by a solid beta alumina ceramic electrolyte. Only the positive sodium ions can go through the electrolyte. Operating temperatures of 300-350°C must be maintained, but the charge/discharge efficiency is high at approximately 90%. The materials are non-toxic and the batteries have a long life. Output can exceed five times the rated capacity for up to 30 seconds, providing both power quality and peak shaving/demand response capabilities. This technology was originally developed by Ford Motor Company in the 1960s for an electric vehicle.

The EPRI-DOE Handbook estimates a 2006 price for a NaS 50 kW/400 kWh system of $75,000. A cycle life of approximately 6,000 is estimated at a 70% depth of discharge and 4,000 at a 90% depth of discharge. NYSERDA is sponsoring a demonstration project of a 1 MW/7.2 MWh system for natural gas compressors at the Metropolitan Transportation Authority's Long Island bus maintenance facility in Garden City, New Jersey. This project is currently under development. In February 2008, Xcel Energy announced it will develop a wind farm energy storage battery based on 20-50 kW NaS batteries from NGK Insulators, LTD. The 80 ton, two semi-trailer sized system will be capable of 7.2 MWh of capacity at a charge and discharge rate of 1 MW.[52]

6.4.2 APPLICABILITY TO APS

APS is currently testing Zinc Bromide Flow Batteries at the STAR Center. The Zinc-Flow 45 battery system technology is manufactured by Premium Power Corporation.[53] The Company has configured it for telecom applications,[54] with a nominal storage value of 45 kWh. The enclosure for the battery system is outdoor-rated with a self-contained heat pump for tempering hot and cold extremes. The Zinc-Flow 45 battery system is currently undergoing a long-term float voltage test. During the summer of 2008, the system will be tested in extreme temperature discharge/charge cycles.

6.4.3 RECOMMENDATIONS

Because of the relative newness of this type of technology for DR purposes, APS does not recommend moving forward with a program at this time. The Company plans to continue testing the installation at the STAR Center and, if the technology proves effective, APS will

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52 *See* http://www.businessgreen.com/business-green/news/2211044/xcel-energy-trial-wind-power. For additional information on this technology, see http://www.ngk.co.jp/english/products/power/nas/index.html.

53 *See* http://www.premiumpower.com/.

54 The APS telecom facilities mentioned here help maintain the communications and control network for the Company's power plants and transmission system, and, as such, they require significant amounts of reliable battery backup.

consider the next steps for this technology. APS will also monitor other industry efforts and technology costs with regards to Battery Storage to look for new opportunities in the future for its incorporation.

7. CUSTOMER LOAD RESPONSE

7.1 OVERVIEW OF CUSTOMER LOAD RESPONSE

Customer Load Response refers to DR programs where the utility offers incentives to customers to take action on their own initiative. This differs from Direct Load Control programs in that the utility does not have explicit control over shutting off processes or loads. While the load reductions are actuated by the customer, they may still use automated processes, load switches, or other technologies to effectuate the curtailment.

7.2 CURTAILABLE LOAD/INTERRUPTIBLE RATES

7.2.1 OVERVIEW OF CURTAILABLE LOAD & INTERRUPTIBLE RATES

Curtailable Load and Interruptible Rate programs typically target medium and large customers. Participants agree to firm load reductions when notified by the utility, sometimes with as little advance notice as 10 minutes prior to an event. Curtailment can be either manual (the customer initiates the reduction by shutting off equipment), or automated, via either a DLC device described earlier or under-frequency relays connected to specific customer loads. Customer incentives for Curtailable Load programs can include monthly capacity credits, option payments, or per event credits. Interruptible Rates utilize a tariff with reduced capacity charges in exchange for the customer's obligation to curtail load upon the request of the utility. Both types of programs normally include financial penalties for underperformance or non-performance.

7.2.2 CURRENT PROGRAMS IN OTHER JURISDICTIONS

In a study conducted for the International Energy Agency, it was determined that more than half of the forty North American utilities surveyed were offering Curtailable or Interruptible Rate programs to their C&I customers.[55] Utilities offering programs in 2004 included almost all major utilities in California, Illinois, Indiana, Iowa, Minnesota, and Wisconsin, as well as Allegheny Energy, Colorado Springs Utilities, and Kansas City Power & Light.

Most utilities require relatively small minimum demand reductions to be eligible for the programs, ranging from 50 kW for Xcel Energy in Minnesota, up to 250 kW for MidAmerican Energy. Minnesota Power, however, limits the program eligibility to customers with an annual peak demand of 10 MW or greater, effectively limiting the program to its large steel plants.

Program rate discounts vary considerably, from Commonwealth Edison's ("ComEd") $7-10 per kW reduced per year, to Alliant Energy's $56 per kW reduced annually. Program participation does not appear to be significantly influenced by the magnitude of rate discounts. For example, MidAmerican Energy offers a $39 per kW annual rate discount and has approximately 7% of its total C&I customers peak demand participating, while Xcel Energy's rate discount of $41 per kW annually achieves approximately 8.6% of total C&I customer peak demand participating.

Roughly 20% of the utilities surveyed in the study listed above reported program impacts that amount to 15% or more of their C&I peak demands; however, many of these utilities reported

[55] North American Utility Demand Response Survey Results, Summit Blue Consulting for the International Energy Agency Demand Side Management Programme, Task XIII – Demand Response Resources, March 2005 ("IEA Survey").

that the majority of their reduction comes from steel plants, which comprise a significant portion of the utilities' C&I peak demand. An additional 13% of the utilities surveyed reduce their C&I peak demands by 10-14% though the Curtailable Load/Interruptible Rate programs. Nearly half of the utilities surveyed, however, realize C&I peak demand reductions of 4% or less.

7.2.3 APPLICABILITY TO APS

APS has some experience with Interruptible rates. From the late 1970s until the summer of 2000, APS had several contracts with customers for Interruptible service. Each of these contracts provided either a special fixed price or a demand charge discount for allowing APS to interrupt all or a portion of their load. The seven customers with which APS had these contracts provided anywhere from 2.5-51 MW of load curtailment on no more than thirty minutes notice. While APS has entered into these types of arrangements in the past, there are currently no retail customers with which the Company has an interruptible service agreement in place. APS historically seldom interrupted the service of those contracts, which led to discounted payments for some customers with no associated loss of load.

One program APS does have in place currently is APS Power Partners.[56] Power Partners is a voluntary program aimed at C&I customers. When temperatures exceed 110 degrees, APS sends a notice to participants requesting that they curtail. In 2007, 58 organizations in Phoenix and Yuma participated as Power Partners. As Power Partners, customers pledge to: turn thermostats up two degrees higher than normal, turn off unnecessary lights and equipment, and shift energy-using tasks to morning or evening hours.

7.2.4 RECOMMENDATIONS

APS does not recommend pursuing a Curtailable/Interruptible program at this time. APS has entered into these agreements in the past, and due to various circumstances, they were allowed to terminate without extensions. Also, any customers who would consider entering into an interruptible agreement would be eligible to participate in the planned C&I DLC program, which would provide incentives based on participation and the level of load that was dropped rather than the negotiation of a separate contract providing discounted rates that would require specific Commission approval, or the Critical Peak Pricing Pilot discussed later in this Study.

7.3 DEMAND BIDDING/BUYBACK

7.3.1 OVERVIEW OF DEMAND BIDDING/BUYBACK

DBB programs encourage customers to reduce loads by bidding a load reduction amount (either kWh or a percentage of the baseline) to the utility in exchange for an energy payment. The price for this reduction can either be set by the customer (the price at which they would agree to curtail) or by the utility (the price at which the utility would be willing to pay for a load reduction). Typically, the incentives are tied to spot market electricity prices. DBB programs are often driven by an internet platform where the utility can post program events, and the customers can bid in load reduction amounts by hour. Using a baseline load curve, the utility can estimate the actual amount of load that was reduced for each hour of the event. These programs are best suited for larger customers.

[56] *See* http://www.aps.com/main/services/business/partners/default.html.

7.3.2 CURRENT PROGRAMS IN OTHER JURISDICTIONS

The IEA Survey revealed that DBB programs are estimated to provide the largest peak demand impacts for about 25% of the utilities surveyed, and several additional utilities also estimate significant demand reduction impacts from their DBB programs. The top-performing programs have impacts that amount to 8-9% of the utilities' C&I peak demand. It should be noted that these impacts were reported several years ago (2000 – 2002 timeframe) when spot market electricity prices were higher than they have been in recent years.

In 2007, six utilities that reported high DBB program impacts were re-interviewed.[57] These utilities generally restrict eligibility for their DBB programs to large customers who can reduce loads by at least 500-1,000 kW during peak periods. Of the six utilities interviewed, only ComEd has a low minimum reduction criteria set at 10 kW. Naturally, program participation is significantly influenced by this minimum reduction criteria – ComEd has over 3,700 participants, which is more than 100 times as many as all but one of the other five utilities interviewed.

7.3.3 APPLICABILITY TO APS

APS does not view DBB as a viable DR program at this time. DBB works best in a region with volatile day ahead or hourly market price signals, similar to what is found in RTOs/ISOs. DBB programs rely on such market prices to provide the economic incentive for customers to participate. APS is not currently in an RTO/ISO market that would provide hourly market clearing price signals that would be able to incent a customer to participate.

7.3.4 RECOMMENDATIONS

Currently, a nexus does not exist between the actions APS would request customers to undertake and the pricing mechanism under which they would be paid. In addition, customers who would likely participate in a DBB program are already being captured in the planned C&I DLC program discussed earlier, or the CPP Pilot discussed in the next section. For these reasons, the Company does not recommend moving forward with DBB at this time.

7.4 DISTRIBUTED GENERATION

7.4.1 OVERVIEW OF DISTRIBUTED GENERATION

For purposes of this Study, DG can be broken into two specific categories: Renewable DG and Standby Generation. Currently, Renewable DG involves providing customers incentive payments to encourage the development of DG resources powered by renewable energy. APS is required to acquire a specific percentage of energy each year pursuant to the RES Rules;[58] therefore, this Study will focus on Standby Generation.[59]

[57] North American Utility Demand Response Survey Results, Summit Blue Consulting for the International Energy Agency Demand Side Management Programme, Task XIII: Demand Response Resources, March 2005.

[58] A.A.C. R14-2-1801 through 1816.

[59] Over the course of the next year, APS will be conducting a study on Renewable Distributed Generation technologies and integration.

Standby Generation programs utilize customer-owned standby units, typically run on diesel fuel or natural gas, which are called upon by the utility to reduce loads. These programs encourage the installation of new units and/or provide incentives for existing units to participate. The utility has the ability, under certain system conditions, to call upon the customer to begin production from their DG unit, thus having the same effect as reducing that customer's load requirements. Standby Generation, specifically when located within a load pocket, provides the added benefit of increasing the electric system's reliability by reducing the stress on grid components, supporting local voltage levels, and increasing the diversity of power supply.

7.4.2 CURRENT PROGRAMS IN OTHER JURISDICTIONS

Standby Generation programs are not prevalent in the United States; however, three very different utility programs illustrate how it can be used as a Dispatchable DR resource.

Portland has a Dispatchable Standby Generation program that is geared toward encouraging the development of new distributed generation at customer sites. This Standby Generation can be dispatched by the utility up to 400 hours annually to meet peak power demands. The customer must purchase the generator (minimum 250 kW), but Portland pays for all equipment necessary for parallel interconnection with the utility grid as well as all maintenance and fuel expenses. Once operational, the standby generators can be monitored and dispatched from Portland's control center. They can also provide backup power during an outage. An additional benefit to the customer relative to typical backup generation is the seamless transition to and from the generator without the usual momentary power interruption. The grid-synchronized connection also means that Portland can use the generators for some ancillary service functions. Program participants pay standard electric rates, regardless of whether it is being generated by Portland or their onsite generator. Portland not only pays the fuel costs for the standby generators during an outage, but also for up to 15 hours per year during which the customer chooses to operate the unit.[60] As of December 2007, Portland had 44 MW enrolled in this program, representing 37 generators at 22 unique locations. Another 17 MW are under development, and Portland has a long-term goal of 150 MW.[61]

Progress Energy Carolinas ("PEC") currently has a Premier Power tariff under which approximately 17 MW of PEC-owned DG units are located at the sites of approximately ten participating customers with especially high reliability needs. The customer receives onsite generation capability during system outages in exchange for paying a monthly fee consisting of both levelized capital costs and operation and maintenance costs.[62] PEC is investigating the use of these generators and other PEC- or customer-owned generation to reduce peak demands for up to 100 hours per year.[63] Although these systems are tested periodically at full load, PEC has never tapped into this idle resource in response to supply constraints or high marginal supply costs.

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[60] *See* http://www.portlandgeneral.com/business/large_industrial/dispatchable_generation.asp?bhcp=1 for additional information.

[61] Summit Blue interview with Portland program manager, December 14, 2007.

[62] *See* http://www.progress-energy.com/aboutenergy/rates/NC_Premier_Power.pdf.

[63] *See* Progress Energy Carolinas Resource Plan, North Carolina Utilities Commission, Docket No. E-100, Sub 109, (September 2006) at p. 26.

SDG&E has contracted with EnerNOC Inc., a demand response aggregator, on its Clean Gen program. This program is designed to utilize 25 MW of existing backup generators to support their transmission system during periods of high demand. EnerNOC and SDG&E cooperate with the San Diego County Air Pollution Control District to ensure that the emissions expected from use of these generators comply with their air permits. This is often done by installing Diesel Particulate Filters to reduce the particulate matter by over 85% and also significantly reduce carbon monoxide and hydrocarbon emissions. By all accounts, this program has been successful. On October 24, 2007, the Clean Gen program successfully supplied 17 MW of generation to the grid during a California Independent System Operator state of emergency. In this program, EnerNOC pays all equipment upgrades, fuel costs, and maintenance costs and in return receives a capacity and energy payment from the utility.[64]

7.4.3 APPLICABILITY TO APS

One of the major issues for Standby Generation in the metropolitan Phoenix area is emissions. Portions of Maricopa County have been designated "nonattainment" for three pollutants: PM10, CO and ozone.[65] Ozone is created by a chemical reaction between NOx and Volatile Organic Compounds in the presence of sunlight. Ground-level ozone is the primary constituent of smog.[66] Any program involving Standby Generation in Phoenix, therefore, must take into account the potential impact of NOx emissions. Invariably, citing new generation similar to what Portland is promoting could prove difficult due to these restrictions. APS has a number of customer-owned standby generators on its system, the majority of which are diesel-powered. According to the Santa Barbara County Air Pollution Control District, typical standby generators produce 25-30 pounds of NOx per megawatt hour of power generated.[67]

Based on this information, the most feasible way for APS to approach a program involving Standby Generation is to analyze the utilization of existing, sited standby generators, similar to the Clean Gen program developed by SDG&E. APS believes that capitalizing upon existing customer-owned generators could provide the company with a significant source of local generation capability; however, the issue of NOx emissions cannot be ignored. Therefore, it is recommended that for this program APS would propose to pay the cost to retrofit the existing customer-owned generators with the latest emission-controlling technology to drastically reduce the emission of NOx into the environment. APS would also pay a portion of the Operation & Maintenance costs, fuel costs, and interconnection costs (if applicable). By doing so, it is anticipated that customer participation could be maximized while minimizing the impact of harmful emissions from these generators.

7.4.4 BENEFIT-COST TEST RESULTS

In order to adequately produce a Benefit-Cost ratio for a Standby Generation program, APS contacted a third-party provider of standby generators. This company also performs retrofits to

[64] *See* "Aggregated Backup Generators Help Support San Diego Grid," Power Magazine (February 2008) and http://www.enernoc.com/resources/EnerNOC_CA_CleanGen_FAQ.pdf.

[65] *See* http://www.maricopa.gov/aq/divisions/planning_analysis/state_implementation_plan.aspx.

[66] *See* http://www.epa.gov/air/ozonepollution/.

[67] *See* http://www.sbcapcd.org/generators.htm. For comparison purposes, Redhawk and Sundance produce 0.07 and 0.20 pounds of NOx per megawatt hour, respectively.

reduce the emissions from standby generators. Based upon this informal discussion, APS was able to determine the approximate cost for retrofitting a 2 MW standby generator, plus the expected O&M costs.[68] Because of the volatility in fuel prices, two cases were run with diesel costs per gallon of $3.50 and $4.50.[69] Finally, the Standby Generation program is being analyzed with a total peak capacity of 50 MW, which the Company feels may be attainable if a program such as this were implemented.

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68 For simplistic purposes, it is assumed that APS would bear all emissions control, O&M and fuel costs.

69 Per the Energy Information Administration's Weekly Retail Gasoline and Diesel Prices website, the average price of diesel on April 14, 2008 was $4.06 per gallon. *See* http://tonto.eia.doe.gov/dnav/pet/pet_pri_gnd_dcus_nus_w.htm.

		Standby Generator Program ($3.50 Diesel)	Standby Generator Program ($4.50 Diesel)
	Participants	29	29
	Expected Reduction (kW) per Customer	1750	1750
	Total Program Size (MW)	50.75	50.75
	Technology Cost per Unit (including installation)	$550,000	$550,000
	Program Development Costs	$50,000	$50,000
	Ongoing Program O&M Costs	Variable (see notes)	Variable (see notes)
	Rebates/Incentives	$0	$0
	Benefits		
(1)	Avoided Capacity	$46.1 M	$46.1 M
(2)	Avoided Energy	$5.8 M	$5.8 M
	Costs		
(3)	Technology	$41.6 M	$45.3 M
(4)	Program Costs	$0.0 M	$0.0 M
(5)	Rebates/Incentives	$0.0 M	$0.0 M
	PAC Test		
(6)	Benefits (1+2)	$51.9 M	$51.9 M
(7)	Costs (3+4+5)	$41.6 M	$45.3 M
(8)	Benefit-Cost Ratio (6/7)	1.25	1.15
	Total Resource Cost Test		
(9)	Benefits (1+2)	$51.9 M	$51.9 M
(10)	Costs (3+4)	$41.6 M	$45.3 M
(11)	Benefit-Cost Ratio (9/10)	1.25	1.15

Note 1 Variable annual fuel and O&M costs apply
Note 2 APS assumes all technology costs and pays for all fuel and O&M
Note 3 Assumes total program size of 50 MW with average load avoidance of 1.75 MW
Note 4 Programs analyzed over a 15 year life

Figure 22

The Benefit-Cost test results indicate that the assumed cost of diesel fuel over the life of the project has an impact on the cost-effectiveness of a Standby Generation program, but from a TRCT standpoint Standby Generation could be beneficial to the APS system. The results for the PAC Test and the TRCT are the same because, under the program design proposal studied, APS would not pay rebates or incentives to the customer; rather, the Company pays for all technology, fuel, and O&M expenditures. Therefore, both tests show the same results.

7.4.5 ESTIMATED EMISSIONS IMPACTS

The estimated emissions impact from a Standby Generation program shows a net increase in emissions for the pollutants that APS was able to get data on. The values for CO and NO_x are based on the new government requirements that all standby generators must meet by 2011.[70] The CO_2 values are estimates based on the current emissions from an example generator. If APS were to pursue a Standby Generation program, more research into the estimated emissions impact would have to be performed.

[70] *See* http://www.cumminspower.com/www/literature/technicalpapers/F-1564-EPAEmissionsRegulations.pdf .

Scenario	Life-Cycle Avoided Emissions					
	CO_2	CO	NO_x	PM10	SO_2	Hg
	tons	lbs	lbs	lbs	lbs	lbs
Standby Generation	(16,282)	(621,045)	(609,740)	N/A	N/A	N/A

Note: Data on PM10, SO2 and Hg for standby generators are not available

Figure 23

7.4.6 RECOMMENDATIONS

The preliminary results of the Benefit-Cost analysis described above indicate that there may be a potential benefit to APS and its customers from pursuing a Standby Generation program in load-constrained areas. Because APS has to date only had informal discussions with one potential vendor in order to assess the costs of undertaking a Standby Generation program, it is recommended at this time that APS conduct additional research over the coming months to better assess the true costs of developing a Standby Generation program. APS will put particular focus on the level of emissions that would be expected and the technology costs of retrofitting these generators with advanced emissions control equipment, as well as APS's ability to call upon the dispatch of these generators in emergency situations, when the customers would otherwise be likely to run the generation on their own initiative. If the results of this additional research indicate that a Standby Generation program may be feasible, the Company will assess whether or not to pursue such a program at that time.

7.5 VEHICLE-TO-GRID TECHNOLOGY

7.5.1 OVERVIEW OF VEHICLE-TO-GRID TECHNOLOGY

V2G technology refers to electric vehicles or PHEVs that can both receive power from and push power back onto the power grid. The two-way plug capability allows a utility to take advantage of the extra electrical storage capacity in the vehicle batteries to meet peak demand, provide grid support services, or respond to power outages. During periods where utilities face high power prices, it may make economic sense to pay commuters to plug their vehicles in while at work, and allow the utility to draw from their batteries. V2G technology has the potential to work as follows:[71]

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[71] *Presentation from Vehicle to Grid Power Analysis Seminar, by Willett Kempton, University of Delaware, at NREL, September 2005.*

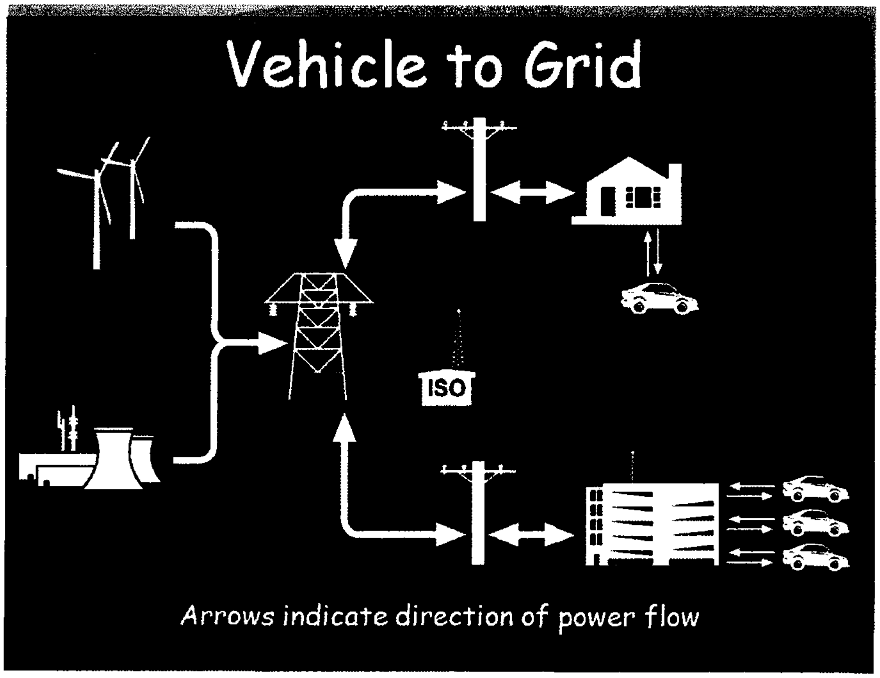

Figure 24

NREL completed a study on the potential effect of PHEVs for Xcel Energy.[72] The NREL Study ran production cost models to simulate the impacts of PHEVs on hourly demand, based on four vehicle charging cases: Uncontrolled Charging, where vehicle owners charge the cars exclusively at home in an uncontrolled manner; Delayed Charging, which is similar to the first case except that the initiation of household charging does not begin until 10pm; Off-Peak Charging, which assumes the utility can exercise some control over the off-peak hours during which the charging occurs to best match with periods of minimum demand; and, Continuous Charging, which assumes that public charging stations are available wherever the vehicle is parked, resulting in the PHEV charging whenever it is not in motion. NREL developed the following conclusions:

- Replacing 30% of the vehicles with PHEVs deriving 39% of their miles traveled from electricity resulted in an increase in total load of less than 3%;
- A large penetration of PHEVs place increased pressure on peaking units if charging is completely uncontrolled;
- Modest attempts to optimize charging results in no additional capacity requirements;
- On Xcel's system, natural gas is used for marginal generation most of the time, resulting in natural gas prices driving the cost of PHEV charging.

There are currently no PHEVs available for purchase in the United States, with the exception of one company that makes PHEV school buses. There are, however, several car manufacturers

[72] *Costs and Emissions Associated with Plug-In Hybrid Electric Vehicle Charging in the Xcel Energy Colorado Service Territory*, K. Parks, P. Denholm, and T. Markel, NREL, May 2007 ("NREL Study").

that plan on releasing PHEVs as early as 2010. Toyota has one PHEV certified for use in Japan. An overview of the development of PHEVs is included in the table below:[73]

Automaker	Description and summary of official statements	Status of production
AFS Trinity	Prototype of lithium battery + supercapacitor combination for licensing by carmakers	With Ricardo, three prototype conversions of Saturn Vue mild hybrid
Aptera	Futuristic lightweight $30,000 3-wheel vehicles in development	Taking deposits on hybrid version to follow electric version in 2009.
Audi	Volkswagen-owned company exploring PHEVs	Metroproject Quattro Sub-compact PHEV Concept Car shown October 2007
BYD	BYD Automobile Company, Shenzhen, China	Plan F6DM $20-$30,000 PHEV with 60-mile range for sale in China late 2008
Chrysler	Chrysler launching electric vehicle division	Renegade/Zeo/Eco-Voyager concept cars
DaimlerChrysler	Joint DaimlerChrysler program managed by Daimler after separation of companies	Several dozen PHEV prototypes on 15-passenger Sprinter van since 2004 (nickel-metal and lithium); no production commitment.
Fisker	Partner with Quantum Technologies for $100,000 PHEV	Taking deposits for small production runs in 2009 and 2010.
Ford	Five to 10 years away. Small long-term evaluation program, including modeling of vehicle-to-grid benefits and economics, with Southern California Edison. Batteries not ready.	First Escape PHEV delivered to SCE Nov 2007; 20 in 2008-2009. (Several after-market companies have done PHEV conversions of the Ford Escape -- see Where PHEVs Are.)
General Motors	Saturn Vue PHEV and Chevy Volt series PHEV, which it calls "extended range electric vehicle" (EREV), part of "E-Flex" multi-fuel platform. Intends to be first. For Volt, insists on high 40-mile electric-only range /lifetime battery/affordability criteria.	Aims to get Saturn Vue on road in 2010; no production goal. Aims for 30-60,000 Volts in first year with late 2010 goal to begin production. Now bench-testing first prototype battery packs.
Honda	Sees PHEVs as having "unnecessary fuel engine and fuel tank; promises all-electrics "assuming we can come up with a really high-performing battery that we are working on currently." Doubts PHEVs have environmental benefits.	No known plug-ins being planned or on the road.
Hyundai	Studying the idea.	No known plug-ins being planned or on the road.
Nissan	Adding PHEVs to "development program," but says it intends to build all-electrics not PHEVs.	No known plug-ins being planned or on the road.
Rocky Mountain Institute	Nonprofit group aims to spin off commmercial venture to build lightweight PHEVs, successor to late 1990s "Hypercar" concept.	No schedule announced.
Saab	GM-owned company exploring PHEVs	Joint Venture with Volvo and others to research PHEVs
Toyota	Agrees on environmental and economic benefits; says batteries need further development before a commitment to mass-production. Says demand and whether people will plug in remain to be proven.	Beginning with road-testing of a dozen "Plug-in HV" Prius PHEVs in the US and Europe, will produce at least 400 leased demonstration vehicles for commercial fleet owners in 2009-2010. Promise production by 2010 at the latest. (Several aftermarket companies and organizations have converted about 150 Priuses -- see Where PHEVs Are.)

[73] Taken from CalCars website: www.calcars.org/carmakers.html on June 20, 2008.

Venture Vehicles	3-wheel vehicle in development.	No schedule announced.
Visionary Vehicles	Team w/Malcolm Bricklin (who brought the Subaru and the Yugo to America) is "starting to build the prototype."	Plans to bring a series PHEV to market in 2010.
Volkswagen	Lead engineer wants release from requirement to build hydrogen fuel cell vehicles.	Space Up! Blue Concept PHEV Van with diesel or hydrogen fuel cells and rooftop photovoltaic.
Volvo	Ford-owned company exploring PHEVs	"ReCharge" flex-fuel series 60-mile concept PHEV w/wheel motors. Joint Venture with Saab and others to research PHEVs.

PG&E is currently researching the use of PHEVs for regulation and peak load management in partnership with Tesla Motors.[74] The companies plan to study V2G technology and smart charging, which allows remote access to the vehicle's charging power level via communication with the utility.

7.5.2 RECOMMENDATIONS

Due to the lack of commercially available PHEVs, an APS-sponsored V2G program is not currently feasible. However, the Company plans to continue monitoring V2G efforts nationwide and will look into the possibility of starting V2G testing at such time as there is proven technology available to APS and its customers.

[74] *See* http://www.teslamotors.com/media/press_room.php?id=667.

8. TIME-DIFFERENTIATED RATES

8.1 OVERVIEW OF TIME-DIFFERENTIATED RATES

Time-Differentiated Rates encompass all rate designs that contain multiple rate levels dependent upon the time of the day energy is consumed. These rate designs can be fixed in nature, where the customer knows that for certain times of each day their rate will be a specific amount higher than other times of the day. Alternatively, Time-Differentiated Rates can fluctuate hour-by-hour, or can increase subject to certain predetermined criteria (such as transmission system emergencies). As discussed earlier in the Study, APS has a long history of offering customers Time of Use rates. In addition, there are two new rate schedules before the Commission in the pending rate case filed in Docket No. E-01345A-08-0172.[75] Final approval of these rates would occur at the time the Commission makes a final determination on the general rate case. This section of the report will serve to provide a brief summary of the two proposals contained in that rate case filing.[76]

8.2 RESIDENTIAL SUPER PEAK RATE

The Company is proposing a new Residential TOU rate that contains a Super Peak period during the most critical summer hours. This rate will be similar to the ET-2 rate plan that has a seven hour on-peak period (Noon to 7pm). During the months of June through August, however, this new rate plan (currently named ET-SP) will have a Super Peak period from 3pm to 6pm on non-holiday weekday afternoons. The Super Peak period will be priced substantially higher than the current on-peak period rate. This will be offset by reduced charges for the off-peak period. The graph below compares ET-SP to the proposed ET-1 and ET-2 rates:

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[75] The Company has also filed a proposal to divide its main General Service rate, E-32, as well as the TOU option E-32-TOU, into four separate groupings based on customer peak demand.

[76] *See* Direct Testimony of Charles A. Miessner, Docket No. E-01345A-08-0172 (June 2008).

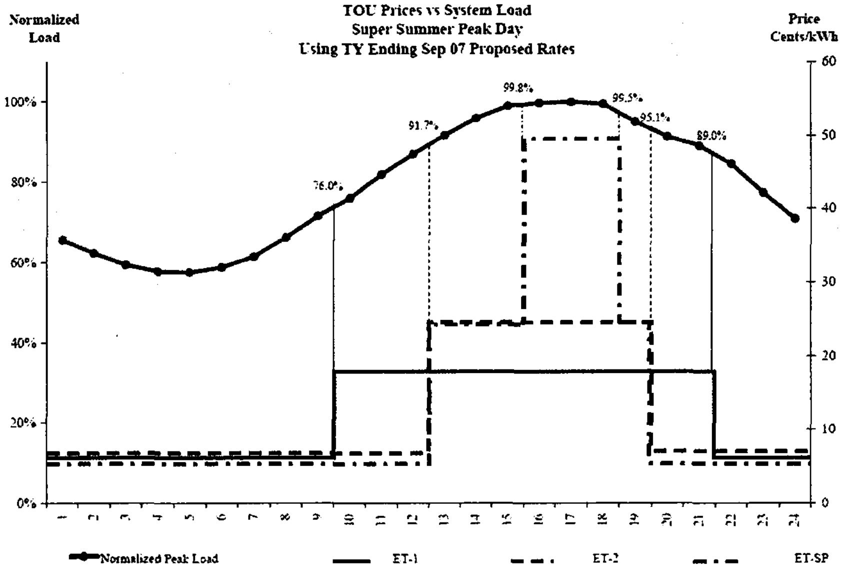

Figure 25

The Normalized Peak Load line portrays the typical load shape for a Residential customer. Rate Schedule ET-SP is designed to meet the top 0.5% of customer demand, whereas the current Rate Schedule ET-2 covers the top 9% of customer demand with one rate. This program, if approved, would be available to any Residential customer currently served by an AMI meter.

8.3 CRITICAL PEAK PRICING PILOT PROGRAM

CPP programs are TOU rate plans that provide an extremely high price signal during a limited number of critical hours on critical days. The customer is notified a day in advance when a critical day will occur and for which hours the event will cover. During those hours, customers must respond by reducing consumption to avoid paying the increased price.

APS is proposing a CPP pilot program for general service and irrigation customers in the general rate case. The pilot would be limited to 100 participants and would last for two years. Each customer must have the ability to reduce demand by at least 200 kW and have interval metering (but not, necessarily, AMI) in order to participate. The pilot program would allow the company to call up to 18 CPP events spanning five hours each (2pm to 7pm) during the summer months of June through September for a total of 90 hours each year. During those 90 hours, participants would be charged an incremental $0.400 per kWh. To offset this increased charge, customers would receive an energy discount of between $0.011755 and $0.014892 per kWh for all consumption during the months of June through September, regardless of any events being called.[77]

[77] The energy discount is dependent upon which rate schedule the participant is currently served under.

8.4 REAL-TIME PRICING

RTP programs utilize prices that fluctuate hourly rather than being fixed far in advance. Utilities tend to post these prices on a day-ahead basis, and are either applied to a customer's total usage or to deviations in usage from an established customer usage baseline. In reviewing different rate concepts prior to the filing of the aforementioned rate case, RTP appeared to be less beneficial to APS customers than the two other Time-Differentiated Rate programs previously discussed; however, APS will continue to monitor industry experience in this area. RTP tends to be more expensive to implement and is better targeted to C&I customers who can manage their usage to reduce the risks of hourly fluctuations in prices. RTP programs are also better suited for utilities with highly variable hourly energy prices with a highly liquid and transparent hourly market, and based on the research performed prior to the rate case filing, are generally less effective in reducing peak load than either CPP or TOU.

9. GLOSSARY

Advanced Metering Infrastructure ("AMI"): Metering system that records customer consumption at least hourly and that provides for frequent bi-directional communications and transmittal of measurements over a communication network to a central collection point. AMI system firmware is remotely upgradeable and extends the utility's network, providing a wireless Home Area Network at the customer site.[78]

Critical Peak Pricing ("CPP"): Time-of-Use rate plans that provide an extremely high price signal during a limited number of hours on critical days.

Curtailable/Interruptible Load: Demand Response programs where the participant agrees to firm load reduction when notified by the utility, many times on very short notice. These programs typically involve a separate contract between the utility and the customer, often embodied in a tariffed rate filed with the state Commission.

Customer Load Response: Demand Response programs where the customer takes action on their own initiative.

Cycling Strategy: The percentage of an air conditioning unit's expected run-time that will be reduced to effectuate a reduction in household demand.

Demand Bidding/Buyback ("DBB"): Programs in which the utility encourages customers to reduce loads by bidding a load reduction amount to the utility in exchange for a payment.

Demand Response ("DR"): Mechanisms designed to provide incentives to customers to reduce their load in response to prices, market conditions, or threats to system reliability.

Demand-Side Management ("DSM"): The planning, implementation, and monitoring of activities designed to encourage consumers to modify patterns of electricity usage, including the timing and level of electricity demand.[79]

Direct Load Control ("DLC"): Demand Response programs where the utility or a third-party contractor can remotely control customer-specific loads and reduce or cycle the energy consumption for a specified period of time.

Load Duration Curve ("LDC"): A graph that sorts a utility's load from highest consumption hour to lowest consumption hour, rather than chronologically.

Load Management: A utility's deliberate action to reduce peak demand or improve operating efficiency.

Nonattainment Area: Any area that does not meet (or that contributes to ambient air quality in a nearby area that does not meet) the national primary or secondary ambient air quality standard for a specific pollutant.[80]

Plug-in Hybrid Electric Vehicle ("PHEV"): A hybrid vehicle (running on both battery storage power and gasoline) that can be plugged into a normal 120-volt household electrical outlet for charging instead of charging from the gasoline-powered engine like current hybrid vehicles.

Program Administrator Test ("PAC Test"): An economic evaluation test that reviews the benefits and costs of a potential program that the administrator (i.e., the utility) would bear. This test does not take into account any net benefits to society from implementing the proposed program.

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[78] Taken from Federal Energy Regulatory Commission, "Assessment of Demand Response and Advanced Metering: 2007" (September 2007) at p. A-1.

[79] *Id.* at p. A-3.

[80] *See* http://www.epa.gov/oar/oaqps/greenbook/define.html.

Real-Time Pricing ("RTP"): Retail pricing program where the utility's costs for generation fluctuate on an hourly basis rather than being fixed in advance.

Roundtrip Efficiency: The roundtrip efficiency of an energy storage system is the product of the recharge efficiency (the ratio of energy stored divided by the total amount inputted into the storage system) and the discharge efficiency (the ratio of the energy delivered to the application divided by how much was stored). For example, if a battery recharge system efficiency is 80% (including losses thru the AC/DC power conversion equipment) and the battery discharge efficiency is 90%, then the roundtrip efficiency calculation is: 80% x 90% = 72%.

Scheduled Load Management ("SLM"): A class of Demand Response programs that require pre-planned load reductions on behalf of the customer.

Snapback Effect: The amount of energy that was not consumed during the Demand Response event that will still be consumed, either from pre-cooling or process shifting before the event or additional air conditioning runtime after the event. The Snapback Effect is what distinguishes Demand Response from Demand-Side Management, where energy is permanently reduced from efforts taken by the utility and/or consumer.

Societal Cost Test ("SCT"): A variation of the Total Resource Cost Test that attempts to extend the quantification of benefits and costs to society as a whole, rather than just the customers for a given utility.

Standby Generation: Customer-owned generation resources, typically diesel- or gas-fired, that provide customers with a guaranteed source of power in the event that either power quality or reliability issues occur with their local utility.

Super Peak Rate: A fixed rate tariff that values a subset of hours in the day much higher than other hours in the day. The super peak period is typically a subset of the on-peak hours in the day where the utility's demand is highest.

Switch: A remote-controlled device similar to a circuit breaker that can temporarily turn off and on an appliance at a customer site.

Thermal Energy Storage ("TES"): TES systems utilize a storage medium, such as chilled water or ice, that is "charged" during off-peak hours and then used as the cooling energy source during on-peak hours, offsetting the need to operate high-demand refrigeration equipment.

Time-Differentiated Rates – also referred to as Time-of-Use ("TOU"): Rate plans that have different tiered prices based on the time of day, day of week, or season in which the customer consumes power.

Total Resource Cost Test ("TRCT"): An economic evaluation test that measures the net costs of a potential program as a resource option based on the total costs of the program, for both the utility as well as the participant. The effects of the program are quantified for both participants and non-participants, under the assumption that all customers receive a benefit from the participation of a subset of customers.

Vehicle-to-Grid ("V2G") Technology: Plug-in Hybrid Electric Vehicles or electric vehicles that can both receive power from and push power back onto the power grid.

10. REFERENCES

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TABLE OF ACRONYMS

A/C: Air Conditioning
ACC: Arizona Corporation Commission
AMI: Advanced Metering Infrastructure
APS: Arizona Public Service Company
Auto-DR: Automated Demand Response
C&I: Commercial & Industrial customers
CC: Combined Cycle
CEC: California Energy Commission
CO: Carbon Monoxide
CO_2: Carbon Dioxide
ComEd: Commonwealth Edison
Commission: Arizona Corporation Commission
Company: Arizona Public Service Company
CPP: Critical Peak Pricing
CT: Combustion Turbine
DBB: Demand Bidding/Buyback
DG: Distributed Generation
DLC: Direct Load Control
DOE: Department of Energy
DR: Demand Response
DRCC: Demand Response Coordinating Committee
DSM: Demand-Side Management
EHV: Extra High Voltage
ELCC: Effective Load Carrying Capability
EMCS: Energy Management Control Systems
EPRI: Electric Power Research Institute
FERC: Federal Energy Regulatory Commission
FP&L: Florida Power & Light
HECO: Hawaiian Electric Company
Hg: Mercury
HVAC: Heating, Ventilation, and Air Conditioning
IDR: Interval Data Recorder
ISAC: Ice Storage Air Conditioning
ISO: Independent System Operator
kW: Kilowatt
LBNL: Lawrence Berkeley National Laboratory
LDC: Load Duration Curve
LM: Load Management
M&V: Measurement & Verification
MHz: Megahertz
MW: Megawatt
NaS: Sodium Sulfur
NOx: Nitrogen Oxide
NPV: Net Present Value
NREL: National Renewable Energy Laboratory
NYSERDA: New York State Energy Research and Development Authority

O&M: Operation & Maintenance
PAC Test: Program Administrator Test
PEC: Progress Energy Carolinas
PG&E: Pacific Gas & Electric
PHEV: Plug-in Hybrid Electric Vehicle
PM10: Particulate Matter
Portland: Portland General Electric
PPA: Power Purchase Agreement
PSB: Polysulfide Bromide
RES: Renewable Energy Standard
RFP: Request for Proposal
RTO: Regional Transmission Operator
RTP: Real-Time Pricing
SCE: Southern California Edison
SCT: Societal Cost Test
SDG&E: San Diego Gas & Electric
SLM: Scheduled Load Management
SMUD: Sacramento Municipal Utility District
Snapback: Snapback Effect
SO_2: Sulfur Dioxide
STAR Center: APS Solar Test and Research Center
STEP: APS Storage of Thermal Energy for the Peak Program
Study: Demand Response & Load Management Program Study
Summit Blue: Summit Blue Consulting
TES: Thermal Energy Storage
TOU: Time-of-Use
TRCT: Total Resource Cost Test
V2G: Vehicle-to-Grid
ZnBr: Zinc Bromide

ATTACHMENT II

ATTACHMENT II
Arizona Public Service Company
Demand Response Compliance Filing
Docket No. E-1345A-05-0816

Commercial & Industrial Load Management Program

Direct load control programs would be the most advantageous resource options for Arizona Public Service Company ("APS" or "Company") to pursue as it begins developing a Demand Response ("DR") portfolio. These resources are likely to be prudent initial investments, as indicated by the successful implementation and operation of such programs in other states. Direct load control can be cost effective and can have material peak demand impacts. Commercial and industrial ("C&I") load management programs would offer commercial and industrial customers an incentive when they participate to limit system peak demand. APS has determined that a "turn-key" or "aggregator" business model, where a third party DR aggregator would guarantee a certain number of megawatts during specified times, is most advantageous under current circumstances. Given that APS does not currently have an existing infrastructure for administering a DR program and providing the necessary technical assistance, contracting with an experienced aggregator would enable the most expeditious ramp-up of curtailable load. The Company believes that an experienced aggregator will be able to address customer concerns and integrate load control technology, which should assure high customer satisfaction levels.

With a turn-key program, APS would be purchasing dispatchable capacity, which is similar in structure to a capacity call option contract, making it comparable to a conventional supply-side resource. Outsourcing for a guaranteed quantity of DR capacity also ensures that APS would pay a known price per megawatt, as opposed to the uncertain economics of developing a new program. In addition, APS would only pay for verified capacity reductions and, as such, the risk of program performance shifts to the aggregator. The aggregator would also be responsible for marketing the program using APS-approved marketing materials, installing and maintaining all equipment, and tracking and reporting program results. APS or a contracted, independent third party would perform measurement and verification of event load reductions and customer satisfaction.

Search for Best Vendor: Request for Proposal

In October 2007, APS issued a Request for Proposal for C&I DR programs ("DR RFP") with guaranteed verifiable demand reductions. The DR RFP specified the scope and parameters for the DR proposals, as described below:

- Turn-key proposal where the respondent would be responsible for customer marketing, recruiting and services; communication protocols; product installation, operations and maintenance; and measurement and verification.
- Minimum load management size: 10 megawatts. The proposals sought required availability during the summer months of May through September; APS did entertain

proposals for other durations. Load reductions are required to be in effect no later than 24 hours after APS notification of a demand reduction event.

- Operation must begin no later than May 1, 2010, and can ramp up over time.
- Respondent must provide on-going real time data on availability and event performance to APS.
- Any customer included in respondent's offering must be an APS C&I customer physically located within either the Greater Phoenix Metropolitan load area or the Yuma load area.

Proposals Received & On-going Negotiations

The Company received proposals in December 2007 from multiple vendors. There was wide variation in the proposals received, including phased-in capacity, with a range of two to forty megawatts in 2009, and increasing to a maximum of approximately 200 megawatts by 2013. The number of anticipated customers participating in the programs varied widely, from 100 to over 10,000. Proposed contract durations ranged from five to fifteen years. The proposals included maximum callable hour limits between forty and one hundred hours during peak load times.

Currently, the Company has on-going contract negotiations with the short-list of vendors. The Company's emphasis in these negotiations – pursuant to Decision No. 69663 – is to develop a cost-effective program that is most beneficial to both customers and the APS electric system. As a result, the Company is rigorously negotiating for clear measurement, verification and performance requirements, including customer service metrics.

Until negotiations have been successfully completed, there remains uncertainty as to the specific parameters of the C&I DR program, such as the size, scope, and term of the program. Upon successful negotiation for a cost-effective program, the Company will supplement this filing with detailed program parameters for approval. Because negotiations are on-going, it is currently unknown whether proposals will be cost-effective; however, in the event that the current negotiations for a C&I DR program are not fruitful, the Company will file an alternative plan for DR.

Supplemental Filing

APS anticipates that contract negotiations will end soon. Assuming those discussions are successful, the Company will supplement this filing with specific information, including program parameters and costs. The Company is optimistic that the result will be a viable C&I DR program that is cost-effective and benefits both customers and the APS electric system. APS believes that the Demand Side Management Adjustment Clause ("DSMAC"), which was approved in Decision No. 67744,[1] is the appropriate mechanism to recover program costs for the C&I Load Management program, including contract costs and program implementation, operational and management costs, and performance incentives.

[1] Issued April 7, 2005, Docket No. E-01345A-03-0437.