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BEFORE THE ARIZONA CORPORATION COMMISSION

AZ CORP COMMISSION

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IN THE MATTER OF THE COMPETITION IN THE PROVISIONS OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA	))))	DOCKET NO. E-01032C-98-0474 **NOTICE OF FILING**

Citizens Utilities Company hereby provides Notice of Filing its Appendices for Stranded Cost Options and Implementation Plan which was filed on Friday, August 21, 1998.

RESPECTFULLY SUBMITTED this 24th day of August, 1998.

Arizona Corporation Commission
DOCKETED
AUG 2 4 1998
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APPENDIX A

APPENDIX A

Calculation of Generation Stranded-Costs

As overviewed in Section II, there are three key elements of generation-related stranded costs for which Citizens is seeking recovery. These include the stranded costs associated with: the Power Service Agreement with APS; the Power Purchase Agreement with APS; and the Mohave County transmission investments. Also addressed are additional generation-related stranded costs. Each of these is addressed in turn below.

A. Power Service Agreement

Citizens and APS have a long-standing business relationship in power supply dating back over 25 years. The current APS Contract supercedes a number of prior power supply agreements that the companies have executed, amended, and renegotiated over this period. The current APS Contract is the result of a re-negotiation process brought to closure in June of 1996 that has resulted in significant savings to Citizens' customers. Today, Citizens is essentially a full-requirements customer of APS for its power supply needs.

The APS Contract consists of a main agreement which dictates the overall terms of the contract, three power delivery schedules (Schedules A, B, and C), and a Resource Integration contract that deals with the future terms and conditions when and if a peaking power plant were built in Mohave County to serve Citizens' loads ("Mohave CT"). As described in the following subsection, it is Citizens' intent to cancel the agreement underlying the construction of the Mohave CT and therefore, the latter Resource Integration contract does not play a part in Citizens' stranded cost exposure. However, Schedules A, B and C all have aspects that create stranded costs as a result of the introduction of open access. In brief, the provisions of the three schedules are as follows:

Schedule A – This is a baseload contract providing 100 MW of capacity and energy at 100% load factor. The effective term of the contract extends until 2011. Nominal pricing is $19.54/kW-mo and $.0145/kWh. Citizens is obligated to take or pay for 100% of the capacity (plus losses) under the contract, regardless if fully utilized.

Schedule B – This is an intermediate supply resource providing the majority of energy requirements of Citizens' customers over and above Schedule A deliveries. The nominal contract term extends through the end of 2002, but the contract can be cancelled by either party on one year's notice. Nominal pricing is currently $4/kW-month and the lower of APS' incremental cost plus 15% or the market price plus 15%.

Schedule C - This schedule provides peaking energy against the capacity of Citizens' Valencia combustion turbines (approx. 47 MW). The term of the contract continues indefinitely and either party can gives a two-year notice of cancellation.

To estimate the stranded cost exposure of the APS Contract, Citizens secured the services of Stone & Webster Management Consulting, Inc. ("Stone & Webster") to forecast the market price for power delivered into Citizens' Arizona service areas and the resulting stranded costs associated with Schedule A. In the immediate following subsections is a summary of the analysis performed by Stone &Webster.

1. Methodology

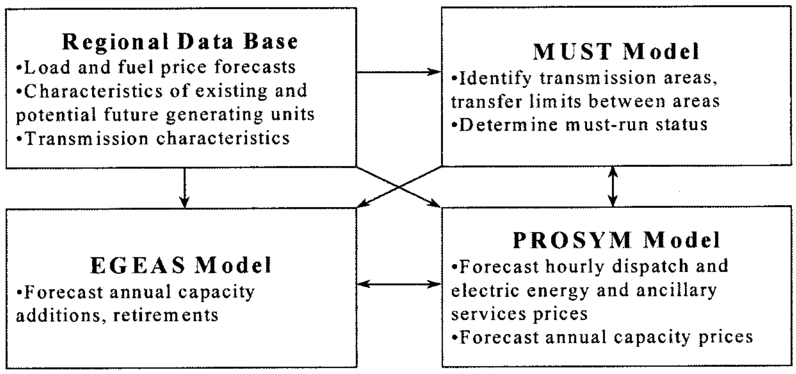
Retail competition has not yet been implemented in Arizona, and the market structure that will emerge after it is introduced is not fully clear. It is reasonable to assume, however, that whatever market structure is eventually adopted in Arizona, the stranded costs associated with a power purchase agreement or a generating unit in a competitive market can be forecast reasonably by modeling the project as if it competes in a mandatory power exchange, such as the one currently operating in California. In such an exchange, generation owners bid supply prices and quantities, load-serving entities bid demand prices and quantities, and market-clearing prices are determined as the prices that equate demand and supply. Typically, such an exchange holds an auction for energy for each hour of the following day, as well as ancillary services on a daily, monthly, or annual basis. It may also hold a similar auction for capacity, if a reserve margin is maintained in the region.

To estimate the stranded costs associated with the APS contract and construction of the Mohave CT, Stone & Webster adopted this approach. The approach was implemented by performing five primary activities, which are summarized in the following paragraphs. The first four steps are also represented by the four boxes in Figure A-1.

2. Develop Data Base

The Citizens Arizona service territory is located within the Western Systems Coordinating Council ("WSCC"), one of the nine North American Electric Reliability Council ("NERC") regions. The WSCC comprises all or nearly all of New Mexico, Arizona, California, Nevada, Utah, Colorado, Wyoming, Montana, Idaho, Oregon, Washington, British Columbia, and Alberta, as well as portions of Mexico. Previous experience and preliminary results from the transmission system analysis suggested that the prices that would be paid to the proposed project in a competitive market would depend on loads, resources, fuel prices, and transmission facilities throughout the WSCC. It was therefore necessary to assemble a data base containing the data listed in the upper left-hand box of Figure A-1 for the entire WSCC. The required data were obtained or developed from the following sources:

Figure A-1. Technical Approach



- Load forecasts – Obtained from Henwood Energy Services, Inc. (HESI), based on utility filings. Loads in the WSCC as a whole are forecast to increase an average of 1.6% per year during the 1998 – 2010 period. Peak loads in the Citizens Arizona transmission area, the primary area of concern, are forecast to increase an average of 3.7% per year during this period, while annual energy consumption is forecast to increase an average 4.3% per year during the period.

- Fuel price forecasts – Prices for coal and oil at each station were forecast as the average 1997 price paid at the station, escalated at 2.5% per year for coal and 3.0% per year for oil. These escalation rates are based on the latest price forecasts from the U.S. Department of Energy, Energy Information Administration. Prices for gas were forecast for each state, using 1997 average prices paid by generating units in the state as the base, and escalating at a rate that varies over time but averages 2.8% per year over the 1998 – 2010 period. The escalation rates were developed from forecasts developed by the U.S. Department of Energy, Energy Information Administration; Data Resources, Inc.; the American Gas Association; and the Gas Research Institute.

- Characteristics of existing generating units – Obtained from HESI, based on utility filings.

- Characteristics of potential future generating units – Extracted from internal Stone & Webster data base. New combustion turbine units are assumed to have an all-in capital cost of $385/kW in 1998, increasing 3% per year.

Units built prior to 2005 are assumed to have a heat rate of 10,338 Btus/kWh; units built in 2005 and later are assumed to have a heat rate of 9,798 Btus/kWh. New combined cycle units are assumed to have an all-in capital cost of $575/kW in 1998, increasing 3% per year. Units built prior to 2005 are assumed to have a heat rate of 6,987 Btus/kWh; units built in 2005 and later are assumed to have a heat rate of 6,748 Btus/kWh. Heat rate penalties caused by temperature and altitude were not imposed.

- Transmission characteristics – Obtained from Power Technologies, Inc. (PTI), based on utility filings.

3. Develop Capacity Forecasts

Using the data base developed in the first activity, Stone & Webster used the Electric Generation Expansion Analysis System (EGEAS) to forecast the existing generating units that would be retired for economic reasons (i.e., in addition to planned retirements) in each year and the characteristics of new units that would be brought into service in each year (i.e., size, technology, heat rate, operating costs) in the WSCC during the 1999 – 2010 period. Capacity additions in the WSCC were allocated to the transmission areas based on the location of the retired units and relative rates of load growth. EGEAS is a state-of-the-art model developed and maintained by Stone & Webster for the Electric Power Research Institute, that forecasts capacity additions and retirements that will occur in competitive markets. The model retires existing units that are not profitable to continue operating, and adds units that are profitable to operate. In addition to the data base assembled in the first activity, key inputs to this activity were:

- Capital structure for new units – 50/50 debt/equity split; 8% interest rate on debt for 20 years; 18% after-tax return-on-equity.

- WSCC-wide reserve margin – 10%

4. Identify Transmission Areas and Transfer Limits

Stone & Webster used the Managing and Utilizing System Transmission (MUST) model to identify transmission areas within the WSCC and determine the power transfer limits between transmission areas. Transmission areas were defined as geographic areas a) within which transmission constraints would not affect transfers, and thus prices; and b) between which transmission constraints would at least occasionally limit transfers, and thus cause prices to differ. MUST is a state-of-the-art simplified load flow model developed by Power Technologies, Inc. (PTI) that Stone & Webster is licensed to use.

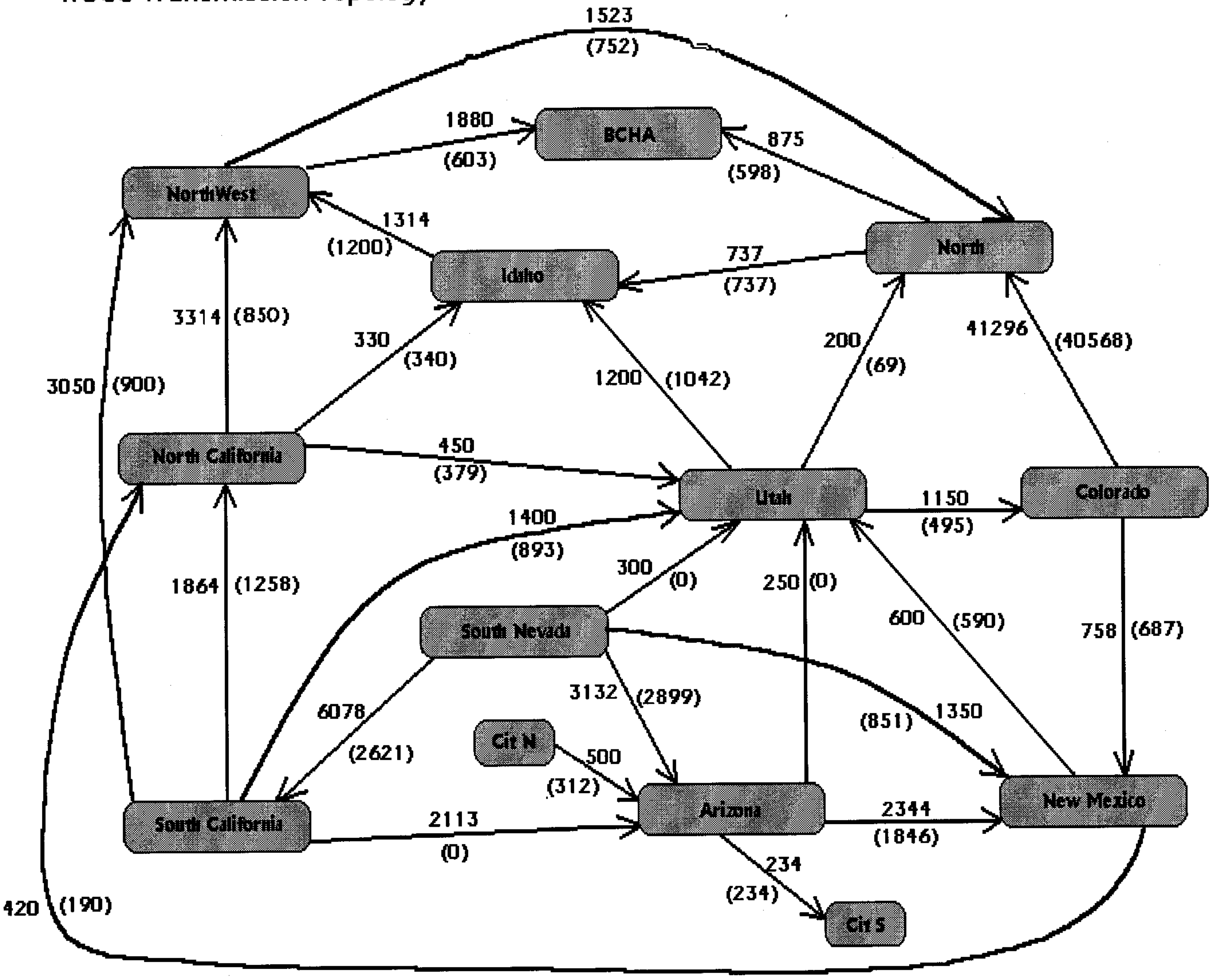
The results of this activity are displayed in Figure A-2. With the exception of the limits in and out of the two Citizens transmission areas, the transfer limits displayed in Figure A-2 are net of existing firm transactions. Values in parentheses are the limits in the direction opposite the arrow. For Citizens Arizona, the most important elements of the transmission system topology presented in Figure A-2 are as follows:

- Thirteen transmission areas were identified. Most of the area borders correspond to state borders, except that Arizona is divided into three areas, California into Northern (including Northern Nevada) and Southern areas, Nevada into Southern and Northern areas (included in Northern California), Washington and Oregon are combined into a single area (called Northwest), Montana and Wyoming are combined into a single area (called North), and the Canadian provinces are combined into a single area (called BCHA).

- Arizona is divided into three areas – Citizens North, comprising the Citizens' territory in Mohave County; Citizens South, comprising the Citizens' territory in Santa Cruz county; and the remainder of Arizona.

1.

Figure A-2
WSCC Transmission Topology



- The Citizens North and Citizens South transmission areas are each connected directly only to the Arizona transmission area. The transfer limits to Citizens North is 500 MW (from Citizens North) and 312 MW (to Citizens North); the transfer limit to Citizens South is 234 MW in both directions.

5. Develop Hourly Electric Energy Prices

Using the data base developed in the first activity, the transmission system mapping developed in the second activity, and the capacity forecasts developed in the third activity, Stone & Webster used the PROSYM model to forecast the market-clearing prices for electric energy that would be paid to generation owners in each hour of each year in each of the transmission areas identified in the second step; as well as forecasts of hourly output by each generating unit and annual energy-market revenues and operating expenses for each generating unit. PROSYM is a state-of-the-art chronological production simulation model developed by HESI that Stone & Webster is licensed to use. The model dispatches units based on their marginal costs, and calculates the price in each hour as the marginal cost of the most costly unit included in the dispatch. Marginal cost in this analysis includes fuel and variable O&M costs, plus start-up and shut-down costs and no-load costs, and reflects the effects of minimum up and down times and ramp rates. In determining the dispatch in a particular transmission area, the model considers exports and imports with other areas up to the transfer limits identified in the second step.

Finally, the PROSYM results were used to forecast the annual capacity price that would be paid to all owners of generating units. Such payments are required to supplement the revenues earned in the energy market, in order to motivate enough capacity to remain in the market (i.e., not retire) or enter the market. Stone & Webster forecast the capacity price, measured in dollars per kW-year, as the amount required to be paid to the last unit (i.e., the one with the largest financial losses per kW of capacity) to make it break even. For existing units, losses are defined as energy-market revenues less fuel, variable O&M, and fixed O&M expenses; for new units, losses also include recovery of capital costs.

6. Calculate Stranded Costs

The results of step 4 were used to estimate the annual revenues that Citizens Arizona could earn by selling the power purchased under the Arizona contract. These revenues were then compared to the annual payments Citizens must make to APS under the contract to calculate the annual stranded costs associated with the contract. In addition, as part of step 4, the annual revenues associated with sale of the output of the Mohave CT were calculated. In this step, these revenues were combined with the payments Citizens must make to APS under the contract to calculate annual stranded costs associated with completion of the CT.

An important aspect of the Stone & Webster approach displayed in Figure A-1 is the iteration between EGEAS and PROSYM on the one hand and MUST and PROSYM on the other. The initial PROSYM results from the fourth activity were input into EGEAS, which was re-run to determine if 1) any of the units that had been retired might, in fact, be profitable, so that they should not be retired; 2) any units not previously retired would be unprofitable, and should be retired; 3) any of the units added by EGEAS would not be profitable, and therefore should not be added; and 4) any additional units, on top of those identified by EGEAS, should be added. PROSYM was then re-run with the revised capacity forecast.

Typically, the dispatches from the final PROSYM run were input to MUST to insure that they were feasible from a transmission standpoint. Due to schedule constraints, this step was not performed. However, based on our experience, we are confident that performing this step would not have changed the price forecast for the two Citizens' transmission areas or the dispatch of units within these two transmission areas.

a) Results

Table A-1 lists the existing units that were forecast to be retired prior to their planned retirement dates because they were unprofitable. Throughout the WSCC, 4,897 MW are forecast to be retired for economic reasons, prior to their planned retirement dates. Stone & Webster expects that these retirements will occur in the first few years following the onset of retail competition in the affected states, when the guarantee of full cost recovery is removed. For convenience, the retirements are spread over the 1999 - 2004 period.

Table A-1. Retirement Analysis

Year Retired	Unit Name	Capacity (MW)	TransArea Name
2003	Humboldt	105	Northern California
2003	Hunters Pnt	270	Northern California
2004	SONGS	2,150	Southern California
2000	Small COG	15	Southern California
2002	Valley	323	Southern California
1999	Kettle Falls	47	Pacific Northwest
1999	Rathdrum GT	88	Pacific Northwest
2002	Clark ST	139	Area
2002	Reid Gardner	330	Area
1999	Little Mtn GT	13	Utah Area
2003	Irvington	423	Arizona
1999	Ben French	44	North Region
1999	Neil Simpson	35	North Region
1999	Osage	10	North Region
2001	Arapahoe	246	Colorado Area
2001	Pawnee	495	Colorado Area
2001	Valmont	178	Colorado Area

Table A-2 summarizes the forecast of capacity additions. A total of 18,577 MW of new capacity is forecast to be installed in the WSCC between 2000 and 2010. Note that the forecast includes the 500-MW combined cycle unit that has been announced in Mohave County, Arizona (i.e., in the Citizens North transmission area), as well as the 77-MW CT specified in the APS-Citizens contract. The 77-MW CT, in fact, is the only CT forecast to be installed in the WSCC during this period. There were no additions forecast for the Arizona, Citizens South, New Mexico, Utah, Colorado, Idaho, or Northwest transmission areas.

Year	Unit Type	Unit Size (MW)	TransArea
2000	CC	1,000	Southern Calif.
2000	CC	500	Citizens North
2001	GT	77	Citizens North
2001	CC	1,000	North
2002	CC	1,000	Southern Calif.
2002	CC	1,000	Southern Calif.
2002	CC	1,000	Southern Nevada
2003	CC	1,000	Northern Calif.
2004	CC	1,000	Southern Calif.
2004	CC	1,000	Southern Calif.
2005	CC	1,000	Southern Calif.
2005	CC	1,000	BCHA
2006	CC	1,000	North
2006	CC	1,000	Southern Calif.
2007	CC	1,000	Southern Calif.
2007	CC	1,000	Northern Calif.
2008	CC	1,000	Northern Calif.
2009	CC	1,000	BCHA
2009	CC	1,000	North
2010	CC	1,000	Southern Calif.

As discussed above, PROSYM was used to forecast electric energy prices in every hour of the years 1999 - 2010 for each of the identified transmission areas. Table A-3 provides a summary of these forecasts, by year and transmission area, for the base case, in which the Mohave CT is constructed. Each price is the simple, unweighted average of the 8,760 hourly prices paid, in $/MWh, to generators in the area and year pertaining to the price, i.e., the average energy price paid to a generator with a 100% capacity factor. The last row of the table displays the annual capacity prices paid to generators in the WSCC, on a $/kW-yr basis. In the base case, the average hourly energy price in the Citizens North transmission area increases from $22.8/MWh in 1999 to $41.8/MWh in 2010; the average hourly energy price in the Citizens South transmission area increases from $23.1/MWh in 1999 to $41.8/MWh in 2010. The WSCC-wide capacity price increases from $6.7/kW-yr in 1999 to a high of $19.5/kW-yr in 2008, before decreasing to $12.0/kW-yr in 2010. Table A-4 provides a similar summary for the case in which the Mohave CT is not completed for the Arizona, Citizens North, and Citizens South transmission areas.

Table A-3. Forecast of Average Annual Energy Prices by Area and Annual Capacity Prices for Base CT Case

(Energy in $/MWh; Capacity in $/kW-yr)

Area	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Arizona	22.1	23.1	25.1	25.3	27.7	30.7	31.5	31.9	32.8	35.4	38.8	41.0
BCHA	24.2	26.9	30.2	32.7	36.6	41.3	39.9	40.5	42.5	45.9	43.3	48.8
Citizens North	22.8	23.8	25.8	26.0	28.4	31.6	32.3	32.7	33.5	36.1	39.4	41.8
Citizens South	23.1	24.1	26.0	26.2	28.4	31.5	32.2	32.6	33.7	36.2	39.5	41.8
Colorado	20.1	22.0	25.1	27.0	30.4	34.7	35.6	35.2	37.3	40.8	41.6	45.8
Idaho	24.5	26.2	28.5	30.6	33.1	37.4	37.8	38.2	39.9	42.9	44.4	48.5
New Mexico	21.8	22.8	24.8	25.6	27.9	31.7	32.3	32.5	34.1	36.4	39.2	42.3
North California	30.9	31.6	33.8	35.2	36.2	40.2	40.9	41.9	42.3	43.9	47.0	51.0
North	21.4	23.0	26.0	28.2	31.4	35.9	36.9	36.4	38.4	41.9	42.3	46.7
North West	25.1	28.9	31.5	33.3	35.7	39.6	40.3	41.1	42.6	45.3	47.9	52.0
South California	32.8	32.9	34.7	34.6	36.6	39.6	39.9	40.6	41.1	43.5	46.7	49.4
South Nevada	30.3	30.5	32.4	31.9	33.6	36.3	36.7	37.2	38.2	40.6	43.4	46.5
Utah	21.7	23.5	25.8	27.4	30.0	34.2	34.7	35.2	36.8	39.7	41.7	45.3
Capacity	6.7	6.7	7.4	9.0	9.8	10.1	10.7	12.2	16.2	19.5	9.9	12.0

Table A-4. Forecast of Average Annual Energy Prices in Citizens North and South Arizona Transmission Areas

For No Mohave County CT Case ($/MWh)

Area	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	**2009**	**2010**
Arizona	22.1	23.1	25.4	25.5	28.2	31.2	32.2	32.6	33.3	35.8	38.9	41.7
Citizens North	22.8	23.8	26.2	26.2	28.9	31.9	32.9	33.3	34.1	36.4	39.6	42.4
Citizens South	23.1	24.1	26.4	26.4	29.0	32.0	33.1	33.4	34.3	36.6	39.7	42.5

Table A-5 provides estimates of the annual stranded costs associated with Service Schedule A of the APS – Citizens contract, both with and without completion of the Mohave County CT (in the table, negative numbers represent stranded costs). In the base case, in which the Mohave County CT is completed, the annual stranded costs associated with Schedule A fall from $15.5 million in 1999 to $.6 million in 2009; in 2010, the contract generates $1.7 million of stranded benefits, i.e., the annual revenues associated with selling the power exceed the payments Citizens must make under the contract by $1.7 million. Using a discount rate of 10%, the net present value of the annual stranded costs (or benefits) over the 1999 – 2010 period are $64.2 million.

In the alternative case, in which the Mohave CT is not completed, the stranded costs associated with Schedule A fall from $15.5 million in 1999 to $.5 million in 2009, with stranded benefits of $2.2 million in 2010. The net present value of the annual stranded costs (or benefits) over the 1999 – 2010 period are $62.4 million.

Table A-5. Stranded Cost Calculations for Schedule A Purchases

	Base Case				No Mohave County CT Case			
	Prices				Prices			
	Energy ($/MWh)	Capacity ($/kw-yr)	Revenues (000 $)	Revenues - Costs (000 $)	Energy ($/MWh)	Capacity ($/kw-yr)	Revenues (000 $)	Revenues - Costs (000 $)
1999	22.80	6.70	20,643	(15,507)	22.80	6.70	20,643	(15,507)
2000	23.80	6.70	21,519	(14,631)	23.80	6.70	21,519	(14,631)
2001	25.80	7.40	23,341	(12,809)	26.20	7.40	23,691	(12,459)
2002	26.00	9.00	23,676	(12,474)	26.20	9.00	23,851	(12,299)
2003	28.40	9.80	25,858	(10,292)	28.90	9.80	26,296	(9,854)
2004	31.60	10.10	28,692	(7,458)	31.90	10.10	28,954	(7,196)
2005	32.30	10.70	29,365	(6,785)	32.90	10.70	29,890	(6,260)
2006	32.70	12.20	29,865	(6,285)	33.30	12.20	30,391	(5,759)
2007	33.50	16.20	30,966	(5,184)	34.10	16.20	31,492	(4,658)
2008	36.10	19.50	33,574	(2,576)	36.40	19.50	33,836	(2,314)
2009	39.40	9.90	35,504	(646)	39.60	9.90	35,680	(470)
2010	41.80	12.00	37,817	1,667	42.40	12.00	38,342	2,192
Net Present Value @ 10%				(64,234)				(62,363)

Table A-6 displays the annual revenues of the Mohave County CT, as well as the annual payments Citizens must make to APS under the contract. The difference between these two annual amounts represents the annual stranded costs associated with completion of the CT; these stranded costs are approximately $2.5 million in both 2001 and 2002, then fall steadily to $.6 million in 2007; between 2008 and 2010 the unit produces stranded benefits, reaching a high of $.9 million in 2010. The net present value of the annual stranded costs over the 1999 – 2010 period at a 10% discount rate is $6.7 million.

b) Implications

A review of the stranded costs shown in Table A-5 illustrates that there are significant amounts associated with the early years of the analysis. In particular, in 1999 and 2000, the intervening years before Citizens is required under the Competition Rules to acquire its Standard Offer power supply through competitive bid, stranded costs associated with Schedule A are estimated to total approximately $30 million in nominal terms for the Base Case. In order to mitigate this effect, one alternative is for Citizens to delay full divestiture of Schedule A until 1/1/2001. In the interim, only a portion of Schedule A would be stranded as customers take competitive service. Based on a preliminary forecast of how much eligible load will elect to take competitive power supply in 1999 and 2000, Citizens estimates that it would utilize approximately 80% of Schedule A power to serve Standard Offer customers in those years. Doing so would have a dramatic impact on stranded costs, reducing them from approximately $64 million to $43 million in present value terms. Due to these significant benefits, it is assumed for purposes of this filing that the sale of Schedule A will be structured such that full assignment of the power delivery rights does not occur until 1/1/2001. This reduces the stranded cost of Schedule A to an estimated $43.2 million.

Table A-6. Operating Revenues, Expenses for 77-MW Mohave County CT

(Dollar Amounts in Thousands)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Energy (GWh)	87	81	96	129	119	120	115	128	116	134
Capacity Factor (%)	13	12	14	19	18	18	17	19	17	20
Revenues										
Energy	3,686	3,487	4,595	6,696	6,474	6,450	6,492	7,764	8,552	9,794
Capacity	570	693	755	778	824	939	1,247	1,502	762	924
Total	4,256	4,180	5,350	7,474	7,298	7,390	7,739	9,266	9,314	10,718
Citizens Costs										
Fuel[1]	2,149	2,104	2,570	3,636	3,499	3,652	3,624	4,197	3,833	5,028
Variable O&M[1]	211	203	247	342	326	338	333	380	355	423
Demand Charge[2]	4,343	4,343	4,343	4,343	4,343	4,343	4,343	4,343	4,343	4,343
Total	6,703	6,650	7,160	8,321	8,168	8,333	8,300	8,920	8,531	9,794
Gross Margin	(2,447)	(2,470)	(1,810)	(847)	(870)	(943)	(561)	346	783	924

1. Per contract, pass-through of actual costs
2. Per contract, fixed amount.

B. Power Purchase Agreement

The Power Purchase Agreement ("PPA") between Citizens and APS is a contract under which APS would construct a nominal 77 MW combustion turbine peaking facility in Mohave County in exchange for a long-term (20-year) capacity purchase agreement with Citizens. The need and economic justification for the Mohave CT was addressed in both the 1992 and 1996 Integrated Resource Plans ("IRP") submitted by Citizens to the Commission. In short, the need for the Mohave CT is driven by the extraordinary economic expansion and attendant load growth in Mohave County that is forecasted to exceed the capacity of the available transmission facilities in the near future. Remedies to this capacity constraint were to construct local generation or reinforce/expand the transmission system. Through extensive analyses documented in its IRP submittals, Citizens determined that the best solution was to install local generation in Mohave County. In order to fulfill its continuing duty to serve, Citizens conducted a bid process that led to the selection of the APS' proposed 77 MW combustion turbine and entered into a contract that would assure the facilities were constructed prior to the need for additional local capacity.

The pending advent of open competition has recently increased interest in Mohave County as the site for "merchant" generation plants to generate competitive power for sale in California, Arizona, and other emerging competitive markets in the Southwest. Currently, two projects have announced their intent to locate gas-fired, combined-cycle power plants with capacities of 500 MW or more in Mohave County. Either project, if constructed, could alleviate the transmission congestion into Mohave County, thus obviating the need for the Mohave CT. In such a case, the advent of electric competition will have in effect rendered as stranded costs any initial investments made in the Mohave CT project. Further, as demonstrated in the prior subsection, Citizens' stranded costs are higher under the case where the Mohave CT and a local combined-cycle facility are put in service. However, even in the case where neither of the planned combined-cycle projects is built, Citizens' initial Mohave CT investments are still technically stranded. This is so because, after open access is implemented, Citizens' reasonable ability to recover generation-related costs as a regulated distribution provider will have ended under the Commission's competition rules. Thus, on the surface, Citizens' only reasonable alternative at this juncture is to minimize any further investment in the Mohave CT and cancel the project as allowed under the PPA. However, given the need to maintain electric reliability in Mohave County, Citizens has not cancelled the project to date. It is clear that maintaining local electric reliability depends on one of two practical alternatives taking place: a) a competitive power plant and the requisite transmission facilities are constructed in the near term; or b) the Mohave CT project and associated transmission are completed on schedule under Citizens' (or some other party's) agreement.

Given the pending implementation of electric competition and Citizens' election of the Auction/Divestiture option for stranded cost recovery, Citizens proposes that the Commission approve the following course of action, conditional on future events, to resolve the Mohave County situation:

> Citizens maintains its PPA with APS until the sooner of January 1, 1999, or until such time as there is high probability that construction of one or both of the Mohave County combined-cycle projects and the necessary transmission facilities to assure local electrical reliability are going to proceed in a timely manner. If and when such assurances are received, but no later than 1/1/1999 if assurances are not received, Citizens will immediately cancel its PPA with APS to construct the Mohave CT. Under such an outcome, Citizens stranded costs will be the contract cancellation costs (as estimated below).
>
> If, prior to 1/1/1999, it becomes evident that neither of the combined-cycle/transmission projects are going to proceed, then Citizens will solicit bids from qualified parties for the power delivery rights under the PPA. In that case, Citizens' stranded costs (if any) would become

the net present value of the difference between the PPA pricing and the highest bid. To the extent such a bid process results in a bid price higher than the contract obligations, the net proceeds would be split equally among shareholders and Citizens' customers, with the latter share used to reduce other Citizens' stranded costs.

Proceeding in this manner will help assure continued electric reliability in Mohave County while allowing Citizens a reasonable opportunity to recover its related stranded costs. For purposes of estimating stranded costs, the following discussion assumes that the PPA is cancelled at or around the end of 1998.

The cancellation provisions of the PPA allow Citizens to unilaterally choose to cancel the project at any time up until the in-service date of the generation facilities. Upon such notice APS is to invoice Citizens for all real and measurable costs incurred under the PPA, plus a 15% mark-up. Citizens has received an estimate from APS of what those cancellation costs would be today, as well as a projection of their magnitude over the next few months, as summarized below:

APS' net cost to date	\$1,428,000
Estimated Additional Through 12/31/98	\$183,000
15% Mark-up	\$242,000
Est. Cancellation Costs as of 12/31/98	**\$1,853,000**

C. Mohave Transmission

In conjunction with the Mohave CT project, Citizens has moved forward with its plans to put in service in a timely manner the required transmission facilities to deliver power from the plant to Citizens' load centers in Mohave County. Citizens has completed: preliminary engineering of the facilities; environmental assessments needed for acquiring a land use permit from the U.S. Bureau of Land Management; required studies to support Citizens' Certificate of Environmental Compatibility and the acquisition of a small fraction of the needed private rights-of-way.

To date, Citizens has invested a total of approximately $2,100,000, including an allowance for funds used during construction (AFUDC). Because these transmission facilities would be required to deliver power from the plant to locations it is needed, it is Citizens' position that it is entitled to full recovery of these funds in the case where the PPA is cancelled and the Mohave CT is not constructed. For purposes of this filing, the assumption is made that, in fact, the Mohave CT will be cancelled on or before 12/31/98.

D. Additional Generation-related Stranded Costs

Three areas of additional costs associated with generation-related stranded costs need to be addressed. These include: the costs to effect the divestiture of the APS Contract; the costs associated with mitigation efforts on APS Contract; and recognition of the effect of dissolving Citizens' PPFAC. With regard to the costs of divestiture, Citizens estimates that consulting support to prepare bid documents, execute the bidding process; and evaluate the bids to be approximately $100,000. Regarding mitigation, Citizens has pursued re-negotiation efforts aimed at mitigating the strandable costs associated with the APS contract. In this filing, Citizens has included a cost of $175,000 for these activities, which the Company estimates would be the total costs should these efforts lead to a filing before the Federal Energy Regulatory Commission ("FERC"). While this is not necessarily the Company's expectation, it has reflected this amount in the filing to cover the "worst-case" scenario. Finally, the Company expects that as early as 1/1/1999, but no later than 1/1/2001, depending on whether Citizens itself continues providing Standard Offer service, that its PPFAC will be dissolved. While it is highly uncertain what the balance in the PPFAC bank may be when the Clause is terminated, Citizens has included a "placeholder" estimate of a $1,000,000 refund to customers in this filing, including deferred tax effects.

APPENDIX B

APPENDIX B

Calculation of DSM Stranded-Costs

In this section, Citizens Utilities Company ("CUC") details its regulatory assets stranded by competition. These assets include deferred expenditures for implementing Demand-Side Management ("DSM") programs during the period covering 1994-96. An economic analysis of all DSM costs and benefits was conducted, and the results are presented to support full recovery of these deferred DSM expenditures. In addition, CUC shows the net loss in revenues sustained as a result of successful implementation of its DSM programs and the impact of net lost revenues ("LNR") on the cost-effectiveness of its DSM accomplishments. In brief, Citizens' DSM programs have provided over $2,000,000 of net economic benefit to its customers when the lifetime benefits of avoided power costs are compared to the costs of the programs (including the impact of lost net revenues). In this filing Citizens includes in its estimates of stranded costs the balance of deferred DSM expenditures plus the net loss in revenues, which together total $2,982,000.

A. Historical Overview

The following is a brief description of the process undertaken by CUC to implement its DSM programs and recover expenditures associated with these programs.

In its Decision No. 58360, (July 23, 1993), the Arizona Corporation Commission ("ACC") ordered that CUC submit its DSM program plans for pre-approval and defer its pre-approved DSM program costs until its next rate case. On August 23, 1993, the ACC ordered CUC to file semi-annual updates of its DSM program activities. Accordingly, CUC filed a DSM update on September 17, 1993. In this update, CUC provided an overview of its program planning process, a review of its DSM planning principles, customer profile highlights, and an overview of proposed 1994 programs which included DSM energy and demand targets, program costs, and net benefits highlights. On February 25, 1994, CUC filed with the ACC its semi-annual report of DSM activities, which covered the period from July 31, 1993 through January 31, 1994. During this period, CUC was predominantly involved in planning activities to introduce a broad portfolio of DSM programs to its customers in 1994 and evaluating responses to its Request for Proposals for a Master Contractor, released on November 10, 1993.

In its Resource Planning Decision No. 58643, (June 1, 1994), the ACC adopted new procedures for reviewing DSM programs undertaken by utilities subject to the resource planning rules. Pursuant to that Decision, CUC filed its request with the ACC for pre-approval of its DSM program plans for 1994. CUC proposed a comprehensive approach to energy conservation and proposed to spend $1,756,485 on DSM programs from January 1, 1994 through September 30, 1995. Of these expenditures, $1,282,786 was for recurring costs and $473,699 was for start-up costs. During this period, CUC expected to reduce annual peak demand and energy consumption by 3,000 kW and 9,761 MWh, respectively, by utilizing a Master Contractor to deliver DSM services. CUC emphasized marketing its programs through education, trade allies, and financing of DSM costs, instead of providing financial incentives to program participants. CUC's portfolio of proposed DSM programs included: (1) Low Income Weatherization Program ("LIWP"), (2) Residential Energy Survey Program ("RESP"), (3) Residential New Construction Program ("RNCP"), (4) Commercial New Construction Program ("CNCP"), (5) Commercial Energy Partners Program ("CEPP"), (6) Financing Program ("FP"), (7) Trade Ally Program ("TAP"), (8) Key Accounts Program ("KAP"), and (9) Shade Tree Program ("STP").

In Decision No. 58984, the ACC pre-approved CUC's proposed DSM programs, except the STP, and ordered, among other things, that up to $1,693,602 may be entered into CUC's deferral account for DSM as expenditures on pre-approved programs are incurred. It further ordered that the pre-approved programs may be automatically extended beyond the time period of the pre-approved budget, if and only if, each particular program is cost-effective to society (with the FP and TAP costs appropriately allocated to each of the other programs), the annual budgeted cost of all DSM programs continued is less than or equal to $576/kW saved, and the expected kWh savings are at least 3,200 kWh/kW saved. In addition, the ACC required that CUC demonstrate good cause for recovery of costs in excess of $576/kW saved from pre-approved programs at the time it requests recovery of DSM program costs from the deferral account.

During the first half of 1995, CUC focused its program implementation efforts on delivering program services to targeted customers in Mohave and Santa Cruz Counties. CUC focused on streamlining processes and procedures to improve program delivery and provide consistent, quality program services to its customers. In the second half of 1995, CUC restructured its program implementation activities by managing and delivering program services in-house rather than through the Master Contractor. This decision allowed CUC to manage the programs in their steady-state phase, further streamline processes and procedures, fine-tune delivery of program services, and quickly make adjustments or modifications to programs based on results from evaluation studies. All of these factors were intended to significantly reduce administrative costs while improving program delivery and maximizing the acquisition of cost-effective DSM resources.

In August 1995, CUC requested that the Decision No. 58360 be extended to include lost net revenues associated with the DSM programs that were pre-approved by the ACC. In addition, CUC also requested that deferrals of lost net revenues be included in the annual cap on the amount of CUC's DSM costs which may be recorded in the deferral account, subject to the provision that CUC is allowed to carry over lost net revenues to the following year if inclusion of the current-year's lost net revenues would cause CUC to exceed its cap. Subsequently, on September 13, 1995, (and later amended on October 11, 1995), CUC filed with the ACC an application for: (1) a permanent increase in electric rates (Docket No. E-1032-95-433) and (2) an extension of its DSM Accounting Order to include lost net revenues (Docket No. E-1032-95-040).

In the first half of 1996, CUC demonstrated a reduction of 39% in its overall DSM program costs compared to the previous reporting period, while improving DSM energy impacts by 180%. This combined performance reduced overall DSM program costs per kW acquired to $577/kW for the reporting period. Through the combination of CUC's direct management of the programs and improved organizational staffing requirements, CUC reduced administrative costs, which improved its performance as reflected in the program-to-date (i.e., cumulative) cost per kW change from $3,319/kW for the last reporting period to $2,257/kW for this reporting period.

During the second half of 1996, CUC showed even greater performance as demonstrated by the continuous reduction in cumulative $/kW saved over time. During this period, CUC launched a limited-time offering of financial incentive (i.e., rebate) for replacement of existing central air-conditioning (A/C) systems with high efficiency units. The rebate was proportional to the size and efficiency of the replacement unit. Energy and demand savings acquired during this period accounted for 40% and 53% of the respective total savings achieved since the programs were implemented in 1994. Reductions in administrative costs, streamlined processes and procedures, and momentum gained over time contributed to this significant improvement in performance.

During this time, CUC and the Arizona Community Action Association ("ACAA") discussed the concept of an integrated plan for CUC's low-income residential customers and entered into a Memorandum of Understanding ("MOU") on the redesign and funding of the LIWP. In the MOU, CUC, and ACAA agreed that the funding of the Low Income Outreach Program be increased from $50,000, as proposed by the ACC Hearing Officer's December 20, 1996, draft Opinion and Order, to $70,000, with the provision that the ACC increase CUC's revenues $20,000 over the amount proposed in the recommended Opinion and Order.

On January 3, 1997, the ACC issued Decision No. 59951, which required CUC to reduce on-going funding of its DSM programs to $175,000, annually with the LIWP to be transformed and funded separately at $70,000 annually, as set out in the December 24, 1996, MOU between CUC and ACAA. The ACC also allowed CUC to recover $200,000 annually of amortized deferred expenditures for DSM with compound interest on the deferred balance and agreed to consider deferral of lost net revenues in future rate cases.

As a result of the ACC's Decision No. 59951, CUC discontinued the TAP, FP, and KAP, transformed the LIWP, and revised its remaining programs in 1997. Existing commitments to RESP participants were honored, but no new customers were enrolled for program services. The RNCP was continued by promoting the purchase of energy efficient homes. The CEPP and CNCP were consolidated into the Commercial Survey Program which targets new and previously served commercial and industrial customers and places a priority on lost opportunities. Despite the drastically reduced funding level for its DSM programs, CUC continued to improve its performance in 1997 by reducing its total cumulative costs per kW saved to $736/kW.

In the first half of 1998, CUC focused its efforts on the RNCP and worked with commercial customers who participated in its DSM programs, but who did not implement recommended cost-effective energy efficient improvements. CUC also devoted resources to completing M&E studies, which will be filed with CUC's 1998 Semi-Annual Report for the period covering January 1, 1998 through June 30, 1998. During this period, CUC continued to improve its performance by acquiring cost-effective DSM resources at lower costs, thus, reducing further its cumulative costs/kW. Total gross savings from measures installed for all programs since they were implemented are 10,852 MWh and 3,916 kW.

B. DSM Expenditures

CUC's semi-annual DSM program expenditures from January 1, 1994 through June 30, 1998 are shown in Table B-1. Expenditures for these semi-annual periods are actual on-going implementation costs, except for those shown for 1998, which are estimated because company books were not closed at the time of this filing. DSM and IRP costs prior to January 1, 1994 are not reflected in Table B-1 since these costs were disallowed in CUC's previous rate case (Decision No. 59951).

In Decision No. 58984 (February 24, 1995), the ACC authorized pre-approved DSM expenditures to be entered into CUC's deferral account as they are incurred. In Decision No. 59951 (January 3, 1997), the ACC authorized collection in rates of $200,000 annually for recovery of part of the deferral account balance and limited future funding of CUC's DSM programs to $175,000 annually. Thus, the actual DSM expenditures shown in Table B-1 that are entered into CUC's deferral account and subject to recovery, are for the period from January 1, 1994, through December 31, 1996.

Pursuant to Decision No. 58984, CUC is allowed to accrue allowance for funds used during construction (AFUDC). In calculating AFUDC for each program year, the following values were used:

- 1994: 7.240%
- 1995: 8.430%
- 1996: 8.570%
- 1997: 6.012%
- 1998: 6.012%

The total amount of AFUDC accrued ($455,596) is included in the CUC's deferral balance.

In its Decision No. 58984, the ACC required CUC to subtract from the AFUDC amount any interest earned on the collateral account in the financing program. As indicated in Table B-1, the amount of interest on collateral is ***$2,096***. Actual deferred expenditures for DSM, including AFUDC less collateral interest, totals ***$2,766,147***. A total of $300,000 (i.e., $200,000 for 1997 and $100,000 for 1998) has been amortized per ACC Decision No. 58984. Therefore, the current deferred balance is ***$2,466,147***, which represents the DSM amount that CUC seeks to recover in this filing.

TABLE B-1

SEMI-ANNUAL UTILITY DSM EXPENDITURES

	1994		1995		1996		1997		1998
	1/1-6/30	7/1-12/31	1/1-6/30	7/1-12/31	1/1-6/30	7/1-12/31	1/1-6/30	7/1-12/31	1/1-6/30
Direct Payroll & Overhead	$28,637	$82,571	$31,276	$74,654	$69,039	$55,634	$65,153	$51,675	$63,875
Contract Labor	$208,900	$336,521	$299,602	$238,728	$109,072	$124,980	$23,098	$0	$0
Non-Payroll Expense	$196,396	$185,863	$171,155	$23,041	$28,233	$189,517	($7,006)	$9,187	$23,625
Less Collateral Interest per Decision No. 58984	$0	$0	$0	($683)	($464)	($421)	($212)	($315)	$0
AFUDC	$5,495	$24,419	$41,015	$78,333	$76,924	$87,710	$70,009	$71,691	$0
Total Utility Costs	**$439,427**	**$629,375**	**$543,048**	**$414,073**	**$282,804**	**$457,420**	**$151,042**	**$132,237**	**$87,500**

CUMULATIVE UTILITY DSM EXPENDITURES

	1994		1995		1996		1997		1998
	1/1-6/30	7/1-12/31	1/1-6/30	7/1-12/31	1/1-6/30	7/1-12/31	1/1-6/30	7/1-12/31	1/1-6/30
Direct Payroll & Overhead	$28,637	$111,208	$142,484	$217,138	$286,178	**$341,812**	$406,965	$458,639	$522,514
Contract Labor	$208,900	$545,421	$845,023	$1,083,751	$1,192,823	**$1,317,803**	$1,340,901	$1,340,901	$1,340,901
Non-Payroll Expense	$196,396	$382,259	$553,414	$576,454	$604,688	**$794,205**	$787,199	$796,386	$820,011
Less Collateral Interest per Decision No. 58984	$0	$0	$0	($683)	($1,147)	**($1,569)**	($1,781)	($2,096)	($2,096)
AFUDC	$5,495	$29,914	$70,929	$149,262	$226,186	**$313,896**	$383,905	$455,596	$455,596
Total Utility Costs	**$439,427**	**$1,068,802**	**$1,611,850**	**$2,025,923**	**$2,308,727**	**$2,766,147**	**$2,917,189**	**$3,049,426**	**$3,136,926**

C. Load Impacts

Since implementing its DSM programs, CUC has aggressively pursued all cost-effective DSM resource opportunities from its residential and commercial customers. For the period between January 1, 1994, through June 30, 1998, CUC acquired 10,852 MWh of gross energy savings from verified installations (Table B-2). Most (85%) of these savings were from two programs, the CEPP and RESP. End-uses that accounted for most of the energy savings were HVAC (60%), followed by lighting (19%), and industrial process improvements (11%).

Table B-2
Distribution of Gross DSM Annual Energy Savings (MWh/yr) by Program and End-Use

	CEPP	CNCP	LIWP	RNCP	RESP	TOTAL
Lighting	1,802.77	188.74	4.43	0.00	44.47	**2,040.41**
HVAC	1,921.85	57.01	132.27	591.70	3,681.43	**6,384.26**
Water Heating	2.50	0.00	83.35	0.00	380.61	**466.46**
Motors	807.21	0.00	0.00	0.00	0.00	**807.21**
Process	618.40	534.99	0.00	0.00	0.00	**1,153.39**
ALL PROGRAMS	**5,152.73**	**780.74**	**220.05**	**591.70**	**4,106.51**	**10,851.73**

The amount of gross coincident peak demand savings captured by CUC since its DSM programs were implemented in 1994 is 3,916 kW (Table B-3). The bulk (75%) of peak demand savings were attributable to HVAC energy efficiency improvements. Nearly 80% of demand savings came from the RESP and CEPP.

Table B-3
Distribution of Gross Peak Demand Savings
(kW) by Program and End-Use

End-Use	CEPP	CNCP	LIWP	RNCP	RESP	TOTAL
Lighting	217.48	34.51	0.38	0.00	3.65	**256.02**
HVAC	657.86	8.61	52.26	685.77	1,531.05	**2,935.55**
Water Heating	4.53	0.00	15.20	0.00	91.69	**111.42**
Motors	169.17	0.00	0.00	0.00	0.00	**169.17**
Process	383.00	61.00	0.00	0.00	0.00	**444.00**
ALL PROGRAMS	**1,432.04**	**104.12**	**67.84**	**685.77**	**1,626.39**	**3,916.16**

These results indicate that the actual gross energy/demand savings ratio was 2,771 kWh/kW and the actual cost of all programs per gross kW saved was ***$801***/kW.

D. Lost Net Revenues

In Decision No. 59951 (January 3, 1997), the ACC allowed deferral of lost net revenues for consideration in future rate cases. Thus, the ACC approved the concept of deferring recovery of lost net revenues associated with the implementation of DSM programs for consideration in future rate cases. In this filing, CUC presents the methodology used to calculate lost net revenues sustained as a result of successful implementation of its DSM programs and shows the amount of lost net revenues it seeks to recover.

1. Methodology:

In its August 7, 1995 filing (Docket No. E-1032-95-040), CUC proposed an equation for calculating lost net revenues. In this filing, CUC presents the same general equation to calculate lost net revenues with some refinements in the detail of its separate components and changes in nomenclature.

Lost net revenue is defined as the net revenue impacts attributable to DSM programs, or more precisely, as the revenue loss less the variable fuel and operating expenses saved by the utility as a result of not having to generate unsold energy (i.e., through its DSM programs). Thus, lost net revenue is simply the difference between the DSM-induced change in demand and energy costs and changes in gross revenue, or:

Lost Net Revenue = Lost Revenue – Avoided Production Costs

The first component, Lost Revenue (LR) from DSM, is calculated for each month over the period of interest as:

$$LR = (C_{kWh} * DSM_{kWh}) + (C_{kW} * DSM_{kW})$$

where:

C_{kWh}	= Energy charge under customer's applicable tariff(s) ($/kWh)
C_{kW}	= Demand charge under customer's applicable tariff(s) ($/kW)
DSM_{kWh}	= Energy savings attributable to DSM (kWh)
DSM_{kW}	= Demand savings attributable to DSM (kW)

The second component, Avoided Production Costs (APC), is calculated for each month over the period of interest as:

$$\begin{aligned} APC = {} & DSM_{kW} *[A_{kW} / (1 - LR_{APS} - MTD_{kW} + AC_{APS}*MTD_{kW})] + \\ & DSM_{kWh} *[A_{kWh} / (1 - LR_{APS} - MTD_{kWh} + AC_{APS}*MTD_{kWh})] \end{aligned}$$

where:

A_{kW}	= Avoided APS demand charge ($/kW)
A_{kWh}	= Avoided APS energy charge ($/kWh)
LR_{APS}	= APS Loss Rate (%)
MTD_{kWh}	= Marginal Transmission & Distribution Energy Loss Rate (%)
MTD_{kW}	= Marginal Transmission & Distribution Demand loss rate (%)

For each month, CUC's AFUDC rates were applied to monthly net revenue impacts. The sum of lost net revenue plus AFUDC for each month was cumulated over the period of interest to arrive at the final lost net revenue value.

2. Assumptions and Calculations:

To calculate LR for the period covering January 1, 1994, through June 30, 1998, the following assumptions and calculations were used:

1. End-use data as reported in CUC's semi-annual reports were used instead of measure-level savings data;

2. The initial month to which energy and demand savings were applied for each semi-annual period was the middle month of that semi-annual period (i.e., April and October) based on the assumption that, on average, half of all measures within an end-use were installed before and after this month for the semi-annual period;

3. Monthly energy and demand savings for all end-uses were applied equally across the period of interest, except HVAC, which was applied to only those months for which A/C cooling was needed. The distribution of monthly HVAC savings was based on the percent of total cooling-degree-days (CDD) for each month. Average monthly CDD was determined from 5-years of weather data (1993-1997) for Kingman and Lake Havasu City.

4. Energy (DSM_{kWh}) and demand (DSM_{kW}) savings were first adjusted by multiplying gross savings values by program-level savings realization rates, which were taken from Monitoring and Evaluation (M&E) studies. The savings realization rate is defined as the ratio of actual to estimated savings. The M&E studies utilized a variety of methods to determine extent to which estimated DSM savings were actually realized, including direct metering, time-series analysis, cross-sectional time-series analysis, regression analysis, and calibrated engineering analysis. Results of these studies have been included in CUC's Semi-Annual Reports or will be included in its next Semi-Annual

Report. The following Table B-4 shows the energy and demand savings realization rates for each program that were applied to gross (estimated) savings values.

Table B-4
Program-Level Energy and Demand Savings Realization Rates

PROGRAM	ENERGY	DEMAND	SOURCE
CEPP	0.88	0.96	Impact Evaluation of CUC's CEPP, June 2, 1998, p. 11
LIWP	1.17	0.75	Residential Energy Savings Calculation Final Report, Equipoise Consulting, Inc. July, 1998, p. 4-5
CNCP	1.00	1.00	No data on realization rates were determined for CNCP due to limited sample size.
RESP	1.17	0.75	Residential Energy Savings Calculation Final Report, Equipoise Consulting, Inc. July, 1998, p. 4-5
RNCP	0.88	0.88	Residential New Construction Impact Evaluation, January 31, 1997, p. 23, IN: CUC's 1997 Semi-Annual Report, February 28, 1997, Attachment A.

5. The energy charge (C_{kWh}) for residential customers was taken from: (1) applicable tariff approved by the ACC in Decision No. 58360 for the period covering April, 1994 through December, 1996, and (2) applicable tariff approved by the ACC in Decision No. 59951 for the period cover January, 1997, through June, 1998. Similarly, the demand charge (C_{kW}) for commercial customers for these same periods was taken from tariffs approved by the ACC in Decision Nos. 58360 and 59951. The following Table B-5 summarizes these tariffs:

Table B-5
Applicable Tariffs for Residential and Commercial Customer Classes

TAFIFFS	1994-96		1997-98	
CLASS	kW	kWh	kW	kWh
Residential	$0	0.0759	$0	0.0765
Commercial – Large General Service (LGS)	$9.50	0.0544	$9.50	0.0549
Commercial – Large Power Service (LPS)	$24.75	0.0250	$24.75	0.0250

Note: (1) all residential program participants were in Mohave County, (2) all commercial program participants were under either the LGS or LPS tariffs.]

6. The avoided APS demand charge (A_{kW}) and avoided APS energy charge (A_{kWh}) was calculated for each month over the period of interest based on data taken from Supplemental Capacity (Schedule B) APS bills.

7. The APS loss rate (LR_{APS}) value was 4%, as noted in Schedule B of APS bills.

8. The marginal transmission & distribution energy- (MTD_{kWh}) and demand-loss (MTD_{kW}) rates were weighted averages. The marginal loss rate factors for Winter-On and -Off Peak, Summer-On and -Off Peak, and Capacity-Winter and -Summer were taken from CUC's 1996 IRP and weighted by the average distribution of total adjusted energy savings for these respective periods to arrive at the weighted average value of 14% for both MTD_{kWh} and MTD_{kW}.

9. AFUDC values used in the lost net revenue calculation were the same as those shown earlier under DSM Expenditures. The AFUDC value for each year was divided by twelve (12) to arrive at the monthly AFUDC rate within the given year.

10. Lost net revenue with AFUDC was cumulated by month over the period of interest to arrive at the final lost net revenue value. For ease of computation, lost net revenue was determined for residential and commercial customer groups separately, then summed to yield the total lost net revenue (Table B-6).

Table B-6
Summary of Lost Net Revenues

GROUP	DSM Revenue Loss	Avoided Production Costs	Lost Net Revenues w/o AFUDC	AFUDC	Lost Net Revenues with AFUDC
RESIDENTIAL	$567,731	$384,716	$183,015	$12,316	**$195,332**
COMMERCIAL	$768,434	$463,222	$305,212	$15,057	**$320,268**
TOTAL	**$1,336,165**	**$847,938**	**$488,227**	**$27,372**	**$515,600**

From the preceding computation, CUC seeks to recover, as part of its stranded costs, ***$515,600*** in lost net revenues sustained as a result of successfully implementing its DSM programs during the period covering January 1, 1994, through June 30, 1998.

E. COST-EFFECTIVENESS EVALUATION

A cost-effectiveness evaluation was conducted using the DSM costs and savings values noted previously. Program cost-effectiveness analysis takes into account all the costs of fielding each program, reflecting specific market approaches and delivery mechanisms. The objective of this evaluation was to determine whether the net value (benefits less costs) in aggregate of the savings from DSM measures installed for each program exceeded the program administration and delivery costs associated with having those measures installed.

The key elements used for the benefits side of the analysis included avoided energy and capacity costs over a 30-years. The avoided costs used in this analysis were taken from CUC's 1996 IRP, using 1997 as the base year. Load impacts for each program year were forecasted over the lifetime of the measures installed. For this analysis, the following data processing elements included:

- End-use data presented in CUC's Semi-Annual Reports were used because most measures within a given end-use had the same useful life. For measures within a given end-use that had different useful lifetimes, the weighted life for that end-use was calculated. End-uses included: (1) Lighting, (2) HVAC, (3) water heating, (4) motors (large and small), and (5) industrial process improvements.

- Gross energy and demand savings for each end-use were adjusted by program-level realization rates. The realization rates shown previously (Table B-4) in the lost net revenue calculation were used to here.

- Average seasonally differentiated adjusted energy savings were multiplied by the associated loss adjusted marginal energy costs for each year over the life of the end-use; coincident peak demand savings was multiplied by the total avoidable capacity related costs for the same period.

- For future years, the discount rate of 10.8% in CUC's 1996 IRP was used to calculate net benefits in terms of their net present value ("NPV").

- The NPV of program benefits was calculated as the cumulative sum of the NPV of end-use benefits over its useful life for each program.

The key elements of the cost side of the analysis are: (1) CUC administrative costs, (2) contract labor costs, (3) non-payroll expenses which includes the cost of the installed measures paid for by CUC, (4) cost of installed measures paid for by the customer, (5) AFUDC, and (6) less interest earned on collateral. For each program, the following data elements included:

- CUC's administrative costs include payroll plus overhead;

- Measure costs that are included in CUC's non-payroll expenses when paid for by CUC including rebates; otherwise, these costs are born by the customer along with any non-electric operations and maintenance (O&M) cost changes experienced by the customer. Total measure costs are the sum of costs paid by CUC to have measures installed plus costs paid by the customer to have measures installed. CUC paid for measure installations in the LIWP (all measures except energy efficient A/C units) and RESP (except for ceiling insulation and energy efficient A/C units that were not part of the limited A/C rebate offering). The customer paid for measure installations in all other programs.

Actual customer costs were included when available, however, CUC does not routinely track customer costs. When actual cost data were not available, CUC used cost data from its pre-approval filing or more recent available data to estimate the cost of measures paid by program participants. For example, incremental cost data for measures installed under the RNCP, along with penetration rates and square footage values were taken from CUC Semi-Annual Report to estimate total measure costs.

Since gross DSM savings were adjusted by program realization rates to reflect actual savings, total measure costs for each program were multiplied by the program realization rates shown in Table B-4 to arrive at the net total measure cost.

- Costs for the Key Accounts Program ("KAP") were allocated to the CEPP.

- Costs for the trade ally program ("TAP") were allocated to the RNCP, RESP, CESP, and CINC based on their proportion of combined program costs.

- Costs for the financing program ("FP") were allocated to the RNCP and RESP based on their proportion of combined program costs.

- The total amount of AFUDC accrued ($455,596 from Table B-1) is included on the cost side of the analysist. AFUDC was allocated to all programs based on their proportion of total program costs.

- Pursuant to ACC Decision No. 58984, CUC subtracted from the AFUDC amount the interest earned on the collateral account ($2,026 from Table B-1) in the financing program.

The cost-effectiveness analysis was conducted on a total resource and utility basis. The total resource cost ("TRC") test for cost-effectiveness includes the total costs incurred by CUC and participating customers in putting the programs and measures in place. The Benefit /Cost ("B/C") ratio for the TRC test is the ratio of the present value of the avoided generation and capacity costs to the present value of total costs incurred. The B/C ratio for the utility cost ("UC") test is the present value of the avoided generation and capacity costs to the present value of costs incurred by CUC.

The TRC and UC tests were conducted on a gross and net basis, that is, with gross measure costs and adjusted measure costs. Results of this analysis are summarized in Table B-7. Results of the TRC tests indicate that all programs are cost effective except the RNCP and LIWP, which are marginally not cost-effective. Results of the UC tests indicate that all programs are cost-effective. For all programs combined, both the TRC and UC tests show CUC's DSM programs are cost-effective.

Of particular interest is whether CUC's programs are cost-effective if lost net revenues are included in the cost side of the analysis. While it may be controversial whether lost net revenues should be included as a program cost or merely a transfer payment that should not be included in the assessment of cost-effectiveness, it is noteworthy that by its inclusion, CUC's DSM programs remain highly cost-effective from both a societal (TRC) and utility (UC) perspective.

These results clearly show that although CUC's DSM programs exceeded the $576/kW savings threshold, they were still highly cost-effective overall, and even with lost net revenues included, the net economic benefits of CUC's DSM programs to its ratepayers exceeds $2,000,000. CUC believes that this is compelling evidence to provide full recovery of its DSM costs including lost net revenues.

Table B-7 Summary of Results of Cost Effectiveness Analysis

	MULTI-YEAR PROGRAM IMPACTS	RNCP	RESP	LIWP	CNCP	CEPP	ALL PROGRAMS
	Direct Payroll & Overhead	$140,491	$96,871	$30,831	$16,680	$237,641	$522,514
	Contract Labor	$233,591	$281,711	$51,451	$51,649	$722,500	$1,340,902
	Non-Payroll Expense	$146,240	$160,634	$37,470	$40,658	$333,341	$718,344
	Total Measure Cost Paid by Utility (gross $)	$0	$91,202	$10,466	$0	$0	$101,668
	AFUDC & Less Collateral Interest per Dec. #58984	$91,397	$94,716	$21,035	$19,144	$227,207	$453,500
	Total Utility Costs (gross $)	$611,720	$725,134	$151,253	$128,132	$1,520,689	$3,136,928
	Total Measure Cost Paid by Customer (gross $)	$248,505	$767,020	$16,196	$228,448	$634,938	$1,895,106
	Average Realization Rates	0.88	0.96	0.96	1.00	0.93	
	Total Measure Cost Paid by Customer (net $)	$218,684	$734,581	$15,511	$228,448	$590,492	$1,787,716
0	Total Measure Cost Paid by Utility (net $)	$0	$87,345	$10,023	$0	$0	$97,368
1	Total Utility Costs (net $)	$611,720	$721,276	$150,810	$128,132	$1,520,689	$3,132,628
2	Total Program Costs (gross $)	$860,224	$1,492,154	$167,449	$356,580	$2,155,627	$5,032,034
4	Total Program Costs (net $)	$830,404	$1,455,858	$166,322	$356,580	$2,111,181	$4,920,344
5	PV Resource Benefits (net $)	$791,078	$3,423,644	$150,199	$371,699	$2,979,269	$7,715,889
6	TRC B/C Ratio (gross)	0.92	2.29	0.90	1.04	1.38	1.53
7	TRC B/C Ratio (net)	0.95	2.35	0.90	1.04	1.41	1.57
8	UC B/C Ratio (gross)	1.29	4.72	0.99	2.90	1.96	2.46
9	UC B/C Ratio (net)	1.29	4.75	1.00	2.90	1.96	2.46
	TRC and UC Tests With Lost Net Revenues Included in Total Costs						
0	Lost Net Revenue (LNR)						$515,600
1	TRC B/C Ratio (gross w/LNR)						1.39
2	TRC B/C Ratio (net w/LNR)						1.42
3	UC B/C Ratio (gross w/LNR)						2.11
4	UC B/C Ratio (net w/LNR)						2.12

Attachment B-1

Annual Summary of CUC's DSM Program Costs

	1994	1995	1996	1997	1998	TOTAL
Residential New Construction Program						
Direct Payroll & Overhead	$15,868	$11,994	$33,577	$33,588	$31,938	$126,964
Contract Labor	$68,249	$53,373	$62,611	$5,078	$0	$189,311
Non-Payroll Expense	$62,577	$25,796	$23,152	$341	$11,813	$123,679
Total	$146,694	$91,164	$119,340	$39,007	$43,750	$439,954
Residential Energy survey Program						
Direct Payroll & Overhead	$24,762	$24,634	$13,939	$19,518	$0	$82,853
Contract Labor	$110,643	$98,602	$24,995	$1,583	$0	$235,824
Non-Payroll Expense	$94,840	$48,435	$88,505	-$3,325	$0	$228,455
Total	$230,244	$171,671	$127,439	$17,777	$0	$547,132
Low-Income Weatherization Program						
Direct Payroll & Overhead	$8,694	$10,169	$11,968	$0	$0	$30,832
Contract Labor	$37,005	$9,781	$4,665	$0	$0	$51,451
Non-Payroll Expense	$18,330	$22,233	$7,373	$0	$0	$47,936
Total	$64,030	$42,182	$24,006	$0	$0	$130,218
Commercial New Construction Program						
Direct Payroll & Overhead	$5,068	$3,707	$2,924	$3,812	$0	$15,511
Contract Labor	$32,864	$10,187	$2,146	$307	$0	$45,504
Non-Payroll Expense	$10,495	$6,579	$21,110	-$22	$0	$38,161
Total	$48,426	$20,474	$26,180	$4,097	$0	$99,176
Commercial Energy Partners Program						
Direct Payroll & Overhead	$32,873	$25,480	$62,265	$59,910	$31,938	$212,466
Contract Labor	$174,503	$310,138	$139,636	$16,129	$0	$640,406
Non-Payroll Expense	$147,975	$51,878	$77,611	$5,187	$11,813	$294,463
Total	$355,352	$387,496	$279,512	$81,225	$43,750	$1,147,334
ALL PROGRAMS						
Interest on Collateral	$0	-$683	-$885	-$527	$0	-$2,096
AFUDC	$29,914	$119,348	$164,634	$141,700	$0	$455,596
Grand Total	**$1,068,802**	**$957,121**	**$740,225**	**$283,279**	**$87,500**	**$3,136,926**

Attachment B-2

Summary of CUC's DSM Energy (MWh/yr) Savings

End-Use	1995	1996	1997	1998	TOTAL
Residential New Construction Program					
Ltg	0.00	0.00	0.00	0.00	0.00
HVAC	74.40	286.56	204.00	26.74	591.70
Wat Ht	0.00	0.00	0.00	0.00	0.00
Motors	0.00	0.00	0.00	0.00	0.00
Process	0.00	0.00	0.00	0.00	0.00
TOTAL	74.40	286.56	204.00	26.74	591.70
Residential Energy Survey Program					
Ltg	32.00	12.28	0.19	0.00	44.47
HVAC	22.10	2,497.74	1,161.59	0.00	3,681.43
Wat Ht	336.60	44.01	0.00	0.00	380.61
Motors	0.00	0.00	0.00	0.00	0.00
Process	0.00	0.00	0.00	0.00	0.00
TOTAL	390.70	2,554.03	1,161.78	0.00	4,106.51
Low Income Weatherization Program					
Ltg	0.00	3.41	1.02	0.00	4.43
HVAC	88.30	40.21	3.76	0.00	132.27
Wat Ht	57.60	22.33	3.42	0.00	83.35
Motors	0.00	0.00	0.00	0.00	0.00
Process	0.00	0.00	0.00	0.00	0.00
TOTAL	145.90	65.95	8.20	0.00	220.05
Commercial New Construction Program					
Ltg	34.10	93.60	61.04	0.00	188.74
HVAC	36.20	0.00	20.81	0.00	57.01
Wat Ht	0.00	0.00	0.00	0.00	0.00
Motors	0.00	0.00	0.00	0.00	0.00
Process	0.00	397.52	137.47	0.00	534.99
TOTAL	70.30	491.12	219.32	0.00	780.74
Commercial Energy Partners Program					
Ltg	1,233.90	253.91	314.96	0.00	1,802.77
HVAC	15.20	1,413.99	492.66	0.00	1,921.85
Wat Ht	0.25	0.00	2.25	0.00	2.50
Motors	0.00	806.10	1.11	0.00	807.21
Process	415.50	135.89	67.01	0.00	618.40
TOTAL	1,664.85	2,609.89	877.99	0.00	5,152.73
GRAND TOTAL	**2,346.15**	**6,007.55**	**2,471.29**	**26.74**	**10,851.73**

Attachment B-2 (Continued)

Summary of CUC's DSM Coincident Peak Demand (kW) Savings

End-Use	1995	1996	1997	1998	TOTAL
Residential New Construction Program					
Ltg	0.00	0.00	0.00	0.00	0.00
HVAC	73.90	340.41	241.51	29.95	685.77
Wat Ht	0.00	0.00	0.00	0.00	0.00
Motors	0.00	0.00	0.00	0.00	0.00
Process	0.00	0.00	0.00	0.00	0.00
TOTAL	73.90	340.41	241.51	29.95	685.77
Residential Energy Survey Program					
Ltg	2.60	1.04	0.01	0.00	3.65
HVAC	20.40	1031.96	478.69	0.00	1531.05
Wat Ht	80.10	11.59	0.00	0.00	91.69
Motors	0.00	0.00	0.00	0.00	0.00
Process	0.00	0.00	0.00	0.00	0.00
TOTAL	103.10	1044.59	478.70	0.00	1,626.39
Low Income Weatherization Program					
Ltg	0.00	0.29	0.09	0.00	0.38
HVAC	25.40	22.38	4.48	0.00	52.26
Wat Ht	9.40	5.20	0.60	0.00	15.20
Motors	0.00	0.00	0.00	0.00	0.00
Process	0.00	0.00	0.00	0.00	0.00
TOTAL	34.80	27.87	5.17	0.00	67.84
Commercial New Construction Program					
Ltg	6.30	13.04	15.17	0.00	34.51
HVAC	4.20	0.00	4.41	0.00	8.61
Wat Ht	0.00	0.00	0.00	0.00	0.00
Motors	0.00	0.00	0.00	0.00	0.00
Process	0.00	45.28	15.72	0.00	61.00
TOTAL	10.50	58.32	35.30	0.00	104.12
Commercial Energy Partners Program					
Ltg	155.20	53.83	8.45	0.00	217.48
HVAC	16.00	398.60	243.26	0.00	657.86
Wat Ht	0.03	0.00	4.50	0.00	4.53
Motors	0.00	89.17	80.00	0.00	169.17
Process	56.00	219.00	108.00	0.00	383.00
TOTAL	227.23	760.60	444.21	0.00	1,432.04
GRAND TOTAL	**449.53**	**2,231.79**	**1,204.89**	**29.95**	**3,916.16**

Attachment B-3

Program-Level Energy and Demand Savings Realization Rates

PROGRAM	ENERGY	DEMAND	SOURCE
CEPP	0.88	0.96	Impact Evaluation of CUC's CEPP, June 2, 1998, p. 11
LIWP	1.17	0.75	Residential Energy Savings Calculation Final Report, Equipoise Consulting, Inc. July, 1998, p. 4-5
CNCP	1.00	1.00	No data on realization rates were determined for CNCP due to limited sample size.
RESP	1.17	0.75	Residential Energy Savings Calculation Final Report, Equipoise Consulting, Inc. July, 1998, p. 4-5
RNCP	0.88	0.88	Residential New Construction Impact Evaluation, January 31, 1997, p. 23, IN: CUC's 1997 Semi-Annual Report, February 28, 1997, Attachment A.

Attachment B-4

Applicable Tariffs for Residential and Commercial Customer Classes

TAFIFFS	1994-96		1997-98	
CLASS	KW	kWh	kW	kWh
Residential	$0	0.0759	$0	0.0765
Commercial – Large General Service (LGS)	$9.50	0.0544	$9.50	0.0549
Commercial – Large Power Service (LPS)	$24.75	0.0250	$24.75	0.0250

Note: (1) all residential program participants were in Mohave County, (2) all commercial program participants were under either the LGS or LPS tariffs.]

Attachment B-5

Summary Data from APS Bills

Mo/Yr	Demand Charge	Total Supplem'tl Energy (kWh)	Adj'mt to Meter Reads (kWh)	Total Supplem'tl Energy Cost ($)	Adj'mt to Meter Reads Cost ($)	TOTAL Energy (kWh)	TOTAL Cost ($)	Average Charge ($/kWh)	Adj'td Demand Cost ($/kW)	Adj'td Energy Cost ($/kWh)
Mar-95	$6	0	-1,726	$0	($47)	-1,726	-$47	$0.0270	$7.2674	$0.0327
Apr-95	$6	0	-7,214	$0	($195)	-7,214	-$195	$0.0270	$7.2674	$0.0327
May-95	$6	6,011,218	9,944	$162,309	$268	6,021,162	$162,577	$0.0270	$7.2674	$0.0327
Jun-95	$6	16,914,962	-8,272	$456,705	($223)	16,906,690	$456,481	$0.0270	$7.2674	$0.0327
Jul-95	$6	32,687,247	1,067	$884,626	$29	32,688,314	$884,655	$0.0271	$7.2674	$0.0328
Aug-95	$6	38,304,168	780,524	$1,079,930	$21,074	39,084,692	$1,101,004	$0.0282	$7.2674	$0.0341
Sep-95	$6	25,989,044	64,559	$701,742	$1,743	26,053,603	$703,485	$0.0270	$7.2674	$0.0327
Oct-95	$6	6,139,568	23,836	$165,768	$644	6,163,404	$166,412	$0.0270	$7.2674	$0.0327
Nov-95	$6	0	49,372	$0	$1,333	49,372	$1,333	$0.0270	$7.2674	$0.0327
Dec-95	$6	4,325,941	-6,541	$116,801	($177)	4,319,400	$116,624	$0.0270	$7.2674	$0.0327
Jan-96	$6	8,285,212	-11,230	$223,747	($303)	8,273,982	$223,444	$0.0270	$7.2674	$0.0327
Feb-96	$6	6,306,097	-1,291	$170,365	($35)	6,304,806	$170,330	$0.0270	$7.2674	$0.0327
Mar-96	$6	2,238,624	-17	$60,442	($0)	2,238,607	$60,442	$0.0270	$7.2674	$0.0327
Apr-96	$6	7,261,402	-7,214	$196,058	($195)	7,254,188	$195,863	$0.0270	$7.2674	$0.0327
May-96	$6	15,715,877	-4,745	$424,435	($128)	15,711,132	$424,307	$0.0270	$7.2674	$0.0327
Jun-96	$6	24,203,797	-6,255	$667,220	($169)	24,197,542	$667,051	$0.0276	$7.2674	$0.0334
Jul-96	$6	38,549,536	-4,034	$1,091,315	($109)	38,545,502	$1,091,206	$0.0283	$7.2674	$0.0343
Aug-96	$6	36,191,123	-3,583	$1,117,348	($97)	36,187,540	$1,117,251	$0.0309	$7.2674	$0.0374
Sep-96	$6	18,486,548	-2,438	$510,525	($66)	18,484,110	$510,459	$0.0276	$7.2674	$0.0334
Oct-96	$6	11,013,758	21,849	$297,371	$590	11,035,607	$297,961	$0.0270	$7.2674	$0.0327
Nov-96	$6	0	-10,239	$0	($276)	-10,239	-$276	$0.0270	$7.2674	$0.0327
Dec-96	$6	8,527,643	8,246	$269,141	$223	8,535,889	$269,364	$0.0316	$7.2674	$0.0382
Jan-97	$6	11,110,226	-40,626	$318,608	($1,097)	11,069,600	$317,512	$0.0287	$7.2674	$0.0347
Feb-97	$6	7,591,484	8,116	$205,193	$219	7,599,600	$205,412	$0.0270	$7.2674	$0.0327
Mar-97	$6	4,147,338	-1,811	$111,989	($49)	4,145,527	$111,940	$0.0270	$7.2674	$0.0327
Apr-97	$6	5,463,188	-1,804	$148,787	($49)	5,461,384	$148,739	$0.0272	$7.2674	$0.0330
May-97	$6	22,399,656	-29,911	$643,452	($808)	22,369,745	$642,645	$0.0287	$7.2674	$0.0348
Jun-97	$6	21,654,619	28,126	$606,774	$759	21,682,745	$607,533	$0.0280	$7.2674	$0.0339
Jul-97	$6	32,974,185	29,771	$1,152,743	$804	33,003,956	$1,153,546	$0.0350	$7.2674	$0.0423
Aug-97	$6	38,832,141	-14,449	$1,616,633	($390)	38,817,692	$1,616,243	$0.0416	$7.2674	$0.0504
Sep-97	$6	27,420,831	-2,184	$1,289,452	($59)	27,418,647	$1,289,393	$0.0470	$7.2674	$0.0570
Oct-97	$6	11,063,171	-50,617	$368,796	($1,367)	11,012,554	$367,429	$0.0334	$7.2674	$0.0404
Nov-97	$6	1,617,228	673,189	$43,782	$18,176	2,290,417	$61,958	$0.0271	$7.2674	$0.0328
Dec-97	$6	13,357,140	11,854	$362,987	$320	13,368,994	$363,307	$0.0272	$7.2674	$0.0329
Jan-98	$6	12,635,992	-11,037	$342,365	($298)	12,624,955	$342,067	$0.0271	$7.2674	$0.0328
Feb-98	$6	9,498,502	-4,252	$264,138	($115)	9,494,250	$264,024	$0.0278	$7.2674	$0.0337
Mar-98	$4	6,276,358	-7,402	$123,672	($200)	6,268,956	$123,472	$0.0197	$4.8450	$0.0239
Apr-98	$4	6,477,621	-223	$118,813	($4)	6,477,398	$118,809	$0.0183	$4.8450	$0.0222
May-98	$4	9,958,221	-5,378	$174,895	($77)	9,952,843	$174,818	$0.0176	$4.8450	$0.0213
Jun-98	$4	21,935,918	-7,174	$461,012	($111)	21,928,744	$460,901	$0.0210	$4.8450	$0.0255

Attachment B-6

Lost Net Revenue Calculations for All Residential Programs

	1995								
	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
Unadjusted Total kW	85.71	92.43	99.14	105.85	105.85	105.85	161.24	138.03	91.60
Unadjusted Total MWh	29.29	35.20	38.15	41.11	41.11	41.11	53.86	35.00	35.00
Adjusted Total kW	64.69	70.13	75.58	81.02	81.02	81.02	126.91	107.51	68.70
Adjusted Total MWh	34.27	40.81	44.08	47.34	47.34	47.34	60.34	40.95	40.95
Revenue Loss – Total $	$2,601	$3,097	$3,345	$3,593	$3,593	$3,593	$4,580	$3,108	$3,108
Revenue Loss - Cumulative $	$2,601	$5,698	$9,043	$12,637	$16,230	$19,824	$24,404	$27,512	$30,621
Total Avoided Monthly APS Demand $	$470	$510	$549	$589	$589	$589	$922	$781	$499
Total Avoided Monthly APS Energy $	$1,121	$1,335	$1,441	$1,552	$1,615	$1,548	$1,973	$1,339	$1,339
Total Avoided Monthly APS Costs	$1,591	$1,844	$1,991	$2,141	$2,204	$2,137	$2,896	$2,121	$1,839
Cumulative Avoided APS Demand $	$470	$980	$1,529	$2,118	$2,707	$3,295	$4,218	$4,999	$5,498
Cumulative Avoided APS Energy $	$1,121	$2,455	$3,897	$5,449	$7,064	$8,612	$10,586	$11,925	$13,265
Cumulative Avoided APS Costs $	$1,591	$3,435	$5,426	$7,566	$9,771	$11,908	$14,804	$16,924	$18,763
Monthly Total Lost Net Revenue $ w/o AFUDC	$1,010	$1,253	$1,355	$1,453	$1,389	$1,456	$1,684	$988	$1,270
Cumulative Lost Net Revenue $ w/o AFUDC	$1,010	$2,263	$3,618	$5,070	$6,460	$7,916	$9,600	$10,588	$11,858
AFUDC Rate	0.7025%	0.7025%	0.7025%	0.7025%	0.7025%	0.7025%	0.7025%	0.7025%	0.7025%
AFUDC $/Month	$7.10	$15.95	$25.58	$35.96	$45.97	$56.53	$68.75	$76.18	$85.63
AFUDC Cumulative $	$7.10	$23.04	$48.62	$84.58	$130.55	$187.08	$255.83	$332.01	$417.64
LOST NET REVENUE w/AFUDC	**$1,017**	**$2,286**	**$3,666**	**$5,155**	**$6,590**	**$8,103**	**$9,856**	**$10,920**	**$12,275**

Attachment B-6 (Continued)

Lost Net Revenue Calculations for All Residential Programs

	1996											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
Unadjusted Total kW	91.60	91.60	91.60	171.31	237.99	304.66	371.33	371.33	371.33	1225.42	853.52	109.72
Unadjusted Total MWh	35.00	35.00	35.00	39.59	68.80	83.41	98.01	98.01	98.01	484.37	41.84	41.84
Adjusted Total kW	68.70	68.70	68.70	135.21	191.94	248.67	305.39	305.39	305.39	958.24	666.25	82.29
Adjusted Total MWh	40.95	40.95	40.95	46.32	75.18	89.61	104.04	104.04	104.04	551.58	48.95	48.95
Revenue Loss - Total $	$3,108	$3,108	$3,108	$3,516	$5,706	$6,801	$7,897	$7,897	$7,897	$41,865	$3,716	$3,716
Revenue Loss - Cumulative $	$33,729	$36,838	$39,946	$43,462	$49,168	$55,970	$63,866	$71,763	$79,660	$121,524	$125,240	$128,955
Total Avoided Monthly APS Demand $	$499	$499	$499	$983	$1,395	$1,807	$2,219	$2,219	$2,219	$6,964	$4,842	$598
Total Avoided Monthly APS Energy $	$1,340	$1,340	$1,339	$1,515	$2,459	$2,992	$3,568	$3,891	$3,480	$18,038	$1,601	$1,871
Total Avoided Monthly APS Costs	$1,839	$1,839	$1,839	$2,497	$3,854	$4,799	$5,787	$6,110	$5,700	$25,002	$6,443	$2,469
Cumulative Avoided APS Demand $	$5,998	$6,497	$6,996	$7,979	$9,374	$11,181	$13,400	$15,620	$17,839	$24,803	$29,645	$30,243
Cumulative Avoided APS Energy $	$14,604	$15,944	$17,284	$18,799	$21,258	$24,250	$27,818	$31,708	$35,188	$53,227	$54,828	$56,699
Cumulative Avoided APS Costs $	$20,602	$22,441	$24,280	$26,777	$30,632	$35,431	$41,218	$47,328	$53,028	$78,030	$84,473	$86,942
Monthly Total Lost Net Revenue $ w/o AFUDC	$1,270	$1,269	$1,270	$1,018	$1,852	$2,002	$2,110	$1,787	$2,197	$16,862	-$2,727	$1,246
Cumulative Lost Net Revenue $ w/o AFUDC	$13,127	$14,396	$15,666	$16,684	$18,536	$20,539	$22,648	$24,435	$26,632	$43,494	$40,767	$42,013
AFUDC Rate	0.7142%	0.7142%	0.7142%	0.7142%	0.7142%	0.7142%	0.7142%	0.7142%	0.7142%	0.7142%	0.7142%	0.7142%
AFUDC $/Month	$96.73	$106.49	$116.32	$124.42	$138.53	$153.82	$169.99	$183.96	$200.97	$322.83	$305.65	$316.74
AFUDC Cumulative $	$514.37	$620.86	$737.17	$861.59	$1,000.13	$1,153.95	$1,323.94	$1,507.90	$1,708.87	$2,031.70	$2,337.35	$2,654.09
LOST NET REVENUE w/AFUDC	**$13,642**	**$15,017**	**$16,403**	**$17,546**	**$19,537**	**$21,693**	**$23,972**	**$25,943**	**$28,341**	**$45,526**	**$43,104**	**$44,668**

Attachment B-6 (Continued)

Lost Net Revenue Calculations for All Residential Programs

	1997											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
Unadjusted Total kW	109.72	109.72	109.72	505.08	899.74	1294.39	1689.05	1689.05	1689.05	1769.63	1216.56	110.42
Unadjusted Total MWh	41.84	41.84	41.84	42.23	345.17	496.64	648.11	648.11	648.11	690.16	42.23	42.23
Adjusted Total kW	82.29	82.29	82.29	394.63	706.45	1018.27	1330.08	1330.08	1330.08	1389.94	954.23	82.82
Adjusted Total MWh	48.95	48.95	48.95	49.40	391.68	562.82	733.96	733.96	733.96	783.47	49.40	49.40
Revenue Loss - Total $	$3,745	$3,745	$3,745	$3,779	$29,964	$43,056	$56,148	$56,148	$56,148	$59,936	$3,779	$3,779
Revenue Loss - Cumulative $	$132,700	$136,445	$140,190	$143,969	$173,933	$216,989	$273,137	$329,285	$385,432	$445,368	$449,148	$452,927
Total Avoided Monthly APS Demand $	$598	$598	$598	$2,868	$5,134	$7,400	$9,666	$9,666	$9,666	$10,101	$6,935	$602
Total Avoided Monthly APS Energy $	$1,701	$1,603	$1,601	$1,630	$13,629	$19,101	$31,072	$37,015	$41,806	$31,662	$1,619	$1,626
Total Avoided Monthly APS Costs	$2,299	$2,201	$2,199	$4,498	$18,763	$26,501	$40,738	$46,681	$51,473	$41,763	$8,554	$2,228
Cumulative Avoided APS Demand $	$30,841	$31,439	$32,037	$34,905	$40,039	$47,439	$57,106	$66,772	$76,438	$86,540	$93,474	$94,076
Cumulative Avoided APS Energy $	$58,400	$60,002	$61,603	$63,233	$76,862	$95,963	$127,035	$164,051	$205,857	$237,519	$239,138	$240,764
Cumulative Avoided APS Costs $	$89,241	$91,441	$93,641	$98,138	$116,902	$143,403	$184,141	$230,823	$282,295	$324,059	$332,612	$334,840
Monthly Total Lost Net Revenue $ w/o AFUDC	$1,446	$1,544	$1,546	-$718	$11,200	$16,555	$15,409	$9,466	$4,675	$18,172	-$4,774	$1,551
Cumulative Lost Net Revenue $ w/o AFUDC	$43,460	$45,004	$46,550	$45,831	$57,032	$73,586	$88,995	$98,462	$103,137	$121,310	$116,535	$118,087
AFUDC Rate	0.5100%	0.5100%	0.5100%	0.5100%	0.5100%	0.5100%	0.5100%	0.5100%	0.5100%	0.5100%	0.5100%	0.5100%
AFUDC $/Month	$235.18	$244.25	$253.38	$251.01	$309.41	$395.42	$476.03	$526.73	$553.26	$648.76	$627.72	$638.84
AFUDC Cumulative $	$2,889.27	$3,133.52	$3,386.91	$3,637.92	$3,947.33	$4,342.75	$4,818.78	$5,345.51	$5,898.77	$6,547.53	$7,175.26	$7,814.09
LOST NET REVENUE w/AFUDC	**$46,349**	**$48,137**	**$49,936**	**$49,469**	**$60,979**	**$77,929**	**$93,814**	**$103,807**	**$109,036**	**$127,857**	**$123,711**	**$125,901**

Attachment B-6 (Continued)

Lost Net Revenue Calculations for All Residential Programs

	1998					
	Jan	Feb	Mar	Apr	May	June
Unadjusted Total kW	110.42	110.42	110.42	643.67	1177.12	1710.56
Unadjusted Total MWh	42.23	42.23	42.23	42.04	466.35	678.51
Adjusted Total kW	82.82	82.82	82.82	501.61	920.54	1339.48
Adjusted Total MWh	49.40	49.40	49.40	49.19	531.16	772.14
Revenue Loss - Total $	$3,779	$3,779	$3,779	$3,763	$40,634	$59,069
Revenue Loss - Cumulative $	$456,706	$460,486	$464,265	$468,028	$508,662	**$567,731**
Total Avoided Monthly APS Demand $	$602	$602	$401	$2,430	$4,460	$6,490
Total Avoided Monthly APS Energy $	$1,621	$40	$1,179	$1,093	$11,300	$19,657
Total Avoided Monthly APS Costs	$2,223	$642	$1,580	$3,523	$15,760	$26,147
Cumulative Avoided APS Demand $	$94,678	$95,280	$95,681	$98,112	$102,572	$109,061
Cumulative Avoided APS Energy $	$242,385	$242,425	$243,604	$244,697	$255,997	$275,654
Cumulative Avoided APS Costs $	$337,063	$337,705	$339,285	$342,808	$358,569	**$384,716**
Monthly Total Lost Net Revenue $ w/o AFUDC	$1,556	$3,138	$2,200	$240	$24,873	$32,922
Cumulative Lost Net Revenue $ w/o AFUDC	$119,643	$122,781	$124,980	$125,220	$150,093	$183,015
AFUDC Rate	0.5100%	0.5100%	0.5100%	0.5100%	0.5100%	0.5100%
AFUDC $/Month	$650.03	$669.35	$683.98	$688.69	$819.06	$991.14
AFUDC Cumulative $	$8,464.13	$9,133.47	$9,817.45	$10,506.14	$11,325.20	$12,316.34
LOST NET REVENUE w/AFUDC	**$128,107**	**$131,914**	**$134,798**	**$135,726**	**$161,418**	**$195,332**

Attachment B-7

Lost Net Revenue Calculations for All Commercial Programs

	1995								
	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
LGS - Adjusted Total kW	78.10	79.72	81.34	82.96	83.26	83.26	142.88	139.61	133.82
LGS - Adjusted Total MWh	46.30	46.75	48.32	49.21	49.88	49.88	83.42	80.95	77.53
LPS - Adjusted Total kW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LPS - Adjusted Total MWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LGS - Adjusted Cumulative kW	78.10	157.83	239.17	322.14	405.40	488.67	631.55	771.17	904.99
LGS - Adjusted Cumulative MWh	46.30	93.06	141.38	190.59	240.47	290.35	373.78	454.73	532.26
LPS - Adjusted Cumulative kW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LPS - Adjusted Cumulative MWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Monthly Revenue Loss Total $ LGS Customers	$3,261	$3,301	$3,401	$3,465	$3,505	$3,505	$5,896	$5,730	$5,489
Monthly Revenue Loss Cumul $ LGS Customers	$3,261	$6,562	$9,963	$13,428	$16,933	$20,438	$26,333	$32,063	$37,552
Monthly Revenue Loss Total $ LPS Customers	$0	$0	$0	$0	$0	$0	$0	$0	$0
Monthly Revenue Loss Cumul $ LPS Customers	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Avoided Monthly APS Demand $	$568	$579	$591	$603	$605	$605	$1,038	$1,015	$973
Total Avoided Monthly APS Energy $	$1,514	$1,529	$1,580	$1,613	$1,702	$1,631	$2,728	$2,647	$2,536
Total Avoided Monthly APS Costs	$2,082	$2,108	$2,171	$2,216	$2,307	$2,237	$3,767	$3,662	$3,508
Cumulative Avoided APS Demand $	$568	$1,147	$1,738	$2,341	$2,946	$3,551	$4,590	$5,604	$6,577
Cumulative Avoided APS Energy $	$1,514	$3,043	$4,624	$6,237	$7,939	$9,570	$12,298	$14,946	$17,481
Cumulative Avoided APS Costs $	$2,082	$4,190	$6,362	$8,578	$10,885	$13,122	$16,888	$20,550	$24,058
Monthly Total Lost Net Revenue $ w/o AFUDC	$1,179	$1,192	$1,230	$1,249	$1,197	$1,268	$2,129	$2,068	$1,981
Cumulative Net Lost Revenue $ w/o AFUDC	$1,179	$2,371	$3,601	$4,850	$6,048	$7,316	$9,445	$11,513	$13,494
AFUDC Rate	0.7025%	0.7025%	0.7025%	0.7025%	0.7025%	0.7025%	0.7025%	0.7025%	0.7025%
AFUDC $/Mo	$8.28	$16.72	$25.47	$34.43	$43.08	$52.29	$67.62	$82.62	$97.12
AFUDC Cumulative $	$8.28	$25.00	$50.47	$84.90	$127.99	$180.28	$247.90	$330.52	$427.63
LOST NET REVENUE w/AFUDC	$1,187	$2,396	$3,652	$4,935	$6,176	$7,496	$9,693	$11,844	$13,922

Attachment B-7 (Continued)

Lost Net Revenue Calculations for All Commercial Programs

	1996											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LGS - Adjusted Total kW	132.32	132.32	132.32	241.53	263.84	286.14	308.44	309.19	309.19	625.48	526.54	329.42
LGS - Adjusted Total MWh	77.53	77.53	77.53	132.61	189.00	219.47	248.80	249.94	249.94	388.73	199.61	196.19
LPS - Adjusted Total kW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	210.24	210.24	210.24
LPS - Adjusted Total MWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.97	9.97	9.97
LGS - Adjusted Cumulative kW	1037.32	1169.64	1301.97	1543.50	1807.34	2093.47	2401.91	2711.10	3020.29	3645.77	4172.31	4501.74
LGS - Adjusted Cumulative MWh	609.78	687.31	764.84	897.45	1086.45	1305.92	1554.72	1804.67	2054.61	2443.34	2642.95	2839.14
LPS - Adjusted Cumulative kW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	210.24	420.48	630.72
LPS - Adjusted Cumulative MWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.97	19.93	29.90
Monthly Revenue Loss Total $ LGS Customers	$5,475	$5,475	$5,475	$9,509	$12,788	$14,657	$16,465	$16,534	$16,534	$27,089	$15,861	$13,802
Monthly Revenue Loss Cumul $ LGS Customers	$43,027	$48,502	$53,976	$63,485	$76,273	$90,930	$107,395	$123,929	$140,463	$167,552	$183,413	$197,216
Monthly Revenue Loss Total $ LPS Customers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,453	$5,453	$5,453
Monthly Revenue Loss Cumul $ LPS Customers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,453	$10,905	$16,358
Total Avoided Monthly APS Demand $	$962	$962	$962	$1,755	$1,917	$2,079	$2,242	$2,247	$2,247	$6,074	$5,355	$3,922
Total Avoided Monthly APS Energy $	$2,536	$2,537	$2,535	$4,337	$6,182	$7,328	$8,531	$9,347	$8,361	$13,039	$6,854	$7,880
Total Avoided Monthly APS Costs	$3,498	$3,499	$3,497	$6,092	$8,100	$9,408	$10,773	$11,594	$10,608	$19,112	$12,208	$11,802
Cumulative Avoided APS Demand $	$7,539	$8,500	$9,462	$11,217	$13,135	$15,214	$17,456	$19,703	$21,950	$28,023	$33,378	$37,300
Cumulative Avoided APS Energy $	$20,017	$22,554	$25,090	$29,426	$35,609	$42,937	$51,468	$60,815	$69,176	$82,214	$89,068	$96,948
Cumulative Avoided APS Costs $	$27,556	$31,055	$34,552	$40,644	$48,744	$58,151	$68,924	$80,518	$91,125	$110,238	$122,446	$134,248
Monthly Total Lost Net Revenue $ w/o AFUDC	$1,977	$1,976	$1,978	$3,416	$4,688	$5,250	$5,692	$4,940	$5,927	$13,429	$9,105	$7,453
Cumulative Net Lost Revenue $ w/o AFUDC	$15,471	$17,447	$19,425	$22,841	$27,529	$32,779	$38,471	$43,411	$49,338	$57,315	$60,967	$62,968
AFUDC Rate	0.7142%	0.7142%	0.7142%	0.7142%	0.7142%	0.7142%	0.7142%	0.7142%	0.7142%	0.7142%	0.7142%	0.7142%
AFUDC $/Mo	$113.54	$128.47	$143.51	$168.93	$203.62	$242.56	$284.95	$322.26	$366.89	$465.42	$494.83	$512.65
AFUDC Cumulative $	$541.18	$669.64	$813.15	$982.08	$1,185.70	$1,428.26	$1,713.21	$2,035.47	$2,402.36	$2,867.78	$3,362.61	$3,875.26
LOST NET REVENUE w/AFUDC	$16,012	$18,117	$20,238	$23,823	$28,715	$34,207	$40,184	$45,447	$51,740	$60,183	$64,330	$66,843

Attachment B-7 (Continued)

Lost Net Revenue Calculations for All Commercial Programs

	1997											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LGS - Adjusted Total kW	327.92	327.92	327.92	545.61	662.64	779.66	896.69	898.54	898.54	925.16	766.74	451.75
LGS - Adjusted Total MWh	196.19	196.19	196.19	232.32	371.69	445.73	517.59	519.77	519.77	497.81	242.62	236.08
LPS - Adjusted Total kW	210.24	210.24	210.24	210.24	210.24	210.24	210.24	210.24	210.24	313.92	313.92	313.92
LPS - Adjusted Total MWh	9.97	9.97	9.97	9.97	9.97	9.97	9.97	9.97	9.97	14.88	14.88	14.88
LGS - Adjusted Cumulative kW	4829.66	5157.59	5485.51	6031.12	6693.76	7473.42	8370.11	9268.66	10167.20	11092.35	11859.09	12310.84
LGS - Adjusted Cumulative MWh	3035.33	3231.52	3427.71	3660.04	4031.72	4477.45	4995.05	5514.82	6034.59	6532.40	6775.02	7011.10
LPS - Adjusted Cumulative kW	840.96	1051.20	1261.44	1471.68	1681.92	1892.16	2102.40	2312.64	2522.88	2836.80	3150.72	3464.64
LPS - Adjusted Cumulative MWh	39.86	49.83	59.79	69.76	79.72	89.69	99.65	109.62	119.58	134.46	149.34	164.22
Monthly Revenue Loss Total $ LGS Customers	$13,886	$13,886	$13,886	$17,938	$26,701	$31,877	$36,934	$37,072	$37,072	$36,119	$20,604	$17,252
Monthly Revenue Loss Cumul $ LGS Customers	$211,102	$224,988	$238,874	$256,812	$283,513	$315,390	$352,325	$389,396	$426,468	$462,587	$483,190	$500,443
Monthly Revenue Loss Total $ LPS Customers	$5,453	$5,453	$5,453	$5,453	$5,453	$5,453	$5,453	$5,453	$5,453	$8,142	$8,142	$8,142
Monthly Revenue Loss Cumul $ LPS Customers	$21,810	$27,263	$32,715	$38,168	$43,621	$49,073	$54,526	$59,978	$65,431	$73,572	$81,714	$89,855
Total Avoided Monthly APS Demand $	$3,911	$3,911	$3,911	$5,493	$6,344	$7,194	$8,045	$8,058	$8,058	$9,005	$7,854	$5,564
Total Avoided Monthly APS Energy $	$7,162	$6,749	$6,743	$7,993	$13,280	$15,465	$22,334	$26,716	$30,174	$20,719	$8,437	$8,260
Total Avoided Monthly APS Costs	$11,073	$10,660	$10,654	$13,486	$19,624	$22,659	$30,379	$34,774	$38,232	$29,724	$16,291	$13,825
Cumulative Avoided APS Demand $	$41,211	$45,122	$49,033	$54,526	$60,870	$68,064	$76,108	$84,166	$92,224	$101,229	$109,083	$114,647
Cumulative Avoided APS Energy $	$104,110	$110,860	$117,602	$125,595	$138,875	$154,341	$176,675	$203,391	$233,564	$254,283	$262,720	$270,981
Cumulative Avoided APS Costs $	$145,321	$155,982	$166,635	$180,121	$199,745	$222,404	$252,783	$287,557	$325,789	$355,513	$371,803	$385,628
Monthly Total Lost Net Revenue $ w/o AFUDC	$8,265	$8,678	$8,685	$9,905	$12,529	$14,671	$12,008	$7,750	$4,292	$14,536	$12,455	$11,569
Cumulative Net Lost Revenue $ w/o AFUDC	$65,781	$69,006	$72,239	$76,691	$83,768	$92,986	$99,541	$101,839	$100,679	$107,074	$111,387	$114,814
AFUDC Rate	0.5100%	0.5100%	0.5100%	0.5100%	0.5100%	0.5100%	0.5100%	0.5100%	0.5100%	0.5100%	0.5100%	0.5100%
AFUDC $/Mo	$383.05	$401.46	$419.99	$444.84	$483.20	$532.67	$568.83	$583.45	$580.50	$629.79	$655.00	$675.82
AFUDC Cumulative $	$4,258.32	$4,659.77	$5,079.76	$5,524.60	$6,007.80	$6,540.48	$7,109.30	$7,692.75	$8,273.25	$8,903.04	$9,558.05	$10,233.87
LOST NET REVENUE w/AFUDC	$70,039	$73,666	$77,318	$82,216	$89,776	$99,526	$106,651	$109,532	$108,952	$115,977	$120,945	$125,048

Attachment B-7 (Continued)

Lost Net Revenue Calculations for All Commercial Programs

	1998					
	Jan	Feb	Mar	Apr	May	June
LGS – Adjusted Total kW	448.05	448.05	448.05	563.22	680.25	797.27
LGS – Adjusted Total MWh	236.08	236.08	236.08	236.08	375.44	449.48
LPS – Adjusted Total kW	313.92	313.92	313.92	313.92	313.92	313.92
LPS – Adjusted Total MWh	14.88	14.88	14.88	14.88	14.88	14.88
LGS – Adjusted Cumulative kW	12758.89	13206.94	13654.98	14218.20	14898.45	15695.72
LGS – Adjusted Cumulative MWh	7247.17	7483.25	7719.32	7955.40	8330.84	8780.32
LPS – Adjusted Cumulative kW	3778.56	4092.48	4406.40	4720.32	5034.24	5348.16
LPS – Adjusted Cumulative MWh	179.10	193.98	208.86	223.74	238.62	253.50
Monthly Revenue Loss Total $ LGS Customers	$17,217	$17,217	$17,217	$18,311	$27,074	$32,251
Monthly Revenue Loss Cumul $ LGS Customers	$517,660	$534,877	$552,094	$570,405	$597,479	**$629,729**
Monthly Revenue Loss Total $ LPS Customers	$8,142	$8,142	$8,142	$8,142	$8,142	$8,142
Monthly Revenue Loss Cumul $ LPS Customers	$97,997	$106,138	$114,280	$122,421	$130,563	**$138,704**
Total Avoided Monthly APS Demand $	$5,538	$5,538	$3,692	$4,250	$4,817	$5,384
Total Avoided Monthly APS Energy $	$8,236	$8,453	$5,987	$5,575	$8,304	$11,822
Total Avoided Monthly APS Costs	$13,773	$13,991	$9,679	$9,825	$13,121	$17,205
Cumulative Avoided APS Demand $	$120,185	$125,722	$129,414	$133,664	$138,481	$143,864
Cumulative Avoided APS Energy $	$279,217	$287,670	$293,657	$299,232	$307,536	$319,358
Cumulative Avoided APS Costs $	$399,402	$413,392	$423,071	$432,896	$446,017	**$463,222**
Monthly Total Lost Net Revenue $ w/o AFUDC	$11,585	$11,368	$15,680	$16,628	$22,095	$23,187
Cumulative Net Lost Revenue $ w/o AFUDC	$118,258	$121,484	$129,023	$137,509	$151,462	**$305,212**
AFUDC Rate	0.5100%	0.5100%	0.5100%	0.5100%	0.5100%	0.5100%
AFUDC $/Mo	$696.83	$716.84	$758.94	$806.09	$881.36	$962.59
AFUDC Cumulative $	$10,930.70	$11,647.53	$12,406.48	$13,212.57	$14,093.93	$15,056.52
LOST NET REVENUE w/AFUDC	$129,189	$133,132	$141,429	$150,722	$165,556	**$320,268**

APPENDIX C

APPENDIX C

Table III-__ Summary of Stranded Costs and Illustrative Revenue Requirement Calculation

Cost Category	One-Time Costs	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Generation											
APS Contract											
Sched. A Divestiture	$ 43,198,000										
Outside Svcs. - Divestiture	$ 100,000										
Outside Svcs. - Mitigation	$ 175,000										
Mohave Transmission Abandonment	$ 2,100,000										
Mohave CT Cancellation	$ 1,853,000										
PPFAC Balance	$ (1,000,000)										
Total Generation	**$ 46,426,000**										
Regulatory Assets											
Deferred DSM	$ 2,982,000										
Total Regulatory Assets	**$ 2,982,000**										
Metering and Billing											
Metering and Meter Reading		$ 7,000	$ 12,000	$ 17,000	$ 25,000	$ 33,000	$ 39,000	$ 48,000	$ 58,000	$ 71,000	$ 86,000
Billing and Collections		$ 16,000	$ 37,000	$ 57,000	$ 93,000	$ 136,000	$ 168,000	$ 208,000	$ 258,000	$ 320,000	$ 398,000
Total Metering & Billing		**$ 23,000**	**$ 49,000**	**$ 74,000**	**$ 118,000**	**$ 169,000**	**$ 207,000**	**$ 256,000**	**$ 316,000**	**$ 391,000**	**$ 484,000**
NPV Metering and Billing	$1,129,000										
New Functions											
New Salary and Overhead	105000	759000	725000	720000	485000	167000	172000	177000	182000	187000	192000
Energy Transactions	$ 555,000	$ 150,000	$ 154,000	$ 158,000	$ 163,000	$ 167,000	$ 172,000	$ 177,000	$ 181,000	$ 186,000	$ 191,000
Operational Processes	$ 710,000	$ 240,000	$ 247,000	$ 253,000	$ 108,000	$ 111,000	$ 115,000	$ 118,000	$ 121,000	$ 124,000	$ 128,000
Regulatory Costs	$ 430,000	$ 175,000	$ 180,000	$ 185,000	$ 190,000	$ 195,000	$ 200,000	$ 206,000	$ 212,000	$ 217,000	$ 223,000
Cust. Comm & Ed.	$ 150,000	$ 200,000	$ 206,000	$ 211,000	$ 22,000	$ 22,000	$ 23,000	$ 24,000	$ 24,000	$ 25,000	$ 26,000
Total New Functions	**$ 1,845,000**	**$ 765,000**	**$ 787,000**	**$ 807,000**	**$ 483,000**	**$ 495,000**	**$ 510,000**	**$ 525,000**	**$ 538,000**	**$ 552,000**	**$ 568,000**
NPV New Functions(On-going)	$ 4,028,000										
Total One-Time Stranded Costs	$ 51,358,000	$ 51,358,000	$ 51,358,000	$ 51,358,000	$ 51,358,000	$ 51,358,000	$ 51,358,000	$ 51,358,000	$ 51,358,000	$ 51,358,000	$ 51,358,000
Amortization of One-Time Costs		$ 5,135,800	$ 5,136,000	$ 5,136,000	$ 5,136,000	$ 5,136,000	$ 5,136,000	$ 5,136,000	$ 5,136,000	$ 5,136,000	$ 5,136,000
Accum Amortization of One-Time $		$ 5,135,800	$ 10,271,600	$ 15,407,400	$ 20,543,200	$ 25,679,000	$ 30,814,800	$ 35,950,600	$ 41,086,400	$ 46,222,200	$ 51,358,000
Accumulated Deferred Taxes	$ 20,337,768	$ 18,303,991	$ 16,270,214	$ 14,236,438	$ 12,202,661	$ 10,168,884	$ 8,135,107	$ 6,101,330	$ 4,067,554	$ 2,033,777	$ (0)
Net One-time Stranded Costs	**$ 31,020,232**	**$ 27,918,209**	**$ 24,816,186**	**$ 21,714,162**	**$ 18,612,139**	**$ 15,510,116**	**$ 12,408,093**	**$ 9,306,070**	**$ 6,204,046**	**$ 3,102,023**	**$ 0**
Return on Net One-Time SC											
Debt Return		$ 964,000	$ 868,000	$ 772,000	$ 675,000	$ 579,000	$ 482,000	$ 386,000	$ 289,000	$ 193,000	$ 96,000
Equity Return		$ 1,786,000	$ 1,607,000	$ 1,429,000	$ 1,250,000	$ 1,072,000	$ 893,000	$ 714,000	$ 536,000	$ 357,000	$ 179,000
Total Return		**$ 2,750,000**	**$ 2,475,000**	**$ 2,201,000**	**$ 1,925,000**	**$ 1,651,000**	**$ 1,375,000**	**$ 1,100,000**	**$ 825,000**	**$ 550,000**	**$ 275,000**
Income Taxes:											
Taxes on Equity Return		**$ 1,170,530**	**$ 1,052,980**	**$ 937,086**	**$ 819,536**	**$ 703,642**	**$ 586,093**	**$ 468,543**	**$ 350,993**	**$ 233,444**	**$ 117,550**
Total On-Going Stranded Costs		**$ 1,547,000**	**$ 1,561,000**	**$ 1,601,000**	**$ 1,086,000**	**$ 831,000**	**$ 889,000**	**$ 958,000**	**$ 1,036,000**	**$ 1,130,000**	**$ 1,244,000**
Total Revenue Requirement		**$ 10,603,330**	**$ 10,224,980**	**$ 9,875,086**	**$ 8,966,536**	**$ 8,321,642**	**$ 7,986,093**	**$ 7,662,543**	**$ 7,347,993**	**$ 7,049,444**	**$ 6,772,550**
Net Present Value of RR	$56,774,000										
Levelized Revenue Requirement	$8,794,381										

Financial Assumptions:	
Escalation Rate	2.75%
Cost of Debt	7.23%
Cost of Equity	10.10%
% Equity in Cap Struc.	57%
Cost of Capital	8.87%
Income Tax Rate	39.6%

[a] all one-time expenditures made in 1998.
[b] all one-time costs amortized over 10-years
[c] most values rounded to nearest $1000