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June 15, 2006

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Docket Control
Arizona Corporation Commission
1200 W. Washington
Phoenix, AZ 85007

Re: *AEPCO's Equity Improvement Analysis; Decision No. 68071; Docket Nos. E-01773A-04-0528 and E-04100A-04-0527*

Dear Sir/Madam:

Pursuant to the eighth ordering paragraph at page 16 of Decision No. 68071, enclosed are the original and 15 copies of the Equity Improvement Analysis of the Arizona Electric Power Cooperative, Inc. The date for filing this report was extended from March 31, 2006 to June 16, 2006 by Procedural Orders dated April 6 and June 13, 2006.

Very truly yours,

GALLAGHER & KENNEDY, P.A.

Michael M. Grant

By:
Michael M. Grant

MMG/plp
10421-47/1378882
Attachment

Original and 15 copies filed with Docket Control this 15th day of June, 2006.

cc (w/attachment): Dirk Minson
Gary Pierson

Equity Improvement Analysis

Arizona Electric Power Cooperative, Inc.

Introduction

The Arizona Electric Power Cooperative, Inc. ("AEPCO" or the "Cooperative") is a non-profit generation cooperative owned by its members. There are six Class A member distribution cooperatives, one Class B member and one Class C member. Representatives from each member comprise AEPCO's Board of Directors which governs its operations.

The Class A members are Anza Electric Cooperative, which serves electricity at retail in south-central California; and Duncan Valley Electric Cooperative, Graham County Electric Cooperative, Mohave Electric Cooperative, Sulphur Springs Valley Electric Cooperative and Trico Electric Cooperative—all of which serve electricity at retail in rural areas of Arizona. Mohave Electric Cooperative ("MEC") is provided power pursuant to a partial-requirements contract. The other five distribution cooperative members receive their power on an all-requirements basis, although Sulphur Springs Valley Electric Cooperative is in the process of converting its status to partial requirements. The Class B member is the City of Mesa and the Class C member is the Salt River Project. Both have firm contracts for fixed terms for specific amounts of power and energy.

AEPCO produces much of the power it supplies to its members at the Apache Generating Station near Wilcox, Arizona, which has approximately 555 MWs of coal and natural gas fired capacity. To meet members' needs or where it is more economical to do so, AEPCO also enters into other power purchase arrangements, including short- and long-term purchase agreements with other utilities. Current long-term purchase agreements include a 15 MW year-round contract with Public Service Company of New Mexico which expires at the end of 2008 and a five-year agreement with TECO-Panda Gila River, LLC for summer peaking capacity and energy which expires in 2007. AEPCO has also entered into two long-term seasonal purchased power contracts for 2008-2014 with Calpine and PPL.

AEPCO's current rates were established in Decision No. 68071 dated August 17, 2005 (the "Decision"). During the rate case leading to the Decision, there was discussion about AEPCO equity levels. (Decision, pp. 11-14, Findings 43-54.) Citing, among other things, prior financing Decision No. 64227, Staff urged the Commission to set an equity goal for AEPCO of 30% by 2015. While AEPCO agreed with Staff that an equity analysis should be filed, the Cooperative responded that a 30% equity goal was excessive for a generation cooperative and argued that no equity goal should be established because an inflexible target could leave both it and the Commission in the position of requesting and setting unnecessarily high rates in the future. MEC agreed that the equity level recommended by Staff is excessive, but in briefing suggested that AEPCO's equity filing also examine differences in benefits, if any, which partial- versus all-requirements members receive from an improved AEPCO equity position.

The Commission resolved these issues in Findings 53 and 54 of the Decision as follows:

> We believe that AEPCO should update its December 2002 Capital Improvement Plan, with updated assumptions, and provide an analysis of the rates that would be required to achieve an equity level of 30 percent, within ten years, or 2015. <u>We do not adopt a requirement now, nor does Decision No. 64227 specifically require, that AEPCO achieve any specific equity goal</u>. We do adopt the rates herein with the expectation that AEPCO will be able to

> build much needed equity. Because we are requiring AEPCO to file another rate case in no more than five years, in any case, adopting an ultimate goal of 30 percent at this time is not necessary. (Emphasis supplied).
>
> * * *
>
> We believe Mohave's suggestion that the capital improvement plan that AEPCO will file in 2006 should specifically address its obligations to partial requirements members is well-founded, and direct AEPCO to include such analysis in its 2006 updated report.

At page 16, 11. 21-25 of the Decision, the Commission accordingly ordered AEPCO to file an analysis of three issues as follows:

> IT IS FURTHER ORDERED that Arizona Electric Power Cooperative, Inc. shall file by March 31, 2006, an equity improvement plan that will indicate [1] the effect on AEPCO's equity under the rates approved herein and [2] an analysis of the effect on rates if equity of 30 percent of total capitalization is to be reached by 2015, as well as [3] an analysis of the benefits and equities of capitalization on its partial requirements and full requirements members.

By Procedural Orders dated April 6 and June 13, 2006, the date for filing this updated report was extended to June 16, 2006. This equity analysis updates assumptions and addresses the three issues identified in the Decision.

Equity Analysis

Executive Summary

The Cooperative used its 2005 Financial Forecast in preparing this update of its December 2002 filing. As required by the Decision, AEPCO first developed a "base case" which assumed no further rate increases for the period 2008-2015 after the phased rates approved in the Decision take effect in 2006. Under the base case, equity levels as a percentage of assets generally rise to slightly more than 20% in 2012 and then decline to just over 15% by 2015.

In order to produce an equity level of approximately 30% by 2015, three rate increases of 3%, 3% and 7% would be required in 2008, 2013 and 2015, respectively. At the present time, it also appears that an energy rate decrease would be necessary in 2011 to account for the expiration of the 100 MW long-term sale agreement to SRP in 2010 and the corresponding return of that coal-fired capacity and expense responsibility to the members in 2011. Both the base case and 30% equity case results, of course, are premised on all of the updated assumptions in the financial forecast holding true over the ten-year forecast period. To place the 30% equity level in context, the 2004 G&T Trend Analysis prepared by the CFC indicated a median equity level as a percentage of assets for all G&Ts nationwide of just under 15.5%.

For several reasons, AEPCO believes that both all- and partial-requirements members benefit equally from the Cooperative's equity improvement. As discussed in greater detail herein, much of AEPCO's past and future borrowing has nothing to do with adding capacity, but instead is focused on necessary repairs, replacements, upgrades or improvements to the existing system which benefit all members. To the extent that future capacity is built, a non-participating partial-requirements member is not charged rates for that capacity. Also, all members have the same interest in assuring that AEPCO meets the financial performance requirements of the RUS, CFC and its mortgage which, as met, will build equity gradually over time. Further, maintaining adequate credit strength is important for all members in AEPCO's dealings with third-party vendors. Finally, assuming agreement, partial-requirements members may participate in future resource additions constructed or acquired by AEPCO.

Equity Requirements and History

In addition to the Commission, the Rural Utilities Service ("RUS") also regulates AEPCO. RUS' jurisdiction over AEPCO is based on a variety of sources, including its guarantee of debt which AEPCO, as a power supply borrower, obtains from the Federal Financing Bank. Neither the RUS nor AEPCO's other primary source of borrowed funds, the National Rural Utilities Cooperative Finance Corporation ("CFC"), impose equity level or equity management requirements on power supply borrowers such as AEPCO. Further, neither the RUS nor CFC "rate" the debt which they guarantee or provide to AEPCO, i.e., charge different interest rates based on the borrower's credit characteristics or equity level.

However, RUS and CFC do require that AEPCO meet certain retrospective and prospective Times Interest Earned Ratio ("TIER") and Debt Service Coverage Ratio ("DSC") requirements. The retrospective requirement of the mortgage covenants mandates that average TIER and DSC levels achieved in the two best out of the three most recent calendar years must meet the levels of 1.05 and 1.0, respectively. Prospectively, AEPCO must design and implement rates for electric power, energy and other services sufficient to provide revenue to (1) pay all fixed and variable expenses, (2) provide and maintain reasonable working capital and (3) maintain, on an annual basis, the TIER and DSC margin requirements.

AEPCO's equity history was discussed in the filing it made with the Commission on December 23, 2002 as directed by Decision No. 64227. Briefly to summarize, the most significant prior changes in AEPCO's equity profile were caused by the economic recession of the 1980s and, most notably, a collapse in the copper market. The latter factor resulted in the loss of 125 MWs of copper mining and refining load—more than one-third of the generating capacity of Apache Steam Units 2 and 3 which had been brought on-line in the late 1970s. Ultimately, because of load losses, AEPCO was forced to put one of its 175 MW steam units in "stand-by" status and deferred recording its associated fixed costs during 1988 and 1989. As a result of these developments, the Cooperative's negative equity grew over time and ultimately exceeded a negative $51 million in 1990.

Through a combination of factors including rate increases in 1982 and 1984, cost reduction and cost containment programs, debt-restructurings, increasing member load levels and sales in the economy energy markets as well as a gradually improving economy, AEPCO was able to raise its equity level from this $51 million deficit in 1990 to a positive level of approximately $17.8 million or 6.7% at the end of 2002, while simultaneously reducing member rates by approximately 22% after 1985. General inflationary pressures, increasing fuel costs and higher maintenance expense, however, produced negative margins in the test year of 2003 leading to the rate filing in the summer of 2004. In last year's rate decision, the Commission approved new rates for September 1, 2005 implementation, but by the end of 2005, AEPCO's equity level had slipped to 4.4% as a result of these negative margins in the 2003 to 2005 period.

The Financial Forecast

The financial forecast used as the basis for this analysis was approved by AEPCO's Board of Directors at its November 7, 2005 meeting and, as required by the Decision, updates the assumptions used in the December 2002 filing.[1] Although financial forecasts are prepared annually to guide the Cooperative on various operational and financial matters, RUS Rule 7 CFR 1710.300(b) requires a long-range financial forecast be prepared in conjunction with AEPCO's currently pending 2005-2008 Construction Work Plan loan request (the "2005 Forecast").

As with any forecast, a number of assumptions must be made concerning a variety of different factors. The 2005 Forecast represents AEPCO's best current judgment as to what is likely to happen in relation to these factors over the next ten years. These include member and other firm and contingent load growth; resulting kW and kWh energy sales, revenues and power costs; operating expenses; required future borrowings and associated interest and principal expense; and labor costs. Obviously, to the extent that actual experience differs from these projections, both the forecast results and this equity analysis will be impacted accordingly.

The more significant assumptions built into the 2005 Forecast are:

- Load forecasts are based primarily upon the medium economic scenario in the 2004 Load Forecast Study.

- Class A member revenues are a function of peak demand multiplied by the expected demand rate and billable energy sales multiplied by the forecast energy rate. Non-Class A revenues are either calculated based on cost items per the contract or the billable units multiplied by the stated contract rate.

[1] Forecast accruals on overhaul expense, however, were changed to reflect a decision made after November 2005 to perform major overhauls on a six- instead of eight-year cycle as well as to increase minor overhaul costs.

- Operating expenses are based on the 2005 annual operating plan and the base amount is escalated at 3% throughout the study period. Fuel and purchased power costs are calculated in PROMOD, the generation costing model, and then input into IMPACT, the financial forecasting model.

- The 2005-2008 Construction Work Plan ("CWP") and the Long Range Plan ("LRP") are used to determine plant additions reflected in the financial forecast. No new generating resources are included in the current CWP or LRP.

- A general inflation rate of 3% is used for the base case, including labor costs.

- Sulphur Springs Valley Electric Cooperative, Inc. is assumed to become a partial-requirements member in 2006. This assumption also required different, but revenue neutral rate levels for all-and partial-requirements members.

One additional point should be noted which is not reflected in the 2005 Forecast. AEPCO currently has pending before the RUS a request that its principal payment schedule be revised to reflect the lower depreciation rates for Steam Units 2 and 3 which were approved at Finding 38 of the Decision. The lower depreciation rates are based on a life assessment study which confirmed the expected useful lives of Steam Units 2 and 3 through 2035. If the RUS approves that request this year, the lower principal payments will impact this equity analysis.

AEPCO's Equity Under the Rates Approved in the Decision

As reflected in Exhibit A to the Decision, the Commission last year approved phased rates and an FPPCA for AEPCO's all- and partial-requirements members. The first phase took effect September 1, 2005. Additional 1.5% increases have been approved effective September 1, 2006 and September 1, 2007. In the 2005 Forecast, AEPCO used these rates and fuel adjustor through 2007 and then assumed revenue requirements and rates sufficient to produce either a DSC ratio of 1.05 or a 1.15 TIER for the period 2008-2015.

In order to "indicate the effect on AEPCO's equity under the rates approved herein... by 2015,"[2] these revenue requirements/DSC ratio and TIER assumptions for 2008-2015 were removed from the 2005 Forecast. Attached as Exhibit A is a Balance Sheet demonstrating the effects of the rates approved in the Decision on AEPCO's equity level assuming no further rate adjustment through 2015.

As the Balance Sheet indicates, under this assumption, equity as a percent of total assets generally increases to approximately 20.4% in 2012 and then declines to about 15.2% in 2015. This, of course, assumes that all projections in the 2005 Forecast hold true over the ten-year forecast period. It must also be stressed that, while equity grows in the 2007-2012 period, this does not mean that the margins generated in those years by current rates would be adequate to meet mortgage requirements.

Rates Required for 30% Equity By 2015

In order to "indicate the effect on AEPCO's equity... if equity of 30 percent of total capitalization is to be reached by 2015,"[3] the revenue requirements/DSC ratio and TIER assumptions for 2008-2015 were once again removed from the 2005 Forecast. Instead, rate adjustments were assumed at levels sufficient to achieve a 30% equity level by December 31, 2015. Attached as Exhibit B is a Balance Sheet which reflects the results of that analysis.

As the Balance Sheet indicates, AEPCO's equity as a percent of total assets would reach slightly more than 30% in 2015. In order to produce this result, two rate increases of 3% each

[2] Decision, p. 16, Eighth Ordering Paragraph.
[3] *Id.*

over the previous year's rates would be necessary in 2008 and 2013 and a 7% increase would be necessary in 2015. At the present time, it also appears that an energy rate decrease may be necessary in 2011 to account for the expiration of the long-term, 100 MW sale agreement with SRP at the end of 2010 and the corresponding return of that coal-fired capacity for members' use in 2011. As with the base case, these results are dependent upon all of the assumptions in the 2005 Forecast holding true through the ten-year forecast period.

Analysis of AEPCO's Equity on Partial-Requirements and Full-Requirements Members

Finally, the Decision required AEPCO to provide "an analysis of the benefits and equities of capitalization on its partial requirements and full requirements members."[4] MEC filed no testimony during the rate case, but in its Closing Brief argued that, because AEPCO does not have the same power supply obligation for partial-requirements members as all-requirements members, revenues necessary to support increases in equity should not be paid for by partial-requirements members:

> Mohave argues that Staff's recommended revenue requirement is based on the need to maintain financial stability to finance future plant additions and replacements [footnote omitted], and Mohave believes there is a question of the fairness of a requirement that a customer who will not cause, and is not allowed to participate in, the future event to have revenue responsibility for that event.

(Decision, Finding 49, pp. 12-13.)

As stated previously, AEPCO agrees with MEC that the 30% equity target which Staff recommended and the Commission rejected in the Decision was excessive. For a number of reasons, however, it does not agree that there is any unfairness or discrimination associated with

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[4] *Id.*

revenue requirements and rates which generally allow the Cooperative to build an adequate level of equity over time.

First, much of AEPCO's borrowing has nothing to do with building additional capacity. Instead, the vast majority of new debt is devoted to necessary repairs, replacements, upgrades or improvements to the existing system in which MEC participates as a partial-requirements member. For example, as mentioned previously, the 2005 Forecast assumes no generation resource additions in the next ten years, yet AEPCO's currently pending Construction Work Plan includes $29 million to finance necessary repairs, replacements and improvements to the existing system.[5] Historically, the gas turbine at Apache Station was the first generation resource built by AEPCO in more than 20 years. Since 2001, the Commission has authorized approximately $86 million in new long-term debt for AEPCO.[6] Only $30 million or roughly 35% of that amount was for a generation addition, i.e., Gas Turbine #4. The remaining two-thirds was spent on projects such as closure of the old Ash Pond, construction of the new Low Volume Waste Water disposal facility and acquisition of a coal blending facility designed to make more efficient, reduce costs and improve the environmental characteristics of Steam Units 2 and 3—units in which MEC participates. To the extent that sufficient rates support adequate equity levels and the credit strength of AEPCO to make those borrowings, MEC derives the same benefits as do the all-requirements members. If MEC does not participate in a future facility, it is not assigned cost responsibility for it.

[5] This finance request is currently pending in Docket No. E-01773A-06-0084.
[6] Decision Nos. 63305, 64227, 65210 and 68065.

Second, AEPCO is required to meet certain prospective and retrospective TIER and DSC requirements in order to comply with RUS requirements and the covenants of its mortgage agreements. Consistently maintained, achieving these requirements over time gradually builds equity. All- and partial-requirements members have the same interest in assuring that AEPCO remains in good standing with all regulatory and mortgage instrument requirements.

Third, while the RUS and CFC do not have equity level or equity management requirements, AEPCO does transact business with a number of third-party vendors for goods and services. They do look at its credit quality in determining the basis upon which they will transact business with the Cooperative. Inadequate equity levels or a weak balance sheet may raise the costs, change the terms or increase the security required for a vendor to sell goods, services or fuels on credit to AEPCO. Again, all- and partial-requirements members like MEC benefit equally from AEPCO's ability to enter into these kinds of transactions at the lowest reasonable cost and on the most favorable terms possible.

Fourth and finally, MEC derives valuable market flexibility on a going forward basis as a result of its partial-requirements agreement with the Cooperative. While AEPCO has no obligation to construct generating capacity or execute purchased power agreements to meet the future demands of a partial-requirements member like MEC, partial-requirements members do have the option of participating in future resources acquired by AEPCO, assuming the parties can reach agreement on that participation. MEC, thus, has the ability to use the collective strength of the generation cooperative in assessing various options available to it to meet load growth on its system. To the extent that sufficient equity levels and credit strength place

AEPCO in a better position to acquire such future resources, MEC and other partial-requirements members tangibly benefit from that position.

Again, AEPCO stresses that it does not agree that a 30% equity target or any other pre-determined equity level should be established for the Cooperative. AEPCO should continue the gradual equity improvement which it has been achieving over the past 15 years. That improvement has and will continue to benefit all- and partial-requirements members alike.

Conclusion

AEPCO agrees that equity is an important consideration in assessing its overall financial profile, but it is only one of many relevant considerations. For example, the CFC regularly monitors more than 30 key financial indicators of generation and transmission cooperatives operating nationwide. The CFC's G&T Trend survey for 2004—the most recent year for which data is available—indicated a median equity level for all G&Ts nationwide of 15.47% (excluding four systems which failed to make scheduled debt service payments or which are operating under a debt restructure agreement). AEPCO does not believe that any equity target or goal should be established and 30% is unnecessarily high.

The phased rate increases for 2005-2007 which the Commission approved in the Decision will allow the Cooperative to resume its gradual equity improvement over the next few years. AEPCO and its Board of customer representatives will continue to monitor its progress and work with the Commission to assure that adequate rate levels sufficient for safe, reliable and adequate service are maintained.

EXHIBIT A

Arizona Electric Power Cooperative
Equity Plan Base Case
(Based on 2005 Financial Forecast with Changes to Overhaul Costs)

Balance Sheet Liabilities And Other Credits	2005 Actuals	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Capitalization											
Memberships	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33
Patronage Capital	17,803.24	17,803.24	17,803.24	17,803.24	17,803.24	17,803.24	17,803.24	17,803.24	17,803.24	17,803.24	17,803.24
Operating Margins - Prior & Current Years	-$7,427	$1,593	$14,760	$17,144	$17,456	$13,567	$18,775	$20,786	$18,768	$15,076	$2,667
Non-Operating Margins	$1,098	$4,353	$6,211	$8,743	$10,229	$11,584	$12,714	$13,902	$15,109	$16,406	$17,642
Total Margins/Equities	$11,475	$23,750	$38,775	$43,691	$45,489	$42,955	$49,293	$52,491	$51,680	$49,286	$38,113
Long Term Debt											
Ltd - RUS (Net)	$3,104	$2,255	$1,407	$633	$107	$0	$0	$0	$0	$0	$0
Ltd - FFB	$148,707	$115,459	$115,973	$109,812	$109,816	$101,305	$95,381	$94,674	$96,193	$99,277	$102,211
Total Ltd - Other (Net)	$53,547	$62,893	$58,422	$55,763	$52,854	$49,536	$45,932	$42,007	$37,831	$33,252	$28,844
Total Long-Term Debt	$205,357	$180,606	$175,801	$166,209	$162,777	$150,842	$141,313	$136,681	$134,023	$132,529	$131,056
Accum Operating Provisions	$2,700	$4,897	$4,897	$4,897	$4,897	$4,897	$4,897	$4,897	$4,897	$4,897	$4,897
Total Noncurrent Liabilities	$2,700	$4,897	$4,897	$4,897	$4,897	$4,897	$4,897	$4,897	$4,897	$4,897	$4,897
Current Liabilities											
Notes Payable	$15,247	$4,524	$1,834	$1,834	$1,834	$7,034	$6,422	$4,745	$1,834	$1,834	$8,664
Accts Payable	$9,708	$22,088	$30,747	$26,357	$25,359	$26,497	$24,068	$24,271	$25,110	$25,079	$25,683
Taxes Accrued	$2,039	$1,596	$1,550	$1,588	$1,598	$1,612	$1,609	$1,605	$1,598	$1,588	$1,574
Interest Accrued	$914	$254	$234	$221	$207	$190	$172	$152	$129	$103	$79
Other Current Liabilities	$8,536	$14,542	$16,704	$21,432	$25,315	$26,822	$30,771	$32,311	$35,852	$39,514	$39,265
Total Current Liabilities	$36,445	$43,004	$51,069	$51,432	$54,312	$62,156	$63,042	$63,084	$64,523	$68,119	$75,264
Deferred Credits	$5,513	$2,635	$2,297	$1,960	$1,623	$1,285	$948	$695	$695	$695	$695
Total Liabilities	$261,490	$254,891	$272,839	$268,188	$269,097	$262,134	$259,493	$257,848	$255,818	$255,525	$250,024
Equity as a Percent of total assets	4.39%	9.32%	14.21%	16.29%	16.90%	16.39%	19.00%	20.36%	20.20%	19.29%	15.24%

EXHIBIT B

Arizona Electric Power Cooperative
Equity Plan - 30% by 2015
(Based on 2005 Financial Forecast with Increased OH Costs)

Balance Sheet Liabilities And Other Credits	2005 Actuals	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Capitalization											
Memberships	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Patronage Capital	$17,803	$17,803	$17,803	$17,803	$17,803	$17,803	$17,803	$17,803	$17,803	$17,803	$17,803
Operating Margins - Prior & Current Years	-$7,427	$1,593	$14,760	$21,961	$27,457	$29,046	$34,929	$37,549	$40,713	$42,337	$46,601
Non-Operating Margins	$1,098	$4,353	$6,211	$8,829	$10,652	$12,641	$14,511	$16,600	$18,911	$21,738	$25,147
Total Margins/Equities	$11,475	$23,750	$38,775	$48,594	$55,913	$59,491	$67,243	$71,953	$77,427	$81,879	$89,552
Long Term Debt											
Ltd - RUS (Net)	$3,104	$2,255	$1,407	$633	$107	$0	$0	$0	$0	$0	$0
Ltd - FFB	$148,707	$115,459	$115,973	$109,812	$109,816	$101,305	$95,381	$94,674	$96,193	$99,277	$102,211
Total Ltd - Other (Net)	$53,547	$62,893	$58,422	$55,763	$52,854	$49,536	$45,932	$42,007	$37,831	$33,252	$28,844
Total Long-Term Debt	$205,357	$180,606	$175,801	$166,209	$162,777	$150,842	$141,313	$136,681	$134,023	$132,529	$131,056
Accum Operating Provisions	$2,700	$4,897	$4,897	$4,897	$4,897	$4,897	$4,897	$4,897	$4,897	$4,897	$4,897
Total Noncurrent Liabilities	$2,700	$4,897	$4,897	$4,897	$4,897	$4,897	$4,897	$4,897	$4,897	$4,897	$4,897
Current Liabilities											
Notes Payable	$15,247	$4,524	$1,834	$1,834	$1,834	$1,834	$1,834	$1,834	$1,834	$1,834	$1,834
Accts Payable	$9,708	$22,088	$30,747	$26,357	$25,359	$26,497	$24,068	$24,271	$25,110	$25,079	$25,683
Taxes Accrued	$2,039	$1,596	$1,550	$1,588	$1,598	$1,612	$1,609	$1,605	$1,598	$1,588	$1,574
Interest Accrued	$914	$254	$234	$221	$207	$190	$172	$152	$129	$103	$79
Other Current Liabilities	$8,536	$14,542	$16,704	$21,432	$25,315	$26,822	$30,771	$32,311	$35,852	$39,514	$39,265
Total Current Liabilities	$36,445	$43,004	$51,069	$51,432	$54,312	$56,956	$58,454	$60,173	$64,523	$68,119	$68,434
Deferred Credits	$5,513	$2,635	$2,297	$1,960	$1,623	$1,285	$948	$695	$695	$695	$695
Total Liabilities	$261,490	$254,891	$272,839	$273,091	$279,522	$273,470	$272,855	$274,399	$281,565	$288,118	$294,633
Equity as a Percent of Total Assets	4.39%	9.32%	14.21%	17.79%	20.00%	21.75%	24.64%	26.22%	27.50%	28.42%	30.39%