PINNACLE WEST CAPITAL CORP

FORM 8-K
(Current report filing)

Filed 04/22/02 for the Period Ending 03/31/02

Address	400 NORTH FIFTH STREET MS8695 PHOENIX, AZ 85004
Telephone	602 250 1000
CIK	0000764622
Symbol	PNW
SIC Code	4911 - Electric Services
Industry	Electric Utilities
Sector	Utilities
Fiscal Year	12/31

PINNACLE WEST CAPITAL CORP

FORM 8-K
(Unscheduled Material Events)

Filed 4/22/2002 For Period Ending 3/31/2002

Address	400 NORTH FIFTH STREET .
	PHOENIX, Arizona 85004
Telephone	602-379-2500
CIK	0000764622
Industry	Electric Utilities
Sector	Utilities
Fiscal Year	12/31

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of the
Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): March 31, 2002

PINNACLE WEST CAPITAL CORPORATION

(Exact name of registrant as specified in its charter)

Arizona	1-8962	86-0512431
(State or other jurisdiction of incorporation)	**(Commission File Number)**	**(IRS Employer Identification Number)**

400 North Fifth Street, P.O. Box 53999, Phoenix, Arizona	85072-3999
(Address of principal executive offices)	**(Zip Code)**

(602) 250-1000
(Registrant's telephone number, including area code)

NONE
(Former name or former address, if changed since last report)

Item 5. Other Events

Arizona Electric Industry Restructuring

As previously reported, on February 8, 2002, the Chief Administrative Law Judge of the Arizona Corporation Commission (the "ACC") issued a procedural order which consolidated several ACC dockets, including:

- the ACC docket relating to an October 2001 filing by Arizona Public Service Company ("APS") requesting approval of a long-term purchase power agreement between APS and Pinnacle West Capital Corporation (the "Company"), as well as a variance from a competitive bidding process required by an ACC rule; and

- a "generic" docket requested by the ACC Chairman to "determine if changed circumstances require the [ACC] to take another look at restructuring in Arizona."

See Note 3 of Notes to Consolidated Financial Statements in the Company's Report on Form 10-K for the fiscal year ended December 31, 2001 for additional information about the consolidated docket, the comprehensive 1999 Settlement Agreement approved by the ACC among APS and various parties related to the implementation of retail electric competition in Arizona, and the retail electric competition rules adopted by the ACC.

On April 19, 2002, APS filed a motion in the consolidated docket addressing the following issues, among others:

- APS confirmed its position that whether or not the ACC approved the matters requested in its October 2001 filing, APS would proceed with the divestiture of its generation assets this year.

- APS also advised the ACC that whether or not the ACC approved the matters requested in its October 2001 filing, APS would implement a competitive bidding process later this year to the extent legally required.

- APS noted that Pinnacle West Energy Corporation ("Pinnacle West Energy"), the affiliate to which APS intends to transfer the generation assets, had committed to a $1 billion investment in generating capacity to meet APS customer needs in reliance on the 1999 Settlement Agreement and in accordance with an ACC rule that prohibited APS' ownership of new generation assets. APS further noted that it had taken numerous actions in reliance on the 1999 Settlement Agreement and the ACC retail electric competition rules, including writing off $234 million of prudently incurred costs, reducing retail rates by approximately $120 million in a still-ongoing series of rate reductions, and incurring tens of millions of dollars in expenses related to the expected generation asset transfer. APS stated that if the ACC elects to reverse course on retail electric competition or attempts to stay the transfer of APS' generation assets, the

ACC would be legally required to address just compensation to APS and Pinnacle West Energy, which would include, at a minimum:

- recognizing the transfer to APS of all assets that Pinnacle West Energy constructed to meet APS' load-serving requirements, and subsequently including such units in APS' rate base in accordance with traditional rate-of-return regulation;
- reversing APS' $234 million write-off and providing for the recovery of such amounts in future rates; and
- providing for the recovery of all costs incurred as a result of the transition to competition, including 100 percent of the costs incurred in preparation for divestiture (and not just the 2/3 of costs permitted under the Settlement Agreement approved by the ACC in 1999).

- APS recommended that the ACC confirm whether or not Arizona would proceed with the transition to a competitive electric market, and proposed the following procedural plan in response to issues identified by the ACC staff in a previous report:
  - Market Power and Market Monitoring: APS recommended that the ACC monitor evolving federal regulatory developments in the wholesale power markets and respond to market power or market monitoring issues at the state level after the federal issues are more fully developed.
  - Competitive Bidding: APS advised the ACC that it intends to issue a request for proposal for competitive bidding no later than September 1, 2002, with the amount bid dependent on the ACC's action on the October 2001 filing made by APS.
  - Transfer of Generation Assets: Consistent with, and in reliance upon, the 1999 Settlement Agreement, APS has been addressing the legal and regulatory requirements necessary to complete the transfer of its generation assets to Pinnacle West Energy on or before December 31, 2002. As required and authorized by the 1999 Settlement Agreement, on or about August 1, 2002, APS intends to formally provide the ACC with a 30-day notice of the generation assets being transferred to Pinnacle West Energy.
  - Transmission Constraints and Reliability: APS recommended that the ACC staff structure a process to address the various issues affecting transmission constraints and reliability in Arizona, and suggested that this process could begin in May 2002 as part of the ACC's 2002-2003 Biennial Transmission Assessment.
  - Adjustor Mechanisms: APS recommended that it is appropriate for the ACC to consider specific standard-offer rate adjustor mechanisms in utility-specific proceedings and noted that the 1999 Settlement Agreement requires APS to submit an adjustment clause for ACC approval that will recover electric competition-related costs specified in the 1999 Settlement Agreement.
  - Retail Direct Access and Shopping Credits: APS recommended that the ACC staff initiate a workshop process to assess the appropriate scope of direct access and noted that the specific issues surrounding the "shopping credit" for APS should be addressed in the general rate case that APS is required to file by June 30, 2003 pursuant to the 1999 Settlement Agreement. A "shopping credit" is the amount that a customer does not pay to a utility distribution company if the customer obtains generation from another party.

A copy of APS' motion is attached to this Form 8-K as Exhibit 99.11. The Company cannot currently predict the outcome of the October 2001 filing or the consolidated docket, including the potential for changes to the existing Arizona electric competition rules or effects to the 1999 Settlement Agreement.

Item 7. Financial Statements, Pro Form Financial Information and Exhibits

(c) Exhibits.

Exhibit No.	Description
99.1	Pinnacle West Capital Corporation quarterly consolidated statistical summary for March 31, 2002 (cover page, table of contents and list of contents).
99.2	Pinnacle West Capital Corporation quarterly consolidated statistical summary for the periods ended March 31, 2002 and 2001.
99.3	Pinnacle West Capital Corporation consolidated statistics by quarter for 2002.
99.4	Pinnacle West Capital Corporation consolidated statistics by quarter for 2001.
99.5	Pinnacle West Capital Corporation consolidated statistics by quarter for 2000.
99.6	Pinnacle West Capital Corporation consolidated statistics by quarter for 1999.
99.7	Pinnacle West Capital Corporation earnings variance explanations for the periods ended March 31, 2002 and 2001 and condensed consolidated statements of income for the three months and twelve months ended March 31, 2002 and 2001.

99.8	Glossary of Terms.
99.9	Pinnacle West Capital Corporation graphical data presentation for the periods from January 1999 through February 2002 and January 1999 through March 2002.
99.10	Slide presentation for use at the analyst conferences to be held in Boston, Massachusetts on April 23, 2002 and in New York, New York on April 24, 2002.
99.11	Motion of Arizona Public Service Company for Procedural Schedule, as filed with the Arizona Corporation Commission on April 19, 2002.

Item 9. Regulation FD Disclosure

The Company is providing quarterly consolidated statistical summaries, earnings variance explanations, and a glossary of relevant terms (collectively, "Information") to help interested parties better understand its business. This Information is concurrently being posted to the Company's website at www.pinnaclewest.com. The Information may not represent all of the factors that could affect the Company's operating or financial results for various periods. Some of the Information is preliminary in nature and could be subject to significant adjustment. Some of the Information is based on information received from third parties and may contain inaccuracies. The Company is not responsible for any such inaccuracies. Although the Company may update or correct the Information if it is aware that such Information has been revised or is inaccurate, the Company assumes no obligation to update or correct the Information and reserves the right to discontinue the provision of all or any portion of the Information at any time or to change the type of Information provided.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Company has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

PINNACLE WEST CAPITAL CORPORATION

(Registrant)

Dated: April 22, 2002

By: Barbara M. Gomez
Barbara M. Gomez
Treasurer

PINNACLE WEST CAPITAL CORPORATION
Exhibit Index to Current Report on Form 8-K

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99.10	Slide presentation for use at the analyst conferences to be held in Boston, Massachusetts on April 23, 2002 and in New York, New York on April 24, 2002.
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Exhibit 99.1

Pinnacle West Capital Corporation

Quarterly Consolidated Statistical Summary
Period Ended March 31, 2002

This file contains financial and operating statistics for the three-month and twelve-month periods ended March 31, 2002 and 2001.

The same statistics by quarter for 2002 through 1999 are available in the complete-format PDF and Excel files, which are posted to this website.

Please see the Glossary of Terms on this website for definitions of terms used in this summary.

Exhibit 99.2

Last Updated 4/23/2002

Pinnacle West Capital Corporation

Quarterly Consolidated Statistical Summary
Periods Ended March 31, 2002 and 2001

Line		3 MO. ENDED MARCH 31 2002	2001	I
	EARNINGS CONTRIBUTION BY SUBSIDIARY ($ IN MILLIONS)			
1	Arizona Public Service	$ 32	$ 65	
2	Pinnacle West Energy	1	--	
3	APS Energy Services	2	(8)	
4	SunCor	2	--	
5	El Dorado	--	1	
6	Parent Company	17	4	
7	Income Before Accounting Change	54	62	
8	Cumulative Effect of Change in Accounting - Net of Tax	--	(3)	
9	Net Income	$ 54	$ 59	

	EARNINGS PER SHARE BY SUBSIDIARY - DILUTED		
10	Arizona Public Service	$ 0.37	$ 0.76
11	Pinnacle West Energy	0.01	--
12	APS Energy Services	0.03	(0.10)
13	SunCor	0.02	0.01
14	El Dorado	--	0.01
15	Parent Company	0.20	0.05
16	Income Before Accounting Change	0.63	0.73
17	Cumulative Effect of Change in Accounting - Net of Tax	--	(0.03)
18	Net Income	$ 0.63	$ 0.70
19	BOOK VALUE PER SHARE	$ 30.06	$ 28.83
	COMMON SHARES OUTSTANDING - DILUTED (THOUSANDS)		
20	Average	84,884	84,966
21	End of Period	84,789	84,718

See Glossary of Terms.

Last Updated 4/23/2002

Pinnacle West Capital Corporation

Quarterly Consolidated Statistical Summary
Periods Ended March 31, 2002 and 2001

		3 MO. ENDED MARCH 3		
Line		2002	2001	I
	ELECTRIC OPERATING REVENUES (DOLLARS IN MILLIONS)			
	Retail			
22	Residential	$ 171	$ 173	
23	Business	195	199	
24	Total retail	366	372	
	Wholesale revenue on delivered electricity			
25	Traditional contracts	2	26	
26	Retail load hedge management	2	5	
	Marketing and trading -- delivered			
27	Generation sales other than native load	8	87	
28	Other delivered electricity (a)	185	359	
29	Total delivered marketing and trading	193	446	
30	Total delivered wholesale electricity	197	477	
	Other marketing and trading			
	Realized margins on delivered commodities			
31	other than electricity (a)	4	(5)	
	Prior period mark-to-market (gains) losses realized			
32	on contracts delivered during current period (a)	(22)	6	

33	Change in mark-to-market for future-period deliveries	25	47
34	Total other marketing and trading	7	48
35	Transmission for others	6	4
36	Other miscellaneous services	4	6
37	Total electric operating revenues	$ 580	$ 907
	ELECTRIC SALES (GWH)		
	Retail sales		
38	Residential	2,141	2,122
39	Business	2,771	2,824
40	Total retail	4,912	4,946
	Wholesale electricity delivered		
41	Traditional contracts	71	569
42	Retail load hedge management	158	75
	Marketing and trading -- delivered		
43	Generation sales other than native load	376	623
44	Other delivered electricity	3,836	3,050
45	Total delivered marketing and trading	4,212	3,673
46	Total delivered wholesale electricity	4,441	4,317
47	Total electric sales	9,353	9,263

(a) The net effect on net electric operating revenues from realization of prior-period mark-to-market included in line 37 is zero. Realization of prior-period mark-to-market relates to cash flow recognition, not revenue recognition. The arithmetic opposites of amounts included in line 32 are included in lines 28 and 31. For example, line 32 shows that a prior-period mark-to-market gain of $22 million was transferred to "realized" for the first quarter of 2002. Lines 28 and 31 include amounts totaling $22 million of realized revenues for the first quarter of 2002.

See Glossary of Terms.

Last Updated 4/23/2002

Pinnacle West Capital Corporation

Quarterly Consolidated Statistical Summary
Periods Ended March 31, 2002 and 2001

		3 MO. ENDED MARCH 3		
Line		2002	2001	I
	MARKETING AND TRADING PRETAX GROSS MARGIN ANALYSIS (DOLLARS IN MILLIONS)			
	REALIZED AND MARK-TO-MARKET COMPONENTS			
	Current Period Effects			
	Realized margin on delivered commodities			
	Electricity			
48	Generation sales other than native load	$ 2	$ 48	

49	Other electricity marketing and trading (a)	33	4
50	Total electricity	35	52
51	Other commodities (a)	4	(5)
52	Total realized margin	39	47
	Prior-period mark-to-market (gains) losses on contracts delivered during current period		
53	Electricity (a)	(16)	1
54	Other commodities (a)	(6)	12
55	Charge related to trading activities with Enron and its affiliates	--	--
56	Subtotal	(22)	13
57	Total current period effects (b)	17	60
	Change in mark-to-market gains (losses) for future period deliveries (b)		
58	Electricity	25	45
59	Other commodities	(2)	2
60	Subtotal	23	47
61	Total gross margin	$ 40	$ 107
	BY COMMODITY SOLD OR TRADED		
62	Electricity	$ 45	$ 98
63	Natural gas	(5)	(3)
64	Coal	(1)	14
65	Emission allowances	1	(2)
66	Other	--	--
67	Total Gross Margin	$ 40	$ 107

FUTURE MARKETING AND TRADING MARK-TO-MARKET REALIZATION

As of March 31, 2002, Pinnacle West had accumulated mark-to-market net gains of $139 million related to our power marketing and trading activities. We estimate that these gains will be reclassified to realized gains as the underlying commodities are delivered, as follows: remainder of 2002, $24 million; 2003, $26 million; 2004, $27 million; 2005 and thereafter, $62 million.

(a) The net effect on pretax gross margin from realization of prior-period mark-to-market included in line 57 and in line 61 is zero. Realization of prior-period mark-to-market relates to cash flow recognition, not earnings recognition. The arithmetic opposites of amounts included in line 53 are included in line 49. The opposites of amounts included in line 54 are included in line 51. For example, line 53 shows that a prior-period mark-to-market gain of $16 million was transferred to "realized" for the first quarter of 2002. A $16 million realized gain is included in the $33 million on line 49 for the first quarter of 2002.

(b) Quarterly amounts do not total to the annual amounts because of intra-year mark-to-market eliminations.

See Glossary of Terms.

Pinnacle West Capital Corporation

Quarterly Consolidated Statistical Summary
Periods Ended March 31, 2002 and 2001

Line		3 MO. ENDED MARCH 3		
		2002	2001	I
	AVERAGE ELECTRIC CUSTOMERS			
	Retail customers			
68	Residential	801,000	775,317	
69	Business	99,335	97,222	
70	Total	900,335	872,539	
71	Wholesale customers	67	68	
72	Total customers	900,402	872,607	
73	Customer Growth (% over prior year)	3.2%	4.0%	
	RETAIL ELECTRIC SALES (GWH) - WEATHER NORMALIZED			
74	Residential	2,164	2,037	
75	Business	2,774	2,825	
76	Total	4,938	4,862	
	RETAIL ELECTRICITY USAGE (KWH/AVERAGE CUSTOMER)			
77	Residential	2,673	2,737	
78	Business	27,896	29,047	
	RETAIL ELECTRICITY USAGE - WEATHER NORMALIZED (KWH/AVERAGE CUSTOMER)			
79	Residential	2,702	2,627	
80	Business	27,926	29,057	
	ELECTRICITY DEMAND (MW)			
81	System peak demand	3,708	3,661	

See Glossary of Terms.

Pinnacle West Capital Corporation

Quarterly Consolidated Statistical Summary
Periods Ended March 31, 2002 and 2001

3 MO. ENDED MARCH 3

Line		2002	2001	I
	ENERGY SOURCES (GWH)			
	Generation production			
82	Nuclear	2,257	2,261	
83	Coal	2,890	2,901	
84	Gas, oil and other	337	1,007	
85	Total	5,484	6,169	
	Purchased power			
86	Firm load	429	170	
87	Marketing and trading	3,993	3,126	
88	Total	4,422	3,296	
89	Total energy sources	9,906	9,465	
	POWER PLANT PERFORMANCE			
	Capacity Factors			
90	Nuclear	96%	96%	
91	Coal	78%	78%	
92	Gas, oil and other	12%	39%	
93	System average	62%	71%	
	Generation Capacity Out of Service (average MW/day)			
94	Nuclear	62	57	
95	Coal	184	284	
96	Gas	12	36	
97	Total	258	376	
98	Generation Fuel Cost ($/MWh)	$ 11.57	$ 19.64	

See Glossary of Terms.

Last Updated 4/23/2002

Pinnacle West Capital Corporation

Quarterly Consolidated Statistical Summary
Periods Ended March 31, 2002 and 2001

		3 MO. ENDED MARCH 3		
Line		2002	2001	I
	ENERGY MARKET INDICATORS (a)			
	Electricity Average Daily Spot Prices ($/MWh)			
	On-Peak			
99	Palo Verde	$ 26.86	$ 214.21	
100	SP15	$ 28.46	$ 219.66	
	Off-Peak			
101	Palo Verde	$ 22.17	$ 130.40	
102	SP15	$ 22.76	$ 159.80	

WEATHER INDICATORS

Line			
	Actual		
103	Cooling degree-days	89	106
104	Heating degree-days	472	657
105	Average humidity	28%	50%
	10-Year Averages		
106	Cooling degree-days	71	71
107	Heating degree-days	556	556
108	Average humidity	45%	45%
	ECONOMIC INDICATORS		
	Building Permits--- Metro Phoenix (b) (d)		
109	Single-family	6,983	7,476
110	Multi-family	1,094	3,137
111	Total	8,077	10,613
	Arizona Job Growth (c) (d)		
112	Payroll job growth (% over prior year)	(1.3)%	3.2%
113	Unemployment rate (%, seasonally adjusted)	5.8%	3.9%

Sources:

(a) This price is an average of daily prices obtained and used with permission from Dow Jones & Company, Inc.

(b) Arizona Real Estate Center, Arizona State University College of Business

(c) Arizona Department of Economic Security

(d) The economic indicators reflect three month and twelve month ended February 2001 and February 2002.

See Glossary of Terms.

Exhibit 99.3

Last Updated 4/23/2002

Pinnacle West Capital Corporation

Consolidated Statistics By Quarter
2002

Line		1ST QTR	2ND QTR
	EARNINGS CONTRIBUTION BY SUBSIDIARY ($ MILLIONS)		
1	Arizona Public Service	$ 32	
2	Pinnacle West Energy	1	
3	APS Energy Services	2	
4	SunCor	2	
5	El Dorado	--	
6	Parent Company	17	
7	Income Before Accounting Change	54	
8	Cumulative Effect of Change in Accounting - Net of Tax	--	

Line		1ST QTR	2ND QTR
9	Net Income	$ 54	
	EARNINGS PER SHARE BY SUBSIDIARY - DILUTED		
10	Arizona Public Service	$ 0.37	
11	Pinnacle West Energy	0.01	
12	APS Energy Services	0.03	
13	SunCor	0.02	
14	El Dorado	--	
15	Parent Company	0.20	
16	Income Before Accounting Change	0.63	
	Cumulative Effect of Change in Accounting -		
17	Net of Tax	--	
18	Net Income	$ 0.63	
19	BOOK VALUE PER SHARE	$ 30.06	
	COMMON SHARES OUTSTANDING - DILUTED (THOUSANDS)		
20	Average	84,884	
21	End of Period	84,789	

See Glossary of Terms.

Last Updated 4/16/2002

Pinnacle West Capital Corporation

Consolidated Statistics By Quarter
2002

Line		1ST QTR	2ND QTR
	ELECTRIC OPERATING REVENUES (DOLLARS IN MILLIONS)		
	Retail		
22	Residential	$ 171	
23	Business	195	
24	Total retail	366	
	Wholesale revenue on delivered electricity		
25	Traditional contracts	2	
26	Retail load hedge management	2	
	Marketing and trading -- delivered		
27	Generation sales other than native load	8	
28	Other delivered electricity (a)	185	
29	Total delivered marketing and trading	193	
30	Total delivered wholesale electricity	197	
	Other marketing and trading		
	Realized margins on delivered commodities		

31	other than electricity (a)	4	
	Prior period mark-to-market (gains) losses on		
32	contracts delivered during current period (a)	(22)	
	Change in mark-to-market for		
33	future-period deliveries	25	
34	Total other marketing and trading	7	
35	Transmission for others	6	
36	Other miscellaneous services	4	
37	Total electric operating revenues	$ 580	
	ELECTRIC SALES (GWH)		
	Retail sales		
38	Residential	2,141	
39	Business	2,771	
40	Total retail	4,912	
	Wholesale electricity delivered		
41	Traditional contracts	71	
42	Retail load hedge management	158	
	Marketing and trading -- delivered		
43	Generation sales other than native load	376	
44	Other delivered electricity	3,836	
45	Total delivered marketing and trading	4,212	
46	Total delivered wholesale electricity	4,441	
47	Total electric sales	9,353	

(a) The net effect on net electric operating revenues from realization of prior-period mark-to-market included in line 37 is zero. Realization of prior-period mark-to-market relates to cash flow recognition, not revenue recognition. The arithmetic opposites of amounts included in line 32 are included in lines 28 and 31. For example, line 32 shows that a prior-period mark-to-market gain of $22 million was transferred to "realized" for the first quarter of 2002. Lines 28 and 31 include amounts totaling $22 million of realized revenues for the first quarter of 2002.

See Glossary of Terms.

Last Updated 4/23/2002

Pinnacle West Capital Corporation

Consolidated Statistics By Quarter
2002

Line		1ST QTR	2ND QTR
	MARKETING AND TRADING PRETAX GROSS MARGIN ANALYSIS (DOLLARS IN MILLIONS)		
	REALIZED AND MARK-TO-MARKET COMPONENTS		

	Current Period Effects		
	Realized margin on delivered commodities		
	Electricity		
48	Generation sales other than native load	$ 2	
49	Other electricity marketing and trading (a)	33	
50	Total electricity	35	
51	Other commodities (a)	4	
52	Total realized margin	39	
	Prior-period mark-to-market (gains) losses on contracts delivered during current period		
53	Electricity (a)	(16)	
54	Other commodities (a)	(6)	
55	Charge related to trading activities with Enron and its affiliates	--	
56	Subtotal	(22)	
57	Total current period effects (b)	17	
	Change in mark-to-market gains (losses) for future period deliveries (b)		
58	Electricity	25	
59	Other commodities	(2)	
60	Total future period effects	23	
61	Total gross margin	$ 40	
	BY COMMODITY SOLD OR TRADED		
62	Electricity	$ 45	
63	Natural gas	(5)	
64	Coal	(1)	
65	Emission allowances	1	
66	Other	--	
67	Total gross margin	$ 40	

FUTURE MARKETING AND TRADING MARK-TO-MARKET REALIZATION

As of March 31, 2002, Pinnacle West had accumulated mark-to-market net gains of $139 million related to our power marketing and trading activities. We estimate that these gains will be reclassified to realized gains as the underlying commodities are delivered, as follows: remainder of 2002, $24 million; 2003, $26 million; 2004, $27 million; 2005 and thereafter, $62 million.

(a) The net effect on pretax gross margin from realization of prior-period mark-to-market included in line 57 and in line 61 is zero. Realization of prior-period mark-to-market relates to cash flow recognition, not earnings recognition. The arithmetic opposites of amounts included in line 53 are included in line 49. The opposites of amounts included in line 54 are included in line 51. For example, line 53 shows that a prior-period mark-to-market gain of $16 million was transferred to "realized" for the first quarter of 2002. A $16 million realized gain is included in the $33 million on line 49 for the first quarter of 2002.

(b) Quarterly amounts do not total to the annual amounts because of intra-year mark-to-market eliminations.

See Glossary of Terms.

Last Updated 4/23/2002

Pinnacle West Capital Corporation

Consolidated Statistics By Quarter
2002

Line		1ST QTR	2ND QTR
	AVERAGE ELECTRIC CUSTOMERS		
	Retail customers		
68	Residential	801,000	
69	Business	99,335	
70	Total	900,335	
71	Wholesale customers	67	
72	Total customers	900,402	
73	Customer Growth (% over prior year)	3.2%	
	RETAIL ELECTRIC SALES (GWH) - WEATHER NORMALIZED		
74	Residential	2,164	
75	Business	2,774	
76	Total	4,938	
	RETAIL ELECTRICITY USAGE (KWH/AVERAGE CUSTOMER)		
77	Residential	2,673	
78	Business	27,896	
	RETAIL ELECTRICITY USAGE - WEATHER NORMALIZED (KWH/AVERAGE CUSTOMER)		
79	Residential	2,702	
80	Business	27,926	
	ELECTRICITY DEMAND (MW)		
81	System peak demand	3,708	

See Glossary of Terms.

Last Updated 4/23/2002

Pinnacle West Capital Corporation

Consolidated Statistics By Quarter
2002

Line		1ST QTR	2ND QTR
	ENERGY SOURCES (GWH)		
	Generation production		
82	Nuclear	2,257	
83	Coal	2,890	
84	Gas, oil and other	337	
85	Total	5,484	
	Purchased power		
86	Firm load	429	
87	Marketing and trading	3,993	
88	Total	4,422	
89	Total energy sources	9,906	
	POWER PLANT PERFORMANCE		
	Capacity Factors		
90	Nuclear	96%	
91	Coal	78%	
92	Gas, oil and other	12%	
93	System average	62%	
	Generation Capacity Out of Service (average MW/day)		
94	Nuclear	62	
95	Coal	184	
96	Gas	12	
97	Total	258	
98	Generation Fuel Cost ($/MWh)	$ 11.57	

See Glossary of Terms.

Last Updated 4/23/2002

Pinnacle West Capital Corporation

Consolidated Statistics By Quarter
2002

Line		1ST QTR	2ND QTR
	ENERGY MARKET INDICATORS (a)		
	Electricity Average Daily Spot Prices ($/MWh)		
	On-Peak		
99	Palo Verde	$ 26.86	
100	SP15	$ 28.46	
	Off-Peak		
101	Palo Verde	$ 22.17	
102	SP15	$ 22.76	

Line			
	WEATHER INDICATORS		
	Actual		
103	Cooling degree-days	89	
104	Heating degree-days	472	
105	Average humidity	28%	
	10-Year Averages		
106	Cooling degree-days	71	
107	Heating degree-days	556	
108	Average humidity	45%	
	ECONOMIC INDICATORS		
	Building Permits -- Metro Phoenix (b) (d)		
109	Single-family	6,983	
110	Multi-family	1,094	
111	Total	8,077	
	Arizona Job Growth (c) (d)		
112	Payroll job growth (% over prior year)	(1.3)%	
113	Unemployment rate (%, seasonally adjusted)	5.8%	

Sources:

(a) This price is an average of daily prices obtained and used with permission from Dow Jones & Company, Inc.
(b) Arizona Real Estate Center, Arizona State University College of Business
(c) Arizona Department of Economic Security
(d) The economic indicators reflect three month ended February 2002.

See Glossary of Terms.

Exhibit 99.4

Last Updated 4/23/2002

Pinnacle West Capital Corporation

Consolidated Statistics By Quarter
2001

Line		1ST QTR	2ND QTR
	EARNINGS CONTRIBUTION BY SUBSIDIARY ($ MILLIONS)		
1	Arizona Public Service	$ 65	$ 70
2	Pinnacle West Energy	--	1
3	APS Energy Services	(8)	--
4	SunCor	--	--
5	El Dorado	1	--
6	Parent Company	4	(4)
7	Income Before Accounting Change	62	67
	Cumulative Effect of Change in Accounting -		

8	Net of Tax	(3)	--
9	Net Income	$ 59	$ 67
	EARNINGS PER SHARE BY SUBSIDIARY - DILUTED		
10	Arizona Public Service	$ 0.76	$ 0.82
11	Pinnacle West Energy	--	0.02
12	APS Energy Services	(0.10)	--
13	SunCor	0.01	--
14	El Dorado	0.01	--
15	Parent Company	0.05	(0.05)
16	Income Before Accounting Change	0.73	0.79
	Cumulative Effect of Change in Accounting -		
17	Net of Tax	(0.03)	--
18	Net Income	$ 0.70	$ 0.79
19	BOOK VALUE PER SHARE	$ 28.83	$ 28.17
	COMMON SHARES OUTSTANDING - DILUTED (THOUSANDS)		
20	Average	84,966	85,042
21	End of Period	84,718	84,713

See Glossary of Terms.

Last Updated 4/23/2002

Pinnacle West Capital Corporation

Consolidated Statistics By Quarter
2001

Line		1ST QTR	2ND QTR
	ELECTRIC OPERATING REVENUES (DOLLARS IN MILLIONS)		
	Retail		
22	Residential	$ 173	$ 234
23	Business	199	258
24	Total retail	372	492
	Wholesale revenue on delivered electricity		
25	Traditional contracts	26	55
26	Retail load hedge management	5	182
	Marketing and trading -- delivered		
27	Generation sales other than native load	87	51
28	Other delivered electricity (a)	359	443
29	Total delivered marketing and trading	446	494
30	Total delivered wholesale electricity	477	731

	Other marketing and trading		
	Realized margins on delivered commodities		
31	other than electricity (a)	(5)	(12)
	Prior period mark-to-market (gains) losses on		
32	contracts delivered during current period (a)	6	5
	Change in mark-to-market for		
33	future-period deliveries	47	35
34	Total other marketing and trading	48	28
35	Transmission for others	4	5
36	Other miscellaneous services	6	5
37	Total electric operating revenues	$ 907	$ 1,261
	ELECTRIC SALES (GWH)		
	Retail sales		
38	Residential	2,122	2,467
39	Business	2,824	3,445
40	Total retail	4,946	5,912
	Wholesale electricity delivered		
41	Traditional contracts	569	598
42	Retail load hedge management	75	736
	Marketing and trading -- delivered		
43	Generation sales other than native load	623	436
44	Other delivered electricity	3,050	3,169
45	Total delivered marketing and trading	3,673	3,605
46	Total delivered wholesale electricity	4,317	4,939
47	Total electric sales	9,263	10,851

(a) The net effect on net electric operating revenues from realization of prior-period mark-to-market included in line 37 is zero. Realization of prior-period mark-to-market relates to cash flow recognition, not revenue recognition. The arithmetic opposites of amounts included in line 32 are included in lines 28 and 31. For example, line 32 shows that a prior-period mark-to-market gain of $1 million was transferred to "realized" for the total year 2001. Lines 28 and 31 include amounts totaling $1 million of realized revenues for the year 2001.

See Glossary of Terms.

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Pinnacle West Capital Corporation

Consolidated Statistics By Quarter
2001

Line		1ST QTR	2ND QTR
	MARKETING AND TRADING PRETAX GROSS MARGIN ANALYSIS (DOLLARS IN MILLIONS)		

	REALIZED AND MARK-TO-MARKET COMPONENTS		
	Current Period Effects		
	Realized margin on delivered commodities		
	Electricity		
48	Generation sales other than native load	$ 48	$ 26
49	Other electricity marketing and trading (a)	4	43
50	Total electricity	52	69
51	Other commodities (a)	(5)	(12)
52	Total realized margin	47	57
	Prior-period mark-to-market (gains) losses on contracts delivered during current period		
53	Electricity (a)	1	--
54	Other commodities (a)	12	5
55	Charge related to trading activities with Enron and its affiliates	--	--
56	Subtotal	13	5
57	Total current period effects (b)	60	62
	Change in mark-to-market gains (losses) for future period deliveries (b)		
58	Electricity	45	42
59	Other commodities	2	(6)
60	Total future period effects	47	36
61	Total gross margin	$ 107	$ 98
	BY COMMODITY SOLD OR TRADED		
62	Electricity	$ 98	$ 111
63	Natural gas	(3)	(12)
64	Coal	14	2
65	Emission allowances	(2)	(3)
66	Other	--	--
67	Total gross margin	$ 107	$ 98

FUTURE MARKETING AND TRADING MARK-TO-MARKET REALIZATION

As of December 31, 2001, Pinnacle West had accumulated mark-to-market net gains of $138.0 million related to our power marketing and trading activities. We estimate that these gains will be reclassified to realized gains as the underlying commodities are delivered, as follows: 2002, $43.0 million; 2003, $22.6 million; 2004, $23.6 million; 2005 and thereafter, $48.8 million.

(a) The net effect on pretax gross margin from realization of prior-period mark-to-market included in line 57 and in line 61 is zero. Realization of prior-period mark-to-market relates to cash flow recognition, not earnings recognition. The arithmetic opposites of amounts included in line 53 are included in line 49. The opposites of amounts included in line 54 are included in line 51. For example, line 53 shows that a prior-period mark-to-market gain of $11 million was transferred to "realized" for the total year 2001. A $11 million realized gain is included in the $117 million on line 49 for the total year 2001.

(b) Quarterly amounts do not total to the annual amounts because of intra-year mark-to-market eliminations.

See Glossary of Terms.

Last Updated 4/23/2002

Pinnacle West Capital Corporation

Consolidated Statistics By Quarter
2001

Line		1ST QTR	2ND QTR
	AVERAGE ELECTRIC CUSTOMERS		
	Retail customers		
68	Residential	775,317	770,335
69	Business	97,222	98,065
70	Total	872,539	868,400
71	Wholesale customers	68	66
72	Total customers	872,607	868,466
73	Customer Growth (% over prior year)	4.0%	3.9%
	RETAIL ELECTRIC SALES (GWH) - WEATHER NORMALIZED		
74	Residential	2,037	2,204
75	Business	2,825	3,321
76	Total	4,862	5,525
	RETAIL ELECTRICITY USAGE (KWH/AVERAGE CUSTOMER)		
77	Residential	2,737	3,203
78	Business	29,047	35,130
	RETAIL ELECTRICITY USAGE - WEATHER NORMALIZED (KWH/AVERAGE CUSTOMER)		
79	Residential	2,627	2,861
80	Business	29,057	33,865
	ELECTRICITY DEMAND (MW)		
81	System peak demand	3,661	5,358

See Glossary of Terms.

Last Updated 4/23/2002

Pinnacle West Capital Corporation

Consolidated Statistics By Quarter
2001

Line		1ST QTR	2ND QTR
	ENERGY SOURCES (GWH)		
	Generation production		
82	Nuclear	2,261	1,985
83	Coal	2,901	3,245
84	Gas, oil and other	1,007	1,256
85	Total	6,169	6,486
	Purchased power		
86	Firm load	170	845
87	Marketing and trading	3,126	3,905
88	Total	3,296	4,750
89	Total energy sources	9,465	11,236
	POWER PLANT PERFORMANCE		
	Capacity Factors		
90	Nuclear	96%	84%
91	Coal	78%	87%
92	Gas, oil and other	39%	46%
93	System average	71%	73%
	Generation Capacity Out of Service (average MW/day)		
94	Nuclear	57	180
95	Coal	284	166
96	Gas	36	52
97	Total	376	398
98	Generation Fuel Cost ($/MWh)	$ 19.64	$ 19.28

See Glossary of Terms.

Last Updated 4/23/2002

Pinnacle West Capital Corporation

Consolidated Statistics By Quarter
2001

Line		1ST QTR	2ND QTR
	ENERGY MARKET INDICATORS (a)		
	Electricity Average Daily Spot Prices ($/MWh)		
	On-Peak		
99	Palo Verde	$ 214.21	$ 182.71
100	SP15	$ 219.66	$ 186.30
	Off-Peak		
101	Palo Verde	$ 130.40	$ 70.32
102	SP15	$ 159.80	$ 84.78
	WEATHER INDICATORS		

Line			
	Actual		
103	Cooling degree-days	106	1,733
104	Heating degree-days	657	43
105	Average humidity	50%	25%
	10-Year Averages		
106	Cooling degree-days	71	1,458
107	Heating degree-days	556	35
108	Average humidity	45%	25%
	ECONOMIC INDICATORS		
	Building Permits -- Metro Phoenix (b)		
109	Single-family	8,681	9,270
110	Multi-family	3,918	1,820
111	Total	12,599	11,090
	Arizona Job Growth (c)		
112	Payroll job growth (% over prior year)	2.9%	1.4%
113	Unemployment rate (%, seasonally adjusted)	4.1%	4.3%

Sources:

(a) This price is an average of daily prices obtained and used with permission from Dow Jones & Company, Inc.
(b) Arizona Real Estate Center, Arizona State University College of Business
(c) Arizona Department of Economic Security

See Glossary of Terms.

Exhibit 99.5

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Pinnacle West Capital Corporation

Consolidated Statistics By Quarter
2000

Line		1ST QTR	2ND QTR
	EARNINGS CONTRIBUTION BY SUBSIDIARY ($ MILLIONS)		
1	Arizona Public Service	$ 33	$ 96
2	Pinnacle West Energy	--	(1)
3	APS Energy Services	(2)	(2)
4	SunCor	5	1
5	El Dorado	19	(3)
6	Parent Company	(1)	(1)
7	Income Before Accounting Change	54	90
	Cumulative Effect of Change in Accounting -		
8	Net of Tax	--	--
9	Net Income	$ 54	$ 90
	EARNINGS PER SHARE BY SUBSIDIARY - DILUTED		
10	Arizona Public Service	$ 0.39	$ 1.13

11	Pinnacle West Energy	--	(0.01)
12	APS Energy Services	(0.02)	(0.03)
13	SunCor	0.06	0.01
14	El Dorado	0.22	(0.04)
15	Parent Company	(0.01)	--
16	Income Before Accounting Change	0.64	1.06
	Cumulative Effect of Change in Accounting -		
17	Net of Tax	--	--
18	Net Income	$ 0.64	$ 1.06
19	BOOK VALUE PER SHARE	$ 26.29	$ 27.00
	COMMON SHARES OUTSTANDING - DILUTED (THOUSANDS)		
20	Average	84,834	84,891
21	End of Period	84,723	84,727

See Glossary of Terms.

Last Updated 4/23/2002

Pinnacle West Capital Corporation

Consolidated Statistics By Quarter
2000

Line		1ST QTR	2ND QTR
	ELECTRIC OPERATING REVENUES (DOLLARS IN MILLIONS)		
	Retail		
22	Residential	$ 157	$ 228
23	Business	196	253
24	Total retail	353	481
	Wholesale revenue on delivered electricity		
25	Traditional contracts	12	18
26	Retail load hedge management	7	36
	Marketing and trading -- delivered		
27	Generation sales other than native load	9	13
28	Other delivered electricity (a)	56	134
29	Total delivered marketing and trading	65	147
30	Total delivered wholesale electricity	84	201
	Other marketing and trading		
	Realized margins on delivered commodities		
31	other than electricity (a)	(5)	1
	Prior period mark-to-market (gains) losses on		
32	contracts delivered during current period (a)	--	--
	Change in mark-to-market for		
33	future-period deliveries	7	25
34	Total other marketing and trading	2	26
35	Transmission for others	3	4

36	Other miscellaneous services	4	8
37	Total electric operating revenues	$ 446	$ 720
	ELECTRIC SALES (GWH)		
	Retail sales		
38	Residential	1,877	2,370
39	Business	2,736	3,379
40	Total retail	4,613	5,749
	Wholesale electricity delivered		
41	Traditional contracts	331	391
42	Retail load hedge management	232	585
	Marketing and trading -- delivered		
43	Generation sales other than native load	396	215
44	Other delivered electricity	2,029	2,404
45	Total delivered marketing and trading	2,425	2,619
46	Total delivered wholesale electricity	2,988	3,595
47	Total electric sales	7,601	9,344

(a) The net effect on net electric operating revenues from realization of prior-period mark-to-market included in line 37 is zero. Realization of prior-period mark-to-market relates to cash flow recognition, not revenue recognition. The arithmetic opposites of amounts included in line 32 are included in lines 28 and 31. For example, line 32 shows that a prior-period mark-to-market gain of $2 million was transferred to "realized" for the total year 2000. Lines 28 and 31 include amounts totaling $2 million of realized revenues for the year 2000.

See Glossary of Terms.

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Pinnacle West Capital Corporation

Consolidated Statistics By Quarter
2000

Line		1ST QTR	2ND QTR
	MARKETING AND TRADING PRETAX GROSS MARGIN ANALYSIS (DOLLARS IN MILLIONS)		
	REALIZED AND MARK-TO-MARKET COMPONENTS		
	Current Period Effects		
	Realized margin on delivered commodities		
	Electricity		
48	Generation sales other than native load	$ 2	$ 6
49	Other electricity marketing and trading (a)	3	28
50	Total electricity	5	34
51	Other commodities (a)	(5)	1
52	Total realized margin	--	35

Line			
	Prior-period mark-to-market (gains) losses on contracts delivered during current period (b)		
53	Electricity (a)	--	--
54	Other commodities (a)	--	--
55	Charge related to trading activities with Enron and its affiliates	--	--
56	Subtotal	--	--
57	Total current period effects (b)	--	35
	Change in mark-to-market gains (losses) for future period deliveries (b)		
58	Electricity	2	27
59	Other commodities	5	(2)
60	Total future period effects	7	25
61	Total gross margin	$ 7	$ 60
	BY COMMODITY SOLD OR TRADED		
62	Electricity	7	61
63	Natural gas	--	(1)
64	Coal	--	--
65	Emission allowances	--	--
66	Other	--	--
67	Total gross margin	$ 7	$ 60

(a) The net effect on pretax gross margin from realization of prior-period mark-to-market included in line 57 and in line 61 is zero. Realization of prior-period mark-to-market relates to cash flow recognition, not earnings recognition. The arithmetic opposites of amounts included in line 53 are included in line 49. The opposites of amounts included in line 54 are included in line 51. For example, line 53 shows that a prior-period mark-to-market gain of $2 million was transferred to "realized" for the total year 2000. A $2 million realized gain is included in the $69 million on line 49 for the total year 2000.

(b) Quarterly amounts do not total to the annual amounts because of intra-year mark-to-market eliminations.

See Glossary of Terms.

Last Updated 4/23/2002

Pinnacle West Capital Corporation

Consolidated Statistics By Quarter
2000

Line		1ST QTR	2ND QTR
	AVERAGE ELECTRIC CUSTOMERS		
	Retail customers		
68	Residential	746,528	742,485
69	Business	92,667	93,343
70	Total	839,195	835,828

Line			
71	Wholesale customers	67	67
72	Total customers	839,262	835,895
73	Customer Growth (% over prior year)	4.0%	4.1%
	RETAIL ELECTRIC SALES (GWH) - WEATHER NORMALIZED		
74	Residential	1,933	2,218
75	Business	2,736	3,276
76	Total	4,669	5,494
	RETAIL ELECTRICITY USAGE (KWH/AVERAGE CUSTOMER)		
77	Residential	2,514	3,192
78	Business	29,525	36,200
	RETAIL ELECTRICITY USAGE - WEATHER NORMALIZED (KWH/AVERAGE CUSTOMER)		
79	Residential	2,589	2,987
80	Business	29,525	35,096
	ELECTRICITY DEMAND (MW)		
81	System peak demand	3,315	5,095

See Glossary of Terms.

Last Updated 4/23/2002

Pinnacle West Capital Corporation

Consolidated Statistics By Quarter
2000

Line		1ST QTR	2ND QTR
	ENERGY SOURCES (GWH)		
	Generation production		
82	Nuclear	2,325	2,090
83	Coal	2,828	3,163
84	Gas, oil and other	323	526
85	Total	5,476	5,779
	Purchased power		
86	Firm load	51	819
87	Marketing and trading	2,261	2,989
88	Total	2,312	3,808
89	Total energy sources	7,788	9,587
	POWER PLANT PERFORMANCE		
	Capacity Factors		

90	Nuclear	98%	88%
91	Coal	76%	85%
92	Gas, oil and other	13%	21%
93	System average	63%	67%
	Generation Capacity Out of Service (average MW/day)		
94	Nuclear	27	129
95	Coal	223	124
96	Gas	8	43
97	Total	258	296
98	Generation Fuel Cost ($/MWh)	$ 10.65	$ 12.69

See Glossary of Terms.

Last Updated 4/23/2002

Pinnacle West Capital Corporation

Consolidated Statistics By Quarter
2000

Line		1ST QTR	2ND QTR
	ENERGY MARKET INDICATORS (a)		
	Electricity Average Daily Spot Prices ($/MWh)		
	On-Peak		
99	Palo Verde	$ 30.52	$ 90.49
100	SP15	$ 31.40	$ 82.67
	Off-Peak		
101	Palo Verde	$ 22.97	$ 31.91
102	SP15	$ 24.52	$ 32.45
	WEATHER INDICATORS		
	Actual		
103	Cooling degree-days	71	1,712
104	Heating degree-days	459	9
105	Average humidity	37%	23%
	10-Year Averages		
106	Cooling degree-days	71	1,458
107	Heating degree-days	556	35
108	Average humidity	45%	25%
	ECONOMIC INDICATORS		
	Building Permits -- Metro Phoenix (b)		
109	Single-family	8,163	9,605
110	Multi-family	3,208	2,651
111	Total	11,371	12,256
	Arizona Job Growth (c)		
112	Payroll job growth (% over prior year)	4.4%	4.0%
113	Unemployment rate (%, seasonally adjusted)	4.1%	3.9%

Sources:

(a) This price is an average of daily prices obtained and used with permission from Dow Jones & Company, Inc.

(b) Arizona Real Estate Center, Arizona State University College of Business
(c) Arizona Department of Economic Security

See Glossary of Terms.

Exhibit 99.6

Last Updated 4/23/2002

Pinnacle West Capital Corporation

Consolidated Statistics By Quarter
1999

Line		1ST QTR	2ND QTR
	EARNINGS CONTRIBUTION BY SUBSIDIARY ($ MILLIONS)		
1	Arizona Public Service	$ 33	$ 70
2	Pinnacle West Energy	--	--
3	APS Energy Services	(2)	(2)
4	SunCor	1	3
5	El Dorado	--	--
6	Parent Company	(1)	(2)
7	Income From Continuing Operations	31	69
8a	Income Tax Benefit From Discontinued Operations	--	--
8b	Extraordinary Charge-- Net of Income Tax	--	--
9	Net Income	$ 31	$ 69
	EARNINGS PER SHARE BY SUBSIDIARY - DILUTED		
10	Arizona Public Service	$ 0.38	$ 0.82
11	Pinnacle West Energy	--	--
12	APS Energy Services	(0.02)	(0.02)
13	SunCor	0.01	0.03
14	El Dorado	--	--
15	Parent Company	(0.01)	(0.02)
16	Income From Continuing Operations	0.36	0.81
17a	Income Tax Benefit From Discontinued Operations	--	--
17b	Extraordinary Charge-- Net of Income Tax	--	--
18	Net Income	$ 0.36	$ 0.81
19	BOOK VALUE PER SHARE	$ 25.49	$ 25.58
	COMMON SHARES OUTSTANDING - DILUTED (THOUSANDS)		
20	Average	85,176	85,093
21	End of Period	84,645	84,771

See Glossary of Terms.

Pinnacle West Capital Corporation

Consolidated Statistics By Quarter
1999

Line		1ST QTR	2ND QTR
	ELECTRIC OPERATING REVENUES (DOLLARS IN MILLIONS)		
	Retail		
22	Residential	$ 157	$ 189
23	Business	190	237
24	Total retail	347	426
	Wholesale revenue on delivered electricity		
25	Traditional contracts	11	16
26	Retail load hedge management	--	--
	Marketing and trading--- delivered		
27	Generation sales other than native load	7	6
28	Other delivered electricity (a)	44	51
29	Total delivered marketing and trading	51	57
30	Total delivered wholesale electricity	62	73
	Other marketing and trading		
	Realized margins on delivered commodities		
31	other than electricity (a)	(1)	--
	Prior period mark-to-market (gains) losses on		
32	contracts delivered during current period (a)	--	--
	Change in mark-to-market for		
33	future-period deliveries	--	6
34	Total other marketing and trading	(1)	6
35	Transmission for others	3	3
36	Other miscellaneous services	3	4
37	Total electric operating revenues	$ 414	$ 512
	ELECTRIC SALES (GWH)		
	Retail sales		
38	Residential	1,796	1,939
39	Business	2,665	3,239
40	Total retail	4,461	5,178
	Wholesale electricity delivered		
41	Traditional contracts	309	351
42	Retail load hedge management	--	--
	Marketing and trading -- delivered		
43	Generation sales other than native load	348	254
44	Other delivered electricity	2,188	2,390
45	Total delivered marketing and trading	2,536	2,644
46	Total delivered wholesale electricity	2,845	2,995
47	Total electric sales	7,306	8,173

(a) The net effect on net electric operating revenues from realization of prior-period mark-to-market included in line 37 is zero. Realization of prior-period mark-to-market relates to cash flow recognition, not revenue recognition. The arithmetic opposites of amounts included in line 32 are included in lines 28 and 31. For example, line 32 shows that a prior-period mark-to-market gain of $0 million was transferred to "realized" for the total year 1999. Lines 28 and 31 include amounts totaling $0 million of realized revenues for the year 1999.

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Last Updated 4/23/2002

Pinnacle West Capital Corporation

Consolidated Statistics By Quarter
1999

Line		1ST QTR	2ND QTR
	MARKETING AND TRADING PRETAX GROSS MARGIN ANALYSIS (DOLLARS IN MILLIONS)		
	REALIZED AND MARK-TO-MARKET COMPONENTS		
	Current Period Effects		
	Realized margin on delivered commodities		
	Electricity		
48	Generation sales other than native load	$ 2	$ 1
49	Other electricity marketing and trading (a)	6	(2)
50	Total electricity	8	(1)
51	Other commodities (a)	(1)	--
52	Total realized margin	7	(1)
	Prior-period mark-to-market (gains) losses on contracts delivered during current period (a)		
53	Electricity	--	--
54	Other commodities	--	--
55	Charge related to trading activities with Enron and its affiliates	--	--
56	Subtotal	--	--
57	Total current period effects	7	(1)
	Change in mark-to-market gains (losses) for future period deliveries		
58	Electricity	(1)	4
59	Other commodities	1	2
60	Total future period effects	--	6
61	Total gross margin	$ 7	$ 5
	BY COMMODITY SOLD OR TRADED		
62	Electricity	$ 7	$ 3
63	Natural gas	(1)	--
64	Coal	--	--
65	Emission allowances	1	2

66	Other	--	--
67	Total gross margin	$ 7	$ 5

(a) Quarterly amounts do not total to the annual amounts because of intra-year mark-to-market eliminations.

See Glossary of Terms.

Last Updated 4/23/2002

Pinnacle West Capital Corporation

Consolidated Statistics By Quarter
1999

Line		1ST QTR	2ND QTR
	AVERAGE ELECTRIC CUSTOMERS		
	Retail customers		
68	Residential	717,540	713,259
69	Business	89,046	89,949
70	Total	806,586	803,208
71	Wholesale customers	67	67
72	Total customers	806,653	803,275
73	Customer Growth (% over prior year)	4.2%	4.3%
	RETAIL ELECTRIC SALES (GWH) - WEATHER NORMALIZED		
74	Residential	1,859	1,952
75	Business	2,669	3,264
76	Total	4,528	5,216
	RETAIL ELECTRICITY USAGE (KWH/AVERAGE CUSTOMER)		
77	Residential	2,503	2,719
78	Business	29,928	36,009
	RETAIL ELECTRICITY USAGE - WEATHER NORMALIZED (KWH/AVERAGE CUSTOMER)		
79	Residential	2,591	2,737
80	Business	29,973	36,287
	ELECTRICITY DEMAND (MW)		
81	System peak demand	3,343	4,885

See Glossary of Terms.

Last Updated 4/23/2002

Pinnacle West Capital Corporation

Consolidated Statistics By Quarter
1999

Line		1ST QTR	2ND QTR
	ENERGY SOURCES (GWH)		
	Generation production		
82	Nuclear	2,295	2,080
83	Coal	2,677	2,764
84	Gas, oil and other	241	477
85	Total	5,213	5,321
	Purchased power		
86	Firm load	170	753
87	Marketing and trading	2,189	2,390
88	Total	2,359	3,143
89	Total energy sources	7,572	8,464
	POWER PLANT PERFORMANCE		
	Capacity Factors		
90	Nuclear	98%	88%
91	Coal	72%	74%
92	Gas, oil and other	9%	18%
93	System average	61%	61%
	Generation Capacity Out of Service (average MW/day)		
94	Nuclear	36	135
95	Coal	337	368
96	Gas	--	--
97	Total	373	503
98	Generation Fuel Cost ($/MWh)	$ 10.00	$ 10.96

See Glossary of Terms.

Last Updated 4/23/2002

Pinnacle West Capital Corporation

Consolidated Statistics By Quarter
1999

Line		1ST QTR	2ND QTR
	ENERGY MARKET INDICATORS (a)		
	Electricity Average Daily Spot Prices ($/MWh)		
	On-Peak		
99	Palo Verde	$ 21.57	$ 29.02
100	SP15	$ 21.26	$ 27.17
	Off-Peak		

101	Palo Verde	$ 13.94	$ 15.33
102	SP15	$ 13.68	$ 14.47
	WEATHER INDICATORS		
	Actual		
103	Cooling degree-days	71	1,312
104	Heating degree-days	459	112
105	Average humidity	34%	27%
	10-Year Averages		
106	Cooling degree-days	71	1,458
107	Heating degree-days	556	35
108	Average humidity	45%	25%
	ECONOMIC INDICATORS		
	Building Permits -- Metro Phoenix (b)		
109	Single-family	8,873	9,299
110	Multi-family	2,337	2,396
111	Total	11,210	11,695
	Arizona Job Growth (c)		
112	Payroll job growth (% over prior year)	3.9%	4.4%
113	Unemployment rate (%, seasonally adjusted)	4.4%	4.4%

Sources:

(a) This price is an average of daily prices obtained and used with permission from Dow Jones & Company, Inc.
(b) Arizona Real Estate Center, Arizona State University College of Business
(c) Arizona Department of Economic Security

See Glossary of Terms.

Exhibit 99.7

Last Updated 4/19/02

Pinnacle West Capital Corporation
Earnings Variance Explanations
For Periods Ended March 31, 2002 and 2001

This discussion explains the changes in our earnings for the three and twelve months ended March 31, 2002 and 2001. We suggest this section be read along with the Pinnacle West Annual Report on Form 10-K for the fiscal year ended December 31, 2001. Consolidated income statements for the three and twelve months ended March 31, 2002 and 2001 follow this discussion. Additional operating and financial statistics and a glossary of terms are available on the Company’s website (www.pinnaclewest.com).

Earnings Contributions by Subsidiary

The following table summarizes net income for the three and twelve months ended March 31, 2002 and the comparable prior-year periods for Pinnacle West and each of its subsidiaries (dollars in millions):

	Three Months Ended March 31,		Twelve Months Ended March 31,	
	2002	2001	2002	2001

Arizona Public Service (APS)	$ 32	$ 65	$ 248	$ 338
Pinnacle West Energy	1	--	19	(2)
APS Energy Services (APSES)	2	(8)	--	(20)
SunCor	2	--	5	7
El Dorado	--	1	--	(17)
Parent Company (a)	17	4	46	5
Income before accounting change	54	62	318	311
Cumulative effect of a change in accounting – net of income taxes	--	(3)	(12)	(3)
Net income	$ 54	$ 59	$ 306	$ 308

(a) These amounts primarily include marketing and trading activities. APS also includes some marketing and trading activities in 2001.

Business Segments

We have two principal business segments determined by products, services and regulatory environment, which consist of our regulated retail electricity business and related activities (retail business segment) and competitive business activities (marketing and trading segment). Our retail business segment currently includes activities related to electricity transmission and distribution, as well as electricity generation. Our marketing and trading segment currently includes activities related to wholesale marketing and trading and APSES' competitive energy services.

The following table summarizes net income by business segment for the three and twelve months ended March 31, 2002 and the comparable prior-year periods (dollars in millions):

	Three Months Ended March 31,		Twelve Months Ended March 31,	
	2002	2001	2002	2001
Retail	$ 31	$ 3	$ 179	$ 199
Marketing and trading	21	58	134	122
Other	2	1	5	(10)
Income before accounting change	54	62	318	311
Cumulative effect of a change in accounting – net of income taxes	--	(3)	(12)	(3)
Net income	$ 54	$ 59	$ 306	$ 308

Earnings Variance Explanations

Operating Results - Three-month period ended March 31, 2002 compared with three-month period ended March 31, 2001

Our consolidated net income for the three months ended March 31, 2002 was $54 million compared with $59 million for the same period in the prior year. In 2001, we recognized a $3 million after-tax loss in net income as the cumulative effect of a change in accounting for derivatives, as required by Statement of Financial Accounting Standards (SFAS) No.133.

Income before accounting change for the three months ended March 31, 2002 was $54 million compared with $62 million for the same period in the prior year. The period-to-period decrease is the result of lower marketing and trading earnings contributions and a retail electricity price decrease. These negative factors were partially offset by lower costs for replacement power due to lower market prices and less outages, power plant maintenance, and generation reliability. The major factors that increased (decreased) income before accounting change were as follows (dollars in millions):

	Increase (Decrease)
Increases (decreases) in electric revenues, net of purchased power and fuel expense due to:	
Marketing and trading activities:	
Decrease from generation sales other than native load due to lower market prices and resulting lower sales volumes	$ (46)
Increase in other realized marketing and trading in the current period primarily due to higher unit margins on increased volumes	38(a)
Change in prior-period mark-to-market gains for contracts delivered during the current period (b)	(35)(a)
Lower mark-to-market gains for future-period deliveries (b)	(24)
Net decrease in marketing and trading gross margin	(67)
Lower replacement power costs for plant outages due to lower market prices and fewer unplanned outages	50
Increased fuel costs related to higher hedged natural gas and purchased power prices	(11)
Change in mark-to-market for hedged natural gas and purchased power costs for future-period deliveries related to accounting for derivatives	3
Effects of milder weather on retail sales	(6)
Higher retail sales volumes due to customer growth and higher average usage excluding weather effects	4
Retail price reductions effective July 1, 2001	(5)
Miscellaneous factors – net	1
Total decrease in electric revenues, net of purchased power and fuel expense	(31)
Lower operations and maintenance expenses primarily related to reliability, outage and maintenance costs, and the absence of a provision for credit expense, partially offset by higher employee benefit costs	8
Lower depreciation and amortization primarily due to lower regulatory asset amortization	5
Miscellaneous items, net	4
Decrease in income before income taxes	(14)
Lower income taxes primarily due to lower income	6
Decrease in income before accounting change	$ (8)

(a) Net marketing and trading gains (excluding the effects of generation sales other than native load) realized during the current period increased $3 million.

(b) Essentially all of our marketing and trading activities are structured activities. This means our portfolio of forward sales positions is hedged with a portfolio of forward purchases that protects the economic value of the sales transactions.

Electric operating revenues decreased approximately $327 million primarily because of:

- changes in marketing and trading revenues ($294 million, net decrease) due to:
  - decreased revenues related to generation sales other than native load due to lower market prices and resulting lower sales volumes ($79 million);

    - decreased realized revenues related to other realized marketing and trading in the current period primarily due to lower prices ($165 million);
    - change in prior-period mark-to-market gains on contracts delivered during the current period ($28 million decrease);
    - lower mark-to-market gains for future-period deliveries primarily as a result of lower market price volatility ($22 million);
- decreased revenues related to other wholesale sales as a result of lower sales volumes and lower prices ($27 million);
- decreased retail revenues related to milder weather ($9 million);
- increased retail revenues related to customer growth and higher usage excluding weather effects ($7 million);
- decreased retail revenues related to a reduction in retail electricity prices ($5 million); and
- other miscellaneous factors ($1 million increase).

Purchased power and fuel expenses decreased approximately $296 million primarily because of:

- changes in purchased power and fuel costs related to marketing and trading activities ($227 million, net decrease) due to:
    - decreased fuel costs related to generation sales other than native load primarily because of lower sales volumes and lower natural gas prices ($33 million);
    - decreased purchased power costs related to other realized marketing and trading in the current period primarily due to lower prices ($203 million);
    - change in prior-period mark-to-market fuel costs for current-period deliveries related to accounting for derivatives ($7 million increase);
    - change in mark-to-market fuel costs for future-period deliveries related to accounting for derivatives ($2 million increase);
- decreased costs related to other wholesale sales as a result of lower sales volumes and lower prices ($27 million);
- increased fuel costs related to higher hedged natural gas and purchased power prices ($11 million);
- change in mark-to-market for hedged natural gas and purchased power costs for future-period deliveries related to accounting for derivatives ($3 million decrease);
- decreased costs related to the effects of milder weather on retail sales ($3 million);
- increased costs related to retail sales growth excluding weather effects ($3 million); and
- decreased replacement power costs for power plant outages due to lower market prices and fewer unplanned outages ($50 million).

The decrease in operations and maintenance expenses of $8 million primarily related to costs incurred in 2001 for the generation reliability program (the addition of generation capacity to enhance reliability for the summer of 2001) and plant outages and maintenance ($7 million); and the absence of a provision for credit exposure related to the California energy situation recorded in 2001 ($5 million). These factors were partially offset by increased employee benefit and other costs in the current period ($4 million).

The decrease in depreciation and amortization expenses of $5 million primarily related to lower regulatory asset amortization, in accordance with APS' 1999 regulatory settlement agreement.

Operating Results - Twelve-month period ended March 31, 2002 compared with twelve-month period ended March 31, 2001

Our consolidated net income for the twelve months ended March 31, 2002 was $306 million compared with $308 million for the same period in the prior year. We recognized a $12 million after-tax loss in the twelve months ended March 31, 2002 and a $3 million after-tax loss in the twelve months ended March 31, 2001 as cumulative effects of a change in accounting for derivatives, as required by SFAS No.133.

Income before accounting change for the twelve months ended March 31, 2002 was $318 million compared with $311 million for the same period a year earlier. The period-to-period comparison benefited from favorable marketing and trading results, including significant benefits in the third quarter of 2001 from structured trading activities; lower replacement power costs; and retail customer growth. These factors were partially offset by continuing retail electricity price decreases; higher hedged purchased power and fuel costs, costs of generation reliability measures; and charges related to Enron and its affiliates. The major factors that increased (decreased) income before accounting change were as follows (dollars in millions):

	Increase (Decrease)
Increases (decreases) in electric revenues, net of purchased power and fuel expense due to:	
Marketing and trading activities:	
Decrease from generation sales other than native load due to lower market prices and resulting lower sales volumes	$ (66)
Increase in other realized marketing and trading in the current	

period primarily due to higher unit margins on increased sales volumes	80(a)
Change in prior-period mark-to-market gains for contracts delivered in the current period (b)	(24)(a)
Change in prior-period mark-to-market value related to trading with Enron and its affiliates (c)	(8)
Increase in mark-to-market gains for future-period deliveries (b)	42
Net increase in marketing and trading	24
Lower replacement power costs for plant outages related to lower market prices and fewer unplanned outages	24
Retail price reductions effective July 1, 2001 and 2000	(27)
Charges related to purchased power contracts with Enron and its affiliates(c)	(13)
Change in mark-to-market for hedged natural gas and purchased power costs for future-period deliveries related to accounting for derivatives	(9)
Higher retail sales primarily related to customer growth and weather impacts, partially offset by lower usage and higher hedged cost of purchased power and fuel	20
Total increase in electric revenues, net of purchased power and fuel expense	19
Higher operations and maintenance expense primarily related to 2001 generation reliability program	(57)
Lower depreciation and amortization primarily due to lower regulatory asset amortization	11
Lower net interest expense primarily due to higher capitalized interest	15
Lower other net expense primarily related to El Dorado	33
Miscellaneous items, net	(4)
Net increase in income before income taxes	17
Higher income taxes primarily due to higher income	(10)
Net increase in income before accounting change	$ 7

(a) Net marketing and trading gains (excluding the effects of generation sales other than native load) realized during the current period increased $56 million.

(b) Essentially all of our marketing and trading activities are structured activities. This means our portfolio of forward sales positions is hedged with a portfolio of forward purchases that protects the economic value of the sales transactions.

(c) We recorded charges totaling $21 million for exposure to Enron and its affiliates in the fourth quarter of 2001.

Electric operating revenues increased approximately $64 million primarily because of:

- changes in marketing and trading revenues ($105 million, net increase) due to:
  - decreased revenues related to generation sales other than native load as a result of lower market prices and resulting lower sales volumes ($125 million);
  - increased realized revenues related to other marketing and trading in the current period primarily due to higher sales volumes ($212 million);
  - decrease in prior-period mark-to-market value related to trading with Enron and its affiliates ($8 million);
  - change in prior-period mark-to-market gains for contracts delivered during the current period ($14 million decrease);
  - increased mark-to-market gains for future-period deliveries primarily because of higher sales volumes ($40 million);
- decreased wholesale and other revenues as a result of lower sales volumes ($69 million);
- higher retail sales related to customer growth and weather impacts, partially offset by lower average residential usage ($55 million); and

- decreased retail revenues related to reductions in retail electricity prices effective July 1, 2001 and 2000 ($27 million).

Purchased power and fuel expenses increased approximately $45 million primarily because of:

- changes in purchased power and fuel costs related to marketing and trading activities ($81 million, net increase) due to:
  - decreased fuel costs related to generation sales other than native load as a result of lower sales volumes ($59 million);
  - increased fuel and purchased power costs related to other realized marketing and trading in the current period primarily due to higher sales volumes ($132 million);
  - change in prior-period mark-to-market fuel costs for current-period deliveries related to accounting for derivatives ($10 million increase);
  - change in mark-to-market fuel costs for future-period deliveries related to accounting for derivatives ($2 million decrease);
- decreased costs related to other wholesale sales as a result of lower sales volumes ($69 million);
- lower replacement power costs primarily due to lower market prices and fewer unplanned outages ($24 million);
- higher costs related to retail sales as a result of the higher hedged cost of purchased power and fuel and higher retail sales volumes related to customer growth and weather impacts ($35 million);
- change in mark-to-market for hedged natural gas and purchased power costs for future-period deliveries related to accounting for derivatives ($9 million increase) and;
- charges related to purchased power contracts with Enron and its affiliates ($13 million).

The increase in operations and maintenance expenses of $57 million primarily related to the 2001 generation reliability program (the addition of generating capability to enhance reliability for the summer of 2001) and scheduled plant outages and maintenance ($39 million); and increased employee benefit and other costs ($28 million). These factors were partially offset by a provision for our credit exposure related to the California energy situation recorded in the prior period ($10 million).

The decrease in depreciation and amortization expenses of $11 million primarily related to lower regulatory asset amortization, in accordance with APS' 1999 regulatory settlement agreement.

Net other expense decreased $33 million primarily because of a change in the market value of El Dorado's investment in a technology-related venture capital partnership in the prior period and an insurance recovery of environmental remediation costs, partially offset by other non-operating costs. The major investment in the venture capital partnership was sold in the first quarter of 2001.

Net interest expense decreased by $15 million primarily because of the increase in capitalized interest ($23 million) related to our generation expansion program and the effects of lower interest rates. The reductions in net interest expense more than offset the increases in interest expense for higher debt balances that were related primarily to our generation expansion program.

Exhibit 99.7

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATED STATEMENTS OF INCOME
(Dollars in Thousands, Except Per Share Amounts)
(Unaudited)

	THREE MONTHS ENDED MARCH		TW
	2002	2001	
OPERATING REVENUES			
Electric	$ 579,772	$ 906,494	$
Real estate	41,185	32,335	
Total	620,957	938,829	
OPERATING EXPENSES			
Purchased power and fuel	221,036	516,424	
Operations and maintenance	117,430	125,250	
Real estate operations	37,358	31,008	
Depreciation and amortization	99,913	104,781	
Taxes other than income taxes	26,758	25,303	

Total	502,495	802,766	
OPERATING INCOME	118,462	136,063	
OTHER INCOME (EXPENSE)	1,088	(738)	
INTEREST EXPENSE			
Interest charges	44,688	42,749	
Capitalized interest	(14,123)	(10,427)	
Total	30,565	32,322	
INCOME BEFORE INCOME TAXES	88,985	103,003	
INCOME TAXES	35,228	40,798	
INCOME BEFORE ACCOUNTING CHANGE	53,757	62,205	
CUMULATIVE EFFECT OF A CHANGE IN ACCOUNTING FOR DERIVATIVES - NET OF INCOME TAX	--	(2,755)	
NET INCOME	$ 53,757	$ 59,450	$
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING - BASIC	84,735	84,727	
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING - DILUTED	84,884	84,966	
EARNINGS PER WEIGHTED AVERAGE COMMON SHARE OUTSTANDING			
Income Before Accounting Change - Basic	$ 0.63	$ 0.73	$
Net Income - Basic	$ 0.63	$ 0.70	$
Income Before Accounting Change - Diluted	$ 0.63	$ 0.73	$
Net Income - Diluted	$ 0.63	$ 0.70	$

Certain prior year amounts have been restated to conform to the 2002 presentation.

Exhibit 99.8

Last Updated 4/23/02

Pinnacle West Capital Corporation
Quarterly Consolidated Statistical Summary
Glossary of Terms

Arizona Job Growth	Percentage growth over the prior year in total non-farm payroll employment for the state of Arizona, non-seasonally adjusted.
Building Permits - Metro Phoenix	The number of residential dwellings permitted to be built by authorized agencies in Maricopa County, Arizona. Single-family refers to detached buildings intended to be occupied by one family each. Multi-family permits represent the number of units authorized to be built in condominium, townhouse and apartment complexes.

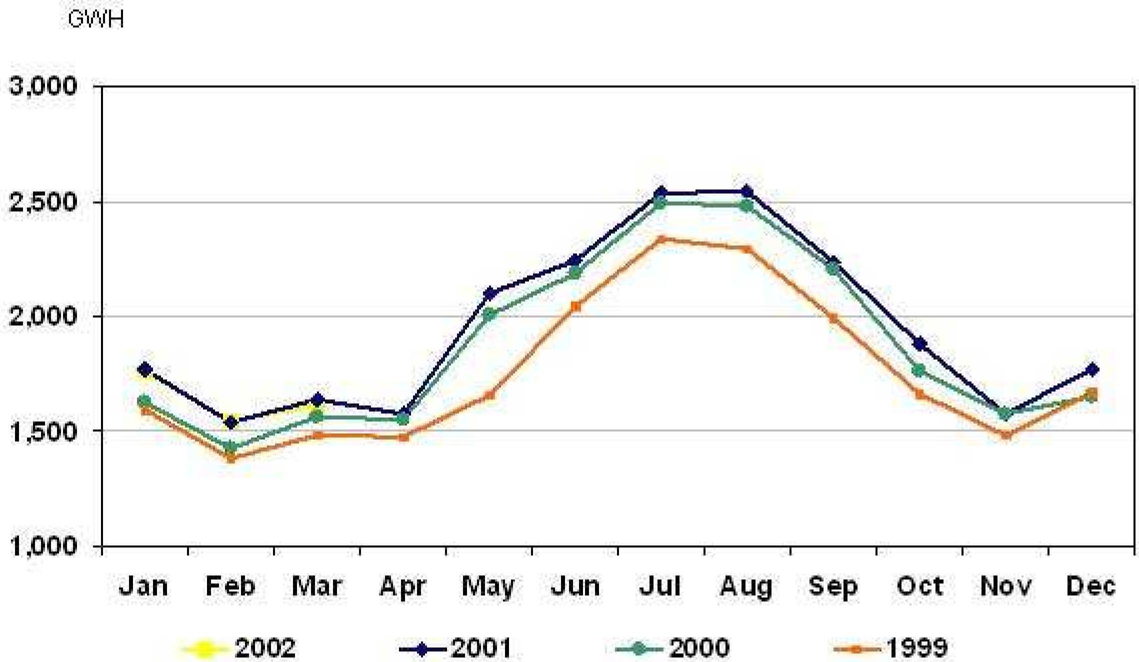
Capacity Factor	The ratio of the average operating load of an electric power generating unit for a period of time to the capacity rating of the unit during that period.
Change in Mark-To-Market Gains (Losses) For Future-Period Deliveries	The gross margin related to the change in mark-to-market value in the current period of transactions which have been entered into during the current period or prior periods for which the commodities are scheduled for delivery in a future period.
Current Period Effects	The net effect of the total revenue or gross margins realized on delivery of commodities in the period being measured, and the amount of prior-period mark-to-market (gains) losses on contracts delivered during period. The net effect of transferring prior-period mark-to-market to realized does not affect total revenues, gross margin or earnings.
Degree-Days -- Cooling	A measure of temperatures designed to indicate the amount of electricity demand for cooling purposes. Cooling degree-days are calculated by summing the difference between each day's actual average temperature and a base temperature of 65(degree)F for the month. Average temperatures less than the base temperature are ignored.
Degree-Days -- Heating	A measure of temperatures designed to indicate the amount of electricity demand for heating purposes. Heating degree-days are calculated by summing the difference between each day's actual average temperature and a base temperature of 65(degree)F for the month. Average temperatures greater than the base temperature are ignored.
Electricity Marketing and Trading - Delivered	All wholesale sales of electricity not accounted for in sales under traditional contracts or retail load hedge management. These sales are made to other electric companies, power marketers, or public entities for the purpose of resale. Measured in gigawatt-hours.
Electricity Spot Prices --Palo Verde - Off-Peak	Electricity average daily spot prices at Palo Verde substation during off-peak hours. It measures electric prices at the producer level and is the result of real time prices used for benchmarking, price comparisons, and establishing price contracts. Measured in dollars per megawatt-hour.
Electricity Spot Prices -- Palo Verde - On-Peak	Electricity average daily spot prices at Palo Verde substation during on-peak hours. It measures electric prices at the producer level and is the result of real time prices used for benchmarking, price comparisons, and establishing price contracts. Measured in dollars per megawatt-hour.
Electricity Spot Prices -- SP15 - Off-Peak	Electricity average daily spot prices at SP15, a region of California substations, during off-peak hours. It measures electric prices at the producer level and is the result of real time prices used for benchmarking, price comparisons, and establishing price contracts. Measured in dollars per megawatt-hour.
Electricity Spot Prices -- SP15 - On-Peak	Electricity average daily spot prices at SP15, a region of California substations, during on-peak hours. It measures electric prices at the producer level and is the result of real time prices used for benchmarking, price comparisons, and establishing price contracts. Measured in dollars per megawatt-hour.
Generation Capacity Out of Service	Total capacity required and economic yet unavailable due to

	scheduled or unscheduled outages. Measured in megawatts per day.
Generation Sales Other Than Native Load	Sales of electricity from generation owned by the company that is over and above the amount required to serve retail customers and traditional wholesale contracts.
Generation Production -- Coal	Amount of net energy produced by coal-fueled generators. Measured in gigawatt-hours.
Generation Production -- Gas/Oil/Other	Amount of net energy predominately produced by natural gas and oil-fueled generators. A small amount of energy from hydroelectric and solar power plants is also included. Measured in gigawatt-hours.
Generation Production -- Nuclear	Amount of net energy produced by nuclear-fueled generators. Measured in gigawatt-hours.
Gigawatt-hour (GWH)	A unit of energy equivalent to 1,000 megawatt-hours or 1,000,000 kilowatt-hours.
Marketing and Trading Gross Margin - Pretax	Revenues from marketing and trading activities (other than retail sales, traditional wholesale sales and retail load hedge management) less the costs of the related commodities, with mark-to-market gains or losses, before income taxes.
Marketing and Trading Gross Margin by Commodity -- Pretax	Marketing and trading gross margin, before income taxes, for generation sales other than native load and for sales and purchases of electricity and other commodities by the company in the wholesale market, summarized by the underlying commodities.
Realized and Mark-to-Market Components	Marketing and trading gross margin, before income taxes, for generation sales other than native load and for sales and purchase of electricity and other commodities by the company in the wholesale market, summarized by the period of delivery and whether the margin is realized or mark-to-market. Realized margins relate to commodities that have been delivered. Mark-to-market margins relate to commodities that have delivery dates in future periods.
Mark-To-Market	Adjustments to revenues or costs to recognize value of sales and purchase contracts, for which the commodities are scheduled for delivery in a future period, at current forward wholesale prices.
Megawatt (MW)	One million watts.
Megawatt-hour (MWh)	A unit of energy equivalent to 1,000 kilowatt-hours.
Prior Period Mark-To-Market (Gains) Losses on Contracts Delivered During Current Period	The reversal of the gross margin related to mark-to-market transactions entered into in prior periods for which the commodities were delivered in the current period. Realization of prior-period mark-to-market relates to cash flow recognition, not revenue recognition or earnings recognition, because in accordance with mark-to-market accounting, the margin was already recorded in the prior period. A negative amount shown in this category represents the arithmetic opposite of a gain recognized in the period in which the commodities were delivered; an equal positive amount is reflected in the realized revenue or margin for delivered commodities. A positive amount shown in this category represents the arithmetic opposite of a loss recognized in the period in which the commodities were delivered; an equal negative amount is

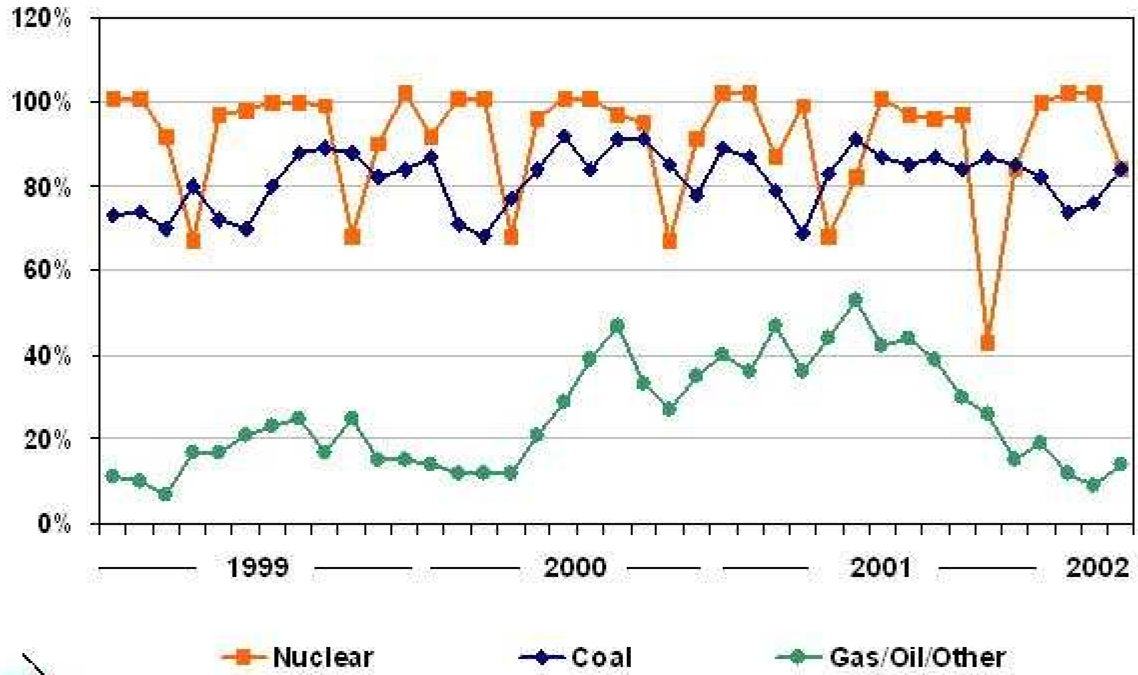
	reflected in the realized revenue or margin for delivered commodities.
Purchased Power - Firm Load	Power purchased from wholesale market sources used to serve regulated retail demand and traditional wholesale contracts. Measured in gigawatt-hours.
Purchased Power - Marketing and Trading	Power purchased from wholesale market sources used to serve marketing and trading sales not served by company-owned generation. Measured in gigawatt-hours.
Realized Margin on Delivered Commodities	Marketing and trading gross margin related to electricity and other commodities that were delivered in the then-current period.
Retail Customer Growth	Percentage growth over the prior year in the number of retail customers.
Retail Electricity Usage	Total retail sales for a period divided by the average retail customers for the same period. Measured in kilowatt-hours per average customer.
Retail Load Hedge Management	Wholesale sales to liquidate electricity purchases originally intended to meet firm load during peak times, which purchases were not needed ultimately for firm load. These sales are made to other electric companies, power marketers, or public entities for the purpose of resale. Measured in gigawatt-hours.
Retail Sales	Sales of electricity made directly to retail customers or ultimate customers. Residential retail sales are sales to households. Business retail sales include commercial, industrial, irrigation, and streetlighting sales. Measured in gigawatt-hours.
System Peak Demand	The demand for electricity during the one hour of highest use each month. Measured in megawatts.
Traditional Contracts	Wholesale sales resulting from unique cost-based, long-term contracts held by the company with various entities for the supply of electricity at agreed-upon prices.
Weather Normalized	Adjusted to exclude the effects of abnormal weather patterns.

Exhibit 99.9

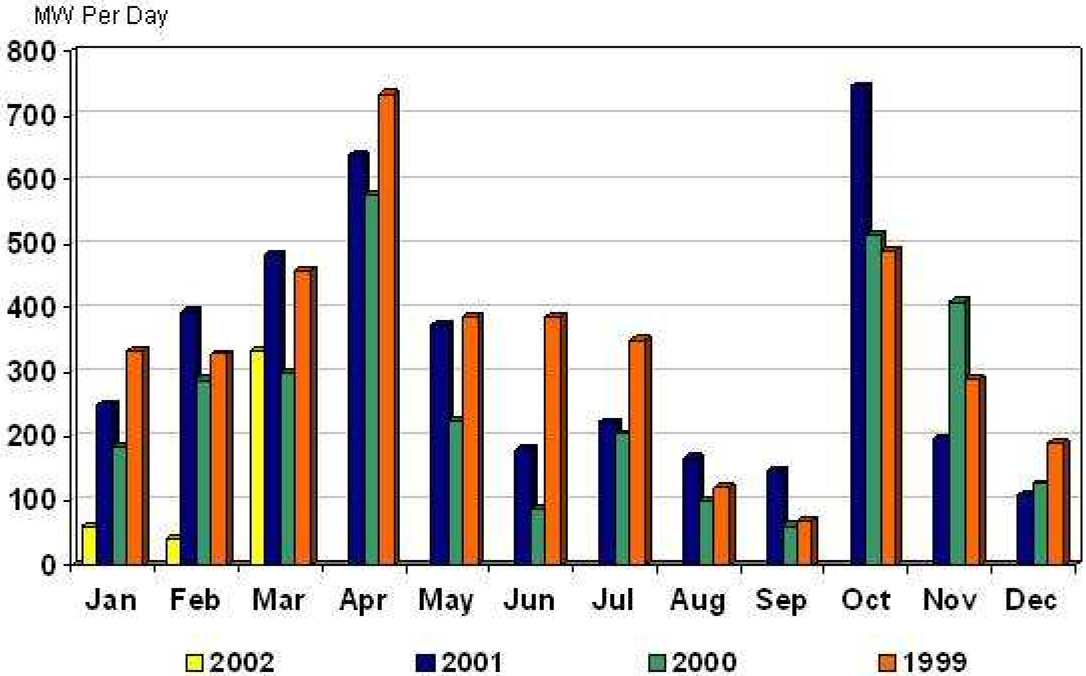
Retail Electricity Sales
January 1999 - March 2002



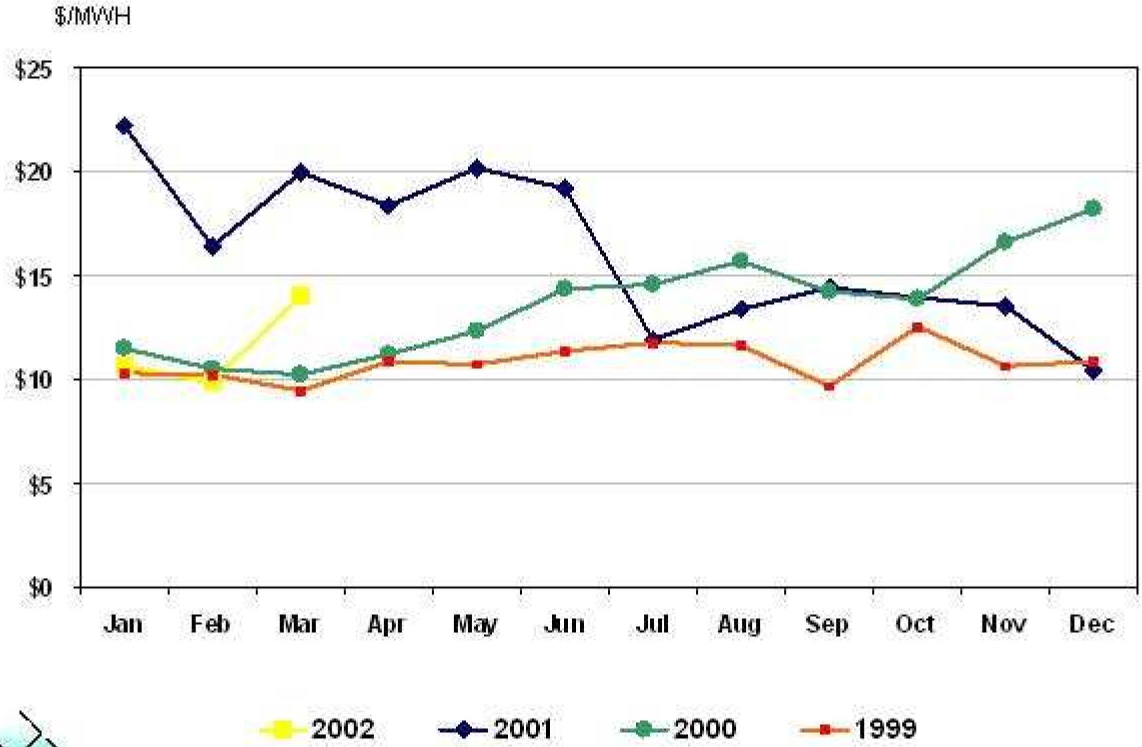
Generating Plant Capacity Factors
January 1999 - March 2002



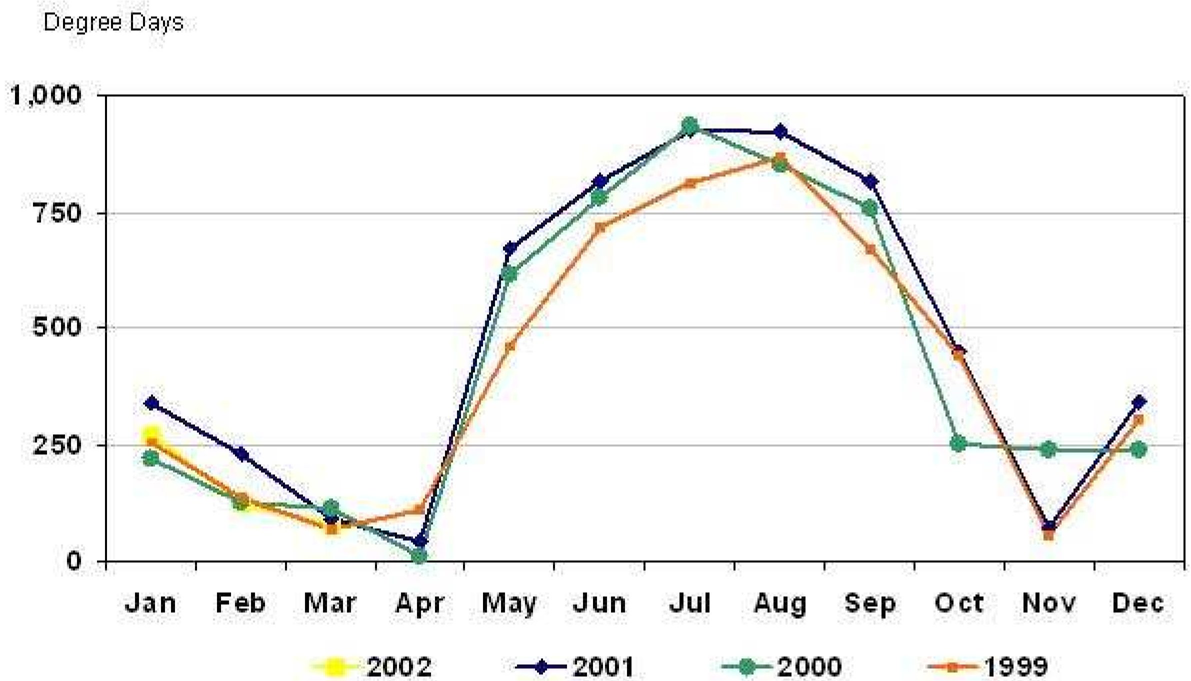
Average Generating Capacity Out of Service
January 1999 - March 2002



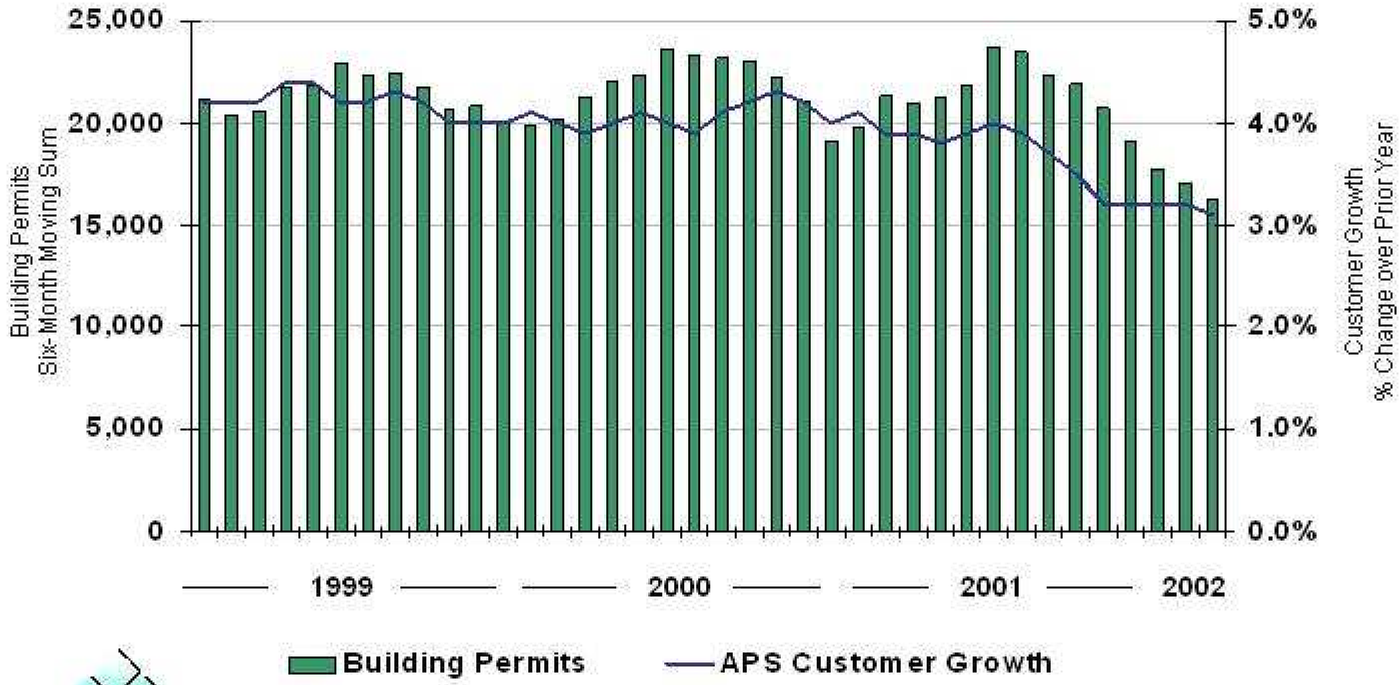
Generation Fuel Costs
January 1999 - March 2002



Metropolitan Phoenix Area
Cooling and Heating Degree Days
January 1999 - March 2002



Metro Phoenix Building Permits vs. APS Retail Electricity Customer Growth January 1999 - February 2002



Arizona vs U.S.
Payroll Job Growth
January 1999 - February 2002

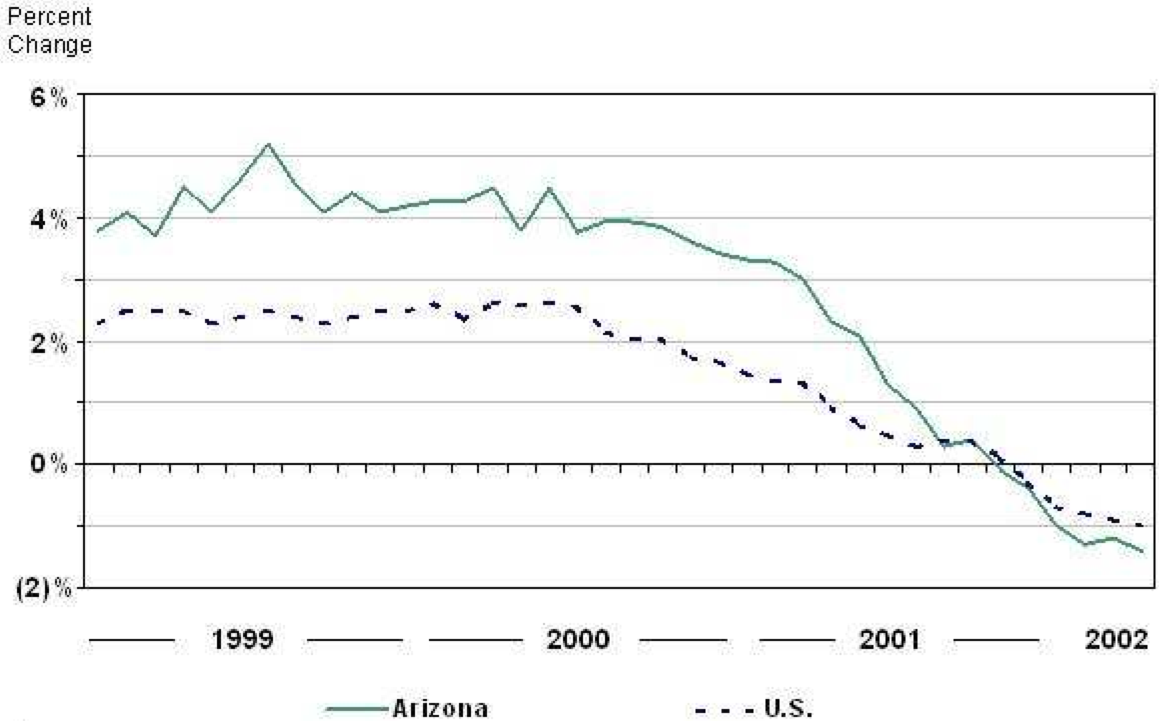


Exhibit 99.10

Analyst Presentations
Boston and New York
April 23-24, 2002

dif·fer·en·ti·ate
PINNACLE WEST CAPITAL CORPORATION

Forward-Looking Statements

This presentation contains forward-looking statements based on current expectations and the company assumes no obligation to update these statements. Because actual results may differ materially from expectations, the company readers not to place undue reliance on these statements. A number of factors could cause future results to differ materially from historical results, or from results or outcomes currently expected or sought by the company. These factors include the ongoing restructuring of the electric industry, including the introduction of retail electric competition in Arizona and APS' October 2001 ACC filing; the outcome of regulatory and legislative proceedings relating to the restructuring; state and federal regulatory and legislative decisions and actions, including the price mitigation plan adopted by the FERC in June 2001; regional economic and market conditions, including the California energy situation and completion of generation construction in the region, which could affect customer growth and the cost of power supplies; the cost of debt and equity capital; weather variations affecting local and regional customer energy usage; conservation programs; power plant performance; the successful completion of the company's generation expansion program; regulatory issues associated with generation expansion, such as permitting and licensing; the company's ability to compete successfully outside traditional regulated markets (including the wholesale market); technological developments in the electric industry; and the strength of the real estate market in SunCor's market areas, which include Arizona, New Mexico and Utah.

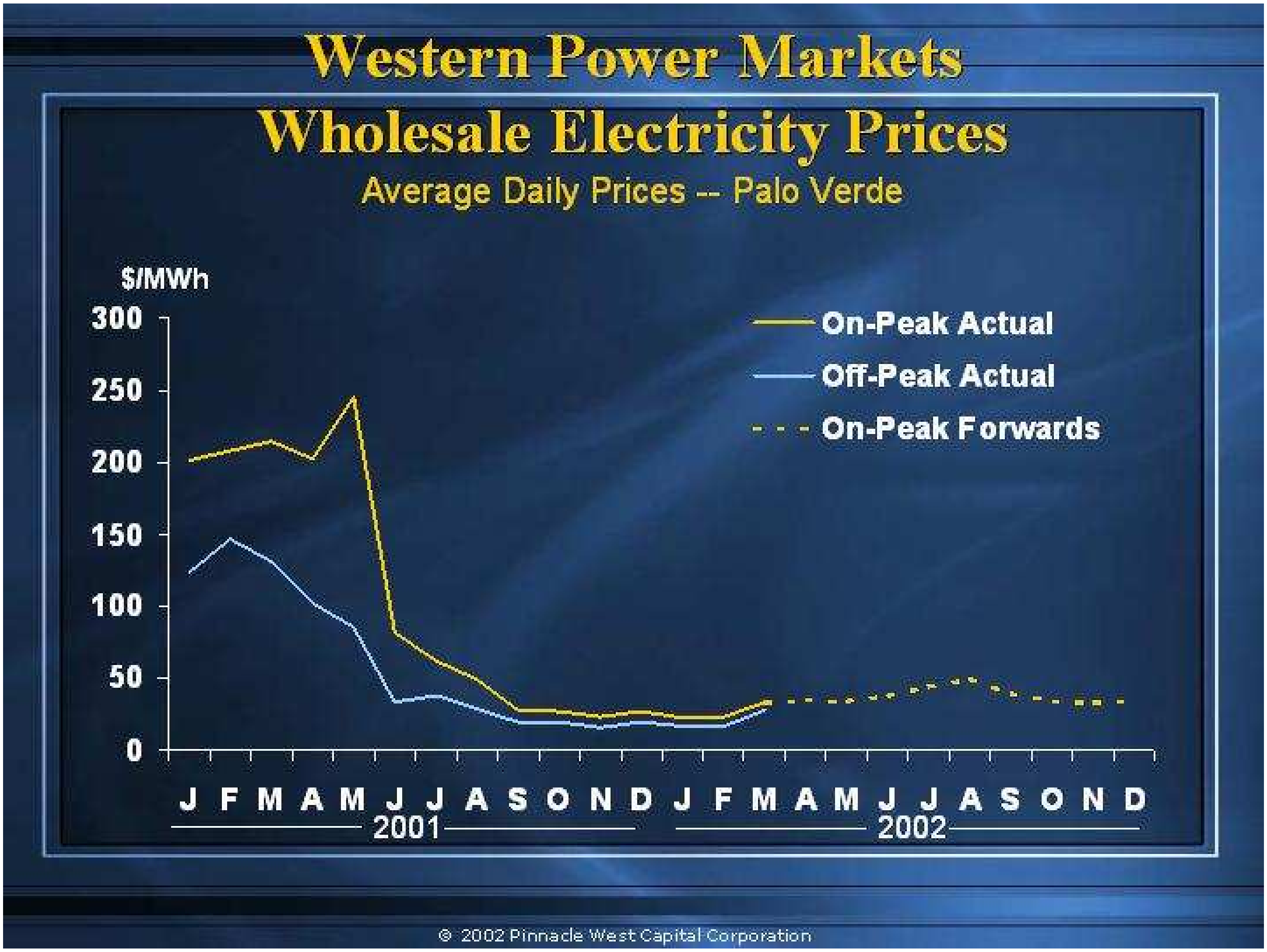
Pinnacle West
Presentation Agenda

- Strategic overview
- Western power market overview
- Power marketing and hedging
- Regulated delivery issues
- Generation operations and expansion
- Financial objectives and results

Chairman's Strategic Overview

Western Power Market Overview

Marketing & Trading and Hedging


Western Power Markets
Wholesale Electricity Prices
Average Daily Prices -- Palo Verde
$/MWh
300
250
200
150
100
50
0
On-Peak Actual
Off-Peak Actual
On-Peak Forwards
J F M A M J J A S O N D J F M A M J J A S O N D
2001
2002
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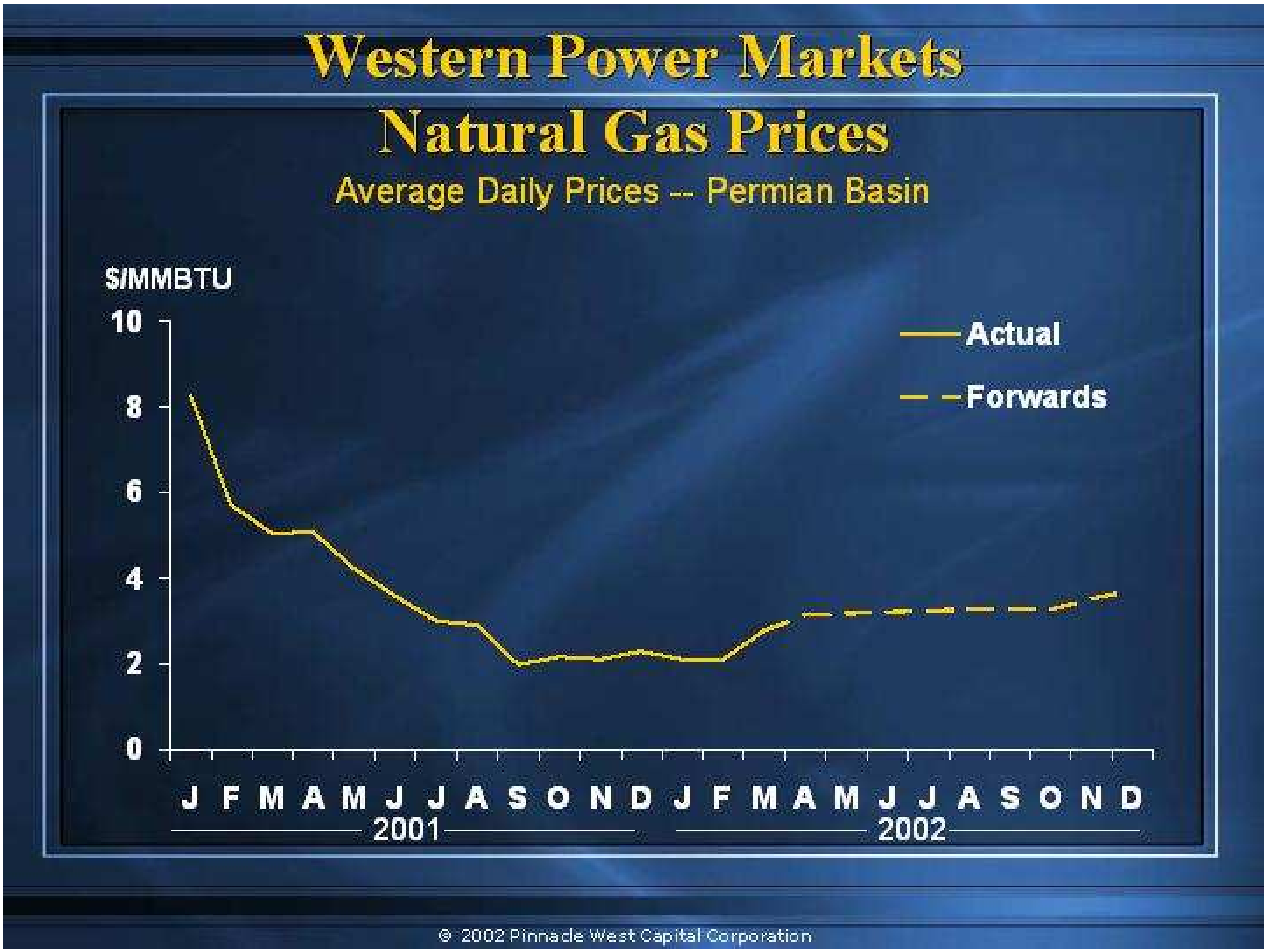
Western Power Markets
Natural Gas Prices
Average Daily Prices -- Permian Basin
$/MMBTU
10
8
6
4
2
0
Actual
Forwards
J F M A M J J A S O N D J F M A M J J A S O N D
2001
2002
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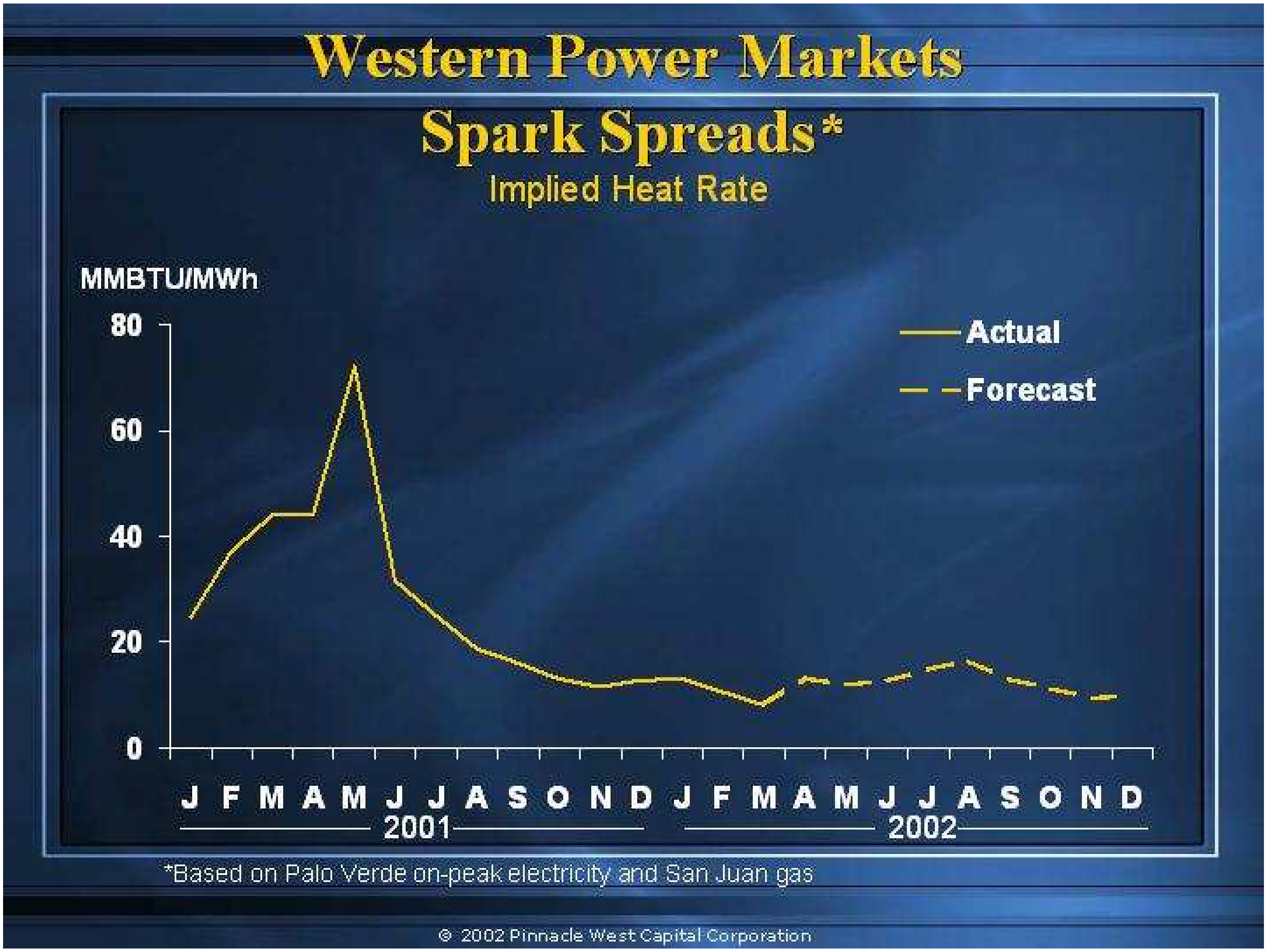
Western Power Markets
Spark Spreads*
Implied Heat Rate
MMBTU/MWh
80
60
40
20
0
Actual
Forecast
J F M A M J J A S O N D J F M A M J J A S O N D
2001
2002
*Based on Palo Verde on-peak electricity and San Juan gas
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Western Power Market Influences

- Regulatory pressures flatten spark spreads
- FERC market interference
- California DWR contracts and issues


Pinnacle West
Enterprisewide Hedging Strategy
MWs
8,000
6,000
4,000
2,000
0
2002
2003
2004
Hedge
West Phoenix 5
Saguaro
Redhawk 1 & 2
Existing Resources
Retail Peak Load
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Pinnacle West
Natural Gas Supply

El Paso Natural Gas Line
FERC Issues

- Arizona companies signed firm contracts
- California shippers contesting firm requirements contracts
- Staff recommendation would reduce Arizona rights
- Technical conference

Regulatory Update

APS Regulatory Plan

- APS filed with ACC in October 2001 requests for:
  - Variance from competitive bidding requirements
  - Approval of purchase power agreement
- Hearing to begin on April 29, 2002
- Major issues
  - Competitive bidding amounts
  - Purchase power agreement pricing
  - Certain terms and conditions
  - Market power

APS Regulatory Plan

- Generation asset transfer
  - Still required by end of 2002
  - ACC Staff has recommended "stay" pending outcome of generic proceedings
- Related developments
  - ACC generic review proceedings on electric restructuring
  - Panda show-cause motion on bidding

ACC Generic Review Proceedings on Electric Restructuring

- All three commissioners desire to "re-look" at Electric Competition Rules
- Interested parties have responded to commissioners' questions
- ACC Staff report recommends continued wholesale/retail competition, but also unspecified rule changes

ACC Generic Review Proceedings on Electric Restructuring

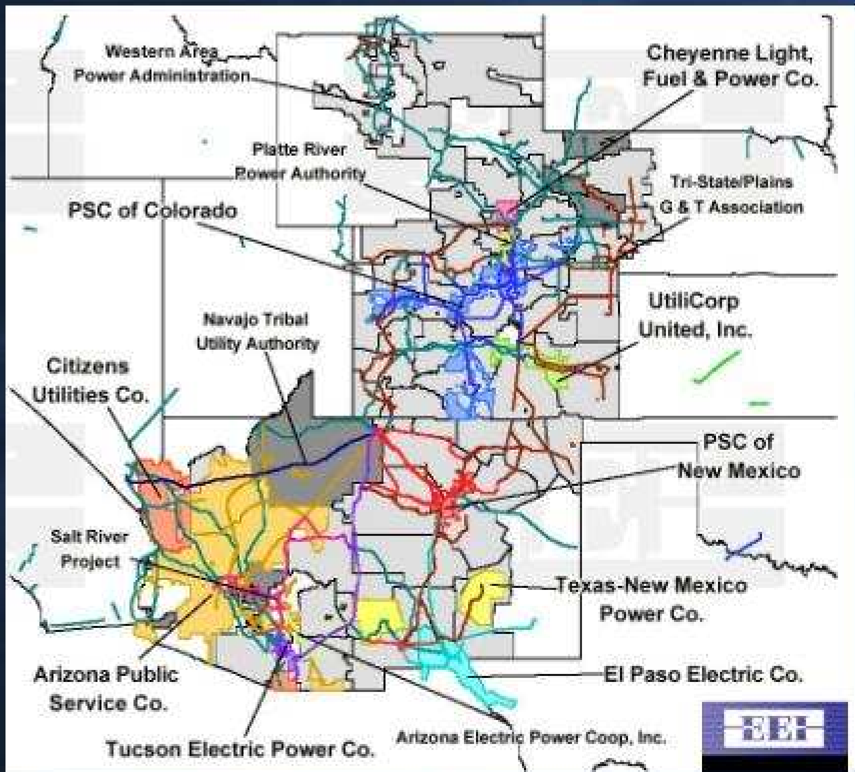
- ACC staff urges commission review in six specific areas
  - ACC monitoring of market conditions and market power
  - Competitive bidding process guidance
  - Alternatives to generation asset transfers
  - Transmission constraints
  - Adjustor mechanisms for standard-offer rates
  - Customer shopping credits
- Generic time table

Legal Proceedings
Related to Regulatory Matters

- 1999 APS Settlement Agreement
  - Affirmed by Arizona Supreme Court
- Electric Competition Rules
  - Declared unconstitutional by Arizona Superior Court
  - Still in effect pending review by Arizona Court of Appeals

Regulated Delivery Update

West Connect - RTO



West Connect - RTO

- Filing made October 15, 2001
- No action by FERC to date
- Filing parties
  - Arizona Public Service
  - El Paso Electric
  - Public Service of New Mexico
  - Tucson Electric Power

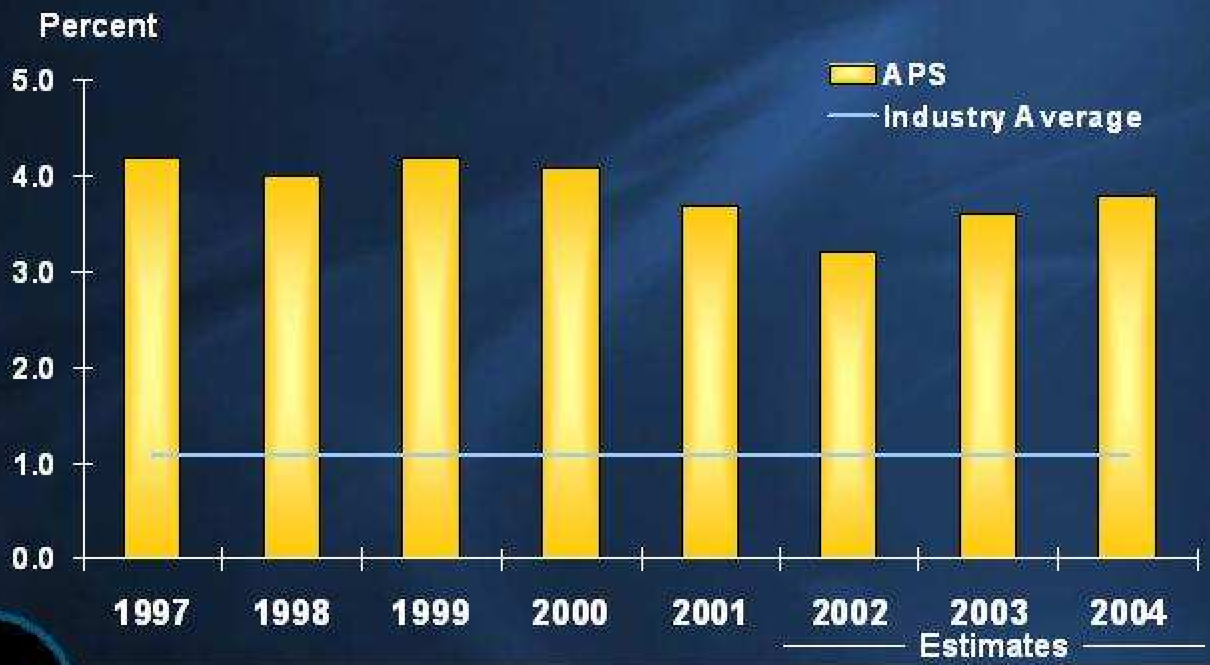
West Connect - RTO

- Entities supporting the filing
  - Salt River Project
  - Washington Area Power Administration
  - Southwest Transmission Corporation
- Discussions with Translink and Public Service of Colorado

Retail Customer Strategies

- Capitalize on superior customer growth

Superior Retail Customer Growth



Retail Customer Strategies

- Capitalize on superior customer growth
- Maintain high customer satisfaction

Retail Customer Satisfaction
J.D. Power Performance Comparisons

	APS	West Region	Rank Within Region
Overall Customer Satisfaction Index	103	95	2 of 10
Power Quality & Reliability	103	97	3 of 10
Company Image	105	93	2 of 10
Price & Value	104	93	2 of 10
Billing & Payment	107	97	1 of 10
Customer Service	105	100	3 of 10

Retail Customer Strategies

- Capitalize on superior customer growth
- Maintain high customer satisfaction
- Provide reliable service

Retail Customer Strategies

- Capitalize on superior customer growth
- Maintain high customer satisfaction
- Provide reliable service
- **Achieve constructive regulatory plan**


Power Markets, Marketing & Trading
and Regulated Delivery Summary
• Superior retail customer growth continues
• Western market conditions provide challenges, yet opportunities, for marketing and trading results
• Hedging manages risks of power and fuel procurement
• Constructive regulatory outcomes being sought
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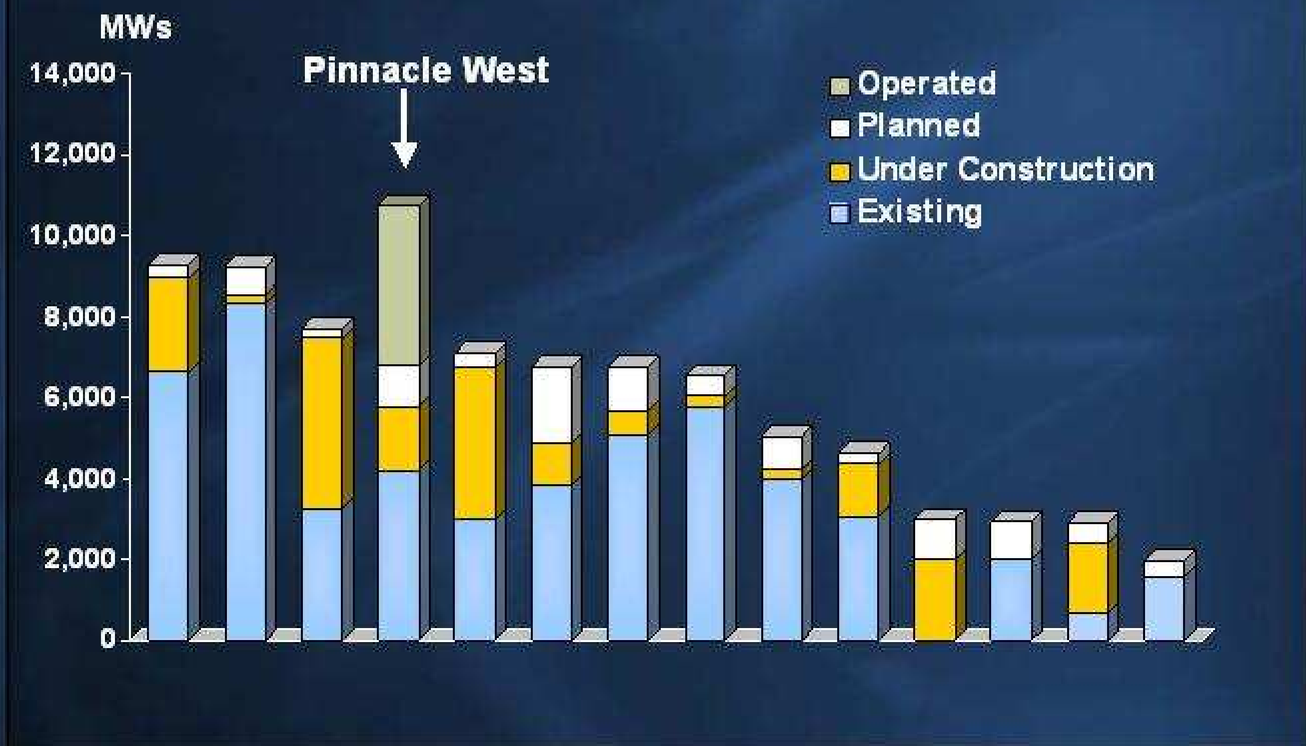
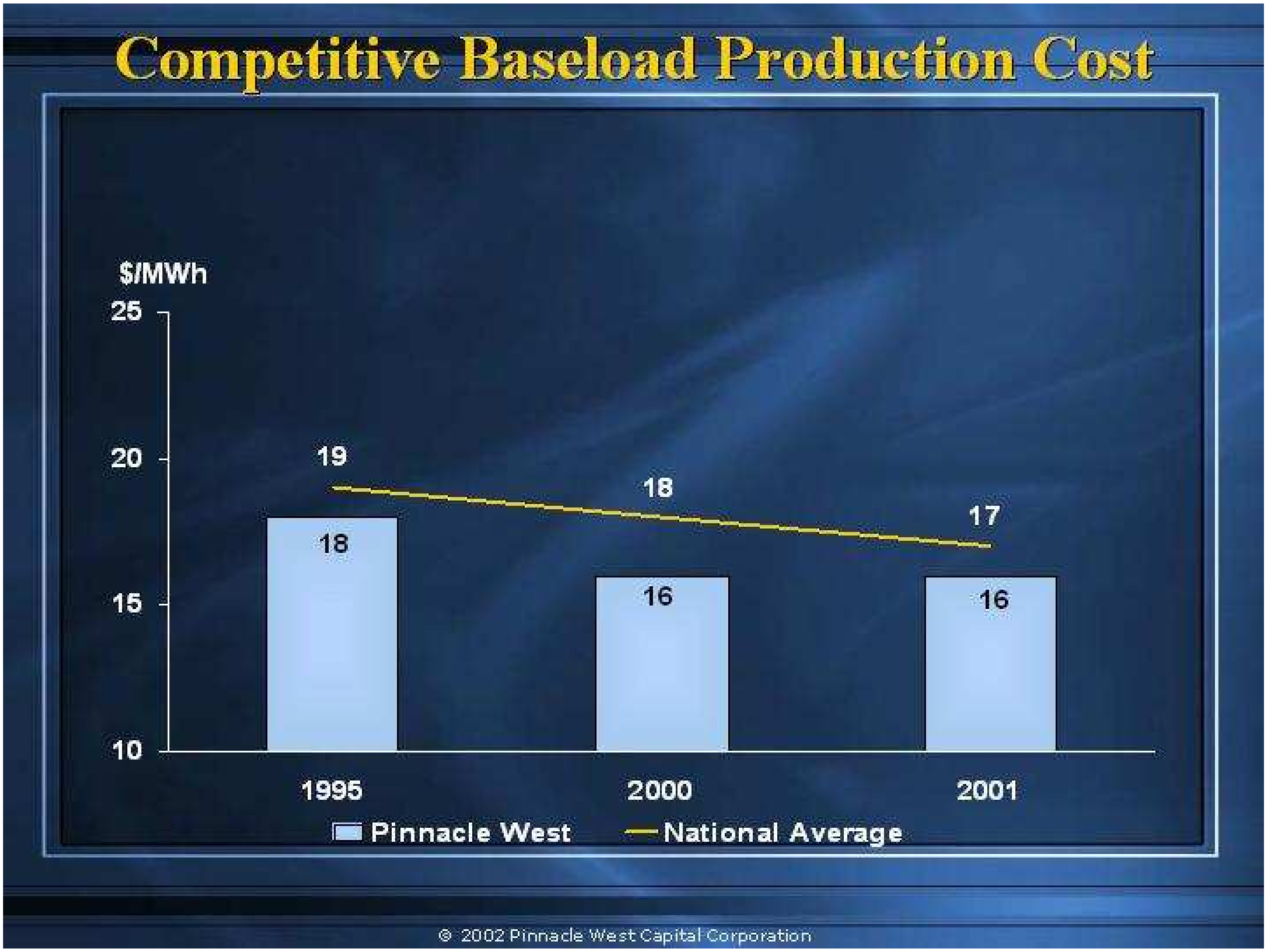
Generation Overview

Pinnacle West Generation

- Existing generation
- Generation expansion
- Market position

Major Generators in the West




Competitive Baseload Production Cost
$/MWh
25
20
15
10
19
18
17
18
16
16
1995
2000
2001
Pinnacle West
National Average
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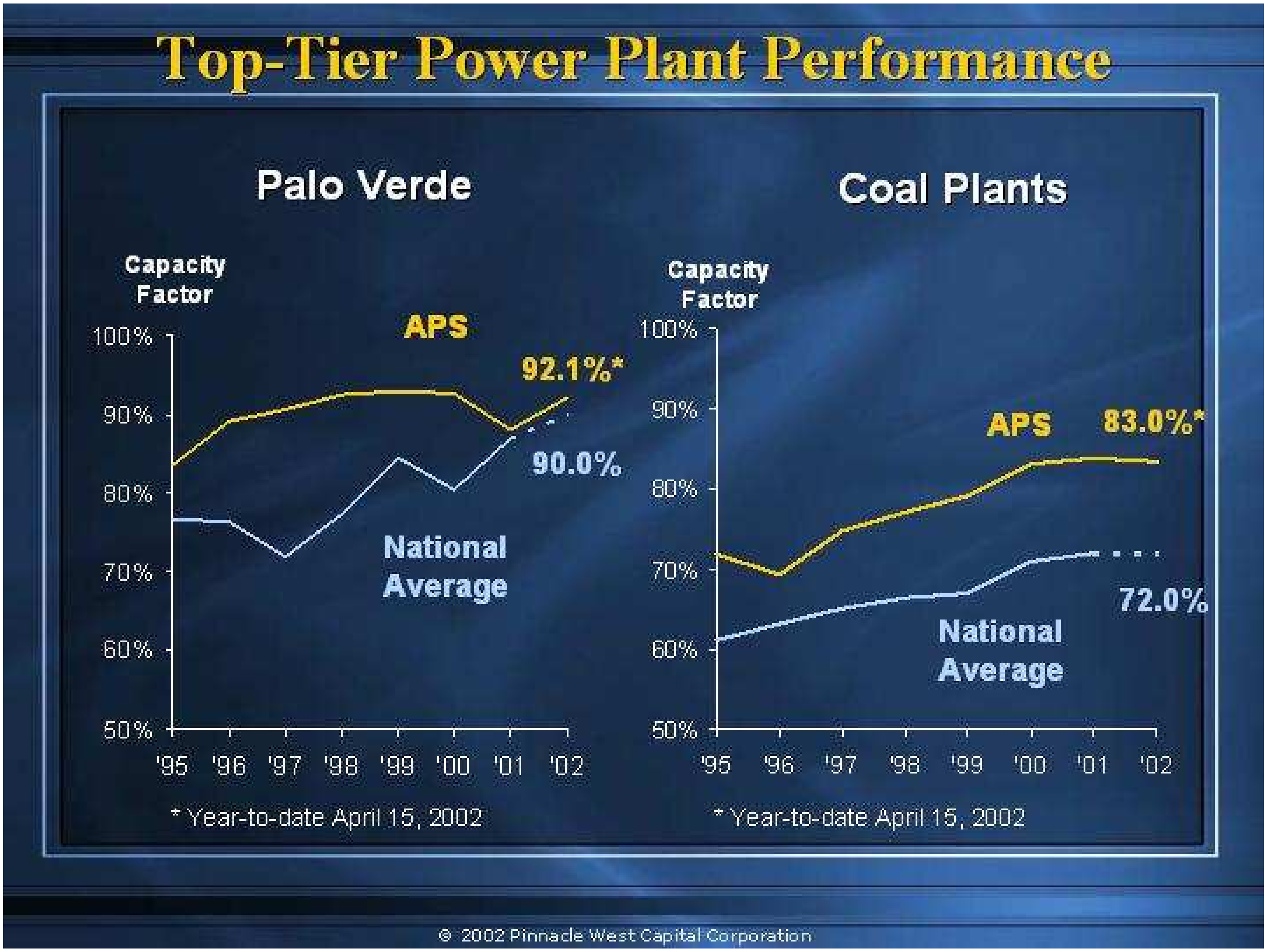

Top-Tier Power Plant Performance
Palo Verde
Capacity Factor
APS
92.1%*
90.0%
National Average
100%
90%
80%
70%
60%
50%
'95 '96 '97 '98 '99 '00 '01 '02
* Year-to-date April 15, 2002
Coal Plants
Capacity Factor
APS
83.0%*
72.0%
National Average
100%
90%
80%
70%
60%
50%
'95 '96 '97 '98 '99 '00 '01 '02
* Year-to-date April 15, 2002
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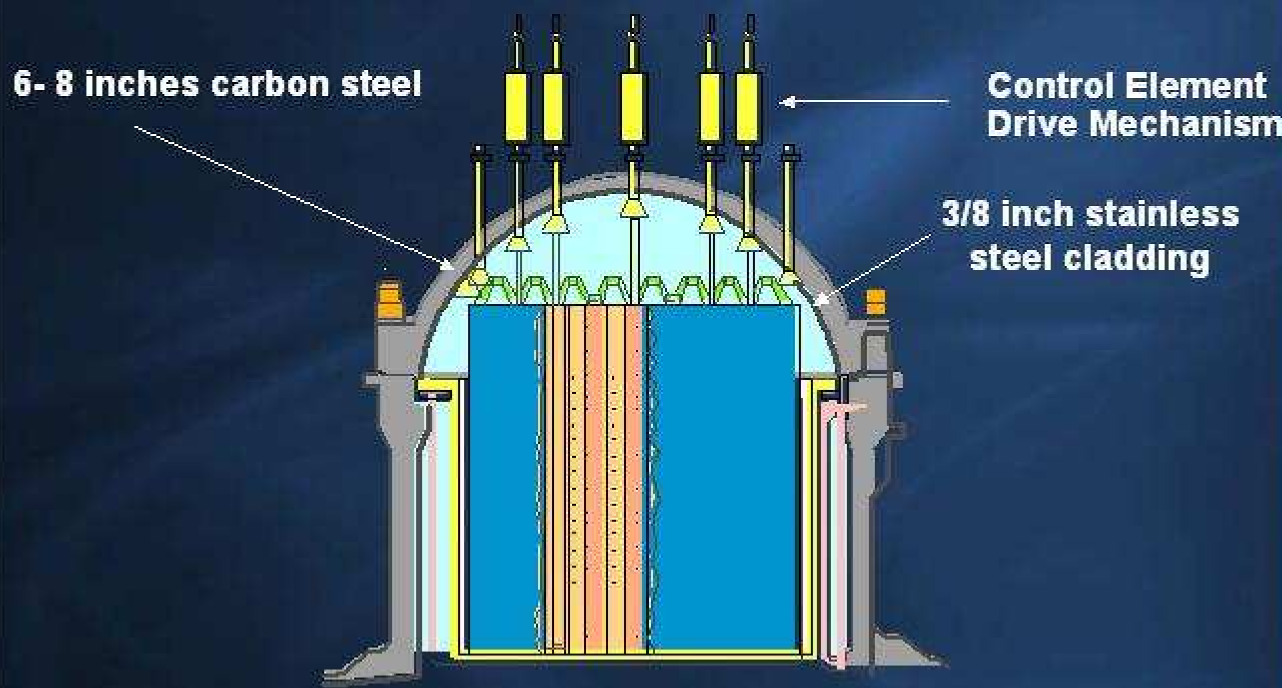
Pinnacle West Generation

- Coal plant performance
  - Surpassed generation records in 2001
  - 2001 capacity factor of 84%
- Gas units
  - High availability
  - West Phoenix CC4: 99.8% availability
- Nuclear performance
  - Fourth consecutive INPO 1
  - Met the challenges of two simultaneous outages

Palo Verde Refueling Outages

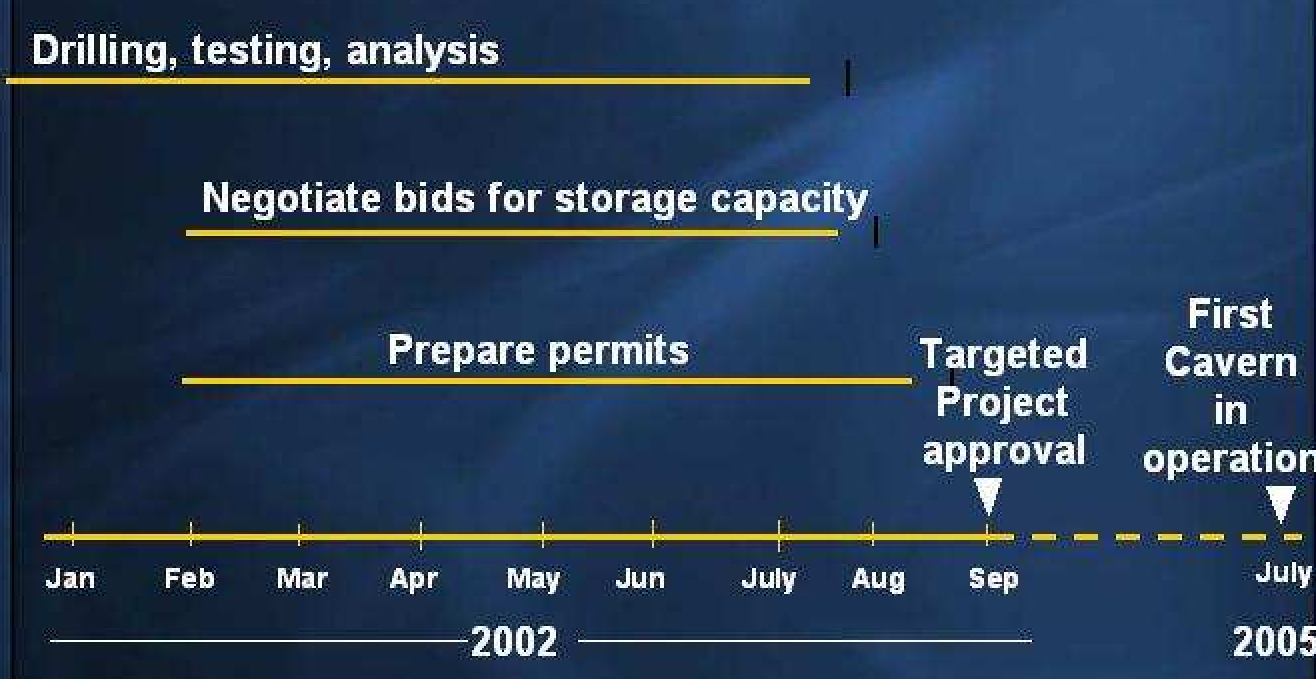
- Unit 2 - Spring 2002
  - Reactor vessel head inspection complete - no repairs required
  - Modifications made for steam generator replacement in Fall 2003
- Unit 1 - Fall 2002
  - Reactor vessel head inspection
  - Steam generator chemical cleaning

Nuclear Reactor Vessel Head



Steam Generator Replacement

Copper Eagle Natural Gas Storage



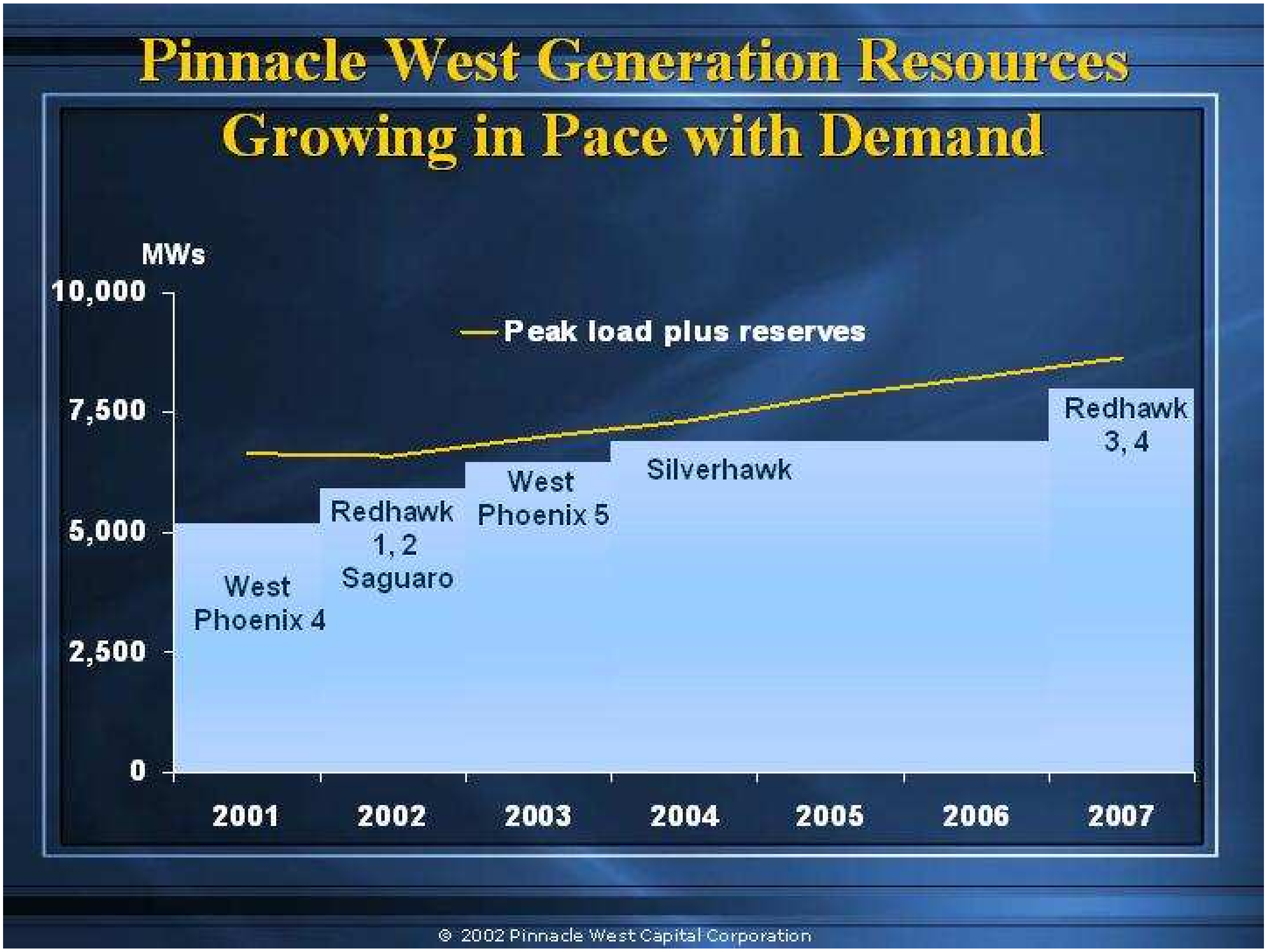
Pinnacle West
Generation Expansion Strategy

- Disciplined
- Flexible to meet load growth

Pinnacle West

Growing Generation Capability

Commercial Operation	New Facilities	MWs
2001	West Phoenix 4	120
2002	Redhawk 1 & 2	1,060
2002	Saguaro CT 3	80
2003	West Phoenix 5	530
2004	Silverhawk	570
2006/2007	Redhawk 3 and 4	1,060


Pinnacle West Generation Resources Growing in Pace with Demand
MWs
10,000
7,500
5,000
2,500
0
Peak load plus reserves
West Phoenix 4
Redhawk 1, 2 Saguaro
West Phoenix 5
Silverhawk
Redhawk 3, 4
2001
2002
2003
2004
2005
2006
2007
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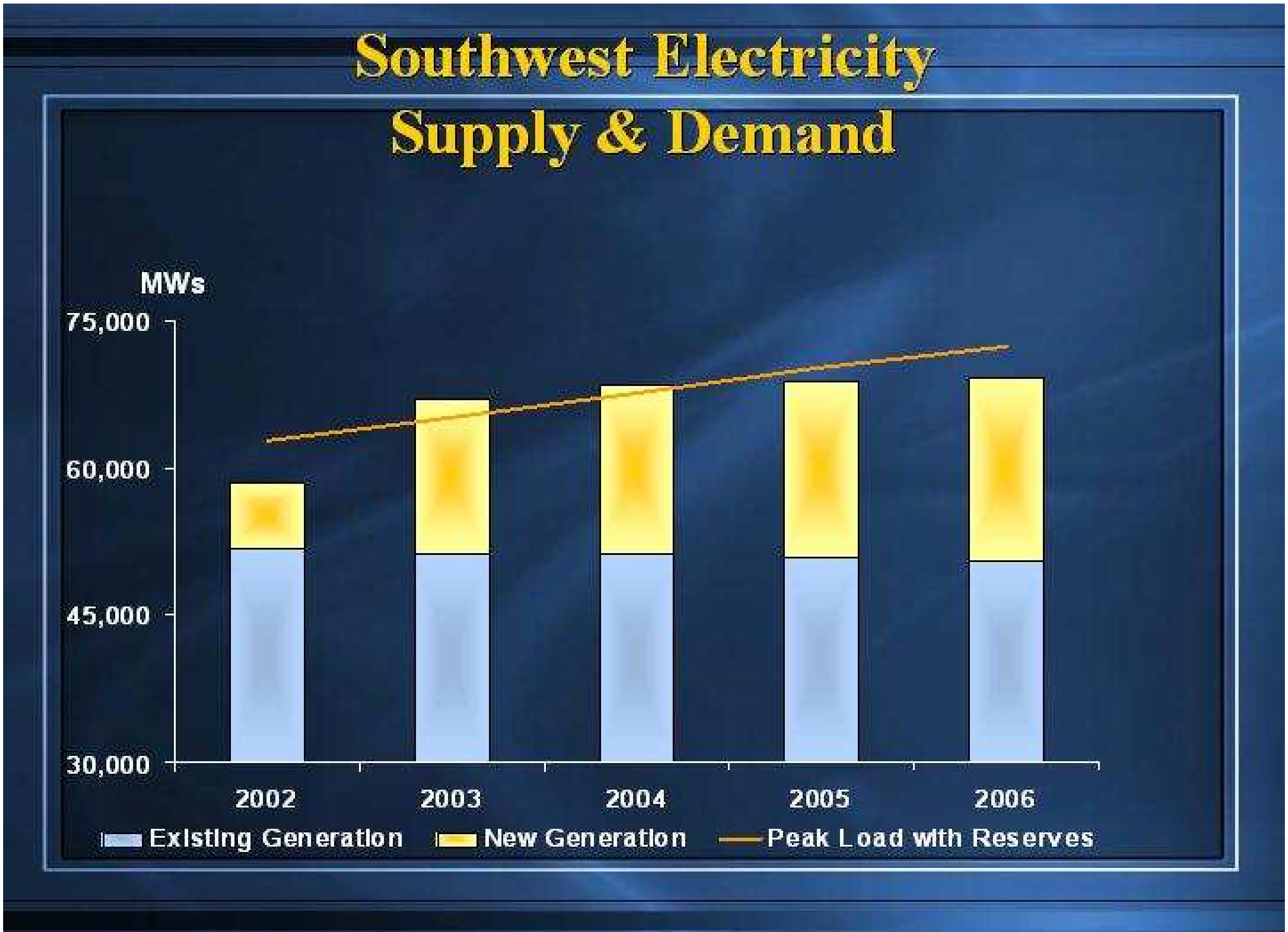
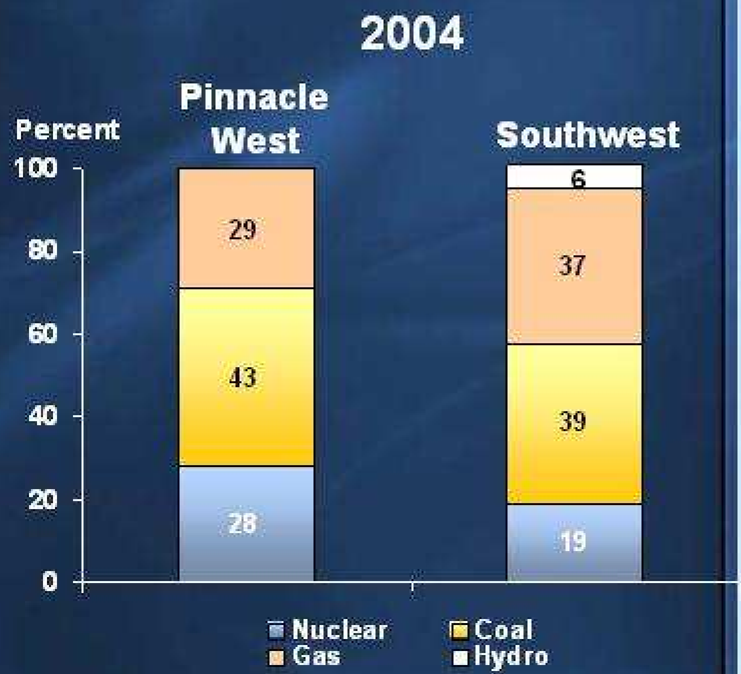


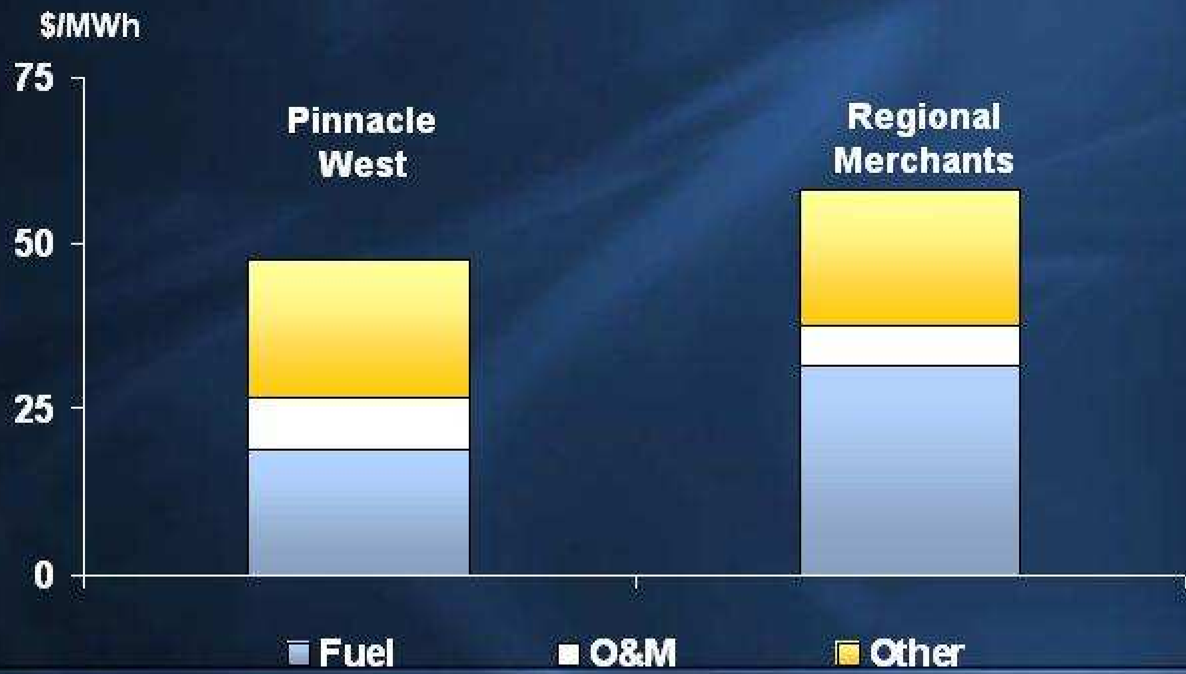
Southwest Electricity
Supply & Demand
MWs
75,000
60,000
45,000
30,000
2002
2003
2004
2005
2006
Existing Generation
New Generation
Peak Load with Reserves

Pinnacle West Generation Fuel Mix

- Dependable, stable supply mix
- PNW will benefit from the market during low hydro or high gas years



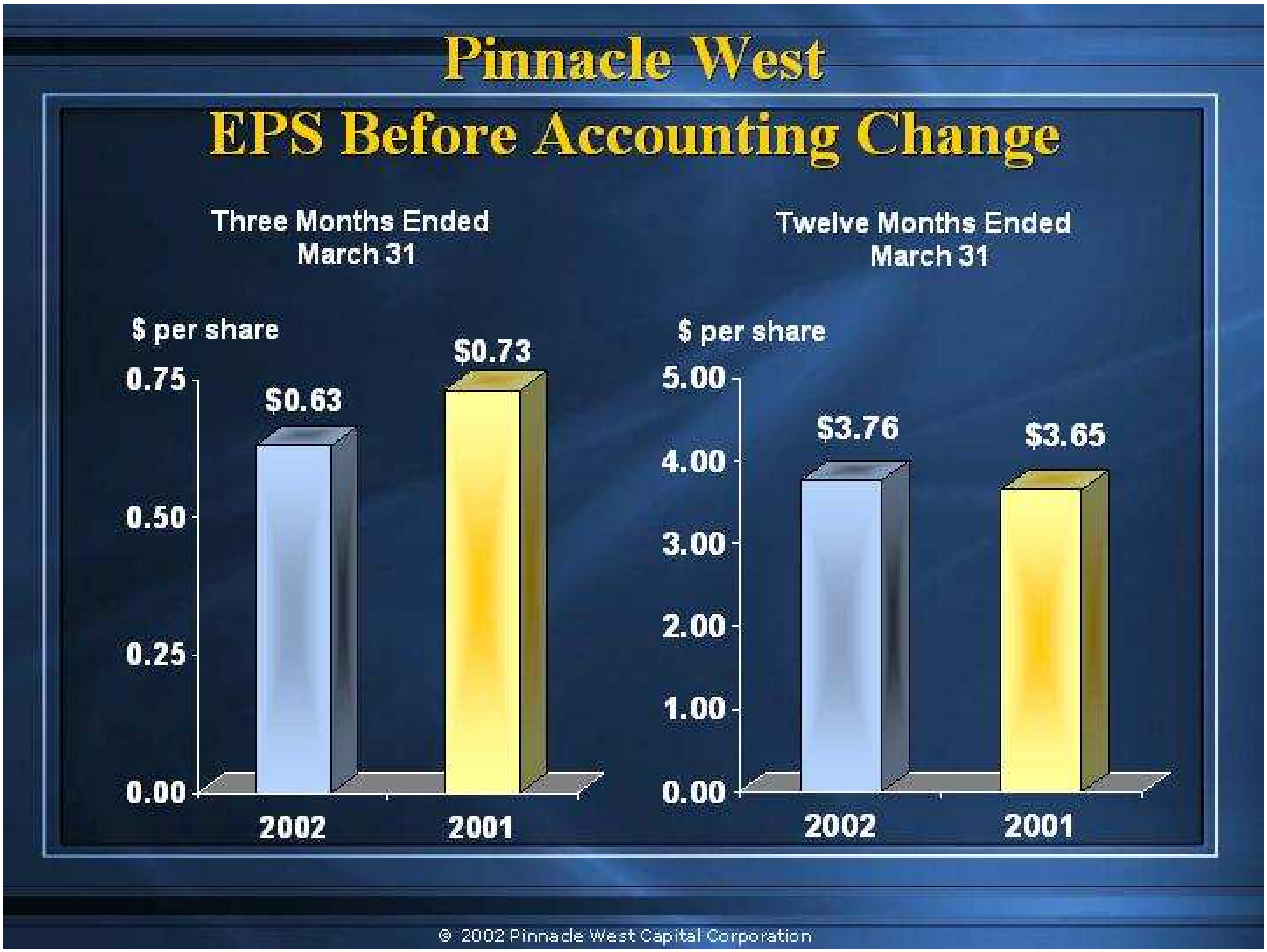
Pinnacle West
Total Generation Cost



Pinnacle West
Generation Summary

- Favorable fuel mix
- Competitive production cost
- Top nuclear and coal production
- High plant reliability
- Disciplined expansion plan

Financial Objectives and Results


Pinnacle West
EPS Before Accounting Change
Three Months Ended
March 31
$ per share
0.75
0.50
0.25
0.00
$0.63
$0.73
2002
2001
Twelve Months Ended
March 31
$ per share
5.00
4.00
3.00
2.00
1.00
0.00
$3.76
$3.65
2002
2001
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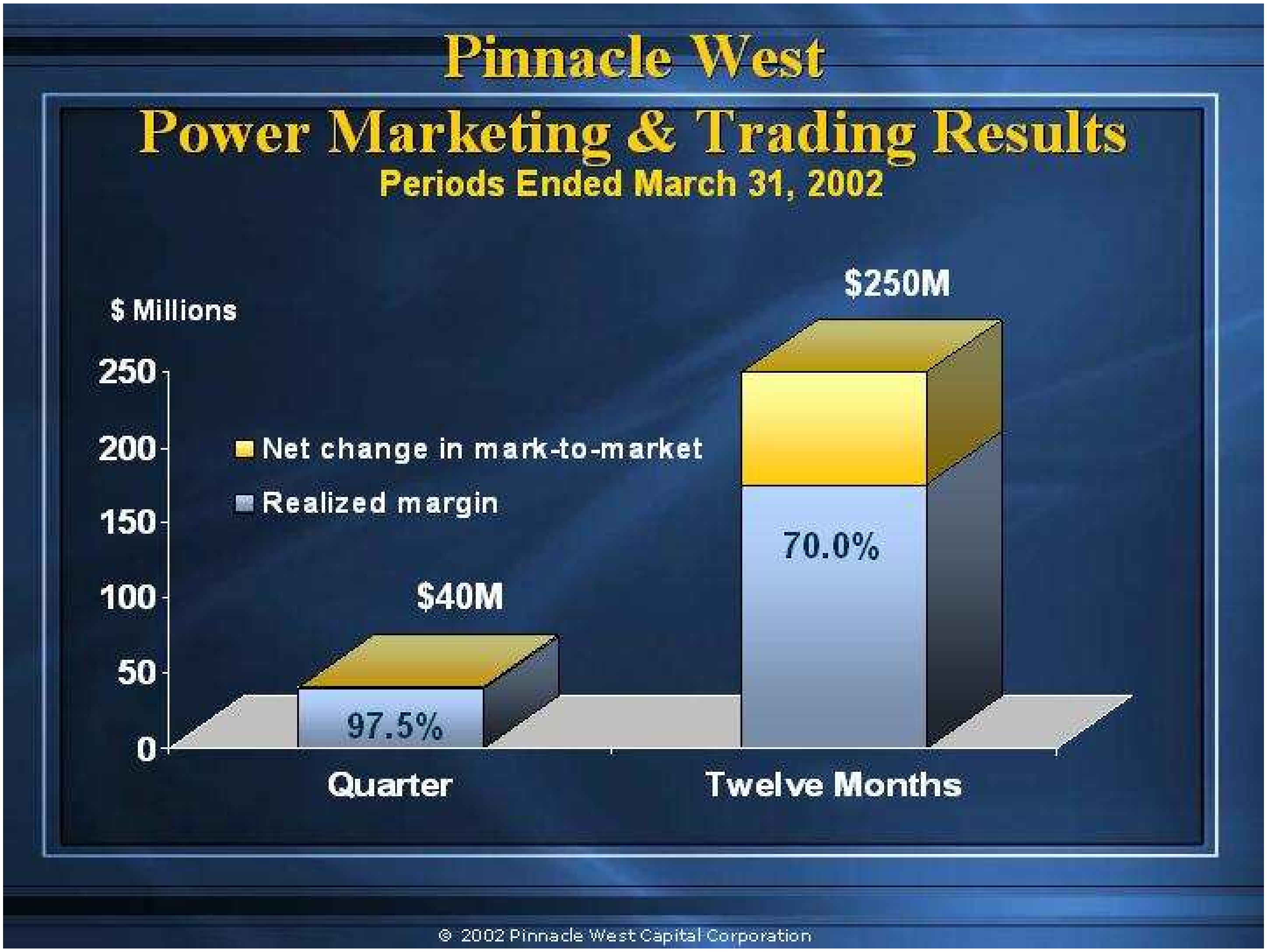
Pinnacle West

Earnings Drivers 2002 - 2003

- Strong retail customer growth
- Reversal of 2001 reliability program costs
- Regulatory asset amortization
- Retail price reductions
- Power marketing and trading results
- Regulatory and legislative developments
- SFAS No. 133
- Weather effects
- Economic conditions


Pinnacle West
Power Marketing & Trading Results
Periods Ended March 31, 2002
$ Millions
250
200
150
100
50
0
Net change in mark-to-market
Realized margin
$40M
97.5%
$250M
70.0%
Quarter
Twelve Months
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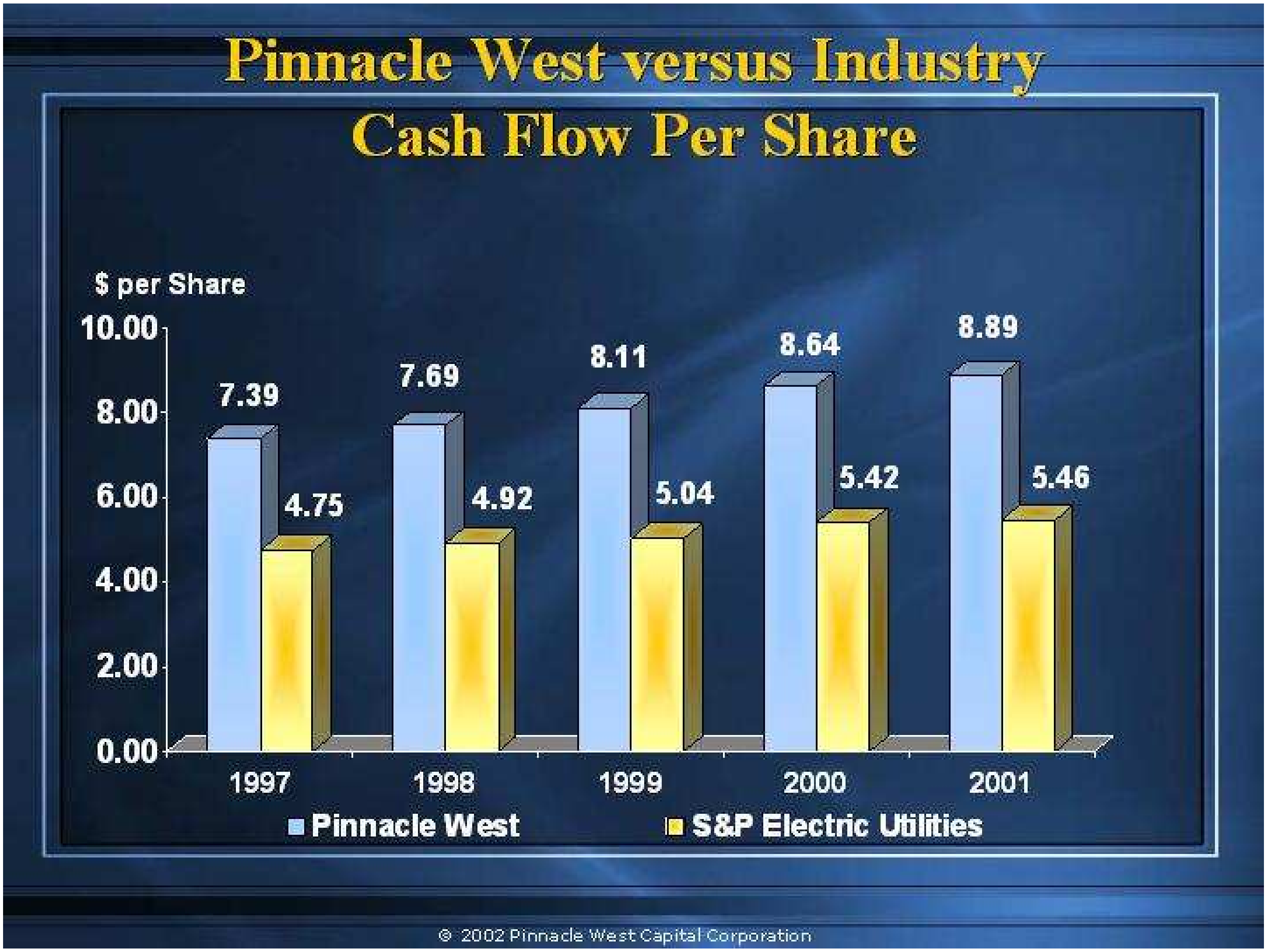

Pinnacle West versus Industry
Cash Flow Per Share
$ per Share
10.00
8.00
6.00
4.00
2.00
0.00
7.39
4.75
7.69
4.92
8.11
5.04
8.64
5.42
8.89
5.46
1997
1998
1999
2000
2001
Pinnacle West
S&P Electric Utilities
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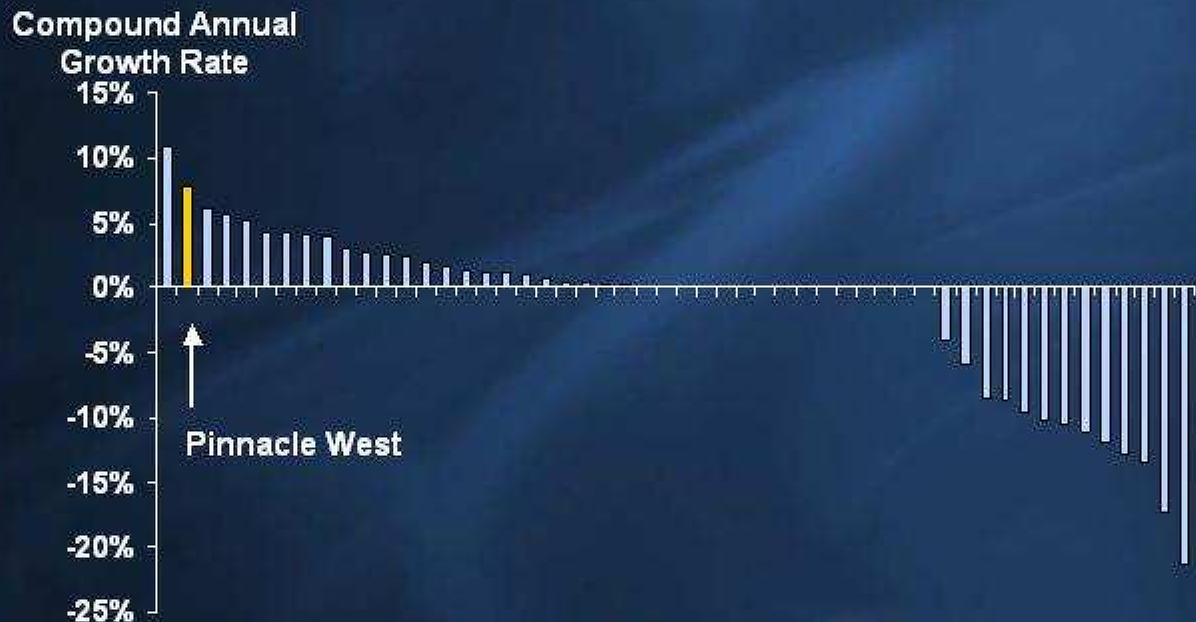
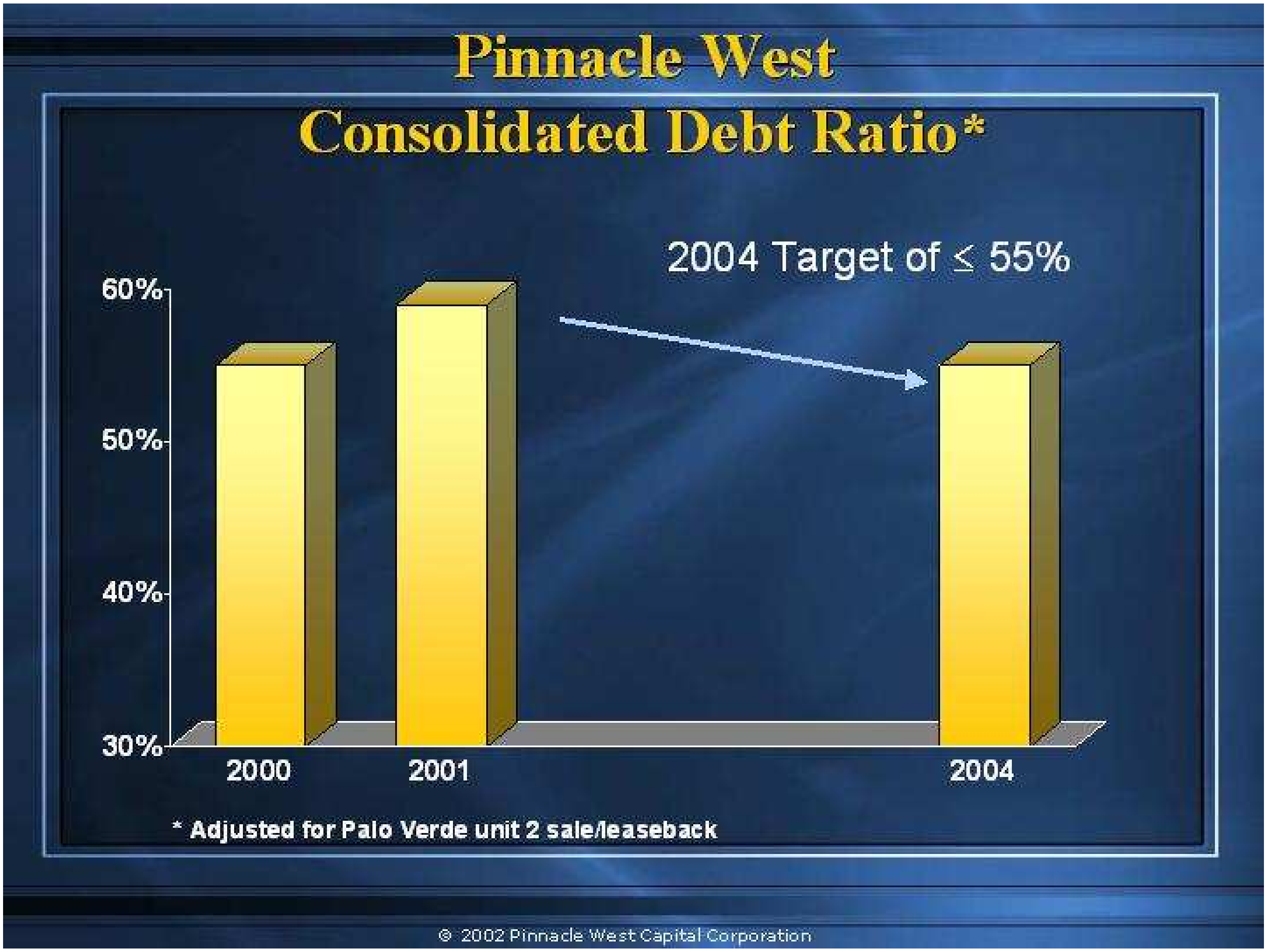
Pinnacle West versus Electric Industry Dividend Growth 1997 - 2001



Excludes companies that eliminated their dividends during the period



Pinnacle West
Consolidated Debt Ratio*
2004 Target of ≤ 55%
60%
50%
40%
30%
2000
2001
2004
* Adjusted for Palo Verde unit 2 sale/leaseback
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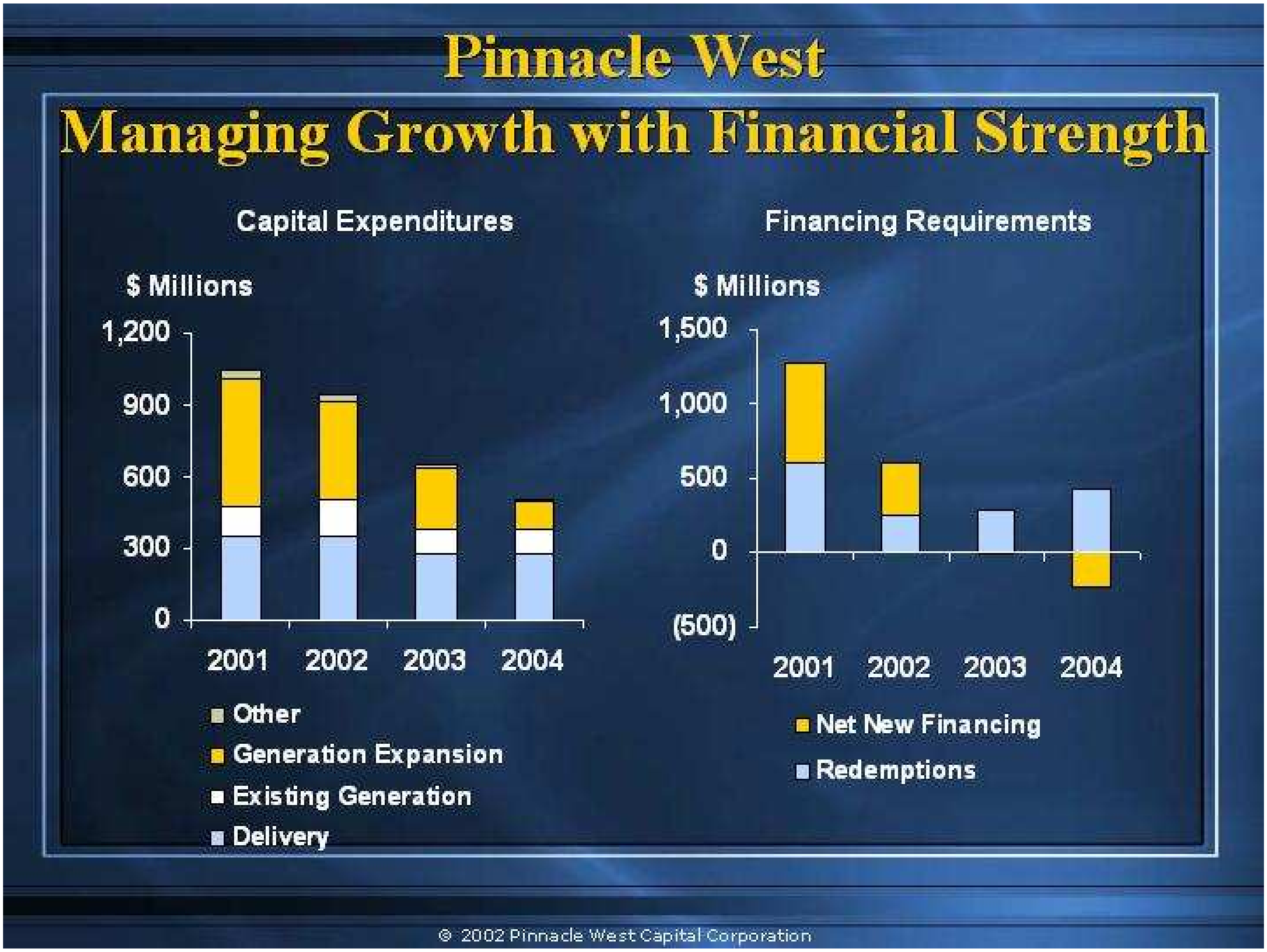
Pinnacle West
Managing Growth with Financial Strength
Capital Expenditures
$ Millions
1,200
900
600
300
0
2001
2002
2003
2004
Other
Generation Expansion
Existing Generation
Delivery
Financing Requirements
$ Millions
1,500
1,000
500
0
(500)
2001
2002
2003
2004
Net New Financing
Redemptions
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Pinnacle West Financial Focus

- Manage business strategies for superior shareholder value creation
- Continue superior combined earnings and dividend growth
- Maintain balance sheet strength

Exhibit 99.11

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING	DOCKET NO. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. 4-14-2-1606	DOCKET NO. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR	DOCKET NO. E-00000A-01-0630

IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC POWER COMPETITION RULES COMPLIANCE DATES	DOCKET NO. E-01933A-98-0471
ISSUES IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES.	DOCKET NO. E-01933A-02-0069

MOTION OF
ARIZONA PUBLIC SERVICE COMPANY
FOR DETERMINATION OF THRESHOLD ISSUE

Arizona Public Service Company ("APS") hereby submits this Motion and respectfully requests that the Arizona Corporation Commission ("Commission") promptly decide the critical threshold questions described below concerning the direction that this Commission intends to take on Retail Electric Competition. These questions would exist irrespective of and independent from the outcome of APS' pending Request for a Partial Variance. APS further requests that the Chief Administrative Law Judge establish a procedural schedule in the Generic Electric Restructuring Docket, Docket No. E-00000A-02-0051 ("Generic Docket"), to set a course towards resolving each of the principal recommendations identified in Staff's March 22, 2002 Report in the Generic Docket ("Staff Report").

I. INTRODUCTION.

Over six months ago, APS filed its Request for a Partial Variance to Rule 1606(B) in Docket No. E-01365A-01-0822, which is scheduled for a hearing commencing on April 29, 2002. [1] Contrary to the positions take by some in reaction to that filing, APS did not ask the Commission to change the competitive model established by the Retail Electric Competition Rules. Rather, APS' request addresses only "how much" and "how fast" the transition to competitive acquisition of power for APS Standard Offer customers would occur at the wholesale level. [2] APS has never argued, and does not argue now, that the Commission should retreat from the core competitive market model that it adopted and affirmed in decision after decision starting back in 1996.

APS' goal in filing the Request for a Partial Variance was to protect its Standard Offer customers without impeding the continued development of a competitive wholesale market. The Company has repeatedly stated that if the Commission determines that the requested partial variance and proposed Purchase Power Agreement are not in the best interests of APS' Standard Offer customers, then the Company will proceed with the divestiture of its generation and with good faith compliance with Rule 1606(B) as written. It is, after all, the Commission that is ultimately accountable to the citizens of Arizona, just as APS has a responsibility for protecting the interests of its customers and shareholders.

However, based on comments in the Staff Report and the current absence of any timetable or plan to resolve what appear to APS to be fundamental questions on Retail Electric Competition, APS is becoming increasingly concerned that the Commission's focus is being diverted by the details, rather than the fundamental policy choice that either needs to be reconfirmed or, with appropriate consideration, reversed. That threshold policy choice is straightforward—do we continue towards Retail Electric Competition or does the Commission reverse course and return to traditional cost-of-service monopoly regulation. The answer, of course, is more complex than the question, but it must be made promptly and fairly so that affected parties can take those steps necessary to implement the Commission's decision.

II. APS' SCHEDULE FOR COMPETITIVE BIDDING

Given the Commission's and APS' mutual obligation under the Settlement Agreement relating to the transfer of APS' generation assets no later than the end of 2002, the answer to the threshold question posed above must be at hand no later than September 1, 2002. Accordingly, in addition to proposing a plan to address the six issue areas identified by Staff in the Staff Report, which is discussed in more detail in Section IV below, [3] APS intends to submit the 30-day letter regarding the asset transfer on approximately August 1, 2002 irrespective of whether the Commission has by then decided APS' Request for a Partial Variance and irrespective of how it decides that matter.

The Company will then proceed to issue an RFP (or RFPs) on September 1, 2002 for the procurement of Standard Offer power, to the extent it is then legally required to do so. If the Request for a Partial Variance has been approved by that date, APS will issue an RFP for the first 270 MW with implementation scheduled for January 1, 2003. If the Request for a Partial Variance is denied or is not decided by September 1, 2002, APS will issue an RFP or RFPs for at least the full 50 percent requirement specified in Rule 1606(B). Both of these RFP processes, of course, will be contingent upon the transfer of APS generating assets to Pinnacle West Energy Corporation (PWEC") and the status of the Electric Competition Rules at that time. PWEC will be invited to competitively bid with its generating assets, including those to be transferred from APS. In either case, APS intends to discuss with Staff and other consumer groups its plan for competitive bidding and will consider the comments filed by the merchant generators in this consolidated docket, but does not intend to promote a free-for-all among merchant generators attempting to manipulate a competitive bid to suit their own commercial interests rather than the best interests of APS' Standard Offer customers.

If, however, the Commission elects to reverse its course on Retail Electric Competition or attempts to stay the transfer of APS' generating assets as recommended by Staff, APS will not be subject to the competitive bidding requirements of Rule 1606(B), which only apply to Utility Distribution Companies (i.e., utilities without generation). Neither, in this event, would it have 50 percent of its Standard Offer load to bid. Obviously, if APS is required to retain cost-of-service regulated generation, it would only look to the market when it is short capacity or cannot economically self-supply its own requirements. Additionally, APS would have to acquire any PWEC generating assets that were built to serve APS customers to avoid continued bifurcated ownership of such reliability-related generation and the financing difficulties that result from such bifurcated ownership. A tabular summary of actions and outcomes reflecting each of these issues is provided below:

Commission Action	Competitive Bidding/Asset Transfer Outcomes
Approval of Partial Variance as proposed	• Bidding process discussed with Staff • APS transfers assets on or after 9/1/02 but before 12/31/02 • Proposed PPA entered between APS and PWCC • Competitive bidding for 270 MW on 9/1/02
Denial of Partial Variance	• Bidding process discussed with Staff • APS transfers assets on or after 9/1/02 but before 12/31/02 • Competitive bidding for at least 50 percent on 9/1/02 • Bilateral contracts or spot purchases for other requirements
Stay or Reversal of Asset Transfer	• Rule 1606(B) no longer applicable to APS • No competitive bidding required • APS acquires PWEC Dedicated Assets • Analysis of legal options, damages incurred by APS, PWCC, PWEC, and just compensation

III. 1999 APS SETTLEMENT AGREEMENT.

As the discussion in Section II illustrates, the Commission's evaluation in the Generic Docket must be grounded on not only the previous competition-related rulemaking decisions that it approved, but also the regulatory settlements into which it entered. APS has made significant sacrifices pursuant to and in reliance on its 1999 Settlement Agreement with the Commission and has incurred tens of millions of dollars of additional costs associated with implementing the Electric Competition Rules. And, as discussed below, APS' affiliate PWEC was created solely for the purpose and with the expectation that it would receive APS' generation assets pursuant to the 1999 Settlement Agreement. PWEC has committed to a $1 billion investment in generating capacity that neither it nor APS would have undertaken had it not been necessary to meet the APS customer needs. Moreover, it was the Commission's explicit prohibition on APS ownership of new generation set forth in Rule 1615 that required the formation of PWEC to construct this needed capacity for APS' customers. Put simply, there is no "clean slate" upon which to write "new" rules relating to competition without first settling existing obligations.

With respect to the 1999 Settlement Agreement, APS has taken the following steps pursuant to that agreement and the Commission's Electric Competition Rules:

- Written off $234 million of prudently incurred costs;
- Reduced retail rates to date by roughly $120 million in a still-ongoing series of rate reductions;
- Created a generation company affiliate, PWEC, and hired and transferred personnel to such affiliate, and to Pinnacle West Capital

Corporation ("PWCC") Marketing and Trading, to effect the required separation of competitive assets;
- Dismissed its legal challenges to the Electric Competition Rules;
- Initiated negotiations with co-participants, fuel suppliers, governmental entities, creditors, and others for consents relating to the transfer of APS' generation;
- Prepared and filed an application with the Nuclear Regulatory Commission for approval of the transfer of APS' share in the Palo Verde Nuclear Generating Station to PWEC;
- Obtained contingent credit ratings for PWEC from the three credit rating agencies premised on the assumption that PWEC would receive the APS generating assets; and
- Prepared appraisals, legal documents of transfer, and obtained Private Letter Rulings from the Internal Revenue Service relating to the asset transfer.

APS undertook all of these steps and provided its customers with rate reductions during a period in which many Western United States utility customers were experiencing rate shock and rolling blackouts.

Just as significant, however, is the $1 billion commitment that PWEC made since the 1999 Settlement Agreement to construct generation to assure that APS customers enjoyed continued reliable electric service. When the Electric Competition Rules were adopted and APS was told it could no longer construct new generation, it was necessarily PWEC that constructed local generation within the Phoenix area, installed trailer mounted temporary and now permanent generation to provide needed peaking capacity to APS customers, and constructed Redhawk Units 1 and 2 to meet the needs of APS customers beginning this summer, bypassing the option to sell Redhawk into the rich California market. No other party stepped forward to undertake this reliability obligation for APS, and without this commitment APS customers would have faced last summer and would be facing this summer and next significant risk of curtailments. In addition, PWCC provided bridge financing for this construction program, with the understanding that PWEC would be able to secure its own long-term financing once the APS generating assets were transferred pursuant to the 1999 Settlement Agreement.

Thus, APS was disappointed with Staff's recommendation that the asset transfer already approved by the Commission should be stayed or modified until at least the completion of an as yet undetermined generic review. The Electric Competition Rules never intended for generating assets to be bifurcated between PWEC and APS, and the added financing costs associated with the continued bifurcation of generation asset ownership between APS and the $1 billion investment in generation by PWEC is adversely affecting the financial integrity of both companies, as well as PWCC. In fact, APS believes that if the Commission indeed reneges on its approval of the asset transfer, the resultant financial impact could well result in a downgrade of both PWCC and APS by its rating agencies, [4] exacerbating the damages incurred by such a breach of the 1999 Settlement Agreement.

If, notwithstanding the Settlement Agreement, the Commission stays or refuses to allow the transfer of APS' generation to PWEC, which would amount to a reversal of course towards Retail Electric Competition, then the Commission would be legally required to address just compensation to APS, PWCC and PWEC as well as be subject to other appropriate remedies for breach of the Settlement Agreement in the Company's next rate case. At a minimum, this would include (1) recognizing the transfer to APS of all assets that PWEC constructed to meet APS' load-serving requirements, and subsequently including such units in APS' rate base in accordance with traditional rate-of-return regulation, [5] (2) reversing APS' $234 million write-off and providing for the recovery of such amounts in future rates, and (3) providing for the recovery of <u>all</u> costs incurred as a result of the transition to competition, including 100 percent of the costs incurred in preparation for divestiture (and not just the 2/3 permitted under the Settlement Agreement). APS, however, believes that such a reversal in course is neither necessary nor worth the costs to all involved.

Moreover, given the commitments and actions discussed above, APS does not believe that simply delaying everything is an acceptable alternative. There is significant concern in the financial community regarding the Commission's apparent or potential change in direction with respect to the Electric Competition Rules and the 1999 Settlement Agreement. This uncertainty that the Commission has created regarding these subjects itself threatens the bond ratings of the Company and its affiliates. Thus, APS believes that Arizona can and should move forward towards Retail Electric Competition, irrespective of the Commission's decision in APS' Request for a Partial Variance, by adopting the procedural plan discussed below.

IV. PROPOSED PROCEDURAL PLAN.

APS recommends that the following procedural plan be adopted to address the issues identified by Staff in its Staff Report and that such a plan proceed concurrently with the procedural schedule for APS' Request for a Partial Variance. This plan is focused around the six issue areas identified in the Staff Report, and is discussed in the same order presented in the Staff Report, and will allow parties to take those steps necessary to make real progress in implementing the principles of electric competition on a realistic but still aggressive schedule while not upsetting the continuation of reliable, predictable, and reasonably-priced Standard Offer Service to APS' customers.

1. Market Power and Market Monitoring.

With respect to wholesale markets, there is significant activity at the Federal Energy Regulatory Commission ("FERC") dealing with these issues. FERC has issued and is taking comment on its standard market design working papers for wholesale power markets. [6] It is expected this summer to commence the "GigaNOPR" rulemaking for wholesale power markets that will necessarily impact wholesale market issues in Arizona. Additionally, in Arizona the formation of the WestConnect Regional Transmission Organization ("RTO") and the continued implementation of FERC's Order 2000 regarding RTO formation will affect wholesale power markets, specifically regarding interstate transmission. Thus, many of the significant federal drivers affecting wholesale power issues and market monitoring are still under development and are unlikely to be implemented this year. Accordingly, the most appropriate course of action on this issue is for the Commission to continue to actively monitor and participate in these issues at FERC and before Congress, and to continue to review all jurisdictional public service corporation filings at FERC on wholesale power issues. If and when the Commission believes that action at the state level is necessary and appropriate on market power or market monitoring issues, the Commission could respond specifically to such issues in the then-current context. However, the federal issues probably need to develop further before specific state action can be discerned or undertaken to complement for Arizonans the future actions of FERC and, potentially, the Congress.

2. Competitive Bidding.

Regardless of the ultimate resolution of APS' Request for a Partial Variance, a competitive bidding process needs to be developed and implemented. APS intends to issue an RFP (or RFPs) for competitive bidding no later than September 1, 2002. APS will discuss this RFP with Staff and consumer groups, but does not intend to open the competitive bidding plan for debate by those who would prefer to structure the process in a way that suits their desires, rather than the best interests of APS' customers. If the Commission determined that a rulemaking was required to provide more definition to Rule 1606(B), it could initiate such a proceeding which, pursuant to the Administrative Procedures Act, would apply prospectively.

3. Transfer of Generation Assets.

Rule 1615 requires the separation of Competitive Services, including generation assets, from Affected Utilities such as APS. In the 1999 Settlement Agreement and in Decision No. 61973, the Commission approved the transfer of APS' generating assets and Competitive Services to separate affiliates of APS. As discussed above, APS has substantially relied on that approval, and that the Commission should not and legally cannot now revoke the authority to transfer APS' generation assets. Further, the Commission's decision that generation would be regulated by FERC under the Federal Power Act, rather than by the state under cost-of-service principles, was made four years ago and cannot realistically be revisited now. Accordingly, APS intends to submit its 30-day letter regarding the generation asset transfer on approximately August 1, 2002.

4. Transmission Constraints and Reliability.

The siting of new merchant generating capacity has created transmission constraints and is a factor affecting the configuration and operation of the transmission system in Arizona. There are also significant emerging regulatory and market-based initiatives, including the WestConnect RTO, that give rise to uncertainty in future system planning. For example, there are significant issues regarding the allocation and recovery of costs for transmission upgrades driven not by system reliability, but by economics and the siting choices of merchant power plants. All of these evolving issues have the potential to affect continued reliable service to APS' customers.

Due to facilities siting requirements, reliability issues, long permitting and construction lead times, the treatment of existing contracts, and the continued development of the RTO process and standard market design, addressing transmission constraints and associated issues is a long-term process. Accordingly, further Commission activity addressing this issue should occur in the context of the 2002-2003 Biennial Transmission Assessment which is scheduled to commence in May 2002. APS believes that Staff should attempt to structure that process to address and collaboratively resolve as many of these transmission issues as possible. Also, an explicit transmission study addressing Arizona transmission constraints, system reliability, and market issues could be performed as part of the Biennial Transmission Assessment, which study could include the regulatory treatment and appropriate function of must run local generation resources.

5. Adjustor Mechanisms.

Section 2.6 of the 1999 APS Settlement Agreement requires APS to submit an adjustment clause for Commission approval that will recover Electric Competition-related costs specified in that Settlement Agreement. APS believes that it is appropriate to consider specific adjustor mechanisms in utility-specific proceedings. Thus, for APS, the submission of the adjustor mechanism and the process for addressing that mechanism should occur in the context laid out in the 1999 Settlement Agreement.

6. Retail Direct Access and Shopping Credits.

As part of the Generic Docket, Staff should initiate a workshop process to assess the appropriate scope of retail Direct Access. The purpose of the workshop process shall be to determine whether a rulemaking proceeding to amend the Electric Competition Rules should be initiated to facilitate Direct Access to all or certain customer classes. Also pursuant to the 1999 Settlement Agreement, APS is required to file a general rate case by June 30, 2003, with any resulting rate changes to be implemented beginning July 1, 2004. Specific issues surrounding the "shopping credit" for APS, as well as rate design and unbundling can best be addressed in this already scheduled proceeding for APS.

7. Other Issues.

Certainly, the six issues outlined in Staff's recommendations in the Staff Report do not represent every issue that must or should be addressed in the Generic Docket. However, they do represent the core issues. Other issues can be addressed in a more *ad hoc* fashion, using the most appropriate procedural vehicle (workshops, rulemakings, etc.).

V. CONCLUSION.

The Commission is at a critical juncture where it must make a threshold decision adopting one or the other of two alternatives. It must make the decision of whether we continue towards Retail Electric Competition—irrespective of whatever action it takes in APS' Request for a Partial Variance—or whether we reverse course now, and try to repair the damage that has been done. Simply delaying a decision is not an option given the 1999 Settlement Agreement and the significant commitments that APS, PWCC and PWEC have made in reliance on the Settlement Agreement and the Commission's prior decisions regarding Retail Electric Competition.

Accordingly, APS respectfully requests that the Commission timely take whatever action it deems necessary to make the threshold decision and eliminate at least the harmful uncertainty surrounding whether Arizona continues towards retail competition and whether the Commission will honor its commitments in the 1999 Settlement Agreement. The Chief Administrative Law Judge could then approve an appropriate procedural schedule, or otherwise initiate a process, to adopt a plan to follow through on that threshold decision.

RESPECTFULLY SUBMITTED this 19th day of April, 2002.

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Original and 18 copies of the foregoing
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transmitted electronically this 19th
day of April, 2002, to:

All parties of record

Lisa Krafve

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1 APS is not in any way suggesting in this Motion that the April 29, 2002 hearing be delayed.

2 APS is not speaking for any of the other Affected Utilities, although most of them are already exempt from Rule 1606(B).

3 APS is not requesting Commission approval of the schedule set forth in this Section II. What is set forth in this section is simply intended to advise the Commission of the schedule that APS plans to pursue irrespective of the resolution of APS' Request for a Partial Variance or proceedings in the generic docket. Additionally, in part, this is intended to provide parties (including Staff) some degree of certainty as to when APS intends to file the 30-day letter regarding the asset transfer.

4 PWEC's investment grade rating, which was contingent on the asset transfer, would never materialize, thus crippling its future, perhaps irreversibly.

5 Although these reliability-related generating assets would increase the Company's rate base, they would also offset significant purchased power expenses that APS would otherwise incur and have to recover through rates.

6 Federal Energy Regulatory Commission, *Working Paper on Standardized Transmission Service and Wholesale Electric Market Design* (March 15, 2002); Federal Energy Regulatory Commission, *Options for Resolving Rate and Transition Issues* (April 10, 2002).

End of Filing