STATE OF NEW JERSEY
OFFICE OF ADMINISTRATIVE LAW
BEFORE THE HONORABLE GAIL M. COOKSON, ALJ

I/M/O THE PETITION OF SOUTH JERSEY GAS FOR APPROVAL OF INCREASED BASE TARIFF RATES AND CHARGES FOR GAS SERVICE AND OTHER TARIFF REVISIONS	)	**BPU DOCKET No. GR10010035** **OAL DOCKET No. PUC-01598-2010N**

DIRECT TESTIMONY OF DAVID E. PETERSON ON BEHALF OF THE NEW JERSEY DEPARTMENT OF THE PUBLIC ADVOCATE, DIVISION OF RATE COUNSEL

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is David E. Peterson. I am a Senior Consultant employed by Chesapeake Regulatory Consultants, Inc. ("CRC"). Our business address is 1698 Saefern Way, Annapolis, Maryland 21401-6529. I maintain an office in Dunkirk, Maryland.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE IN THE PUBLIC UTILITY FIELD?

A. I graduated with a Bachelor of Science degree in Economics from South Dakota State University in May of 1977. In 1983, I received a Master's degree in Business Administration from the University of South Dakota. My graduate program included accounting and public utility courses at the University of Maryland.

In September 1977, I joined the Staff of the Fixed Utilities Division of the South Dakota Public Utilities Commission as a rate analyst. My responsibilities at the South Dakota Commission included analyzing and testifying on ratemaking matters arising in rate proceedings involving electric, gas and telephone utilities.

Since leaving the South Dakota Commission in 1980, I have continued performing cost of service and revenue requirement analyses as a consultant. In December 1980, I joined the public utility consulting firm of Hess & Lim, Inc. I remained with that firm until August 1991, when I joined CRC. Over the years, I have analyzed filings by electric, natural gas, propane, telephone, water, wastewater, and steam utilities in connection with utility rate and certificate proceedings before federal and state regulatory commissions.

Q. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY IN PUBLIC UTILITY RATE PROCEEDINGS?

A. Yes. I have presented testimony in 122 other proceedings before the state regulatory commissions in Alabama, Arkansas, Colorado, Connecticut, Delaware, Indiana, Kansas, Maine, Maryland, Montana, Nevada, New Jersey, New Mexico, New York, Pennsylvania, South Dakota, West Virginia, and Wyoming, and before the Federal Energy Regulatory Commission. In addition, I have twice testified before the Energy Subcommittee of the Delaware House of Representatives on the issues of consolidated tax savings and tax normalization.

Collectively, my testimonies have addressed the following topics: the appropriate test year, rate base, revenues, expenses, depreciation, taxes, capital structure, capital costs, rate of return, cost allocation, rate design, life-cycle analyses, affiliate transactions, mergers, acquisitions, and cost-tracking procedures.

Q. HAVE YOU TESTIFIED IN OTHER PROCEEDINGS BEFORE THE NEW JERSEY BOARD OF PUBLIC UTILITIES ("BOARD")?

A. Yes, I have. A list of utility cases in which I have testified in New Jersey and elsewhere is attached hetero as Appendix A.

II. SCOPE AND PURPOSE OF TESTIMONY

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. My appearance in this proceeding is on behalf of the New Jersey Department of the Public Advocate, Division of Rate Counsel ("Rate Counsel").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I was asked to assist Rate Counsel in analyzing South Jersey Gas Company's ("SJG" or "the Company") request for a rate base allowance for working capital. SJG's request for a cash working capital allowance is based on a lead-lag study conducted by Michael E. Barrett, a witness testifying on behalf of SJG. The purpose of my testimony is to present the results of my analysis of Mr. Barrett's lead-lag study to Your Honor and the Board and to recommend alternative ratemaking treatments for several items included in Mr. Barrett's study.

III. SUMMARY OF FINDINGS AND CONCLUSIONS

Q. DO YOU RECOMMEND AN ADJUSTMENT TO THE COMPANY'S PROPOSED WORKING CAPITAL ALLOWANCE?

A. Yes. Based on my calculation of SJG's working capital requirement, I recommend the inclusion of a $22,272,682 working capital rate base allowance for SJG's gas distribution operations. This amount is $14,621,339 less than the amount that is included in SJG's proposed rate base (9+3 filing).[1] See SJG's April 2010 9+3 filing, Schedule MEB-1.

Q. HAVE YOU PREPARED A SCHEDULE THAT SUMMARIZES THE EFFECT OF YOUR RECOMMENDED WORKING CAPITAL ADJUSTMENTS?

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[1] See SJG's April 2010 9+3 filing, Schedule MEB-1.

A. Yes. Schedule DEP-1 (attached hereto) serves this purpose. The first line on this schedule shows the effect of my recommended adjustments to Mr. Barrett's lead-lag calculations, which are detailed in my Schedule DEP-2, also attached hereto. After I removed non-cash expenses and incentive compensation from Mr. Barrett's lead-lag study, I determined that SJG's cash working capital requirement is $969,240; rather than $14,018,541 that Mr. Barrett calculated.

After I removed the claimed cash and working fund balances and reversed Mr. Barrett's proposed deductions for accrued construction invoices and payroll, I determined that SJG's net working capital requirement, including the cash working capital allowance, is $22,272,682. As stated above, this amount is $14,621,339 less than what is reflected in SJG's proposed 9+3 rate base. Therefore, I have recommended that Rate Counsel's revenue requirement witness, Mr. Robert Henkes, reduce SJG's proposed rate base by $14,621,339. In the following section of my testimony, my specific findings and recommendations are set forth in more detail.

IV. CASH WORKING CAPITAL ANALYSIS

Q. FOR WHAT PURPOSE SHOULD A CASH WORKING CAPITAL ALLOWANCE BE INCLUDED IN RATE BASE?

A. A cash working capital allowance should be included in rate base to compensate investors for investor-supplied funds, if any, used to provide the day-to-day cash needs of the utility. These cash needs can be measured in a lead-lag study. A lead-lag study measures the time between (1) the provision of service to utility customers and the receipt of revenue for that service by the utility, and (2) the provision of service by the utility and its disbursements to employees and suppliers in payment for the associated costs. The difference between the revenue "lag" and the expense "lead" is expressed in days. The difference, which can be either a net lag or a net lead, multiplied by the average daily cash operating expenses, quantifies the cash working capital required for, or available from utility operations.

In this proceeding, Mr. Barrett sponsored a lead-lag study based on accounting and payment information for the twelve months ended December 31, 2008. Mr. Barrett's analysis, however, goes far beyond the measurement of SJG's cash working capital requirement.

Q. HOW DOES MR. BARRETT'S CASH WORKING CAPITAL CALCULATION OVERSTATE SJG'S WORKING CASH REQUIREMENT?

A. The overstatement results primarily from Mr. Barrett's improper inclusion of non-cash transactions in the working capital calculation. Non-cash transactions do not create a requirement for cash working capital. The non-cash transactions that Mr. Barrett included in his lead-lag calculation are: prepaid expenses, uncollectible accounts, deferred expenses, materials and supplies issues, depreciation and amortization expenses, deferred income taxes, and return on investment. Combined, inclusion of these non-cash transactions in the lead-lag calculation significantly overstates the Company's actual working cash requirement.

Q. WHY IS IT IMPROPER TO INCLUDE NON-CASH EXPENSES IN CASH WORKING CAPITAL?

A. As I stated earlier in my testimony, a rate base allowance for cash working capital allowance compensates the utility for investor funds used to finance the day-to-day cash operating needs of the utility. Cash flows arising from non-cash expenses do not serve this purpose and, therefore, should not be included in the working cash allowance.

Q. THE FIRST NON-CASH EXPENSE INCLUDED IN MR. BARRETT'S LEAD-LAG ANALYSIS THAT YOU MENTIONED IS PREPAID INSURANCE. WHAT IS YOUR OBJECTION TO INCLUDING PREPAID INSURANCE IN THE LEAD-LAG ANALYSIS?

A. Payment for insurance premiums is typically required prior to the effective coverage date of the policy. Thus, most insurance premiums are "pre-paid" in this manner. There are two ways that these types of prepayments can be recognized for ratemaking purposes. One way is to count the actual number of days from when the cash payment was made until the mid-point of the insurance coverage period and include those days in the lead-lag calculation along with the amount of the prepayment. This we can call a lead-lag approach to recognizing prepayments. Another way to recognize prepayments is to include the average monthly balance of prepayments as a separate line item in rate base. This we can call a balance sheet approach for recognizing prepayments. One method or the other is appropriate; but not both. My problem with Mr. Barrett's proposed treatment of insurance prepayments is that he improperly combines the lead-lag approach and the balance sheet approach. That is, he includes the test year average prepaid balances in rate base, i.e., the balance sheet approach. But, he also includes prepaid expenses in his lead-lag analysis using zero expense lead days. This has the effect of increasing the cash working capital allowance for this expense by the 41.64-day revenue lag. Since the balance sheet approach does not actually measure the expense lead days associated with prepaid insurance, it is improper to include a separate lead-lag allowance for the revenue lag portion of the transaction as Mr. Barrett has done. On my Schedule DEP-2 attached hereto, I recalculated Mr. Barrett's lead-lag analysis to exclude prepaid insurance. On my Schedule DEP-1, which summarizes my determination of the SJG's entire working capital requirement, I have included the average balance of prepaid insurance. That is, my determination consistently follows the balance sheet approach for prepaid insurance.

Q. WHAT IS YOUR SPECIFIC OBJECTION TO INCLUDING UNCOLLECTIBLE ACCOUNTS EXPENSES IN THE LEAD-LAG STUDY?

A. Despite the fact that including uncollectible expenses in the lead-lag study decreases the Company's cash working capital and revenue requirements in this case, it is simply illogical and improper to do so. In fact, doing so is contrary to the definition of cash working capital that I provided earlier.

SJG writes off an account after service has been rendered if the account has been determined to be uncollectible. Thus, Mr. Barrett measured the average time interval between the provision of service and the dates where uncollectible accounts were written off – 456.08 days on average.[2] Mr. Barrett's inclusion of uncollectible accounts in his lead-lag analyses thus implies that since revenues from paying customers are received, on average, 41.64 days after service is rendered, the Company enjoys a 414.44 day net cash working capital benefit arising from the uncollectible accounts.

I do not dispute that uncollectible accounts represent a legitimate expense in an accounting sense given that the expense reduces net income and that uncollectible accounts represent a legitimate ratemaking expense as well. But, the administrative decision to declare an account uncollectible does not create a source of working cash for the Company. To see the obvious fallacy of including

[2] See Corrected Direct Testimony of Michael E. Barrett, page 16.

the uncollectible accounts expense in the lead-lag study one need only answer the question: How does a customer who does not pay his utility bill become a source of cash working capital for the utility? If that were the case, utilities would be encouraging all customers to not pay their utility bills. Obviously, this is an absurd result. The average lag in customer payments, including late paying customers, is measured in the revenue lag portion of the study. All that is necessary and appropriate to complete the lead-lag study is to measure the timing of SJG's payment of <u>cash</u> expenses. SJG's uncollectible accounts, however, are not <u>cash</u> expenses. Therefore, uncollectible accounts expenses should not be included in the lead-lag study. On my Schedule DEP-2, I recalculated SJG's cash working capital requirement after excluding uncollectible accounts expenses.

Q. WHY SHOULD SJG'S MANUFACTURED GAS PLANT REMEDIATION EXPENSES BE REMOVED FROM THE LEAD-LAG ANALYSIS?

A. The amount of remediation costs included in Mr. Barrett's lead-lag analysis represents the amortization of costs incurred in prior accounting periods. Mr. Barrett acknowledges that the amortization is a non-cash expense.[3] Given my objection to including non-cash expenses in the lead-lag analysis, SJG's remediation cost amortization expenses should be removed as well.

For the same reason, I also excluded from my lead-lag analysis the materials and supplies issue expenses, which Mr. Barrett included in his analysis. The cash transaction associated with materials and supplies took place when the materials and supplies were purchased and initially booked to an inventory account. A separate rate base allowance is provided for SGJ's inventories (the "balance sheet method" described earlier). No further exchange of cash takes place when materials and supplies are removed from inventory and used by the utility. Thus,

[3] Corrected Direct Testimony of Michael E. Barrett, page 16.

there is no additional requirement for cash working capital that arises when materials and supplies are issued from inventory.

Q. WHAT IS YOUR OBJECTION TO INCLUDING DEPRECIATION EXPENSE IN THE LEAD-LAG STUDY?

A. Simply stated, depreciation is a non-cash expense. The cash transaction associated with a plant asset occurred when the asset was first acquired. No additional investor-supplied funds for working capital purposes are required following the initial investment.

Rather, the depreciation expense is an accounting accrual established to provide a systematic means for the utility to recover the cost of a plant asset over its useful service life. The utility, however, does not write out a check at the end of each month for "depreciation expense" to investors. For that reason, depreciation expense represents a significant source of cash flow for the utility even though it is a non-cash expense as far as SJG's cash working capital requirement is concerned. Therefore, it is not appropriate to include depreciation and amortization expenses in the lead-lag study.

Q. MR. BARRETT ARGUES THAT BECAUSE INVESTOR CAPITAL WAS EXPENDED WHEN PLANT ASSETS WERE ACQUIRED THIS JUSTIFIES INCLUDING DEPRECATION AND DEFERRED TAXES IN THE LEAD-LAG STUDY. DO YOU AGREE?

A. No. This is *non sequitur* reasoning. No one can dispute that investors expended funds at the time the Company acquired plant assets. This undisputed fact, however, actually supports my position that depreciation and deferred taxes should not be recognized in the cash working capital calculation. The cash transaction with investors associated with plant in service giving rise to depreciation and deferred taxes already occurred in the past. There is no further cash outlay from either investors or the Company that is in any way connected with depreciation and deferred taxes from that point on. No working capital is needed by the utility for this item. Thus, there is no justification for a cash working capital allowance for depreciation or deferred income taxes.

Q. DO YOU HAVE ANY OTHER OBJECTIONS TO MR. BARRETT'S INCLUSION OF DEFERRED TAXES IN HIS LEAD/LAG ANALYSIS?

A. Yes. As I previously stated, it is appropriate to exclude deferred taxes from the working capital calculation because there is no continuing cash payment required from either the Company or from investors for tax deferrals. Because no periodic cash outlay is required, no investment in working capital is required either. Deferred taxes have been collected from ratepayers, without being paid to the US Treasury by the utility. It is unreasonable to conclude that deferred tax expenses create a cash working capital requirement, since no investor funds were expended for them.

Q. IS MR. BARRETT'S TREATMENT OF RETURN ON INVESTMENT IN HIS LEAD-LAG ANALYSIS APPROPRIATE?

A. No, it is not. Mr. Barrett's proposed lead-lag calculation includes an amount for SJG's returns on the common equity and long-term debt used to finance rate base. Looking first at common equity, Mr. Barrett includes the common equity return in his lead-lag study using a zero-day expense lead. Mr. Barrett's treatment is as if stockholders are being compensated on a daily basis. The fact is that stockholders receive compensation in two forms: 1) through quarterly dividend payments, if any, and 2) through capital appreciation, if any, upon the sale of the stock. If one were to measure the actual delay in the utility's cash outlay to stockholders, one would refer to the quarterly dividends that are being paid, rather than assume a zero lag as Mr. Barrett has done. But, because there is no contractual requirement for SJG to pay stockholders a quarterly dividend, the common equity return should not be included in the lead-lag analysis in the first place.

Q. HOW DID MR. BARRETT TREAT LONG-TERM DEBT INTEREST IN HIS LEAD-LAG ANALYSIS?

A. Mr. Barrett treated interest on long-term debt in same way that he treated the common equity return, i.e., he simply lumped debt interest in with the common equity return and applied a zero-day lag to SJG's total net income.

Q. SHOULD LONG-TERM DEBT INTEREST BE ACCOUNTED FOR IN THIS MANNER?

A. No. Unlike common stock dividends, there are contractual requirements associated with debt interest that obligate SJG to make specified payments on certain dates. In this respect, the debt interest portion of SJG's return allowance more closely resembles its other cash operating expenses. Therefore, the average payment lead for long-term debt interest should be separately recognized in the lead-lag calculation. Long-term debt interest is paid semi-annually, creating 91.25-day expense lead. These expense lead days are incorporated into the lead-lag calculation shown on Schedule DEP-2 attached hereto.

Q. ARE YOU RECOMMENDING ANY OTHER CHANGES IN MR. BARRETT'S LEAD-LAG CALCULATION?

A. Yes. Mr. Barrett included SJG's incentive compensation expenses in his lead-lag analysis using a 383.81-day average expense lead. Rate Counsel witness Mr. Robert Henkes, however, recommends that SJG's incentive compensation expenses not be included in SJG's revenue requirement. Therefore, it is appropriate for me to also remove incentive compensation from the lead-lag analysis. The effect of removing incentive compensation from the lead-lag analysis is incorporated into the calculations shown in my Schedule DEP-2, at line 5.

Q. IN ADDITION TO A CASH WORKING CAPITAL ALLOWANCE CALCULATED USING LEAD-LAG STUDY, MR. BARRETT ALSO ADDS OTHER AVERAGE ACCOUNT BALANCES TO RATE BASE. ARE YOU RECOMMENDING ANY ADJUSTMENTS TO THE OTHER WORKING CAPITAL ELEMENTS THAT MR. BARRETT INCLUDED?

A. I agree with most of the other rate base elements that Mr. Barrett included in his working capital summary. I disagree, however, with including SJG's cash and working fund average balances in rate base and with reducing rate base by the average balances of accrued construction material and payroll invoices.

Q. WHY DO YOU DISAGREE WITH INCLUDING CASH AND WORKING FUND BALANCES IN RATE BASE?

A. The mere existence of SJG's temporary cash investments held by financial institutions and by working funds maintained by the utility does not establish the need for those balances. SJG has performed no studies demonstrating the optimal amount of cash or working funds it requires; nor has SJG shown whether investors or New Jersey ratepayers provided those funds. The lead-lad calculation quantifies SJG's working cash requirements based on the analysis of revenues received and the timing of cash payments. SJG has not shown where any additional investor-supplied funds are required for operations. Thus, including allowances cash balances and working funds in rate base is inappropriate.

Q. WHY SHOULD MR. BARRETT'S PROPOSED RATE BASE DEDUCTIONS FOR ACCRUED CONSTRUCTION MATERIALS AND PAYROLL INVOICES BE REVERSED?

A. Eliminating these accrued costs is consistent with my proposed working capital treatment for depreciation expense and deferred taxes. Mr. Barrett points out in his testimony that accrued invoices and accrued payroll are not sources of cash working capital. On the opposite side of the same coin, it is my position that depreciation and deferred taxes to not create requirements for cash working capital. Therefore, neither should be reflected in rate base. However, if Your Honor or the Board find it is appropriate to include either depreciation expense or deferred taxes in the lead-lag calculation, SJG's rate base should be reduced by the average accrued invoices and accrued payroll balances as Mr. Barrett proposed.

Q. DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?

A. Yes, it does.

SCHEDULES

SOUTH JERSEY GAS COMPANY

Working Capital Summary
Test Year Ended June 30, 2010

		SJG As Filed	Rate Counsel	Adjustment
	(A)	(B)	(C)	(D)
1.	Lead-lag study results	$14,018,541	$969,240	($13,049,301)
	Other working capital elements			
2.	Cash balance	3,601,742	0	(3,601,742)
3.	Working funds	280,177	0	(280,177)
4.	General prepayments	2,004,829	2,004,829	0
5.	Prepaid Energy Sales and Use Tax	7,960,130	7,960,130	0
6.	USF/Lifeline reserve	(98,567)	(98,567)	0
7.	Prepaid pension	18,155,121	18,155,121	0
8.	Prepaid postretirement healthcare	40,381	40,381	0
9.	Accrued invoiced related to plant	(1,989,635)	0	1,989,635
10.	Accrued payroll related to plant	(320,246)	0	320,246
11.	Vacation accrual reserve	(1,034,294)	(1,034,294)	0
12.	Uninsured risk reserve	(470,862)	(470,862)	0
13.	Marketer payment reserve	(5,253,296)	(5,253,296)	0
14.	Net working capital	$36,894,021	$22,272,682	($14,621,339)

Sources:
Line 1: Schedule 2, herein
Lines 2-13: SJG Schedule MEB-1 and Peterson Testimony

SOUTH JERSEY GAS COMPANY

Lead-Lag Cash Working Capital

Lead-Lag Study for the Twelve Months Ended December 31, 2008

	As Filed	Adjustments	As Adjusted	Lag Days	Dollar Days
(A)	(B)	(C)	(D)	(E)	(F)
1. Purchased gas	$383,403,386		$383,403,386	39.92	$15,305,463,169
Other Operating Expenses					
2. Prepaid insurance	1,179,197	($1,179,197)	0	0.00	0
3. Pensions	1,090,708		1,090,708	(9.44)	(10,296,284)
4. Payroll	16,879,947		16,879,947	15.67	264,508,769
5. Other compensation	343,344	(343,344)	0	383.81	0
6. Motor vehicle	1,313,082		1,313,082	11.40	14,969,135
7. Uncollectible accounts expense	1,865,617	(1,865,617)	0	456.08	0
8. Outside services (audit)	299,674		299,674	164.64	49,338,327
9. Employee benefits	2,507,758		2,507,758	41.32	103,620,561
10. FASS 106	761,001		761,001	37.50	28,537,538
11. NJ Clean Energy Program	6,554,116		6,554,116	45.83	300,375,136
12. Other accounts payable	11,186,838		11,186,838	44.86	501,841,553
13. Remediation expense (RAC)	3,994,038	(3,994,038)	0	0.00	0
14. Affiliate provided services	11,403,806		11,403,806	74.41	848,557,204
15. Meter reading expenses	2,897,027		2,897,027	43.45	125,875,823
16. Materials & supplies issues	54,256	(54,256)	0	0.00	0
17. Membership dues	311,603		311,603	19.53	6,085,607
18. Utility location markout services	1,558,397		1,558,397	36.93	57,551,601
19. Bank service fees	399,715		399,715	76.01	30,382,337
20. Other O&M not lagged	(1,156,193)	1,156,193	0	0.00	0
21. Subtotal	$63,443,931	($6,280,259)	$57,163,672		$2,321,347,307
22. Depreciation	25,588,540	($25,588,540)	0	0.00	0
23. Amortization	237,963	(237,963)	0	0.00	0
24. TEFA & PUA taxes	8,655,836		8,655,836	7.86	68,034,871
25. Other taxed	1,971,572		1,971,572	11.83	23,323,697
26. Federal income - current	1,000,368		1,000,368	37.00	37,013,616
27. Federal income - deferred	18,877,231	(18,877,231)	0	0.00	0
28. CBT - current	4,075,187		4,075,187	(47.25)	(192,552,586)
29. CBT - deferred	2,818,359	(2,818,359)	0	0.00	0
30. Other operating income	58,291,451	(58,291,451)	0	0.00	0
31. Long-term debt interest		21,800,990	21,800,990	91.25	1,989,340,352
					0
32. Subtotal	$121,516,507	($84,012,554)	$37,503,953		$1,925,159,950
33. Total cash expenses	$568,363,824	($90,292,813)	$478,071,011	40.90	$19,551,970,426
34. Revenue lag days					41.64
35. Expense lead days					40.90
36. Net lag days					0.74
37. Expense per day					$1,309,784
38. Cash working capital requirement					$969,240

Sources:
- SJG's Corrected Schedules MEB-1, MEB-2, and MEB-3
- Direct Testimony of David E. Peterson
- Line 31: Rate base times weighted cost of long-term debt

APPENDIX

David E. Peterson
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Proceedings In Which Mr. Peterson Filed Testimony

	Jurisdiction	Date	Utility	Case No.	Client	Issues Addressed
1.	South Dakota PUC	12/77	Iowa Public Service Co. (electric)	F-3179	Commission Staff	Operating expenses
2.	South Dakota PUC	10/78	Montana-Dakota Utilities Co. (electric & gas)	F-3240-3241	Commission Staff	Cash working capital and inflation
3.	South Dakota PUC	01/79	Black Hills Power and Light Co. (electric)	F-3282	Commission Staff	Cash working capital
4.	South Dakota PUC	05/79	Northwestern Public Service Co. (electric)	F-3301	Commission Staff	Cash working capital
5.	South Dakota PUC	07/79	Minnesota Gas Company (gas)	F-3302	Commission Staff	Operating expenses
6.	South Dakota PUC	11/79	Montana-Dakota Utilities Co. (gas)	F-3312	Commission Staff	Rate base & cash working capital
7.	South Dakota PUC	10/80	Montana-Dakota Utilities Co. (gas)	F-3355	Commission Staff	Cash working capital
8.	South Dakota PUC	10/80	Northern States Power Co. (electric)	F-3353	Commission Staff	Rate design
9.	Alabama PSC	05/81	Alabama Gas Corporation (gas)	19046	Attorney General	Revenue requirements
10.	FERC	07/82	Pennsylvania Power Company (electric)	ER81-779	Municipal wholesale customers	Operating expenses
11.	FERC	11/82	Utah Power and Light Co. (electric)	ER82-211	Muni. & Coop. wholesale customers	Taxes and cash working capital
12.	Indiana PSC	05/83	Generic PGA investigation	37091	US Steel Corp.	Rate design and PGA's
13.	New Mexico PSC	02/84	Public Service Co. of New Mexico (electric)	1835	Attorney General	Depreciation & cash working capital
14.	FERC	03/84	Utah Power and Light Co. (electric)	ER83-427&428	Muni. & Coop. wholesale customers	Revenue requirements
15.	FERC	07/84	Generic - Cash Working Capital NOPR	RM84-9-000	Muni. & Coop. wholesale customers	Cash working capital
16.	Colorado PSC	11/84	Public Service Co. of Colorado (electric)	1640 (Phase II)	Consumer Counsel	Price elasticity
17.	Montana PSC	11/84	Pacific Power & Light Co. (electric)	84.7.38	Consumer Counsel	Revenue requirements, elasticity
18.	Montana PSC	10/85	Pacific Power & Light Co. (electric)	84.7.38	Consumer Counsel	Plant life cycle costs
19.	Montana PSC	02/86	Pacific Power & Light Co. (electric)	85.10.41	Consumer Counsel	Revenue requirements
20.	FERC	08/86	Niagara Mohawk Power Corp. (electric)	ER86-354	NY Transit Authority	Class cost allocation
21.	Maryland PSC	01/87	Eastern Shore Gas Co. (propane)	8010	People's Counsel	Revenue requirements
22.	New Jersey BPU	09/87	South Jersey Gas Co. (gas)	GR8704329	Industrial intervenors	Revenue requirements
23.	FERC	03/88	Niagara Mohawk Power Corp. (electric)	ER87-612	NY Transit Authority	Class cost allocation
24.	Colorado PUC	11/88	Mountain Bell (telephone)	36883	Consumer Counsel	ELG depreciation
25.	New Jersey BPU	12/88	New Jersey-American Water (water)	WR88070639	Wholesale customer	Class cost allocation

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Proceedings In Which Mr. Peterson Filed Testimony

	Jurisdiction	Date	Utility	Case No.	Client	Issues Addressed
26.	Maryland PSC	01/89	Chesapeake Utilities Corp. (gas)	8157	People's Counsel	Revenue requirements
27.	Maryland PSC	04/89	Easton Utilities Commission (electric)	8176	People's Counsel	Revenue requirements
28.	Colorado PUC	07/89	Mountain Bell (telephone)	36883	Consumer Counsel	Refund procedures
29.	Maryland PSC	09/89	Town of Berlin, MD (electric)	8210	People's Counsel	Revenue requirements
30.	Kansas Corp. Comm.	10/90	Kansas Public Service Co. (gas)	171,827-U	CURB	Revenue requirements, rate design
31.	Colorado PUC	01/91	US West Communications (telephone)	90S-544T	Consumer Counsel	Revenue requirements
32.	New Jersey BRC	01/92	New Jersey-American Water (water)	WR91081399J	Wholesale customers	Cost allocation, rate design
33.	Maine PUC	01/92	Portland Water District (water)	91-162	Intervenor Cities	Cost allocation
34.	Maryland PSC	04/92	Columbia Gas of Maryland (gas)	8437	People's Counsel	Revenue requirements
35.	West Virginia PSC	07/92	West Virginia-American Water (water)	92-0250-W-42T	Consumer Advocate Division	Revenue requirements
36.	Maryland PSC	08/92	Easton Utilities Commission (gas)	8467	People's Counsel	Revenue Requirements
37.	Kansas Corp. Comm.	10/92	Arkansas-Lousiana Gas Co. (gas)	181,200-U	CURB	Revenue Requirements
38.	New York PSC	10/92	New York-American Water (water)	92-W-0494	New York Municipals	Revenue requirements
39.	Connecticut DPUC	10/92	Connecticut-American Water (water)	92-06-12	New York Municipals	Cost allocation, rate design
40.	West Virginia PSC	12/92	West Virginia-American Water (water)	92-0992-W-PC	Consumer Advocate Division	SFAS 106
41.	New Jersey BRC	02/93	New Jersey-American Water (water)	WR92090906J	Wholesale customers	Cost allocation, rate design
42.	Colorado PUC	05/93	Public Servic Co. of Colorado (elec,gas&stea	93S-001EG	Consumer Counsel	Future test year
43.	West Virginia PSC	07/93	Hope Gas, Inc. (gas)	93-0004-G-42T	Consumer Advocate Division	Revenue requirements
44.	Maine PUC	09/93	Portland Water District (water)	93-027	Intervenor Cities	Cost allocation
45.	Arkansas PSC	09/93	Arkansas Louisiana Gas Co. (gas)	93-081-U	Attorney General CURAD	Revenue requirements
46.	Maryland PSC	11/93	Town of Berlin, MD (electric)	8590	People's Counsel	Revenue requirements
47.	Nevada PSC	05/94	Nevada Power Company (electric)	93-11045	Consumer Advocate	Revenue requirements
48.	New Jersey BPU	06/94	New Jersey-American Water (water)	WR94030059	Wholesale customers	Cost allocation, rate design
49.	New York DEC	08/94	New York City Water Board (water)	8865	Scarsdale, NY	Revenue requirements
50.	West Virginia PSC	09/94	West Virginia-American Water (water)	94-0138-W-42T	Consumer Advocate Division	Revenue requirements

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51.	Arkansas PSC	11/94	Arkla, Inc. (gas)	94-175-U	Attorney General CURAD	Revenue requirements
52.	New York PSC	12/94	New York-American Water (water)	94-W-0579	New York Municipalities	Prudence review purchased water
53.	New Jersey BPU	08/95	New Jersey-American Water (water)	WR95040165	Wholesale customers	Cost allocation, rate design
54.	Colorado PUC	08/95	Greeley Gas (gas)	95S-146G	Consumer Counsel	Cost allocation, rate design
55.	Colorado PUC	09/95	San Miguel Power Assoc. (electric)	95I-144E	Consumer Counsel	Cost allocation, rate design
56.	West Virginia PSC	09/95	West Virginia-American Water (water)	95-0228-W-42T	Consumer Advocate Division	Revenue requirements
57.	Colorado PUC	03/96	Delta County Tele-Comm. (telephone)	95S-522T	Consumer Counsel	Revenue requirements
58.	Colorado PUC	04/96	Public Service Co. of Colorado (electric)	95A-531EG	Consumer Counsel	Revenue requirements, merger
59.	Colorado PUC	10/96	Public Service Co. of Colorado (gas)	96S-290G	Consumer Counsel	Revenue requirements
60.	New Jersey BPU	08/97	Atlantic City Electric Co. (electric)	EM97020103	Div. of the Ratepayer Advocate	Merger
61.	Colorado PUC	08/97	Greeley Gas Company (gas)	97F-221G	Consumer Counsel	Revenue Requirements
62.	Colorado PUC	09/97	Public Service Co. of Colorado (gas)	97S-366G	Consumer Counsel	Weather Normalization
63.	Colorado PUC	10/97	Public Service Co. of Colorado (electric)	97A-299EG	Consumer Counsel	Merger costs; Wholesale costs
64.	Colorado PUC	03/98	Public Service Co. of Colorado (gas)	97A-622G	Consumer Counsel	Pipeline certificate application
65.	West Virginia PSC	06/98	Mountaineer Gas Company (gas)	98-0008-G-42T	Consumer Advocate Division	Revenue requirements
66.	New Jersey BPU	06/98	New Jersey-American Water (water)	WR98010015	Wholesale customers	Cost allocation, rate design
67.	Colorado PUC	08/98	Public Service Company of Colorado (electric	95A-531EG	Consumer Counsel	Revenue requirements
68.	Colorado PUC	02/99	Public Service Compnay of Colorado (gas)	98S-518G	Consumer Counsel	Revenue requirements
69.	West Virginia PSC	04/99	West Virginia Power (electric)	98-1345-E-42T	Consumer Advocate Division	Revenue requirements
70.	Pennsylvania PUC	05/99	City of Lancaster - Water Fund (water)	R-00984567	Townships outside of City	Rate of return/rate spread
71.	West Virginia PSC	05/99	West Virginia Power Gas Service (gas)	98-1496-G-42T	Consumer Advocate Division	Revenue requirements
72.	Maryland PSC	02/00	Potomac Edison Company (electric)	8827	Office of People's Counsel	CPCN - cost allocation
73.	Colorado PUC	11/00	Public Service Company of Colorado (gas)	00S-422G	Consumer Counsel	Revenue requirements
74.	New Jersey BPU	05/01	FirstEnergy/GPU (electric merger)	EM00110870	Div. of the Ratepayer Advocate	Merger
75.	West Virginia PSC	06/01	Mountaineer Gas Company (gas)	01-0011-G-42T	Consumer Advocate Division	Revenue requirements

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76.	New Jersey BPU	09/01	Conectiv/Pepco (electric merger)	EM01050308	Div of the Ratepayer Advocate	Merger
77.	Maryland	11/01	nv Nuon/Utilities, Inc. (water merger)	8898	Office of People's Counsel	Merger
78.	New Jersey BPU	09/02	Elizabethtown Gas Company (gas)	GR02040245	Div of the Ratepayer Advocate	Revenue requirements
79.	Colorado PUC	11/02	Public Service Co. of Colorado (ele. & gas)	02S-315EG	Consumer Counsel	Revenue requirements
80.	New Jersey BPU	12/02	Jersey Central Power & Light Co. (electric)	ER02080506	Div of the Ratepayer Advocate	Revenue requirements
81.	New Jersey BPU	01/03	Rockland Electric Company (electric)	ER02100724	Div of the Ratepayer Advocate	Cost allocation; rate design
82.	New Jersey BPU	02/03	Public Service Electric & Gas Company	EM00040253	Div of the Ratepayer Advocate	Street Lighting; Service Company
83.	Maryland PSC	08/03	Greenridge Utilities, Inc. (water)	8962	Office of People's Counsel	Revenue requirements
84.	West Virginia PSC	08/03	West Virginia-American Water Co. (water)	03-0353-W-42T	Consumer Advocate Division	Revenue requirements
85.	Wyoming PSC	11/03	PacifiCorp, Inc. (electric)	20000-ER-03-198	Wy. Industrial Energy Consumers	Revenue requirements
86.	New Jersey BPU	12/03	New Jersey-American Water Co. (water)	WR03070511	Wholesale customers	Cost allocation; rate design
87.	New Jersey BPU	01/04	South Jersey Gas Company (gas)	GR03050413	Div of the Ratepayer Advocate	BGSS
88.	New Jersey BPU	02/04	South Jersey Gas Company (gas)	GR03080683	Div of the Ratepayer Advocate	Revenue requirements
89.	New Jersey BPU	02/04	Atlantic City Electric Company (electric)	ER03020110	Div of the Ratepayer Advocate	Service Company
90.	West Virginia PSC	07/04	West Virginia-American Water Co. (water)	04-0373-W-42T	Consumer Advocate Division	Revenue requirements
91.	Maryalnd PSC	09/04	Allegheny Power Company (electric)	8998	Office of People's Counsel	CPCN - Transmission line
92.	New Jersey BPU	11/04	Jersey Central Power & Light Co. (electric)	ER02080506	Div of the Ratepayer Advocate	Revenue requirements
93.	Delaware PSC	12/04	Delaware Electric Cooperative (electric)	04-288	Commission Staff	Revenue requirements
94.	West Virginia PSC	04/05	Cranberry Pipeline Corporation (gas)	04-0160-GT-42A	Consumer Advocate Division	Revenue requirements
95.	Maryland PSC	08/05	Hagerstown Light Department (electric)	9039	Office of People's Counsel	Revenue requirements
96.	Colorado PUC	10/05	Public Service Company of Colorado (gas)	05S-264G	Consumer Counsel	Revenue requirements
97.	New Jersey BPU	11/05	Public Service Electric & Gas Company	EM05020106	Div of the Ratepayer Advocate	Merger
98.	Delaware PSC	12/05	Delmarva Power & Light Company	05-304	Commission Staff	Revenue requirements
99.	DE. House of Rep *	03/06	Delmarva Power & Light Company		Delaware PSC	Consolidated tax savings
100.	New Jersey BPU	06/06	Jersey Central Power & Light Co. (electric)	ER05121018	Div of the Ratepayer Advocate	Deferred energy costs

* Testified before the Energy Committee of the Delaware House of Representatives

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	Jurisdiction	Date	Utility	Case No.	Client	Issues Addressed
101.	Colorado PUC	08/06	Public Service Company of Colorado (elect)	06S-234EG	Consumer Counsel	Revenue requirements
102.	Delaware PSC	09/06	Tidewater Utilities, Inc. (water)	06-145	Commission Staff	Revenue requirements
103.	New Jersey BPU	10/06	New Jersey-American Water Company	WR06030257	Municipal customers	Cost allocation; rate design
104.	New Jersey BPU	11/06	Rockland Electric Company	ER06060483	Div of Rate Counsel	Revenue requirements
105.	Colorado PUC	04/07	Public Service Company of Colorado (gas)	06S-656G	Consumer Counsel	Consolidated tax savings
106.	New Jersey BPU	06/07	United Water New Jersey, Inc.	WR07020135	Div of Rate Counsel	Cash working capital; income taxes
107.	Maryland PSC	07/07	Southern Md. Electric Cooperative, Inc.	9106	Office of People's Counsel	Revenue requirements
108.	Montana PSC	10/07	Montana-Dakota Utilities Co.	D2007.7.79	Industrial Intervenor	Revenue requirements
109.	West Virginia PSC	11/07	West Virginia-American Water Company	07-0998-W-42T	Consumer Advocate Division	Revenue requirements
110.	Wyoming PSC	01/08	Rocky Mountain Power	20000-277-ER-07	Industrial Intervenors	Revenue requirements
111.	New Jersey BPU	04/08	New Jersey Natural Gas Company	GR07110889	Div of Rate Counsel	Cash working capital
112.	Maryland PSC	09/08	Easton Utilities Commission (electric)	9145	Office of People's Counsel	Revenue requirements
113.	Maryland PSC	10/08	Choptank Electric Cooperative, Inc. (elect)	9146	Office of People's Counsel	Rev req.; cost allocation; rate design
114.	Nevada PUC	11/08	Spring Creek Utilities Co (water)	08-06036	Spring Creek Utilities Co.	Water rate design
115.	Wyoming PSC	01/09	Rocky Mountain Power (electric)	20000-333-ER-08	Industrial Intervenors	Revenue requirements
116.	Colorado PUC	02/09	Public Service Co. of Colorado (electric)	08S-520E	Consumer Counsel	Appropriate test year
117.	New Jersey BPU	08/09	Elizabethtown Gas Company (gas)	GR09030195	Div of Rate Counsel	Cash working capital
118.	Colorado PUC	09/09	Public Service Co. of Colorado (electric)	09AL-299E	Consumer Counsel	Test year; revenue requirements
119.	New Jersey BPU	11/09	Public Service Elect. & Gas Co (elec & gas)	GR09050422	Div of Rate Counsel	Cash working capital
120.	Nevada PUC	12/09	Utilities Inc. of Central Nevada (water)	09-12017	UICN	Cost allocation; rate design
121.	Wyoming PSC	02/10	Rocky Mountain Power (electric)	20000-354-ER-09	Industrial Intervenors	Test year; revenue requirements
122.	New Jersey BPU	03/10	Rockland Electric Company (electric)	ER09080668	Div of Rate Counsel	Revenue requirements