

PENNSYLVANIA POWER & LIGHT COMPANY

ORIGINAL

Exhibit JMK 3

Distribution Subfunctionalization/
Classification Studies

RECEIVED

Allocation of Meter Costs

APR 01 1997

Witness: Joseph M. Kleha

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PENNSYLVANIA POWER & LIGHT COMPANY

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Pennsylvania Power & Light Company

Distribution Subfunctionalization / Classification Studies

Allocation of Meter Costs

ERM

PENNSYLVANIA POWER & LIGHT COMPANY

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Distribution Plant - Subfunctionalization/Classification Studies

Summary

This exhibit provides the results of studies used in the functionalization, subfunctionalization, and classification distribution plant. The studies are based on distribution plant data as of December 31, 1993. The results of these studies were applied to distribution plant data for both the historic and future test years.

Distribution Plant is functionalized into the following categories:

- Substations
- Overhead Lines
- Underground Lines
- Line Transformers
- Services
- Meters
- Area Lighting
- Street Lighting

Distribution Plant is subfunctionalized by the following voltage levels for cost allocation purposes:

- Subtransmission voltage - 66/138 KV
- Primary voltage - 3 phase 12 KV or 3 phase 23 KV
- Secondary voltage - everything below 3 phase 12 KV

Distribution Plant is subfunctionalized into subtransmission, primary, and secondary components based on the functions of specifically identified units of property within the distribution plant accounts.

The subfunctionalization of secondary distribution plant then is classified into the demand and customer components based on a "minimum size system" study.

The following tables provide summaries of:

- Distribution Plant Account Balances as of December 31, 1993
- Distribution Plant - Subfunctionalization/Classification Percentages by Plant Account
- Distribution Plant-Subfunctionalization on a % of Account Total Basis

Pennsylvania Power & Light Company

Distribution Plant Account Balances
As of December 31, 1993

Account	Description	December 31, 1993 Balance	
360.2	Land	\$11,839,672	
360.4	Land Rights	81,026,094	
360 Total	Land & Land Rights		\$92,866,366
361	Structures & Improvements		29,813,584
362	Station Equipment		273,750,726
364.2	Tower & Fixtures	78,852,749	
364.4	Poles & Fixtures	483,185,321	
364.6	Clearing Land & R/W - Towers	3,725,783	
364.8	Clearing Land & R/W - Poles	31,844,613	
364 Total	Poles & Towers		597,608,466
365	Overhead Conductors		418,597,606
366	Underground Conduit		68,982,181
367	Underground Conductors		144,489,486
368	Line Transformers		273,073,741
369	Services		267,218,735
370	Meters		77,698,054
371	Area Lighting		3,844,569
373	Street Lighting		43,895,002
Total Distribution Plant			\$2,291,838,516

Pennsylvania Power & Light Company

Distribution Plant - Subfunctionalization/Classification

**Percentages by Plant Account
as of December 31, 1993**

Account	Description	66/138 KV and Primary % of Account Total	Secondary % of Account Total	Customer Component % of Secondary	Demand Component % of Secondary
360	Land & Land Rights	See Note	See Note	See Note	See Note
361	Structures & Improvements	98.84	1.16	0.00	100.00
362	Station Equipment	98.38	1.62	0.00	100.00
364	Poles, Towers & Fixtures	36.94	63.06	47.01	52.99
365	Overhead Conductors & Devices	43.59	56.41	65.14	34.86
366	Underground Conduit	17.61	82.39	62.53	37.47
367	Underground Conductors	17.61	82.39	62.53	37.47
368	Line Transformers	0.00	100.00	56.45	43.55
369	Services	0.00	100.00	91.52	8.48
370	Meters	0.00	100.00	100.00	0.00
371	Area Lighting Fixtures	0.00	100.00	100.00	0.00
373	Street Lighting	0.00	100.00	100.00	0.00

Note: Account 360 (Land & Land Rights) is functionalized and classified by direct assignment based on an analysis of plant records.

**PENNSYLVANIA POWER & LIGHT COMPANY
 SUBFUNCTIONALIZATION OF DISTRIBUTION PLANT
 BASED ON % OF ACCOUNT TOTAL
 FOR COST ALLOCATION PURPOSES
 AS OF DECEMBER 31, 1993**

		3602	3604	3610	3620	3640
		LAND	LAND RIGHTS	STRUCT. & IMP.	STATION EQUIP.	POLES & TOWERS
Substation	Step Up	0.14	0.00	1.25	2.00	
	230 KV	0.00	0.00	0.00	0.00	
	138 KV	3.90	0.12	4.16	2.07	
	69 KV	9.28	0.00	20.65	19.85	
	Primary	58.45	0.00	72.80	74.46	
	Secondary	0.75	0.00	1.16	1.62	
	Subtotal	72.52	0.12	100.00	100.00	
Overhead Lines	138 KV	2.33	2.37			1.82
	69 KV	24.41	41.62			24.25
	Primary	0.21	15.56			19.58
	Sec. DMD	0.23	17.21			26.37
	Sec. CUST	0.28	21.07			23.39
	Street LT	0.03	1.97			4.59
	Subtotal	27.48	99.80			100.00
Underground Lines	138 KV		0.00			
	69 KV		0.00			
	Primary		0.01			
	Sec. DMD		0.03			
	Sec. CUST		0.04			
	Subtotal		0.08			
Line Transformers	Sec. DMD					
	Sec. CUST					
	Subtotal					
Services	Sec. DMD					
	Sec. CUST					
	Subtotal					
Meters	Meters					
	Subtotal					
Area Light	Area LT					
	Subtotal					
Street Lighting	Street LT					
	Subtotal					
Account Total		100.00	100.00	100.00	100.00	100.00

**PENNSYLVANIA POWER & LIGHT COMPANY
 SUBFUNCTIONALIZATION OF DISTRIBUTION PLANT
 BASED ON % OF ACCOUNT TOTAL
 FOR COST ALLOCATION PURPOSES
 AS OF DECEMBER 31, 1993**

		3650	3660	3670	3680	3690
		O.H. CONDUCTORS	U.G. CONDUIT	U.G. CONDUCTORS	LINE TRANSFORMER	SERVICES
Substation	Step Up					
	230 KV					
	138 KV					
	69 KV					
	Primary					
	Secondary					
	Subtotal					
Overhead Lines	138 KV	1.09				
	69 KV	18.65				
	Primary	23.85				
	Sec. DMD	19.66				
	Sec. CUST	36.75				
	Street LT					
	Subtotal	100.00				
Underground Lines	138 KV		0.46	0.96		
	69 KV		4.16	2.70		
	Primary		12.99	13.95		
	Sec. DMD		30.87	30.87		
	Sec. CUST		51.52	51.52		
	Subtotal		100.00	100.00		
Line Transformers	Sec. DMD				43.55	
	Sec. CUST				56.45	
	Subtotal				100.00	
Services	Sec. DMD					8.48
	Sec. CUST					91.52
	Subtotal					100.00
Meters	Meters					
	Subtotal					
Area Light	Area LT					
	Subtotal					
Street Lighting	Street LT					
	Subtotal					
Account Total		100.00	100.00	100.00	100.00	100.00

**PENNSYLVANIA POWER & LIGHT COMPANY
 SUBFUNCTIONALIZATION OF DISTRIBUTION PLANT
 BASED ON % OF ACCOUNT TOTAL
 FOR COST ALLOCATION PURPOSES
 AS OF DECEMBER 31, 1993**

		3700	3710	3730
		METERS	AREA LIGHTS	STREET LIGHTING
Substation	Step Up			
	230 KV			
	138 KV			
	69 KV			
	Primary			
	Secondary			
	Subtotal			
Overhead Lines	138 KV			
	69 KV			
	Primary			
	Sec. DMD			
	Sec. CUST			
	Street LT			
	Subtotal			
Underground Lines	138 KV			
	69 KV			
	Primary			
	Sec. DMD			
	Sec. CUST			
	Subtotal			
Line Transformers	Sec. DMD			
	Sec. CUST			
	Subtotal			
Services	Sec. DMD			
	Sec. CUST			
	Subtotal			
Meters	Meters	100.00		
	Subtotal	100.00		
Area Light	Area LT		100.00	
	Subtotal		100.00	
Street Lighting	Street LT			100.00
	Subtotal			100.00
Account Total		100.00	100.00	100.00

Distribution Plant - Subfunctionalization

Station Equipment (Account 362)

Distribution substations are subfunctionalized by analyzing engineering one line diagrams to identify the voltage levels of each substation. The associated plant account retirement units for the substations are used to determine the investment at each voltage level.

The associated distribution plant in Land (Account 360.2), Land Rights (Account 360.4), and Structures & Improvements (Account 361) are subfunctionalized based on an analysis of Station Equipment (Account 362).

Overhead Conductors and Devices (Account 365)

The subfunctionalization of Overhead Conductors and Devices (Account 365) is based on plant account retirement units which are used to determine the investment at subtransmission/primary and secondary voltages. Because this account contains retirement units for property other than conductors (e.g., circuit breakers), the total investment in the account is subfunctionalized based on the analysis of overhead conductors. Direct assignment of subtransmission conductors is then subtracted from the subtransmission/primary total to obtain the primary conductor investment.

Land (Account 360.2) and Land Rights (Account 360.4) associated with overhead conductors is subfunctionalized based on the total subfunctionalization investment of Overhead Conductors and Devices (Account 365) and Poles, Towers, and Fixtures (Account 364).

Poles, Towers, and Fixtures (Account 364)

Account 364 is composed of the following subaccounts:

- 364.2 - Towers and Fixtures
- 364.4 - Poles and Fixtures
- 364.6 - Clearing, Land and Right-of-Way - Towers
- 364.8 - Clearing, Land and Right-of-Way - Poles

Investment in subaccounts 364.2 and 364.6 is segmented to the subtransmission and primary subfunctions only.

Subaccount 364.4 Poles and Fixtures is segmented to subtransmission/primary and secondary subfunctions based on plant account retirement units. Investment in 40-foot and 45-foot poles can be assigned to either the primary or secondary subfunction, therefore, segmentation is based on the ratio of investment in overhead conductors assigned to the subtransmission/primary and secondary subfunctions.

The remaining investment in Account 364 (hardware and devices, guys, anchors, etc.) is assigned to the subtransmission/primary and secondary subfunctions based on the number of poles assigned to each subfunctions. The number of poles used to segment the subtransmission/primary subfunction is doubled to reflect the fact that subtransmission/primary poles require twice the investment in attachments.

Investment in subaccount 364.8, Clearing, Land and Right-of-Way-Poles, is split into subfunctions based on the segmentation of subaccount 364.4, Poles and Fixtures.

The investment for street lighting/area lighting is based on the number of wood poles used for street/area lighting and the determination as to whether those poles are used for sole-use or joint-use purposes.

Underground Conductors and Devices (Account 367)

The subfunctionalization of Underground Conductors and Devices (Account 367) is based on plant account retirement units which are used to determine the investment in the subtransmission/primary and secondary voltages. Only the investment in location 0095 - Underground System Other Than Low Tension Network, is included in this part of the analysis. Locations other than 0095 are directly assigned to one of the subfunctions. The segmented investment from all applicable locations is used to determine the segmentation between the subtransmission/primary and secondary voltages. Direct assignment to subtransmission is subtracted from the subtransmission/primary investment to obtain the primary investment.

Land (Account 360.2) and Land Rights (Account 360.4) associated with underground conductors are subfunctionalized based on the total subfunctionalized investment in Underground Conductors (Account 367) and Underground Conduit (Account 366).

Underground Conduit (Account 366)

The subfunctionalization of Underground Conduit (Account 366) is based on the subfunctionalization of underground conductor. Consequently, the same percentages of subtransmission, primary, and secondary apply.

Line Transformers (Account 368)

The investment in Line Transformers (Account 368) is considered to be a 100% secondary subfunction.

Services (Account 369)

The investment in Services (Account 369) is considered to be a 100% secondary subfunction.

Area Lighting (Account 371)

The investment in area lighting is considered to be a 100% secondary subfunction.

Street Lighting (Account 373)

The investment in street lighting is considered to be a 100% secondary subfunction.

Distribution Plant - Classification

Minimum Size System Study

A "minimum size system" study, using plant balances as of December 31, 1993, was conducted to determine the demand and customer components of the distribution plant accounts. The study involved the determination of the current cost of "minimum size" distribution system facilities (poles, conductors, cables, transformers, and services) that are necessary to provide reliable electric service to customers. The current average book costs of the minimum size units are used to determine the customer component of the account; the remaining balance represents the demand component.

The "minimum size" method, described in the NARUC Cost Allocation Manual, was used as a guide in the preparation of this study.

Summary Results

ACCOUNT	DESCRIPTION	% CUSTOMER	% DEMAND
364	Poles, Towers, & Fixtures	47.01	52.99
365	Overhead Conductors & Devices	65.14	34.86
366	Underground Conduit	62.53	37.47
367	Underground Conductors & Devices	62.53	37.47
368	Line Transformers	56.45	43.55
369	Services	91.52	8.48

Account Details

Poles, Towers, and Fixtures (Account 364)

The Company's Plant Account Continuing Property Records were analyzed to determine the average installed book cost per pole (a 40-foot wood pole is the current "minimum size" pole being installed on PP&L's system). The current average book cost is multiplied by the total number of poles in the distribution system to determine the customer component. The balance of the plant account is the demand component.

Overhead Conductors And Devices (Account 365)

The Continuing Property Records were analyzed to determine the average installed book cost per foot of overhead conductor (1/0 Triplex is the current "minimum size" overhead conductor being installed on PP&L's system). The current average book cost is multiplied by the total number of feet of overhead conductor in the distribution system to determine the customer component. The balance of the plant account is the demand component.

The unit of property retirement code for 1/0 Triplex conductor contains all conductors (2/0 through 1/0 Aluminum); however, 1/0 Triplex is the predominate size conductor.

Underground Conduit (Account 366)

This account is assigned the same customer/demand ratio as Underground Conductors (Account 367).

Underground Conductors (Account 367)

The Continuing Property Records were analyzed to determine the average installed book cost per foot of underground conductor (1/0 Triplex is the current "minimum size" underground conductor being installed on PP&L's system). The current average book cost is then multiplied by the total number of feet of underground conductor in the distribution system to determine the customer component. The balance of the plant account is the demand component.

The unit of property retirement code for 1/0 Triplex conductor contains all conductors (2/0 through 1/0 Aluminum); however, 1/0 Triplex is the predominate size conductor.

Line Transformers (Account 368)

The Continuing Property Records were analyzed to determine the average installed book cost per transformer (a 10 KVA overhead transformer and a 25 KVA underground transformer are the current "minimum size" transformers being installed on PP&L's system).

The current average book cost of the "minimum size" overhead transformer is multiplied by the total number of overhead transformers in the distribution system to determine the customer component.

The current average book cost of the "minimum size" underground transformer is multiplied by the total number of underground transformers to determine the customer component.

The customer component of both overhead and underground transformers are combined to determine the total customer component for the account. The balance of the plant account is the demand component.

Services (Account 369)

The Continuing Property Records were analyzed to determine the average installed book cost per service (#4 Triplex Overhead Service and #10 Aluminum TX Underground Service are the current "minimum size" services being installed on PP&L's system). Because these are the only units of property maintained for services, the total current installed book cost of overhead and underground services is combined to determine the customer component of Account 369. The balance of the plant account is the demand component.

The following table provides a summary of the calculations.

**PENNSYLVANIA POWER & LIGHT COMPANY
MINIMUM SIZE SYSTEM STUDY
AS OF DECEMBER 31, 1991**

(1)	(2)	(3)	MINIMUM SIZE			(7)	(8)	(9)	(10)	(11)
ACCOUNT	MINIMUM SIZE (UNITCODE)	UNIT	TOTAL INSTALLED COST	TOTAL INSTALLED UNITS	AVERAGE UNIT COST (4)/(5)	ACCOUNT TOTAL UNITS	TOTAL CUSTOMER COMPONENT (6)*(7)	ACCOUNT TOTAL	% CUSTOMER (8)/(9)	% DEMAND 100-(10)
364	40 Foot Wood Pole (613007)	Pole	\$121,710,423	376,621	\$323.16	869,317	\$280,928,482	\$597,608,466	47.01	52.99
365	1/0 Triplex Overhead Conductor (625211)	Feet	\$97,466,088	166,381,234	\$0.59	462,130,630	\$272,657,072	\$418,597,606	65.14	34.86
366	Underground Conduit - uses same percentages as Account 367						\$68,982,181		62.53	37.47
367	1/0 Triplex - Underground #2 Conductor (625211)	Feet	\$73,897,122	48,510,627	\$1.52	59,443,369	\$90,353,921	\$144,489,486	62.53	37.47
368.2	10 KVA Overhead Transformer (388315)	Trans.	\$24,672,275	76,734	\$321.53	338,575	\$108,862,020			
368.4	25 KVA Underground Transformer (388419)	Trans.	\$9,268,311	9,393	\$986.73	45,906	\$45,296,827			
368	Total Overhead and Underground Transformers						\$154,158,847	\$273,073,741	56.45	43.55
369	#4 Triplex Overhead Service (683801)	Service	\$97,687,004	870,834	\$112.18		\$97,687,004			
	#1-0 Aluminum TX Underground Service (683802)	Service	\$146,882,839	299,494	\$490.44		\$146,882,839			
369	Total Overhead and Underground Service						\$244,569,843	\$267,218,733	91.52	8.48

Notes:

- Account 366 Underground Conduit is split the same customer and demand percentages as Account 367 Underground Conductor as stated in the NARUC Cost Allocation Manual.
- Account 368 Line Transformers are first split between overhead and underground to determine the customer component and then summarized for the account.
- Account 369 Services are first split between overhead and underground service to determine the customer component and then summarized for the account.

Operation & Maintenance Expense

The process of subfunctionalizing Distribution O&M expense begins with the proration of Supervision and Engineering (Accounts 580 and 590) to the other distribution expense accounts based on the ratio of the labor component of each account to the total distribution labor cost. After prorating the Supervision and Engineering expense, the other expense accounts are subfunctionalized and classified based on the subfunctionalization of distribution plant.

The following tables provide summaries of the subfunctionalization of distribution expense by account.

PENNSYLVANIA POWER & LIGHT COMPANY
DISTRIBUTION EXPENSE ACCOUNTS
FOR COST ALLOCATION PURPOSES
FOR THE 12 MONTHS ENDED SEPTEMBER 30, 1994
(0000)

CATEGORY	ACCOUNT	DESCRIPTION	AMOUNT
OPERATION	580	SUPERVISION & ENGINEERING	\$5,264
	581	LOAD DISPATCHING	3,663
	582	STATION EXPENSES	3,554
	583	OVERHEAD LINE EXPENSES	2,667
	584	UNDERGROUND LINE EXPENSES	1,167
	585	STREET LIGHTING & SIGNALS	153
	586	METER EXPENSES	5,008
	587	CUSTOMER INSTALLATION EXPENSES	3,017
	588	MISCELLANEOUS DISTRIBUTION EXP	5,645
	589	RENTS	5,128
		SUBTOTAL	
MAINTENANCE	590	SUPERVISION & ENGINEERING	\$5,525
	591	MAINTENANCE OF STRUCTURES	204
	592	MAINTENANCE OF STATION EQUIP.	5,702
	593	MAINTENANCE OF OVERHEAD LINES	28,507
	5935	MAINTENANCE OVERHEAD SERVICES	2,833
	594	MAINTENANCE OF UNDERGROUND LINES	1,363
	5943	MAINTENANCE OF UNDERGROUND SERVICES	60
	5946	MAINTENANCE OF UNDERGROUND - OTHER	1,193
	595	MAINTENANCE OF LINE TRANSFORMERS	4,032
	596	MAINTENANCE OF STREET LIGHTING	1,586
	597	MAINTENANCE OF METERS	2,881
598	MAINTENANCE OF MISC. DISTRIBUTION	414	
	SUBTOTAL		\$54,300
TOTAL DISTRIBUTION EXPENSES			\$89,566

PENNSYLVANIA POWER & LIGHT COMPANY
SUBFUNCTIONALIZATION OF DISTRIBUTION EXPENSE ACCOUNTS
PRORATION OF SUPERVISION AND ENGINEERING ACCOUNTS
FOR COST ALLOCATION PURPOSES
FOR THE 12 MONTHS ENDED SEPTEMBER 30, 1994
(\$000)

ACCOUNT	CATEGORY	TOTAL	LABOR	MATERIAL	ACCOUNT 580 PRORATION
582	SUBSTATION	\$3,554	\$2,257	\$1,296	\$969
583	OVERHEAD LINES	2,667	1,050	1,617	451
584	UNDERGROUND LINES	1,167	747	693	203
585	STREET LIGHTING	154	135	19	58
586	METERS	5,007	3,907	1,101	1,676
587	CUSTOMER INSTALLATIONS	3,017	1,955	1,062	839
588	MISCELLANEOUS	5,645	2,490	3,155	1,068
TOTAL		\$21,212	\$12,268	\$8,944	\$5,264

PENNSYLVANIA POWER & LIGHT COMPANY
SUBFUNCTIONALIZATION OF DISTRIBUTION EXPENSE ACCOUNTS
PRORATION OF SUPERVISION AND ENGINEERING ACCOUNTS
FOR COST ALLOCATION PURPOSES
FOR THE 12 MONTHS ENDED SEPTEMBER 30, 1994
(\$000)

ACCOUNT	CATEGORY	TOTAL	LABOR	MATERIAL	ACCOUNT 590 PRORATION
591	SUBSTATION	\$204	\$93	\$111	\$27
592	SUBSTATION	5,702	3,124	2,577	921
593	OVERHEAD LINES	28,508	7,943	20,565	2,341
5935	OVERHEAD SERVICE	2,833	1,696	1,137	500
594	UNDERGROUND LINES	1,363	798	565	235
5943	UNDERGROUND SERVICES	60	42	17	13
5946	UNDERGROUND SERVICE - OTHER	1,193	651	541	192
595	LINE TRANSFORMERS	4,032	2,063	1,969	608
596	STREET LIGHTING	1,585	557	1,028	164
597	METERS	2,881	1,602	1,278	472
598	STREET LIGHTING	414	178	236	52
TOTAL		\$48,774	\$18,748	\$30,026	\$5,525

PENNSYLVANIA POWER & LIGHT COMPANY
SUBFUNCTIONALIZATION OF DISTRIBUTION EXPENSE ACCOUNTS
BASED ON % OF ACCOUNT TOTAL
FOR COST ALLOCATION PURPOSES
FOR THE 12 MONTHS ENDED SEPTEMBER 30, 1994

	DESCRIPTION	520	521	522	523	524	525	526	527	528	529
Substation	Step Up	0.35	0.36	1.88							
	138 KV	0.44	0.46	2.38							
	69 KV	3.63	3.79	19.74							
	Primary	13.70	14.30	74.44							
	Secondary	0.29	0.30	1.56							
	Subtotal	18.40	19.22	100.00							
Overhead Lines	138 KV	0.14	1.07		1.60						
	69 KV	2.01	15.75		23.53						
	Primary	1.79	13.98		20.88						
	Sec. DMD	1.98	15.45		23.08						
	Sec. CUST	2.42	18.94		28.28						
	Street LT	0.23	1.76		2.63						
	Subtotal	8.56	66.95		100.00						
Underground Lines	138 KV	0.03	0.11			0.80					
	69 KV	0.12	0.44			3.16					
	Primary	0.53	1.89			13.65					
	Sec. DMD	1.19	4.27			30.87					
	Sec. CUST	1.99	7.12			51.52					
	Subtotal	3.86	13.83			100.00					
Miscellaneous	Misc. Exp.	20.30								100.00	100.00
	Subtotal	20.30								100.00	100.00
Meters	Meters	31.85						100.00			
	Subtotal	31.85						100.00			
Street Lighting	Street LT	1.10					100.00				
	Subtotal	1.10					100.00				
Customer Installations	Cust. Inst.	15.94							100.00		
	Subtotal	15.94							100.00		
Account Total		100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00

PENNSYLVANIA POWER & LIGHT COMPANY
SUBFUNCTIONALIZATION OF DISTRIBUTION EXPENSE ACCOUNTS
BASED ON % OF ACCOUNT TOTAL
FOR COST ALLOCATION PURPOSES
FOR THE 12 MONTHS ENDED SEPTEMBER 30, 1994

CATEGORY	DESCRIPTION	590	591	592	593	594	595	596	597	598
Substation	Step Up	0.32	1.88	1.88						
	138 KV	0.41	2.38	2.38						
	69 KV	3.39	19.74	19.74						
	Primary	12.77	74.44	74.44						
	Secondary	0.27	1.56	1.56						
	Subtotal	17.16	100.00	100.00						
Overhead Lines	138 KV	0.68			1.45					
	69 KV	9.97			21.40					
	Primary	8.85			18.99					
	Sec. DMD	9.78			20.99					
	Sec. CUST	11.98			25.73					
	Street LT	1.12			2.40					
	Subtotal	42.37			90.96					
Underground Lines	138 KV	0.03				0.42				
	69 KV	0.13				1.65				
	Primary	0.58				7.11				
	Sec. DMD	1.31				16.09				
	Sec. CUST	2.19				26.85				
	Subtotal	4.25				52.11				
Services	Sec. DMD	1.08			0.77	4.06				
	Sec. CUST	11.67			8.27	43.83				
	Subtotal	12.75			9.04	47.89				
Line Transformers	Sec. DMD	4.79					43.55			
	Sec. CUST	6.21					56.45			
	Subtotal	11.00					100.00			
Meters	Meters	8.55							100.00	
	Subtotal	8.55								100.00
Street Lighting	Street LT	3.92						100.00		100.00
	Subtotal	3.92						100.00		100.00
Total		100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00

Allocation of Meter Investment

Meters (Account 370)

A Meter Investment study using data as of December 31, 1993, was conducted to estimate the metering cost per customer. The process included the following steps.

1. - Typical metering configurations were identified.
2. - The total material cost was calculated by using the current purchase price for each material item in the typical metering configuration. For items, such as single phase, 30A, 240V self-contained meters, where a large quantity is purchased from several vendors, a weighted average cost is calculated based on the number of units purchased from each vendor and each vendor's price. Stores Expense, which includes the cost of stocking and handling the materials, is added to the purchase price to obtain the total material cost. The current Stores Expense rate is about 14.5%.
3. - The total labor cost for each typical meter configuration is calculated using current labor costs. Labor costs include shop labor, overheads on shop labor, field labor, overheads on field labor, and vehicle use.
4. - The total cost for each typical meter configuration is the sum of the material and labor costs.
5. - The estimated meter investment for each rate schedule designation is calculated by multiplying the estimated meter cost per customer, based on the typical meter configuration, by the total number of customers.
6. - The Company's property records provide the historical cost data for the predominate typical metering configuration (Type A meters).
7. - The difference between the Meter Investment (Account 370) and the historical cost of Type A meters is prorated to the rate schedule designations based on the current estimated metering costs.

The current estimated metering investment by rate schedule using historical costs and prorated costs is summarized on the following tables.

**PENNSYLVANIA POWER & LIGHT COMPANY
 ALLOCATION OF METER COSTS
 FOR THE 12 MONTHS ENDED DECEMBER 31, 1993
 (\$000)**

RATE CLASS	METER TYPE	UNIT COST	CUSTOMERS	TOTAL COST
RS	A	\$41	1,045,280	\$42,856,480
	B	205	323	66,215
	C	164	404	66,256
	TOTAL RATE CLASS		1,046,007	42,988,951
RTS	C	164	13,683	2,244,012
	TOTAL RATE CLASS		13,683	2,244,012
GS1	A	41	49,042	2,010,722
	B	205	87	17,835
	C	164	811	133,004
	D	123	68,771	8,458,833
	E	3,072	17	52,224
	TOTAL RATE CLASS		118,728	10,672,618
GS3	A	41	36	1,476
	F	634	15,992	10,138,928
	G	734	2,046	1,501,764
	H	1,336	77	102,872
	TOTAL RATE CLASS		18,151	11,745,040
LP4	I	3,200	826	2,643,200
	K	1,408	4	5,632
	TOTAL RATE CLASS		830	2,648,832
LP5	J	16,278	117	1,904,490
	TOTAL RATE CLASS		117	1,904,490
Standby	J	15,420	8	123,360
	TOTAL RATE CLASS		8	123,360
ISA	J	231,774	1	231,774
	TOTAL RATE CLASS		1	231,774
GH	E	3,072	3	9,216
	F	634	4,489	2,846,026
	G	734	134	98,356
	I	3,200	1	3,200
	TOTAL RATE CLASS		4,627	2,956,798
TOTAL METER COST			1,202,152	\$75,515,875

PENNSYLVANIA POWER & LIGHT COMPANY
ALLOCATION OF METER COSTS
METER PLANT INVESTMENT (GWI)
AS OF SEPTEMBER 30, 1994
(X000)

RATE CLASS	1993 TYPE A METER COST	1993 METER STUDY NON TYPE A METERS	PRORATED METER COST	1994 METER COST	1994 CUSTOMERS	AVERAGE COST
RS	\$39,393	\$132	\$165	\$39,558	1,049,213	\$38
RTS	0	2,244	2,798	2,798	14,059	199
GS1	1,848	8,662	10,801	12,649	119,249	106
GS3	1	11,744	14,644	14,645	18,566	789
LP4	0	2,649	3,303	3,303	832	3,970
LP5	0	1,904	2,374	2,374	119	19,950
Standby	0	123	153	153	9	17,000
ISA	0	232	289	289	1	289,000
GH	0	2,957	3,687	3,687	4,565	808
SL	0	0	0	0	993	0
TOTAL PPUC	41,242	30,648	38,215	79,457	1,207,606	0
RES66	99		0	99	9	0
RES12	48		0	48	9	0
TOTAL RESALE	147		0	147	18	0
UGI	0	0	0	0	1	0
TOTAL SYSTEM	\$41,389	\$30,648	\$38,215	\$79,604	1,207,625	\$0

Distribution Expense

Meter Reading Expense (Account 902)

The Meter Reading expense account has the following two subaccounts:

- 902.4 - Large Power Meter Reading Expense
- 902.5 - Other Meter Reading Expense

Subaccount 902.4 records the expenses associated with extracting load profile data for large power customers and other customers. The expense is prorated to the specific rate classes on the basis of the number of load profile customers in each rate class.

Subaccount 902.5 is prorated to specific rate classes based on the number of remaining customers in each rate class.

A summary of the proration is provided on the following table.

PENNSYLVANIA POWER & LIGHT COMPANY
ALLOCATION OF METER COSTS
METER READING EXPENSE (CW2)
FOR THE 12 MONTHS ENDED SEPTEMBER 30, 1994
(1000)

RATE CLASS	LARGE POWER CUSTOMERS		OTHER CUSTOMERS		TOTALS		AVERAGE
	CUSTOMERS	PRORATED EXPENSE	CUSTOMERS	PRORATED EXPENSE	CUSTOMERS	METER READING EXPENSE	METER READING EXPENSE
RS	444	\$65	1,048,769	\$7,418	1,049,213	\$7,483	\$7
RTS	145	21	13,914	98	14,059	119	8
GS1	550	81	118,699	840	119,249	921	8
GS3	619	91	17,947	127	18,566	218	12
LP4	546	81	286	2	832	83	100
LP5	119	18	0	0	119	18	151
Standby	9	1	0	0	9	1	111
ISA	1	0	0	0	1	0	0
QH	343	51	4,222	30	4,565	81	18
SL	983	0	10	0	993	0	0
TOTAL PPUC	3,760	409	1,203,847	8,515	1,207,607	8,924	0
R resale-66 KV	9	1	0	0	9	1	0
R resale-12 KV	9	1	0	0	9	1	0
TOTAL RESALE	18	2	0	0	18	2	222
TOTAL SYSTEM	3,778	\$411	1,203,847	\$8,515	1,207,625	\$8,926	\$0

Direct Testimony

Volume 1

Statements 1-8

Docket No. R-00973954

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Pennsylvania Power & Light Company
Docket No. R-00973954
Index of Direct Testimony

<u>Company Witness</u>	<u>Nature of Testimony</u>	<u>Statement</u>	<u>Exhibits</u>
Joseph P. Kalt	<ul style="list-style-type: none"> • Policy overview • Discussion of changes in the industry • Appropriateness of PP&L's proposals 	1	JPK 1
Ronald E. Hill	<ul style="list-style-type: none"> • Financial overview • PP&L's mitigation initiatives • PP&L's future financial outlook • Stranded cost securitization 		-
Joseph M. Kleha	<ul style="list-style-type: none"> • Cost allocation study • Jurisdictional and class allocations • Ratemaking adjustments to base year data • ECR roll-in • Recovery of nuclear decommissioning costs • CTC reconciliation 	3	JMK 1-3
Michael J. Berish	<ul style="list-style-type: none"> • Accounting overview • Ratemaking adjustments to base year data 	4	-
Donald S. Hoch	<ul style="list-style-type: none"> • Depreciation overview • Transfer of T&D depreciation reserve to generation depreciation reserve 	5	-

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<u>Company Witness</u>	<u>Nature of Testimony</u>	<u>Statement</u>	<u>Exhibits</u>
Paul R. Moul	<ul style="list-style-type: none"> • Cost of common equity at 12/31/96 • Future trends in cost of common equity 	6	PRM 1-3
Scott T. Jones	<ul style="list-style-type: none"> • Market clearing price of generation • Estimate of market revenues 	7	STJ 1-8
Joseph R. Schadt	<ul style="list-style-type: none"> • Model for calculating stranded costs • Calculation of stranded costs 	8	JRS 1
Susan F. Tierney	<ul style="list-style-type: none"> • Theory of traditional rate design • Theory of optional rate design • Design of CTC • Application of the rate cap • Rate comparisons 	9	SFT 1-12
Douglas A. Krall	<ul style="list-style-type: none"> • Development of traditional rate design • Development of optional rate design • Calculation of the rate cap 	10	DAK 1
Oliver G. Kasper	<ul style="list-style-type: none"> • Tariff provisions • Treatment of EDI/IDI, demand-free days, interruptible rate and CRR • Retail transmission rate schedule 	11	OGK 1-5
William H. Whitehead	<ul style="list-style-type: none"> • Status of PJM reorganization • Retail transmission tariff • Federal/state jurisdictional split 	12	WHW 1-3

<u>Company Witness</u>	<u>Nature of Testimony</u>	<u>Statement</u>	<u>Exhibits</u>
Robert M. Geneczko	<ul style="list-style-type: none"> • Functional separations • Proposed fire walls • Proposed code of conduct • Application of Order 888/889 	13	RMG 1-3
Henry W. Baumann	<ul style="list-style-type: none"> • Retail access pilot program • Retail access - customer rules • Retail access - supplier rules 	14	-
Bernard J. Bujnowski	<ul style="list-style-type: none"> • Customer metering • Customer billing • Account collections • Upgrade of PP&L's customer accounting system 	15	BJB 1
Timothy R. Dahl	<ul style="list-style-type: none"> • Public purpose programs 	16	-
Dawn G. Lennon	<ul style="list-style-type: none"> • Consumer education program 	17	-

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Docket No. R-00973954

PENNSYLVANIA POWER & LIGHT COMPANY

Statement No. 1

Direct Testimony of Joseph P. Kalt, Ph.D.

I INTRODUCTION: OVERVIEW AND WITNESS QUALIFICATIONS

I.A Qualifications

1 Q. Please state your name and business address.

2 A. I am Joseph P. Kalt. My business address is The Economics Resource
3 Group, Inc., One Mifflin Place, Cambridge, MA 02138.

4 Q. What is your professional and educational background?

5 A. I am the Ford Foundation Professor of International Political Economy and
6 the Chairman of the Economics and Quantitative Methods Section at the
7 John F. Kennedy School of Government, Harvard University. I have also
8 been the Academic Dean for Research, Faculty Chair of the Kennedy
9 School's Environment and Natural Resources Program, Chairman of Degree
10 Programs, and Chairman of Ph.D. Programs. I specialize in natural
11 resources and energy policy, and have published widely on matters relating
12 to the regulation of natural gas, electricity, oil, and coal markets. I have
13 testified in numerous administrative, judicial, and Congressional proceedings
14 concerning the performance of the nation's energy markets.

1 I received the Master's (1977) and Ph.D. (1980) degrees in economics
2 from the University of California, Los Angeles, and an undergraduate degree in
3 economics from Stanford University (1973). I joined the faculty at Harvard in
4 1978, and served as Instructor, Assistant Professor, and Associate Professor in
5 the Department of Economics before becoming a Professor in the Kennedy
6 School of Government in 1986. During my years at Harvard I have had
7 responsibility for the teaching of graduate courses in antitrust and regulation,
8 microeconomics, and environment and natural resource policy, among others. I
9 have received research grants from the National Science Foundation, the Ford
10 Foundation, the Northwest Area Foundation, the IRIS Fund, and many other
11 sources. A detailed description of my qualifications, research publications, and
12 related background is provided in Exhibit JPK-1.

I.B Overview of Testimony

13 Q. Please describe the purpose of your testimony.

14 A. I have been asked by Pennsylvania Power & Light Company (the "Company"
15 or "PP&L") to articulate the conditions necessary to restructure the electric
16 power industry consistent with sound economic principles and public policy
17 objectives and to evaluate whether or not the Company's filing is consistent
18 with these principles. The transition to a restructured electricity industry
19 offers the potential for improvement in the efficiency of the industry and the

1 value that it delivers to customers. To realize this potential, however,
2 restructuring proposals need to have four key ingredients: proper treatment
3 of stranded costs, efficient rate design, even-handed rules for competition
4 and open access, and appropriate ratepayer protection. I address each of
5 these key ingredients in turn after reviewing the economic and public policy
6 principles that should be applied to electric industry restructuring.

II ECONOMIC AND PUBLIC POLICY PRINCIPLES IN ELECTRICITY RESTRUCTURING

II.A The Setting

7 Q. Professor Kalt, please describe the economic and regulatory setting that
8 currently exists with regards to restructuring the electric power industry.

9 A. Over the last several decades, a wave of deregulation and increased
10 competition has swept regulated industries, including telecommunications,
11 natural gas, railroads, banking, airlines, stock brokerage and trucking;
12 privatization and decreased regulation have also spread through many
13 industries, including electric utilities, in Great Britain, New Zealand, Australia
14 and elsewhere. This trend is consistent with what economic principles and
15 practical experience confirm: competition is a powerful force in promoting the
16 public's interest in a healthy, efficient economy. In some industries, however,

1 economies of scale¹ and/or economies of scope² can create conditions of
2 what economists call "natural monopoly." In industries characterized by
3 natural monopoly, a single firm or a small number of firms can produce the
4 entire industry output at lower cost than if that same output were divided up
5 among many firms. Unless an affected market is rendered "contestable" by
6 the ability of firms to enter and exit freely as the prospect of above-
7 competitive pricing waxes and wanes, robust competition is not feasible in
8 industries characterized by natural monopoly. In the U.S. at least, the classic
9 response to problems of natural monopoly in private markets has been to
10 regulate firms in such markets as public utilities.

11 In the past, the U.S. electric power industry, in virtually all its stages from
12 generation through transmission and down to retail distribution, has been
13 subjected to pervasive regulation under traditional public utility principles. In
14 fact, this regulatory model was little objected to for decades as real electricity
15 costs declined steadily and electricity consumption consistently grew faster than
16 the economy as a whole. Beginning in the 1970s, however, this relatively placid

¹ Economies of scale are said to exist when costs rise less than proportionately with the level of total production.

² Economies of scope are said to exist when it is less costly to produce multiple products, or serve multiple customers, with a single firm than it is to produce those products or serve those customers with multiple firms.

1 picture began to unravel. Rapidly accelerating inflation, combined with volatile
2 fuel prices and shortages of natural gas, created tremendous pressure on
3 electric rates and pushed utilities to abandon construction of natural gas and oil-
4 fired base-load generation in favor of coal and nuclear plants. In fulfillment of
5 franchise obligations to ensure sufficient capacity, and aware of the long lead
6 times necessary for the construction of nuclear plants, the regulatory process in
7 many jurisdictions operated to induce and require many utilities to initiate and
8 carry through large construction programs to create the additional capacity that
9 was anticipated to be needed in the 1980s and 1990s.

10 In many cases, however, events and circumstances (including
11 restrained growth, availability of substitutes, need for reliable service to meet
12 high peak load combined with the capital-intensive nature of the industry, and
13 energy conservation) have combined to leave utilities with excess capacity.
14 This excess capacity has resulted in a situation in which the price of electricity
15 that would occur in unregulated competitive markets would be below the
16 embedded, average cost of producing that power. Herein lies the policy
17 problem: Excess capacity in the electric power industry implies pressure toward
18 (and concomitant political support for) lower prices, but traditional principles of
19 public utility regulation have operated to insulate franchise utilities from
20 competitive pressures. Removal of that protection would effectively deny them

1 the opportunity to recover costs prudently incurred in the course of fulfilling their
2 obligations as publicly-regulated utilities.

3 In response to high costs, technological changes, successes in
4 deregulating other industries, low natural gas fuel prices, and international
5 competitive pressures, Federal legislation and regulatory policy are moving the
6 electricity industry towards a new structure. The basic outlines of this structure
7 are now clear: The generation sector of the industry is not generally naturally
8 monopolistic and is being opened to competition. Transmission and distribution
9 sectors, however, exhibit strong economies of single-firm operation and will likely
10 continue to be regulated. In order for power generators to compete to sell
11 electricity, Federal policy now requires transmission owners to provide access to
12 their transmission systems on the same terms and conditions (including access
13 to information) as those owners provide to their own vertically-integrated
14 generation and distribution operations.

15 It is in this context that the Pennsylvania legislature enacted the Electricity
16 Generation, Customer Choice and Competition Act (the "Act") to bring to
17 Pennsylvania the benefits of competition while addressing the proper regulatory
18 approach for the remaining natural monopoly elements of the electricity industry.
19 During the resulting transition to a new industry structure and policy, there are
20 many important issues and competing interests that regulators must contend with
21 to move successfully ahead. Customers want lower prices and protection from

1 changing prices, utilities want to recover their investments, and all citizens have
2 a stake in a healthy and efficient electricity industry. Given the heightened
3 importance of properly transitioning to and arriving at an improved industry and
4 regulatory structure, the present proceeding is not just another rate case in
5 Pennsylvania. Instead, this proceeding is a critical step in applying sound
6 economic and public policy principles to restructuring the electricity industry.

II.B Summary of Pennsylvania's Legislation

7 Q. Professor Kalt, what are the key public policy goals of the Act?

8 A. The Act states: "The transition to a competitive generation market shall be
9 orderly, protect electric system reliability, be fair to ratepayers and provide
10 the investors in Pennsylvania electric utilities with a fair opportunity to fully
11 recover the amount of transition or stranded costs that the commission
12 determines to be just and reasonable."³

13 Q. What specific policies does the Act adopt in order to achieve its objectives?

14 A. The Act contains a variety of policies that are designed to work hand in glove
15 to achieve its objectives. The Act provides for recovery of utilities' transition
16 or stranded, non-mitigable costs within nine years subject to a rate cap. It

³ Section 2804(14) of the Act.

1 also provides that there should be no inter- or intra-class cost shifting and
2 requires the use of a non-bypassable and competitively neutral access
3 charge as a stranded cost recovery mechanism. Consumers will have
4 unbundled rates so that they can choose their energy supplier directly.
5 Customer choice begins with a pilot program and then is phased in over
6 several years. Consumer programs and services, such as universal service
7 and energy conservation measures, will continue.

8 Q. Can you summarize the important findings of the Act?

9 A. The Act finds in part that: (1) competitive market forces are more effective
10 than economic regulation in controlling the cost of generating electricity; (2)
11 the Commonwealth must begin the transition from regulation to greater
12 competition in the electricity generation market to benefit all classes of
13 customers and to protect the Commonwealth's ability to compete in the
14 national and international marketplace; (3) in moving toward greater
15 competition in the electricity generation market, the Commonwealth must
16 resolve certain transitional issues in a manner that is fair to customers,
17 electric utilities, investors, the employees of electric utilities, local
18 communities, nonutility generators of electricity and other affected parties;

1 and (4) electric service should be available to all customers on reasonable
2 terms and conditions.⁴

II.C Sound Economic and Public Policy Principles that Apply to Electricity Restructuring

3 Q. Professor Kalt, please describe the economic and public policy principles
4 that should be applied to electricity restructuring.

5 A. The findings and policies of the Pennsylvania Legislature provide a sound
6 framework for restructuring. A restructured electricity industry offers the
7 potential for improvement in the efficiency of the industry and the value that it
8 delivers to customers. To realize this potential, however, restructuring will
9 have to be implemented so as to foster efficient competition within a
10 framework defined by a set of key policy principles that are consistent with
11 the Act. These principles lie in four primary areas of policy concern:

12 **Stranded Investment**

- 13 • Provide the opportunity for utilities to recover the above-market
14 portion of cost obligations that have been incurred in fulfillment
15 of responsibilities stemming from *ex ante* pre-reform public
16 utility policy and law.

⁴ Sections 2802(5) and (7-9) of the Act.

1

Rate Design

2

3

4

5

- Create a non-bypassable access charge for retail consumers in order to provide a mechanism for recovery of the costs of over-market generation and regulatory assets while ensuring no distortion to competitive market access;

6

7

8

- Move towards more efficient, market-driven pricing of electricity, and encourage development of a wider variety of products and services than currently exists;

9

Competition and Access Rules

10

11

- Rely on market forces to establish the price, mix and performance characteristics of power production and capacity;

12

13

14

15

- Make transmission and distribution services available on an unbundled basis and under comparable rates, terms and conditions to both utility-affiliated and independent suppliers and marketers of electric power and related services;

16

17

18

- Use appropriate self-dealing rules to govern the relationships between transmission/distribution entities and affiliated companies that compete for electricity sales;

19

Ratepayer Benefits and Protection

20

21

- Provide for ratepayer access to benefits from supplier-expanding competition and related regulatory reform;

22

23

24

- Ensure ratepayer protection from the burden of rising rates for regulated services during the period of transition to competition and recovery of stranded costs;

25

26

- Maintain guarantees of consumer access to electric power service and related consumer protection;

27

- Maintain safe and reliable electric service for all consumers.

III TREATMENT OF STRANDED COSTS

1 Q. Professor Kalt, what is the major financial implication of changing the
2 regulatory structure of the electric power industry?

3 A. The introduction of competition into the electric utility sector constitutes a
4 fundamental change in public policy. It is now widely recognized that this
5 change creates a problem of "stranded" costs—costs that were incurred by
6 utilities playing by the then-existing rules of the game, but that cannot be
7 recovered at market prices.

8 Despite semantic and legalistic arguments to the contrary, it has been
9 recognized at the highest levels of economic and public policy-making that
10 there exists a "regulatory compact" that has historically governed the
11 relationship between regulated utilities and the government; and that this
12 compact appropriately requires that regulatory reform not take away the
13 reasonable prospect for recovery of costs that utilities incurred pursuant to
14 their obligations under the regulatory regime in place at the time of their key
15 cost-creating decisions.⁵ In the pre-reform regulatory setting, utilities and the
16 investors who provide utility capital accepted an obligation to serve all
17 electric demand in their service territory. Pursuant to this obligation to serve,

⁵ This principle has been recognized by, among others, the President's Council of Economic Advisers. Economic Report of the President, February 1996, Ch. 6.

1 utilities accepted the obligation to incur the costs of sufficient generation and
2 related capacity to ensure that expected demand could be satisfied, with
3 these investment plans being subject to review and oversight by regulators
4 and with their decisions reflected in the just and reasonable rates regulators
5 have allowed utilities to charge their customers. Investors in utility
6 companies agreed to provide the capital necessary to make these
7 investments under regulatory rules that subjected cost recovery to cost-of-
8 service regulatory principles rather than market forces.

9 Of course, in a period of excess capacity and increased ability to
10 "shop around" for power supplies, it is understandable that self-interested
11 parties would desire to avoid paying for costs that have turned out to be
12 above market prices. But it is disingenuous to assert that the pre-reform
13 regulatory regime did not constitute a laying down of the rules of the game by
14 the public sector. The rules of the game told private investors that the
15 general rule and expectation was that costs incurred would be recoverable
16 under cost-of-service principles; they did not tell investors "costs will be
17 recoverable if competition allows them to be." Indeed, assertions that the
18 public sector was not party to a regulatory compact upon which investors
19 relied when they incurred costs is belied by the incontrovertible observation
20 that the regulatory reform now underway in Pennsylvania and elsewhere
21 represents a fundamental change in the rules of the game. In fact, the

1 reforms underway are *fundamental* in precisely the way implied by the issue
2 of stranded costs: We are moving to a regulatory regime in which substantial
3 segments of the industry will no longer be subjected to cost-of-service
4 regulation. Instead, recovery of costs incurred now and in the future will be
5 subjected to the test of competitive viability. If the rules of the game were not
6 being changed in this fundamental way, legislatures would not have to act
7 and principled regulators would not have to preside over proceedings as
8 extensive and far-reaching as these.

9 Q. But, couldn't it be argued that investors had no guarantee that the rules of
10 the game wouldn't change, and they could anticipate fundamental change?

11 A. This kind of argument does not alter the conclusions that Pennsylvania's
12 reforms represent fundamental change, and that failure to provide for
13 recovery of stranded costs would constitute a breach of the reasonable
14 expectations of utility shareholders and employees developed over decades
15 of governmental involvement in their decisions. Government is the
16 promulgator and enforcer of the rules of the game. If it uses its power to alter
17 those rules after other parties have sunk investments into the game, such
18 action imposes costs on all of the citizens under its jurisdiction. As
19 underdeveloped and unstable countries around the world have taught us,
20 instability in the rules of the game by which investors must play is the recipe

1 for failure. In a world of intense international competition and capital that can
2 flee from policy instability, regulatory change in Pennsylvania's electric power
3 sector that would have the effect of stranding utilities' previously incurred
4 costs would be decidedly contrary to the public's interest in a healthy
5 Pennsylvania economy. One immediate consequence of policy instability
6 would be a higher cost of capital for firms investing in Pennsylvania,
7 particularly transmission and distribution utilities.

8 Q. Does the Act properly address and define stranded costs?

9 A. Yes. In addressing the competing interests referred to above and in
10 establishing a process for the transition to a competitive generation market,
11 the Act properly allows for the recovery of "transition or stranded costs." It
12 defines these costs as "an electric utility's known and measurable net electric
13 generation-related costs, determined on a net present value basis over the
14 life of the asset or liability as part of its restructuring plan, which traditionally
15 would be recoverable under a regulated environment but which may not be
16 recoverable in a competitive electric generation market and which the
17 commission determines will remain following mitigation by the electric utility."⁶
18 The Act acknowledges the long-term commitments that utilities were required

⁶ Section 2803 of the Act.

1 to undertake in order to fulfill their obligation to serve. The Act states:
2 "...public utilities generally have had an obligation to serve customers within
3 their defined service territories; consistent with that obligation, have
4 undertaken long-term investments in generation, transmission and
5 distribution facilities in order to meet the needs of their customers; and have
6 entered into long-term power supply agreements as required by Federal law.
7 In many instances, these investments and agreements have created costs
8 which may not be recoverable in a competitive market."⁷

9 Q. Professor Kalt, are you aware that some argue that there was no regulatory
10 compact?

11 A. Yes. These arguments are beside the point given the fact that the
12 Pennsylvania Legislature recognizes stranded costs.

13 Q. Are all stranded costs recoverable under the Act?

14 A. No. The Act provides for a transition period during which stranded costs can
15 be recovered. Any costs remaining after that time will not be recovered
16 through regulated rates. In addition, the Act imposes several rate caps,
17 which will limit the annual recovery of stranded costs. Moreover, if market
18 prices drop below the level anticipated when stranded costs were originally

⁷ Section 2802(15) of the Act.

1 estimated, thereby increasing stranded costs, the Act prevents the raising of
2 the competitive transition charge ("CTC") except under extreme
3 circumstances, and it directs that consumers see the benefit of the actual,
4 lower real prices. Alternatively, if market prices rise above the level that was
5 used to estimate stranded costs and to set the CTC, the Company may
6 charge no more than the generation-related rate cap. Thus, the recovery of
7 stranded costs is constrained both in time and in amount. This puts
8 shareholders at risk for otherwise recoverable investments that utilities made.

9 Q. What role should stranded cost mitigation play in stranded cost recovery?

10 A. Utilities should be required, as they are under the Act, to take appropriate
11 measures to reduce their costs as they prepare for competition. As Mr. Hill
12 describes, PP&L has taken many steps in the areas of refinancing, O&M cost
13 reductions, employee reductions, inventory reductions, power plant
14 operations, and economic development initiatives.

1 Q. How should stranded costs be calculated?

2 The first step in calculating stranded costs is to estimate the price of
3 electricity that would occur in a competitive market. Price in a competitive
4 market equilibrium equals the short-run marginal cost of the marginal
5 producer. The next step is to determine the revenues the utility would
6 receive based on the forecast of the market price of power. The net present
7 value of the difference between these revenues and the utility's known and
8 measurable net generation-related costs which traditionally would be
9 recoverable under a regulated environment and which will remain after
10 mitigation is the utility's stranded investment. PP&L employs this
11 methodology in this filing.⁸

IV RATE DESIGN

12 Q. Will the recovery of stranded costs distort competition?

13 A. If done properly, recovery of stranded costs can be accomplished without
14 distorting competition. In order to achieve a swift and orderly transition to a
15 restructured industry, the sunk costs of generation assets made uneconomic
16 by the transition, and the value of assets created by regulatory action, should

⁸ See the testimony of Dr. Jones and Mr. Schadt.

1 be recovered through a non-bypassable charge paid by all retail electricity
2 customers, regardless of supplier. By recovering stranded costs from all
3 users of the electricity system, this charge will permit restructuring to yield
4 competition based on the merits of each competitor. Since this charge is
5 paid by all parties using the transmission and distribution system, it permits
6 stranded cost recovery without tilting the competitive balance for or against
7 any party. The CTC as defined in the Act is a proper non-bypassable
8 charge, and is an important component of PP&L's rate proposal.⁹

9 Q. Are there other economic and public policy guidelines applicable to rate
10 design in a restructured electric power industry?

11 A. In the standard economic analysis of competition, consumers' ability to "shop
12 around" to find the best price for a particular product ensures that goods and
13 services will be produced efficiently. Producers enter a market based on
14 their expectations of making a profit, and high-cost, inefficient producers
15 cannot survive for long because they lose money at the prices charged by
16 efficient producers. Efficient producers, meanwhile, tend to see their
17 production levels and, hence, market shares rise. This process is at the
18 heart of the economic argument as to why competition is generally efficient.

⁹ Section 2803 of the Act. Also see the testimony of Dr. Tierney.

1 The situation "on the ground" in the electricity industry is not this
2 simple. *If* the prices charged by the existing utility suppliers of power
3 approximated their incremental resource cost, then allowing other firms to
4 compete for their customers would likely increase efficiency by the
5 mechanism described in the previous paragraph. Utility customers would
6 choose new suppliers only if those other suppliers offered a better deal. But
7 the suppliers could profitably offer a better deal only if their *costs* were lower
8 than the utilities' *prices*. Thus, *if* utilities' prices reflect their incremental
9 costs, consumers choosing the lower-*priced* alternative would also be
10 choosing the alternative that was lowest-*cost* in terms of society's
11 resources.¹⁰

12 Utility prices in Pennsylvania (and elsewhere) do not, however,
13 necessarily or even typically approximate their true going-forward economic
14 costs. There are a number of reasons for this situation: (1) Pennsylvania
15 utilities have incurred certain costs in pursuit of their obligation to serve and
16 under regulatory oversight which can only be recovered by charging prices
17 that exceed going-forward costs of supplying power; (2) many Pennsylvania
18 utilities are required to engage in public-policy activities such as mandatory
19 universal service programs that the competitive market would not necessarily

¹⁰ Broadman, H. and J. Kalt, "How Natural is Natural Monopoly? The Case of Bypass in Natural Gas Distribution Markets," Yale Journal of Regulation, Summer 1989.

1 support; and (3) electricity rates for many consumers in Pennsylvania are not
2 now structured to show marginal cost price signals.

3 In this situation, competition will be inefficient and *increase* overall
4 costs unless rate structures are carefully designed. An efficient rate structure
5 will have two key features: (1) a universal access charge that is paid by all
6 customers, regardless of their supplier, and that is designed to recover sunk
7 costs and the cost of regulatory and state-created obligations; and (2) a rate
8 structure in which new suppliers must compete against utilities' going-forward
9 "incremental" costs. I have already noted that the CTC satisfies the first of
10 these criteria.

11 With respect to the second criterion, only by forcing new entrants to
12 compete against utilities' incremental costs will regulators ensure that
13 competition lowers costs rather than raises them. The relevant concept of
14 cost for this purpose depends on market conditions. In the long run, prices
15 should reflect the "all-in" cost of electric generation, including the cost of
16 financing the capital investment. If, however, there is surplus generating
17 capacity (as is currently the case in the mid-Atlantic region and elsewhere),
18 then the true social cost of incremental electricity generation is currently only
19 the short-run "incremental cost" of that generation. That is, the short-run
20 incremental cost comprises the only resources that are used up, and hence
21 not available for other productive use, by utility generation of electricity. If

1 the utility does not generate electricity, society does not have the capital that
2 is sunk in utility generation facilities available for some other use. Efficiency
3 requires that new entrants be able to provide electricity at a price at or below
4 this short-run incremental cost. Otherwise, the entry of new firms into
5 generation will raise the overall social cost of delivering electricity to
6 Pennsylvania customers. The Act's proposed unbundling of electric energy
7 from transmission and distribution services will foster efficient competition
8 between utility generation and other power suppliers.

9 Q. What are other important features of PP&L's rate design proposal?

10 A. PP&L's proposal contains several other rate design features. As required by
11 the Act, the Company's rates are capped, which means customers will
12 experience an energy and capacity rate reduction in real terms for
13 approximately a decade (see further below). Moreover, once the transition
14 period is completed, PP&L cannot recover any of its stranded costs that
15 remain. In addition, residential customers will have the ability to choose an
16 alternative supplier and will be able to switch back to PP&L within a grace
17 period without any changes in their original rates. Finally, PP&L's proposed
18 rates will result in significant reductions in the marginal cost of electricity for
19 its customers. The Company's rate design reduces the kilowatt-hour charge
20 for incremental energy purchased. This change has important efficiency

1 implications. At the margin, customers under the new rate design will see
2 prices that better reflect the social cost of generating electricity. This
3 provides consumer benefits and permits them to make more efficient choices
4 in their personal and business purchases. It also reduces the risk associated
5 with the recovery of stranded costs.

V COMPETITION AND ACCESS RULES

6 Q. Professor Kalt, could you describe the steps that the Pennsylvania
7 Legislature has taken to provide consumers with access to competitive
8 energy suppliers and how these steps fit in with Federal policy?

9 A. Three necessary conditions for efficient competition among electricity
10 providers are that competitors must compete at incremental costs, consumers
11 must have the information necessary to make intelligent decisions regarding
12 who their supplier should be, and energy suppliers should have access to
13 transmission and distribution on comparable terms and conditions.

14 Q. Why is comparable access a necessary condition for effective competition?

15 A. There is a legitimate and important concern that exists regarding the
16 interaction between the regulated and unregulated portions of a utility's
17 business. The issue is: Can a utility leverage its transmission and

1 distribution assets to exclude in whole or in part non-affiliate wholesale and
2 retail generators and marketers?

3 In theory, there are two ways that control of transmission and
4 distribution assets could translate into market abuse in electricity markets.
5 First, if PP&L or its affiliates have superior access to these resources; or if
6 customers purchasing electricity from the company have superior access to
7 these delivery resources, then the company might be able to translate this
8 superior access into higher prices for electricity that other competitors cannot
9 discipline. Second, if the nature of regulation of prices for transmission and
10 distribution services were to operate in such a way that the Company could
11 use revenues from distribution and transmission to subsidize its competitive
12 electricity sales operations, then the Company would have an advantage in
13 these markets, and could charge prices lower than other competitors and
14 perhaps prevent their entry.

15 To prevent these abuses, it is appropriate for the Commission, along
16 with other regulators, to enforce functional separation of competitive
17 electricity marketing activities from the distribution and transmission activities
18 of the Company. If wholesale and retail electricity marketing are separated
19 from transmission and distribution, then it is possible to enforce comparability
20 of access to the transmission and distribution system. The wholesale and

1 retail marketing arms of the Company properly should be required to deal
2 with the transmission and distribution arms on the same bases that are
3 available to competing marketing entities. This means that goods, services,
4 or information that is provided by the regulated transmission/distribution
5 operation to generation or marketing entities should be provided under the
6 same rates, terms, conditions, and restrictions as are imposed on other
7 parties.

8 The issue of possible cross-subsidy arises from the continued cost-of-
9 service regulation of the distribution and transmission activities. Because the
10 distribution/transmission arm is entitled to recovery of its costs through
11 regulated distribution and transmission tariffs, a utility company that could
12 "disguise" some of its electricity marketing costs as distribution or
13 transmission costs could have the ability to impose those costs on
14 transmission/distribution customers (i.e., non-affiliate energy suppliers) that
15 compete with utility-affiliated unregulated activities, thereby giving affiliated
16 activities a step up on their third-party competitors. To prevent this, costs of
17 the transmission/distribution and marketing arms should be properly
18 allocated, and operational "firewalls" should exist between regulated and
19 unregulated activities. As I discuss below, PP&L has proposed precisely
20 such measures.

1 Q. What measures is PP&L taking to ensure comparability of access to its
2 transmission and distribution systems and to ensure against cross-subsidy?

3 A. First, the Company's implementation of a rate cap greatly mitigates any risk
4 of cross-subsidy. This is because cross-subsidy can derive from the ability of
5 the regulated entity to increase prices if its costs increase, allowing it to
6 "hide" marketing costs in increased distribution or transmission rates. The
7 rate cap detaches distribution and transmission rates from future changes in
8 costs, providing no means to increase distribution/transmission revenues to
9 cover losses from competitive activities. Rate caps are a mechanism for
10 ensuring functional separation. Second, the Company will make all of its
11 regulated activities available to qualified third parties on the same rates,
12 terms, conditions, and restrictions as those activities are made available to
13 any unregulated affiliate or activity of the Company. Third, the Company is
14 implementing organizational changes and instituting rules of conduct so that
15 firewalls are erected and comparability of access is assured.

16 Q. Professor Kalt, please describe the organizational structure and rules of
17 conduct that PP&L is implementing.

18 A. Starting with the Pennsylvania direct access pilot program, the Company is
19 organizing itself into two major business groups to segregate electric
20 generating supplier activities from electric delivery activities. This functional

1 separation will be governed by a code of conduct and accompanying
2 structural changes.

3 This code of conduct has eight primary components. First, the Electric
4 Delivery Group of PP&L will not share information that would give the
5 Generation Supply Group a competitive advantage. Information of this type
6 would include information regarding alternative supplier pricing and billing
7 information. Second, restrictions will exist to segregate employees and limit
8 their transfer between the two Groups. Third, accounting and cost allocation
9 procedures will be implemented so that charges for services between groups
10 are appropriately priced, and separate accounting books will be kept for each
11 group.

12 Fourth, the Delivery Group will not preferentially treat customers of its
13 affiliates over customers of competitive energy supplies, and it will provide all
14 of its services to all customers -- affiliated and unaffiliated alike -- at the same
15 prices and under the same terms and conditions. Fifth, the application of
16 tariffs and responses to requests will be done in a non-discriminatory
17 manner. Sixth, the Company will educate its employees as to these codes of
18 conduct; and seventh, it will conduct audits and implement procedural checks
19 and safeguards to enforce them. Finally, a dispute resolution process will be
20 established to record and resolve complaints pertaining to PP&L's code of
21 conduct and functional separation.

1 Q. Professor Kalt, have similar codes of conduct worked in other partially
2 regulated industries?

3 A. Yes. The interstate natural gas pipeline industry is a good example. Strict
4 codes of conduct between the competitive gas producing and marketing
5 affiliates and their regulated pipeline affiliates have worked well to prevent
6 abuses of the types that I have described above while allowing pipeline firms
7 to organize themselves in the ways they find most effective in meeting their
8 customers' needs. Meanwhile, unregulated services that utilize regulated
9 pipeline services have flourished and are overwhelmingly being provided by
10 unaffiliated third parties. Regulated pipelines have not been able to leverage
11 these third parties out of the way of affiliates.

12 Q. Dr. Kalt, is there a role for regulators in monitoring and enforcing functional
13 separation of the regulated and unregulated activities of utilities?

14 A. Yes. It is a proper function of regulators to monitor these relationships and
15 dealings, and to take appropriate actions as necessary to enforce functional
16 separation. By allowing utilities to compete in the unregulated energy
17 service markets, on comparable terms as other competitors, regulators can
18 further competition and efficiency by permitting eminently viable suppliers to
19 provide valuable services to Pennsylvania consumers. Regulators, however,
20 properly should take appropriate measures to ensure that open and equal

1 access occurs so as to ensure that viable non-utility competitors have the
2 opportunity to flourish as well.

3 Q. How does PP&L's rate design stack up to the Act's objective of having direct
4 access?

5 As described above, in order to have meaningful competition, competitors
6 must compete against the true incremental cost of producing electricity.

7 PP&L's unbundling and functional separation will put PP&L's electricity
8 generation into direct and efficient competition with other suppliers' power.

9 On the buyers' side of energy service markets, consumers must have the
10 information necessary to make comparisons between potential suppliers. To

11 do this, consumers must have unbundled bills. They must know how much
12 they are paying for energy and capacity, and how much they are paying for

13 transmission and distribution. PP&L will provide this information in
14 customers' bills, along with additional consumer information programs, so

15 that consumers have the knowledge and information needed to choose their
16 suppliers.

VI RATEPAYER BENEFITS AND PROTECTION

1 Q. Professor Kalt, please describe the ratepayer benefits that are likely to occur
2 under PP&L's plan.

3 A. Ratepayers stand to benefit from the Act and PP&L's proposal in four major
4 ways. First, in the near-term, consumers will see a rate reduction in real
5 terms due to the rate cap. Under the cap, the Company will have the
6 incentive to cut costs and operate efficiently, because if it does not, its profits
7 will suffer. Moreover, with the effects of inflation, the rate cap translates into
8 declining real prices for consumers. Second, the shifting of utility fixed costs
9 into access charges will result in reductions in the marginal rates paid by
10 customers. Their incremental costs of electricity will be substantially lower
11 than they otherwise would be, allowing consumers to respond to more
12 efficient price signals and to increase their consumption of electricity at the
13 margin when doing so is beneficial. Third, PP&L is proposing to expand its
14 low-income program, and other important customer programs and protections
15 will continue. PP&L will continue to stand as customers' supplier of last
16 resort. Finally, the overall balance of consumer and investor interests in the
17 Competition Act will permit PP&L to preserve a reliable and safe electric
18 power system.

1 We should not lose sight of the long-term goals and impact of
2 Pennsylvania's reforms. As competition expands, it is customers who will
3 benefit. By enabling unregulated suppliers to access PP&L's transmission
4 and distribution system, customers will benefit from access to competitively
5 priced electricity. By enabling customers to shop across competitive
6 suppliers and marketers, customers will be able to choose how to best meet
7 their needs, and competitors will try to outdo themselves in attracting
8 customers.

VII SUMMARY AND CONCLUSIONS

9 Q. Professor Kalt, please summarize your testimony.

10 A. By providing for a principled and balanced transition, Pennsylvania has
11 positioned itself to respond to the national and regional development of
12 competitive electricity markets, while avoiding potentially lengthy and large
13 transaction costs of protracted litigation and potential bankruptcies. The four
14 key ingredients in achieving the benefits of competition must be kept in mind.
15 Transition or stranded costs must be recovered in such a way as to not
16 distort competition. Rates must be designed so as to promote economic
17 efficiency while avoiding inter- and intra-class cost shifting. Competition
18 must be implemented in an even-handed manner, and ratepayers should

1 continue to have protection, particularly during the transition, from rising
2 prices. In mixing these ingredients properly, the Pennsylvania Public Utility
3 Commission will help shape the regulatory and industry structure so that
4 consumers will have the benefits of lower prices, a smooth transition to a fully
5 competitive electricity supplier market, and choice of their electricity supplier.

6 Q. Does this conclude your testimony?

7 A. Yes.

EXHIBIT JPK 1

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Proceedings of the Fourth Annual DOE-NARUC Natural Gas Conference, Orlando, FL, February 1995, Publication forthcoming.

Keynote Address, "Sovereignty and American Indian Economic Development," Arizona Town Hall, Grand Canyon, AZ, October 1994.

"Is the Movement Toward a Less-Regulated, More Competitive LDC Sector Inexorable?, (Re)Inventing State/Federal Partnerships: Policies for Optimal Gas Use," U.S. Department of Energy and The National Association of Regulatory Utility Commissioners Annual Conference, Nashville, TN, February 1994.

"Cultural Evolution and Constitutional Public Choice: Institutional Diversity and Economic Performance on American Indian Reservations," Festschrift in Honor of Armen A. Alchian, Western Economic Association, Vancouver, BC, July 1994.

"Precedent and Legal Argument in U.S. Trade Policy: Do they Matter to the Political Economy of the Lumber Dispute?" National Bureau of Economic Research, Conference on Political Economy of Trade Protection, February, September 1994.

"The Redesign of Rate Structures and Capacity Auctioning in the Natural Gas Pipeline Industry," Natural Gas Supply Association, Houston, TX, March 1988.

"Property Rights and American Indian Economic Development," Pacific Research Institute Conference, Alexandria, VA, May 1987.

"The Development of Private Property Markets in Wilderness Recreation: An Assessment of the Policy of Self-Determination by American Indians," Political Economy Research Center Conference, Big Sky, MT, December 4-7, 1985.

"Lessons from the U.S. Experience with Energy Price Regulation," International Association of Energy Economists Delegation to the People's Republic of China, Beijing and Shanghai, PRC, June 1985.

"The Impact of Domestic Regulation on the International Competitiveness of American Industry," Harvard/NEC Conference on International Competition, Ft. Lauderdale, FL, March 7-9, 1985.

"The Welfare and Competitive Effects of Natural Gas Pricing," American Economic Association Annual Meetings, December 1984.

"The Ideological Behavior of Legislators," Stanford University Conference on the Political Economy of Public Policy, March 1984.

"Principal-Agent Slack in the Theory of Bureaucratic Behavior," Columbia University Center for Law and Economic Studies, 1984.

"The Political Power of the Underground Coal Industry," FTC Conference on the Strategic Use of Regulation, March 1984.

"Decontrolling Natural Gas Prices: The Intertemporal Implications of Theory," International Association of Energy Economists Annual Meetings, Houston, TX, November 1981.

"The Role of Government and the Marketplace in the Production and Distribution of Energy," Brown University Symposium on Energy and Economics, March 1981.

"A Political Pressure Theory of Oil Pricing," Conference on New Strategies for Managing U.S. Oil Shortages, Yale University, November 1980.

"The Politics of Energy," Eastern Economic Association Annual Meetings, 1977.

WORKSHOPS PRESENTED

University of Indiana; University of Montana; Oglala Lakota College; University of New Mexico; Columbia University Law School; Department of Economics and John F. Kennedy School of Government, Harvard University; MIT; University of Chicago; Duke University; University of Rochester; Yale University; Virginia Polytechnic Institute; U.S. Federal Trade Commission; University of Texas; University of Arizona; Federal Reserve Bank of Dallas; U.S. Department of Justice; Rice University; Washington University; University of Michigan; University of Saskatchewan; Montana State University; UCLA; University of Maryland; National Bureau of Economic Research; University of Southern California

OTHER PROFESSIONAL ACTIVITIES

Chief Mediator *In the Matter of the White Mountain Apache Tribe v. United States Fish and Wildlife Service*, re: endangered species management authority, May-December, 1994

Steering Committee, National Park Service, 75th Anniversary Symposium, 1991-93

Board of Trustees, Foundation for American Communications, 1989 to present

Editorial Board, *Economic Inquiry*, 1988 to present

Advisory Committee, Oak Ridge National Laboratory, Energy Division, 1987 to 1989

Commissioner, President's Aviation Safety Commission, 1987-88

Principal Lecturer in the Program of Economics for Journalists, Foundation for American Communications, teaching economic principles to working journalists in the broadcast and print media, 1979 to present

Lecturer in the Economics Institute for Federal Administrative Law Judges, University of Miami School of Law, 1983 to 1991

Research Fellow, Energy and Environmental Policy Center, John F. Kennedy School of Government, Harvard University, 1981 to 1987

Editorial Board, MIT Press Series on *Regulation of Economic Activity*, 1984 to 1992

Research Advisory Committee, American Enterprise Institute, 1979 to 1985

Editor, *Quarterly Journal of Economics*, 1979 to 1984

Referee for *American Economic Review*, *Bell Journal of Economics*, *Economic Inquiry*, *Journal of Political Economy*, *Review of Economics and Statistics*, *Science Magazine*, *Journal of Policy Analysis and Management*, *Social Choice and Welfare*, *Quarterly Journal of Economics*, MIT Press, North-Holland Press, Harvard University Press, *American Indian Culture and Research Journal*

TEACHING EXPERIENCE

Introduction to Environment and Natural Resource Policy (Graduate, Kennedy School of Government); Seminar in Positive Political Economy (Graduate, Kennedy School of Government); Intermediate Microeconomics (Graduate, Kennedy School of Government); Natural Resources and Public Lands Policy (Graduate, Kennedy School of Government); Economics of Regulation and Antitrust (Graduate); Economics of Regulation (Undergraduate); Introduction to Energy and Environmental Policy (Graduate, Kennedy School of Government); Graduate Seminar in Industrial Organization and Regulation; Intermediate Microeconomics (Undergraduate); Principles of Economics (Undergraduate); Seminar in Energy and Environmental Policy (Graduate, Kennedy School of Government)

HONORS AND AWARDS

Allyn Young Prize for Excellence in the Teaching of the Principles of Economics, Harvard University, 1978-79
and 1979-80

Chancellor's Intern Fellowship in Economics, 9/73 to 7/78, one of two awarded in 1973, University of California, Los Angeles

Smith-Richardson Dissertation Fellowship in Political Economy, Foundation for Research in Economics and

Education, 6/77 to 9/77, UCLA

Summer Research Fellowship, UCLA Foundation, 6/76 to 9/76

Dissertation Fellowship, Hoover Institution, Stanford University, 9/77 to 6/78

Four years of undergraduate academic scholarships, 1969-1973; graduated with University Distinction and

Departmental Honors, Stanford University

Research funding sources have included: The National Science Foundation; USAID (IRIS Foundation); Pew Charitable Trust; Christian A. Johnson Family Endeavor; The Ford Foundation; The Northwest Area Foundation; the U.S. Department of Energy; the Research Center for Managerial Economics and Public Policy, UCLA Graduate School of Management; the MIT Energy Laboratory; Harvard's Energy and Environmental Policy Center; the Political Economy Research Center; the Center for Economic Policy Research, Stanford University; the Federal Trade Commission; and Resources for the Future

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Docket No. R-00973954

PENNSYLVANIA POWER & LIGHT COMPANY

Statement No. 2

Direct Testimony of Ronald E. Hill

1 Q. Please state your full name and business address.

2 A. Ronald E. Hill, Two North Ninth Street, Allentown, Pennsylvania 18101.

3

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by Pennsylvania Power & Light Company ("PP&L" or the
6 "Company") as Senior Vice President - Financial.

7

8 Q. What are your responsibilities as Senior Vice President - Financial?

9 A. I am the Chief Financial Officer of the Company. The functional activities
10 under my supervision include the accounting, finance and treasury activi-
11 ties of the Company.

12

13 Q. What is your educational background?

14 A. I graduated in 1964 from Carnegie Mellon University with a Bachelor of
15 Science degree in Industrial Management. I received a Masters Degree in
16 Business Administration from Lehigh University in 1972 and also attended
17 Muhlenberg College taking several accounting courses. Additionally, I
18 have attended numerous seminars and special courses related to the
19 accounting and finance areas and also attended the Edison Electric Insti-
20 tute (EEI) Executive Leadership Program.

21

22 Q. How long have you been employed by PP&L and in what capacities?

1 A. I joined PP&L in 1964 as a graduate trainee. Following a two-year leave
2 for military service, I rejoined PP&L as a Systems Analyst and was named
3 Accountant in 1968. From 1968 through 1978, I served in various
4 accounting positions, working principally in the budgeting, financial plan-
5 ning and financial reporting areas. In 1979, I was appointed Manager -
6 Financial Reporting with responsibility for all internal and external financial
7 reporting activities. In 1987, I was appointed to the position of Vice Presi-
8 dent and Comptroller with responsibility for all accounting, financial report-
9 ing, tax and depreciation functions. On January 1, 1994, I was appointed
10 Senior Vice President - Financial, which is the position I now hold.

11

12 Q. Are you or have you been active in any industry organizations?

13 A. I am a past member and chairman of the EEI's Application of Accounting
14 Principles and Accounting Research Committees, and am currently a
15 member of the Finance Committee of EEI. I also am a member of the
16 Board of Directors of Nuclear Electric Insurance Ltd., a mutual insurance
17 company providing property and damage insurance for operators of
18 nuclear generating facilities.

19

20 Q. Do you belong to any professional organizations?

21 A. I am a member of the Financial Executives Institute and am also a member
22 of the Institute of Management Accountants.

1 Q. What is the purpose of your testimony in this proceeding?

2 A. My testimony first describes the past and future mitigation efforts under-
3 taken by PP&L which have reduced its stranded cost claim in this proceed-
4 ing. I also address the importance of reasonable stranded cost recovery in
5 this case on the future ability of PP&L to provide safe and reliable service
6 to its customers.

7

8 MITIGATION

9 Q. Why is mitigation an issue in this proceeding?

10 A. Under the Electricity Generation Customer Choice and Competition Act
11 ("Act"), the Pennsylvania Public Utility Commission (the "PUC" or
12 "Commission") is authorized "to determine the level of transition or
13 stranded cost for each electric utility and provide a mechanism, the com-
14 petitive transition charge, for recovery of an appropriate amount of such
15 cost in accordance with the standards established" by the Act. 66 Pa. C.S.
16 § 2802(15). Transition or stranded costs are defined as "an electric utility's
17 known and measurable net electric generation-related costs, determined
18 on a net present value basis over the life of the asset or liability as part of
19 its restructuring plan, which traditionally would be recoverable under a
20 regulated environment but which may not be recoverable in a competitive
21 generation market and which the Commission determines will remain fol-
22 lowing mitigation by the electric utility." 66 Pa. C.S. § 2803. In determin-

1 ing the appropriate amount of stranded cost recovery, the PUC is required
2 to "consider the extent to which the electric utility has undertaken efforts to
3 mitigate generation-related transition or stranded costs by appropriate
4 means in a manner that is reasonable under all of the circumstances, in-
5 cluding consideration of whether mitigation has been commensurate with
6 the magnitude of the electric utility's generation-related transition or
7 stranded costs." 66 Pa. C.S. § 2808(c)(4). In addition, and "of equal
8 importance," the Commission is directed to "consider efforts undertaken
9 over time, prior to the enactment of this Chapter to reduce or moderate
10 customer rate levels while maintaining safe and efficient operations." 66
11 Pa. C.S. § 2808(c)(5). The purpose of this section of my testimony is to
12 summarize PP&L's past and future mitigation efforts which have signifi-
13 cantly reduced its stranded cost claim in this proceeding.

14
15 Q. Please explain your understanding and use of the term "mitigation" in this
16 testimony.

17 A. I am using the term "mitigation" to describe any efforts by a utility to reduce
18 costs or increase revenues (other than by rate increases), both historically
19 and prospectively, and thereby reduce its stranded costs. Historic mitiga-
20 tion refers to past efforts to reduce costs and increase revenues. The
21 effect of these historic efforts is reflected in the level of a utility's current
22 rates and its corresponding level of stranded costs. Future mitigation

1 refers to prospective plans and efforts during the transition period to com-
2 petition and thereafter to reduce costs or increase revenues, which will
3 further reduce a utility's stranded cost claim.

4
5 Q. Under the Act, both future and historic mitigation efforts are to be given
6 equal consideration by the PUC. In your view, is this equal consideration
7 of past and future mitigation appropriate?

8 A. It is not only appropriate, it is essential to any fair evaluation of a utility's
9 claim for stranded cost recovery. Stranded cost, as defined in the Act, is
10 essentially a measure of the difference between a utility's regulated cost of
11 service and the market price for electricity. Those utilities who have been
12 successful in controlling costs in the past will have lower current rates and
13 correspondingly lower stranded costs. Conversely, those utilities with a
14 higher cost of service will have higher rates and higher stranded costs. It
15 is my belief that those utilities with high rates and high stranded costs
16 should have more opportunity to "mitigate" stranded costs through future
17 mitigation than utilities with lower costs and lower rates. Utilities with
18 higher costs and higher rates also may be able to offer rate reductions and
19 characterize these reductions as a "sharing" of stranded costs, even
20 though their rates remain relatively high even after the reduction. On the
21 other hand, utilities with lower costs and lower rates already have accom-
22 plished significant mitigation by controlling costs and have passed the

1 benefits of lower costs through to ratepayers by maintaining lower rates
2 over time. These past "mitigation" efforts must be considered and given
3 equal weight in order to fairly evaluate a utility's stranded cost claim.
4

5 Q. Please describe PP&L's past efforts to reduce costs and maintain reason-
6 able rates.

7 A. PP&L has an outstanding record of controlling costs and rates. Cost con-
8 trol and efficient management have been an integral part of the Company's
9 corporate culture for many years. Although it would be impossible to
10 provide an exhaustive list of these efforts, I have compiled some examples
11 of PP&L's efforts to control costs and maintain reasonable rates. These
12 efforts include refinancings, O&M cost reductions, reductions in planned
13 capital expenditures, employee reductions, inventory reductions, cost-
14 effective nuclear plant and fossil plant operations, reduced costs of NUG
15 contracts and economic development initiatives.
16

17 Q. Please describe the cost reductions obtained through refinancings.

18 A. Since 1985, the Company has aggressively sought to refinance higher
19 cost securities at lower rates. The Company's most recent base rate case
20 used a September 30, 1995 test year. The rate case prior to that was
21 based on a test year ended March 31, 1985. In that more than 10-year
22 period, the Company's cost of debt was reduced by approximately 30%,

1 from 11.27% (allowed in the 1985 case) to 7.97% (allowed in the 1995
 2 case). The cost of preferred/preference stock over the same period was
 3 reduced from 9.89% to 7.31%. These capital cost reductions reduced the
 4 Company's revenue requirement in its most recent base rate case by
 5 almost \$100 million.

6
 7 Q. Please describe PP&L's efforts to control O&M costs.

8 A. After the Susquehanna Unit 2 rate case was decided in 1985, the Com-
 9 pany undertook extensive efforts to avoid filing a base rate increase.

10 These efforts included aggressive cost containment measures, elimination
 11 of unnecessary functions, restructuring at the corporate level and a re-
 12 engineering of critical processes. Although it is not possible to measure
 13 directly the specific savings achieved by these efforts, it is instructive to
 14 compare PP&L's O&M production costs over time adjusted for inflation.

15 The following table shows PP&L's O&M production costs, excluding fuel,
 16 for 1986, 1986 adjusted for inflation and 1996.

	1986	1986	1996
	FERC	Adjusted	FERC
	<u>Form 1</u>	for	<u>Form 1</u>
		<u>Inflation</u>	
		(Millions \$)	
22 Steam Production	\$139.1	\$189.0	\$142.2
23 Nuclear Production	118.2	160.6	155.8
24 Hydraulic Production	6.1	8.3	6.3
25 Other Production	<u>1.8</u>	<u>2.4</u>	<u>2.7</u>
26	\$265.2	\$360.3	\$307.0

1 As this table shows, PP&L's O&M production costs have increased by only
2 16% from 1986 to 1996, and adjusted for inflation, have declined in real
3 terms, by 15%.

4
5 Q. Please describe PP&L's employee reductions.

6 A. The Company has undertaken a continuous effort over an extended period
7 of time to achieve cost reductions through more efficient utilization of
8 employees. For example, in 1994, in an effort to reduce costs and
9 improve operating efficiency, the Company offered an early retirement
10 program to 851 employees who would reach age 55 by December 31,
11 1994. A total of 604 employees elected early retirement under this pro-
12 gram. From the end of 1985 to the end of 1996, there has been an
13 employee reduction of 2,005 regular full-time employees, or almost 24% of
14 PP&L's 1985 workforce. Most of the reduction occurred through normal
15 attrition, the early retirement program, a voluntary severance program or
16 an equitable displacement policy.

17
18 Q. Please describe PP&L's inventory reduction efforts.

19 A. In 1991, the Company changed its method of accounting for spare parts at
20 its power plants. Spare parts were previously expensed at the time of pur-
21 chase. After the change, spare parts were recorded in an inventory bal-
22 ance sheet account. Although not required to do so, the Company

1 changed its ratemaking treatment of spare parts between base rate cases,
2 and passed back \$94 million to customers over a five-year period through
3 the Special Base Rate Credit Adjustment ("SBRCA"). Subsequent to this
4 change in accounting method, the Company also undertook a thorough
5 review to identify any obsolete or excess inventory. As a result of this
6 review, the Company wrote off approximately \$35 million of inventory.
7 This has further mitigated the Company's stranded costs.

8
9 Q. Please describe the Company's planned reduction in capital expenditures.

10 A. In late 1995, the Company announced plans to reduce planned capital
11 expenditures by \$671 million over a five-year period. Included in this
12 planned reduction was \$486 million of expenditures for fossil generating
13 plants. Reduced capital spending lessens the amount of the Company's
14 unrecovered investment in generating facilities, its associated revenue
15 requirements and, consequently, has mitigated the Company's stranded
16 costs.

17
18 Q. Please describe the Company's mitigation efforts for its nuclear power
19 plant.

20 A. A significant portion of the Company's stranded cost claim relates to the
21 Susquehanna Steam Electric Station ("Susquehanna"). The Company has

1 undertaken various measures that have resulted in a significant reduction
2 in stranded costs associated with this facility.

3 The Company's efforts began while the plant was under construc-
4 tion. As explained in prior rate proceedings, the Company initiated an
5 aggressive program to complete the Susquehanna plant as soon as pos-
6 sible, which significantly reduced its capital costs. As a result, the Com-
7 pany was able to construct two large nuclear units at a cost of about
8 \$3.6 billion for the Company's 90% ownership of 1,890 megawatts, or
9 \$1,900 per kilowatt. Other plants in Pennsylvania and around the United
10 States which were under construction at the same time were significantly
11 delayed in their construction and were completed at a significantly higher
12 cost.

13 After the completion of the Susquehanna plant, the Company pur-
14 sued certain claims against the containment supplier, General Electric. In
15 1991, the Company settled those claims. Because the cost of the plant
16 already had been included in rate base, the Company, between rate
17 cases, sought and obtained PUC approval to pass back to customers
18 through the SBRCA the PUC jurisdictional amount of the proceeds from
19 the settlement (\$55 million).

20 The Company also has undertaken significant efforts to ensure that
21 the Susquehanna plant operates with as high a capacity factor as possible.
22 Nuclear power plants have high capital costs, but very low fuel costs.

1 Thus, the more the plant operates, the more fuel savings are generated.
2 Susquehanna has had an outstanding operating record, and is recognized
3 by industry organizations and the investment community as an efficient,
4 well-run plant. This excellent operating record has reduced the Company's
5 energy costs and customers' rates significantly.

6 To further increase Susquehanna's generation, the Company spent
7 \$45 million between 1991 and 1995 to uprate Susquehanna's capacity by
8 90 mw, or a cost of \$500 per kw. This has produced significant additional
9 energy cost savings to customers.

10

11 Q. Please describe the Company's past mitigation efforts for its fossil generat-
12 ing plants.

13 A. The Company has undertaken significant expenditures to maintain the
14 availability of its low cost coal-fired generating stations and to extend their
15 useful lives. This has benefited customers through lower fuel costs,
16 increased interchange sales and lower rates. One specific recent example
17 is the project to convert the Martins Creek 3 and 4 units to gas/oil co-firing.
18 This project has permitted the Company to burn both gas and oil at this
19 plant, which has increased the cost effectiveness of this plant.

20

21 Q. Please describe the Company's efforts to mitigate NUG contract costs.

1 A. Under PURPA, the Company was compelled to enter into long-term supply
2 contracts with non-utility generators. Although the rates in these agree-
3 ments were based upon expected future market prices at the time the con-
4 tracts were signed, the contracts have turned out to be significantly above
5 the Company's avoided cost and current market prices. In an effort to
6 reduce the level of this stranded cost, the Company has undertaken sev-
7 eral actions.

8 In March 1988, the Company took steps to minimize future NUG
9 contracts by limiting its "Pioneer Rate," the rate paid to NUGs at that time.
10 The Pioneer Rate provided a flat 6¢ per kilowatt hour sale for all NUG out-
11 put. In 1988, the Company proposed to limit the availability of the rate to
12 project developers who contracted with the Company prior to March 1988
13 and who actually signed an agreement on or before January 1, 1990. The
14 Commission approved this proposal with minor modifications.

15 In 1995, PP&L agreed to a settlement of litigation before the Com-
16 mission which effectively renegotiated the Paxton Creek NUG contract.
17 The new agreement reduced the term of the power purchase agreement
18 from 15 to 7 years and effectively converted Paxton Creek from a base
19 load unit to a peaking unit.

20 In 1996, the Company bought out the contracts for the Continental
21 and Archbald NUGs. These facilities represent 118.5 mw or 25% of the
22 474 mw of large NUG units under contract to PP&L. The buy-out agree-

1 ments are structured to produce substantial savings as compared to the
2 level of projected future payments under the power purchase agreements.
3 The PUC approved the Continental buyout in January 1997. The Archbald
4 agreement currently is being reviewed by the Commission. The effect of
5 these agreements on stranded costs is discussed in the future mitigation
6 section of my testimony.

7 The Company also has conducted extensive audits of existing NUG
8 contracts to monitor compliance with terms and conditions of the contract.
9 As a result of these audits, legal action was initiated in one particular case
10 for noncompliance. If this litigation is successful, the Company's NUG
11 contract costs will be reduced by approximately \$10 million per year.

12
13 Q. Please describe the Company's economic development programs.

14 A. On the revenue side of the equation, the Company has made major
15 commitments to economic development in order to retain existing industry
16 and to attract new businesses to its service territory. These measures in-
17 clude interruptible service rates, Economic Development Initiative ("EDI")
18 credits, Industrial Development Initiative ("IDI") credits and Demand Free
19 Days. In addition, the Company has been involved nationally in prospect-
20 ing to attract new industries, has been involved in numerous cooperative
21 efforts with regional economic development organizations and has pro-
22 vided loans for economic development initiatives. These initiatives have

1 enhanced the Company's revenues, helped PP&L to avoid rate increases
2 and have helped generate thousands of new jobs in the Company's serv-
3 ice territory. Although increasing sales, the Company also has established
4 conservation, load management and demand-side management programs
5 designed to promote more efficient and cost-effective use of electricity by
6 its customers.

7

8 Q. What has been the net result of these past mitigation efforts?

9 A. The bottom line result is lower rates to customers and lower stranded
10 costs. Although it is not possible to quantify the precise savings achieved
11 through these past mitigation efforts, I believe it is instructive to place
12 PP&L's rates in perspective over time and to compare those rates to the
13 rates of other utilities.

14 PP&L's average rate in 1996 was 7.38¢/kWh which is only slightly
15 above the 1986 average rate of 7.34¢/kwh coming out of the Susque-
16 hanna 2 rate case in 1985. Thus, PP&L's rates have declined, in real
17 terms, by over 25% since 1986, as measured by the GDP Implicit Price
18 Deflator. Given the initial 54-month rate cap contained in the Act, this real
19 price decrease will likely continue. Assuming that rates today remain in
20 place through June 2001, and assuming 2.5% annual inflation, PP&L's
21 rates will have declined, in real terms, by approximately 34% since 1986.

22

1 Q. How do PP&L's rates compare to those of other electric utilities?

2 A. A detailed description of this subject is addressed in the testimony of
3 Dr. Susan Tierney. In summary, based on 1996 data, PP&L's rates were
4 approximately 7% below the Pennsylvania average.

5

6 Q. Why is the relative level of PP&L's rates important?

7 A. PP&L's rate levels are relevant for several reasons. Lower rates mean
8 lower stranded costs and demonstrate the Company's aggressive past
9 mitigation efforts. As explained above, these efforts should be fully con-
10 sidered in this proceeding in determining the level of stranded cost recov-
11 ery.

12 Further, PP&L's current rate levels demonstrate that PP&L has
13 been doing for years what the current proposal for competition is supposed
14 to spur high cost utilities to do -- cut costs, operate efficiently and pass
15 those savings on to customers.

16 Finally, a review of the restructuring activity in other states indicates
17 that these proposals often include requests or mandates for significant rate
18 reductions, i.e., 10% to 20%, as a condition for recovery of stranded costs.
19 As demonstrated in Dr. Tierney's testimony, the existing rate levels in
20 these states are significantly higher than PP&L's rates. Even with 10% to
21 20% rate reductions, the rates of those utilities would still be significantly
22 above PP&L's existing rates. PP&L has done an outstanding job of main-

1 taining reasonable rate levels for its customers through a combination of
2 aggressive efforts over an extended period of time. Those efforts should
3 be considered and given full credit in this proceeding.

4
5 Q. Has PP&L included the effects of any future mitigation efforts in its filing?

6 A. Yes. The Company has included additional cost reductions designed to
7 reduce further its stranded cost claim. In addition, the Company is propos-
8 ing a depreciation swap between generation and transmission/distribution
9 facilities.

10
11 Q. Please describe the projected cost reductions included in PP&L's claim.

12 A. As noted above, in late 1995, the Company announced plans to reduce
13 planned capital expenditures by \$671 million over a five-year period. The
14 associated reductions in revenue requirement reflected by this reduction
15 have been incorporated into the Company's stranded cost calculation.
16 The Company has projected approximately \$513 million of unspecified
17 reductions to future O&M and A&G costs. Similarly, the NUG buyouts
18 referenced above are not reflected in PP&L's current rates and reduce
19 stranded costs by \$100 million. The net savings from these proposals
20 have been removed from the Company's stranded cost claim, even though
21 these savings have not yet been achieved. In other words, the Company
22 and its shareholders will be at risk for achieving these savings.

1 Q. Please address the Company's proposal regarding reallocation of depre-
2 ciation reserves.

3 A. In its 1995 rate filing, the Company filed for and was granted the right to
4 extend the lives of its transmission and distribution plant. Had the Com-
5 pany used these longer lives when the transmission and distribution facili-
6 ties were originally placed into service, the accumulated depreciation for
7 these facilities would have been less than what is currently recorded on
8 the Company's books. The Company proposes to take the \$205 million
9 difference between the current actual accumulated depreciation and theo-
10 retical accumulated depreciation and transfer it to accumulated reserve for
11 depreciation associated with the Susquehanna plant. This exchange of
12 excess depreciation reserves reduces the net plant balance for Susque-
13 hanna by approximately \$205 million and reduces the Company's stranded
14 cost claim by \$317 million.

15 Q. What is the effect of these future mitigation efforts described above?

16 A. As explained in Mr. Schadt's testimony, the effect of the reduction in the
17 growth rate of operations and maintenance costs at the nuclear and fossil
18 generating plants and cost reductions in administrative and general activi-
19 ties, the two NUG buyouts, the reallocation of depreciation reserves, and a
20 reduction in planned capital expenditures is to reduce the Company's
21 stranded cost claim by over \$1 billion.

22

1 Q. Are there other mitigation efforts you wish to address at this time?

2 A. Yes. As explained in Mr. Schadt's testimony, the Company's net mitigated
3 stranded cost claim is \$ 4.611 billion. As explained in Mr. Krall's testi-
4 mony, by applying the CTC and rate cap provisions over the next nine
5 years, the Company anticipates collecting \$4.210 billion of its stranded
6 cost. The remaining \$401 million would not be collected from customers
7 and would be absorbed, all else equal, by the Company's shareholders.

8 In addition, I should emphasize that the Company's stranded cost
9 claim is based upon a projection of future market prices and assumes that
10 a significant portion of the utility stranded cost will be recovered by way of
11 increased market prices for electricity. This increase in market price may
12 or may not occur, thereby placing the Company at risk for significant non-
13 recovery of those stranded costs.

14

15 Q. Does the recovery of stranded costs under the CTC give the Company the
16 opportunity to mitigate its exposure to an accounting write-off?

17 A. Yes. As explained in Mr. Krall's testimony, the Company is proposing to
18 hold rates at December 31, 1996 levels except for the SBRCA. As part of
19 its Restructuring Plan and CTC recovery, the Company is requesting PUC
20 approval to accelerate the amortization of regulatory assets and post-
21 transition NUG costs in amounts to offset the scheduled reduction in
22 Susquehanna depreciation in 1999, the end of the amortization of the

1 costs of the voluntary early retirement program and the buyout of NUG
2 contracts.

3
4 Q. Mr. Hill, one of the examples of mitigation listed in the Act is the securitiza-
5 tion of stranded costs. Is the Company proposing to securitize any portion
6 of its stranded cost?

7 A. The Company is considering securitizing some portion of its stranded cost.
8 However, the Company has not included an application for a qualified rate
9 order as part of its restructuring filing in this proceeding. This should not
10 be viewed as an indication that the Company is opposed to securitization
11 or that the Company will not securitize a portion of its stranded cost and
12 use that as a mechanism to reduce customer's rates to even lower levels.

13
14 Q. Why did the Company not include a request for securitization as part of its
15 restructuring filing?

16 A. The current filing is a Restructuring Plan designed to unbundle the Com-
17 pany's rates, establish the terms and conditions for a competitive market
18 and the Company's role in that market, set forth an estimate of the Com-
19 pany's stranded costs and a calculation of a competitive transition charge
20 to recover those costs. The Company has not included a request for
21 securitization at this time for several reasons. First, there is tremendous
22 uncertainty at this time as to when and if the Company will be allowed to

1 securitize stranded costs. The current PECO securitization proceeding
2 has been highly contentious and based upon the Company's participation
3 in that proceeding, it appears likely that the Commission's decision may be
4 appealed by one or more parties. This would significantly delay the actual
5 issuance of any transition bonds.

6 Second, there are several unresolved issues regarding tax matters,
7 structure and accounting issues that require further review. It is apparent
8 that securitization requires much more analysis than originally contem-
9 plated. Rather than rushing to include securitization in its restructuring fil-
10 ing, PP&L has elected to attempt to resolve these issues and to present a
11 more definitive proposal to the Commission.

12 Third, the restructuring filing is itself complex and raises many
13 important and novel issues. Given this likelihood of substantial delay, the
14 Company decided not to needlessly complicate its restructuring filing with
15 a securitization proposal at this time. The Company supports securitiza-
16 tion, will continue to monitor the timing issues, and will advise the Com-
17 mission as soon as its plans regarding securitization are more formalized.

18
19 FINANCIAL IMPORTANCE OF STRANDED COST RECOVERY

20 Q. Please describe the principles you believe should be applied in consider-
21 ing PP&L's stranded costs claim.

1 A. Stranded cost recovery will undoubtedly be a significant and controversial
2 issue in this proceeding. The economic and policy reasons supporting
3 stranded cost recovery are discussed in Dr. Kalt's testimony. In consider-
4 ing this issue, however, I feel that it is important for the Commission to
5 keep in mind several important financial points.

6 First, the cost of the Company's generating facilities, including the
7 generation-related portion of regulatory assets, was incurred as part of the
8 Company's statutory obligation to provide reliable service to the Com-
9 pany's customers. The Company was required by federal law to enter into
10 its current NUG contracts. The Commission has repeatedly reviewed the
11 Company's base rates, and has included the cost of the Company's gen-
12 erating facilities in rate base and has approved recovery of regulatory
13 assets. The Commission reviewed and approved recovery of NUG costs
14 through the Company's ECR. The generating plants were built based
15 upon the reasonable expectation that the Company would be provided with
16 a fair opportunity to recover these costs in its rates. The NUG contracts
17 were expressly conditioned upon a Commission Order that the Company
18 would receive full and current recovery of these costs through its ECR or
19 future equivalent. In my opinion, it would be fundamentally unfair and
20 unreasonable to disallow recovery of prudent and reasonably incurred
21 stranded costs. The Act appropriately recognizes this and provides an
22 opportunity for reasonable stranded cost recovery.

1 Second, the amount of stranded cost recovery permitted in this
2 case will have a significant impact on the Company's overall financial
3 condition. While the Act calls for an "unbundling" of the generation,
4 transmission and distribution functions, PP&L will continue to be the
5 transmission and distribution provider to its existing customers and will be
6 the generation supplier of last resort to its customers who do not elect to
7 purchase their electricity from alternative suppliers. In order for PP&L to
8 fulfill these obligations, it must have reasonable financial health that will
9 allow it to attract capital on fair and reasonable terms. This is essential for
10 PP&L to make ongoing investments necessary to serve its customers
11 safely and reliably as the transmission and distribution supplier and to
12 secure reasonable cost generation supplies for those customers as to
13 whom PP&L remains the supplier of last resort.

14 Third, the Commission should carefully consider PP&L's extensive
15 past and future efforts to mitigate stranded costs. These efforts, which are
16 explained in detail above, have significantly reduced PP&L's stranded
17 costs and demonstrate PP&L's commitment to a reasonable sharing of
18 stranded costs. As noted above, PP&L's past mitigation efforts have pro-
19 duced rates which are below the Pennsylvania average. This demon-
20 strates PP&L's efforts to control costs and produce reasonable rates for its
21 customers. PP&L's future mitigation plans, which have reduced its

1 stranded cost claim by over \$1 billion, further demonstrate its continued
2 commitment to its customers.

3 Fourth, even if the Company's claim is approved, it still faces sub-
4 stantial risks and uncertainties. Under the rate caps imposed by the stat-
5 ute and the projections in this case, PP&L will fail to recover approximately
6 \$401 million of its net mitigated stranded costs.

7 Finally, the net result of stranded cost recovery in this case will be to
8 permit PP&L to continue to charge rates equal to the rate caps imposed by
9 the Act for the next nine years. Even under current low rates of inflation
10 over the next nine years, PP&L's customers will likely see significantly
11 declining rates in real terms under the Company's proposal. Increases in
12 the cost of capital, O&M costs and capital additions in excess of those pro-
13 jected by the Company will largely be borne by the Company because of
14 the rate caps. This will place further financial pressure on the Company.

15 In addition, a very significant portion of the Company's generation-
16 related costs are projected to be recovered out of future market revenues,
17 not out of the CTC. For these reasons, it is critically important that the
18 Company be permitted to recover its stranded costs in this proceeding.

19
20 Q. Does that conclude your testimony?

21 A. Yes, it does.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Docket No. R-00973954

PENNSYLVANIA POWER & LIGHT COMPANY

Statement No. 3

Direct Testimony of Joseph M. Kleha

1 Q. Please state your full name and business address.

2 A. Joseph M. Kleha, Two North Ninth Street, Allentown, Pennsylvania,
3 18101.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by Pennsylvania Power & Light Company (PP&L or the
6 Company) in its Office of General Counsel as Manager - Regulatory
7 Projects.

8 Q. What are your duties as Manager - Regulatory Projects?

9 A. I am responsible for overseeing corporate projects involving regulatory
10 agencies. As part of this function, I review and provide technical oversight
11 on the preparation of the Company's cost allocation and revenue
12 requirements studies.

13 Q. What is your educational background?

14 A. I graduated from the Pennsylvania State University in 1974 with a
15 Bachelor of Science Degree in Accounting. I also have taken specialized
16 courses dealing with public utility accounting and depreciation. In addition,
17 I attended the NARUC Regulatory Studies Program in the summer of
18 1979.

19 Q. Please describe your professional experience.

20 A. I was employed by the Pennsylvania Department of Public Welfare as
21 Field Auditor and Institutional Collections Officer from 1974 to 1977. In

1 1977, I joined the technical staff of the Pennsylvania Public Utility
2 Commission ("PUC") as a Utility Rate Analyst in the Bureau of Rates and
3 Research. In this position, my responsibilities included review of proposed
4 retail electric rate filings and the preparation and presentation of testimony
5 in formal rate proceedings. This testimony primarily dealt with the
6 allowable levels and jurisdictional allocations of claimed operating
7 revenues, operating expenses, and rate base. In July 1981, I joined PP&L
8 as a Senior Accountant with responsibility for assembling financial data
9 and preparing revenue requirement studies to support the Company's
10 retail and wholesale rate filings. I was named Manager - Regulatory
11 Projects, the position I now hold, in January 1990.

12 Q. Have you previously testified as a witness on cost-of-service-related
13 issues?

14 A. Yes. As an analyst in the Commission's Bureau of Rates and Research, I
15 offered testimony in the following rate proceedings:

<u>Company</u>	<u>Docket No.</u>
Duquesne Light Company	R-79010740
UGI Corp. - Luzerne Division	R-79050863
Philadelphia Electric Company	R-79060865
West Penn Power Company	R-80021082
Pennsylvania Power & Light Co.	R-80031114

1 Metropolitan Edison Company R-80051196

2 Pennsylvania Electric Company R-80051197

3 As an employee of PP&L, I have offered testimony in the following rate
4 proceedings before the PUC and the Federal Energy Regulatory Commission
5 (FERC):

6 Docket No. I-900005 Docket No. ER88-545-000

7 Docket No. P-910521 Docket No. ER91-322-000

8 Docket No. M-00930406 Docket No. ER95-1267-000

9 Docket No. C-00935175 Docket No. ER96-930-000

10 Docket No. C-00935403 Docket No. ER96-931-000

11 Docket No. R-00943271 Docket No. ER96-932-000

12 Docket No. C-00957559 Docket No. ER96-933-000

13 Docket No. P-00961023 Docket No. ER96-1428-000

14 Docket no. C-00967591 Docket No. SC97-1-000

15 Docket No. C-00967955

16 Docket No. C-00968035

17 Docket No. P-00961114

18 Q. What is the purpose of your testimony in this proceeding?

19 A. My testimony and accompanying exhibits describe and support the Com-
20 pany's calculation of base year retail rate base and operating revenues;
21 development of the cost allocation study which forms the basis for

1 approved retail rates; determination of retail jurisdictional costs and reve-
2 nue requirements; unbundling of the retail cost of providing service and
3 applicable revenue requirements into functional components; calculation of
4 the Energy Cost Rate ("ECR") roll-in; proposed treatment of nuclear
5 decommissioning costs in the Competitive Transition Charge ("CTC"); and
6 reconciliation of the CTC.

7 Q. Are you responsible for any of the Company's responses to the Commis-
8 sion's filing guidelines submitted in Exhibit No. 2.

9 A. Yes. I am responsible for responses to the following Commission filing
10 guidelines: RP-A.3., A.4., A.6., A.7., C.17., F.1., F.14., I.1., I.4., I.5., I.8.,
11 I.9., I.18., L.5., L.12., L.13., L.14, and L.15.

12 Q. What base year is the Company utilizing in this proceeding?

13 A. The Company is using the 12 months ended December 31, 1996 as the
14 base year.

15 Q. How is the base year data utilized in this proceeding?

16 A. The base year data constitutes the starting point for computation of the
17 Company's stranded costs, development of the CTC and design of
18 unbundled rates.

19 Q. What is the source of the Company's base year data?

20 A. The base year data reflected in this filing are taken directly from the
21 Company's books and records.

1 Q. Is the Company proposing any adjustments to the base year data?

2 A. Yes. The Company is proposing a number of adjustments to the base
3 year data to reflect a normal level of operations.

4 Q. Are you responsible for any of these adjustments?

5 A. Yes. I am responsible for the adjustment to rate base and the three
6 adjustments to operating revenues.

7 Q. Please discuss the Company's proposed adjustment to base year rate
8 base.

9 A. In accordance with the policy established by the Commission, the Com-
10 pany reduced its base year rate base to reflect the cash working capital
11 hypothetically available from payments of interest on long-term debt and
12 payments of dividends on preferred stock.

13 Q. Please describe the three adjustments to base year operating revenue.

14 A. The first adjustment annualizes sales for changes in customer usage and
15 growth. The second adjustment to base year revenue eliminates unbilled
16 base rate revenue, a non-recurring ECR interest refund and a PJM billing
17 adjustment. The third adjustment to base year revenue weather-normal-
18 izes sales billed during calendar year 1996. All of the adjustments are
19 shown in PP&L's Financial Report for the 12 Months Ended December 31,
20 1996. This report, which was filed with the PUC pursuant to its regulations

1 at 52 Pa. Code § 71.1 et seq., is provided as Attachment 1 of the response
2 to the Commission's filing guideline at Appendix A, Section A, Item 3.

3 Q. Are you sponsoring any additional exhibits in this proceeding.

4 A. Yes. I am responsible for Exhibit JMK 1, Exhibit JMK 2 and Exhibit JMK 3.

5 Q. Would you briefly describe the contents of Exhibit JMK 1?

6 A. Exhibit JMK 1, which is provided in response to the Commission's filing
7 guideline at Appendix A, Section I, Item 1, presents a fully distributed allo-
8 cation of the Pennsylvania jurisdictional costs of providing electric service
9 to PP&L's various retail rate classes. The study contained in Exhibit JMK
10 1 is based on costs and operating conditions for the 12 months ended
11 September 30, 1995 and represents PP&L's compliance with the results of
12 the Commission's Final Order in the Company's most recent base rate
13 proceeding at Docket No. R-00943271. Exhibit JMK 1 provides a sum-
14 mary of the allocation process results, a computer printout of the cost allo-
15 cation study and supporting schedules which show assignment of costs,
16 and the various allocation factors used. Explanatory materials regarding
17 assignment techniques employed also are included.

18 Q. What allocation method was utilized in the Company's cost allocation
19 studies?

20 A. The Company's cost allocation studies follow the same allocation princi-
21 ples utilized by PP&L in its most recent base rate filing at Docket No.

1 R-00943271. As explained in Exhibit JMK 1, PP&L employs the monthly
2 peak responsibility demand allocation method, or 12 coincident peak
3 method (12 CP), which is based on the average of the twelve monthly
4 class demands coincident with the time of the system monthly peak loads.

5 The Company believes that, for its system, this method is a reasonable
6 and appropriate methodology for the allocation of its demand-related
7 costs. This cost allocation methodology was accepted by the Commission
8 at Docket No. R-00943271, and in numerous prior retail base rate pro-
9 ceedings.

10 Q. Please explain how the Company's Pennsylvania jurisdictional costs are
11 derived.

12 A. This filing is based on the costs incurred to provide service to Pennsylva-
13 nia jurisdictional customers. Section III of Exhibit JMK 1 provides the allo-
14 cation of total electric costs between the Federal (wholesale) and Pennsyl-
15 vania (retail) jurisdictions. The result is that all costs associated with the
16 bulk power supply services to Atlantic City Electric Company ("ACE"),
17 Baltimore Gas & Electric Company ("BG&E"), Jersey Central Power &
18 Light Company ("JCP&L"), and UGI Utilities, Inc. ("UGI"), as well as the full
19 requirements wholesale services to Citizens' Electric Company of
20 Lewisburg, the Allegheny Electric Cooperative, Inc. and sixteen municipali-
21 ties are excluded from PUC jurisdictional revenue requirements.

1 Q. Please describe Exhibit JMK 2.
2 A. Exhibit JMK 2 contains the studies supporting the Company's proposed
3 functional unbundling of its costs of providing PUC jurisdictional electric
4 service into their constituent elements. Unbundling of costs begins with
5 PP&L's cost allocation study, which complies with the results of the
6 Commission's Final Order at Docket No. R-00943271, contained in Exhibit
7 JMK 1, which I just described. All costs included in Exhibit JMK 1 and
8 upon which approved rates are based were assigned and allocated to the
9 applicable functional cost categories: Energy, Other Production, Trans-
10 mission and Distribution. Section III of Exhibit JMK 2 contains the details
11 of this unbundling.

12 The data contained in each of the four summary columns in Section
13 III are inserted into a separate allocation program which assigns the
14 unbundled functional cost categories to the Company's various retail rate
15 classes. Sections IV, V, VI and VII show the details of these calculations.
16 In each section, the revenue requirements developed at class rates of
17 return are used as the basis for rate development. A summary of these
18 results is shown in Section II of Exhibit JMK 2.

19 Q. Please describe the distribution plant investment studies contained in
20 Exhibit JMK 3.

1 A. Exhibit JMK 3 contains the results of two studies: (1) the subfunctionalization of distribution plant investment and expense into primary and
2 secondary voltage components and the classification of the secondary
3 components into customer and demand-related costs, and (2) the development of allocators for meter investment and meter reading expense,
4 which are used in the cost allocation study provided in Exhibit JMK 1. It
5 should be noted that the subfunctionalization and classification of distribution
6 plant investment and expense is based on a detailed analysis of specific
7 PP&L plant records and cost data. In classifying its distribution plant
8 investment and operating expenses into customer and demand-related
9 costs, PP&L used the "minimum size system" method to identify the
10 applicable cost components. The methodologies employed in the studies
11 are explained in detail in Exhibit JMK 3 and the results of these studies are
12 reflected in Sections A and B of Exhibit JMK 1.

13
14
15 Q. Are you familiar with the Company's proposal to roll its ECR into base
16 rates?

17 A. Yes.

18 Q. Please summarize that proposal.

19 A. On December 13, 1996, PP&L filed an application with the PUC requesting
20 permission to roll into base rates its ECR and State Tax Adjustment
21 Surcharge ("STAS"). PP&L made this filing in response to the Electricity

1 Generation Customer Choice and Competition Act ("Act"), particularly Sec-
2 tion 2804(4) of the Act which establishes certain caps on utility rates.

3 In its filing, the Company also requested that the Commission
4 determine that two categories of costs are "regulatory assets" or "other
5 deferred charges" that are recoverable as "transition or stranded costs"
6 under the Act. The first category is PP&L's actual undercollected energy
7 costs as of December 31, 1996. The Company initially estimated that its
8 ECR undercollection as of December 31, 1996 would be approximately
9 \$13.9 million. PP&L committed to update this estimate to reflect actual
10 costs prior to including those costs as "transition or stranded costs" in its
11 Restructuring Plan. The second category is a normalized level of esti-
12 mated future on-going energy costs. The Company estimated that its
13 normalized level of future on-going energy costs would be approximately
14 \$31.5 million higher than the level of energy costs rolled into base rates.
15 PP&L calculated this amount by taking an average of actual energy costs
16 for a 5-year period from 1992 through 1996 and subtracting the level of
17 energy costs included in jurisdictional base rates after the ECR roll-in.

18 The Company emphasized that it was not seeking a determination
19 of the prudence of its energy costs for the period ended December 31,
20 1996. The Company requested only a determination that the costs identi-
21 fied above would be classified as a "regulatory asset" or "other deferred

1 charge" and would be recoverable as a "transition or stranded cost" in its
2 Restructuring Plan.

3 Q. Did the Commission approve the Company's ECR roll-in?

4 A. Yes. In a tentative order entered December 19, 1996 at Docket Nos.
5 P-00961131 and R-00963842, the Commission fully approved the Com-
6 pany's application.

7 Q. Please describe the impact of the ECR roll-in on this Restructuring Plan
8 filing.

9 A. The Commission's approval of the Company's ECR roll-in created two
10 regulatory assets. The first, which represents PP&L's actual undercol-
11 lected energy costs at December 31, 1996, is \$17.2 million. The second,
12 which represents a normalized level of future on-going energy costs, is
13 approximately \$31.5 million on an annual basis.

14 Q. Has Mr. Schadt reflected this impact in his calculation of the Company's
15 stranded costs?

16 A. Yes. As shown in Exhibit JRS 1, these two regulatory assets are reflected
17 in the Company's stranded cost calculations. The regulatory asset asso-
18 ciated with undercollected energy costs is reflected only in 1997. This
19 undercollection is not a recurring item and should be recovered only once.
20 The regulatory asset associated with a normalized level of future on-going
21 energy costs is reflected in 1997 and 1998. Based on the Company's

1 normalization calculation, it will experience an undercollection of its on-
2 going energy costs every year from the date of the ECR roll-in until the
3 beginning of the CTC period.

4 Q. Please explain the potential impact of the Act on PP&L's recovery of
5 nuclear decommissioning costs.

6 A. The transition to full competition raises two related concerns regarding
7 PP&L's recovery of nuclear decommissioning costs. First, there is some
8 concern regarding whether the Act will provide for adequate recovery of
9 nuclear decommissioning costs. Specifically, the Act provides electric utili-
10 ties with an opportunity to recover "stranded costs" through the CTC over a
11 nine-year period, including those nuclear decommissioning costs that may
12 not be recoverable in a competitive generation market. As a result, PP&L
13 will have to fund a significant portion of its nuclear decommissioning costs
14 out of revenue from market rates. These market rates provide no assur-
15 ance that revenues will be sufficient to meet PP&L's funding obligations for
16 nuclear decommissioning.

17 Second, there is a risk that PP&L may become subject to substan-
18 tial financial qualification requirements under Nuclear Regulatory Com-
19 mission ("NRC") regulations. NRC regulations allow "electric utilities" to
20 provide financial assurance for decommissioning by establishing an
21 external sinking fund without additional surety or insurance. The NRC's

1 rules define "electric utilities" as "any entity that generates or distributes
2 electricity and which recovers the cost of electricity, either directly or
3 indirectly, through rates established by the entity itself or by a separate
4 regulatory authority." 10 C.F.R. §50.2.

5 As a utility with rates set by the PUC on the basis of the Company's
6 cost of providing electric service, PP&L clearly has met the NRC's defini-
7 tion of an "electric utility" under traditional rate regulation. Under current
8 rates set by the PUC, PP&L is authorized to recover the estimated future
9 cost of nuclear decommissioning in current rates over the life of the
10 Susquehanna generating plant. These recovered costs are deposited into
11 an external trust fund. However, the unbundling of the generation function
12 from the regulated transmission and distribution functions arguably will
13 remove costs related to Susquehanna from traditional "cost-of-service"
14 ratemaking. Moreover, as I explained earlier, there is some concern
15 regarding whether a portion of PP&L's nuclear decommissioning costs will
16 have to be recovered through market rates after the CTC expires.

17 Therefore, it is possible that, following the transition to competition,
18 the NRC will determine that the Company's nuclear decommissioning
19 costs are not recovered through rates established by the PUC. This
20 determination could cause the NRC to reconsider PP&L's status as an
21 "electric utility" exempt from decommissioning financial assurance

1 requirements. If PP&L were to lose its status as an "electric utility," it might
2 have to pre-fund the entire cost of decommissioning Susquehanna or, at a
3 minimum, provide some form of insurance or other surety for future
4 decommissioning trust fund collections. Either option would have a signifi-
5 cant financial impact on PP&L and would increase the level of its stranded
6 costs.

7 Q. Please describe PP&L's proposed solution to address the concerns you
8 have just described.

9 A. The Company proposes to address these two concerns by extending the
10 CTC beyond the nine-year window provided by the Act to permit recovery
11 of its nuclear decommissioning costs over the remaining life of the
12 Susquehanna generating plant. Section 2808(b) of the Act specifically
13 permits the PUC to extend the nine-year term of the CTC for "good cause
14 shown." PP&L believes that its proposal to extend the CTC clearly meets
15 this standard for several reasons.

16 First, unlike most other stranded costs, nuclear decommissioning
17 cost funding is an important public health and safety issue. The PUC has
18 consistently recognized the importance of adequate funding for future
19 decommissioning costs and has consistently approved the advanced
20 funding of nuclear decommissioning costs since the 1970s.

1 Second, PP&L's proposal would ensure that its nuclear decom-
2 missioning costs will be recovered through rates set by the PUC. As such,
3 PP&L's proposal would enable the Company to retain its status as an
4 "electric utility," thereby eliminating an NRC requirement to pre-fund or
5 insure decommissioning costs. Avoiding these requirements would reduce
6 the level of PP&L's stranded costs to the benefit of both PP&L and its
7 customers.

8 Third, the Company's proposal will ensure adequate nuclear
9 decommissioning funding both during and after the transition to retail
10 competition.

11 Finally, it is important to note that the charge resulting from PP&L's
12 proposal would be extremely small and its impact on customers will be
13 minimal. For example, PP&L is currently collecting approximately \$9.5
14 million per year in jurisdictional rates for nuclear decommissioning costs.
15 For the average residential customer using 500 kilowatt-hours per month,
16 this amounts to 0.03¢/kwh, which is about \$0.15 per month and less than
17 \$2.00 per year.

18 Q. Are you generally familiar with the Company's proposed CTC?

19 A. Yes.

20 Q. Please briefly describe the purpose and operation of the CTC.

1 A. The CTC is the mechanism, provided for in Section 2808(f) of the Act,
2 through which a utility is permitted to recover its stranded costs. It is a
3 non-bypassable monthly charge that must be paid by every customer
4 connected to the distribution utility company's system. The CTC may be
5 different each year and may be different for each customer or customer
6 class. The CTC can be billed to customers in the form of a fixed customer
7 charge, a per-KW demand charge or a per-KWH energy charge, or any
8 combination of these alternatives.

9 Q. Should collections under the CTC be "trued-up" or reconciled?

10 A. Section 2808(f) of the Act calls for a limited true-up of the CTC to reconcile
11 CTC revenues with the CTC-recoverable costs approved by the Commis-
12 sion. The Act does not contemplate a recalculation of stranded costs col-
13 lected through the CTC. The reconciliation contemplated by the Act
14 appears to be limited to a true-up for changes in sales from the level of
15 sales that the Commission uses to establish the CTC initially. Under this
16 approach, the utility and its customers would be assured that the collection
17 of stranded costs through the CTC would track the Commission's order. At
18 the same time, this approach could be implemented in a relatively simple
19 manner which would not lead to re-litigation of the many complex issues
20 raised in the utility's original Restructuring Plan filing.

1 Q. Please discuss the concern that you have identified regarding CTC
2 reconciliation.

3 A. In its initial analysis, the Company considered recommending an annual
4 CTC reconciliation procedure similar to the annual ECR reconciliation pro-
5 cedure that has been in place in Pennsylvania for many years. However,
6 this approach raises a significant concern. For example, assume that a
7 utility's rates (including the CTC) are exactly at its rate cap level. Also,
8 assume that the utility undercollects its CTC in year one. Under an ECR-
9 type reconciliation process, the utility would be entitled to recover that
10 undercollection in year two. However, because the utility's rates already
11 are at its rate cap level in year two, it would not be permitted to recover the
12 undercollection. Presumably, it would be forced to forego that amount of
13 its CTC.

14 Q. Please describe the Company's proposed procedure for reconciling the
15 CTC.

16 A. The Company is proposing the following approach: A utility would track its
17 annual collections under the CTC and compare those annual collections
18 with the CTC collection levels authorized by the Commission. All undercol-
19 lections or overcollections would be tracked by the utility, subject to Com-
20 mission review and verification. During the term of the CTC, the tracking
21 of overcollections and undercollections would not lead to a change in the

1 CTC rate. However, near the end of CTC application period, the utility
2 would calculate the net amount of the overcollections and undercollections
3 which occurred during the entire term of the CTC. The final termination
4 date of the CTC would be adjusted to provide for a full refund of any
5 overcollections and a full recovery of any undercollections. Accordingly, if
6 a utility experienced a net undercollection during the term of the CTC, the
7 termination date of the CTC would be extended to permit the utility to
8 recover those amounts. On the other hand, if a utility experienced a net
9 overcollection during the term of the CTC, termination of the CTC would
10 occur sooner. In this way, Pennsylvania electric utilities and their custom-
11 ers would be assured that the amount of stranded costs recovered through
12 the CTC is neither greater than nor less than the amount authorized by the
13 Commission. Moreover, this approach avoids the rate cap concern and
14 other concerns associated with an actual change in the CTC rate each
15 year to account for undercollections and overcollections. Admittedly, this
16 approach could extend the term of the CTC to more than nine years, but it
17 also could shorten the CTC term if overcollections occur. Unless a utility
18 experiences a major change in load, it is expected that these variations in
19 the term of the CTC will be minimal. The Act specifically authorizes the
20 Commission to change the CTC collection period "in its discretion and for

1 good cause shown." I believe that the Company's proposed reconciliation
2 procedure provides good cause for varying the length of the CTC.

3 Q. Does that conclude your direct testimony?

4 A. Yes.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Docket No. R-00973954

PENNSYLVANIA POWER & LIGHT COMPANY

Statement No. 4

Direct Testimony of Michael J. Berish

1 Q. Please state your full name and business address.

2 A. Michael J. Berish, Two North Ninth Street, Allentown, Pennsylvania 18101.

3

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by the Pennsylvania Power & Light Company (PP&L or the
6 Company) as Team Leader-Business Planning.

7

8 Q. What are your responsibilities as Team Leader-Business Planning for
9 PP&L?

10 A. I am responsible for coordinating the development of financial operating
11 plans for the Company's various departments, administering its functional
12 group (cost area) budget control system and various special studies.

13

14 Q. What is your educational background?.

15 A. I graduated in 1967 from the Pennsylvania State University with a Bache-
16 lor of Science Degree in Accounting. I also received a Masters Degree in
17 Business Administration from Lehigh University in 1971.

18

19 Q. How long have you been employed by PP&L and in what capacities?

20 A. I joined PP&L in 1967 as a Methods Accountant in the Data Processing
21 Division of the Financial Department where I worked as a computer pro-
22 grammer until 1969. From 1969 to 1973, I was a Systems Analyst and

1 later a Senior Systems Analyst in the Division Operations Department
2 where I was responsible for analyzing clerical systems with a goal of mak-
3 ing them more efficient or computerizing them. From 1973 to 1975, I was
4 a Fuel Adjustment Specialist in the System Power & Engineering Depart-
5 ment, where my duties were to analyze the fuel costs recovered through
6 the fuel adjustment clause. In 1975, I was appointed Supervisor-Financial
7 Planning in the Financial Department, and in 1979 was appointed to
8 Manager-Financial Planning. In 1996, I was named to my present
9 position.

10
11 Q. What is the purpose of your testimony in this proceeding?

12 A. My testimony describes and supports the Company's accounting and other
13 financial data submitted in response to the filing guidelines for Electric
14 Utility Restructuring established by the Commission in its order at Docket
15 No. M-00960890. The Company's responses to these filing guidelines are
16 provided in Exhibit No. 2.

17
18 Q. What specific information are you sponsoring?

19 A. The Commission's order requires all utilities to use a pro forma base year
20 ended December 31, 1996. PP&L's base year financial data is provided
21 as Attachment 1 to Appendix A, Section A, Item 3. The first page of this
22 attachment provides a summary of Rate Base, Income Available for Return

1 and Rate of Return. Within the Rate Base category, I am sponsoring the
2 data under the column heading "Actual per Books" for Materials & Supplies
3 and Fuel Stocks (Line 5); Cash Working Capital (Line 6); Liberalized
4 Depreciation (Line 9); Customer Advances (Line 12); and, Customer
5 Deposits (Line 13). Within the section for Income Available for Return, I
6 am sponsoring the data under the column heading "Actual per Books," for
7 Operating Revenues (Line 17) and all Operating Expenses (Lines 18
8 through 24). I also will describe and support all of the operating expense
9 adjustments listed under the column heading "Pro Forma Intrastate
10 Adjustments," except for the annual depreciation adjustment.

11
12 Q. Please describe the source and method used to establish the book cost
13 figures shown in the Company's books of account.

14 A. The accounts of the Company are kept in accordance with the Uniform
15 System of Accounts prescribed by the PUC and the FERC for Electric
16 Utilities and Licensees.

17
18 Q. Are these accounts audited?

19 A. They are audited annually by an independent certified public accounting
20 firm. In addition, the FERC and PUC audit staffs conduct periodic audits of
21 the Company's books and records.

22

Rate Base

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Q. Mr. Berish, the base year Rate Base includes an amount for "Materials & Supplies and Fuel Stocks." Please explain this item.

A. This item reflects the amount invested in coal and oil used as fuel at PP&L's various generating stations, as well as the materials and supplies stored principally at power plants and service area storerooms to supply line crews. These values are increased by the fuel stock expense applicable to the various fuels, which is principally the cost of purchasing and other procurement expense of the fuel in inventory and storeroom expenses for the materials and supplies inventory.

The amount for materials and supplies and fuel stocks is based on a 13-month average of the various items included in Accounts 151, 152, 154 and 163.

Q. The base year rate base shows an amount for "Cash Working Capital." Would you explain this amount?

A. This amount represents the Company's average investment in cash working capital. There are three major components in this item: cash working capital required for operation and maintenance expenses; funds invested in prepayments; and accrued taxes.

1 Q. Would you explain these three components?

2 A. The first component is cash working capital required for operation and
3 maintenance expenses. The Company bills all of its customers once every
4 month but the due date for payment varies between 15 and 30 days from
5 the billing date. On this basis, there is a considerable lag between the
6 time electricity is furnished to a customer and the time the customer pays
7 for such electricity. This lag averages 35 days for customers with 15-day
8 due dates, 42 days for customers with 20-day due dates, and 39 days for
9 customers with 30-day due dates. Payments received for interchange
10 sales lags the time electricity is delivered by an average of 35 days. The
11 revenue lag from bulk power contracts and sales to UGI have 20 days and
12 17 days, respectively. The average lag in receipt of revenues from all
13 these sources is 35.6 days on a dollar-weighted basis.

14 In most instances, the Company must pay its bills for payroll, fuel
15 and other operating expenses prior to the time it is able to collect the
16 amount due for the service that gives rise to these expenses. The
17 Company has examined its records to determine, as to the major
18 categories of expense, the average span of days between the time an
19 expense is incurred and the time it must be paid. This lag ranges from 11
20 days to 46 days for various types of costs. The overall average for all
21 expenses is 30.9 days. Thus, the average net lag between the payment of
22 expenses and the receipt of the related revenue is 4.7 days (35.6 days

1 less 30.9 days). To cover its expenses and continue to conduct its
2 business during this time lag the Company must provide a cash
3 investment.

4 The second major component of cash working capital is made up of
5 funds which are invested in prepayments. In conducting its electric busi-
6 ness, the Company must pay certain costs prior to the time such items are
7 properly charged to expense for accounting and ratemaking purposes. For
8 example, many insurance premiums must be prepaid, but are expensed
9 monthly over the period to which they apply. Costs of this nature are ini-
10 tially charged to Account 165, Prepayments, and are subsequently
11 charged to expense from this account.

12 The amount for prepaid expenses is based on a 13-month average
13 of the various items included in Account 165.

14 The third major component of cash working capital is an amount for
15 accrued taxes. In the case of Federal income tax, estimated payments
16 must be made on April, June, September and December 15 of the year to
17 which the tax is applicable. Because revenue is collected from customers
18 monthly, there are funds temporarily available for payment of other costs.
19 The Company's computations indicate that funds available from this
20 source average 6.72 percent of the federal income tax due.

1 Presently, the Pennsylvania income tax and Pennsylvania capital
2 stock tax have an effective pattern of required estimated payments as
3 follows:

- 4 • 22.5 percent on March 15
- 5 • 22.5 percent on June 15
- 6 • 22.5 percent on September 15
- 7 • 22.5 percent on December 15
- 8 • 10 percent on April 15 of the following year

9 The Company's computations indicate that the funds available from these
10 taxes average 11.72 percent of the tax due.

11 The Pennsylvania gross receipts tax must be paid on an estimated
12 basis by March 15 with final payment due on March 15 of the following
13 year. The Company's estimated payment on March 15 generally is equal
14 to 90 percent of the final tax due. Revenue is collected from customers
15 monthly and funds must be provided by investors to pay these taxes prior
16 to collection of revenues from customers. The Company's computations
17 indicate that the funds which must be provided for this purpose average
18 22.87 percent of the tax due. The amount for this tax item is based on the
19 total Pennsylvania gross receipts tax which must be paid at the 44 mill rate
20 actually in effect.

21 The Pennsylvania Public Utility Realty Tax must be paid on an esti-
22 mated basis by April 15 with final payment due on April 15, of the following

1 year. The Company's estimated payment on April 15 generally is equal to
2 90 percent of the final tax due. PP&L's computations indicate that funds
3 which must be provided for this purpose average 14.53 percent of the tax
4 due.

5 A calculation of these working capital components is provided as
6 Attachment 1 of response to the Commission's filing guideline at Appendix
7 A, Section A, Item 4.

8
9 Q. Please explain "Liberalized Depreciation."

10 A. Liberalized depreciation is the total of various deferred income taxes which
11 have been established over time to reflect the difference between the cal-
12 culation of taxes paid to the Federal government and taxes calculated for
13 ratemaking purposes. They represent, in essence, a zero cost loan from
14 the government. The carrying cost savings from deferred income taxes
15 are passed back to customers through a rate base deduction equal to the
16 deferred income tax balances.

17
18 Q. Please describe the Rate Base reductions for "Customer Advances" and
19 "Customer Deposits."

20 A. Customer advances for construction represent the amounts provided by
21 customers and recorded in Account 252 at December 31, 1996, pending
22 completion of construction or conclusion of the period during which some

1 portions may be refundable under tariff provisions and service contracts
2 with those customers. The second item is Customer Deposits. These
3 deposits are deducted from rate base in compliance with the Commission's
4 Order at Docket No. R-80031114.

5
6 Q. Why aren't Accumulated Deferred Investment Tax Credits (as shown in
7 Account 255) reflected in the computation of Rate Base?

8 A. Under provisions of the Revenue Act of 1971, public utilities were afforded
9 the option of treating the investment tax credit in rate proceedings as a
10 reduction of operating taxes over the life of the property and not deducting
11 the accumulated amount of the credit from rate base. The Company made
12 this election on March 8, 1972, and amortizes this tax credit to operating
13 expense over the life of the related property.

14
15 Income Available for Return

16
17 Q. Mr. Berish, would you please explain the determination of book Operating
18 Revenue?

19 A. Yes. Operating revenue is the revenue included in Accounts 440 through
20 456. It includes revenue from the sale of electricity to residential,
21 commercial and industrial customers, streetlighting and public authorities,
22 sales to other electric companies for resale, rentals of electric property,

1 late payment charges, miscellaneous service revenue, and other revenue,
2 e.g., unbilled revenue and PJM capacity credit amounts.

3

4 Q. What is included in the operating expense category?

5 A. Operating expense includes amounts for operation and maintenance
6 expense, depreciation, income taxes, deferred taxes, investment tax
7 credit, and taxes other than income.

8 The net of operating revenue and operating expense is the income
9 available for return.

10

11 Pro-Forma Adjustments

12

13 Q. Turning to the adjustments to book data, please explain the adjustment for
14 "Energy Costs."

15 A. This adjustment was made to normalize energy costs by eliminating a non-
16 recurring credit to energy costs associated with a fuel oil refund received
17 from the Department of Energy. This refund relates to purchases of petro-
18 leum products from various suppliers during the period August 1973
19 through January 1981.

20

21 Q. Mr. Berish, please explain the adjustment for "Wage Expense."

1 A. This adjustment normalizes wages. The total wages paid to all employees
2 during the last three months of the base year were examined to determine
3 the average wage per employee. The use of the three-month average was
4 necessary to reflect the level of wages which were in effect at
5 December 31, 1996. This average monthly wage was then multiplied by
6 the total number of personnel employed at year end 1996. By multiplying
7 the total monthly payroll by twelve months, the total annual wages were
8 computed. From this amount was deducted the actual wages for the year.
9 The difference was then multiplied by the portion charged to operating
10 expense to arrive at the wage adjustment.

11

12 Q. Mr. Berish, please explain the adjustment for "Management Audit
13 Expense."

14 A. This provides for the amortization over a five-year period of the costs of a
15 comprehensive management audit required by the PUC. The audit was
16 performed by Shumaker & Company. This amortization was approved by
17 the Commission in its Final Order at Docket No. R-00943271.

18

19 Q. Will you please explain the adjustment for "Land Management/Recrea-
20 tional Facilities Expense?"

21 A. In its Final Order at Docket No. R-822169, the Commission determined
22 that operation and maintenance expenses incurred for certain land

1 management projects/recreational facilities which are not owned or
2 operated pursuant to a specific Federal or State licensing requirement
3 should not be reflected in rates. This adjustment provides for the elimi-
4 nation of the base year operating expense for such facilities.

5
6 Q. Will you please explain the adjustment for "Customer Deposits Interest
7 Expense"?

8 A. Yes. This adjustment is for interest expense applicable to customer
9 deposits. This adjustment is consistent with the Commission's policy of
10 allowing appropriate interest expense when customer deposits are treated
11 as a reduction to rate base. In this filing, PP&L has treated customer
12 deposits as a reduction to rate base.

13
14 Q. Please explain the adjustment to "Annual Depreciation Expense."

15 A. Adjustments relating to annual depreciation expense will be explained by
16 Mr. Hoch.

17
18 Q. Please explain the adjustment for "Interest Synchronization."

19 A. This is an adjustment to income taxes resulting from the annualized inter-
20 est expense associated with intrastate pro forma results.

21
22 Q. Would you explain the adjustment for "R&E Tax Expense."

1 A. Yes. This adjustment was made to normalize base year income tax
2 expense by eliminating a non-recurring credit associated with research and
3 experimentation activities. This tax credit is based on prior period
4 investments in technology and computer software.

5

6 Q. Are you responsible for any of the Company's other responses to the
7 Commission's filing guidelines?

8 A. Yes. My name is indicated on those responses for which I am responsible.

9

10 A. Does this conclude your direct testimony?

11 A. Yes it does.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Docket No. R-00973954

PENNSYLVANIA POWER & LIGHT COMPANY

Statement No. 5

Direct Testimony of Donald S. Hoch

1 Q. Please state your full name and business address.

2 A. Donald S. Hoch, Two North Ninth Street, Allentown, Pennsylvania, 18101.

3

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by Pennsylvania Power & Light Company (PP&L or Com-
6 pany) as Financial Specialist -- Depreciation / Systems.

7

8 Q. What are your duties as Financial Specialist -- Depreciation/Systems?

9 A. I am responsible for all policy and procedure issues related to book
10 depreciation at PP&L. Included within my responsibilities are the prepara-
11 tion of service life studies using the retirement records of the Company to
12 ascertain the average service life and dispersion characteristics of utility
13 property. I also assist in the identification, development and implementa-
14 tion of computer systems for the Financial Department at PP&L.

15

16 Q. Please describe your educational background.

17 A. I am a graduate of Grove City College with a Bachelor of Science degree
18 in mathematics and of Lehigh University with a Master of Science degree
19 in Industrial Engineering with an emphasis on Information Systems. I also
20 have participated in depreciation seminars for five years at Michigan Tech-
21 nological University and at Calvin College in Michigan, and in numerous

1 IBM courses and seminars concerning computer programming, system
2 analysis and design, and computer-related topics.

3
4 Q. How long have you been employed by PP&L and in what capacities?

5 A. I was employed by PP&L in 1969. From 1969 through 1971, I worked in
6 the Operations Research Section of the Company where my responsibili-
7 ties were to design systems and computer programs for engineering,
8 scientific and financial applications. This work primarily consisted of the
9 development of a critical path method system that was used to schedule
10 construction projects and allocate resources.

11 In 1971, I was assigned to assist in the redesign of the Company's
12 Plant Accounting System, the associated data base of plant records and
13 all the programs and related systems. This work included subsystems for
14 actuarial and simulated plant record (SPR) life analysis studies, deprecia-
15 tion studies, the maintenance of Company trend and Iowa curve files, plant
16 valuations, the depreciation reserve and a variety of other reports and
17 records. This work also included the preparation of all trending and
18 depreciation exhibits and studies that were filed in support of rate filings
19 submitted to the Pennsylvania Public Utility Commission in 1969 (Docket
20 No. C-18908), 1971 (Docket No. C-19244), 1973 (R.I.D. No. 84), 1975
21 (R.I.D. No. 221), 1980 (Docket No. R-80031114), 1981 (Docket No.

1 R-811636), 1982 (Docket No. R-822169), 1984 (Docket No. R-842651),
2 and 1994 (Docket No. R-943271).

3 Subsequent to the redesign assignment, I developed and main-
4 tained several deterministic/probabilistic modeling systems, including a
5 Company financial model, a general modeling system to simulate user-
6 defined models and a model of future plant based on budget estimates. In
7 September 1981, I assumed full responsibilities as Manager-Depreciation.
8 In that position, I was responsible for all aspects of book depreciation,
9 including preparation of depreciation studies using the retirement records
10 of the Company to ascertain the average life and dispersion characteristics
11 of electric property. These studies currently are used as a basis for calcu-
12 lating annual depreciation for accounting purposes, as well as both annual
13 and accrued depreciation for rate studies.

14 In November 1994, I assumed the position of Supervisor-Plant
15 Accounting. In that position, I was responsible for managing the mainte-
16 nance of Company records of construction, plant in service and deprecia-
17 tion in accordance with Federal and State regulatory bodies and Company
18 requirements. I also was responsible for providing timely information con-
19 cerning the physical property of the Company to various corporate
20 departments for use in studies and reports for management and regulatory
21 bodies.

1 In February 1996, I assumed the position of Financial Specialist --
2 Depreciation / Systems.

3

4 Q. Have you participated in professional programs or educational projects
5 other than those you previously mentioned?

6 A. I am a member of the Property Accounting & Valuation Committee of the
7 Edison Electric Institute. I have received certification in data processing
8 (C.D.P.) from the Institute for the Certification of Computer Professionals.

9

10 Q. What is the purpose of your testimony?

11 A. I will explain the Company's base year amounts for the original cost of util-
12 ity plant in service, accrued depreciation and annual depreciation expense.
13 These amounts are set forth in Attachment 1 of the Company's response
14 to the Commission's filing guideline at Appendix A, Section A, Item 3.

15

16 Q. Are you responsible for any other responses to the Commission's filing
17 guidelines submitted in Exhibit No 2?

18 A. Yes. Under the caption entitled Depreciation, I am responsible for the fol-
19 lowing guidelines: RP-E.1., E.2., E.3., E.4., E.5., E.6., E.7. and E.8.

20 Under the caption entitled Rate Base, I am responsible for the following
21 guidelines: RP-F.1., F.7., F.10., F.11., F.12., F.13. and F.18. Under the

1 caption entitled Restructuring Issues, I am responsible for the following
2 guideline: RP-L.5.

3

4 Q. Mr. Hoch, were these responses prepared by you or under your supervi-
5 sion?

6 A. They were prepared under my direct supervision.

7

8 Q. Please summarize the major components of the Company's original cost of
9 utility plant-in-service, accrued depreciation and annual depreciation
10 expense.

11 A. The following is an enumeration of the key plant or depreciation items in
12 this filing:

13 1. ORIGINAL COST MEASURE OF VALUE

14 PP&L is basing its rate base on the original cost measure of value.

15 2. TRANSMISSION, DISTRIBUTION AND GENERAL PLANT

16 AVERAGE SERVICE LIVES, RETIREMENT DISPERSIONS, AND

17 ANNUAL DEPRECIATION RATES

18 For all plant accounts in these functions, the average service lives,

19 retirement dispersions and/or amortization periods are based on a

20 service life study completed in 1993. That service life study was

21 accepted by the Commission in the Company's most recent retail

22 base rate filing at Docket No. R-00943271. The actuarial tech-

1 niques used in that study are the same as those employed in a prior
2 service life study which was accepted by the Commission at Docket
3 No. R-842651. The calculation of the annual accruals reflects the
4 application of the service life parameters from the service life study
5 and the straight-line remaining life method of depreciation. In its
6 Order at Docket No. P-880332, the Commission instructed the
7 Company to change from the whole-life technique to the remaining
8 life technique, effective January 1, 1989.

9 3. STEAM PRODUCTION, NUCLEAR PRODUCTION, HYDRO
10 PRODUCTION AND OTHER PRODUCTION INTERIM SURVIVOR
11 CURVES

12 The interim survivor curves used as a parameter of the life-spanning
13 depreciation system for power production facilities in Steam Pro-
14 duction, Nuclear Production, Hydro Production and Other Produc-
15 tion are based on an interim retirement study completed in 1993.
16 This study was accepted by the Commission at Docket No.
17 R-00943271. A prior interim survivor study, which used the same
18 analytic techniques as the current study, was accepted by the
19 Commission at Docket No. R-842651.

20 4. POWER PRODUCTION UNIT DEACTIVATION DATES

1 The deactivation dates and resulting life spans used for life-span-
2 ning depreciation calculations are those accepted by the Commis-
3 sion at Docket No. R-00943271.

4 5. BOOK DEPRECIATION RESERVE

5 As indicated in prior retail rate filings, PP&L's book reserve is the
6 proper depreciation reserve to use in determining the rate base for
7 all plant. The book reserve was accepted for ratemaking purposes
8 by the Commission at Docket No. R-842651.

9 6. SUSQUEHANNA MODIFIED SINKING FUND DEPRECIATION

10 Property installed at Susquehanna prior to January 1, 1989 was
11 originally depreciated using a system of depreciation known as
12 modified sinking fund (MSF). This method, which was approved by
13 the Commission in its Final Order at Docket No. R-842651, subse-
14 quently was modified by the Commission, in its Final Order at
15 Docket No. P-880332, to permit the Company to comply with the
16 requirements of Statement of Financial Accounting Standards
17 No. 92 ("SFAS 92"). In its Final Order at Docket No. R-00943271,
18 the Commission approved the Company's request to levelize the
19 remaining MSF annual depreciation amount through 1998, rather
20 than maintaining the prior annual escalation of MSF depreciation
21 expense. On January 1, 1999, the annual depreciation expense for
22 Susquehanna property is scheduled to decrease from the levelized

1 MSF amount of approximately \$173 million per year to a straight-
2 line amount of approximately \$105 million per year.

3 7. GENERAL PLANT AMORTIZATION

4 In its Final Order at Docket No. R-00943271, the Commission
5 approved the Company's request to switch to amortization account-
6 ing for the following classes of assets: General Plant Accounts
7 391.2, 391.4, 391.6, 393.0, 394.0, 394.4, 394.6, 394.8, 395.0 and
8 398.0 and for similar equipment contained in the Miscellaneous
9 Power Plant Equipment accounts.

10 8. DEPRECIATION RESERVE ADJUSTMENT

11 The Company is proposing to adjust its depreciation reserve detail
12 books of account to reflect the results of various Commission-
13 approved changes in depreciation life parameters.

14

15 Q. Please discuss the depreciation reserve adjustment that the Company is
16 proposing.

17 A. Through December 31, 1988, the Company used the whole-life technique
18 of depreciation. This technique simply applies a depreciation rate, known
19 as a whole-life rate, to the existing balance of plant in service. An esti-
20 mated, or theoretical, depreciation reserve can be calculated for this tech-
21 nique by applying calculated vintaged accrued depreciation rates to exist-
22 ing vintaged plant in service. Whenever approval is given by the Commis-

1 sion for a change in depreciable life or dispersion characteristics, the new
2 depreciation parameters are used to calculate an entirely new theoretical
3 depreciation reserve. The assumption is made that the new parameters
4 have been in effect for the entire existence of the plant account being
5 analyzed, although this is obviously not the case. A comparison of the
6 resultant theoretical depreciation reserve to the book reserve reveals a
7 newly created variance. This variance can be either positive or negative,
8 depending on whether the depreciation parameters were extended or
9 shortened.

10 Prior to filing its most recent retail base rate case at Docket No.
11 R-00943271, the Company had not filed a base rate case with the PUC for
12 over 10 years. The depreciation service life study filed in the prior base
13 rate request was completed in 1981 using data ended December 31, 1980.
14 In its most recent rate filing, the Company submitted an updated deprecia-
15 tion service life study that reflected service life or dispersion characteristic
16 changes for virtually every plant account. Within the Transmission plant
17 function, these changes generally produced a positive reserve variance
18 when the calculated depreciation reserve was compared to the book
19 reserve. That is, the calculated reserve exceeded the book reserve.
20 Within the Distribution plant function, these changes generally produced a
21 negative reserve variance when the calculated depreciation reserve was
22 compared to the book reserve. That is, the calculated reserve was less

1 than the book reserve. The net variance for both plant functions is
2 approximately \$204.8 million, with the calculated theoretical reserve being
3 less than the book depreciation reserve.

4

5 Q. What is the Company's proposal regarding this depreciation reserve vari-
6 ance?

7 A. Because the Company currently uses the remaining life technique in its
8 calculation of depreciation expense, these depreciation reserve variances
9 would tend to be ameliorated over the remaining life of the property. How-
10 ever, in the context of this proceeding, the Company is proposing to make
11 a one-time adjustment to the detailed depreciation reserve books of
12 account. It is proposing to adjust the Transmission and Distribution
13 depreciation reserves on its books of account to the level calculated as the
14 theoretical depreciation reserve at December 31, 1998. It also is propos-
15 ing to adjust the Nuclear Production depreciation reserve on its books of
16 account by an equal amount. The net effect would be to increase net plant
17 for the Distribution function, and to decrease net plant for both the Trans-
18 mission and Nuclear Production functions.

19

20 Q. Why does the Company believe that this proposed adjustment is appro-
21 priate?

1 A. The Company believes this proposed adjustment is appropriate for the
2 following three reasons. First, the proposed adjustments to the Transmis-
3 sion and Distribution depreciation reserves on the Company's books of
4 account accurately reflect the theoretical depreciation reserve calculated at
5 December 31, 1998 for these accounts. Second, the adjustment to the
6 Nuclear Production depreciation reserve on the Company's books of
7 account will enable the Company to reduce its stranded cost claim by more
8 than \$ 317 million, as discussed by Mr. Schadt in his direct testimony.
9 Third, the Act specifically contemplates this type of depreciation reserve
10 reallocation as a means of mitigating stranded costs. Finally, the proposal
11 for an adjustment to the Nuclear Production depreciation reserve to offset
12 the adjustments to the Transmission and Distribution depreciation reserves
13 is consistent with the implementation of the rate cap established by the
14 Act, and maintains the Company's retail charges at the level in effect on
15 January 1, 1997.

16

17 Q. Does this conclude your statement of direct testimony?

18 A. Yes, it does.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

DOCKET NO. R-00973954

PENNSYLVANIA POWER & LIGHT COMPANY

STATEMENT NO. 6

DIRECT TESTIMONY OF PAUL R. MOUL

1 Q. Please state your name, occupation and business address.

2 A. My name is Paul Ronald Moul. My business address is Cherry Tree Corporate
3 Center, 535 Route 38 East, Suite 200, Cherry Hill, New Jersey 08002. I am
4 Managing Consultant of the firm P. Moul & Associates, Inc., an independent,
5 financial and regulatory consulting firm. In my capacity as Managing Consultant
6 and for over twenty years, I have provided cost of capital and fair rate of return
7 testimony in numerous proceedings before the Pennsylvania Public Utility
8 Commission ("PUC" or the "Commission") and before many other regulatory
9 commissions at the federal and state level. I appeared as an expert witness on
10 behalf of Pennsylvania Power & Light Company ("PP&L" or the "Company") in its
11 most recent base rate case at Docket No. R-00943271.

12

13 Q. What is the purpose of your testimony?

14 A. My testimony presents evidence, analysis and a recommendation concerning the
15 appropriate rate of return on common equity that the Commission should
16 recognize in calculating the transition or stranded costs for PP&L. My testimony
17 addresses two issues. First, what is the appropriate cost of equity for PP&L in
18 the historic base year 1996? Second, is that cost of equity appropriate for
19 calculating the Company's transition or stranded costs extending into the future,
20 which may encompass costs which will be incurred for up to 30 years?

21

1 Q. What cost of equity have you determined for PP&L applicable to the 1996
2 historic base year?

3 A. My analysis indicates that the rate of return on common equity which should be
4 used for the base year is at least 12.75%. I understand, however, that the
5 Company has reflected an 11.5% rate of return on common equity in its filing
6 with the Commission. The 11.5% rate of return on common equity is consistent
7 with the Commission's Final Order in the Company's most recent base rate case
8 at Docket No. R-00943271. Based upon my independent analysis, the 11.5%
9 rate of return on common equity contained in the calculation of the transition or
10 stranded costs is below the Company's actual cost of equity.

11

12 Q. What is your basis for the determination of the Company's cost of equity?

13 A. In arriving at my determination that the Company's cost of equity is at least
14 12.75%, I have relied on four, well-recognized measures: the Discounted Cash
15 Flow ("DCF") model, the Risk Premium analysis, the Capital Asset Pricing Model
16 ("CAPM"), and the Comparable Earnings approach. By considering the results
17 of a variety of approaches, I determined that my cost of equity is consistent with
18 the well-recognized principles for determining a fair rate of return. The models
19 which I used to measure the cost of equity for the Company have been applied
20 with capital market and financial data relied upon by investors when assessing
21 the relative risk, and hence cost of equity, for an electric utility such as PP&L. In
22 this regard, the models have been applied with market data taken from PP&L

1 Resources, Inc. ("PP&L Resources"), the parent company of PP&L, and a
2 Barometer Group of Eight Electric Companies (the "Barometer Group"). The
3 results of my study are contained in a report which accompanies my direct
4 testimony and is identified as Exhibit PRM 1. The financial and market data
5 supporting my report are identified as Exhibit PRM 2.

6 In general, the use of more than one approach provides a superior
7 foundation to arrive at the cost of equity. At any point in time, individual methods
8 can provide an incomplete measure of the cost of equity depending upon a
9 variety of extraneous factors which may influence the way the market regards
10 the stock. The following table provides a summary of the indicated costs of
11 equity using each of these approaches.

	<u>DCF</u>	<u>Risk Premium</u>	<u>CAPM</u>	<u>Comparable Earnings</u>	<u>Average of Four Methods</u>	<u>Midpoint of Range</u>
12 PP&L Resources	11.09%	12.50%	12.44%	15.05%	12.77%	13.07%
13 Barometer Group	10.47%	12.50%	12.28%	15.05%	12.58%	12.76%

14
15
16
17
18 Using the PP&L Resources and Barometer Group data, the appropriate
19 cost of equity is at least 12.75%. The rate of return on common equity that the
20 Company should receive should be near the top of the range in recognition of its
21 exemplary management performance. It is my opinion that an 11.5% rate of
22 return on common equity, which is reflected in the Company's filing, is below that
23 indicated by the market models. Moreover, it is my opinion that an 11.5% rate of
24 return on common equity is the minimum necessary to support reasonable credit
25 quality in light of the credit quality benchmarks established for electric utilities. I

1 have provided a more detailed discussion of the credit quality implications of the
2 Company's overall rate of return in Exhibit PRM 1. As a consequence, the
3 Company must be provided an opportunity to experience a financial profile that
4 fits those criteria and is commensurate with the business risks of the electric
5 utility industry.

6
7 Q. In your opinion, does a determination of the cost of equity for the base year 1996
8 provide a reasonable basis to determine costs which may extend up to 30 years
9 in the future?

10 A. The use of 1996 as a base period to establish a long-term rate of return on
11 common equity is likely to result in an understatement of the cost of equity for the
12 next 30 years. I say this because interest rates in 1996 were relatively low by
13 recent historical standards. The level of interest rates in 1996 are shown
14 together with historical interest rates on the graph presented in Exhibit PRM 3.
15 On that exhibit, I have presented the monthly yields for Moody's index of A rated
16 public utility bonds from January 1986 through December 1996. This graph
17 shows that the 1996 data which the Commission will use in setting the transition
18 or stranded costs for PP&L have been taken from a period of relatively low
19 interest rates by historical standards. Essentially, the yield on public utility bonds
20 at the beginning of 1996 was near the trough of interest rates which occurred in
21 October 1993. Although interest rates rose from the beginning of 1996, the
22 average yield for the year was 7.75% for A rated public utility bonds.

1

2 Q. What are the implications of relatively low interest rates regarding the Company's
3 cost of equity for the future?

4 A. As I understand it, PP&L is utilizing 1996 capital cost data as a proxy for future
5 capital costs in calculating its stranded cost recovery claim. It appears obvious
6 that if interest rates rise from their current low levels, the cost of equity
7 determined from 1996 data will understate the future cost of equity. Although it
8 is always possible that interest rates could move lower, this possibility is out-
9 weighed by the prospect of higher future interest rates. That is to say, there is
10 more potential for higher rather than lower interest rates when the beginning
11 point in the process contains relatively low interest rates. Indeed, the average
12 yield for Moody's index of A rated public utility bonds was 9.03% for the monthly
13 yields from 1986 to 1996, shown on Exhibit PRM 3, when this average yield is
14 compared to the average yield for 1996 of 7.75% noted above.

15

16 Q. What recommendations do you have for the Commission concerning the rate of
17 return on common equity which should be reflected in the determination of the
18 Company's transition or stranded cost recovery?

19 A. First, the 11.5% rate of return on common equity used for the base period 1996
20 in the Company's filing is low. My independent analysis indicates that a higher
21 12.75% cost of equity is indicated from the market evidence taken from the year
22 1996. Second, whatever rate of return on common equity is used for the base

1 year 1996 will likely prove to be too low for the future because 1996 was a period
2 of relatively low interest rates. PP&L's use of an 11.5% cost of equity in its
3 analysis is clearly conservative and is at the low end of any range of
4 reasonableness.

5

6 Q. Does this conclude your direct testimony?

7 A. Yes.

8

EXHIBIT PRM 1

PENNSYLVANIA POWER & LIGHT COMPANY

Determination of the Cost of Equity

Pennsylvania Power & Light Company ("PP&L" or the "Company") has engaged P. Moul & Associates, Inc., of Cherry Hill, N.J. to measure the Company's cost of equity for the determination of its transition or stranded cost recovery. The cost of equity was derived from the application of a variety of methods/models including: Discounted Cash Flow ("DCF") model, Risk Premium approach, Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings method. The resulting rate of return on common equity is represented by the average and range of the results of each of the models/methods. Detailed financial and market data in support of the rate of return on common equity is provided in Exhibit PRM 2. Schedule references throughout this report relate to data contained in Exhibit PRM 2.

The common stock shares of PP&L are not traded because the Company is a wholly-owned subsidiary of PP&L Resources, Inc. ("PP&L Resources"). PP&L Resources' stock is traded on the NYSE and regional exchanges and is a member of the S&P 500 Composite Index and S&P Public Utilities. In addition to data for PP&L Resources, a Barometer Group (i.e., proxy group) approach has also been used to measure the cost of equity with financial and market data derived from a group of eight electric companies. The selection criteria for the Barometer Group and identities of the component companies may be found on page 2 of Schedule 3. Prior to undertaking an analysis of the Company's cost of equity using PP&L Resources and the Barometer Group data, it is first necessary to assess the relative risk position of PP&L. From a risk assessment perspective, PP&L has been assigned an "Average" business position by Standard & Poor's Corporation ("S&P"), a major credit rating agency.

It is useful to enumerate the factors which impact the Company's business risk profile. A list of strengths as perceived by investors in PP&L include:

- . Regionally competitive rates
- . Winter-peaking utility in a summer-peaking region
- . Strong capacity position
- . High levels of generating station availability
- . Aggressive marketing and economic development programs
- . Emphasis on cost control, especially the size of the workforce, and the refinancing of high cost debt and preferred stock
- . Initiatives to strengthen its position in the wholesale markets through marketing of capacity and energy

The factors which adversely affect the Company's business risk profile as perceived by investors include:

- . The relatively large concentration of assets in the Susquehanna station
- . Nuclear decommissioning costs
- . Coal mine closure costs, including miners' health care costs
- . Relatively high cost of energy obtained from NUGs
- . Potential CAAA compliance in Phase II
- . Other environmental issues

The Company's financial condition was compared to that of the Barometer Group and the S&P Public Utilities (an industry-wide group identified on pages 3 and 4 of Schedule 4). The financial data for the fundamental risk analysis may be found on Schedules 2, 3 and 4. An objective assessment of these data would indicate that the Barometer Group has somewhat lower risk than PP&L Resources, and thus its market evidence would understate the Company's cost of equity. Higher risk traits for the Company vis-a-vis Barometer Group would include: the Company has a somewhat lower bond rating (i.e., A- for PP&L compared with A for the Barometer Group), the Company has higher financial risk (i.e., a 42.3% common equity ratio for PP&L Resources compared to 44.7% common equity ratio for the Barometer Group), the Company has more variable earned returns (i.e., a coefficient of variation of 0.156 for PP&L Resources compared to 0.018 for the Barometer Group), and the Company has somewhat higher systematic risk (i.e., .77 beta for PP&L Resources compared to .72 beta for the Barometer Group).

Highlights of the methods employed to measure the cost of equity with PP&L Resources and the Barometer Group data follows:

Discounted Cash Flow ("DCF") provides a familiar measure of the cost of equity for PP&L Resources and the Barometer Group. The DCF return (i.e., "k") is the sum of the adjusted dividend yield (i.e., " D_1/P_0 ") and the growth rate (i.e., "g"). The resulting DCF cost rate is:

	D_1/P_0	+	g	=	k
PP&L Resources	7.59%	+	3.50%	=	11.09%
Barometer Group	6.97%	+	3.50%	=	10.47%

The DCF result shown above represents the simplified form of the model which contains a constant growth assumption.

Although the DCF model contains a variety of restrictive assumptions which severely limit its usefulness in the ratesetting context, the model has been employed with data for PP&L Resources and the Barometer Group using a dividend yield of 7.40% and

6.80%, respectively, based upon consideration of the 12-month average (i.e., 7.24% for PP&L Resources and 6.74% for the Barometer Group), 6-month average (7.44% for PP&L Resources and 6.81% for the Barometer Group), and 3-month average (7.31% for PP&L Resources and 6.75% for the Barometer Group) dividend yields shown on Schedule 5 pages 1 and 2. The dividend yields shown on that schedule reflect an ex-dividend adjustment. While the 7.40% and 6.80% dividend yields are not intended to represent a specific historical average, they are similar to the six-month averages. Using three different but generally acceptable formulas, the 7.40% and 6.80% dividend yields have been positioned in a forward-looking manner to arrive at the 7.59% adjusted dividend yield for PP&L Resources and 6.97% adjusted dividend yield for the Barometer Group.

The growth component for PP&L Resources and the Barometer Group consists of 3.00% growth attributed to company-specific factors and 0.50% attributed to market-wide factors. The support for the company-specific growth rates may be found on Schedules 6 and 7. The elements considered were growth in earnings per share, dividend per share, book value per share, cash flow per share, and internal growth for PP&L Resources and the Barometer Group using historical and projected data typically considered by investors. While some DCF devotees would advocate that mathematical precision should be followed when selecting a growth rate (i.e., precise input variables often considered within the confines of retention growth), the fact is that investors, when establishing the market prices for a firm, do not behave in the same manner assumed by the constant growth rate models using accounting values. Rather, investors consider both company-specific variables and overall market sentiment (i.e., level of inflation rates, interest rates, economic conditions, etc.) when balancing their capital gains expectations with their current dividend yield requirements.

To the company-specific growth rate of 3.00%, market-wide factors add 0.50% to the growth rate. Market-wide factors would include overall business conditions, monetary policy, fiscal and tax policy, the value of the dollar in foreign exchange, the balance of trade, all of which would comprise qualitative influences on investors' total return expectations. Qualitative factors must be considered because the fundamental analysis employed in reaching a growth rate forecast -- see Schedules 6 and 7 -- will not fully account for all market-wide factors because the quantitative growth analysis is company-specific. It is also not known to what extent securities' analysts incorporate market-wide factors into their estimates, or that analysts do this uniformly. In addition, as the electric industry adjusts to the new business environment, additional opportunities and risk will surely develop beyond the five-year horizon typically considered by the analysts' forecasts. The combination of both quantitative factors, as shown by company-specific variables, and qualitative factors, as shown by general investor sentiment, together form

the foundation for the capital appreciation (i.e., capital gains yield) that investors expect from owning a common stock.

As noted above, there are a wide variety of factors that influence investor expected returns which are not linked to company-specific performance. In an article in Standard & Poor's The Outlook (February 21, 1996), the relative valuation of common stocks was explained in part by qualitative factors (i.e., favorable psychology). Recognition of market-wide factors is needed to synchronize the growth rate in the DCF with the stock price which includes both company-specific factors and general market sentiment which includes relative P/Es, dividend yields, interest rates, the supply of stocks, etc. Therefore, for the purpose of this case, a modest 0.5% growth rate for market-wide factors has been added to the growth rate shown by company-specific variables. By considering both company-specific and market-wide factors, a 3.50% growth rate is warranted for PP&L Resources and the Barometer Group. Recognition of market-wide qualitative factors represents a reasonable adjustment to the DCF growth rate. It has been demonstrated by the Goldman Sachs study that 38% of the rise in stock prices in the 1980s occurred due to unknown factors. As to the proposition that such qualitative factors are already reflected in stock prices under the efficient market hypothesis, it is the need to synchronize the growth rate employed in the DCF with the growth rate reflected in stock prices that necessitates recognition of qualitative factors. That is to say, while stock prices may reflect all information concerning both market-related and company-specific factors, the analysts' forecasts represent only company-specific growth. To make the DCF model at all useful, the growth rate component combined with the dividend yield must provide a result that conforms with the mix of current returns from dividends and long-term returns from capital gains.

Risk Premium approach is determined by a corporate bond yield -- here defined as the interest rate on A rated public utility bonds -- plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital. The cost rate of common equity (i.e., "k") is represented by the sum of the long-term public utility debt yield (i.e., "i") and the equity risk premium (i.e., "RP"). The Risk Premium approach provides a cost of equity of:

$$\begin{array}{rcl} i & + & RP & = & k \\ 7.75\% & + & 4.75\% & = & 12.50\% \end{array}$$

The interest rate component of the Risk Premium approach is 7.75% based upon historical yields on A rated public utility bonds -- see Schedule 8 -- and forecasts published by Blue Chip Financial Forecasts. Forecast yields for A rated public utility long-term debt (according to the January 1, 1997 Blue Chip Financial Forecast) are as follows:

<u>Quarter</u>	<u>Yield</u>
1st Qtr. 1997	7.6%
2nd Qtr. 1997	7.6
3rd Qtr. 1997	7.6
4th Qtr. 1997	7.5
1st Qtr. 1998	7.6
2nd Qtr. 1998	7.6

The average analysts' projection for the second quarter of 1998 is bounded by an 8.3% average of the highest ten estimates and a 7.0% average of the lowest ten estimates. Given these forecasts and the historical long-term interest rates, a 7.75% yield on A rated public utility bonds is reasonable.

Schedule 9 provides the financial returns that were used to develop the appropriate equity risk premium for the S&P Public Utilities, from which the equity risk premium for PP&L Resources and the Barometer Group was determined. To develop an appropriate risk premium, the results were analyzed for the S&P Public Utilities by averaging (i) the midpoint of the range shown by the geometric mean and median and (ii) the arithmetic mean. As shown by the values indicated on page 2 of Schedule 9, the indicated risk premiums for the various time periods analyzed are 5.28% (1928-1996), 6.15% (1952-1996), 5.28% (1974-1996), and 5.55% (1979-1996). The selection of the shorter periods taken from the entire historical series was designed to provide a risk premium which conforms more nearly with present investment fundamentals and removes some of the more distant data from the analysis. Using the summary values provided on page 2 of Schedule 9, the 1928-1996 and 1974-1996 periods provided the lowest indicated risk premium, while the 1952-1996 period provides the highest risk premium for the S&P Public Utilities. Within these bounds, a common equity risk premium of 5.42% ($5.28\% + 5.55\% = 10.83\%$, $\div 2$) is shown from data covering the periods 1974-1996 and 1979-1996 which represents the more recent results. Based upon various measures of risk differentials among PP&L Resources, the Barometer Group and the S&P Public Utilities including size, market ratios, common equity ratio, return on book equity, operating ratios, coverages, quality of earnings, internally generated funds, and betas (see Schedules 2, 3, and 4), these differences indicate that 4.75% represents a reasonable common equity risk premium in this case. This represents 88% ($4.75\% \div 5.42\%$) of the risk premium of the S&P Public Utilities and is reflective of the risk of PP&L Resources and the Barometer Group compared with that of the S&P Public Utilities.

Capital Asset Pricing Model ("CAPM") cost of equity is represented by a yield on a risk-free interest bearing obligation plus a return representing a premium which is proportional to the systematic risk of an investment. In contrast to the Risk Premium

approach which considers industry and company-specific factors, the CAPM reflects just systematic risk as measured by a stock's beta -- the risk associated with changes in the overall market for common equities. Two forms of the CAPM have been employed -- the traditional Sharpe-Lintner model and a zero-beta form of the model. The components used to implement the traditional CAPM are shown on Schedule 10: page 1 for the beta, pages 2, 3 and 4 for the risk-free rate of return, and pages 5, 6 and 7 for the market premiums. From both the historical and forecast data, a risk-free rate of return of 6.75% for 30-year Treasury bonds is reasonable for CAPM purposes. The calculation of the market premium is developed from both historical market performance (i.e., 12.7% - 5.4% = 7.3%) and by the Value Line and S&P forecasts (i.e., 13.48% - 6.75% = 6.73%). The resulting market premium is 7.02% (7.3% + 6.73% = 14.03% , 2) which represents the average market premium using the historical SBBI data and the Value Line forecasts. Using the 6.75% risk-free rate of return, the average beta of .76 for PP&L Resources and .73 for the Barometer Group, and the appropriate market premium, the following CAPM results are indicated:

	<i>R_f</i>	+	<i>b</i>	(<i>R_m</i> - <i>R_f</i>)	=	<i>k</i>
PP&L Resources	6.75%	+	.76	(7.02%)	=	12.09%
Barometer Group	6.75%	+	.73	(7.02%)	=	11.87%

To develop a return on a portfolio with a zero-beta ("R_z"), one-half of the market premium was assigned to the intermediate term Treasury note yield -- the Treasury note yield being 0.25% less than the yield on 30-year Treasury bonds. Here, the R_z is 10.07% (6.50% + 3.57%). The market premium which provides the basis for the return on the zero-beta portfolio was calculated in a manner similar to that described for the traditional CAPM above. Here, the forecast market premium (13.48% - 6.50% = 6.98%) was developed from the Value Line and S&P projections and was combined with the historical results taken from the SBBI data series (i.e., 12.7% - 5.4% = 7.3%) to produce an average 7.14% (6.98% + 7.3% = 14.28% , 2) market premium. One-half of the market premium (7.14% , 2 = 3.57%) was then assigned to the zero-beta portfolio and the remaining 3.57% was adjusted for the systematic risk of PP&L Resources and Barometer Group. Using the 10.07% return on a zero-beta portfolio, the average beta of .76 for PP&L Resources and .73 for the Barometer Group, and the appropriate market premium, the following results are indicated.

	R_f	+	b	$(R_m - R_f)$	=	k
PP&L Resources	10.07%	+	.76	(3.57%)	=	12.78%
Barometer Group	10.07%	+	.73	(3.57%)	=	12.68%

The average CAPM result is 12.44% (12.09% + 12.78% = 24.87% , 2) for PP&L Resources and the average CAPM result is 12.28% (11.87% + 12.68% = 24.55% , 2) for the Barometer Group.

Comparable Earnings approach has been used extensively in rate of return analysis for over a half century. The Comparable Earnings approach has been implemented in this case with data taken from thirteen (13) non-regulated companies using six criteria from the Value Screen Data Base to establish comparability as set forth on page 1 of Schedule 11. Based upon an average of historical and forecast rates of return on book common equity, the Comparable Earnings result is supported by the data provided on page 2 of Schedule 11. That average is 15.05% (15.4% + 14.7% = 30.1% , 2) for the Comparable Earnings group. The Comparable Earnings result was verified by use of a market-determined cost of equity for the same Comparable Earnings companies as set forth on page 3 of Schedule 11. The Comparable Earnings approach is consistent with the Company's move from cost-of-service ratesetting to competitive markets. As such, the Company's risk will increase in the future and the ratesetting process should emulate the returns achieved by non-regulated firms operating in a competitive market . This makes the Comparable Earnings approach relevant to a measurement of the Company's cost of equity.

Credit Quality issues also play a critical role in the determination of the Company's rate of return on common equity. It is necessary to verify the reasonableness of the overall rate of return which must include a reasonable cost of equity by reference to the benchmarks of credit quality in order to satisfy the capital attraction and maintenance of credit standards of a fair rate of return. It is important that the Company is provided with a reasonable opportunity to achieve adequate credit quality so that its financial condition is commensurate with its public service obligation. In this regard, coverage of the Company's senior capital costs reveals the level of protection that PP&L can supply for its fixed obligations. Interest coverage is measured on both a before- and after-income tax basis. Normally, before-income tax coverage is used for the purpose of a company's debt interest coverage and overall after-income tax coverage is the measure employed with regard to interest charges and preferred stock dividends.

It is important to re-emphasize that public utilities must compete in the capital markets to attract needed future dollars and, as such, interest coverage should be used as a test to measure the adequacy of the rate of return. Of course, it is not the only factor to be considered in testing the appropriate rate of return and must be viewed in relation to

an individual company's degree of financial leverage and cash flow benchmarks. Maintenance of a strong A bond rating financial profile is the appropriate regulatory objective and an AA bond rating should be encouraged. Strong credit quality is necessary to provide a utility with the highest degree of financial flexibility in order to attract capital on reasonable terms during all economic conditions. Using a 41.4935% statutory federal and state income tax rate, the pre-tax coverage of interest expense would be 3.65 times assuming the Company could actually realize an 11.5% rate of return on common equity in the context of the December 31, 1996 capital structure. This pre-tax interest coverage is shown on Schedule 1, together with post-tax coverage of interest expense and overall coverage of interest and preferred stock dividends.

The pre-tax interest coverage and debt leverage shown on Schedule 1 should be viewed in the context of the S&P bond rating criteria which specifies 3.50 times pre-tax interest coverage and a 47% debt ratio for an A bond rating for an electric utility with an average business position. It is important to recognize that the benchmarks represent levels expected to be achieved. With these credit quality benchmarks, the Company needs to achieve at a minimum the credit quality profile reflective of the financial conditions shown on Schedule 1. The Commission should encourage higher levels of interest coverage in the context of higher credit quality standards for the electric utilities in an increasingly competitive electric utility industry.

EXHIBIT PRM 2

PENNSYLVANIA POWER & LIGHT COMPANY

Exhibit to Accompany
the Direct Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates, Inc.

Concerning
Fair Rate of Return

PENNSYLVANIA POWER & LIGHT COMPANY

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Pennsylvania Power & Light Company
Rate of Return Calculation
Actual at December 31, 1996

<u>Type of Capital</u>	<u>Ratios</u>	<u>Cost Rate</u>	<u>Weighted Cost Rate</u>
Long-Term Debt	47.01%	7.89%	3.71%
Preferred Stock	7.79%	7.10%	0.55%
Common Equity	<u>45.20%</u>	<u>11.50%</u>	<u>5.20%</u>
Overall Cost of Capital	<u>100.00%</u>		<u>9.46%</u>

Indicated level of fixed coverage assuming the Company could actually achieve a 9.46% overall rate of return.

Before-income tax coverage of interest expense based upon a 41.4935% effective federal and state income tax rate.

(13.54% / 3.71%)

3.65x

After-income tax coverage of interest expense

(9.46% / 3.71%)

2.55x

Overall coverage of interest expense and preferred stock dividends (9.46% / 4.26%)

2.22x

PP&L Resources
Capitalization and Financial Statistics
1991-1995, Inclusive

	<u>1995</u>	<u>1994</u>	<u>1993</u>	<u>1992</u>	<u>1991</u>	
	(Thousands of Dollars)					
<u>Amount of Capital Employed</u>						
Total Permanent Capital (incl. cap. leases)	\$6,141,853	\$6,086,397	\$5,843,805	\$5,794,368	\$5,748,184	
Short-Term Debt	89,145	74,168	202,260	159,348	147,170	
Total-Capital Employed	<u>\$6,230,998</u>	<u>\$6,160,565</u>	<u>\$6,046,065</u>	<u>\$5,953,716</u>	<u>\$5,895,354</u>	
<u>Indicated Average Capital Cost Rates (1)</u>						
Long Term Debt	6.8%	7.1%	7.8%	8.4%	8.2%	
<u>Financial Ratios-Market Based</u>						
Earnings/Price Ratio	9.2%	6.1%	7.2%	7.8%	8.5%	<u>5 Year Average</u> 7.8%
Market/Average Book	138.3%	144.6%	181.2%	169.6%	158.1%	158.4%
Dividend Yield	7.5%	7.3%	5.8%	6.1%	6.6%	6.7%
Dividend Payout Ratio	81.7%	118.8%	79.8%	79.2%	77.2%	87.3%
<u>Capital Structure Ratios</u>						
Based on Total Permanent Capital:						
Long-Term Debt	50.1%	52.0%	49.8%	49.7%	49.6%	50.2%
Preferred Stock	7.6%	7.7%	8.7%	9.5%	10.4%	8.8%
Common Equity	<u>42.3%</u>	<u>40.3%</u>	<u>41.5%</u>	<u>40.8%</u>	<u>40.0%</u>	<u>41.0%</u>
	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>
Based on Total Capital:						
Total Debt, Including Short Term	50.8%	52.6%	51.5%	51.0%	50.9%	51.3%
Preferred Stock	7.5%	7.6%	8.4%	9.2%	10.1%	8.6%
Common Equity	<u>41.7%</u>	<u>39.8%</u>	<u>40.1%</u>	<u>39.8%</u>	<u>39.0%</u>	<u>40.1%</u>
	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>
<u>Rate of Return on Average Book Common Equity</u>	12.8%	8.8%	13.1%	13.1%	13.4%	12.2%
<u>Operating Ratios (2)</u>	69.6%	73.6%	70.7%	70.8%	68.8%	70.7%
<u>Coverages-Including All AFC (3)</u>						
Before Income Taxes: All Interest Charges	3.6 x	2.8 x	3.4 x	3.3 x	3.2 x	3.3 x
After Income Taxes: All Interest Charges	2.4	2.0	2.4	2.4	2.4	2.3
Overall Coverage: All Interest + Pfd. Div.	2.1	1.8	2.1	2.0	2.0	2.0
<u>Coverages-Excluding All AFC</u>						
Before Income Taxes: All Interest Charges	3.5 x	2.8 x	3.4 x	3.2 x	3.2 x	3.2 x
After Income Taxes: All Interest Charges	2.3	2.0	2.4	2.3	2.3	2.3
Overall Coverage: All Interest + Pfd. Div.	2.1	1.8	2.1	2.0	2.0	2.0
<u>Quality of Earnings</u>						
AFC/Income Available for Common Equity	3.7%	6.1%	5.0%	4.9%	3.9%	4.7%
Effective Income Tax Rate	46.9	42.4	40.2	39.7	38.3	41.5
Internal Cash Generation/Gross Construction (4)	97.1	91.9	88.9	108.0	137.6	104.7
Gross Cash Flow/ Permanent Capital (5)	10.9	12.1	12.1	12.5	13.5	12.2
Gross Cash Flow/ Avg. Total Debt(6)	20.9	23.2	22.9	23.9	25.8	23.3
Gross Cash Flow Interest Coverage(7)	3.9 x	4.1 x	3.9 x	3.9 x	4.1 x	4.0 x
Common Dividend Coverage (8)	2.4	2.8	2.7	2.8	3.1	2.8

See Page 2 for Notes

PP&L Resources, Inc.
Capitalization and Financial Statistics
1991-1995, Inclusive

Notes:

- (1) Computed by relating actual long-term debt interest expense booked to average of beginning and ending long-term debt reported to be outstanding.
- (2) Total operating expenses, maintenance, depreciation and taxes other than income as a percentage of operating revenues.
- (3) Coverage calculations represent the number of times available earnings, including AFC (allowance for funds used during construction), as reported in its entirety cover fixed charges.
- (4) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally generated funds from operations and after payment of all cash dividends.
- (5) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less AFC) as a percentage of Permanent Capital (long-term debt, current maturities and preferred, preference and common equity).
- (6) Gross Cash Flow (as defined in Note 5) as a percentage of average total debt.
- (7) Gross Cash Flow (as defined in Note 5) plus interest charges, divided by interest charges.
- (8) Common dividend coverage is the relationship of internally generated funds from operations after payment of preferred stock dividends to common dividends paid.

	<u>Bond Rating</u>		<u>Common Stock Traded</u>	<u>S&P Common Stock Ranking</u>	<u>Market Sensitivity Statistics</u>		<u>Business Position</u>
	<u>Moody's</u>	<u>S&P</u>			<u>Beta</u>	<u>R²</u>	
PP&L Resources, Inc.	A2	A-	NYSE	A-	0.77	0.09	Average

Source of Information: OneSource
Standard & Poor's Utility Compustat
Moody's Public Utilities Manual and Bond Survey
S&P Bond Guide and Creditweek
S&P Stock Guide
Merrill Lynch Security Risk Evaluation, January 1997

Barometer Group of Eight Electric Companies
Capitalization and Financial Statistics (1)
1991-1995, Inclusive

	<u>1995</u>	<u>1994</u>	<u>1993</u>	<u>1992</u>	<u>1991</u>	
	(Thousands of Dollars)					
Amount of Capital Employed						
Total Permanent Capital	\$5,501,810	\$5,516,467	\$5,314,474	\$5,182,525	\$4,998,591	
Short-Term Debt	<u>303,305</u>	<u>176,721</u>	<u>184,327</u>	<u>152,307</u>	<u>200,394</u>	
Total Capital Employed	<u>\$5,805,115</u>	<u>\$5,693,188</u>	<u>\$5,498,800</u>	<u>\$5,334,832</u>	<u>\$5,198,985</u>	
Indicated Average Capital Cost Rates (2)						
Long Term Debt	6.6%	6.7%	7.2%	7.4%	7.6%	
Financial Ratios-Market Based						
Earnings/Price Ratio	7.5%	8.3%	7.2%	7.5%	8.4%	<u>5 Year Average</u> 7.8%
Market/Average Book	147.0%	140.7%	162.6%	149.8%	135.8%	147.2%
Dividend Yield	6.9%	7.2%	6.3%	6.9%	7.6%	7.0%
Dividend Payout Ratio	104.8%	88.1%	89.6%	91.3%	91.3%	93.0%
Capital Structure Ratios						
Based on Total Permanent Capital:						
Long-Term Debt	49.2%	48.7%	48.3%	48.5%	49.4%	48.8%
Preferred Stock	6.1%	7.0%	7.6%	8.0%	7.7%	7.3%
Common Equity	<u>44.7%</u>	<u>44.4%</u>	<u>44.2%</u>	<u>43.5%</u>	<u>42.9%</u>	<u>43.9%</u>
	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>
Based on Total Capital:						
Total Debt, Including Short Term	51.5%	49.9%	49.6%	50.0%	51.1%	50.4%
Preferred Stock	5.8%	6.8%	7.4%	7.8%	7.4%	7.1%
Common Equity	<u>42.7%</u>	<u>43.3%</u>	<u>43.0%</u>	<u>42.2%</u>	<u>41.4%</u>	<u>42.5%</u>
	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>
Rate of Return on Average Book Common Equity	10.9%	11.5%	11.5%	11.3%	11.4%	11.3%
Operating Ratios (3)	76.0%	76.4%	76.4%	78.2%	78.0%	77.0%
Coverages-Including All AFC (4)						
Before Income Taxes: All Interest Charges	3.1 x	3.3 x	3.1 x	3.0 x	2.9 x	3.1 x
After Income Taxes: All Interest Charges	2.3	2.5	2.4	2.3	2.3	2.4
Overall Coverage: All Interest + Pfd. Div.	2.1	2.2	2.1	2.0	2.0	2.1
Coverages-Excluding All AFC						
Before Income Taxes: All Interest Charges	3.1 x	3.2 x	3.0 x	2.9 x	2.7 x	3.0 x
After Income Taxes: All Interest Charges	2.3	2.4	2.3	2.2	2.1	2.3
Overall Coverage: All Interest + Pfd. Div.	2.0	2.1	2.0	1.9	1.9	2.0
Quality of Earnings						
AFC/Income Available for Common Equity	5.1%	7.1%	7.0%	8.0%	12.5%	7.9%
Effective Income Tax Rate	35.8	33.4	33.4	32.6	31.8	33.4
Internal Cash Generation/Gross Construction (4)	113.1	84.9	67.8	71.9	56.6	78.8
Gross Cash Flow/ Permanent Capital (5)	11.3	10.7	10.0	9.8	9.6	10.3
Gross Cash Flow/ Avg. Total Debt(7)	22.2	21.6	20.3	19.5	18.7	20.5
Gross Cash Flow Interest Coverage(8)	4.0 x	4.0 x	3.7 x	3.6 x	3.4 x	3.7 x
Common Dividend Coverage (9)	2.5	2.3	2.2	2.1	2.1	2.2

See Page 2 for Notes.

Barometer Group of Eight Electric Companies
Capitalization and Financial Statistics
1991-1995. Inclusive

Notes:

- (1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
- (2) Computed by relating actual long-term interest expense booked to average beginning and ending long-term debt reported to be outstanding.
- (3) Total operating expenses, maintenance, depreciation and taxes other than income as a percentage of operating revenues.
- (4) Coverage calculations represent the number of times available earnings, including AFC (allowance for funds used during construction) as reported in its entirety cover fixed charges.
- (5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations and after payment of all cash dividends.
- (6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income tax and investment tax credits, less total AFC) as a percentage of Permanent Capital (long-term debt, current maturities and preferred, preference and common equity).
- (7) Gross Cash Flow (as defined in Note 6) as a percentage of average total debt.
- (8) Gross Cash Flow (as defined in Note 6) plus interest charges, divided by interest charges.
- (9) Common dividend coverage is the relationship of internally-generated funds from operations and after payment of preferred stock dividends to common dividends.

Basis of Selection:

The criteria used in the selection of this barometer group of Electric Companies were to include those companies that are included in Standard & Poor's Utility Compustat II, have SIC Code, 4911 (Electric Services) and 4931 (Electric and other services combined), common stock which is traded on the NYSE, operate in Pennsylvania or the six contiguous states to it, have not cut or omitted their dividends, have 1995 operating revenues above \$750 million.

	<u>Bond Rating</u>		<u>Common Stock Traded</u>	<u>S&P Common Stock Ranking</u>	<u>Market Sensitivity Statistics</u>		<u>Business Position</u>
	<u>Moody's</u>	<u>S&P</u>			<u>Beta</u>	<u>R²</u>	
Allegheny Power System(1)	Aa3	A+	NYSE	A-	0.71	0.10	High Average
American Electric Power Co.(2)	Baa1	BBB+	NYSE	B+	0.70	0.07	Somewhat Above Avg.
Atlantic Energy, Inc.(3)	A3	A-	NYSE	A-	0.65	0.04	Low Average
Baltimore Gas & Electric Co.	A1	A+	NYSE	A	0.85	0.20	Average
Delmarva Power & Light Co.	A2	A	NYSE	B+	0.58	0.04	Average
DPL, Inc.(4)	A1	AA-	NYSE	A-	0.60	0.07	High Average
Potomac Electric Power Co.	A1	A	NYSE	B	0.81	0.12	Somewhat Above Avg.
Public Service Enterprise Group (5)	<u>A2</u>	<u>A-</u>	NYSE	<u>B+</u>	<u>0.87</u>	<u>0.21</u>	<u>Somewhat Below Avg.</u>
	<u>A2</u>	<u>A</u>		<u>A-</u>	<u>0.72</u>	<u>0.11</u>	<u>Average</u>

- Notes: (1) Bond ratings are a subsidiary composite.
 (2) Bond ratings are a subsidiary composite.
 (3) Bond ratings are those of Atlantic City Electric Co.
 (4) Bond ratings are those of Dayton Power & Light Co.
 (5) Bond ratings are those of Public Service Electric & Gas Co.

Source of Information: OneSource;
 Standard & Poor's Utility Compustat II
 Moody's Public Utility Manual and Bond Surveys
 S&P Bond Guides, CreditWeek
 S&P Stock Guides
 Merrill Lynch Security Risk Evaluation, January 1997

Standard & Poor's Utility Index
Capitalization and Financial Statistics(1)
1991-1995, Inclusive

	<u>1995</u>	<u>1994</u>	<u>1993</u>	<u>1992</u>	<u>1991</u>	
Amount of Capital Employed						
Total Permanent Capital	\$8,234,409	\$8,186,018	\$8,193,131	\$8,283,170	\$8,287,889	
Short-Term Debt	<u>413,347</u>	<u>441,852</u>	<u>471,132</u>	<u>376,505</u>	<u>368,474</u>	
Total Capital Employed	<u>\$8,647,757</u>	<u>\$8,627,870</u>	<u>\$8,664,263</u>	<u>\$8,659,674</u>	<u>\$8,656,363</u>	
Indicated Average Capital Cost Rates (2)						
Long Term Debt	4.0%	4.6%	5.5%	5.5%	5.8%	
Financial Ratios-Market Based						
Earnings/Price Ratio	6.7%	6.9%	4.7%	7.1%	6.0%	<u>5 Year Average</u> 6.3%
Market/Average Book	236.6%	200.8%	215.6%	180.4%	170.2%	200.7%
Dividend Yield	4.8%	5.5%	4.9%	5.7%	5.9%	5.4%
Dividend Payout Ratio	68.8%	77.6%	99.3%	78.4%	93.2%	83.5%
Capital Structure Ratios						
Based on Total Permanent Capital:						
Long-Term Debt	50.2%	48.5%	48.2%	49.1%	49.7%	49.1%
Preferred Stock	4.6%	4.6%	4.4%	4.4%	4.4%	4.5%
Common Equity	<u>45.2%</u>	<u>46.9%</u>	<u>47.4%</u>	<u>46.5%</u>	<u>45.9%</u>	<u>46.4%</u>
	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>
Based on Total Capital:						
Total Debt, Including Short Term	52.6%	51.2%	51.0%	51.3%	51.9%	51.6%
Preferred Stock	4.4%	4.3%	4.2%	4.2%	4.2%	4.3%
Common Equity	<u>43.0%</u>	<u>44.5%</u>	<u>44.8%</u>	<u>44.5%</u>	<u>43.9%</u>	<u>44.1%</u>
	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>
Rate of Return on Average Book Common Equity	14.5%	13.7%	10.4%	12.9%	10.7%	12.4%
Operating Ratios (3)	83.8%	84.7%	86.5%	84.1%	84.9%	84.8%
Coverages-Including All AFC (4)						
Before Income Taxes: All Interest Charges	3.4 x	3.5 x	2.8 x	3.0 x	2.5 x	3.0 x
After Income Taxes: All Interest Charges	2.5	2.6	2.1	2.3	2.0	2.3
Overall Coverage: All Interest + Pfd. Div.	2.3	2.4	2.0	2.2	1.9	2.2
Coverages-Excluding All AFC						
Before Income Taxes: All Interest Charges	3.4 x	3.4 x	2.7 x	3.0 x	2.5 x	3.0 x
After Income Taxes: All Interest Charges	2.5	2.5	2.1	2.3	1.9	2.3
Overall Coverage: All Interest + Pfd. Div.	2.3	2.4	2.0	2.1	1.8	2.1
Quality of Earnings						
AFC/Income Available for Common Equity	2.7 %	2.9 %	5.6 %	4.6 %	6.9 %	4.5 %
Effective Income Tax Rate	37.8	36.2	36.5	34.5	34.6	35.9
Internal Cash Generation/Gross Construction (5)	113.7	100.7	104.9	95.5	91.7	101.3
Gross Cash Flow/ Permanent Capital (6)	16.1	16.2	16.5	15.0	14.4	15.6
Gross Cash Flow/ Avg. Total Debt(7)	29.6	30.0	30.4	27.7	27.0	28.9
Gross Cash Flow Interest Coverage(8)	4.6 x	4.9 x	4.8 x	4.3 x	4.0 x	4.5 x
Common Dividend Coverage (9)	3.5	3.2	3.3	3.1	3.1	3.2

See Page 2 for Notes.

Standard & Poor's Utility Index
Capitalization and Financial Statistics
1991-1995, Inclusive

Notes:

- (1) All capitalization and financial statistics for the group are the aggregated result of the 48 companies in the group.
- (2) Computed by relating actual long-term debt interest booked to average of beginning and ending long-term debt reported to be outstanding.
- (3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
- (4) Coverage calculations represent the number of times available earnings, including AFC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
- (5) Internal cash generation/gross construction is the percentage of capital additions to utility plant, provided by internally-generated funds from operations, excluding all AFC, and after payment of all cash dividends divided by gross contribution expenditures.
- (6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFC) as a percent of preference and common equity).
- (7) Gross Cash Flow (as defined in Note 6) as a percentage of average total debt.
- (8) Gross Cash Flow (as defined in Note 6) plus interest charges, divided by interest charges.
- (9) Common dividend coverage is the relationship of internally-generated funds from operations, excluding all AFC, and after payment of preferred stock dividends to common dividends paid.

Source of Information: Standard & Poor's
Compustat Customer Business Unit

Standard & Poor's Utility Index
Capitalization and Financial Statistics
December 31, 1995

	<u>Bond</u>		<u>Common</u> <u>Stock</u> <u>Traded</u>	<u>S&P</u> <u>Common</u> <u>Stock</u> <u>Ranking</u>	<u>Market</u> <u>Sensitivity</u> <u>Statistics</u>		
	<u>Rating</u>				<u>Adjusted</u>	<u>Beta</u>	<u>R²</u>
	<u>Moody's</u>	<u>S&P</u>					
<u>Electric Utilities</u>							
American Electric Power Co., Inc. (1)	Baa1	BBB+	NYSE	B+	0.70	0.07	
Baltimore Gas & Electric Company	A1	A+	NYSE	A	0.85	0.20	
Carolina Power & Light Company	A2	A	NYSE	A-	0.85	0.15	
Central & South West Corp. (1)	Aa3	AA-	NYSE	A-	0.77	0.13	
CINergy Corporation (1)	Baa2	A-	NYSE	B	0.85	0.24	
Consolidated Edison Co.	Aa3	A+	NYSE	A	0.73	0.07	
DTE Energy Company	Baa1	BBB+	NYSE	B+	0.87	0.19	
Dominion Resources, Inc. (1)	A1	A	NYSE	A-	0.61	0.07	
Duke Power Company	Aa2	AA-	NYSE	A-	0.63	0.07	
Edison International (1)	Aa2	A+	NYSE	B+	1.08	0.18	
Entergy Corp. (1)	Baa3	BBB	NYSE	B	0.90	0.14	
FPL Group, Inc. (1)	A2	AA-	NYSE	B	0.59	0.04	
General Public Utilities	Baa1	BBB+	NYSE	B	0.80	0.15	
Houston Industries, Inc. (1)	A2	A	NYSE	B+	0.76	0.09	
Niagara Mohawk Power Corp.	Baa3	BB-	NYSE	B	0.70	0.02	
Northern States Power Company (2)	Aa2	AA	NYSE	A-	0.74	0.18	
Ohio Edison Company (2)	Baa2	BBB-	NYSE	B	0.81	0.15	
Pacific Gas & Electric Company	A2	A	NYSE	B	1.08	0.24	
Pacificorp (2)	A2	A	NYSE	B+	0.62	0.05	
PECO Energy Company (1)	Baa1	BBB+	NYSE	B	0.80	0.13	
PP&L Resources	A2	A-	NYSE	A-	0.77	0.09	
Public Service Enterprise Group (1)	A2	A-	NYSE	B+	0.87	0.21	
Southern Company (1)	A2	A+	NYSE	A-	0.69	0.08	
Texas Utilities Company (1)	Baa2	BBB+	NYSE	B+	0.53	0.01	
Unicom Corporation (1)	Baa2	BBB	NYSE	B	1.04	0.17	
Union Electric (2)	<u>A1</u>	<u>AA-</u>	NYSE	<u>A-</u>	<u>0.82</u>	<u>0.20</u>	
Average	<u>A2</u>	<u>A</u>		<u>A-</u>	<u>0.79</u>	<u>0.13</u>	

Standard & Poor's Utility Index
Capitalization and Financial Statistics
December 31, 1995

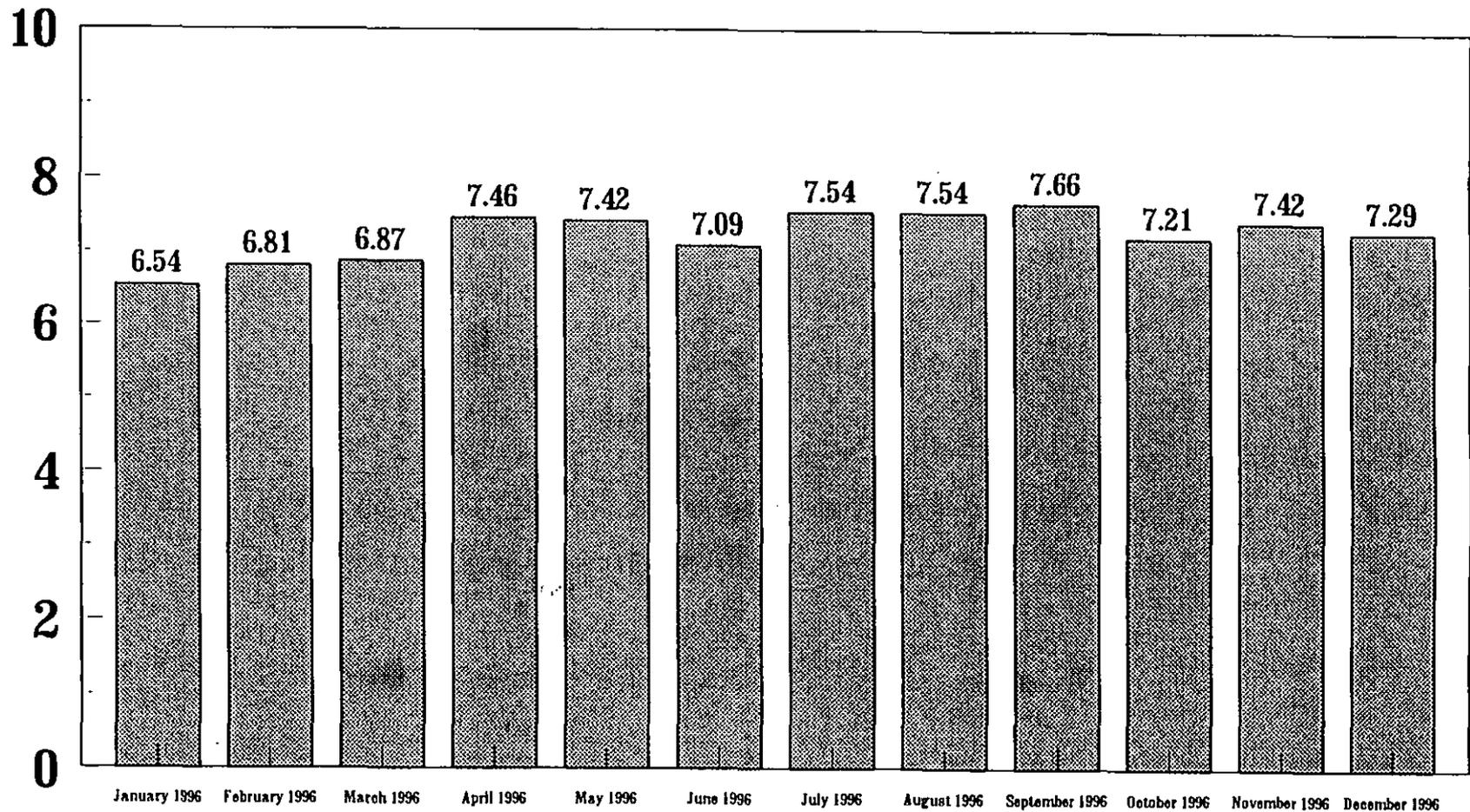
	<u>Bond Rating</u>		<u>Common Stock Traded</u>	<u>S&P Common Stock Ranking</u>	<u>Market Sensitivity Statistics</u>	
	<u>Moody's</u>	<u>S&P</u>			<u>Adjusted Beta</u>	<u>R²</u>
<u>Natural Gas Utilities</u>						
Coastal Corporation (2)	Baa2	BBB-	NYSE	B+	1.22	0.29
Columbia Gas System, Inc.	Baa3	BBB	NYSE	NR	0.94	0.09
Consolidated Natural Gas Co.	A1	AA-	NYSE	B+	0.98	0.18
Eastern Enterprises (1)	A3	A	NYSE	B+	0.70	0.06
Enron Corporation (3)	Baa2	BBB+	NYSE	B+	0.85	0.07
ENSERCH Corporation	Baa2	BBB	NYSE	B	1.47	0.20
NICOR, Inc. (1)	Aa1	AA	NYSE	B+	0.82	0.14
NorAm Energy Corp. (2)	Ba2	BB+	NYSE	B	1.22	0.10
ONEOK, Inc.	Baa1	A-	NYSE	B	0.45	0.01
Pacific Enterprises (1)	A2	AA-	NYSE	B-	0.72	0.04
Pan Energy (1)	Baa3	BBB	NYSE	B	1.33	0.25
Peoples Energy Corp. (1)	Aa3	AA-	NYSE	B+	1.16	0.27
Sonat, Inc. (1)	Baa1	A-	NYSE	B	0.97	0.09
Williams Company	<u>Baa3</u>	<u>BBB-</u>	NYSE	<u>B+</u>	<u>1.07</u>	<u>0.18</u>
Average	<u>Baa1</u>	<u>BBB+</u>		<u>B+</u>	<u>1.00</u>	<u>0.14</u>
<u>Telecommunications Companies</u>						
Alltel Corporation (3)	A1	A+	NYSE	A	0.64	0.03
Ameritech Corp. (1)	Aa	AAA	NYSE	A-	0.97	0.21
Bell Atlantic Corporation (1)	Aa2	AA+	NYSE	A-	0.81	0.15
BellSouth Corporation (1)	Aaa	AAA	NYSE	B+	0.69	0.05
GTE Corporation (1)	A1	A+	NYSE	B+	0.69	0.05
NYNEX Corporation (1)	Aa3	A	NYSE	B+	0.83	0.15
Pacific Telesis Group (1)	Aa3	AA-	NYSE	B+	0.98	0.08
SBC Communications, Inc.	A1	A+	NYSE	A	0.72	0.09
US WEST, Inc. (1)	<u>Aa3</u>	<u>AA-</u>	NYSE	<u>B+</u>	<u>0.51</u>	<u>0.01</u>
Average	<u>Aa3</u>	<u>AA-</u>		<u>B+</u>	<u>0.78</u>	<u>0.14</u>
Average for S&P Utilities	<u>A2</u>	<u>A</u>		<u>B+</u>	<u>0.85</u>	<u>0.13</u>
Indexes:						
S&P Public Utilities					0.81	0.29
S&P Industrials					1.01	0.96
S&P Composite					1.00	1.00

Notes: (1) Composite rating for subsidiaries of holding companies.
(2) Composite rating for parent company as well as subsidiaries.
(3) Parent Company rating.

Source of Information: Moody's Public Utility Manual and Bond Survey
Standard & Poor's Stock and Bond Guide
Merrill Lynch Security Risk Evaluation, January 1997

PP & L Resources, Inc.
Monthly Dividend Yields
for the Twelve Months Ended December 1996

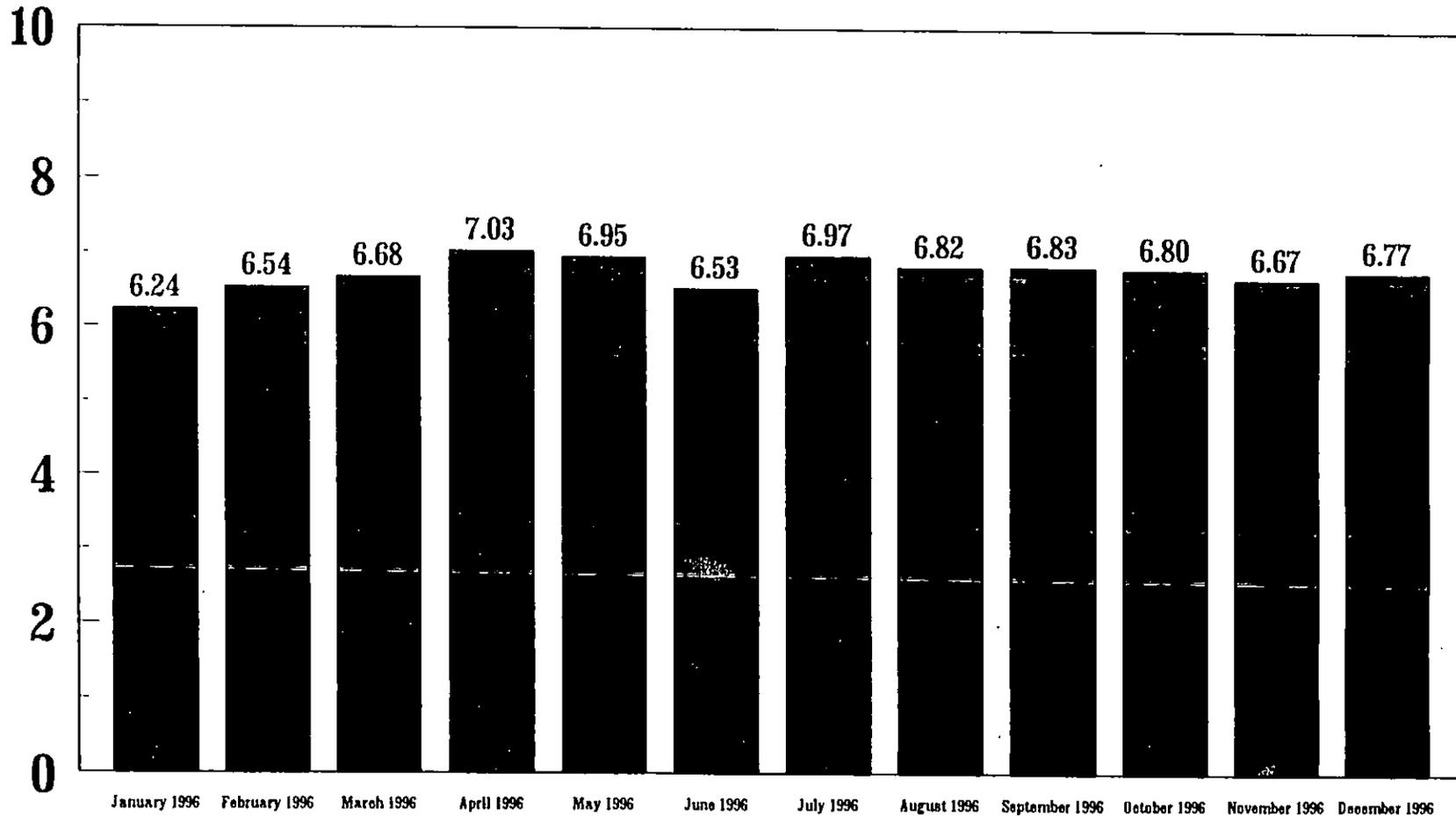
Percent (%)



Dividend Yields

Barometer Group of Eight Electric Companies
Monthly Dividend Yields
for the Twelve Months Ended December 1996

Percent (%)

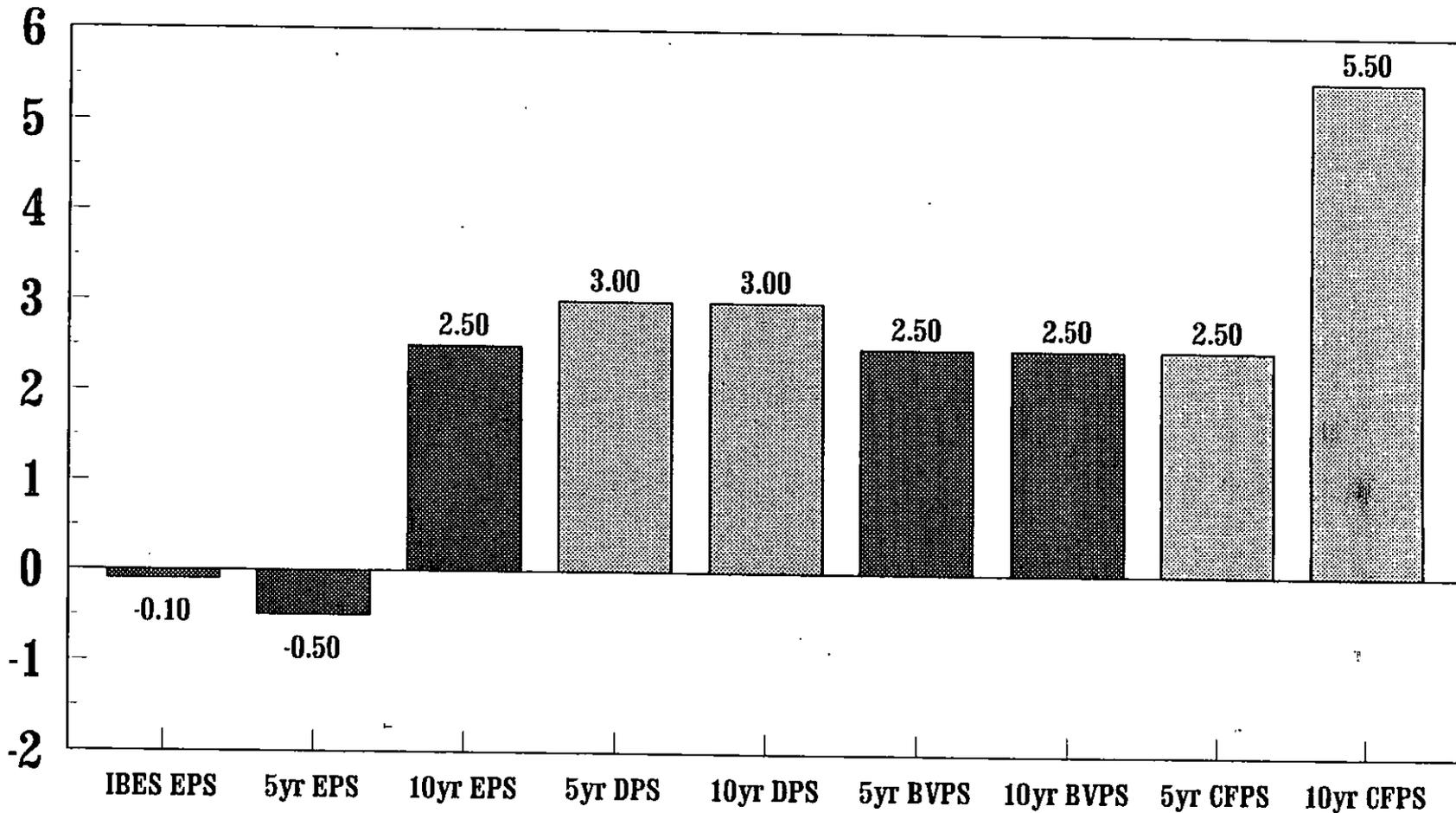


Dividend Yields

PP & L Resources, Inc.

Historical Growth Rates

Percent (%)

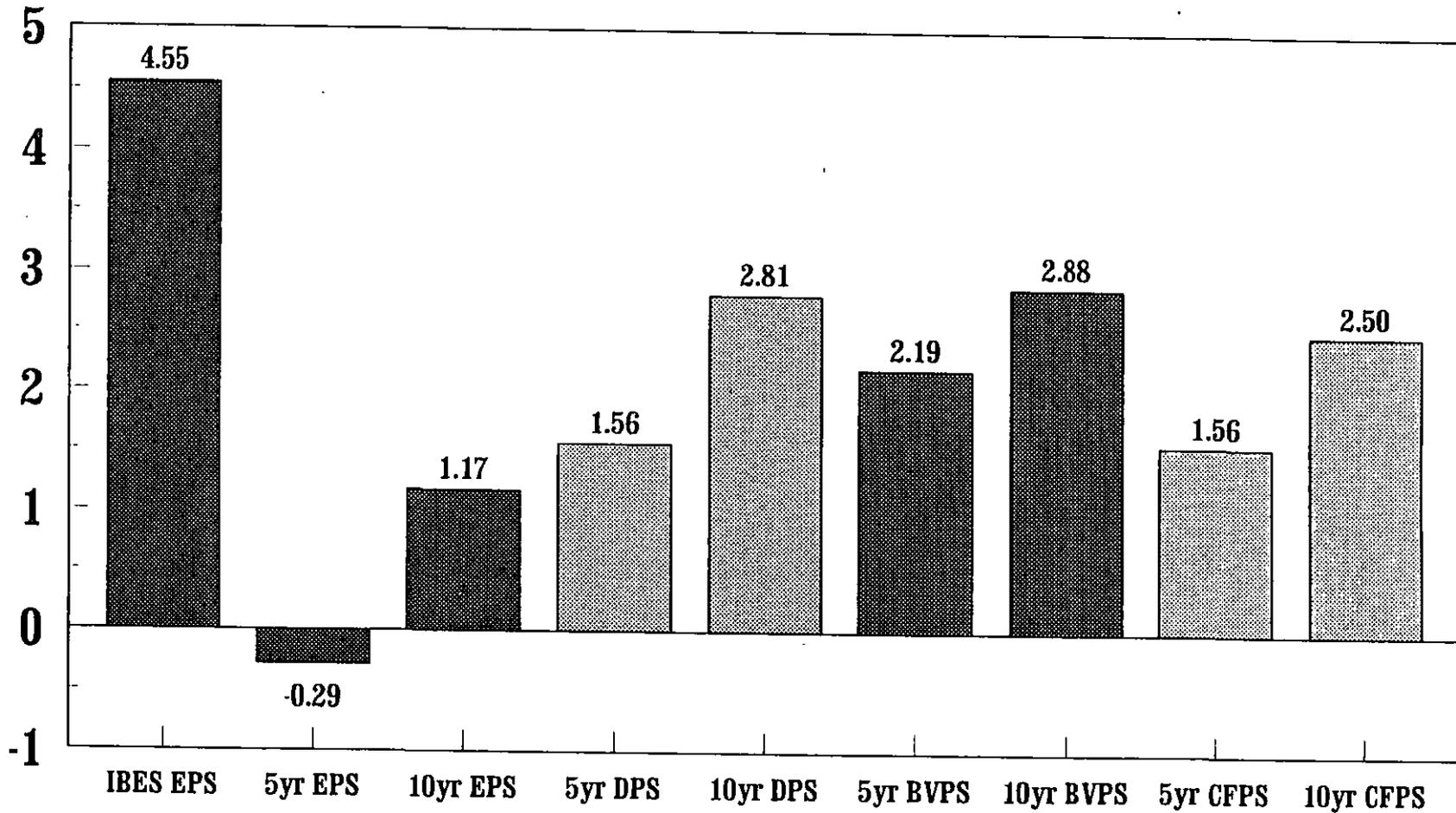


Growth Rates

EPS= Earnings Per Share, DPS= Dividends per Share,
BVPS= Book Value Per Share, CFPS= Cash Flow Per Share

Barometer Group of Eight Electric Companies Historical Growth Rates

Percent (%)



Growth Rates

EPS= Earnings Per Share, DPS= Dividends per Share,
BVPS= Book Value Per Share, CFPS= Cash Flow Per Share

Historic Internal Growth Rates
For the Years 1991-1995

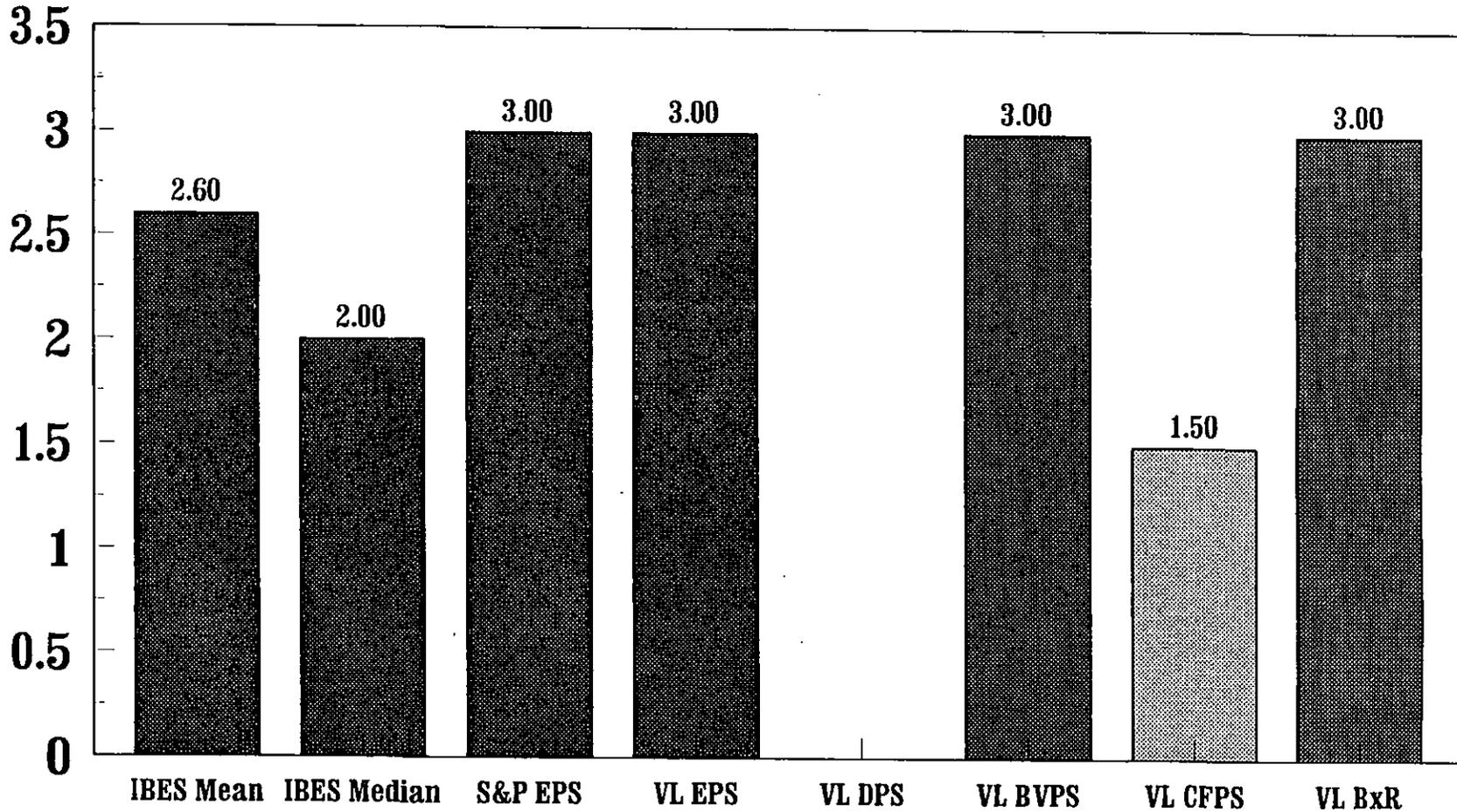
	1995	1994	1993	1992	1991	Five-Year Average	Five-Year Average Excluding Negatives
PP&L Resources Inc							
Earnings Rate on Book Common Equity	12.8%	8.8%	13.1%	13.1%	13.4%		
Dividend Rate on Book Common Equity	10.4%	10.5%	10.5%	10.4%	10.4%		
Internal Growth Rate	2.3%	-1.7%	2.7%	2.7%	3.1%	1.8%	1.8%
Barometer Group of Eight Electric Companies							
Allegheny Power System							
Earnings Rate on Book Common Equity	11.4%	10.9%	11.4%	11.6%	11.7%		
Dividend Rate on Book Common Equity	9.4%	9.7%	9.9%	10.2%	10.3%		
Internal Growth Rate	2.0%	1.3%	-1.5%	1.4%	1.4%	0.9%	1.5%
American Electric Power							
Earnings Rate on Book Common Equity	12.4%	11.9%	8.4%	11.1%	11.9%		
Dividend Rate on Book Common Equity	10.4%	10.6%	10.5%	10.5%	10.6%		
Internal Growth Rate	2.0%	1.4%	-2.1%	0.6%	1.3%	0.6%	0.3%
Atlantic Energy Inc							
Earnings Rate on Book Common Equity	9.9%	9.1%	11.7%	11.1%	12.1%		
Dividend Rate on Book Common Equity	9.8%	9.9%	10.0%	10.1%	10.5%		
Internal Growth Rate	0.1%	-0.9%	1.7%	1.0%	1.6%	0.7%	0.7%
Baltimore Gas & Electric							
Earnings Rate on Book Common Equity	10.8%	10.6%	10.4%	9.5%	9.0%		
Dividend Rate on Book Common Equity	8.3%	8.3%	8.3%	8.4%	8.4%		
Internal Growth Rate	2.5%	2.3%	2.1%	1.1%	0.7%	1.7%	1.9%
Delmarva Power & Light							
Earnings Rate on Book Common Equity	11.9%	11.3%	12.6%	12.4%	11.0%		
Dividend Rate on Book Common Equity	10.3%	10.5%	11.2%	11.4%	11.9%		
Internal Growth Rate	1.6%	0.9%	1.4%	1.0%	-1.0%	0.8%	0.5%
Dpl Inc							
Earnings Rate on Book Common Equity	14.4%	14.4%	13.7%	13.4%	11.1%		
Dividend Rate on Book Common Equity	10.9%	11.0%	10.8%	10.7%	10.4%		
Internal Growth Rate	3.5%	3.4%	2.9%	2.7%	0.7%	2.6%	2.6%
Potomac Electric Power							
Earnings Rate on Book Common Equity	4.1%	10.8%	11.9%	10.5%	12.6%		
Dividend Rate on Book Common Equity	10.3%	10.0%	10.0%	10.2%	10.6%		
Internal Growth Rate	-6.2%	0.8%	1.9%	0.4%	2.0%	-0.2%	-0.2%
Public Service Entpr							
Earnings Rate on Book Common Equity	12.3%	13.0%	12.0%	10.8%	12.1%		
Dividend Rate on Book Common Equity	9.8%	10.1%	10.5%	10.8%	10.6%		
Internal Growth Rate	2.5%	2.9%	1.5%	0.0%	1.5%	1.7%	1.7%
Average							
Earnings Rate on Book Common Equity	10.9%	11.5%	11.5%	11.3%	11.4%		
Dividend Rate on Book Common Equity	<u>9.9%</u>	<u>10.0%</u>	<u>10.2%</u>	<u>10.3%</u>	<u>10.4%</u>		
Internal Growth Rate	<u>1.0%</u>	<u>1.5%</u>	<u>1.4%</u>	<u>1.0%</u>	<u>1.0%</u>	1.1%	1.1%

Source of Information : OneSource
Standard & Poor's Utility Compustat

PP & L Resources, Inc.

Analysts' Five-Year Projected Growth Rates

Percent (%)

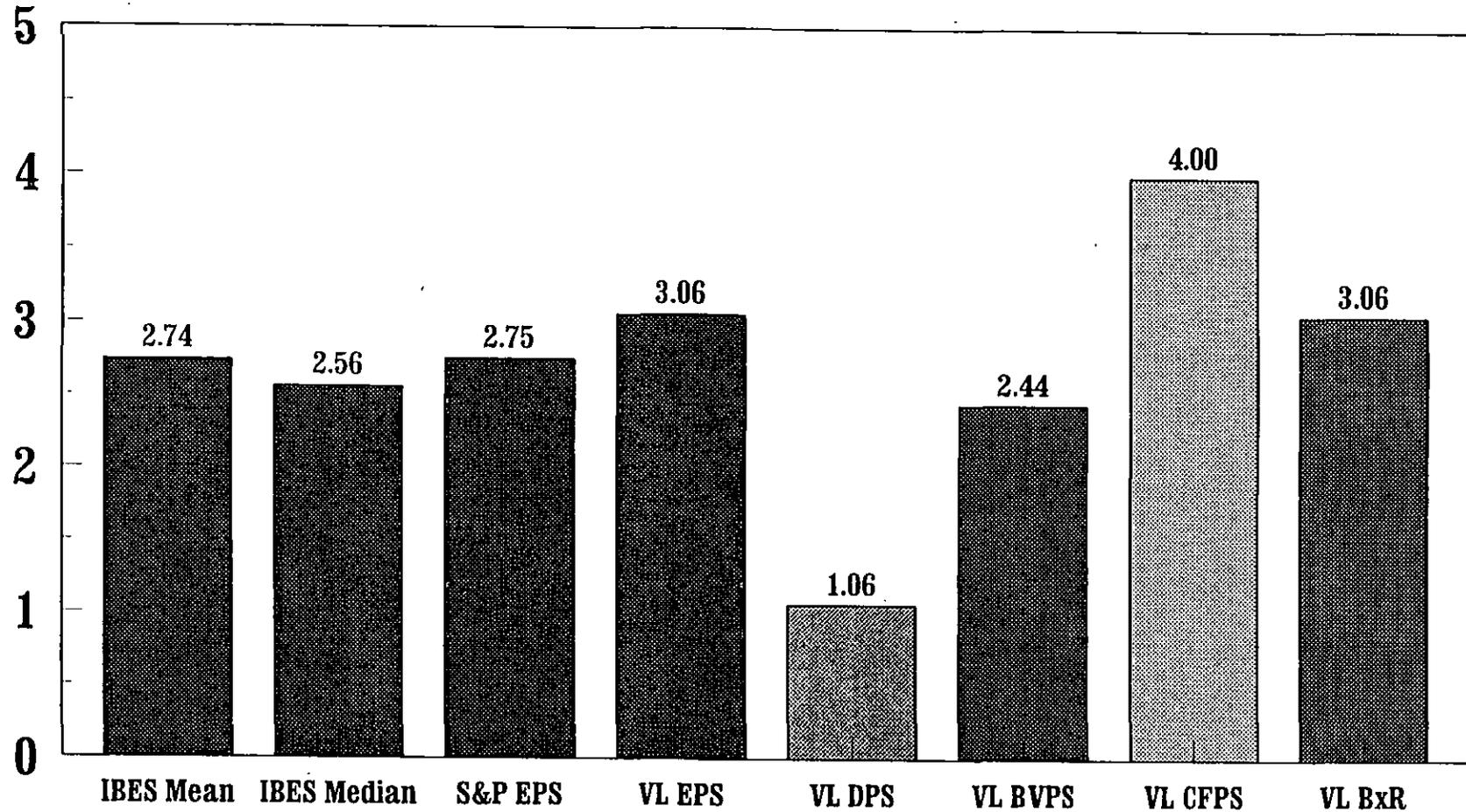


Growth Rates

EPS= Earnings Per Share, DPS= Dividends Per Share,
BVPS= Book Value Per Share, CFPS= Cash Flow Per Share

Barometer Group of Eight Electric Companies Analysts' Five-Year Projected Growth Rates

Percent (%)

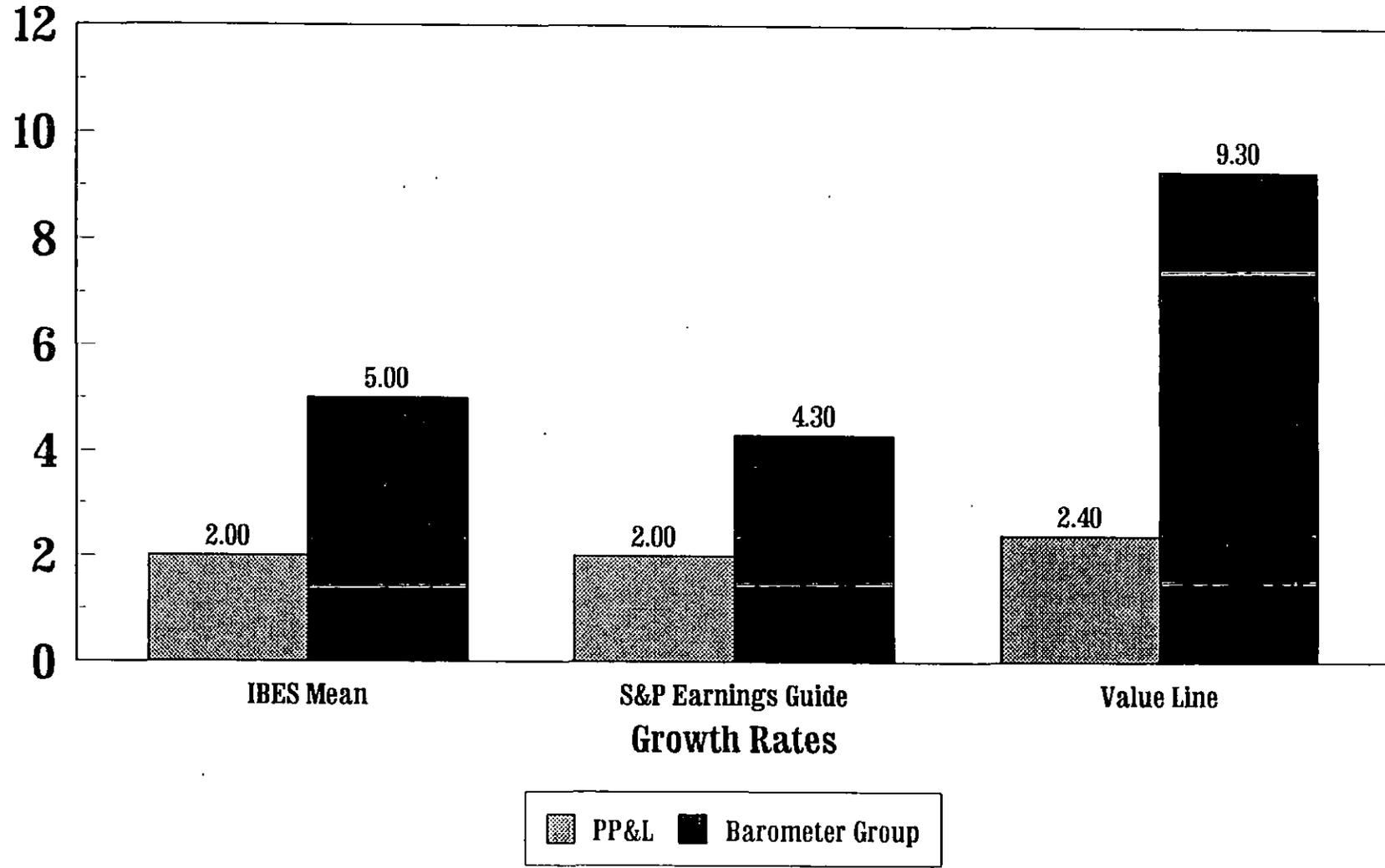


Growth Rates

EPS= Earnings Per Share, DPS= Dividends Per Share,
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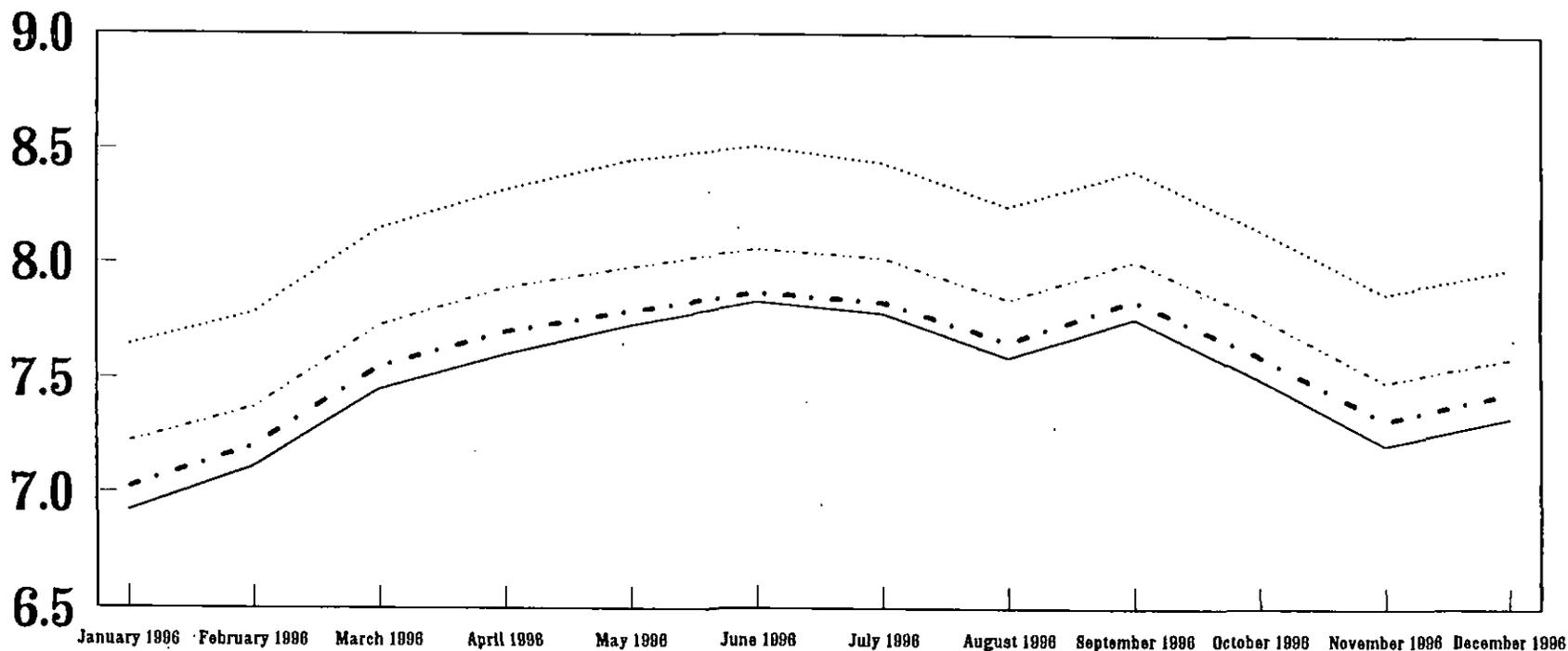
PP & L Resources, Inc. and the Barometer Group of Eight Electric Companies Analysts' Projected Short-Run Earnings Growth Rates

Percent (%)

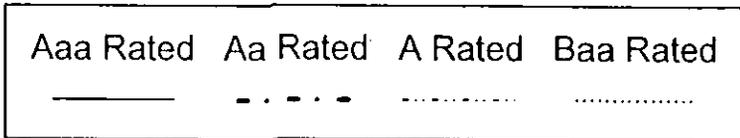


**PP & L Resources, Inc.
Interest Rate Trends
for Public Utility Bonds**

Percent (%)



Bond Yields



Interest Rate Trends for Investor-Owned Public Utility Bonds
 Yearly for 1992-1996
and the Twelve Months Ended December 1996

<u>Years</u>	<u>Aaa Rated</u>	<u>Aa Rated</u>	<u>A Rated</u>	<u>Baa Rated</u>	<u>Average</u>
1992	8.19%	8.55%	8.69%	8.86%	8.57%
1993	7.29%	7.44%	7.59%	7.91%	7.56%
1994	8.06%	8.21%	8.30%	8.63%	8.30%
1995	7.68%	7.77%	7.89%	8.29%	7.92%
1996	7.48%	7.57%	7.75%	8.16%	7.74%
 <u>Months</u>					
January 1996	6.92%	7.02%	7.22%	7.64%	7.20%
February 1996	7.11%	7.20%	7.37%	7.78%	7.37%
March 1996	7.45%	7.55%	7.73%	8.15%	7.72%
April 1996	7.60%	7.70%	7.89%	8.32%	7.88%
May 1996	7.73%	7.79%	7.98%	8.45%	7.99%
June 1996	7.83%	7.87%	8.06%	8.51%	8.07%
July 1996	7.78%	7.83%	8.02%	8.44%	8.02%
August 1996	7.59%	7.66%	7.84%	8.25%	7.84%
September 1996	7.76%	7.84%	8.01%	8.41%	8.01%
October 1996	7.50%	7.60%	7.77%	8.15%	7.76%
November 1996	7.21%	7.32%	7.49%	7.87%	7.48%
December 1996	<u>7.33%</u>	<u>7.44%</u>	<u>7.59%</u>	<u>7.98%</u>	<u>7.58%</u>
Twelve-Month Average	<u>7.48%</u>	<u>7.57%</u>	<u>7.75%</u>	<u>8.16%</u>	<u>7.74%</u>

Source of Information : Moody's Investors Services, Inc. (Public Utility Manuals and Bond Surveys)

S&P Composite Index and S&P Public Utility Index
Long-Term Corporate and Public Utility Bonds
Yearly Total Returns
1928-1996

Year	S & P Composite Index	S & P Public Utility Index	Long Term Corporate Bonds	Public Utility Bonds
1928	43.61%	57.47%	2.84%	3.08%
1929	-8.42%	11.02%	3.27%	2.34%
1930	-24.90%	-21.96%	7.98%	4.74%
1931	-43.34%	-35.90%	-1.85%	-11.11%
1932	-8.19%	-0.54%	10.82%	7.25%
1933	53.99%	-21.87%	10.38%	-3.82%
1934	-1.44%	-20.41%	13.84%	22.61%
1935	47.67%	76.63%	9.61%	16.03%
1936	33.92%	20.69%	6.74%	8.30%
1937	-35.03%	-37.04%	2.75%	-4.05%
1938	31.12%	22.45%	6.13%	8.11%
1939	-0.41%	11.26%	3.97%	6.76%
1940	-9.78%	-17.15%	3.39%	4.45%
1941	-11.59%	-31.57%	2.73%	2.15%
1942	20.34%	15.39%	2.60%	3.81%
1943	25.90%	46.07%	2.83%	7.04%
1944	19.75%	18.03%	4.73%	3.29%
1945	36.44%	53.33%	4.08%	5.92%
1946	-8.07%	1.26%	1.72%	2.98%
1947	5.71%	-13.16%	-2.34%	-2.19%
1948	5.50%	4.01%	4.14%	2.65%
1949	18.79%	31.39%	3.31%	7.16%
1950	31.71%	3.25%	2.12%	2.01%
1951	24.02%	18.63%	-2.69%	-2.77%
1952	18.37%	19.25%	3.52%	2.99%
1953	-0.99%	7.85%	3.41%	2.08%
1954	52.62%	24.72%	5.39%	7.57%
1955	31.56%	11.26%	0.48%	0.12%
1956	6.56%	5.06%	-6.81%	-6.25%
1957	-10.78%	6.36%	8.71%	3.58%
1958	43.36%	40.70%	-2.22%	0.18%
1959	11.96%	7.49%	-0.97%	-2.29%
1960	0.47%	20.26%	9.07%	9.01%
1961	26.89%	29.33%	4.82%	4.85%
1962	-8.73%	-2.44%	7.95%	6.55%
1963	22.80%	12.36%	2.19%	3.44%
1964	16.48%	15.91%	4.77%	4.94%
1965	12.45%	4.67%	-0.46%	0.50%
1966	-10.06%	-4.48%	0.20%	-3.45%
1967	23.98%	-0.63%	-4.95%	-3.63%
1968	11.06%	10.32%	2.57%	1.87%
1969	-8.50%	-15.42%	-8.09%	-6.66%
1970	4.01%	16.56%	18.37%	15.90%
1971	14.31%	2.41%	11.01%	11.59%
1972	18.98%	8.15%	7.26%	7.19%
1973	-14.66%	-18.07%	1.14%	2.42%
1974	-26.47%	-21.55%	-3.06%	-5.28%
1975	37.20%	44.49%	14.64%	15.50%
1976	23.84%	31.81%	18.65%	19.04%
1977	-7.18%	8.64%	1.71%	5.22%
1978	6.56%	-3.71%	-0.07%	-0.98%
1979	18.44%	13.58%	-4.18%	-2.75%
1980	32.42%	15.08%	-2.76%	-0.23%
1981	-4.91%	11.74%	-1.24%	4.27%
1982	21.41%	26.52%	42.56%	33.52%
1983	22.51%	20.01%	6.26%	10.33%
1984	6.27%	26.04%	16.86%	14.82%
1985	32.16%	33.05%	30.09%	26.48%
1986	18.47%	28.53%	19.85%	18.16%
1987	5.23%	-2.92%	-0.27%	3.02%
1988	16.81%	18.27%	10.70%	10.19%
1989	31.49%	47.80%	16.23%	15.61%
1990	-3.17%	-2.57%	6.78%	8.13%
1991	30.55%	14.61%	19.89%	19.24%
1992	7.67%	8.10%	9.39%	8.65%
1993	9.99%	14.41%	13.19%	10.59%
1994	1.31%	-7.94%	-5.76%	-4.72%
1995	37.43%	42.15%	27.20%	22.81%
1996	23.07%	3.14%	1.40%	3.04%
Geometric Mean	10.35%	8.85%	5.58%	5.40%
Arithmetic Mean	12.33%	11.05%	5.92%	5.71%
Standard Deviation	20.39%	21.95%	8.81%	8.30%
Median	14.31%	11.26%	3.52%	4.27%

Tabulation of Risk Rate Differentials for
S&P Public Utility Index and Public Utility Bonds
For the Years 1928-1996, 1952-1996, 1974-1996 and 1979-1996

<u>Total Returns</u>	<u>Range</u>			<u>Point Estimate</u>	<u>Average of Midpoint and Point Estimate</u>
	<u>Geometric Mean</u>	<u>Median</u>	<u>Midpoint</u>	<u>Arithmetic Mean</u>	
<u>1928-1996</u>					
S&P Public Utility Index	8.85%	11.26%		11.05%	
Public Utility Bonds	<u>5.40</u>	<u>4.27</u>		<u>5.71</u>	
Risk Differential	<u>3.45%</u>	<u>6.99%</u>	<u>5.22%</u>	<u>5.34%</u>	<u>5.28%</u>
<u>1952-1996</u>					
S&P Public Utility Index	11.57%	11.74%		12.69%	
Public Utility Bonds	<u>6.24</u>	<u>4.65</u>		<u>6.60</u>	
Risk Differential	<u>5.33%</u>	<u>7.09%</u>	<u>6.21%</u>	<u>6.09%</u>	<u>6.15%</u>
<u>1974-1996</u>					
S&P Public Utility Index	14.74%	14.61%		16.06%	
Public Utility Bonds	<u>9.75</u>	<u>10.19</u>		<u>10.20</u>	
Risk Differential	<u>4.99%</u>	<u>4.42%</u>	<u>4.71%</u>	<u>5.86%</u>	<u>5.28%</u>
<u>1979-1996</u>					
S&P Public Utility Index	16.29%	14.85%		17.20%	
Public Utility Bonds	<u>10.74</u>	<u>10.26</u>		<u>11.18</u>	
Risk Differential	<u>5.55%</u>	<u>4.59%</u>	<u>5.07%</u>	<u>6.02%</u>	<u>5.55%</u>

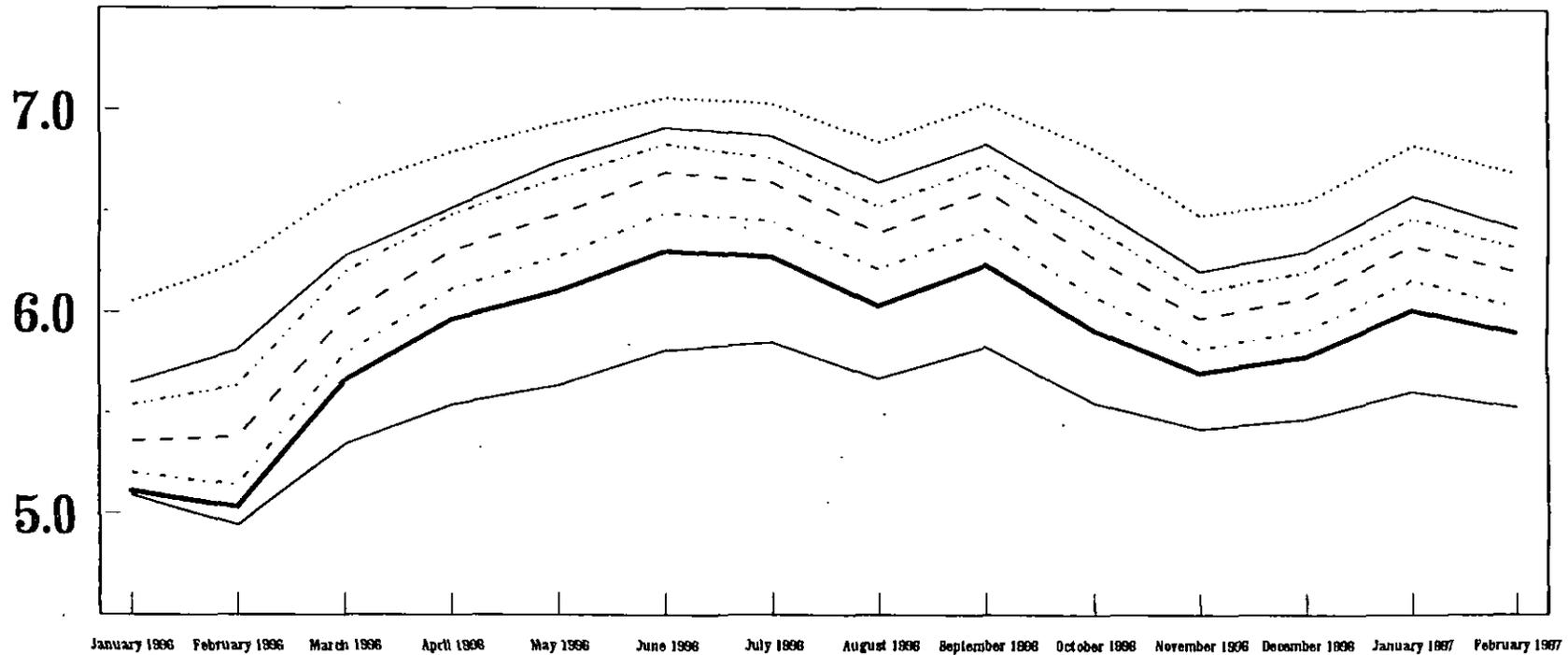
Merrill Lynch and Value Line
Adjusted Betas for PP&L Resources Inc., and the
Barometer Group of Eight Electric Companies

	<u>Merrill Lynch</u> Adjusted Beta	<u>Value Line</u> Adjusted Beta	Average Adjusted Beta
PP&L Resources Inc	<u>0.77</u>	<u>0.75</u>	<u>0.76</u>
Barometer Group of Eight Electric Companies			
Allegheny Power System	0.71	0.70	0.71
American Electric Power	0.70	0.70	0.70
Atlantic Energy Inc	0.65	0.70	0.68
Baltimore Gas & Electric	0.85	0.85	0.85
Delmarva Power & Light	0.58	0.70	0.64
Dpl Inc	0.60	0.70	0.65
Potomac Electric Power	0.81	0.80	0.81
Public Service Entrp	<u>0.87</u>	<u>0.80</u>	<u>0.84</u>
Average	<u>0.72</u>	<u>0.74</u>	<u>0.73</u>

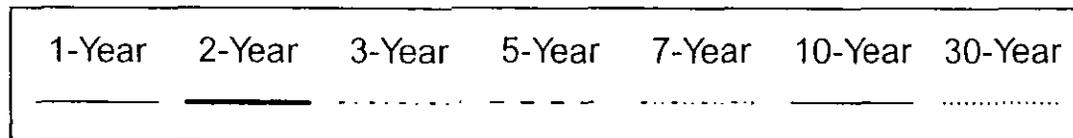
Source of Information : Merrill Lynch Security Price Index, January 1997
Value Line Investment Survey, December 13, 1996 and October 11, 1996

PP & L Resources, Inc.
Interest Rate Trends
for Treasury Constant Maturities

Percent (%)



Bond Yields



**Interest Rate Trends for Treasury Constant Maturities
Yearly for 1992-1996
and the Twelve Months Ended December 1996**

<u>Years</u>	<u>1-Year</u>	<u>2-Year</u>	<u>3-Year</u>	<u>5-Year</u>	<u>7-Year</u>	<u>10-Year</u>	<u>30-Year</u>
1992	3.89%	4.77%	5.31%	6.19%	6.63%	7.01%	7.67%
1993	3.43%	4.05%	4.44%	5.15%	5.55%	5.87%	6.60%
1994	5.31%	5.94%	6.26%	6.68%	6.90%	7.08%	7.37%
1995	5.95%	6.16%	6.26%	6.39%	6.50%	6.58%	6.88%
1996	5.51%	5.84%	5.99%	6.18%	6.34%	6.44%	6.70%
<u>Months</u>							
January 1996	5.09%	5.11%	5.20%	5.36%	5.54%	5.65%	6.05%
February 1996	4.94%	5.03%	5.14%	5.38%	5.64%	5.81%	6.24%
March 1996	5.34%	5.66%	5.79%	5.97%	6.19%	6.27%	6.60%
April 1996	5.54%	5.96%	6.11%	6.30%	6.48%	6.51%	6.79%
May 1996	5.64%	6.10%	6.27%	6.48%	6.66%	6.74%	6.93%
June 1996	5.81%	6.30%	6.49%	6.69%	6.83%	6.91%	7.06%
July 1996	5.85%	6.27%	6.45%	6.64%	6.76%	6.87%	7.03%
August 1996	5.67%	6.03%	6.21%	6.39%	6.52%	6.64%	6.84%
September 1996	5.83%	6.23%	6.41%	6.60%	6.73%	6.83%	7.03%
October 1996	5.55%	5.91%	6.08%	6.27%	6.42%	6.53%	6.81%
November 1996	5.42%	5.70%	5.82%	5.97%	6.10%	6.20%	6.48%
December 1996	<u>5.47%</u>	<u>5.78%</u>	<u>5.91%</u>	<u>6.07%</u>	<u>6.20%</u>	<u>6.30%</u>	<u>6.55%</u>
Twelve-Month Average	<u>5.51%</u>	<u>5.84%</u>	<u>5.99%</u>	<u>6.18%</u>	<u>6.34%</u>	<u>6.44%</u>	<u>6.70%</u>

Source of Information : Federal Reserve Statistical Release

Measures of the Risk Free Rate
Using Blue Chip Financial Forecasts

The forecast 30-year Treasury Bond yields per the consensus of nearly 50 economists reported in the Blue Chip Financial Forecasts dated January 1, 1997.

	<u>Treasury Note Yield</u> <u>10-Year</u>	<u>Treasury Bond Yield</u> <u>30-Year</u>
First Quarter 1997	6.3%	6.5%
Second Quarter 1997	6.3	6.5
Third Quarter 1997	6.3	6.5
Fourth Quarter 1997	6.3	6.5
First Quarter 1998	6.3	6.5
Second Quarter 1998	6.3	6.5

Source of Information: Blue Chip Financial Forecasts, January 1, 1997.

THE VALUE LINE

Investment Survey®

Part 1
Summary & Index

File at the front of the Ratings & Reports binder. Last week's Summary & Index should be removed.

December 27, 1996

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The Median of Estimated
PRICE-EARNINGS RATIOS
of all stocks with earnings

15.7

26 Weeks Ago*	Market Low	Market High
15.2	12-23-74*	9-4-87*
	4.8	16.9

The Median of
ESTIMATED YIELDS
(next 12 months) of all dividend paying stocks under review

2.2%

26 Weeks Ago*	Market Low	Market High
2.3%	12-23-74*	9-4-87*
	7.8%	2.3%

The Estimated Median
APPRECIATION POTENTIAL
of all 1700 stocks in the hypothesized economic environment 3 to 5 years hence

50%

26 Weeks Ago*	Market Low	Market High
50%	12-23-74*	9-4-87*
	234%	40%

*Estimated medians as published in *The Value Line Investment Survey* on the dates shown.

ANALYSES OF INDUSTRIES IN ALPHABETICAL ORDER WITH PAGE NUMBER
Numeral in parenthesis after the industry is rank for probable performance (next 12 months).

PAGE		PAGE		PAGE		PAGE	
Advertising (34)	1837	Drug (49)	1241	Insurance(Prop/Casualty) (83)	609	Recreation (26)	1761
Aerospace/Defense (36)	551	Drugstore (8)	802	Investment Co.(Domestic) (60)	2183	Restaurant (33)	294
Air Transport (72)	251	Electrical Equipment (50)	1001	Investment Co.(Foreign) (48)	355	Retail Building Supply (12)	883
Aluminum (92)	1218	Electric Util. (Central) (93)	701	Investment Co. (Income) (58)	971	Retail (Special Lines) (29)	1676
Apparel (9)	1611	Electric Utility (East) (95)	160	Machinery (47)	1301	Retail Store (25)	1641
Auto & Truck (67)	101	Electric Utility (West) (82)	1728	Machinery (Const&Mining) (15)	1339	Securities Brokerage (21)	1413
Auto Parts (OEM) (27)	813	Electronics (55)	1020	Manuf. Housing/Rec Veh (6)	1544	Semiconductor (45)	1052
Auto Parts (Replacement) (41)	113	Entertainment (79)	1776	Maritime (85)	278	Semiconductor Cap Equip (66)	1068
Bank (46)	2101	Environmental (13)	343	Medical Services (35)	654	Shoe (3)	1666
Bank (Canadian) (4)	1568	Financial Services (5)	2139	Medical Supplies (71)	196	Steel (General) (73)	592
Bank (Midwest) (44)	635	Food Processing (69)	1461	Metal Fabricating (14)	578	Steel (Integrated) (52)	1397
Beverage (Alcoholic) (89)	1530	Food Wholesalers (77)	1519	Metals & Mining (Div.) (86)	1218	Telecom. Equipment (22)	774
Beverage (Soft Drink) (19)	1538	Foreign Electron/Enterm (84)	1553	*Natural Gas (Distrib.) (88)	472	Telecom. Services (78)	741
Building Materials (11)	851	Foreign Telecom. (54)	786	*Natural Gas(Diversified) (42)	450	Textile (43)	1628
Cable TV (96)	836	Furn./Home Furnishings (18)	901	Newspaper (59)	1819	Thrift (16)	1151
*Canadian Energy (40)	434	Gold/Silver Mining (91)	1204	Office Equip & Supplies (24)	1115	Tire & Rubber (81)	122
Cement & Aggregates (20)	892	Grocery (56)	1501	Oilfield Services/Equip. (1)	1858	Tobacco (37)	1575
Chemical (Basic) (75)	1232	Healthcare Information (32)	681	Packaging & Container (64)	941	Toiletries/Cosmetics (30)	829
Chemical (Diversified) (74)	1885	Home Appliances (94)	128	Paper & Forest Products (76)	912	Toys (53)	1906
*Chemical (Specialty) (68)	499	Homebuilding (31)	872	*Petroleum (Integrated) (61)	401	Trucking/Transp. Leasing (70)	265
Coal/Alternate Energy (2)	1879	Hotel/Gaming (63)	1785	Petroleum (Producing) (7)	1845	Water Utility (87)	1406
Computer & Peripherals (10)	1075	Household Products (80)	955	Precision Instrument (65)	135		
Computer Software & Svcs (23)	2195	Industrial Services (39)	319	Publishing (62)	1802		
Copper (90)	1219	Insurance (Diversified) (57)	2166	Railroad (17)	284		
Diversified Co. (38)		Insurance (Life) (28)	1188	R.E.I.T. (51)	1170		

*Reviewed in this week's edition.

In three parts: This is Part 1, the Summary & Index. Part 2 is Selection & Opinion. Part 3 is Ratings & Reports. Volume LII, No. 18.

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**Capital Asset Pricing Model
 Component Inputs
Market Return for the Standard & Poor's 500 Index**

Standard & Poor's 500

<u>Data Values</u>		<u>Computations</u>	
Dividends	14.89	Adjusted Yield (2)	2.08%
Price Index	757.02	5-Year Projected Earnings Growth	12.00
Dividend Yield (1)	1.97%	DCF Result (3)	14.08%

- Notes: (1) Dividend Yield is the result of the index dividend amount divided by the index price reported in the S&P Stock Guide.
- (2) Adjusted dividend yield reflects an adjustment for next period dividend payments of $1 + 0.5g$.
- (3) The growth rate for the S&P 500 is the 5 year projected Eps growth rate reported in the S&P Earnings Guide.
- (4) DCF results equals the adjusted dividend yield plus the projected 5-Years Earnings Growth for the Index from the S&P Earnings Guide.

Source of Information: Standard & Poor's Earnings Guide - December 1996
 Standard & Poor's Stock Guide - December 1996

Table 2-1

Basic Series:
Summary Statistics of
Annual Total Returns

Exhibit
Schedule 10
Page 7 of 7

From 1926 to 1996

Series	Geometric Mean	Arithmetic Mean	Standard Deviation	Distribution
Large Company Stocks	10.7%	12.7%	20.3%	
Small Company Stocks	12.6	17.7	34.1	
Long-Term Corporate Bonds	5.6	6.0	8.7	
Long-Term Government	5.1	5.4	9.2	
Intermediate-Term Government	5.2	5.4	5.8	
U.S. Treasury Bills	3.7	3.8	3.3	
Inflation	3.1	3.2	4.5	

*The 1933 Small Company Stock Total Return was 142.9 percent.

Comparable Earnings Approach for PP & L Resources, Inc. and
the Barometer Group of Eight Electric Companies
All Value Line Non-Utility Companies with Timeliness of 4 and 5,
Safety Ranking of 2 and 3, Financial Strength of B++ and A,
Price Stability 75 and Higher, Beta's Between .70 and .85
and Technical Rank of 3 and 4.

<u>Company Name</u>	<u>Industry Name</u>	<u>Time- liness Rank</u>	<u>Safety Rank</u>	<u>Financial Strength</u>	<u>Price Stability</u>	<u>Beta</u>	<u>Technical Rank</u>
BANDAG, INC.	Tire/Rubber	4	2	A	90	0.75	4
CHRIS-CRAFT	Entertainment	4	2	B++	85	0.85	3
GIANT FOOD 'A'	Grocery	4	2	B++	85	0.70	3
HORMEL FOODS	Food Processing	4	2	A	85	0.75	4
LEARONAL INC.	Chemical: Spec	5	3	B++	75	0.75	4
LEE ENTERPRISES	Newspaper	4	2	A	90	0.80	3
OHIO CASUALTY	Insurance: P/C	4	2	B++	75	0.80	4
OLD KENT FIN'L	Bank: Midwest	4	2	B++	90	0.75	3
ROLLINS, INC.	Industrial Svcs	5	2	A	75	0.85	3
ST. PAUL COS.	Insurance: P/C	5	2	B++	90	0.80	4
STANHOME INC.	Retail: Spec'l	4	2	A	80	0.80	4
UNITRIN, INC.	Insurance: Divr	4	2	A	85	0.80	3
WILMINGTON TR	Bank	4	2	A	85	0.85	3
Averages		<u>4.2</u>	<u>2.1</u>	<u>A</u>	<u>83.8</u>	<u>0.79</u>	<u>3.5</u>
PP&L Resources, Inc.		<u>4.0</u>	<u>2.0</u>	<u>B++</u>	<u>95.0</u>	<u>0.75</u>	<u>4.0</u>
Barometer Group	- Average	<u>4.3</u>	<u>2.3</u>	<u>A</u>	<u>96.9</u>	<u>0.74</u>	<u>3.8</u>
	- Range	<u>4 to 5</u>	<u>2 to 3</u>	<u>B++ to A</u>	<u>90 to 100</u>	<u>.70 to .85</u>	<u>3 to 4</u>

Source of Information: Value Line - Value Screen Data Base, January 1997

Comparable Earnings Approach
 Five Year Average Historical Earned Returns
 for the Years 1991-1995 and
Projected 3-5 Year Returns

<u>Company Name</u>	<u>1991</u>	<u>1992</u>	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>Average</u>	<u>Projected 3-5 Year Return</u>
BANDAG, INC.	26.8%	24.8%	19.1%	21.7%	24.3%	23.3%	17.5%
CHRIS-CRAFT	5.5%	5.9%	11.8%	5.0%	1.7%	6.0%	4.5%
GIANT FOOD 'A'	14.0%	12.3%	12.8%	12.5%	12.4%	12.8%	13.5%
HORMEL FOODS	14.8%	14.8%	17.7%	17.8%	16.5%	16.3%	16.5%
LEARONAL INC.	9.8%	10.7%	11.5%	12.2%	14.0%	11.6%	14.0%
LEE ENTERPRISES	17.2%	18.9%	18.5%	21.0%	18.8%	18.9%	16.5%
OHIO CASUALTY	13.9%	11.8%	10.1%	10.7%	8.6%	11.0%	13.0%
OLD KENT FIN'L	13.8%	15.3%	15.7%	15.8%	14.0%	14.9%	14.0%
ROLLINS, INC.	30.0%	29.3%	27.7%	25.6%	21.8%	26.9%	20.0%
ST. PAUL COS.	15.2%	5.5%	14.2%	16.2%	14.0%	13.0%	15.5%
STANHOME INC.	18.7%	18.2%	17.5%	16.4%	15.7%	17.3%	16.5%
UNITRIN, INC.	7.3%	8.4%	4.5%	8.4%	9.9%	7.7%	10.5%
WILMINGTON TR	20.8%	20.9%	20.9%	20.4%	19.6%	<u>20.5%</u>	<u>19.5%</u>
Average						<u>15.4%</u>	<u>14.7%</u>

Source of Information: Value Line - Value Screen Data Base, January 1997
 Value Line Investment Survey (Various Editions)

Simple DCF Results for the Comparable Earnings Group
 for PP & L Resources, Inc. and the Barometer Group of Eight Electric Companies

<u>Company Name</u>	<u>Industry Name</u>	<u>Dividend Yield</u>	<u>Projected Earnings Growth Rate</u>	<u>DCF Result</u>
BANDAG, INC.	Tire/Rubber	2.1%	4.5%	6.6%
CHRIS-CRAFT	Entertainment	0.0%	NMF	NMF
GIANT FOOD 'A'	Grocery	2.3%	11.0%	13.3%
HORMEL FOODS	Food Processing	2.6%	7.5%	10.1%
LEARONAL INC.	Chemical: Spec	3.4%	13.0%	16.4%
LEE ENTERPRISES	Newspaper	2.3%	11.5%	13.8%
OHIO CASUALTY	Insurance: P/C	4.9%	12.0%	16.9%
OLD KENT FIN'L	Bank: Midwest	3.1%	7.0%	10.1%
ROLLINS, INC.	Industrial Svcs	3.1%	1.0%	4.1%
ST. PAUL COS.	Insurance: P/C	3.3%	8.5%	11.8%
STANHOME INC.	Retail: Spec'l	4.0%	7.5%	11.5%
UNITRIN, INC.	Insurance: Divr	4.5%	11.5%	16.0%
WILMINGTON TR	Bank	3.5%	11.0%	<u>14.5%</u>
Average				<u>12.1%</u>

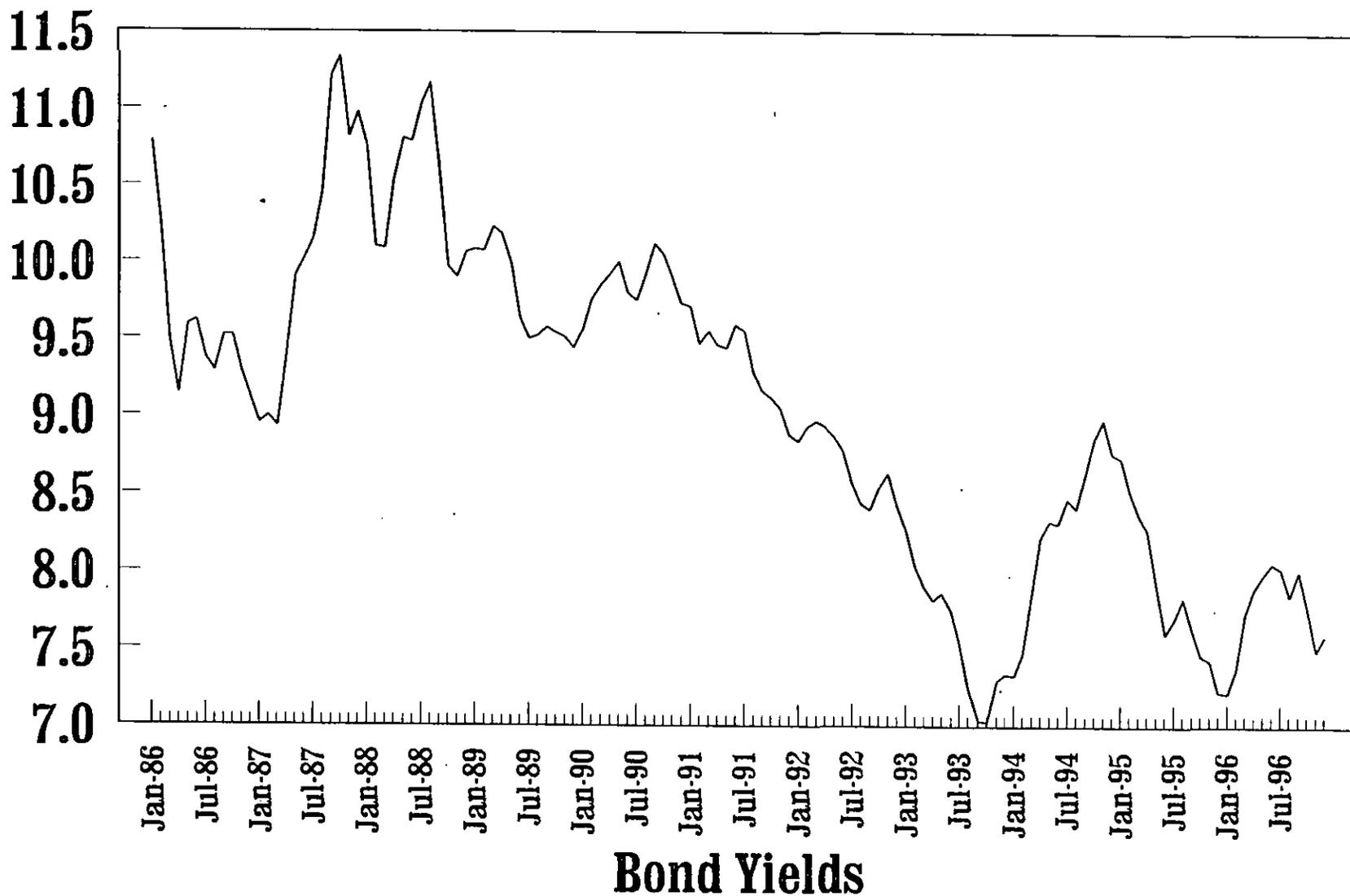
Source of Information: Value Line - Value Screen Data Base, January 1996
 Value Line Investment Survey - various issues

EXHIBIT PRM 3

Interest Rate Trends from January 1986 to December 1996

Moody's A Rated Public Utility Average Monthly Yields

Percent (%)



**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Docket No. R-00973954

PENNSYLVANIA POWER & LIGHT COMPANY

Statement No. 7

Direct Testimony of Scott T. Jones, Ph.D.

1 **I INTRODUCTION**

2

3 Q. Please state your name and business address.

4 A. My name is Scott T. Jones. My business address is One Mifflin Place,
5 Cambridge, Massachusetts, 02138.

6

7 Q. What position do you hold?

8 A. I am CEO, The Economics Resource Group, Inc. My firm specializes
9 in economic and regulatory policy consulting services to private and, to
10 a lesser extent, public organizations in traditionally regulated
11 industries.

12

13 **II QUALIFICATIONS AND EXPERIENCE**

14 Q. Please describe your educational background and prior work
15 experience.

16 A. I have been involved in issues related to the regulation of utilities and
17 regulatory policy for 12 years. My experience with regulated utilities
18 and regulatory policy includes research and testimony on behalf of
19 clients as well as working with regulators at the state and federal level
20 as a senior executive in the energy industry. Over this period, I have

1 been directly involved with matters that are the subject of this
2 proceeding, particularly matters pertaining to the transition of a
3 regulated industry to a more competitive environment. My previous
4 work experience and testimony includes rate design, the role of
5 regulation in project economics, the determination of workably
6 competitive markets and market prices, facilities siting, resource cost
7 analysis, and financial economics pertaining to tariff structure, mergers
8 and debt refinancing. I have acted as a consultant and as a member
9 of the energy industry in matters pertaining to electric utilities, oil
10 pipelines, natural gas pipelines and natural gas liquids pipelines.

11 My experience in the energy industry, including forecasting and
12 market price determination, spans 22 years. Over this period, I have
13 worked in the oil and gas industry on two occasions. I hold a Ph.D. in
14 Economics from Virginia Tech. My resume is attached as Exhibit
15 STJ 1, listing my background and experience in further detail.

16
17 **III PURPOSE AND CONCLUSIONS**

18 Q. What is the purpose of your testimony?

19 A. Pennsylvania Power and Light Company ("PP&L" or the "Company")
20 has asked me to provide estimates for the price of electricity in a

1 competitive retail and wholesale environment. Given that price
2 estimate, I have been asked to compute the expected revenue
3 generated by each PP&L generating facility over its remaining plant
4 life.

5 These price estimates and generating plant revenue estimates
6 are used as inputs to the Company's calculation of stranded cost, as
7 described in the testimony of Mr. Joseph Schadt. The market price
8 estimates are also an input into PP&L's proposed rate design, as
9 described in the testimony of Dr. Susan Tierney, Mr. Douglas Krall,
10 Mr. Joseph Kleha and Mr. Oliver Kasper.

11
12 Q. Please state the scope of your testimony and any conclusions.

13 A. I will explain each of the key assumptions and explain anticipated
14 market conditions as they affect the forecasted market price. I will
15 explain how PP&L's dispatch model was used to derive hourly market-
16 clearing prices in the Pennsylvania-New Jersey-Maryland Power Pool
17 ("PJM"), inclusive of imports and exports. I will explain the role of the
18 capacity market and how capacity prices are formed. I will explain the
19 role of the energy market and how energy prices are formed. I will
20 discuss how the market prices are used to estimate generation

1 revenues of PP&L plants and how those revenue estimates are used
2 by other witnesses to calculate stranded costs.

3 The prices I have produced for energy and capacity reflect the
4 market conditions and assumptions that are expected to prevail in PJM
5 beginning in 1999. All plants in PJM will be subjected to these prices,
6 including those owned by PP&L. Market prices are assumed to
7 determine generating plant revenue. The prices are lower than the full
8 cost of service rate regulation, suggesting that consumers will be able
9 to *directly observe* the beneficial effects of competition on their
10 unbundled rates, net of the unby-passable competitive transition
11 charge, during the transition from regulated monopoly service to fully
12 competitive supply service.

13
14 **IV OVERVIEW: KEY POLICY AND MARKET FACTORS**

15 Q. Please identify the policy context in which your market price estimates
16 and projections of generation-related revenue have been developed.

17 A. The Commonwealth of Pennsylvania has passed the Electricity
18 Generation Customer Choice and Competition Act ("Act") which
19 requires electric utilities in the state to unbundle their rates and
20 services and to provide open access over their transmission and

1 distribution systems to allow competitive suppliers to generate and sell
2 electricity directly to consumers beginning in 1999. The Act calls for
3 retail choice to be fully instituted within three years, so that all
4 residents of the state will have the opportunity to decide which
5 generation company will supply their electricity. Customer choice and
6 retail access are intended to replace the regulated generation of
7 electricity as a public utility function.
8

9 Q. Please describe the nature of the market in which PP&L's generation
10 facilities will operate as part of a restructured electric industry.

11 A. In the future competitive generation market, each plant PP&L has in
12 service can expect to receive the current competitive price for the
13 electricity it provides as determined by market forces. An independent
14 system operator ("ISO"), presumably formed within the PJM control
15 area, will ensure reliability for Pennsylvania customers by dispatching
16 the generation units within the power pool. Under the current PJM
17 proposal, the regional power market would also perform market
18 functions associated with the short-term markets for electric energy,
19 capacity, and ancillary services. Suppliers, like PP&L, seeking to
20 supply load in the PJM-ISO region will bid prices into the regional

1 capacity and hourly energy markets. These bids represent the prices
2 at which generators are willing to supply electric generation services.
3 If they are called upon in any hour, generators will behave as “price-
4 takers”, receiving a market price for the electricity they generate. In
5 competitive markets, where suppliers receive the market clearing
6 price, producers will tend to bid their generation at its marginal cost.
7 The variable costs of the last generation facility dispatched will
8 determine price, rather than sunk investment costs. In such a system,
9 competition is fostered through the activities of each generator, acting
10 in its own self-interest, which together produce electricity at the lowest
11 possible cost.

12
13 Q. In a competitive environment, what are the components and
14 component markets that will determine the market prices for
15 electricity?

16 A. Electricity prices are based on prices in two component markets:
17 energy and capacity. These two markets satisfy two different forms of
18 demand for electricity: the capacity requirements of producers and the
19 demand for power supplied by the energy market. These two markets
20 have different attributes, costs, and key variables. However, both

1 markets are expected to clear at prices which approximate variable
2 cost.

3
4 Q. What do you mean by the market "clearing" at prices which
5 approximate variable cost?

6 A. Firms in competitive markets are driven by the cost of production.
7 Competition among sellers will act to drive market prices toward the
8 incremental cost of production. Hence, the factors affecting the market
9 price for energy are those that make up the direct cost of generating
10 electricity, such as fuel, variable operating and maintenance ("O&M")
11 costs, and any regulatory costs associated with generation (e.g., the
12 cost of emissions allowances).

13 The factors that determine the capacity component of electricity
14 prices include the short-term costs associated with the last capacity-
15 holder that succeeds in making its capacity available to the system. In
16 an excess capacity situation, those costs tend to be the incremental
17 fixed costs of keeping a plant available for operation (e.g., a single
18 year's fixed O&M costs, any necessary investment, and taxes). In a
19 capacity deficit period, the marginal cost of capacity would tend toward
20 the cost of adding new capacity.

1

2

Q. What method is used to estimate annual revenue from each of PP&L's facilities?

3

4

A. Once the market price of electricity is estimated, based on energy and capacity market prices, the annual revenues for each of PP&L's plants are derived in two basic steps. The first step determines the amount of expected revenue from capacity sales. The second step, using the Company's "EGEAS" model¹, determines the amount of expected revenue from energy sales.

5

6

7

8

9

10

11

Q. Has PP&L's EGEAS model been used as part of other proceedings before the Pennsylvania Public Utility Commission ?

12

13

A. Yes. EGEAS has been used to generate estimates in documents that have been cited in Commission proceedings or used to meet other regulatory requirements. From 1994-96, EGEAS was used to help produce PP&L's Annual Resource Planning Report, PURPA 210 avoided cost filings, the Energy Information Administration's 767 filings

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¹ EGEAS is a model developed by The Electric Power Research Institute (EPRI) and used by numerous electric utilities.

1 for fuel forecasts, and PP&L's data provided to the Global Climate
2 Challenge filings which track CO₂ emission reductions.

3
4 **V THE PRICE OF ELECTRICITY AND THE STRUCTURE OF**
5 **THE MARKET IN PJM**
6

7 Q. What is the scope of the relevant market that will determine prices in a
8 competitive market for energy or capacity?

9 A. At the very least, the supply-side of the relevant generation market
10 facing PP&L appropriately includes the generation sources in and
11 available to the PJM region. This includes all of the power sources in
12 PJM, and energy and capacity that can be delivered to PJM over lines
13 connecting other regions to PJM. The demand-side of the relevant
14 generation market should include all customers in and with access to
15 electricity that can be delivered over lines within and connected to
16 PJM.

17
18 Q. How will electricity prices be formed in PJM?

19 A. In tomorrow's competitive generation markets, electricity prices will be
20 formed by forces of supply and demand brought to bear on its two
21 component (product) markets, energy and capacity. In the short run,

1 the price for energy will reflect the variable cost of producing power
2 from generation equipment. This is primarily the fuel and other costs
3 that rise and fall in proportion to the amount of time and the output of
4 the generators on-line and producing power. Therefore, the fuel and
5 variable O&M of the least-efficient producer in any hour will set the
6 market clearing price in that hour.

7 By contrast, the short-term capacity price is driven largely by the
8 amount of installed generation capacity available in each area at that
9 particular point in time. If there is more capacity available than
10 demanded--the current situation in PJM--the price for capacity will be
11 low, since there is surplus capacity. As capacity tightens, capacity
12 prices are likely to rise to the level required to install the lowest-cost
13 new capacity additions.

14 Each of these two markets, energy (kilowatt-hour, or kwh) and
15 capacity (kilowatt, or kW), is expected to undergo identifiable structural
16 changes. These changes result from the continuing increase in
17 wholesale competition and the move toward retail competition brought
18 about by the forces of economics, technology and law, including the
19 changes mandated by the Act. For example, with the introduction of
20 retail competition, short-term incremental cost of generating electricity

1 may decline. Since customers will have the option to buy electricity
2 from the generator of their choice and they will see lower energy rates,
3 lower incremental energy costs should stimulate demand. Growing
4 electricity demand should continue to absorb existing generation
5 capacity, causing the incremental cost of capacity to gradually rise.

6 Q. What are some of the key elements that are going to impact the price
7 of energy following the introduction of retail competition to the electric
8 industry in Pennsylvania?

9 A. The energy market sets the kilowatt-hour (kwh) price for electricity.
10 The energy price is driven mainly by the incremental cost of fuel
11 required to generate electricity. Depending on the type of generation
12 equipment, the fuel used may be coal, uranium, oil (residual fuel or
13 distillate), natural gas, or water (hydroelectric facilities), or other
14 renewable energy. In addition, the incremental cost of energy
15 depends on variable O&M costs.

16 Energy prices may be affected by system constraints within
17 PJM. There are times when PJM is constrained at its Eastern transfer
18 limit. This constraint may effect economic dispatch. Lower cost
19 energy on the Western side of the constraint is unable to reach certain

1 areas within the Eastern area of PJM, so higher cost generation must
2 run in the East to meet incremental load requirements in those areas.

3
4 Q. What are some of the key elements that are going to effect the price of
5 capacity in a competitive market?

6 A. The capacity market sets the kilowatt (kW) price for electricity. The
7 incremental capacity price is driven by the mix and availability of
8 generation equipment that can be dispatched within PJM, or relied
9 upon by PJM as delivered over the inter-ties with neighboring regions.
10 Given the present surplus of capacity, this market clears near the net
11 cost of keeping capacity in operation. Depending on the expected
12 prices of energy and capacity in the future, generators may decide to
13 add new capacity. In the future, there will be a competitive incentive to
14 add new capacity if prices rise sufficiently to induce the addition of new
15 efficient units, such as combined cycle units, with lower fuel and
16 operating costs. In order for companies to commit capital for new
17 generation equipment, the expected competitive market price
18 (combined energy and capacity prices) must be high enough to offer a
19 return on capital as well as cover incremental operating costs.

1 An important determinant of expectations about electricity
2 prices is the demand for electricity. As demand grows, existing
3 capacity is absorbed. As capacity is absorbed, short-term prices for
4 capacity will rise, eventually coaxing new capacity into the competitive
5 market. Putting new capacity to work generating electricity in place of
6 existing capacity may or may not increase the demand for fuel,
7 depending on the size, age, and type of generation capacity it
8 displaces.

9 10 **V A. The Energy Market (kwh)**

11 Q. How is the post-1999 competitive market for electric energy likely to
12 operate within PJM?

13 A. The bid prices for electricity within PJM should closely reflect the
14 variable cost of each unit bidding in any hour. The hourly market
15 clearing price within PJM will reflect the variable cost of the last unit
16 dispatched to meet the energy requirements.

17 Currently, PJM serves 22 million customers within 50,000
18 square miles from Virginia to New York and west to the Ohio border
19 using about 8 percent of the nation's generation capacity. The vast
20 majority of PJM's approximately 56,000 MW of capacity (1996 summer

1 peak) is steam generation equipment, fueled largely by coal and
2 nuclear fuels. Additionally, hydroelectric units compose about 5% of
3 capacity. Combined cycle ("CC") units, some of which are operated by
4 non-utility generators, integrate the best feature of rapid-starting
5 turbines with the economy of low heat rates. Combustion turbine
6 ("CT") and diesel generators are normally used to meet peaking
7 capacity requirements.

8 Part of PJM's demand is, of course, met through power
9 interchange (imports/exports) that results from agreements and
10 physical interconnections with the pools, systems and companies
11 bordering the PJM area. Imports of power result in the receipt of low
12 cost electricity from great distances.

13 Subject to various constraints on the interconnections that move
14 power between other regions and PJM, individual companies within
15 PJM and PJM itself arrange for the purchase and sale of generation
16 with power sources in neighboring pools and systems such as those to
17 the west which operate with less expensive coal-fired generation.
18 These imports of power are used whenever possible and economical,
19 providing part of the system's base energy supply.

1 Given this mix of existing generation facilities within and
2 available to PJM, the price of energy in any hour is a function of the
3 mix of available units, including imports, their relative efficiencies, and
4 their fuel and operating costs and the demand for energy. With
5 demand levels rising and falling over the course of the day and night,
6 and across seasonal peaks, the spot price in any hour is set by the
7 marginal unit needed to meet demand.

8 As noted previously, transmission constraints within PJM
9 sometimes cause the PJM system to separate into two or more "sub-
10 markets" for energy during certain hours of the year. Prices in these
11 sub-regional markets will vary during those hours.

12
13 Q. Can you explain how transfer limits within PJM affect PP&L?

14 A. Exhibit STJ 2 contains several pages of tables with data and graphs
15 showing the effect and extent of the western, central and eastern
16 transfer limits and how electricity prices are affected in PP&L.

17 The one recurring constraint is the eastern transfer limit that
18 forms along the border between PP&L and the PJM companies that lie
19 electrically to the east of PP&L. (See Exhibit STJ 2, page 5). When
20 PJM load and supply characteristics cause the flow of large volumes of

1 economical power from western to eastern PJM, the transfer limit may
2 be reached, at which point additional economical supplies in the west
3 can no longer be called upon to satisfy incremental demand in the
4 east.

5 This is best explained with graphs that appear on pages 2 and 3
6 of Exhibit STJ 2. These two graphs are two days showing the system
7 lambdas, or the effect of changes in electricity use during the day on
8 the hourly price of electricity. These graphs show, simultaneously, the
9 lambdas for the portions of PJM lying on either side of the eastern
10 constraint. The graphs show that as the day progresses, from
11 midnight near the vertical axis to mid-day near the center of the
12 horizontal axis, electricity use grows to the point where the power
13 transfer capability from the area west of the constraint to east of the
14 constraint is "maxed-out". When that happens, prices rise for
15 customers to the east and fall, or remain constant, for customers to the
16 west of the constraint.

17
18 Q. Is this a persistent problem in PJM?

19 A. The extent that the eastern transfer limit economically constrained
20 PJM is summarized on page 4 of Exhibit STJ 2 in a table titled

1 "Frequency and Magnitude of the Eastern Constraint in PJM, 1992-
2 1996".

3
4 Q. What do you mean by "economically constrained" PJM?

5 A. One of the first things that PP&L's system engineers told me when I
6 asked about the effect of the Eastern constraint on prices in PJM was,
7 "You cannot look at the number of hours that PJM reports as
8 constrained." The engineers noted that PJM reports the system as
9 constrained for an hour if it is constrained for the entire hour or only a
10 few seconds of the hour. If one or more of the system lambdas, which
11 are reported every 20 seconds of every hour, indicates the constraint
12 is affecting the system, then that hour is recorded as being
13 constrained. For example, in 1996, PJM reports that for 15% of the
14 hours the system was in operation, the Eastern constraint affected the
15 system.² However, my examination of the system lambdas was
16 limited to those hours where, on average, the Eastern constraint
17 created an economic impact on the region, or where the average
18 hourly price east and west of the constraint differed. If the constraint

² "Report on Interconnection Operation, December 1996" PJM Interconnection Association, January 1997, p. 10.

1 lasted for a few seconds before being corrected, then average hourly
2 lambdas would show no record of an economic impact on the system.

3 The data on page 4 of Exhibit STJ 2 indicate that the price
4 effect was one mill or greater only 2.45% of the time over the five
5 years from 1992-96. A one mill differential in price was selected
6 because while it is small, it is still a distinct difference, at approximately
7 4% of the historical average price of electricity when the eastern
8 transfer limit begins to affect the system. In other words, customers to
9 the east of the constraint will face electricity prices that are at least 4%
10 greater than prices to the west one hour in forty, on average,
11 throughout the year.

12
13 Q. Why is this fact important to your market price testimony?

14 A. It demonstrates the insignificance of the constraint to long-term
15 forecasts of market prices. While I have provided the facts to show
16 that the constraint is real, to an economist it is not a large, recurring
17 factor in the way annual average electricity prices are determined in
18 PJM.

1 Q. Are spot market transactions the only way power is going to be bought
2 and sold in a competitive environment?

3 A. No. While I anticipate that spot transactions will dominate the way
4 price is set for the majority of electricity transactions within PJM,
5 bilateral contracts will be executed between generating companies and
6 certain customers, especially certain industrial and large commercial
7 accounts. For that matter, bilateral agreements exist today and will
8 continue to be used whenever one or more parties to the transaction
9 think they can benefit from tailoring the terms and conditions of the
10 transaction. Even so, I expect that over time, the price of electricity
11 sold under bilateral contracts will approximate the prices for spot
12 transactions of electricity. For this reason, I assume that market prices
13 will approximate the short-term marginal cost of generating electricity.
14

15 Q. How will spot prices for energy be reported in the PJM competitive
16 market?

17 A. I expect that spot prices will be transparent, i.e. readily available,
18 electronically, in real-time or near real-time. It is probable that the PJM
19 regional power market will report spot prices for electricity in a way that
20 will encourage use of the spot market.

1 I hold this view based on my experience in natural gas pipeline
2 markets. When the merchant function of gas pipelines was
3 deregulated, the natural gas industry benefited from the emergence of
4 electronic bulletin boards, where pipeline capacity could be matched
5 with spot gas supplies at "hubs" throughout the interstate natural gas
6 pipeline system. Hub pricing quickly emerged as the dominant market
7 force within the industry. A similar, fully integrated system is likely to
8 emerge for electricity since parts of that system are already in place.
9 For example, electricity futures markets currently operate in the
10 western U.S. and utilities within PJM already operate an electronic
11 bulletin board (OASIS).

12

13 **V B. The Capacity Market (kW)**

14 Q. How is the post-1999 competitive market for capacity likely to operate
15 within PJM?

16 A. The forces that will form the market for capacity are the disposition of
17 the current surplus capacity (i.e., the forecasted load versus capacity
18 and reserve requirements), the net cost to keep a plant in operation,
19 and the cost to install new capacity. I expect that the bid price for
20 capacity will reflect PJM's current surplus capacity status by remaining

1 at or above the net cost of keeping capacity available for operation,
2 but below the cost of incremental new capacity (combustion turbines
3 or CT's) until after the turn of the century.³ However, as the capacity
4 surplus is depleted, the price of capacity could rise rapidly, creating the
5 expectation that sustained high prices for capacity will be maintained.
6

7 Q. What will happen when capacity prices rise as the surplus is depleted?

8 A. Two forces will act to blunt the severity of anticipated capacity deficits
9 and any corresponding increase in capacity price. These two forces
10 are a planned increase in generation capacity and a reaction by
11 buyers and sellers to the increased electricity price.

12 First, when expected revenues in the energy and capacity
13 markets are high enough, generators who anticipate price increases
14 will plan capacity additions. Since competitive markets do not restrict
15 who can enter the generation market, new capacity will be planned by
16 both incumbent generators and third-party generators new to PJM.
17 Added capacity will work to relieve the growing capacity deficit within
18 PJM.

³The bid price will also reflect the revenue benefit, if any, of sales into the energy market.

1 Second, aggregators and power marketers will have every
2 incentive to encourage customers, who will react to the higher
3 electricity prices, to shift their purchases of firm load to lower-cost
4 interruptible power. This restructuring of load within PJM ought to be
5 efficiency-enhancing, as competitive forces bring actual customer
6 requirements more in line with the electricity generation capabilities of
7 the system. Any efficiency shift from the way electricity has been
8 traditionally bought and sold toward alternative terms and conditions
9 should delay the time when actual capacity additions are needed in
10 PJM.

11
12 Q. How do power interchange agreements affect the price of capacity in
13 PJM?

14 A. Power interchange agreements for imports of energy affect the price of
15 capacity by reducing the marginal cost of electricity at any point in
16 time. Absent the interchange agreements, higher cost facilities would
17 have to be dispatched within PJM to meet the hourly load
18 requirements of the system.

19 Second, interchange agreements affect the amount of capacity
20 needed to be maintained within PJM for reliability purposes. While

1 energy may be transacted across coordinated areas and PJM may
2 even count out-of-region capacity to meet reserve requirements, there
3 are limits to the amount of external capacity that may be counted
4 towards system reserve requirements for reliability purposes.
5

6 Q. Will PJM's current reserve requirement be affected by the move
7 toward retail competition in PJM?

8 A. Yes. Suppose that suppliers are load-serving entities ("LSE's") in
9 PJM. Then, in accordance with Section 2809 of the Act, electric
10 generation suppliers will be required by the Commission to ensure that
11 the present quality of service does not deteriorate. Even so, PJM's
12 current reserve requirement of 20% is likely to gradually be reduced as
13 a result of the move toward competition. Competition will cause LSE's
14 to search for ways to save costs. One of the obvious sources for cost-
15 savings for LSE's will be the current reserve requirement. Many
16 LSE's, responding to the demands created by customers and
17 marketers, will have an incentive to reduce the reserve requirement. I
18 expect that reliability standards will be re-examined and re-adjusted on
19 a regular basis, that reserve requirements will ultimately reflect the

1 expectations of customers.⁴ Individual states and regional reliability
2 councils will also be involved in setting reliability standards.

3 Considering all of these factors, I have used an 18% reserve
4 requirement in my analysis.

5 Q. Are spot market transactions the only way capacity transactions take
6 place in a competitive environment?

7 A. No. Bilateral capacity agreements are currently in place in PJM. I
8 anticipate that the same sorts of suppliers and purchasers will remain
9 within the system, so that short-term and long-term bilateral capacity
10 contracts will continue to exist in PJM. However, I expect that forces
11 of supply and demand will cause the price for capacity, as determined
12 by these agreements, to closely approximate the competitive market,
13 especially in the long run. For this reason, I have not separately
14 modeled the bilateral capacity market.

15
16 **VI THE METHOD USED TO ESTIMATE MARKET PRICES:**
17 **THE EGEAS MODEL**
18

19 Q. What method did you use to estimate market prices?

⁴ Discussions with PJM personnel indicated that the calculated PJM reserve requirement from the Association's reserve requirement studies has been reduced each year since 1992.

1 A. I directed personnel from my firm and from PP&L to use the
2 Company's EGEAS (Economic Generation Expansion Analysis
3 System) model to project market prices, using 1996 system data and
4 forecasting through the year 2016.⁵

5 EGEAS is an economic dispatch model designed primarily for
6 long-term system planning. As its name implies, the primary purpose
7 of the model is to find the best possible combination of generation
8 resources for meeting system load in the short run and in the long run.
9 In the short run, EGEAS is a production cost model, dispatching units
10 to meet demand levels in each hour of the year. Over the long run, the
11 model adds capacity to the existing system to meet reliability
12 constraints. Depending upon the economics at the point in time a new
13 unit will be added, either peaking or combined-cycle technology is
14 added to minimize cost.

15 Based on a variety of engineering and economic inputs
16 associated with the cost and performance characteristics of the
17 existing set of supply resources available to the system, EGEAS
18 dispatches an electric power system -- in this case, PJM -- in the most

⁵ Mr. Schadt's testimony reports projected revenue data to the end of the book life of the plants. In most cases, that is beyond 2016. He has simply taken the last revenue data provided by me, using EGEAS to 2016, and escalated that data by the assumed rate of inflation from EGEAS.

1 economic manner. Output includes hourly (variable) costs for the
2 marginal unit which, in turn, determines the market price of electricity
3 in a competitive generation market.

4 EGEAS can calculate the market clearing price for a pre-
5 specified set of units or for a least-cost expansion plan. I used the
6 model in both modes. I used EGEAS to determine the least-cost
7 expansion plan by selecting between a combustion turbine and a
8 combined cycle unit. Every year the model selected which type of
9 generation equipment was needed to meet load, including which, if
10 any, were to be added to the mix in PJM. In this (dynamic capacity)
11 mode, the model checks the need for additional capacity and brings on
12 the most economically viable increment of new capacity. Additionally,
13 within the model, reliability constraints eliminate combinations of
14 generation resources with insufficient or over-abundant reserve
15 capacity, energy, or LOLP (loss of load probability). The model also
16 supports environmental and fuel-use constraints.

17
18 Q. What are the key variables used in EGEAS?

19 A. EGEAS dispatches units in a least-cost manner using a load duration
20 curve approach. Two curves are generated, representing on-peak and

1 off-peak periods for each month. Generation is then economically
2 stacked according to its variable costs within these curves in
3 compliance with PJM operating constraints. A utility's capacity is
4 dispatched based on power pool economics and native load
5 requirements.

6 To accomplish unit dispatch, EGEAS requires four categories of
7 input data: fuel prices, engineering or unit data, load, and reserve
8 constraints. For example, EGEAS requires that each facility be
9 identified by fuel type. EGEAS also requires that fuel price escalators,
10 like the ones shown in Exhibit STJ 3, be provided as an input along
11 with the last actual fuel price. Along with generic unit data like loading
12 strategy (base, intermediate, peaking) and whether the plant is
13 designated for spinning reserve, EGEAS requires users to provide an
14 escalation rate for operating costs, like variable O&M. The escalation
15 rate used for variable O&M is shown in Exhibit STJ 4. Other unit data
16 are the plant heat rate and block loading of the facility's capacity by
17 heat rate, as well as the plant maintenance cycle (years). A summary
18 of the key assumptions provided to EGEAS is shown in Exhibit STJ 5.
19

1 Q. Where did you get plant specific information like fuel costs and load
2 data for non-PP&L facilities?

3 A. I used data and information provided to me by PP&L personnel. For
4 the most part, these data are reported to PJM and made available to
5 member companies. For example, the fuel related information can be
6 found in 1996 "Allocation of Forecast Requirements" reports that each
7 company files with the PJM Interconnection Association. This
8 information was updated for PP&L facilities as late at November of
9 last year. For non-PP&L facilities, fuel price data have been reviewed
10 and, when necessary, updated by the Company's fuels department.

11
12 Q. How does EGEAS treat plant outages, reserve requirements and
13 production costs?

14 A. Plant outages are modeled as planned and unplanned, to occur
15 randomly, by unit.

16 A reserve requirement is specified in the model. On an hourly
17 basis, EGEAS will compare peak load to available capacity in the
18 system. If necessary, a "dynamic programming" module will add
19 capacity based on the incremental cost of capacity. If the prevailing

1 capacity price is insufficient to add a combined cycle unit, then a
2 combustion turbine unit is added to the system.

3 EGEAS minimizes the production cost by using a merit order
4 that reflects increasing total variable operating costs (i.e., fuel and
5 O&M). The dispatch order can specify must-run units and units
6 designated for spinning reserves (like PP&L's Montour facility).
7 EGEAS then divides generating units into several blocks of capacity
8 that are dispatched separately. Each block has a different heat rate,
9 capacity (Mw) and block outage rate and as a result, a different
10 variable cost. Variable O&M is assumed to be the same across
11 blocks.

12
13 Q. Did you adjust the heat rates provided to you for PJM by PP&L?

14 A. No. Member companies provide PJM with heat rate information along
15 with unit engineering data. Since these data are provided for PJM
16 operating purposes, I saw no reason to adjust the data. EGEAS
17 models a heat rate curve for blocks of generation using five different
18 heat rate blocks. Having the option to use multiple heat rate blocks
19 more closely approximates how a unit will perform under actual
20 operating conditions.

1

2

Q. Does EGEAS take into account sales and purchases of electricity?

3

A. Yes. EGEAS allows the programmer to designate sales and purchases of power, like PP&L's sales contract with GPU, as an input to the model. These contracts are identified by size, cost (\$/Mwh), type (e.g., on-peak purchase), contract duration, and so forth. In this way, the impact of power purchases and sales to other utilities and non-PJM regions are directly accounted for in the estimate of market price.

4

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Q. What method was used to model unit availability?

12

A. EGEAS allows the programmer to designate unit availability. For this market price analysis, I set non-nuclear unit-availability factors at their actual average availability from the last five years. For nuclear units, I studied historical availability records (capacity factors) for nuclear plants in PJM and other systems. I concluded, that with one exception, PJM nuclear availability should be set at 78%, reflecting trends in historical data. I show the data used to calculate nuclear availability in Exhibit STJ 6.

13

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1 Q. What was the exception to the historic capacity factors for nuclear
2 plants in PJM?

3 A. I excluded Salem from the average. Its consistent history of low
4 capacity factors would have, in my opinion, unfairly reduced the
5 average capacity factor below that suggested by trends in the data
6 from other nuclear plants. Hence, while Salem's historically low
7 capacity factor was prevented from unfairly reducing the expected
8 average availability of nuclear capacity, Salem's capacity is included in
9 EGEAS at the 78% capacity factor applied to all nuclear plants in PJM.
10

11 Q. How does EGEAS estimate the market price of electricity?

12 A. Using the inputs I provided to the model and the capacity expansion
13 plan that EGEAS identified as most viable under these economic
14 assumptions, the model calculates the hourly market clearing price for
15 PJM. The market clearing price is the incremental cost of the last unit
16 dispatched within PJM for each hour. Those market clearing prices
17 are listed in Exhibit STJ 7.
18

19 Q. In your estimate of competitive market prices, do you include
20 compensation for start-up and no-load costs?

1 A. Yes, in part. Generating companies will require compensation for
2 these additional costs. I capture no-load costs in EGEAS through the
3 multi-block heat rates which account for no-load costs. EGEAS does
4 not have the ability to model start-up costs. However, when compared
5 to energy costs, start-up costs are a small part of the cost of energy.
6 Hence, start-up costs are not likely to impact plant dispatch in any way
7 that will significantly affect stranded cost estimates.

8 In calculating PP&L's stranded costs, any increase in the
9 market price of energy due to start-up costs is not accounted for in
10 PP&L's revenues. Similarly, these costs are not accounted for on the
11 cost side of the analysis. Start-up costs do not enter into the stranded
12 cost estimate on either side of the ledger.

13
14 Q. As part of your market price analysis, do you expect generating units
15 to realize revenue from other market products, such as spinning
16 reserve or other ancillary services?

17 A. Yes. However, as noted by PP&L's Mr. Whitehead, transmission
18 service will include all ancillary services defined by the FERC in Order
19 No. 888. I have, however, accounted for revenue from spinning
20 reserves in my estimate of market price.

1

2

Q. How do you capture revenue for spinning reserves?

3

A. First of all, EGEAS is set using the same assumptions for spinning reserves as provided to PJM by its member companies. EGEAS identifies those units that will provide enough spinning reserve to equal the largest unit on the system. Second, economic dispatch of units in EGEAS takes into account plants with spinning reserves. EGEAS loads the first blocks of spinning reserve before adding other blocks of capacity from other units. Because EGEAS gives priority to spinning reserve, the variable cost of these blocks of energy will impact energy price. The capacity price is not directly affected by spinning reserve.

11

12

Q. What are the resulting market prices for power and capacity in PJM?

13

A. The prices shown in Exhibit STJ 7 are annual average market-clearing energy prices for PJM.

14

15

16

Q. The market prices that you are sponsoring on behalf of PP&L are lower than those sponsored by PECO witnesses in that company's recent "Application of PECO Energy Company for Issuance of a Qualified Rate Order", January 22, 1997. Why?

17

18

19

1 A. As I have explained, my estimates of market prices were derived from
2 the incremental cost, as estimated by EGEAS, needed to serve the
3 demand for electricity on an hourly basis throughout the system.
4 These are the market-clearing prices facing buyers and sellers of
5 electric power throughout PJM, including imports and exports.

6 The market values or prices supplied by PECO's witnesses do
7 not represent a single market-wide price at any point in time that
8 reflects the pressures of buyers and sellers for both energy and
9 capacity in PJM (as affected by imports/exports of energy). Instead,
10 PECO's witnesses reported the per Mwh price needed to dispatch
11 PECO's facilities, on average, for that year.

12 PECO's witnesses testified that they provided "the realized
13 market price of PECO units"⁶ and the "revenues per Mwh generated"
14 by PECO facilities.⁷ These are not the same as the market prices I
15 generated. The prices shown in Exhibit STJ 7 would clear the regional
16 market on an hourly basis, including hours in which PP&L's facilities
17 are not dispatched. Unseen in any of PECO's analysis are the prices
18 for energy during the hours that PECO's plants are not being

⁶ PECO Statement No. 8, Direct Testimony of B.S. Venkateshwara, Application of PECO Energy Company for Issuance of a Qualified Rate Order, p. 8, lines 24-25.

⁷ PECO Statement No. 9, Direct Testimony of W.H. Hieronymous, Application of PECO Energy Company for Issuance of a Qualified Rate Order, p. 3, line 13.

1 dispatched by PJM. Average annual market prices have to include
2 both the observations sufficiently high enough to dispatch PECO's
3 generation facilities and those that were too low to call up 100% of a
4 PECO plant.

5 Q. Does this mean PECO's revenue by plant analysis is wrong?

6 A. No. When asked to determine the revenue each plant produces each
7 year, PECO appears to do the arithmetic correctly to get plant cash
8 flows, but this is not the market clearing price. It would be more
9 accurate to say that PECO's figures represent the market value of its
10 own generating units, not market price.

11
12 **VII INPUT VARIABLES: SOURCES AND ASSUMPTIONS**

13 Q. You have relied on forecasts of a number of variables to produce your
14 estimates for market clearing prices in PJM. Can you explain why you
15 chose to forecast variables rather than assume 1996 values for these
16 variables would prevail throughout the transition period?

17 A. Yes. There are a number of good reasons why I chose to forecast key
18 input variables, like fuel prices and O&M, rather than do something
19 simple like using today's energy and capacity prices in EGEAS for the
20 next twenty years. Market forces are dynamic, not static. As a result,

1 economists must deal with variables like prices and costs that change,
2 rather than stay the same over time.

3 Fixing future electricity prices, at their last known value, implies
4 that market forces are going to come together over the forecast time
5 horizon like they did in 1996. A simple examination of the movement
6 in key variables, like fuel and O&M, indicates that market forces are
7 causing certain variables to change at different rates and in different
8 directions over time.

9 Second, in many cases, it is possible to identify trends in
10 historic data that appear to be moving in a predictable direction and at
11 a predictable rate. Good examples are recent changes in the annual
12 rate of inflation and the annual change in economic growth.

13 Third, secular change in key factors such as the introduction of
14 competition, or a change in the regulatory environment, have
15 predictable impacts on variables. For example, economic theory is
16 clear about the tendency toward lower prices in markets that evolve
17 from more to less monopoly power, as market efficiency is enhanced
18 and costs reduced due to competitive pressures.

19 For all of these reasons, attempts to forecast prices by
20 forecasting the key variables that contribute to price formation is an

1 improvement on simply assuming that variables do not change over
2 the forecast horizon, or that all variables change in similar ways in the
3 future.

4
5 Q. How do you respond to critics of energy price forecasts that say
6 predicted values are never accurate and are biased upward?

7 A. The critics are right with regard to the general issue of accuracy and
8 forecast bias since 1973, and wrong with regard to the implication that
9 forecasting has failed to add value since the first energy crisis. In
10 1973, 1980 and again in 1986, American consumers and the oil
11 industry sat on the precipice of the unknown. The world's largest
12 market was shocked by major price dislocations that threatened
13 everything from national security to household budgets. Granted, the
14 long-term forecasts that emerged during the weeks and months
15 following these shocks were varied and (eventually) found to be
16 inaccurate; yet forecasting added structure and discipline to a process
17 when consumers, the business community and politicians demanded
18 expert opinion.

19
20 Q. How do you use forecast information?

1 A. As I stated earlier, I am more comfortable relying, whenever possible,
2 on a combination of forecasts (consensus view). In this way, I can
3 observe how a number of organizations think key variables will change
4 and how those changes are likely to impact a competitive market for
5 electricity.

6
7 **VII A. Energy Prices**

8 Q. Can you provide a brief explanation of the data sources and
9 assumptions that underlie the price forecast in Exhibit STJ 7?

10 A. Yes. I will take them in turn beginning with the assumption and data
11 sources for the fuel price projections.

12 I have a long history forecasting fuel prices. I used and
13 developed forecasting models and evaluated industry data for oil, gas
14 and coal as early as 1975 and extensively beginning with my
15 assignments with ARCO. In 1986, I joined Chase Econometrics, the
16 nation's second largest economic/industry forecasting firm. I was a
17 member of the firm's senior management in charge of most of the
18 industry groups, including energy. I am very familiar with the way firms
19 like Data Resources, Inc. ("DRI"), WEFA and the Gas Research
20 Institute ("GRI") forecast energy prices. I am also familiar with the

1 models, methods and data used by the Energy Information
2 Administration ("EIA") and the International Energy Agency ("IEA"). My
3 knowledge of energy forecasting methods leads me to review a
4 number of forecasts, not just one forecast, when arriving at a view of
5 energy price trends.

6 Additionally, I examined the recent historical record for price
7 behavior in assessing the short-to-intermediate term forecasts of
8 others. In that regard, I have examined forecasts from the following
9 sources in producing the outlook for fuel oil, natural gas and coal
10 escalation rates found in Exhibit STJ 3: DRI; WEFA; GRI; American
11 Gas Association ("AGA"); EIA; IEA; State of Alaska; Oil & Gas Journal
12 ("O&GJ"); Society of Professional Petroleum Engineers ("SPEE");
13 Enron Corporation; British Petroleum; Coal Outlook; and others.
14 Whenever possible, I looked at the explanation of the variables
15 underlying the organization's forecast, such as predictions about
16 economic growth, OPEC production, regulatory trends, reserve
17 additions, and transportation costs.

18 As a result, the outlook in Exhibit STJ 3 for fuel oil, natural gas
19 and coal, delivered to utilities, is compiled from a large body of data,

1 and in my view, represents a reasonable consensus forecast of fuel
2 prices.

3
4 Q. Did you perform a similar analysis to develop your view about
5 inflation?

6 A. Yes. In recent years, the rate of inflation has been steady, fluctuating
7 annually in a relatively narrow range. Inflation rates since 1992 reflect
8 the Federal Reserve's efforts to control the money supply and an
9 improved competitive environment for U.S. businesses. Hence,
10 despite the fact that the current economic expansion is six years old,
11 there is little evidence that inflation is likely to return to levels seen in
12 the 1980's.

13 For purposes of estimating market prices for electricity or
14 stranded costs, I am not assuming that a recession impacts the U.S.
15 economy. This is a conservative assumption from the point of view of
16 estimating stranded cost since a recession would reduce electricity
17 demand and spot electricity prices compared to continued economic
18 growth. Therefore, I have adopted a steady 2.5% inflation rate for the
19 economy throughout the forecast horizon.
20

1 Q. What assumptions have you incorporated into your forecast of variable
2 O&M?

3 A. My view of future changes in variable O&M costs, as shown in Exhibit
4 STJ 4, stems from three sources of data. First, an examination of the
5 trends in O&M costs in capital intensive industries beginning with the
6 1980's suggests that periods of competitive change often cause
7 internal cost escalation rates in variable O&M to decline, at least in
8 real terms. For example, a recent article on the highly-competitive
9 (and partially regulated) oil refining industry, cited data showing O&M
10 costs declining as much as 10-15 percent per year over the last
11 several years.⁸

12 Second, the recent restructuring that has taken place in the
13 natural gas pipeline industry caused variable O&M costs to trail
14 inflation. Following FERC Order No. 636, pipeline company
15 restructuring produced firms that were encouraged to respond to
16 competitive pressures, and firms that encouraged the introduction of
17 cost-saving technology. Third, evidence and opinion from various
18 industry and academic publications suggest that variable O&M costs in

⁸ Anne Rhodes, "Hostile Operating Climate Augurs Further Closures for U.S. Refiners," *Oil & Gas Journal*, March 10, 1997, 21-23.

1 parts of the industry may be rising slower than inflation for some time.
2 Evidence from these three categories of information led me to use an
3 escalation of 1.5% (negative one percent real price escalation) through
4 the year 2000, and 2.5% (flat real price escalation) thereafter.
5

6 Q. What assumption and sources of information have you used to
7 establish the escalation in emissions allowance prices for SO₂?

8 A. EGEAS allows the user to input an escalation rate for emissions
9 allowances by adjusting the fuel price escalators. The first step is to
10 identify which units will be running when the region is not in
11 compliance. EGEAS accomplishes this by checking the emission
12 production rate against the annual emission limit input for each facility.
13 Once the units are identified, then those units that are subject to
14 emissions limits are assigned allowances sufficient to bring them into
15 compliance. The cost of bringing those units into compliance is built
16 into the fuel escalation rates for PJM.

17 There has been a steady decline in the cost of SO₂ allowances
18 over the past several years, with a modest increase in recent months.
19 Expert opinion varies with regard to a "consensus" forecast of
20 allowance prices, like all other forecasts. One such forecast, prepared

1 by ICF Kaiser, estimates allowance prices under various
2 assumptions.⁹ In my view, recent trends in allowance costs more
3 closely approximate the ICF "low case" from this 1996 study. This
4 view was reinforced by industry publications and conversations I have
5 had with environmental economists and emissions experts at both
6 Harvard University and the Massachusetts Institute of Technology.

7 Based on the information and data gathered from a variety of
8 sources, I assigned EGEAS an initial SO₂ allowance cost consistent
9 with that found in the ICF Kaiser study (low case) through 2000. After
10 that, the allowance costs were escalated with inflation (2.5% per
11 annum).

12 NO_x emission allowance costs are too uncertain and allowance
13 markets are still too thin to form reliable estimates of current price
14 levels or future rates of change in this variable. The market for these
15 allowances will be driven by the cost of the equipment used to reduce
16 NO_x emissions. A survey of the literature and academic experts
17 convinced me that industry has not established a credible technique
18 for estimating the future market value for these allowances. Further,
19 when cost-based estimates are provided, the apparent impact on the

⁹ ICF Kaiser, "The Potential Market Value of SO₂ Allowances," June 1996.

1 PJM market-clearing price would be so small as to be almost
2 undetectable. Hence, NO_x emission allowance costs are excluded in
3 the forecast of future market prices for electricity.
4

5 Q. What assumption and data source was used for EGEAS regarding
6 plant mix and availability?

7 A. Plant mix and availability data were provided by PP&L staff for the
8 Company's facilities. For non-PP&L generation plants, estimates of
9 availability and plant type are based on PP&L operating experience,
10 marketing efforts, and reports filed by other utilities with PJM as
11 required by the power pool.
12

13 Q. What was the source of the electricity demand forecast used in
14 EGEAS?

15 A. Rather than forecast electricity demand for PJM and PP&L, I relied on
16 personnel from PP&L to supply me with PJM documents showing
17 forecasted electricity demand and with updates of PP&L's estimates of
18 its electricity demand. For example, PP&L updated its forecast for
19 electricity demand as late as December 1996¹⁰.

¹⁰ PJM, "Allocation of Forecast Requirements," updated December 7, 1996.

1
2 Q. What heat rate does EGEAS use for capacity additions in the model?

3 A. The assumed heat rates are 10,200 BTU/kwh for a combustion turbine
4 unit and 7,000 BTU/kwh for a combined cycle unit. PP&L provided
5 these data to me based on information from vendors. These data are
6 consistent with other heat rate assumptions that I am aware of in
7 other recent industry studies.
8

9 **VII B. Capacity Prices**

10 Q. What capacity prices were used to derive the market price of electricity
11 in PJM?

12 A. The capacity prices are shown in Exhibit STJ 8. These forecast values
13 are based in part on PP&L's energy marketers' experience negotiating
14 with buyers of the Company's capacity. PP&L is a net seller of
15 capacity, both in the short-term (spot) market and in the forward
16 market. Hence, PP&L has data based on actual transactions.

17 Second, my forecast for capacity prices recognizes that
18 competitive markets tend to exhibit a rapid increase in spot prices as a
19 potential shortage builds. It is this increase in price that brings on new
20 capacity and creates the environment where marketers may succeed

1 in shifting the utility's electricity customers off firm load to the
2 marketers less costly interruptible loads. However, the "peakedness"
3 of any price increase into the early part of the next century will be
4 tempered by the impact of a shift from a regulated to a competitive
5 environment as a result of restructuring of the industry. Economists
6 know from the deregulation of other industries, such as airlines,
7 railroads and most recently natural gas, that persistent price softness
8 can be sustained for several years at market prices below that needed
9 to bring on new capacity (long run marginal cost).

10 Economic theory holds that prices will tend toward short-run
11 marginal cost (SRMC) in competitive markets, sending efficient signals
12 to markets for production, consumption and investment.¹¹ However,
13 the anticipated entry of new generation sources to PJM, in the form of
14 marketers, aggregators and other utilities, will exert added competitive
15 pressure on existing utilities to supply power at lower energy prices.
16 These new competitive pressures will require disciplined cost-saving

¹¹ In general, pricing on the basis of SRMC results in different prices and quantities than prevailing long-run marginal or average cost. When prices are equal to long-run marginal cost (LRMC), they reflect not only short-run variable costs, but capital costs as well. Alfred E. Kahn, The Economics of Regulation (1993), pp. 88-89 and 174.

1 by utilities and the rapid adoption of efficiency enhancing operation
2 and management techniques.

3
4 Q. How are assumed summer and winter loads used in the peak day
5 analysis for EGEAS?

6 A. The peak day analysis was performed as part of the load shape
7 provided by PP&L for use in EGEAS. Summer and winter peaks help
8 to determine the load shape. The load projections are consistent with
9 those accepted by PJM as part of the most recent planning exercise.
10

11 **VIII REVENUE BY PLANT**

12 Q. What method did you use to convert the market price information to
13 revenue by plant information?

14 A. The revenue by plant information was generated in two basic steps:
15 revenue by plant for capacity and revenue by plant for energy.
16

17 Q. Please explain how you calculate capacity revenue by plant.

18 A. PP&L provided me with the (summer) capacity by plant (Mw). The
19 data were combined with the (annual average) capacity price shown
20 for PJM in Exhibit STJ 8 to produce a capacity revenue stream for

1 each year of the forecast. In this way, I have implicitly assumed that
2 even with competitive market pricing, PP&L will receive capacity
3 revenue for the full year from each available plant, with revenues
4 based on the incremental cost of that capacity.
5

6 Q. What do you do with the capacity revenue by plant data?

7 A. I provide PP&L Witness Mr. Schadt with that information. Mr. Schadt's
8 Exhibit JRS 1 includes that data in his stranded cost evaluation for
9 each plant. It appears in his plant by plant summary sheets titled
10 "Stranded Evaluation" under the heading "Revenues" near the bottom
11 of each of those summary sheets.
12

13 Q. Please explain how you calculate energy revenue by plant.

14 A. The energy revenue calculation requires several inter-related steps.
15 Some of the steps are needed to decompose the average price of
16 energy into corresponding peak, intermediate and base load prices.
17 The rest of the calculations focus on the distribution of the number of
18 hours a plant was dispatched during the year into peak, intermediate
19 and base load.
20

1 Q. Please explain the steps necessary to determine peak, intermediate
2 and base load prices for each plant.

3 A. First, I collected the annual capacity factor for each plant from EGEAS.
4 I also collected the annual hourly system load requirements. In
5 addition, I collected the hourly market clearing price for each hour's
6 system load.

7 Second, I arranged the annual hourly system load requirements
8 from highest to lowest. I then divided this group of hourly system load
9 requirement data as follows: the highest 10% into peak load, the next
10 highest 30% into intermediate load, and the remaining 60% into base
11 load. In this way, each year's system load is allocated into peak,
12 intermediate and base load categories.

13 The third step is to identify the price for each of these hourly
14 loads and array those prices in the same manner. However, since
15 stranded cost calculations only need one price for peak, intermediate
16 and base load, I averaged the individual prices in each group to create
17 peak, intermediate and base load prices for that period. These are
18 the prices that were used to produce the individual annual plant
19 revenue data that are part of PP&L Witness Schadt's stranded cost
20 calculations.

1
2 Q. Where does Mr. Schadt get the generation data, by plant, that can be
3 used with the price data to produce plant revenues?

4 A. The method for determining hourly generation by plant is also
5 conducted in several steps.

6 I start by taking the annual plant capacity factor data from
7 EGEAS and distribute generation into peak, intermediate and base
8 load depending on the hours the plant was dispatched during the year.

9 For example, suppose EGEAS indicates that market conditions
10 determined one plant's capacity factor to be 15%. That means the
11 plant was dispatched about 1300 hours during the year (0.15/yr. *
12 8760 hr./yr.).

13 I turned to PP&L for a standard I could use to determine how
14 many of this plant's 1300 hours should be allocated to peak,
15 intermediate or base load. PP&L sets its plants' equivalent availability
16 factor at 80% (hours that the plant is available).¹² That means PP&L
17 expects that their plants would be available to operate (8760 hours per
18 year * 0.8/yr.), or about 7000 hours. Plants like Montour actually

¹² Actual operation of a facility is captured by EGEAS' estimated capacity factors while the equivalent availability estimate is the standard used by PP&L.

1 operate (as measured by Montour's annual capacity factor) near the
2 80% level, while plants like Martin's Creek 3 & 4 operate at much lower
3 levels, nearer to 15%.¹³

4 The next step is to divide the plant's hourly annual generation
5 (hours the plant was running) into peak, intermediate and base load,
6 assuming that the plant's availability is spread evenly over the loads.
7 For example, 10% of 7000 hours is 700 hours, 30% of 7000 hours is
8 2100 hours, and so forth.

9 Hence, for 700 of the plant's 1300 hours of annual operation,
10 the plant should be credited with the peak price taken from the data I
11 provided above. The remaining 600 hours would receive the price for
12 intermediate load. This plant was not in operation enough of the year
13 to warrant base load prices.

14 I repeat this method for each of PP&L's plants, then provide the
15 data to Mr. Schadt. Those results appear under "Revenue" in each of
16 Mr. Schadt's plant level "Stranded Evaluation" sheets in Exhibit JRS 1.
17

¹³ Susquehanna's equivalent available factor was set equal to its capacity factor at 78%. Hence, when Susquehanna was available, it was running.

1 Q. What other data do you supply that is used in Mr. Schadt's estimates
2 of stranded cost on a plant-by-plant basis?

3 A. Each of Mr. Schadt's plant level "Stranded Evaluation" sheets lists five
4 lines under "Revenues". I supply the data for each of those five lines.
5 Hence, in addition to the energy and capacity revenue entries noted
6 above, the market clearing price of generation (MCPG) entry is derived
7 by dividing "Total Revenues" (energy plus capacity) by "Generation".
8

9 Q. Does this conclude your prepared direct testimony?

10 A. Yes.