Regulatory Assets @ 12/31/96

			Generation (1)		Generation (2)				Total Duquesne
	Trans.	Distr.	Fossil	Nuclear	Nuclear	Fossil	Other	Total	Light
10-K Regulatory Assets									
Regulatory Tax Receivable	32.66	56.52			172.66	132.29		304.94	394.12
Unamortized Debt Premium/Discount (3)	6.46	27.18	7.98	13.56	18.84	11.08		29.92	85.11
Beaver Valley 2 Lease Premium				3.88	4.31			4.31	8.19
Total Unamortized Debt Cost	6.46	27.18	7.98	17.44	23.14	11.08	0.00	34.22	93.30
Deferred Rate Synch. Costs					41.45			41.45	41.45
BV2 Sale/Leaseback Premium				13.55	16.51			16.51	30.06
Deferred Employee Costs (4)	0.70	11.09			10.51	7.29		17.80	29.59
Deferred Nuclear Maintenance					13.46			13.46	13.46
DOE Decom & Decon					9.78			9.78	9.78
Deferred Coal Costs						12.19		12.19	12.19
Other									
Deferred Caretaker Costs						6.77		6.77	6.77
BV2 Training Costs					2.62			2.62	2.62
Low Level Rad. Waste					2.27			2.27	2.27
Coal Cost Equalization						0.32		0.32	0.32
Deferred Oxford Centre Costs	0.00	0.07			0.07	0.05		0.12	0.20
PA Deregulation Expenses	0.01	0.09			0.08	0.06		0.14	0.23
Demand Side Management	0.00	0.06			0.06	0.04		0.10	0.16
Corporate Development Project	0.00	0.04			0.04	0.03		0.07	0.11
Section 211	0.00	0.04			0.04	0.03		0.06	0.10
1996 Management Audit	0.00	0.02			0.02	0.01		0.03	0.05
Administrative & General	0.00	0.01			0.01	0.01		0.01	0.02
Total Other	0.02	0.33	0.00	0.00	5.20	7.31	0.00	12.51	12.86
Total Regulatory Assets per 10-K	**39.85**	**95.12**	**7.98**	**30.99**	**292.71**	**170.16**	**0.00**	**462.87**	**636.80**
Adjustments									
PV Beaver Valley Lease					291.44			291.44	291.44
Nuclear Decommissioning					0.00			0.00	0.00
Pre-Accrue Nuclear Outages					22.65			22.65	22.65
Gain on Sale/Leaseback (5)					61.13			61.13	61.13
Deferred Rate Synch. Costs (5)					0.27			0.27	0.27
Beaver Valley 2 (5)					0.17			0.17	0.17
Fossil Decommissioning						0.00		0.00	0.00
Deferred Fuel Cost						14.81		14.81	14.81
Transition Costs							18.10	18.10	18.10
FAS 106 (4)(6)	0.28	4.43	2.91	4.20				0.00	11.82
FAS 106 (4)(7)	0.17	2.63			2.49	1.73		4.22	7.02
Total Adjustments	0.45	7.06	2.91	4.20	378.15	16.54	18.10	412.79	427.40
Adjusted Regulatory Assets	**40.29**	**102.18**	**10.90**	**35.19**	**670.86**	**186.70**	**18.10**	**875.66**	**1,064.21**

(1) Recovered through interest and lease expense.

(2) Recovered through amortization.

(3) Allocation based on gross plant balances.

(4) Allocation based on labor costs.

(5) Shown as deferred tax assets in 1996 Form 10-K.

(6) FAS 106 with amortization shedule ending 2002, included in non-production expense

(7) FAS 106 with amortization schedule ending 2012, PV @ 1999

Allocation Percentages	Trans	Distr	Fossil	Nuclear	Total
Labor Costs	2.37%	37.47%	24.65%	35.51%	100.00%
Gross Plant	7.59%	31.94%	22.40%	38.07%	100.00%

Amortization Schedule
Regulatory Assets
Generation

	Actual Year - End 1996	Estimated Change 1997	Estimated Change 1998	Estimated Year - End 1998	1999	2000	2001	2002	2003	2004	2005	Net Balance 12/31/2006
Total Regulatory Assets												
10-K Regulatory Assets												
Regulatory Tax Receivable	304.94	(31.55)	(36.91)	236.48	(33.78)	(33.78)	(33.78)	(33.78)	(33.78)	(33.78)	(33.78)	(0.00)
Unamortized Debt Costs (1)	34.22	0.00	0.00	34.22	(4.89)	(4.89)	(4.89)	(4.89)	(4.89)	(4.89)	(4.89)	(0.00)
Deferred Rate Synch. Costs	41.45	(4.14)	(4.14)	33.16	(4.74)	(4.74)	(4.74)	(4.74)	(4.74)	(4.74)	(4.74)	(0.00)
BV2 Sale/Leaseback Premium	16.51	0.00	0.00	16.51	(2.36)	(2.36)	(2.36)	(2.36)	(2.36)	(2.36)	(2.36)	0.00
Deferred Employee Costs (2)	17.80	0.00	0.00	17.80	(2.54)	(2.54)	(2.54)	(2.54)	(2.54)	(2.54)	(2.54)	0.00
Deferred Nuclear Maintenance	13.46	0.56	(10.77)	3.25	(0.46)	(0.46)	(0.46)	(0.46)	(0.46)	(0.46)	(0.46)	(0.00)
DOE Decom & Decon	9.78	(1.30)	(1.30)	7.18	(1.03)	(1.03)	(1.03)	(1.03)	(1.03)	(1.03)	(1.03)	0.00
Deferred Coal Costs	12.19	0.31	1.00	13.50	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	0.00
Other												
Deferred Caretaker Costs	6.77	0.00	0.00	6.77	(0.97)	(0.97)	(0.97)	(0.97)	(0.97)	(0.97)	(0.97)	0.00
BV2 Training Costs	2.62	(0.10)	(0.10)	2.42	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	0.00
Low Level Rad. Waste	2.27	0.00	0.00	2.27	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	0.00
Coal Cost Equalization	0.32	(0.10)	(0.10)	0.12	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	0.00
Other Regulatory Assets	0.53	0.00	0.00	0.53	(0.08)	(0.08)	(0.08)	(0.08)	(0.08)	(0.08)	(0.08)	0.00
Total Other	12.51	(0.20)	(0.20)	12.11	(1.73)	(1.73)	(1.73)	(1.73)	(1.73)	(1.73)	(1.73)	0.00
Total Regulatory Assets per 10-K	462.87	(36.33)	(52.33)	374.21	(53.46)	(53.46)	(53.46)	(53.46)	(53.46)	(53.46)	(53.46)	(0.00)
Adjustments												
PV Beaver Valley Lease	291.44	(25.00)	(38.66)	227.78	(15.40)	(15.40)	(15.40)	(15.40)	(15.40)	(15.40)	(40.02)	95.38
Pre-Accrue Nuclear Outages	22.65	0.00	0.00	22.65	(3.24)	(3.24)	(3.24)	(3.24)	(3.24)	(3.24)	(3.24)	0.00
Gain on Sale/Leaseback (3)	61.13	(3.00)	(3.00)	55.13	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	0.00
Deferred Rate Synch. Costs (3)	0.27	0.00	0.00	0.27	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	0.00
Beaver Valley 2 (3)	0.17	0.00	0.00	0.17	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.00)
Deferred Fuel Cost	14.81	0.00	0.00	14.81	(2.12)	(2.12)	(2.12)	(2.12)	(2.12)	(2.12)	(2.12)	0.00
Transition Costs	18.10	0.00	0.00	18.10	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	0.00
FAS 106 (2)	4.22	0.00	0.00	4.22	(0.60)	(0.60)	(0.60)	(0.60)	(0.60)	(0.60)	(0.60)	0.00
Total Adjustments	412.79	(28.00)	(41.66)	343.12	(31.87)	(31.87)	(31.87)	(31.87)	(31.87)	(31.87)	(56.49)	95.38
Adjusted Regulatory Assets	875.66	(64.33)	(93.99)	717.33	(85.33)	(85.33)	(85.33)	(85.33)	(85.33)	(85.33)	(109.95)	95.38
Remove outage accounting (4)		(0.56)	10.77									
FAS 109 Plant (5)	0.00	0.00	0.00	62.94	(8.99)	(8.99)	(8.99)	(8.99)	(8.99)	(8.99)	(8.99)	(0.00)
Total	875.66	(64.89)	(83.22)	780.28	(94.33)	(94.33)	(94.33)	(94.33)	(94.33)	(94.33)	(118.95)	95.38
Regulatory Assets Recovered through Interest/Lease Expense												
Unamortized Debt Cost	21.55	(2.39)	(2.39)	16.76	(2.39)	(2.39)	(2.39)	(2.39)	(2.39)	(2.39)	(2.39)	0.00
BV2 Sale/Leaseback Premium	17.43	(1.94)	(1.94)	13.55	(1.94)	(1.94)	(1.94)	(1.94)	(1.94)	(1.94)	(1.94)	(0.00)
Total	38.97	(4.33)	(4.33)	30.31	(4.33)	(4.33)	(4.33)	(4.33)	(4.33)	(4.33)	(4.33)	0.00
Total Generation	914.63	(69.22)	(87.55)	810.59	(98.66)	(98.66)	(98.66)	(98.66)	(98.66)	(98.66)	(123.28)	95.38

(1) Allocation based on gross plant balances
(2) Allocation based on labor costs
(3) Shown as deferred tax assets in 1996 Form 10-K.
(4) Outage accounting is reflected in the revenue requirement for the generating unit
(5) FAS 109 allocated to plant is reflected in the generating plant balance through 12/31/98

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Amortization Schedule
Regulatory Assets
Generation

Regulatory Assets	Actual Year - End 1996	Estimated Change 1997	Estimated Change 1998	Estimated Year - End 1998	1999	2000	2001	2002	2003	2004	2005	Net Balance 12/31/2005
Nuclear Related												
10-K Regulatory Assets												
Regulatory Tax Receivable	172.66	(21.85)	(26.36)	124.44	(17.78)	(17.78)	(17.78)	(17.78)	(17.78)	(17.78)	(17.78)	(0.00)
Unamortized Debt Premium/Discount (1)	18.84	0.00	0.00	18.84	(2.69)	(2.69)	(2.69)	(2.69)	(2.69)	(2.69)	(2.69)	0.00
Beaver Valley 2 Lease Premium	4.31	0.00	0.00	4.31	(0.62)	(0.62)	(0.62)	(0.62)	(0.62)	(0.62)	(0.62)	(0.00)
Total Unamortized Debt Cost	23.14	0.00	0.00	23.14	(3.31)	(3.31)	(3.31)	(3.31)	(3.31)	(3.31)	(3.31)	0.00
Deferred Rate Synch. Costs	41.45	(4.14)	(4.14)	33.16	(4.74)	(4.74)	(4.74)	(4.74)	(4.74)	(4.74)	(4.74)	(0.00)
BV2 Sale/Leaseback Premium	16.51	0.00	0.00	16.51	(2.36)	(2.36)	(2.36)	(2.36)	(2.36)	(2.36)	(2.36)	0.00
Deferred Employee Costs (2)	10.51	0.00	0.00	10.51	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	0.00
Deferred Nuclear Maintenance	13.46	0.56	(10.77)	3.25	(0.46)	(0.46)	(0.46)	(0.46)	(0.46)	(0.46)	(0.46)	(0.00)
DOE Decom & Decon	9.78	(1.30)	(1.30)	7.18	(1.03)	(1.03)	(1.03)	(1.03)	(1.03)	(1.03)	(1.03)	0.00
Other												
BV2 Training Costs	2.62	(0.10)	(0.10)	2.42	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	0.00
Low Level Rad. Waste	2.27	0.00	0.00	2.27	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	0.00
Other Regulatory Assets	0.31	0.00	0.00	0.31	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	0.00
Total Other	5.20	(0.10)	(0.10)	5.00	(0.71)	(0.71)	(0.71)	(0.71)	(0.71)	(0.71)	(0.71)	(0.00)
Total Regulatory Assets per 10-K	292.71	(26.84)	(42.68)	223.19	(31.88)	(31.88)	(31.88)	(31.88)	(31.88)	(31.88)	(31.88)	0.00
Adjustments												
PV Beaver Valley Lease	291.44	(25.00)	(36.66)	227.78	(15.40)	(15.40)	(15.40)	(15.40)	(15.40)	(15.40)	(40.02)	95.38
Pre-Accrue Nuclear Outages	22.65	0.00	0.00	22.65	(3.24)	(3.24)	(3.24)	(3.24)	(3.24)	(3.24)	(3.24)	0.00
Gain on Sale/Leaseback (3)	61.13	(3.00)	(3.00)	55.13	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	0.00
Deferred Rate Synch. Costs (3)	0.27	0.00	0.00	0.27	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	0.00
Beaver Valley 2 (3)	0.17	0.00	0.00	0.17	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.00)
FAS 106 (2)	2.49	0.00	0.00	2.49	(0.36)	(0.36)	(0.36)	(0.36)	(0.36)	(0.36)	(0.36)	(0.00)
Total Adjustments	378.15	(28.00)	(41.66)	308.49	(26.93)	(26.93)	(26.93)	(26.93)	(26.93)	(26.93)	(51.55)	95.38
Adjusted Regulatory Assets	670.86	(54.84)	(84.34)	531.67	(58.81)	(58.81)	(58.81)	(58.81)	(58.81)	(58.81)	(83.43)	95.38
Remove outage accounting (4)		(0.56)	10.77									
FAS 109 Plant (5)	0.00	0.00	0.00	62.94	(8.99)	(8.99)	(8.99)	(8.99)	(8.99)	(8.99)	(8.99)	(0.00)
Total	670.86	(55.40)	(73.57)	594.62	(67.80)	(67.80)	(67.80)	(67.80)	(67.80)	(67.80)	(92.42)	95.38
Regulatory Assets Recovered through Interest/Lease Expense												
Unamortized Debt Premium/Discount	13.56	(1.51)	(1.51)	10.55	(1.51)	(1.51)	(1.51)	(1.51)	(1.51)	(1.51)	(1.51)	0.00
BV2 Sale/Leaseback Premium	17.43	(1.94)	(1.94)	13.55	(1.94)	(1.94)	(1.94)	(1.94)	(1.94)	(1.94)	(1.94)	(0.00)
Total	30.99	(3.44)	(3.44)	24.10	(3.44)	(3.44)	(3.44)	(3.44)	(3.44)	(3.44)	(3.44)	0.00
Total Nuclear Generation	701.85	(58.84)	(77.01)	618.72	(71.25)	(71.25)	(71.25)	(71.25)	(71.25)	(71.25)	(95.87)	95.38

(1) Allocation based on gross plant balances.
(2) Allocation based on labor costs.
(3) Shown as deferred tax assets in 1996 Form 10-K.
(4) Outage accounting is reflected in the revenue requirement for the generating unit
(5) FAS 109 allocated to plant is reflected in the generating plant balance through 12/31/98

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Amortization Schedule
Regulatory Assets
Generation

	Actual Year - End 1996	Estimated Change 1997	Estimated Change 1998	Estimated Year - End 1998	1999	2000	2001	2002	2003	2004	2005	Net Balance 12/31/2006
Regulatory Assets												
Fossil Related												
10-K Regulatory Assets												
Regulatory Tax Receivable	132.29	(9.70)	(10.55)	112.04	(16.01)	(16.01)	(16.01)	(16.01)	(16.01)	(16.01)	(16.01)	(0.00)
Unamortized Debt Costs (1)	11.08	0.00	0.00	11.08	(1.58)	(1.58)	(1.58)	(1.58)	(1.58)	(1.58)	(1.58)	0.00
Deferred Employee Costs (2)	7.29	0.00	0.00	7.29	(1.04)	(1.04)	(1.04)	(1.04)	(1.04)	(1.04)	(1.04)	0.00
Deferred Coal Costs	12.19	0.31	1.00	13.50	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	0.00
Other												
Deferred Caretaker Costs	6.77	0.00	0.00	6.77	(0.97)	(0.97)	(0.97)	(0.97)	(0.97)	(0.97)	(0.97)	0.00
Coal Cost Equalization	0.32	(0.10)	(0.10)	0.12	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	0.00
Other Regulatory Assets	0.22	0.00	0.00	0.22	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.00)
Total Other	7.31	(0.10)	(0.10)	7.11	(1.02)	(1.02)	(1.02)	(1.02)	(1.02)	(1.02)	(1.02)	0.00
Total Regulatory Assets per 10-K	170.16	(9.49)	(9.65)	151.02	(21.57)	(21.57)	(21.57)	(21.57)	(21.57)	(21.57)	(21.57)	0.00
Adjustments												
Deferred Fuel Cost	14.81	0.00	0.00	14.81	(2.12)	(2.12)	(2.12)	(2.12)	(2.12)	(2.12)	(2.12)	0.00
FAS 106 (2)	1.73	0.00	0.00	1.73	(0.25)	(0.25)	(0.25)	(0.25)	(0.25)	(0.25)	(0.25)	0.00
Total Adjustments	16.54	0.00	0.00	16.54	(2.36)	(2.36)	(2.36)	(2.36)	(2.36)	(2.36)	(2.36)	0.00
Total	186.70	(9.49)	(9.65)	167.56	(23.94)	(23.94)	(23.94)	(23.94)	(23.94)	(23.94)	(23.94)	0.00
Regulatory Assets Recovered through Interest Expense												
Unamortized Debt Premium/Discount	7.98	(0.89)	(0.89)	6.21	(0.89)	(0.89)	(0.89)	(0.89)	(0.89)	(0.89)	(0.89)	0.00
Total Fossil Generation	194.68	(10.37)	(10.54)	173.77	(24.82)	(24.82)	(24.82)	(24.82)	(24.82)	(24.82)	(24.82)	0.00

(1) Allocation based on gross plant balances
(2) Allocation based on labor costs

Amortization Schedule
Regulatory Assets
Generation

	Actual Year - End 1996	Estimated Change 1997	Estimated Change 1998	Estimated Year - End 1998	1999	2000	2001	2002	2003	2004	2005	Net Balance 12/31/2005
Regulatory Assets												
Other												
Total Regulatory Assets per 10-K	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Adjustments	18.10	0.00	0.00	18.10	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	0.00
Transition Costs	18.10	0.00	0.00	18.10	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	0.00
Total Adjustments												
Total Other Regulatory Assets	18.10	0.00	0.00	18.10	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	0.00

Net Regulatory Assets
Tax Effect

	Trans.	Distr.	Generation (1) Fossil	Generation (1) Nuclear	Generation (2) Nuclear	Generation (2) Fossil	Generation (2) Other	Generation (2) Total	*Total* Duquesne Light
10-K Regulatory Assets									
Regulatory Tax Receivable	(32.66)	(56.52)			(34.22)	(46.22)		(80.44)	(169.61)
Unamortized Debt Premium/Discount (3)	(2.68)	(11.28)	(3.31)	(5.63)	(6.85)	(4.03)		(10.88)	(33.78)
Beaver Valley 2 Lease Premium				(1.61)	(1.53)			(1.53)	(3.14)
Total Unamortized Debt Cost	(2.68)	(11.28)	(3.31)	(7.24)	(8.38)	(4.03)		(12.41)	(36.92)
Deferred Rate Synch. Costs					(3.05)			(3.05)	(3.05)
BV2 Sale/Leaseback Premium				(5.62)	(6.85)			(6.85)	(12.47)
Deferred Employee Costs (4)	(0.29)	(4.60)			0.00	0.00		0.00	(4.89)
Deferred Nuclear Maintenance					(5.59)			(5.59)	(5.59)
DOE Decom & Decon					(4.07)			(4.07)	(4.07)
Deferred Coal Costs						0.00		0.00	0.00
Other									
Deferred Caretaker Costs						(2.86)		(2.86)	(2.86)
BV2 Training Costs					(0.92)			(0.92)	(0.92)
Low Level Rad. Waste					0.00			0.00	0.00
Coal Cost Equalization						0.00		0.00	0.00
Deferred Oxford Centre Costs	0.00	0.00			0.00	0.00		0.00	0.00
PA Deregulation Expenses	0.00	0.00			0.00	0.00		0.00	0.00
Demand Side Management	0.00	0.00			0.00	0.00		0.00	0.00
Corporate Development Project	0.00	0.00			0.00	0.00		0.00	0.00
Section 211	0.00	0.00			0.00	0.00		0.00	0.00
1996 Management Audit	0.00	0.00			0.00	0.00		0.00	0.00
Administrative & General	0.00	0.00			0.00	0.00		0.00	0.00
Total Other	*0.00*	*0.00*	*0.00*	*0.00*	*(0.92)*	*(2.86)*	*0.00*	*(3.77)*	*(3.77)*
Total Regulatory Assets per 10-K	**(35.63)**	**(72.40)**	**(3.31)**	**(12.86)**	**(63.08)**	**(53.10)**	**0.00**	**(116.18)**	**(240.38)**
Adjustments									
PV Beaver Valley Lease					(120.93)			(120.93)	(120.93)
Nuclear Decommissioning					0.00			0.00	0.00
Pre-Accrue Nuclear Outages					(9.40)			(9.40)	(9.40)
Gain on Sale/Leaseback (5)					*0.00*			0.00	0.00
Deferred Rate Synch. Costs (5)					0.00			0.00	0.00
Beaver Valley 2 (5)					0.00			0.00	0.00
Fossil Decommissioning						0.00		0.00	0.00
Deferred Fuel Cost						(6.14)		(6.14)	(6.14)
Transition Costs							(7.51)	(7.51)	(7.51)
FAS 106 (4)(6)	(0.12)	(1.84)	(1.21)	(1.74)				0.00	(4.91)
FAS 106 (4)(7)	(0.07)	(1.09)			(1.03)	(0.72)		(1.75)	(2.91)
Total Adjustments	*(0.19)*	*(2.93)*	*(1.21)*	*(1.74)*	*(131.36)*	*(6.86)*	*(7.51)*	*(145.73)*	*(151.80)*
Adjusted Regulatory Assets	(35.82)	(75.32)	(4.52)	(14.60)	(194.44)	(59.96)	(7.51)	(261.91)	(392.18)

Amortization Schedule
Regulatory Assets
Generation

	Actual Year - End 1996	Estimated Change 1997	Estimated Change 1998	Estimated Year - End 1998	1999	2000	2001	2002	2003	2004	2005	Net Balance 12/31/2005
Total Tax Effect												
10-K Regulatory Assets												
Regulatory Tax Receivable	(80.44)	10.31	12.64	(57.48)	8.21	8.21	8.21	8.21	8.21	8.21	8.21	(0.00)
Unamortized Debt Costs (1)	(12.41)	0.00	0.00	(12.41)	1.77	1.77	1.77	1.77	1.77	1.77	1.77	(0.00)
Deferred Rate Synch. Costs	(3.05)	0.31	0.31	(2.44)	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.00
BV2 Sale/Leaseback Premium	(6.85)	0.00	0.00	(6.85)	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.00
Deferred Employee Costs (2)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Deferred Nuclear Maintenance	(5.59)	(0.23)	4.47	(1.35)	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.00
DOE Decom & Decon	(4.07)	0.54	0.54	(2.99)	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.00
Deferred Coal Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other												
Deferred Caretaker Costs	(2.86)	0.00	0.00	(2.86)	0.41	0.41	0.41	0.41	0.41	0.41	0.41	(0.00)
BV2 Training Costs	(0.92)	0.04	0.04	(0.84)	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.00
Low Level Rad. Waste	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal Cost Equalization	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Regulatory Assets	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Other	(3.77)	0.04	0.04	(3.69)	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.00
Total Regulatory Assets per 10-K	(116.18)	10.96	18.00	(87.21)	12.46	12.46	12.46	12.46	12.46	12.46	12.46	0.00
Adjustments												
PV Beaver Valley Lease	(120.93)	10.37	16.04	(94.51)	6.39	6.39	6.39	6.39	6.39	6.39	16.60	(39.58)
Pre-Accrue Nuclear Outages	(9.40)	0.00	0.00	(9.40)	1.34	1.34	1.34	1.34	1.34	1.34	1.34	(0.00)
Gain on Sale/Leaseback (3)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Deferred Rate Synch. Costs (3)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Beaver Valley 2 (3)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Deferred Fuel Cost	(6.14)	0.00	0.00	(6.14)	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.00
Transition Costs	(7.51)	0.00	0.00	(7.51)	1.07	1.07	1.07	1.07	1.07	1.07	1.07	0.00
FAS 106 (2)	(1.75)	0.00	0.00	(1.75)	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.00
Total Adjustments	(145.73)	10.37	16.04	(119.32)	9.93	9.93	9.93	9.93	9.93	9.93	20.15	(39.58)
Adjusted Regulatory Assets	(261.91)	21.34	34.04	(206.53)	22.39	22.39	22.39	22.39	22.39	22.39	32.61	(39.58)
Remove outage accounting (4)		0.23	(4.47)									
FAS 109 Plant	0.00	0.00	0.00	(17.56)	2.51	2.51	2.51	2.51	2.51	2.51	2.51	(0.00)
Total Amortization Tax Effect	(261.91)	21.57	29.57	(224.09)	24.90	24.90	24.90	24.90	24.90	24.90	35.12	(39.58)
Regulatory Assets Recovered through Interest/Lease Expense												
Unamortized Debt Cost	(8.94)	0.99	0.99	(6.95)	0.99	0.99	0.99	0.99	0.99	0.99	0.99	(0.00)
BV2 Sale/Leaseback Premium	(7.23)	0.80	0.80	(5.62)	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.00
Total	(16.17)	1.80	1.80	(12.58)	1.80	1.80	1.80	1.80	1.80	1.80	1.80	(0.00)
Total Generation	(278.08)	23.37	31.37	(236.67)	26.70	26.70	26.70	26.70	26.70	26.70	36.91	(39.58)

(1) Allocation based on gross plant balances
(2) Allocation based on labor costs
(3) Shown as deferred tax assets in 1996 Form 10-K.
(4) Outage accounting is reflected in the revenue requirement for the generating unit

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Amortization Schedule
Regulatory Assets
Generation

Tax Effect	Actual Year - End 1996	Estimated Change 1997	Estimated Change 1998	Estimated Year - End 1998	1999	2000	2001	2002	2003	2004	2005	Net Balance 12/31/2005
Nuclear Related												
10-K Regulatory Assets												
Regulatory Tax Receivable	(34.22)	6.95	8.82	(18.45)	2.64	2.64	2.64	2.64	2.64	2.64	2.64	0.00
Unamortized Debt Premium/Discount (1)	(6.85)	0.00	0.00	(6.85)	0.98	0.98	0.98	0.98	0.98	0.98	0.98	(0.00)
Beaver Valley 2 Lease Premium	(1.53)	0.00	0.00	(1.53)	0.22	0.22	0.22	0.22	0.22	0.22	0.22	(0.00)
Total Unamortized Debt Cost	(8.38)	0.00	0.00	(8.38)	1.20	1.20	1.20	1.20	1.20	1.20	1.20	0.00
Deferred Rate Synch. Costs	(3.05)	0.31	0.31	(2.44)	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.00
BV2 Sale/Leaseback Premium	(6.85)	0.00	0.00	(6.85)	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.00
Deferred Employee Costs (2)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Deferred Nuclear Maintenance	(5.59)	(0.23)	4.47	(1.35)	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.00
DOE Decom & Decon	(4.07)	0.54	0.54	(2.99)	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.00
Other												
BV2 Training Costs	(0.92)	0.04	0.04	(0.84)	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.00
Low Level Rad. Waste	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Regulatory Assets	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Other	(0.92)	0.04	0.04	(0.84)	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.00
Total Regulatory Assets per 10-K	(63.08)	7.61	14.18	(41.29)	5.90	5.90	5.90	5.90	5.90	5.90	5.90	(0.00)
Adjustments												
PV Beaver Valley Lease	(120.93)	10.37	16.04	(94.51)	6.39	6.39	6.39	6.39	6.39	6.39	16.60	(39.58)
Pre-Accrue Nuclear Outages	(9.40)	0.00	0.00	(9.40)	1.34	1.34	1.34	1.34	1.34	1.34	1.34	(0.00)
Gain on Sale/Leaseback (3)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Deferred Rate Synch. Costs (3)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Beaver Valley 2 (3)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FAS 106 (2)	(1.03)	0.00	0.00	(1.03)	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.00
Total Adjustments	(131.36)	10.37	16.04	(103.91)	7.73	7.73	7.73	7.73	7.73	7.73	17.95	(39.58)
Adjusted Regulatory Assets	(194.44)	17.98	30.22	(145.20)	13.63	13.63	13.63	13.63	13.63	13.63	23.85	(39.58)
Remove outage accounting		0.23	(4.47)									
FAS 109 Plant	0.00	0.00	0.00	(17.56)	2.51	2.51	2.51	2.51	2.51	2.51	2.51	(0.00)
Total	(194.44)	18.21	25.75	(162.77)	16.14	16.14	16.14	16.14	16.14	16.14	26.35	(39.58)
Regulatory Assets Recovered through Interest/Lease Expense												
Unamortized Debt Cost	(5.63)	0.63	0.63	(4.38)	0.63	0.63	0.63	0.63	0.63	0.63	0.63	(0.00)
BV2 Sale/Leaseback Premium	(7.23)	0.80	0.80	(5.62)	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.00
Total	(12.86)	1.43	1.43	(10.00)	1.43	1.43	1.43	1.43	1.43	1.43	1.43	(0.00)
Total Nuclear Generation	(207.30)	19.64	27.18	(172.77)	17.57	17.57	17.57	17.57	17.57	17.57	27.78	(39.58)

(1) Allocation based on gross plant balances
(2) Allocation based on labor costs
(3) Shown as deferred tax assets in 1996 Form 10-K
(4) Outage accounting is reflected in the revenue requirement for the generating unit
(5) FAS 109 allocated to plant is reflected in the generating plant balance through 12/31/98

Amortization Schedule
Regulatory Assets
Generation

	Actual Year - End 1996	Estimated Change 1997	Estimated Change 1998	Estimated Year - End 1998	1999	2000	2001	2002	2003	2004	2005	Net Balance 12/31/2005
Tax Effect												
Fossil Related												
10-K Regulatory Assets												
Regulatory Tax Receivable	(46.22)	3.36	3.82	(39.04)	5.58	5.58	5.58	5.58	5.58	5.58	5.58	0.00
Unamortized Debt Costs (1)	(4.03)	0.00	0.00	(4.03)	0.58	0.58	0.58	0.58	0.58	0.58	0.58	(0.00)
Deferred Employee Costs (2)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Deferred Coal Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	(2.86)	0.00	0.00	(2.86)	0.41	0.41	0.41	0.41	0.41	0.41	0.41	(0.00)
Deferred Caretaker Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal Cost Equalization	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Regulatory Assets	(2.86)	0.00	0.00	(2.86)	0.41	0.41	0.41	0.41	0.41	0.41	0.41	(0.00)
Total Other												
Total Regulatory Assets per 10-K	(53.10)	3.36	3.82	(45.92)	6.56	6.56	6.56	6.56	6.56	6.56	6.56	0.00
Adjustments	(6.14)	0.00	0.00	(6.14)	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.00
Deferred Fuel Cost	(0.72)	0.00	0.00	(0.72)	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.00
FAS 106 (2)	(6.86)	0.00	0.00	(6.86)	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.00
Total Adjustments												
Total	(59.96)	3.36	3.82	(52.78)	7.54	7.54	7.54	7.54	7.54	7.54	7.54	0.00
Regulatory Assets Recovered through Interest Expense												
Unamortized Debt Cost	(3.31)	0.37	0.37	(2.58)	0.37	0.37	0.37	0.37	0.37	0.37	0.37	(0.00)
Total Fossil Generation	(63.28)	3.73	4.19	(55.36)	7.91	7.91	7.91	7.91	7.91	7.91	7.91	0.00

(1) Allocation based on gross plant balances
(2) Allocation based on labor costs

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Amortization Schedule
Regulatory Assets
Generation

Tax Effect	Actual Year - End 1996	Estimated Change 1997	Estimated Change 1998	Estimated Year - End 1998	1999	2000	2001	2002	2003	2004	2005	Net Balance 12/31/2006
Other												
10-K Regulatory Assets												
Total Regulatory Assets per 10-K	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Adjustments												
Transition Costs	(7.51)	0.00	0.00	(7.51)	1.07	1.07	1.07	1.07	1.07	1.07	1.07	0.00
Total Adjustments	(7.51)	0.00	0.00	(7.51)	1.07	1.07	1.07	1.07	1.07	1.07	1.07	0.00
Total Other Regulatory Assets	(7.51)	0.00	0.00	(7.51)	1.07	1.07	1.07	1.07	1.07	1.07	1.07	0.00

Net Regulatory Assets

			Generation (1)		Generation (2)				Total Duquesne
	Trans.	Distr.	Fossil	Nuclear	Nuclear	Fossil	Other	Total	Light
10-K Regulatory Assets									
Regulatory Tax Receivable	0.00	0.00			138.44	86.07		224.51	224.51
Unamortized Debt Premium/Discount (3)	3.78	15.90	4.67	7.94	11.99	7.05		19.04	51.33
Beaver Valley 2 Lease Premium				2.27	2.78			2.78	5.05
Total Unamortized Debt Cost	3.78	15.90	4.67	10.21	14.76	7.05		21.81	56.38
Deferred Rate Synch. Costs					38.39			38.39	38.39
BV2 Sale/Leaseback Premium				7.92	9.66			9.66	17.59
Deferred Employee Costs (4)	0.41	6.49			10.51	7.29		17.80	24.70
Deferred Nuclear Maintenance					7.87			7.87	7.87
DOE Decom & Decon					5.71			5.71	5.71
Deferred Coal Costs						12.19		12.19	12.19
Other									
Deferred Caretaker Costs						3.92		3.92	3.92
BV2 Training Costs					1.70			1.70	1.70
Low Level Rad. Waste					2.27			2.27	2.27
Coal Cost Equalization						0.32		0.32	0.32
Deferred Oxford Centre Costs	0.00	0.07			0.07	0.05		0.12	0.20
PA Deregulation Expenses	0.01	0.09			0.08	0.06		0.14	0.23
Demand Side Management	0.00	0.06			0.06	0.04		0.10	0.16
Corporate Development Project	0.00	0.04			0.04	0.03		0.07	0.11
Section 211	0.00	0.04			0.04	0.03		0.06	0.10
1996 Management Audit	0.00	0.02			0.02	0.01		0.03	0.05
Administrative & General	0.00	0.01			0.01	0.01		0.01	0.02
Total Other	0.02	0.33	0.00	0.00	4.29	4.45	0.00	8.73	9.09
Total Regulatory Assets per 10-K	**4.21**	**22.72**	**4.67**	**18.13**	**229.63**	**117.06**	**0.00**	**346.69**	**396.42**
Adjustments									
PV Beaver Valley Lease					170.51			170.51	170.51
Nuclear Decommissioning					0.00			0.00	0.00
Pre-Accrue Nuclear Outages					13.25			13.25	13.25
Gain on Sale/Leaseback (5)					61.13			61.13	61.13
Deferred Rate Synch. Costs (5)					0.27			0.27	0.27
Beaver Valley 2 (5)					0.17			0.17	0.17
Fossil Decommissioning						0.00		0.00	0.00
Deferred Fuel Cost						8.66		8.66	8.66
Transition Costs							10.59	10.59	10.59
FAS 106 (4)(6)	0.16	2.59	1.71	2.46				0.00	6.92
FAS 106 (4)(7)	0.10	1.54			1.46	1.01		2.47	4.11
Total Adjustments	0.26	4.13	1.71	2.46	246.79	9.67	10.59	267.05	275.60
Adjusted Regulatory Assets	4.47	26.85	6.38	20.59	476.42	126.73	10.59	613.74	672.03

(1) Recovered through interest and lease expense.

(2) Recovered through amortization

(3) Allocation based on gross plant balances

(4) Allocation based on labor costs

(5) Shown as deferred tax assets in 1996 Form 10-K

(6) FAS 106 with amortization shedule ending 2002, included in non-production expense

(7) FAS 106 with amortization schedule ending 2012, PV @ 1999

Allocation Percentages	Trans	Distr	Fossil	Nuclear	Total
Labor Costs	2.37%	37.47%	24.65%	35.51%	100.00%
Gross Plant	7.50%	31.94%	22.40%	38.07%	100.00%
Effective Tax Rate	41.49%				

Amortization Schedule
Regulatory Assets
Generation

	Actual Year - End 1996	Estimated Change 1997	Estimated Change 1998	Estimated Year - End 1998	1999	2000	2001	2002	2003	2004	2005	Net Balance 12/31/2005
Total Net Regulatory Assets												
10-K Regulatory Assets												
Regulatory Tax Receivable	224.51	(21.24)	(24.27)	179.00	(25.57)	(25.57)	(25.57)	(25.57)	(25.57)	(25.57)	(25.57)	0.00
Unamortized Debt Costs (1)	21.81	0.00	0.00	21.81	(3.12)	(3.12)	(3.12)	(3.12)	(3.12)	(3.12)	(3.12)	0.00
Deferred Rate Synch. Costs	38.39	(3.84)	(3.84)	30.72	(4.39)	(4.39)	(4.39)	(4.39)	(4.39)	(4.39)	(4.39)	(0.00)
BV2 Sale/Leaseback Premium	9.66	0.00	0.00	9.66	(1.38)	(1.38)	(1.38)	(1.38)	(1.38)	(1.38)	(1.38)	(0.00)
Deferred Employee Costs (2)	17.80	0.00	0.00	17.80	(2.54)	(2.54)	(2.54)	(2.54)	(2.54)	(2.54)	(2.54)	0.00
Deferred Nuclear Maintenance	7.87	0.33	(6.30)	1.90	(0.27)	(0.27)	(0.27)	(0.27)	(0.27)	(0.27)	(0.27)	0.00
DOE Decom & Decon	5.71	(0.76)	(0.76)	4.19	(0.60)	(0.60)	(0.60)	(0.60)	(0.60)	(0.60)	(0.60)	(0.00)
Deferred Coal Costs	12.19	0.31	1.00	13.50	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	0.00
Other												
Deferred Caretaker Costs	3.92	0.00	0.00	3.92	(0.56)	(0.56)	(0.56)	(0.56)	(0.56)	(0.56)	(0.56)	0.00
BV2 Training Costs	1.70	(0.06)	(0.06)	1.58	(0.23)	(0.23)	(0.23)	(0.23)	(0.23)	(0.23)	(0.23)	0.00
Low Level Rad. Waste	2.27	0.00	0.00	2.27	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	0.00
Coal Cost Equalization	0.32	(0.10)	(0.10)	0.12	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	0.00
Other Regulatory Assets	0.53	0.00	0.00	0.53	(0.08)	(0.08)	(0.08)	(0.08)	(0.08)	(0.08)	(0.08)	0.00
Total Other	8.73	(0.16)	(0.16)	8.42	(1.20)	(1.20)	(1.20)	(1.20)	(1.20)	(1.20)	(1.20)	0.00
Total Regulatory Assets per 10-K	346.69	(25.36)	(34.33)	287.00	(41.00)	(41.00)	(41.00)	(41.00)	(41.00)	(41.00)	(41.00)	0.00
Adjustments												
PV Beaver Valley Lease	170.51	(14.63)	(22.62)	133.27	(9.01)	(9.01)	(9.01)	(9.01)	(9.01)	(9.01)	(23.41)	55.80
Pre-Accrue Nuclear Outages	13.25	0.00	0.00	13.25	(1.89)	(1.89)	(1.89)	(1.89)	(1.89)	(1.89)	(1.89)	(0.00)
Gain on Sale/Leaseback (3)	61.13	(3.00)	(3.00)	55.13	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	0.00
Deferred Rate Synch. Costs (3)	0.27	0.00	0.00	0.27	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	0.00
Beaver Valley 2 (3)	0.17	0.00	0.00	0.17	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.00)
Deferred Fuel Cost	8.66	0.00	0.00	8.66	(1.24)	(1.24)	(1.24)	(1.24)	(1.24)	(1.24)	(1.24)	(0.00)
Transition Costs	10.59	0.00	0.00	10.59	(1.51)	(1.51)	(1.51)	(1.51)	(1.51)	(1.51)	(1.51)	0.00
FAS 106 (2)	2.47	0.00	0.00	2.47	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	0.00
Total Adjustments	267.05	(17.63)	(25.62)	223.81	(21.94)	(21.94)	(21.94)	(21.94)	(21.94)	(21.94)	(36.35)	55.80
Adjusted Regulatory Assets	613.74	(42.99)	(59.95)	510.80	(62.94)	(62.94)	(62.94)	(62.94)	(62.94)	(62.94)	(77.35)	55.80
Remove outage accounting (4)		(0.33)	6.30									
FAS 109 Plant (5)	0.00	0.00	0.00	45.38	(6.48)	(6.48)	(6.48)	(6.48)	(6.48)	(6.48)	(6.48)	(0.00)
Total	613.74	(43.32)	(53.65)	556.18	(69.42)	(69.42)	(69.42)	(69.42)	(69.42)	(69.42)	(83.83)	55.80
Regulatory Assets Recovered through Interest/Lease Expense												
Unamortized Debt Cost	12.61	(1.40)	(1.40)	9.81	(1.40)	(1.40)	(1.40)	(1.40)	(1.40)	(1.40)	(1.40)	0.00
BV2 Sale/Leaseback Premium	10.19	(1.13)	(1.13)	7.93	(1.13)	(1.13)	(1.13)	(1.13)	(1.13)	(1.13)	(1.13)	0.00
Total	22.80	(2.53)	(2.53)	17.73	(2.53)	(2.53)	(2.53)	(2.53)	(2.53)	(2.53)	(2.53)	(0.00)
Total Generation	636.54	(45.85)	(56.18)	573.92	(71.96)	(71.96)	(71.96)	(71.96)	(71.96)	(71.96)	(86.36)	55.80

(1) Allocation based on gross plant balances
(2) Allocation based on labor costs.
(3) Shown as deferred tax assets in 1996 Form 10-K.
(4) Outage accounting is reflected in the revenue requirement for the generating unit
(5) FAS 109 allocated to plant is reflected in the generating plant balance through 12/31/98

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Amortization Schedule
Regulatory Assets
Generation

Net Regulatory Assets	Actual Year - End 1996	Estimated Change 1997	Estimated Change 1998	Estimated Year - End 1998	1999	2000	2001	2002	2003	2004	2005	Net Balance 12/31/2005
Nuclear Related												
10-K Regulatory Assets												
Regulatory Tax Receivable	138.44	(14.90)	(17.54)	105.99	(15.14)	(15.14)	(15.14)	(15.14)	(15.14)	(15.14)	(15.14)	0.00
Unamortized Debt Premium/Discount (1)	11.99	0.00	0.00	11.99	(1.71)	(1.71)	(1.71)	(1.71)	(1.71)	(1.71)	(1.71)	(0.00)
Beaver Valley 2 Lease Premium	2.78	0.00	0.00	2.78	(0.40)	(0.40)	(0.40)	(0.40)	(0.40)	(0.40)	(0.40)	0.00
Total Unamortized Debt Cost	14.76	0.00	0.00	14.76	(2.11)	(2.11)	(2.11)	(2.11)	(2.11)	(2.11)	(2.11)	0.00
Deferred Rate Synch. Costs	38.39	(3.84)	(3.84)	30.72	(4.39)	(4.39)	(4.39)	(4.39)	(4.39)	(4.39)	(4.39)	(0.00)
BV2 Sale/Leaseback Premium	9.66	0.00	0.00	9.66	(1.38)	(1.38)	(1.38)	(1.38)	(1.38)	(1.38)	(1.38)	(0.00)
Deferred Employee Costs (2)	10.51	0.00	0.00	10.51	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	0.00
Deferred Nuclear Maintenance	7.87	0.33	(6.30)	1.90	(0.27)	(0.27)	(0.27)	(0.27)	(0.27)	(0.27)	(0.27)	0.00
DOE Decom & Decon	5.71	(0.76)	(0.76)	4.19	(0.60)	(0.60)	(0.60)	(0.60)	(0.60)	(0.60)	(0.60)	(0.00)
Other												
BV2 Training Costs	1.70	(0.06)	(0.06)	1.58	(0.23)	(0.23)	(0.23)	(0.23)	(0.23)	(0.23)	(0.23)	0.00
Low Level Rad. Waste	2.27	0.00	0.00	2.27	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	0.00
Other Regulatory Assets	0.31	0.00	0.00	0.31	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	0.00
Total Other	4.29	(0.06)	(0.06)	4.17	(0.60)	(0.60)	(0.60)	(0.60)	(0.60)	(0.60)	(0.60)	(0.00)
Total Regulatory Assets per 10-K	229.63	(19.24)	(28.50)	181.89	(25.98)	(25.98)	(25.98)	(25.98)	(25.98)	(25.98)	(25.98)	0.00
Adjustments												
PV Beaver Valley Lease	170.51	(14.63)	(22.62)	133.27	(9.01)	(9.01)	(9.01)	(9.01)	(9.01)	(9.01)	(23.41)	55.80
Pre-Accrue Nuclear Outages	13.25	0.00	0.00	13.25	(1.89)	(1.89)	(1.89)	(1.89)	(1.89)	(1.89)	(1.89)	(0.00)
Gain on Sale/Leaseback (3)	61.13	(3.00)	(3.00)	55.13	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	0.00
Deferred Rate Synch. Costs (3)	0.27	0.00	0.00	0.27	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	0.00
Beaver Valley 2 (3)	0.17	0.00	0.00	0.17	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.00)
FAS 106 (2)	1.46	0.00	0.00	1.46	(0.21)	(0.21)	(0.21)	(0.21)	(0.21)	(0.21)	(0.21)	(0.00)
Total Adjustments	246.79	(17.63)	(25.62)	203.54	(19.05)	(19.05)	(19.05)	(19.05)	(19.05)	(19.05)	(33.45)	55.80
Adjusted Regulatory Assets	476.42	(36.86)	(54.12)	385.44	(45.03)	(45.03)	(45.03)	(45.03)	(45.03)	(45.03)	(59.44)	55.80
Remove outage accounting (4)		(0.33)	6.30									
FAS 109 Plant (5)	0.00	0.00	0.00	45.38	(6.48)	(6.48)	(6.48)	(6.48)	(6.48)	(6.48)	(6.48)	(0.00)
Total	476.42	(37.19)	(47.82)	430.82	(51.52)	(51.52)	(51.52)	(51.52)	(51.52)	(51.52)	(65.92)	55.80
Regulatory Assets Recovered through Interest/Lease Expense												
Unamortized Debt Cost	7.94	(0.88)	(0.88)	6.17	(0.88)	(0.88)	(0.88)	(0.88)	(0.88)	(0.88)	(0.88)	(0.00)
BV2 Sale/Leaseback Premium	10.19	(1.13)	(1.13)	7.93	(1.13)	(1.13)	(1.13)	(1.13)	(1.13)	(1.13)	(1.13)	0.00
Total	18.13	(2.01)	(2.01)	14.10	(2.01)	(2.01)	(2.01)	(2.01)	(2.01)	(2.01)	(2.01)	(0.00)
Total Nuclear Generation	494.55	(39.20)	(49.83)	444.92	(53.53)	(53.53)	(53.53)	(53.53)	(53.53)	(53.53)	(67.93)	55.80

(1) Allocation based on gross plant balances
(2) Allocation based on labor costs
(3) Shown as deferred tax assets in 1996 Form 10-K.
(4) Outage accounting is reflected in the revenue requirement for the generating unit
(5) FAS 109 allocated to plant is reflected in the generating plant balance through 12/31/98

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Amortization Schedule
Regulatory Assets
Generation

Net Regulatory Assets	Actual Year - End 1996	Estimated Change 1997	Estimated Change 1998	Estimated Year - End 1998	1999	2000	2001	2002	2003	2004	2005	Net Balance 12/31/2005
Fossil Related												
10-K Regulatory Assets												
Regulatory Tax Receivable	86.07	(6.34)	(6.73)	73.00	(10.43)	(10.43)	(10.43)	(10.43)	(10.43)	(10.43)	(10.43)	0.00
Unamortized Debt Costs (1)	7.05	0.00	0.00	7.05	(1.01)	(1.01)	(1.01)	(1.01)	(1.01)	(1.01)	(1.01)	0.00
Deferred Employee Costs (2)	7.29	0.00	0.00	7.29	(1.04)	(1.04)	(1.04)	(1.04)	(1.04)	(1.04)	(1.04)	0.00
Deferred Coal Costs	12.19	0.31	1.00	13.50	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	0.00
Other												
Deferred Caretaker Costs	3.92	0.00	0.00	3.92	(0.56)	(0.56)	(0.56)	(0.56)	(0.56)	(0.56)	(0.56)	0.00
Coal Cost Equalization	0.32	(0.10)	(0.10)	0.12	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	0.00
Other Regulatory Assets	0.22	0.00	0.00	0.22	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.00)
Total Other	4.45	(0.10)	(0.10)	4.25	(0.61)	(0.61)	(0.61)	(0.61)	(0.61)	(0.61)	(0.61)	0.00
Total Regulatory Assets per 10-K	117.06	(6.13)	(5.83)	105.10	(15.01)	(15.01)	(15.01)	(15.01)	(15.01)	(15.01)	(15.01)	(0.00)
Adjustments												
Deferred Fuel Cost	8.66	0.00	0.00	8.66	(1.24)	(1.24)	(1.24)	(1.24)	(1.24)	(1.24)	(1.24)	(0.00)
FAS 106 (2)	1.01	0.00	0.00	1.01	(0.14)	(0.14)	(0.14)	(0.14)	(0.14)	(0.14)	(0.14)	0.00
Total Adjustments	9.67	0.00	0.00	9.67	(1.38)	(1.38)	(1.38)	(1.38)	(1.38)	(1.38)	(1.38)	0.00
Total	126.73	(6.13)	(5.83)	114.78	(16.40)	(16.40)	(16.40)	(16.40)	(16.40)	(16.40)	(16.40)	(0.00)
Regulatory Assets Recovered through Interest Expense												
Unamortized Debt Cost	4.67	(0.52)	(0.52)	3.63	(0.52)	(0.52)	(0.52)	(0.52)	(0.52)	(0.52)	(0.52)	0.00
Total Fossil Generation	131.40	(6.65)	(6.35)	118.41	(16.92)	(16.92)	(16.92)	(16.92)	(16.92)	(16.92)	(16.92)	(0.00)

(1) Allocation based on gross plant balances.
(2) Allocation based on labor costs.

Amortization Schedule
Regulatory Assets
Generation

	Actual Year - End 1996	Estimated Change 1997	Estimated Change 1998	Estimated Year - End 1998	1999	2000	2001	2002	2003	2004	2005	Net Balance 12/31/2005
Net Regulatory Assets												
Other												
10-K Regulatory Assets												
Total Regulatory Assets per 10-K	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Adjustments	10.59	0.00	0.00	10.59	(1.51)	(1.51)	(1.51)	(1.51)	(1.51)	(1.51)	(1.51)	0.00
Transition Costs	10.59	0.00	0.00	10.59	(1.51)	(1.51)	(1.51)	(1.51)	(1.51)	(1.51)	(1.51)	0.00
Total Adjustments												
Total Other Regulatory Assets	10.59	0.00	0.00	10.59	(1.51)	(1.51)	(1.51)	(1.51)	(1.51)	(1.51)	(1.51)	0.00

Regulatory Assets @ 12/31/96
Included in Rate Base

			Generation (1)		Generation (2)				Total Duquesne
	Trans.	Distr.	Fossil	Nuclear	Nuclear	Fossil	Other	Total	Light
10-K Regulatory Assets									
Regulatory Tax Receivable	32.66	56.52			172.66	132.29		304.94	394.12
Unamortized Debt Premium/Discount (3)	0.00	0.00	0.00	0.00	18.84	11.08		29.92	29.92
Beaver Valley 2 Lease Premium				0.00	4.31			4.31	4.31
Total Unamortized Debt Cost	0.00	0.00	0.00	0.00	23.14	11.08		34.22	34.22
Deferred Rate Synch. Costs					0.00			0.00	0.00
BV2 Sale/Leaseback Premium				0.00	16.51			16.51	16.51
Deferred Employee Costs (4)	0.00	0.00			0.00	0.00		0.00	0.00
Deferred Nuclear Maintenance					13.46			13.46	13.46
DOE Decom & Decon					0.00			0.00	0.00
Deferred Coal Costs						12.19		12.19	12.19
Other									
Deferred Caretaker Costs						6.77		6.77	6.77
BV2 Training Costs					2.62			2.62	2.62
Low Level Rad. Waste					2.27			2.27	2.27
Coal Cost Equalization						0.32		0.32	0.32
Deferred Oxford Centre Costs	0.00	0.07			0.07	0.05		0.12	0.20
PA Deregulation Expenses	0.01	0.09			0.08	0.06		0.14	0.23
Demand Side Management	0.00	0.06			0.06	0.04		0.10	0.16
Corporate Development Project	0.00	0.04			0.04	0.03		0.07	0.11
Section 211	0.00	0.04			0.04	0.03		0.06	0.10
1996 Management Audit	0.00	0.02			0.02	0.01		0.03	0.05
Administrative & General	0.00	0.01			0.01	0.01		0.01	0.02
Total Other	0.02	0.33	0.00	0.00	5.20	7.31	0.00	12.51	12.86
Total Regulatory Assets per 10-K	**32.68**	**56.85**	**0.00**	**0.00**	**230.98**	**162.87**	**0.00**	**393.84**	**483.37**
Adjustments									
PV Beaver Valley Lease					0.00			0.00	0.00
Nuclear Decommissioning					0.00			0.00	0.00
Pre-Accrue Nuclear Outages					0.00			0.00	0.00
Gain on Sale/Leaseback (5)					61.13			61.13	61.13
Deferred Rate Synch. Costs (5)					0.00			0.00	0.00
Beaver Valley 2 (5)					0.17			0.17	0.17
Fossil Decommissioning						0.00		0.00	0.00
Deferred Fuel Cost						0.00		0.00	0.00
Transition Costs (6)							0.00	0.00	0.00
FAS 106 (4)(7)	0.00	0.00			0.00	0.00		0.00	0.00
FAS 106 (4)(8)	0.00	0.00			0.00	0.00		0.00	0.00
Total Adjustments	0.00	0.00	0.00	0.00	61.30	0.00	0.00	61.30	61.30
Adjusted Regulatory Assets	**32.68**	**56.85**	**0.00**	**0.00**	**292.28**	**162.87**	**0.00**	**455.14**	**544.67**

(1) Recovered through interest and lease expense.
(2) Recovered through amortization.
(3) Allocation based on gross plant balances. 8/17 included in rate base.
(4) Allocation based on labor costs.
(5) Shown as deferred tax assets in 1996 Form 10-K.
(6) Item is included in rate base beginning 1/1/99.
(7) FAS 106 with amortization shedule ending 2002, included in non-production expense
(8) FAS 106 with amortization schedule ending 2012, PV @ 1999

Allocation Percentages	Trans.	Distr.	Fossil	Nuclear	Total
Labor Costs	2.37%	37.47%	24.65%	35.51%	100.00%
Gross Plant	7.59%	31.94%	22.40%	38.07%	100.00%

Amortization Schedule

Generation Regulatory Assets Included in Rate Base

	Actual Year - End 1996	Estimated Change 1997	Estimated Change 1998	Estimated Year - End 1998	1999	2000	2001	2002	2003	2004	2005	Net Balance 12/31/2006
Total Generation												
10-K Regulatory Assets												
Regulatory Tax Receivable	304.94	(31.55)	(36.91)	236.48	(33.78)	(33.78)	(33.78)	(33.78)	(33.78)	(33.78)	(33.78)	(0.00)
Unamortized Debt Costs (1)	34.22	0.00	0.00	34.22	(4.89)	(4.89)	(4.89)	(4.89)	(4.89)	(4.89)	(4.89)	(0.00)
Deferred Rate Synch. Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
BV2 Sale/Leaseback Premium	16.51	0.00	0.00	16.51	(2.36)	(2.36)	(2.36)	(2.36)	(2.36)	(2.36)	(2.36)	0.00
Deferred Employee Costs (2)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Deferred Nuclear Maintenance	13.46	0.56	(10.77)	3.25	(0.46)	(0.46)	(0.46)	(0.46)	(0.46)	(0.46)	(0.46)	(0.00)
DOE Decom & Decon	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Deferred Coal Costs	12.19	0.31	1.00	13.50	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	0.00
Other												
Deferred Caretaker Costs	6.77	0.00	0.00	6.77	(0.97)	(0.97)	(0.97)	(0.97)	(0.97)	(0.97)	(0.97)	0.00
BV2 Training Costs	2.62	(0.10)	(0.10)	2.42	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	0.00
Low Level Rad. Waste	2.27	0.00	0.00	2.27	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	0.00
Coal Cost Equalization	0.32	(0.10)	(0.10)	0.12	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	0.00
Other Regulatory Assets	0.53	0.00	0.00	0.53	(0.08)	(0.08)	(0.08)	(0.08)	(0.08)	(0.08)	(0.08)	0.00
Total Other	12.51	(0.20)	(0.20)	12.11	(1.73)	(1.73)	(1.73)	(1.73)	(1.73)	(1.73)	(1.73)	0.00
Total Regulatory Assets per 10-K	393.84	(30.88)	(46.89)	316.07	(45.15)	(45.15)	(45.15)	(45.15)	(45.15)	(45.15)	(45.15)	(0.00)
Adjustments												
PV Beaver Valley Lease	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nuclear Decommissioning	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pre-Accrue Nuclear Outages	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gain on Sale/Leaseback (3)	61.13	(3.00)	(3.00)	55.13	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	0.00
Deferred Rate Synch. Costs (3)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Beaver Valley 2 (3)	0.17	0.00	0.00	0.17	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.00)
Fossil Decommissioning	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Deferred Fuel Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transition Costs (4)	0.00	0.00	0.00	18.10	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	0.00
FAS 106 (2)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Adjustments	61.30	(3.00)	(3.00)	73.40	(10.49)	(10.49)	(10.49)	(10.49)	(10.49)	(10.49)	(10.49)	0.00
Adjusted Regulatory Assets	455.14	(33.88)	(49.89)	389.47	(55.64)	(55.64)	(55.64)	(55.64)	(55.64)	(55.64)	(55.64)	(0.00)
FAS 109 Plant (5)	0	0.00	0.00	62.94	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	62.67
Total Generation	455.14	(33.88)	(49.89)	452.41	(55.68)	(55.68)	(55.68)	(55.68)	(55.68)	(55.68)	(55.68)	62.67

(1) Allocation based on gross plant balances

(2) Allocation based on labor costs

(3) Shown as deferred tax assets in 1996 Form 10-K.

(4) Included in rate base beginning 1/1/99

(5) FAS 109 allocated to plant is reflected in the generating plant balance through 12/31/98

Amortization Schedule

Generation Regulatory Assets Included in Rate Base

Nuclear Related 10-K Regulatory Assets	Actual Year - End 1996	Estimated Change 1997	Estimated Change 1998	Estimated Year - End 1998	1999	2000	2001	2002	2003	2004	2005	Net Balance 12/31/2005
Regulatory Tax Receivable	172.66	(21.85)	(26.36)	124.44	(17.78)	(17.78)	(17.78)	(17.78)	(17.78)	(17.78)	(17.78)	(0.00)
Unamortized Debt Premium/Discount (1)	18.84	0.00	0.00	18.84	(2.69)	(2.69)	(2.69)	(2.69)	(2.69)	(2.69)	(2.69)	0.00
Beaver Valley 2 Lease Premium	4.31	0.00	0.00	4.31	(0.62)	(0.62)	(0.62)	(0.62)	(0.62)	(0.62)	(0.62)	(0.00)
Total Unamortized Debt Cost	23.14	0.00	0.00	23.14	(3.31)	(3.31)	(3.31)	(3.31)	(3.31)	(3.31)	(3.31)	0.00
Deferred Rate Synch. Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
BV2 Sale/Leaseback Premium	16.51	0.00	0.00	16.51	(2.36)	(2.36)	(2.36)	(2.36)	(2.36)	(2.36)	(2.36)	0.00
Deferred Employee Costs (2)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Deferred Nuclear Maintenance	13.46	0.56	(10.77)	3.25	(0.46)	(0.46)	(0.46)	(0.46)	(0.46)	(0.46)	(0.46)	(0.00)
DOE Decom & Decon	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other												
BV2 Training Costs	2.62	(0.10)	(0.10)	2.42	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	0.00
Low Level Rad. Waste	2.27	0.00	0.00	2.27	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	0.00
Other Regulatory Assets	0.31	0.00	0.00	0.31	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	0.00
Total Other	5.20	(0.10)	(0.10)	5.00	(0.71)	(0.71)	(0.71)	(0.71)	(0.71)	(0.71)	(0.71)	(0.00)
Total Regulatory Assets per 10-K	230.98	(21.40)	(37.24)	172.34	(24.62)	(24.62)	(24.62)	(24.62)	(24.62)	(24.62)	(24.62)	(0.00)
Adjustments												
PV Beaver Valley Lease	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nuclear Decommissioning	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pre-Accrue Nuclear Outages	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gain on Sale/Leaseback (3)	61.13	(3.00)	(3.00)	55.13	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	(7.88)	0.00
Deferred Rate Synch. Costs (3)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Beaver Valley 2 (3)	0.17	0.00	0.00	0.17	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.00)
FAS 106 (2)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Adjustments	61.30	(3.00)	(3.00)	55.30	(7.90)	(7.90)	(7.90)	(7.90)	(7.90)	(7.90)	(7.90)	(0.00)
Adjusted Regulatory Assets	292.28	(24.40)	(40.24)	227.64	(32.52)	(32.52)	(32.52)	(32.52)	(32.52)	(32.52)	(32.52)	0.00
FAS 109 Plant (4)	0.00	0.00	0.00	62.94	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	62.67
Total Nuclear Generation	292.28	(24.40)	(40.24)	290.58	(32.56)	(32.56)	(32.56)	(32.56)	(32.56)	(32.56)	(32.56)	62.67

(1) Allocation based on gross plant balances

(2) Allocation based on labor costs.

(3) Shown as deferred tax assets in 1996 Form 10-K.

(4) FAS 109 allocated to plant is reflected in the generating plant balance through 12/31/98

Amortization Schedule

Generation Regulatory Assets Included in Rate Base

	Actual Year - End 1996	Estimated Change 1997	Estimated Change 1998	Estimated Year - End 1998	1999	2000	2001	2002	2003	2004	2005	Net Balance 12/31/2005
Fossil Related												
10-K Regulatory Assets												
Regulatory Tax Receivable	132.29	(9.70)	(10.55)	112.04	(16.01)	(16.01)	(16.01)	(16.01)	(16.01)	(16.01)	(16.01)	(0.00)
Unamortized Debt Costs (1)	11.08	0.00	0.00	11.08	(1.58)	(1.58)	(1.58)	(1.58)	(1.58)	(1.58)	(1.58)	0.00
Deferred Employee Costs (2)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Deferred Coal Costs	12.19	0.31	1.00	13.50	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	(1.93)	0.00
Other												
Deferred Caretaker Costs	6.77	0.00	0.00	6.77	(0.97)	(0.97)	(0.97)	(0.97)	(0.97)	(0.97)	(0.97)	0.00
Coal Cost Equalization	0.32	(0.10)	(0.10)	0.12	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	0.00
Other Regulatory Assets	0.22	0.00	0.00	0.22	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.00)
Total Other	7.31	(0.10)	(0.10)	7.11	(1.02)	(1.02)	(1.02)	(1.02)	(1.02)	(1.02)	(1.02)	0.00
Total Regulatory Assets per 10-K	162.87	(9.49)	(9.65)	143.73	(20.53)	(20.53)	(20.53)	(20.53)	(20.53)	(20.53)	(20.53)	(0.00)
Adjustments												
Fossil Decommissioning	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Deferred Fuel Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FAS 106 (2)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Adjustments	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Fossil Generation	162.87	(9.49)	(9.65)	143.73	(20.53)	(20.53)	(20.53)	(20.53)	(20.53)	(20.53)	(20.53)	(0.00)

(1) Allocation based on gross plant balances.

(2) Allocation based on labor costs.

Amortization Schedule
Generation Regulatory Assets Included in Rate Base

	Actual Year - End 1996	Estimated Change 1997	Estimated Change 1998	Estimated Year - End 1998	1999	2000	2001	2002	2003	2004	2005	Net Balance 12/31/2006
Other												
10-K Regulatory Assets												
Total Regulatory Assets per 10-K	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Adjustments												
Transition Costs	0.00	0.00	0.00	18.10	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	0.00
Total Adjustments	0.00	0.00	0.00	18.10	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	0.00
Total Other	0.00	0.00	0.00	18.10	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	(2.59)	0.00

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Duquesne Light Company

Committed Generation Related Depreciation and Amortization
1999 - 2005
($ Millions)

1999	198.5
2000	268.5
2001	274.5
2002	283.6
2003	268.9
2004	265.4
2005	222.5
	1,781.9

DUQUESNE LIGHT COMPANY

Fossil and Nuclear Plant Decommissioning Estimates

$ in Millions

	Decomm. Cost	NPV @ 12/31/05	Funding Level	(Under)/Over Funding
Elrama	43.41	35.05	0.00	(35.05)
Cheswick	59.39	23.59	0.00	(23.59)
Eastlake	14.11	7.03	0.00	(7.03)
Sammis	14.99	8.01	0.00	(8.01)
Brunot Island	28.63	13.87	0.00	(13.87)
Phillips	11.76	9.49	0.00	(9.49)
Mansfield 1	33.42	12.60	0.00	(12.60)
Mansfield 2	2.54	0.89	0.00	(0.89)
Mansfield 3	8.35	2.33	0.00	(2.33)
Total Fossil	**$216.59**	**$112.85**	**$0.00**	**($112.85)**
Beaver Valley 1	587.68	110.45	110.45	(0.00)
Beaver Valley 2	198.74	31.17	22.63	(8.54)
Perry	342.64	53.74	42.71	(11.03)
Total Nuclear	**$1,129.06**	**$195.36**	**$175.79**	**($19.57)**
Total Generation	**$1,345.65**	**$308.21**	**$175.79**	**($132.42)**

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DUQUESNE LIGHT COMPANY
Detail of Fossil Decommissioning
$ in Millions

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total	NPV @ 2006
Elrama - Year 1	4.918	4.918	4.918	4.918	4.918																	24.589	20.496
Elrama - Year 2		3.765	3.765	3.765	3.765	3.765																18.824	14.551
Elrama - Year 3			0.000	0.000	0.000	0.000	0.000															0.000	0.000
Total Elrama	4.918	8.683	8.683	8.683	8.683	3.765	0.000															43.414	35.048
Cheswick - Year 1										4.504	4.504	4.504	4.504	4.504								22.522	9.525
Cheswick - Year 2											4.608	4.608	4.608	4.608	4.608							23.041	9.037
Cheswick - Year 3												2.764	2.764	2.764	2.764	2.764						13.822	5.028
Total Cheswick										4.504	9.113	11.877	11.877	11.877	7.373	2.764						59.385	23.590
Eastlake - Year 1							0.995	0.995	0.995	0.995	0.995											4.976	2.639
Eastlake - Year 2								1.290	1.290	1.290	1.290	1.290										6.450	3.172
Eastlake - Year 3									0.536	0.536	0.536	0.536	0.536									2.681	1.223
Total Eastlake							0.995	2.285	2.821	2.821	2.821	1.826	0.536									14.107	7.033
Sammis - Year 1						0.973	0.973	0.973	0.973	0.973												4.863	2.781
Sammis - Year 2							1.262	1.262	1.262	1.262	1.262											6.312	3.347
Sammis - Year 3								0.764	0.764	0.764	0.764	0.764										3.818	1.878
Total Sammis						0.973	2.235	2.999	2.999	2.999	2.026	0.764										14.993	8.005
Brunot Island - Year 1								4.569	4.569	4.569	4.569	4.569										22.843	11.233
Brunot Island - Year 2									1.157	1.157	1.157	1.157	1.157									5.786	2.639
Brunot Island - Year 3										0.000	0.000	0.000	0.000	0.000								0.000	0.000
Total Brunot Island								4.569	5.726	5.726	5.726	5.726	1.157	0.000								28.629	13.872
Phillips - Year 1	1.332	1.332	1.332	1.332	1.332																	6.659	5.551
Phillips - Year 2		1.020	1.020	1.020	1.020	1.020																5.098	3.941
Phillips - Year 3			0.000	0.000	0.000	0.000	0.000															0.000	0.000
Total Phillips	1.332	2.351	2.351	2.351	2.351	1.020	0.000															11.757	9.492
Mansfield 1 - Year 1											3.104	3.104	3.104	3.104	3.104							15.522	6.088
Mansfield 1 - Year 2												3.579	3.579	3.579	3.579	3.579						17.897	6.510
Mansfield 1 - Year 3													0.000	0.000	0.000	0.000	0.000					0.000	0.000
Total Mansfield 1											3.104	6.684	6.684	6.684	6.684	3.579	0.000					33.418	12.598
Mansfield 2 - Year 1												0.236	0.236	0.236	0.236	0.236						1.181	0.430
Mansfield 2 - Year 2													0.272	0.272	0.272	0.272	0.272					1.362	0.459
Mansfield 2 - Year 3														0.000	0.000	0.000	0.000	0.000				0.000	0.000
Total Mansfield 2												0.236	0.509	0.509	0.509	0.509	0.272	0.000				2.543	0.889
Mansfield 3 - Year 1															0.775	0.775	0.775	0.775	0.775			3.876	1.125
Mansfield 3 - Year 2																0.894	0.894	0.894	0.894	0.894		4.469	1.202
Mansfield 3 - Year 3																	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Mansfield 3															0.775	1.669	1.669	1.669	1.669	0.894	0.000	8.346	2.327
																						$216.593	$112.853

DUQUESNE LIGHT COMPANY

Detail of Projected Nuclear Decommissioning Trust Fund Activity

$ In Millions

		1997 Balance	1998 Balance	1999 Balance	2000 Balance	2001 Balance	2002 Balance	2003 Balance	2004 Balance	2005 Balance	Required Balance	Funding (Over)/ Under
After-Tax Interest Rate	7.5%											
Beaver Valley 1												
Trust Fund Beginning Balance		24.029	31.543	39.621	48.305	57.640	67.676	78.464	90.061	102.528		
Interest on Balance		1.802	2.366	2.972	3.623	4.323	5.076	5.885	6.755	7.690		
Contribution		5.509	5.509	5.509	5.509	5.509	5.509	5.509	5.509	0.224		
Interest on Contribution		0.203	0.203	0.203	0.203	0.203	0.203	0.203	0.203	0.008		
End of Year Fund Balance		**31.543**	**39.621**	**48.305**	**57.640**	**67.676**	**78.464**	**90.061**	**102.528**	**110.450**	**110.450**	**0.000**
Beaver Valley 2												
Trust Fund Beginning Balance		5.099	6.533	8.074	9.731	11.512	13.426	15.485	17.697	20.076		
Interest on Balance		0.382	0.490	0.606	0.730	0.863	1.007	1.161	1.327	1.506		
Contribution		1.014	1.014	1.014	1.014	1.014	1.014	1.014	1.014	1.014		
Interest on Contribution		0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037		
End of Year Fund Balance		**6.533**	**8.074**	**9.731**	**11.512**	**13.426**	**15.485**	**17.697**	**20.076**	**22.633**	**31.170**	**8.537**
Perry												
Trust Fund Beginning Balance		4.611	7.278	10.145	13.227	16.540	20.102	23.930	28.046	32.471		
Interest on Balance		0.346	0.546	0.761	0.992	1.240	1.508	1.795	2.103	2.435		
Contribution		2.239	2.239	2.239	2.239	2.239	2.239	2.239	2.239	7.524		
Interest on Contribution		0.082	0.082	0.082	0.082	0.082	0.082	0.082	0.082	0.277		
End of Year Fund Balance		**7.278**	**10.145**	**13.227**	**16.540**	**20.102**	**23.930**	**28.046**	**32.471**	**42.707**	**53.739**	**11.032**
Total												
Trust Fund Beginning Balance		33.739	45.354	57.840	71.263	85.692	101.204	117.879	135.805	155.075		
Interest on Balance		2.530	3.402	4.338	5.345	6.427	7.590	8.841	10.185	11.631		
Contribution		8.762	8.762	8.762	8.762	8.762	8.762	8.762	8.762	8.762		
Interest on Contribution		0.323	0.323	0.323	0.323	0.323	0.323	0.323	0.323	0.323		
End of Year Fund Balance		**45.354**	**57.840**	**71.263**	**85.692**	**101.204**	**117.879**	**135.805**	**155.075**	**175.790**	**$195.359**	**$19.569**

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DUQUESNE LIGHT COMPANY

Detail of Nuclear Decommissioning Costs

$ in Millions

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Beaver Valley 1 (1997 CAPCO$)		27.464	18.673	3.813	3.813	3.823	3.813	3.813	3.813	3.823	3.813	3.813	3.206	2.810	18.691
Beaver Valley 1 (1997 DLC$)	47.50%	13.045	8.869	1.811	1.811	1.816	1.811	1.811	1.811	1.816	1.811	1.811	1.523	1.335	8.878
Inflation factor (4%)		2.107	2.191	2.279	2.370	2.465	2.563	2.666	2.772	2.883	2.999	3.119	3.243	3.373	3.508
Cash Expenditures		27.485	19.434	4.127	4.292	4.476	4.642	4.828	5.021	5.236	5.431	5.648	4.940	4.502	31.145
Discount factor (to 2005, 7.5%)		2.137	2.297	2.469	2.655	2.854	3.068	3.298	3.545	3.811	4.097	4.404	4.735	5.090	5.471
Amt Required (2005 DLC$)		12.862	8.460	1.671	1.617	1.568	1.513	1.464	1.416	1.374	1.326	1.282	1.043	0.884	5.692
Beaver Valley 2 (1997 CAPCO$)													25.489	48.963	56.753
Beaver Valley 2 (1997 DLC$)	13.74%												3.502	6.728	7.798
Inflation factor (4%)													3.243	3.373	3.508
Cash Expenditures													11.359	22.693	27.355
Discount factor (to 2005, 7.5%)													4.735	5.090	5.471
Amt Required (2005 DLC$)													2.399	4.459	5.000
Perry (1997 CAPCO$)													43.946	84.417	97.847
Perry (1997 DLC$)	13.74%												6.038	11.599	13.444
Inflation factor (4%)													3.243	3.373	3.508
Cash Expenditures													19.584	39.125	47.163
Discount factor (to 2005, 7.5%)													4.735	5.090	5.471
Amt Required (2005 DLC$)													4.136	7.687	8.626

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Exhibit DJC-7
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REvised

DUQUESNE LIGHT

Detail of Nuclear Dec ommissioning Costs

S in Millions

	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	Total
Beaver Valley 1 (1997 CAPCO$)	42.688	65.805	65.718	52.785	14.326	4.160									350.661
Beaver Valley 1 (1997 DLCS)	20.277	31.257	31.216	25.073	6.805	1.976									
Inflation factor (4%)	3.648	3.794	3.946	4.104	4.268	4.439									
Cash Expenditures	73.978	118.600	123.182	102.897	29.044	8.772									587.679
Discount factor (to 2005, 7.5%)	5.882	6.323	6.797	7.307	7.855	8.444									
Amt Required (2005 DLCS)	12.578	18.757	18.123	14.082	3.698	1.039									110.450
Beaver Valley 2 (1997 CAPCO$)	53.143	49.267	51.701	30.167	25.320	16.805	1.598	1.593	1.593	1.593	1.598	1.593	1.593	8.238	377.009
Beaver Valley 2 (1997 DLCS)	7.302	6.769	7.104	4.145	3.479	2.309	0.220	0.219	0.219	0.219	0.220	0.219	0.219	1.132	
Inflation factor (4%)	3.648	3.794	3.946	4.104	4.268	4.439	4.616	4.801	4.993	5.193	5.400	5.617	5.841	6.075	
Cash Expenditures	26.640	25.685	28.032	17.010	14.849	10.249	1.013	1.051	1.093	1.137	1.186	1.230	1.279	6.876	198.737
Discount factor (to 2005, 7.5%)	5.882	6.323	6.797	7.307	7.855	8.444	9.077	9.758	10.490	11.277	12.122	13.032	14.009	15.060	
Amt Required (2005 DLCS)	4.529	4.062	4.124	2.328	1.890	1.214	0.112	0.108	0.104	0.101	0.098	0.094	0.091	0.457	31.170
Perry (1997 CAPCO$)	91.624	84.942	89.137	52.010	43.655	28.973	2.755	2.747	2.747	2.747	2.755	2.747	2.747	14.203	650.000
Perry (1997 DLCS)	12.589	11.671	12.247	7.146	5.998	3.981	0.378	0.377	0.377	0.377	0.378	0.377	0.377	1.952	
Inflation factor (4%)	3.648	3.794	3.946	4.104	4.268	4.439	4.616	4.801	4.993	5.193	5.400	5.617	5.841	6.075	
Cash Expenditures	45.930	44.283	48.330	29.328	25.601	17.670	1.747	1.812	1.885	1.960	2.044	2.120	2.205	11.855	342.642
Discount factor (to 2005, 7.5%)	5.882	6.323	6.797	7.307	7.855	8.444	9.077	9.758	10.490	11.277	12.122	13.032	14.009	15.060	
Amt Required (2005 DLCS)	7.809	7.004	7.110	4.014	3.259	2.093	0.192	0.186	0.180	0.174	0.169	0.163	0.157	0.787	53.739

(J) Revenue Requirements Forecast
Fossil Generation
(Revised)

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Cheswick									
Off-system Sales Revenue	3.5	3.7	9.8	10.2	10.2	11.4	9.6	10.2	3.9
Revenue from Customers	90.3	91.8	108.7	113.9	118.7	127.9	134.5	137.0	167.8
Total Revenue	93.8	95.6	118.5	124.0	128.9	139.3	144.2	147.2	171.7
Operating Expenses									
Fuel	39.9	36.8	45.9	48.1	47.2	52.8	52.9	48.7	59.5
Emissions	0.7	0.2	5.9	6.2	8.8	10.8	11.0	9.3	13.4
Non Fuel O&M (production)	11.0	24.6	15.8	14.9	16.8	16.8	15.6	28.6	18.1
Outage Accounting	2.7	(10.9)	2.2	2.2	2.2	2.2	2.2	(13.0)	3.1
Non-production Expenses	10.1	13.5	12.2	14.8	14.5	15.6	18.0	22.3	18.4
Major Maintenance Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Book Depreciation	8.7	9.7	9.9	10.1	10.0	10.3	11.8	15.5	15.9
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	4.0	4.0	4.8	5.0	5.2	5.6	5.9	6.0	7.4
Property Taxes	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Other Taxes	1.3	1.3	1.3	1.3	1.4	1.3	1.3	1.3	1.4
Current Taxes	7.4	1.8	11.2	11.6	13.5	14.9	15.9	10.2	20.3
Deferred Taxes	(3.0)	2.7	(2.7)	(2.7)	(2.8)	(3.0)	(3.3)	2.3	(4.0)
ITC Amortization	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
Total Operating Expenses	83.5	84.2	107.2	112.2	117.4	128.1	131.9	131.9	154.2
Operating Income	10.3	11.3	11.3	11.8	11.5	11.2	12.2	15.3	17.6
Interest Expense	4.6	5.0	5.0	5.3	5.1	5.0	5.4	6.8	7.8
Net Income	5.7	6.3	6.3	6.6	6.4	6.2	6.8	8.5	9.7
Preferred Return	0.8	0.9	0.9	0.9	0.9	0.8	0.9	1.2	1.3
Income Available for Equity Return	4.9	5.4	5.4	5.7	5.5	5.4	5.9	7.4	8.4
Operating Income	10.3	11.3	11.3	11.8	11.5	11.2	12.2	15.3	17.6
Rate Base	106.9	117.9	118.1	122.9	119.3	116.3	127.5	159.6	182.7
Return on Rate Base	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	42.8	47.3	47.3	49.3	47.8	46.6	51.1	64.0	73.2
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Cheswick										
Off-system Sales Revenue	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Revenue from Customers	174.3	175.3	189.8	190.2	177.3	209.8	208.1	209.2	221.2	4.5
Total Revenue	174.3	175.3	189.8	190.2	177.3	209.8	208.1	209.2	221.2	4.5
Operating Expenses										
Fuel	62.7	61.8	69.8	72.0	66.3	81.0	80.5	80.0	89.5	0.0
Emissions	14.4	14.4	17.2	17.0	14.3	20.3	20.6	20.2	23.8	0.0
Non Fuel O&M (production)	16.9	19.1	19.4	18.1	31.3	20.8	19.6	22.0	22.3	0.0
Outage Accounting	3.1	3.1	3.1	3.1	(17.0)	0.0	0.0	0.0	0.0	0.0
Non-production Expenses	16.8	17.4	18.7	19.1	21.6	21.4	22.2	23.5	24.5	0.0
Major Maintenance Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5
Book Depreciation	17.5	18.2	18.9	19.9	22.9	24.1	25.2	26.2	32.5	0.0
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	7.7	7.7	8.4	8.4	7.8	9.2	9.2	9.2	9.7	0.2
Property Taxes	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.0
Other Taxes	1.4	1.4	1.4	1.3	1.4	1.4	1.4	1.5	1.4	0.0
Current Taxes	19.1	19.1	21.1	21.0	11.7	23.2	23.0	22.6	24.7	(0.1)
Deferred Taxes	(2.5)	(2.9)	(3.3)	(3.8)	3.4	(4.2)	(4.5)	(5.1)	(7.9)	0.0
ITC Amortization	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.1)	(0.1)	(0.1)	(0.1)
Total Operating Expenses	157.8	159.9	175.4	176.9	164.3	198.0	197.9	200.8	221.2	4.5
Operating Income	16.5	15.5	14.4	13.3	12.9	11.9	10.2	8.4	(0.0)	(0.0)
Interest Expense	7.4	6.9	6.4	5.9	5.8	5.3	4.6	3.7	(0.0)	(0.0)
Net Income	9.2	8.6	8.0	7.4	7.2	6.6	5.7	4.7	(0.0)	(0.0)
Preferred Return	1.2	1.2	1.1	1.0	1.0	0.9	0.8	0.6	(0.0)	(0.0)
Income Available for Equity Return	7.9	7.4	6.9	6.4	6.2	5.7	4.9	4.0	(0.0)	(0.0)
Operating Income	16.5	15.5	14.4	13.3	12.9	11.9	10.2	8.4	0.0	0.0
Rate Base	172.0	160.9	150.1	138.9	134.7	123.6	106.6	87.4	0.0	0.0
Return on Rate Base	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	68.9	64.5	60.2	55.7	54.0	49.6	42.7	35.0	0.0	0.0
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Cheswick											
Off-system Sales Revenue	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Revenue from Customers	9.5	12.4	12.4	12.4	7.7	2.9	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Total Revenue	9.5	12.4	12.4	12.4	7.7	2.9	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Operating Expenses											
Fuel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emissions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Fuel O&M (production)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Outage Accounting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non-production Expenses	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Major Maintenance Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	9.1	11.9	11.9	11.9	7.4	2.8	0.0	0.0	0.0	0.0	0.0
Book Depreciation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	0.4	0.5	0.5	0.5	0.3	0.1	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Property Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Current Taxes	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Deferred Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ITC Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Operating Expenses	9.5	12.4	12.4	12.4	7.7	2.9	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Operating Income	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Interest Expense	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Net Income	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Preferred Return	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Income Available for Equity Return	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Operating Income	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate Base	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return on Rate Base	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

(J) Revenue Requirements Forecast
Fossil Generation
(Revised)

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Elrama									
Off-system Sales Revenue	2.7	2.9	6.8	7.0	7.4	8.0	6.2	8.5	0.0
Revenue from Customers	94.6	104.4	105.8	107.3	108.0	111.3	107.1	113.2	12.3
Total Revenue	97.3	107.3	112.6	114.3	115.4	119.3	113.3	121.7	12.3
Operating Expenses									
Fuel	34.8	41.1	38.1	37.6	38.7	42.0	39.1	45.2	0.0
Emissions	0.0	0.0	6.5	7.0	6.3	7.3	6.1	8.1	0.0
Non Fuel O&M (production)	17.8	16.7	22.8	20.8	20.3	20.4	23.6	21.3	0.0
Outage Accounting	(0.7)	1.7	(2.8)	(1.0)	0.5	0.5	(2.9)	0.0	0.0
Non-production Expenses	11.1	11.6	12.0	13.4	13.2	13.2	12.8	13.0	0.0
Major Maintenance Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Book Depreciation	14.7	16.2	17.1	18.1	19.0	19.8	20.5	21.5	12.3
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	4.2	4.6	4.7	4.7	4.8	4.9	4.7	5.0	0.5
Property Taxes	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.0
Other Taxes	1.2	1.2	1.2	1.2	1.2	1.2	1.3	1.3	0.0
Current Taxes	7.4	8.7	7.0	8.0	8.7	8.7	7.1	8.3	2.7
Deferred Taxes	(3.6)	(4.9)	(3.5)	(4.7)	(5.7)	(6.1)	(5.0)	(6.7)	(3.0)
ITC Amortization	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.3)
Total Operating Expenses	87.4	97.3	103.3	105.5	107.3	112.3	107.6	117.2	12.3
Operating Income	9.9	9.9	9.2	8.8	8.1	7.0	5.7	4.4	0.0
Interest Expense	4.4	4.4	4.1	3.9	3.6	3.1	2.6	2.0	0.0
Net Income	5.5	5.5	5.1	4.9	4.5	3.9	3.2	2.5	0.0
Preferred Return	0.7	0.7	0.7	0.7	0.6	0.5	0.4	0.3	0.0
Income Available for Equity Return	4.8	4.8	4.4	4.2	3.9	3.4	2.8	2.1	0.0
Operating Income	9.9	9.9	9.2	8.8	8.1	7.0	5.7	4.4	0.0
Rate Base	103.5	103.3	96.1	91.9	84.1	72.9	59.7	46.1	0.0
Return on Rate Base	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	41.5	41.4	38.5	36.8	33.7	29.2	23.9	18.5	0.0
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Elrama										
Off-system Sales Revenue	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Revenue from Customers	5.1	9.1	9.1	9.1	9.1	3.9	0.0	0.0	0.0	0.0
Total Revenue	5.1	9.1	9.1	9.1	9.1	3.9	0.0	0.0	0.0	0.0
Operating Expenses										
Fuel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emissions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Fuel O&M (production)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Outage Accounting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non-production Expenses	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Major Maintenance Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	4.9	8.7	8.7	8.7	8.7	3.8	0.0	0.0	0.0	0.0
Book Depreciation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	0.2	0.4	0.4	0.4	0.4	0.2	0.0	0.0	0.0	0.0
Property Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Current Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Deferred Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ITC Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Operating Expenses	5.1	9.1	9.1	9.1	9.1	3.9	0.0	0.0	0.0	0.0
Operating Income	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Interest Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Income	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preferred Return	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Income Available for Equity Return	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Income	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate Base	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return on Rate Base	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Elrama											
Off-system Sales Revenue	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Revenue from Customers	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Revenue	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Expenses											
Fuel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emissions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Fuel O&M (production)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Outage Accounting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non-production Expenses	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Major Maintenance Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Book Depreciation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Property Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Current Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Deferred Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ITC Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Operating Expenses	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Income	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Interest Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Income	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preferred Return	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Income Available for Equity Return	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Income	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate Base	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return on Rate Base	9.61%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate Base - Equity	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return on Equity	11.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

(J) Revenue Requirements Forecast
Fossil Generation
(Revised)

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Brunot Island									
Off-system Sales Revenue	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Revenue from Customers	6.0	5.7	6.0	5.6	5.4	5.2	5.1	6.7	5.8
Total Revenue	6.1	5.7	6.0	5.6	5.4	5.2	5.1	6.7	5.8
Operating Expenses									
Fuel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emissions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Fuel O&M (production)	0.7	0.4	0.6	0.6	0.6	0.6	0.7	0.7	0.7
Outage Accounting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non-production Expenses	0.5	0.4	0.5	0.3	0.3	0.3	0.3	1.0	0.3
Major Maintenance Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Book Depreciation	2.0	2.0	2.1	2.0	1.9	1.9	1.9	2.3	2.3
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.3	0.3
Property Taxes	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Other Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Current Taxes	1.3	1.3	1.3	1.2	1.1	1.1	1.1	1.3	1.2
Deferred Taxes	(0.7)	(0.6)	(0.7)	(0.6)	(0.6)	(0.6)	(0.6)	(0.7)	(0.7)
ITC Amortization	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Total Operating Expenses	4.4	4.0	4.3	4.0	3.9	3.8	3.8	5.1	4.4
Operating Income	1.7	1.7	1.7	1.6	1.5	1.4	1.3	1.5	1.4
Interest Expense	0.8	0.8	0.8	0.7	0.7	0.6	0.6	0.7	0.6
Net Income	0.9	0.9	1.0	0.9	0.8	0.8	0.7	0.9	0.8
Preferred Return	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Income Available for Equity Return	0.8	0.8	0.8	0.8	0.7	0.7	0.6	0.7	0.7
Operating Income	1.7	1.7	1.7	1.6	1.5	1.4	1.3	1.5	1.4
Rate Base	17.6	17.7	17.9	16.7	15.6	14.5	13.4	16.1	14.7
Return on Rate Base	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	7.1	7.1	7.2	6.7	6.2	5.8	5.4	6.5	5.9
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Brunot Island										
Off-system Sales Revenue	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Revenue from Customers	5.9	5.7	5.5	5.2	5.1	7.2	0.7	4.8	6.0	6.0
Total Revenue	5.9	5.7	5.5	5.2	5.1	7.2	0.7	4.8	6.0	6.0
Operating Expenses										
Fuel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emissions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Fuel O&M (production)	0.7	0.7	0.7	0.8	0.8	0.8	0.0	0.0	0.0	0.0
Outage Accounting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non-production Expenses	0.3	0.3	0.3	0.3	0.3	0.3	0.1	0.0	0.0	0.0
Major Maintenance Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.6	5.7	5.7
Book Depreciation	2.6	2.7	2.7	2.6	2.6	5.7	0.1	0.0	0.0	0.0
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	0.3	0.3	0.2	0.2	0.2	0.3	0.0	0.2	0.3	0.3
Property Taxes	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.0	0.0	0.0
Other Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Current Taxes	1.3	1.2	1.2	1.1	1.1	2.0	0.1	(0.0)	(0.0)	(0.0)
Deferred Taxes	(0.8)	(0.8)	(0.9)	(0.8)	(0.9)	(2.1)	0.0	0.0	0.0	0.0
ITC Amortization	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.1)	0.0	0.0	0.0	0.0
Total Operating Expenses	4.6	4.6	4.6	4.4	4.4	7.2	0.7	4.8	6.0	6.0
Operating Income	1.3	1.1	0.9	0.8	0.6	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Interest Expense	0.6	0.5	0.4	0.4	0.3	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Net Income	0.7	0.6	0.5	0.4	0.4	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Preferred Return	0.1	0.1	0.1	0.1	0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Income Available for Equity Return	0.6	0.5	0.5	0.4	0.3	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Operating Income	1.3	1.1	0.9	0.8	0.6	0.0	0.0	0.0	0.0	0.0
Rate Base	13.0	11.4	9.8	8.2	6.6	0.0	0.0	0.0	0.0	0.0
Return on Rate Base	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	5.2	4.6	3.9	3.3	2.7	0.0	0.0	0.0	0.0	0.0
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Brunot Island											
Off-system Sales Revenue	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Revenue from Customers	6.0	6.0	1.2	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Total Revenue	6.0	6.0	1.2	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Operating Expenses											
Fuel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emissions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Fuel O&M (production)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Outage Accounting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non-production Expenses	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Major Maintenance Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	5.7	5.7	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Book Depreciation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	0.3	0.3	0.1	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Property Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Current Taxes	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Deferred Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ITC Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Operating Expenses	6.0	6.0	1.2	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Operating Income	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Interest Expense	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Net Income	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Preferred Return	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Income Available for Equity Return	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Operating Income	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate Base	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return on Rate Base	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

(J) Revenue Requirements Forecast
Fossil Generation
(Revised)

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
B.L. Cold Reserve									
Off-system Sales Revenue	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Revenue	2.4	2.4	2.4	2.3	2.3	2.3	2.3	2.3	30.0
Total Revenue	2.4	2.4	2.4	2.3	2.3	2.3	2.3	2.3	30.0
Operating Expenses									
Fuel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emissions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Fuel O&M (production)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Outage Accounting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non-production Expenses	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Major Maintenance Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Book Depreciation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	28.8
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	1.3
Property Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Current Taxes	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	11.9
Deferred Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(11.9)
ITC Amortization	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Total Operating Expenses	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	30.0
Operating Income	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	(0.0)
Interest Expense	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	(0.0)
Net Income	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	(0.0)
Preferred Return	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	(0.0)
Income Available for Equity Return	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	(0.0)
Operating Income	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	0.0
Rate Base	17.5	17.5	17.5	17.4	17.4	17.4	17.4	17.4	0.0
Return on Rate Base	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	0.0
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
B.I. Cold Reserve										
Off-system Sales Revenue	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Revenue	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.0)	(0.0)
Total Revenue	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.0)	(0.0)
Operating Expenses										
Fuel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emissions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Fuel O&M (production)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Outage Accounting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non-production Expenses	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Major Maintenance Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Book Depreciation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Property Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Current Taxes	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Deferred Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ITC Amortization	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	0.0	0.0
Total Operating Expenses	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.0)	(0.0)
Operating Income	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Interest Expense	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Net Income	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Preferred Return	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Income Available for Equity Return	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Operating Income	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate Base	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return on Rate Base	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
B.I. Cold Reserve											
Off-system Sales Revenue	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Revenue	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Total Revenue	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Operating Expenses											
Fuel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emissions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Fuel O&M (production)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Outage Accounting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non-production Expenses	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Major Maintenance Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Book Depreciation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Property Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Current Taxes	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Deferred Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ITC Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Operating Expenses	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Operating Income	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Interest Expense	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Net Income	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Preferred Return	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Income Available for Equity Return	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Operating Income	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate Base	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return on Rate Base	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

(J) Revenue Requirements Forecast
Fossil Generation
(Revised)

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Phillips									
Off-system Sales Revenue	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Revenue from Customers	7.2	7.7	6.7	6.6	6.6	6.6	30.1	56.3	0.1
Total Revenue	7.2	7.7	6.7	6.6	6.6	6.6	30.1	56.3	0.1
Operating Expenses									
Fuel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emissions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Fuel O&M (production)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Outage Accounting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non-production Expenses	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Major Maintenance Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Book Depreciation	0.5	1.0	0.0	0.0	0.0	0.0	24.4	53.6	0.4
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	0.3	0.3	0.3	0.3	0.3	0.3	1.3	2.5	0.0
Property Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Current Taxes	1.7	1.9	1.5	1.6	1.6	1.6	11.2	22.2	(0.0)
Deferred Taxes	0.1	(0.1)	0.2	0.2	0.1	0.1	(10.0)	(22.2)	(0.1)
ITC Amortization	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
Total Operating Expenses	2.4	2.9	1.9	1.9	1.9	1.8	26.7	55.9	0.1
Operating Income	4.8	4.8	4.8	4.8	4.8	4.8	3.4	0.4	(0.0)
Interest Expense	2.1	2.1	2.1	2.1	2.1	2.1	1.5	0.2	(0.0)
Net Income	2.7	2.7	2.7	2.7	2.6	2.6	1.9	0.2	(0.0)
Preferred Return	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.0	(0.0)
Income Available for Equity Return	2.3	2.3	2.3	2.3	2.3	2.3	1.6	0.2	(0.0)
Operating Income	4.8	4.8	4.8	4.8	4.8	4.8	3.4	0.4	0.0
Rate Base	50.1	50.2	50.0	49.8	49.7	49.6	35.2	3.8	0.0
Return on Rate Base	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	20.1	20.1	20.0	20.0	19.9	19.9	14.1	1.5	0.0
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Phillips										
Off-system Sales Revenue	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Revenue from Customers	1.4	2.5	2.5	2.5	2.5	1.1	(0.0)	(0.0)	(0.0)	(0.0)
Total Revenue	1.4	2.5	2.5	2.5	2.5	1.1	(0.0)	(0.0)	(0.0)	(0.0)
Operating Expenses										
Fuel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emissions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Fuel O&M (production)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Outage Accounting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non-production Expenses	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Major Maintenance Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	1.3	2.4	2.4	2.4	2.4	1.0	0.0	0.0	0.0	0.0
Book Depreciation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	0.1	0.1	0.1	0.1	0.1	0.0	(0.0)	(0.0)	(0.0)	(0.0)
Property Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Current Taxes	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Deferred Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ITC Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Operating Expenses	1.4	2.5	2.5	2.5	2.5	1.1	(0.0)	(0.0)	(0.0)	(0.0)
Operating Income	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Interest Expense	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Net Income	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Preferred Return	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Income Available for Equity Return	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Operating Income	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate Base	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return on Rate Base	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Phillips											
Off-system Sales Revenue	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Revenue from Customers	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Revenue	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Expenses											
Fuel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emissions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Fuel O&M (production)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Outage Accounting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non-production Expenses	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Major Maintenance Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Book Depreciation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Property Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Current Taxes	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Deferred Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ITC Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Operating Expenses	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Income	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Interest Expense	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Income	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preferred Return	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Income Available for Equity Return	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Income	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate Base	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return on Rate Base	9.61%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate Base - Equity	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return on Equity	11.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

(J) Revenue Requirements Forecast
Fossil Generation
(Revised)

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Mansfield									
Off-system Sales Revenue	3.1	3.3	7.4	7.1	8.4	8.4	7.4	9.3	2.9
Revenue from Customers	89.9	97.6	101.6	78.0	82.9	82.0	89.6	90.7	98.9
Total Revenue	92.9	100.9	109.0	85.1	91.4	90.4	96.9	100.0	101.8
Operating Expenses									
Fuel	40.5	46.7	48.9	32.8	37.0	36.9	38.5	41.5	42.1
Emissions	0.0	0.0	5.5	5.3	6.2	6.1	6.6	7.3	7.4
Non Fuel O&M (production)	12.6	12.8	12.8	12.6	11.8	11.9	13.6	12.7	13.2
Outage Accounting	1.2	1.2	1.3	(2.7)	(0.4)	(1.1)	0.9	0.9	0.9
Non-production Expenses	9.5	10.8	11.4	10.0	10.6	10.6	11.3	11.4	12.2
Major Maintenance Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Book Depreciation	8.2	8.4	8.4	8.0	7.5	7.6	7.8	8.0	8.2
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	4.0	4.3	4.5	3.4	3.6	3.6	3.9	4.0	4.4
Property Taxes	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Other Taxes	1.4	1.3	1.4	1.3	1.3	1.3	1.3	1.4	1.3
Current Taxes	5.8	6.3	6.5	4.6	5.3	5.0	5.7	5.6	5.5
Deferred Taxes	(1.7)	(2.2)	(2.7)	(0.9)	(1.7)	(1.5)	(2.3)	(2.3)	(2.3)
ITC Amortization	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
Total Operating Expenses	81.9	90.0	98.5	75.0	81.6	81.0	87.8	91.1	93.3
Operating Income	11.0	10.9	10.4	10.1	9.7	9.4	9.1	9.0	8.5
Interest Expense	4.9	4.8	4.6	4.5	4.3	4.2	4.1	4.0	3.8
Net Income	6.1	6.0	5.8	5.6	5.4	5.2	5.1	5.0	4.7
Preferred Return	0.8	0.8	0.8	0.8	0.7	0.7	0.7	0.7	0.6
Income Available for Equity Return	5.3	5.2	5.0	4.8	4.7	4.5	4.4	4.3	4.1
Operating Income	11.0	10.9	10.4	10.1	9.7	9.4	9.1	9.0	8.5
Rate Base	114.7	113.0	108.8	105.2	101.2	97.6	95.2	93.4	89.0
Return on Rate Base	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	46.0	45.3	43.6	42.2	40.6	39.1	38.2	37.5	35.7
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Mansfield										
Off-system Sales Revenue	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Revenue from Customers	96.1	105.3	104.0	111.8	114.0	116.3	114.7	117.1	126.4	141.2
Total Revenue	96.1	105.3	104.0	111.8	114.0	116.3	114.7	117.1	126.4	141.2
Operating Expenses										
Fuel	40.1	45.8	46.2	47.4	50.9	51.7	49.3	52.4	54.3	58.9
Emissions	6.9	8.3	8.3	8.7	9.6	9.8	9.1	9.9	10.3	11.8
Non Fuel O&M (production)	14.6	13.8	13.4	16.6	14.6	15.2	17.4	15.1	15.3	20.7
Outage Accounting	(2.1)	(0.0)	(0.6)	0.9	0.9	0.9	(1.9)	(1.4)	(1.5)	(0.1)
Non-production Expenses	10.8	11.7	11.5	12.7	12.9	13.2	14.0	14.7	14.6	17.2
Major Maintenance Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Book Depreciation	8.4	8.5	8.6	9.0	9.1	9.4	10.1	10.4	11.0	11.4
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	4.2	4.6	4.6	4.9	5.0	5.1	5.0	5.2	5.6	6.2
Property Taxes	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Other Taxes	1.4	1.4	1.4	1.4	1.5	1.4	1.5	1.5	1.5	1.5
Current Taxes	4.2	4.9	4.5	5.1	5.0	5.1	3.8	3.2	5.3	0.5
Deferred Taxes	(1.1)	(2.0)	(1.8)	(2.5)	(2.6)	(2.7)	(1.3)	(0.9)	(1.3)	3.0
ITC Amortization	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
Total Operating Expenses	87.8	97.5	96.7	104.7	107.4	109.7	107.6	110.7	115.7	131.7
Operating Income	8.2	7.8	7.4	7.1	6.6	6.7	7.1	6.4	10.7	9.5
Interest Expense	3.7	3.5	3.3	3.2	2.9	3.0	3.1	2.8	4.8	4.2
Net Income	4.6	4.3	4.1	3.9	3.7	3.7	3.9	3.5	5.9	5.3
Preferred Return	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.8	0.7
Income Available for Equity Return	4.0	3.7	3.5	3.4	3.2	3.2	3.4	3.1	5.1	4.5
Operating Income	8.2	7.8	7.4	7.1	6.6	6.7	7.1	6.4	10.7	9.5
Rate Base	85.8	81.3	76.9	74.0	68.9	69.5	73.5	66.6	111.5	98.5
Return on Rate Base	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	34.4	32.6	30.8	29.6	27.6	27.8	29.4	26.7	44.7	39.5
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Mansfield											
Off-system Sales Revenue	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Revenue from Customers	75.0	59.1	55.0	62.6	14.0	11.8	8.0	7.7	7.7	6.9	6.0
Total Revenue	75.0	59.1	55.0	62.6	14.0	11.8	8.0	7.7	7.7	6.9	6.0
Operating Expenses											
Fuel	26.1	15.4	17.5	17.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emissions	5.7	3.4	4.2	4.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Fuel O&M (production)	7.9	4.9	5.5	5.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Outage Accounting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non-production Expenses	6.1	3.8	4.5	4.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Major Maintenance Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	3.1	6.9	7.2	7.2	8.0	5.8	1.9	1.7	1.7	0.9	0.0
Book Depreciation	10.7	7.9	0.1	16.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	3.3	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Property Taxes	0.4	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Taxes	0.8	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Current Taxes	0.3	0.4	(2.4)	(47.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Deferred Taxes	2.8	2.3	5.0	47.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ITC Amortization	(0.3)	(0.3)	(0.3)	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Operating Expenses	66.8	51.6	48.0	62.6	14.0	11.8	8.0	7.7	7.7	6.9	6.0
Operating Income	8.3	7.5	7.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Interest Expense	3.7	3.3	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Income	4.6	4.1	3.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preferred Return	0.6	0.6	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Income Available for Equity Return	4.0	3.6	3.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Income	8.3	7.5	7.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate Base	86.1	77.6	72.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return on Rate Base	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
Rate Base - Equity	34.5	31.1	29.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Revised Karl Exhibits

Exhibit MGK-3
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Duquesne Light Company

Nuclear Plant Fuel Cost cents/ mmBtu

Year	Beaver Valley 1	Beaver Valley 2	Perry	Spent Fuel $/ MWHr
1997	47.24	40.00	57.28	1.00
1998	41.80	38.38	43.34	1.00
1999	39.66	37.73	42.44	1.00
2000	38.12	39.30	41.58	1.00
2001	38.19	40.33	42.56	1.00
2002	39.35	39.48	42.80	1.00
2003	39.00	39.06	43.31	1.00
2004	40.05	39.84	43.69	1.00
2005	41.72	39.40	46.01	1.00
2006	42.44	40.13	46.20	1.00
2007	43.82	41.48	47.73	1.00
2008	45.29	42.78	49.28	1.00
2009	46.66	44.17	50.82	1.00
2010	48.22	45.65	52.46	1.00
2011	49.77	47.13	54.11	1.00
2012	51.33	48.61	55.85	1.00
2013	52.97	50.19	57.58	1.00
2014	54.62	51.76	59.32	1.00
2015	56.27	53.43	61.26	1.00
2016		55.09	63.09	1.00
2017		56.76	65.02	1.00
2018		58.29	66.78	1.00
2019		59.87	68.58	1.00
2020		61.48	71.43	1.00
2021		63.14	72.34	1.00
2022		64.85	74.29	1.00
2023		66.60	76.30	1.00
2024		68.40	78.36	1.00
2025		70.24	80.47	1.00
2026		72.14	82.64	1.00

Exhibit MGK-6

Projected Unit Equivalent Availability Factors

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Cheswick	67.6%	80.4%	80.8%	77.4%	84.1%	80.8%	70.8%	84.1%	80.8%	77.4%	84.1%	80.8%	70.7%	84.1%
Elrama 1	65.5%	58.5%	69.6%	69.6%	68.2%	65.4%	72.4%							
Elrama 2	56.4%	58.7%	48.0%	59.9%	58.7%	56.3%	62.3%							
Elrama 3	59.3%	52.5%	62.5%	58.8%	61.3%	62.5%	61.3%							
Elrama 4	65.7%	77.9%	70.4%	70.4%	77.9%	60.0%	73.4%							
Sammis	91.2%	82.5%	91.2%	75.5%	91.2%	84.2%	91.2%	84.2%	91.2%	75.5%	91.2%	84.2%	91.2%	
Eastlake	65.3%	79.3%	70.8%	80.0%	70.8%	70.8%	75.8%	65.7%	70.8%	80.0%	70.8%	70.8%	74.3%	67.3%
Mansfield 1	89.6%	89.6%	69.0%	89.6%	89.6%	81.0%	89.6%	89.6%	69.0%	89.6%	89.6%	81.0%	89.6%	89.6%
Mansfield 2	79.7%	92.0%	92.0%	70.8%	92.0%	92.0%	83.2%	92.0%	92.0%	70.8%	92.0%	92.0%	83.2%	92.0%
Mansfield 3	90.8%	82.1%	90.8%	90.8%	69.9%	90.8%	90.8%	82.1%	90.8%	90.8%	69.9%	90.8%	90.8%	82.1%
Perry	93.5%	83.2%	93.5%	83.2%	93.5%	83.2%	93.5%	83.2%	93.5%	83.2%	93.5%	83.2%	93.5%	83.2%
Beaver Valley 1	94.1%	76.0%	79.9%	94.1%	79.9%	79.9%	94.1%	79.9%	79.9%	94.1%	79.9%	79.9%	94.1%	79.9%
Beaver Valley 2	83.7%	83.7%	94.1%	83.7%	83.7%	94.1%	83.8%	83.7%	94.1%	83.7%	83.8%	94.1%	83.7%	83.7%

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cheswick	80.8%	77.4%	84.1%											
Elrama 1														
Elrama 2														
Elrama 3														
Elrama 4														
Sammis														
Eastlake														
Mansfield 1	73.9%	84.7%	89.6%	89.6%										
Mansfield 2	92.0%	70.8%	92.0%	92.0%	92.0%									
Mansfield 3	90.8%	90.8%	70.9%	89.8%	90.8%	82.1%	90.8%	90.8%						
Perry	93.5%	83.2%	93.5%	83.2%	93.5%	83.2%	93.5%	83.2%	93.5%	83.2%	93.5%	83.2%	93.5%	83.2%
Beaver Valley 1	79.9%	94.1%	79.9%	94.1%										
Beaver Valley 2	94.1%	83.7%	83.7%	94.1%	83.8%	83.7%	94.1%	83.7%	83.8%	94.1%	83.7%	83.7%	94.1%	83.7%

Exhibit MGK-7A
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Duquesne Light Company
Projected Annual Unit Output (GWHr)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Cheswick	3272	3608	3652	3485	3823	3733	3303	3947	4030	3866	4211	4027	3528	4200
Elrama 1	541	449	543	507	532	514	568							
Elrama 2	456	453	372	465	458	441	485							
Elrama 3	533	473	571	534	557	571	552							
Elrama 4	990	1126	1027	1015	1133	862	1122							
Sammis	1370	1206	1324	1119	1331	1250	1359	1261	1493	1236	1498	1378	1474	
Eastlake	1110	1158	1045	1172	1027	1053	1131	956	1149	1302	1151	1148	1207	1069
Mansfield 1	1580	1561	1249	1687	1695	1535	1709	1710	1377	1789	1794	1615	1789	1789
Mansfield 2	449	432	463	358	472	473	440	477	500	385	501	499	452	500
Mansfield 3	869	720	830	842	645	845	848	764	875	875	693	874	875	791
Perry	1343	1195	1347	1195	1343	1195	1346	1195	1343	1195	1346	1195	1343	1195
Beaver 1	3172	2564	2703	3172	2694	2694	3181	2694	2694	3172	2703	2694	3172	2694
Beaver 2	816	829	934	829	829	931	832	829	931	829	832	931	829	829

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cheswick	4044	3866	4163											
Elrama 1														
Elrama 2														
Elrama 3														
Elrama 4														
Sammis														
Eastlake														
Mansfield 1	1481	1691	1789	1769										
Mansfield 2	501	385	500	500	493									
Mansfield 3	877	875	683	865	877	791	875	870						
Perry	1346	1195	1343	1195	1346	1195	1343	1195	1347	1195	1343	1195	1347	1195
Beaver 1	2703	3172	2694	3137										
Beaver 2	934	829	829	931	832	829	931	829	832	931	829	829	934	829

Exhibit MGK-7B
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Duquesne Light Company
Projected Annual Unit Production Cost ($millions)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Cheswick	68.0	69.4	71.9	72.9	79.8	78.9	87.6	90.3	93.4	94.9	105.5	106.7	113.7	121.5
Elrama 1	11.6	13.6	13.3	13.4	14.0	14.1	15.4							
Elrama 2	10.2	11.6	12.1	12.3	12.4	12.5	13.6							
Elrama 3	11.6	14.2	13.8	13.7	14.4	15.2	15.2							
Elrama 4	20.2	24.9	23.2	24.1	26.3	25.9	27.7							
Sammis	22.9	24.4	25.4	25.9	27.1	27.8	29.3	29.5	32.6	32.0	35.5	33.9	37.4	
Eastlake	21.6	22.5	21.7	25.1	23.6	24.4	27.7	25.8	29.0	33.8	31.9	32.6	36.5	34.5
Mansfield 1	37.7	37.7	25.9	30.1	30.9	30.3	33.6	34.7	31.7	37.6	38.2	38.2	41.3	42.7
Mansfield 2	10.5	10.3	8.1	7.5	8.5	9.1	8.5	9.6	10.0	9.1	10.5	11.4	10.4	11.8
Mansfield 3	19.3	16.9	14.5	14.8	13.2	16.3	16.5	15.5	17.5	18.2	16.5	20.2	20.0	19.1
Perry	25.3	25.9	22.4	26.1	23.6	26.9	24.7	28.3	25.9	29.7	27.3	31.2	28.8	32.9
Beaver 1	52.9	60.8	52.6	42.0	54.9	55.9	44.8	59.1	60.5	48.4	63.8	65.4	52.3	68.9
Beaver 2	17.8	16.1	12.1	14.9	15.2	12.7	15.8	16.0	13.4	16.9	17.3	14.5	18.2	18.7

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cheswick	120.0	122.4	135.4											
Elrama 1														
Elrama 2														
Elrama 3														
Elrama 4														
Sammis														
Eastlake														
Mansfield 1	40.2	42.7	45.2	49.6										
Mansfield 2	12.1	10.5	12.4	13.8	13.6									
Mansfield 3	21.3	21.3	19.6	24.2	24.3	20.7	23.5	23.9						
Perry	30.4	34.7	32.0	36.6	33.8	38.6	35.5	40.7	37.5	41.7	37.4	41.8	37.5	41.7
Beaver 1	70.8	56.7	74.6	59.1										
Beaver 2	15.7	19.7	20.3	17.0	21.4	21.9	18.4	23.1	23.7	19.3	23.7	23.7	19.4	23.7

Revised Nelson Exhibits

Duquesne Statement No. 10
Docket No. R-00974104
Witness: Ralph Nelson
Revision 1: October 13, 1997

Revision to Direct Testimony of Ralph L. Nelson

The following exhibits have been revised to reflect more recent forecasts of non-fuel O&M and capital expenditures:

Exhibit RLN-1 Fossil Non-Fuel O&M Expenses
Exhibit RLN-2 Fossil Non-Fuel O&M Expenses (Constant 1996 $)
Exhibit RLN-5 20 year Projected Capital Expenditures
Exhibit RLN-6 20 year Projected Capital Expenditures (Constant 1996$)

These revisions incorporate the projections from Duquesne's operating 1998 and 1999 operating plan and also more recent forecast data obtained from Ohio Edison Company and Pennsylvania Power Company for Sammis and Mansfield Power Stations, respectively.

Exhibit RLN-1
Revision 1
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FOSSIL NON-FUEL O&M EXPENSES
($ x 1000)

STATION		CHESWICK	ELRAMA	BRUNOT IS	PHILLIPS	EASTLAKE	SAMMIS	MANSFIELD	TOTAL
1993	(A)	18,191	16,753	259	117	5,313	4,498	8,912	54,043
1994	(A)	14,125	17,263	310	215	3,977	5,460	15,027	56,377
1995	(A)	16,420	18,652	327	162	5,210	6,260	12,009	59,040
1996	(A)	18,492	21,891	341	178	3,814	3,638	12,817	61,171
4 YEAR AVG	(A)	16,807	18,640	309	168	4,579	4,964	12,191	57,658
1997	(P)	14,651	20,950	425	292	4,845	4,496	12,859	58,518
1998	(P)	27,920	19,593	430	290	6,551	6,174	12,200	73,158
1999	(P)	15,830	22,772	446	300	6,830	7,421	12,845	66,444
2000	(P)	14,932	20,823	457	308	5,403	5,509	12,644	60,076
2001	(P)	16,816	20,263	468	315	5,999	8,290	11,807	63,959
2002	(P)	16,828	20,359	481	324	6,203	5,535	11,912	61,642
2003	(P)	15,618	23,595	493	332	5,893	6,785	13,630	66,345
2004	(P)	28,562	21,511	506	341	6,552	5,963	12,754	76,189
2005	(P)	18,126		520	350	7,904	7,112	13,218	47,231
2006	(P)	16,858		534		6,398	6,578	14,558	44,927
2007	(P)	19,038		549		7,108	9,677	13,812	50,184
2008	(P)	19,420		563		7,299	7,193	13,525	48,000
2009	(P)	18,173		578		6,933	6,884	16,611	49,179
2010	(P)	31,178		593		7,705	7,249	14,592	61,316
2011	(P)	20,801		609		9,303		15,157	45,870
2012	(P)	19,604		625				18,250	38,479
2013	(P)	21,961						14,337	36,298
2014	(P)	22,420						15,350	37,770
2015	(P)							20,737	20,737
2016	(P)							7,936	7,936

FOSSIL UNITS REMOVED FROM GENERATING LINEUP FOLLOWING THE END OF BOOK LIFE.

STATION	END OF BOOK LIFE
ELRAMA	2004
SAMMIS	2010
EASTLAKE	2011
BRUNOT IS	2012
CHESWICK	2014
MANSFIELD 1	2015

(A) - ACTUAL
(P) - PROJECTED

FOSSIL NON-FUEL O&M EXPENSES

(1996 CONSTANT $ x 1000)

STATION		CHESWICK	ELRAMA	BRUNOT IS	PHILLIPS	EASTLAKE	SAMMIS	MANSFIELD	TOTAL
1993	(A)	19,475	17,936	277	125	5,688	4,816	9,541	57,858
1994	(A)	14,797	18,084	325	225	4,166	5,720	15,741	59,058
1995	(A)	16,765	19,044	334	165	5,319	6,391	12,261	60,280
1996	(A)	18,492	21,891	341	178	3,814	3,638	12,817	61,171
4 YEAR AVG	(A)	17,382	19,239	319	173	4,747	5,141	12,590	59,592
1997	(P)	14,308	20,459	415	285	4,731	4,391	12,558	57,146
1998	(P)	26,600	18,667	410	277	6,242	5,882	11,623	69,701
1999	(P)	14,714	21,167	414	279	6,349	6,898	11,940	61,760
2000	(P)	13,527	18,864	414	279	4,895	4,991	11,455	54,426
2001	(P)	14,849	17,892	414	278	5,297	7,320	10,426	56,475
2002	(P)	14,483	17,521	414	279	5,338	4,764	10,252	53,050
2003	(P)	13,087	19,772	413	278	4,938	5,686	11,422	55,597
2004	(P)	23,306	17,552	413	278	5,346	4,866	10,407	62,167
2005	(P)	14,402	[illegible]	413	278	6,280	5,651	10,502	37,525
2006	(P)	13,042	[illegible]	413	[illegible]	4,950	5,089	11,262	34,756
2007	(P)	14,355	[illegible]	414	[illegible]	5,359	7,297	10,414	37,839
2008	(P)	14,272	[illegible]	414	[illegible]	5,364	5,286	9,940	35,276
2009	(P)	13,017	[illegible]	414	[illegible]	4,966	4,931	11,898	35,226
2010	(P)	21,745	[illegible]	413	[illegible]	5,374	5,056	10,177	42,765
2011	(P)	14,127	[illegible]	413	[illegible]	6,318	[illegible]	10,293	31,151
2012	(P)	12,963	[illegible]	413	[illegible]	[illegible]	[illegible]	12,068	25,445
2013	(P)	14,141	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	9,231	23,372
2014	(P)	14,056	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	9,624	23,680
2015	(P)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	12,659	12,659
2016	(P)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	4,717	4,717

FOSSIL UNITS REMOVED FROM GENERATING LINEUP FOLLOWING THE END OF BOOK LIFE.

STATION	END OF BOOK LIFE
ELRAMA	2004
SAMMIS	2010
EASTLAKE	2011
BRUNOT IS	2012
CHESWICK	2014
MANSFIELD 1	2015

(A) - ACTUAL
(P) - PROJECTED

20-YEAR PROJECTED CAPITAL EXPENDITURES

($ X 1000)

		(A) 1994	(A) 1995	(A) 1996	(A) AVG	(P) 1997	(P) 1998	(P) 1999	(P) 2000	(P) 2001	(P) 2002	(P) 2003	(P) 2004	(P) 2005	(P) 2006	(P) 2007	(P) 2008	(P) 2009	(P) 2010	(P) 2011	(P) 2012	(P) 2013	(P) 2014	(P) 2015	(P) 2016
CHESWICK																									
	GEN. CAP	1,329	2,170	3,024	2,174	5,720	13,341	3,790	4,286	4,414	4,547	4,683	14,028	4,969	5,118	5,272	5,431	5,593	14,966	4,451	3,056	1,574	973		
	CAAA	344	1,108	1,932	1,128	0	4,984	0	0	0	0	15,126	30,130	0	0	0	0	0	0	0	0	0	0		
	RSW	2,074	747	1,586	1,469	2,140	5,690	1,240	7,610	60	60	60	60	70	70	70	70	80	80	80	80	90	90		
	TOTAL	3,747	4,025	6,542	4,771	7,860	24,015	5,030	11,896	4,474	4,607	19,868	44,218	5,039	5,188	5,342	5,501	5,673	15,045	4,531	3,136	1,664	1,063		
ELRAMA																									
	GEN. CAP	8,636	4,913	6,807	6,785	10,146	3,450	1,840	3,951	3,052	2,098	1,079	667												
	CAAA	5,834	3,653	2,273	3,920	1,383	5,600	950	0	0	0	0	0												
	RSW	871	538	11	473	1,505	1,790	90	4,250	2,260	270	60	0												
	TOTAL	15,341	9,104	9,091	11,179	13,016	10,840	2,880	8,201	5,312	2,368	1,139	667												
BRUNOT IS																									
	GEN. CAP	34	41	3	26	888	1,475	4,850	100	103	105	108	111	114	117	120	123	104	107	110	113				
	CAAA	0	0	0	0	0	0	0	0	0	0	0	4,200	0	0	0	0	0	0	0	0				
	RSW	0	0	0	0	460	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				
	TOTAL	34	41	3	26	1,348	1,475	4,850	100	103	105	108	4,311	114	117	120	123	104	107	110	113				
PHILLIPS																									
	GEN. CAP	0	0	0	0	0	210	216																	
	CAAA	0	0	0	0	0	0	0																	
	RSW	465	156	9	210	401	750	0																	
	TOTAL	465	156	9	210	401	960	216																	
EASTLAKE																									
	GEN. CAP	652	933	32	539	656	1,813	1,330	338	222	778	1,266	3,034	3,469	2,258	526	770	764	905	621					
	CAAA	88	98	2	62	1,237	37	218	100	5,040	5,100	300	0	0	0	0	0	0	0	0					
	RSW	196	36	73	102	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0					
	TOTAL	936	1,067	107	703	1,893	1,850	1,548	438	5,262	5,878	1,566	3,034	3,469	2,258	526	770	764	905	621					
SAMMIS																									
	GEN. CAP	1,582	1,671	819	1,357	1,876	211	909	55	1,370	867	1,118	291	1,279	64	3,999	321	1,412	337						
	CAAA	194	46	62	101	38	38	194	0	2,076	100	100	0	0	0	0	0	0	0						
	RSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0						
	TOTAL	1,776	1,717	881	1,458	1,914	249	1,103	55	3,446	967	1,218	291	1,279	64	3,999	321	1,412	337						
MANSFIELD																									
	GEN. CAP	9,378	7,774	35	5,729	1,567	4,072	1,694	2,899	780	1,668	2,877	1,082	1,796	3,098	1,143	1,935	3,338	1,232	2,083	3,493	1,326	2,245	716	1,387
	CAAA	3,853	1,144	697	1,898	75	0	0	731	200	350	0	2,900	0	0	0	0	0	0	0	0	0	0	0	0
	RSW	361	101	191	218	547	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL	13,592	9,019	923	7,845	2,189	4,072	1,694	3,630	980	2,018	2,877	3,982	1,796	3,098	1,143	1,935	3,338	1,232	2,083	3,493	1,326	2,245	716	1,387
TOTAL																									
	GEN. CAP	21,611	17,502	10,720	16,611	20,855	24,572	14,628	11,629	9,941	10,061	11,121	19,193	11,627	10,655	11,060	8,580	11,211	17,546	7,265	6,662	2,900	3,218	716	1,387
	CAAA	10,313	6,047	4,966	7,109	2,713	10,659	1,362	831	7,316	5,550	15,526	37,230	0	0	0	0	0	0	0	0	0	0	0	0
	RSW	3,967	1,580	1,870	2,472	5,053	8,230	1,330	11,860	2,320	330	120	60	70	70	70	70	80	80	80	80	90	90	0	0
	TOTAL	35,891	25,129	17,556	26,192	28,621	43,461	17,320	24,320	19,579	15,941	26,768	56,483	11,697	10,725	11,130	8,650	11,291	17,626	7,345	6,742	2,990	3,308	716	1,387

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Revision 1
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20-YEAR PROJECTED CAPITAL EXPENDITURES

(CONSTANT 1996 $ x 1000)

		(A) 1994	(A) 1995	(A) 1996	(A) AVG	(P) 1997	(P) 1998	(P) 1999	(P) 2000	(P) 2001	(P) 2002	(P) 2003	(P) 2004	(P) 2005	(P) 2006	(P) 2007	(P) 2008	(P) 2009	(P) 2010	(P) 2011	(P) 2012	(P) 2013	(P) 2014	(P) 2015	(P) 2016
CHESWICK																									
	GEN. CAP	1,392	2,218	3,024	2,211	5,586	12,711	3,623	3,693	3,898	3,913	3,924	11,448	3,948	3,959	3,975	3,991	4,008	10,437	3,023	2,021	1,013	610		
	CAAA	360	1,131	1,932	1,141	0	4,748	0	0	0	0	12,675	24,585	0	0	0	0	0	0	0	0	0	0		
	RSW	2,173	763	1,586	1,507	2,090	5,421	1,153	6,894	53	52	50	49	56	54	53	51	57	56	54	53	58	56		
	TOTAL	3,926	4,110	6,542	4,859	7,676	22,880	4,675	10,777	3,951	3,965	16,649	36,080	4,004	4,014	4,028	4,043	4,063	10,493	3,077	2,074	1,071	666		
ELRAMA																									
	GEN. CAP	9,047	5,016	8,807	6,957	9,910	3,287	1,710	3,579	2,695	1,804	904	544												
	CAAA	6,111	3,730	2,273	4,036	1,331	5,335	883	0	0	0	0	0												
	RSW	912	549	11	491	1,470	1,705	84	3,850	1,996	232	50	0												
	TOTAL	16,070	9,295	9,091	11,486	12,711	10,328	2,677	7,430	4,690	2,036	954	544												
BRUNOT IS																									
	GEN. CAP	36	42	3	27	867	1,405	4,508	91	91	90	91	91	91	91	90	90	74	75	75	75				
	CAAA	0	0	0	0	0	0	0	0	0	0	0	3,427	0	0	0	0	0	0	0	0				
	RSW	0	0	0	0	449	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				
	TOTAL	36	42	3	27	1,316	1,405	4,508	91	91	90	91	3,518	91	91	90	90	74	75	75	75				
PHILLIPS																									
	GEN. CAP	0	0	0	0	0	200																		
	CAAA	0	0	0	0	0	0																		
	RSW	487	159	9	218	392	715																		
	TOTAL	487	159	9	218	392	915																		
EASTLAKE																									
	GEN. CAP	683	953	32	556	641	1,727	1,236	306	198	670	1,053	2,476	2,756	1,747	397	566	547	631	422					
	CAAA	92	98	2	64	1,208	35	203	91	4,450	4,389	251	0	0	0	0	0	0	0	0					
	RSW	205	39	73	106	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0					
	TOTAL	981	1,089	107	726	1,849	1,763	1,439	397	4,648	5,059	1,304	2,476	2,756	1,747	397	566	547	631	422					
SAMMIS																									
	GEN. CAP	1,657	1,708	819	1,394	1,832	201	845	50	1,210	746	937	237	1,018	50	3,015	236	1,011	235						
	CAAA	203	47	62	104	37	36	180	0	1,835	86	84	0	0	0	0	0	0	0						
	RSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0						
	TOTAL	1,860	1,753	881	1,498	1,869	237	1,025	50	3,045	832	1,021	237	1,018	50	3,015	236	1,011	235						
MANSFIELD																									
	GEN. CAP	9,824	7,937	35	5,932	1,530	3,880	1,575	2,626	689	1,436	2,411	867	1,427	2,397	862	1,422	2,391	859	1,415	2,021	854	1,408	437	824
	CAAA	4,036	1,168	697	1,967	73	0	0	662	177	301	0	2,366	0	0	0	0	0	0	0	0	0	0	0	0
	RSW	378	103	191	224	534	0	0	0	0	0	0	0	0	0	0	0	0	0	0	53	0	0	0	0
	TOTAL	14,238	9,208	923	8,123	0	0	1,575	3,289	865	1,737	2,411	3,233	1,427	2,397	0	1,753	1,980	3,347	2,180	4,956	0	2,380	0	449
TOTAL																									
	GEN. CAP	22,639	17,870	10,720	17,076	20,366	23,411	13,397	10,535	8,778	8,659	9,319	15,661	9,238	8,243	8,339	6,308	8,030	12,238	4,934	4,116	1,867	2,018	437	824
	CAAA	10,803	6,174	4,966	7,314	2,649	10,155	1,266	753	6,462	4,776	13,010	30,378	0	0	0	0	0	0	0	0	0	0	0	0
	RSW	4,156	1,613	1,870	2,546	4,935	7,841	1,236	10,745	2,049	284	101	49	56	54	53	51	57	56	54	105	58	56	0	0
	TOTAL	37,597	25,657	17,556	26,937	27,950	41,407	15,899	22,033	17,288	13,719	22,430	46,088	9,293	8,297	8,392	6,357	8,088	12,293	4,988	4,222	1,925	2,074	437	824

Revised Duckworth Exhibits

O and M 1

Exhibit RED-1

Duquesne Light Company
Nuclear Non-Fuel O&M Costs
(millions of dollars)

Year		Beaver Valley Unit 1	Beaver Valley Unit 2	Total Beaver Valley	Perry Nuclear Power Plant	Total All Units
1992	(A)	$77.9	$86.0	$163.9	$113.2	$277.1
1993	(A)	$89.2	$82.9	$172.1	$170.1	$342.2
1994	(A)	$78.7	$64.7	$143.4	$170.2	$313.6
1995	(A)	$81.3	$68.3	$149.6	$168.1	$317.7
1996	(A)	$75.7	$72.5	$148.2	$134.2	$282.4
3 year avg	(A)	$78.6	$68.5	$147.1	$157.5	$304.6
3 Year Average - 2 Unit Westinghouse PWR Sites (a)				$150.4		
1997	(P)	$74.5	$75.1	$149.6	$116.0	$265.6
1998	(P)	$83.5	$82.0	$165.5	$116.8	$282.3
1999	(P)	$75.1	$68.8	$143.9	$109.7	$253.6
2000	(P)	$62.1	$55.0	$117.1	$101.0	$218.1
2001	(P)	$60.6	$56.4	$117.0	$108.3	$225.3
2002	(P)	$62.5	$57.7	$120.2	$108.0	$228.2
2003	(P)	$64.0	$59.1	$123.1	$110.9	$234.0
2004	(P)	$65.6	$61.0	$126.6	$113.9	$240.5
2005	(P)	$67.7	$62.5	$130.2	$117.0	$247.2
2006	(P)	$69.4	$64.0	$133.4	$120.2	$253.6
2007	(P)	$71.0	$66.0	$137.0	$123.3	$260.3
2008	(P)	$73.2	$67.6	$140.8	$126.5	$267.3
2009	(P)	$74.9	$69.2	$144.1	$129.8	$273.9
2010	(P)	$76.7	$71.3	$148.0	$133.3	$281.3
2011	(P)	$79.2	$73.1	$152.3	$136.9	$289.2
2012	(P)	$81.2	$74.9	$156.1	$140.6	$296.7
2013	(P)	$83.1	$77.3	$160.4	$144.4	$304.8
2014	(P)	$85.8	$79.2	$165.0	$148.3	$313.3
2015	(P)	$78.4	$81.1	$159.5	$152.3	$311.8
2016	(P)	N/A	$83.7	$83.7	$156.4	$240.1

(A) - actual

(P) - projected

(a) - source: RDI

O and M 2

Exhibit RED-2

Duquesne Light Company
Nuclear Non-Fuel O&M Costs
(millions of constant dollars)

Year		Beaver Valley Unit 1	Beaver Valley Unit 2	Total Beaver Valley	Perry Nuclear Power Plant	Total All Units
1992	(A)	$85.6	$94.5	$180.1	$124.4	$304.5
1993	(A)	$95.5	$88.8	$184.3	$182.2	$366.5
1994	(A)	$82.5	$67.8	$150.2	$178.3	$328.5
1995	(A)	$83.0	$69.8	$152.8	$171.7	$324.5
1996	(A)	$75.7	$72.5	$148.2	$134.2	$282.4
3 year avg	(A)	$80.4	$70.0	$150.4	$161.4	$311.8
3 Year Average - 2 Unit Westinghouse PWR Sites (a)				$157.4		
1997	(P)	$72.8	$73.3	$146.1	$113.3	$259.4
1998	(P)	$79.6	$78.1	$157.7	$111.3	$269.0
1999	(P)	$69.8	$64.0	$133.8	$102.0	$235.7
2000	(P)	$56.3	$49.9	$106.2	$91.6	$197.8
2001	(P)	$53.6	$49.8	$103.4	$95.7	$199.1
2002	(P)	$51.1	$51.0	$102.1	$95.5	$197.6
2003	(P)	$51.1	$51.0	$102.1	$95.5	$197.6
2004	(P)	$51.1	$51.0	$102.1	$95.5	$197.6
2005	(P)	$51.1	$51.0	$102.1	$95.5	$197.6
2006	(P)	$51.1	$51.0	$102.1	$95.5	$197.6
2007	(P)	$51.1	$51.0	$102.1	$95.5	$197.6
2008	(P)	$51.1	$51.0	$102.1	$95.5	$197.6
2009	(P)	$51.1	$51.0	$102.1	$95.5	$197.6
2010	(P)	$51.1	$51.0	$102.1	$95.5	$197.6
2011	(P)	$51.1	$51.0	$102.1	$95.5	$197.6
2012	(P)	$51.1	$51.0	$102.1	$95.5	$197.6
2013	(P)	$51.1	$51.0	$102.1	$95.5	$197.6
2014	(P)	$51.1	$51.0	$102.1	$95.5	$197.6
2015	(P)	$51.1	$51.0	$102.1	$95.5	$197.6
2016	(P)	N/A	$51.0	$51.0	$95.5	$146.5

(A) - actual

(P) - projected

Index: 1996 = 100.0

(a) - source: RDI

Capital 1

Exhibit RED-3

Duquesne Light Company
Nuclear Capital Costs
(millions of dollars)

Year		Beaver Valley Unit 1	Beaver Valley Unit 2	Total Beaver Valley	Perry Nuclear Power Plant	Total All Units
1992	(A)	$18.9	$18.9	$37.8	$35.9	$73.7
1993	(A)	$19.5	$6.0	$25.5	$41.0	$66.5
1994	(A)	$8.6	$1.9	$10.5	$41.2	$51.7
1995	(A)	$11.1	$4.2	$15.3	$24.4	$39.7
1996	(A)	$9.4	$6.9	$16.3	$30.1	$46.4
3 year avg	(A)	$9.7	$4.3	$14.0	$31.9	$45.9
1996 Average - 2 Unit Westinghouse PWR Sites (a)				$30.7		
1996 Average - 1 Unit BWR Sites (a)					$21.4	
1997	(P)	$14.4	$10.7	$25.1	$35.3	$60.4
1998	(P)	$13.4	$14.2	$27.6	$17.5	$45.1
1999	(P)	$10.9	$13.6	$24.5	$25.5	$50.0
2000	(P)	$10.0	$10.0	$20.0	$8.2	$28.2
2001	(P)	$10.3	$10.3	$20.6	$12.6	$33.2
2002	(P)	$10.5	$10.5	$21.0	$11.6	$32.6
2003	(P)	$10.8	$10.8	$21.6	$13.3	$34.9
2004	(P)	$11.1	$11.1	$22.2	$12.2	$34.4
2005	(P)	$11.4	$11.4	$22.8	$14.0	$36.8
2006	(P)	$11.7	$11.7	$23.4	$12.8	$36.2
2007	(P)	$12.0	$12.0	$24.0	$14.8	$38.8
2008	(P)	$12.3	$12.3	$24.6	$13.5	$38.1
2009	(P)	$12.6	$12.6	$25.2	$15.5	$40.7
2010	(P)	$13.0	$13.0	$26.0	$14.3	$40.3
2011	(P)	$13.3	$13.3	$26.6	$16.4	$43.0
2012	(P)	$13.7	$13.7	$27.4	$15.0	$42.4
2013	(P)	$14.1	$14.1	$28.2	$17.3	$45.5
2014	(P)	$14.4	$14.4	$28.8	$15.9	$44.7
2015	(P)	$14.8	$14.8	$29.6	$18.2	$47.8
2016	(P)	N/A	$15.2	$15.2	$16.7	$31.9

(A) - actual

(P) - projected

(a) - Source: Electric Utility Cost Comparison Group

Capital 2

Exhibit RED-4

Duquesne Light Company
Nuclear Capital Costs
(millions of constant dollars)

Year		Beaver Valley Unit 1	Beaver Valley Unit 2	Total Beaver Valley	Perry Nuclear Power Plant	Total All Units
1992	(A)	$20.8	$20.8	$41.5	$39.5	$81.0
1993	(A)	$20.9	$6.4	$27.3	$43.9	$71.2
1994	(A)	$9.0	$2.0	$11.0	$43.2	$54.2
1995	(A)	$11.3	$4.3	$15.6	$24.9	$40.5
1996	(A)	$9.4	$6.9	$16.3	$30.1	$46.4
3 year avg	(A)	$9.9	$4.4	$14.3	$32.7	$47.0
1996 Average - 2 Unit Westinghouse PWR Sites (a)				$30.7		
1996 Average - 1 Unit BWR Sites (a)					$21.4	
1997	(P)	$14.1	$10.4	$24.5	$34.5	$59.0
1998	(P)	$12.8	$13.5	$26.3	$16.7	$43.0
1999	(P)	$10.1	$12.6	$22.8	$23.7	$46.5
2000	(P)	$9.1	$9.1	$18.1	$7.4	$25.6
2001	(P)	$9.1	$9.1	$18.2	$11.1	$29.3
2002	(P)	$9.1	$9.1	$18.2	$10.3	$28.5
2003	(P)	$9.1	$9.1	$18.2	$11.1	$29.3
2004	(P)	$9.1	$9.1	$18.2	$10.3	$28.5
2005	(P)	$9.1	$9.1	$18.2	$11.1	$29.3
2006	(P)	$9.1	$9.1	$18.2	$10.3	$28.5
2007	(P)	$9.1	$9.1	$18.2	$11.1	$29.3
2008	(P)	$9.1	$9.1	$18.2	$10.3	$28.5
2009	(P)	$9.1	$9.1	$18.2	$11.1	$29.3
2010	(P)	$9.1	$9.1	$18.2	$10.3	$28.5
2011	(P)	$9.1	$9.1	$18.2	$11.1	$29.3
2012	(P)	$9.1	$9.1	$18.2	$10.3	$28.5
2013	(P)	$9.1	$9.1	$18.2	$11.1	$29.3
2014	(P)	$9.1	$9.1	$18.2	$10.3	$28.5
2015	(P)	$9.1	$9.1	$18.2	$11.1	$29.3
2016	(P)	N/A	$9.1	$9.1	$10.3	$19.4

(A) - actual

(P) - projected

(a) - Source: Electric Utility Cost Comparison Group

Index: 1996 = 100.0

Capacity Factors

Exhibit RED-5

Duquesne Light Company
Nuclear Capacity Factors

Year		Beaver Valley Unit 1	Beaver Valley Unit 2	Perry Nuclear Power Plant
1992	(A)	88.5%	78.4%	69.0%
1993	(A)	61.4%	72.4%	38.7%
1994	(A)	77.6%	97.8%	44.4%
1995	(A)	76.7%	84.1%	87.8%
1996	(A)	80.0%	66.2%	72.0%
3 year avg	(A)	78.1%	82.7%	68.1%
1997	(P)	84.7%	97.0%	81.5%
1998	(P)	95.4%	86.4%	95.2%
1999	(P)	78.1%	86.4%	84.5%
2000	(P)	82.4%	97.0%	95.3%
2001	(P)	97.0%	86.4%	84.4%
2002	(P)	82.4%	86.4%	95.6%
2003	(P)	82.4%	97.0%	84.4%
2004	(P)	97.0%	86.4%	95.3%
2005	(P)	82.4%	86.4%	84.4%
2006	(P)	82.4%	97.0%	95.6%
2007	(P)	97.0%	86.4%	84.4%
2008	(P)	82.4%	86.4%	95.3%
2009	(P)	82.4%	97.0%	84.4%
2010	(P)	97.0%	86.4%	95.6%
2011	(P)	82.4%	86.4%	84.4%
2012	(P)	82.4%	97.0%	95.3%
2013	(P)	97.0%	86.4%	84.4%
2014	(P)	82.4%	86.4%	95.6%
2015	(P)	81.1%	97.0%	84.4%
2016	(P)	N/A	86.4%	95.3%

(A) - actual

(P) - projected

Revisions to Schnitzer

Revision to Schnitzer Delayed Entry Calculation to Reflect Revised Exhibit DJC-3

Mr. Schnitzer's testimony (pp. 25-30) addresses the effective "ceiling" on market prices for electricity following the transition period. The range of ceiling market prices is based on the cost of entry for new construction in 2006 and beyond. Mr. Schnitzer estimates a "high" ceiling price of $44/MWH and a "low" ceiling price of $34/MWh in 2006, based on 2006 as the year of entry for new construction assuming such new construction is then economic. The assumptions and data underlying the estimates are set out in Exhibits MMS-2, MMS-3 and MMS-4.

At pp. 30-35 of his testimony, Mr. Schnitzer discusses the market evidence from the 1997 Duquesne solicitation and other reasons why new capacity might not be economic in 2006. He concludes at p. 35 "Therefore, it is highly unlikely that new combined cycle capacity would be economic to build in 2006 based on the results of the 1997 Solicitation, particularly if required new entry prices are at the high end of the range."

To account for the likelihood of new entry being delayed beyond 2006, Mr. Schnitzer prepared two additional "delayed entry" ceiling market price cases summarized at pp. 35-36 and in Exhibit MMS-5 of his testimony. The two cases assume that the year of entry is delayed to 2010 and assumed a significant real escalation in market prices over five years to permit new construction to be economic in 2010 under the "high" and "low" cost cases for competitive capital structures. Exhibit MMS-5 assumes that market prices trend upward from the 2005 spot price (as calculated from the 1997 Duquesne solicitation in Exhibit MMS-4) at escalation rates of 12.8% and 9.0% respectively. The two new cases produce levelized prices in 2006 of $41/MWh and $35/MWh respectively. Using the delayed entry price trajectory that ramps from the 2005 spot price to the high price in 2010 would yield a 2005 market value of only $278 million as compared to the $527 million projected by Mr. Clayton under the high ceiling price (see Schnitzer, p. 36, lines 11-14).

Mr. Clayton's revised Exhibit DJC-3 updates the net book value and market values for Duquesne's generation at December 31, 2005. The revised estimate for the market value under the high case of $44/MWh in 2006 is $766 million. Using Mr. Schnitzer's delayed entry price trajectory that ramps from the 2005 spot price to the high price in 2010 would yield a 2005 market value of only $496 million. This value is still below the projected $533 million net book value in the Revised Exhibit DJC-3. The changes are summarized in the table below and shown on the attached workpapers.[1]

$ Million at 12/31/2005	Original Estimates (8/1/97)	Revised Estimates (10/15/97)
Book Value	$535	$533
Market Value – High Case	$527	$766
Stranded Cost – High Case	$8	($233)
Market Value – Delayed Entry Case	$278	$496
Stranded Cost – Delayed Entry Case	$257	$37

[1] For the Delayed Entry Cases, Mr. Clayton's margin analysis was recalculated using a 2005 spot price of $27/MWh escalated at 12.8% annually for 5 years, followed by the High Case price trajectory used by Mr. Clayton in the years 2011 and beyond. The year-by-year price trajectory for the Delayed Entry Cases is shown on the attached workpapers. Please note that the workpapers for the Original Estimate of the Delayed Entry Case show a value of $276.4 million that was rounded up to $278 million in Mr. Schnitzer's pre-filed testimony.

Adjustments to Ohio Edison Data

Items from Ohio Edison that were not used

Item	Reason
1) Perry fuel costs	Ohio Edison / Penn Power used an average fuel cost based on nuclear plants in the region. Duquesne did not find to be appropriate since the company has fuel arrangements that are unique. Hence, Duquesne used its internal forecast of nuclear fuel cost.
2) Perry outage costs	Ohio Edison / Penn power did not provide a break-out of their their outage related O&M costs. Hence, Duquesne used a prior estimate of those costs, and deducted this amount from the total provided by Ohio Edison / Penn Power. Ohio Edison / Penn Power has since provided an estimate of outage costs which is not substantially different from Duqense's estimates and does not affect stranded costs.
3) Fossil Clean Air O&M	Ohio Edison / Penn Power has made different assumptions regarding how Clean Air Act costs are characterized and the levels to which emissions are restricted. Duquesne's assumptions for Sammis and Mansfield are consistent with the environmental assumptions used for the other plants in its system.
4) Fossil capital	The OE/PP estimates for capital related to Clean Air compliance were not used for reasons similar to 3), above.
5) Energy Output	Ohio Edison used different assumptions for the market price of power which implied that it was economic to run a plant for a differing number of hours per year. Duquesne dispatched all of its plants against estimated market prices based on its recent solicitation through 2005. Duquesne's plants were dispatched up to their equivalent availabilities after 2005.

Item No.: HSS-1-043
Witness: O'Brien
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DUQUESNE LIGHT COMPANY

First Set of Interrogatories of Hospital Shared Services and Administrative Resources, Inc.

43. For each item claimed as a regulatory asset, please provide the Commission order that authorized, or you rely upon, for such treatment.

Response:

They are as follows:

	PUC Order
Regulatory Tax Receivable	R-860378
Unamortized Premium on Reacquired Debt	R-870651
Unamortized Debt Expense	R-870651
Beaver Valley No. 2 Premium on Reacquired Debt	R-870651
Deferred Rate Synchronization Costs	R-870222
Injuries and Damages	R-870651
Compensated Absences	R-87-0651
Def'd Nuclear Maintenance Outage Costs	R-870651
DOE Decontamination and Decommissioning	RM93-18-000
Deferred Coal Costs	P-890386-387
Deferred Caretaker Expenses	P-900485
BV2 Training Costs	R-870651
Cold Reserved Units	R-860378
Warwick Mine Investment	R-870651
Low Level Radiation Waste	R-870651

*FERC Order

Item No.: HSS-1-043 (Supp.)
Witness: O'Brien
Page 1 of 1

DUQUESNE LIGHT COMPANY

First Set of Interrogatories of Hospital Shared Services and Administrative Resources, Inc.

43. For each item claimed as a regulatory asset, please provide the Commission order that authorized, or you rely upon, for such treatment.

Response:

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BV2 Training Costs	R-870651
Cold Reserved Units	R-860378
Warwick Mine Investment	R-870651
Low Level Radiation Waste	R-870651

*FERC Order

Item No.: HSS-1-092
Witness: O'Brien
Page 1 of 1

DUQUESNE LIGHT COMPANY

First Set of Interrogatories of Hospital Shared Services and Administrative Resources, Inc.

92. For each generation-related capital expenditure following the date of the Case No. R-870651 test period, please identify and provide each order of the PUC authorizing the expenditure and determining that it should be included in rate base. Please provide an index identifying the expenditure with the relevant order.

Response:

The question incorrectly assumes that in Pennsylvania an electric utility is required to obtain "authorization" from the PUC to make any capital expenditure. I note, however, that the PaPUC Bureau of Audits performed a review of Duquesne's plant assets in conjunction with its review of potential stranded costs (Report issued August 1997). As part of that review, testing of the continuing property records of Duquesne was performed to ensure that costs were accurately and properly recorded on the company's books. The testing process concentrated on generation assets and was supplemented by visits to selected plant sites to physically inspect facilities.

Item No.: HSS-2-023
Witness: O'Brien
Page 1 of 1

DUQUESNE LIGHT COMPANY

Second Set of Interrogatories of Hospital Shared Services and Administrative Resources, Inc.

23. Please provide a copy of the Pa PUC Bureau of Audits Report referenced in Duquesne's response to Interrogatory No. HSS-1-092.

Response:

The requested document is attached.

Item No.: ENV-3-148
Witness: Clayton
Page 1 of 1

DUQUESNE LIGHT COMPANY

Environmentalists' Interrogatories Set III

148. Mr. Clayton's Exhibit DJC-3 appears to show a net rate base as of 1999 of $1,227.7 million for generation and $295.7 million for generation related regulatory assets, for a total of $1,525.4 million. Please explain how, after taking off $1,700 million for depreciation and amortization (Clayton, page 29), Duquesne still has a net book value of $535 million. Provide the supporting documents in the Company's possession or control.

Response:

The comparison made neglects the tax effect on the committed level of amortization and its effect on rate base. the calculations below reconcile the rate base at December 31, 1999 with the book value at December 31, 2005 and the committed level of amortization.

Beginning Rate Base 12/31/99	$1,523.4 Million
Committed Depreciation and Amortization	1,747.3 Million
Tax Effect (41,4935%)	725.0 Million
Net Rate Base Reduction	1,022.3 Million
Net Additions ('00 to '05)	35.9 Million
Rate Base at 12/31/05	$ 537.0 Million
Less: Working Capital	48.5 Million
Accumulated ITC	23.3 Million
Plus: Present Value of BV-2 Lease	70.2 Million
Book Value at 12/31/05	$535.4 Million

Exhibit DJC-24

Duquesne Light Company

ECR Roll-in
(Mills/kWh)

Item	1995 Data	1996 Data	Forecast 1997 Data	Forecast 1998 Data	Forecast Average 1999 to 2005
Fuel Cost in Base Rates	16.450	16.450	16.450	16.450	16.450
Correction for Overcollections	(0.890)	(0.448)	-	-	
Adjustment to Fuel Costs	(2.738)	(1.921)	(1.800)	(1.349)	(1.534)
Total ECR Adjustment	(3.628)	(2.369)			
Total Fuel Cost (w/ Correction Factor)	12.822	14.081			
ECR Roll-in Amount (w/o Correction Factor)	13.712	14.529	14.650	15.101	14.916

THE PENNSYLVANIA UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION,	:	
v.	:	Docket No. R-00974104
DUQUESNE LIGHT COMPANY Application to approve restructuring plan pursuant to 66 Pa. C.S. Section 2806(d).	:	

Washington, D.C.

Wednesday, November 19, 1997

Deposition of

ROBERT B. WEISENMILLER, PH.D.

a witness, called for examination by counsel for Duquesne, pursuant to notice and agreement of counsel, beginning at approximately 11:25 a.m., at the Law Firm of Skadden, Arps, Slate, Meagher & Flom, L.L.P., 1440 New York Avenue, Northwest, Washington, D.C., before Shari R. Broussard, notary public in and for the District of Columbia, when were present on behalf of the respective parties:

Q Would an auction of one fossil asset provide an accurate valuation of the remaining fossil assets?

A Depending upon how representative that one asset was, it might at least give you a data point, but it would not be as indicative as an auction of all of those assets.

Q Have you undertaken any analysis of whether, under Mr. Schnitzer's high line, whether the company not only has no stranded cost in 2005 but has no stranded cost in 1999?

A No, I did not look at that.

Duquesne Statement No. 3-R

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DUQUESNE LIGHT COMPANY
DOCKET NO. R-00974104

Rebuttal Testimony
of
Michael M. Schnitzer

Contents:

I. Introduction and Summary

Q. Please state your name.

A. My name is Michael M. Schnitzer

Q. Are you the same Michael Schnitzer who filed direct testimony in this docket on August 1, 1997?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. A number of parties have filed responsive testimony criticizing the Company's proposal for stranded cost quantification, its proposal for stranded cost recovery, as well as the proposed annual CGC determination. The purpose of my rebuttal testimony is fourfold. First, I will describe and catalogue on as consistent a basis as possible the stranded cost position of the Company and certain major parties to illustrate the major sources of difference and contention. Second, I will respond to four of the major stranded cost quantification criticisms put forward by the parties:

- The Company's proposal is deficient in that it does not include a "one-time" quantification of stranded costs as of January 1, 1999;
- The Company's claimed range of stranded generation costs is excessive;
- The Company's proposal will result in over-recovery of stranded costs, unduly burdening customers; and
- The Company's proposal does not include adequate sharing of stranded costs between shareholders and customers.

Third, I will respond to criticisms of the Company's stranded cost recovery proposal, particularly the contention that the Company is not entitled to a price cap under Section 2804(4)(v) of the restructuring statute.

The fourth and final purpose of my testimony is to respond to the criticism that the Company's procedure for determining the CGC on an annual basis using a market auction is flawed.

Q. Could you please summarize your major conclusions?

A. Yes. There are four, one corresponding to each of the purposes of my testimony.

Conclusion 1: Intervenor's Stranded Costs Estimates and Disallowance Proposals

Q. What is your conclusion with respect to the relative stranded cost positions of the Company and the parties?

A. While the Company believes that generation stranded costs should be determined through market mechanisms rather than by debating experts, its best estimate today of stranded costs is $1,916 million as of January 1, 1999, including $374 million in regulatory assets. As shown in the table below, other parties' stranded cost figures are from $139 to $658 million lower than the Company's figure -- $461 million lower in the case of the Industrials, $658 million lower for the OCA, and at least $139 million lower for the OTS (staff has endorsed the Company's proposed future market valuation of generation assets, but has excluded Phillips and Brunot Island from stranded cost recovery and has proposed a lower level of decommissioning stranded costs).

	Duquesne	OCA	OTS	Industrials
Stranded Costs	$1,916 million	$1,258 million	N/A	$1,455 million
Difference from Duquesne	--	$658 million	At least $139 million	$461 million

The largest source of the significant difference between the Company and the Industrials and the OCA is divergent views on generation value and hence on generation stranded costs. There is also a sizable difference between the Company and the Industrials concerning the amount of stranded regulatory assets. In addition to these significant differences concerning the magnitude of stranded costs, there is a further significant difference between the Company and both the OCA and Industrials concerning the amount of stranded costs properly recoverable from customers. The Company proposes that it have an opportunity, but not a guarantee of fully recovering its stranded costs. The OCA and the Industrials propose "sharing" -- the disallowance of prudently incurred costs -- of $232 million and $460 million, respectively. In fact, shareholder losses would be much greater under both OCA's and DII's rate proposals due to tax-related revenue requirements errors in each of their analyses, as further discussed by Mr. Clayton.

Conclusion 2: Four Criticisms of Company's Proposal

Q. What is your conclusion with respect to the four criticisms of the Company's stranded cost quantification proposal you described above?

A. My overall conclusion is that none of these four types of criticism are valid. Thus, as modified, the Company's proposal to value generation through divestiture, at the Commission's direction, should be approved. Specifically:

- The Company's reliance on a future market-based stranded cost evaluation – rather than an administrative determination today – is a strength, not a weakness, as recognized by the Office of Trial Staff. Almost all parties agree that any administratively determined long term market price forecast is nearly certain to be wrong, and thus the one time administrative approach requires both customers and shareholders to make a risky and unnecessary "bet". If the forecast turns out to be too low, customers are harmed; if the forecast is too high, shareholders are harmed. The difference of opinion over market prices and generation value among witnesses in this proceeding serves only to underscore the futility of making a one-time determination of known and measurable stranded costs using administrative techniques. The Company's market based proposal for stranded cost determination, modified to include full divestiture at the Commission's direction, is superior to one-time administrative approaches and should be adopted. However, should the Commission reject this proposal in favor of a one time administrative determination, the Company has put forward adequate evidence to support a stranded cost determination of $1,916 million as of 1 January 1999.
- The claims that the Company has overestimated the likely range of generation stranded costs are not valid. The OCA has overestimated generation market value – and hence underestimated generation stranded costs – by relying on a flawed

analysis of unit shutdown savings and on a speculative assessment of life extension benefits 30 plus years into the future. DII has overestimated generation market value by relying on an inflated forecast of near term capacity prices; a forecast that is at odds both with available market evidence and the OCA's near term price forecast. While Duquesne's projections are reasonable and supportable, this whole debate between dueling experts would be mooted by approval of the Company's market valuation proposal which includes, at the Commission's option, full divestiture.

- Duquesne's proposal will not result in over-recovery of its stranded costs due to the market valuation in 2003 (or earlier) and the ROE spillover provision in the interim. While the market valuation is conveniently ignored by many who accuse the Company of over recovery, this provision does protect customers by ensuring that Duquesne cannot over recover, and thus that customers will not have to "pay twice". As mentioned above, the Company has modified its market valuation proposal and is willing, at the Commission's direction, to auction its generating plants to establish their value. In view of the fact that all parties agree that valuation through divestiture is superior to administrative valuation, the Company cannot legitimately be accused of attempting to over recover -- in fact, it is the one time administrative approach proposed by OCA and the Industrials that creates an over recovery risk.
- The OCA, Industrial, and Environmentalist proposals to disallow recovery of stranded costs are arbitrary and unjustified. They represent the denial of a reasonable opportunity to earn a fair return on prudently incurred, fully mitigated

costs and thus impose asymmetric risks on shareholders for which they have not previously been compensated. These proposals would also have a significant adverse impact on Duquesne's financial performance. Approving such an uncompensated wealth transfer with resulting financial impairment would violate the public policy standards articulated in the Pennsylvania restructuring statute and Duquesne v. Barasch and would be poor public policy. These sharing proposals should be denied. The Company's proposal to recover all of its stranded costs from customers in a competitively neutral, economically efficient manner should be approved.

Conclusion 3: Section 2804(4)(v) Showing by Company

Q. What is your conclusion with respect to the Company's stranded cost recovery proposal?

A. Contrary to the contention of the OCA and HSS, the Company is entitled to a rate cap under Section 2804(4)(v). The Company's analysis demonstrates that it has substantial stranded costs, and this conclusion is corroborated by the OCA and the Industrials -- both estimate stranded costs (before sharing) in excess of $1.2 billion. The possibility of "negative" stranded costs" in 2005 (in the Company's High ceiling price case only) does not disqualify Duquesne from reliance on Section 2804(4)(v); it only raises the issue of the necessary duration of the rate cap. Even under the Company's High ceiling price case, the Company is entitled to the rate cap through the end of 2003 and partway through 2004. Accepting, for arguments sake, all of OCA's assumptions except for its sharing proposal, the Company is entitled to the rate cap through the end of 2003 and partway into 2004, and under the Industrials'

assumptions (except for sharing), the Company is entitled to the rate cap through 2005. Thus, while the Company does not agree that the OCA and Industrial analyses are correct, their testimony does corroborate the Company's position on the likely duration of the rate cap and the proper timing of the market valuation. The proposed market valuation in 2003, together with the trigger provisions for accelerating the market valuation, ensure that the rate cap will be of appropriate duration. The Company's stranded cost recovery proposal should be approved.

Conclusion 4: CGC Determination Through an Annual Auction

Q. What is your conclusion concerning the Company's proposed annual CGC determination?

A. The Company's proposal to determine the CGC on an annual basis is not flawed. In fact, it is necessary to provide an opportunity for fair competition as well as to provide the Company with a reasonable opportunity for stranded cost recovery. This is true because of the statutory provision which gives customers a valuable option – the right, but not the obligation to take service at the rate cap level during the pendency of the transition period, and to return to service at the rate cap level after they have switched to another supplier. The existence of this option requires that the CGC be set on an annual basis using current market prices, otherwise customers will be held hostage to rate cap service if the CGC is too low, and will avoid stranded cost responsibility if the CGC is too high. None of the criticisms of the Company's proposal acknowledge this essential linkage between the rate cap option and the CGC determination.

The criticisms of the Company's proposal to determine the annual CGC by using an RFP are also unfounded. The RFP does not understate the value of power, and any additional credits for retail marketing expense would distort competition and jeopardize stranded cost recovery.

II. Summary of Stranded Cost Positions

Q. Please summarize the major differences between Duquesne and the opposing parties on the magnitude of recoverable stranded costs.

A. Let me answer that in two pieces, starting with differences in the magnitude of stranded costs, and then addressing the different positions on the recoverability of those costs from customers.

Q. How significant are the differences between Duquesne and the opposing parties with respect to the magnitude of stranded costs?

A. There are significant differences as shown in the table below. The largest difference between Duquesne and opposing parties presenting comprehensive stranded cost proposals[1] is in the area of owned-generation stranded costs.

[1] Pennsylvania Office of Consumer Advocate, Office of Trial Staff and Duquesne Industrial Intervenors.

	Duquesne	OCA	OTS	Industrials
Regulatory Assets	$374 million	$331 million	$371 million	$283 million
Owned-Generation Stranded Costs	$1,542 million	$927 million	N/A[2]	$1,172 million
TOTAL	$1,916 million	$1,258 million	N/A	$1,455 million

Regulatory Assets

Q. What are the sources of the above differences in quantified stranded costs as of December 31, 1998 that result from regulatory assets?

A. Duquesne's claim for regulatory assets has largely been accepted by the main intervenors. As detailed in Mr. Clayton's rebuttal testimony and Exhibit DJC-10, once the accounting for taxes and the Beaver Valley II lease are presented on a consistent basis, the OTS is proposing only a minor adjustment of $4 million to the Company claim. The OCA proposes a reduction of $44 million resulting from deferred coal and caretaker costs, and pre-accrued nuclear outage costs. The Duquesne Industrial Intervenors ("DII") are proposing additional adjustments to unamortized debt costs, deferred employee costs and transition costs. These result in total proposed reductions to regulatory assets in the amount of $92 million.

Owned-Generation Stranded Costs

Q. What differences exist with regard to owned-generation stranded costs?

[2] The Office of Trial Staff has not prepared a separate analysis of Duquesne's owned-generation stranded costs. See the testimony of ITS witness Mtero 19:4-13.

A. There are four main elements of the stranded cost calculation for owned-generation reflected in the table below.

	Duquesne	OCA	OTS	Industrials
Net Book Value	$1,237 million	$1,275 million	$1,139 million	$1,257 million
PV of Decommissioning	$124 million	$44 million	$45 million	$43 million
PV of Costs Independent of Operation	$208 million	0	N/A	0
(less) Market Value	($27 million)	($392 million)	N/A	($128 million)
Stranded Plant	$1,542 million	$927 million	N/A	$1,172 million

The net book value of generating plant reflects the unrecovered sunk costs of Duquesne's generation at December 31, 1998. The present value of decommissioning expense reflects the projected future cost of retiring Duquesne's nuclear and fossil units. The costs independent of operation reflects costs at those units showing a negative margin under Mr. Clayton's NPV analysis that will be incurred whether or not that particular generating unit is operated. The estimated market value reflects the present value of the projected future worth of Duquesne's generation valued at market prices for capacity and energy.

Net Book Value

Q. What are the main differences regarding net book value between Duquesne and the intervenors?

A. As detailed in Mr. Clayton's rebuttal testimony and Exhibit DJC-10, Duquesne's net book value number includes the unrecovered cost of cold reserved units, certain M&S and fuel-related sunk costs, and the present value of the Beaver Valley II lease.

Q. How have the intervenor witnesses valued Duquesne's book value?

A. When restated on a consistent basis, the OCA and the DII have also included the unrecovered costs of Duquesne's cold reserved plants and the present value of the Beaver Value II lease in their estimates of total net book value. In addition, as detailed in Exhibit DJC-10, these parties have included a cost of $62 million for working capital. The OTS did not include the cold reserved plants or working capital in its net book value number.

Decommissioning Expense

Q. How have Duquesne and the intervenors dealt with decommissioning expense?

A. Duquesne has included as a future cost (or alternatively, as an offset to future market value) the cost of retiring Duquesne's nuclear and fossil plants of $124 million. The OCA, OTS and the DII have all included present value costs of $43-$45 million for nuclear decommissioning in their estimates.

Costs Independent of Operation

Q. What is the $208 million cost of generation independent of operation?

A. Duquesne's one-time January 1, 1999 administrative valuation shows that under the low market ceiling price scenario Perry, Elrama and Cheswick have negative operating margins and therefore no market value. However, there are operating costs that are unavoidable and will be incurred regardless of whether these units operate such as property taxes and allocated A&G. These costs have not been reflected in

Mr. Clayton's margin analysis which sets the market value of a plant to zero if the present value of the future margin stream is negative, and hence the market value of the Company's generation could be overstated. Mr. Clayton's rebuttal testimony sponsors a preliminary analysis of these units under the spot prices from the solicitation through 2005 and the Low ceiling market price forecast thereafter, and the avoidable operating costs associated with this plants. Based on this analysis, he concludes that Perry and Cheswick are economic to operate on a "to go " basis, and that Elrama is a potential shutdown candidate[3]. His analysis also shows that assumption of a zero value for plants with a negative margin fails to account for $208 million in costs which are not avoidable, and hence represent sunk costs. These unavoidable costs must be included as a stranded cost in the Company's January 1, 1999 valuation.

Market Value

Q. On the issue of market value, what differences exist between the parties?

[3] As detailed in Mr. Karl's rebuttal testimony, the Elrama facility has additional value as a transmission support facility when the Duquesne system is in a "first contingency" status. The cost of less expensive overall solutions to the combined Elrama/transmission constraints problem will require a more detailed analysis, including an option value analysis. Mr. Marshall's rebuttal testimony details the Company's commitment to undertake such a study in 1998 and submit it to the Commission for approval.

A. When adjusted for its treatment of the Beaver Valley II lease expense, the DII estimate of Duquesne's generation market value is $128 million[4]. The OCA estimate of $392 million reflects estimates of added value for temporary shutdowns, life extensions and productivity gains, as discussed in more detail below. As noted earlier, the OTS did not make an explicit calculation of the market value of Duquesne's generation at December 31, 1998, expressing instead a preference for the final 2003 valuation proposed by Duquesne[5]. Duquesne's market value estimate ranges from $27 million in the Low market ceiling case to $159 million in the Delayed entry case, to $278 million in the High market ceiling case. The specific causes of these significant differences in generation market value are discussed at length later in the testimony.

Recoverability

Q. Let's turn now to the second issue, the extent to which stranded costs, of whatever magnitude, are recoverable from customers. Please summarize the proposals of the intervenors regarding the "sharing" of stranded costs by Duquesne.

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[4] The filed DII testimony indicated a value of negative $17 million for Duquesne's generation, but includes the Beaver Valley II lease payments in the A & G expense. Removing these expenses from A&G and treating the lease on a consistent basis with the approach taken by Duquesne and OCA results in an increase in the market value of generation to positive $128 million.

[5] At p. 19 of his direct testimony, OTS witness Metro recommends – if the Commission determines the Duquesne approach is not permitted under the Act – that, as an alternative, Duquesne be permitted to file a CTC based on Duquesne's stranded costs as of January 1, 1999 using "stranded costs quantified but not claimed in the Company's filing."

A. Both the DII and the OCA advance different sharing proposals based on some level of disallowance of return on the owned-generation stranded costs. In the case of the Industrial Intervenors, witness Baron recommends that the Company be allowed no equity return on its own-generation stranded costs over the seven year amortization period. According to Mr. Baron, the economic effect of this proposal is equivalent to a $232 million stranded cost disallowance.

Q. How does the OCA proposal differ?

A. Mr. Kahal's sharing proposal is to allow customers to pay for amortization of owned-generation stranded costs over seven years with no return allowed for common equity, preferred or debt.

Q. What is the effect of OCA's "sharing" proposal?

A. Mr. Clayton details the impact of the OCA proposal in Exhibit DJC-12 to his rebuttal testimony. He has adopted the approach used by the DII witness to calculate the net present value difference between revenue requirements calculated using a full return and using the disallowance proposed by the OCA. The NPV impact of the OCA "sharing" proposal is $460 million. The effect of the "sharing" proposed by the Industrials and the OCA is to disallow a significant amount of prudent investment currently in rates.

III. Stranded Cost Quantification and Recovery Criticisms Are Invalid

Market Based Stranded Cost Valuation Preferred

Q. Let's start with the complaint that the Company's proposal is deficient because it does not include a "one time" administrative quantification of stranded costs as of January 1, 1999. Which parties raise this issue?

A. The witnesses for the OCA and the Industrials make this point.

Q. there an advantage to making a one time administrative stranded cost determination?

A. No. In fact there are significant disadvantages to a one time administrative determination in comparison to a market-based determination of stranded costs. The most significant problem is that an administrative determination is almost certain to be wrong, largely due to our inability to accurately forecast market prices in the manner proposed by the OCA and the Industrials. There is a long history of such "avoided cost" price forecasts in Pennsylvania and other parts of the country, and the experience is quite consistent: actual market prices turn out to be far different, and usually lower, than the administratively determined forecast (see Exhibit MMS-6 for descriptions of three case studies). In short, these forecasts have proven to be very inaccurate. For this reason, the Company prefers a market based stranded cost determination, and has proposed such an approach rather than a one time administrative determination.

Q. Do the other parties insist that an administrative determination is as good as or better than a market determination.

A. No, they do not. In fact, many parties agree that at least one type of market valuation -- divestiture -- is superior to a one time administrative valuation. Mr. Marshall's rebuttal testimony describes the positions of the intervenors with more specificity.

Q. Well, if the parties agree that some form of market valuation is preferable to a one time administrative determination, what is the problem? Why hasn't the Company's proposal for market valuation of stranded costs been endorsed by parties other than the OTS?

A. There are two reasons. First, some parties do not accept the appraisal process proposed by the Company to be an adequate market valuation. While the Company believes that the process it proposed, relying on market data rather than computer simulations, is a decided improvement over the administrative determination proposed by the OCA and the Industrials, it has modified its original proposal to utilize divestiture for valuation purposes rather than the market appraisal process, at the Commission's option. This modification leaves to the Commission the decision as to whether an auction of the Company's generation, or another market valuation technique should be utilized. This should satisfy the expressed concerns with the appraisal process.

Q. *You mentioned there were two reasons why certain parties have not endorsed the* Company's market valuation proposal. What is the second reason?

A. The second reason has to do with timing. The Industrials, in particular, argue that divestiture is preferred to administrative valuation only if it can be completed before the January 1, 1999 access date. If divestiture would not take place until after this

date, as in the Company's proposal, Industrials argue that administrative valuation would be preferred.

Q. Why do the Industrials take this position?

A. While they do not dispute that valuation through divestiture is superior to administrative valuation, they claim that the certainty of the stranded cost and CTC amounts prior to access is more important than the accuracy of the valuation.

Q. Do you agree?

A. No, I do not, for two reasons. First, even assuming for the moment that the certainty vs. accuracy tradeoff is real, the potential for error introduced by administrative valuation, and the attendant risk to both customers and shareholders is just too significant to overlook, or ignore. If the administrative valuation errs on the low side, customers are harmed because stranded costs are overstated. If the administrative valuation errs on the high side, shareholders are harmed because stranded costs are understated. And in both cases, the error can be significant. Simply stated, in the face of the horrible historical performance of administratively determined market prices, sacrificing the accuracy of market valuation to the expedient of CTC certainty is a poor trade.

The second and perhaps more important reason is that the choice framed by Mr. Baron between certainty and accuracy is itself flawed and illusory -- pre-1999 valuation, either through market or administrative mechanisms, will not result in CTC certainty. The reason for this is the customer option under the statute to take service at the rate cap level throughout the transition period. So long as customers have this option, their choice between rate cap service and service from another supplier will be

influenced by the relationship between the CGC and the market price. If the CGC is less than the market price, there will be an uneconomic incentive to take rate cap service; conversely, if the CGC is greater than the market price, there will be an uneconomic incentive to switch to another supplier. Only by setting the CGC equal to the current market price will the choice between rate cap service and other suppliers be competitively neutral and fair to all parties. This is precisely the approach adopted in California during the pendency of the price cap alternative. The CGC will be based on the actual average power exchange price.

The implication of this is that the CGC cannot be predetermined so long as customers have the option of rate cap service. And if the CGC cannot be predetermined, then the certainty benefits that Mr.Baron alleges are associated with pre-1999 valuation are illusory. Put another way, achieving the certainty benefits in the manner advocated by Mr. Baron requires:

- An administrative valuation which exposes both customers and shareholders to significant valuation risk; and
- A predetermined CGC schedule that will almost certainly distort customer choices between rate cap and competitive supply.

The costs of such an approach outweigh any potential benefits. The OTS and Industrial proposals for one time administrative valuation of the Company's generation should be rejected. The Company's modified valuation proposal should be approved.

Generation Stranded Costs Not Over Estimated

Q. Which parties present alternate views of the value of the Company's generating assets?

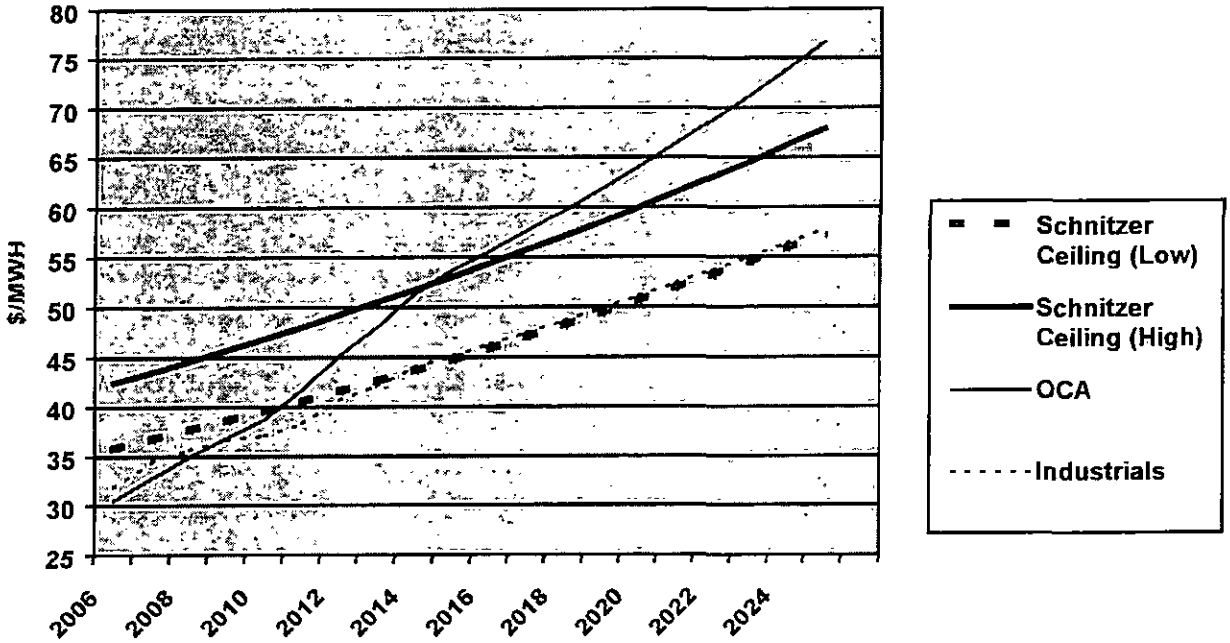
A. The OCA and the Industrials each present estimates of generation value which are significantly higher than the Company estimates as shown in the table below.

	Duquesne	OCA	Industrials
Generation Operating Value	($181 million)	$392 million	$128 million
Difference from Duquesne	--	$573 million	$309 million

Q. The OCA and the Industrials have been quite critical of your ceiling market price estimates on which the Company relied to estimate generation market value. I take it that your ceiling price range is much lower than the market price forecasts of OCA and the Industrials?

A. Actually, and surprisingly given their rhetoric, the answer is no. The figure below illustrates my ceiling market price range from 2006 on, together with the market price assumptions relied on by OCA and the Industrials.

As the figure shows, through the year 2010 both parties forecast market prices lower than the low end of my ceiling price range, indeed the Industrial forecast is lower through the year 2013. Over the remaining forecast period, the Industrial forecast lies nearly on top of the low end of my ceiling price range, while the OCA forecast escalates more sharply to a point just above the high end of the range in the year 2015, and diverges further from that point.



Q. On average, how do the OCA and Industrial market price estimates compare to your ceiling price range over the 2006 to 2025 time period?

A. My ceiling market price ranges from $36 per MWh to $43 per MWh in 2006, on a real levelized (that is, escalating at inflation) basis. The comparable number for the OCA is $39 per MWh, and for the Industrials $35 per MWh. Thus, the Industrial market price forecast for 2006 and beyond is actually below the low end of my ceiling price range, while the OCA's figure is well within my range.

Q. Given all of the criticisms of your approach, why isn't there more of a difference between your ceiling price range and the market price forecasts of OCA and the Industrials?

A. While it is true that some of my assumptions, capital cost and heat rate in particular, are lower than those of these other parties, other of my assumptions, notably cost of capital and capital recovery period, are higher. Thus, to some extent the differences in assumptions offset each other. In addition, my ceiling price range assumes that market prices will have risen to the combined cycle new entry level by 2006,

although I acknowledge the possibility that with all the excess baseload generation in ECAR, prices may not in fact rise to that level until after 2006. Industrials and OCA conclude that combined cycle capacity will not be economic under their assumptions until well after 2006, again with the result that the market price estimates are closer together rather than further apart. But underlying the apparent numerical similarity, there are significant differences of opinion over the usefulness of such forecasts.

Q. What do you mean?

A. Both the OCA and the Industrials are willing to rely on these forecasts as the basis of a one time stranded cost valuation, hedging their bet on market prices through their sharing proposals, which would impose significant costs on shareholders. The Company, on the other hand, believes these forecasts are useful only for the purpose of establishing the likely magnitude of stranded costs so as to determine the appropriate timing for the proposed second stage market valuation.

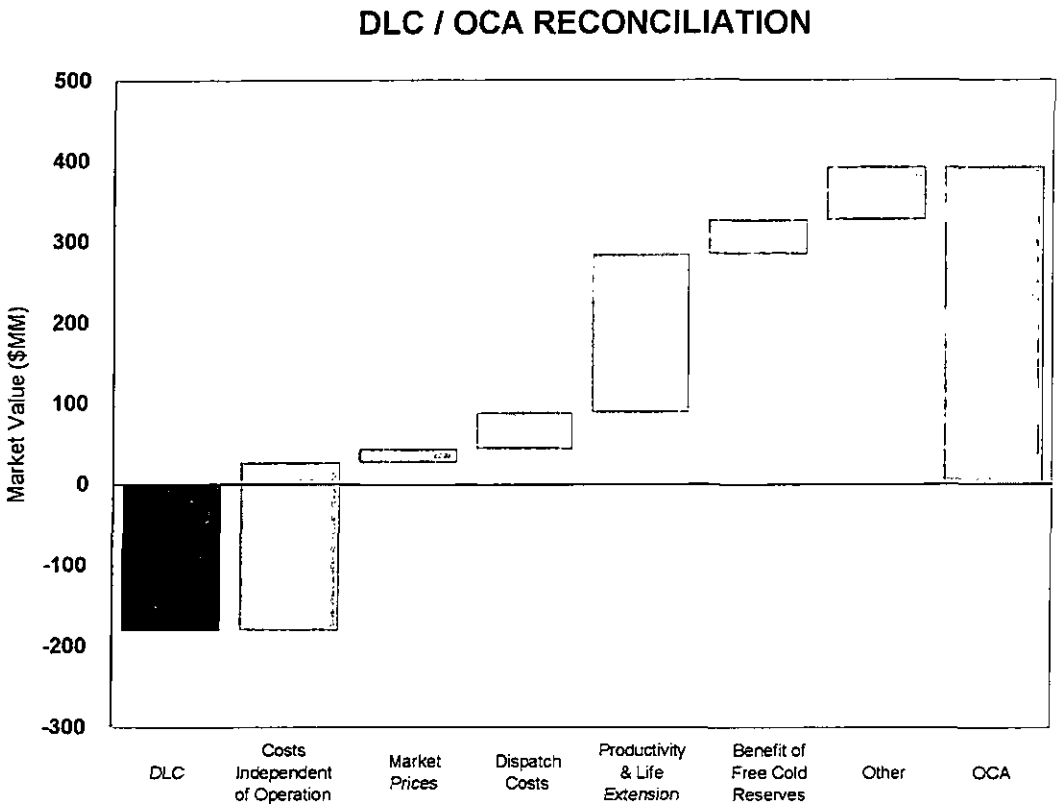
Q. To what do you attribute this difference of opinion?

A. I attribute it to a fundamentally different view of how competitive markets work. The specific criticisms of my approach are very revealing in this regard. The core criticism of the other parties is that I have assumed lower capital costs and higher efficiencies than any combined cycle unit currently operating, or than any unit currently available for construction. The first contention is true, the second arguable, but both miss the point. The critical question that OCA and the Industrials never even bother to ask is: has administrative determination based on current technology cost been an accurate predictor of market prices 10 to 20 years hence? The answer is no. In my experience the administrative approach based on a fixed technology view of

the world has been high nearly every time, and three specific examples are summarized in Exhibit MMS-6. Yet, for instance, OCA has the temerity to value life extensions 29 to 37 years hence based on such a fixed technology forecast. In light of the documented failures of accurately predicting market prices even five years in the future, OCA's position is somewhere between silly and reckless. Technological progress in electricity production is a fact. Gas combined cycle costs have fallen dramatically in nominal dollars over the last several years. Indeed, a review of Gas Turbine World, one of the sources cited by Mr. Falkenberg, indicates that in the just the last year, turnkey cost estimates for some combined cycle technologies have fallen by 17 to 33 percent (even more in real terms), and installed costs are now quoted as low as $318 to $380 per kW. In a similar vein, the Energy Information Administration, citing improved efficiency and lower costs of generation has reduced its forecast of long term electricity prices by 13 percent relative to a similar forecast made only one year ago. Given these trends, given the prospect of new technologies displacing combined cycle, and given the experience of the last 15 years, it is only reasonable to acknowledge the real possibility that future market prices could be lower than the ceiling price range, and lower than the OCA and Industrial forecasts.

Q. Well, if differences in long term market price assumptions are not that significant, why are the Company's estimates of generation value lower than the other parties?

A. The specific reasons vary for each party. Let me start with a discussion of the OCA analysis. The figure below illustrates the major sources of the $573 million difference between the Company's $(181) million estimate of net generation value and OCA's $392 million estimate.



Q. Please explain the $208 million of difference attributable to costs independent of operation.

A. Under Mr. Kahal's cost and market price assumptions, several of Duquesne's generating plants have a negative margin over their remaining lives – that is, the present value of costs exceeds the present value of revenues. For stranded cost quantification purposes, Mr. Kahal does not use this negative margin figure, but instead uses a value of zero. Implicit in his choice to use zero rather than the projected negative margin is the assumption that the operating costs which produce the negative margin are all avoidable if the unit is shut down or placed in cold

reserve. Unfortunately, as Mr. O'Brien, Mr. Duckworth and Mr. Nelson testify, this is not the case. Certain operating costs are not avoidable, and cannot be saved. Mr. Kahal's incorrect assumption that these costs are avoidable causes him to overstate net generation value by over $200 million.

Q. What about the $17 million difference attributable to market prices.

A. The OCA market prices are virtually identical to the prices derived from Duquesne's recent auction through 2002, but escalate more quickly thereafter, and thus are above the low end of the ceiling price range, on average, over the forecast period. But the net effect of these market price differences is only $17 million, as the figure illustrates.

Q. Please explain the difference in value attributable to dispatch costs.

A. The Company and OCA use different assumptions with respect to fuel and variable O&M costs. The effect of using OCA's assumptions, rather than the Company's, is to increase net generation value by $44 million.

Q. What about the $196 million in the figure above attributable to life extensions and productivity improvement?

A. A more significant source of difference involves life extension and productivity assumptions. The Company believes that future life extension economics are speculative, and will hinge both on future market prices and environmental requirements for coal generation. OCA has assumed that life extension will be economic, particularly at the higher long-term price levels they project. In addition, OCA has assumed further, unspecified improvement in generation productivity above and beyond the Company's projections. As shown above, these speculative life

extension assumptions together with their unspecified productivity improvements increase net generation value by $196 million.

Q. What is the next item, the benefit of free cold reserves?

A. Mr. Kahal's analysis suggests that the Cheswick unit has negative margins on an annual basis until 2006, at which time the annual margin turns positive. For valuation purposes, Mr. Kahal assumes that the Cheswick unit can be placed in reserve for free until 2006, at which point it can be reactivated at no cost. Unfortunately, as Mr. Nelson describes, this is not technically or economically feasible. The "free cold reserve" error causes generation value to be overstated by $42 million.

Q. What is in the "Other" category?

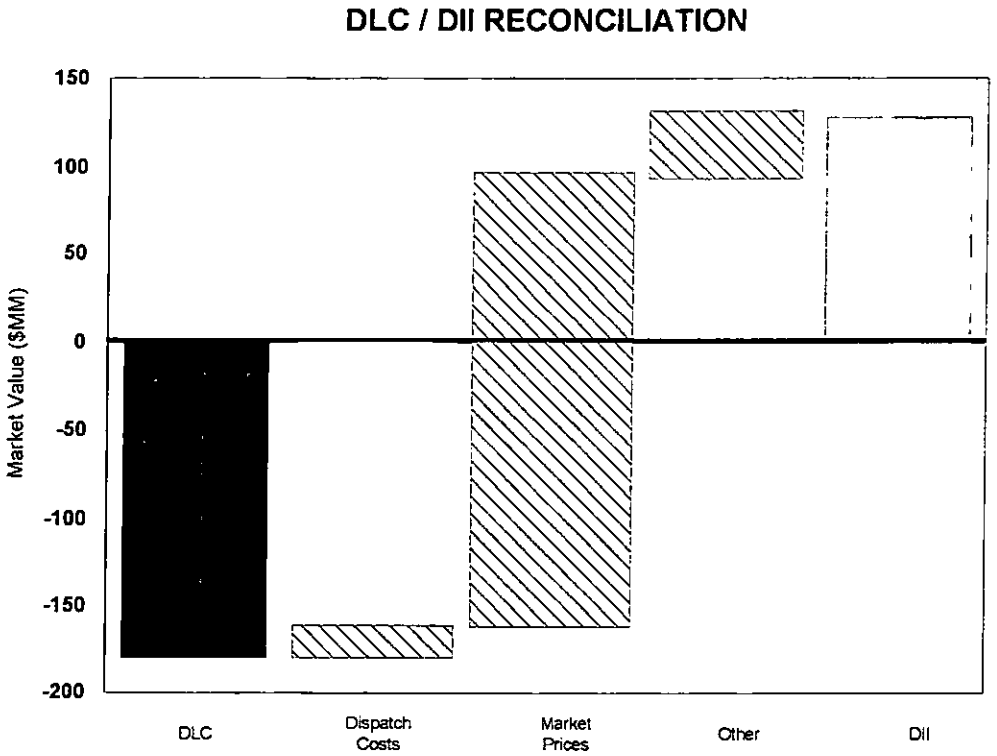
A. There are several other differences in assumptions between OCA and the Company, including inflation and discount rates. As the figure illustrates, these other differences account for $66 million of the difference in net generation value.

Q. What do you conclude from this analysis of differences between the Company and OCA net generation plant valuations?

A. The difference in values of nearly $600 million is clearly a significant difference. Much of it is attributable to errors in the OCA's analysis. The assumption that all costs are immediately avoidable, and that there are no costs independent of operation is just wrong. Likewise the assumption that a unit can be placed in cold reserve for a number of years and then reactivated for free is also incorrect. The life extension benefits are possible, but extremely speculative, and the productivity improvement assumption is unsupported. On balance, the Company's valuation is more reasonable than the OCA valuation.

Q. What about the DII analysis of net generation plant value?

A. The figure below summarizes the major sources of the $309 million difference in net



generation value between the Company and DII. As the figure illustrates, the major source of difference -- $255 million – is market price assumptions. Different fuels price assumptions account for a very small part of the difference, and all other sources account for about $35 million of the difference.

Q. Why is the market price difference so significant? From 2006 on, isn't DII's market price forecast actually a little lower than the Company's?

A. In the long term DII's market price projection is just below the Company's ceiling price range, but during the transition period DII's market price is well above the projection based on RFP results and well above OCA's projection as well.

Q. Why is that?

A. On an energy basis, all the forecasts are quite comparable during the transition period. The difference is entirely attributable to Mr. Falkenberg's capacity price assumption. Based on his reserve margin analysis, he assumes that the market will support a capacity price equal to the economic costs of a new combustion turbine starting in 1999. Neither the results of Duquesne's RFP nor the Company's experience in the market as a purchaser of capacity (as described by Mr. Lahtinen and Mr. Irvin in their direct testimony) are consistent with this assumption, but Mr. Falkenberg is apparently undeterred. With no market evidence to support the DII assumption, and ample market evidence to support the Company's position (plus, in this regard, the analysis of OCA), the Company's net generation value is much more reasonable than DII's.

Q. What about HSS's contention that there are no generation stranded costs?

A. Mr. Clayton discusses Mr. Weisenmiller's valuation contentions in more detail, but I have two observations. First, to the extent Mr. Weisenmiller is relying on the Fort Martin transaction to support his valuation, his valuation should be rejected. Relying on a single, old transaction to value all of Duquesne's generating assets is simply not credible. Mr. Weisenmiller offers no evidence that similar transactions could be achieved today, or that such a transaction can reasonably be generalized to all of the Company's generation. Second, while he references selected values from past assessments of the market value of the Company's assets performed by Duquesne and others, he offers no evidence that the market price assumptions underlying the valuations he cites are in fact reflective of current power markets. The Company's

RFP results indicate that they are not. To the extent his valuation relies on these selective citations, it should be rejected.

No Opportunity for Over Recovery

Q. Opposing parties have made the claim that Duquesne's rate cap and market valuation proposal may result in over recovery of stranded costs. Why do they believe this will be the case?

A. For the most part, this concern stems from a belief that the Company has overestimated its stranded costs, and that allowing recovery of the amount requested would translate to over recovery. There are also secondary issues concerning the ROE spillover mechanism; particularly whether the Company could game that mechanism to achieve over recovery, or would have insufficient incentives to mitigate stranded costs to the detriment of customers.

Q. How do you respond?

A. Duquesne's proposal will not result in over recovery of its stranded costs because the proposal is premised on a market valuation of its generation assets, not on a one time administrative valuation. If the market valuation indicates that stranded costs are lower than what the Company now believes, and maintaining the rate cap through the end of 2005 is not necessary, then the recovery period can be shortened. That is why the Company is proposing that the valuation be completed in 2003 so that any required adjustments to the rate cap could be made in 2004 and 2005. As shown in Mr. Clayton's Exhibit DJC-21 (Revised Exhibit DJC-3, p.2) over 600 million of the Company's minimum amortization commitment is not funded until 2004 and 2005, so

even if stranded costs turn out to be significantly lower than the Company believes likely, no over recovery will have taken place prior to 2004.

Q. But what if market prices turn out to be much higher than the Company's current projections – couldn't a 2003 valuation be "too late"?

A. That possibility certainly exists as a theoretical matter. And rather than debate the probabilities, the Company has instead proposed a market price trigger, described by Mr. Clayton, which would accelerate the market valuation if market prices rise more quickly than now anticipated. As well, Mr. Clayton describes a second trigger for early valuation in the event the Company is able to fund accelerated amortization more quickly than it now forecasts, as a consequence of higher load growth or lower costs, for instance. Thus the Company's proposal provides for acceleration of the market valuation in circumstances where 2003 might be "too late".

Q. What if, despite the Company's best intent, the market valuation indicated that the Company had already over recovered its stranded costs?

A. In that unlikely event, the rate cap would be terminated, and the Company would credit the over recovery back to customers, with interest, according to a Commission approved schedule. The Company would not retain the over recovery.

Q. Could you please summarize why there is no opportunity for over recovery under the Company's proposal?

A. Yes. The Company has proposed a market valuation of stranded costs to ensure there is no opportunity for over recovery. The timing of that valuation, and the triggers for accelerating it, provide adequate protection for customers that the rate cap will not remain in place any longer than necessary. In the unlikely event that, despite these

protections, the rate cap did provide more recovery than required, the rate cap would be terminated and all excess recovery credited back to customers. Thus, under the Company's proposal, in contrast to the one time administrative valuation proposals put forward by the OCA and the Industrials, there is no opportunity for Duquesne to over recover its stranded costs.

Q. What about the criticism that during the price cap period the ROE cap creates an opportunity for excess earnings, which effectively represent over recovery?

A. As discussed by Mr. Clayton, the Company has modified its proposal to eliminate the 50 basis point band above the allowed return on equity. Therefore, all earnings above an 11.5 percent return would be used to fund amortization – there is no opportunity for the Company to earn a return in excess of the Commission authorized rate.

Q. What about the related criticism that the Company does not have adequate incentives to minimize stranded costs under the ROE spillover, and that either gaming or inefficiency will cause customers to pay more for stranded cost recovery than they should?

A. These criticisms are incorrect. The Company has strong incentives to mitigate stranded costs and to operate efficiently during the rate cap period.

Q. What are these incentives?

A. There are two. The first stems from the minimum amortization commitment, a complementary feature of the Company's plan. Simply stated, the Company has committed to fund at least $1.7 Billion of accelerated amortization during the rate cap period independent of its effect on earnings. That means that the Company is effectively at risk for creating enough operating income to both fund the amortization

commitment and to achieve the Commission authorized return. If the Company is not able to generate the required level of operating income over the rate cap period, for whatever reason, then its earnings will suffer. Given that the amortization commitment already reflects aggressive operating performance assumptions (increased fossil output and significant nuclear performance improvement at Perry, for instance), this is a significant incentive to maximize operating income through any means available, including stranded cost mitigation specifically and improved operating efficiency more generally. I should also note that no party has presented an analysis suggesting that this minimum commitment is inadequate or not sufficiently aggressive under the Company's return on equity assumptions.

Q. What is the second incentive to mitigate under the rate cap?

A. The second incentive is that it is in the Company's interest to minimize any remaining unrecovered stranded costs at the end of the transition period, to eliminate them entirely if at all possible, and to generally keep the stranded cost recovery period as short as possible. The best way to do that during the rate cap period is to aggressively mitigate stranded costs, operate as efficiently as possible, and therefore maximize the amount of additional amortization that can be funded through the ROE spillover mechanism.

Q. Why is it in the Company's interest to keep the stranded cost recovery period as short as possible?

A. There are a number of reasons. First, the Company has a strong interest in avoiding the time expense and uncertainty associated with a future proceeding to extend stranded cost recovery beyond 2005. While it believes, as a matter of law, that it is

entitled to such recovery if required, the best outcome from the Company's perspective is that stranded cost recovery be completed prior to the end of 2005. Beyond that, completing stranded cost recovery as soon as possible will allow customers to benefit from lower rates, and it will relieve the Company from its obligation to provide generation service at the rate cap level – both desirable outcomes.

Q. For the skeptics among us, is there any evidence that this is an effective incentive?

A. Yes, there is. Prior to the passage of the restructuring statute, Duquesne was faced with a similar, if weaker set of incentives. There was no defined rate cap process, and no specific schedule for access or stranded cost recovery – but there was a general sense in the Company that reducing potentially strandable costs as quickly as possible was important. With no stronger nor more explicit incentive than this, the Company aggressively pursued cost reductions that allowed it to petition for authorization to accelerate amortization of its nuclear plants, and subsequently entered into the Fort Martin transaction which allowed it to further mitigate stranded cost. In light of its past actions, it is clear that Duquesne is motivated to do everything possible to fully mitigate its stranded costs and to recover them as quickly as possible. It has continued strong incentives to do so under its proposal.

Q. Have any parties offered any constructive proposals to further strengthen the Company's incentives?

A. No, they have not.

Disallowance of Stranded Costs Is Arbitrary, Unjustified and Poor Public Policy

Q. Would you now please address the sharing proposals that have been put forward by several parties?

A. Yes, I will.

Q. Could you please define the term "sharing" as it is used in the context of quantifying stranded costs?

A. Yes. Proponents of sharing advocate that after the magnitude of stranded costs has been determined, a further determination be made as to what portion of these stranded costs is recoverable from customers and what portion is imposed on investors. This latter determination of the allocation of stranded cost responsibility between customers and shareholders is referred to as sharing. A more accurate, if also more blunt, definition of sharing is: the denial of a reasonable opportunity for shareholders to earn a fair return on prudently incurred, fully mitigated costs currently authorized to be included in just and reasonable rates.

Q. What parties advocate "sharing" of stranded costs?

A. At least three parties -- OCA, Industrials, and Environmentalists – advocate sharing of one type or another. HSS may also be an advocate of sharing, as well, but the issue is mooted by its conclusion that the Company has no stranded costs.

Q. Are all the sharing proposals the same?

A. No, they are not. The OCA's sharing proposal is to allow seven year amortization, with no return, of generation stranded investment. As discussed by Mr. Clayton, this proposal translates to a $460 million stranded cost disallowance under OCA assumptions, and a larger disallowance under Company assumptions. The

Industrials' sharing proposal is to allow amortization, with no equity return, of generation stranded investment. This proposal would result in a $232 million disallowance under Industrials' assumptions, and a larger disallowance under Company stranded cost assumptions. In addition, as described by Mr. Clayton, the OCA and the Industrial recovery proposals provide for an additional "sharing" of $42 million and $166 million respectively, due to treatment of deferred taxes. The Environmentalists recommend no more than 60 percent recovery of generation stranded investment. Under Company stranded cost assumption, this proposal would result in a disallowance of at least $766 million.

Q. What is the basis for your conclusion that these sharing proposals are unwarranted and are poor public policy?

A. There are two reasons. First, these sharing proposals are arbitrary and are not consistent with the public policy standards for stranded cost recovery set out in the Pennsylvania statute. Second, these sharing proposals are inconsistent with the public policy standards articulated in Duquesne v. Barasch.

Q. Let's start with the first reason. Why are these sharing proposals arbitrary and inconsistent with the public policy standards in the statute?

A. The statute describes a number of factors relevant to the determination of generation stranded cost recovery [See Sections 2808(c)(4) and 2808(c)(5)]. They all deal fundamentally with the issue of mitigation, both historically prior to the passage of the statute and prospectively during the transition period. By their nature, these statutory considerations are company and fact specific, rather than generic. Despite this statutory requirement, the sharing proposals put forward by the parties are not

based on any assessment of the Company's mitigation efforts, either historically or prospectively. In fact, the sharing proposals do not appear to be company-specific at all. Rather they are proposed to be applicable to any company with generation stranded cost, regardless of the circumstances.

Q. How do you know these proposals are not based on an assessment of Duquesne's mitigation activities?

A. Each party has offered a justification of its sharing proposal. None of them mention mitigation. Mr. Kahal for the OCA states "Given the 'just and reasonable' standard and the fact that virtually all of the owned-generation stranded cost would normally be considered 'economic excess capacity,' a sharing mechanism is clearly appropriate."[Kahal; p. 41:22-25] Similarly, Mr. Baron on behalf of the Industrials provides his justification for the sharing proposal:

> Q: Based on your understanding of the provisions of the Competition Act and the Commission's application of that Act in the PECO QRO proceeding, does the Commission have a responsibility to apply the just and reasonable standard in the determination of the amount of generation-related stranded costs that may be recovered from ratepayers?
>
> A: Yes. I believe that some adjustment or discount from the total calculated level of stranded generation costs (if they are found to be a positive value) should be made prior to the calculation of the recovery of such costs through a CTC. The methodology that I am recommending in this proceeding is a reasonable approach to making such a stranded generation cost adjustment to

arrive at a just and reasonable level to recover from its customers. [Baron; p. 18:10-21]

In fact, Mr. Baron is not familiar with, and thus presumably did not consider any specific standards for generation stranded cost recovery specified in the statute:

> Q: Is it your understanding whether the statute sets forth any standards for the Commission to consider?
>
> A: I am not aware of specific standards in that regard. Rather the statute, and I've cited some sections in my testimony, discusses the general obligation of the Commission to determine a just and reasonable level of stranded cost recovery. [Baron; p. 52:20 to p. 53:3]

Finally, Mr. Schoengold offers the justification for the Environmentalist sharing proposal. He, too, is silent on the issue of mitigation. "The stockholders have already received a return on their investments in the generating assets, even on that investment which has turned out to be valueless. It is necessary to take this into consideration when determining how to share the economic loss." [Schoengold; p. 20:7-10] And further: "I am recommending that the Commission allow for recovery of no more than 60% of the level of stranded generating assets which it determines are appropriately recoverable. This is a reasonable level which allows stockholders a reasonable authorized return on investment." [Schoengold; p. 23:8-11]

Q. I understand that these proposals are not based on an assessment of the Company's mitigation efforts, but could you comment on the alternative justifications offered by the parties?

A. Yes. OCA and the Industrials appeal to the just and reasonable standard as permitting or requiring sharing of the type they propose. But the just and reasonable standard is not a new standard – it applies to Duquesne today. I fail to see how Duquesne's rates can be just and reasonable today based on prudently incurred costs and magically be unjust and unreasonable the next day based on the same prudently incurred costs. The Environmentalist's justification for sharing is no better. Mr. Schoengold invents a new concept of IRR realized to date to effectively deny any further equity return on generation stranded investment. There is no theoretical basis for his proposal; it is an arbitrary method for determining stranded cost recovery on the basis of average asset vintage, rather than the mitigation considerations specified in the statute.

Q. What about the bases for the particular sharing calculations proposed: no return, no equity return, and no more than 60 percent recovery, respectively?

A. They are all arbitrary and unsupported. Neither Mr. Kahal nor Mr. Baron offers any explanation as to why their particular return penalty is more appropriate than a more or less severe penalty. Neither recommendation is based on an assessment of Duquesne's mitigation efforts, neither is even specific to the Company's circumstances in any way. These are simply arbitrary blunt instruments designed to shift costs from customers to investors. Mr. Schoengold's proposal is no better – his particular recommendation stems from an accident of history, the average vintage of Duquesne's generation. A younger, less depreciated asset mix would deserve a lower ROE under his theory, an older more depreciated asset mix would be entitled to a higher ROE. There is no basis in the statute or in logic for such an arbitrary proposal.

Q. In your earlier summary, you mentioned additional policy standards by which to evaluate these sharing proposals, the policy standards articulated in Duquesne v. Barasch (*Duquesne*). What are those standards, and why do these sharing proposals fail to meet them?

A. I will preface my response by noting that I am not a lawyer and I am not offering a legal opinion. But, from a non-lawyer's perspective, the *Duquesne* opinion includes two useful policy standards. In dealing with the issue of whether the consequences of unsuccessful investments could be imposed on investors, the notion that prudence was by itself determinative of the issue was rejected. But *Duquesne* did continue to recognize the "end results test" of a company's financial performance as a relevant policy standard. In addition, *Duquesne* put forward an additional policy standard that opportunistic switching by regulators from one set of rate setting rules to another is not appropriate. It also suggests that the question of distinguishing opportunistic switching from permissible cost recovery rules which appropriately impose losses on shareholders hinges on whether there is a match between the losses imposed on shareholders and the prior level of risk compensation they received through the rate of return on equity. Thus, to meet these policy standards, a sharing proposal must produce financial performance which passes the "end results" test, and show evidence of prior compensation to distinguish the proposal from opportunistic switching. None of the sharing proposals satisfy either of these policy standards.

Q. How do you know that none of these proposals pass the end results test?

A. None of the proposing parties considered, let alone demonstrated that the end result of their proposal is reasonable in terms of the financial consequences to the Company.

Mr. Clayton does address this issue, however. His testimony summarizes the financial consequences of the OCA proposal and the DII proposal on the Company. His analysis indicates that the end result of either proposal is significant deterioration of the Company's financial health. He further concludes that applying Mr. Schoengold's proposal to the Company stranded cost assumptions would have similar consequences.

A. Have any of the parties proposing sharing made a showing of prior compensation?

A. No, they have not, nor have they acknowledged that the question of prior compensation is even relevant. Mr. Kahal states that evidence of prior compensation is not the basis of his sharing recommendation:

> Q: Are you contending that Duquesne's shareholders have been compensated for this disallowance or adjustment?
>
> A: They may have been in the sense that during some period of time Duquesne shareholders may have earned returns that exceeded the cost of capital, but that's not the basis of what I'm doing. [Kahal Deposition; p. 82:13-20]

Mr. Baron states that he doesn't know whether shareholders have been compensated for the risk of a disallowance:

> Q: Do you believe that Duquesne's shareholders have been compensated for the risk of such a disallowance that you propose?
>
> A: I haven't made that determination. I simply don't know at this point in time. [Baron Deposition; p. 55:4-8]

And finally, Mr. Schoengold states that he doesn't know whether there has been compensation, but that the presence or absence of compensation was not relevant to his analysis:

> Q: Is it fair to say that your analysis or your calculations assume that the shareholders have not already been compensated for the stranded cost disallowance or sharing that you propose?
>
> A: That the shareholders have not been compensated for the stranded cost disallowance that I proposed?
>
> Q: That's correct.
>
> A: I haven't followed the performance of Duquesne stock, so I don't know just what they may or may not have been compensated for. But, I didn't make any assumptions in my analysis as to whether or not they had been compensated for that potential disallowance. [Schoengold Deposition; p. 42:12-22; p. 43:1-4]

Thus, none of these sharing proposals are based on any evidence of prior compensation.

Q. I understand that none of the parties have demonstrated that shareholders have been compensated for the risk of the losses they now propose to impose on them. Do you think it is likely that shareholders have been compensated to assume these risks?

A. No, I do not.

Q. Why not?

A. For shareholders to have been compensated in the manner envisioned in *Duquesne*, the PUC would have had to adjust the risk premium element of the rate of return to

account for the risk of prudent, but economically unsuccessful investments. To do so would have required some sort of mechanism to quantify the magnitude of this risk, to translate it into an ROE premium, and to add it to the expected ROE determined through normal means. The problem is that this is easier said than done. There were no formal techniques used, to my knowledge, to quantify this type or asymmetric risk in Pennsylvania. Nor would this risk premium have been picked up automatically through some other estimation technique. As Kolbe, Tye and Myers conclude: "However, unlike debt, *the 'observed rate of return for equity is its expected rate of return, not the equivalent of a promised rate of return.*" (Kolbe, Tye, and Myers; Regulatory Risk: Economic Principles and Applications to Natural Gas Pipelines and Other Industries; pp.42-43; emphasis in original) The ROE estimation techniques typically relied on by cost of capital witnesses and Commissions estimate the expected rate of return, not the higher promised rate required to meet the *Duquesne* standard.

Q. Could you please elaborate on the meaning of the terms "expected return" and "promised return" as you have just used them?

A. Yes. The expected return is the return that investors expect to earn on an investment of comparable risk. The promised return, in contrast, is not the return that investors expect to earn, but includes a premium to compensate for asymmetric risks such as bond defaults. For instance, the promised rate of return on high yield bonds – the average of the coupon rates of the bonds – is about 200 basis points higher than the expected rate of return on the bond funds.

Q. Could you please summarize your conclusion with respect to these sharing proposals?

A. Yes. All three proposals are arbitrary and inconsistent with reasonable policy standards and the restructuring statute. They would impose severe financial hardship on Duquesne. They would be poor public policy and should be rejected.

The Company is Entitled to a Rate Cap Under Section 2804(4)(v)

Q. Which parties take issue with the Company's rate cap proposal for stranded cost recovery?

A. The OCA rejects the Company's rate cap proposal and substitutes an 18 percent rate reduction in its place. HSS also challenges the Company rate cap proposal, claiming that the Company has failed to meet its own test for meeting the provisions of Section 2804(4)(v).

Q. How do you respond?

A. The OCA and HSS positions are incorrect. The Company's rate cap stranded cost proposal is consistent with Section 2804(4)(v), is fully supported by the Company's own evidence, and is corroborated by the stranded cost analyses of OCA and the Industrials.

Q. Could you please elaborate on this conclusion?

A. Yes. Let me start with a brief description of the Company's rate cap recovery proposal so that its consistency with Section 2804(4)(v) is readily apparent. First, the Company is proposing to roll its authorized ECR into base rates, and to cap rates at that level. Second, the Company is proposing a minimum amortization commitment under the rate cap and, through the ROE spillover, additional amortization to the extent operating income exceeds the level necessary to achieve an 11.5 percent return on equity. Thus, during the rate cap period, the Company will not exceed its

authorized rate of return. Third, the rate cap will remain in effect until the earlier of December 31, 2005 or the date on which the Company has fully amortized its generation-related regulatory assets and market determined stranded costs. The Company has not proposed a rate cap through 2005 independent of the ultimate level of stranded costs, but rather has proposed a rate cap for only as long as is necessary to amortize its stranded costs. Contrary to HSS's contention, the possibility of "negative stranded costs" at the end of 2005 does not disqualify Duquesne from reliance on Section 2804(4)(v); under the Company's proposal such circumstances would result in earlier termination of the rate cap.

Q. But how do you know that the 2003 market valuation proposed by the Company is timely? Couldn't accelerated amortization under the rate cap through the end of 2003 exceed the amount required to allow the Company to recover its stranded costs?

A. The evidence put forward by the Company and by other parties suggests that a 2003 valuation is timely. Under its base case assumptions, the Company projects a remaining generation book value of $533 million at year end 2005, with a corresponding generation market value of only $110 million. Under these assumptions, a 2003 valuation date is clearly timely – the Company would have stranded costs remaining even with a rate cap through the end of 2005. Under the Company's high ceiling price case, end of year 2005 generation book value would again be $533 million, but the corresponding generation market value would be $765 million, and thus stranded costs would be negative $232 million. Clearly the rate cap would terminate prior to the end of 2005 in this circumstance, but that does not necessarily imply that valuation earlier than 2003 would be required. The table below

summarizes the generation asset book and market values at year end 2003 and 2004, as well as the net stranded cost exposure.

	12/31/03	12/31/04
Generation Book Value	$678 million	$624 million
Generation Market Value	$552 million	$661 million
Stranded Costs	$126 million	($37 million)

As the table illustrates, the Company would still have $125 million in stranded costs as of year end 2003, but by year end 2004 would have a negative $37 million in stranded cost. The implication of these figures is that even in the high ceiling price case, the Company would require the rate cap through the end of 2003 and well into 2004. A valuation in 2003 would still be timely for determining a mid- to late- 2004 rate cap termination date.

Q. You mentioned earlier that the OCA and Industrial stranded cost analyses corroborate the timeliness of the proposed 2003 valuation. Could you elaborate on that point?

A. Yes. As I have discussed at length above, these two parties have conducted detailed analysis of the Company's stranded costs and proposed specific one time administrative valuations. While I do not accept all of their assumptions and conclusions as discussed above, the question naturally arises: if the OCA or the Industrials are right about the future – how much of a rate cap will the Company require, and will a 2003 valuation still be timely?

Q. I take it that you have performed an analysis to answer this question?

A. Yes, I have. Let me start with the analysis based on the OCA's view of the world. For purposes of this analysis, I accepted all of OCA assumptions concerning the future value of generation – market prices, inflation, life extension economics, fossil decommissioning, avoidable costs and productivity improvements. I also accepted, for this purpose only, their lower ECR level, their 10 percent required return on equity, and their more levered capital structure. I did not accept their proposal to deny any return on generation stranded costs, for the reasons discussed above.

The resulting generation book value, generation market value, and net stranded cost are summarized in the table below for the years 2002 through 2005.

	12/31/02	**12/31/03**	**12/31/04**	**12/31/05**
Generation Book Value	$648 million	$567 million	$530 million	$445 million
Generation Market Value	$510 million	$552 million	$590 million	$632 million
Stranded Costs	$138 million	$15 million	($60 million)	($187 million)

The table shows that at year end 2005, generation market value exceeds remaining book value, and stranded costs are a negative $187 million. Under OCA assumptions, the Company would not require a rate cap through the end of 2005. Likewise, at year end 2004, generation value exceeds remaining book value by $60 million, and thus the Company would not require a rate cap through the end of 2004. At year end 2003, remaining book value exceeds generation market value by $15 million, and thus the Company would require a rate cap through the end of 2003 and into 2004 if OCA turns out to be right about the future. The valuation schedule proposed by the Company would support a timely determination to end the rate cap at the year end

2003. I also performed a sensitivity to the above analysis: I replaced the OCA capital structure and ROE assumptions with the Company's assumptions. These are issues that will be decided in this case, and they have a significant effect on the required term of the rate cap. Making just this one change in favor of the Company's position shifts the end of the rate cap from early in 2004 through the end of 2005. Thus, in both cases, the valuation schedule proposed by the Company is consistent with OCA's assumptions about the future.

Q. What about the analysis using the Industrials' assumptions to which you referred earlier?

A. Again, for purposes of this analysis, I accepted all of the Industrial's assumptions about the future value of generation – their market prices, their fuel and operating costs and their output levels. I did not accept the Industrials' sharing assumptions, for the reasons discussed above. The resulting book value, generation market value and stranded cost figures are shown in the table below as of year end 2002 through 2005.

	12/31/02	**12/31/03**	**12/31/04**	**12/31/05**
Generation Book Value	$818 million	$749 million	$713 million	$635 million
Generation Market Value	$93 million	$149 million	$213 million	$258 million
Stranded Costs	$725 million	$600 million	$500 million	$377 million

As the table shows, under the Industrial's assumptions about the future, the Company would have remaining stranded costs as of year end 2005, and thus would be entitled to the rate cap through the end of 2005. The 2003 valuation schedule proposed by the

Company would be timely if the Industrial's assumptions about the future turn out to be correct.

Q. This result surprises me. I thought generation market values under the Industrials' assumptions are higher than the Company figures, and that this would have an effect on the required length of the rate cap.

A. You are right about the first, and wrong about the second. The Industrials' generation market value estimate is higher than the Company's, largely because of higher market price assumptions from 1999 to 2005. But this difference in market price assumptions has no effect on the required length of the rate cap. This is because the market price between 1999 and 2005 has almost no effect on the end of year 2005 generation book value, on the one hand, and no effect on generation market value at year end 2005, on the other.

Q. Please explain.

A. As the above tables illustrate, the required length of the rate cap is determined by comparing the remaining generation book value at a particular point in time with the market value of generation at that same time. The end of the required rate cap period is the point where the two values are equal. During the generation rate cap period the remaining book value figure is largely independent of the market price for power – the remaining book value is instead a function of how much accelerated amortization can be funded under the rate cap. So, on the one hand, higher market price assumptions between 1999 and 2005 have almost no effect on the year end 2005 book value.

On the other hand, market price assumptions between 1999 and 2005 also have no effect on the value of generation at the end of 2005 – that is a function of market prices from 2006 on. And, as discussed above, the Industrials' market price forecast from 2006 on is actually below the Company's low ceiling price estimate. Thus, other things being equal, the Industrial generation value as of 2005 will be lower than the comparable Company figure.

The Proposed Annual CGC Determination is Appropriate

Q. Let's turn now to the CGC issue. Which parties take issue with the Company's proposed annual CGC determination?

A. Several parties criticize the Company's proposal, for two major reasons. First, the OCA and DII criticize the annual CGC determination, arguing that "certainty" considerations require a predetermined CTC schedule (and, hence, a CGC schedule under the rate cape) known to all parties in advance. Second, HSS, MAPSA, and OCA argue that the quantification methodology is flawed, either because the RFP will tend to understate the market value of power or because the Company fails to include a retail marketing credit in the CGC, to take account of the marketing expenses that will be incurred by competing retail marketers, and to ensure that there is a reasonable opportunity for them to compete against the incumbent's rate cap service.

Q. How do you respond to these criticisms?

A. Neither of the criticisms is valid. First, while certainty is an understandable objective, it cannot be achieved without distorting customer choice and jeopardizing stranded cost recovery during the transition so long as service at the rate cap level is available

from the incumbent. These problems are even more severe if the CGC is predetermined using administrative market price estimates as OCA and DII propose. Second, the quantification criticisms are unfounded. The RFP process will not understate the value of power, as discussed in more detail by Mr. Lahtinen. Until such time as an acceptable market index is available, the RFP process is the best way to set the CGC. As discussed by Mr. Marshall, the Company is willing to submit the proposed RFP procedures and contracts to the Commission for approval. A further credit for retail marketing expense as proposed by OCA and MAPSA will distort competition and could jeopardize the Company's opportunity for stranded cost recovery as well. The magnitude of OCA's proposed credit far exceeds the level requested by an ENRON affiliate for a limited retail pilot, let alone a full access scenario. If the policy goal is to ensure that many customers choose a new supplier, a better solution is to eliminate the option to take service at the rate cap level, and to substitute a market-priced option in its place.

Q. Let's start with the certainty issue. Why would a predetermined CGC distort customer choice and jeopardize stranded cost recovery during the transition period?

A. The answer lies in the interaction between the CGC and the rate cap. Recall that the statute gives every customer a valuable option -- the right but not the obligation to take service at the rate cap level during the pendency of the transition period, and to return to service at the rate cap level even after they have switched to another supplier. This means that at any point in time, a customer contemplating a choice between rate cap service and another supplier will be comparing, among other things, the level of the CGC compared to the price offered by the potential supplier. If the

CGC is set in advance, as OCA and DII propose, it is very likely that the predetermined CGC will diverge from the actual market price, perhaps substantially. What will happen then? If the actual market price is higher than the predetermined CGC, suppliers will have a difficult time competing against the rate cap service. Both suppliers and customers will likely complain to the Commission that the CGC is biased in favor of the incumbent, and needs to be increased. They will be right. On the other hand, if the actual market price is lower than the predetermined CGC, then neither customers nor suppliers will complain. It will be easy to compete against the rate cap service, but this competition will not be economic either, and will result in reduced levels of stranded cost recovery. Under this circumstance, the utility will likely complain to the Commission that the CGC is too high and should be reduced – and it will be right. These problems will only be more severe if the CGC is predetermined using an administratively- determined market price forecast, as OCA and DII propose. Their two market price forecasts are significantly different from each other during the transition period, and both are above the 8 year forward price that is the only market evidence in this proceeding. The probability that the predetermined CGC and the actual market price will diverge seems a virtual certainty. The only way to avoid these problems is to set the CGC on an annual basis using market evidence as the Company has proposed.

Q. You stated earlier that certainty was an understandable objective. Is there a reasonable way to provide increased certainty as to what the CGC will be?

A. Yes, there is. The Company has already proposed one such approach in the Pilot, which was attacked by many parties (including some now arguing for certainty) and

rejected by the Commission. Under that proposal, customers choosing to waive their right to return to rate cap service could have their CGC predetermined for the remainder of the transition period based on the then current forward market price. This option would provide increased levels of certainty while avoiding the competitive problems described above. But given the hostile reception this option received in the Pilot, the Company has not proposed it in this proceeding.

Q. What about the first of the quantification criticisms; that the RFP process itself is flawed and that it will understate the market value of power?

A. Mr. Lahtinen responds to these criticisms in some detail, but I will offer a few comments. First, the Company made every effort to maximize the value of the power by offering a flexible product – fully dispatchable between 50 percent and 100 percent capacity factor – as well as a product that would be perceived as offering liquidity to purchasers. The RFP was widely advertised and attracted interest and participation from some of the largest power marketers in the country. Second, while the 1998 RFP results may well have been influenced by the current market structure in ECAR and by current FERC transmission pricing policies, that is the real power market today. Duquesne cannot sell its power at higher prices today simply by wishing that market reforms were already in place or that more markets were open at retail. If and as these conditions change during the transition period, and if and as they influence the market price, those effects will be reflected in the auction results. Finally, the Company is willing to replace the RFP process with an acceptable published index or forward price. But in the interim, the RFP process proposed by

the Company, subject to the review and approval of the Commission, is the best alternative.

Q. What about the second quantification criticism concerning the need for a retail marketing credit? Why would such a credit distort competition and jeopardize the Company's opportunity for stranded cost recovery?

A. The role of the CGC, including any proposed additional credits, is to establish the proverbial "level playing field" for efficient competition. By efficient competition, economists mean competition that takes place on the basis of marginal costs, not sunk costs. When a customer decides to take service from Duquesne at the rate cap price, the marginal costs incurred by Duquesne are the opportunity cost of not having that power available to sell in the wholesale market. This is precisely the opportunity cost that the RFP measures, adjusted only for the customer's load shape and for distribution losses. Duquesne will not be marketing its rate cap service, so there are no marginal marketing costs to be added to the wholesale opportunity cost. Likewise, Duquesne Light Company has no capability or authority to sell power at retail on an unregulated basis, so there is no retail opportunity cost that would be appropriate to measure. Efficient competition requires that the customer compare Duquesne's marginal cost of serving the customer – the RFP-based CGC – against the pricing and other product attributes offered by the competing supplier. Duquesne's proposal accomplishes precisely that.

Q. What would be the effect of adding a retail marketing expense credit to the CGC as proposed by OCA and MAPSA?

A. The effect would be to artificially inflate the marginal cost of providing rate cap service above its actual level, distorting the comparison between rate cap service and the offering of the competing supplier. This would result in subsidized competition, rather than efficient competition, with Duquesne providing the subsidy to the competing suppliers. To illustrate, under Duquesne's proposal, customers will switch to a new supplier when the attributes and pricing of the competitive offering are more valuable to the customer than rate cap service priced at its marginal or opportunity cost. Under the OCA/MAPSA proposals, customers will switch to a new supplier when the attributes and pricing of the competitive offering are more valuable to the customer than rate cap service priced at its marginal cost plus an allowance for its competitors' marketing costs. More customers may switch, but there can be no assurance of improved efficiency. In addition, the Company's opportunity for stranded cost recovery is reduced.

Q. How is the opportunity for stranded cost recovery reduced?

A. Under the OCA/MAPSA proposals, when a customer switches from rate cap service to a new supplier, the Company loses revenues equal to the CGC plus the retail marketing credit, as compared to the customer continuing to take rate cap service. The only costs that go away are the cost of purchasing power to supply that customer (or the extra revenues from having more power to sell at wholesale). This leaves a gap equal to the retail marketing credit, lost revenue that would otherwise have been available for amortization of stranded costs. The larger the retail marketing credit, and the more customers that switch, the larger the revenue shortfall.

Q. Do you have any comments on the size of the proposed retail marketing credits?

A. As should be clear from the foregoing, any subsidy of this type, regardless of size, is a bad idea. But the potential magnitude of the subsidies suggested here are particularly egregious. As a yardstick for comparison, I have in mind a proposal by Portland General Electric Company, an affiliate of ENRON, "to provide a monthly credit to Energy Service Providers (ESPs) during the introduction of the Company's Customer Choice Program." The size of the credit varies by type of customer and by number of participating customers, but would average around $2 per MWH if applied to Duquesne. Under the Portland proposal, the credit was to be available only for a short period of time (approximately one year) prior to the date of full customer choice. Contrast this proposal with those of parties in this proceeding which seek to institutionalize credits that are as much as twice as large for the seven year duration of the transition period. Measured against the Portland General yardstick, the proposals for a retail credit in this proceeding are excessive.

Q. But what if the Company's proposals are adopted and not many customers switch suppliers? Wouldn't that indicate that some type of additional credit is required?

A. No, that would not be the best solution. The problem is that there are competing policy goals during the transition: providing customers a stable, predictable and familiar option during the transition, on the one hand; and creating an environment where customers choose from among competitive suppliers in significant numbers, on the other. The restructuring statute places heavy emphasis on the first of these goals. It provides the rate cap option, which is stable, predictable, familiar and perhaps attractive to many customers. That of course makes the job of competitive suppliers much more difficult; they must offer something more attractive than the rate cap

option. But if the predominant policy goal is to assure that significant numbers of customers choose competitive suppliers, the right answer is not to subsidize switching, but rather to revisit the rate cap option. A bottom up approach, where customers choosing default service pay a delivery charge, a CTC charge, and a market-determined power charge might result in more customer switching without any inefficient subsidies. Of course, the "cost" of this approach would be the loss of any rate cap safety net. Default service prices might turn out to be higher or lower than the rate cap level. But if the goal is significant numbers of customers choosing competitive suppliers, this is an option worth considering.

Q. Does this conclude your testimony?

A. Yes, it does.

ESTIMATION PROBLEMS FOR MARKET PRICE FORECASTS

Overview

There are two major causes of the over-estimation of likely future market prices:

- Over-estimation of the likely future market price of busbar power (the point at which power exits the plant and enters the grid), and
- Inappropriate use of various "adders" which further inflate the market price estimates of staff and certain other parties.

The bottom-up "administrative" approach of determining future prices is based on the estimated cost of new resource additions – principally gas fired combined cycle capacity. By bottom-up administrative approach I mean a cost-based forecast of market prices typically generated using a computer model, with the input numbers based on assumptions rather than actual market transactions.

Projection of Market Prices Revisits Avoided Cost Proceedings

The procedure of estimating market prices based on the cost of new supply is not a new idea, it is just a new name. In the nearly twenty years since the passage of PURPA, many state commissions have engaged in the administrative determination of "avoided cost" using the same bottom up procedure to price purchase power obligations. The results of these avoided cost determinations reveal a history of excessive overestimation – actual market prices have turned out to be far lower than the estimated avoided costs. Indeed, in New England, New York, New Jersey, Pennsylvania and California, these above-market avoided

cost contracts represent a significant portion of the stranded cost problem. This overestimation problem is too pervasive to be dismissed as simply bad luck. Rather the chronic overestimation results from basic flaws in the approach, flaws which also infect the market price analysis of staff and other parties. To illustrate these basic flaws in the avoided cost approach let me describe three specific examples of the avoided cost overestimation problem from Texas, Massachusetts and New York.

Texas

In Texas, the Docket No 6064, "Application of Houston Lighting & Power Company For Approval of Standard Avoided Cost Calculation" was a filing that represented a stipulated settlement agreed to among the parties pursuant to PUC ruling 23.66 (h) (3). That ruling required HL&P to file an application for approval of a standard avoided cost calculation and terms and conditions for purchase of firm energy and capacity from qualifying facilities. The methodology adopted in that case used a proxy unit to determine HL&P's avoided cost. They found that the avoided source of incremental capacity and energy was a lignite-fired base load generating station. This filing contained the forecasted energy and capacity costs of that station stipulated to by the parties.

The table below shows the energy, capacity and total costs for the facility assuming an 84% capacity factor:

Year	Energy ($/MWh)	Capacity ($/MWh)	Total ($/MWh)
1985	26.0	18.1	44.1
1986	27.8	19.2	47.0
1987	29.7	20.4	50.1
1988	31.9	21.7	53.6
1989	34.1	23.0	57.1
1990	36.6	24.4	61.0
1991	39.0	26.0	65.0
1992	41.5	27.6	69.1
1993	44.3	29.3	73.6
1994	47.1	31.1	78.2
1995	50.1 (est)	33.0	83.1
1996	53.2 (est)	35.0	88.2

These forecasts are substantially in excess of actual prices. The average of the weekly *on-peak* ERCOT prices published by Power Markets Week in 1996 was $24.4/MWh. The 1996 price in all hours averaged $19.0/MWh. Today the price paid to HL&P's wholesale generators is approximately $20/MWh.

Massachusetts

In Massachusetts in 1991, the Department of Public Utilities (DPU) ordered Boston Edison to issue a request for proposals for power from non-utility generators (DPU 90-270). The RFP would contain maximum, or ceiling prices,

that could be bid to Boston Edison, based on the company's avoided costs. The DPU required Boston Edison to use the cost of its avoided unit, a gas-fired combined cycle facility. Boston Edison had previously submitted an IRP filing to the Massachusetts Energy Facilities Siting Council containing the cost to build this facility (EFSC 90-12/12A). The capital cost was $900 per kW, the heat rate 8,236 Btu/kWh, and gas prices were forecast at $4.42 per Mcf in 1995.

The ceiling prices based on that methodology are produced in the table below which shows the total costs for the facility:

Year	Total ($/MWh)
1995	55.9
1996	58.3
1997	63.5
1998	69.5
1999	76.2
2000	83.6
2001	90.1
2002	99.5
2003	108.9
2004	118.4

These forecasts are substantially in excess of actual prices. The average of the weekly *on peak* NEPOOL prices published by Power Markets Week in 1995 was $25.4/MWh. The 1996 price in all hours averaged $24.0/MWh, and through August, 1997 the average all hours price was $25.6/MWh. Current projects under

discussion in New England quote prices in the $30 to $40 per MWh range, less than half the level projected just six years ago.

New York

In New York in 1986, the Public Service Commission (NYPSC) issued an order (Opinion 86-8) adopting long-run avoided cost estimates for the purpose of establishing the price at which New York utilities would sign purchase power agreements with non-utility generators. The NYPSC required the following methodology for determining the ceiling price. The NYPSC adopted a two-phased approach. In the first phase, avoided energy costs were calculated using production cost modeling, while avoided capacity costs were calculated based on the cost of a new combustion turbine, adjusted to reflect existing capacity excess. In the second phase avoided costs in total were based on a new coal-fired proxy unit. The avoided costs based on that methodology are shown in the table below for New York State Electric and Gas Company, the company with the lowest avoided costs:

Year	Total ($/MWh)
1990	46.3
1991	48.8
1992	55.8
1993	63.0
1994	69.0
1995	74.7

1996	82.2
1997	90.6
1998	99.8
1999	109.9

Once again, these forecasts are substantially in excess of actual prices. The average of the weekly *on-peak* NYPP prices published by Power Markets Week in 1995 was $25.3/MWh. The 1996 price in all hours averaged $20.2/MWh, and through August, 1997 the average all hours price was $22.3/MWh.

Summary: Flaws in the Avoided Cost Approach

There are at least three major flaws in the avoided cost approach. First, all of these avoided cost projections were premised on a "fixed technology" perspective. That is, all assumed that the then-current preferred technology would remain the economic choice for a long period of time, and that its cost and performance would not improve. In each of the three cases, this assumption turned out to be incorrect. In two cases the wrong technology was picked – gas, and not coal turned out to be the economic choice due both to technological progress and changes in relative fuels prices. In the third case, gas combined cycle was the proxy unit, but the cost and performance assumptions did not take the possibility of further improvement into account, and thus this forecast also turned out to be too high.

The second problem is the assumption that projected reserve margins could be used to estimate the need date for new supply, and that the power market would remain in equilibrium thereafter. In at least two of these cases, the power market did not behave in this fashion. Supply and demand did not in fact achieve equilibrium on the forecast schedule, and prices turned out to be lower than forecast for this reason as well. The notion that markets move predictably to equilibrium conditions and remain there has yet to be demonstrated.

The third problem has been fuels price forecasts, particularly oil and natural gas. Past forecasts have proven to be much too high, contributing significantly to the over-estimation of avoided cost.

COPY

PENNSYLVANIA UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION,	:	
v.	:	Docket No. R-00974104
DUQUESNE LIGHT COMPANY Application for approval of restructuring plan pursuant to 66 Pa. C.S. Section 2806(d).	:	

Washington, D.C.

Monday, November 17, 1997

Deposition of

DAVID SCHOENGOLD

a witness, called for examination by counsel for Duquesne, pursuant to notice and agreement of counsel, beginning at approximately 2:20 p.m., at the offices of Skadden Arps Slate Meagher & Flom, L.L.P., 1440 New York Avenue, Northwest, Washington, D.C., before Shari R. Broussard, notary public in and for the District of Columbia, when were present on behalf of the respective parties:

Q Is it fair to say that your analysis or your calculations assume that the shareholders have not already been compensated for the stranded cost disallowance or sharing that you proposed?

A That the shareholders have not been compensated for the stranded cost disallowance that I proposed?

Q That's correct.

A I haven't followed the performance of Duquesne stock, so I don't know just what they

may or may not have been compensated for. But I didn't make any assumptions in my analysis as to whether or not they had been compensated for that potential disallowance.

THE PENNSYLVANIA UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION,	:	
v.	:	Docket No. R-00974104
DUQUESNE LIGHT COMPANY Application to approve restructuring plan pursuant to 66 Pa. C.S. Section 2806(d).	:	

Washington, D.C.

Wednesday, November 19, 1997

Deposition of

ROBERT B. WEISENMILLER, PH.D.

a witness, called for examination by counsel for Duquesne, pursuant to notice and agreement of counsel, beginning at approximately 11:25 a.m., at the Law Firm of Skadden, Arps, Slate, Meagher & Flom, L.L.P., 1440 New York Avenue, Northwest, Washington, D.C., before Shari R. Broussard, notary public in and for the District of Columbia, when were present on behalf of the respective parties:

Q Have you undertaken any analysis of whether, under Mr. Schnitzer's high line, whether the company not only has no stranded cost in 2005 but has no stranded cost in 1999?

A No, I did not look at that.

PENNSYLVANIA PUBLIC UTILITY COMMISSION

In re	:	
DUQUESNE LIGHT COMPANY Application to approve restructuring plan pursuant to 66 Pa. C.S. Section 2806.	:	Docket No. R-00974104

Washington, D.C.

Friday, November 21, 1997

Deposition of

MATTHEW KAHAL

a witness, called for examination by counsel for Applicant pursuant to notice and agreement of counsel, beginning at approximately 11:08 a.m. at the law offices of Skadden Arps Slate Meagher & Flom, L.L.P., 1440 New York Avenue, Northwest, Washington, D.C., before Shari R. Broussard, notary public in and for the District of Columbia, when were present on behalf of the respective parties:

Q Are you contending that Duquesne's shareholders have been compensated for this disallowance or adjustment?

A They may have been in the sense that during some period of time Duquesne shareholders may have earned returns that exceeded the cost of capital, but that's not the basis of what I'm doing.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-00974104
Duquesne Light Company Application to approve restructuring plan pursuant to 66 Pa. C.S. S 2806(d)	)	

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DEPOSITION OF

STEPHEN J. BARON

November 18, 1997

10:00 a.m.

J. Kennedy and Associates, Inc.

35 Glenlake Parkway

Suite 435

Atlanta, GA 30328

Wanda L. Robinson, RMR, CRR-B-1973

Q. Do you believe that Duquesne's shareholders have been compensated for the risk of such a disallowance that you propose?

A. I haven't made that determination. I simply don't know at this point in time.

Duquesne Statement No. 4-R

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DUQUESNE LIGHT COMPANY
DOCKET NO. R-00974104

Rebuttal Testimony
of
Morgan K. O'Brien

Contents:

Response to Intervenor Testimony Regarding
Potential Shut-Down of Generation Facilities

REBUTTAL TESTIMONY OF MORGAN K. O'BRIEN

Q. Please state your name and business address.

A. Morgan K. O'Brien, 411 Seventh Avenue, Pittsburgh, PA 15219.

Q. Have you previously participated in this proceeding?

A. Yes. I submitted direct testimony (Duquesne Statement No. 4) and various supporting exhibits with Duquesne's August 1, 1997 filing. A statement of my qualifications is contained in my direct testimony.

Q. What is the purpose of your rebuttal testimony?

A. I will provide certain data to be incorporated in an analysis by Mr. Clayton examining the ramifications of the potential shut-down of one or more generation facilities. The data that I will provide are operating costs which would not be avoidable by shutting down a generation facility. These costs include: (i) a portion of the general and administrative overheads; (ii) certain property taxes; and (iii) certain other taxes. In addition, I will estimate a likely amount of severance costs which would be incurred by the Company if a generation facility were shut down.

Q. Do you address regulatory asset issues in your rebuttal testimony?

A. No. Regulatory asset issues are addressed in Mr. Clayton's rebuttal testimony.

Q. Please describe the costs included in the general and administrative overhead costs that are included in the allocation to generation facilities.

A. Included in the general and administrative overhead allocation are the following: (i) benefits; (ii) facilities and transportation costs; (iii) corporate security; (iv) treasury; (v) corporate accounting; (vi) legal services; (vii) human resources; (viii) executive officers; (ix) environmental analysis; (x) public affairs; (xii) internal audit; and (xiii) payroll.

Q. Would these costs be avoided by shutting down a generation facility?

A. No. These costs are corporate costs which have been allocated to each generation facility based on the ratio of the direct costs of each facility to the total direct costs of all facilities. Thus, these costs would merely be reallocated to the remaining generation facilities after a facility has been shut down.

Q. Have you estimated any reduction in these overhead allocations if a facility were to be shut down?

A. Yes. I based my estimate upon the principle that with fewer employees to administer, as well as fewer accounting transactions as a direct result of shutting down, a portion of the corporate overhead costs would be reduced. Exhibit MKO-2 provides the quantification of the reduction in corporate overheads.

Q. What portion of the corporate overhead have you estimated to be avoidable if a facility were to be shut down?

A. Based upon the analysis provided in Exhibit MKO-2, approximately 20% of the general and administrative overhead cost would be removed from the Company's cost of operation and would be avoidable if a facility were shut down. The remaining portion of the overheads would continue to be incurred by the Company and would be reallocated to the remaining generation facilities.

Q. What would be the effect on property taxes included in the generation facilities' operating costs if a generation facility were shut down?

A. Property taxes for the Pennsylvania generation facilities would be reduced to zero once the value of the unit was written off the Company's accounting records. However, property taxes on the Ohio generation facilities would continue after the value of the unit was written off the Company's accounting records.

Q. Please describe why there would be a difference in the property tax treatment between the Pennsylvania and Ohio facilities.

A. The different outcomes are due to the differences in the way property taxes are calculated and levied in Pennsylvania and Ohio. Pennsylvania bases property taxes for electric utilities on the book value of the plant. The Ohio

property tax law bases property taxes on an assumed 50% of the original historic cost of the plant, plus the cost of any capital additions. The effect of the Ohio law is that property taxes are levelized over the license period of the nuclear facility located in Ohio. The Company is currently litigating this specific provision of the Ohio law and it is clear based upon the litigation record that the Ohio department of revenue applies the law in this manner.

Q. Are there any other taxes that could be avoided if a generation facility were shut down?

A. Yes. Pennsylvania capital stock taxes are based in part on a revenue factor and in part on a capitalization factor. Writing off the book value of a generation facility would have the effect of decreasing the capitalization component of the tax calculation, but would not affect the revenue component. Based upon the relevant magnitude of each component, 40% of the capital stock tax could be avoided once the book value of the generating facility was written off.

Q. If a generating facility were shut down, would the Company incur incremental costs which have not been included in the Company's projected operating expenses?

A. Yes. The Company would incur incremental severance costs for the employees who would be terminated based upon an administrative decision to shut

down a generating facility. Mr. Duckworth will describe the estimated severance costs the Company would incur if the Perry Unit were shut down. This unit is operated by the joint owners of the facility and would be subject to their specific severance policies. As for the Company-operated facilities, we estimate the severance cost of shutting down the Elrama Units to be $8.0 million and the Cheswick Unit to be $6.0 million.

Q. Please describe how your severance calculations were computed.

A. The Company based these estimates on the severance costs estimated to be incurred in the merger case between the Company and Allegheny Power. In that filing, the Company estimated that it would incur $24 million of severance costs if it reduced its workforce by 500 employees. Reducing that total amount to a cost per employee results in a cost of $48,000 per employee. It is estimated that a shut down of the Elrama unit would reduce the Company's headcount by 160 employees and the Cheswick unit by 120 employees. Simply multiplying the affected employee numbers by the average cost results in the estimate of $8 million at the Elrama Unit and $6 million at the Cheswick Unit.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

Q. Thank you.

DUQUESNE LIGHT COMPANY
Avoidable Overhead

	$ Millions	$ Thousands			Allocation Basis for Savings
		Ches.	Elrama	Perry	
MIS	$17	$228	$228	$0	MIS Usage Report
Marketing & sales	10	0	0	0	
Admin Services - net of CAPCO billings	8	271	395	0	# of employees
Treasury	4	0	0	0	
Legal	4	0	0	0	
Reg & Econ Analysis	3	0	0	0	
Human Resources	3	102	148	0	# of employees
Executive Office	3	0	0	0	
Fringes	3	102	148	0	# of employees
Environmental Analysis	2	83	83	125	Assessment of regs.
Public Affairs	2	0	0	0	
V&PR	2	104	95	353	% of gross plant
Customer Accounting	1	0	0	0	
Accounts Payable	1	47	75	0	% of O&M
Reporting/Accounting	1	0	0	0	
Payroll/Tax	1	34	49	0	# of employees
CFO	1	0	0	0	
Internal Audit	1	34	49	0	# of employees
Corporate Secretary	1	0	0	0	
Overhead Avoidable	$68	$1,004	$1,270	$478	
Overhead Allocated*		$5,194	$6,424	$5,166	
% Overhead Avoidable		19.3%	19.8%	9.3%	

* Overhead allocated to Generation (60.2% of total) was allocated to plants based upon each plant's prorata share of total direct operating and maintenance costs.

Duquesne Statement No. 5-R

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DUQUESNE LIGHT COMPANY
DOCKET NO. R-00974104

Rebuttal Testimony
of
James A. Lahtinen

Contents:

Response to Intervenor Testimony on Duquesne's Market-based RFP and CGC Determination, the Unbundled Allocated Cost of Service, and Duquesne's Proposal to Redesign its Tariffs to Mitigate Stranded Costs

REBUTTAL TESTIMONY OF JAMES A. LAHTINEN

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is James A. Lahtinen and my business address is 411 Seventh Avenue, Pittsburgh, Pennsylvania 15230-1930.

Q. By whom are you employed and what is your position?

A. I am employed by Duquesne Light Company ("Duquesne") as General Manager of the Regulatory and Economic Analysis Unit.

Q. Are you the same Mr. Lahtinen that filed direct testimony earlier in this proceeding?

A. Yes. I submitted direct testimony, Duquesne Statement No. 5, in the Duquesne Restructuring Plan filing on issues pertaining to the allocated cost of service, market prices, and unbundled rate design.

Q. What is the purpose of your rebuttal testimony?

A. My primary purpose is to respond to intervenor testimony regarding the following major topics:

- Duquesne's proposal to use the results from an annual RFP process to establish market power prices and customer generation credits (CGCs),
- Duquesne's unbundled allocated cost of service study (In this section I will also comment on ENRON witness Reising's proposed cost unbundling proposal.)

- Duquesne's proposal to unbundle and redesign its tariffs towards more efficient levels in order to mitigate stranded costs.

Q. I take it that your responding testimony is organized along these lines.

A. That is correct.

Q. Could you please summarize your major conclusions?

A. Yes, I have three of them, one for each major topic above.

Q. Please summarize your first conclusion regarding the RFP and necessary adjustments to establish a customer generation credit.

A. The intervenors launch attacks on two fronts in an attempt to criticize Duquesne's proposal to rely upon market evidence in setting customer generation credits (CGCs). The first front attacks the RFP process head on, while the second front comes equipped with a barrage of "adder" adjustments. I find the criticisms against Duquesne's annual RFP process and the results from its 1997 solicitation to be nothing more than a collective wish to ignore reality. And that reality is the existence of available coal-fired capacity in ECAR that tends to "depress" the current market value of power in the region.

I am equally unimpressed with the rationale offered to support the legitimacy of upward adjustments to the RFP market price to either include costs the RFP process "misses" or to recognize the "spread" between retail and wholesale prices. In large part these adjustments are offered to account for what the intervenor witnesses describe as the high transaction costs involved with selling at retail,

leaving one to wonder why we are moving to competition in the first place. If adopted by the Commission, these "markups" and "incentives" will create new stranded costs during the transition period as readily acknowledged by several witnesses for the intervenors. Finally, Duquesne is proposing to modify its market-based proposal to include avoidable distribution line losses in the CGC based on intervenor comments. Duquesne will continue to adjust for customer class time-of-use consumption patterns, transmission losses and gross receipts tax in establishing market-based CGC's. In addition, Duquesne will apply a market-based credit for ancillary services that can be competitively procured.

Q. What is your second major conclusion regarding the unbundled allocated cost of service?

A. Many of the objections to Duquesne's allocated cost of service appear to be veiled attempts to shift costs from distribution to the production function with the effect of denying the Company the opportunity to recover its stranded costs through a CTC. (It should be pointed out that OSBA witness Kalcic's proposal is different from that recommended by ENRON witness Reising in that he appears to allow Duquesne the opportunity to recover these costs through the CTC.) Duquesne has unbundled its costs using methodologies consistent with those used in the Company's most recent base rate proceeding, and the guidance provided in FERC Order 888. However, consistent with our proposed modification to the CGC's described above, Duquesne will remove the cost of supplying distribution losses from the distribution charges and put them back into generation. The CGC will

be adjusted to reflect avoidable distribution losses thereby allowing customers the choice of having their suppliers provide these losses. As a result, Duquesne will either directly charge suppliers for distribution losses or allow them to supply them on their own account.

Q. Please summarize your third major conclusion regarding Duquesne's proposal to unbundle rates and redesign its tariffs.

A. Finally, all but a few of the intervenor witnesses fail to properly comprehend the benefits they propose to deny consumers by rejecting Duquesne's rate design proposal. Their arguments mostly invoke concerns over cost-shifting. Either the intervenor witnesses have absolutely **no** understanding of the difference between cost shifting (which the Act prohibits) and revenue shifting (which happens whenever customers change consumption between rate years under any rate design) or their objections have absolutely nothing to do with efficiency, adequacy, or fairness. Duquesne's rate design utilizes customer-specific CTC's in order to prevent cost shifting within and among customer classes. For those customers who continue to purchase electricity from Duquesne, the unbundled rates will result in the same bill the customer would otherwise pay under current bundled rates (adjusted for the ECR roll-in) assuming 1996 test year sales levels.

The intervenor witnesses also fail to recognize the stranded cost mitigation potential of Duquesne's proposed rate re-design ($15 million per year). The restructuring legislation contemplates that utilities will undertake efforts to fully

mitigate stranded costs and rate re-design affords Duquesne one of the best opportunities to do so.

Nonetheless, some have argued that the new rate design is confusing and could raise equity concerns for customers that reduce consumption. In response, Duquesne will accept OSBA witness Kalcic's recommendation that customers be given a choice between a simple unbundled rate structure or Duquesne's more efficient rate proposal. Offering an option should put to rest any intervenor concerns over the fairness of Duquesne's rate re-design proposal.

The remainder of my rebuttal testimony supports these conclusions in greater detail.

II. THE MARKET PRICE OF POWER AND ESTABLISHING THE CGC

Q. Mr. Lahtinen, several witnesses have taken exception with your use of the RFP price for purposes of setting the CGC. Could you first categorize the arguments raised by the intervenors and then respond?

A. I will try. Several witnesses raised concerns over setting the CGC's on the basis of prices obtained from Duquesne's proposed RFP process. I will not deal here with each witness individually since many of them raise the same arguments. (However, I am attaching Exhibit JAL-14 that responds to the plethora of specific attacks on Duquesne's proposal.) I believe it is possible to summarize the opinion

of the opposing parties along the following lines:

- The RFP price is a downward biased estimate of the wholesale commodity price.
- Even if the RFP price was a reasonable measure of the wholesale commodity price, it still would be too low since it does not include the value of capacity, installed reserve requirements, and the costs of ancillary services.
- Even if the RFP was "properly" adjusted to reflect wholesale prices, it is not an accurate measure of the retail market price because it fails to adjust for distribution line losses, overheads, and marketing costs that competitors will bear.

A. The RFP Approach Provides An Accurate, Known and Measurable Market Price At Which Duquesne Can Sell Power When Retail Load Chooses Alternative Suppliers

Q. How do you respond to the first point raised by the intervenor witnesses that the RFP is downward biased?

A. First, I would like to address the issues Mr. Russell raises on behalf of MAPSA regarding the design of the RFP at pages 25-27 of his testimony. There he asserts that the design of Duquesne's RFP encouraged low bids because the take provisions of the power sale are inflexible reducing its market value as a product for sale at the retail level. He also suggests that recent postings by Duquesne of no firm ATC indicate that purchasers under the RFP will be left with non-firm

transmission service further reducing the appeal of the power product. Finally, he asserts that the relatively short response time between issuance of the bid and the date on which bids were due resulted in discounted bid prices to hedge against the uncertainty created by the "time constraints".

Q. How do you respond?

A. First, the product Duquesne offered for sale under its RFP was designed to enhance value and is appropriate to calculate stranded costs for Duquesne customers. Duquesne's generation portfolio is comprised primarily of baseload units. The minimum 50% capacity factor appropriately recognized that these units cannot be "cycled" below certain minimum levels. In addition, a 75% capacity factor is an appropriate product because it essentially combines a baseload product with a sale of on-peak power. Finally, as discussed in my direct testimony, Duquesne has proposed to adjust the winning prices from the RFP to account for the hourly differences in usage among Duquesne's rate classes, thus transforming the RFP price to a class-specific retail price.

Q. Could Duquesne have used a different capacity factor in the RFP for purposes of establishing the CGC?

A. Yes, but it is unlikely to have a significant effect on the market price.

Q. Would using a 100% capacity factor (i.e., all hours) sale provide a better estimate of the market price?

A. No. An all hours sale would undoubtedly lead to a lower average price from the RFP process, because the price would reflect an equal weighting of on-peak and

off-peak hours. However, this price would need to be adjusted upward to recognize customer class usage patterns.

Q. Would using an on-peak only (i.e., "5 by 16") sale provide a better estimate of the market price?

A. No. An on-peak "5 by 16" sale refers to selling power in the sixteen on-peak hours during Monday through Friday. A "5 by 16" sale would undoubtedly lead to a higher average price from the RFP process because the price would reflect only the on-peak hours. As a result, this higher price would then need to be adjusted downward to reflect the customer class load pattern.

Q. Why do you claim that the RFP was designed to enhance value?

A. While Duquesne could require purchasers to take an all hours or a "5 by 16" contract, it would afford a potential purchaser no flexibility to vary schedules. The product Duquesne has proposed to sell under the RFP (indeed, sold in its 1997 solicitation) is intended to provide purchasers with scheduling flexibility between 50% - 100% in any hour.

Q. Why did Duquesne's 1997 RFP impose a 50% minimum take in any hour and specify an annual capacity factor of 75%?

A. Duquesne witness Mr. Irvin informs me that the 50% minimum hourly take is necessary for operational reasons. This allows Duquesne's generating units to be backed down, but does not require them to be taken off-line during minimum daily load periods when Duquesne's system load is at its lightest (roughly 50 percent of on-peak demands). The annual capacity factor requirement is

necessary in order to establish a known and measurable contract quantity and market price.

Q. Did Duquesne consider other factors in developing the RFP?

A. Yes, the Company spoke with several traders who are actively engaged in buying and selling wholesale power through competitive solicitations prior to designing the RFP. These discussions revealed that potential purchasers were most concerned with two things: a) the sincerity of the offer and b) the ability to take power during the peak period. Traders who we spoke to indicated that bidders were primarily concerned that the offer was credible. As Mr. Irvin states in his direct testimony, this is why Duquesne made a commitment to sell power to the highest bidder(s) because in his experience "it is not uncommon for a utility to conduct an RFP without following through by awarding capacity and energy to the winning bidders". (See Irvin direct at page 7.) In fact, Mr. Irvin informs me that neither of these issues ever came up during his discussions with any of the parties who contacted him about Duquesne's RFP.

Q. How do you respond to Mr. Russell's second assertion that the bid prices were depressed because of the possibility that firm transmission would be unavailable?

A. First, the argument is disingenuous because, under the power sales agreement, the purchaser does not bear the risk of transmission constraints on the Duquesne system. Duquesne specifically modified Section 6 of the PSA, at the behest of interested bidders, to provide that, if there were transmission constraints on the Duquesne system, Duquesne would be required to deliver the power at other

delivery points. Consequently, the claims of Mr. Russell and Mr. Weisenmiller that the power was "non firm" because of the lack of "firm transmission" are meritless. Second, it is astonishing that Mr. Russell would suggest that Duquesne should have included firm transmission in the RFP, thereby "bundling" transmission rights with the firm power offering. At every occasion in other portions of Mr. Russell's testimony, he criticizes Duquesne for bundling any services together. Third, given that these witnesses criticize the RFP for having "inflexible" terms, one would think that the most flexible power product would be one in which the purchaser, rather than Duquesne, chooses the necessary transmission service. In this way, it can purchase the service most appropriate and economic to its needs, as Order No. 888 permits. Finally, there is no evidence that a purchaser will be unable to buy firm transmission on Duquesne's system. Obviously, a purchaser of power in the RFP who chose to sell at retail in Duquesne's service territory would place no additional load on our system. If the transmission system provides adequate capability in a world before retail choice, it follows that the Company will have sufficient firm transmission capability after retail choice begins since the same amount of load will be served using the same transmission network. And more to the point, the power supplied under the RFP will be coming from the same generation sources Duquesne currently uses to serve its retail and full requirement customer. There is absolutely no reason a knowledgeable purchaser under the RFP would be concerned that the transmission service offered by Duquesne under its FERC tariff would be any less firm than the

transmission service Duquesne provides its full requirement customers today.

Q. How do you respond to Mr. Russell's last point concerning time constraints?

A. Mr. Irvin informs me that no bidder (potential or actual) expressed any concern over the fact that bids were due within 3 weeks from the issuance of the RFP. Moreover, the traders who we spoke to indicated that a lead-time as short as 1 week would not be viewed by market participants as an unreasonable time constraint. (It should be pointed out that in subsequent RFP's, the Company could easily extend the response time if this becomes an issue with bidders in the future.)

Q. Mr. David Boonin on behalf of New Energy Ventures, a potential retail supplier, proposes that the unbundled price for generation be determined by the wholesale market. Do you agree with his position?

A. Yes. Duquesne agrees "that this is necessary in order to make choice a reality for retail customers while treating all affected parties equitably."(See direct of Mr. Boonin at page 3.)

Q. Would you accept his argument that the price for generation should be determined by the market-clearing price of the power exchange?

A. Yes, I agree that a power exchange would be a good source for gathering market clearing price data. There is only one problem: a power exchange doesn't exist for Duquesne. This is why Duquesne has proposed to rely upon a competitive RFP process to determine market prices. However, as Mr. Marshall explains, if a power exchange emerges, Duquesne could be willing to terminate use of the RFP

and substitute the PX price.

Q. Since many intervenors have criticized the RFP product and process, would Duquesne consider changing future RFP's that are used to set the CGC and CTC?

A. Yes. The Company would be willing to adopt constructive changes in either contract terms or bidding procedures for future solicitations. Our primary objective is to establish a known and measurable market price for Duquesne's generation. To demonstrate our flexibility, Duquesne will commit to file the RFP with the Commission for prior approval. In this manner, all interested parties may provide suggestions to improve it.

Q. Have any of the intervenors proposed alternative contract terms or procedures for the RFP?

A. No, unfortunately they have not.

Q. Why is this?

A. I am not sure. However, I can only guess that their objective is to shoot down the RFP without providing the Commission any market-based alternative, thereby leaving the Commission no choice but to set CGCs using an administrative "forecast" method. I must conclude this because of the inordinate effort they expend on criticizing every facet of the RFP. I consider most of these objections to be so unfounded, and contrary to accepted economic principles, as to merit no response. However, I am concerned that the Commission may be mislead by these statements and that, if unrebutted, the intervenors will claim that they have identified "unrebutted" flaws in the RFP. For this reason, I have taken the time to

itemize each criticism (including those related to other aspects of CGC calculation and unbundling) and provide a specific response in Exhibit JAL-14 attached hereto.

Q. Do you agree with Mr. Boonin's recommendation that the unbundled CGC and CTC always be kept in balance so that the total of the two never varies and never exceeds the rate cap?

A. Yes, this is a pillar of Duquesne's unbundling proposal. If market prices increase over time (as revealed in the competitive RFP), the CGC would increase and the CTC would fall accordingly, and vice versa. As Mr. Boonin correctly points out on page 5 of his testimony, the electricity price will vary depending on market conditions and "the appropriate unbundled price of generation should also vary with the market and not be fixed." This "frees the Commission from the impossible task of accurately predicting the prevailing market price of generation." Mr. Boonin correctly observes that this "approach is also consistent with the intent of the legislation which is to deregulate the price of generation, not to reestablish a regulated price of generation on a different concept than historical rate base regulation." I agree that this approach is "far more accurate than one based upon a one time estimate of market prices." (See Boonin direct at page 17.)

B. The RFP Approach Appropriately Accounts for Capacity, Installed Reserves and Ancillary Services

Q. Please respond to the second set of arguments that the RFP price is too low

because Duquesne failed to make adjustments necessary to fully measure the market value of wholesale power.

A. Based on my reading of the intervenors' testimony, the criticisms can be grouped along the following lines:

- The RFP price is an energy only value,
- A value for capacity plus an adjustment for installed reserves is necessary, and
- The market price must also be adjusted for the cost of ancillary services.

First, it is clear that many of the intervenors either did not read or did not understand our proposal to use the RFP price as the basis for setting the CGC, nor our treatment of ancillary services. Second, it is quite clear that many of the intervenors would prefer that Duquesne be required to set a high CGC as opposed to a market-based one, since customers would have a greater incentive to switch to an alternate supplier and/or suppliers would have a greater opportunity to make a profit. Most importantly, the rationale supporting the intervenors' arguments for adjusting the RFP price are conceptually flawed and should be rejected by the Commission.

Q. Please begin by summarizing the opponents' assertions that the RFP price is an energy-only price.

A. Certainly. Again Mr. Russell states the case most clearly for the intervenors. He argues that the prices set in the RFP "are more akin to bulk power rates into a power exchange than the rates to individual customers within a market region". He therefore concludes that "they reflect only a part of the value of the power

supplied". (See Russell direct at page 21.) Presumably, this means that the RFP price reflects only the energy value for wholesale exchanges in the ECAR region. This is clearly not the case. The power that is provided under the RFP is a firm obligation to sell electricity, as well as a financial obligation to pay replacement costs if Duquesne fails to perform. The bottom line is that Duquesne will provide the power or pay the supplier replacement costs holding the purchaser harmless. That is precisely the definition of firm power in today's market, as explained by Mr. Irvin.

This sale is not akin to a spot or non-firm sale of power into a power exchange as Mr. Russell asserts. I suspect that the real objection Mr. Russell and others have with the RFP price is that the "market" doesn't place as much value on firm power as these "experts" would like. The fact that capacity has little or no value in the ECAR region is a reality that everyone, most of all Mr. Russell, wants to ignore in this proceeding.

Q. Has Duquesne provided additional evidence in this case on the capacity value of generation within the ECAR region that supports the results from the RFP?

A. Yes. And it is interesting, although not surprising that no intervenor mentions it. I find it interesting because this data was provided in Mr. Irvin's direct testimony and again by me in response to discovery request DII-2-04. That data indicated a peak capacity value ranging between $0.43/kW/year to $1.06/kW/year during 1996 and 1997. I am not surprised no one mentions this because it does not support claims by Duquesne's opponents that capacity has substantial value in the

ECAR region.

Q. What is the source of this data?

A. This data comes from actual prices Duquesne paid for the rights to call upon a specified amount of generating capacity. As Mr. Irvin describes in his direct testimony, Duquesne made two capacity purchases over the past two years. In 1996, Duquesne purchased the call rights on 75 MW's of capacity for 6 weeks at a price of $32,000 or $0.9 per MWH after factoring in the number of on-peak MWH. A similar arrangement was made during the summer of 1997 but only for 50 MW's over a nine-week period. The reservation price in this case was $52,800 or $1.5 per MWH after adjustment for the number of on-peak MWH. It should also be pointed out that these prices represent capacity value during Duquesne's summer peak period, indicating that similar purchases of reserved capacity during times of lighter demand could be obtained at lower prices. As a result, the effective annual price for peaking capacity is likely to be even lower than indicated by the above figures.

Q. Is there anything else notable about these capacity purchases?

A. Yes. They were unencumbered by any of the "flaws" that the intervenors attach to the RFP. They were negotiated at arms-length between two parties. No pre-specified terms were set. There was no auction. There was no "short" response time. Yet, the capacity prices produced in these negotiations are entirely consistent with the RFP prices.

Q. Is there any other evidence of which you are aware that corroborates the RFP

prices?

A. Yes. The OCA's market price witness, Mr. Smith, has predicted a price stream during the transition period that mirrors the prices produced by Duquesne's 8-year RFP, with only exception being a forecast by Mr. Smith that prices will "bump up" in 2003 to reflect new capacity additions. Whether or not this occurs is, of course, anyone's guess, but I find it interesting that Mr. Smith's projection otherwise is entirely consistent with the results of Duquesne's supposedly "flawed" RFP.

Q. What is your response to those who argue that Duquesne's estimate of market value fails to make a necessary adjustment for installed reserves?

A. It is correct that Duquesne does not adjust the RFP price for installed reserve margins. This is because the RFP price fully reflects this value. As explained by Duquesne witness Mr. Karl, Duquesne has traditionally maintained installed reserves to serve retail load. Now that we have sold firm power in the RFP, Duquesne will continue to maintain installed reserves to support that firm sale. In effect, there is little difference between selling retail and wholesale from the standpoint of the generator. This is consistent with the "firmness" issue described above. Winning RFP suppliers need not worry about acquiring additional installed reserves since the RFP provides the purchaser with the reliability needed to serve retail load.

Q. Will retail suppliers be required to carry installed reserves in order to sell at retail in Duquesne's service territory?

A. As Mr. Karl explains, Duquesne and other ECAR companies do not have installed reserve requirements like the PJM companies. As a result, neither the RFP price nor its capacity component equivalent requires any adjustment for a requirement that does not exist. As explained by Mr. Karl, Duquesne plans to maintain installed reserves of 12% for its full requirements customers consistent with the Company's continued obligation to serve during the transition period. However, Duquesne will not impose an installed reserve requirement obligation on competing suppliers. The Company agrees with Enron witness Coles that the level of installed reserves should be set by market participants, not by regulatory fiat.

Q. So are you saying that the RFP price you propose as the basis for setting the CGC's fully reflects the market value of both energy and capacity, including installed capacity reserves?

A. Yes. Furthermore, I am saying that any adjustment for reserve margin requirements would overstate the market value of power in the ECAR region and would be inconsistent with current requirements.

Q. Several witnesses suggest that the CGC should be adjusted by adding thereto Duquesne's proposed ancillary service rates. How do you respond?

A. That proposal mixes apples and oranges. The purpose of the CGC is to provide a credit for the market value of generation services that can be competitively procured. It is not a measure of regulated "cost" of service.

Q. Then how would Duquesne ensure that it does not collect ancillary service costs twice -- once from customers and once from suppliers?

A. Ancillary services will be charged (or credited) with regard to whether the particular service can be competitively procured (i.e., is akin to the market for deregulated generation sales) or cannot be competitively procured (i.e., is akin to a "wires" service, such as transmission or distribution). If it is the former, and can be competitively procured (today, only supplemental reserves falls in this category), Duquesne will treat it just like competitively procurable power: a market-based credit will be computed and added to the CGC, which in turn reduces the CTC by the market value of the generation-based ancillary service. (For example, as to supplemental reserves, a market based credit would be added to the CGC that reflects the pure cost of generating capacity (currently approximately 1.5 mills/kWh).) If it is the latter, and the service cannot be competitively procured, Duquesne will treat it just like other wires services: the customer will continue to pay a cost-based, FERC-approved rate and suppliers will not be obligated to supply it.

Q. Some suppliers contend that Duquesne is thwarting the development of a competitive market by not making all these ancillary services competitively procurable. How do you respond?

A. Their complaints are with ECAR, not with Duquesne. Duquesne does not set the rules; it follows them. As indicated in Mr. Irvin's direct testimony, Duquesne will abide by Order No. 888, which requires transmission providers to permit their customers to self-provide ancillary services to the extent it is technically feasible under applicable regional reliability council standards.

Q. MAPSA witness Mr. Russell and OCA witness Ms. Smith assert that ancillary service costs are primarily generation-related and should be included in generation. How do you respond?

A. Ancillary services that can be competitively procured, such as supplemental reserves, will be included in generation. As noted above, a market-based credit will be computed and added to the CGC. The remaining embedded costs will be reflected in the CTC. Those ancillary services that cannot be competitively procured will be included in transmission rates.

C. Other Adjustments For Customer Time-of –Use Consumption, T&D Losses and GRT Are Necessary

Q. Please summarize the arguments put forth by the opposing parties that since retail market prices will be higher than the wholesale power prices, your CGCs are too low and should be adjusted upwards by the Commission?

A. The intervenor witnesses present four main arguments:

- Duquesne's take provisions in the RFP do not reflect actual retail customer consumption patterns
- Duquesne's CGCs must include distribution line losses to reflect the market value of power at the retail level,
- Duquesne's market price estimate needs to be adjusted for A&G expense adders,
- Duquesne's market price estimate needs to be adjusted for retail marketing

costs.

Q. What about the first issue?

A. Several intervenors criticize the take provisions of the RFP and express concern that these do not reflect customer consumption patterns. Ms. Smith states that it is not clear how the Company adjusted the wholesale market price to reflect average system load shape. (Direct testimony of Ms. Smith, p. 10) These criticisms are unfounded. I provided a detailed description of the methodology I used to convert the RFP price into a customer class load-weighted CGC. (See Lahtinen direct testimony pp. 54-61.) I even prepared a simplified example to illustrate the approach.

Q. Please address the issue regarding distribution line losses.

A. ENRON witness Reising, OCA witness Lee Smith, and DIIC witness Baron all argue that Duquesne has improperly included the cost of distribution line losses in its distribution tariff and therefore understated the CGCs. Mr. Reising is the most vociferous opponent of our proposal.

Q. How do you respond to this complaint?

A. Duquesne's original proposal would have provided the distribution losses for all load served within our territory, eliminating the option of competitive procurement. This is the same logic Duquesne applied in its treatment of reactive power, frequency control, and operating spinning reserves. It is important to point out that our proposal would not have resulted in customers paying twice for distribution losses since Duquesne would have provided this service for all

customers within our territory regardless of their power provider. However, Duquesne has no objection to removing the cost of losses from its distribution tariff and making them available at market-based prices or allowing suppliers to competitively procure their own distribution losses. (It is interesting to note that not one of the intervenor witnesses referenced Duquesne's offer to make this change - DLC response to Environmentalist 3-157.) However, it should be pointed out that the vast majority of these costs are associated with the capacity cost of distribution line losses which reflects Duquesne's embedded cost of generation. As such, Duquesne will now include these costs as part of the generation cost component for cost of service purposes. These non-avoidable costs will be recovered in the CTC. In addition, Duquesne will reflect the market value of distribution line losses in its CGCs, as requested. Exhibit JAL-15 shows the class-specific CGCs reflecting transmission and distribution losses as well as the gross receipts tax adjustment.

Q. Do you agree with those witnesses who say that the CGCs need to be adjusted to reflect an A&G adder?

A. Absolutely not. The rationale for this adjustment is confused and confusing. It points out a fundamental misunderstanding of the relationship between market prices and how overhead costs will be recovered in a competitive market. The argument in favor of an adjustment for overheads is made most clearly by OCA witness Lee Smith. At page 10 of her direct testimony she says that "an appropriate amount of administrative and general expenses should be in an

avoidable generation rate component which should be added to the wholesale price to determine the appropriate avoidable generation credit for retail customers". The effect of her proposal is to add almost $4 per MWH to an administrative estimate of market prices. Presumably, Ms. Smith would apply the same adder to Duquesne's market-based RFP price assuming the PaPUC adopted it.

Q. What is your reaction to Lee Smith's testimony?

A. Surprise. I am surprised because another OCA witness named Smith (Doug) quite correctly observes that in a competitive market, a generator will receive a market clearing price "equal to or greater than its own bid price, resulting in a "contribution" of net revenue to offset the generator's fixed costs of owning and operating its generating source(s)". (See Doug Smith Direct at page 11.) There is absolutely no reason to expect that market clearing prices in a competitive market will reflect the marginal cost of power plus an A&G "adder", whether the sale is at the wholesale or retail level. Individual competitors are price takers, not price setters, in a workably competitive market. Competitive suppliers will compete to supply the demand for the commodity electricity up to the point where the marginal cost of the least efficient (i.e., highest supplier) producer is equal to the marginal value consumers place on the use of electricity for heating, lighting, or operating machines. Since the market clearing price is set by the least efficient supplier providing power in the marketplace, all other power suppliers selling into the market at the same time, will receive revenues that cover their out-of-pocket

costs plus some contribution to overheads and profit ("fixed cost contribution"). Of course, it is also true that more efficient suppliers will enjoy higher levels of "fixed cost" contribution, than less efficient suppliers But this is exactly how competition is supposed to work The adjustment for A&G expenses proposed by OCA witness Lee Smith and some of the other intervenor witnesses should be rejected by the Commission. Indeed, OCA witness Doug Smith makes a compelling case why such an adjustment to market power prices is unnecessary and unwarranted. One of the major goals of this proceeding is to move away from cost-based pricing for generation and toward market-based pricing.

Q. What is the implication of setting the CGC's above market levels?

A. Inefficiency as Mr. Schnitzer explains in his rebuttal testimony and the creation of a new class of stranded costs. Duquesne believes that the purpose of the transition period is to mitigate stranded costs, not create new ones to be dealt with at a later time. Mr. Russell's position on behalf of MAPSA is the exact opposite. He proposes to set the CGC on the high side and "keep track of the extent to which the utility's amortization of stranded costs is penalized or hurt." He goes on to recommend that the Commission allow utilities to recover these additional stranded costs and suggests a possible extension of the transition period. (Russell deposition, pp. 11-13)

Q. Please summarize the testimony of those intervenor witnesses who assert that the wholesale market price estimate needs to be adjusted for retail marketing costs in order to set appropriate class-specific competitive generation credits.

A. Some of the witnesses (e.g., Mr. Russell at page 33) suggest that the Commission place "the utilities' costs of marketing and back-office overhead at risk" by adjusting the CGCs upwards. ENRON witness Mr. Reising on the other hand, argues that sales expense should be removed from Duquesne's distribution tariff and placed entirely in the production-related function for cost of service purposes. He also recommends that the Commission deny Duquesne the opportunity to recover these costs through the CTC because failing to do so will give Duquesne's and its affiliate an unfair competitive advantage. (I will have much more to say about the Reising testimony in a separate section of my rebuttal testimony.) Both recommendations are designed to accomplish the same thing: to deny the Company an opportunity to recover its stranded costs. This is so because both proposals would reduce revenues by an amount equal to the full amount of retail sales expense, ignoring any distinction between avoidable and non-avoidable expenses.

Q. Please explain the Russell proposal.

A. Mr. Russell's proposal would increase the CGCs for retail marketing expenses presumably using Duquesne's test year sales expenses. This approach will simply provide suppliers a higher price umbrella and increase Duquesne's stranded costs.

Q. Has Ms. Smith identified marketing expenses that Duquesne, as a distribution company, can avoid?

A. No. The sales expenses booked by Duquesne in 1996 do not represent the costs Duquesne is likely to avoid if it sells fewer kWh during the transition period This

is because the sales expense category represents costs that have nothing to do with marketing activities at the retail level and includes many costs that are unavoidable overheads. (Mr. Hoffmann explains this in greater detail in his rebuttal testimony.) I simply would point out that the upper limit of avoidable marketing costs provided by Mr. Hoffmann is relatively small, $6.7 million, as one would expect since Duquesne was a monopoly provider of retail service during 1996. In addition, if some portion of these costs are avoidable, Duquesne's restructuring plan called for these savings to be used as mitigation of stranded generation and other asset costs during the transition period.

III. COST OF SERVICE ISSUES

Q. Please describe what areas you will cover in this section of your testimony.

A. I will respond to intervenor criticisms regarding the allocated cost of service study I filed on behalf of Duquesne. These criticisms focused on two main areas: Duquesne's functionalization of costs among production, transmission, and distribution and my use of a required rate of return rather than an overall "realized" rate of return for establishing cost based rates for distribution and transmission service.

Q. Who are the witnesses raising these issues?

A. Mr. Reising testifying on behalf of ENRON sets forth the most detailed rebuttal to the Company's approach to allocating its cost of service He is joined by OSBA witness Kalcic, in attacking my use of the required rate of return instead of an

overall realized rate of return for establishing unbundled costs and ultimately rates for transmission and distribution service. Mr. Reising also proposes that the Company design rates based on the customer's voltage service level rather than historical identification by traditional "class" of service. (See Reising direct pages 25-28.)

A. Duquesne's Functional Cost of Service Study Properly Assigns Costs

Q. Please respond to Mr. Reising's assertion that Duquesne improperly assigned sales expenses, customer information and assistance expense, and a portion of un-collectible accounts expense to distribution.

A. Mr. Reising's proposal to re-assign customer information and assistance expense from distribution to production is poorly conceived and improper.

Q. Can you summarize why you assert that Mr. Reising's position is poorly conceived and improper?

A. Yes, but first I will explain his proposal. Mr. Reising claims that FERC account 908 - customer assistance expense and account 909 - informational and instructional advertising expenses include many expense elements that should be assigned to Duquesne's production, not its distribution function. (See Reising Direct at pages 8-9.) He asserts that each account includes many elements associated with efficient use of electric equipment. Therefore, his recommendation is to remove all of these expenses from distribution and assign them to production because none of these expenses is related to "rendering energy

delivery or revenue cycle services". He does however concede that a portion of the expenses associated with electric line safety (which are included in accounts 908 and 909) might be properly allocated to the distribution function.

Q. How do you respond?

A. Even if Mr. Reising is correct that these costs should not be entirely assigned to distribution, it stretches credulity to conclude that all of these costs should be assigned to the production function. Even in an unbundled world as a regulated monopoly, electric distribution companies (EDC) will continue to have an interest to build and operate their delivery system efficiently This will include incurring expenditures that promote efficient use of the delivery system where it is cost effective to do so. It makes no sense for the Commission to adopt a proposal that would deny an EDC from recovering the costs associated with worthwhile expenditures promoting the efficient use of electricity. Mr. Reising's proposal would leave the EDC no choice but to reject low cost efficiency-related activities in favor of more investments in poles and wires This proposal would result in customers paying delivery service rates that are higher than necessary and should therefore be rejected by the Commission.

Q. Is Mr. Reising correct that the Company included uncollectible accounts expense entirely in the distribution function?

A. Yes, Mr. Reising correctly notes that Duquesne assigned all of its uncollectible accounts expense to the distribution function. I will explain why Mr. Reising's proposal is inherently unfair to Duquesne given its obligation as supplier of last

resort under the Competition Act.

Q. Explain.

A. Mr. Reising argues that the $11 million of uncollectible accounts expense Duquesne includes as a distribution-related cost of service component should be "allocated between production, transmission, and distribution". (See Reising direct pages 10 -11). The recommendation is based on his assertion that an allocated share of these costs is necessary "to create a fair and competitive market." I understand Mr. Reising's position as follows: in a competitive market, all generation suppliers will incur the cost of uncollectibles and therefore, Duquesne's proposal would result in competitive suppliers being unfairly disadvantaged because their customers would pay for uncollectible expenses twice - once through Duquesne's distribution rate and once through their power charge from the supplier. His analysis is flawed because he ignores the fact that under the Competition Act, Duquesne continues to be the supplier of last resort during the transition period while competing suppliers can choose who they serve. This means that ENRON and other suppliers are likely to serve those customers with a much lower risk of payment default, leaving them to be served by Duquesne. This will result in Duquesne continuing to bear most if not all of the uncollectible expenses it incurred during 1996. Moreover, competing suppliers can protect themselves against customer default by requiring customer deposits and including more flexible cancellation provisions than Duquesne can under its obligations under the Public Service Law (and as amended by the Act) throughout

the transition period. These facts suggest that suppliers are unlikely to face an unfair disadvantage in competing against Duquesne for retail customers In fact, the situation may be just the opposite The Commission should reject Mr. Reising's proposal to assign a proportionate share of uncollectible expenses to the production cost function.

Q. Would you care to discuss the allocated cost of service Mr. Reising presents as an alternative to the one you submitted on behalf of the Company?

A. Yes I have two comments about Mr. Reising's study: first I will discuss some of the errors I found in reviewing his results and then I want to illustrate why his proposal to allocate costs (and to then ultimately re-design service classes on the basis of voltage service levels) is fraught with cost-shifting problems and therefore inconsistent with the Competition Act.

Q. What did you find in reviewing the results of Mr. Reising's allocated cost of service study?

A. I reviewed the spreadsheets supplied by Mr. Reising and discovered several problems First, his spreadsheets contain numerous circular references, failed to account for $29 million in revenues associated rate class GL, and allocated $25 million in revenue requirements to Duquesne's only FERC jurisdictional customer (Pitcairn) Circular references can be a particularly nasty problem because they involve a formula that depends either directly or indirectly on its own value The Lotus manual for 1-2-3 Release 5 informs readers that " a circular reference is almost always an error, and you should correct it immediately". (See

Using 1-2-3 release 5 for Windows, Special Edition, 1994, pages 131-133.) While circular references in a spreadsheet sometimes can be deliberate Mr. Reising provided no documentation of the reasons for these circular references and it is therefore unclear to me whether these were intentional. Until Mr. Reising explains whether or to what extent these circular references lead to problems of indeterminacy in results, the Commission can place no confidence on the results from his study. The second problem I found involves his failure to include the billed revenue associated with rate class GL This causes a problem because his cost of service is based on "realized returns" which is dependent on billed revenues. (An approach that I find conceptually flawed as I explain in the next section of my testimony.) Since the realized return is computed by subtracting expenses from actual revenues and then dividing by allocated rate base, his returns are biased downward, and as a result, so are his unbundled delivery service rates. Finally, Mr. Reising shows allocated revenue requirements at Exhibit 2 PDR-3, attached to his testimony These results show revenue requirements of $25,358,000 for FERC jurisdictional customers This is clearly in error because Duquesne serves only one customer at the FERC jurisdiction (Pitcairn) which provided billed revenues of less than $900,000 during 1996. As a consequence, his value of retail revenue requirements is seriously under-estimated. In my opinion, Mr. Reising's study is so flawed that it can not be relied upon at all by the Commission in its adjudication of cost allocation issues in this proceeding.

Q. Would you care to comment on that portion of Mr. Reising's testimony where he

calls upon the Commission to adopt his proposal to set rates that "reflect the characteristics of the customer's service rather than historical identification by traditional class of service"? (See Reising direct pages 25-28)

A. Yes I would Let me begin by saying that Duquesne's rate classes have historically been differentiated on the basis of size, not necessarily voltage service level. While I do not disagree on a conceptual basis with his proposal, I find it completely unreasonable given the Act's prohibition against cost-shifting within and among rate classes. And that would be the effect of his proposal because Duquesne's general service rate classes contain customers served at various voltage levels. As a result, establishing rate classes on the basis of voltage service levels will shift costs from customers served at higher voltage levels to those served at lower voltage levels.

Q. What is the basis for your conclusion?

A. Based on an analysis I have done for rate class GL This class contains customers served at the transmission level (both transformed and untransformed), 23 KV level, and some who receive service below the 23kV subtransmission level Load research data for 1996 indicates that rate class GL had a diversified peak demand of 573,790 kW Of this amount, 558,465 kW remained on the sub-transmission system while 46,415 kW of demand was served at the primary and secondary voltages As a result, certain costs allocated to all customers would be attributable to only a few under Mr. Reising's proposal.

Q. Have you attempted to quantify the cost shifting for this class under the Reising

proposal?

A. Yes I used rate base items included in accounts 364-368 which are allocated by allocator 8(D30 in the last cost of study service) in Duquesne's cost of service study I then made an estimate of the return and O&M expense associated with these items to identify the current allocation of costs to all customers in rate class GL This amount was calculated to be $1.04/kW/year I then allocated the annual revenue requirements associated with these costs to just the load served at the lower voltage levels The resulting cost was $12.88/kW/year - in excess of a 12 fold increase Clearly the Reising proposal would produce significant cost shifting among customers in rate class GL Exhibit JAL-16 summarizes the results of this analysis.

Q. Can you illustrate this problem with a simple numerical example?

A. Yes To do so I will assume that a utility has a system characterized only by plant investment in secondary, primary, and transmission plant and equipment To complete the picture I will attach costs to each type of investment and assume that this company currently serves only two customers in a single rate class. Customer Number 1 is served at the secondary voltage while customer Number 2 is served at the highest voltage level - transmission These data are summarized below:

		ALLOCATED COST OF SERVICE			
CUST. ID	LOAD	SECONDARY	PRIMARY	TRANSMISSON	TOTAL
Number 1	10	$50	$30	$20	$100
Number 2	40	$200	$120	$80	$400
TOTAL	50	$250	$150	$100	$500

Under generally accepted principles of cost allocation, each customer will be responsible for a load ratio share of the total cost of service given the above situation This allocation will result in each customer paying a rate of $10 for each kW of billed demand Under Mr Reising's proposal, rate classes would be established on the basis of voltage service level As such, applying the Reising approach to the above set of numbers would produce a substantially different cost of service allocation as shown below:

		ALLOCATED COST OF SERVICE			
CUST ID	LOAD	SECONDARY	PRIMARY	TRANSMISSION	TOTAL
Number 1	10	$250	$150	$20	$420
Number 2	40	$0	$0	$80	$80
TOTAL	50	$250	$150	$100	$500

In Mr. Reising's world customer Number 1 would be responsible for all the costs of the secondary and primary network and a load ratio share of transmission cost. As a result, his cost of service would rise from $100 to $420. Customer Number 2 will be happy because his allocated share of costs will drop to $80 since he will no longer be responsible for any of the costs associated with the secondary and primary voltage levels since his service only involves the transmission voltage service level. Clearly the Reising proposal involves substantial cost shifting activity among customers within a particular rate class. While the illustration is over simplified, the implications of significant cost shifting among Duquesne customers are real as I have already discussed. The Commission should reject this proposal.

Q. Earlier you said that Enron witness Reising and OSBA witness recommend the use of realized rather than required rates of return for setting unbundled delivery charges. Since Mr. Kalcic explains his rationale for this position, would you describe his objections to the Company's use of a required rate of return, instead of an imputed rate of return to calculate the cost of unbundled distribution and transmission services.

A. Mr. Kalcic asserts that "it is inappropriate to impute a (claimed) system rate of return (9.61%) to the transmission and distribution rate base but only a residual return to the generation". (See Kalcic direct at page 6.) He goes on to argue that the Company's method is the equivalent of a petition to increase distribution rates - an action which is prohibited by the Act until mid-2001". (See Kalcic direct at page 7.)

Q. Would you care to respond?

A. Yes. Mr. Kalcic's proposal would impute the same rate of return to determine unbundled revenue requirements for each functional component of costs. He would use the "realized" imputed rate of return (8.86%) he computes on the basis of 1996 revenue levels. Duquesne prepared its unbundled cost of service study on the basis of its estimated required cost of capital (9.61%). This study produced revenue requirements in excess of its test year revenues. Therefore, consistent with its top down approach and the overall rate cap provision of the Act, Duquesne subtracted the allocated transmission and distribution costs from the rate cap level to determine the recoverable amount of generation-related dollars.

As I explained in my direct testimony, the production component of costs was then broken into its market value and its recoverable portion of above market costs.

Q. Is Duquesne's use of the required cost of capital consistent with other recent regulatory filings?

A. Yes. Duquesne used the required cost of capital to develop rates for the pilot program and the Commission approved transmission and distribution rates based on the cost of service submitted. Duquesne also used the same methodology to develop the rates for transmission and ancillary services that have been filed with FERC.

Q. Why do you believe the Company's approach is consistent with the requirements of the Act.

A. As I explained in my direct testimony, the Commission never approved rates on an unbundled basis. Rather it only approved revenues and rates on a bundled basis. Duquesne designed unbundled transmission and distribution rates on the basis of a 1996 allocated cost of service study using allocations consistent with those used in its last base rate proceeding. There is no basis for Mr. Kalcic's claim that the Company's approach produces results that are prohibited by the Act. Furthermore, Mr. Kalcic's contention that it is inappropriate to provide only "a residual return to generation" ignores the fact that this is precisely what the PaPUC did in Duquesne's last base rate proceeding implicitly allowing a much higher rate of return for transmission and distribution plant than it did for

generation. Not using a higher rate of return in unbundling transmission and distribution costs could be claimed as being inconsistent with the cost of service approved by the Commission in Duquesne's previous base rate proceeding.

Q. Please explain.

A. In Duquesne's last base rate proceeding, the Commission approved an overall rate of return of 10.94%. However, the PaPUC disallowed an equity return for Beaver Valley 2 and the Elrama units. The result of this equity disallowance was to approve revenues that provided for an overall"realized" rate of return of 8.9%. Clearly the implicit rate of return for generation was lower than the realized rate of return since transmission and distribution-related revenue requirements were based on an allowed return of 10.94%, which is 130 basis points higher than the 9.61% used in computing the allocated cost of service study results for this proceeding.

Q. Is there anything else you would like to say on this issue?

A. Yes. Under the Act, distribution and transmission rates will continue to be based on an embedded cost of service basis. It therefore seems logical to me that the unbundled rates approved in this proceeding be set on the same basis Duquesne has proposed and not on the basis of an overall"realized" rate of return as Mr. Kalcic recommends.

IV. RATE DESIGN ISSUES

Q. Several intervenors have criticized Duquesne's proposal to re-design its rates as part of its restructuring proposal. Could you summarize the objections raised against the Company's plan?

A. There is almost unanimous agreement among the intervenors that the rate re-design proposed by Duquesne would result in a shift of costs from growing to declining load customers. MAPSA witness Russell believes the cost-shifting problem to be so severe that it violates the rate cap provisions of the Competition Act. OSBA witness Kalcic and OCA witness Lee Smith have similar concerns over cost shifting but do not appear to find the statutory problem Mr. Russell finds. DIIC witness Baron finds no cost shifting problem when comparing the rate impacts of Duquesne's proposal relative to its current bundled rates at the test year level of sales. However, he goes on to assert that because the Company's proposal recovers a higher proportion of revenues through a fixed CTC, it results in higher customer rates on a "risk adjusted" basis. These "alleged" problems of cost shifting lead them to question the fairness of the Duquesne proposal and recommend against its acceptance. OSBA witness Kalcic acknowledges the "theoretical" efficiency justification for Duquesne's proposal but like OCA witness Smith and Environmentalist witness Shoengold assert that the Company has not provided sufficient support. Mr. Shoengold also complains that energy efficiency programs will be harmed under the proposal since rates for incremental

usage will be substantially lower than they are under current bundled rates. Finally, Mr. Russell (MAPSA) and Ms. Smith (OCA) express concerns over customer acceptance.

Q. Would you care to make some general observations before you respond to these specific criticisms?

A. Yes. Given the numerous complaints about the high level of retail rates in Pennsylvania I am truly amazed by the negative reaction this proposal engendered. The Duquesne proposal embodies a rate cut of up to 50% for incremental usage which: is revenue neutral, increases consumer welfare, and facilitates stranded cost mitigation (as the Competition Act requires), thereby shortening the CTC recovery period. In short, a proposal with the potential of benefiting everyone and harming no one. It is understandable why some might oppose a rate design proposal that improves efficiency at the expense of fairness or adequacy. It is inconceivable why anyone would oppose improved efficiency where neither is sacrificed. Intervenor claims notwithstanding, Duquesne's proposal will bring rates closer to market prices raising the same amount of revenue as the current bundled rates at the test year level of sales. And it will do so without shifting costs from one rate class to another. Indeed, since the Company's proposal uses customer-specific transition charges to recover above market costs, it meets the most stringent test of fairness: it prevents cost shifting among individual customers. The intervenor witnesses confuse issues of cost shifting (which the Act prohibits) with revenue shifting (which occurs normally

between rate periods under any rate design proposal).

Q. *Would you turn to the specific criticisms offered by the intervenor witnesses?*

A. I will begin by addressing cost shifting and the related issue of fairness and then conclude by discussing the aspect of efficiency. As I have already said, almost all of the witnesses discussing rate design argue that the Duquesne proposal should be rejected because it would involve a shifting of stranded cost responsibility. (See OCA witness Lee Smith at page 8.) DIIC witness Baron, recognizes correctly that "specific costs have not been explicitly shifted under the Company's proposal" although he goes on to reject the proposal because it increases the "take-or-pay obligations" of the customer. (See Baron direct at page 52.) Even MAPSA's witness Russell concedes this point by correctly pointing out that customer charges under the re-design proposal are the same as they otherwise would be under current rates when measured at the baseline level of sales. (However, he then uses this observation to conclude that Duquesne's proposal will not be in compliance with the Act if a customer's usage declines between 1996 and 1999.) OSBA witness Kalcic and OCA witness Lee Smith are less precise in their concerns than either Russell or Baron, but both raise cost shifting concerns with the Company's proposal. All of the witnesses miss the mark by confusing cost shifting with changes in revenue recovery over time. (Apparently the term cost shifting is used so often in an attempt to imply than the Duquesne proposal is inconsistent with the Competition Act.)

Q. I take it that you disagree with those who contend that Duquesne's proposal will

shift costs.

A. Yes I do. I disagree because the "top down approach" used by the Company to compute customer-specific CTCs is premised on maintaining an equivalency between bundled and unbundled revenues. As I explained in my direct testimony, the Company's approach to unbundling insures that no customer pays more in total (for the sum of his unbundled rate components assuming power is purchased at the CGC rate) than he would have paid under current bundled tariffs at the test or base year level of sales. This is a basic arithmetic identity of the top down approach in general and the Duquesne proposal here. (Revenue neutrality is demonstrated in Exhibit JAL-4 attached to my direct testimony.) Moreover, unlike top down approaches proposed elsewhere (California and New York) which maintain revenue neutrality between bundled and unbundled rates on a class specific basis, Duquesne's approach maintains revenue neutrality on a customer specific basis. Since there is no shifting of revenues at the base year level of sales there can be no cost shifting. This test of cost shifting is a traditional measure used by regulatory jurisdictions since time immemorial to compare the cost shifting implications of alternative rate designs. Rate design alternatives are always assessed on the basis of ***test year sales*** to insure that each alternative recovers the same overall level of revenues, and to see whether there is cost shifting across classes and finally to determine individual customer impacts within a particular rate class. Often times a more efficient rate design proposal will be rejected because of unacceptable customer bill impacts. Duquesne's

proposal will lead to more efficient prices for incremental use without any cost shifting trade-off at the class or individual customer level.

Q. I think I understand your point as it relates to test year sales, but wouldn't you concede that the intervenors have a point when they say that costs will be shifted from growing to static or declining load customers?

A. Absolutely not. What Mr. Kalcic and the other witnesses miss is the fact that customers with growing load will contribute a higher not lower percentage of overall revenues. More importantly, since the prices for incremental usage are set above the sum of market power prices and the marginal cost of delivery service, these customers will cover all costs associated with their incremental consumption **plus** provide a contribution towards fixed cost recovery. These additional margins to accelerate the write-down of stranded costs will benefit all customers with the Company's proposed "spill-over" mechanism.

Q. Can you provide an illustration?

A. I will even though the conclusion seems obvious from what I have just said. First, assume a utility has an existing rate schedule that is comprised of a fixed monthly charge of $10 and energy charge of 10¢/kWh. I will also assume that this utility has just two customers: RS1 (a low use customer whose usage will decline given current rates) and RS2 (a high use customer whose usage will grow given current rates). The existing rate schedule will recover $1,940, at the base year sales level, as shown in the table below. This table also shows revenue recovery given assumed future usage levels. Note that these changes in usage are totally

unrelated to any change in prices.

REVENUE RECOVERY UNDER EXISTING RATES					
Customer	Base kWh	Revenues		Future kWh	Revenues
RS1	5,000	$620		4,750	$595
RS2	12,000	$1,320		12,500	$1,370
Total	17,000	$1,940		17,250	$1,965

As shown, in the future period RS1 uses 250 kWh less and saves at the rate of 10¢/kWh resulting in annual savings of $25. On the other hand, RS2 increases usage by 500 kWh and will see his bill rise $25 per year. (Note that the average revenue per kWh will rise for RS1 from 12.4 ¢/kWh to 12.5 ¢/kWh and fall for RS2 from 11.0 ¢/kWh to 10.9 ¢/kWh even under the existing rate structure because of the fixed monthly charge. Following the intervenors' logic, one could argue that the existing rate design violates the rate cap provision of the Act.) Now I will assume that the existing rate structure is re-designed by increasing the fixed charge rate portion and reducing the energy charge to 6.0 ¢/kWh. The fixed charges will be set so that each customer has the same total bill each paid under the existing rates measured at their respective base consumption levels. Under this alternative: RS1 will pay a monthly charge of $26.67 while RS2 will pay a monthly fixed charge of $50 (This is the essence of Duquesne's rate re-design proposal.) The future sales levels will be different than those assumed under the existing rate structure given consumer response to a 40% reduction in their price for incremental consumption. In the table below, I have assumed that the elasticity effect is .10, which means that customers will increase consumption by about 4% given a 40% drop in the energy charge.

BASE AND FUTURE REVENUES WITH RATE RE-DESIGN					
Customer	Base kWh	Revenues		Future kWh	Revenues
RS1	5,000	$620		4,950	$617
RS2	12,000	$1,320		13,000	$1,380
Total	17,000	$1,940		17,950	$1,997

First, it should be pointed out that the alternative rate design recovers the same level of revenues as existing rates for the base consumption levels and $32 more revenues in the future period. Also, notice that customer RS1 reduces his consumption less than he does under the existing rate, while RS2 increases his consumption more. This is the result of providing each customer lower usage rates. In other words, the elasticity-induced effects from the re-design in rates encourage more usage from **both** customers providing welfare gains. Provided that the incremental cost is less than the marginal energy price, society and customers are better of from more efficient pricing signals and accelerated stranded cost mitigation.

Q. How do you respond to the intervenor witnesses who contend that Duquesne has not demonstrated its claimed efficiency benefits from its rate re-design?

A. As I explained in my direct testimony, Duquesne's current rates far exceed the incremental cost of additional consumption. With current power prices below 2.0 ¢/kWh and marginal distribution and transmission losses of 20% (double the average losses at the secondary level) to serve customers at the secondary voltage level, purely efficient prices would be set at levels approaching 2.4 ¢/kWh. For no rate class does Duquesne propose tariffs (i.e., the sum of transmission, distribution, variable CTC, and CGC) anywhere near this level. For the RH class,

the lowest proposed charge is during the off-peak period (for usage in excess of 500 kWh per month the combined price is set at 4.49 ¢/kWh). There is clearly no support for the intervenors' arguments that Duquesne is proposing usage-based prices that are below marginal cost.

Q. Will Duquesne modify its proposed rate design proposal to allow customers the option of a simple unbundled rate design structure?

A. Yes. Duquesne will adopt the proposal set forth by OSBA witness Kalcic to allow customers the choice of Duquesne's rate re-design or a simple unbundled rate structure. Offering customers the option of a simple unbundled tariff should put to rest any intervenor concerns over the fairness of Duquesne's rate re-design proposal.

Q. Does this conclude your testimony?

A. Yes, it does.

Other Rebuttal Issues By Witness

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
Weisenmiller – Direct (HSS1)	26	8-21	RFP Market Definition	The current RFP reflects market prices only for the Company's region and service area. Future prices will be determined by the clearing price in the region as a whole. The current RFP prices are therefore deceptive.	The point is that the one-year RFP represents Duquesne's opportunity cost – the price it can achieve in the wholesale power market today. If that market changes during the transition period, the RFPs conducted in those years will reflect market clearing prices at that time. Finally, the eight-year RFP should not be an issue because it is not being used to set a one-time determination of stranded costs.
	30	7-19	RFP Contract Terms	The structure of the RFP was not conducive to estimating an accurate market price estimate. The inflexible nature of the contract durations limited the number of interested respondents.	Dr. Weisenmiller fails to acknowledge that Duquesne solicited comments on the RFP and adopted a significant change (regarding transmission constraints) when it was appropriate to do so. This process can be continued in future solicitations. Duquesne is willing to consider any reasonable suggestions to adjust contract terms and procedures that increase market value, something Dr. Weisenmiller seems uninterested in pursuing. Finally, these arguments do not justify rejection of a market-based RFP process, which is superior to picking an estimate from a multitude of expert opinions.
	32	6-14	RFP Delivery Costs	The final prices are misleading because they do not include the costs of delivering the power. "Under the RFP, purchasers were required to secure transmission service over the Company transmission system".	The RFP prices are adjusted in setting the CGC for retail delivery costs that will be incurred by suppliers. For the 8-year sale of power, however, this adjustment is not necessary: it is used to calculate market clearing prices, not customer generation credits.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	33	8-14	Wholesale RFP Relevance	Since the RFPs were for wholesale power only, this power is only valuable to independent merchants after a competitive market exists for retail customers.	This is not true. There is no impediment to purchasers using this power to serve retail load in Duquesne's pilot. In any event, Duquesne will conduct future solicitations concurrent with retail choice in its service territory.
	34	16-18	Transmission and RFP Price	Because of the uncertainty in paying 'pancaked' transmission access charges, bidders would have offered lower prices.	Dr. Weisenmiller fails to understand that elimination of pancaked rates will have a downward effect on market prices, all other things being equal.
	35	15-21	RFP Transmission Uncertainty	Because the physical limitations of the system will not change, delivery of the power, even after payment for transmission access, is not assured. "These uncertainties would further depress the bids."	This argument is without merit. There is no evidence that a supplier would not be able to purchase firm transmission on Duquesne's system, if so desired. Moreover, Section 6 of the PSA was amended, at the request of suppliers, to eliminate the risk of transmission curtailments on Duquesne's system. These risks are borne by Duquesne. Dr. Weisenmiller concedes this point in his interrogatory response # 28, Set I.
Weisenmiller Interrogatories Set I (HSS1)	1-2	Response 12	RFP Contract Terms	The RFP produces a distorted measure of real market value of electric generation. He suggests that the purchaser should be able to specify the conditions of the contract.	First, the RFP product terms and procedures could be modified in future solicitations. Duquesne is willing to consider any reasonable suggestions to adjust contract terms and procedures that increase market value. These arguments do not justify rejection of a market-based RFP process. Second, the purpose of the RFP is to establish a known and measurable market price to establish market-based CTCs and CGCs. Allowing each bidder to specify and bid on different products would complicate the RFP evaluation process without increasing prices. For example, the bidders that did submit bids conditional on changes in terms and conditions had price quotes lower than the winning bidders.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	1	Response 13	Valuation Based on Output from an Asset	Market valuation based on an agreement to sell the output of an asset is possible, although other factors are likely to come into play, such as strategic premiums.	First, Dr. Weisenmiller fails to detail what is meant by strategic premiums associated with asset sales. It is especially unclear what this strategic premium might be for Duquesne's remaining assets, particularly those units which Duquesne does not have operational control. Second, Dr. Weisenmiller contends that the market value of all Duquesne's assets should be set on the basis of the value received from the Ft. Martin sale. This assertion is not credible and is in direct contrast to his deposition. There, he admits that the sale of one fossil unit does not set the value for the remaining fossil units (much less the nuclear units). (pp. 5-6)
	1	Response 14	Relevant Market	To calculate a value for Duquesne's generating assets, the relevant price would be the highest price that Duquesne could get for that power.	Duquesne agrees that it should be based on what Duquesne could actually get for that power. The primary purpose of the RFP was to establish that value.
	1-3	Response 20	RFP Contract Terms	By establishing a series of off-putting, seemingly hard-and-fast rules, Duquesne effectively could have screened out other, potentially higher bidding, buyers.	First, the RFP product terms and procedures could be modified in future solicitations. Duquesne is willing to consider any reasonable suggestions to adjust contract terms and procedures that increase market value. These arguments do not justify rejection of a market-based RFP process. Second, the purpose of the RFP is to establish a known and measurable market price to establish market-based CTCs and CGCs. Allowing each bidder to specify and bid on different products would complicate the RFP evaluation process. Thus, as indicated by Mr. Marshall, Duquesne is willing to submit the RFP in advance to the Commission for prior approval. Finally, Dr. Weisenmiller ignores the fact that not a single marketer indicated to Duquesne that it was not submitting a bid because it could not set its own terms.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	1	Response 30	Accurate Measures of Market Price	Dr. Weisenmiller supports asset divestiture. He argues that if Duquesne is unwilling to sell more assets the sale of Fort Martin should be used. He also acknowledges that published price indices can be a valid measure of market prices, but are not readily available for Duquesne's service area.	First, as Mr. Marshall testifies, Duquesne will, if the Commission deems it appropriate, divest all its generating units in the year 2003 to establish a final valuation for those assets. Second, as Mr. Clayton testifies, Dr. Weisenmiller's recommendation to use Fort Martin as the basis for evaluating other Duquesne assets is meritless and inconsistent with his position taken in his deposition. (pp. 5-6) There, he recognizes that the sale of one asset is not necessarily a good indicator of the value of other assets. Finally, Duquesne relied on the market-based RFP process absent a valid market price index today. Once markets evolve, Duquesne would be willing to use a forward contract to establish the annual CGC and CTC.
	1	Response 33	RFP Take or Pay Requirement	The take or pay provision is viewed as an additional risk that causes buyers to bid down the price.	The annual RFP is being used to value the output from Duquesne's generating assets. Therefore, the terms of the sale need to reflect the characteristics of the Duquesne system. First, the 50% minimum take is consistent with the operational constraints faced by Duquesne during minimum load periods. Second, Duquesne's generation portfolio is comprised primarily of baseload units and a 75% capacity factor is appropriate. The RFP power was fully dispatchable within 50% and 100% of the contract amount. Finally, the annual capacity factor requirement is necessary in order to establish a known and measurable contract quantity and market price. As noted above, Duquesne is willing to consider any reasonable suggestions to adjust contract terms and procedures that increase market value, and the Company is willing to submit the RFP to the Commission for prior approval.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	1	Response 35	Relevant Market	To assume that the price for a purchase in Duquesne's service territory, which is at one side of ECAR, is representative of the market-clearing price for all of ECAR is incorrect.	The primary purpose of the RFP was to establish the market value of Duquesne's generation based on what Duquesne could actually get paid for that power. This is consistent with Dr. Weisenmiller's response to interrogatory #14, Set I.
Russell—Direct (MAPSA)	19-21	19:11-21:34	Ancillary Service	The Company should add the ancillary charges which the Company charges itself to the credit for ancillary services given to customers for revenues collected from suppliers.	Duquesne will separate ancillary services that can be competitively procured from those that Duquesne will be the sole provider. Those that can be competitively procured will be included in generation. A market-based credit will be computed and added to the CGC, which in turn will reduce the CTC by the market value of the generation-based ancillary service. The remaining embedded costs will be recovered in the CTC. Other ancillary services that cannot be competitively procured will be treated just like other wires services (i.e., transmission) and the customer will continue to pay cost-based FERC-approved rates and suppliers will not be obligated to supply them.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	22-23	22:8-23:20	Evidence of Market Prices	*Power Markets Week* in Mr. Lahtinen's testimony shows ECAR and PJM prices above the Company's RFP results of 18 mill per kWh, revealing the value of APS transmission facilities.	This is untrue. The prices reported in Power Markets Week support both the prices obtained in Duquesne's RFP and the differences between ECAR and PJM. According to the editors of Power Markets Week, the publication conducts confidential surveys of buyers and sellers of the prices charged in wholesale power transactions in different regions. Using this information, Power Markets Week constructs a weekly weighted average power price index for peak periods and a weekly price range for off peak periods for several regions of the country, including ECAR and PJM. The weighted average market price of power in ECAR shown in my direct testimony was below $0.02/kWh ($20/MWH) in both 1997 and 1996, and for the year 1996 it was approximately $18/MWH. (p.76) That data is consistent with the prices resulting from the RFP and Duquesne's system lambda data, both of which are around $18/MWH. The Power Markets Week data also confirms the proposition that power prices in PJM tend to be materially higher than in ECAR. The "value" of APS transmission facilities to which Mr. Weisenmiller refers is undefined and, in any event, irrelevant to this case.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	23-24	23:21-24:26	Market Value for Capacity	PJM value of capacity for a deficient member is $56 per kW-yr, which translates to 13 mills per kWh before necessary adjustments. Moreover, the Company's sales indicate the value of capacity from $42-$52 per kWh-yr. Capacity value should eventually approach the long run equilibrium price of $87 per kW-yr.	First, the value of capacity in ECAR is significantly below these levels. Mr. Irvin's direct testimony indicated peak capacity value ranging between $0.43 per kW-yr to $1.06 per kW-yr during 1996 and 1997. This data comes from actual prices Duquesne paid for the rights to call upon capacity. It should also be pointed out that these prices represent capacity value during Duquesne's summer peak period, indicating similar purchases of capacity during lighter demand could be obtained at lower prices. As a result, the effective annual price for peaking capacity is likely to be even lower than indicated by the above figures. Second, Mr. Russell conceded in deposition that the PJM market tends to be different than the ECAR market. (p.61) Therefore the value of capacity in PJM is not relevant to this case since Duquesne is in ECAR. In any event, the power sold in the RFP is firm and already includes the value of capacity. Therefore, no additional adjustment is necessary.
	25	1-17	Use of a Wholesale RFP	The RFP will not provide a representative price. Sales to wholesalers with a myriad of sources to serve load have been historically lower than sales to those with fewer options to supply load. The buyer and seller also need not concern themselves with the load shape of the user, or the statutory requirement to serve load, which will also depress the price.	First, the RFP price represents the best measure of Duquesne's opportunity cost of serving retail load – the price it can achieve in the wholesale power market. Second, Duquesne has made adjustments for retail customer load shapes. Third, retail customers will have the same options in 1999 as wholesale customers do today.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	25-29	25:18-29:	RFP Contract Terms and Procedures	The RFP will produce low bids. The 75% capacity factor is high, higher even than the Company's average. The RFP requires scheduling of 50% at all hours, and the Company is not required to deliver above the 75% take or pay amount, which decreases flexibility. No guarantee is made the winner will obtain the MW block of power which was bid (min. of 10 MW only) and limited time was given to respond to the RFP.	First, Duquesne is willing to consider any reasonable suggestions to adjust contract terms and procedures that increase market value. These arguments do not justify rejection of a market-based RFP process, which is superior to picking an estimate from a multitude of expert opinions. Mr. Russell seems content to regrettably, "throw rocks" at the RFP, rather than offer constructive comments. Second, Mr. Russell conceded in deposition that the best way to set the CGC is to use public indices of market clearing prices. (pp. 35-36, 67) Today, the RFP is the best such index. To the extent that other market-based solutions evolve in the future, Duquesne would consider them. Third, RFP power was fully dispatchable within 50% and 100% of the contract amount. Fourth, the 50% minimum is consistent with the operational constraints faced by Duquesne during minimum load periods. Finally, Mr. Irvin informs me that these provisions did not cause any problems with suppliers.
	27-28	27:32-28:25	RFP Panel and Adjustments	A disinterested panel such as the Commission should administer the RFP, and the results should be adjusted for capacity cost, load factor of retail loads, ancillary services, and other costs.	As indicated by Mr. Marshall, Duquesne is willing to submit the RFP in advance to the Commission for prior approval. The "proper" adjustments to RFP prices are addressed in the main testimony.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	29-32	29:4-32:13	Setting the CGC Based on Long Run Marginal Costs	CGC should be set administratively based on the long run marginal cost.	This will create new stranded costs during the transition period. When retail load chooses another supplier, Duquesne will not be able to sell excess generation at long-run marginal cost, especially in the near term. (See Mr. Schnitzer's testimony) It is undisputed that market-clearing prices today are far below long run marginal costs. Mr. Russell himself conceded in deposition that ECAR has excess capacity. (p.16) Furthermore, Mr. Russell states he would not expect prices to tighten or rise until you get toward the end of the transition period. (pp.28-29) Finally, Mr. Russell acknowledges that he is unable to forecast market prices with any certainty and in his response to interrogatory 27, he states that he "is unsure and is anxiously awaiting the results of a competitive market to determine this." (Interrogatories, set 1, p.14) The Commission should reject administratively setting the CGC based on long run marginal costs and avoid the creation of new stranded costs.
	32-37	32:15-37:18	Using Market Indices and Adders for the CGC	If the long run marginal cost is not accepted, various market indices could be used for the CGC which would need to have the following adders: capacity, installed reserves, ancillary services, marketing and overhead, losses, and profit.	These "adders" are addressed in the main testimony.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	37-40	37:20-40:31	Customer Specific CTC	The Company's CTC proposal should be rejected. The CTC does not comply with the rate cap. The process is confusing, burdensome to implement, and would hamper competition. Also, the CTC is really premise specific, which is not appropriate.	First, the customer-specific CTCs are in full compliance with the rate cap and prevent cost shifting. For those customers who continue to purchase electricity from Duquesne, the unbundled rates will result in the same bill the customer would otherwise pay under bundled rates assuming test year 1996 sales. Second, the resulting efficiency and stranded cost mitigation benefits far exceed any implementation hurdles. None of the intervenors made any substantive criticisms of the resulting efficiency gains and potential stranded cost mitigation that I have provided in my direct testimony. There I estimated that the proposed rate redesign provides an opportunity to further mitigate stranded costs by approximately $15 million per year or more. The restructuring legislation orders utilities to fully mitigate stranded costs and rate re-design affords Duquesne one of the best opportunities to do so. Stranded cost mitigation benefits all consumers and not just those who increase consumption. Finally, Duquesne proposes to give customers the option to choose between the current and the proposed rate design. This allows customers to decide which option is best for them.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	54-55	54:1-55:27	Customer Participation Credit (CPC)	CPC should be set at same level as in the pilot to foster competition. Even though the pilot was oversubscribed, this level may not provide robust competition.	First, this will create new stranded costs during the transition period. (See Mr. Schnitzer's testimony) The purpose of the transition period is to mitigate stranded costs, not create new ones that would have to be dealt with at a later time. Mr. Russell's position is the exact opposite. He proposes to set the CGC on the high side with adders and a CPC and "keep track of the extent to which the utility's amortization of stranded costs is penalized or hurt." He goes on to recommend that the Commission allow utilities to recover these additional stranded costs and suggests a possible extension of the transition period. (Russell deposition, pp. 11-13) Duquesne, on the other hand, proposes to mitigate stranded costs during the transition period as quickly as possible. Critical to Duquesne's approach is the establishment of CGCs that reflect the market value of its generation. Second, the need for such a credit is not based on any market evidence. Mr. Russell concedes in deposition that it is "just carried over from the retail pilot" (p.41) Mr. Russell has no opinion about what prices will be, but nonetheless, recommends that whatever the CGC is set at initially, it should be marked up for a 13% customer participation credit. I find little comfort in Mr. Russell's deposition where he states that "it's not exactly a self-serving recommendation from the point of view of the suppliers." (p.42) It is quite clear that many of the intervenors would prefer that Duquesne be required to set a high CGC as opposed to a market-based one, since customers would have a greater incentive to switch to an alternate supplier and/or suppliers would have a greater opportunity to make a profit.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
Russell– Interrogatories Set 1 (MAPSA)	1	Response 1	Estimating Market Prices	The market price in a competitive environment cannot be known beforehand. It can only be known after the fact.	First, Mr. Russell seems not to understand markets. A one-year forward sale does establish a market price for that product and that term. Because of this, the proposed annual RFP will reflect market conditions and expectations at the time when customers choose retail access. As the market changes during the transition period, the RFPs conducted in those years will reflect market-clearing prices at that time. Mr. Russell, has few practical solutions other than to set the CGC on the high side based on long run marginal costs. His solution ignores reality – the fact that current market prices are significantly below long run marginal costs.
	3	Response 4	RFP Contract Terms	Mr. Russell did not testify that terms should be deleted, added or changed in the Duquesne RFP.	Mr. Russell claims that Duquesne's RFP terms yield biased low prices, but when asked how he might alter the solicitation, he fails to propose any practical solutions to establish a market-based price that is known and measurable.
	11	Response 18	Excess Capacity in ECAR	Mr. Russell agrees with Duquesne's position that there is excess capacity in ECAR.	While Mr. Russell agrees that there is excess capacity in ECAR, he argues that the CGC should be based on the cost of adding new capacity. His recommendation should be denied since by his own admission, his proposal fails to reflect market conditions.
	12	Response 22	Market Prices in ECAR vs. PJM	Mr. Russell states that there is a material difference between market clearing prices in ECAR and PJM.	Duquesne agrees and CGCs established in these markets should reflect these differences.
	12	Response 23	Relevance of PJM Capacity Prices	To the extent that Duquesne can obtain capacity to the border with PJM, its capacity should be valued at the capacity value within PJM.	This is incorrect. The value of capacity in ECAR is determined by supply and demand in ECAR taking into account import and export limitations.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	14	Response 28	Firmness of RFP	Mr. Russell asserts that the RFP process sampled "non-firm" power.	This is incorrect. First, the power that is provided under the RFP is a firm obligation to sell electricity backed up by Duquesne's financial obligation to pay replacement costs if Duquesne fails to perform. The bottom line is that Duquesne will physically provide the power or pay the supplier replacement costs. The RFP purchaser therefore is held harmless. Therefore, this sale is not akin to a spot or non-firm sale of power into a power exchange as Mr. Russell asserts. I suspect that the real objection Mr. Russell and others have with the RFP price is that the "market" doesn't place as much value on firm power as these "experts" would like. The fact that capacity has little or no value in the ECAR region is a reality that everyone, most of all Mr. Russell, wants to ignore in this proceeding. Second, Duquesne provided additional evidence in this case on the capacity value of generation within the ECAR region that supports the results from the RFP. That data based on actual prices Duquesne paid for the rights to call upon capacity indicated a peak capacity value ranging from $0.43 per kW-yr to $1.06 per kW-yr during 1996 and 1997. These prices represent the capacity value during Duquesne's summer peak period, indicating that similar purchases of reserved capacity during times of lighter demand could be obtained at lower prices.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	16	Response 32	Adjustments to CGC	Mr. Russell advocates that the CGC rate beyond 1999 be adjusted by the prices experienced in the marketplace and known and measurable changes to the markets.	Duquesne has attempted to set the CGC and proposes to adjust it based on prices experienced in the marketplace and known and measurable changes to the markets. The primary difference is that Duquesne is relying on a contemporaneous wholesale RFP as an index, whereas, Mr. Russell wishes to rely on a historical retail index. His suggestion is not as simple as it sounds. He fails to describe the terms of the retail sale, whether or not a standard retail product would be chosen, how historical prices would reflect expectations about the future, how retail prices would be recorded, and so forth. In essence, he is proposing a continuous, eight-year litigation schedule to predict and true-up CGCs.
	16	Response 34	RFP Capacity Factor	Mr. Russell is unable to specify the capacity factor that would have optimized the value of the RFP power.	Mr. Russell is unable to provide constructive suggestions with respect to a market-based RFP valuation. He claims the RFP yields a low value, but cannot "fix" it.
	18-19	Response 38	RFP Contract Terms and Take Flexibility	Mr. Russell does not advocate a fine tuning of the RFP but its total abandonment.	Again, Mr. Russell presents no practical solutions for establishing a known and measurable market-based price.
	19-20	Response 39	Load Following and Balancing Services in RFP	"It is the duty of the proposer to design an appropriate RFP."	When asked how he would resolve his own criticisms of the RFP, Mr. Russell is unable or unwilling to comment. While Mr. Russell talks about wanting to see markets set prices, he relies on an administrative market price estimate, which according to his responses regarding excess capacity in ECAR, fail to reflect current market conditions.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	25-26	Response 53	High CGC for Competitors to Recoup Their Costs	Mr. Russell argues for setting a high CGC so that MAPSA suppliers can recoup all their generating costs in competitive markets.	Mr. Russell recommends the use of long run marginal costs or indices with a variety of adders including supplier profit margins to set the CGC. However, according to this interrogatory response he has not been provided any data from MAPSA regarding the cost of serving retail customers on which to base his recommendations. His recommendations for the CGC therefore should be rejected since they are not based on any evidence. Furthermore, Duquesne does not believe that it is appropriate to establish the CGC based on suppliers' costs. Prices should be determined by the competitive market and not some administrative cost-plus estimation process. As noted earlier, a biased high CGC would likely result in a new category of stranded costs during the transition period.
Yarolin (OTS 3)	9	1-18	Unbundling Distribution	The Company did not unbundle distribution components such as metering, Universal Service Charge, billing, and service drop lines.	The Company's proposal to include these charges in bundled distribution charges is consistent with recent proposed rulemakings regarding customer information disclosure and advanced metering in Pennsylvania. (See rebuttal testimonies of Mr. Flynn and Mr. Allison)
	10	16-17	Unbundling Demand Side Management and social costs.	These costs are not solely related to distribution charges and should be separately stated on the bill.	This continues to be a regulated distribution activity under the PUC direction.
Schoengold (Environ-mentalists 1)	10-11	10:27-11:7	CTC True-up	"...it is not clear whether The Company intends to true up the CTC collection to reflect changes in sales levels. If there are going to be true-ups, these true-ups should adjust for both market price and sales uncertainty."	As market prices change each year, Duquesne's CTC will also change. Changes in sales that impact CTC revenues and Company earnings will be taken into account in the ROE spillover mechanism. (See Mr. Clayton's testimony)

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	11-12	11:10-12:14	RFP Price	"Since the annual power sale will be for only a portion of the Company's power, it is not clear how well the sale price will reflect the overall market price."	*If the Company sold more power in the RFP*, the weighted average winning bid price would likely be lower. In any event, the amount sold represents Duquesne's opportunity cost as retail load selects alternative suppliers.
	11-12	11:10-12:14	RFP Price	"Since the power sale will take place in the context of a mixed competitive/regulated market, it is unlikely that the price will accurately reflect a true market price."	The RFP price represents Duquesne's opportunity cost as retail load leaves. As competition is phased in, Duquesne will continue to issue RFPs each year.
	11-12	11:10-12:14	RFP Price	"As long as buyers and sellers in the marketplace are receiving stranded cost recovery in a regulated setting, it is likely that the market price will be artificially low."	This is not correct. Sales and purchase offers will be determined by supply and demand. In today's markets with excess capacity, prices are driven toward short-run marginal costs.
	13	10-17	High Market Price	A higher initial market price estimate would bring more suppliers into the market and establish a lower CTC. Even if corrected by a true-up, it would induce more realistic market prices.	Biased high market price estimates will create a new category of stranded costs during the transition period.
	16	4-9	Rate Relief	There is no rate relief for customers under the restructuring plan. There are unlikely to see any benefit from competition.	Duquesne has significantly reduced rates on incremental consumption. Residential customers will receive a marginal rate reduction of 50%.
	24	18-22	New Rate Design	With regard to the customer rate, there is a shift from volume-based charges to fixed customer charges. It is simply a rate redesign that should be rejected.	Duquesne's rate design could mitigate stranded costs by $15 million or more annually. The Act requires utilities to fully mitigate stranded costs and rate design is one of the best opportunities to do so.
	24-25	24:24-25:6	*Justification for Rate Redesign*	*Rate redesigns are typically the result of very extensive studies that justify the change. There is no evidence of any in depth study or logic that would justify this change.*	Duquesne has submitted extensive analysis and testimony supporting its rate design. Principles of economic theory and pricing also strongly support the efficiency benefits of moving usage charges closer to market levels.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	25	11-25	New Rate Design	"Each customer will have a different rate structure, causing problems with fairness and comparability."	The customer-specific CTCs results in no bill impacts or cost-shifting based on test year sales.
	25	11-25	New Rate Design	"There will be negative environmental impacts from increased air pollution resulting from the promotional character of the new rate design."	More efficient market-based pricing will result in significant benefits. One of the primary purposes of moving toward competition is to eventually lower electricity prices. The proposed rate design does this for incremental consumption.
	25	11-25	New Rate Design	"The new rate design undermines efforts to promote energy efficiency and customer-owned renewable resources."	The new rate design increases efficiency and promotes more economic load management and distributed generation activities.
	25	11-25	New Rate Design	"The new rate design undermines efforts to reduce inefficient use of energy in low-income households with older, less efficient appliances."	The new rate design sends customers more efficient price signals and encourages more economic behavior. The efficiency gains potentially are large and will benefit all customers.
	25-26	25:29-26:4	Rate Cap and Rate Adjustment	It appears that the Company would be able to adjust rates so that the rate for the present level of usage could be increased.	The Company already responded to this concern during interrogatories and has no intention of this. Further, he is inconsistent when he states that the Company has provided no rate relief, while at the same time he is concerned that we could later raise rates under the rate cap.
Baron (DII 1)	24-26	24:14-26:4	Certainty of CTC	Finally, no customer would enter into a contract for longer than one year since there is no certainty in the level of the CTC. The Company should provide the level of certainty other Pennsylvania utilities are proposing.	Duquesne did propose a fixed CTC for the entire transition period in its pilot based on a long-term RFP. In any event, the statement is not correct. In California, they are backing out of rates a monthly power exchange price and adjusting the CTC, yet suppliers and customers will certainly be willing to offer/purchase longer term products.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	37-38	37:4-38:18	DII's Unbundling: Ancillary Services	The $18M was removed from transmission rates, and the costs for reactive supply and voltage control were added to the generation rate. Spinning reserve and other ancillary services are captured in a 15% margin adder to capacity costs in generation prices.	First, Duquesne will separate ancillary services that can be competitively procured from those that Duquesne will be the sole provider. Those that can be competitively procured will be included in generation. A market-based credit will be computed and added to the CGC, which in turn will reduce the CTC by the market value of the generation-based ancillary service. The remaining embedded costs will be recovered in the CTC. Other ancillary services that cannot be competitively procured will be treated just like other wires service (in transmission) and the customer will continue to pay cost-based FERC-approved rates and suppliers will not be obligated to supply them. Second, the RFP price includes the value of capacity and installed reserves and no adjustment is necessary.
	38-41	38:4-41:12	DII's Unbundling: Losses	Costs are switched back from distribution rates to generation rates. The company actually keeps these costs in generation for customers who continue to take generation from the Company. Losses should also be at market prices, not embedded costs. Finally, the shift of these costs to distribution is in violation of the Act.	The Company has agreed to remove distribution losses from distribution and increase the CGC credit. Distribution losses will now either be charged to suppliers or competitively supplied.
	42-45	42:18-45:2	DII's Unbundling: Market Price	Hourly marginal costs and annual capacity costs are calculated for on- and off-peak hours. A weighted average is used in unbundling calculations. Where no demand charge is included in a class tariff, the capacity revenue requirements are unitized by total kWh sales.	Duquesne's methodology is similar but more sophisticated. The CGC is based on *hourly* customer load patterns for each rate class and market price data based on the RFP price level and 1996 lambda price shape. The RFP includes the value of capacity costs and installed reserves.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	45-47	45:4-17:15	DII's Unbundling: Rate Schedules	It would be inconsistent to vary the market price and CTC when the stranded cost estimate would not be adjusted as well. Since the stranded cost calculation will not be modified, it is not appropriate to modify the elements of the unbundled rate for any of the transition years.	Duquesne does not propose to lock in stranded costs based on a one-time estimate of market prices. Duquesne does propose to modify stranded costs in the future in the second stage valuation. This argument is invalid.
	48-53	48:1-53:5	The Company's "Fixed" CTC	The CTC rate design equates to a fixed charge for 54% on the monthly bill, which shifts additional risks to customers. On a risk adjusted basis, customers will pay more than under bundled rates.	The Duquesne rate design embodies a rate cut of up to 50% for incremental usage which is revenue neutral, increases consumer welfare, and facilitates stranded cost mitigation, as the Competition Act requires.
	57-58	57:10-58:7	HVPS and "Generation Avoidance"	The Company's proposal does not include a provision for generation avoidance in HVPS. This is a violation of the Act which does not allow elimination of tariffs.	The Company will modify its tariffs to include this provision.
	59-60	59:9-60:7	Transmission Rate Design	If a large customer wishes to access transmission service rates under FERC 888, the T&D rate cap would not be expected to apply to any additional ancillary services. However, if a customer chooses alternative generation supplier, then at least for the 54 months, no additional ancillary services should apply since they are already in the base rate and this would violate the rate cap.	Duquesne will separate ancillary services that can be competitively procured from those that Duquesne will be the sole provider. Those that can be competitively procured will be included in generation. A market-based credit will be computed and added to the CGC, which in turn will reduce the CTC by the market value of the generation-based ancillary service. The remaining embedded costs will be recovered in the CTC. Other ancillary services that cannot be competitively procured will be treated just like other wires service (in transmission) and the customer will continue to pay cost-based FERC-approved rates and suppliers will not be obligated to supply them.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
Kahal (OCA 1)	9	21-23	Rate Cap	The rates will not actually remain capped. The will remain constant after a rate increase of roughly 2%.	The Act allows utilities to accelerate amortization to mitigate transition and stranded costs under section 2804 (4)(v). The ECR adjustment is cost-justified and equal to the cap approved by the Commission.
	12	10-13	Rate Increase	The Company already has one of the highest residential rates. It should not be increased further.	(See answer above.) Also, Duquesne has significantly reduced rates on incremental consumption. Residential customers will receive a marginal rate reduction of 50%.
Smith (OCA 4)	2	15-19	Unbundling generation costs	The Company's definition of generation costs excludes line losses and a portion of the generation assets. This assumes in a restructured industry, the Company will retain monopoly control over a portion of the generation services.	The Company has agreed to remove distribution losses from distribution and increase the CGC credit. Distribution losses will now either be charged to suppliers or competitively supplied.
	3-4	3:18-4:16	Inclusion of ancillary service costs with transmission and stranded costs	These services are actually provided by generating units. As such, they will result in revenues going to owners of generation. If the Company does not attribute these revenues to generation, stranded costs will be over-stated.	Duquesne will separate ancillary services that can be competitively procured from those that Duquesne will be the sole provider. Those that can be competitively procured will be included in generation. A market-based credit will be computed and added to the CGC, which in turn will reduce the CTC by the market value of the generation-based ancillary service. The remaining embedded costs will be recovered in the CTC. Other ancillary services that cannot be competitively procured will be treated just like other wires service (in transmission) and the customer will continue to pay cost-based FERC-approved rates and suppliers will not be obligated to supply them.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	4-5	4:19-5:4	Customer's Paying Twice	Since the need for capacity is determined by load plus reserves, there is a reflection of reserve capacity in Mr. Doug Smith's market price. Therefore, the market price estimates result in customers paying for generation ancillary services, so including them again in transmission rates would result in customer's paying twice. Ms. Lee Smith removed the Company adjustment which moves ancillary costs to transmission.	First, it is not correct that customers would have paid twice for ancillary services in Duquesne's proposal. However, Duquesne will now separately unbundle its ancillary services. Duquesne will separate ancillary services that can be competitively procured from those that Duquesne will be the sole provider. Those that can be competitively procured will be included in generation. A market-based credit will be computed and added to the CGC, which in turn will reduce the CTC by the market value of the generation-based ancillary service. The remaining embedded costs will be recovered in the CTC. Other ancillary services that cannot be competitively procured will be treated just like other wires service (in transmission) and the customer will continue to pay cost-based FERC-approved rates and suppliers will not be obligated to supply them. Second, the RFP price already includes the value of capacity and installed reserves and no adjustment is necessary.
	5-7	5:10-7:7	Line Losses in T&D	The costs of line losses belong with generation since suppliers will supply energy to make up for line losses, and charge higher prices than wholesale to reflect these costs. In addition, the revenues associated with line losses should not be segregated from those for customer load.	The Company has agreed to remove distribution losses from distribution and increase the CGC credit. Distribution losses will now either be charged to suppliers or competitively supplied.
	7	9-18	Line Losses, Ancillary services and the Company CTC calculation	Since the Company has included line losses and ancillary services in T and/or D, the generation costs are understated.	See changes described above.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	7-8	7:20-8:13	The Two-Part CTC	The Company has not proven lower usage charges will improve efficiency since it has not presented a marginal cost study that demonstrates that the proposed charges are equal to full marginal cost. Proposed design will shift stranded cost responsibilities from customers who increase their usage, relative to a usage-based charge. Also the proposed rate design may be lead to a large number of disputes, especially with new customers.	Duquesne has provided substantial justification and analysis for the proposed rate design in my direct testimony and response to interrogatories. None of the intervenors has provided substantive criticisms of the efficiency gains and potential stranded cost mitigation (of $15 million per year) that I provided in that direct testimony. All customers will benefit from reduced stranded costs regardless of future changes in consumption and the customer-specific CTC prevents cost-shifting. Current and proposed usage rates significantly exceed the marginal costs of generation, distribution, and transmission. The benefits will far exceed any implementation hurdles. Nonetheless, Duquesne agrees to give customers a choice between unbundling of the current rate design and Duquesne's proposed rate design. Customers will be able to choose the best option for them.
	10	6-22	CGC Determination and Adder	It is not clear how the adjustment to reflect average system load shape is done, does not think line losses should be removed, and feels A&G should be added to the wholesale market price.	Adjustments to the RFP price have been made based on hourly retail customer time-of-use data as described in my direct testimony. Duquesne agrees to add avoided distribution and transmission line losses to the CGC. Duquesne rejects the A&G adder. These costs are not avoidable, and if implemented, could create a new category of stranded costs during the transition period.
	11	1-17	Ms. Smith's Calculation of Avoidable Generation Price	Starting with Mr. Doug Smith's projections, Ms. Smith adjusts for line losses and class load shape. A combined DQE and Allegheny system load shape for 1999-2005 was used as a proxy for class load shapes. Line losses were adjusted using generation sales to total sales ratio (5.1%), and adjustment was made for the GRT.	We have agreed to adjust the CGC for avoided line losses using Duquesne figures. The average load shape methodology that Ms. Smith uses is less precise than what the Company used and is not relevant for customers in Duquesne's service area.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	12-13	12:21013:15	Retail Marketing Costs	What Ms. Smith has included is what a competitive supplier would incur and leaving these costs in the CTC would give the Company an unfair advantage.	Duquesne has a monopoly franchise in a regulated environment. Duquesne does not currently incur the marketing costs that Ms. Smith implies and the costs that she identifies are not avoidable.
	14-15	14:7-15:2 15:2-15:19	Ms. Smith's Rate Design	Overall rate design is presented including T&D rates, avoidable generation, and CTC as described earlier. Rates are calculated using Mr. Catlin's adjustments, Mr. Smith's market prices, and Mr. Kahal's stranded costs. Rates provide an 18% reduction.	Ms. Smith's rate design is based on a one-time determination of market prices, which will likely result in uneconomic customer price signals. Further, she fails to recognize the Company's right under Section 2804 (4)(v) to apply excess earnings under the rate cap to mitigate stranded costs for the benefit of ratepayers.
	16	1-2	CTC reconciliation	Reconciliation of the approved CTC should be performed on a class-wide basis to avoid the possibility that certain classes will escape full responsibility.	Duquesne has developed a CTC on an individual customer basis to ensure that all customers pay their fair share of stranded costs.
Alexander (OCA 5)	43-44	43:19-44:3	Load Profiles	It is likely load profiles will be used for some customers, and if they are, they should be updated frequently.	Duquesne will continue to update load profiles and is in the process of installing the CARS system which will greatly aid this effort.
Kalcic (OSBA 1)	3	3-8	Rate Redesign	The Fixed CTC would negatively impact ratepayers and shift responsibility from customers with growing load to those with constant/declining loads. Customers should be able to choose from two tariffs: fixed CTC or variable CTC.	All customers will benefit from more efficient rates and accelerated stranded cost mitigation. The Company's proposal uses customer-specific CTCs and meets the most stringent test of fairness – it prevents cost shifting among individual customers. Mr. Kalcic confuses issues of cost shifting (which the Act prohibits) with revenue shifting (which occurs normally between rate periods under any rate design proposal). However, Duquesne has modified its proposal to give customers a choice between two sets of tariffs as Mr. Kalcic suggests. Customers will be able to choose which rate is better for them.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	9-10	9:9-10:18	Distribution Losses Included in Distribution Rates	The Company is denying customers the opportunity to purchase energy to cover losses. Even if the costs were to be in distribution rates, it should be at market prices, not embedded costs.	Duquesne has modified its proposal and included avoided losses in the CGC.
	10-12	10:19-12:1	Rate Design of CTC and Economic Efficiency	Mr. Kalcic agrees a fixed/variable CTC is preferable to a total variable CTC based on economic theory, but theory would also conclude no CTC is even more efficient.	The Company has proposed to increase efficiency in order to mitigate stranded costs while maintaining other rate principles of fairness and adequacy.
	12-14	12:12-14:4	Rate Design of CTC and Equity	Some customers would be adversely affected by CTC rate design, specifically those with growing loads would do better than those without. Recommends two tariffs option for the CTC (fixed/variable and total variable).	Duquesne has modified its proposal to give customers a choice between two sets of tariffs as Mr. Kalcic suggests. Customers will be able to choose which rate is better for them.
Reising (Enron 2)	2	15-20	Distribution Charges	"The Company inappropriately includes in its distribution charges the cost of losses computed on the basis of its embedded production costs...The production related cost of losses must be removed from unbundled distribution charges."	Duquesne has modified its proposal.
	2	21-24	Distribution Charges	The distribution charge should be split up into a wires charge and a non-wires charge.	This is not consistent with the Commission's proposed rulemaking regarding advanced metering. (See Allison testimony)

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	2-3	2:25-3:3	Ancillary Service Charges	The FERC-regulated ancillary services that the Company has bundled into its proposed transmission charge should be unbundled and stated separately.	Duquesne will separate ancillary services that can be competitively procured from those that Duquesne will be the sole provider. Those that can be competitively procured will be included in generation. A market-based credit will be computed and added to the CGC, which in turn will reduce the CTC by the market value of the generation-based ancillary service. The remaining embedded costs will be recovered in the CTC. Other ancillary services that cannot be competitively procured will be treated just like other wires service (in transmission) and the customer will continue to pay cost-based FERC-approved rates and suppliers will not be obligated to supply them.
	8	5-18	Sales Expenses	"Sales expenses are incurred to promote the sale of additional energy to retail customers." This is not a pure distribution function and shouldn't be included in a distribution charge.	The distribution business will continue to have an interest to build and operate the delivery system efficiently. These and other informational and instructional advertising expenses will still be necessary after retail access. These costs should remain in the distribution function.
	9-10	9:21-10:9	Uncollectable Accounts	Uncollectable accounts expenses should be allocated to production, transmission and distribution based on proportional revenue requirements. The simple allocation of the total expense to distribution is unreasonable.	This argument is flawed because it ignores the fact that under the Competition Act, Duquesne continues to be the supplier of last resort during the transition period while competing suppliers can choose who they serve. This will result in Duquesne continuing to bear the uncollectible expenses.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
Boonin (NEV 2)	3	19-26	Unbundled Price for Generation and CTC	Unbundled price should be set by the market, and should be determined by the market clearing price plus costs for retail delivery. Also unbundled charge and CTC should always be in balance so the total of the two never changes.	Duquesne agrees that a market-based approach to setting the CGC is superior to a one-time administrative estimate. Duquesne has converted the wholesale RFP price to a retail price making adjustments for retail customer time of use consumption, T&D losses, GRT, and will also provide a customer credit for ancillary services. The RFP price includes the value of energy and capacity.
	3-5	3:28-5:1	Unbundling Methodology and the Law	Unbundling is required by 2840(3), and for those customers who do not choose an alternate supplier, the EDU must supply energy at the prevailing market rate as stated in 2807(E)(3).	This passage in the Act refers to the period after the transition period.
	5	3-29	Variable (Market Based) Price for Generation vs. a Fixed Price	A variable price for generation, which can change with market conditions, is more appropriate than estimating and establishing a fixed price.	Duquesne agrees.
	6	5-25	NEV Proposal for Unbundling	Unbundled rate for generation should be set by the power exchange clearing price fully adjusted for ancillary services.	This would be acceptable except a power exchange does not exist in Duquesne's market. That is why Duquesne adopted the RFP process to establish market prices.
	7-8	7:26-8:	Adjustments to Market Price for Reliable, Deliverable Electricity	Costs for capacity, spinning reserve, load balancing (and possibly others) should be included in the price of generation. Price will either be set by ISO and FERC, or through market.	Duquesne has converted the wholesale RFP price to a retail price making adjustments for retail customer time of use consumption, T&D losses, GRT, and will also provide a customer market-based credit for ancillary services that can be competitively procured. There is no ISO in Duquesne's market today. The RFP price includes the value of energy and capacity.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	8	8-20	Other Adjustments to Price for Generation	Price should be adjusted for voltage differences, and for customer location if the ISO establishes different pricing for different regions.	This is not practical and will result in cost shifting. However, if there were an ISO and transmission constraints existed within Duquesne's system, it could make sense to have different pricing for different regions, just as it makes sense to have different pricing in ECAR and PJM.
	8	22-27	Adjusted Power Exchange Price is Good Proxy for Market Price	This is the way goods and services are usually priced (starting with a prevailing wholesale price and adding the costs to convert to retail service).	I agree that a power exchange price could be a good proxy. Depending on how it was designed, it may require different adjustments than what Duquesne sells in the RFP. In any event, this is hypothetical absent a visible power exchange.
	8-9	8:29-9:8	Conversion from Wholesale to Retail Price	The system wholesale energy and capacity price is converted to kWh using a system load factor. Added to this price are: ancillary charges at market prices, A&G and a true-up for tax. A number for each rate class should be then calculated in a similar manner.	Duquesne rejects the A&G adder, and effectively accounts for the other adjustments in its customer credits..
	10	12-16	Load Shape Determination	It is premature to develop load shapes now.	Load shapes are necessary now for the supplier settlement process. Duquesne's CARS project will greatly improve the accuracy of these load shapes in the future.
	10-13	10:18-13:9	Mr. Boonin's Unbundling Proposal and the Rate Cap, Splitting the CTC	Keep the total of the unbundled price of generation and the generation portion of the CTC constant. If market price goes up, the generation portion of the CTC is decreased. The CTC would be split into "generation related" and "non-generation related."	Duquesne does the balancing of the CGC and CTC as Mr. Boonin suggests. However, the Company rejects determining the CTC based on a one-time administrative market price forecast and rejects the proposal to split the CTC into two components. It is not clear what value this extra complication serves and is not intended in the Act.
	13-14	13:11-14:12	Mr. Boonin's Unbundling and Reconciling the ITC and CTC	Reconciliation would be done to each of the two components of the CTC and over/under collections would be deferred to the end of the transition period.	The Company rejects this proposal.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	18	9-19	Final Tariffs	Commission should direct the Company to submit CTC tariffs consistent with Mr. Boonin's approach as shown in Exhibit #2.	See answers above.
	18-19	18:23-19:5	Portability of Tariffs	Any rate discounts should be available to any customer regardless of their chosen supplier to create a level playing field and comply with the Act.	Interruptible customers should not be allowed to receive discounts while obtaining firm electricity service from other suppliers. The discounts are tied to the electricity supply and are therefore discontinued if a customer selects an alternative supplier.

ATTACHMENT IN RESPONSE TO OSBA-02-17

RATE CLASS	CGC BEFORE LOSS OR GRT ADJUSTMENT	T&D LOSS ADJUSTMENT FACTOR*	ADJUSTMENT FOR LOSSES	ADJUSTMENT FOR LOSSES & GRT
RS	17.59	1.105	19.44	20.33
RA	17.51	1.105	19.35	20.24
RH	17.47	1.105	19.30	20.19
GS/GM	17.66	1.096	19.36	20.25
GMH	17.57	1.090	19.15	20.03
GLH	17.60	1.052	18.52	19.37
GL	17.55	1.051	18.45	19.29
L	17.50	1.036	18.13	18.96
HVPS	17.51	1.009	17.67	18.48
SE	17.19	1.105	18.99	19.87
MTS	17.45	1.105	19.28	20.17
AL	17.18	1.077	18.50	19.35
PAL	17.18	1.105	18.98	19.86

* Loss adjustment factors are from Exh. JAL-1d

COST SHIFTING EXAMPLE

		Cumulative (bottom up)		
		Allocator #		Rate GL (kW)
Class Diversified Demand		na, 3		573,790
Portion at Subtransmission		D20, 6		
		D30, 8		46,415
Costs Allocated by Allocator 8 (D30)		Allocated Balance	Percentage of Accounts	Balance In Accounts
Plant Account #'s:				
364&365-Ovhd. Conductor	$	2,759,132	14.18%	
364&365--Accum. depreciation	$	(904,049)		$ (6,375,490)
366&367--Undgd. Lines	$	481,500	0.88%	
366&367-Accum. Dep.	$	(128,169)		$(14,523,015)
368--Transformers	$	532,222	1.73%	
368--Accum. Depreciation	$	(181,688)		$(10,523,089)
Estimated Rate Base	$	2,558,948		
Return @ 15.0% (including tax)	$	383,842		
Depreciation Expense				
acct 364	$	37,040	14.18%	$ 261,212
acct 365	$	26,778	14.18%	$ 188,844
acct 366	$	2,802	0.88%	$ 317,492
acct 367	$	8,045	0.88%	$ 911,574
acct 368	$	12,700	1.73%	$ 735,582
Subtotal Depreciation Expense	$	87,365		
O&M Expenses:				
acct 583	$	25,894	14.18%	$ 182,605
acct 584	$	2,061	0.88%	$ 233,540
acct 593	$	96,293	14.18%	$ 679,072
acct 594	$	2,172	0.88%	$ 246,077
acct 595	$	370	1.73%	$ 21,448
Cost of Service: selected items	$	597,997		
currently divided by GL load of 573,790 kW	$	1.04	per kw yr	
imputed for load at primary/secondary of 46,415 kW	$	12.88	per kw yr	

COPY

PENNSYLVANIA UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION,	:	
v.	:	Docket No. R-00974104
DUQUESNE LIGHT COMPANY Application for approval of restructuring plan pursuant to 66 Pa. C.S. Section 2806(d).	:	

Washington, D.C.

Monday, November 17, 1997

Deposition of

WHITFIELD RUSSELL

a witness, called for examination by counsel for Duquesne, pursuant to notice and agreement of counsel, beginning at approximately 2:20 p.m., at the offices of Skadden Arps Slate Meagher & Flom, L.L.P., 1440 New York Avenue, Northwest, Washington, D.C., before Shari R. Broussard, notary public in and for the District of Columbia, when were present on behalf of the respective parties:

Q You said may be appropriate for some special treatment. Did you mean to use the word "will" or did you mean to use the word "may be"?

A Well, I -- I think that under the statutory scheme in Pennsylvania, as I understand it, I would recommend that any overstatement of the market price or the CGC turn out to be higher than the market price, that differential should be taken in account in the annual review and in any consideration of an extension of the period of -- transition period. Yes.

Q What do you mean by should be taken into account? The utility should be able to

recover it or no?

A Yes. You know, if they've done all of the other cross -- cleared all the other hurdles.

Q Which are?

A Their obligation to mitigate costs, mitigate stranded costs, increase their efficiency. there's quite a few of them in the statute. We can run through the standards if you would like. I'm not thinking of anything beyond what's in the statute.

during a given calendar year to the Commission?

A I think we will all know where the market price is settling out. Customers talk about what prices they're paying. Customers will be making comparisons. Customers -- there be will be general information. There may even be an indexed published of what people are paying for retail prices.

If that kind of information is not sufficient to indicate where the retail market price has settled out or is trending, then we may have to have some sort of confidential review by an unbiased Commissioner, intermediary to tell us how the CGC and the retail market price, whether they converged or diverged.

Q Is it your, I think you called it a secondary proposal, is it your secondary proposal that the competitive generation credit be set to reflect the anticipated level of cost that retail suppliers would bear? Is that a fair statement?

FILE CONTINUED