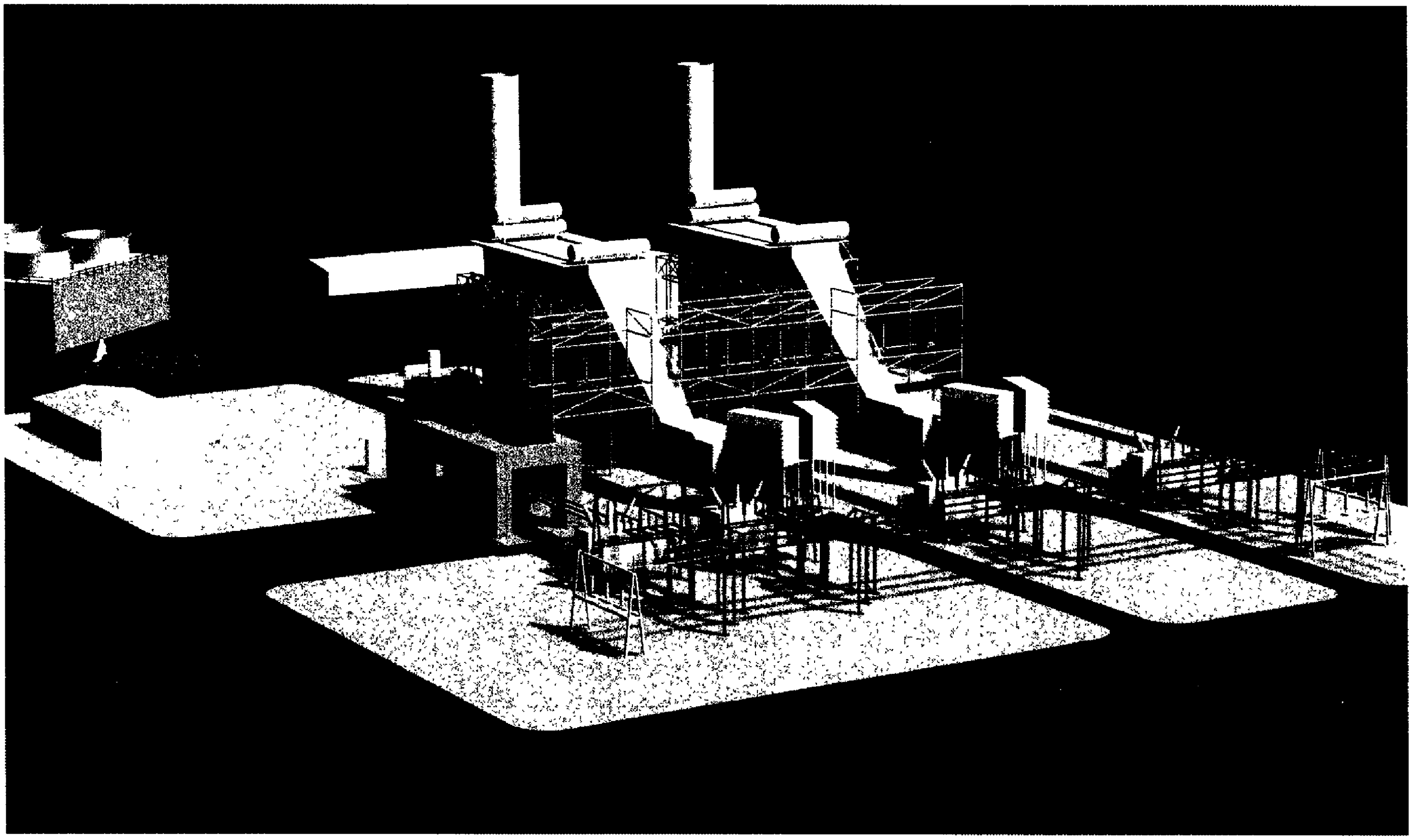
Need for Power Application/Revisions

Volume 1G – Revisions

010142-EM



Orlando Utilities Commission
Curtis H. Stanton Energy Center
Combined Cycle Unit A

DOCUMENT NUMBER-DATE
02880 MAR-5 ō

FPSC-RECORDS/REPORTING

B&V Project 97185 2001

FMPA

KUA KISSIMMEE UTILITY AUTHORITY

OUC The *Reliable* One

SOUTHERN COMPANY
Energy to Serve Your World

1A.2.0 Overview and Summary

1A.2.1 Overview

Stanton A will be the third unit installed at the Stanton Energy Center site located approximately 12 miles southeast of Orlando, Florida. Stanton A is being planned for a nominal net generating capacity of 633 MW at 70° F based on new and clean conditions.

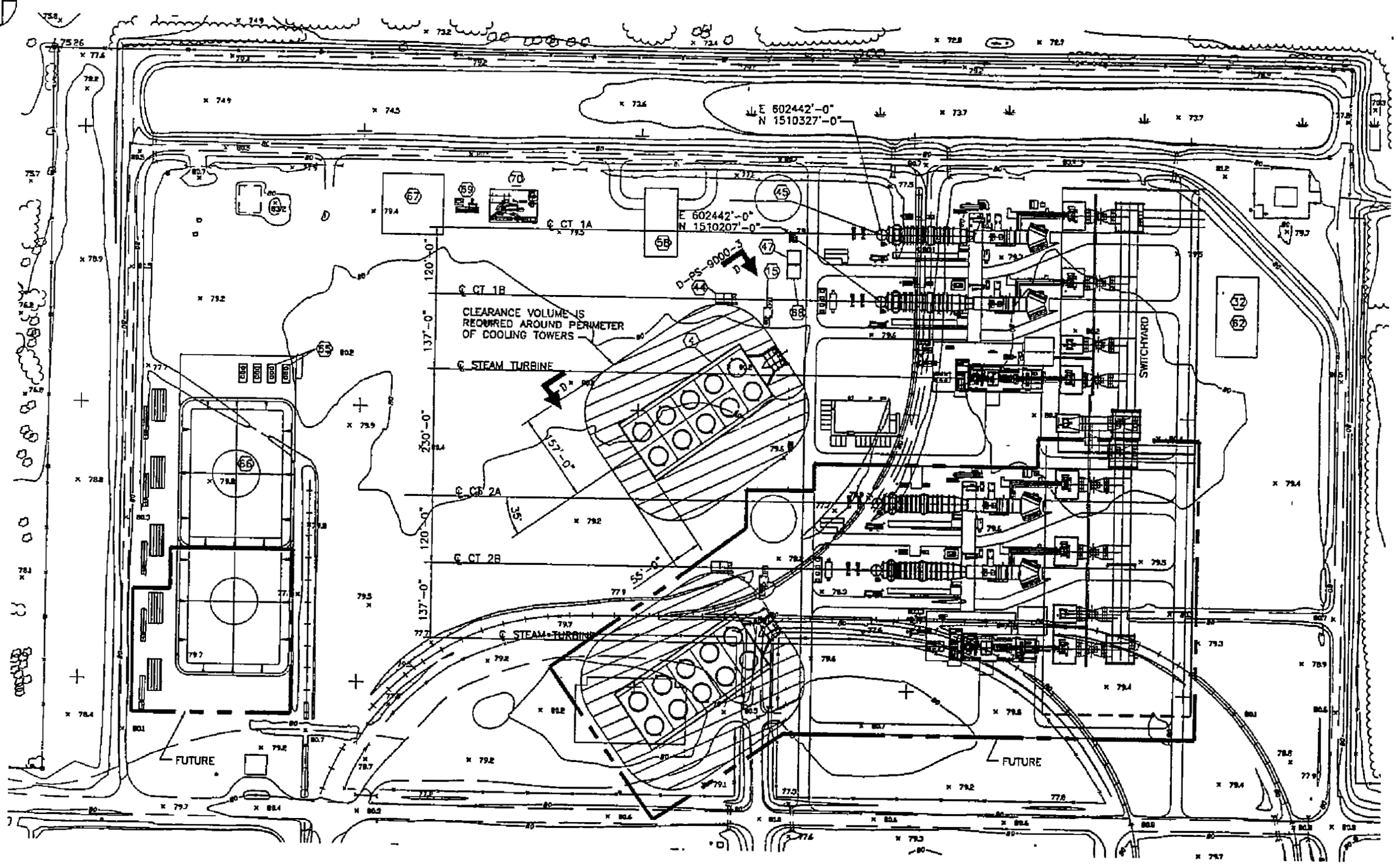
Stanton A is jointly owned by OUC, KUA, FMPA, and Southern-Florida as follows:

- OUC - 28 percent.
- KUA - 3.5 percent.
- FMPA - 3.5 percent.
- Southern-Florida - 65 percent.
- OUC, KUA, and FMPA will purchase all of the capacity owned by Southern-Florida, pursuant to the PPAs, for a minimum 10 year term. The PPAs provide OUC, KUA, and FMPA the unilateral option to acquire Southern-Florida capacity for a term of up to 30 years, which is assumed to be the life of the plant. The purchased capacity will be allocated among these utilities as follows:
  - OUC - 80 percent.
  - KUA - 10 percent.
  - FMPA - 10 percent.

The details of the PPAs are set forth in Section 1A.4.0.

1A.2.2 Summary

Stanton A is planned to utilize a 2 x 1 combined cycle configuration with two General Electric PG-7241 FA combustion turbines, two heat recovery steam generators, and a steam turbine. The estimated capital cost for OUC's, KUA's, and FMPA's collective share is [redacted] including costs for the power block as well as interconnection facilities. Stanton A is projected to have a new and clean output of 633 MW at 70° F with a higher heating value (HHV) heat rate of [redacted] Btu/kWh. Stanton A is planned to be equipped with evaporative inlet cooling, duct firing, and power augmentation to increase output. Natural gas is the primary fuel for Stanton A and No. 2 oil is the planned backup fuel. Stanton A will not be equipped with bypass stacks and dampers, but will have the condenser sized such that both combustion turbines can be operated at full load with the steam turbine out of service.



NOTES:

NEW STACK COORDINATES BASED ON NAD83 FLORIDA STATE PLANES, EASTERN ZONE, U.S. FOOT.

CENTER UNIT 1A HRSG STACK.	E 602442'-0" N 1510327'-0"
CENTER UNIT 1B HRSG STACK.	E 602442'-0" N 1510207'-0"
CENTER UNIT 2A HRSG STACK.	E 602442'-0" N 1509840'-0"
CENTER UNIT 2B HRSG STACK	E 602442'-0" N 1509720'-0"

NEW STACK COORDINATES BASED ON NAD83 UTM, ZONE 16 NORTH, METER.

CENTER UNIT 1A HRSG STACK.	E 1071425.2056 N 3165216.3816
CENTER UNIT 1B HRSG STACK	E 1071427.0434 N 3165176.3166
CENTER UNIT 2A HRSG STACK	E 1071432.6637 N 3165067.5830
CENTER UNIT 2B HRSG STACK	E 1071434.5014 N 3165030.9181

◯ DENOTES EQUIP. NO – SEE D-PS-9000-2 FOR DESCRIPTION

REFERENCES:

D-PS-9000-2	STANTON ENERGY CENTER – UNIT 3 1-2x1 COMBINED CYCLE BLOCK SITE PLAN 1"=30'-0"
D-PS-9000-3	STANTON ENERGY CENTER – UNIT 3 1-2x1 COMBINED CYCLE BLOCK SECTIONS
D-PS-9000-4	STANTON ENERGY CENTER – UNIT 3 1-2x1 COMBINED CYCLE BLOCK SITE PLAN 1"=200'-0"

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AutoCad SHW-14

PRELIMINARY

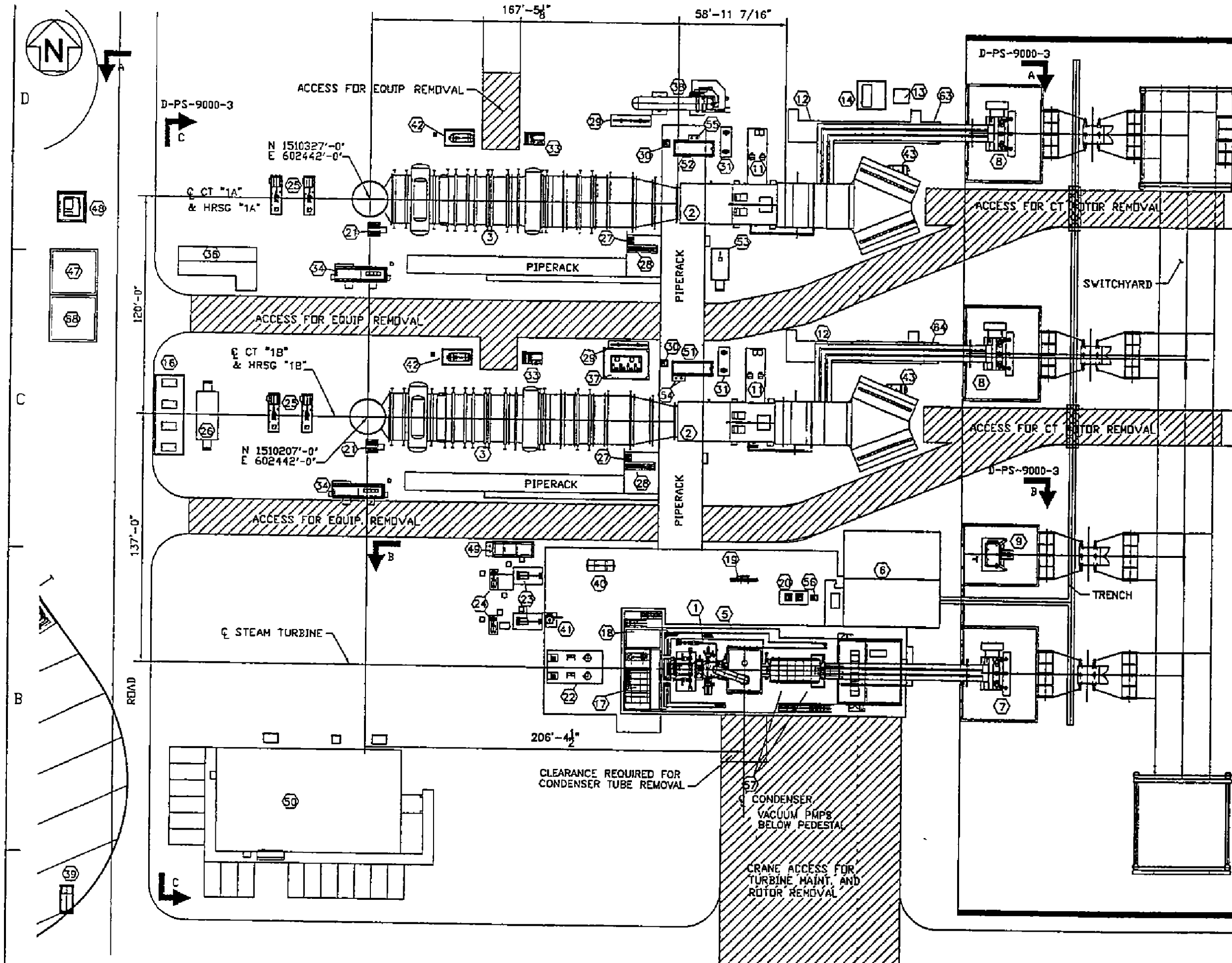
Revision	Date	Description	By
REVISION E	DATE 02/02/01	3. (CONT'D) RELOCATED ITEM 65 FUEL OIL FORWARDING PUMPS AND ITEM 66 FUEL OIL STORAGE TANK	SHW
REVISION E	DATE 02/02/01	1. DELETED ITEM NO. 67 IPC. 2. ADDED BRINE CONCENTRATOR 68, CRYSTALLIZER 70 AND BRINE CRYSTALLIZER POND 67 3. RELOCATED ITEM 62 GAS CONDITIONING, ITEM 32 GAS METERING STATION,	SHW
REVISION D	DATE 01/16/00	1 REVISED TITLE BLOCK	SHW
REVISION C	DATE 12/7/00	1 ADDED CONCENTRATION WASTE BLOWDOWN SUMP ITEM NO 68	DWR
REVISION B	DATE 10/24/00	1 ADDED SERVICE WATER COOLER 1 ADDED LOCATION OF FUTURE BLOCK	SHW
REVISION A	DATE 9/22/00	ISSUED FOR REVIEW	SHW

Southern Company Services, Inc.
FOR
SOUTHERN-FLORIDA, LLC

STANTON ENERGY CENTER – UNIT A
1-2x1 COMBINED CYCLE BLOCK
SITE PLAN 1"=100'-0"

DESIGNED	DRAWN	CHECKED	SCALE	PROJECT I.D.	DRAWING NUMBER	REV.
SHW	SHW		1"=100'-0"		D-PS-9000-1	E

D-PS-9000-1



LEGEND

1. STEAM TURBINE
2. COMBUSTION TURBINE
3. HEAT RECOVERY STEAM GENERATOR
4. COOLING TOWER (SEE D-PS-9000-1)
5. CONDENSER
6. ELECTRICAL BUILDING
7. STEAM GENERATOR GSU
8. COMBUSTION TURBINE GSU
9. STATION SERVICE TRANSFORMER
10. AUX. TRANSFORMER (N.A.)
11. COMBUSTION TURBINE ACCESSORY MOD
12. COMBUSTION TURBINE PEEC
13. DC LINK TRANSFORMER
14. ISOLATION TRANSFORMER
15. 480V TRANSFORMER & MCC (SEE DWG. D-PS-9000-1)
16. FEEDWATER TRANSFORMER
17. STEAM TURBINE LUBE OIL SKID
18. STEAM TURBINE HPU
19. GLAND STEAM CONDENSER
20. CONDENSATE PUMPS
21. CONDENSATE RECIRC PUMPS
22. AIR COMPRESSOR
23. SERVICE WATER HEAT EXCHANGER
24. SERVICE WATER PUMPS
25. BOILER FEED PUMPS
26. BOILER FEED PUMP DRIVE SKID
27. SCANNER AIR BLOWER
28. FUEL GAS PIPING MODULES
29. FUEL GAS HEATER
30. FUEL GAS ELECTRIC WATER HEATER
31. FUEL GAS FILTER
32. GAS METERING STATION (SEE D-PS-9000-1)
33. SCR AMMONIA BLR/CONTROL
34. CEMS BUILDING
35. WATER TREATMENT BUILDING (N/A)
36. WATER ANALYSIS BUILDING
37. PHOSPHATE FEED PUMP SKID
38. AMMONIA SUPPLY SYSTEM
39. CO2 SKID
40. CLOSED LOOP COOLING WTR TANK
41. STEAM TURBINE BLOWDOWN TANK
42. HRSG BLOWDOWN TANK
43. CT CO2 TANK
44. CHEMICAL FEED TANKS (SEE D-PS-9000-1)
45. DEMIN STORAGE TANK (SEE DWG. D-PS-9000-1)
46. RAW WATER STORAGE TANK (N/A)
47. WASTE WATER SUMP
48. OIL/WATER SEPARATOR
49. MAIN STEAM SUMP
50. CONTROL/ADMIN BLDG
51. SUMP 'A'
52. SUMP 'B'
53. WASH WATER SKID
54. SUMP 'A' PUMPS
55. SUMP 'B' PUMPS
56. TURBINE SEAL OIL SKID
57. VACUUM PUMPS
58. WAREHOUSE (SEE DWG. D-PS-9000-1)
59. FIRE PROT. PUMP HSE (N/A)
60. FIRE PROT. STORAGE TK (N/A)
61. FILTERED WTR STORAGE TK (N/A)
62. GAS CONDITIONING STATION (SEE DWG. D-PS-9000-1)
63. LCI EXCITATION COMPT (LEC)
64. STATIC EXCITATION COMPT (EC)
65. FUEL OIL FORWARDING PUMPS (SEE DWG D-PS-9000-1)
66. FUEL OIL STORAGE TANK (SEE DWG D-PS-9000-1)
67. BRINE CRYSTALLIZER POND (SEE DWG. D-PS-9000-1)
68. CONCENTRATION WASTE BLOWDOWN SUMP
69. BRINE CONCENTRATOR (SEE DWG. D-PS-9000-1)
70. CRYSTALLIZER (SEE DWG D-PS-9000-1)

REFERENCES

D-PS-9000-1	STANTON ENERGY CENTER - UNIT 3 1-2x1 COMBINED CYCLE BLOCK SITE PLAN 1"=100'-0"
D-PS-9000-3	STANTON ENERGY CENTER - UNIT 3 1-2x1 COMBINED CYCLE BLOCK SECTIONS
D-PS-9000-4	STANTON ENERGY CENTER - UNIT 3 1-2x1 COMBINED CYCLE BLOCK SITE PLAN 1"=200'-0"

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AutoCad SHV-14

PRELIMINARY

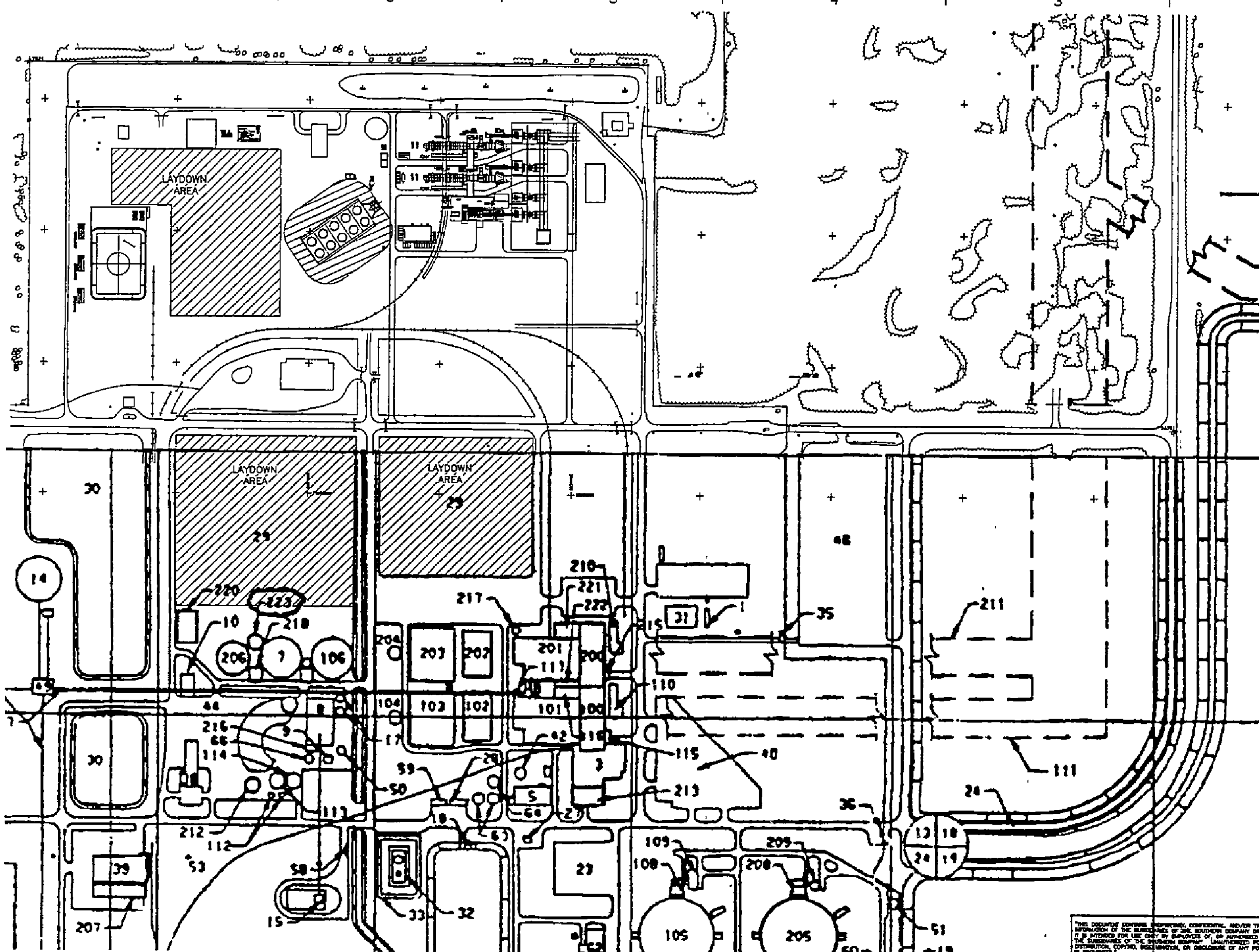
REVISION	DATE	DESCRIPTION	BY
REVISION E	DATE 02/02/01	1 DELETED ITEM NO 67 IPC 2 ADDED ITEM NO 67 BRINE CRYSTALLIZER POND. ADDED ITEM NO 69 CRYSTALLIZER ADDED ITEM NO 70 BRINE CONCENTRATOR	SHW
REVISION D	DATE 01/16/01	1 REVISED TITLE BLOCK	SHW
REVISION C	DATE 12/7/00	1 ADDED CONCENTRATION WASTE BLOWDOWN SUMP ITEM NO 68	DWR
REVISION B	DATE 10/24/00	ADDED ITEM NO 67 IPC	SHW
REVISION A	DATE 9/22/00	ISSUED FOR REVIEW	SHW

Southern Company Services, Inc.
FOR
SOUTHERN-FLORIDA, LLC

STANTON ENERGY CENTER - UNIT A
1-2x1 COMBINED CYCLE BLOCK
SITE PLAN 1"=30'-0"

DESIGNED	DRAWN	CHECKED
SHW	SHW	

SCALE	PROJECT I.D.	DRAWING NUMBER	REV.
1"=30'-0"		D-PS-9000-2	E



REFERENCES:

D-PS-9000-1 STANTON ENERGY CENTER – UNIT 3 1-2x1 COMBINED CYCLE BLOCK SITE PLAN 1"=100'-0"

D-PS-9000-2 STANTON ENERGY CENTER – UNIT 3 1 – 2x1 COMBINED CYCLE BLOCK SITE PLAN 1"=30'-0"

D-PS-9000-3 STANTON ENERGY CENTER – UNIT 3 1-2x1 COMBINED CYCLE BLOCK SECTIONS

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Southern Company Services, Inc.
FOR
SOUTHERN–FLORIDA, LLC

STANTON ENERGY CENTER – UNIT A
1-2x1 COMBINED CYCLE BLOCK
SITE PLAN 1"=200'-0"

REVISION	DATE	REVISION E, DATE 02/02/01	REVISION D, DATE 01/16/01	REVISION C, DATE 12/7/00	REVISION B, DATE 10/27/00	REVISION A, DATE 9/22/00
		1 ADDED BRINE CRYSTALLIZER POND, CRYSTALLIZER AND BRINE CONCENTRATOR 2 RELOCATED GAS METERING/CONDITIONING, RELOCATED FUEL OIL FORWARDING PUMPS AND FUEL OIL STORAGE TANK	1 REVISED TITLE BLOCK	1 ADDED CONCENTRATION WASTE BLOWDOWN SUMP	ADDED IPC	ISSUED FOR REVIEW
BY		SHW	SHW	SHW	SHW	SHW

DESIGNED SHW	DRAWN SHW	CHECKED	
SCALE	PROJECT I.D.	DRAWING NUMBER	REV
1"=200'-0"		D-PS-9000-4	E

1A.5.0 Evaluation Criteria

1A.5.1 Economic Parameters

With several different entities having ownership interests in Stanton A, the economic parameters used for evaluation vary between the various participants primarily due to differences in their cost of money. Other economic parameters such as general inflation rates and escalation rates which do not vary between the participants are kept consistent for evaluation purposes. Because Southern-Florida is the majority owner of Stanton A, its economic parameters are used for decisions dealing with equipment selection. Because OUC is the agent for KUA and FMPA and has the largest entitlement to output from the project, OUC's economic criteria are used to determine the cost-effectiveness of the project as a whole. KUA's and FMPA's economic parameters are described in Volumes 1C and 1D and are used to determine the cost-effectiveness of their portion of the project for their respective systems.

1A.5.1.1 Escalation Rates

The general inflation rate applied is assumed to be 2.5 percent. The escalation rate for capital costs and operation and maintenance (O&M) expenses is assumed to be 2.5 percent.

1A.5.1.2 Cost of Capital

Southern-Florida uses a real interest rate of [redacted] percent, which with the general inflation rate of 2.5 percent corresponds to a nominal interest rate of [redacted] percent. The real interest rate of [redacted] percent is used to evaluate emission control equipment in accordance with the Environmental Protection Agency guidelines.

OUC uses a weighted average cost of capital for economic evaluations. The weighted average cost of capital is based on the debt/equity ratio, which is approximately 70/30, the embedded debt rate, which is approximately 6.6 percent, and the return on equity, which is approximately 10.3 percent. The weighted average cost of capital is thus approximately 7.7 percent. For economic evaluation for the need for power, the weighted average cost of capital is rounded to 8 percent.

1A.5.1.3 Present Worth Discount Rate

Southern-Florida uses a real present worth discount rate of [redacted] percent, corresponding to Southern-Florida's real interest rate.

OUC's present worth discount rate is assumed to be equal to the weighted average cost of capital of 8.0 percent.

1A.5.1.4 Interest During Construction Interest Rate

The interest during construction interest rate is assumed to be 6.0 percent.

1A.5.1.5 Levelized Fixed Charge Rate

The levelized fixed charge rate is assumed to be the sum of the capital recovery rate and insurance rate. Based on the weighted average cost of capital of 8.0 percent, a 1.0 percent annual insurance cost, and a capital recovery period of 20 years, the levelized fixed charge rate is assumed to be 11.19 percent.

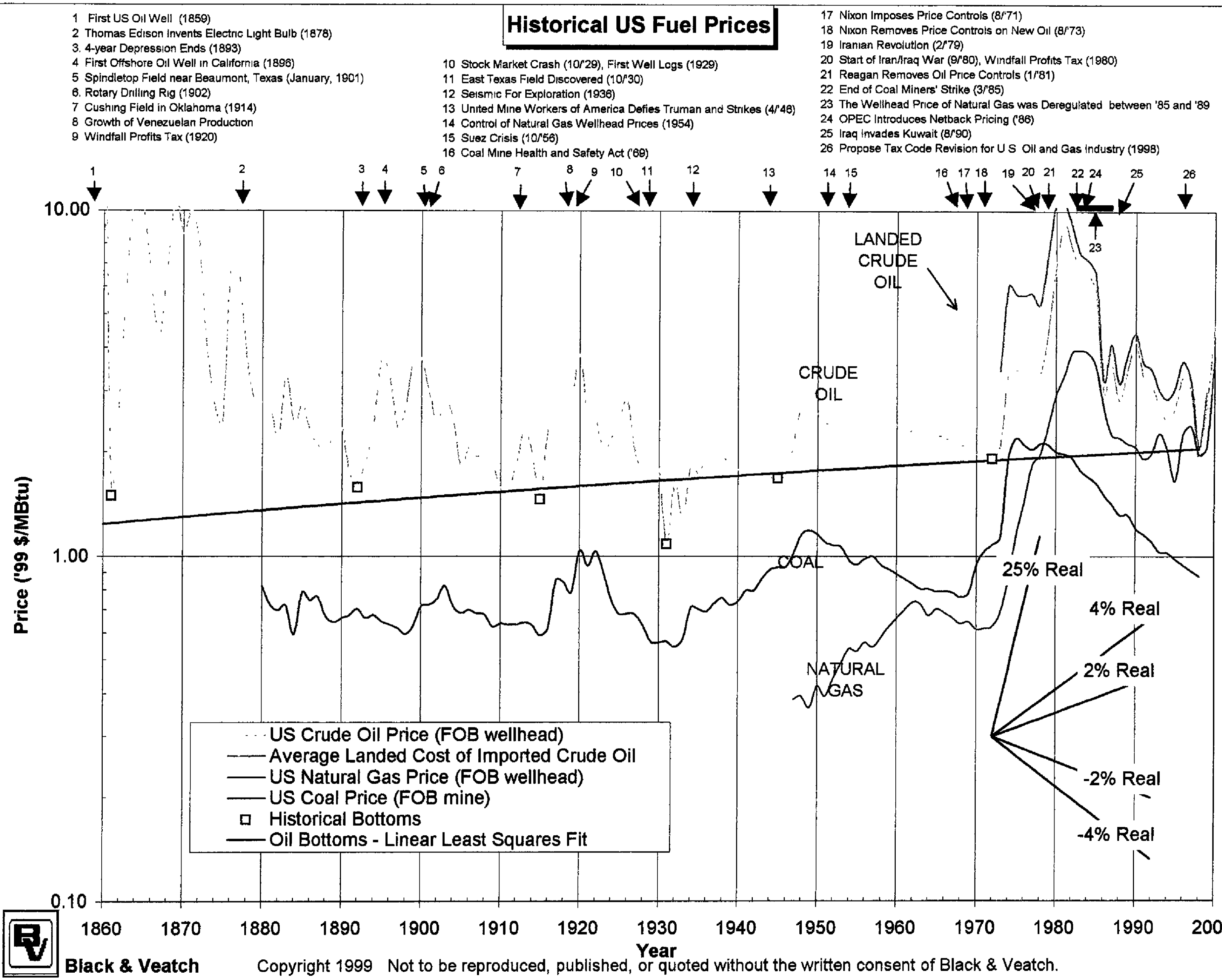
1A.5.2 Fuel Price Projections

This section presents the fuel price projections for coal, petroleum coke, natural gas, oil, and nuclear fuel. For consistency, a single set of fuel price projections is developed to apply to OUC, KUA, and FMPA. In general, the projections are developed based on projected prices for OUC since OUC has the largest amount of generation of the three applicants. Also, many of the generating units are jointly owned by the three applicants and thus have similar fuel costs. Natural gas and oil are generally fungible and would be expected to have generally the same costs for each of the utilities for the same general geographical region over time.

The base case forecasts are based on forecasts provided by Energy Ventures Analysis, Inc. (EVA) who were commissioned by OUC and Southern-Florida because of its fuel forecasting expertise and the belief that the EVA forecast would be the best available. EVA developed fuel forecasts for natural gas, coal, West Texas Intermediate (WTI) crude oil, and petroleum coke.

Fuel prices are highly volatile and are dependent not only on supply and demand, but also political stability and interdependent markets. Even the best forecasters face a tough job of forecasting in such a volatile market. Figure 1A.5-1 shows historical US fuel prices and the wide range of fluctuations and responses to market conditions. Because of the difficulty of forecasting in this environment, several sensitivity scenarios have been developed. These sensitivity scenarios include a high and low forecast based on the forecast developed from the EVA forecast, a scenario where OUC's actual 2000 fuel prices remain constant throughout the evaluation period in real terms, the 2001 Annual Energy Outlook (AEO) projections developed by the United States Department of Energy (DOE), and, finally, a scenario in which OUC's actual 2000 fuel prices escalate based on the 2001 AEO escalation rates for the various fuels.

Historical US Fuel Prices



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1A.5.2.1 EVA Fuel Price Projections

EVA developed projections for natural gas, coal, WTI crude oil, and petroleum coke on a real price basis.

1A.5.2.1.1 Natural Gas. The natural gas price projections are for Henry Hub. The greatest concern with the forecast is in the years 2003 and 2004. The industry has entered a new era in which short-term supply increases cannot keep pace with short-term demand increases. This imbalance has resulted in very high gas prices. Despite record levels of drilling in both the United States and Canada, it appears this era will last for at least 3 years and could last up to 5 years. The big variable in the length of this era is the severity of winter weather in each of the forthcoming years 2002 through 2004, as the difference between a mild and cold winter can represent between 1.5 and 2.0 BCFD per year in additional demand. The projection does not assume any carbon taxes or other such major pieces of legislation that could significantly impact supply and demand. The Henry Hub natural gas projection in constant 2001 dollars is presented in Table 1A.5-1.

1A.5.2.1.2 Coal. The long-term coal price projection is based on low sulfur (1.8-2.5 lb SO_2/MBtu with a 12,500 Btu/lb heating value) Appalachian coal delivered to Orlando in railcars. The projection by mine and rail costs in constant 2001 dollars is presented in Table 1A.5-2.

1A.5.2.1.3 WTI Crude Oil. Crude oil prices are expected to decline. The projected WTI crude oil prices in constant 2000 dollars are presented in Table 1A.5-3.

1A.5.2.1.4 Petroleum Coke. The petroleum coke forecast is a delivered price where the initial delivery is via barge from the Gulf Coast refineries and then offloaded to railcars. Crude oil prices, which are the largest cost component, are expected to decline as indicated in Table 1A.5-3. Larger coke volumes are projected to be produced as crude oil becomes heavier. Refinery upgrades are producing a larger gasoline fraction from residue, which increases coke production, which has risen 36 percent in the last 3 years. Higher value markets for petroleum coke are limited including calcined coke for aluminum production and needle grade for steel refineries. Fuel grade (green coke) is the lowest value use for petroleum coke, but also is the only remaining expansion market. Petroleum coke is a thinly traded commodity and is at risk of rapid price escalation with large increases in demand. However, the cap is set by alternative coal prices ($1.80/MBtu) in the US market and alternative fuels in Europe. Fuel use, however, has discounted value because of the high metals content, high sulfur content, and low volatile content. Market potential for petroleum coke could grow and the price increase if more flue gas desulfurization (FGD) systems are retrofitted on existing plants. The projected power demand and projected price of petroleum coke delivered to Stanton Energy Center in constant 2001 dollars are presented in Table 1A.5-4.

Table 1A.5-1
EVA Forecast Natural Gas Prices At Henry Hub ($2001)

Year	[$/MBtu]
2000	4.30
2001	5.64
2002	4.24
2003	3.27
2004	2.75
2005	2.65
2006	2.59
2007	2.63
2008	2.67
2009	2.71
2010	2.75
2011	2.80
2012	2.85
2013	2.90
2014	2.95
2015	3.01
2016	3.07
2017	3.13
2018	3.20
2019	3.26

Table 1A.5-2
EVA Forecast Long-Term Coal Prices ($2001)

Year	Mine $/ton	Rail $/ton	Delivered $/ton	Delivered $/MBtu
2000	23.43	19.95	43.38	1.74
2001	28.97	19.50	48.47	1.94
2002	25.85	19.07	44.92	1.80
2003	24.99	18.77	43.76	1.75
2004	24.89	18.50	43.39	1.74
2005	24.65	18.42	43.07	1.72
2006	24.45	18.29	42.74	1.71
2007	24.31	18.15	42.45	1.70
2008	24.17	18.01	42.18	1.69
2009	24.10	17.88	41.98	1.68
2010	24.03	17.75	41.78	1.67
2011	23.98	17.64	41.62	1.66
2012	23.92	17.54	41.46	1.66
2013	23.87	17.43	41.30	1.65
2014	23.79	17.33	41.12	1.64
2015	23.74	17.23	40.96	1.64
2016	23.69	17.14	40.84	1.63
2017	23.68	17.06	40.74	1.63
2018	23.68	16.98	40.65	1.63
2019	23.66	16.89	40.55	1.62

Note: Long-term delivered cost to Stanton Energy Center based on Appalachian low-sulfur coal with 12,500 Btu/lb heating value and 1.8 to 2.5 lb SO_2/MBtu.

Table 1A.5-3
EVA Forecast WTI Crude Oil Price ($2000)

Year	WTI Crude Oil [$/BBL]
2000	30.82
2001	27.36
2002	24.14
2003	21.00
2004	19.50
2005	18.50
2006	18.25
2007	18.25
2008	18.25
2009	18.25
2010	18.50
2011	18.50
2012	18.50
2013	18.50
2014	18.50
2015	18.50
2016	18.75
2017	18.75
2018	18.75
2019	18.75

Table 1A.5-4
EVA Forecast Petroleum Coke Demand and Delivered Prices ($2001)

Year	Power Demand 1,000 tons	Most Probable $/MBtu	Low $/MBtu	High $/MBtu
2000	3,254	1.29	0.83	1.64
2001	3,686	1.28	0.75	1.64
2002	3,686	1.20	0.74	1.64
2003	3,761	1.14	0.73	1.63
2004	3,987	1.12	0.73	1.63
2005	4,101	1.11	0.72	1.63
2006	4,214	1.09	0.72	1.63
2007	4,341	1.09	0.71	1.62
2008	4,471	1.08	0.70	1.62
2009	4,605	1.08	0.70	1.62
2010	4,743	1.09	0.69	1.61
2011	4,886	1.09	0.68	1.61
2012	5,032	1.10	0.68	1.61
2013	5,183	1.12	0.67	1.61
2014	5,338	1.13	0.66	1.60
2015	5,498	1.15	0.66	1.60
2016	5,663	1.17	0.65	1.60
2017	5,833	1.19	0.66	1.60
2018	6,008	1.21	0.65	1.59
2019	6,189	1.23	0.64	1.59

1A.5.2.2 Base Case Fuel Price Projections

The coal price projections are assumed to apply to McIntosh 3 as well as units at Stanton Energy Center.

The annual general inflation rate of 2.5 percent is added to EVA's constant dollar fuel price forecasts to obtain nominal fuel price projections for evaluation purposes which are presented in Table 1A.5-5.

For natural gas, transportation charges must be added to obtain a delivered fuel cost. OUC, KUA, and FMPA, as well as FMPA's generating member cities, all have varying amounts of natural gas transportation capability from Florida Gas Transmission Company (FGT) under FTS-1 and FTS-2 tariffs. The FTS-2 tariff is expected to change as additional expansions are conducted on FGT's system. In general, it is expected that FTS-2 tariff rates will lower somewhat as additional expansions are added. Also impacting the natural gas transportation situation is the proposed Gulfstream pipeline. In general, increased competition would be expected to increase pressure to lower transportation costs. Finally, the impacts of transportation capacity being bought and sold on the secondary market will also influence the average natural gas transportation costs. For the purposes of this evaluation, OUC has assumed that natural gas transportation costs will be approximately $0.75/MBtu over the evaluation period. The $0.75/MBtu natural gas transportation cost is assumed to remain constant over the forecast period and is included in the natural gas price forecast in Table 1A.5-5.

EVA did not provide forecasts for No. 2 and No. 6 oil. Delivered projections of No. 2 and No. 6 oil were developed by comparing OUC's actual delivered cost for No. 2 and No. 6 oil in 2000 to EVA's projected 2000 WTI crude oil price and applying the percentage difference in cost to EVA's WTI crude oil price.

Projections for nuclear fuel prices are based on OUC's actual 2000 nuclear fuel cost escalating at the general inflation rate.

1A.5.2.3 High and Low Case Fuel Price Projections

High and low case fuel price projections for all fuels except petroleum coke are developed by applying a 2 percent higher annual escalation rate to the base case fuel price projections for the high case and a 2 percent lower annual escalation rate to the base case projections for the low case except for the petroleum coke projections which apply the 2.5 percent general inflation rate to the EVA high and low projections. The high and low petroleum coke forecasts were provided directly by EVA. The high and low case fuel price projections are presented in Tables 1A.5-6 and 1A.5-7, respectively.

Table 1A.5-5
Base Case Fuel Price Forecast Summary (Delivered Price $/MBtu)

Year	Coal	Natural Gas	No. 2 Oil	No. 6 Oil	Nuclear	Petroleum Coke
2000	1.70	4.95	5.79	4.42	0.52	1.26
2001	1.94	6.39	5.27	4.02	0.53	1.28
2002	1.85	5.10	4.76	3.64	0.55	1.23
2003	1.84	4.19	4.25	3.24	0.56	1.20
2004	1.87	3.71	4.04	3.09	0.57	1.21
2005	1.90	3.56	3.93	3.00	0.59	1.23
2006	1.93	3.68	3.98	3.04	0.60	1.23
2007	1.97	3.80	4.08	3.11	0.62	1.26
2008	2.01	3.92	4.18	3.19	0.63	1.28
2009	2.05	4.05	4.28	3.27	0.65	1.32
2010	2.09	4.18	4.45	3.40	0.67	1.36
2011	2.12	4.33	4.56	3.48	0.68	1.40
2012	2.20	4.49	4.67	3.57	0.70	1.44
2013	2.22	4.65	4.79	3.66	0.72	1.51
2014	2.26	4.82	4.91	3.75	0.73	1.56
2015	2.32	5.00	5.03	3.84	0.75	1.62
2016	2.36	5.20	5.23	3.99	0.77	1.69
2017	2.42	5.40	5.36	4.09	0.79	1.77
2018	2.48	5.62	5.49	4.19	0.81	1.84
2019	2.53	5.83	5.63	4.30	0.83	1.92
Average Annual Escalation (%)	2.12%	0.87%	-0.15%	-0.15%	2.50	2.24%

Note: Fuel prices in nominal dollars including the general inflation rate. Natural gas prices include estimated transportation.

Table 1A.5-6
High Case Fuel Price Forecast Summary (Delivered Price $/MBtu)

Year	Coal	Natural Gas	No. 2 Oil	No. 6 Oil	Nuclear	Petroleum Coke
2000	1.70	4.95	5.79	4.42	0.52	1.60
2001	1.97	6.47	5.38	4.11	0.54	1.64
2002	1.92	5.26	4.98	3.80	0.57	1.68
2003	1.95	4.40	4.54	3.46	0.59	1.71
2004	2.02	3.98	4.41	3.37	0.62	1.76
2005	2.09	3.88	4.38	3.34	0.65	1.80
2006	2.17	4.08	4.51	3.44	0.68	1.84
2007	2.26	4.28	4.72	3.60	0.71	1.88
2008	2.35	4.50	4.93	3.76	0.74	1.93
2009	2.44	4.72	5.15	3.93	0.77	1.97
2010	2.53	4.96	5.45	4.16	0.81	2.01
2011	2.63	5.23	5.70	4.35	0.84	2.06
2012	2.78	5.51	5.96	4.55	0.88	2.11
2013	2.86	5.81	6.22	4.75	0.92	2.17
2014	2.97	6.13	6.50	4.96	0.96	2.21
2015	3.10	6.49	6.80	5.19	1.01	2.26
2016	3.22	6.86	7.20	5.49	1.05	2.32
2017	3.37	7.26	7.52	5.74	1.10	2.38
2018	3.52	7.70	7.86	6.00	1.15	2.42
2019	3.65	8.15	8.21	6.27	1.20	2.48
Average Annual Escalation (%)	4.12%	2.66%	1.86%	1.86%	4.50%	2.33%

Note: Fuel prices in nominal dollars including the general inflation rate. Natural gas prices include estimated transportation.

Table 1A.5-7
Low Case Fuel Price Forecast Summary (Delivered Price $/MBtu)

Year	Coal	Natural Gas	No. 2 Oil	No. 6 Oil	Nuclear	Petroleum Coke
2000	1.70	4.95	5.79	4.42	0.52	0.81
2001	1.91	6.31	5.15	3.93	0.52	0.75
2002	1.77	4.91	4.56	3.48	0.53	0.76
2003	1.73	3.94	3.97	3.03	0.53	0.77
2004	1.73	3.46	3.70	2.83	0.53	0.79
2005	1.72	3.26	3.53	2.69	0.53	0.79
2006	1.72	3.32	3.49	2.67	0.54	0.81
2007	1.72	3.37	3.51	2.68	0.54	0.82
2008	1.71	3.43	3.53	2.69	0.54	0.83
2009	1.71	3.48	3.55	2.71	0.54	0.85
2010	1.71	3.54	3.61	2.76	0.55	0.86
2011	1.71	3.60	3.63	2.77	0.55	0.87
2012	1.74	3.67	3.65	2.79	0.55	0.89
2013	1.72	3.74	3.67	2.80	0.55	0.90
2014	1.71	3.80	3.69	2.81	0.56	0.91
2015	1.72	3.88	3.71	2.83	0.56	0.93
2016	1.72	3.96	3.78	2.88	0.56	0.94
2017	1.73	4.04	3.79	2.90	0.57	0.96
2018	1.74	4.14	3.81	2.91	0.57	0.99
2019	1.73	4.22	3.83	2.93	0.57	1.00
Average Annual Escalation (%)	0.11%	-0.83%	-2.15%	-2.15%	0.50%	1.11%

Note: Fuel prices in nominal dollars including the general inflation rate. Natural gas prices include estimated transportation.

1A.5.2.4 Constant 2000 Fuel Price Projections

The constant 2000 fuel price projection assumes that the actual OUC 2000 fuel costs remain constant in real terms over the forecast period. The constant 2000 fuel price projection thus applies the 2.5 percent general inflation rate to OUC's actual 2000 fuel costs for all fuels except petroleum coke. The constant 2000 projection for petroleum coke was developed by applying the 2.5 percent general inflation rate to the base case forecast provided by EVA. Figure 1A.5-1 indicates that it would be unprecedented for high fuel prices such as those occurring in 2000 to continue in real terms for an entire 20 year period. Nevertheless, the constant 2000 fuel price projection offers the opportunity to evaluate the cost effectiveness of Stanton A with continuing high fuel prices. The constant 2000 fuel price projection is presented in Table 1A.5-8. For purposes of this evaluation, the delivered gas price projection assumes the commodity portion of the price escalates at the 2.5 percent general inflation rate and the $0.75/MBtu transportation cost remains constant over the forecast period. This results in the delivered cost of natural gas escalating at slightly less than the general inflation rate of 2.5 percent. The constant 2000 fuel price projection for natural gas is 33 percent higher than the base case by 2019.

1A.5.2.5 2001 Annual Energy Outlook Fuel Price Projections

The final two fuel price projections used in the sensitivity evaluations are based on the Annual Energy Outlook (AEO) fuel price data published by the Energy Information Administration (EIA), which is an independent agency of the Department of Energy (DOE). The AEO 2001 energy data is a comprehensive and reliable source of domestic and international energy supply, consumption, and price information.

AEO provides energy forecasts through the year 2020 and takes into account a number of important factors, some of which include:

- Restructuring of the US electricity markets
- Current regulations and legislation affecting the energy markets
- Current energy issues:
  - Appliance, gasoline, and diesel fuel, and renewable portfolio standards.
  - Expansion of natural gas industry
  - Carbon emissions
  - Competitive energy pricing

AEO 2001 energy information is objective and nonpartisan. It is used widely by both government and private sectors to assist in decision-making processes and in analyzing important policy issues.

Table 1A.5-8
Constant 2000 Fuel Price Forecast ($/MBtu)

Year	Coal	Natural Gas	No. 2 Oil	No. 6 Oil	Nuclear	Petroleum Coke
2000	1.67	5.03	5.79	4.42	0.52	1.26
2001	1.71	5.14	5.94	4.53	0.53	1.29
2002	1.75	5.25	6.09	4.64	0.55	1.32
2003	1.80	5.36	6.24	4.76	0.56	1.36
2004	1.84	5.47	6.39	4.88	0.57	1.39
2005	1.89	5.59	6.55	5.00	0.59	1.43
2006	1.94	5.71	6.72	5.13	0.60	1.46
2007	1.99	5.84	6.88	5.25	0.62	1.50
2008	2.03	5.96	7.06	5.39	0.63	1.54
2009	2.09	6.10	7.23	5.52	0.65	1.57
2010	2.14	6.23	7.41	5.66	0.67	1.61
2011	2.19	6.37	7.60	5.80	0.68	1.65
2012	2.25	6.51	7.79	5.94	0.70	1.69
2013	2.30	6.65	7.98	6.09	0.72	1.74
2014	2.36	6.80	8.18	6.25	0.73	1.78
2015	2.42	6.95	8.39	6.40	0.75	1.82
2016	2.48	7.10	8.60	6.56	0.77	1.87
2017	2.54	7.26	8.81	6.73	0.79	1.92
2018	2.60	7.43	9.03	6.89	0.81	1.97
2019	2.67	7.59	9.26	7.07	0.83	2.01
Average Annual Escalation (%)	2.50%	2.19%	2.50%	2.50%	2.50%	2.50%

Note: Fuel prices in nominal dollars including the general inflation rate. Natural gas prices include estimated transportation.

AEO 2001 publishes 1999, 2005, 2010, 2015, and 2020 fuel price projections, which are presented in Table 1A.5-9. From these projections, real compound annual escalation rates (CAERs) can be calculated for 1999 through 2005, 2005 through 2010, 2010 through 2015, and 2015 through 2020 periods. These real CAERs are used to develop annual fuel price projections to which the 2.5 percent general inflation rate is applied. The AEO 2001 fuel price projections are presented in Table 1A.5-10. The delivered price of natural gas adds a constant $0.75/MBtu transportation cost to the AEO 2001 commodity projection. AEO does not project nuclear or petroleum coke prices. The nuclear and petroleum coke projections are those presented in the base case in Table 1A.5-5. The AEO 2001 fuel price projections for 2000 are much lower than the actual 2000 OUC fuel prices shown in Table 1A.5-8. Furthermore, the AEO projections are on a national average basis, which is heavily weighted by low cost western coal and do not reflect the relatively higher coal transportation costs to Florida. As a result, the AEO projections understate coal costs for Florida.

The second fuel price projection based on the AEO 2001 fuel price projections applies the AEO 2001 real escalation rates along with the 2.5 percent annual general inflation rate to the actual 2000 OUC fuel prices. These fuel price projections are presented in Table 1A.5-11. The nuclear and petroleum coke projections are those presented in the base case in Table 1A.5-5. This projection initially matches the actual 2000 OUC fuel prices and continues to escalate them into the future. High fuel prices continuing to escalate for a 20 year period would be unprecedented compared to historical prices presented in Figure 1A.5-1.

1A.5.3 Fuel Availability

Plentiful coal and natural gas reserves exist both in the United States and North American mainland and coastal regions. Large coal reserves within the east, central, and western United States are adequate to supply power generation needs for the foreseeable future. Oil reserves are dependent on both domestic and offshore production and imports. Natural gas reserves are mostly dependent on domestic production. Increasing demand for natural gas as a fuel for both home heating and power production is contributing to the volatility of its price, which in turn has provided incentives for increased production. A somewhat cyclic effect is expected, where short-term demand and volatility will drive increased production and future price stability.

1A.5.3.1 Service to Proposed Plant Site.

FGT's 26 inch pipeline is located approximately 2.5 miles south of the Stanton Energy Center site.

Table 1A.5-9
2001 Annual Energy Outlook Real Fuel Price Projections and CAERs

	1999	2005	2010	2015	2020
No. 2 Oil,* $/MBtu	4.05	4.65	4.84	5.10	5.28
Residual Oil,* $/MBtu	2.42	3.52	3.88	4.00	4.07
Coal,* $/MBtu	1.21	1.13	1.05	1.01	0.98
Natural Gas,** $/MBtu	2.08	2.49	2.69	2.83	3.13
	1999-2005	2005-2010	2010-2015	2015-2020	1999-2020
No. 2 Oil* Real CAERs, percent	2.33	0.80	1.05	0.70	1.27
Residual Oil* Real CAERs, percent	6.49	1.97	0.61	0.35	2.51
Coal* Real CAERs, percent	-1.13	-1.46	-0.77	-0.60	-1.00
Natural Gas** Real CAERs, percent	3.04	1.56	1.02	2.04	1.97

*Delivered price.

**Well head price.

Source: DOE Energy Information Administration web site

Table 1A.5-10
AEO 2001 Fuel Price Forecast ($/MBtu)

Year	Coal	Natural Gas	No. 2 Oil	No. 6 Oil	Nuclear	Petroleum Coke
2000	1.23	2.95	4.25	2.64	0.52	1.26
2001	1.25	3.07	4.46	2.88	0.53	1.28
2002	1.26	3.20	4.68	3.14	0.55	1.23
2003	1.28	3.34	4.90	3.43	0.56	1.20
2004	1.30	3.48	5.14	3.74	0.57	2.21
2005	1.31	3.64	5.40	4.08	0.59	2.23
2006	1.33	3.76	5.57	4.27	0.60	1.23
2007	1.34	3.88	5.76	4.46	0.62	1.26
2008	1.35	4.01	5.95	4.66	0.63	1.28
2009	1.37	4.14	6.15	4.87	0.65	1.32
2010	1.38	4.28	6.35	5.09	0.67	1.36
2011	1.41	4.40	6.58	5.25	0.68	1.40
2012	1.43	4.53	6.82	5.41	0.70	1.44
2013	1.45	4.67	7.06	5.58	0.72	1.51
2014	1.48	4.81	7.31	5.76	0.73	1.56
2015	1.50	4.95	7.57	5.94	0.75	1.62
2016	1.53	5.14	7.82	6.11	0.77	1.69
2017	1.56	5.35	8.07	6.28	0.79	1.77
2018	1.59	5.56	8.33	6.46	0.81	1.84
2019	1.62	5.78	8.60	6.65	0.83	1.92
Average Annual Escalation (%)	1.46%	3.61%	3.78%	4.98%	2.50%	2.24%

Note: Fuel prices in nominal dollars including the general inflation rate. Natural gas prices include estimated transportation.

Table 1A.5-11
AEO 2001 Escalation Applied to 2000 OUC Fuel Prices ($/MBtu)

Year	Coal	Natural Gas	No. 2 Oil	No. 6 Oil	Nuclear	Petroleum Coke
2000	1.67	5.03	5.79	4.42	0.52	1.26
2001	1.69	5.27	6.08	4.82	0.53	1.28
2002	1.71	5.52	6.37	5.26	0.55	1.23
2003	1.74	5.79	6.68	5.74	0.56	1.20
2004	1.76	6.08	7.01	6.26	0.57	2.21
2005	1.78	6.38	7.35	6.83	0.59	2.23
2006	1.80	6.61	7.60	7.14	0.60	1.23
2007	1.82	6.85	7.85	7.46	0.62	1.26
2008	1.84	7.10	8.11	7.80	0.63	1.28
2009	1.86	7.36	8.38	8.15	0.65	1.32
2010	1.88	7.63	8.66	8.52	0.67	1.36
2011	1.91	7.87	8.97	8.79	0.68	1.40
2012	1.94	8.12	9.29	9.06	0.70	1.44
2013	1.97	8.38	9.62	9.35	0.72	1.51
2014	2.01	8.65	9.97	9.64	0.73	1.56
2015	2.04	8.93	10.32	9.94	0.75	1.62
2016	2.08	9.31	10.65	10.22	0.77	1.69
2017	2.12	9.70	11.00	10.52	0.79	1.77
2018	2.16	10.11	11.35	10.82	0.81	1.84
2019	2.20	10.54	11.72	11.13	0.83	1.92
Average Annual Escalation (%)	1.46%	3.97%	3.78%	4.98%	2.50%	2.24%

Note: Fuel prices in nominal dollars including the general inflation rate. Natural gas prices include estimated transportation.

1A.5.3.2 Florida Gas Transmission Company

FGT is an open access interstate pipeline company transporting natural gas for third parties through its 5,000 mile pipeline system extending from South Texas to Miami, Florida. FGT is a subsidiary of Citrus Corporation which, in turn, is jointly owned by Enron Corporation, the largest integrated natural gas company in America, and El Paso Energy Corporation, one of the largest independent producers of natural gas in the United States.

The FGT pipeline system accesses a diversity of natural gas supply regions, including:

- Anadarko Basin (Texas, Oklahoma, and Kansas).
- Arkona Basin (Oklahoma and Arkansas).
- Texas and Louisiana Gulf Areas (Gulf of Mexico).
- Black Warrior Basin (Mississippi and Alabama).
- Louisiana – Mississippi – Alabama Salt Basin.
- Mobile Bay.

FGT's total receipt point capacity is in excess of 3.0 billion cubic feet per day and includes connections with 10 interstate and 10 intrastate pipelines to facilitate transfers of natural gas into its pipeline system. FGT reports a current delivery capability to Peninsular Florida in excess of 1.4 billion cubic feet per day.

1A.5.3.3 Florida Gas Transmission Market Area Pipeline System

The FGT multiple pipeline system corridor enters the Florida Panhandle in northern Escambia County and runs easterly to a point in southwestern Clay County, where the pipeline corridor turns southerly to pass west of the Orlando area. The mainline corridor then turns to the southeast to a point in southern Brevard County, where it turns south generally paralleling Interstate Highway 95 to the Miami area. A major lateral line (the St. Petersburg Lateral) extends from a junction point in southern Orange County westerly to terminate in the Tampa, St. Petersburg, Sarasota area. A major loop corridor (the West Leg Pipeline) branches from the mainline corridor in southeastern Suwannee County to run southward through western Peninsular Florida to connect to the St. Petersburg Lateral system in northeastern Hillsborough County. Each of the above major corridors includes stretches of multiple pipelines (loops) to provide flow redundancy and transport capability. Numerous lateral pipelines extend from the major corridors to serve major local distribution systems and industrial/utility customers.

1A.5.3.4 Florida Gas Transmission Expansion Project

FGT filed for FERC approvals of the Phase IV expansion project December 2, 1998. The filing consists of expanding services to southwest Florida with 139 miles of underground pipelines. The $268 million Phase IV project will add more than 38,000 horsepower of compression, and associated facilities and will provide approximately 197 million cubic feet per day (MMcf/d) of incremental firm transportation service on an average annual basis. FGT announced in May of 2000 that construction related to the Phase IV had begun and is scheduled for service by the May 2001 target.

FGT's Phase V expansion project, filed with the FERC on December 1, 1999, will deliver natural gas to a variety of new and current FGT customers and make natural gas available to areas that have not previously had gas service. The Phase V expansion project is intended to add approximately 167 miles of new pipeline and 132,615 horsepower of compression to the existing system. The result of this expansion will be the addition of more than 428 MMcf/d of incremental mainline capacity to Florida. With an estimated cost of $466 million, the Phase V expansion plan has a target in-service date of April 1, 2002.

The Phase V expansion faced many changes that caused it to file an amended project application with FERC. After the Florida Supreme Court ruling that limited the ability of nonutility merchant plants to use the Florida Electrical Power Plant Siting Act, two major Phase V customers, Enron and Dynergy, withdrew from Phase V. However, FGT subsequently gained back some of the lost market by signing a long-term contract with Tampa Electric Company as a Phase V customer. FERC granted preliminary approval to the expansion in November of 2000. The Phase V expansion still requires final environmental approval.

FGT recently concluded an open season for Phase VI. FGT received what it defined as 'a positive response' to the open season. The intent of the project is to provide incremental firm transportation service to Florida. The new pipeline is proposed to extend from Savannah, Georgia, to Jacksonville, Florida, with access to Southern LNG Company's liquefied natural gas. Phase VI is scheduled for an in-service date of Spring 2003.

FERC approved in November of 2000 FGT's request for the purchase of an undivided interest in Koch Gateway Pipeline's Mobile Bay Lateral. This purchase will give FGT the right to an additional 300,000 MMcf/d of input capacity. The acquisition is set to become effective April 1, 2002.

1A.5.3.5 Alternative Natural Gas Supply Pipelines for Peninsular Florida

There is currently one transportation company serving Peninsular Florida: FGT. Two additional pipelines, Buccaneer and Gulfstream, received preliminary approval from the Federal Energy Regulatory Commission (FERC) in April of last year. In September of last year, both pipelines also received one of the two required approvals from FERC.

In November of 2000, the developers of the Buccaneer gas pipeline, Williams Energy and Duke Energy, announced their intent to purchase the Gulfstream pipeline from Coastal Corporation. The purchase is subject to federal regulatory approvals and conditioned upon completion of the Coastal/El Paso Energy Corporation merger.

Duke Energy and Williams Energy will collaborate on the Gulfstream pipeline in lieu of the Buccaneer pipeline. Gulfstream has precedent agreements with 10 large Florida utilities and power generation facilities representing long-term commitments for the majority of its 1.1 billion cubic feet of gas per day capacity. The Gulfstream pipeline was designed primarily to serve Florida utilities and power generation facilities that plan on using high efficiency natural gas turbines to meet the incremental demand for electrical energy. The pipeline is discussed below. At this time, it is uncertain as to what effect the purchase will have on the pipeline configuration.

FGT, El Paso Merchant, and Gulfstream have all made competitive proposals to provide gas transportation to Stanton A.

1A.5.3.5.1 Gulfstream Pipeline. The Gulfstream pipeline is a 744 mile pipeline originally proposed by the Coastal Corporation. The pipeline will originate from the Mobile Bay region, crossing the Gulf of Mexico to a landfall in Manatee County (south Tampa Bay). The pipeline is expected to supply Florida with 1.1 billion cubic feet of gas per day serving existing and prospective electric generation and industrial projects in southern Florida.

The 1.6 billion dollar pipeline won FERC approval, subject to environmental review, on April 24, 2000. Final environmental and routing approvals by FERC are expected in March of 2001. Construction for the Gulfstream pipeline is scheduled to begin in June of 2001, with an estimated operation date of June of 2002. The first major acquisition of right-of-way occurred July 20, 2000, with a signed agreement between Coastal Corporation and the Manatee County Port Authority. The Gulfstream pipeline gained the permanent right-of-way easement to cross through Port Manatee. In addition to a payment to Port Manatee, Coastal Corporation will lease up to 190 acres of vacant land at Port Manatee to serve as a logistics base during Gulfstream's construction phase.

- Decreases or increases in revenue due to demand-side programs will impact rate levels and will be passed on to all customers.
- Additional conservation taking place after the next deferred generating unit will affect subsequent units.

1A.8.1.1.1 FIRE Model Inputs. There are two types of FIRE Model input files. The first input file contains data specific to the utility's next proposed unit, the avoided unit. The second input file contains data specific to the DSM measure being tested for cost-effectiveness. Input data for the avoided unit is placed on a per kW basis. Because the avoided unit data is input on a per kW basis, the potential DSM measures can be tested individually to determine cost-effectiveness.

1A.8.1.1.2 Avoided Unit. The avoided unit used in the DSM analysis is the proposed Southern-Florida 633 MW 2 x 1 combined cycle unit. Stanton A is unique because it entails 35 percent ownership by OUC, KUA, and FMPA, which have a right to the remaining 65 percent of Stanton A capacity pursuant to PPAs with Southern-Florida. Therefore, the 35 percent ownership capacity will be considered the avoided unit since it represents the utility's ownership interest.

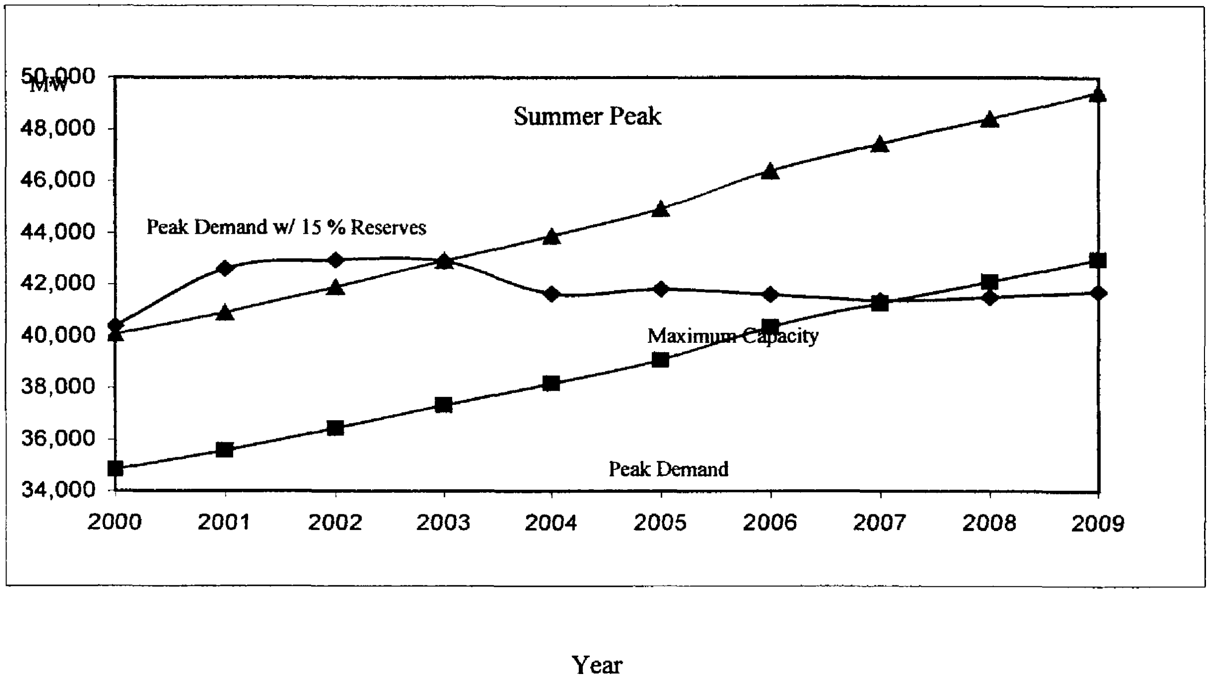
1A.8.1.1.3 DSM Measures. Potential DSM measures for cost-effective analyses were selected based on the potential to be cost-effective. OUC, KUA, and FMPA did not model each possible DSM measure; instead, OUC, KUA, and FMPA focused on alternatives that were expected to have the highest potential for being cost-effective.

The DSM measures analyzed were compiled from measures deemed cost-effective in the 2000 Demand-Side Management Plan of Florida Power & Light (FPL). By testing the most cost-effective measures from FPL, the assumption was made that if the most cost-effective measure for FPL did not prove cost-effective for OUC, KUA, and FMPA, then FPL's lesser cost-effective measures would also fail the analysis. Using this methodology, OUC, KUA, and FMPA have effectively screened all of FPL's measures.

FPL's most cost-effective residential measure is Direct Load Control and its most cost-effective commercial/industrial measure is Off-Peak Battery Charging. OUC, KUA, and FMPA separately tested both FPL measures. The FIRE Model results for OUC, KUA, and FMPA can be found in Volumes 1B, 1C, and 1D, respectively.

1A.8.1.2 FIRE Model Outputs

FIRE Model results are presented in the form of three cost-effectiveness tests. All the DSM cost-effectiveness tests are based on the comparison of discounted present worth benefits to costs for a specific DSM measure. Each test is designed to measure costs and benefits from a different perspective.



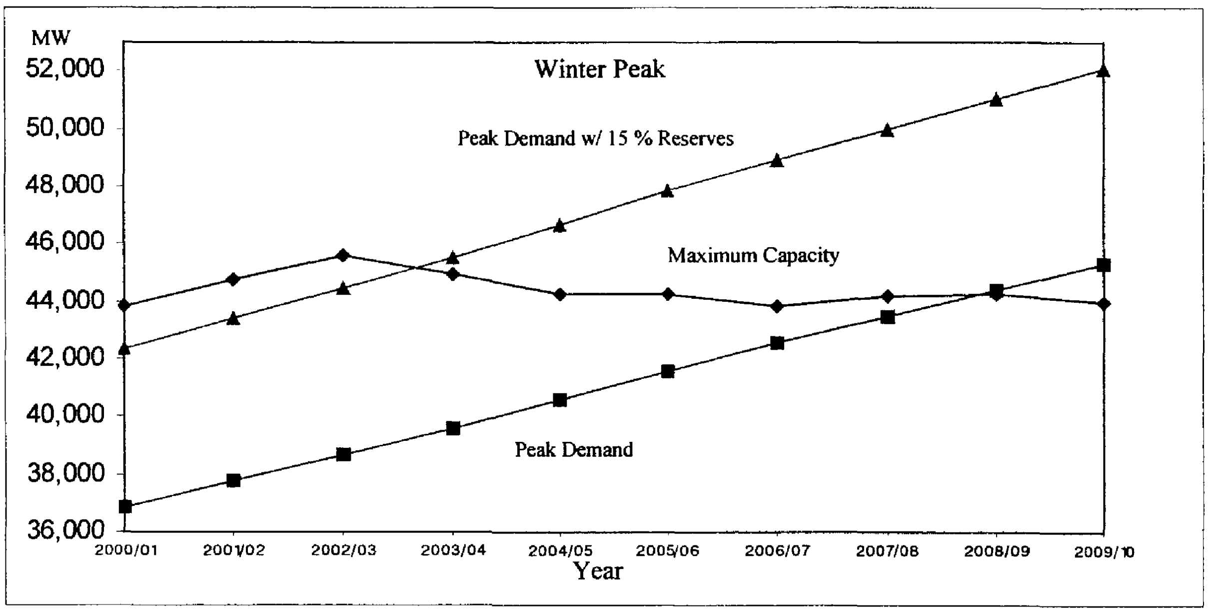


Figure 1A.9-1
2000 Load and Resource Plan – Peak Demand and Reserve Margin
Excluding Capacity Required to be Approved Under the Florida Electrical Power Plant
Siting Act but Not Yet Approved

Stanton Energy Center Combined Cycle Unit A

Need for Power Application

Orlando Utilities Commission - Volume 1B

Project Number 97185

March 5, 2001

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Table 1B.2-1
Summary of OUC Generation Facilities

Plant Name	Unit No.	Location (County)	Unit Type	Fuel		Fuel Transport		Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen. Max Nameplate MW	Net Capability[1]	
				Pri	Alt	Pri	Alt				Summer MW	Winter MW
Indian River	A	Brevard	GT	NG	FO2	PL	TK	06/89	Unknown	41.400	18	23.4
Indian River	B	Brevard	GT	NG	FO2	PL	TK	07/89	Unknown	41.400	18	23.4
Indian River	C	Brevard	GT	NG	FO2	PL	TK	08/92	Unknown	122.040	85.3	100.3
Indian River	D	Brevard	GT	NG	FO2	PL	TK	10/92	Unknown	122.040	85.3	100.3
Stanton Energy Center	1	Orange	ST	BIT	---	RR	---	07/87	Unknown	464.580	301.6	303.7
Stanton Energy Center	2	Orange	ST	BIT	---	RR	---	06/96	Unknown	464.580	319.3	319.3
McIntosh	3	Polk	ST	BIT	REF	RR	TK	09/82	Unknown	363.870	133	136
Crystal River	3	Citrus	NP	UR	---	TK	---	03/77	Unknown	890.460	13	13
St. Lucie[2]	2	St. Lucie	NP	UR	---	TK	---	08/83	Unknown	839.000	51	52
St. Cloud[3]	1	Osceola	IC	NG	FO2	PL	TK	07/82	11/04	2.000	2	1.825
	2		IC	NG	FO2	PL	TK	12/74	11/04	5.850	5.85	5
	3		IC	NG	FO2	PL	TK	09/82	11/04	2.000	2	1.825
	4		IC	NG	FO2	PL	TK	08/61	11/04	3.750	3	3
	6		IC	NG	FO2	PL	TK	03/67	11/04	3.750	3	3
	7		IC	NG	FO2	PL	TK	09/82	11/04	6.300	6	6
	8		IC	NG	FO2	PL	TK	04/77	11/04	6.445	6	6

OUC ownership share.

OUC owns St. Lucie Unit No. 2. Reliability exchange divides 50% power from Unit No. 1 and 50% power from Unit No. 2.

St. Cloud No. 8 has never been connected to the grid and, therefore, OUC receives no capacity from this unit. St. Cloud owns the units, but OUC controls their operation.

and water conservation. Students are taught how electricity is generated and are encouraged to perform mini electric and water audits on their own homes.

1B.5.1.6 Commercial Energy Survey Program

This survey is a physical walk-through inspection of the commercial facility. The commercial customer having a Commercial Energy Survey receives a report at the time of the survey. Within 30 days of a detailed audit, the customer receives a written report. Conservation literature is provided to all customers. The program is focused on commercial customers to increase the energy efficiency and energy conservation. OUC has also developed an alliance with a large performance contractor in order to provide large commercial customers with a more complete solution to their needs.

1B.5.2 Analysis of Demand-Side Management Alternatives

OUC used the FIRE model to evaluate the most cost-effective DSM measures from FPL's 2000 Demand-Side Management Plan as discussed in Section 1A.8. The results of that analysis are as follows.

1B.5.2.1 FIRE Model Output Analysis

OUC requires all measures to pass the Rate Impact Test to be considered cost-effective. Of the potential DSM measures tested, none passed the Rate Impact Test. Thus, OUC has concluded that there are no cost-effective DSM measures reasonably available that would avoid or defer the need for Stanton A. Table 1B.5-2 presents the FIRE model results of the DSM analysis.

Table 1B.5-2
FIRE Model Results

Program Description	Rate Impact Test	Participant's Test	Total Resource Cost Test
Residential			
Direct Load Control	0.49	1.00	2.33
Commercial			
Off-Peak Battery Charging	0.98	0.00	0.62

The results of the DSM analysis are not surprising due to the previously performed analysis for similarly situated utilities. The failing cost-effectiveness of DSM has been exhibited in the Need for Power Dockets for Kissimmee Utility Authority (KUA) and Florida Municipal Power Agency (FMPA) for Cane Island Unit 3 (Docket nature of OUC's relatively small, high interconnected system, LOLP for OUC's system is driven almost entirely by the interconnections. Since the reliability of the interconnections is driven by the capacity from other systems available to the interconnection, the reliability of interconnections is difficult to predict and is generally out of the control of OUC. For these reasons, OUC does not use LOLP as the reliability criterion and instead uses the reserve margin criterion. LOLP is much better suited for measuring reliability of large systems such as FRCC.

1B.6.2 Reliability Need

Since OUC has elected to use a 15 percent reserve margin criterion, OUC applies it to St. Cloud's load as well as partial requirements (PR) purchases and sales. Tables 1B.6-1 and 1B.6-2 display the forecast reserve margins for OUC and St. Cloud for the winter and summer seasons, respectively.

Table 1B.6-1 indicates that additional capacity will be needed by the winter of 2002. Furthermore, Table 1B.6-2 shows that additional capacity will be necessary to satisfy forecast demand requirements for the summer of 2002. The majority of the capacity required in 2002 and 2003 can be satisfied by exercising the additional 10 percent option on the Reliant contract, which represents 52.5 MW. Regardless, OUC will need a substantial amount of capacity beginning with the expiration of the Reliant agreement on October 1, 2003.

1B.7.0 Economic Analysis

The economic analysis for the cost-effectiveness of the project consists of several evaluations to arrive at the least-cost supply plan to meet the growing needs of OUC's customers. The methodology of the analyses, the expansion candidates evaluated, and the results of the base case evaluations are discussed in detail in this section.

A four phase economic analysis was conducted to determine OUC's optimum capacity expansion plan. The four phases included supply-side evaluations, demand-side evaluations, proposal evaluations, and sensitivity analyses. The results of the supply-side analyses are included in this section and discussed in detail. The results of the demand-side evaluation analyses are presented in Section 1B.5.0. The proposal evaluations are presented in Section 1A.6. The sensitivity analyses are discussed in Section 1B.8.0.

1B.7.1 Methodology

The supply-side evaluations of generating unit alternatives were performed using POWROPT, an optimal generation expansion model. Black & Veatch developed POWROPT as an alternative to other optimization programs. POWROPT has been benchmarked against other optimization programs and has proven to be an effective modeling program and has been used in several other Need for Power proceedings before the FPSC. The program operates on an hourly chronological basis and is used to determine a set of capacity expansion plans based on capacity requirements, simulate the operation of each of these plans, and select the most desirable plan based on cumulative present worth revenue requirements. POWROPT evaluates all combinations of available generating unit alternatives and purchase power options to maintain user-defined reliability criteria. The reserve requirement utilized was a minimum reserve margin of 15 percent. All capacity expansion plans were analyzed over a 20 year period from 2000 to 2019.

After the optimal generation expansion plan was selected using POWROPT, Black & Veatch's detailed chronological production costing program, POWRPRO, was used to obtain the annual production cost for the expansion plan. OUC's and St. Cloud's systems were combined for purposes of expansion planning.

1B.7.2 Expansion Candidates

The expansion candidates for the POWROPT evaluation represent the conventional alternatives presented in Section 1A.7. Table 1B.7-1 summarizes the expansion alternatives considered for OUC in the optimization study for supply-side alternatives.

Table 1B.7-1
Summary of OUC Generation Alternatives (2000 $, unless otherwise noted)

Description	Capital Costs	Capacity[1]	O&M Costs		Fuel Type	Full Load Heat Rate (HHV)[1]	Forced Outage Rate	Scheduled Maintenance	First Year Available
			Variable	Fixed					
	$1,000	MW	$/MWh	$/kW-yr		Btu/kWh	percent	days/year	
Pulverized Coal	513,163	446	3.73	14.17	Coal	9,979	3.0	30	2006
Fluidized Bed	366,076	267	5.53	23.55	Pet. Coke	10,543	3.0	28	2005
501F 2x1 CC (standard)	275,756[4]	514	[redacted]	[redacted]	Nat. Gas	7,074	4.0	[redacted]	2005
501F 2x1 CC (oversized)	288,211[4]	610	[redacted]	[redacted]	Nat. Gas	7,542	4.0	[redacted]	2005
7FA SC	68,615	156	2.33	5.13	Nat. Gas	10,940	1.96	7	2005
7FA 2x1 CC (self-build)[3]	232,169[4]	488	[redacted]	[redacted]	Nat. Gas	[redacted]	4.0	[redacted]	2003[5]
7FA 2x1 CC (joint development)[3]	[redacted]	171	[redacted]	[redacted]	Nat. Gas	[redacted]	[redacted]	[redacted]	2003[5]

1. At 70 – 72° F, depending on the generation alternative (after degradation).
2. (2003 $)
3. Reflects OUC's portion of total generation alternative capacity.
4. Mixed year dollars to reflect commercial operation date of October 1, 2003.
5. October 1, 2003.

1B.7.3 Results of Economic Analysis

The economic evaluation was first conducted for a base case scenario of the future, which assumed the base case load forecast, base case fuel price forecast, and planned reserve margins. The evaluations were based upon the cost and performance characteristics described in detail in Section 1A.7 and summarized in Table 1B.7-1. Production costs were modeled at temperatures which closely approximate (within 2 degrees) the average annual temperature for OUC. Winter and summer unit ratings were used to determine capacity requirements.

The expansion plan outlined in Table 1B.7-2 shows that the joint development project with Southern-Florida is the least-cost capacity addition plan for OUC under the base case scenario. For comparison purposes, Table 1B7-3 displays the least-cost expansion capacity addition plan for OUC that does not include the joint-development project with Southern-Florida. The units and power purchases comprising the expansion plans are listed in the tables according to their year of commercial operation. Tables 1B.7-4 through 1B.7-7 present the summer and winter capacity balances for the expansion plans presented in Tables 1B.7-2 and 1B.7-3, respectively. Appendix 1B.B presents tables showing the fuel, O&M, and capital costs for expansion plans on an annual basis.

The addition of the Southern-Florida joint development project and the self-build General Electric 7FA 2x1 combined cycle represent the only two available alternatives that allow OUC to meet OUC's reserve requirements in 2004. In fact, even the self-build General Electric 7FA 2x1 combined cycle is no longer an option because it was based on obtaining the General Electric 7FA combustion turbines that KUA had under option with General Electric. The option for the two General Electric 7FA combustion turbines expired on September 30, 2000. However, the option was available during the time that OUC was evaluating the joint development and purchase power proposals and is presented to demonstrate the prudence of the selection of the Southern-Florida joint development project. The extension of the full 500 MW of the Reliant Agreement does not provide sufficient capacity for OUC to meet its capacity requirements in 2004 without the Southern-Florida joint development project. The extension of the full 500 MW of the Reliant Agreement would still result in a 93 MW shortfall for OUC in the summer of 2004 as demonstrated by Table 1B.6-2. OUC is precluded from installing other options until at least 2005 as shown in Table 1B.7-1 due to the delivery schedule for combustion turbines.

It is clear from a comparison of Tables 1B.7-2 and 1B.7-3 that the joint development project with Southern-Florida provides the most cost-effective solution to satisfy OUC's forecast capacity requirements. The joint development project with Southern-Florida results in a projected $6.611 million in cumulative present worth savings over the self-build alternative while providing the flexibility and strategic advantages discussed in Section 1A.6.4.

Table 1B.7-2
OUC Least-Cost Base Case Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	162,239	294,508
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	171,252	441,329
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	182,007	585,812
2004	171 MW Joint Development with Southern – Florida (10/03)	220,059	747,562
	317 MW Southern – Florida Power Purchase (10/03)		
	100 MW Indian River Power Purchase (10/03 - 09/04)		
2005	100 MW Indian River Power Purchase (10/04 - 09/05)	221,751	898,482
2006	100 MW Indian River Power Purchase (10/05 – 09/06)	216,636	1,034,999
2007	156 MW GE 7FA Simple Cycle (06/07)	230,334	1,169,397
2008	156 MW GE 7FA Simple Cycle (06/08)	245,040	1,301,784
2009		264,023	1,433,862
2010		271,624	1,559,676
2011		280,395	1,679,933
2012		294,709	1,796,966
2013	Terminate 317 MW Southern – Florida Power Purchase (11/13)	306,249	1,909,573
	514 MW WH 501F 2x1 Combined Cycle (11/13)		
2014		333,383	2,023,077
2015		348,476	2,132,931
2016		361,220	2,238,368
2017		374,723	2,339,644
2018		393,013	2,437,995
2019		413,921	2,533,905

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.7-3
OUC Base Case Expansion Plan – Runner Up #1

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	162,239	294,508
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	171,252	441,329
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	183,056	586,644
2004	488 MW Self-Build GE 7FA 2x1 (10/03)	219,114	747,699
	100 MW Indian River Power Purchase (10/03 - 09/04)		
2005	100 MW Indian River Power Purchase (10/04 - 09/05)	220,746	897,935
2006	100 MW Indian River Power Purchase (10/05 – 09/06)	218,215	1,035,448
2007	156 MW GE 7FA Simple Cycle (06/07)	233,111	1,171,466
2008	156 MW GE 7FA Simple Cycle (06/08)	243,714	1,303,137
2009		263,213	1,434,809
2010		271,205	1,560,429
2011		278,923	1,680,055
2012		294,851	1,797,144
2013		307,495	1,910,209
2014		339,450	2,025,779
2015		339,155	2,132,694
2016	156 MW GE 7FA Simple Cycle (06/16)	364,773	2,239,168
2017		378,698	2,341,518
2018		406,327	2,443,201
2019		419,978	2,540,516

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.7-4
OUC Summer Capacity Balance (After Expansion Plan Outlined in Table 1B.7-2)

Year	Retail Peak Demand[1] (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1062	440	1502	1047	608	1655	153	170	(17)
2001	1092	341	1433	1047	608	1655	222	176	46
2002	1136	323	1459	1047	593	1639	180	183	(3)
2003	1170	312	1482	1047	593	1639	157	190	(33)
2004	1197	263	1460	1213	465	1679	219	196	23
2005	1227	172	1399	1192	449	1641	242	201	41
2006	1254	139	1393	1192	434	1626	233	203	29
2007	1278	139	1417	1332	324	1656	239	210	28
2008	1306	142	1448	1472	324	1796	348	215	133
2009	1339	144	1483	1472	324	1796	313	220	92
2010	1372	146	1518	1472	324	1796	278	225	53
2011	1399	0	1399	1472	324	1796	396	208	189
2012	1428	0	1428	1472	324	1796	368	212	156
2013	1463	0	1463	1472	309	1781	318	219	98
2014	1495	0	1495	1953	0	1953	457	224	233
2015	1526	0	1526	1953	0	1953	427	229	198
2016	1557	0	1557	1953	0	1953	395	234	162
2017	1591	0	1591	1953	0	1953	361	239	123
2018	1625	0	1625	1953	0	1953	328	244	84
2019	1656	0	1656	1953	0	1953	297	248	48

[1]Includes St. Cloud.

Table 1B.7-5
OUC Winter Capacity Balance (After Expansion Plan Outlined in Table 1B.7-2)

Year	Retail Peak Demand[1] (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1051	440	1491	1092	608	1700	208	168	40
2001	1090	341	1431	1092	608	1700	268	176	93
2002	1144	323	1467	1092	593	1684	218	184	33
2003	1182	312	1494	1092	593	1684	190	192	(1)
2004	1210	263	1473	1273	492	1765	293	198	95
2005	1239	172	1411	1252	476	1729	317	203	114
2006	1267	139	1406	1252	461	1714	308	205	103
2007	1292	139	1431	1427	351	1779	348	212	135
2008	1323	142	1465	1602	351	1954	489	218	271
2009	1356	144	1500	1602	351	1954	454	223	231
2010	1386	146	1532	1602	351	1954	422	228	194
2011	1416	0	1416	1602	351	1954	537	210	327
2012	1449	0	1449	1602	351	1954	505	215	290
2013	1480	0	1480	1602	336	1939	458	222	236
2014	1512	0	1512	2166	0	2166	655	227	428
2015	1542	0	1542	2166	0	2166	624	231	393
2016	1572	0	1572	2166	0	2166	594	236	358
2017	1608	0	1608	2166	0	2166	558	241	316
2018	1643	0	1643	2166	0	2166	523	246	277
2019	1675	0	1675	2166	0	2166	491	251	240

[1]Includes St. Cloud.

Table 1B.7-6
OUC Summer Capacity Balance (After Expansion Plan Outlined in Table 1B.7-3)

Year	Retail Peak Demand[1] (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1062	440	1502	1047	608	1655	153	170	(17)
2001	1092	341	1433	1047	608	1655	222	176	46
2002	1136	323	1459	1047	593	1639	180	183	(3)
2003	1170	312	1482	1047	593	1639	157	190	(33)
2004	1197	263	1460	1523	156	1679	219	196	23
2005	1227	172	1399	1501	140	1641	242	201	41
2006	1254	139	1393	1501	125	1626	233	203	29
2007	1278	139	1417	1641	15	1656	239	210	28
2008	1306	142	1448	1781	15	1796	348	215	133
2009	1339	144	1483	1781	15	1796	313	220	92
2010	1372	146	1518	1781	15	1796	278	225	53
2011	1399	0	1399	1781	15	1796	396	208	189
2012	1428	0	1428	1781	15	1796	368	212	156
2013	1463	0	1463	1781	0	1781	318	219	98
2014	1495	0	1495	1781	0	1781	285	224	61
2015	1526	0	1526	1781	0	1781	255	229	26
2016	1557	0	1557	1921	0	1921	363	234	130
2017	1591	0	1591	1921	0	1921	330	239	91
2018	1625	0	1625	1921	0	1921	296	244	52
2019	1656	0	1656	1921	0	1921	265	248	17

[1]Includes St. Cloud.

Table 1B.7-7
OUC Winter Capacity Balance (After Expansion Plan Outlined in Table 1B.7-3)

Year	Retail Peak Demand[1] (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1051	440	1491	1092	608	1700	208	168	40
2001	1090	341	1431	1092	608	1700	268	176	93
2002	1144	323	1467	1092	593	1684	218	184	33
2003	1182	312	1494	1092	593	1684	190	192	(1)
2004	1210	263	1473	1609	156	1765	293	198	95
2005	1239	172	1411	1589	140	1729	317	203	114
2006	1267	139	1406	1589	125	1714	308	205	103
2007	1292	139	1431	1764	15	1779	348	212	135
2008	1323	142	1465	1939	15	1954	489	218	271
2009	1356	144	1500	1939	15	1954	454	223	231
2010	1386	146	1532	1939	15	1954	422	228	194
2011	1416	0	1416	1939	15	1954	537	210	327
2012	1449	0	1449	1939	15	1954	505	215	290
2013	1480	0	1480	1939	0	1939	458	222	236
2014	1512	0	1512	1939	0	1939	427	227	200
2015	1542	0	1542	1939	0	1939	397	231	166
2016	1572	0	1572	1939	0	1939	366	236	130
2017	1608	0	1608	2114	0	2114	505	241	264
2018	1643	0	1643	2114	0	2114	471	246	224
2019	1675	0	1675	2114	0	2114	439	251	187

[1]Includes St. Cloud.

1B.8.0 Sensitivity Analysis

OUC performed several sensitivity analyses to measure the impact of key assumptions on the least-cost plan. The sensitivity analyses are presented in Sections 1B.8.1 through 1B.8.7 and include low and high fuel escalation as well as three additional fuel price scenarios. Two were based on the AEO fuel price projections. One uses the actual AEO projections and the other applies the AEO escalation rates to the actual 2000 OUC prices. Finally, a fuel price that assumes the actual OUC 2000 fuel prices remain constant in real terms is analyzed. High load and energy growth and low load and energy growth scenarios were also evaluated. For each sensitivity analysis, the two least-cost plans over the planning horizon are identified. The sensitivity analyses were performed over a 20 year planning horizon, similar to the base case economic evaluation, with a projection of annual costs and cumulative present worth costs.

1B.8.1 High Fuel Price Escalation

The high fuel price scenario applies an annual escalation rate that is 2.0 percentage points higher than that used for the base case forecast. The high fuel price forecast is provided in Table 1A.5-6. Table 1B.8-1 displays the results of the economic evaluation for the least-cost expansion plan for the high fuel price escalation sensitivity and Table 1B.8-2 presents the runner-up expansion plan. The plan including the joint development alternative is $18.96 million lower than the plan with the self-build alternative indicating the benefit of flexibility with the joint development project.

1B.8.2 Low Fuel Price Escalation

The low fuel price scenario applies an annual growth rate that is 2.0 percentage points lower than that used for the base case forecast. The low fuel price forecast is provided in Table 1A.8-7. Table 1B.8-3 displays the results of the economic evaluation for the least-cost expansion plan for the low fuel price escalation sensitivity and Table 1B.8-4 presents the runner-up expansion plan. Comparing the two plans indicates the plan with the joint development project continues to be the lowest cost with a $4.55 million cumulative present worth savings over the self-build plan.

1B.8.3 AEO Fuel Price Projections

This sensitivity analysis utilizes the fuel forecast provided by AEO as presented in Table 1A.5-10. The results of the economic evaluation for the least-cost expansion plan using the AEO fuel price forecast are shown in Tables 1B.8-5. Table 1B.8-6 presents the runner-up expansion plan. Under this screen, the expansion plan with the joint development project is $6 million lower in cumulative present worth cost.

1B.8.4 OUC 2000 Fuel Costs with 2001 AEO Escalation

This sensitivity analysis is based on the 2001 AEO fuel price escalation rates being applied to OUC's actual 2000 fuel costs as presented in Table 1A.5-11. Table 1B.8-7 presents the results of the economic evaluation for the least cost expansion plan and Table 1B.8-8 presents the runner-up expansion plan. With these higher fuel prices, the plan with the joint development project shows its increasing value with a $28.4 million savings over the plan with the self-build project.

1B.8.5 Constant 2000 Fuel Price Projections

This sensitivity analysis utilizes the fuel forecast resulting from escalating OUC's average 2000 fuel prices at the general inflation rate as presented in Table 1A.5-8. The results of the economic evaluation for the least-cost expansion plan using the constant 2000 fuel price forecast are shown in Table 1B.8-9 and Table 1B.8-10 presents the runner-up expansion plan. Again, the plan with the joint development project represents the lowest cost by $9 million.

1B.8.6 High Load and Energy Growth

The high load and energy growth scenario provides insight into the effect of resource decisions made in an environment where load and energy growth is greater than the base case forecast. The high load and energy growth scenario requires the addition of more generation and therefore an increase in cumulative present worth for the least-cost capacity addition plan. The high load and energy growth scenario is based upon the high load and energy growth forecast presented in Section 1B.4. Tables 1B.8-11 and 1B.8-12 indicate the summer and winter need for capacity based upon the high load and energy forecast.

As indicated in Table 1B.8-11, the high load and energy growth scenario results in a 59 MW capacity shortfall in the summer of 2002. Since the only option available to OUC for the summer of 2002 and 2003 is the additional 52.5 MW purchase from the Reliant Agreement, it has been assumed that OUC will purchase power on the spot market to make up the resultant deficit.

As indicated in Table 1B.8-12, the high load and energy growth scenario results in a capacity shortfall in the winter of 2002. The additional 52.5 MW purchase from the Reliant Agreement will satisfy OUC's needs for the winter of 2002 as well as for the winter of 2003.

Table 1B.8-13 displays the results of the economic evaluation for the least-cost expansion plan for the high load and energy growth sensitivity and Table 1B.8-14 presents the runner-up expansion plan. Comparing the two plans indicates that the plan including the self-build alternative is [redacted] million lower in cost than the plan including joint development project. It is not surprising that continued assured high growth would favor the self-build plan. The joint development project has been structured to provide relatively greater protection to OUC in scenarios that would have negative consequences such as loss of retail load or increases in the cost of fuel than it would be scenarios that would have positive consequences such as higher load growth or lower fuel prices.

1B.8.7 Low Load and Energy Growth

The low load and energy growth scenario provides insight into the effect of resource decisions made in an environment where load and energy growth is less than the base case forecast. The low load and energy growth scenario requires less generation resources than the base case forecast. The low load and energy growth scenario is based upon the low load and energy growth forecast presented in Section 1B.4.0. Tables 1B.8-15 and 1B.8-16 indicate the summer and winter need for capacity based upon the low load and energy forecast.

Capacity is required beginning in the summer of 2002 and the winter of 2004 for the low load and energy forecast. The extension of the 52.5 MW Reliant Agreement option will satisfy OUC's capacity requirements in the summer of 2002 and 2003 for the low load and energy growth scenario.

Table 1B.8-17 displays the results of the economic evaluation for the least-cost expansion plan for the low load and energy growth sensitivity and Table 1B.8-18 presents the runner-up expansion plan. Over the entire 20 year planning horizon, the cumulative present worth cost of the joint development alternative is only $90,000 over the cost of the self-build alternative. Notably, closer examination of Tables 1B.8-17 and 1B.8-18 indicate that the joint development alternative was lower in cumulative present worth cost every year until 2019. As discussed in Section 1A.4.1, the PPA has provisions for reducing the contract demand beginning in the sixth year. While this provision has not been explicitly evaluated, it would have significant economic benefit to OUC in a scenario such as this with low load and energy growth.

Table 1B.8-1
OUC High Fuel Price Escalation Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	164,296	296,413
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	177,126	448,270
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	190,849	599,772
2004	171 MW Joint Development with Southern–Florida (10/03)	231,489	769,923
	317 MW Southern-Florida Power Purchase (10/03)		
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 - 09/05)	236,101	930,610
2006	100 MW Reliant Power Purchase (10/05 - 09/06)	233,753	1,077,914
2007	156 MW GE 7FA SC (06/07)	251,687	1,224,771
2008	156 MW GE 7FA SC (06/08)	270,915	1,371,138
2009		295,247	1,518,834
2010		307,799	1,661,405
2011		323,212	1,800,025
2012		344,259	1,936,735
2013	Terminate 317 MW Southern–Florida Power Purchase (11/13)	363,258	2,070,305
	514 MW WH 501F 2x1 Combined Cycle (11/13)		
2014		396,384	2,205,258
2015		419,684	2,337,560
2016		441,382	2,466,395
2017		465,221	2,592,130
2018		496,565	2,716,395
2019		529,979	2,839,197

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-2
OUC High Fuel Price Escalation Runner Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	164,296	296,413
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	177,126	448,270
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	191,948	600,644
2004	488 MW Self-build GE 7FA 2x1 Combined Cycle (10/03)	230,795	770,286
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 - 09/05)	235,695	930,695
2006	100 MW Reliant Power Purchase (10/05 - 09/06)	235,886	1,079,344
2007	156 MW GE 7FA Simple Cycle (06/07)	254,957	1,228,108
2008	156 MW GE 7FA Simple Cycle (06/08)	270,225	1,374,102
2009		294,810	1,521,581
2010		307,904	1,664,200
2011		322,025	1,802,311
2012		344,937	1,939,290
2013		365,063	2,073,523
2014		405,479	2,211,573
2015		414,694	2,342,302
2016	156 MW GE 7FA Simple Cycle (06/16)	451,016	2,473,949
2017		475,406	2,602,437
2018		518,102	2,732,091
2019		544,055	2,858,155

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-3
OUC Low Fuel Price Escalation Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	160,192	292,613
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	164,871	433,963
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	173,094	571,371
2004	171 MW Joint Development with Southern–Florida (10/03)	208,994	724,988
	317 MW Southern-Florida Power Purchase (10/03)		
2005	100 MW Reliant Power Purchase (10/03 - 09/04)		
2006	100 MW Reliant Power Purchase (10/04 - 09/05)	207,750	866,379
2007	100 MW Reliant Power Purchase (10/05 - 09/06)	200,626	992,807
2008	156 MW GE 7FA SC (06/07)	210,874	1,115,850
2009	156 MW GE 7FA SC (06/08)	221,690	1,235,622
2010		236,622	1,353,992
2011		240,421	1,465,354
2012		245,689	1,570,725
2013	Terminate 317 MW Southern–Florida Power Purchase (11/13)	254,781	1,671,903
	514 MW WH 501F 2x1 Combined Cycle (11/13)	261,501	1,768,056
2014			
2015		283,548	1,864,593
2016		292,001	1,956,644
2017		298,822	2,043,867
2018		306,041	2,126,580
2019		317,550	2,206,047
		328,694	2,282,209

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-4
OUC Low Fuel Price Escalation Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	160,192	292,613
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	164,871	433,963
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	174,271	572,305
2004	488 MW Self-build GE 7FA 2x1 Combined Cycle (10/03)	208,291	725,406
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 - 09/05)	207,098	866,353
2006	100 MW Reliant Power Purchase (10/05 - 09/06)	202,650	994,057
2007	156 MW GE 7FA Simple Cycle (06/07)	213,997	1,118,922
2008	156 MW GE 7FA Simple Cycle (06/08)	220,775	1,238,200
2009		235,859	1,356,188
2010		240,138	1,467,419
2011		244,155	1,572,132
2012		254,857	1,673,340
2013		262,395	1,769,822
2014		288,183	1,867,937
2015		281,862	1,956,791
2016	156 MW GE 7FA Simple Cycle (06/16)	300,532	2,044,514
2017		308,417	2,127,869
2018		326,864	2,209,667
2019		332,718	2,286,762

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-5 AEO Fuel Price Projection Expansion Plan			
Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	118,921	118,921
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	122,380	232,236
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	130,892	344,455
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	148,674	462,477
2004	171 MW Joint Development with Southern–Florida (10/03)	190,039	602,161
	317 MW Southern–Florida Power Purchase (10/03)		
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 – 09/05)	193,703	733,992
2006	100 MW Reliant Power Purchase (10/05 – 09/06)	188,233	852,611
2007	156 MW GE 7FA Simple Cycle (06/07)	199,987	969,301
2008	156 MW GE 7FA Simple Cycle (06/08)	213,237	1,084,507
2009		233,123	1,201,126
2010		238,759	1,311,718
2011		245,150	1,416,859
2012		256,120	1,518,567
2013	Terminate 317 MW Southern–Florida Power Purchase (11/13)	266,644	1,616,612
	446 MW Pulverized Coal (11/13)		
2014		302,925	1,719,746
2015		310,247	1,817,549
2016		320,120	1,910,989
2017		327,099	1,999,393
2018		340,022	2,084,484
2019		356,216	2,167,023
Note: Capacity is stated at average annual temperature for OUC.			

Table 1B.8-6
OUC AEO Fuel Price Projection Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	118,921	118,921
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	122,380	232,236
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	130,892	344,455
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	149,656	463,257
2004	488 MW Self-build GE 7FA 2x1 Combined Cycle (10/03)	189,375	602,453
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 - 09/05)	193,434	734,101
2006	100 MW Reliant Power Purchase (10/05 - 09/06)	190,400	854,085
2007	156 MW GE 7FA Simple Cycle (06/07)	203,025	972,548
2008	156 MW GE 7FA Simple Cycle (06/08)	212,032	1,087,102
2009		232,397	1,203,359
2010		238,513	1,313,836
2011		243,586	1,418,306
2012		256,263	1,520,072
2013		268,753	1,618,891
2014		300,157	1,721,083
2015		296,715	1,814,620
2016	156 MW GE 7FA Simple Cycle (06/16)	319,793	1,907,965
2017		332,233	1,997,757
2018		356,987	2,087,092
2019		370,876	2,173,029

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-7
OUC 2000 + 2001 AEO Escalation Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	142,721	142,721
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	151,466	282,967
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	180,039	437,322
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	203,058	598,516
2004	171 MW Joint Development with Southern–Florida (10/03)	253,620	784,934
	317 MW Southern–Florida Power Purchase (10/03)		
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 – 09/05)	258,420	960,810
2006	100 MW Reliant Power Purchase (10/05 – 09/06)	250,414	1,118,614
2007	446 MW Pulverized Coal (06/07)	269,942	1,276,122
2008		288,247	1,431,853
2009		303,651	1,583,754
2010		310,518	1,727,584
2011		315,782	1,863,017
2012		327,195	1,992,951
2013	Terminate 317 MW Southern–Florida Power Purchase (11/13)	340,189	2,118,038
	156 MW GE 7FA Simple Cycle (11/13)		
2014		338,452	2,233,268
2015		349,052	2,343,304
2016	156 MW GE 7FA Simple Cycle (06/08)	366,711	2,450,343
2017		382,870	2,553,821
2018		402,287	2,654,493
2019		428,066	2,753,681

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-8
OUC 2000 + 2001 AEO Escalation Fuel Price Projection Runner Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	142,721	142,721
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	151,466	282,967
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	180,039	437,522
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	201,995	597,672
2004	488 MW Self-build GE 7FA 2x1 Combined Cycle (10/03)	251,916	782,838
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 - 09/05)	258,438	958,726
2006	100 MW Reliant Power Purchase (10/05 - 09/06)	252,843	1,118,060
2007	446 MW Pulverized Coal (06/07)	267,861	1,274,354
2008		285,990	1,428,866
2009		303,410	1,580,647
2010		312,674	1,725,475
2011		312,870	1,859,660
2012		327,155	1,989,578
2013		344,194	2,116,137
2014		362,857	2,239,676
2015		369,949	2,356,299
2016		389,837	2,470,089
2017		395,058	2,576,861
2018		412,529	2,680,096
2019		440,054	2,782,062

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-9
OUC Constant 2000 Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	142,721	142,721
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	151,191	282,712
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	175,598	433,259
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	197,052	589,686
2004	171 MW Joint Development with Southern–Florida (10/03)	247,056	771,280
	317 MW Southern–Florida Power Purchase (10/03)		
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 - 09/05)	251,529	942,466
2006	100 MW Reliant Power Purchase (10/05 - 09/06)	244,615	1,096,615
2007	156 MW GE 7FS Simple Cycle (06/07)	260,608	1,248,677
2008	156 MW GE 7FS Simple Cycle (06/08)	276,878	1,398,266
2009		303,257	1,549,970
2010		311,701	1,694,348
2011		319,979	1,831,581
2012		335,338	1,964,749
2013	Terminate 317 MW Southern–Florida Power Purchase (11/13)	349,905	2,093,408
	446 MW Pulverized Coal (11/13)		
2014		380,309	2,222,888
2015		392,229	2,346,535
2016		407,450	2,465,466
2017		416,981	2,578,163
2018		431,843	2,686,231
2019		452,146	2,790,999

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-10
OUC Constant 2000 Fuel Price Projection Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	142,721	142,721
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	151,191	282,712
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	175,598	433,259
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	196,022	588,868
2004	488 MW Self-build GE 7FA 2x1 Combined Cycle (10/03)	245,124	769,042
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 - 09/05)	250,986	939,859
2006	100 MW Reliant Power Purchase (10/05 - 09/06)	246,819	1,095,397
2007	267 MW Circulating Fluidized Bed (06/07)	270,023	1,252,952
2008		283,728	1,406,242
2009		303,691	1,558,163
2010		311,841	1,702,606
2011		317,723	1,838,872
2012		333,218	1,971,197
2013		350,713	2,100,154
2014		383,039	2,230,564
2015		385,175	2,351,987
2016	156 MW GE 7FA Simple Cycle (06/16)	407,963	2,471,067
2017		418,305	2,584,122
2018		439,226	2,694,038
2019		457,245	2,799,987

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-11
OUC Summer Reserve Requirements - High Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1062	440	1502	1047	608	1655	153	170	(17)
2001	1100	341	1441	1047	608	1655	214	177	37
2002	1139	323	1462	1047	540	1587	125	184	(59)
2003	1180	312	1492	1047	540	1587	95	191	(96)
2004	1222	263	1485	1047	15	1062	-423	199	(622)
2005	1265	172	1437	1025	15	1040	-397	207	(604)
2006	1301	139	1440	1025	15	1040	-400	210	(610)
2007	1337	139	1476	1025	15	1040	-436	219	(655)
2008	1375	142	1517	1025	15	1040	-477	225	(702)
2009	1413	144	1557	1025	15	1040	-517	231	(749)
2010	1453	146	1599	1025	15	1040	-559	238	(797)
2011	1493	0	1493	1025	0	1025	-468	224	(691)
2012	1533	0	1533	1025	0	1025	-508	230	(738)
2013	1575	0	1575	1025	0	1025	-550	236	(786)
2014	1618	0	1618	1025	0	1025	-593	243	(836)
2015	1662	0	1662	1025	0	1025	-637	249	(886)
2016	1708	0	1708	1025	0	1025	-683	256	(939)
2017	1755	0	1755	1025	0	1025	-730	263	(993)
2018	1803	0	1803	1025	0	1025	-778	270	(1048)
2019	1852	0	1852	1025	0	1025	-827	278	(1105)

Table 1B.8-12
OUC Winter Reserve Requirements - High Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1051	440	1491	1092	608	1700	209	168	40
2001	1092	341	1433	1092	608	1700	267	176	91
2002	1135	323	1458	1092	540	1632	174	183	(9)
2003	1179	312	1491	1092	540	1632	141	191	(51)
2004	1225	263	1488	1092	15	1107	-381	200	(581)
2005	1273	172	1445	1071	15	1086	-359	208	(567)
2006	1309	139	1448	1071	15	1086	-362	212	(574)
2007	1347	139	1486	1071	15	1086	-400	221	(621)
2008	1386	142	1528	1071	15	1086	-442	227	(668)
2009	1425	144	1569	1071	15	1086	-483	233	(716)
2010	1466	146	1612	1071	15	1086	-526	240	(766)
2011	1505	0	1505	1071	0	1071	-434	226	(660)
2012	1546	0	1546	1071	0	1071	-475	232	(707)
2013	1587	0	1587	1071	0	1071	-516	238	(755)
2014	1630	0	1630	1071	0	1071	-559	245	(804)
2015	1674	0	1674	1071	0	1071	-603	251	(854)
2016	1720	0	1720	1071	0	1071	-649	258	(907)
2017	1767	0	1767	1071	0	1071	-696	265	(961)
2018	1815	0	1815	1071	0	1071	-744	272	(1017)
2019	1865	0	1865	1071	0	1071	-794	280	(1074)

Table 1B.8-13
OUC High Load and Energy Growth Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	163,316	295,505
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	173,482	444,237
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	186,502	592,289
2004	488 MW Self-build GE 7FA 2x1 Combined Cycle (10/03)	224,943	757,629
	200 MW Reliant Power Purchase (10/03 - 09/04)		
2005	200 MW Reliant Power Purchase (10/04 - 09/05)	230,976	914,827
2006	200 MW Reliant Power Purchase (10/05 - 09/06)	226,792	1,057,744
2007	200 MW Reliant Power Purchase (10/06 - 09/07)	244,455	1,200,381
2008	610 MW WH 501F 2x1 Combined Cycle (06/08)	258,724	1,340,162
2009		286,270	1,483,368
2010		296,837	1,620,861
2011		306,477	1,752,304
2012		322,542	1,880,389
2013		337,271	2,004,403
2014		359,225	2,126,705
2015		370,994	2,243,658
2016		391,488	2,357,930
2017		412,787	2,469,493
2018		433,819	2,578,056
2019	156 MW GE 7FA Simple Cycle (06/19)	459,965	2,684,636

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-14
OUC High Load and Energy Growth Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	163,316	295,505
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	173,482	444,237
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	186,448	592,246
2004	171 MW Joint Development with Southern-Florida (10/03)	229,304	760,791
	317 MW Southern-Florida Power Purchase (10/03)		
	200 MW Reliant Power Purchase (10/03 - 09/04)		
2005	200 MW Reliant Power Purchase (10/04 - 09/05)	232,466	919,004
2006	200 MW Reliant Power Purchase (10/05 - 09/06)	229,273	1,063,485
2007	200 MW Reliant Power Purchase (10/06 - 09/07)	246,638	1,207,396
2008	610 MW WH 501F 2x1 Combined Cycle (06/08)	259,828	1,347,773
2009		288,881	1,492,285
2010		299,302	1,630,920
2011		308,461	1,763,213
2012		324,990	1,892,271
2013	Terminate 317 MW Southern–Florida Power Purchase (11/13)	336,629	2,016,049
	156 MW GE 7FA Simple Cycle (11/13)		
2014		346,693	2,134,084
2015	156 MW GE 7FA Simple Cycle (06/15)	369,997	2,250,723
2016		391,959	2,365,132
2017		415,571	2,477,448
2018	267 MW Circulating Fluidized Bed (06/18)	459,699	2,592,487
2019		502,907	2,709,017

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-15
OUC Summer Reserve Requirements - Low Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1062	440	1502	1047	608	1655	153	170	(17)
2001	1084	341	1425	1047	608	1655	230	175	55
2002	1106	323	1429	1047	540	1587	158	179	(21)
2003	1129	312	1441	1047	540	1587	146	184	(38)
2004	1152	263	1415	1047	15	1062	-353	189	(542)
2005	1176	172	1348	1025	15	1040	-308	194	(502)
2006	1192	139	1331	1025	15	1040	-291	194	(485)
2007	1209	139	1348	1025	15	1040	-308	200	(508)
2008	1226	142	1368	1025	15	1040	-328	203	(531)
2009	1243	144	1387	1025	15	1040	-347	206	(552)
2010	1260	146	1406	1025	15	1040	-366	209	(575)
2011	1275	0	1275	1025	0	1025	-250	191	(442)
2012	1291	0	1291	1025	0	1025	-266	194	(460)
2013	1307	0	1307	1025	0	1025	-282	196	(478)
2014	1323	0	1323	1025	0	1025	-298	198	(496)
2015	1339	0	1339	1025	0	1025	-314	201	(515)
2016	1355	0	1355	1025	0	1025	-330	203	(533)
2017	1371	0	1371	1025	0	1025	-346	206	(551)
2018	1387	0	1387	1025	0	1025	-362	208	(570)
2019	1403	0	1403	1025	0	1025	-378	211	(589)

Table 1B.8-16
OUC Winter Reserve Requirements - Low Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1051	440	1491	1092	608	1700	209	168	40
2001	1078	341	1419	1092	608	1700	281	174	107
2002	1106	323	1429	1092	540	1632	203	179	24
2003	1134	312	1446	1092	540	1632	186	184	1
2004	1163	263	1426	1092	15	1107	-319	191	(510)
2005	1193	172	1365	1071	15	1086	-279	196	(475)
2006	1210	139	1349	1071	15	1086	-263	197	(459)
2007	1227	139	1366	1071	15	1086	-280	203	(482)
2008	1244	142	1386	1071	15	1086	-300	206	(506)
2009	1261	144	1405	1071	15	1086	-319	209	(528)
2010	1279	146	1425	1071	15	1086	-339	212	(551)
2011	1294	0	1294	1071	0	1071	-223	194	(418)
2012	1310	0	1310	1071	0	1071	-239	197	(436)
2013	1326	0	1326	1071	0	1071	-255	199	(454)
2014	1342	0	1342	1071	0	1071	-271	201	(472)
2015	1358	0	1358	1071	0	1071	-287	204	(491)
2016	1374	0	1374	1071	0	1071	-303	206	(509)
2017	1390	0	1390	1071	0	1071	-319	209	(528)
2018	1407	0	1407	1071	0	1071	-336	211	(547)
2019	1423	0	1423	1071	0	1071	-352	213	(566)

Table 1B.8-17
OUC Low Load and Energy Growth Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	160,822	293,196
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	167,665	436,942
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	176,304	576,898
2004	488 MW Self-build GE 7FA 2x1 Combined Cycle (10/03)	211,595	732,425
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant River Power Purchase (10/04 - 09/05)	213,802	877,935
2006		207,424	1,008,647
2007	156 MW GE 7FA SC (06/07)	211,585	1,132,105
2008		220,912	1,251,457
2009		239,899	1,371,467
2010		241,165	1,483,172
2011		246,476	1,588,882
2012		259,106	1,691,776
2013		268,149	1,790,374
2014		299,017	1,892,178
2015		292,159	1,984,278
2016		313,582	2,075,810
2017		307,061	2,158,799
2018		333,532	2,242,265
2019		339,328	2,320,891

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-18
OUC Low Load and Energy Growth Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	160,822	293,196
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	167,665	436,942
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	172,724	574,056
2004	171 MW Joint Development with Southern–Florida (10/03)	214,166	731,474
	317 MW Southern-Florida Power Purchase (10/03)		
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant River Power Purchase (10/04 - 09/05)	219,366	876,687
2006		203,692	1,005,047
2007	156 MW GE 7FA SC (06/07)	216,845	1,131,574
2008		225,042	1,253,157
2009		237,138	1,371,786
2010		241,196	1,483,506
2011		247,667	1,589,726
2012		259,560	1,692,801
2013	Terminate 317 MW Southern–Florida Power Purchase (11/13)	264,093	1,789,907
	Extension of 317 MW Southern-Florida Power Purchase (11/13)		
2014		297,971	1,891,355
2015		291,445	1,983,230
2016		313,141	2,074,633
2017		308,630	2,158,046
2018	Terminate 317 MW Southern–Florida Power Purchase (11/18)	331,107	2,240,905
	514 MW WH 501F 2x1 Combined Cycle (11/18)		
2019		345,582	2,320,981

Note: Capacity is stated at average annual temperature for OUC.

Orlando Utilities Commission Economic Evaluation

Case

Scenario: Base Case
Joint Development

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	171			2003.833	[redacted]	
GE 7FA SC	156	68,615	12	2007.417	83,801	9,377
GE 7FA SC	156	68,615	12	2008.417	85,896	9,612
WH 501F 2x1 (small)	514	258,481	24	2013.912	376,879	42,173

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	141,221	20,267	751	0	162,239	0	162,239	294,508
2002	147,392	20,870	2,989	0	171,252	0	171,252	441,329
2003	147,248	22,448	10,227	(219)	179,705	2,303	182,007	585,812
2004	150,345	26,676	34,710	(882)	210,848	9,210	220,059	747,562
2005	151,703	28,059	33,674	(895)	212,540	9,210	221,751	898,482
2006	149,461	27,782	31,091	(908)	207,426	9,210	216,636	1,034,999
2007	160,655	29,669	26,251	(921)	215,653	14,681	230,334	1,169,397
2008	164,045	30,469	27,266	(935)	220,845	24,195	245,040	1,301,784
2009	176,711	32,318	27,744	(949)	235,824	28,199	264,023	1,433,862
2010	183,009	33,559	27,820	(964)	243,425	28,199	271,624	1,559,876
2011	190,023	35,252	27,898	(978)	252,195	28,199	280,396	1,679,939
2012	202,945	36,580	27,979	(993)	266,510	28,199	294,709	1,796,988
2013	211,868	39,047	24,629	(1,009)	274,535	31,714	306,249	1,909,573
2014	215,884	40,435	7,717	(1,025)	263,011	70,372	333,383	2,023,077
2015	228,876	42,358	7,910	(1,041)	278,104	70,372	348,476	2,132,931
2016	239,262	44,537	8,107	(1,058)	290,848	70,372	361,220	2,238,368
2017	250,972	46,144	8,310	(1,075)	304,351	70,372	374,723	2,339,644
2018	266,669	48,547	8,518	(1,093)	322,641	70,372	393,013	2,437,995
2019	285,248	50,680	8,731	(1,111)	343,548	70,372	413,921	2,533,905

Notes:
(1) Includes start-up costs
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case	
Scenario: Base Case Self Build	

Economic	
CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self-Build	488			2003.833	251,663	28,161
GE 7FA SC	156	68,615	12	2007.417	83,801	9,377
GE 7FA SC	156	68,615	12	2008.417	85,896	9,612
GE 7FA SC	156	68,615	12	2016.417	104,656	11,711

Finance	
Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-FI, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	141,221	20,267	751	0	162,239	0	162,239	294,508
2002	147,392	20,870	2,989	0	171,252	0	171,252	441,329
2003	149,126	22,460	4,430	0	176,015	7,040	183,056	586,644
2004	154,106	26,841	10,006	0	190,952	28,161	219,114	747,699
2005	154,186	28,253	10,146	0	192,585	28,161	220,746	897,936
2006	153,546	27,837	8,671	0	190,054	28,161	218,215	1,036,448
2007	166,024	30,032	3,424	0	199,480	33,631	233,111	1,171,466
2008	165,379	30,704	4,486	0	200,569	43,145	243,714	1,303,137
2009	178,683	32,368	5,012	0	216,063	47,150	263,213	1,434,809
2010	185,254	33,664	5,137	0	224,055	47,150	271,205	1,560,429
2011	191,052	35,455	5,265	0	231,773	47,150	278,923	1,680,065
2012	205,553	36,751	5,397	0	247,700	47,150	294,851	1,797,144
2013	215,617	39,196	5,532	0	260,345	47,150	307,495	1,910,209
2014	245,428	41,202	5,670	0	292,300	47,150	339,450	2,025,779
2015	243,011	43,182	5,812	0	292,005	47,150	339,155	2,132,694
2016	258,930	45,207	6,654	0	310,792	53,982	364,773	2,239,168
2017	265,300	47,212	7,325	0	319,836	58,861	378,698	2,341,518
2018	290,162	49,797	7,508	0	347,466	58,861	406,327	2,443,201
2019	301,583	51,839	7,696	0	361,117	58,861	419,978	2,540,616

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case		Economic	
Scenario: High Fuel Price Projections		CPW Discount Rate:	8.0%
Joint Development		Capital Escalation Rate:	2.5%
		Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	171			2003.833	[redacted]	[redacted]
GE 7FA SC	156	68,615	12	2007.417	83,801	9,377
GE 7FA SC	156	68,615	12	2008.417	85,896	9,612
WH 501F 2x1 (small)	514	258,481	24	2013.912	376,879	42,173

Finance	
Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,738	19,547	0	0	144,287	0	144,287	144,287
2001	143,279	20,266	751	0	164,296	0	164,296	296,419
2002	153,267	20,870	2,989	0	177,126	0	177,126	448,270
2003	156,086	22,452	10,227	(219)	188,547	2,303	190,849	599,772
2004	161,763	26,687	34,710	(882)	222,278	9,210	231,489	769,923
2005	166,048	28,063	33,674	(895)	226,891	9,210	236,101	930,610
2006	166,494	27,865	31,091	(908)	224,542	9,210	233,753	1,077,914
2007	181,924	29,753	26,251	(921)	237,007	14,681	251,687	1,224,777
2008	189,810	30,579	27,266	(935)	246,720	24,195	270,915	1,371,136
2009	207,820	32,433	27,744	(949)	267,047	28,199	295,247	1,516,834
2010	219,038	33,705	27,820	(964)	279,600	28,199	307,799	1,661,405
2011	232,814	35,278	27,898	(978)	295,012	28,199	323,212	1,800,026
2012	252,380	36,695	27,979	(993)	316,060	28,199	344,259	1,938,795
2013	268,829	39,095	24,629	(1,009)	331,545	31,714	363,259	2,070,305
2014	278,866	40,454	7,717	(1,025)	326,012	70,372	396,384	2,205,258
2015	300,032	42,411	7,910	(1,041)	349,312	70,372	419,684	2,337,580
2016	319,497	44,464	8,107	(1,058)	371,010	70,372	441,382	2,466,395
2017	341,508	46,106	8,310	(1,075)	394,849	70,372	465,221	2,592,130
2018	370,212	48,556	8,518	(1,093)	426,193	70,372	496,565	2,716,295
2019	401,252	50,736	8,731	(1,111)	459,607	70,372	529,979	2,839,187

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case	
Scenario: High Fuel Price Projections	
Self Build	

Economic	
CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self-Build	488			2003 833	251,663	28,161
GE 7FA SC	156	68,615	12	2007 417	83,801	9,377
GE 7FA SC	156	68,615	12	2008 417	85,896	9,612
GE 7FA SC	156	68,615	12	2016.417	104,656	11,711

Finance	
Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	143,279	20,266	751	0	164,296	0	164,296	296,413
2002	153,267	20,870	2,989	0	177,126	0	177,126	448,270
2003	158,012	22,465	4,430	0	184,908	7,040	191,948	600,644
2004	165,779	26,849	10,006	0	202,634	28,161	230,795	770,286
2005	169,130	28,257	10,146	0	207,533	28,161	235,695	930,695
2006	171,139	27,914	8,671	0	207,725	28,161	235,886	1,079,344
2007	187,781	30,120	3,424	0	221,325	33,631	254,957	1,228,108
2008	191,774	30,819	4,486	0	227,079	43,145	270,225	1,374,102
2009	210,166	32,483	5,012	0	247,660	47,150	294,810	1,521,581
2010	221,824	33,793	5,137	0	260,754	47,150	307,904	1,664,209
2011	234,154	35,456	5,265	0	274,875	47,150	322,026	1,802,311
2012	255,516	36,873	5,397	0	297,787	47,150	344,937	1,939,290
2013	273,162	39,218	5,532	0	317,913	47,150	365,063	2,073,520
2014	311,401	41,258	5,670	0	358,329	47,150	405,479	2,211,573
2015	318,413	43,319	5,812	0	367,544	47,150	414,694	2,342,302
2016	345,089	45,291	6,654	0	397,034	53,982	451,016	2,473,949
2017	361,891	47,329	7,325	0	416,544	58,861	475,406	2,602,437
2018	401,865	49,867	7,508	0	459,241	58,861	518,102	2,732,091
2019	425,450	52,048	7,696	0	485,194	58,861	544,055	2,858,155

Notes:

(1) Includes start-up costs.

(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.

(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case
Scenario: Low Fuel Price Projections Joint Development

Economic	
CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	171			2003.833	[redacted]	
GE 7FA SC	156	68,615	12	2007.417	83,801	9,377
GE 7FA SC	156	68,615	12	2008.417	85,896	9,612
WH 501F 2x1 (small)	514	258,481	24	2013.912	376,879	42,173

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	139,174	20,267	751	0	160,192	0	160,192	292,613
2002	141,016	20,867	2,989	0	164,871	0	164,871	433,963
2003	138,342	22,441	10,227	(219)	170,791	2,303	173,094	571,371
2004	139,286	26,670	34,710	(882)	199,784	9,210	208,994	724,988
2005	137,802	27,958	33,674	(895)	198,540	9,210	207,750	866,379
2006	133,452	27,780	31,091	(908)	191,415	9,210	200,626	992,807
2007	141,198	29,666	26,251	(921)	196,193	14,681	210,874	1,115,850
2008	140,694	30,471	27,266	(935)	197,495	24,195	221,690	1,235,822
2009	149,337	32,291	27,744	(949)	208,423	28,199	236,622	1,353,992
2010	151,791	33,574	27,820	(964)	212,221	28,199	240,421	1,465,354
2011	156,350	35,220	27,898	(978)	217,489	28,199	245,689	1,570,725
2012	163,034	36,563	27,979	(993)	226,582	28,199	254,781	1,671,903
2013	167,163	39,003	24,629	(1,009)	229,787	31,714	261,501	1,768,056
2014	166,066	40,417	7,717	(1,025)	213,176	70,372	283,548	1,864,593
2015	172,350	42,410	7,910	(1,041)	221,628	70,372	292,001	1,956,644
2016	176,910	44,491	8,107	(1,058)	228,450	70,372	298,822	2,043,867
2017	182,329	46,105	8,310	(1,075)	235,669	70,372	306,041	2,126,580
2018	191,214	48,539	8,518	(1,093)	247,178	70,372	317,550	2,206,047
2019	200,034	50,668	8,731	(1,111)	258,322	70,372	328,694	2,282,209

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case	
Scenario. Low Fuel Price Projections	
Self Build	

Economic	
CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self-Build	488			2003.833	251,663	28,161
GE 7FA SC	156	68,615	12	2007.417	83,801	9,377
GE 7FA SC	156	68,615	12	2008.417	85,896	9,612
GE 7FA SC	156	68,615	12	2016.417	104,656	11,711

Finance	
Fixed Charge Rate:	11 19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	139,174	20,267	751	0	160,192	0	160,192	292,613
2002	141,016	20,867	2,989	0	164,871	0	164,871	433,963
2003	140,358	22,443	4,430	0	167,231	7,040	174,271	572,805
2004	143,286	26,838	10,006	0	180,130	28,161	208,291	725,406
2005	140,638	28,153	10,146	0	178,937	28,161	207,098	866,363
2006	137,988	27,830	8,671	0	174,489	28,161	202,650	994,057
2007	146,918	30,027	3,424	0	180,365	33,631	213,997	1,118,922
2008	142,432	30,712	4,486	0	177,630	43,145	220,775	1,238,200
2009	151,354	32,344	5,012	0	188,709	47,150	235,859	1,356,188
2010	154,170	33,661	5,137	0	192,988	47,150	240,138	1,467,219
2011	156,318	35,421	5,265	0	197,004	47,150	244,155	1,572,192
2012	165,583	36,727	5,397	0	207,707	47,150	254,857	1,673,340
2013	170,557	39,155	5,532	0	215,245	47,150	262,395	1,769,822
2014	194,192	41,171	5,670	0	241,033	47,150	288,183	1,857,937
2015	185,792	43,107	5,812	0	234,711	47,150	281,862	1,956,791
2016	194,753	45,143	6,654	0	246,550	53,982	300,532	2,044,514
2017	195,120	47,112	7,325	0	249,556	58,861	308,417	2,127,869
2018	210,689	49,807	7,508	0	268,003	58,861	326,864	2,209,667
2019	214,445	51,716	7,696	0	273,856	58,861	332,718	2,286,762

Notes:

(1) Includes start-up costs.

(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.

(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case	
Scenario: AEO Fuel Price Projections	
Joint Development	

Economic	
CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	171			2003 833	[redacted]	
GE 7FA SC	156	68,615	12	2007.417	83,801	9,377
GE 7FA SC	156	68,615	12	2008.417	85,896	9,612
Pulverized Coal	446	513,163	42	2013.912	767,298	85,861

Finance	
Fixed Charge Rate.	11.19%
Interest During Const :	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	99,303	19,618	0	0	118,921	0	118,921	118,921
2001	101,306	20,324	751	0	122,380	0	122,380	232,236
2002	106,949	20,954	2,989	0	130,892	0	130,892	344,465
2003	113,861	22,502	10,227	(219)	146,371	2,303	148,674	462,477
2004	120,254	26,748	34,710	(882)	180,829	9,210	190,039	602,181
2005	123,706	28,008	33,674	(895)	184,493	9,210	193,703	738,992
2006	121,032	27,807	31,091	(908)	179,022	9,210	188,233	852,811
2007	130,310	29,668	26,251	(921)	185,307	14,681	199,987	969,301
2008	132,236	30,477	27,266	(935)	189,043	24,195	213,237	1,084,807
2009	145,831	32,297	27,744	(949)	204,923	28,199	233,123	1,201,126
2010	150,116	33,587	27,820	(964)	210,560	28,199	238,759	1,311,718
2011	154,774	35,266	27,898	(978)	216,951	28,199	245,150	1,416,859
2012	164,381	36,555	27,979	(993)	227,921	28,199	256,120	1,518,867
2013	167,780	39,128	25,391	(1,009)	231,289	35,355	266,644	1,616,612
2014	136,093	41,412	12,386	(1,025)	188,866	114,060	302,925	1,719,746
2015	141,067	43,466	12,695	(1,041)	196,187	114,060	310,247	1,817,549
2016	148,389	45,716	13,013	(1,058)	206,060	114,060	320,120	1,910,989
2017	153,367	47,409	13,338	(1,075)	213,038	114,060	327,099	1,999,393
2018	163,416	49,968	13,671	(1,093)	225,962	114,060	340,022	2,084,484
2019	176,831	52,422	14,013	(1,111)	242,156	114,060	356,216	2,167,023

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case	
Scenario: AEO Fuel Price Projections Self Build	

Economic	
CPW Discount Rate:	8.0%
Capital Escalation Rate	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	488			2003.833	251,663	28,161
GE 7FA SC	156	68,615	12	2007.417	83,801	9,377
GE 7FA SC	156	68,615	12	2008.417	85,896	9,612
GE 7FA SC	156	68,615	12	2016.417	104,656	11,711

Finance	
Fixed Charge Rate:	11.19%
Interest During Const	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	99,303	19,618	0	0	118,921	0	118,921	118,921
2001	101,306	20,324	751	0	122,380	0	122,380	232,236
2002	106,949	20,954	2,989	0	130,892	0	130,892	344,455
2003	115,677	22,509	4,430	0	142,616	7,040	149,656	463,257
2004	124,286	26,922	10,006	0	161,214	28,161	189,375	602,463
2005	126,901	28,226	10,146	0	165,273	28,161	193,434	734,101
2006	125,694	27,873	8,671	0	162,239	28,161	190,400	854,085
2007	135,944	30,026	3,424	0	169,394	33,631	203,025	972,648
2008	133,699	30,702	4,486	0	168,887	43,145	212,032	1,087,102
2009	147,883	32,352	5,012	0	185,246	47,150	232,397	1,203,559
2010	152,521	33,705	5,137	0	191,362	47,150	238,513	1,313,836
2011	155,725	35,446	5,265	0	196,436	47,150	243,586	1,418,306
2012	166,993	36,722	5,397	0	209,113	47,150	256,263	1,520,072
2013	176,906	39,165	5,532	0	221,602	47,150	268,753	1,616,891
2014	206,114	41,222	5,670	0	253,007	47,150	300,157	1,721,083
2015	200,548	43,205	5,812	0	249,565	47,150	296,715	1,814,620
2016	213,941	45,216	6,654	0	265,811	53,982	319,793	1,907,965
2017	218,853	47,194	7,325	0	273,372	58,861	332,233	1,997,757
2018	240,877	49,741	7,508	0	298,126	58,861	356,987	2,087,092
2019	252,457	51,863	7,696	0	312,015	58,861	370,876	2,173,029

Notes.
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case	
Scenario: OUC 2000 + 2001 AEO Escalators	
Joint Development	

Economic	
CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	171			2003.833	[redacted]	
Pulverized Coal PC	446	513,163	42	2007.417	653,601	73,138
GE 7FA SC	156	68,615	12	2013.912	98,379	11,009
GE 7FA SC	156	68,615	12	2016.417	104,656	11,711

Finance	
Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	123,174	19,547	0	0	142,721	0	142,721	142,721
2001	130,398	20,317	751	0	151,466	0	151,466	282,967
2002	156,097	20,953	2,989	0	180,039	0	180,039	437,322
2003	168,251	22,497	10,227	(219)	200,758	2,303	203,058	598,516
2004	183,770	26,812	34,710	(882)	244,410	9,210	253,620	784,934
2005	188,396	28,036	33,674	(895)	249,209	9,210	258,420	960,810
2006	183,187	27,834	31,091	(908)	241,204	9,210	250,414	1,118,614
2007	159,170	29,723	30,097	(921)	218,068	51,874	269,942	1,276,122
2008	142,314	31,101	33,418	(935)	205,898	82,348	288,247	1,431,863
2009	155,866	32,751	33,636	(949)	221,303	82,348	303,651	1,583,754
2010	160,948	34,326	33,860	(964)	228,169	82,348	310,518	1,727,584
2011	164,402	35,922	34,089	(978)	233,434	82,348	315,782	1,863,017
2012	174,107	37,409	34,324	(993)	244,847	82,348	327,195	1,992,951
2013	187,823	39,466	30,623	(1,009)	256,923	83,266	340,189	2,118,036
2014	193,236	41,631	11,254	(1,025)	245,095	93,357	338,452	2,233,288
2015	201,337	43,865	11,535	(1,041)	255,695	93,357	349,052	2,343,304
2016	209,158	45,902	12,521	(1,058)	266,523	100,188	366,711	2,450,343
2017	218,126	47,414	13,338	(1,075)	277,802	105,068	382,870	2,553,821
2018	234,588	50,052	13,671	(1,093)	297,219	105,068	402,287	2,654,493
2019	257,506	52,589	14,013	(1,111)	322,998	105,068	428,066	2,753,681

Notes:

(1) Includes start-up costs.

(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.

(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case	
Scenario: OUC 2000 + 2001 AEO Escalators Self Build	

Economic	
CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self-Build	488			2003.833	251,663	28,161
Pulverized Coal PC	446	513,163	42	2007 417	653,601	73,138

Finance	
Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	123,174	19,547	0	0	142,721	0	142,721	142,721
2001	130,398	20,317	751	0	151,466	0	151,466	282,967
2002	156,097	20,953	2,989	0	180,039	0	180,039	437,322
2003	168,004	22,521	4,430	0	194,955	7,040	201,995	597,672
2004	186,763	26,986	10,006	0	223,755	28,161	251,916	782,838
2005	191,897	28,233	10,146	0	230,277	28,161	258,438	958,726
2006	187,994	28,017	8,671	0	224,682	28,161	252,843	1,118,060
2007	159,864	29,902	7,271	0	197,036	70,825	267,861	1,274,354
2008	142,807	31,246	10,638	0	184,691	101,299	285,990	1,425,966
2009	158,237	32,970	10,904	0	202,111	101,299	303,410	1,580,647
2010	165,638	34,561	11,176	0	211,375	101,299	312,674	1,725,475
2011	163,955	36,161	11,456	0	211,571	101,299	312,870	1,869,660
2012	176,595	37,518	11,742	0	225,856	101,299	327,155	1,989,578
2013	191,109	39,751	12,036	0	242,895	101,299	344,194	2,116,137
2014	207,583	41,639	12,337	0	261,558	101,299	362,857	2,239,676
2015	212,627	43,378	12,645	0	268,650	101,299	369,949	2,356,289
2016	229,515	46,062	12,961	0	288,538	101,299	389,837	2,470,089
2017	233,293	47,181	13,285	0	293,759	101,299	395,058	2,576,861
2018	247,653	49,960	13,617	0	311,230	101,299	412,529	2,680,096
2019	272,734	52,063	13,958	0	338,755	101,299	440,054	2,782,082

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case	
Scenario: High Load and Energy Growth	
Self Build	

Economic	
CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self-Build	488			2003.833	251,663	28,161
WH 501 F 2x1 (large)	630	267,633	24	2008.417	340,709	38,125
GE 7FA SC	156	68,615	12	2019.417	112,703	12,611

Finance	
Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	142,244	20,321	751	0	163,316	0	163,316	295,505
2002	149,486	21,006	2,989	0	173,482	0	173,482	444,237
2003	150,899	22,633	5,930	0	179,462	7,040	186,502	592,289
2004	153,835	26,966	15,981	0	196,782	28,161	224,943	757,629
2005	157,834	28,704	16,277	0	202,814	28,161	230,976	914,827
2006	153,715	28,340	16,575	0	198,631	28,161	226,792	1,057,744
2007	173,347	30,512	12,435	0	216,294	28,161	244,455	1,200,381
2008	171,395	31,838	5,090	0	208,323	50,401	258,724	1,340,182
2009	179,920	33,289	6,774	0	219,983	66,286	286,270	1,488,368
2010	188,485	35,122	6,944	0	230,551	66,286	296,837	1,620,861
2011	196,135	36,938	7,117	0	240,190	66,286	306,477	1,752,304
2012	210,110	38,850	7,295	0	256,255	66,286	322,542	1,880,389
2013	222,094	41,413	7,478	0	270,986	66,286	337,271	2,004,403
2014	241,706	43,567	7,665	0	292,938	66,286	359,225	2,126,705
2015	250,970	45,881	7,856	0	304,707	66,286	370,994	2,243,658
2016	268,465	48,685	8,053	0	325,202	66,286	391,488	2,357,930
2017	287,674	50,572	8,254	0	346,500	66,286	412,787	2,469,493
2018	305,215	53,857	8,460	0	367,532	66,286	433,819	2,578,066
2019	320,697	56,202	9,423	0	386,322	73,643	459,965	2,684,636

Notes:

(1) Includes start-up costs.

(2) Fixed costs are included only for new units. Also includes purhase power capacity charges.

(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case	
Scenario: High Load and Energy Growth	
Joint Development	

Economic	
CPW Discount Rate:	8.0%
Capital Escalation Rate:	2 5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	171			2003.833	[redacted]	
WH 501F 2x1 (large)	630	267,633	24	2008.417	340,709	38,125
GE 7FA SC	156	68,615	12	2013.912	98,379	11,009
GE 7FA SC	156	68,615	12	2015.417	102,103	11,425
CFB PC	267	366,076	36	2018.417	606,660	67,885

Finance	
Fixed Charge Rate.	11.19%
Interest During Const.	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	142,244	20,321	751	0	163,316	0	163,316	295,505
2002	149,486	21,006	2,989	0	173,482	0	173,482	444,237
2003	150,010	22,627	11,728	(219)	184,146	2,303	186,448	592,246
2004	153,337	26,954	40,685	(882)	220,094	9,210	229,304	760,791
2005	155,720	28,626	39,805	(895)	223,256	9,210	232,466	919,004
2006	153,632	28,343	38,996	(908)	220,062	9,210	229,273	1,063,485
2007	172,635	30,453	35,261	(921)	237,427	9,210	246,638	1,207,396
2008	169,703	31,740	27,870	(935)	228,378	31,450	259,828	1,347,773
2009	179,708	33,280	29,507	(949)	241,545	47,336	288,881	1,492,285
2010	188,183	35,120	29,627	(964)	251,966	47,336	299,302	1,630,920
2011	195,446	36,907	29,750	(978)	261,126	47,336	308,461	1,763,213
2012	209,974	38,797	29,877	(993)	277,654	47,336	324,990	1,892,271
2013	221,903	41,417	26,065	(1,009)	288,376	48,253	336,629	2,016,049
2014	239,218	43,574	6,582	(1,025)	288,349	58,344	346,693	2,134,084
2015	252,507	46,095	7,426	(1,041)	304,988	65,009	369,997	2,250,723
2016	266,418	48,726	8,104	(1,058)	322,189	69,770	391,959	2,365,132
2017	287,726	50,844	8,307	(1,075)	345,801	69,770	415,571	2,477,448
2018	279,329	57,829	14,264	(1,093)	350,330	109,369	459,699	2,592,487
2019	284,771	62,813	18,779	(1,111)	365,252	137,655	502,907	2,709,017

Notes:

(1) Includes start-up costs.

(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.

(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case	
Scenario. Low Load and Energy Growth	
Self Build	

Economic	
CPW Discount Rate:	8.0%
Capital Escalation Rate:	2 5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self-Build	488			2003.833	251,663	28,161
GE 7FA SC	156	68,615	12	2008.417	85,896	9,612

Finance	
Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	139,882	20,189	751	0	160,822	0	160,822	293,196
2002	143,940	20,736	2,989	0	167,665	0	167,665	436,942
2003	142,628	22,206	4,430	0	169,264	7,040	176,304	576,898
2004	147,356	26,070	10,006	0	183,432	28,161	211,593	732,426
2005	149,764	27,309	8,568	0	185,641	28,161	213,802	877,935
2006	148,127	27,133	4,003	0	179,263	28,161	207,424	1,008,647
2007	151,825	28,174	3,424	0	183,423	28,161	211,585	1,132,105
2008	154,361	28,870	3,914	0	187,144	33,768	220,912	1,251,457
2009	167,869	30,246	4,011	0	202,127	37,773	239,899	1,371,467
2010	168,194	31,086	4,112	0	203,392	37,773	241,165	1,485,772
2011	172,166	32,323	4,215	0	208,703	37,773	246,476	1,588,882
2012	183,519	33,494	4,320	0	221,333	37,773	259,106	1,691,776
2013	190,701	35,247	4,428	0	230,376	37,773	268,149	1,790,374
2014	219,961	36,746	4,539	0	261,244	37,773	299,017	1,892,178
2015	211,723	38,011	4,652	0	254,386	37,773	292,159	1,984,278
2016	231,234	39,807	4,768	0	275,809	37,773	313,582	2,076,810
2017	223,657	40,744	4,888	0	269,288	37,773	307,061	2,158,799
2018	247,470	43,280	5,010	0	295,760	37,773	333,532	2,242,265
2019	252,503	43,917	5,135	0	301,555	37,773	339,328	2,320,891

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case
Scenario: Low Load and Energy Growth
Joint Development

Economic	
CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	171			2003.833	[redacted]	
GE 7FA SC	156	68,615	12	2007.417	83,801	9,377
WH 501F 2x1 (small)	514	258,481	24	2018.912	426,403	47,715

Finance	
Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	139,882	20,189	751	0	160,822	0	160,822	293,196
2002	143,940	20,736	2,989	0	167,665	0	167,665	436,942
2003	142,501	22,190	5,949	(219)	170,421	2,303	172,724	574,056
2004	145,194	25,933	34,710	(882)	204,955	9,210	214,166	731,474
2005	145,807	27,148	32,095	(895)	204,155	9,210	213,366	876,687
2006	142,133	26,833	26,423	(908)	194,481	9,210	203,692	1,005,047
2007	148,815	28,020	26,251	(921)	202,164	14,681	216,845	1,131,674
2008	152,046	28,650	26,693	(935)	206,454	18,588	225,042	1,253,157
2009	162,720	30,036	26,744	(949)	218,551	18,588	237,138	1,371,786
2010	165,872	30,905	26,795	(964)	222,608	18,588	241,196	1,483,506
2011	171,033	32,177	26,848	(978)	229,079	18,588	247,667	1,589,728
2012	181,861	33,203	26,901	(993)	240,972	18,588	259,560	1,692,801
2013	184,072	34,329	28,114	(1,009)	245,506	18,588	264,093	1,789,907
2014	210,726	35,743	33,940	(1,025)	279,383	18,588	297,971	1,891,355
2015	202,964	36,936	33,998	(1,041)	272,857	18,588	291,445	1,983,280
2016	222,714	38,840	34,057	(1,058)	294,553	18,588	313,141	2,074,693
2017	217,363	39,635	34,119	(1,075)	290,042	18,588	308,630	2,158,046
2018	237,723	42,228	29,683	(1,093)	308,543	22,564	331,107	2,240,905
2019	230,264	42,676	7,450	(1,111)	279,279	66,302	345,582	2,320,981

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

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Tables

KUA believes that Stanton 2 represents the minimal cost and performance risk to its customers due to the proven performance of the "F" class combined cycle technology. As demonstrated in this application, Stanton A has proven to be KUA's most cost-effective alternative through exhaustive evaluations as well as a thorough test of the marketplace.

1C.1.2 Summary

KUA historically has been one of the fastest growing utilities in the United States with a 5.7 percent annual growth rate in peak demand over the last 10 years. Rapid growth is projected to continue with a 3.7 percent annual growth rate in peak demand projected through the end of the 20 year planning period. The development of the proposed World Exposition Center (Expo Center) in KUA's service territory is projected to contribute significantly to KUA's load growth. KUA has incorporated estimates of the direct loads from the Expo Center into KUA's forecast. Indirect loads from the Expo Center are likely to be significant and currently are only considered in sensitivity projections.

KUA is currently using a 15 percent reserve margin for planning purposes. KUA has a supplemental resale contract with Florida Power Corporation which allows KUA to purchase the capacity necessary to maintain a 15 percent reserve margin with the Expo Center's loads. While this purchase has not been explicitly included in KUA's expansion plans, KUA can implement it, if necessary, as the Expo Center loads develop. In 2004, KUA's reserve margin is projected to be negative with and without the Expo Center requiring the addition of capacity.

KUA has evaluated numerous demand-side and supply-side alternatives to meet capacity requirements. The low cost of Stanton A precludes demand-side alternatives from being cost-effective. Stanton A was found to be the least-cost alternative under the base case and all but one sensitivity condition.

would avoid or defer the need for Stanton A. Table 1C.5-3 presents the FIRE model results of the DSM analysis.

Table 1C.5-3
FIRE Model Results

Program Description	Rate Impact Test	Participant's Test	Total Resource Cost Test
Residential			
BuildSmart - EPI Less Than 90 - New Construction	0.44	0.71	[redacted]
Commercial			
Off-Peak Battery Charging	0.37	0.04	[redacted]

The results of the DSM analysis are not surprising due to the previously performed analyses for similarly situated utilities. The failing cost-effectiveness of DSM has been exhibited in the Need for Power Dockets for KUA and FMPA for Cane Island Unit 3 (Docket No. 980802) and Lakeland Electric's conversion of McIntosh Unit 5 (Docket No. 990023), and in recent Demand-Side Management Ten Year Plans for OUC (Docket No. 990722-EG) and JEA (Docket No. 990720-EG).

The decrease in the cost-effectiveness of the DSM measures can be attributed to the decreased price of installing new generation, the higher efficiency of new generation, relatively low interest rates, and the general increase in the efficiency of appliances and dwellings.

1C.8.0 Sensitivity Analysis

KUA performed several sensitivity analyses to measure the impact of key assumptions on the least-cost plan. The sensitivity analyses are presented in Sections 1C.8.1 through 1C.8.7 and includes high and low fuel escalation as well as three additional fuel price scenarios. Two were based on the AEO fuel price projections. One uses the actual AEO projections and the other applies the AEO escalation rates to the actual 2000 OUC prices. Finally, a fuel price that assumes the actual OUC 2000 fuel prices remain constant in real terms is analyzed. High load and energy growth and low load and energy growth scenarios were also evaluated. For each sensitivity analysis, the two least-cost plans over the planning horizon are identified. The sensitivity analyses were performed over a 20 year planning horizon, similar to the base case economic evaluation, with a projection of annual costs and cumulative present worth costs.

1C.8.1 High Fuel Price Escalation

The high fuel price scenario applies an annual escalation rate that is 2.0 percentage points higher than that used for the base case forecast. The high fuel price forecast is provided in Table 1A.5-6. Table 1C.8-1 displays the results of the economic evaluation for the least-cost expansion plan for the high fuel price escalation sensitivity and Table 1C.8-2 presents the runner-up expansion plan. The plan including the self build alternative on a cumulative present worth basis over a 20 year planning horizon is only $170,000 lower than the plan with the joint development project.

1C.8.2 Low Fuel Price Escalation

The low fuel price scenario applies an annual growth rate that is 2.0 percentage points lower than that used for the base case forecast. The low fuel price forecast is provided in Table 1A.8-7. Table 1C.8-3 displays the results of the economic evaluation for the least-cost expansion plan for the low fuel price escalation sensitivity and Table 1C.8-4 presents the runner-up expansion plan. Comparing the two plans indicates the plan with the joint development project continues to be the lowest cost with a $0.8 million cumulative present worth savings over the self build plan.

1C.8.3 AEO Fuel Price Projections

This sensitivity analysis utilizes the fuel forecast provided by AEO as presented in Table 1A.5-10. The results of the economic evaluation for the least-cost expansion plan using the AEO fuel price forecast are shown in Tables 1C.8-5 and Table 1C.8-6 presents the runner-up expansion plan. Under this screen, the expansion plan with the joint development project is $1.8 million lower in cumulative present worth cost.

1C.8.4 OUC 2000 Fuel Costs with 2001 AEO Escalation

This sensitivity analysis is based on the 2001 AEO fuel price escalation rates being applied to OUC's actual 2000 fuel costs as presented in Table 1A.5-11. Table 1C.8-7 presents the results of the economic evaluation for the least cost expansion plan and Table 1C.8-8 presents the runner-up expansion plan. With these higher fuel prices, the plan with the joint development project shows a $467,000 savings over the plan with the self build project.

1C.8.5 Constant 2000 Fuel Price Projections

This sensitivity analysis utilizes the fuel forecast resulting from escalating OUC's average 2000 fuel prices at the general inflation rate as presented in Table 1A.5-8. The results of the economic evaluation for the least-cost expansion plan using the constant 2000 fuel price forecast are shown in Table 1C.8-9 and Table 1C.8-10 presents the runner-up expansion plan. Again, the plan with the joint development project represents the lowest cost by $2.9 million.

1C.8.6 High Load and Energy Growth

The high load and energy growth scenario provides insight into the effect of resource decisions made in an environment where load and energy growth is greater than the base case forecast. The high load and energy growth scenario requires the addition of more generation and therefore an increase in cumulative present worth for the least-cost capacity addition plan. The high load and energy growth scenario is based upon the high load and energy growth forecast presented in Section 1C.4. Table 1C.8-11 indicates the summer need for capacity based upon the high load and energy forecast.

As indicated in Table 1C.8-11, the high load and energy growth scenario results in a minimal 4 MW capacity shortfall in the summer of 2003 growing to a 53 MW shortfall in 2004. It has been assumed that KUA will purchase power on the spot market to make up the resultant deficit in 2003.

Table 1C.8-12 displays the results of the economic evaluation for the least-cost expansion plan for the high load and energy growth sensitivity and Table 1C.8-13 presents the runner-up expansion plan. Comparing the two plans indicates that the plan including the joint development project is $5.4 million lower in cost than the plan including self build alternative.

1C.8.7 Low Load and Energy Growth

The low load and energy growth scenario provides insight into the effect of resource decisions made in an environment where load and energy growth is less than the base case forecast. The low load and energy growth scenario requires less generation resources than the base case forecast. The low load and energy growth scenario is based upon the low load and energy growth forecast presented in Section 1C.4.0. Table 1C.8-14 indicates the summer need for capacity based upon the low load and energy forecast.

Capacity additions are not required for the low load and energy forecast, however, for evaluations the effect of adding the joint development project and the self build project are presented in Tables 1C.8-15 and 1C.8-16, respectively.

Table 1C.8-15 displays the results of the economic evaluation for the least-cost expansion plan for the low load and energy growth sensitivity and Table 1C.8-16 presents the runner-up expansion plan. Again, the plan with the joint development project is least cost by $6.0 million in cumulative present worth cost over the 20 year period.

1C.8.8 Sensitivity Analysis Summary

The plan with the Southern-Florida joint development project is the lowest cost in all but one of the sensitivity analyses. In several of these analyses, the extension of the PPA for an additional five years is part of the expansion plan. Since extension of the PPA must be done collectively, it may not be possible for KUA to obtain the five year extension. Costs would then increase for the plans with the joint development project. However, a more realistic comparison would be to compare a plan that does not include participation in any project at Stanton Energy Center. For that comparison there would be substantial savings associated with the Southern-Florida joint development project.

Table 1C.8-1
KUA High Fuel Price Escalation Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,163	72,163
2001		75,945	142,482
2002		58,330	192,491
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	55,134	236,258
2004		52,393	274,769
2005		53,463	311,155
2006		58,080	347,755
2007		64,441	385,356
2008	36 MW LM6000 Simple Cycle (06/08)	70,300	423,337
2009		77,383	462,047
2010		82,516	500,268
2011	36 MW LM6000 Simple Cycle (06/11)	92,858	540,093
2012		99,036	579,422
2013	36 MW LM6000 Simple Cycle (06/13)	107,486	618,944
2014		117,083	658,807
2015		125,664	698,421
2016	36 MW LM6000 Simple Cycle (06/16)	135,677	738,024
2017		147,901	777,997
2018	36 MW LM6000 Simple Cycle (06/18)	161,858	818,502
2019		174,712	858,985

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-2
KUA High Fuel Price Escalation Runner Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,163	72,163
2001		75,945	142,482
2002		58,330	192,491
2003	21 MW Joint Development with Southern–Florida (10/03)	55,251	236,351
	40 MW Southern-Florida Power Purchase (10/03)		
2004		50,776	273,673
2005		52,967	309,721
2006		58,544	346,614
2007		64,405	384,194
2008	78 MW 7FA Simple Cycle (06/08)	71,372	422,754
2009		78,956	462,252
2010		84,118	501,215
2011		94,251	541,637
2012		97,760	580,459
2013	Terminate 40 MW Southern–Florida Power Purchase (11/13)	105,300	619,177
	Extension of 40 MW Southern-Florida Power Purchase (11/13)		
2014	36 MW LM6000 Simple Cycle (06/14)	115,693	658,566
2015		126,525	698,452
2016	36 MW LM6000 Simple Cycle (06/16)	136,912	738,415
2017			
2018	36 MW LM6000 Simple Cycle (06/18)	148,923	778,665
	Terminate 40 MW Southern–Florida Power Purchase (11/18)	160,795	818,904
2019	36 MW LM6000 Simple Cycle (06/19)	173,713	859,155

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-3
KUA Low Fuel Price Escalation Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,163	72,163
2001		74,370	141,024
2002		54,486	187,737
2003	21 MW Joint Development with Southern–Florida (10/03)	50,186	227,576
	40 MW Southern-Florida Power Purchase (10/03)		
2004		44,908	260,585
2005		45,684	291,677
2006		49,457	322,843
2007		52,975	353,753
2008	78 MW 7FA Simple Cycle (06/08)	57,608	384,877
2009		62,455	416,120
2010		64,847	446,157
2011		70,494	476,391
2012		71,114	504,631
2013	Terminate 40 MW Southern–Florida Power Purchase (11/13)	74,479	532,017
	Extension of 40 MW Southern-Florida Power Purchase (11/13)		
2014	36 MW LM6000 Simple Cycle (06/14)	80,276	559,348
2015		86,031	586,468
2016	36 MW LM6000 Simple Cycle (06/16)	91,895	613,291
2017		97,631	639,678
2018	36 MW LM6000 Simple Cycle (06/18)	104,038	665,713
	Terminate 40 MW Southern–Florida Power Purchase (11/18)		
2019	36 MW LM6000 Simple Cycle (06/19)	111,040	691,443

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-4
KUA Low Fuel Price Escalation Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,163	72,163
2001		74,370	141,024
2002		54,486	187,737
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	50,050	227,467
2004		46,423	261,590
2005		46,092	292,960
2006		48,902	323,776
2007		52,675	354,512
2008	78 MW 7FA Simple Cycle (06/08)	57,488	385,571
2009		62,157	416,665
2010		64,692	446,630
2011		70,273	476,768
2012		70,967	504,950
2013		74,322	532,278
2014	36 MW LM6000 Simple Cycle (06/14)	79,835	559,459
2015		85,500	586,412
2016	36 MW LM6000 Simple Cycle (06/16)	91,341	613,074
2017		97,153	639,331
2018	78 MW 7FA Simple Cycle (06/18)	106,187	665,905
2019		113,472	692,198

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-5
AEO Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		48,822	48,822
2001		41,165	86,038
2002		37,509	119,096
2003	21 MW Joint Development with Southern–Florida (10/03)	43,272	153,447
	40 MW Southern-Florida Power Purchase (10/03)		
2004		44,535	186,181
2005		49,253	219,702
2006		53,733	253,563
2007		58,268	287,562
2008	78 MW 7FA Simple Cycle (06/08)	64,026	322,153
2009		70,247	357,294
2010		73,908	391,528
2011		81,160	426,336
2012		82,476	459,088
2013	Terminate 40 MW Southern–Florida Power Purchase (11/13)	87,174	491,142
	Extension of 40 MW Southern-Florida Power Purchase (11/13)		
2014	36 MW LM6000 Simple Cycle (06/14)	94,617	523,355
2015		101,482	555,347
2016	36 MW LM6000 Simple Cycle (06/16)	108,994	587,161
2017		116,826	618,735
2018	36 MW LM6000 Simple Cycle (06/18)	125,108	650,044
	Terminate 40 MW Southern–Florida Power Purchase (11/18)		
2019	36 MW LM6000 Simple Cycle (06/19)	134,249	681,151

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-6
KUA AEO Fuel Price Projection Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		48,822	48,822
2001		41,164	86,937
2002		37,509	119,095
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	43,138	153,339
2004		46,070	187,202
2005		49,704	221,029
2006		53,210	254,561
2007		57,990	288,397
2008	78 MW 7FA Simple Cycle (06/08)	63,931	322,937
2009		69,980	357,945
2010		73,760	392,110
2011		80,960	426,832
2012		82,367	459,541
2013		87,044	491,547
2014	36 MW LM6000 Simple Cycle (06/14)	94,244	523,633
2015		100,958	555,460
2016	36 MW LM6000 Simple Cycle (06/16)	108,452	587,116
2017		116,417	618,579
2018	78 MW 7FA Simple Cycle (06/18)	128,587	650,758
2019		138,921	682,948

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-7
OUC 2000 + 2001 AEO Escalation Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,957	72,957
2001		64,554	132,729
2002		60,498	184,596
2003	21 MW Joint Development with Southern–Florida (10/03)	69,202	239,531
	40 MW Southern-Florida Power Purchase (10/03)		
2004		72,519	292,835
2005		79,665	347,053
2006		86,359	401,474
2007		93,455	456,004
2008	112 MW Pulverized Coal (06/08)	100,551	510,329
2009		110,304	565,508
2010		114,492	618,540
2011		122,878	671,240
2012		125,171	720,947
2013	Terminate 40 MW Southern–Florida Power Purchase (11/13)	132,347	769,611
2014	Extension of 40 MW Southern-Florida Power Purchase (11/13)		
2015		140,199	817,343
2016		147,468	863,831
2017		156,121	909,402
2018	36 MW LM6000 Simple Cycle (06/17)	168,832	955,032
2019	Terminate 40 MW Southern–Florida Power Purchase (11/18)	181,750	1,000,514
	78 MW 7FA Simple Cycle (06/19)	196,997	1,046,161

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-8
OUC 2000 + 2001 AEO Escalation Fuel Price Projection Runner Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,957	72,957
2001		64,554	132,729
2002		60,498	184,596
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	69,234	239,556
2004		73,928	293,896
2005		80,072	348,391
2006		85,735	402,419
2007		93,268	456,840
2008	112 MW Pulverized Coal (06/08)	100,392	511,079
2009		109,962	566,087
2010		114,305	619,032
2011		122,635	671,628
2012		125,119	721,314
2013		132,074	769,878
2014		139,678	817,433
2015		147,109	863,808
2016	36 MW LM6000 Simple Cycle (06/16)	158,398	910,042
2017		170,625	956,157
2018		181,365	1,001,543
2019	36 MW LM6000 Simple Cycle (06/19)	194,570	1,046,628

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-9
OUC Constant 2000 Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,957	72,957
2001		62,899	131,197
2002		57,961	180,889
2003	21 MW Joint Development with Southern–Florida (10/03)	64,881	232,394
	40 MW Southern-Florida Power Purchase (10/03)		
2004		65,887	280,822
2005		71,296	329,345
2006		76,525	377,569
2007		82,100	425,474
2008	78 MW 7FA Simple Cycle (06/08)	88,299	473,179
2009		95,686	521,046
2010		99,875	567,307
2011		109,396	614,225
2012		110,759	658,209
2013	Terminate 40 MW Southern–Florida Power Purchase (11/13)	116,444	701,025
	Extension of 40 MW Southern-Florida Power Purchase (11/13)		
2014	36 MW LM6000 Simple Cycle (06/14)	124,728	743,490
2015		132,312	785,200
2016	36 MW LM6000 Simple Cycle (06/16)	139,525	825,927
2017		147,465	865,782
2018	36 MW LM6000 Simple Cycle (06/18)	154,721	904,501
	Terminate 40 MW Southern–Florida Power Purchase (11/18)		
2019	36 MW LM6000 Simple Cycle (06/19)	163,339	942,348

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-10
OUC Constant 2000 Fuel Price Projection Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,957	72,957
2001		62,898	131,196
2002		57,961	180,889
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	64,735	232,277
2004		67,382	281,805
2005		71,828	330,690
2006		76,052	378,616
2007		81,875	426,389
2008	78 MW 7FA Simple Cycle (06/08)	88,273	474,080
2009		95,446	521,827
2010		99,797	568,053
2011		109,258	614,911
2012		110,758	658,895
2013		116,399	701,695
2014	36 MW LM6000 Simple Cycle (06/14)	124,528	744,091
2015		131,855	785,658
2016	36 MW LM6000 Simple Cycle (06/16)	139,069	826,251
2017		147,135	866,017
2018	78 MW 7FA Simple Cycle (06/18)	159,363	905,897
2019		169,780	945,237

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-11
KUA Summer Reserve Requirements - High Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	247	0	0	176	108.1	284	37	37	0
2001	265	0	0	297	68.1	365	100	40	60
2002	292	0	0	297	68.1	365	73	44	29
2003	321	0	0	297	68.1	365	44	48	(4)
2004	346	0	0	297	48.1	345	0	53	(53)
2005	368	0	0	297	48.1	345	0	78	(78)
2006	391	0	0	297	48.1	345	0	105	(105)
2007	410	0	0	297	48.1	345	0	127	(127)
2008	431	0	0	297	48.1	345	0	151	(151)
2009	452	0	0	297	48.1	345	0	175	(175)
2010	474	0	0	297	48.1	345	0	200	(200)
2011	497	0	0	297	48.1	345	0	227	(227)
2012	520	0	0	297	48.1	345	0	253	(253)
2013	545	0	0	297	48.1	345	0	282	(282)
2014	571	0	0	297	48.1	345	0	312	(312)
2015	598	0	0	297	48.1	345	0	343	(343)
2016	625	0	0	297	48.1	345	0	374	(374)
2017	653	0	0	297	48.1	345	0	406	(406)
2018	682	0	0	297	48.1	345	0	439	(439)
2019	713	0	0	297	48.1	345	0	475	(475)

Table 1C.8-12
KUA High Load and Energy Growth Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		76,013	76,013
2001		80,875	150,897
2002		61,970	204,026
2003	21 MW Joint Development with Southern–Florida (10/03)	59,209	251,028
	40 MW Southern-Florida Power Purchase (10/03)		
2004	36 MW LM6000 Simple Cycle (06/04)	54,817	291,320
2005	78 MW 7FA Simple Cycle (06/05)	62,223	333,668
2006		70,369	378,012
2007		76,554	422,680
2008		81,721	466,832
2009	36 MW LM6000 Simple Cycle (06/09)	89,568	511,638
2010	36 MW LM6000 Simple Cycle (06/10)	98,818	557,410
2011		109,719	604,467
2012	36 MW LM6000 Simple Cycle (06/12)	116,344	650,668
2013	36 MW LM6000 Simple Cycle (06/13)	126,625	697,228
	Terminate 40 MW Southern–Florida Power Purchase (11/13)		
	Extension of 40 MW Southern-Florida Power Purchase (11/13)		
2014	78 MW 7FA Simple Cycle (06/14)	137,302	743,974
2015	36 MW LM6000 Simple Cycle (06/15)	149,361	791,059
2016	36 MW LM6000 Simple Cycle (06/16)	160,972	838,045
2017	36 MW LM6000 Simple Cycle (06/17)	172,454	884,654
2018	36 MW LM6000 Simple Cycle (06/18)	185,799	931,150
	Terminate 40 MW Southern–Florida Power Purchase (11/18)		
2019	78 MW 7FA Simple Cycle (06/19)	203,166	978,226

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-13 KUA High Load and Energy Growth Runner-Up Expansion Plan			
Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		76,013	76,013
2001		80,875	150,897
2002		61,970	204,026
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	59,114	250,953
2004	36 MW LM6000 Simple Cycle (06/04)	56,249	292,298
2005	78 MW 7FA Simple Cycle (06/05)	62,535	334,858
2006		69,686	378,772
2007		76,349	423,321
2008		81,604	467,409
2009	36 MW LM6000 Simple Cycle (06/09)	89,408	512,135
2010	36 MW LM6000 Simple Cycle (06/10)	98,585	557,799
2011		109,371	604,707
2012	36 MW LM6000 Simple Cycle (06/12)	115,988	650,767
2013	36 MW LM6000 Simple Cycle (06/13)	127,355	697,595
2014	78 MW 7FA Simple Cycle (06/14)	140,771	745,522
2015		152,841	793,704
2016	36 MW LM6000 Simple Cycle (06/16)	163,127	841,319
2017	36 MW LM6000 Simple Cycle (06/17)	175,725	888,812
2018	36 MW LM6000 Simple Cycle (06/18)	189,140	936,145
2019	36 MW LM6000 Simple Cycle (06/19)	204,936	983,631
Note: Capacity is stated at average annual temperature for KUA.			

Table 1C.8-14
KUA Summer Reserve Requirements - Low Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/(Deficit) to Maintain 15% Reserve Margin (MW)
2000	237	0	0	176	108.1	284	47	36	11
2001	238	0	0	297	68.1	365	127	36	91
2002	245	0	0	297	68.1	365	120	37	83
2003	252	0	0	297	68.1	365	113	38	75
2004	259	0	0	297	48.1	345	86	39	47
2005	263	0	0	297	48.1	345	82	39	42
2006	266	0	0	297	48.1	345	79	40	39
2007	267	0	0	297	48.1	345	78	40	38
2008	267	0	0	297	48.1	345	78	40	38
2009	268	0	0	297	48.1	345	77	40	36
2010	269	0	0	297	48.1	345	76	40	35
2011	268	0	0	297	48.1	345	77	40	36
2012	267	0	0	297	48.1	345	78	40	38
2013	266	0	0	297	48.1	345	79	40	39
2014	264	0	0	297	48.1	345	81	40	41
2015	263	0	0	297	48.1	345	82	39	42
2016	260	0	0	297	48.1	345	85	39	46
2017	257	0	0	297	48.1	345	88	39	49
2018	254	0	0	297	48.1	345	91	38	53
2019	251	0	0	297	48.1	345	94	38	56

Table 1C.8-15
KUA Low Load and Energy Growth Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		68,424	68,424
2001		67,713	131,121
2002		50,042	174,024
2003	21 MW Joint Development with Southern–Florida (10/03)	45,187	209,895
	40 MW Southern-Florida Power Purchase (10/03)		
2004		41,431	240,348
2005		42,026	268,950
2006		44,718	297,130
2007		46,696	324,377
2008		48,112	350,370
2009		49,486	375,125
2010		50,945	398,723
2011		53,364	421,610
2012		54,278	443,164
2013	Terminate 40 MW Southern–Florida Power Purchase (11/13)	54,739	463,292
2014		53,210	481,408
2015		54,930	498,724
2016		56,028	515,078
2017		57,482	530,613
2018		59,263	545,444
2019		60,249	559,404

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-16
KUA Low Load and Energy Growth Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		68,424	68,424
2001		67,713	131,121
2002		50,042	174,024
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	45,017	209,760
2004		42,677	241,129
2005		42,243	269,878
2006		43,900	297,542
2007		46,321	324,570
2008		47,659	350,319
2009		49,017	374,840
2010		50,479	398,221
2011		52,909	420,913
2012		53,934	442,331
2013		55,067	462,579
2014		56,657	481,868
2015		58,612	500,345
2016		60,030	517,867
2017		61,718	534,548
2018		63,238	550,373
2019		64,947	565,422

Note: Capacity is stated at average annual temperature for KUA.

Kissimmee Utility Authority Economic Evaluation

Case

Scenario: AEO Fuel Price Projections
Joint Development

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833	[redacted]	
Joint 7FA SC	70	36,939	12	2008.417	46,242	5,175
LM 6000	36	36,778	8	2014.417	53,095	5,941
LM 6000	36	36,778	8	2016.417	55,783	6,242
LM 6000	36	36,778	8	2018.417	58,607	6,558
LM 6000	36	36,778	8	2019.417	60,072	6,722

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	44,573	4,250	0	0	48,822	0	48,822	48,822
2001	37,176	3,989	0	0	41,166	0	41,165	86,938
2002	33,675	3,835	0	0	37,509	0	37,509	119,098
2003	37,961	4,226	807	(9)	42,984	288	43,272	153,447
2004	38,728	4,602	89	(35)	43,384	1,151	44,535	186,181
2005	41,899	4,931	1,306	(35)	48,102	1,151	49,253	219,702
2006	44,926	5,237	2,453	(35)	52,582	1,151	53,733	253,563
2007	48,383	5,557	3,212	(35)	57,117	1,151	58,268	287,582
2008	50,689	5,786	3,417	(34)	59,857	4,170	64,028	322,153
2009	54,294	6,089	3,572	(34)	63,921	6,326	70,247	357,294
2010	57,585	6,448	3,584	(34)	67,583	6,326	73,908	391,528
2011	64,501	6,771	3,596	(34)	74,834	6,326	81,160	426,336
2012	65,395	7,180	3,609	(34)	76,150	6,326	82,476	459,088
2013	69,622	7,577	3,684	(34)	80,848	6,326	87,174	491,142
2014	72,562	7,882	4,415	(34)	84,825	9,792	94,617	523,355
2015	76,148	8,366	4,736	(34)	89,215	12,267	101,482	556,347
2016	79,263	8,655	5,201	(34)	93,086	15,908	108,994	587,161
2017	83,707	9,086	5,557	(33)	98,317	18,509	116,826	616,735
2018	87,928	9,390	5,487	(33)	102,773	22,335	125,108	650,044
2019	92,471	9,352	3,471	(33)	105,260	28,989	134,249	681,151

Notes:

(1) Includes start-up costs.
(2) Fixed costs are included only for new units.
(3) Includes fees for site lease as well as credit for services and cooling water.

Kissimmee Utility Authority Economic Evaluation

Case	
Scenario: AEO Fuel Price Proje ti ns	
Self Build	

Economic	
CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	63			2003.833	31,458	3,520
Joint 7FA SC	78	36,939	12	2008 417	46,242	5,175
LM 6000	36	36,778	8	2014 412	53,089	5,941
LM 6000	36	36,778	8	2016.412	55,776	6,241
Joint 7FA SC	78	36,939	12	2018.412	59,187	6,623

Finance	
Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed [2] ($1,000)	Fees and Credits [3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	44,573	4,250	0	0	48,822	0	48,822	48,822
2001	37,175	3,989	0	0	41,164	0	41,164	86,937
2002	33,675	3,835	0	0	37,509	0	37,509	119,095
2003	37,941	4,223	82	13	42,258	880	43,138	163,339
2004	38,937	4,598	(1,037)	51	42,550	3,520	46,070	187,202
2005	42,141	4,936	(947)	53	46,183	3,520	49,704	221,029
2006	45,261	5,232	(857)	54	49,690	3,520	53,210	254,561
2007	48,499	5,557	358	55	54,470	3,520	57,990	288,397
2008	50,984	6,782	570	57	57,392	6,539	63,931	322,937
2009	54,410	6,087	730	58	61,285	8,695	69,980	357,945
2010	57,812	6,446	749	59	65,065	8,695	73,760	392,170
2011	64,664	6,773	767	61	72,265	8,695	80,960	426,832
2012	65,643	7,180	786	62	73,672	8,695	82,367	459,541
2013	69,900	7,580	806	64	78,349	8,695	87,044	491,547
2014	72,897	7,884	1,238	66	82,084	12,160	94,244	523,633
2015	76,324	8,365	1,567	67	86,323	14,635	100,958	555,460
2016	79,422	8,647	2,038	69	90,175	18,276	108,452	587,116
2017	83,990	9,078	2,402	71	95,540	20,877	116,417	618,579
2018	91,488	9,565	2,721	72	103,847	24,740	128,587	650,758
2019	98,320	10,050	2,977	74	111,421	27,500	138,921	682,848

Notes:

(1) Includes start-up costs.

(2) Fixed costs are included only for new units.

(3) Includes fees for site lease as well as credit for services and cooling water.

Kissimmee Utility Authority Economic Evaluation

Case	
Scenario: OUC 2000 + 2001 AEO Escalators	
Joint Development	

Economic	
CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833	[redacted]	
Coal	112	128,291	42	2008 417	167,486	18,742
LM 6000	36	36,778	8	2017.417	57,178	6,398
Joint 7FA SC	70	36,939	12	2019 417	60,674	6,789

Finance	
Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life.	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	68,740	4,217	0	0	72,957	0	72,957	72,957
2001	60,547	4,007	0	0	64,554	0	64,554	132,729
2002	56,662	3,836	0	0	60,498	0	60,498	184,586
2003	63,893	4,223	807	(9)	68,914	288	69,202	239,531
2004	66,711	4,603	89	(35)	71,368	1,151	72,519	292,836
2005	72,317	4,926	1,306	(35)	78,514	1,151	79,665	347,059
2006	77,550	5,238	2,453	(35)	85,207	1,151	86,359	401,474
2007	83,587	5,539	3,212	(35)	92,304	1,151	93,455	456,004
2008	77,958	6,200	4,343	(34)	88,467	12,084	100,651	510,929
2009	78,519	6,735	5,191	(34)	90,411	19,893	110,304	565,508
2010	82,251	7,138	5,244	(34)	94,599	19,893	114,492	618,540
2011	90,258	7,464	5,298	(34)	102,985	19,893	122,878	671,240
2012	92,064	7,895	5,353	(34)	105,278	19,893	125,171	720,947
2013	98,698	8,318	5,471	(34)	112,454	19,893	132,347	769,611
2014	105,803	8,702	5,835	(34)	120,306	19,893	140,199	817,343
2015	112,511	9,203	5,894	(34)	127,575	19,893	147,468	863,831
2016	120,612	9,694	5,956	(34)	136,228	19,893	156,121	909,402
2017	128,666	10,113	6,461	(33)	145,207	23,625	168,832	955,032
2018	138,584	10,628	6,280	(33)	155,459	26,291	181,750	1,000,514
2019	151,951	11,073	3,754	(33)	166,746	30,252	196,997	1,046,161

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units.
(3) Includes fees for site lease as well as credit for services and cooling water.

Kissimmee Utility Authority Economic Evaluation

Case	
Scenario. OUC 2000 + 2001 AEO Escalators	
Self Build	

Economic	
CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	63			2003.833	31,458	3,520
Joint 7FA SC	78	36,939	12	2008.417	46,242	5,175
LM 6000	36	36,778	8	2014.412	53,089	5,941
LM 6000	36	36,778	8	2016.412	55,776	6,241
Joint 7FA SC	78	36,939	12	2018.412	59,187	6,623

Finance	
Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	68,740	4,217	0	0	72,957	0	72,957	72,957
2001	60,547	4,007	0	0	64,554	0	64,554	132,729
2002	56,662	3,836	0	0	60,498	0	60,498	184,596
2003	64,040	4,220	82	13	68,354	880	69,234	239,556
2004	66,794	4,600	(1,037)	51	70,408	3,520	73,928	293,896
2005	72,521	4,925	(947)	53	76,552	3,520	80,072	348,391
2006	77,780	5,238	(857)	54	82,215	3,520	85,735	402,419
2007	83,795	5,540	358	55	89,748	3,520	93,268	456,840
2008	78,193	6,194	1,496	57	85,939	14,453	100,392	511,079
2009	78,559	6,734	2,350	58	87,700	22,262	109,962	566,087
2010	82,440	7,136	2,408	59	92,043	22,262	114,305	619,032
2011	90,383	7,461	2,469	61	100,373	22,262	122,635	671,628
2012	92,371	7,893	2,530	62	102,857	22,262	125,119	721,314
2013	98,838	8,316	2,593	64	109,812	22,262	132,074	769,878
2014	105,990	8,702	2,658	66	117,416	22,262	139,678	817,433
2015	112,853	9,202	2,725	67	124,847	22,262	147,109	863,808
2016	119,559	9,641	3,225	69	132,495	25,903	158,398	910,042
2017	128,339	10,093	3,619	71	142,121	28,504	170,625	956,157
2018	138,451	10,628	3,709	72	152,861	28,504	181,365	1,001,543
2019	146,677	11,126	4,268	74	162,145	32,425	194,570	1,046,628

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units.
(3) Includes fees for site lease as well as credit for services and cooling water

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Tables (Continued)

Figures

As discussed in the remainder of this application, FMPA has evaluated appropriate alternatives to Stanton A to determine if they are lower in cumulative present worth revenue requirements.

FMPA believes that Stanton A represents the minimal cost and performance risk to its members due to the proven performance of the "F" class combined cycle technology. As demonstrated in this application, Stanton A has proven to be FMPA's most cost-effective through exhaustive evaluations as well as a thorough test of the marketplace.

1D.1.2 Summary

FMPA's All-Requirements has been growing rapidly through the addition of new members, with Lake Worth projected to join in 2002. FMPA's peak demand is projected to grow at a 1.8 percent average annual rate from 2000 through the end of the planning period in 2019. The projected load growth assumes no new members will join after Lake Worth in 2002.

FMPA uses an 18 percent summer reserve margin and a 15 percent winter reserve margin as reliability criterion. FMPA's reserve margin is projected to drop to 14.1 percent during the summer of 2003, dictating the need to add capacity.

FMPA has evaluated numerous demand-side and supply-side alternatives to meet capacity requirements. The low cost of Stanton A precludes demand-side alternatives from being cost-effective. Stanton A was found to be the least-cost alternative under both base and all but two sensitivity analysis.

FMPA member cities within Peninsular Florida. Table 1D.2-2 provides a summary of the existing FMPA generating facilities with project capacities combined where appropriate.

1D.2.1.1 St. Lucie Project

On May 12, 1983, the Agency purchased from Florida Power & Light Company (FPL) an 8.806 percent undivided ownership interest in St. Lucie 2 (the St. Lucie Project), a nuclear generating unit with a summer Seasonal Net Capability of approximately 839 MW and a winter Seasonal Net Capability of approximately 853 MW. St. Lucie 2 was declared in commercial operation August 8, 1983, and in Firm Operation, as defined in the participation agreement, on August 14, 1983. Fifteen of the Agency's members are participants in the St. Lucie Project and nine of the fifteen (ten of the fifteen including the City of Lake Worth which is projected to become a member in 2002) are also members of the All-Requirements Project.

1D.2.1.2 Stanton Project

On August 13, 1984, the Agency purchased from Orlando Utilities Commission (OUC) a 14.8193 percent undivided ownership interest in Stanton 1. Stanton 1 is a pulverized coal unit that went into commercial operation July 1, 1987. Six of the Agency's members are participants in the Stanton Project and three of the six are also members of the All-Requirements Project.

1D.2.1.3 Tri-City Project

On March 22, 1985, the FMPA Board approved the agreements associated with the Tri-City Project. The Tri-City Project involves the purchase from OUC of an additional 5.3012 percent undivided ownership interest in Stanton 1. Three of the Agency's members are participants in the Tri-City Project and two of the three are also members of the All-Requirements Project.

1D.2.1.4 Stanton II Project

On June 6, 1991, the Agency, under the Stanton II Project, purchased from OUC a 23.2 percent undivided ownership interest in OUC's Stanton 2, a coal fired unit virtually identical to Stanton Unit 1. The unit commenced commercial operation in June 1996. Seven of the Agency's members are participants in the Stanton II Project and four of the seven are also members of the All-Requirements Project.

1D.3.0 Evaluation Criteria

1D.3.1 Economic Parameters

1D.3.1.1 Escalation Rates

The general inflation rate applied is assumed to be 2.5 percent. The escalation rate for capital cost and Operations and Maintenance (O&M) expenses is also assumed to be 2.5 percent.

1D.3.1.2 Bond Interest Rates

The long-term tax-exempt bond interest rate is assumed to be 6.0 percent. For smaller financing requirements, such as the Stanton A joint development project, FMPA can utilize the FMPA Pooled Loan Project, which has a 5.0 percent interest rate.

1D.3.1.3 Present Worth Discount Rate

The present worth discount rate is assumed to be equal to the 6.0 percent long-term bond interest rate.

1D.3.1.4 Interest During Construction

The interest during construction interest rate is assumed to be 6.0 percent.

1D.3.1.5 Levelized Fixed Charge Rate

FMPA plans to use the FMPA Pooled Loan Project for small financing requirements such as the equity portion of Stanton A. The fixed charge rate for the equity portion of Stanton A is merely the capital recovery factor over a 20 year period at the FMPA Pooled Loan Project interest rate of 5.0 percent plus one percent for insurance, resulting in a rate of 9.02 percent.

For larger financing requirements, FMPA issues tax-exempt bonds. The fixed charge rate for these larger requirements is 8.602 percent based on a bond term of 30 years with a 6.0 percent bond interest rate, 2.9 percent bond issuance fee, a 1 year debt service reserve fund earning interest at the 6.0 percent bond interest rate, and one percent for insurance.

1D.7.0 Economic Analysis

The economic analysis for the cost-effectiveness of the project consists of several evaluations to arrive at the least-cost supply plan to meet the growing needs of FMPA's customers. The methodology of the analyses, the expansion candidates evaluated, and the results of the base case evaluations are discussed in detail in this section.

A four phase economic analysis was conducted to determine FMPA's optimum capacity expansion plan. The four phases included supply-side evaluations, demand-side evaluations, proposal evaluations, and sensitivity analyses. The results of the supply-side analyses are included in this section and discussed in detail. The results of the demand-side evaluations were discussed in 1D.5.0. The sensitivity analyses are discussed in Section 1D.8.0. The proposal evaluations were discussed in Section 1A.5.0.

1D.7.1 Methodology

The supply-side evaluations of generating unit alternatives were performed using POWROPT, an optimal generation expansion model. Black & Veatch developed POWROPT as an alternative to other optimization programs. POWROPT has been benchmarked against other optimization programs and has proven to be an effective modeling program. The program operates on an hourly chronological basis and is used to determine a set of optimal capacity expansion plans, simulate the operation of each of these plans, and select the most desirable plan based on cumulative present worth revenue requirements. POWROPT evaluates all combinations of generating unit alternatives and purchase power options while maintaining user-defined reliability criteria. The reserve requirement utilized was a minimum reserve margin of 18 percent. All capacity expansion plans were analyzed over a twenty-year period from 2000 to 2019.

After the optimal generation expansion plan was selected using POWROPT, Black & Veatch's detailed chronological production costing program, POWRPRO was used to obtain the annual production cost for the expansion plan.

1D.7.2 Expansion Candidates

The expansion candidates for the POWROPT evaluation were discussed in Section 1A.7.0. Table 1D.7-1 Summarizes the expansion alternatives considered for FMPA in the optimization study for supply-side alternatives.

Table 1D.7-1
Summary of FMPA Generation Alternatives (2000 $, unless otherwise noted)

Description	Capital Costs	Capacity[1]	O&M Costs Variable	O&M Costs Fixed	Fuel Type	Full Load Heat Rate (HHV)[1]	Forced Outage Rate	Scheduled Maintenance	First Year Available
	$1,000	MW	$/MWh	$/kW-yr		Btu/kWh	percent	days/year	
Pulverized Coal (50%)	256,581	212.5	3.73	14.17	Coal	9,979	3.0	30	2005
501F 2x1 CC (50%) (standard)	129,594[2]	257	3.68[3]	6.32[3]	Nat. Gas	7,074	1.0	14	2005
501F 1x1 CC (50%)	73,984	125	2.49	4.66	Nat. Gas	10,841	2.86	15	2005
7FA SC	76,681	156	2.24	3.63	Nat. Gas	10,940	1.96	7	2005
7FA 2x1 CC (self-build)[4]	29,021[2]	61	[redacted]	[redacted]	Nat. Gas	[redacted]	4.0	[redacted]	2003[5]
7FA 2x1 CC (joint development)[4]	[redacted]	21	[redacted]	[redacted]	Nat. Gas	[redacted]	[redacted]	14	2003[5]

1. At 70 – 72° F, depending on the generation alternative (after degradation).
2. Mixed year dollars to reflect commercial operation date of October 1, 2003.
3. (2003 $)
4. Reflects FMPA's portion of total generation alternative capacity.
5. October 1, 2003.

1D.7.3 Results of Economic Analysis

The economic evaluation was first conducted for a base case scenario of the future, which assumed the base case load forecast, base case fuel price forecast, and planned reserve margins. The evaluations were based upon the cost and performance characteristics described in detail in Section 1A.7.0 and summarized in Table 1D.7-1. The expansion plan outlined in Table 1D.7-2 represents the least-cost capacity addition plan for FMPA under the base case scenario. The units comprising the least-cost capacity addition plan are listed in the table according to their year of commercial operation. Table 1D.7-3 displays the reserve margins for the base case after the construction of the generating resources identified.

Table 1D.7-4 provides the runner up to the least-cost expansion plan identified in Table 1D.7-2. Comparing the two plans indicates that the plan with the Southern-Florida joint development project is $38.7 million lower in cumulative present worth costs over the 20 year evaluation period.

Table 1D.7-2
FMPA Base Case Expansion Plan

Year	Expansion Plan	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,813	119,813
2001		147,836	259,281
2002		156,804	398,836
2003	21 MW Joint Development with Southern-Florida (10/03)	162,459	535,240
	40 MW Southern-Florida Power Purchase (10/03)		
2004		163,011	664,360
2005		169,962	791,366
2006	257 MW WH 501F 2x1 Combined Cycle (06/06)	176,667	915,909
2007		186,924	1,040,224
2008		199,823	1,165,595
2009	257 MW WH 501F 2x1 Combined Cycle (06/09)	214,675	1,292,661
2010		227,849	1,419,891
2011		237,135	1,544,811
2012		248,146	1,668,132
2013	Terminate 40 MW Southern-Florida Power Purchase (11/13)	260,548	1,790,287
2014	156 MW GE 7FA Simple Cycle (06/14)	274,706	1,911,789
2015		289,042	2,032,397
2016		301,313	2,151,007
2017		311,359	2,266,635
2018		325,154	2,380,551
2019		338,956	2,492,580

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.7-3
Projected Reliability Levels – Summer/Base Case with Expansion Plan Identified in Table 1D.7-2

Year	Net Generating Capacity (MW)	Net System Purchases (MW)	Net System Sales (MW)	Net System Capacity (MW)	System Peak Demand (MW)		Reserve Margin (MW)		Excess / (Deficit) to Maintain 18 % Reserve Margin (MW)	
					Before Interruptible & Load Management	After Interruptible & Load Management	Before Interruptible & Load Management	After Interruptible & Load Management	Before Interruptible & Load Management	After Interruptible & Load Management
2000	377.0	675.9	0.0	1,177.9	996.0	992.0	20.9	21.4	25.1	29.8
2001	497.0	620.9	0.0	1,202.9	1,024.4	1,020.2	19.0	19.5	9.4	14.4
2002	525.5	683.8	0.0	1,356.3	1,123.5	1,119.0	23.8	24.4	57.0	62.3
2003	525.5	622.8	0.0	1,283.3	1,145.7	1,141.0	13.6	14.1	(44.3)	(38.8)
2004	546.3	616.5	0.0	1,297.8	1,167.8	1,163.0	12.6	13.1	(55.9)	(50.3)
2005	646.3	594.5	0.0	1,400.8	1,189.0	1,184.0	20.6	21.2	26.5	32.4
2006	887.3	573.5	0.0	1,580.8	1,209.1	1,204.0	34.1	34.8	175.6	181.6
2007	887.3	551.5	0.0	1,558.8	1,228.2	1,223.0	29.8	30.4	131.1	137.2
2008	887.3	551.5	0.0	1,483.8	1,246.3	1,241.0	19.8	20.3	21.2	27.5
2009	1,128.3	551.5	0.0	1,724.8	1,273.3	1,268.0	36.8	37.3	230.4	236.6
2010	1,128.3	551.5	0.0	1,724.8	1,290.0	1,285.0	34.9	35.5	210.7	216.6
2011	1,128.3	451.5	0.0	1,579.8	1,306.0	1,301.0	21.0	21.4	38.7	44.6
2012	1,128.3	451.5	0.0	1,579.8	1,322.0	1,317.0	19.5	20.0	19.8	25.7
2013	1,128.3	451.5	0.0	1,579.8	1,336.0	1,331.0	18.2	18.7	3.3	9.2
2014	1,268.3	412.8	0.0	1,681.1	1,350.0	1,345.0	24.5	25.0	88.1	94.0
2015	1,268.3	412.8	0.0	1,681.1	1,363.0	1,358.0	23.3	23.8	72.8	78.7
2016	1,268.3	412.8	0.0	1,681.1	1,376.0	1,371.0	22.2	22.6	57.4	63.3
2017	1,268.3	412.8	0.0	1,681.1	1,387.0	1,382.0	21.2	21.6	44.5	50.4
2018	1,268.3	412.8	0.0	1,681.1	1,398.0	1,393.0	20.3	20.7	31.5	37.4
2019	1,268.3	412.8	0.0	1,681.1	1,408.0	1,403.0	19.4	19.8	19.7	25.6

Table 1D.7-4
FMPA Base Case Runner Up Expansion Plan

Year	Expansion Plan	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,813	119,813
2001		147,836	259,281
2002		156,804	398,836
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (61 MW)	162,497	535,272
2004		162,210	663,757
2005		169,264	790,241
2006	257 MW WH 501F 2x1 Combined Cycle (06/06)	175,990	914,307
2007		186,224	1,038,156
2008		199,187	1,163,128
2009	125 MW WH 501F 1x1 Combined Cycle (06/09)	214,367	1,290,012
2010		227,486	1,417,039
2011	125 MW WH 501F 1x1 Combined Cycle (06/11)	244,783	1,545,987
2012		266,257	1,678,309
2013	257 MW WH 501F 2x1 Combined Cycle (06/13)	272,869	1,806,241
2014		288,761	1,933,960
2015		297,482	2,058,089
2016		310,564	2,180,342
2017		320,421	2,299,334
2018		334,374	2,416,480
2019		347,209	2,531,237

Note: Capacity is stated at average annual temperature for FMPA.

1D.8.0 Sensitivity Analysis

FMPA performed several sensitivity analyses to measure the impact of key assumptions on the least-cost plan. The sensitivity analyses are presented in Sections 1D.8.1 through 1D.8.7 and includes high and low fuel escalation as well as three additional fuel price scenarios. Two were based on the AEO fuel price projections. One uses the actual AEO projections and the other applies the AEO escalation rates to the actual 2000 OUC prices. Finally, a fuel price that assumes the actual OUC 2000 fuel prices remain constant in real terms is analyzed. High load and energy growth and low load and energy growth scenarios were also evaluated. For each sensitivity analysis, the two least-cost plans over the planning horizon are identified. The sensitivity analyses were performed over a 20 year planning horizon, similar to the base case economic evaluation, with a projection of annual costs and cumulative present worth costs.

1D.8.1 High Fuel Price Escalation

The high fuel price scenario applies an annual escalation rate that is 2.0 percentage points higher than that used for the base case forecast. The high fuel price forecast is provided in Table 1A.5-6. Table 1D.8-1 displays the results of the economic evaluation for the least-cost expansion plan for the high fuel price escalation sensitivity and Table 1D.8-2 presents the runner-up expansion plan. The plan including joint development is $52.4 million lower than the plan with the self build alternative.

1D.8.2 Low Fuel Price Escalation

The low fuel price scenario applies an annual growth rate that is 2.0 percentage points lower than that used for the base case forecast. The low fuel price forecast is provided in Table 1A.8-7. Table 1D.8-3 displays the results of the economic evaluation for the least-cost expansion plan for the low fuel price escalation sensitivity and Table 1D.8-4 presents the runner-up expansion plan. Comparing the two plans indicates the plan with the joint development project continues to be the lowest cost with an $8.4 million cumulative present worth savings over the self build plan.

1D.8.3 AEO Fuel Price Projections

This sensitivity analysis utilizes the fuel forecast provided by AEO as presented in Table 1A.5-10. The results of the economic evaluation for the least-cost expansion plan using the AEO fuel price forecast are shown in Tables 1D.8-5 and Table 1D.8-6 presents the runner-up expansion plan. Under this scenario, the expansion plan with the joint development project is $45 million lower in cumulative present worth cost.

1D.8.4 OUC 2000 Fuel Costs with 2001 AEO Escalation

This sensitivity analysis is based on the 2001 AEO fuel price escalation rates being applied to OUC's actual 2000 fuel costs as presented in Table 1A.5-11. Table 1D.8-7 presents the results of the economic evaluation for the least cost expansion plan and Table 1D.8-8 presents the runner-up expansion plan. With these higher fuel prices, the plan with the joint development project shows a $75.7 million savings over the plan with the self build project.

1D.8.5 Constant 2000 Fuel Price Projections

This sensitivity analysis utilizes the fuel forecast resulting from escalating OUC's average 2000 fuel prices at the general inflation rate as presented in Table 1A.5-8. The results of the economic evaluation for the least-cost expansion plan using the constant 2000 fuel price forecast are shown in Table 1D.8-9 and Table 1D.8-10 presents the runner-up expansion plan. Again, the plan with the joint development project represents the lowest cost by $60.7 million.

1D.8.6 High Load and Energy Growth

The high load and energy growth scenario provides insight into the effect of resource decisions made in an environment where load and energy growth is greater than the base case forecast. The high load and energy growth scenario requires the addition of more generation and therefore an increase in cumulative present worth for the least-cost capacity addition plan. The high load and energy growth scenario is based upon the high load and energy growth forecast presented in Section 1D.4.0. Table 1D.8-11 indicates the summer need for capacity based upon the high load and energy forecast.

As indicated in Table 1D.8-11, the high load and energy growth scenario results in capacity shortfall beginning the summer of 2000. Since there are no capacity alternatives identified which can be placed in operation until Stanton A, it has been assumed that FMPA will purchase power on the spot market to make up the resultant deficits.

Table 1D.8-12 displays the results of the economic evaluation for the least-cost expansion plan for the high load and energy growth sensitivity and Table 1D.8-13 presents the runner-up expansion plan. Comparing the two plans indicates that the plan including the joint development project is slightly higher in cost ($3.711 million) than the plan including self build alternative.

1D.8.7 Low Load and Energy Growth

The low load and energy growth scenario provides insight into the effect of resource decisions made in an environment where load and energy growth is less than the base case forecast. The low load and energy growth scenario requires less generation resources than the base case forecast. The low load and energy growth scenario is based upon the low load and energy growth forecast presented in Section 1D.4.0. Table 1D.8-14 indicates the summer need for capacity based upon the low load and energy forecast.

Capacity additions are not required for the low load and energy forecast until 2006. Nevertheless, for evaluation purposes, Table 1D.8-15 displays the results of the economic evaluation for the least-cost expansion plan for the low load and energy growth sensitivity and Table 1D.8-16 presents the runner-up expansion plan with the joint development and self build projects installed for October 1, 2003 commercial operation. The plan with the joint development project is slightly higher in cumulative present worth cost ($1.17 million) over the 20 year period.

1D.8.8 Sensitivity Analysis Summary

The plan with the Southern-Florida joint development project is the lowest cost in all but two of the sensitivity analyses. However, it should be noted that for the sensitivity scenarios in which the self build alternative shows as the more cost-effective approach the margins are relatively small. These cumulative present worth savings do not even compare to those provided by participation in the joint development project with Southern-Florida for the remaining five sensitivity cases.

Table 1D.8-1
FMPA High Fuel Price Escalation Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,813	119,813
2001		148,660	260,058
2002		158,920	401,497
2003	21 MW Joint Development with Southern-Florida (10/03)	163,162	538,491
	40 MW Southern-Florida Power Purchase (10/03)		
2004		169,032	672,380
2005		179,688	806,653
2006	257 MW WH 501F 2x1 Combined Cycle (06/06)	188,731	939,701
2007		202,500	1,074,376
2008		224,015	1,214,926
2009	257 MW WH 501F 2x1 Combined Cycle (06/09)	239,447	1,356,654
2010		257,341	1,500,352
2011		274,357	1,644,879
2012		291,476	1,789,734
2013	Terminate 40 MW Southern-Florida Power Purchase (11/13)	311,077	1,935,580
2014	223 MW Pulverized Coal (06/14)	330,687	2,081,843
2015		352,962	2,229,121
2016		371,162	2,375,228
2017		386,758	2,518,856
2018		408,501	2,661,972
2019		428,619	2,803,636

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-2
FMPA High Fuel Price Escalation Runner Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,813	119,813
2001		148,660	260,058
2002		158,920	401,497
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	163,230	538,548
2004		168,247	671,815
2005		178,972	805,553
2006	257 MW WH 501F 2x1 Combined Cycle (06/06)	188,065	938,132
2007		201,832	1,072,361
2008		223,390	1,212,519
2009	125 MW WH 501F 1x1 Combined Cycle (06/09)	239,348	1,354,189
2010		256,709	1,497,534
2011	156 MW GE 7FA Simple Cycle (06/11)	285,583	1,647,976
2012		316,364	1,805,199
2013		325,395	1,957,757
2014		346,356	2,110,951
2015	223 MW Pulverized Coal (06/15)	360,946	2,261,561
2016		383,855	2,412,664
2017		400,768	2,561,495
2018		422,567	2,709,539
2019		443,282	2,856,050

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-3
FMPA Low Fuel Price Escalation Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,813	119,813
2001		146,984	258,477
2002		154,419	395,909
2003	21 MW Joint Development with Southern-Florida (10/03)	154,827	525,905
	40 MW Southern-Florida Power Purchase (10/03)		
2004		157,104	650,346
2005		160,968	770,631
2006	257 MW WH 501F 2x1 Combined Cycle (06/06)	165,185	887,080
2007		172,529	1,001,822
2008		181,576	1,115,745
2009	257 MW WH 501F 2x1 Combined Cycle (06/09)	192,980	1,229,970
2010		203,000	1,343,324
2011		206,796	1,452,261
2012		213,425	1,558,327
2013	Terminate 40 MW Southern-Florida Power Purchase (11/13)	219,715	1,661,338
2014	125 MW WH 501F 1x1 Combined Cycle (06/14)	229,638	1,762,907
2015		238,172	1,862,288
2016		245,122	1,958,779
2017		249,724	2,051,518
2018		257,401	2,141,697
2019	125 MW WH 501F 1x1 Combined Cycle	270,289	2,231,031

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-4
FMPA Low Fuel Price Escalation Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,813	119,813
2001		146,984	258,477
2002		154,419	395,909
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	154,868	525,940
2004		156,320	649,760
2005		163,110	771,645
2006	257 MW WH 501F 2x1 Combined Cycle (06/06)	164,503	887,613
2007		171,834	1,001,893
2008		180,912	1,115,399
2009	125 MW WH 501F 1x1 Combined Cycle (06/09)	192,366	1,229,260
2010		201,641	1,341,856
2011	125 MW WH 501F 1x1 Combined Cycle (06/11)	212,068	1,453,570
2012		227,536	1,566,649
2013	257 MW WH 501F 2x1 Combined Cycle (06/13)	227,505	1,673,312
2014		233,718	1,776,686
2015		237,878	1,875,944
2016		244,188	1,972,068
2017		248,022	2,064,174
2018		254,827	2,153,451
2019		260,008	2,239,387

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-5
AEO Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		105,189	105,189
2001		117,096	215,657
2002		131,554	332,739
2003	21 MW Joint Development with Southern-Florida (10/03)	141,534	451,574
	40 MW Southern-Florida Power Purchase (10/03)		
2004		152,985	572,752
2005		162,639	694,286
2006	223 MW Pulverized Coal (06/06)	167,911	812,656
2007		176,666	930,149
2008		190,593	1,049,730
2009	257 MW WH 501F 2x1 Combined Cycle (06/09)	203,398	1,170,121
2010		213,640	1,289,416
2011		221,962	1,406,343
2012		230,575	1,520,932
2013	Terminate 40 MW Southern-Florida Power Purchase (11/13)	238,134	1,632,579
2014	257 MW WH 501F 2x1 Combined Cycle (06/14)	252,457	1,744,241
2015		264,925	1,854,785
2016		274,341	1,962,778
2017		281,747	2,067,409
2018		292,775	2,169,981
2019		303,548	2,270,308

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-6
FMPA AEO Fuel Price Projection Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		105,189	105,189
2001		117,096	215,657
2002		131,554	332,739
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	141,572	451,606
2004		152,208	572,168
2005		161,957	693,192
2006	223 MW Pulverized Coal (06/06)	167,225	811,079
2007		175,966	928,106
2008		190,048	1,047,345
2009	125 MW WH 501F 1x1 Combined Cycle (06/09)	204,022	1,168,105
2010		214,226	1,287,728
2011	125 MW WH 501F 1x1 Combined Cycle (06/11)	232,341	1,410,122
2012		251,177	1,534,950
2013	257 MW WH 501F 2x1 Combined Cycle (06/13)	254,015	1,654,042
2014		266,475	1,771,904
2015		272,762	1,885,718
2016		283,254	1,997,220
2017		291,485	2,105,467
2018		302,823	2,211,559
2019		314,010	2,315,344

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-7
OUC 2000 + 2001 AEO Escalation Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,731	119,731
2001		140,103	251,903
2002		157,841	392,381
2003	21 MW Joint Development with Southern-Florida (10/03)	172,324	537,068
	40 MW Southern-Florida Power Purchase (10/03)		
2004		190,802	688,201
2005		218,431	851,426
2006	223 MW Pulverized Coal (06/06)	212,677	1,001,354
2007		220,451	1,147,966
2008		248,207	1,303,694
2009	257 MW WH 501F 2x1 Combined Cycle (06/09)	265,350	1,460,755
2010		279,944	1,617,074
2011		311,381	1,781,105
2012		326,130	1,943,182
2013	Terminate 40 MW Southern-Florida Power Purchase (11/13)	339,036	2,102,135
2014	257 MW WH 501F 2x1 Combined Cycle (06/14)	357,715	2,260,353
2015		373,682	2,416,277
2016		389,927	2,569,771
2017		401,874	2,719,012
2018		420,993	2,866,505
2019		439,636	3,011,810

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-8
OUC 2000 + 2001 AEO Escalation Fuel Price Projection Runner Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,731	119,731
2001		140,103	251,903
2002		157,841	392,381
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	172,381	537,116
2004		190,249	687,811
2005		217,770	850,541
2006	223 MW Pulverized Coal (06/06)	212,320	1,000,219
2007		220,032	1,146,552
2008		247,858	1,302,062
2009	125 MW WH 501F 1x1 Combined Cycle (06/09)	268,438	1,460,950
2010		284,035	1,619,554
2011	125 MW WH 501F 1x1 Combined Cycle (06/11)	332,485	1,794,703
2012		362,590	1,974,899
2013	257 MW WH 501F 2x1 Combined Cycle (06/13)	359,154	2,143,284
2014		375,277	2,309,269
2015		385,421	2,470,092
2016		403,718	2,629,014
2017		416,866	2,783,824
2018		436,195	2,936,642
2019		456,319	3,087,461

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-9
OUC Constant 2000 Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,731	119,731
2001		139,717	251,540
2002		156,909	391,188
2003	21 MW Joint Development with Southern-Florida (10/03)	170,102	534,009
	40 MW Southern-Florida Power Purchase (10/03)		
2004		185,622	681,039
2005		203,276	832,938
2006	223 MW Pulverized Coal (06/06)	206,585	978,573
2007		216,782	1,122,745
2008		239,531	1,273,030
2009	257 MW WH 501F 2x1 Combined Cycle (06/09)	255,315	1,424,150
2010		268,759	1,574,224
2011		288,040	1,725,960
2012		299,817	1,874,960
2013	Terminate 40 MW Southern-Florida Power Purchase (11/13)	309,557	2,020,092
2014	257 MW WH 501F 2x1 Combined Cycle (06/14)	325,236	2,163,944
2015		338,967	2,305,383
2016		349,912	2,443,125
2017		356,902	2,575,665
2018		369,133	2,704,989
2019		380,574	2,830,773

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-10
OUC Constant 2000 Fuel Price Projection Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,731	119,731
2001		139,717	251,540
2002		156,909	391,188
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	170,213	534,102
2004		185,052	680,680
2005		202,682	832,136
2006	223 MW Pulverized Coal (06/06)	206,152	977,465
2007		216,288	1,121,309
2008		239,135	1,271,345
2009	125 MW WH 501F 1x1 Combined Cycle (06/09)	257,042	1,423,488
2010		270,816	1,574,710
2011	125 MW WH 501F 1x1 Combined Cycle (06/11)	304,360	1,735,043
2012		328,714	1,898,404
2013	257 MW WH 501F 2x1 Combined Cycle (06/13)	327,786	2,052,083
2014		341,125	2,202,963
2015		348,776	2,348,495
2016		361,007	2,490,604
2017		369,657	2,627,881
2018		381,413	2,761,507
2019		393,338	2,891,510

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-11
FMPA Summer Reserve Requirements - High Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/(Deficit) to Maintain 18% Reserve Margin (MW)
2000	1,049.0	0	0	377.0	800.9	1,177.9	151	189	(37.4)
2001	1,098.1	0	0	497.0	705.9	1,202.9	120	198	(77.6)
2002	1,226.0	0	0	525.5	830.8	1,356.3	157	221	(63.9)
2003	1,271.0	0	0	525.5	757.8	1,283.3	37	229	(192.2)
2004	1,316.0	0	0	525.5	712.8	1,238.3	0	237	(290.3)
2005	1,357.0	0	0	625.5	715.8	1,341.3	13	244	(231.2)
2006	1,397.0	0	0	625.5	654.8	1,280.3	0	251	(346.6)
2007	1,435.0	0	0	625.5	632.8	1,258.3	0	258	(413.4)
2008	1,471.0	0	0	625.5	557.8	1,183.3	0	265	(544.4)
2009	1,515.0	0	0	625.5	557.8	1,183.3	0	273	(596.3)
2010	1,548.0	0	0	625.5	557.8	1,183.3	0	279	(635.2)
2011	1,581.0	0	0	625.5	412.8	1,038.3	0	285	(827.3)
2012	1,611.0	0	0	625.5	412.8	1,038.3	0	290	(862.7)
2013	1,640.0	0	0	625.5	412.8	1,038.3	0	295	(896.9)
2014	1,668.0	0	0	625.5	412.8	1,038.3	0	300	(929.9)
2015	1,694.0	0	0	625.5	412.8	1,038.3	0	305	(960.6)
2016	1,719.0	0	0	625.5	412.8	1,038.3	0	309	(990.1)
2017	1,742.0	0	0	625.5	412.8	1,038.3	0	314	(1,017.3)
2018	1,764.0	0	0	625.5	412.8	1,038.3	0	318	(1,043.2)
2019	1,784.0	0	0	625.5	412.8	1,038.3	0	321	(1,066.8)

Table 1D.8-12
FMPA High Load and Energy Growth Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		130,844	130,844
2001		163,269	284,[illegible]
2002		176,044	441,550
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	184,415	596,388
2004		191,718	748,247
2005	257 MW WH 501F 2x1 Combined Cycle (06/05)	194,543	893,621
2006	257 MW WH 501F 2x1 Combined Cycle (06/06)	209,974	1,041,644
2007		226,571	1,192,327
2008	257 MW WH 501F 2x1 Combined Cycle (06/08)	248,273	1,348,096
2009		268,295	1,506,900
2010		281,619	1,664,154
2011	223 MW Pulverized Coal (06/11)	305,973	1,825,337
2012		332,430	1,990,545
2013		342,363	2,151,058
2014		356,581	2,308,774
2015		370,256	2,463,269
2016		386,211	2,615,300
2017	125 MW WH 501F 1x1 Combined Cycle (06/17)	405,219	2,765,783
2018		428,557	2,915,926
2019		442,826	3,062,285

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-13
FMPA High Load and Energy Growth Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
20000		130,844	130,844
2001		163,269	284,871
2002		176,044	441,550
2003	21 MW Joint Development with Southern-Florida (10/03)	184,356	596,339
	40 MW Southern-Florida Power Purchase (10/03)		
2004		192,367	748,711
2005	257 MW WH 501F 2x1 Combined Cycle (06/05)	195,230	894,598
2006	257 MW WH 501F 2x1 Combined Cycle (06/06)	210,580	1,043,048
2007		227,306	1,194,220
2008	156 MW GE 7FA Simple Cycle (06/08)	247,749	1,349,661
2009		266,457	1,507,376
2010		280,141	1,663,805
2011	223 MW Pulverized Coal (06/11)	302,943	1,823,392
2012		326,578	1,985,691
2013	Terminate 40 MW Southern-Florida Power Purchase (11/13)	337,603	2,143,973
2014	257 MW WH 501F 2x1 Combined Cycle (06/14)	358,148	2,302,382
2015		378,403	2,460,276
2016		395,097	2,615,805
2017		406,606	2,766,804
2018		438,050	2,920,272
2019		440,903	3,065,996

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-14
FMPA Summer Reserve Requirements - Low Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 18% Reserve Margin (MW)
2000	943.0	0	0	377.0	800.9	1,177.9	257.4	170	87.7
2001	959.6	0	0	497.0	705.9	1,202.9	258.6	173	85.9
2002	1,043.0	0	0	525.5	830.8	1,356.3	339.8	188	152.0
2003	1,055.0	0	0	525.5	757.8	1,283.3	252.6	190	62.7
2004	1,066.0	0	0	525.5	712.8	1,238.3	196.6	192	4.7
2005	1,076.0	0	0	625.5	715.8	1,341.3	294.1	194	100.4
2006	1,086.0	0	0	625.5	654.8	1,280.3	215.9	195	20.4
2007	1,095.0	0	0	625.5	632.8	1,258.3	184.9	197	(12.2)
2008	1,104.0	0	0	625.5	557.8	1,183.3	87.4	199	(111.3)
2009	1,122.0	0	0	625.5	557.8	1,183.3	69.4	202	(132.6)
2010	1,131.0	0	0	625.5	557.8	1,183.3	60.4	204	(143.2)
2011	1,139.0	0	0	625.5	412.8	1,038.3	0	205	(305.7)
2012	1,146.0	0	0	625.5	412.8	1,038.3	0	206	(314.0)
2013	1,154.0	0	0	625.5	412.8	1,038.3	0	208	(323.4)
2014	1,160.0	0	0	625.5	412.8	1,038.3	0	209	(330.5)
2015	1,167.0	0	0	625.5	412.8	1,038.3	0	210	(338.8)
2016	1,173.0	0	0	625.5	412.8	1,038.3	0	211	(345.8)
2017	1,179.0	0	0	625.5	412.8	1,038.3	0	212	(352.9)
2018	1,184.0	0	0	625.5	412.8	1,038.3	0	213	(358.8)
2019	1,189.0	0	0	625.5	412.8	1,038.3	0	214	(364.7)

Table 1D.8-15
FMPA Low Load and Energy Growth Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		108,436	108,436
2001		133,277	234,169
2002		140,565	359,272
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	141,860	478,380
2004		143,832	592,308
2005		145,491	701,028
2006		152,205	808,326
2007		160,806	915,271
2008	257 MW WH 501F 2x1 Combined Cycle (06/08)	172,067	1,023,229
2009		181,598	1,130,717
2010		188,277	1,235,850
2011	223 MW Pulverized Coal (06/11)	205,232	1,343,963
2012		221,209	1,453,897
2013		226,240	1,559,968
2014		233,441	1,663,219
2015		239,015	1,762,951
2016		247,548	1,860,398
2017		252,705	1,954,243
2018		261,927	2,046,008
2019		269,491	2,135,078

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-16
FMPA Low Load and Energy Growth Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		108,436	108,436
2001		133,277	234,169
2002		140,565	359,272
2003	21 MW Joint Development with Southern-Florida (10/03)	141,784	478,317
	40 MW Southern-Florida Power Purchase (10/03)		
2004		144,643	592,887
2005		146,196	702,133
2006		152,897	809,920
2007		161,523	917,342
2008	257 MW WH 501F 2x1 Combined Cycle (06/08)	172,734	1,025,717
2009		182,252	1,133,592
2010		188,968	1,239,110
2011	223 MW Pulverized Coal (06/11)	205,771	1,347,508
2012		221,702	1,457,687
2013	Terminate 40 MW Southern-Florida Power Purchase (11/13)	226,326	1,563,797
2014		232,028	1,666,423
2015		238,207	1,765,819
2016		246,184	1,862,728
2017		251,522	1,956,134
2018		260,800	2,047,504
2019		268,514	2,136,251

Note: Capacity is stated at average annual temperature for FMPA.

Florida Municipal Power Agency Economic Evaluation

Case	
Scenario: Base Case	
Joint Development	

Economic	
CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833	[redacted]	
WH 501F 2x1	257	129,241	24	2006.417	156,602	13,471
WH 501F 2x1	257	129,241	24	2009.417	168,643	14,507
GE 7FA SC	156	76,681	12	2014.417	111,323	9,576

Finance	
Fixed Charge Rate:	*8.60%
Interest During Const :	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	114,059	5,754	0	0	119,813	0	119,813	119,813
2001	137,753	10,083	0	0	147,836	0	147,836	259,281
2002	144,902	11,902	0	0	156,804	0	156,804	398,836
2003	148,809	12,641	807	(30)	162,227	232	162,459	535,240
2004	145,329	13,671	3,203	(119)	162,083	928	163,011	664,360
2005	149,502	16,446	3,205	(119)	169,034	928	169,962	791,366
2006	146,399	17,368	4,234	(120)	167,881	8,786	176,667	916,909
2007	148,696	18,945	5,004	(120)	172,525	14,399	186,924	1,040,224
2008	158,609	21,685	5,052	(121)	185,424	14,399	199,823	1,165,595
2009	162,951	22,780	6,205	(122)	191,814	22,861	214,675	1,292,861
2010	168,130	23,855	7,081	(122)	198,943	28,906	227,849	1,419,891
2011	175,742	25,429	7,181	(123)	208,230	28,906	237,136	1,544,611
2012	185,638	26,443	7,284	(123)	219,241	28,906	248,146	1,668,132
2013	197,417	27,476	6,873	(124)	231,642	28,906	260,548	1,790,287
2014	207,288	28,172	4,879	(124)	240,214	34,492	274,706	1,911,769
2015	216,297	29,047	5,341	(125)	250,561	38,482	289,042	2,032,397
2016	227,168	30,315	5,474	(126)	262,832	38,482	301,313	2,151,007
2017	236,256	31,186	5,611	(126)	272,877	38,482	311,359	2,266,635
2018	248,772	32,278	5,752	(127)	286,673	38,482	325,154	2,380,551
2019	261,385	33,322	5,895	(128)	300,475	38,482	338,956	2,492,580

Notes:

* FMPA assumed to finance the Southern-Florida project at a 9.02 percent rate

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water

Florida Municipal Power Agency Economic Evaluation

Case	
Scenario	Base Case
Self Build	

Economic	
CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	61			2003.833	31,458	2,706
WH 501F 2x1	257	129,241	24	2006.417	156,602	13,471
WH 501F 1x1	125	73,984	23	2009.417	96,404	8,293
WH 501F 1x1	125	73,984	23	2011.417	101,285	8,713
WH 501F 2x1	257	129,241	24	2013.417	186,150	16,013

Finance	
Fixed Charge Rate:	8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	114,059	5,754	0	0	119,813	0	119,813	119,813
2001	137,753	10,083	0	0	147,836	0	147,836	259,281
2002	144,902	11,902	0	0	156,804	0	156,804	398,836
2003	148,842	12,641	325	13	161,820	677	162,497	535,272
2004	145,468	13,652	333	51	159,503	2,706	162,210	663,757
2005	149,726	16,440	341	53	166,558	2,706	169,264	790,241
2006	146,627	17,370	1,375	54	165,426	10,564	175,990	914,307
2007	148,897	18,944	2,151	55	170,047	16,177	186,224	1,036,156
2008	159,063	21,686	2,204	57	183,010	16,177	199,187	1,163,126
2009	168,411	22,197	2,687	58	193,353	21,014	214,367	1,290,012
2010	176,758	23,136	3,063	59	203,018	24,470	227,488	1,417,039
2011	187,591	23,991	3,588	61	215,231	29,552	244,783	1,545,987
2012	204,029	24,982	4,003	62	233,075	33,182	266,257	1,678,309
2013	198,239	26,722	5,321	64	230,347	42,523	272,869	1,806,241
2014	205,149	28,017	6,336	66	239,567	49,195	288,761	1,933,960
2015	212,701	29,025	6,494	67	248,288	49,195	297,482	2,058,089
2016	224,413	30,230	6,656	69	261,369	49,195	310,564	2,180,342
2017	233,417	30,916	6,823	71	271,226	49,195	320,421	2,299,334
2018	245,935	32,179	6,993	72	285,179	49,195	334,374	2,415,460
2019	257,786	32,986	7,168	74	298,014	49,195	347,209	2,531,237

Notes:

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency Economic Evaluation

Case

Scenario: High Fuel Price Projections
Joint Development

Economic

CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833	[redacted]	
WH 501F 2x1	257	129,241	24	2006.417	156,602	13,471
WH 501F 2x1	257	129,241	24	2009 417	168,643	14,507
Pulverized Coal	223	256,581	42	2014.417	388,463	33,416

Finance

Fixed Charge Rate:	*8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	114,059	5,754	0	0	119,813	0	119,813	119,813
2001	138,595	10,065	0	0	148,660	0	148,660	260,[illegible]
2002	147,028	11,892	0	0	158,920	0	158,920	401,497
2003	149,678	12,475	807	(30)	162,930	232	163,162	538,491
2004	151,486	13,534	3,203	(119)	168,104	928	169,032	672,380
2005	159,377	16,297	3,205	(119)	178,760	928	179,688	806,653
2006	158,565	17,267	4,234	(120)	179,946	8,786	188,731	939,701
2007	164,361	18,857	5,004	(120)	188,101	14,399	202,500	1,074,376
2008	182,854	21,832	5,052	(121)	209,616	14,399	224,015	1,214,926
2009	187,528	22,974	6,205	(122)	216,586	22,861	239,447	1,356,564
2010	197,491	23,986	7,081	(122)	228,436	28,906	257,341	1,500,852
2011	212,378	26,015	7,181	(123)	245,451	28,906	274,357	1,644,679
2012	228,370	27,041	7,284	(123)	262,571	28,906	291,478	1,789,734
2013	247,319	28,104	6,873	(124)	282,172	28,906	311,077	1,985,580
2014	245,522	29,747	7,145	(124)	282,289	48,398	330,687	2,081,843
2015	250,316	31,148	9,302	(125)	290,641	62,321	352,962	2,229,121
2016	266,969	32,463	9,534	(126)	308,841	62,321	371,162	2,375,228
2017	281,463	33,328	9,773	(126)	324,437	62,321	386,758	2,518,856
2018	301,777	34,512	10,017	(127)	346,180	62,321	408,501	2,661,972
2019	320,536	35,622	10,268	(128)	366,298	62,321	428,619	2,803,636

Notes
* FMPA assumed to finance the Southern-Florida project at a 9.02 percent rate.
[1] Includes start-up costs.
[2] Fixed costs are included only for new units.
[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency Economic Evaluation

Case	
Scenario: High Fuel Price Projections Self Build	

CPW Discount Rate:	6.0%
Capital Escalation Rate	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	61			2003.833	31,458	2,706
WH 501F 2x1	257	129,241	24	2006.417	156,602	13,471
WH 501F 1x1	125	73,984	23	2009.417	96,404	8,293
GE 7FA SC	156	76,681	12	2011.417	103,374	8,892
Pulverized Coal	223	256,581	42	2015.417	398,174	34,251

Finance	
Fixed Charge Rate:	8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed [2] ($1,000)	Fees and Credits [3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	114,059	5,754	0	0	119,813	0	119,813	119,813
2001	138,595	10,065	0	0	148,660	0	148,660	260,058
2002	147,028	11,892	0	0	158,920	0	158,920	401,497
2003	149,744	12,473	325	13	162,554	677	163,230	538,648
2004	151,631	13,526	333	51	165,541	2,706	168,247	671,616
2005	159,586	16,286	341	53	176,266	2,706	178,972	805,553
2006	158,796	17,277	1,375	54	177,501	10,564	188,065	938,132
2007	164,578	18,871	2,151	55	185,655	16,177	201,832	1,072,361
2008	183,122	21,830	2,204	57	207,213	16,177	223,390	1,212,519
2009	193,212	22,377	2,687	58	218,334	21,014	239,348	1,354,189
2010	205,672	23,446	3,063	59	232,240	24,470	256,709	1,497,534
2011	227,762	24,529	3,575	61	255,927	29,657	285,583	1,647,976
2012	253,513	25,447	3,980	62	283,003	33,362	316,364	1,805,199
2013	261,578	26,312	4,079	64	292,033	33,362	325,395	1,957,767
2014	281,542	27,206	4,181	66	312,994	33,362	346,356	2,110,951
2015	270,881	29,567	7,090	67	307,605	53,342	360,946	2,261,561
2016	275,363	31,516	9,294	69	316,243	67,613	383,855	2,412,664
2017	291,202	32,356	9,527	71	333,156	67,613	400,768	2,561,495
2018	311,618	33,499	9,765	72	354,954	67,613	422,567	2,709,539
2019	331,041	34,545	10,009	74	375,670	67,613	443,282	2,856,050

Notes:

[1] Includes start-up costs.

[2] Fixed costs are included only for new units

[3] Includes fees for site lease as well as credit for services and cooling wate..

Florida Municipal Power Agency Economic Evaluation

Case	
Scenario: Low Fuel Price Projections	
Joint Development	

Economic	
CPW Discount Rate:	6 0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833	[redacted]	
WH 501F 2x1	257	129,241	24	2006.417	156,602	13,471
WH 501F 2x1	257	129,241	24	2009 417	168,643	14,507
WH 501F 1x1	125	73,984	23	2014.417	109,072	9,382
WH 501F 1x1	125	73,984	23	2019.417	123,406	10,615

Finance	
Fixed Charge Rate:	*8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life.	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed [2] ($1,000)	Fees and Credits [3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	114,059	5,754	0	0	119,813	0	119,813	119,813
2001	136,916	10,068	0	0	146,984	0	146,984	258,477
2002	142,131	12,288	0	0	154,419	0	154,419	395,909
2003	141,314	12,505	807	(30)	154,595	232	154,827	525,905
2004	139,095	13,997	3,203	(119)	156,176	928	157,104	650,346
2005	140,584	16,370	3,205	(119)	160,040	928	160,968	770,631
2006	134,506	17,779	4,234	(120)	156,399	8,786	165,185	887,080
2007	133,777	19,470	5,004	(120)	158,130	14,399	172,529	1,001,822
2008	140,844	21,403	5,052	(121)	167,177	14,399	181,576	1,115,745
2009	141,454	22,582	6,205	(122)	170,119	22,861	192,980	1,229,970
2010	143,385	23,749	7,081	(122)	174,094	28,906	203,000	1,343,324
2011	145,433	25,398	7,181	(123)	177,890	28,906	206,796	1,452,261
2012	150,942	26,417	7,284	(123)	184,520	28,906	213,425	1,558,327
2013	156,775	27,286	6,873	(124)	190,810	28,906	219,715	1,661,338
2014	162,596	27,895	4,893	(124)	195,259	34,379	229,638	1,762,907
2015	165,821	28,824	5,365	(125)	199,884	38,288	238,172	1,862,288
2016	171,429	30,031	5,499	(126)	206,834	38,288	245,122	1,958,779
2017	175,108	30,818	5,637	(126)	211,436	38,288	249,724	2,051,518
2018	181,509	31,954	5,778	(127)	219,114	38,288	257,401	2,141,697
2019	186,677	32,790	6,469	(128)	225,809	44,480	270,289	2,231,081

Notes:

* FMPA assumed to finance the Southern-Florida project at a 9.02 percent rate.

[1] Includes start-up costs

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency Economic Evaluation

Case

Scenario. Low Fuel Price Projections
Self Build

Economic

CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	61			2003.833	31,458	2,706
WH 501F 2x1	257	129,241	24	2006.417	156,602	13,471
WH 501F 1x1	125	73,984	23	2009.417	96,404	8,293
WH 501F 1x1	125	73,984	23	2011.417	101,285	8,713
WH 501F 2x1	257	129,241	24	2013.417	186,150	16,013

Finance

Fixed Charge Rate:	8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	114,059	5,754	0	0	119,813	0	119,813	119,813
2001	136,916	10,068	0	0	146,984	0	146,984	258,477
2002	142,131	12,288	0	0	154,419	0	154,419	395,909
2003	141,367	12,487	325	13	154,191	677	154,868	525,940
2004	139,259	13,972	333	51	153,614	2,706	156,320	648,760
2005	143,374	16,636	341	53	160,404	2,706	163,110	771,645
2006	134,722	17,788	1,375	54	153,939	10,564	164,503	887,613
2007	133,983	19,469	2,151	55	155,658	16,177	171,834	1,001,893
2008	141,072	21,402	2,204	57	164,735	16,177	180,912	1,115,399
2009	146,791	21,816	2,687	58	171,382	21,014	192,366	1,229,280
2010	151,566	22,483	3,063	59	177,172	24,470	201,641	1,341,856
2011	155,070	23,796	3,588	61	182,516	29,552	212,068	1,453,570
2012	165,576	24,713	4,003	62	194,354	33,182	227,536	1,566,649
2013	150,776	27,373	6,771	64	184,983	42,523	227,506	1,673,312
2014	146,674	28,914	8,870	66	184,524	49,195	233,719	1,776,686
2015	149,680	29,844	9,092	67	188,683	49,195	237,878	1,875,844
2016	154,501	31,105	9,319	69	194,994	49,195	244,188	1,972,068
2017	157,137	32,067	9,552	71	198,827	49,195	248,022	2,064,174
2018	162,750	33,019	9,791	72	205,632	49,195	254,827	2,153,451
2019	166,552	34,151	10,036	74	210,813	49,195	260,008	2,239,387

Notes:

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency Economic Evaluation

Case
Scenario: AEO Fuel Price Projections
Joint Development

Economic	
CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
	21			2003 833	[redacted]	
Southern	223	256,581	42	2006.417	318,830	27,426
Pulverized Coal	257	129,241	24	2009.417	168,643	14,507
WH 501F 2x1	257	129,241	24	2014.417	190,804	16,413
WH 501F 2x1						

Finance	
Fixed Charge Rate:	*8 60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	98,538	6,651	0	0	105,189	0	105,189	105,189
2001	106,579	10,518	0	0	117,096	0	117,096	215,657
2002	119,526	12,028	0	0	131,554	0	131,554	332,739
2003	127,514	13,011	807	(30)	141,802	232	141,634	451,574
2004	134,962	14,011	3,203	(119)	152,057	928	152,985	572,752
2005	142,371	16,254	3,205	(119)	161,711	928	162,639	694,286
2006	127,452	18,199	5,453	(120)	150,984	16,926	167,911	812,656
2007	121,182	20,115	7,136	(120)	148,313	28,354	176,666	930,149
2008	132,565	22,558	7,237	(121)	162,240	28,354	190,593	1,049,730
2009	134,585	23,674	8,445	(122)	166,582	36,816	203,398	1,170,121
2010	136,780	24,745	9,378	(122)	170,780	42,860	213,640	1,289,416
2011	143,354	26,336	9,535	(123)	179,102	42,860	221,962	1,406,343
2012	150,765	27,377	9,696	(123)	187,715	42,860	230,575	1,520,932
2013	157,638	28,415	9,346	(124)	195,274	42,860	238,134	1,632,579
2014	162,471	29,482	8,194	(124)	200,023	52,435	252,457	1,744,241
2015	165,873	30,603	9,302	(125)	205,652	59,273	264,925	1,854,785
2016	173,776	31,884	9,534	(126)	215,068	59,273	274,341	1,962,778
2017	180,020	32,808	9,773	(126)	222,474	59,273	281,747	2,067,409
2018	189,592	34,020	10,017	(127)	233,502	59,273	292,775	2,169,981
2019	199,077	35,058	10,268	(128)	244,275	59,273	303,548	2,270,308

Notes

* FMPA assumed to finance the Southern-Florida project at a 9.02 percent rate.

[1] Includes start-up costs

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency Economic Evaluation

Case	
Scenario: AEO Fuel Price Projections	
Self Build	

Economic	
CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	61			2003.833	31,458	2,706
Pulverized Coal	223	256,581	42	2006.417	318,830	27,426
WH 501F 1x1	125	73,984	23	2009.417	96,404	8,293
WH 501F 1x1	125	73,984	23	2011.417	101,285	8,713
WH 501F 2x1	257	129,241	12	2013.417	183,051	15,746

Finance	
Fixed Charge Rate:	8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	98,536	6,651	0	0	105,189	0	105,189	105,189
2001	106,579	10,518	0	0	117,096	0	117,096	215,657
2002	119,526	12,028	0	0	131,554	0	131,554	332,739
2003	127,555	13,003	325	13	140,895	677	141,572	451,606
2004	135,131	13,986	333	51	149,502	2,706	152,208	572,168
2005	142,616	16,241	341	53	159,251	2,706	161,957	693,192
2006	127,682	18,191	2,594	54	148,521	18,704	167,225	811,079
2007	121,368	20,108	4,283	55	145,834	30,132	175,966	928,106
2008	132,920	22,550	4,390	57	159,916	30,132	190,048	1,047,345
2009	140,907	23,161	4,927	58	169,053	34,969	204,022	1,168,105
2010	146,459	23,924	5,359	59	175,802	38,424	214,226	1,287,728
2011	157,816	25,015	5,942	61	188,834	43,507	232,341	1,410,122
2012	171,422	26,140	6,415	62	204,040	47,137	251,177	1,534,950
2013	162,057	27,779	7,794	64	197,693	56,322	254,015	1,654,042
2014	165,615	29,041	8,870	66	203,592	62,883	266,475	1,771,904
2015	170,787	29,933	9,092	67	209,879	62,883	272,762	1,885,218
2016	179,788	31,196	9,319	69	220,371	62,883	283,254	1,997,220
2017	186,901	32,079	9,552	71	228,602	62,883	291,485	2,105,467
2018	196,994	33,082	9,791	72	239,940	62,883	302,823	2,211,559
2019	206,857	34,160	10,036	74	251,127	62,883	314,010	2,316,344

Notes:

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency Economic Evaluation

Case
Scenario: OUC 2000 + 2001 AEO Escalators
Joint Development

Economic	
CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833	[redacted]	
Pulverized Coal	223	256,581	42	2006.417	318,830	27,426
WH 501F 2x1	257	129,241	24	2009.417	168,643	14,507
WH 501F 2x1	257	129,241	24	2014.417	190,804	16,413

Finance	
Fixed Charge Rate:	*8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	113,987	5,744	0	0	119,731	0	[illegible]	[illegible]
2001	129,906	10,196	0	0	140,103	0	140,103	[illegible]
2002	146,035	11,806	0	0	157,841	0	[illegible]	[illegible]
2003	158,585	12,730	807	(30)	172,092	232	172,324	537,068
2004	172,899	13,892	3,203	(119)	189,874	928	190,802	688,201
2005	197,980	16,437	3,205	(119)	217,503	928	218,431	851,426
2006	171,291	19,126	5,453	(120)	195,750	16,926	212,677	1,001,354
2007	163,815	21,267	7,136	(120)	192,097	28,354	220,451	1,147,966
2008	188,764	23,973	7,237	(121)	219,853	28,354	248,207	1,303,694
2009	195,166	25,044	8,445	(122)	228,534	36,816	265,350	1,460,755
2010	201,863	25,965	9,378	(122)	237,084	42,860	279,944	1,617,074
2011	232,249	26,859	9,535	(123)	268,520	42,860	311,381	1,781,105
2012	245,803	27,894	9,696	(123)	283,269	42,860	326,130	1,943,182
2013	257,988	28,966	9,346	(124)	296,175	42,860	339,036	2,102,135
2014	267,090	30,122	8,194	(124)	305,280	52,436	357,715	[illegible]
2015	274,010	31,222	9,302	(125)	314,409	59,273	[illegible]	[illegible]
2016	288,710	32,535	9,534	(126)	330,654	59,273	389,927	2,569,771
2017	299,511	33,443	9,773	(126)	342,600	59,273	401,874	[illegible]
2018	317,153	34,676	10,017	(127)	361,720	59,273	420,993	2,866,505
2019	334,436	35,787	10,268	(128)	380,363	59,273	[illegible]	[illegible]

Notes:

* FMPA assumed to finance the Southern-Florida project at a 9.02 percent rate.

[1] Includes start-up costs

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency Economic Evaluation

Case	
Scenario: OUC 2000 + 2001 AEO Escalators	
Self Build	

Economic	
CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	61			2003 833	31,458	2,706
Pulverized Coal	223	256,581	42	2006.417	318,830	27,426
WH 501F 1x1	125	73,984	23	2009.417	96,404	8,293
WH 501F 1x1	125	73,984	23	2011.417	101,285	8,713
WH 501F 2x1	257	129,241	24	2013.417	186,150	16,013

Finance	
Fixed Charge Rate:	8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed [2] ($1,000)	Fees and Credits [3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	113,987	5,744	0	0	119,731	0	119,731	119,731
2001	129,906	10,196	0	0	140,103	0	140,103	251,903
2002	146,035	11,806	0	0	157,841	0	157,841	392,351
2003	158,640	12,727	325	13	171,704	677	172,381	537,116
2004	173,274	13,885	333	51	187,543	2,706	190,249	687,811
2005	198,245	16,426	341	53	215,064	2,706	217,770	850,541
2006	171,833	19,135	2,594	54	193,616	18,704	212,320	1,000,219
2007	164,297	21,264	4,283	55	189,900	30,132	220,032	1,146,552
2008	189,309	23,971	4,390	57	217,727	30,132	247,858	1,302,062
2009	203,813	24,671	4,927	58	233,469	34,969	268,438	1,460,950
2010	214,680	25,513	5,359	59	245,611	38,424	284,035	1,619,554
2011	257,498	25,478	5,942	61	288,979	43,507	332,485	1,794,703
2012	282,330	26,645	6,415	62	315,453	47,137	362,590	1,974,899
2013	266,423	28,395	7,794	64	302,676	56,478	359,154	2,143,284
2014	273,463	29,728	8,870	66	312,127	63,150	375,277	2,309,269
2015	282,465	30,647	9,092	67	322,271	63,150	385,421	2,470,092
2016	299,271	31,910	9,319	69	340,569	63,150	403,718	2,629,014
2017	311,291	32,802	9,552	71	353,717	63,150	418,866	2,789,824
2018	329,359	33,823	9,791	72	373,045	63,150	436,195	2,938,642
2019	348,174	34,886	10,036	74	393,170	63,150	456,319	3,087,461

Notes:

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency Economic Evaluation

Case
Scenario: Constant 2000 Fuel Price Projections Joint Development

Economic	
CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833	[redacted]	
Pulverized Coal	223	256,581	42	2006.417	318,830	27,426
WH 501F 2x1	257	129,241	24	2009.417	168,643	14,507
WH 501F 2x1	257	129,241	24	2014.417	190,804	16,413

Finance	
Fixed Charge Rate:	*8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	113,987	5,744	0	0	119,731	0	119,731	119,731
2001	129,433	10,285	0	0	139,717	0	139,717	251,540
2002	144,959	11,950	0	0	156,909	0	156,909	391,188
2003	156,195	12,898	807	(30)	169,870	232	170,102	534,009
2004	167,660	13,950	3,203	(119)	184,694	928	185,622	681,039
2005	182,845	16,416	3,205	(119)	202,348	928	203,276	832,938
2006	165,238	19,087	5,453	(120)	189,659	16,926	206,586	978,573
2007	160,200	21,212	7,136	(120)	188,428	28,354	216,782	1,122,745
2008	180,184	23,877	7,237	(121)	211,177	28,354	239,531	1,273,030
2009	185,202	24,973	8,445	(122)	218,499	36,816	255,315	1,424,150
2010	190,746	25,897	9,378	(122)	225,898	42,860	268,759	1,574,224
2011	208,946	26,822	9,535	(123)	245,180	42,860	288,040	1,725,960
2012	219,538	27,848	9,696	(123)	256,957	42,860	299,817	1,874,960
2013	228,536	28,939	9,346	(124)	266,696	42,860	309,557	2,020,092
2014	234,649	30,083	8,194	(124)	272,801	52,435	325,236	2,163,944
2015	239,322	31,195	9,302	(125)	279,694	59,273	338,967	2,305,383
2016	248,732	32,498	9,534	(126)	290,639	59,273	349,912	2,443,125
2017	254,564	33,418	9,773	(126)	297,628	59,273	356,902	2,575,665
2018	265,354	34,615	10,017	(127)	309,860	59,273	369,133	2,704,989
2019	275,427	35,734	10,268	(128)	321,300	59,273	380,574	2,830,773

Notes:

* FMPA assumed to finance the Southern-Florida project at a 9.02 percent rate.

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency Economic Evaluation

Case	
Scenario: High Load and Energy Growth Self Build	

Economic	
CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	61			2003.833	31,458	2,706
WH 501F 2x1	257	129,241	24	2005.417	152,782	13,142
WH 501F 2x1	257	129,241	24	2006.417	156,602	13,471
WH 501F 2x1	257	129,241	24	2008.417	164,529	14,153
Pulverized Coal	223	256,581	42	2011 417	360,726	31,030
WH 501F 1x1	125	73,984	23	2017.417	117,459	10,104

Finance

Fixed Charge Rate:	8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed [2] ($1,000)	Fees and Credits [3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,613	6,230	0	0	130,844	0	130,844	130,844
2001	152,479	10,790	0	0	163,269	0	163,269	284,871
2002	163,022	13,022	0	0	176,044	0	176,044	441,650
2003	169,170	14,232	325	13	183,738	677	184,415	596,388
2004	172,689	15,940	333	51	189,012	2,706	191,718	748,247
2005	163,200	19,577	1,341	53	184,171	10,372	194,543	893,621
2006	162,316	20,775	3,123	54	186,268	23,706	209,974	1,041,644
2007	170,520	22,734	3,943	55	197,252	29,319	226,571	1,192,327
2008	179,512	26,011	5,118	57	210,698	37,575	248,273	1,348,096
2009	191,192	27,548	6,025	58	224,823	43,472	268,295	1,508,900
2010	202,890	29,021	6,176	59	238,147	43,472	281,619	1,664,154
2011	203,754	31,715	8,870	61	244,400	61,573	305,973	1,826,337
2012	213,357	33,580	10,929	62	257,928	74,502	332,430	1,990,345
2013	221,514	35,081	11,202	64	267,862	74,502	342,363	2,151,058
2014	233,956	36,576	11,482	66	282,080	74,502	356,581	2,308,774
2015	245,838	38,080	11,769	67	295,754	74,502	370,268	2,462,259
2016	259,828	39,749	12,064	69	311,709	74,502	386,211	2,615,300
2017	270,824	41,043	12,886	71	324,823	80,396	408,619	2,765,783
2018	287,596	42,698	13,584	72	343,951	84,606	428,557	2,915,926
2019	299,997	44,225	13,924	74	358,221	84,606	442,828	3,062,255

Notes:

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency Economic Evaluation

Case
Scenario High Load and Energy Growth
Joint Development

Economic	
CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833	[redacted]	
WH 501F 2x1	257	129,241	24	2005.417	152,782	13,142
WH 501F 2x1	257	129,241	24	2006.417	156,602	13,471
GE 7FA SC	156	76,681	12	2008.417	95,993	8,257
Pulverized Coal	223	256,581	42	2011 417	360,726	31,030
WH 501F 2x1	257	129,241	23	2014.417	190,537	16,390

Finance	
Fixed Charge Rate:	*8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed [2] ($1,000)	Fees and Credits [3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,613	6,230	0	0	130,844	0	130,844	130,844
2001	152,479	10,790	0	0	163,269	0	163,269	284,871
2002	163,022	13,022	0	0	176,044	0	176,044	441,550
2003	169,108	14,240	807	(30)	184,124	232	184,356	598,939
2004	172,411	15,944	3,203	(119)	191,439	928	192,367	748,711
2005	162,960	19,589	4,206	(119)	186,635	8,594	195,230	894,598
2006	162,008	20,781	5,982	(120)	188,651	21,928	210,580	1,043,048
2007	169,984	22,711	7,191	(120)	199,765	27,541	227,306	1,194,220
2008	182,118	25,815	7,579	(121)	215,391	32,358	247,749	1,348,661
2009	195,803	27,285	7,692	(122)	230,659	35,799	266,457	1,507,376
2010	207,973	28,684	7,807	(122)	244,342	35,799	280,141	1,663,805
2011	207,367	31,334	10,465	(123)	249,044	53,899	302,940	1,825,892
2012	214,098	33,288	12,486	(123)	259,750	66,828	326,578	1,985,691
2013	223,946	34,747	12,205	(124)	270,775	66,828	337,603	2,143,979
2014	234,422	36,336	11,125	(124)	281,759	76,389	358,148	2,302,382
2015	245,028	37,976	12,306	(125)	295,185	83,218	378,403	2,460,276
2016	259,780	39,611	12,614	(126)	311,879	83,218	395,097	2,615,805
2017	269,589	40,996	12,929	(126)	323,388	83,218	406,606	2,766,804
2018	299,516	42,191	13,253	(127)	354,832	83,218	438,050	2,920,272
2019	300,041	44,187	13,584	(128)	357,684	83,218	440,903	3,065,996

Notes:

* FMPA assumed to finance the Southern-Florida project at a 9.02 percent rate.

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency Economic Evaluation

Case	
Scenario. Low Load and Energy Growth	
Self Build	

Economic	
CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
						825.149507
Self Build	61			2003.833	31,458	2,706
WH 501F 2x1	257	129,241	24	2008.417	164,529	14,153
Pulverized Coal PC	223	256,581	42	2011.417	360,726	31,030

Finance	
Fixed Charge Rate:	8.60%
Interest During Const :	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	103,096	5,340	0	0	108,436	0	108,436	108,436
2001	123,915	9,362	0	0	133,277	0	133,277	234,169
2002	129,660	10,905	0	0	140,565	0	140,565	369,272
2003	129,714	11,132	325	13	141,183	677	141,860	478,380
2004	128,373	12,369	333	51	141,126	2,706	143,832	592,308
2005	127,993	14,398	341	53	142,785	2,706	145,491	701,028
2006	134,209	14,887	350	54	149,499	2,706	152,205	808,326
2007	141,514	16,172	358	55	158,100	2,706	160,806	915,271
2008	140,832	18,773	1,444	57	161,106	10,962	172,067	1,023,229
2009	142,880	19,542	2,259	58	164,740	16,859	181,598	1,130,717
2010	148,745	20,298	2,316	59	171,419	16,859	188,277	1,235,850
2011	142,909	22,389	4,914	61	170,273	34,959	205,232	1,343,963
2012	142,636	23,748	6,873	62	173,320	47,889	221,209	1,463,897
2013	146,769	24,474	7,045	64	178,352	47,889	226,240	1,659,968
2014	153,084	25,181	7,221	66	185,552	47,889	233,441	1,663,219
2015	157,763	25,894	7,402	67	191,126	47,889	239,015	1,762,951
2016	165,075	26,928	7,587	69	199,659	47,889	247,548	1,860,398
2017	169,450	27,519	7,777	71	204,817	47,889	252,705	1,954,243
2018	177,605	28,390	7,971	72	214,039	47,889	261,927	2,046,008
2019	184,124	29,233	8,170	74	221,602	47,889	269,491	2,136,078

Notes:

[1] Includes start-up costs.

[2] Fixed costs are included only for new units

[3] Includes fees for site lease as well as credit for services and cooling water

Florida Municipal Power Agency Economic Evaluation

Case
Scenario: Low Load and Energy Growth Joint Development

Economic	
CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833	[redacted]	[redacted]
WH 501F 2x1	257	129,241	24	2008.417	164,529	14,153
Pulverized Coal PC	223	256,581	42	2011 417	360,726	31,030

Finance	
Fixed Charge Rate:	*8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	103,096	5,340	0	0	108,436	0	108,436	108,436
2001	123,915	9,362	0	0	133,277	0	133,277	234,189
2002	129,660	10,905	0	0	140,566	0	140,565	359,272
2003	129,643	11,133	807	(30)	141,552	232	141,784	478,317
2004	128,242	12,389	3,203	(119)	143,715	928	144,643	592,887
2005	127,770	14,412	3,205	(119)	145,268	928	146,196	702,133
2006	133,990	14,890	3,208	(120)	151,969	928	152,897	809,920
2007	141,334	16,170	3,212	(120)	160,595	928	161,523	917,342
2008	140,603	18,776	4,292	(121)	163,550	9,184	172,734	1,025,717
2009	142,650	19,542	5,101	(122)	167,171	15,081	182,252	1,133,592
2010	148,557	20,300	5,151	(122)	173,887	15,081	188,968	1,239,110
2011	142,570	22,399	7,743	(123)	172,589	33,182	205,771	1,347,808
2012	142,261	23,758	9,696	(123)	175,591	46,111	221,702	1,457,687
2013	146,536	24,458	9,346	(124)	180,218	46,111	226,928	1,563,797
2014	154,002	25,095	6,945	(124)	185,917	46,111	232,028	1,666,423
2015	159,331	25,773	7,118	(125)	192,096	46,111	238,207	1,765,819
2016	166,076	26,827	7,296	(126)	200,073	46,111	246,184	1,862,728
2017	170,647	27,412	7,479	(126)	205,412	46,111	251,522	1,956,134
2018	178,868	28,282	7,666	(127)	214,689	46,111	260,800	2,047,504
2019	185,552	29,122	7,857	(128)	222,404	46,111	268,514	2,138,251

Notes:

* FMPA assumed to finance the Southern-Florida project at a 9.02 percent rate.

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Table 1A.2-1
Utility Summer Deficits (MW)

Year	OUC	KUA	FMPA	Total
2000	17	0	0	17
2001	0	0	0	0
2002	55	0	0	55
2003	85	0	0	85
2004	593*	11	110	714
2005	560	27	27	614
2006	557	42	119	718
2007	587	53	163	803
2008	623	66	273	962
2009	663	78	305	1,046
2010	703	91	325	1,119
2011	567	104	497	1,168
2012	600	118	516	1,234
2013	640	130	532	1,302
2014	695	144	549	1,388
2015	730	159	564	1,453
2016	766	173	580	1,519
2017	805	187	593	1,585
2018	844	201	605	1,650
2019	879	216	617	1,712

* Reliant purchase power agreement expires September 30, 2003.