OUC

The *Reliable* One

2000 Ten-Year Site Plan

Orlando Utilities Commission

April 2000

ORIGINAL

2000 Ten-Year Site Plan

Orlando Utilities Commission

April 2000

BLACK & VEATCH
Corporation
11401 Lamar, Overland Park, Kansas 66211, (913) 458-2000

05602-00

Table of Contents

1.0 Executive Summary

This report documents the 2000 Orlando Utilities Commission (OUC) Ten-Year Site Plan pursuant to Section 186.801 Florida Statutes and Section 25-17.0852 of Florida Administrative Code. The Ten-Year Site Plan provides information required by this rule. The Plan consists of 9 main sections:

- Utility System Description
- Strategic Issues
- Forecast of Power Demand and Energy Consumption
- Demand-Side Management
- Forecast of Facilities Requirements
- Development of Supply-Side Alternatives
- Analysis Results and Conclusions
- Environmental and Land Use Information
- Ten-Year Site Plan Schedules

This Plan also integrates the power sales, purchases, and loads for the City of St. Cloud into the OUC Plan.

OUC is a member of the Florida Municipal Power Pool (FMPP). Power for OUC is supplied by the OUC jointly owned generation and power purchases. The total installed generating capacity based on OUC's ownership share is 1071.4 MW winter and 1024.5 MW summer as of January 1, 2000. The existing supply system has a broad range of generation technology and fuel diversity with coal providing the largest portion of OUC's energy requirement.

In 1999, OUC sold the Indian River Steam Units to Reliant. As part of the agreement with Reliant, OUC received a power purchase agreement (PPA) through September 30, 2003 with an option for up to four additional years.

Load forecasts for OUC and the City of St. Cloud are provided. A banded forecast is provided with a base case growth, high growth, and low growth scenarios. This analysis considering the forecasted growth, existing units, retiring units, purchase power contracts, and reserve margin indicates a need for additional capacity ranging from 2002 to 2004 depending upon the level of optional capacity purchased from Reliant.

Four alternative power plant technologies were considered for capacity additions in addition to the optional PPA from Reliant. The alternatives were modeled in Black & Veatch's POWROPT and POWRPRO optimal generation expansion and chronological production cost programs to rank the expansion plans according to total cumulative present worth costs over a 20-year planning period. Several sensitivity analyses were performed to determine the impact on the least-cost alternatives as well.

Based on the detailed modeling of the OUC system, forecast of electrical demand and energy, forecast of fuel prices and availability, and environmental considerations, Table 1-1 presents the least-cost expansion plan. OUC plans to further refine the plan through a thorough test of the market and through additional detailed engineering.

Table 1-1
Base Case Expansion Plan[1]

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
2000	Reliant Power Purchase (593 MW) Oct.	143,128	143,128
2001	Reliant Power Purchase (538 MW) Oct.	146,447	281,285
2002	Reliant Power Purchase (553 MW) Oct.	150,818	415,513
2003	Reliant Power Purchase (100 MW) Oct 2x1 501 F Combined Cycle (481.89 MW) Oct.	159,595	549,512
2004		173,945	687,292
2005		175,177	818,195
2006		169,975	938,021
2007	7 FA Simple Cycle (145.98 MW) June	181,227	1,058,547
2008		192,512	1,179,332
2009		204,648	1,300,462
2010		213,912	1,419,909
2011		220,260	1,535,939
2012		233,668	1,652,065
2013		246,010	1,767,404
2014		258,594	1,881,781
2015		275,818	1,996,870
2016	7 FA Simple Cycle (145.98 MW) June	290,419	2,111,192
2017		309,307	2,226,058
2018		326,172	2,340,330
2019		351,612	2,456,543

[1]Capacity is stated in summer ratings.

2.0 Utility System Description

2.1 History of the Orlando Utilities Commission

Back at the turn of the twentieth century, John M. Cheney, an Orlando Judge, organized the Orlando Water and Light Company and supplied electricity on a part-time basis with a 100 kilowatt generator. Twenty-four hour service began in 1903.

By 1922, the City's population had grown to about 10,000 and the Judge, realizing a need for wider services than his company was able to supply, urged his friends to work and vote for a $97,500 bond issue to enable the citizens of Orlando to purchase and municipally operate his privately-owned utilities.

The bond issue carried almost three to one, as did a subsequent issue for additional improvements. The citizens of Orlando took over the company, with its 2,795 electricity customers and 5,000 water customers for a total original investment of $1.5 million.

In 1923, the Orlando Utilities Commission (OUC) was created by an act of the State Legislature and full authority was granted to OUC to operate the plant as a municipal utility. The business was a paying venture from the start. In fact, by 1924 the number of customers had more than doubled and OUC contributed $53,000 to the City. When Orlando citizens took over operations of their utility, the population was less than 10,000. By 1925, it had grown to 23,000. In 1925, more than $165,000 was transferred to the City and in 1926 an additional $111,000 was transferred to the City. In 1928, one outside private utility offered $3 million to purchase the utility.

Between 1928 and 1931 there was a lot of talk for and against the sale of the utility. On August 18, 1931, an election was held and the people voted 1,033 to 140 not to sell the utility; 1,030 to 160 not to mortgage the utility; 744 to 436 not to issue tax notes; and 919 to 158 not to lease the utility. However, the question as to whether or not Orlando's utility should remain under municipal ownership did not end with the vote of the people in 1931. A year later a $5 million offer was made for the plant, $2 million more than the actual physical value at the time.

Intermittent attempts were made to gain control of the utility until around 1940 when OUC instituted a study extending over 18 years of the utility's activity, and adopted a firm policy of keeping the people fully informed of operations to benefit the taxpayers and the citizens of Orlando.

The wisdom of these early Orlando citizens can be fully appreciated with a look at the magnitude of today's operation serving over 139,000 electric customers and 113,000 water customers including the recent addition of customers from the City of St. Cloud.

2.2 General Description of the Orlando Utilities Commission

The Orlando Utilities Commission (OUC) is a statutory commission created by the legislature of the State of Florida as a separate part of the government of the City of Orlando. OUC has the full authority over the management and control of the electric and water works plants in the City of Orlando and has been approved by the Florida Legislature to offer these services in Osceola County as well as Orange County. OUC's charter allows it to undertake, among other things, the construction, operation, and maintenance of electric generation, transmission and distribution systems, and water production, transmission and distribution systems in order to meet the requirements of its customers.

OUC's electric system provides power to customers within Orange County encompassing approximately 244 square miles. As of December 31, 1999, the electric system had 141,242 active services. Of these, 121,767 are residential services, 15,547 are general service non-demand services, and the remaining 3,928 are general service demand services. The agreement with the City of St. Cloud allowed OUC to add an additional 150 square miles of service area as well as an additional 17,725 active services.

2.3 Generation System

2.3.1 Existing Generation Facilities

OUC presently has ownership interests in the following five electric generating plants which are further described below.

- Indian River Plant Combustion Turbine Units A, B, C, and D.

- Stanton Energy Center Units 1 and 2
- Florida Power Corporation Crystal River Unit 3 Nuclear Generating Facility
- City of Lakeland McIntosh Unit 3
- Florida Power and Light Company St. Lucie Unit 2 Nuclear Generating Facility.

Stanton Energy Center. The Stanton Energy Center (SEC) is located 12 miles Southeast of Orlando, Florida. The 3,250 acre site contains SEC Units 1 and 2, and the necessary supporting facilities. SEC 1 was placed in operation on July 1, 1987 followed by SEC Unit 2 which was placed in operation on June 1, 1996 at a cost of $464.9 million, $57 million under budget. Both units are fueled by pulverized coal and operate at emission levels that are below the Environmental Protection Agency (EPA) and the Florida Department of Environmental Protection requirement standards for SO_2, NO_X and particulates.

SEC Unit 1 is a 440 MW net coal-fired facility of which OUC has a 68.6 percent ownership share providing 304 MW of capacity to the OUC system. SEC Unit 2 is a 444 MW net coal-fired generating facility. OUC's ownership share in this facility is 71.6 percent, or 318 MW.

Indian River Plant. The Indian River Plant is located four miles South of Titusville, on U.S. Highway 1. The 160-acre Indian River Plant site contains three steam electric generating units, No. 1, 2, and 3, and four combustion turbine units, A, B, C, and D. The three steam turbine units were sold to Reliant in 1999. As part of the sale, OUC has signed a power purchase agreement (PPA) with Reliant. More detailed information is presented in Section 2.5. The combustion turbine units are primarily fueled by natural gas with No. 2 fuel oil as an alternative.

OUC has a partial ownership share of 48.8 percent, or 46 MW, in Indian River Units A and B as well as a partial ownership share of 79 percent, or 200 MW, in Indian River Units C and D.

McIntosh Unit 3. McIntosh is a 340 MW net coal-fired unit operated by the City of Lakeland. McIntosh Unit 3 has supplementary oil and refuse fuel burning capability and also is capable of burning up to 20 percent petroleum coke. OUC has a 40 percent ownership share in this unit providing approximately 136 MW of capacity to the OUC system.

Crystal River Unit 3. Crystal River Unit 3 is a net 830 MW nuclear generating facility operated by the Florida Power Corporation. OUC has a 1.6015 percent ownership share in this facility providing approximately 13 MW to the OUC system.

St. Lucie Unit 2. St. Lucie Unit 2 is a net 835 MW nuclear generating facility operated by the Florida Power and Light. OUC has a 6.08951 percent ownership share in this facility providing approximately 52 MW to the OUC system.

Table 2-1 summarizes OUC's generating facilities including the capacity, commercial operation date, ownership share, etc.

Table 2-1
Summary of OUC Generation Facilities

Generating Facility	Date in Service Mo/Yr	Net Capability for Total Facility[1]	Ownership Share - %	Net Capability Available for OUC		Unit Type[2]	Fuel[3]	
				Summer MW	Winter MW		Primary	Alternate
Stanton Energy Center (SEC)								
Unit No. 1	07/87	440	68.55	301.6	303.7	FS	C	-
Unit No. 2	06/96	444	71.59	319.3	319.3	FS	C	-
Total SEC		884		620.9	623			
Indian River								
Combustion Turbine	06/89	48	48.8	18	23.4	CT	NG	LO
Unit A	07/89	48	48.8	18	23.4	CT	NG	LO
Unit B	08/92	127	79	85.3	100.3	CT	NG	LO
Unit C	10/92	127	79	85.3	100.3	CT	NG	LO
Unit D		350		206.6	247.4			
Total Indian River								
Crystal River	03/77	830	1.6015	13	13	N	N	-
Unit No. 3								
C.D. McIntosh Jr.	09/82	340	40	133	136	FS	C/R	HO
Unit No. 3								
St. Lucie	08/83	853	6.089	51	52	N	N	-
Unit No. 2 [4]								
Total		3,257		1,024.5	1071.4			

1. Actual net capacity varies with auxiliary power consumption.
2. FS = Fossil Steam; N = Nuclear; CT = Combustion Turbine
3. C = Coal; C/R = Coal and Refuse; HO = Heavy Oil (#6); LO = Light Oil (#2); NG = Natural Gas; N = Nuclear
4. OUC receives 50 percent of this capacity from St. Lucie Unit No.1 pursuant to a reliability exchange agreement with FP&L

2.3.2 Participation Agreements

OUC has entered into a series of participation agreements which convey an undivided ownership interest in units constructed and operated by OUC. Table 2-2 is a summary of those participation agreements.

Table 2-2
Summary of Generation Facility Participation Agreements

Utility	Unit	Amount of Ownership (MW)	Percent of Ownership
FMPA	SEC 1	117	26.6
KUA	SEC 1	21	4.8
FMPA	SEC 2	126	28.4
FMPA	IRP CT A&B	37	39.0
KUA	IRP CT A&B	12	12.2
FMPA	IRP CT C&D	53	21.0

FMPA – Florida Municipal Power Agency
KUA – Kissimmee Utility Authority
SEC – Stanton Energy Center
IRP – Indian River Plant

2.3.3 New Construction of Generation Facilities

OUC is currently studying the addition of a new unit at Stanton Energy Center site. The following options are being evaluated.

- Pulverized Coal Unit
- 501 F 1x1 Combined Cycle
- 501 F 2x1 Combined Cycle
- 7FA Simple Cycle Combustion Turbine

Black & Veatch has conducted extensive evaluations on these options. More detailed information is presented in Section 7.0.

2.4 Transmission System

2.4.1 Existing Transmission Facilities

OUC's existing transmission system consists of 26 substations approximately 302 miles of 230 kV and 115 kV lines and cables. OUC is fully integrated into the state transmission grid through its twelve 230 kV interconnections with other generating utilities which are members of the Florida Reliability Coordinating Council (FRCC) as summarized in Table 2-3. OUC's service area and transmission system are also shown on Figure 2-1.

In addition, OUC is also now responsible for approximately 50 miles of St. Cloud's transmission system including the 69 kV interconnection from St. Cloud's Central Substation to KUA's Carl Wall Substation, and a 230 kV interconnection from the St. Cloud's East Substation to Florida Power Corporation's (FPC's) Holopaw Substation.

Table 2-3
OUC Transmission Interconnections

kV	Utility	Number of Interconnections
230	FPL (2 circuits)	1
230	FPC	5
230	KUA	2
230	KUA/FMPA	1
230	Lakeland	1
230	TECO	1
230	TECO/RCID	1

FPL – Florida Power & Light
FPC – Florida Power Corporation
KUA – Kissimmee Utility Authority
TECO – Tampa Electric Company
RCID – Reedy Creek Improvement District
FMPA – Florida Municipal Power Agency

2.4.2 New Construction of Transmission Facilities

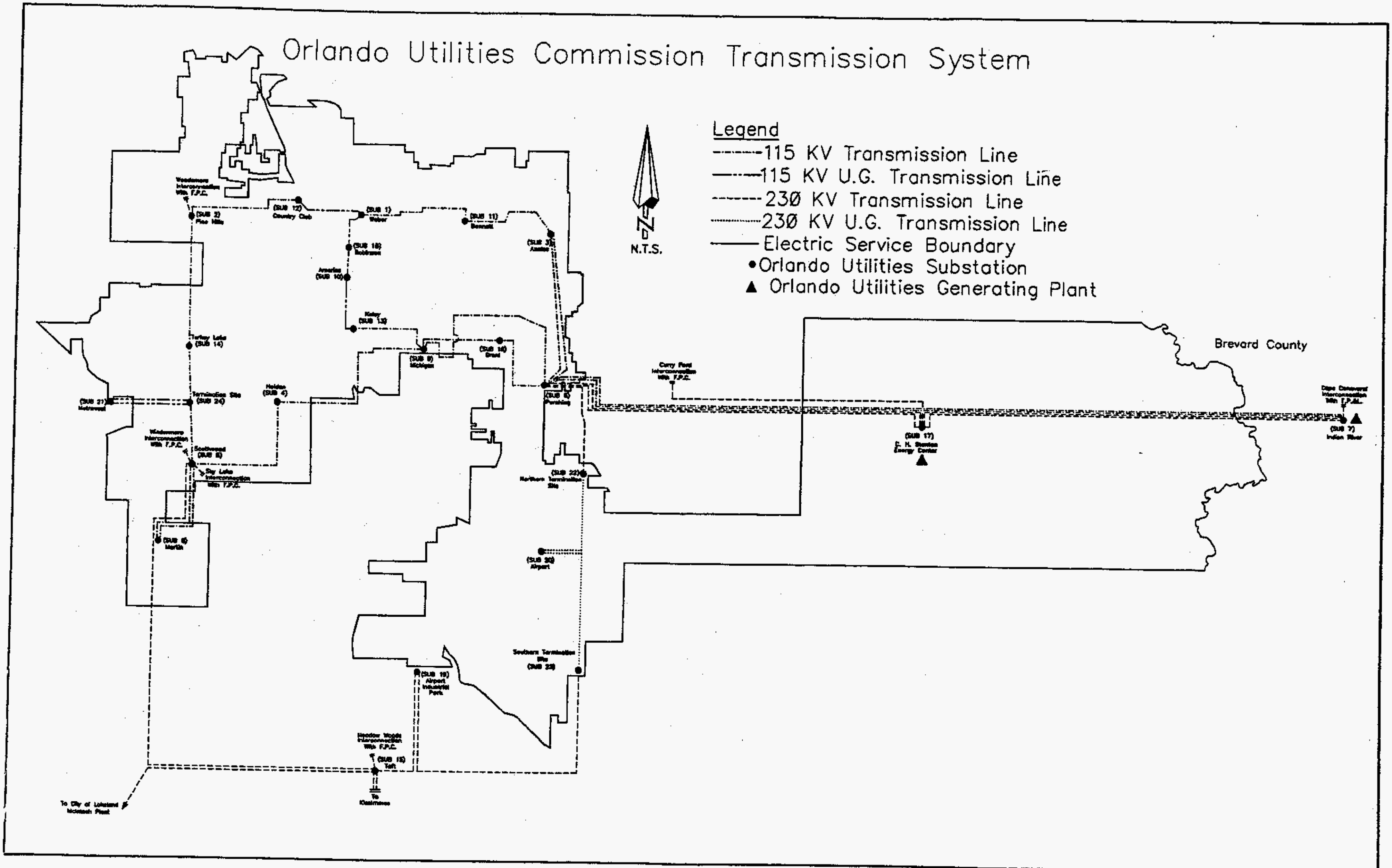
OUC is currently involved in the construction of a second 230 kV tie line between Stanton and FPC. The line is anticipated to be in-service by January, 2001. The addition will ease a line loading constraint as well as increase the available transfer capability between the systems. Further discussion of OUC's on-going and planned transmission construction projects is provided in Section 6.4 of this report.

2.5 Sale of Indian River Steam Units

OUC completed the sale of its Indian River power plant steam units to Reliant Energy in 1999. The capacity from Indian River Units 1 - 3 will continue to provide power to OUC through a four-year PPA. Put into service in 1960, the Indian River steam units near Titusville consist of three conventional steam generation units fueled by both oil and natural gas. By purchasing power from the Indian River plant but not owning the asset, OUC is able to further diversify its generation portfolio and better take advantage of changing market conditions. Years one and two of the agreement call for OUC to purchase 593 MW capacity of the steam plant through September 30, 2001. Years three and four of the agreement call for OUC to purchase 525 MW capacity with an option for an additional ten percent if needed. OUC also has an option to extend the PPA for another four years.

2.6 Agreement with the City of St. Cloud

The year 1997 marked a milestone for OUC as it began a new power supply partnership with the City of St. Cloud (St. Cloud). This 25-year agreement is a precedent setting move as OUC has become the first municipal electric utility in the state to manage, operate and maintain another municipal electric utility. The agreement is OUC's first full requirements power supply contract. It is also unique because the 17,725 St. Cloud customers are paying market-based rates for power received. The agreement has also, in effect, provided a 12 percent increase in OUC's customer base and added 150 square miles of high growth service area to OUC's existing 244 square miles service area. Energy use in the St. Cloud service area has grown at an average rate of approximately 7 percent for the last decade.



Orlando Utilities Commission Transmission System
Legend
115 KV Transmission Line
115 KV U.G. Transmission Line
230 KV Transmission Line
230 KV U.G. Transmission Line
Electric Service Boundary
Orlando Utilities Substation
Orlando Utilities Generating Plant
N.T.S.
Brevard County

Figure 2-1

3.0 Strategic Issues

OUC incorporates a number of strategic considerations while planning for the electrical system. This section provides an overview of a number of these strategic considerations.

3.1 Strategic Business Units

As the entire electric utility industry faces deregulation, OUC is aggressively developing strategies to be competitive in a deregulated environment. One strategy already implemented is to reorganize OUC into the following strategic business units, which are described below.

- Power Resource Business Unit
- Transmission Business Unit
- Electric Distribution Business Unit

3.1.1 Power Resources Business Unit

The Power Resources Business Unit (PRBU) has structured its operations based on a competitive environment that assumes that even OUC's customers are not captive. PRBU will only be profitable if it can produce electricity that is competitively priced in the open market. In line with this strategy, OUC is continually studying strategic options to improve or reposition their generating assets, such as the sale of the Indian River Steam Units and addition of new units.

OUC's generating system has been designed over the years to take advantage of fuel diversity and the resultant system reliability and economic benefits. OUC's longstanding intent to achieve diversity in its fuel mix is evidenced by its participation in other generating facilities in the State of Florida. The first such endeavor occurred in 1977 when OUC secured a share of the Crystal River Unit 3 nuclear plant, followed by the acquisition of an ownership share in the City of Lakeland's McIntosh Unit 3 coal fired unit in 1982. In 1983, OUC also acquired a share of the St. Lucie Unit 2 nuclear unit. OUC's current capacity mix is summarized in Table 3-1.

Table 3-1
Generation Capacity Owned by OUC by Fuel Type - MW

	Winter Capacity				Summer Capacity			
Plant Name	Coal	Nuclear	Gas/Oil	Total	Coal	Nuclear	Gas/Oil	Total
Stanton	622			622	620			620
Indian River			246	246			206	206
Crystal River		13		13		13		13
C.D. McIntosh Jr.	136			136	133			133
St. Lucie		52		52		51		51
Total	758	65	246	1069	753	64	206	1023
Total (%)	70.91	6.08	23.01	100	73.61	6.26	20.13	100

Coal represents more than 70 percent of OUC's capacity. This strategy ensures against interruptions in supply and increases in cost of oil and gas. Additional details of OUC's generating facilities are presented on Schedule 1 of Section 10.

Another example of OUC's commitment to fuel diversity is the use of alternative fuels such as refuse derived fuel (RDF) at the McIntosh Unit 3 facility. The plant is designed to burn a mix of RDF and coal. OUC's use of alternative or renewable fuels is further enhanced by burning a mix of petroleum coke in McIntosh Unit 3 along with coal and RDF. Petroleum coke is a waste by-product of the refining industry and besides the benefits of using a waste product, petroleum coke's lower prices results in significant savings over coal. Tests have been done, indicating the unit has the ability to use petroleum coke for approximately 20 percent of the fuel input. Permits have been modified and approved for this level of use and petroleum coke is being burned in the unit.

OUC's fuel diversity and use of renewable and waste fuels is further enhanced through the burning of landfill gas from the Orange County Landfill at Stanton Energy Center. The use of landfill gas not only reduces fuel costs, but also reduces the emission of greenhouse gases.

OUC's diversified mix of generating units provides protection against disruption of supply while simultaneously providing economic opportunities to reduce cost to customers. The ability to burn a variety of fuels is enhanced through the Indian River purchase power agreement, which also allows the selection of either oil or gas.

3.1.2 Transmission Business Unit

Transmission Business Unit (TBU) also continues to generate new revenues by leasing space on OUC facilities for wireless personal communications systems and leasing dark fiber to other telecommunications companies. It is also marketing its expertise to other utilities and commercial customers.

TBU is also responsible for dispatching all generation for OUC and the Florida Municipal Power Pool (FMPP). The pool consists of OUC, City of Lakeland, Kissimmee Utility Authority and the Florida Municipal Power Agency's All Requirements Project. TBU has operated the pool since its inception in 1988. Section 3.3 of this report provides additional details regarding FMPP and its strategic importance to OUC.

3.1.3 Electric Distribution Business Unit

OUC's Electric Distribution Business Unit (EDBU) is moving forward to use its superior record for reliability to develop new business and to prosper in a deregulated utility industry.

In 1997, EDBU restructured the business unit to take it to the next level of performance. It established a new Division of Costs and Control responsible for all of the business unit's financial operations. EDBU has also added a director of business development to market its expertise to other utilities and secure other revenue-making opportunities for OUC. EDBU is also going beyond the meter to offer customers expanded power quality services.

OUC's leadership in providing reliable electric distribution service is further demonstrated by its commitment to making initial investments in high quality material and equipment, implementing aggressive preventive maintenance programs, and placing more than 40 percent of its electric distribution lines underground which reduces the potential for accidental contacts with live wires and poles and also enhances the appearance of streets, and commercial and residential areas.

During 1999, OUC continued to experience the best reliability in the State of Florida for both the OUC and St. Cloud service area. In addition, OUC has an excellent record for the time it takes to restore outages, a measure of reliability required by the Florida Public Service Commission to be reported on a calendar year basis. That rate has been further improved from 64 minutes in 1998 to 62 minutes in 1999.

3.2 Reposition of Assets

As a strategic consideration, OUC has been working on repositioning its assets. One major issue is the sale of its Indian River power plant steam units to Reliant Energy in 1999. Through a four-year PPA, Indian River steam generation units will continue to provide power to OUC while excess power generated by the plant will be sold by Reliant to other utilities. With the proceeds of the sale and by purchasing power, OUC is better able to diversify its generation portfolio and better take advantage of changing market conditions. The sale offers OUC the ability to replace the lesser competitive oil and gas steam units with more competitive combined cycle generation as well as the alternative of purchasing power when it is more economical for OUC customers.

3.3 Florida Municipal Power Pool

In 1988, OUC joined with the City of Lakeland and Florida Municipal Power Agency's All Requirements and Project members to form the Florida Municipal Power Pool (FMPP). Later, Kissimmee Utility Authority (KUA) joined FMPP. Through time, FMPA's All Requirements Project has added members as well. FMPP is an operating type electric pool, which dispatches all the pool member's generating resources in the most economical manner to meet the total load requirements of the pool. The central dispatch is providing savings to all parties because of reduced commitment costs and lower overall fuel costs. OUC serves as the FMPP dispatcher and handles all accounting for the allocation of fuel expenses and savings. The term of the pool agreement is one year and automatically renews from year to year until terminated by the consent of all participants.

OUC's participation in the FMPP provides significant savings from the joint commitment and dispatch of FMPP's units. Participation in FMPP also provides OUC with a ready market for any excess energy available from OUC's generating units.

3.4 Security of Power Supply

OUC currently maintains interchange agreements with other utilities in Florida to provide electrical energy during emergency conditions. The reliability of power supply is also enhanced by twelve 230 kV interconnections with other Florida utilities, including five interconnections with Florida Power Corporation (FPC), three with Kissimmee Utility Authority (KUA), and one each with Florida Power and Light (FP&L), Tampa Electric Company (TECO), Reedy Creek Improvement District (RCID), and the City of Lakeland. In addition to enhancing reliability, these interconnections also facilitate the marketing of electric energy by OUC to and from other electric utilities in Florida. Through its agreement with St. Cloud, OUC is also now responsible for St. Cloud's 230 kV interconnection to FPC and 69 kV interconnection to KUA.

3.5 Environmental Performance

As the quality of the environment is important to Florida and especially important to the tourist attracted economy in Central Florida, OUC is committed to protecting human health and preserving the quality of life and the environment in Central Florida. To demonstrate this commitment, OUC has chosen to operate their generating units with emission levels below those required by permits and licenses by equipping its power plants with the best available environmental protection systems. As a result, even with a second unit in operation, the Stanton Energy Center is one of the cleanest coal-fired generating stations in the nation. Unit 2 is the first of its size and kind in the nation to use Selective Catalytic Reduction (SCR) to remove nitrogen oxides (NO_x). Using SCR and Low-NO_x burner technology, Stanton 2 successfully meets the stringent air quality requirements imposed upon it.

This superior environmental performance not only preserves the environment, but also results in many economic benefits, which help offset the costs associated with the superior environmental performance. For example, the high quality coal burned at Stanton contributes to the high availability of the unit as well as low heat rate.

Further demonstrating their environmental commitment to clean air, OUC has signed a contract to burn the methane gas collected from the Orange County landfill adjacent to Stanton Energy Center. Methane gas, when released into the atmosphere, is considered to be 20 times worse than carbon dioxide in terms of possible global warming effects. Both Stanton units have the capability of burning methane. In addition to their commitment to clean air, OUC is also equally committed to minimizing the environmental and esthetic impacts on land used for and adjacent to new construction projects. In planning the new transmission line to link Stanton and St. Cloud, OUC employed the best management practices in route selection and design. OUC used low-impact construction and clearing techniques to further minimize the environmental and esthetic impacts of the project. As a result, the state required no additional mitigation measures.

OUC has also voluntarily implemented a product substitution program not only to protect workers' health and safety but also to minimize hazardous waste generation and to prevent environmental impacts. Environmental Affairs and the Safety Division constantly review and replace products to eliminate the use of hazardous substances. To further prevent pollution and reduce waste generation, OUC also reuses and recycles many products.

OUC is also pursuing programs demonstrating alternate fuels for transportation. OUC has purchased two minivans which have been retrofitted with battery powered motors. They will be used in the normal daily activities of OUC's Conservation and Office Services Divisions. One of the vehicles is also equipped with solar photovoltaic panels on the roof to power cooling fans. The vehicles are powered by 10 large gel cell batteries and 27 horsepower, high torque drive motors. OUC purchased these vehicles to learn as much as possible about their operating and recharge characteristics and to demonstrate the new technology to customers. OUC has also donated two vehicles to the University of Central Florida's Alternate Fuels Research Program for purposes of conducting research on alternative fuel sources for transportation.

3.6 Community Relations

Owned by the City of Orlando and its citizens, OUC is especially committed to being a good corporate citizen and neighbor in the areas it serves or impacts.

In Orange, Osceola and Brevard Counties, where OUC serves customers and/or has generating units, OUC gives its wholehearted support to education, diversity, the arts, and social-service agencies. An active Chamber of Commerce participant in all three counties, OUC also supports area Hispanic Chambers and the Metropolitan Orlando Urban League.

Each year, OUC lends a helping hand to charities and civic organizations across Central Florida. In its quest to make a difference, OUC supports the Heart of Florida United Way, United Arts, March of Dimes, Orlando Humane Society, Orlando/UCF Shakespeare Festival, Salvation Army and Second Harvest Food Bank, among many others. A proud and energetic bunch, OUC employees routinely volunteer their valuable free time to participate in such fundraisers as the Junior Achievement Bowl-A-Thon and the American Cancer Society's Relay for Life.

OUC is also a major sponsor of Habitat for Humanity, the Minority/Women Business Enterprise Alliance, Inc., and the Foundations for Education in both Orange and Osceola counties.

As a United Arts trustee, OUC has allowed its historic Lake Ivanhoe Power Plant to be turned into a performing arts center. OUC is also a corporate donor for WMFE public television and a co-sponsor of the "Power Station" exhibit at the Orlando Science Center.

4.0 Forecast of Power Demand and Energy Consumption

4.1 Forecasting Methodology

Orlando Utilities Commission (OUC) currently uses the System for Hourly and Annual Peak and Energy Simulation (SHAPES-PC) end-use/econometric forecasting model from Energy Management Associates. The OUC staff has developed the extensive database required by the SHAPES-PC model. The SHAPES-PC model has been further enhanced to produce loads for each hour of the year in chronological order. OUC staff developed a typical weather year and calibrated this module to the SHAPES-PC model.

4.2 Retail Sales

The SHAPES-PC model produces forecasts of energy and demand for the residential, commercial, industrial, and miscellaneous sectors (street lights and OUC use). Since OUC's rate classes do not correspond to commercial and industrial rate classes as defined in the SHAPES-PC model, these forecasts had to be treated in different manner. The commercial and industrial sector sales forecasts were combined together and then allocated to the general service non-demand and demand classes based on historical ratios.

4.2.1 Residential

Historically, the average number of residential customers has increased at an average annual rate of 2.1 percent for the period from 1990 through 1999. The average number of residential customers for the period 2000 through 2009 was projected as a function of service area population, age distribution, and headship ratio.

OUC's service area population was projected using Orange County population projections developed from University of Florida population estimates. Historically, service area population has grown at an average rate of 2.1 percent for the 1990 through 1999 period. Service area population is projected to grow at an average annual rate of 1.5 percent for the period 2000 through 2009.

The SHAPES-PC model was used to project residential customers. SHAPES-PC uses the following model to estimate residential customers:

CUS_t = $(AGE_t^a * POP_t * BHSR^a * HSRT_t^a) * CHR_t$

Where:

t = the forecast year

a = the age category

CUS = the residential customer forecast

AGE = the fraction of population in a given age category

POP = the service are population forecast

BSHR = the base year headship ratio

CHR = the customer per household ratio

The projected average number of residential customers is expected to grow at an average annual rate of 1.6 percent from 2000 to 2009.

Historically, residential sales have increased at an average annual rate of 2.2 percent for the 1990 through the 1999 period. SHAPES-PC uses the following general equation to project annual appliance usage for seventeen types of residential appliances:

AE_t^a = $NAP_t^a * ADJCL_t^a * AUI^a$

Where:

t = the forecast year

a = the appliance type

AE = the annual energy for appliance in year t

NAP = the forecasted appliance stock for type a in year t

ADJCL = the adjusted connected load for appliance a in year t

AUI = the annual hours of integral use for appliance a

Projected residential sales are the summation of the individual appliance usages for a given year. Residential sales are expected to grow at an average annual rate of 1.4 percent from 2000 to 2009.

4.2.2 Commercial

SHAPES-PC defines the commercial sector as all customers dealing with the following activities: 1) forestry, fishing, and construction, 2) transportation and public utilities, 3) wholesale trade, 4) retail trade, 5) finance, insurance, and real estate and 6) services and government. Annual commercial sales are the sum of baseload, heating, and cooling components. The following equations are used to project these components of commercial sales:

AEB_t^c	=	$EIB_t^c * EMP_t^c * PAF_t^c$
AEC_t^c	=	$EIC_t^c * EMP_t^c * PAF_t^c$
AEH_t^c	=	$EIH_t^c * EMP_t^c * PAF_t^c$

Where:

c	=	the commercial customer category
t	=	the forecast year
AEB	=	the annual baseload energy forecast
AEC	=	the annual cooling energy forecast
AEH	=	the annual heating energy forecast
EIB	=	the baseload energy intensity for customer category c in year y
EIC	=	the cooling energy intensity for customer category c in year t
EIH	=	the heating energy intensity for customer category c in year t
EMP	=	the employment forecast for customer category in year t
PAF	=	the price adjustment factor for customer c in year t

OUC's service area commercial employment historical data and projections were developed by using Orange County commercial employment and applying a trended fraction of OUC's share of the county number.

The commercial sales sector forecast that is developed from these equations is then combined with the industrial sector sales forecast to produce the general service non-demand and general service demand sales forecasts which will be discussed later.

4.2.3 Industrial

In the SHAPES-PC model the industrial sector is defined as those customers dealing in manufacturing and mining activities. The industrial sector is not considered to be weather sensitive like the residential and commercial sectors. Annual industrial energy sales are projected using the following formula:

$$AE_t^i = EI_t^i * EMP_t^i * (I\text{-}FSG_t^i) * PAF_t^i$$

Where:

i	=	the industrial customer category
t	=	the forecast year
AE	=	the annual energy forecast
EI	=	the energy intensity per employee
EMP	=	the industrial employment forecast
FSG	=	the fraction of annual energy self-generated
PAF	=	the price adjustment factor

The history and forecast of industrial employment data for the OUC service area was developed in the same way as the commercial employment forecast.

The industrial sales sector forecast that is developed from this formula is combined with the commercial sector forecast to generate the general service non-demand and general service demand sales forecasts.

4.2.4 General Service Non-Demand

Historically, the average number of General Service Non-Demand (GSND) customers has increased at an average annual rate of 1.6 percent from 1990 through 1999. The average number of GSND customers for the 1999 through 2008 period was projected as a function of service area employment associated with GSND customers. Multiple regression analysis was used to develop an econometric model for projecting the average number of GSND customers. The following model was chosen to be used:

GSNDCUS = 6916.36 + 0.045256 (EMPL)

Where:

GSNDCUS	=	Average number of general service non-demand customers
EMPL	=	OUC service area general service non-demand employment forecast

The projected average number of General Services Non-Demand customers is reported to grow at an average annual rate of 1.4 percent from 2000 to 2009.

The general service non-demand class is a mixture of both commercial and industrial customers as defined by the SHAPES-PC model. Therefore, GSND sales are projected as a percentage of the SHAPES-PC model sales forecast for the commercial and industrial sectors.

Historically, GSND sales have been flat over the period from 1990 through 2000. During the 2000 through 2009 period, GSND sales are projected to grow at an average annual rate of 3.7 percent.

4.2.5 General Service Demand

For the historic period from 1990 through 1999, the number of General Service Demand (GSD) customers grew at a 3.8 percent average annual rate. Multiple regression analysis was used to develop an econometric model to project the average number of GSD customers. The following equation was used:

GSDCUS = -532.564 + 0.105467 (EMPL)

Where:

GSDCUS = Average number of general service demand customers

EMPL = OUC service area general service demand employment forecast

For the forecast period 2000 through 2009, the number of average GSD customers is projected to increase at an annual rate of 2.2 percent. The GSD class is a mixture of commercial and industrial customers as defined by SHAPES-PC model. Therefore, GSD sales are projected as a percentage of the SHAPES-PC model's sales forecast for the commercial and industrial sectors.

Historically, from 1990 through 1999, GSD sales have grown at an average rate of 3.8 percent. For the forecast period, GSD sales are expected to grow at an average annual rate of 3.6 percent.

4.2.6 Street, Highway, and Traffic Lights

Total street and highway lighting use was determined from historical trends. During the forecast period, street and highway lighting is estimated to increase from 24 GWh to 26 GWh. The forecast reflects a decrease in usage per fixture which is more than offset by the increasing number of streetlights. Other sales to ultimate customers (traffic lights) have been projected to be 5 GWh throughout the forecast period.

4.2.7 OUC Use and Losses

OUC use is projected to be 5 GWh at the beginning of the forecast and growing to 6 GWh by the end of the forecast period. Distribution and transmission losses are projected to be 4.1 percent of retail sales.

4.2.8 Total Retail Sales

The sum of the consumption in all of the individual classes equals total OUC retail sales. Historically from 1990 through 1999, retail sales have grown at an average annual rate of 2.9 percent. For the forecast period, retail sales are projected to grow at an average annual rate of 2.9 percent. Retail sales plus OUC use and losses equal Net Energy for Load (NEL).

4.3 Orlando Utilities Commission Demand Forecast

Peak demand on the OUC system is highly weather sensitive with the annual peak demand occurring in both the summer and winter seasons. In seven out of the last ten years, the summer peak has been the higher seasonal peak.

The SHAPES-PC model projects demand on an hour by hour basis. The demand for each of the 8,760 hours in a year is individually projected. A typical weather year is developed by choosing historical months which most closely resemble normal or typical weather. The temperature of each hour of the typical weather year is used to determine the weather sensitive portion of hourly demand.

In the residential sector, the demands of the various appliance types for a given hour are summed together to arrive at the projected residential demand. Certain appliances such as heating and air conditioning are weather sensitive. A weather sensitive portion of demand for a given temperature is added to the non-weather sensitive portion of demand equaling total demand for appliances like air conditioning and heating.

In the commercial sector, the hourly demand forecast is a function of the hourly load profile and the annual commercial energy forecast. The hourly load profile is also a function of the hourly temperature of the typical weather year.

In the industrial sector, the hourly demand is a function of the hourly load profile and the annual industrial energy forecast. The industrial sector is not felt to be weather sensitive.

The hourly demand for OUC use and street, highway, and traffic lights are a function of their annual energy forecasts and their load profile relationships to the other sectors.

The demand forecast developed by the SHAPES-PC model is also a function of economic and demographic parameters such as the population forecast and commercial and industrial employment. Population and employment forecasts used to develop the base, low, and high demand forecasts are shown in Tables 4-1, 4-2, and 4-3 respectively. These projections were developed by using the Orange County population projections from the University of Florida's Population Bulletin.

4.3.1 Most Likely Case Load Forecast

Total peak demand is the sum of the hourly demands for all sectors adjusted for losses. Summer peak demand for the 2000 to 2009 period is the highest hourly peak demand occurring between April 1 and October 31 and is expected to grow at an average annual rate of 2.6 percent. Winter peak demand is the highest hourly demand occurring between November 1 of the prior year and March 31 of the current year, and is projected to grow at an average annual rate of 2.3 percent for the 2000/2001 to 2009/2010 period. The forecasted winter and summer peaks are shown in Tables 4-4 and 4-5 respectively.

4.3.2 Low Case and High Case Load Forecast

Summer peak demand for the 2000 to 2009 period is expected to grow at an average annual rate of 0.7 and 4.2 percent for the low and high demand forecasts respectively. Winter low and high peak demand forecasts are projected to grow at an average annual rate of 0.4 and 4.0 percent respectively for the 2000/2001 to 2009/2010 period. The forecasted winter and summer peaks for the low and high growth rate scenarios are shown in Tables 4-4 and 4-5 respectively.

Table 4-1 Economic Forecast – Most Likely Case			
Year	OUC Service Area Population	OUC Service Area Commercial Employment	OUC Service Area Industrial Employment
2000	312,800	223,293	16,706
2001	317,600	229,493	17,005
2002	323,100	235,693	17,102
2003	328,100	241,689	17,505
2004	333,800	247,076	17,805
2005	338,800	253,276	18,105
2006	344,500	258,662	18,405
2007	349,500	264,659	18,705
2008	354,800	269,334	19,005
2009	356,900	274,092	19,310
AAGR%	1.48%	2.3%	1.62%

Table 4-2 Economic Forecast – Low Case			
Year	OUC Service Area Population	OUC Service Area Commercial Employment	OUC Service Area Industrial Employment
2000	312,000	218,500	16,679
2001	312,300	219,500	16,754
2002	312,600	220,500	16,838
2003	312,900	221,600	16,918
2004	314,300	222,600	16,998
2005	314,600	223,600	17,079
2006	314,900	224,700	17,160
2007	315,200	225,700	17,242
2008	315,500	226,705	17,324
2009	315,801	227,714	17,407
AAGR%	0.13%	0.46%	0.48%

Table 4-3 Economic Forecast – High Case			
Year	OUC Service Area Population	OUC Service Area Commercial Employment	OUC Service Area Industrial Employment
2000	321,000	225,000	17,200
2001	330,800	232,800	17,800
2002	340,800	240,800	18,400
2003	351,100	249,100	19,100
2004	363,100	257,700	19,700
2005	374,100	266,700	20,400
2006	385,400	275,900	21,200
2007	397,100	285,900	21,900
2008	409,157	296,265	22,623
2009	421,580	307,006	23,370
AAGR%	3.07%	3.5%	3.46%

Table 4-4 Winter Peak Demand Forecasts - MW			
Year	Low Growth Case	Most Likely Case	High Growth Case
00 / 01	963	994	1,037
01 / 02	966	1,019	1,078
02 / 03	968	1,044	1,121
03 / 04	972	1,068	1,167
04 / 05	975	1,093	1,214
05 / 06	977	1,118	1,261
06 / 07	980	1,143	1,312
07 / 08	985	1,169	1,366
08 / 09	992	1,193	1,423
09 / 10	997	1,217	1,482
AAGR%	0.36%	2.27%	4.04%

Table 4-5 Summer Peak Demand Forecasts – MW			
Year	Low Growth Case	Most Likely Case	High Growth Case
2000	938	950	971
2001	943	977	1,020
2002	949	1,005	1,054
2003	954	1,033	1,098
2004	962	1,060	1,145
2005	968	1,089	1,193
2006	974	1,116	1,241
2007	980	1,146	1,294
2008	986	1,171	1,347
2009	995	1,198	1,404
AAGR%	0.66%	2.61%	4.18%

4.3.3 Net Energy for Load

Net Energy for Load (NEL) is the sum of the total forecasted energy required to serve retail customers, including energy for utility use and losses, less energy savings through energy conservation measures. As shown in Table 4-6, the NEL for the most likely case is expected to increase at an average annual growth rate of 2.9 percent. The average annual growth rate for the low and high band NEL forecasts in 1.1 and 4.4 percent respectively.

Table 4-6 Forecasts of Net Energy for Load - GWh			
Year	Low Growth Case	Most Likely Case	High Growth Case
2000	4,682	4,745	4,835
2001	4,719	4,883	5,032
2002	4,770	5,037	5,250
2003	4,824	5,197	5,481
2004	4,897	5,367	5,743
2005	4,937	5,517	5,978
2006	4,993	5,676	6,238
2007	5,042	5,836	6,506
2008	5,109	6,000	6,807
2009	5,165	6,145	7,097
AAGR%	1.09%	2.91%	4.36%

4.4 St. Cloud Load Forecast

OUC has an interlocal agreement with the City of St. Cloud. As part of this agreement, OUC is the total requirements supplier for St. Cloud. Therefore OUC has developed a forecast of St. Cloud's net energy for load and peak demand requirements.

The St. Cloud net energy for load forecast was developed using regression analysis. The net energy for load was projected as a function of Osceola County population. The source for the population projections was the University of Florida Bureau of Business and Economic Research's Population Bulletin. The following is the St. Cloud net energy for load equation:

STCLNEL = 21.269 * (OSPOP) – 26791.5

R-squared = 0.9839

The Variables are defined as follows:

STCLNEL = Net Energy for Load for St. Cloud in MWh

OSPOP = Osceola County population

For the historical period 1990 through 1999, St. Cloud's net energy for load has grown at a 4 percent average annual rate. For the forecast period the net energy for load is projected to grow at an average annual rate of 2.9 percent. St. Cloud's population grew at an average annual rate of 3.1 percent for the historical period. The population is projected to grow at an average rate of 2.9 percent for the forecast period.

For the forecast period, the summer peak demand is growing at 2.9 percent and winter peak demand is growing at 2.8 percent. Table 4-7 provides the forecasted summer and winter peak demand for St. Cloud as well as the forecasted net energy for load.

Table 4-7
City of St. Cloud
Demand and Energy Forecast

Year	Total Summer Demand (MW)	Total Winter Demand (MW)	Net Energy for Load (NEL) (GWh)
2000	75	93	332
2001	77	96	343
2002	80	99	354
2003	82	102	365
2004	85	105	376
2005	87	108	387
2006	90	111	398
2007	92	114	409
2008	95	117	420
2009	97	120	431
2010	99	123	442
AAGR%	2.9%	2.8%	2.94%

5.0 Demand-Side Management

Throughout its history, the Orlando Utilities Commission (OUC) has demonstrated a strong commitment to serve its customers' conservation needs. OUC has undertaken many conservation programs to meet customer needs and expectations. The demand-side management goals for OUC were approved by the Florida Public Service Commission (FPSC) on March 23, 2000, by Order No. PSC-00-0587-FOF-EG. The FPSC goals for OUC and the programs implemented to meet these goals are presented briefly in this section and in greater detail in OUC's 2000 Demand-Side Management Plan filed in Docket No. 990722-EG.

5.1 Goals

In Order No. PSC-00-0587-FOF-EG, the Public Service Commission approved the zero numeric conservation goals filed by the OUC in Docket 990722-EG in accordance with Rules 25-17.0001-.005 of the Florida Administrative Code. Even though OUC's goals are zero, OUC plans to continue several Demand-Side Management (DSM) programs as proposed in OUC's DSM Plan. Table 5-1 presents the approved goals for OUC.

5.2 Current Programs

There have been significant changes in the market place in the last 5 years. Today there is much more emphasis on competition as the electric industry prepares for deregulation. Economic conditions have also changed significantly, for example, the cost of power plants and fuel costs have decreased drastically. As a result, conservation programs are significantly less cost effective. The current customer programs include:

- Residential Energy Survey Program
- Residential Heat Pump Program
- Residential Weatherization Program
- Low Income Home Energy Fixup Program
- Educational Outreach Program
- Commercial Energy Survey Program

Table 5-1 Total Conservation Goals Approved by the FPSC						
	Residential			Commercial		
Year	Winter kW Reduction	Summer kW Reduction	MWh Energy Reduction	Winter kW Reduction	Summer kW Reduction	MWh Energy Reduction
1999						
2000	0	0	0	0	0	0
2001	0	0	0	0	0	0
2002	0	0	0	0	0	0
2003	0	0	0	0	0	0
2004	0	0	0	0	0	0
2005	0	0	0	0	0	0
2006	0	0	0	0	0	0
2007	0	0	0	0	0	0
2008	0	0	0	0	0	0
2009	0	0	0	0	0	0

5.2.1 Residential Energy Survey

This program is designed to provide residential homeowners with recommended energy efficiency measures and practices. The Residential Energy Survey includes complete attic, air duct, and air return inspections. The customer is given a choice to receive a low-flow showerhead or compact fluorescent bulb. OUC energy analysts are presently using this walk-thru type audit as a means to get OUC customers to participate in other conservation programs and to qualify for appropriate rebates.

5.2.2 Residential Heat Pump Program

Heat pumps are marketed to the owners of existing residential strip heating systems and older, inefficient central air conditioners and heat pumps. The program requires heat pumps with a SEER of 11 (or greater) and a HSPF of 7.0 (or greater) in order to qualify for rebates. Rebates vary by equipment SEER levels. One of the main benefits of the program is the duct work and insulation level improvements made by contractors when installing the energy efficient heat pumps.

5.2.3 Residential Weatherization Program

This program is designed for existing single family homes and promotes R-19 ceiling insulation (or higher), caulking, weather-stripping, window treatment, water heater insulation and air condition/heating supply and return air duct repair. The customer can receive a $140 rebate for installing R-19 ceiling insulation (or higher), $100 rebate for duct repairs and up to $110 for other conservation measures specified above. In addition, the customer is allowed to carry payments for ceiling insulation on their electric bill for 12 or 24 months. OUC directly pays the total cost for installation when OUC provides the financing.

The program is promoted through Residential Energy Surveys, trade shows, exhibits, and neighborhood meetings.

5.2.4 Low Income Home Energy Fixup Program

This program targets low-income residential customers, customers with an annual income of less than $20,000. Every customer is eligible for an energy audit. Audit recommendations usually require the customer to spend money replacing or adding energy conservation measures. Low-income customers may not have the discretionary income to make these changes.

The program will pay 85 percent of the total contract cost for home weatherization for the following measures:

a) upgrading ceiling insulation to R-19
b) exterior and interior caulking
c) weatherstripping doors and windows
d) air conditioning/heating supply and return air duct repairs
e) water heater insulation

The purpose of the program is to reduce the energy cost for low income households, particularly those households with elderly persons, disabled persons, and children, by improving the energy efficiency of their homes and ensuring a safe and healthy community.

5.2.5 Education Outreach Program

This program is now entering its 15th year of operation. The program is very successful and has won several awards for contributions to education. The program consists of hour long classroom presentations focused on teaching students about energy and water conservation. Students are taught how electricity is generated and are encouraged to perform mini electric and water audits on their own homes.

5.2.6 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.

6.0 Forecast of Facilities Requirements

6.1 Existing Capacity Resources & Requirements

6.1.1 Existing Generating Capacity

OUC existing generating capability is 1,024 MW in the summer and 1,071 MW in the winter as summarized in Table 2-1. The existing generating capability consists of OUC's joint ownership share of Stanton Energy Center and Indian River Combustion Turbines operated by OUC and OUC's joint ownership share of Crystal River 3, McIntosh 3, and St. Lucie 2 operated by FPC, The City of Lakeland, and FP&L, respectively.

6.1.2 Power Purchases Agreements

As part of the sale of the Indian River steam units, OUC entered into a power purchase agreement (PPA) with Reliant for capacity and energy from the Indian River steam units. The term of the PPA extends from October 1, 1999 through September 30, 2003. OUC also has an option to extend the PPA an additional four years.

The capacity from the PPA is as follows:

Period	MW
10/1/99 – 9/30/00	593
10/1/00 – 9/30/01	593
10/1/01 – 9/30/02	525 (Option available for additional 10%)
10/1/02 – 9/30/03	525 (Option available for additional 10%)

The capacity available from the additional four-year option is 500 MW. The 500 MW can be reduced in 100 MW increments through the end of the four year option term through proper notice by OUC.

The cost of the capacity and energy is based on a demand and energy charge. The energy charge is based on fixed heat rate and a specified split of gas and oil for fuel.

6.1.3 Power Sales Agreements

OUC has several power sales agreements resulting in the contracted firm interchange shown in Tables 6-1 and 6-2. OUC has a system power sales agreement with Enron. OUC has unit power sales agreements with Florida Municipal Power Agency (FMPA), Seminole Electric Cooperative (SEC), Reedy Creek Improvement District (RCID), and Kissimmee Utility Authority (KUA) from the Indian River and Stanton Plants. In addition, OUC is the full requirement supplier for St. Cloud.

6.1.4 Modifications & Retirements of Generating Facilities

OUC has not scheduled any unit modifications or retirements over the ten year forecast period, but will continue to evaluate options on an ongoing basis. The St. Cloud diesels are scheduled to retire in the fall of 2004.

6.2 Existing Transmission System

OUC's existing transmission system consists of 26 substations and 302 miles of 230 kV and 115 kV transmission lines as well as 50 miles of St. Cloud's 230 kV and 69 kV transmission lines. Table 2-3 provides additional description of OUC's 12 transmission interconnections. Sections 2.4.2 and 6.4.2 of this report discuss OUC's ongoing and planning transmission projects.

Table 6-1: Summary of Winter Capacity, Demand, and Reserve Margin

Year	Available Capacity					Sales				Reserves			
	Installed Capacity (MW)	Maximum Reliant Purchase (MW)	Minimum Reliant Purchase (MW)	Maximum Available Capacity (MW)	Minimum Available Capacity (MW)	Contracted Firm Sales (MW)	Projected Sales to St. Cloud[1] (MW)	OUC Retail Peak Demand (MW)	Total Sales (MW)	Maximum Reserves		Minimum Reserves	
										(MW)	(%)	(MW)	(%)
2000	1071	593	593	1664	1664	440	60	970	1470	194	13	194	13
2001	1071	593	593	1664	1664	341	64	994	1399	265	19	265	19
2002	1071	578	525	1649	1596	335	67	1019	1421	228	16	175	12
2003	1071	578	525	1649	1596	316	71	1044	1431	218	15	165	12
2004	1071	500	0	1571	1071	261	74	1068	1403	168	12	-332	-24
2005	1071	500	0	1571	1071	171	78	1093	1342	229	17	-271	-20
2006	1071	500	0	1571	1071	139	81	1118	1338	233	17	-267	-20
2007	1071	500	0	1571	1071	139	85	1143	1367	204	15	-296	-22
2008	1071	0	0	1071	1071	142	88	1169	1399	-328	-23	-328	-23
2009	1071	0	0	1071	1071	144	91	1193	1428	-357	-25	-357	-25

[1]Net of St. Cloud's existing resources. OUC manages all of St. Cloud's resources to meet their load requirements.

Table 6-2: Summary of Summer Capacity, Demand, and Reserve Margin

Year	Available Capacity					Sales				Reserves			
	Installed Capacity (MW)	Maximum Reliant Purchase (MW)	Minimum Reliant Purchase (MW)	Maximum Available Capacity (MW)	Minimum Available Capacity (MW)	Contracted Firm Sales (MW)	Projected Sales to St. Cloud[1] (MW)	OUC Retail Peak Demand (MW)	Total Sales (MW)	Maximum Reserves		Minimum Reserves	
										(MW)	(%)	(MW)	(%)
2000	1024	593	593	1617	1617	422	36	950	1408	209	15	209	15
2001	1024	593	593	1617	1617	341	39	977	1357	260	19	260	19
2002	1024	578	525	1602	1549	335	42	1005	1382	220	16	167	12
2003	1024	578	525	1602	1549	316	44	1033	1393	209	15	156	11
2004	1024	500	0	1524	1024	261	48	1060	1369	155	11	-345	-25
2005	1024	500	0	1524	1024	171	50	1089	1310	214	16	-286	-22
2006	1024	500	0	1524	1024	139	54	1116	1309	215	16	-285	-22
2007	1024	500	0	1524	1024	139	56	1146	1341	183	14	-317	-24
2008	1024	0	0	1024	1024	142	59	1171	1372	-348	-25	-348	-25
2009	1024	0	0	1024	1024	144	62	1198	1404	-380	-27	-380	-27

[1]Net of St. Cloud's existing resources. OUC manages all of St. Cloud's resources to meet their load requirements.

6.3 Reserve Margin Criteria

The Florida Reliability Coordinating Council (FRCC) has set a minimum planned reserve margin criteria of 15 percent. The Florida Public Service Commission (FPSC) has established a minimum planned reserve margin criterion of 15 percent in 25-6.035 (1) Fla. Admin. Code as well for the purposes of sharing responsibility for grid reliability. The 15 percent minimum planned reserve margin criteria is generally consistent with practice through out much of the industry. OUC has adopted the 15 percent minimum reserve margin requirement as its planning methodology.

6.4 Future Resource Needs

6.4.1 Generation Capabilities & Requirements Forecast

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 6-3 and 6-4 calculate additional reserve required for winter and summer for St. Cloud above the capacity that OUC has projected to be sold to St. Cloud. As shown in Tables 6-3 and 6-4, St. Cloud has a 15 MW PR purchase from Tampa Electric Company. PR purchases are assumed to not require reserves to be provided by the purchaser.

Tables 6-5 and 6-6 present the total reserve requirements required by OUC for the winter and for the summer. OUC's total reserve requirements are the sum of the reserves required for OUC's retail loads, the reserves required for the PR sale to Reedy Creek Improvement District, and the additional reserves necessary for St. Cloud's loads.

Tables 6-7 and 6-8 present OUC's additional capacity requirements for the winter and summer. OUC's PPA from Reliant offers significant flexibility. Based on the flexibility in that agreement, Tables 6-7 and 6-8 represent minimum additional capacity required if OUC obtains the maximum capacity available from the Reliant purchase as well as the capacity that would be required if OUC obtains the minimum amount of capacity allowed under the Reliant agreement.

Table 6-7 indicates that additional capacity will not be needed until 2004 if OUC elects to take the maximum capacity available from the Reliant purchase. The additional capacity is only needed for the 2003/2004 winter due to a power sales agreement with

Year	St. Cloud Peak Demand (MW)	TECO PR Purchase (MW)	Load Requiring Reserves (MW)	St. Cloud Required Reserves (MW)	Total St. Cloud Capacity Requirements (MW)	Purchase from OUC (MW)	TECO PR (MW)	St. Cloud Diesels (MW)	Total St. Cloud Resources (MW)	Additional St. Cloud Reserves Required (MW)
Table 6-3 St. Cloud Winter Reserve Requirements										
2000	93	15	78	12	105	60	15	21	96	9
2001	96	15	81	12	108	64	15	21	100	8
2002	99	15	84	13	112	67	15	21	103	9
2003	102	15	87	13	115	71	15	21	107	8
2004	105	15	90	14	119	74	15	21	110	9
2005	108	15	93	14	122	78	15	0	93	29
2006	111	15	96	14	125	81	15	0	96	29
2007	114	15	99	15	129	85	15	0	100	29
2008	117	15	102	15	132	88	15	0	103	29
2009	120	15	105	16	136	91	15	0	106	30

Year	St. Cloud Peak Demand (MW)	TECO PR Purchase (MW)	Load Requiring Reserves (MW)	St. Cloud Required Reserves (MW)	Total St. Cloud Capacity Requirements (MW)	Purchase from OUC (MW)	TECO PR (MW)	St. Cloud Diesels (MW)	Total St. Cloud Resources (MW)	Additional St. Cloud Reserves Required (MW)
Table 6-4 St. Cloud Summer Reserve Requirements Loads										
2000	75	15	60	9	84	36	15	21	72	12
2001	77	15	62	9	86	39	15	21	75	11
2002	80	15	65	10	90	42	15	21	78	12
2003	82	15	67	10	92	44	15	21	80	12
2004	85	15	70	11	96	48	15	21	84	12
2005	87	15	72	11	98	50	15	0	65	33
2006	90	15	75	11	101	54	15	0	69	32
2007	92	15	77	12	104	56	15	0	71	33
2008	95	15	80	12	107	59	15	0	74	33
2009	97	15	82	12	109	62	15	0	77	32

Table 6-5 OUC Winter Reserve Requirements				
Year	OUC Retail Reserve Requirement (MW)	Reserves for RCID PR Sale (MW)	Additional St. Cloud Reserves (MW)	Total Reserves Required (MW)
2000	146	13	9	168
2001	149	14	8	171
2002	153	17	9	179
2003	157	17	8	182
2004	160	18	9	187
2005	164	19	29	212
2006	168	18	29	215
2007	171	21	29	221
2008	175	21	29	225
2009	179	22	30	231

Table 6-6 OUC Summer Reserve Requirements				
Year	OUC Retail Reserve Requirement (MW)	Reserves for RCID PR Sale (MW)	Additional St. Cloud Reserves (MW)	Total Reserves Required (MW)
2000	143	13	12	168
2001	147	14	11	172
2002	151	17	12	180
2003	155	17	12	184
2004	159	18	12	189
2005	163	19	33	215
2006	167	18	32	217
2007	172	21	33	226
2008	176	21	33	230
2009	180	21	32	233

Table 6-7
OUC Winter Capacity Addition Requirements

Year	Maximum Available Reserves (MW)	Minimum Available Reserves (MW)	Required Reserves (MW)	Minimum Additional Capacity Required (MW)	Maximum Additional Capacity Required (MW)
2000	194	194	168	-26	-26
2001	265	265	171	-94	-94
2002	228	175	179	-49	4
2003	218	165	182	-36	17
2004	168	-332	187	19	519
2005	229	-271	212	-17	483
2006	233	-267	215	-18	482
2007	204	-296	221	17	517
2008	-328	-328	225	553	553
2009	-357	-357	231	588	588

Table 6-8
OUC Summer Capacity Addition Requirements

Year	Maximum Available Reserves (MW)	Minimum Available Reserves (MW)	Required Reserves (MW)	Minimum Additional Capacity Required (MW)	Maximum Additional Capacity Required (MW)
2000	209	209	168	-41	-41
2001	260	260	172	-88	-88
2002	220	167	180	-40	13
2003	209	156	184	-25	28
2004	155	-345	189	34	534
2005	214	-286	215	1	501
2006	215	-285	217	2	502
2007	183	-317	226	43	543
2008	-348	-348	230	578	578
2009	-380	-380	233	613	613

Seminole Electric Cooperative, which expires May 31, 2004. If OUC takes the maximum amount of capacity from Reliant, OUC begins to need capacity in 2004. On the other hand, if OUC takes the minimum amount of capacity from the Reliant agreement, OUC would need a substantial amount of capacity beginning with the expiration of the Reliant agreement on October 1, 2003.

6.4.2 Transmission Capability and Requirements Forecast

OUC continuously monitors and upgrades the bulk power transmission system as necessary to provide reliable electric service to their customers. OUC has adopted the North American Electric Reliability Council (NERC) Planning Standards as the basis for its and the City of St. Cloud's electric power transmission system planning. For the purposes of planning studies, OUC utilizes certain criteria that pertain to voltage and line and transformer loading. A criterion of 95 percent and 105 percent of nominal system voltage establishes the lower and upper limits of acceptable voltage. Transmission lines are not allowed to exceed 100 percent of their continuous ratings during normal conditions or 100 percent of their emergency ratings during contingency outages. The bus tie transformer loading guideline is 100 percent of the unit's 65° C rating.

OUC's transmission group continually reviews the need and options for increasing the capability of the transmission system based on the following planning criteria.

During the course of a planning study, the OUC and St. Cloud transmission systems are subjected to a single contingency analysis which involves outaging each 69-230 kV transmission line respectively. Bus tie transformers, tie lines with neighboring utilities and off-system facilities known to cause internal problems are included as well. If a violation of the voltage or loading criteria occurs a permanent solution is determined in the form of an upgrade or new construction. The revised system containing the improvement is then subjected to the same analysis as the original to insure that no voltage or loading violations remain.

Based on the above criteria as well as economic and reliability factors, OUC has developed the following schedule of upgrades to maintain reliable and economical electric service to their customers.

- A second 230 kV tie line between Stanton and FPC. Expected completion date is January, 2001.
- Upgrade the 69 kV line from KUA to the City of St. Cloud. Expected completion date is in 2002.
- Addition of the Grant to Robinson 115 kV transmission line. Expected completion date is in 2002.
- Addition of second bus tie transformer at the Southwood substation. Expected completion date is in 2004.

None of these planned transmission system projects are subject to the Transmission Line Siting Act and none of the planned projects will be associated facilities under the Power Plant Siting Act.

Studies are currently underway to determine the associated transmission system needs for the addition of new generating capacity at the Stanton Energy Center.

7.0 Development of Supply-side Alternatives

This section provides the description of supply-side generating unit alternatives considered by OUC. All generating unit alternatives would be located at the existing Stanton site. Black & Veatch has estimated the capital cost, performance, and O&M costs for each alternative. In addition, Black & Veatch has developed the construction schedules for these alternatives based on recent experience.

The configurations of four new unit candidates are as follows:

- Pulverized Coal Unit
- 501 F 1 X 1 Combined Cycle
- 501 F 2 X 1 Combined Cycle
- 7FA Simple Cycle Combustion Turbine

Specific manufacturers were used for the combustion turbine and combined cycle alternatives to provide output and performance data. The use of specific manufacturers is not meant to limit the alternatives to those manufacturers. Several manufacturers providing similar equipment could be utilized.

In addition to the generating unit alternatives, the Reliant PPA options described in Section 6.1.2 are also supply-side alternatives.

7.1 Plant Configurations

Pulverized Coal Unit This configuration will be a pulverized coal fueled plant designed for the competitive power market.

501 F 1 X 1 Combined Cycle This alternative will be one Westinghouse 501 F combustion turbine with one heat recovery steam generator (HRSG) and one steam turbine generator. The ISO capacity is 269.5 MW.

501 F 2 X 1 Combined Cycle This alternative will be two Westinghouse 501 F combustion turbines with two HRSGs and one steam turbine generator. The ISO capacity is 543.8 MW.

GE 7FA Simple Cycle This alternative will be one General Electric 7241 (7FA) simple cycle combustion turbine generator with an ISO capacity of 169.8 MW.

7.2 Capital Cost Estimate Assumptions

The following assumptions form the basis of the capital cost estimates.

- General Assumptions.
- Direct Cost Assumptions
- Indirect Cost Assumptions.

7.2.1 Pulverized Coal Unit

7.2.1.1 General Assumptions

1. The Stanton plant site is considered a brownfield site, which is reasonably level and clear with no wetlands. No demolition of any existing structures is included in the cost estimate.
2. The site has sufficient area available to accommodate construction activities including, but not limited to, offices, laydown, and staging.
3. The plant will feature one (1) steam generator and one (1) condensing steam turbine generator. The steam generator is not enclosed. No consideration was given to possible future expansion of the facility.
4. The steam turbine will be rated at approximately 425 MW net, and is inclusive of standard sound enclosure.
5. Piling is assumed to be required. Stabilization of the existing sub-grade is not anticipated.
6. The Steam Turbine building includes a central control room and electrical equipment area that will have adequate space to support a battery room and motor control center. All buildings, except the Steam Turbine building, will be pre-engineered metal structures.
7. An allowance for a fabric filter and spray dryer scrubber with structural steel and total electrical system is included. It is assumed that the scrubber solids will be disposed of in a lined area of the landfill. An allowance has been included for the landfill and lining.
8. Raw water and make-up water will be available from the existing units.

9. A sanitary sewer treatment system is available on site.
10. Construction power is available on site.
11. Coal will be available at the site. Allowance to expand the existing coal handling system is included. Railroad yard facilities -- locomotive, coal cars, shed, etc.-- are not included.
12. Back up fuel will not exist. No. 2 fuel oil will be used during start up, for low load stabilization, and auxiliary equipment.
13. Existing fire protection system will be extended to new unit.
14. Field Erected Tanks consist only of a condensate storage tank.
15. The air quality control systems would be designed to comply with all applicable emissions requirements. Selective catalytic reduction (SCR) is included with the pulverized coal boiler.
16. It is assumed that adequate treated sewage effluent will be available from the Orange County Easterly Subregional Wastewater Treatment Plant for cooling water makeup.
17. It is assumed that the existing brine concentrator plant in conjunction with the dry scrubber spray dryer is adequate to dispose of cooling tower blowdown.
18. Mechanical draft cooling towers are included.
19. An allowance is included for expanding fly ash storage area.

7.2.1.2 Direct Cost Assumptions

1. All direct costs are expressed in January 1, 2000 dollars.
2. Direct costs include the costs associated with the purchase of equipment, erection and contractors' service.
3. These costs are based on a commercial operation date of overnight.
4. Construction costs are based on an engineer, procure and construction (EPC) contracting philosophy.
5. An allowance of 0.5 percent of the total direct cost is included for spare parts.

7.2.1.3 Indirect Cost Assumptions

1. General indirect costs include relay checkouts and testing, instrumentation and control equipment calibration and testing, systems and plant startup including operating crew during test and initial operation period, operating crew training, electricity, water and fuel used during construction. Insurance--Builder's Risk and General Liability are included.
2. Engineering and related services include Architecture/Engineering services, owner office engineers, outside consultants and other related costs incurred in the permit and licensing process.
3. Field construction management services include field management staff including supporting staff personnel, field contract administration, field inspection and quality assurance, project control, technical direction and management of start up and testing, cleanup expense for the portion not included in the direct-cost construction contracts, safety and medical services, guards and other security services, insurance premiums, other required labor related insurance, performance bond and liability insurance for equipment and tools. Telephone and other utility bills associated with temporary services.
4. Margin is included in the total capital cost.
5. Shipping for equipment and materials is included.
6. No Federal, state, county, and local taxes are included.

7.2.2 501F 1x1 Combined Cycle

7.2.2.1 General Assumptions

1. The site is considered a brownfield site which is reasonably level and clear with no wetlands. No demolition of any existing structures is included in this cost estimate.
2. The site has sufficient areas available to accommodate construction activities including but not limited to offices, laydown and staging.
3. The plant will feature one (1) dual fueled, natural gas/No. 2 oil fueled combustion turbine, one (1) HRSG and one (1) condensing steam turbine

generator. No consideration was given to possible future expansion of the facility.

4. The combustion turbine(s) are inclusive of standard sound and outdoor enclosures.
5. Piling is assumed to be required. Stabilization of the existing subgrade is not anticipated.
6. The central control/electrical building will have adequate space to support a battery room and motor control center. All buildings will be pre-engineered metal structures.
7. This cost estimate is based on one (1) – W501F combustion turbine as manufactured by Westinghouse. The costs of unloading and delivery to the project site are included.
8. Raw and make-up water will be available from the existing units.
9. A sanitary sewer will be available on site.
10. Construction power is available on site.
11. Cost for a natural gas pipeline to connect FGT's system to the site is included and adequate gas pressure is assumed.
12. The cost of receiving pumps for truck unloading of No.2 oil is included.
13. Costs to connect the unit to the existing Stanton substation are included. No costs are included for additional transmission past the substation.
14. Automatic fire protection will consist of the combustion turbine generator vendor's standard CO_2 fire suppression system, water deluge of the transformers, hydrant protection of the cooling tower and site, wet pipe sprinkler system in the buildings except in the control room which will have fire detection equipment only.
15. A cooling tower will provide cycle heat rejection. It is a wooden mechanical draft tower with non-fouling type fill with three nominal 33 percent capacity vertical circulating water pumps.
16. Required new natural gas pipeline cost is $2,625,000 ($750,000 per mile for 3.5 miles).
17. Field Erected Tanks consisting of the following:

- Fuel Oil Storage Tank
- Condensate Storage Tank

18. It is assumed that adequate treated sewage effluent will be available from the Orange County Easterly Subregional Wastewater Treatment Plant for cooling water makeup.
19. It is assumed that the existing brine concentrator plant is adequate to dispose of cooling tower blowdown.
20. It is assumed that location of the combined cycle unit will not require any mitigation costs.
21. Evaporative coolers are included.

7.2.2.2 Direct Cost Assumptions

1. All direct costs are expressed in January 1, 2000 dollars.
2. Direct costs include the costs associated with the purchase of equipment, erection and all contractor services.
3. The costs are based on a commercial operation date of overnight.
4. Construction costs are based on an engineer, procure and construction (EPC) contracting philosophy.
5. An allowance of 1 percent of the total direct cost is included for spare parts.
6. Permitting and licensing are included in this cost estimate.

7.2.2.3 Indirect Cost Assumptions

1. General indirect costs include relay checkouts and testing, instrumentation and control equipment calibration and testing, systems and plant startup including operating crew during test and initial operation period, operating crew training, electricity, water and fuel used during construction, but no local taxes are included in this cost estimate. Insurance including general liability, builders risk, and liquidated damages is included.
2. Engineering and related services include Architecture/Engineering services, owner office engineers, outside consultants and other related costs incurred in the permit and licensing process.

3. Field construction management services include field management staff including supporting staff personnel, field contract administration, field inspection and quality assurance, project control, technical direction and management of start up and testing, cleanup expense for the portion not included in the direct-cost construction contracts, safety and medical services, insurance premiums, other required labor related insurance, performance bond and liability insurance for equipment and tools. Telephone and other utility bills associated with temporary services.
4. Margin is included in the total capital costs.
5. Shipping for equipment and materials is included.
6. No Federal, state, county, and local taxes are included.

7.2.3 501 F 2 x 1 Combined Cycle

7.2.3.1 General Assumptions

1. The site is considered a brownfield site which is reasonably level and clear with no wetlands. No demolition of any existing structures is included in this cost estimate.
2. The site has sufficient areas available to accommodate construction activities including but not limited to offices, laydown and staging.
3. The plant will feature two (2) dual fueled, natural gas/No. 2 oil fueled combustion turbines, one (1) HRSG and one (1) condensing steam turbine generator. No consideration was given to possible future expansion of the facility.
4. The combustion turbine(s) are inclusive of standard sound and outdoor enclosures.
5. Piling is assumed to be required. Stabilization of the existing subgrade is not anticipated.
6. The central control/electrical building will have adequate space to support a battery room and motor control center. All buildings will be pre-engineered metal structures.

7. This cost estimate is based on two (2) – W501F combustion turbines as manufactured by Westinghouse. The costs of unloading and delivery to the project site are included.
8. Raw and make-up water will be available from the existing units.
9. A sanitary sewer will be available on site.
10. Construction power is available on site.
11. Cost for a natural gas pipeline to connect FGT's system to the site is included and adequate gas pressure is assumed.
12. The cost of receiving pumps for truck unloading of No.2 oil is included.
13. Costs to connect the unit to the existing Stanton substation are included. No costs are included for additional transmission past the substation.
14. Automatic fire protection will consist of the combustion turbine generator vendor's standard CO_2 fire suppression system, water deluge of the transformers, hydrant protection of the cooling tower and site, wet pipe sprinkler system in the buildings except in the control room which will have fire detection equipment only.
15. A cooling tower will provide cycle heat rejection. It is a wooden mechanical draft tower with non-fouling type fill with three 33 percent capacity vertical circulating water pumps.
16. Required new natural gas pipeline cost is $2,625,000 ($750,000 per mile for 3.5 miles).
17. Field Erected Tanks consisting of the following:
    - Fuel Oil Storage Tank
    - Condensate Storage Tank
18. It is assumed that adequate treated sewage effluent will be available from the Orange County Easterly Subregional Wastewater Treatment Plant for cooling water makeup.
19. It is assumed that the existing brine concentrator plant is adequate to dispose of cooling tower blowdown.
20. It is assumed that location of the combined cycle unit will not require any mitigation costs.

21. Evaporative coolers are included.

7.2.3.2 Direct Cost Assumptions

1. All direct costs are expressed in January 1, 2000 dollars.
2. Direct costs include the costs associated with the purchase of equipment, erection and all contractor services.
3. The costs are based on a commercial operation date of overnight.
4. Construction costs are based on an engineer, procure and construction (EPC) contracting philosophy.
5. An allowance of 1 percent of the total direct cost is included for spare parts.
6. Permitting and licensing are included in this cost estimate.

7.2.3.3 Indirect Cost Assumptions

1. General indirect costs include relay checkouts and testing, instrumentation and control equipment calibration and testing, systems and plant startup including operating crew during test and initial operation period, operating crew training, electricity, water and fuel used during construction, but no local taxes are included in this cost estimate. Insurance including general liability, builders risk, and liquidated damages is included.
2. Engineering and related services include A/E services, owner office engineers, outside consultants and other related costs incurred in the permit and licensing process.
3. Field construction management services include field management staff including supporting staff personnel, field contract administration, field inspection and quality assurance, project control, technical direction and management of start up and testing, cleanup expense for the portion not included in the direct-cost construction contracts, safety and medical services, insurance premiums, other required labor related insurance, performance bond and liability insurance for equipment and tools. Telephone and other utility bills associated with temporary services.

4. Margin is included in the total capital costs.
5. Shipping for equipment and materials is included.
6. No Federal, state, county, and local taxes are included.

7.2.4 7FA Simple Cycle Combustion Turbine

7.2.4.1 General Assumptions

1. The site is considered a brownfield site which is reasonably level and clear with no wetlands. Also, no demolition of any existing structures is included in this cost estimate.
2. The site has sufficient area available to accommodate construction activities including but not limited to offices, lay-down and staging.
3. The plant will feature one (1) dual-fueled, natural gas/No. 2 oil fueled combustion turbine, no HRSG, and no Steam Turbine Generator. No consideration was given to possible future expansion of the facility.
4. The combustion turbine includes a standard sound enclosure.
5. Piling is assumed for the major equipment foundations. Stabilization of the existing subgrade is not anticipated.
6. The cost estimate is based on one (1) General Electric 7FA combustion turbine rated at approximately 170 MW ISO. The costs of unloading and delivery to the project site are included.
7. Construction power is available on site.
8. The cost of receiving pumps for truck unloading of No.2 oil is included.
9. Costs to connect the unit to the existing Stanton substation are included. No costs are included for additional transmission past the substation.
10. Automatic fire protection will consist of the combustion turbine generator vendor's standard CO_2 fire suppression system, water deluge of the transformers, and miscellaneous site fire hydrants tied into the plants' yard piping.
11. Required new natural gas pipeline cost is $2,625,000 ($750,000 per mile for 3.5 miles).

7.2.4.2 Direct Cost Assumptions

1. Total capital costs are expressed in January 1, 2000 dollars.
2. Direct costs include the costs associated with the purchase of equipment, erection and contractor' services.
3. Construction costs are based on an engineer, procure and construction (EPC) contracting philosophy.
4. An allowance of 1 percent of the total direct cost is included for spare parts.
5. Permitting and licensing are included in this cost estimate.

7.2.4.3 Indirect Cost Assumptions

1. General indirect costs include relay checkouts and testing, instrumentation and control equipment calibration and testing, systems and plant startup including operating crew during test and initial operation period, operating crew training, electricity, water and fuel used during construction, but no local taxes are included in the cost estimates. Also included is project insurance—general liability, builders risk, and freight. No liquidated damages insurance is included.
2. Engineering and related services include Architecture/Engineering services, owner office engineers, outside consultants and other related costs.
3. Field construction management services include field management staff including supporting staff personnel, field contract administration, field inspection and quality assurance, project control, technical direction and management of start up and testing, cleanup expense for the portion not included in the direct-cost construction contracts, safety and medical services insurance premiums, other required labor related insurance, performance bond and liability insurance for equipment and tools. Telephone and other utility bills associated with temporary services.
4. Margin is included in the total capital cost.

5. Shipping costs for equipment and materials is included in the cost of the equipment.
6. No Federal, state, county, and local taxes are included.

7.3 Capital Cost Estimate Summary

Table 7-1 summarizes the capital cost estimates for the four new unit alternatives based on the assumptions presented above.

7.4 Plant Performance Estimates

Black & Veatch has prepared and estimated the performance for all alternatives. It is assumed that the pulverized coal unit will have the same performance as Stanton 2. The performance for other alternatives were estimated based on different ambient temperatures, i.e., 30 F, 59 F, 71 F and 97 F. Tables 7-2 through 7-5 summarize the performance at different conditions for the alternatives, for new and clean conditions. Average degradation is applied to the combustion turbine and combined cycle alternatives as follows:

	Net Output (%)	Heat Rate (%)
7FA Simple Cycle	-4.04	2.87
1x1 501 F Combined Cycle	-3.82	1.94
2x1 501 F Combined Cycle	-3.72	1.84

Table 7-1:OUC – 10 Year Site Plan (Supplyside Alternatives Capital Cost Summary)

Description	425 Net MW	W501F 1x1x1	W501F 2x2x1	GE 7FA SC
Procurement Contracts				
Structural	$10,537,000	$658,000	$997,000	$190,000
Mechanical	$62,795,000	$68,231,000	$123,791,000	$36,280,000
Electrical	$15,744,000	$6,520,000	$11,021,000	$3,402,000
Control	$4,200,000	$1,789,000	$2,712,000	$460,000
Chemical	$1,885,000	$349,000	$529,000	$103,000
Total Procurement Contracts	$95,161,000	$77,547,000	$139,050,000	$40,436,000
Furnish & Erect Contracts				
Structural	$11,315,000	$2,942,000	$4,459,000	$156,000
Mechanical	$106,592,000	$3,042,000	$4,705,000	$986,000
Total Furnish & Erect Contracts	$117,907,000	$5,984,000	$9,164,000	$1,141,000
Construction Contracts				
Civil/Structural	$24,803,000	$11,462,000	$17,372,000	$2,496,000
Mechanical	$19,160,000	$9,297,000	$14,092,000	$1,845,000
Electrical/Control	$12,701,000	$2,988,000	$4,529,000	$1,021,000
Chemical	$443,000	$354,000	$536,000	$0
Construction Services	$2,884,000	$729,000	$1,105,000	$275,000
Total Construction Contracts	$59,991,000	$24,830,000	$37,634,000	$5,637,000
Total Contracts, Direct Cost (01/01/00 $)	$273,059,000	$108,361,000	$185,848,000	$47,214,000
Spare Parts	$1,365,000	$1,084,000	$1,858,000	$472,000
Ocean Shipping	$0	$0	$0	$0
Total Direct Cost (01/01/00 $)	$274,424,000	$109,445,000	$187,706,000	$47,686,000
Indirect Cost				
General Indirects	$13,721,000	$5,472,000	$9,385,000	$1,416,000
Outside Engineering	$16,466,000	$6,567,000	$11,262,000	$1,534,000
Field Construction Mgmt	$10,977,000	$4,378,000	$7,508,000	$1,180,000
Owner Admin/Engineering	$0	$0	$0	$0
Permitting and Licensing	$4,000,000	$4,000,000	$4,000,000	$1,500,000
Substation Modification Costs	$750,000	$2,500,000	$3,250,000	$750,000
Margin	$37,871,000	$15,103,000	$25,903,000	$6,218,000
Total Indirect Cost	$83,785,000	$38,020,000	$61,308,000	$12,598,000
SUBTOTAL	$358,209,000	$147,465,000	$249,014,000	$60,284,000
AFUDC	$0	$0	$0	$0
Land & Land Rights	$0	$0	$0	$0
Natural Gas Pipeline	N/A	$2,625,000	$2,625,000	$2,625,000
Total Capital Cost (01/01/00 $)	$358,209,000	$150,090,000	$251,639,000	$62,909,000
$/kW (based on ISO MW)	$843	$557	$463	$370

Table 7-2
Plant Performance - 30 F

Case	GE 7FA Simple Cycle	WH 501F 1 x1 Combined Cycle	WH 501F 2 x1 Combined Cycle
CTG Type	7241FA	501FD	501FD
Number of CTGs operating	1	1	2
Number of STGs Operating	0	1	1
Ambient Temperature, F	30	30	30
Ambient Relative Humidity, percent	60	60	60
Evaporative Cooler On/Off	Off	Off	Off
Elevation, ft above sea level	0	0	0
CTG Performance (each)			
Fuel Type	Natural Gas	Natural Gas	Natural Gas
Fuel LHV, Btu/lb	21,511	21,511	21,511
Fuel HHV, Btu/lb	23,891	23,891	23,891
NOx Control Method	DryLow	DryLow	DryLow
NOx, ppmvd @ 15% O2	9	25	25
Gross Output, kW	184,300	200,960	200,960
Gross Heat Rate, Btu/kWh LHV	9,180	9,065	9,065
Gross Heat Rate, Btu/kWh HHV	10,196	10,068	10,068
CTG Heat Input, MBtu/h LHV	1,691.87	1,821.70	1,821.70
CTG Heat Input, MBtu/h HHV	1,879.06	2,023.26	2,023.26
STG Performance			
Gross Output, kW	N/A	95,640	196,040
Backpressure, in HgA	N/A	1.17	1.14
Plant Performance (total)			
Gross Output, kW	184,300	296,600	597,960
Gross Heat Rate, Btu/kWh LHV	9,180	6,142	6,093
Gross Heat Rate, Btu/kWh HHV	10,196	6,822	6,767
Auxiliary Load, kW	2,030	6,280	12,820
Auxiliary Load, percent	1.1%	2.12%	2.14%
Net Output	182,270	290,320	585,140
Net Heat Rate, Btu/kWh LHV	9,282	6,275	6,227
Net Heat Rate, Btu/kWh HHV	10,309	6,969	6,915

Table 7-3
Plant Performance - 59 F

Case	GE 7FA Simple Cycle	WH 501F 1 x1 Combined Cycle	WH 501F 2 x1 Combined Cycle
CTG Type	7241FA	501FD	501FD
Number of CTGs operating	1	1	2
Number of STGs Operating	0	1	1
Ambient Temperature, F	59	59	59
Ambient Relative Humidity, percent	60	60	60
Evaporative Cooler On/Off	Off	Off	Off
Elevation, ft above sea level	0	0	0
CTG Performance (each)			
Fuel Type	Natural Gas	Natural Gas	Natural Gas
Fuel LHV, Btu/lb	21,511	21,511	21,511
Fuel HHV, Btu/lb	23,891	23,891	23,891
NOx Control Method	DryLow	DryLow	DryLow
NOx, ppmvd @ 15% O2	9	25	25
Gross Output, kW	171,700	182,690	182,690
Gross Heat Rate, Btu/kWh LHV	9,360	9,250	9,250
Gross Heat Rate, Btu/kWh HHV	10,396	10,273	10,273
CTG Heat Input, MBtu/h LHV	1,607.11	1,689.88	1,689.88
CTG Heat Input, MBtu/h HHV	1,784.92	1,876.85	1,876.85
STG Performance			
Gross Output, kW	N/A	92,980	190,920
Backpressure, in HgA	N/A	2.11	2.05
Plant Performance (total)			
Gross Output, kW	171,700	275,670	556,300
Gross Heat Rate, Btu/kWh LHV	9,360	6,130	6,075
Gross Heat Rate, Btu/kWh HHV	10,396	6,808	6,748
Auxiliary Load, kW	1,890	6,140	12,540
Auxiliary Load, percent	1.1%	2.23%	2.25%
Net Output	169,810	269,530	543,760
Net Heat Rate, Btu/kWh LHV	9,464	6,270	6,216
Net Heat Rate, Btu/kWh HHV	10,511	6,963	6,903

Table 7-4
Plant Performance - 71 F

Case	GE 7FA Simple Cycle	WH 501F 1 x1 Combined Cycle	WH 501F 2 x1 Combined Cycle
CTG Type	7241FA	501FD	501FD
Number of CTGs operating	1	1	2
Number of STGs Operating	0	1	1
Ambient Temperature, F	71	71	71
Ambient Relative Humidity, percent	60	60	60
Evaporative Cooler On/Off	On	On	On
Elevation, ft above sea level	0	0	0
CTG Performance (each)			
Fuel Type	Natural Gas	Natural Gas	Natural Gas
Fuel LHV, Btu/lb	21,511	21,511	21,511
Fuel HHV, Btu/lb	23,891	23,891	23,891
NOx Control Method	DryLow	DryLow	DryLow
NOx, ppmvd @ 15% O2	9	25	25
Gross Output, kW	164,500	175,380	175,380
Gross Heat Rate, Btu/kWh LHV	9,470	9,343	9,343
Gross Heat Rate, Btu/kWh HHV	10,518	10,376	10,376
CTG Heat Input, MBtu/h LHV	1,557.82	1,638.49	1,638.49
CTG Heat Input, MBtu/h HHV	1,730.17	1,819.77	1,819.77
STG Performance			
Gross Output, kW	N/A	90,900	186,780
Backpressure, in HgA	N/A	2.43	2.36
Plant Performance (total)			
Gross Output, kW	164,500	266,280	537,540
Gross Heat Rate, Btu/kWh LHV	9,470	6,153	6,096
Gross Heat Rate, Btu/kWh HHV	10,518	6,834	6,771
Auxiliary Load, kW	1,810	6,070	12,390
Auxiliary Load, percent	1.1%	2.28%	2.30%
Net Output	162,690	260,210	525,150
Net Heat Rate, Btu/kWh LHV	9,575	6,297	6,240
Net Heat Rate, Btu/kWh HHV	10,635	6,993	6,930

Table 7-5
Plant Performance - 97 F

CTG Type	GE 7FA Simple Cycle	WH 501F 1 x1 Combined Cycle	WH 501F 2 x1 Combined Cycle
Number of CTGs operating	1	1	2
Number of STGs Operating	0	1	1
Ambient Temperature, F	97	97	97
Ambient Relative Humidity, percent	60	60	60
Evaporative Cooler On/Off	On	On	On
Elevation, ft above sea level	0	0	0
CTG Performance (each)			
Fuel Type	Natural Gas	Natural Gas	Natural Gas
Fuel LHV, Btu/lb	21,511	21,511	21,511
Fuel HHV, Btu/lb	23,891	23,891	23,891
NOx Control Method	DryLow	DryLow	DryLow
NOx, ppmvd @ 15% O2	9	25	25
Gross Output, kW	147,600	158,940	158,940
Gross Heat Rate, Btu/kWh LHV	9,790	9,620	9,620
Gross Heat Rate, Btu/kWh HHV	10,873	10,684	10,684
CTG Heat Input, MBtu/h LHV	1,445.00	1,529.00	1,529.00
CTG Heat Input, MBtu/h HHV	1,604.88	1,698.17	1,698.17
STG Performance			
Gross Output, kW	N/A	85,540	176,110
Backpressure, in HgA	N/A	3.52	3.44
Plant Performance (total)			
Gross Output, kW	147,600	244,480	493,990
Gross Heat Rate, Btu/kWh LHV	9,790	6,254	6,190
Gross Heat Rate, Btu/kWh HHV	10,873	6,946	6,875
Auxiliary Load, kW	1,620	5,930	12,100
Auxiliary Load, percent	1.1%	2.43%	2.45%
Net Output	145,980	238,550	481,890
Net Heat Rate, Btu/kWh LHV	9,899	6,410	6,346
Net Heat Rate, Btu/kWh HHV	10,994	7,119	7,048

7.5 Operating and Maintenance (O&M) Cost Estimates

Black & Veatch has prepared and estimated the O&M for all alternatives.

7.5.1 O&M Cost Estimate Assumptions – Coal Unit

Nonfuel operating and maintenance (O&M) costs for the pulverized coal unit were developed based on the following assumptions:

- 85 additional personnel will be included to existing Stanton Energy Center.
- Maintenance material costs are highly correlated to maintenance man-hours and represent $28.44 per maintenance man-hour. A total of 1,878 maintenance man-hours are assumed per mechanic per year.
- Annual burdened labor costs are assumed to be $54,000 per person.
- Administrative and general costs are assumed to be the same as Stanton 2.
- One D-9 bulldozer is assumed to be added with a flat rate charge of $40,800 per year.
- The cost of chemicals is assumed to equal the cost of the chemicals for Stanton 2.
- General operations costs are assumed to be equal to Stanton 2.
- It is assumed that there will be no additional costs for outside computer services for maintenance.
- General maintenance costs are assumed to be equal to Stanton 2.
- Brine plant costs are assumed to be equal to Stanton 2.

7.5.2 O&M Cost Estimate Assumptions – Combustion Turbine and Combined Cycle Units

Nonfuel operating and maintenance (O&M) costs for combustion turbine and combined cycles were developed based on the following assumptions:

- Cycle Life: 25 years.
- Variable contingency: 20 percent.
- Fixed contingency: 20 percent.

- Annual capacity factor: 90 percent (7884 hours per year) for combined cycles, 10 percent (876 hours per year) for simple cycle.
- Annual number of starts: 25 for combined cycle, 200 for simple cycle.
- Primary fuel: Natural Gas.
- Operating load: Base
- Net plant performance is estimated at site conditions: 59F, 60% relative humidity, 0 feet elevation.
- NO_x control method for GE 7FA: Dry Low NO_x combustors to meet 9 ppmvd @ 15 percent O_2.
- NOx control method for 501F: Dry Low NO_x combustors to meet 25 ppmvd @ 15 percent O_2 and SCR to 3.5 ppmvd @ 15percent O_2.
- CTG maintenance estimated costs provided by manufacturers.
- CTG specialized labor cost estimated at $38/man-hour for Siemens-Westinghouse(provided by manufacturer). Specialized labor cost estimate is valid for domestic market only.
- CTG specialized labor cost estimated at $35/man-hour for GE (provided by manufacturer). Specialized labor cost estimated is valid for domestic market only.
- HRSG annual inspection costs are estimated based on manufacturer input and Black & Veatch experience.
- Steam turbine annual, minor, and major inspection costs are estimated based on Black & Veatch experience. Annual inspections occur every 8,000 hours of operation, minor occur every 24,000 hours of operation, and major occur every 48,000 hours of operation.
- Balance-of-plant costs are estimated based on B&V experience.
- O&M cost for SCR is included for the combined cycles. O&M costs for CO catalysts are not included.
- SCR uses anhydrous ammonia (@$250/ton/yr) and reduces NO_x from 25 to 3.5 ppmvd @ 15% O_2 with ammonia slip.
- Demineralized and raw water costs are included in the O&M analysis.

- O&M costs for the combined cycle are based on 25 starts per year and a 90 percent capacity factor. O&M costs for the simple cycle combustion turbine are based on 200 starts per year and 10 percent capacity factor.

Estimated staff requirements and salaries shown in Table 7-6 below.

Table 7-6

Estimated Staff Requirements and Salaries

Position	501F(1x1) CC Requirement	501F(2x1) CC Requirement	7FA SC Requirement	Burdened Salary
Plant / Site Manager	1	1	0	108,160
Plant Engineers	1	1	1	79,060
Plant Operators/Sup.	6	8	2	84,800
Plant Aux Operators	4	5	0	58,080
Mechanics	2	3	1	58,620
Electricians	1	2	1	61,430
Water Treatment	1	1	0	57,540

- Staff supplies and materials are estimated to be 10 percent of staff salary.
- Rental equipment and contract labor costs are estimated by Black & Veatch. Rental equipment includes costs for heavy mobile equipment required for specific maintenance activities (i.e. cranes, etc.)
- Routine maintenance costs are estimated based on Black & Veatch experience. Routine maintenance includes maintenance costs for services not included in balance of plant costs or maintenance that is not directly part of power production (i.e. painting of buildings, housekeeping, etc.)
- Contract services includes costs for services not directly related to power production (i.e. HVAC, plumbing, pest control, etc.)
- Insurance, and training, fees, and bonuses are not included.
- Fuel costs are not included in the O&M analysis.
- Employee training costs are not included in the O&M analysis.
- All costs are provided in 2000 dollars.

- The O&M analysis is not guaranteeable and is subject to change upon inspection from an O&M contractor.
- The O&M analysis does not account for escalation or discount factor.

The variable O&M analysis is based on a repeating maintenance schedule for the CTG and will take into account replacement and refurbishment costs. The annual average cost is the estimated average cost over the 25 year cycle life.

The fixed O&M analysis assumes that the fixed costs will remain constant over the life of the plant.

Black & Veatch uses the values provided by the manufacturers or a ratio of such for inspections not provided. The values provided in this analysis are representative of operating and maintenance costs for the given cycle. Each manufacturer has a different set of criteria for their scope. Therefore, numbers between manufacturers will vary.

7.5.3 O&M Cost Estimate Summary

The O&M cost estimate for the pulverized coal unit is shown in Table 7-7. The O&M cost estimates for combustion turbine cycle alternatives are summarized in Table 7-8 through 7-10.

Table 7-7: Annual O&M Cost Estimate for Pulverized Coal Unit	
Fixed Cost	
Labor	$4,590,000
Materials	$5,477,974
Other Expenses	$5,675,237
Total	$15,743,211
Variable Cost	
Lime	$500,000
Ammonia	$200,000
Chemicals	Negligible
Water	N/A
Total	$700,000
Total O&M	$16,443,211

Table 7-8 Non-Fuel 2x1 Siemens-Westinghouse 501F Combined Cycle -- OUC (90% CF)

Non-Fuel Variable Operation and Maintenance Costs (YR2000 US $)

Commercial Operation Date	2004	New and Clean Net Plant Output, kW	543,760	Capacity Factor, percent	90.00%
Fuel Type	Natural Gas	Economic Life, years	25	Annual Number of Starts	25

Years	Annual Operating Hours	Cumulative Number of Operating Hours	Combustion Turbine Major Maintenance Costs			HRSG and SCR Major Maint. Costs	Steam Turbine Major Maint. Costs	Water Consumption	BOP Major Maint. Costs	Total Major Maint. Costs
			Type of Inspection(s)	Labor ($)	Materials ($)	Labor/Materials ($)	Labor/Materials ($)	Cost ($)	Labor / Materials ($)	Labor / Material (Total $) (Incl. Contingency)
2004	7,884	7,884	--	0	0	1,115,500	0	416,200	676,800	2,208,500
2005	7,884	15,768	CI	107,600	2,489,800	1,115,500	385,900	416,200	676,800	5,191,800
2006	7,884	23,652	CI	107,600	2,489,800	1,115,500	385,900	416,200	676,800	5,191,800
2007	7,884	31,536	HG	292,600	7,124,100	1,115,500	1,206,000	416,200	676,800	10,831,200
2008	7,884	39,420	CI	107,600	2,489,800	1,115,500	385,900	416,200	676,800	5,191,800
2009	7,884	47,304	CI	107,600	2,489,800	1,115,500	385,900	416,200	676,800	5,191,800
2010	7,884	55,188	MI	606,700	24,799,700	1,115,500	4,824,000	416,200	676,800	32,438,900
2011	7,884	63,072	CI	107,600	2,489,800	1,115,500	385,900	416,200	676,800	5,191,800
2012	7,884	70,956	CI	107,600	2,489,800	1,115,500	385,900	416,200	676,800	5,191,800
2013	7,884	78,840	HG	292,600	7,124,100	1,115,500	1,206,000	416,200	676,800	10,831,200
2014	7,884	86,724	CI	107,600	2,489,800	1,115,500	385,900	416,200	676,800	5,191,800
2015	7,884	94,608	CI	107,600	2,489,800	1,115,500	385,900	416,200	676,800	5,191,800
2016	7,884	102,492	MI	606,700	24,799,700	1,115,500	4,824,000	416,200	676,800	32,438,900
2017	7,884	110,376	CI	107,600	2,489,800	1,115,500	385,900	416,200	676,800	5,191,800
2018	7,884	118,260	CI	107,600	2,489,800	1,115,500	385,900	416,200	676,800	5,191,800
2019	7,884	126,144	HG	292,600	7,124,100	1,115,500	1,206,000	416,200	676,800	10,831,200
2020	7,884	134,028	CI	107,600	2,489,800	1,115,500	385,900	416,200	676,800	5,191,800
2021	7,884	141,912	CI	107,600	2,489,800	1,115,500	385,900	416,200	676,800	5,191,800
2022	7,884	149,796	MI	606,700	24,799,700	1,115,500	4,824,000	416,200	676,800	32,438,900
2023	7,884	157,680	CI	107,600	2,489,800	1,115,500	385,900	416,200	676,800	5,191,800
2024	7,884	165,564	CI	107,600	2,489,800	1,115,500	385,900	416,200	676,800	5,191,800
2025	7,884	173,448	HG	292,600	7,124,100	1,115,500	1,206,000	416,200	676,800	10,831,200
2026	7,884	181,332	CI	107,600	2,489,800	1,115,500	385,900	416,200	676,800	5,191,800
2027	7,884	189,216	CI	107,600	2,489,800	1,115,500	385,900	416,200	676,800	5,191,800
2028	7,884	197,100	MI	606,700	24,799,700	1,115,500	4,824,000	416,200	676,800	32,438,900
Total Variable O&M Costs (YR2000 $)				5,318,800	167,532,000	27,887,500	30,294,400	10,405,000	16,920,000	258,357,700
Contingency (% Included Above)										
Annual Average Variable O&M Cost				212,800	6,701,300	1,115,500	1,115,500	416,200	676,800	10,334,300

Annual Non-Fuel Fixed Operation and Maintenance Costs (YR2000 US $)

	Staff Cost	Staff Supplies And Materials	Rentals	Contracted Services	Routine Maintenance	Fixed O&M Costs Total
Annual Cost	1,814,700	181,500	120,000	84,000	360,000	2,560,200
Annual Fixed O&M Costs	1,814,700	181,500	120,000	84,000	360,000	2,560,200
Contingency (20% Included Above)						
Annual Average Fixed O&M Costs	1,814,700	181,500	120,000	84,000	360,000	2,560,200

New and Clean Annual Average Variable O&M 2.41 $/MWh — New and Clean Annual Average Fixed O&M 4.71 $/kW-yr

Notes:
1) CI = Combustion Inspection; HG = Hot Gas Path Inspection; MI = Major Inspection
2) Initial Operational spares, Combustion Spares, and Hot Gas Path Spares are not included in the O&M analysis.
3) O&M basis is for a 25-year combined cycle life..

Table 7-9 Non-Fuel 1x0 General Electric 7FA Simple Cycle -- OUC (10% CF)

Non-Fuel Variable Operation and Maintenance Costs (YR2000 US $)

Commercial Operation Date	2004	New and Clean Net Plant Output, kW	169,810	Capacity Factor, percent	10.00%
Fuel Type	Natural Gas	Economic Life, years	25	Annual Number of Starts	200

Years	Annual Number of Starts	Cumulative Number of Starts	Combustion Turbine Major Maintenance Costs			HRSG Major Maint. Costs	Steam Turbine Major Maint. Costs	Water Consumption	BOP Major Maint. Costs	Total Major Maint. Costs
			Type of Inspection	Labor ($)	Materials ($)	Labor/Materials ($)	Labor/Materials ($)	Cost ($)	Labor / Materials ($)	Labor / Material (Total $) (Incl. Contingency)
2004	200	200	--	0	0	0	0	Not Included	217,200	217,200
2005	200	400	--	0	0	0	0	Not Included	217,200	217,200
2006	200	600	CI	37,800	1,175,800	0	0	Not Included	217,200	1,430,800
2007	200	800	--	0	0	0	0	Not Included	217,200	217,200
2008	200	1,000	CI	37,800	1,175,800	0	0	Not Included	217,200	1,430,800
2009	200	1,200	--	0	0	0	0	Not Included	217,200	217,200
2010	200	1,400	HG	117,600	4,148,500	0	0	Not Included	217,200	4,483,300
2011	200	1,600	--	0	0	0	0	Not Included	217,200	217,200
2012	200	1,800	CI	37,800	1,175,800	0	0	Not Included	217,200	1,430,800
2013	200	2,000	--	0	0	0	0	Not Included	217,200	217,200
2014	200	2,200	CI	37,800	1,175,800	0	0	Not Included	217,200	1,430,800
2015	200	2,400	--	0	0	0	0	Not Included	217,200	217,200
2016	200	2,600	MI	197,400	8,834,200	0	0	Not Included	217,200	9,248,800
2017	200	2,800	--	0	0	0	0	Not Included	217,200	217,200
2018	200	3,000	CI	37,800	1,175,800	0	0	Not Included	217,200	1,430,800
2019	200	3,200	--	0	0	0	0	Not Included	217,200	217,200
2020	200	3,400	CI	37,800	1,175,800	0	0	Not Included	217,200	1,430,800
2021	200	3,600	--	0	0	0	0	Not Included	217,200	217,200
2022	200	3,800	HG	117,600	4,148,500	0	0	Not Included	217,200	4,483,300
2023	200	4,000	--	0	0	0	0	Not Included	217,200	217,200
2024	200	4,200	CI	37,800	1,175,800	0	0	Not Included	217,200	1,430,800
2025	200	4,400	--	0	0	0	0	Not Included	217,200	217,200
2026	200	4,600	CI	37,800	1,175,800	0	0	Not Included	217,200	1,430,800
2027	200	4,800	--	0	0	0	0	Not Included	217,200	217,200
2028	200	5,000	MI	197,400	8,834,200	0	0	Not Included	217,200	9,248,800
Total Variable O&M Costs (YR2000 $)				932,400	35,371,800	0	0	0	5,430,000	41,734,200
Contingency (% Included Above)										
Annual Average Variable O&M Cost				37,300	1,414,900	0	0	0	217,200	1,669,400

Annual Non-Fuel Fixed Operation and Maintenance Costs (YR2000 US $)

	Staff Cost	Staff Supplies And Materials	Rentals	Contracted Services	Routine Maintenance	Fixed O&M Costs Total
Annual Cost	442,500	44,200	120,000	84,000	180,000	870,700
Annual Fixed O&M Costs	442,500	44,200	120,000	84,000	180,000	870,700
Contingency (20% Included Above)						
Annual Average Fixed O&M Costs	442,500	44,200	120,000	84,000	180,000	870,700

New and Clean Annual Average Variable O&M 11.22 $/MWh — New and Clean Annual Average Fixed O&M 6.19 $/kW-yr

Notes:
1) CI = Combustion Inspection; HG = Hot Gas Path Inspection; MI = Major Inspection
2) Initial Operational spares, Combustion Spares, and Hot Gas Path Spares are not included in the O&M analysis.
3) O&M basis is for a 25-year combustion turbine life..

Table 7-10 Non-Fuel 1x1 Siemens-Westinghouse 501F Combined Cycle -- OUC (90% CF)

Non-Fuel Variable Operation and Maintenance Costs (YR2000 US $)

Commercial Operation Date	2004	New and Clean Net Plant Output, kW	269,530	Capacity Factor, percent	90.00%
Fuel Type	Natural Gas	Economic Life, years	25	Annual Number of Starts	25

Years	Annual Operating Hours	Cumulative Number of Operating Hours	Combustion Turbine Major Maintenance Costs			HRSG and SCR Major Maint. Costs	Steam Turbine Major Maint. Costs	Water Consumption	BOP Major Maint. Costs	Total Major Maint. Costs
			Type of Inspection(s)	Labor ($)	Materials ($)	Labor/Materials ($)	Labor/Materials ($)	Cost ($)	Labor / Materials ($)	Labor / Material (Total $) (Incl. Contingency)
2004	7,884	7,884	--	0	0	557,000	0	208,100	445,200	1,211,000
2005	7,884	15,768	CI	53,800	1,244,900	557,000	250,600	208,100	445,200	2,760,300
2006	7,884	23,652	CI	53,800	1,244,900	557,000	250,600	208,100	445,200	2,760,300
2007	7,884	31,536	HG	146,300	3,562,000	557,000	783,000	208,100	445,200	5,702,300
2008	7,884	39,420	CI	53,800	1,244,900	557,000	250,600	208,100	445,200	2,760,300
2009	7,884	47,304	CI	53,800	1,244,900	557,000	250,600	208,100	445,200	2,760,300
2010	7,884	55,188	MI	303,300	12,399,900	557,000	3,132,000	208,100	445,200	17,046,200
2011	7,884	63,072	CI	53,800	1,244,900	557,000	250,600	208,100	445,200	2,760,300
2012	7,884	70,956	CI	53,800	1,244,900	557,000	250,600	208,100	445,200	2,760,300
2013	7,884	78,840	HG	146,300	3,562,000	557,000	783,000	208,100	445,200	5,702,300
2014	7,884	86,724	CI	53,800	1,244,900	557,000	250,600	208,100	445,200	2,760,300
2015	7,884	94,608	CI	53,800	1,244,900	557,000	250,600	208,100	445,200	2,760,300
2016	7,884	102,492	MI	30,330	12,399,900	557,000	3,132,000	208,100	445,200	17,046,200
2017	7,884	110,376	CI	53,800	1,244,900	557,000	250,600	208,100	445,200	2,760,300
2018	7,884	118,260	CI	53,800	1,244,900	557,000	250,600	208,100	445,200	2,760,300
2019	7,884	126,144	HG	146,300	3,562,000	557,000	783,000	208,100	445,200	5,702,300
2020	7,884	134,028	CI	53,800	1,244,900	557,000	250,600	208,100	445,200	2,760,300
2021	7,884	141,912	CI	53,800	1,244,900	557,000	250,600	208,100	445,200	2,760,300
2022	7,884	149,796	MI	303,300	12,399,900	557,000	3,132,000	208,100	445,200	17,046,200
2023	7,884	157,680	CI	53,800	1,244,900	557,000	250,600	208,100	445,200	2,760,300
2024	7,884	165,564	CI	53,800	1,244,900	557,000	250,600	208,100	445,200	2,760,300
2025	7,884	173,448	HG	146,300	3,562,000	557,000	783,000	208,100	445,200	5,702,300
2026	7,884	181,332	CI	53,800	1,244,900	557,000	250,600	208,100	445,200	2,760,300
2027	7,884	189,216	CI	53,800	1,244,900	557,000	250,600	208,100	445,200	2,760,300
2028	7,884	197,100	MI	303,300	12,399,900		3,132,000	208,100	445,200	17,046,200
Total Variable O&M Costs (YR2000 $)				2,659,200	83,766,000	13,942,500	19,669,600	5,202,500	11,130,000	136,369,800
Contingency (20% Included Above)										
Annual Average Variable O&M Cost				106,400	3,350,600	557,000	786,800	208,100	445,200	5,454,800

Annual Non-Fuel Fixed Operation and Maintenance Costs (YR2000 US $)

	Staff Cost	Staff Supplies And Materials	Rentals	Contracted Services	Routine Maintenance	Fixed O&M Costs Total
Annual Cost	1,397,500	139,700	120,000	84,000	360,000	2,101,200
Annual Fixed O&M Costs	1,397,500	139,700	120,000	84,000	360,000	2,101,200
Contingency (20% Included Above)						
Annual Average Fixed O&M Costs	1,397,500	139,700	120,000	84,000	360,000	2,101,200

New and Clean Annual Average Variable O&M	2.57 $/MWh	New and Clean Annual Average Fixed O&M	7.80 $/kW-yr

Notes:
1) CI = Combustion Inspection; HG = Hot Gas Path Inspection; MI = Major Inspection
2) Initial Operational spares, Combution Spares, and Hot Gas Path Spares are not included in the O&M analysis.
3) O&M basis is for a 25-year combined cycle life..

7.6 Availability

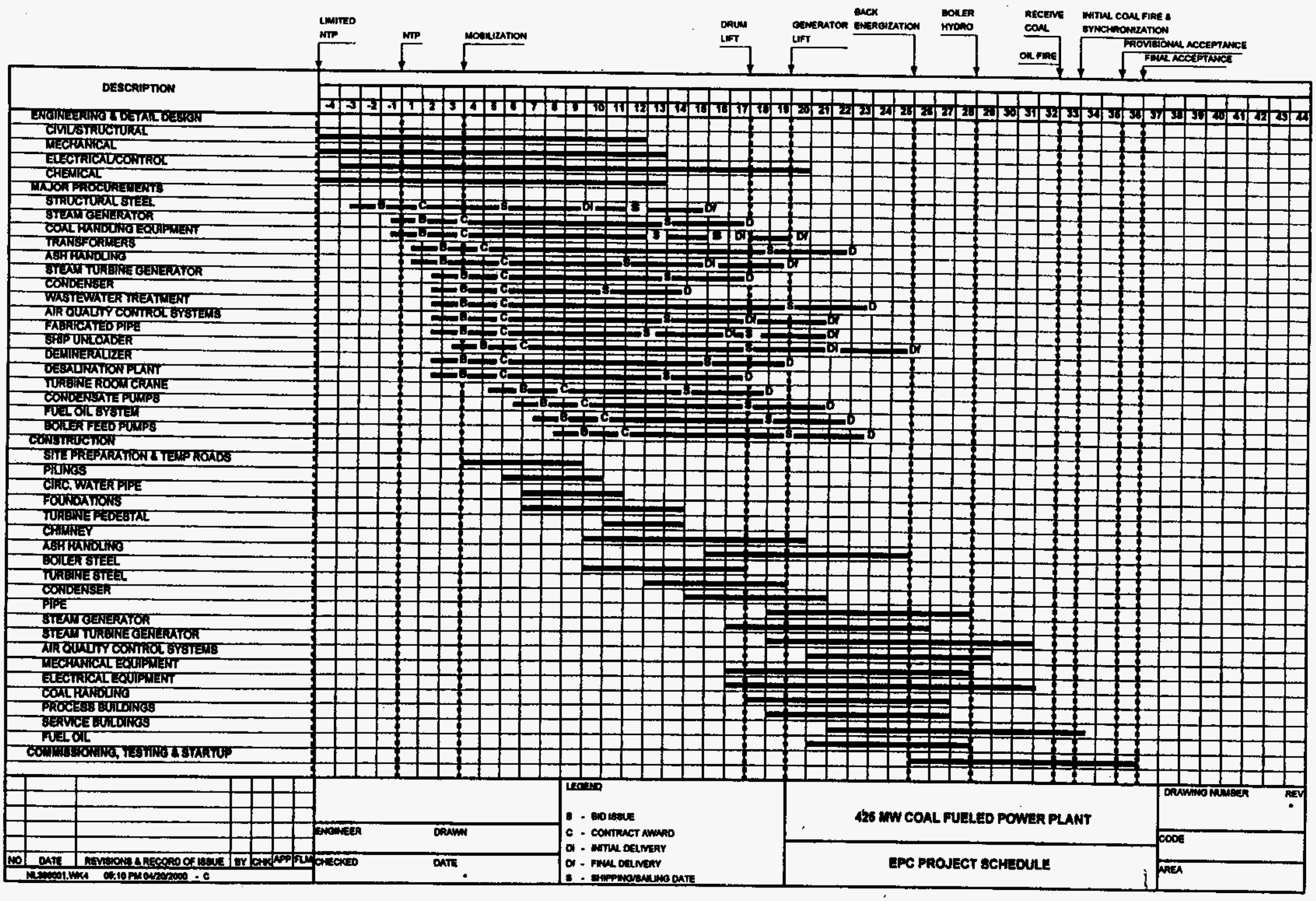
The projected planned maintenance, forced outage rates, and equivalent availability for each of the generation units alternatives are presented below.

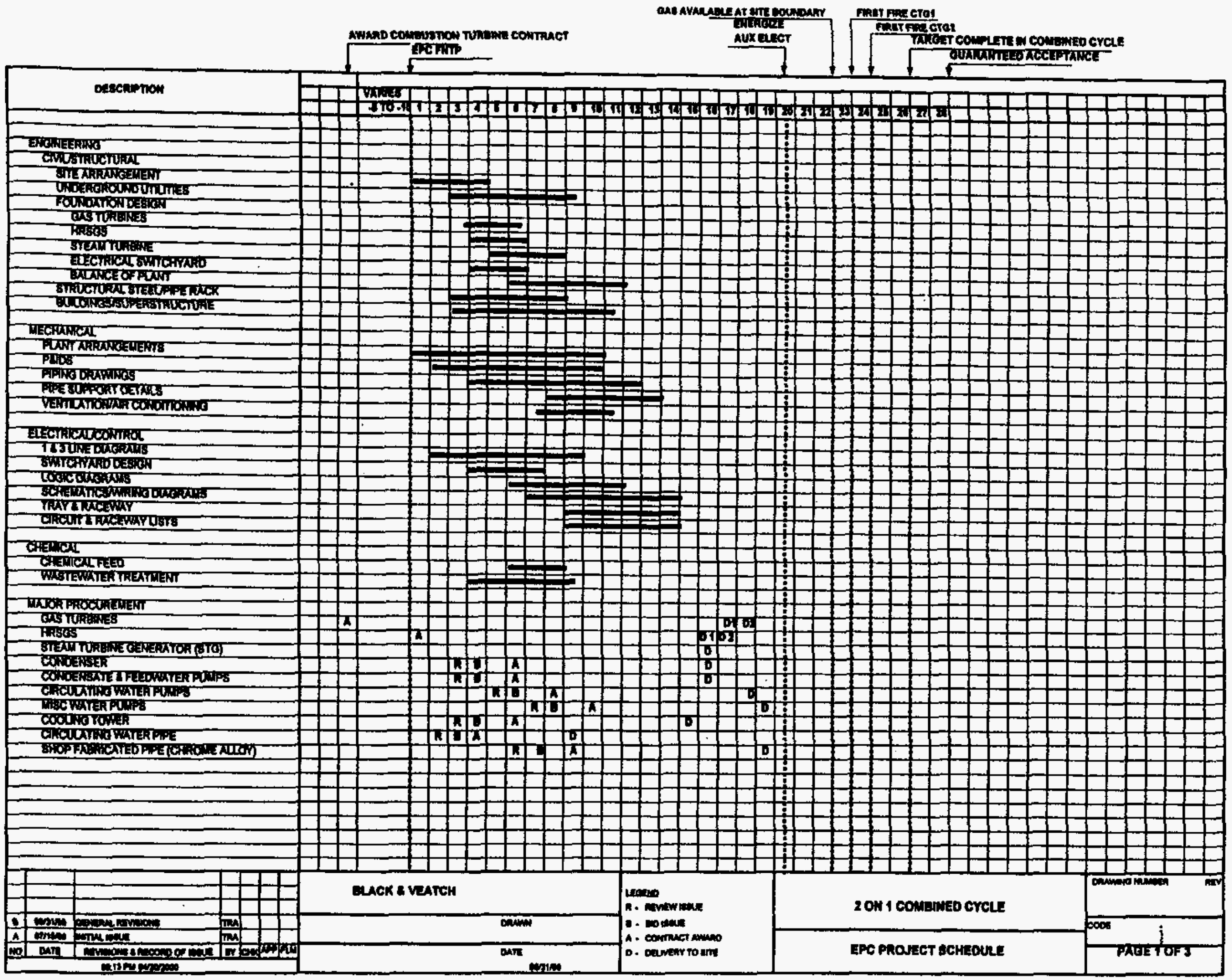
Table 7-11: Summary of Availability for All Alternatives

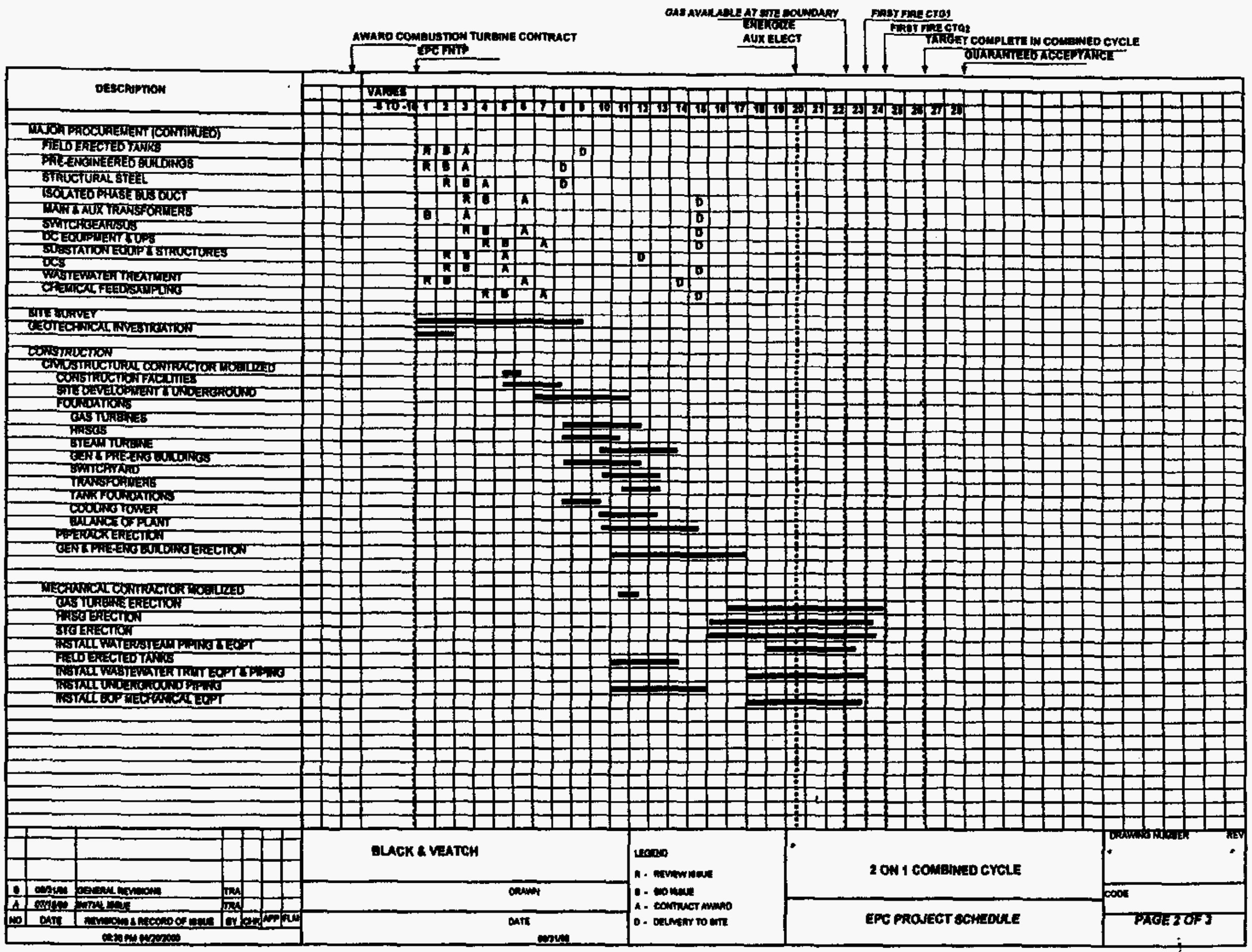
Unit Description	Planned Maintenance (Days Per Year)	Forced Outage Rate (Percent)	Equivalent Availability (Percent)
425 MW Pulverized Coal Unit	28	7	85
1x1 501 F Combined Cycle	15	2.86	94.41
2x1 501 F Combined Cycle	26	4.57	92.7
7 FA Simple Cycle Combustion Turbine	7	1.96	96.2

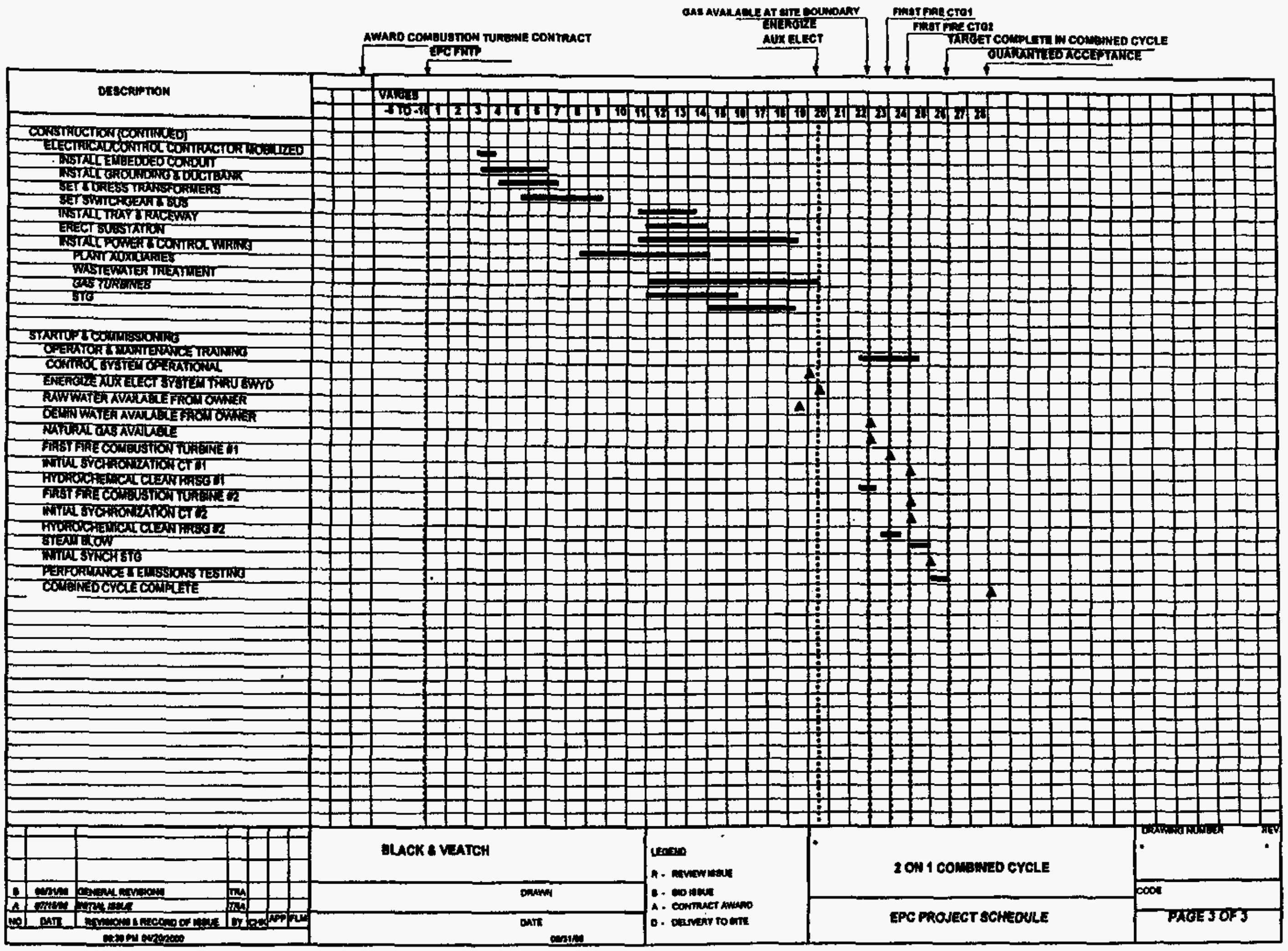
7.7 Construction Schedules

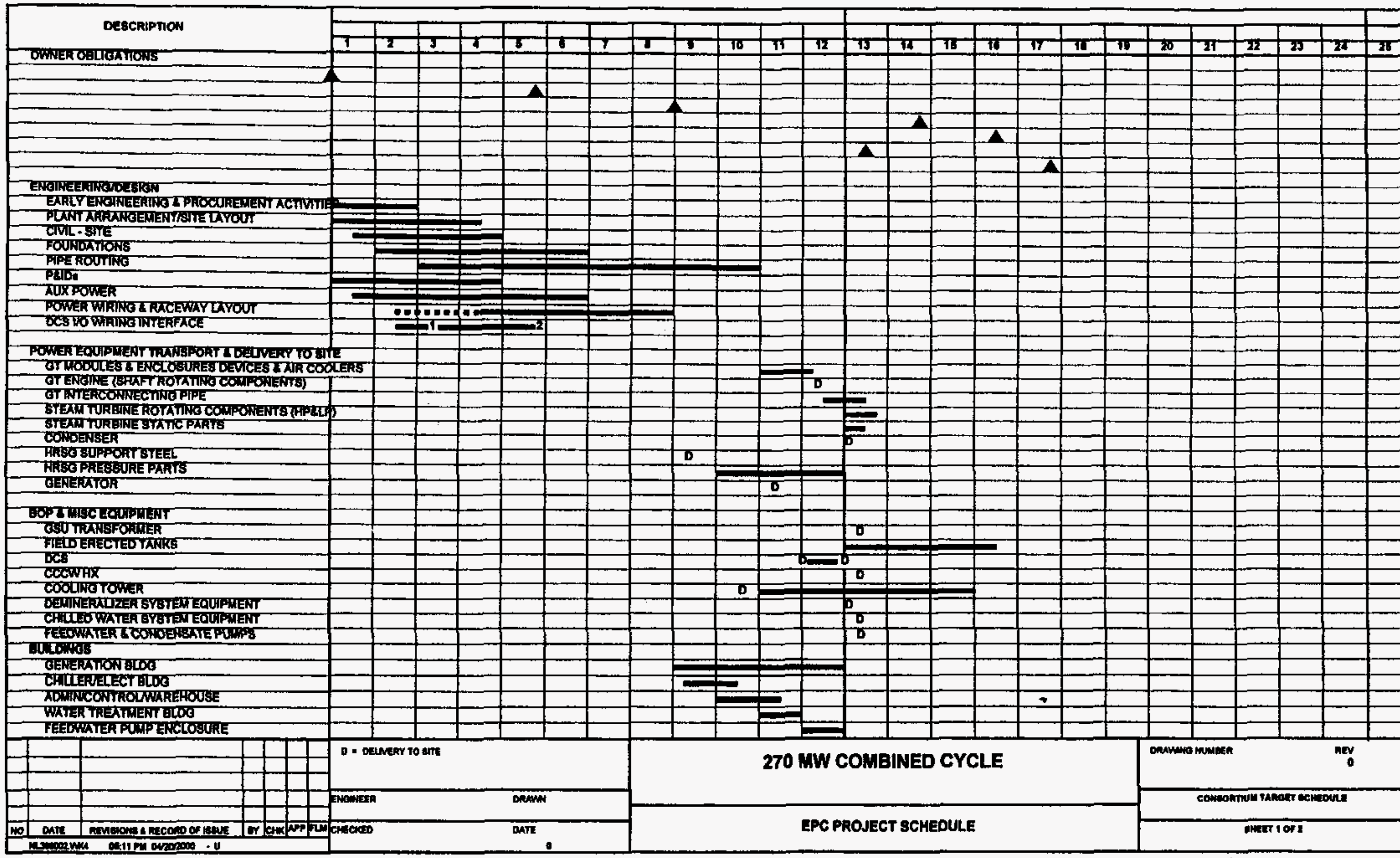
Black & Veatch has developed bar-chart construction schedules for each alternative. The schedules include major activities such as engineering design, equipment procurement, construction, and startup. The construction schedule for each alternative can be found at the end of this section. The schedules do not include considerations of potential long lead times for major equipment such as combustion turbines that currently prevail in the market.

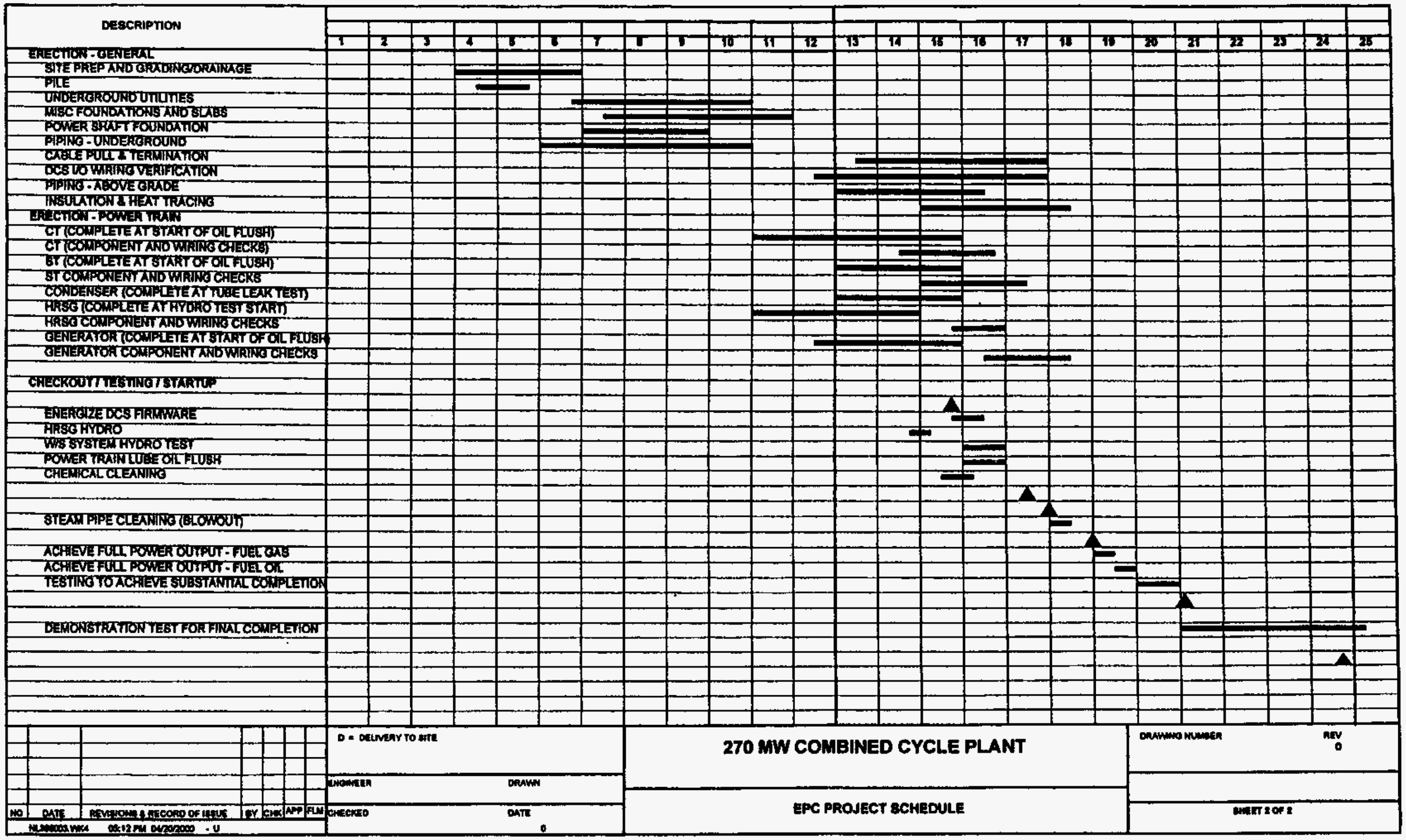

LIMITED NTP
NTP
MOBILIZATION
DRUM LIFT
GENERATOR LIFT
BACK ENERGIZATION
BOILER HYDRO
RECEIVE COAL
OIL FIRE
INITIAL COAL FIRE & SYNCHRONIZATION
PROVISIONAL ACCEPTANCE
FINAL ACCEPTANCE
DESCRIPTION
ENGINEERING & DETAIL DESIGN
CIVIL/STRUCTURAL
MECHANICAL
ELECTRICAL/CONTROL
CHEMICAL
MAJOR PROCUREMENTS
STRUCTURAL STEEL
STEAM GENERATOR
COAL HANDLING EQUIPMENT
TRANSFORMERS
ASH HANDLING
STEAM TURBINE GENERATOR
CONDENSER
WASTEWATER TREATMENT
AIR QUALITY CONTROL SYSTEMS
FABRICATED PIPE
SHIP UNLOADER
DEMINERALIZER
DESALINATION PLANT
TURBINE ROOM CRANE
CONDENSATE PUMPS
FUEL OIL SYSTEM
BOILER FEED PUMPS
CONSTRUCTION
SITE PREPARATION & TEMP ROADS
PILINGS
CIRC. WATER PIPE
FOUNDATIONS
TURBINE PEDESTAL
CHIMNEY
ASH HANDLING
BOILER STEEL
TURBINE STEEL
CONDENSER
PIPE
STEAM GENERATOR
STEAM TURBINE GENERATOR
AIR QUALITY CONTROL SYSTEMS
MECHANICAL EQUIPMENT
ELECTRICAL EQUIPMENT
COAL HANDLING
PROCESS BUILDINGS
SERVICE BUILDINGS
FUEL OIL
COMMISSIONING, TESTING & STARTUP
NO DATE REVISIONS & RECORD OF ISSUE BY CHK APP FLM
NL300001.WK4 08:10 PM 04/20/2000 - C
ENGINEER DRAWN
CHECKED DATE
LEGEND
B - BID ISSUE
C - CONTRACT AWARD
DI - INITIAL DELIVERY
Df - FINAL DELIVERY
S - SHIPPING/SAILING DATE
425 MW COAL FUELED POWER PLANT
EPC PROJECT SCHEDULE
DRAWING NUMBER REV
CODE
AREA

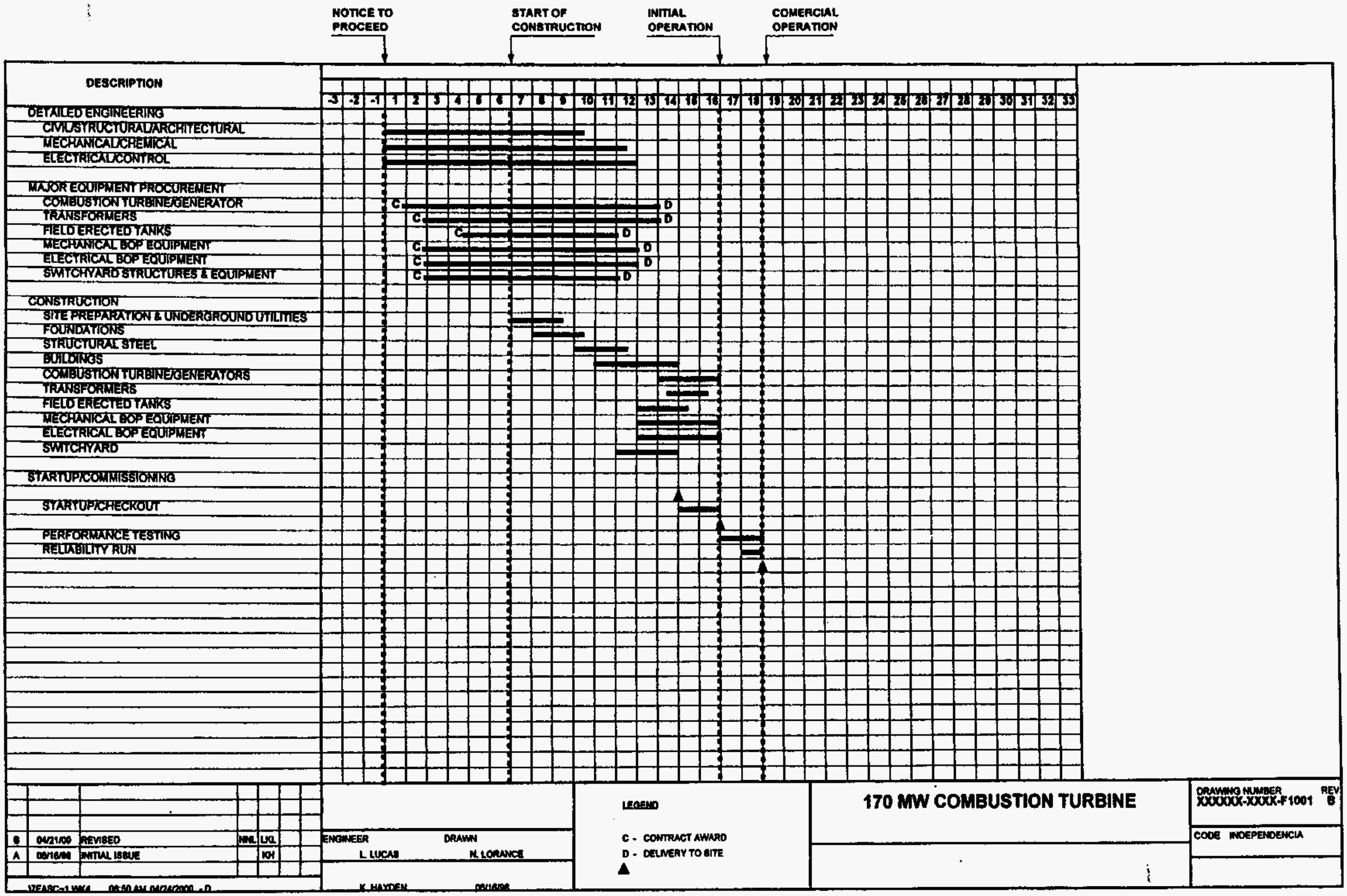

AWARD COMBUSTION TURBINE CONTRACT
EPC FNTP
GAS AVAILABLE AT SITE BOUNDARY
ENERGIZE
AUX ELECT
FIRST FIRE CTG1
FIRST FIRE CTG2
TARGET COMPLETE IN COMBINED CYCLE
GUARANTEED ACCEPTANCE
DESCRIPTION
VARIES
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28
ENGINEERING
CIVIL/STRUCTURAL
SITE ARRANGEMENT
UNDERGROUND UTILITIES
FOUNDATION DESIGN
GAS TURBINES
HRSGS
STEAM TURBINE
ELECTRICAL SWITCHYARD
BALANCE OF PLANT
STRUCTURAL STEEL/PIPE RACK
BUILDINGS/SUPERSTRUCTURE
MECHANICAL
PLANT ARRANGEMENTS
P&IDS
PIPING DRAWINGS
PIPE SUPPORT DETAILS
VENTILATION/AIR CONDITIONING
ELECTRICAL/CONTROL
1 & 3 LINE DIAGRAMS
SWITCHYARD DESIGN
LOGIC DIAGRAMS
SCHEMATICS/WIRING DIAGRAMS
TRAY & RACEWAY
CIRCUIT & RACEWAY LISTS
CHEMICAL
CHEMICAL FEED
WASTEWATER TREATMENT
MAJOR PROCUREMENT
GAS TURBINES
HRSGS
STEAM TURBINE GENERATOR (STG)
CONDENSER
CONDENSATE & FEEDWATER PUMPS
CIRCULATING WATER PUMPS
MISC WATER PUMPS
COOLING TOWER
CIRCULATING WATER PIPE
SHOP FABRICATED PIPE (CHROME ALLOY)
A INITIAL ISSUE TRA
GENERAL REVISIONS TRA
NO DATE REVISIONS & RECORD OF ISSUE BY CHK APP PLM
BLACK & VEATCH
DRAWN
DATE
LEGEND
R - REVIEW ISSUE
B - BID ISSUE
A - CONTRACT AWARD
D - DELIVERY TO SITE
2 ON 1 COMBINED CYCLE
EPC PROJECT SCHEDULE
DRAWING NUMBER
REV
CODE
PAGE 1 OF 3


AWARD COMBUSTION TURBINE CONTRACT
EPC FNTP
GAS AVAILABLE AT SITE BOUNDARY
ENERGIZE AUX ELECT
FIRST FIRE CTG1
FIRST FIRE CTG2
TARGET COMPLETE IN COMBINED CYCLE
GUARANTEED ACCEPTANCE
DESCRIPTION
VARIES
-8 TO -10
MAJOR PROCUREMENT (CONTINUED)
FIELD ERECTED TANKS
PRE-ENGINEERED BUILDINGS
STRUCTURAL STEEL
ISOLATED PHASE BUS DUCT
MAIN & AUX TRANSFORMERS
SWITCHGEAR/SUS
DC EQUIPMENT & UPS
SUBSTATION EQUIP & STRUCTURES
DCS
WASTEWATER TREATMENT
CHEMICAL FEED/SAMPLING
SITE SURVEY
GEOTECHNICAL INVESTIGATION
CONSTRUCTION
CIVIL/STRUCTURAL CONTRACTOR MOBILIZED
CONSTRUCTION FACILITIES
SITE DEVELOPMENT & UNDERGROUND
FOUNDATIONS
GAS TURBINES
HRSGS
STEAM TURBINE
GEN & PRE-ENG BUILDINGS
SWITCHYARD
TRANSFORMERS
TANK FOUNDATIONS
COOLING TOWER
BALANCE OF PLANT
PIPERACK ERECTION
GEN & PRE-ENG BUILDING ERECTION
MECHANICAL CONTRACTOR MOBILIZED
GAS TURBINE ERECTION
HRSG ERECTION
STG ERECTION
INSTALL WATER/STEAM PIPING & EQPT
FIELD ERECTED TANKS
INSTALL WASTEWATER TRMT EQPT & PIPING
INSTALL UNDERGROUND PIPING
INSTALL BOP MECHANICAL EQPT
BLACK & VEATCH
LEGEND
R - REVIEW ISSUE
B - BID ISSUE
A - CONTRACT AWARD
D - DELIVERY TO SITE
2 ON 1 COMBINED CYCLE
EPC PROJECT SCHEDULE
DRAWING NUMBER
REV
CODE
PAGE 2 OF 3
DRAWN
DATE
B 08/31/98 GENERAL REVISIONS TRA
A 07/16/98 INITIAL ISSUE TRA
NO DATE REVISIONS & RECORD OF ISSUE BY CHK APP FLM


GAS AVAILABLE AT SITE BOUNDARY
ENERGIZE
AUX ELECT
FIRST FIRE CTG1
FIRST FIRE CTG2
TARGET COMPLETE IN COMBINED CYCLE
GUARANTEED ACCEPTANCE
AWARD COMBUSTION TURBINE CONTRACT
EPC FNTP
DESCRIPTION
VARIES
-6 TO -10
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28
CONSTRUCTION (CONTINUED)
ELECTRICAL/CONTROL CONTRACTOR MOBILIZED
INSTALL EMBEDDED CONDUIT
INSTALL GROUNDING & DUCTBANK
SET & DRESS TRANSFORMERS
SET SWITCHGEAR & BUS
INSTALL TRAY & RACEWAY
ERECT SUBSTATION
INSTALL POWER & CONTROL WIRING
PLANT AUXILIARIES
WASTEWATER TREATMENT
GAS TURBINES
STG
STARTUP & COMMISSIONING
OPERATOR & MAINTENANCE TRAINING
CONTROL SYSTEM OPERATIONAL
ENERGIZE AUX ELECT SYSTEM THRU SWYD
RAW WATER AVAILABLE FROM OWNER
DEMIN WATER AVAILABLE FROM OWNER
NATURAL GAS AVAILABLE
FIRST FIRE COMBUSTION TURBINE #1
INITIAL SYCHRONIZATION CT #1
HYDROCHEMICAL CLEAN HRSG #1
FIRST FIRE COMBUSTION TURBINE #2
INITIAL SYCHRONIZATION CT #2
HYDROCHEMICAL CLEAN HRSG #2
STEAM BLOW
INITIAL SYNCH STG
PERFORMANCE & EMISSIONS TESTING
COMBINED CYCLE COMPLETE
BLACK & VEATCH
DRAWN
DATE
LEGEND
R - REVIEW ISSUE
B - BID ISSUE
A - CONTRACT AWARD
D - DELIVERY TO SITE
2 ON 1 COMBINED CYCLE
EPC PROJECT SCHEDULE
DRAWING NUMBER
REV
CODE
PAGE 3 OF 3
GENERAL REVISIONS
INITIAL ISSUE
NO
DATE
REVISIONS & RECORD OF ISSUE
BY
CHK
APP
FLM


DESCRIPTION
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25
OWNER OBLIGATIONS
ENGINEERING/DESIGN
EARLY ENGINEERING & PROCUREMENT ACTIVITIES
PLANT ARRANGEMENT/SITE LAYOUT
CIVIL - SITE
FOUNDATIONS
PIPE ROUTING
P&IDs
AUX POWER
POWER WIRING & RACEWAY LAYOUT
DCS I/O WIRING INTERFACE
POWER EQUIPMENT TRANSPORT & DELIVERY TO SITE
GT MODULES & ENCLOSURES DEVICES & AIR COOLERS
GT ENGINE (SHAFT ROTATING COMPONENTS)
GT INTERCONNECTING PIPE
STEAM TURBINE ROTATING COMPONENTS (HP&LP)
STEAM TURBINE STATIC PARTS
CONDENSER
HRSG SUPPORT STEEL
HRSG PRESSURE PARTS
GENERATOR
BOP & MISC EQUIPMENT
GSU TRANSFORMER
FIELD ERECTED TANKS
DCS
CCCW HX
COOLING TOWER
DEMINERALIZER SYSTEM EQUIPMENT
CHILLED WATER SYSTEM EQUIPMENT
FEEDWATER & CONDENSATE PUMPS
BUILDINGS
GENERATION BLDG
CHILLER/ELECT BLDG
ADMIN/CONTROL/WAREHOUSE
WATER TREATMENT BLDG
FEEDWATER PUMP ENCLOSURE
D = DELIVERY TO SITE
270 MW COMBINED CYCLE
EPC PROJECT SCHEDULE
DRAWING NUMBER
REV
0
CONSORTIUM TARGET SCHEDULE
SHEET 1 OF 2
ENGINEER
DRAWN
CHECKED
DATE
NO
DATE
REVISIONS & RECORD OF ISSUE
BY
CHK
APP
FLM


DESCRIPTION
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25
ERECTION - GENERAL
SITE PREP AND GRADING/DRAINAGE
PILE
UNDERGROUND UTILITIES
MISC FOUNDATIONS AND SLABS
POWER SHAFT FOUNDATION
PIPING - UNDERGROUND
CABLE PULL & TERMINATION
DCS I/O WIRING VERIFICATION
PIPING - ABOVE GRADE
INSULATION & HEAT TRACING
ERECTION - POWER TRAIN
CT (COMPLETE AT START OF OIL FLUSH)
CT (COMPONENT AND WIRING CHECKS)
ST (COMPLETE AT START OF OIL FLUSH)
ST COMPONENT AND WIRING CHECKS
CONDENSER (COMPLETE AT TUBE LEAK TEST)
HRSG (COMPLETE AT HYDRO TEST START)
HRSG COMPONENT AND WIRING CHECKS
GENERATOR (COMPLETE AT START OF OIL FLUSH)
GENERATOR COMPONENT AND WIRING CHECKS
CHECKOUT / TESTING / STARTUP
ENERGIZE DCS FIRMWARE
HRSG HYDRO
W/S SYSTEM HYDRO TEST
POWER TRAIN LUBE OIL FLUSH
CHEMICAL CLEANING
STEAM PIPE CLEANING (BLOWOUT)
ACHIEVE FULL POWER OUTPUT - FUEL GAS
ACHIEVE FULL POWER OUTPUT - FUEL OIL
TESTING TO ACHIEVE SUBSTANTIAL COMPLETION
DEMONSTRATION TEST FOR FINAL COMPLETION
NO DATE REVISIONS & RECORD OF ISSUE BY CHK APP FLM
D = DELIVERY TO SITE
ENGINEER DRAWN
CHECKED DATE
270 MW COMBINED CYCLE PLANT
EPC PROJECT SCHEDULE
DRAWING NUMBER
REV
0
SHEET 2 OF 2


NOTICE TO PROCEED
START OF CONSTRUCTION
INITIAL OPERATION
COMERCIAL OPERATION
DESCRIPTION
-3 -2 -1 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32 33
DETAILED ENGINEERING
CIVIL/STRUCTURAL/ARCHITECTURAL
MECHANICAL/CHEMICAL
ELECTRICAL/CONTROL
MAJOR EQUIPMENT PROCUREMENT
COMBUSTION TURBINE/GENERATOR
TRANSFORMERS
FIELD ERECTED TANKS
MECHANICAL BOP EQUIPMENT
ELECTRICAL BOP EQUIPMENT
SWITCHYARD STRUCTURES & EQUIPMENT
CONSTRUCTION
SITE PREPARATION & UNDERGROUND UTILITIES
FOUNDATIONS
STRUCTURAL STEEL
BUILDINGS
COMBUSTION TURBINE/GENERATORS
TRANSFORMERS
FIELD ERECTED TANKS
MECHANICAL BOP EQUIPMENT
ELECTRICAL BOP EQUIPMENT
SWITCHYARD
STARTUP/COMMISSIONING
STARTUP/CHECKOUT
PERFORMANCE TESTING
RELIABILITY RUN
B 04/21/00 REVISED NHL LKL
A 09/16/98 INITIAL ISSUE KH
ENGINEER L. LUCAS
DRAWN N. LORANCE
K. HAYDEN 09/16/98
LEGEND
C - CONTRACT AWARD
D - DELIVERY TO SITE
170 MW COMBUSTION TURBINE
DRAWING NUMBER XXXXXX-XXXX-F1001
REV B
CODE INDEPENDENCIA

8.0 Analysis Results and Conclusions

8.1 Analysis Methodology

8.1.1 Methodology

The economic evaluation is conducted over a 20 year period from 2000 through 2019. The economic evaluation is based on the cumulative present worth of annual costs for capital costs, non-fuel O&M costs, fuel costs, and purchase power demand and energy costs. Capital costs are included for new unit additions only. Capital costs for existing units are not included since they represent sunk costs and are the same for every plan. Annual capital costs for new unit additions are determined by applying an annual fixed charge rate to the capital costs for each unit beginning in the first year of commercial operation. Non-fuel O&M costs include fixed and variable O&M costs. Fixed O&M costs are not included for existing units since these costs are the same for every plan.

Evaluation of the generating unit alternatives was performed using Black & Veatch's optimal generation expansion model POWROPT. POWROPT evaluates all combinations of generating unit and power purchase alternatives and selects the alternatives that provide the lowest cumulative present worth revenue requirements. POWROPT uses an hourly chronological approach to developing the production cost. The results of several scenarios are contained later in this section.

The base case is analyzed using the economic parameters described in Section 8.1.2. Sensitivity analyses are also made to measure the impact of key assumptions on the plan. The sensitivity analyses include:

- High and low load and energy growth
- High and low fuel price escalation
- Constant differential between oil/gas and coal prices over the planning horizon

8.1.2 Economic Parameters

Escalation Rates The general inflation rate applied is assumed to be 2.3 percent. The escalation rate for capital costs and operation and maintenance (O&M) expenses is assumed to be 3.0 percent.

Present Worth Discount Rate The present worth discount rate is assumed to be equal to the bond rate of 6.0 percent.

Bond Interest Rate The current municipal long-term bond interest rate is assumed to be 6.0 percent.

Interest During Construction Interest Rate The interest during construction interest rate for OUC is assumed to be 6.0 percent.

Fixed Charge Rate The fixed charge rate is assumed to be 9.07 percent for simple cycle combustion turbines and combined cycle and 8.47 percent for coal units based on the economic life of each unit, which is 25 and 30 years respectively, a 2.0 percent issuance fee, a 1.0 percent annual insurance cost, a 6 month debt service reserve fund earning interest equal to the bond interest rate of 6.0 percent, and a 6.0 percent bond interest rate.

Table 8.1 summarizes the economic parameters used in this analysis.

Table 8-1 : Summary of Economic Parameters

Parameter Description	Value
General Inflation Rate	2.3 %
Escalation Rate applied to Capital Costs	3.0 %
Escalation Rate applied to O&M expenses	3.0 %
Present Worth Discount Rate	6.0 %
Bond Interest Rate	6.0 %
Interest During Construction Interest Rate	6.0 %
Fixed Charge Rate – CT's and CC's	9.07 %
Fixed Charge Rate - Coal Units	8.47 %

8.2 Fuel Price Forecast

8.2.1 Coal Price Forecast

Coal is the primary fuel used in Stanton Unit 1, Unit 2 and McIntosh Unit 3, which accounts for the majority of generation at OUC.

A majority of the coal requirements for Stanton Energy Center are supplied through two long term contracts with the James River Sales Company and the TECO Coal Corporation. OUC also has a long term transportation contract with CSX Rail Transportation to transport the coal from the TECO and James River coal suppliers to the Stanton Energy Center.

McIntosh Unit 3 burns a combination of RDF, petroleum coke, and coal. Lakeland is currently purchasing abut 90 percent of the coal requirements for McIntosh 3 under 1-year contracts with the remainder of coal requirements purchased on the spot market.

The base coal price forecast is listed in Table 8-2. Low and high band coal price forecasts are presented in Tables 8-3 and 8-4. For the purposes of this Ten-Year Site Plan, the Stanton Energy Center coal cost is assumed to represent the fuel cost for McIntosh 3 as well.

8.2.2 Natural Gas Price Forecast

Natural gas represents the second significant portion of fuel consumed for OUC's energy production. Natural gas transportation is supplied to the Indian River combustion turbines by Florida Gas Transmission Company (FGT) under FTS-1 and FTS-2 tariffs.

The base natural gas price forecast is listed in Table 8-2. The projected commodity price is presented along with the projected delivered price to Indian River based on existing FTS-1 and FTS-2 contracts. Natural gas price projections for natural gas for new units is based on the commodity price plus $0.60/MBtu for transportation, which reflects the assumed transportation price after competing pipelines gain access to the state. Low and high band natural gas price forecasts are presented in Tables 8-3 and 8-4. OUC's natural gas transportation costs and contract amounts under FTS-1 and FTS - 2 are shown in Table 8-5.

8.2.3 Summary of Fuel Price Forecast

Tables 8-2 through Table 8-4 present the base, low and high band fuel price forecast. Table 8-5 shows the demand costs and energy demands under FTS contracts. Table 8-6 shows projected fuel prices assuming a constant differential to coal equal to the differential in 2000.

Table 8-2: Fuel Price Forecast -Base Case

Year	SEC Coal $/MBtu	Natural Gas Commodity $/MBtu	Indian River Delivered Natural Gas $/MBtu	Indian River #6 Oil $/MBtu
2000	1.74	2.55	2.95	3.60
2001	1.79	2.59	3.03	2.97
2002	1.83	2.68	3.13	3.08
2003	1.88	2.77	3.24	3.20
2004	1.92	2.87	3.35	3.33
2005	1.97	2.97	3.47	3.46
2006	1.99	3.08	3.59	3.60
2007	2.01	3.18	3.71	3.74
2008	2.10	3.30	3.84	3.89
2009	2.17	3.41	3.97	4.05
2010	2.22	3.53	4.11	4.21
2011	2.27	3.65	4.25	4.38
2012	2.32	3.78	4.40	4.55
2013	2.37	3.91	4.55	4.74
2014	2.43	4.05	4.70	4.93
2015	2.48	4.19	4.87	5.12
2016	2.54	4.34	5.03	5.33

Table 8-3: Fuel Price Forecast - Low Forecast

Year	SEC Coal $/MBtu	Natural Gas Commodity $/MBtu	Indian River Delivered Natural Gas $/MBtu	Indian River #6 Oil $/MBtu
2000	1.73	2.10	2.36	2.07
2001	1.76	2.20	2.48	2.45
2002	1.78	2.25	2.53	2.52
2003	1.81	2.29	2.58	2.59
2004	1.84	2.34	2.63	2.67
2005	1.86	2.38	2.69	2.75
2006	1.83	2.43	2.74	2.83
2007	1.81	2.48	2.80	2.92
2008	1.86	2.53	2.86	3.01
2009	1.89	2.58	2.92	3.10
2010	1.91	2.63	2.98	3.20
2011	1.92	2.69	3.04	3.30
2012	1.94	2.74	3.11	3.40
2013	1.96	2.79	3.17	3.51
2014	1.97	2.85	3.24	3.61
2015	1.99	2.91	3.31	3.73
2016	2.01	2.97	3.38	3.84

Table 8-4: Fuel Price Forecast - High Forecast

Year	SEC Coal $/MBtu	Natural Gas Commodity $/MBtu	Indian River Delivered Natural Gas $/MBtu	Indian River #6 Oil $/MBtu
2000	1.74	2.74	3.33	3.62
2001	1.81	2.72	3.37	2.89
2002	1.88	2.89	3.56	3.05
2003	1.95	3.06	3.75	3.22
2004	2.02	3.24	3.96	3.41
2005	2.09	3.44	4.18	3.61
2006	2.16	3.64	4.41	3.83
2007	2.24	3.86	4.66	4.05
2008	2.38	4.09	4.92	4.29
2009	2.49	4.34	5.19	4.54
2010	2.58	4.60	5.48	4.81
2011	2.68	4.88	5.79	5.09
2012	2.78	5.17	6.11	5.39
2013	2.88	5.48	6.45	5.71
2014	2.99	5.81	6.82	6.04
2015	3.10	6.16	7.20	6.40
2016	3.22	6.53	7.61	6.78

Table 8-5: FTS Demand Costs and Limits

Year	FTS-2 Demand Cost ($/year)	FTS-1 Demand Cost ($/year)	Total FTS Demand Cost ($/year)	FTS-2 MBtu/yr Maximum	FTS-1 MBtu/yr Maximum
2000	5,071,603	273,119	5,344,722	6,213,965	159,387
2001	4,969,233	277,216	5,246,449	6,213,965	157,387
2002	4,754,788	281,375	5,036,162	5,960,565	157,387
2003	4,596,294	61,930	4,658,224	5,960,565	157,387
2004	4,679,656	62,859	4,742,515	5,960,565	157,387
2005	4,749,851	63,802	4,813,652	5,960,565	157,387
2006	4,821,098	64,759	4,885,857	5,960,565	157,387
2007	4,893,415	65,730	4,959,145	5,960,565	157,387
2008	4,966,816	66,716	5,033,532	5,960,565	157,387
2009	5,041,318	67,717	5,109,035	5,960,565	157,387
2010	5,116,938	68,733	5,185,671	5,960,565	157,387
2011	5,193,692	69,764	5,263,456	5,960,565	157,387
2012	5,271,597	70,810	5,342,408	5,960,565	157,387
2013	5,350,671	71,872	5,422,544	5,960,565	157,387
2014	5,430,932	72,950	5,503,882	5,960,565	157,387
2015	5,512,395	74,045	5,586,440	5,960,565	157,387
2016	5,595,081	75,155	5,670,237	5,960,565	157,387

Table 8-6: Fuel Price Forecast – Constant Differential

Year	SEC Coal $/MBtu	Natural Gas Commodity $/MBtu	Indian River Delivered Natural Gas $/MBtu	Indian River #6 Oil $/MBtu
2000	1.74	2.55	2.95	3.60
2001	1.79	2.60	3.00	3.65
2002	1.83	2.64	3.04	3.69
2003	1.88	2.69	3.09	3.74
2004	1.92	2.73	3.13	3.78
2005	1.97	2.78	3.18	3.83
2006	1.99	2.80	3.20	3.85
2007	2.01	2.82	3.22	3.87
2008	2.10	2.91	3.31	3.96
2009	2.17	2.98	3.38	4.03
2010	2.22	3.03	3.43	4.08
2011	2.27	3.08	3.48	4.13
2012	2.32	3.13	3.53	4.18
2013	2.37	3.18	3.58	4.23
2014	2.43	3.24	3.64	4.29
2015	2.48	3.29	3.69	4.34
2016	2.54	3.35	3.75	4.40

8.3 Results for Capacity Expansion Plans

8.3.1 Methodology

Black & Veatch used POWROPT, an optimal generation expansion model, to evaluate generating unit alternatives. POWROPT was developed by Black & Veatch 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 criterion utilized was a minimum reserve margin of 15 percent. All capacity expansion plans were analyzed over a 20 year period from 2000 to 2019.

The load forecast presented on Section 4.0 was extended to 2019 at the average annual growth rate of the last three years of the forecast. Likewise, the fuel cost projections presented in Section 8.2.3 were extended to 2019 at the average annual escalation rate of the last three years of the forecast.

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

8.3.2 Expansion Candidates

The expansion candidates for the POWROPT evaluation were presented in Section 7.0. The Reliant option PPA was also used as an expansion candidate.

8.3.3 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 minimum reserve margins. The evaluations were based upon the generating unit cost and performance characteristics described in Section 7.0.

Table 8-7 represents the least-cost capacity addition plan for OUC under the base case scenario. All units were modeled using the summer and winter capacity ratings in the respective seasons, but are listed with summer ratings because summer capacities and summer peak demand drive OUC's reserve margin requirements.

Table 8-7 indicates that the 2X1 501 F combined cycle should be selected as the first generating unit addition for the 2004 winter peak. The actual commercial operation date will be October 1, 2003 to correspond to the date that the capacity from the Reliant PPA can be adjusted.

Table 8-7
Base Case Expansion Plan[1]

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
2000	Reliant Power Purchase (593 MW) Oct.	143,128	143,128
2001	Reliant Power Purchase (538 MW) Oct.	146,447	281,285
2002	Reliant Power Purchase (553 MW) Oct.	150,818	415,513
2003	Reliant Power Purchase (100 MW) Oct 2x1 501 F Combined Cycle (481.89 MW) Oct.	159,595	549,512
2004		173,945	687,292
2005		175,177	818,195
2006		169,975	938,021
2007	7 FA Simple Cycle (145.98 MW) June	181,227	1,058,547
2008		192,512	1,179,332
2009		204,648	1,300,462
2010		213,912	1,419,909
2011		220,260	1,535,939
2012		233,668	1,652,065
2013		246,010	1,767,404
2014		258,594	1,881,781
2015		275,818	1,996,870
2016	7 FA Simple Cycle (145.98 MW) June	290,419	2,111,192
2017		309,307	2,226,058
2018		326,172	2,340,330
2019		351,612	2,456,543

[1]Capacity is stated in summer ratings.

8.4 Sensitivity Analysis

The sensitivity analyses are presented in Sections 8.4.1 through 8.4.5, which include the following:

- High load and energy growth.
- Low load and energy growth.
- High fuel price escalation.
- Low fuel price escalation.
- Constant differential between oil/gas and coal prices over the planning horizon.

For each sensitivity analysis, the least cost plan over the planning horizon is identified. The sensitivity analyses were performed over the 20 year planning period used in the base case economic evaluation, with a projection of annual costs and cumulative present worth costs. All capacities listed in the expansion plan summary tables are the summer ratings of the units. The modeling of the units applied both summer and winter ratings of the units in their respective seasons.

8.4.1 High Load and Energy Growth

The high load and energy growth sensitivity provides insight into the effect of resource decisions made in an environment where load and energy growth is greater than the expected forecast. The high load and energy growth requires more generation to cover higher energy and demand levels, thus the increase in supply costs and greater cumulative present worth revenue requirements. Table 8-8 summaries the results. The high load and energy growth sensitivity is based upon the high load and energy growth forecast presented in Section 4.3.2. The high load growth results in a much earlier need for capacity additions with the first additional unit added on October 1, 2002. The 7FA General Electric simple cycle combustion turbine is the first unit selected.. The 2x1 501 F combined cycle is added on October 1, 2003.

8.4.2 Low Load and Energy Growth

The low load and energy growth sensitivity is based upon the low load and energy growth forecast presented in Section 4.3.2. The low load and energy growth sensitivity provides analysis insight into the effect of resource decisions made in an environment where load and energy growth is less than the expected forecast. The low load and energy growth requires less generation, thus the reduced cumulative present worth revenue requirements and resource additions. The first unit additions are installed on

October 1, 2003 to correspond with the date the Reliant PPA can be adjusted and are a 7FA simple cycle combustion turbine and a 1x1 501 F combined cycle.

8.4.3 High Fuel Price Escalation

The high fuel price scenario applies the high fuel price forecast to the generation planning assumptions. The high fuel price forecast is provided in Section 8.2. Table 8-10 displays the results of the economic evaluation for the least cost expansion plan for the high fuel price escalation sensitivity. The expansion plan shows the installation of a 7 FA simple cycle combustion turbine on October 1, 2003 and a 425 MW pulverized coal unit on October 1, 2004.

8.4.4 Low Fuel Price Escalation

The low fuel price scenario applies the low fuel price forecast to the generation planning assumptions. The low fuel price forecast is provided in Section 8.2. Table 8-11 displays the results of the economic evaluation for the least cost expansion plan for the low fuel price escalation sensitivity. The expansion plan is the same as for the base case.

8.4.5 Constant Differential Between Coal Versus Natural Gas/Oil

This sensitivity case assumes the differential price between natural gas/oil and coal remains constant over the planning horizon based on the differential in the base year for the fuel forecasts. The economic evaluation results of the analysis are included in Table 8-12. The expansion plan for the constant differential fuel price is the same as for the base case.

Table 8-8
High Load and Energy Growth Sensitivity[1]

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
2000	Reliant Power Purchase (593 MW) Oct.	147,141	147,141
2001	Reliant Power Purchase (575 MW) Oct.	152,093	290,625
2002	7 FA Simple Cycle (145.98 MW) Oct. Reliant Power Purchase (525 MW) Oct.	159,200	432,313
2003	2x1 501 F Combined Cycle (481.89 MW) Oct.	171,372	576,200
2004		184,431	722,286
2005		189,728	864,062
2006		190,397	998,284
2007	7 FA Simple Cycle (145.98 MW) June	205,384	1,134,877
2008		221,455	1,273,820
2009		242,894	1,417,589
2010	7 FA Simple Cycle (145.98 MW) June	262,689	1,564,273
2011		279,583	1,711,554
2012		302,283	1,861,779
2013		324,982	2,014,143
2014	Pulverized Coal Unit (425 MW) June	356,841	2,171,975
2015		390,288	2,334,828
2016		412,454	2,497,189
2017		435,701	2,658,993
2018		468,893	2,823,267
2019	7 FA Simple Cycle (145.98 MW) June	511,387	2,992,287

[1]Capacity is stated in summer ratings.

Table 8-9
Low Load and Energy Growth Sensitivity[1]

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
2000	Reliant Power Purchase (593 MW) Oct.	146,025	146,025
2001	Reliant Power Purchase (525 MW) Oct.	146,222	283,971
2002	Reliant Power Purchase (525 MW) Oct.	146,478	414,335
2003	7 FA Simple Cycle (145.98 MW) Oct. Reliant Power Purchase (100 MW) Oct. 1X1 501 F Combined Cycle (238.55 MW) Oct.	158,385	547,319
2004		191,452	698,967
2005		192,258	842,633
2006		184,146	972,448
2007		189,123	1,098,226
2008		193,614	1,219,702
2009		205,674	1,341,440
2010		209,923	1,458,660
2011		213,804	1,571,289
2012		221,954	1,681,594
2013		228,972	1,788,945
2014		235,818	1,893,247
2015		244,921	1,995,444
2016		245,296	2,092,004
2017		253,896	2,186,292
2018		264,902	2,279,098
2019		274,497	2,369,823

[1]Capacity is stated in summer ratings.

Table 8-10
High Fuel Price Sensitivity[1]

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
2000	Reliant Power Purchase (593 MW) Oct.	143,772	143,772
2001	Reliant Power Purchase (538 MW) Oct.	148,291	283,669
2002	Reliant Power Purchase (553 MW) Oct.	154,777	421,420
2003	7 FA Simple Cycle (145.98 MW) Oct. Reliant Power Purchase (400 MW) Oct.	165,794	560,624
2004	Pulverized Coal Unit (425 MW) Oct.	180,533	703,623
2005		192,874	847,749
2006		192,360	983,356
2007		201,580	1,117,418
2008		215,247	1,252,466
2009	7 FA Simple Cycle (145.98 MW) June	235,512	1,391,865
2010		250,362	1,531,666
2011		261,055	1,669,186
2012		277,978	1,807,333
2013		292,878	1,944,646
2014		312,024	2,082,654
2015		332,056	2,221,210
2016		350,695	2,359,259
2017		373,363	2,497,913
2018	7 FA Simple Cycle (145.98 MW) June	406,024	2,640,161
2019		447,921	2,788,205

[1]Capacity is stated in summer ratings.

Table 8-11
Low Fuel Price Sensitivity[1]

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
2000	Reliant Power Purchase (593 MW) Oct.	139,579	139,579
2001	Reliant Power Purchase (538 MW) Oct.	141,412	272,987
2002	Reliant Power Purchase (553 MW) Oct.	144,146	401,276
2003	Reliant Power Purchase (100 MW) Oct. 2x1 501 F Combined Cycle (481.89 MW) Oct.	151,605	528,567
2004		164,233	658,654
2005		163,868	781,106
2006		156,052	891,116
2007	7 FA Simple Cycle (145.98 MW) June	164,373	1,000,434
2008		172,468	1,108,642
2009		180,601	1,215,539
2010		188,133	1,320,592
2011		191,352	1,421,394
2012		199,400	1,520,490
2013		206,305	1,617,213
2014		215,057	1,712,333
2015		224,872	1,806,164
2016	7 FA Simple Cycle (145.98 MW) June	237,190	1,899,533
2017		249,642	1,992,241
2018		260,314	2,083,441
2019		277,601	2,175,191

[1]Capacity is stated in summer ratings.

Table 8-12
Constant Differential Between Coal Versus Natural Gas/Oil[1]

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
2000	Reliant Power Purchase (593 MW) Oct.	143,874	143,874
2001	Reliant Power Purchase (538 MW) Oct.	147,497	283,021
2002	Reliant Power Purchase (553 MW) Oct.	151,985	418,288
2003	Reliant Power Purchase (100 MW) Oct. 2x1 501 F Combined Cycle (481.89 MW) Oct.	160,324	552,899
2004		173,828	690,587
2005		174,469	820,960
2006		168,503	939,748
2007	7 FA Simple Cycle (145.98 MW) June	178,885	1,058,717
2008		190,266	1,178,092
2009		201,364	1,297,279
2010		211,094	1,415,153
2011		217,050	1,529,492
2012		227,333	1,642,469
2013		237,863	1,753,989
2014		248,754	1,864,013
2015		261,233	1,973,017
2016	7 FA Simple Cycle (145.98 MW) June	275,716	2,081,551
2017		291,733	2,189,891
2018		305,715	2,296,996
2019		325,159	2,404,465

[1]Capacity is stated in summer ratings.

9.0 Environmental and Land Use Information

The proposed generating units will be installed at the existing Stanton Energy Center site. Stanton Energy Center currently contains two 440 MW pulverized coal units, which went into service in 1987 and 1996. The site was originally certified for 2000 MW of coal fueled capacity. Extensive environmental and land use information was filed with the Site Certification Application for Stanton 1 and additional information was filed with the Supplemental Site Certification application for Stanton 2. The original and supplemental Site Certification Applications were submitted to all the agencies and for sake of brevity have not been reproduced. The following information focuses on the 2x1 501 F combined cycle to be installed for commercial operation on October 1, 2003.

9.1 Status of Site Certification

Ultimate certification for four units totaling 2,000 MW of coal fueled generation was obtained with the Site Certification for Stanton 1. Stanton 2 was certified under the Supplemental Site Certification provisions of Florida Electrical Power Plant Siting Act (Act). The planned new 2x1 501 F combined cycle unit is not eligible for supplemental certification under the Act because of the change in fuel from coal to natural gas. The planned new 2x1 501 F combined cycle unit thus requires certification under the Act. OUC plans to file a Site Certification Application in the summer of 2000.

9.2 Land and Environmental Features

The Stanton Energy Center site is located in Orange County, Florida, with approximately 1,100 acres. The Econlockhatchee River is about three-fourths miles east of the northeast corner of the site boundary. The Orange County Solid Waste Disposal facility is adjacent to the site along the west boundary.

Currently, a natural gas pipeline is planned to be installed to connect the unit to the Florida Gas Transmission (FGT) system. The pipeline will be approximately 3.5 miles in total length, connecting with FGT's system, south of the site. The pipeline is planned to be routed in the existing transmission line right-of-way. Other pipelines may be considered if competing pipelines are successful in getting constructed in the state.

Extensive details regarding land and environmental features are contained in the Site Certification Application for Stanton 1 and the Supplemental Site Certification Application for Stanton 2.

9.3 Air Emissions

The 2x1 501 F combined cycle unit is planned to utilize low NO_x combustors as well as SCR to reduce NO_x emissions. The expected NO_x emissions are 3.5 ppm. The HRSG is planned to be designed with a spool piece for a CO catalyst, but installation of the CO catalyst is not planned. The cost estimates included the costs associated with the requirements for No. 2 oil as an alternative fuel. A final decision as to whether an alternate fuel will be utilized has not been made. If No. 2 fuel oil is used as an alternate fuel, SO_2 emissions will be controlled by limiting the sulfur content of the oil.

9.4 Water and Wastewater

The use of combined cycle technology reduces the amount of water required compared to convention steam generation. The 2x1 501 F combined cycle is expected to obtain water in the same manner as the existing Stanton units. Ground water will be used for steam cycle makeup and water injection if No. 2 oil firing is utilized. Treated sewage effluent from The Orange County Easterly Subregional Wastewater Treatment Plant is planned to be used for the 2x1 501 F combined cycle as it is for Stanton 1 and 2.

The Stanton site is designed to reuse wastewater to the extent possible. When wastewater cannot be reused, it is evaporated with a brine concentrator. Thus the Stanton site is truly a zero discharge site. The planned 2x1 501 F combined cycle will utilize the same wastewater treatment process as the existing Stanton units.

10.0 Ten Year Site Plan Schedules

This section presents the schedules required by the Ten-Year Site Plan rules for the Florida Public Service Commission. OUC has attempted to provide complete information for the FPSC whenever possible.

Table 10-1
Schedule 1.0: Existing Generating Facilities as of December 31, 1999

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				Fuel		Fuel Transport						Net Capability[1]	
Plant Name	Unit No.	Location	Unit Type	Pri	Alt	Pri	Alt	Alt Fuel Days Use[2]	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen. Max. Nameplate kW	Summer MW	Winter MW
Indian River	A	Brevard	GT	NG	F02	PL	TK		6/89	Unknown	41,400	18	23.4
Indian River	B	Brevard	GT	NG	F02	PL	TK		7/89	Unknown	41,400	18	23.4
Indian River	C	Brevard	GT	NG	F02	PL	TK		8/92	Unknown	130,000	85.3	100.3
Indian River	D	Brevard	GT	NG	F02	PL	TK		10/92	Unknown	130,000	85.3	100.3
Stanton Energy Center	1	Orange	ST	BIT	-	RR	-		7/87	Unknown	464,580	301.6	303.7
Stanton Energy Center	2	Orange	ST	BIT	-	RR	-		6/96	Unknown	464,580	319.3	319.3
McIntosh	3	Polk	ST	BIT	REF	RR	TK		9/82	Unknown	363,870	133	136
Crystal River	3	Citrus	NP	UR	-	TK	-		3/77	Unknown	890,460	13	13
St. Lucie [3]	2	St. Lucie	NP	UR	-	TK	-		8/83	Unknown	850,000	51	52

1: OUC ownership share

2: Not recorded

3: OUC owns St. Lucie Unit 2. Reliability exchange divides 50% power from Unit 1 and 50% power from Unit 2.

Table 10-2
Schedule 2.1: History and Forecast of Energy Consumption and Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural & Residential					General Service Non-Demand		
Year	Population	Members per Household	GWh	Average No. of Customers	Average kWh Consumption per Customer	GWh	Average No. of Customers	Average kWh Consumption per Customer
1990	257,450	2.55	1,239	101,097	12,256	307	13,446	22,832
1991	262,590	2.57	1,201	102,134	11,759	320	13,758	23,259
1992	267,500	2.58	1,216	103,495	11,749	308	13,891	22,173
1993	271,500	2.58	1,256	104,978	11,964	310	14,091	22,000
1994	275,300	2.58	1,286	106,462	12,079	316	14,318	22,070
1995	278,500	2.56	1,380	108,805	12,683	316	14,590	21,659
1996	284,000	2.56	1,419	110,949	12,790	318	14,858	21,403
1997	290,600	2.55	1,377	113,977	12,081	322	14,994	21,475
1998	300,400	2.55	1,583	117,814	13,436	311	15,170	20,501
1999	310,500	2.54	1,504	121,767	12,351	308	15,547	19,811
Forecast								
2000	312,800	2.54	1,493	122,661	12,172	315	15,705	20,057
2001	317,600	2.53	1,509	124,793	12,092	327	15,896	20,571
2002	323,100	2.52	1,533	126,953	12,075	340	16,135	21,072
2003	328,100	2.52	1,556	129,155	12,048	354	16,369	21,626
2004	333,800	2.52	1,583	131,398	12,047	368	16,599	22,170
2005	338,800	2.52	1,601	133,648	11,979	381	16,829	22,639
2006	344,500	2.52	1,623	135,898	11,943	394	17,059	23,096
2007	349,500	2.51	1,643	138,148	11,893	408	17,289	23,599
2008	354,800	2.51	1,670	143,235	11,909	422	17,519	24,088
2009	356,900	2.51	1,684	141,350	11,914	435	17,749	24,508

Table 10-3
Schedule 2.2: History and Forecast of Energy Consumption and Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	General Service Demand			Railroads and Railways	Street & Highway Lighting GWh	Other Sales to Public Authorities GWh	Total Sales to Ultimate Consumers GWh
Year	GWh	Average No. of Customers	Average kWh Consumption per Customer				
1990	1,899	2,451	774,786	0	21	4	3,470
1991	1,981	2,461	804,957	0	22	4	3,528
1992	2,004	2,542	788,356	0	23	4	3,555
1993	2,024	2,646	764,928	0	23	4	3,617
1994	2,131	2,749	775,191	0	22	5	3,760
1995	2,207	2,946	749,151	0	22	5	3,930
1996	2,259	3,116	724,968	0	23	5	4,024
1997	2,331	3,452	675,261	0	23	5	4,058
1998	2,497	3,806	656,069	0	22	5	4,418
1999	2,650	3,928	676,020	0	26	5	4,493
Forecast							
2000	2,717	3,990	680,952	0	24	5	4,554
2001	2,821	4,050	696,543	0	24	5	4,686
2002	2,932	4,150	706,506	0	25	5	4,835
2003	3,047	4,212	723,409	0	25	5	4,987
2004	3,169	4,318	733,905	0	25	5	5,150
2005	3,282	4,424	741,863	0	25	5	5,294
2006	3,399	4,528	750,663	0	26	5	5,447
2007	3,518	4,632	759,499	0	26	5	5,600
2008	3,635	4,736	67,525	0	26	5	5,758
2009	3,749	4,840	774,587	0	26	5	5,899

Table 10-4
Schedule 2.3: History and Forecast of Energy Consumption and Number of Customers by Customer Class

(1) Year	(2) Sales for Resale GWh	(3) Utility Use & Losses GWh	(4) Net Energy for Load GWh	(5) Other Customers (Average No.)	(6) Total No. of Customers
1990	0	124	3,594	0	116,994
1991	0	129	3,657	0	118,353
1992	0	118	3,673	0	119,928
1993	0	166	3,783	0	121,715
1994	0	137	3,897	0	123,529
1995	0	171	4,101	0	126,341
1996	0	162	4,186	0	128,923
1997	0	213	4,271	0	132,423
1998	0	160	4,578	0	136,790
1999	0	181	4,674	0	141,234
Forecast					
2000	0	191	4,745	0	142,356
2001	0	197	4,883	0	144,739
2002	0	202	5,037	0	147,238
2003	0	210	5,197	0	149,736
2004	0	217	5,367	0	152,315
2005	0	223	5,517	0	154,901
2006	0	229	5,676	0	157,485
2007	0	236	5,836	0	160,069
2008	0	242	6,000	0	162,490
2009	0	246	6,145	0	163,939

Table 10–5
Schedule 3.1: History and Forecast of Summer Peak Demand Base Case (MW)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
					Residential	Comm./Ind.		
Year	Total	Wholesale	Retail	Interrupt.	Load Management	Load Management	Conservation	Net Firm Demand
1990	708	0	708	0	0	0	-	708
1991	714	0	714	0	0	0	-	714
1992	763	0	763	0	0	0	-	763
1993	760	0	760	0	0	0	-	760
1994	749	0	749	0	0	0	-	749
1995	799	0	799	0	0	0	-	798
1996	788	0	788	0	0	0	-	788
1997	882	0	882	0	0	0	36	846
1998	944	0	944	1	0	0	37	907
1999	1,006	0	1,006	0	0	0	37	969
Forecast								
2000	988	0	988	1	0	0	37	950
2001	1,015	0	1,015	1	0	0	37	977
2002	1,043	0	1,043	1	0	0	37	1,005
2003	1,071	0	1,071	1	0	0	37	1,033
2004	1,098	0	1,098	1	0	0	37	1,060
2005	1,127	0	1,127	1	0	0	37	1,089
2006	1,154	0	1,154	1	0	0	37	1,116
2007	1,184	0	1,184	1	0	0	37	1,146
2008	1,209	0	1,209	1	0	0	37	1,171
2009	1,236	0	1,236	1	0	0	37	1,198

Table 10-6
Schedule 3.2: History and Forecast of Winter Peak Demand Base Case (MW)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
					Residential	Comm./Ind.		
Year	Total	Wholesale	Retail	Interrupt.	Load Management	Load Management	Conservation	Net Firm Demand
1990/91	636	0	636	0	0	0	-	636
1991/92	673	0	673	0	0	0	-	673
1992/93	721	0	721	0	0	0	-	721
1993/94	674	0	674	0	0	0	-	674
1994/95	800	0	800	0	0	0	-	800
1995/96	885	0	885	0	0	0	-	885
1996/97	775	0	775	0	0	0	-	775
1997/98	768	0	768	1	0	0	22	746
1998/99	962	0	962	1	0	0	24	937
1999/00	995	0	995	1	0	0	24	970
Forecast								
2000/01	1,019	0	1,019	1	0	0	24	994
2001/02	1,044	0	1,044	1	0	0	24	1,019
2002/03	1,069	0	1,069	1	0	0	24	1,044
2003/04	1,093	0	1,093	1	0	0	24	1,068
2004/05	1,118	0	1,118	1	0	0	24	1,093
2005/06	1,143	0	1,143	1	0	0	24	1,118
2006/07	1,168	0	1,168	1	0	0	24	1,143
2007/08	1,194	0	1,194	1	0	0	24	1,169
2008/09	1,218	0	1,218	1	0	0	24	1,193
2009/10	1,242	0	1,242	1	0	0	24	1,217

Table 10–7
Schedule 3.3: History and Forecast of Annual Net Energy for Load – GWH
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Year	Total	Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
1990	3,594	-	3,470	-	124	3,594	57.9
1991	3,657	-	3,528	-	129	3,657	58.5
1992	3,673	-	3,555	-	118	3,673	55.0
1993	3,783	-	3,617	-	166	3,783	56.8
1994	3,897	-	3,760	-	137	3,897	59.4
1995	4,101	-	3,930	-	171	4,101	58.7
1996	4,186	-	4,024	-	162	4,186	60.6
1997	4,360	89	4,058	-	213	4,271	57.6
1998	4,669	91	4,418	-	160	4,578	57.6
1999	4,765	91	4,493	-	181	4,674	56.8
Forecast							
2000	4,836	91	4,554	-	191	4,745	57.1
2001	4,974	91	4,686	-	197	4,883	57.1
2002	5,128	91	4,835	-	202	5,037	57.3
2003	5,288	91	4,987	-	210	5,197	57.5
2004	5,458	91	5,150	-	217	5,367	57.9
2005	5,608	91	5,294	-	223	5,517	57.9
2006	5,767	91	5,447	-	229	5,676	58.2
2007	5,927	91	5,600	-	236	5,836	58.3
2008	6,091	91	5,758	-	242	6,000	58.5
2009	6,236	91	5,899	-	246	6,145	58.5

Table 10-8
Schedule 4: Previous Year and Two Year Forecast of Retail Peak Demand and Net Energy for Load by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Month	Actual – 1999		2000 Forecast		2001 Forecast	
	Peak Demand[1] MW	NEL GWh	Peak Demand[1] MW	NEL GWh	Peak Demand[1] MW	NEL GWh
January	873	345	970	396	994	411
February	713	307	813	363	837	361
March	600	329	795	371	819	383
April	781	375	841	367	891	380
May	789	394	828	395	892	405
June	858	419	948	410	975	421
July	969	481	948	441	975	456
August	939	493	950	440	977	454
September	858	434	877	419	903	427
October	785	399	875	401	901	417
November	661	339	776	358	780	372
December	690	359	853	384	875	396

[1] Includes Load Management, Conservation and Interruptible Load.

Table 10-9
Schedule 5: Fuel Requirements

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Fuel Requirements		Units	1999 - Actual	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
(1)	Nuclear		Trillion BTU	5	5	5	5	5	5	5	5	5	5	5
(2)	Coal		1000 Ton	1802	1854	1847	1868	1878	1721	1836	1771	1793	1830	1768
(3)	Residual[1]	Total	1000 BBL	1255	0	0	0	0	0	0	0	0	0	0
(4)		Steam	1000 BBL	1255	0	0	0	0	0	0	0	0	0	0
(5)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(7)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate[2]	Total	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(9)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(10)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(11)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(12)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	1000 MCF	14138	58.7	82.5	94.3	2374.4	10678.2	9467.1	9044.5	9867.4	10386.0	12628.4
(14)		Steam	1000 MCF	11944	0	0	0	0	0	0	0	0	0	0
(15)		CC	1000 MCF	0	0	0	0	2296.6	9813.5	8699.4	8358.5	8918.6	9277.4	11230.7
(16)		CT	1000 MCF	2194	58.7	82.5	94.3	77.8	864.7	767.7	686.0	948.8	1108.6	1397.7

[1] Resideual includes #4, #5 and #6 oil.
[2] Distillate includes #1, #2 oil, kerosene, jet fuel and amounts used at coal burning plants for flame stabilization and on start up.

Table 10-10
Schedule 6.1: Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources		Units	1999 - Actual	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
(1)	Annual Firm Interchange		GWH	0	-804	-616	-552	-692	-1080	-1094	-685	-675	-702	-709
(2)	Nuclear		GWH	447	501	471	501	489	461	496	484	466	496	489
(3)	Residual	Total	GWH	225	0	0	0	0	0	0	0	0	0	0
(4)		Steam	GWH	225	0	0	0	0	0	0	0	0	0	0
(5)		CC	GWH	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	GWH	0	0	0	0	0	0	0	0	0	0	0
(7)		Diesel	GWH	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate	Total	GWH	0	0	0	0	0	0	0	0	0	0	0
(9)		Steam	GWH	0	0	0	0	0	0	0	0	0	0	0
(10)		CC	GWH	0	0	0	0	0	0	0	0	0	0	0
(11)		CT	GWH	0	0	0	0	0	0	0	0	0	0	0
(12)		Diesel	GWH	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	GWH	0	4	5	7	289	1302	1123	1075	1178	1238	1553
(14)		Steam	GWH	0	0	0	0	0	0	0	0	0	0	0
(15)		CC	GWH	0	0	0	0	283	1228	1059	1018	1098	1145	1436
(16)		CT	GWH	0	4	5	7	6	74	64	57	80	93	117
(17)	Coal	Steam	GWH	0	5044	5023	5081	5111	4684	4992	4802	4867	4969	4812
(18)	Other		GWH	0	0	0	0	0	0	0	0	0	0	0
(19)	Net Energy for Load		GWH	897	4745	4883	5037	5197	5367	5517	5676	5836	6001	6145

Table 10-11
Schedule 6.2: Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources		Units	1999 - Actual	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
(1)	Annual Firm Interchange		%	0.0	-16.9	-12.6	-11.0	-13.3	-20.1	-19.8	-12.1	-11.6	-11.7	-11.5
(2)	Nuclear		%	49.8	10.6	9.6	9.9	9.4	8.6	9.0	8.5	8.0	8.3	8.0
(3)	Residual	Total	%	25.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(4)		Steam	%	25.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(5)		CC	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(6)		CT	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(7)		Diesel	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8)	Distillate	Total	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9)		Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10)		CC	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(11)		CT	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(12)		Diesel	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(13)	Natural Gas	Total	%	0.0	0.1	0.1	0.1	5.6	24.3	20.4	18.9	20.2	20.6	25.3
(14)		Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(15)		CC	%	0.0	0.0	0.0	0.0	5.4	22.9	19.2	17.9	18.8	19.1	23.4
(16)		CT	%	0.0	0.1	0.1	0.1	0.1	1.4	1.2	1.0	1.4	1.5	1.9
(17)	Coal	Steam	%	0.0	106.3	102.9	100.9	98.3	87.3	90.5	84.6	83.4	82.8	78.3
(18)	Refuse	Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(19)	Net Energy for Load		%	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Table 10-12

Schedule 7.1: Forecast of Capacity, Demand, and Scheduled Maintenance at time of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Year	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
	MW	MW	MW	MW	MW	MW	MW	%	MW	MW	%
2000	1024	593	422	0	1195	950	220	23.16%	0	220	23.16%
2001	1024	593	341	0	1276	977	274	28.05%	0	274	28.05%
2002	1024	538	335	0	1227	1005	193	19.20%	0	193	19.20%
2003	1024	553	316	0	1261	1033	199	19.26%	0	199	19.26%
2004	1506	100	261	0	1345	1060	255	24.06%	0	255	24.06%
2005	1506	0	171	0	1335	1089	194	17.81%	0	194	17.81%
2006	1506	0	139	0	1367	1116	201	18.01%	0	201	18.01%
2007	1652	0	139	0	1513	1146	313	27.31%	0	313	27.31%
2008	1652	0	142	0	1510	1171	285	24.34%	0	285	24.34%
2009	1652	0	144	0	1508	1198	257	21.45%	0	257	21.45%

Table 10-13
Schedule 7.2: Forecast of Capacity, Demand, and Scheduled Maintenance at time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Year	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
	MW	MW	MW	MW	MW	MW	MW	%	MW	MW	%
2000	1071	593	440	0	1224	970	232	23.92%	0	232	23.92%
2001	1071	593	341	0	1323	994	307	30.89%	0	307	30.89%
2002	1071	538	335	0	1274	1019	229	22.47%	0	229	22.47%
2003	1071	553	316	0	1308	1044	239	22.89%	0	239	22.89%
2004	1656	100	261	0	1495	1068	400	37.45%	0	400	37.45%
2005	1656	0	171	0	1485	1093	344	31.47%	0	344	31.47%
2006	1656	0	139	0	1517	1118	352	31.48%	0	352	31.48%
2007	1656	0	139	0	1517	1143	324	28.35%	0	324	28.35%
2008	1838	0	142	0	1696	1169	477	40.80%	0	477	40.80%
2009	1838	0	144	0	1694	1193	449	37.64%	0	449	37.64%

Table 10-14
Schedule 8.0: Planned and Prospective Generating Facility Additions and Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Plant Name[1]	Unit No.	Location	Unit Type[2]	Fuel [3]		Fuel Transport		Const Start	Commercial In-Service	Expected Retirement	Gen Max Nameplate	Net Capability		Status
				Pri.	Alt.	Pri.	Alt.	Mo/Yr	Mo/Yr	Mo/Yr	kW	Sum MW	Win MW	
SW 501 F 2x1 CC		Stanton Energy Center	CT	NG	LO	Pipeline	N/A	09/01	10/03	--	543,800	481.9	585.1	P
GE 7FA SC		Stanton Energy Center	CT	NG	LO	Pipeline	N/A	06/06	06/07	--	169,800	146.0	182.3	P

(1) Only one of the four alternatives will be constructed.

(2) FS = Fossil Steam; CT = Combustion Turbine.

(3) NG = Natural Gas; LO = Light Oil.

Table 10-15
Schedule 9.1: Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number:	Stanton Unit 3 (2x1 501 F Combined Cycle)
(2)	Capacity:	
	a. Summer MW	481.9
	b. Winter MW	585.1
(3)	Technology Type:	Combined Cycle
(4)	Anticipated Construction Timing:	
	a. Field Construction Start-date:	September 1, 2001
	b. Commercial In-Service date:	October 1, 2003
(5)	Fuel	
	a. Primary	Natural Gas
	b. Alternate	No. 2 Oil
(6)	Air Pollution Control Strategy:	SCR
(7)	Cooling Method:	Mechanical Cooling Tower
(8)	Total Site Area:	1,100 acres; unit 6 acres
(9)	Construction Status:	Planned
(10)	Certification Status:	Will be filed in Summer of 2000
(11)	Status with Federal Agencies:	No Status
(12)	Projected Unit Performance Data:	
	Planned Outage Factor (POF):	7.1 %
	Forced Outage Factor (FOF):	4.57 %
	Equivalent Availability Factor (EAF):	92.7 %
	Resulting Capacity Factor (%):	25.0 %
	Full Load Heat Rate:	6,819 Btu/kWh
(13)	Projected Unit Financial Data:	
	Book Life:	25 years
	Total Installed Cost (In-Service year $/kW):	534
	Direct Construction Cost ($/kW):	463
	AFUDC Amount ($/kW):	31
	Escalation ($/kW):	40
	Fixed O&M ($/kW-yr):	4.71 (2000 $)
	Variable O&M ($/MWh):	2.41 (2000 $)
	K Factor:	1.2290

Table 10-16
Schedule 9.2: Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number:	Stanton Unit 3 (GE 7FA Simple Cycle))
(2)	Capacity:	
	a. Summer MW	146.0
	b. Winter MW	182.3
(3)	Technology Type:	Simple Cycle
(4)	Anticipated Construction Timing:	
	a. Field Construction Start-date:	June 1, 2006
	b. Commercial In-Service date:	June 1, 2007
(5)	Fuel	
	a. Primary	Natural Gas
	b. Alternate	No. 2 Oil
(6)	Air Pollution Control Strategy:	Dry Low NOx Combustor
(7)	Cooling Method:	N/A
(8)	Total Site Area:	1,100 acres; unit 3 acres
(9)	Construction Status:	None
(10)	Certification Status:	Will be filed in Summer of 2004
(11)	Status with Federal Agencies:	No Status
(12)	Projected Unit Performance Data:	
	Planned Outage Factor (POF):	1.92 %
	Forced Outage Factor (FOF):	1.96 %
	Equivalent Availability Factor (EAF):	96.2 %
	Resulting Capacity Factor (%):	3.5 %
	Full Load Heat Rate:	10,467 Btu/kWh
(13)	Projected Unit Financial Data:	
	Book Life:	25 years
	Total Installed Cost (In-Service year $/kW):	467
	Direct Construction Cost ($/kW):	370
	AFUDC Amount ($/kW):	13
	Escalation ($/kW):	84
	Fixed O&M ($/kW-yr):	6.19 (2000 $)
	Variable O&M ($/MWh):	11.22 (2000 $)
	K Factor:	1.2290

Table 10-17
Schedule 10: Status Report and Specifications of Proposed Directly Associated Transmission Lines

(1)	Point of Origin and Termination:	No associated transmission lines are planned during the 2000 through 2009 time period.
(2)	Number of Lines:	
(3)	Right of Way:	
(4)	Line Length:	
(5)	Voltage:	
(6)	Anticipated Construction Time:	
(7)	Anticipated Capital Investment:	
(8)	Substations:	
(9)	Participation with Other Utilities:	