Duke Energy®
St. Lucie, LLC

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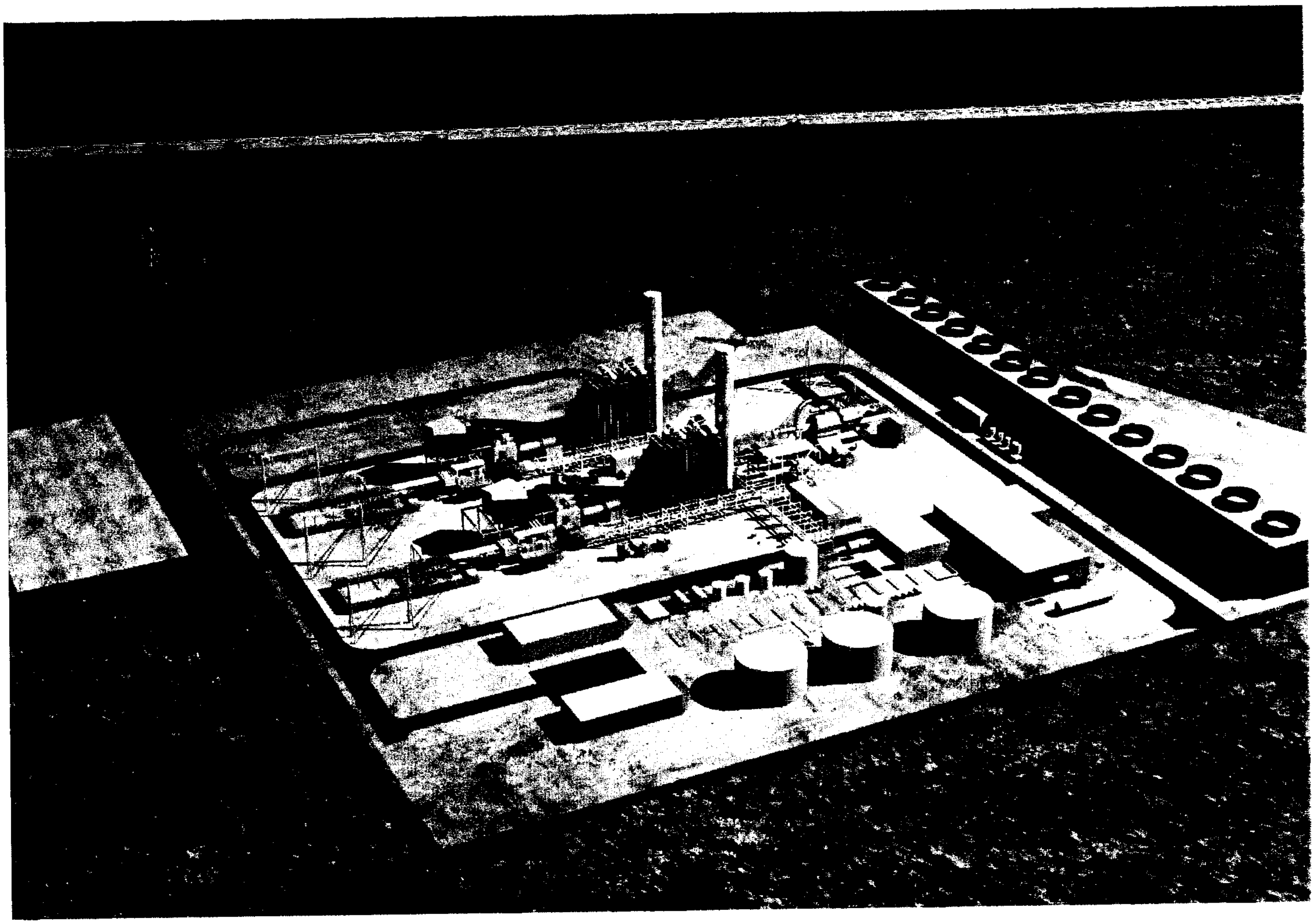
000612-EU

Duke Energy St. Lucie, LLC

Petition for Determination of Need

for the Duke Energy St. Lucie Generating Project



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CH2MHILL

HOLLAND & KNIGHT LLP

DUKE/FLUOR DANIEL

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Executive Summary

Duke Energy St. Lucie, L.L.C. ("DESL"), an electric utility regulated by the Florida Public Service Commission ("Commission") and a public utility under the Federal Power Act subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC"), seeks the Commission's determination of need for a 608 megawatt ("MW") natural gas-fired combined cycle generating unit that will be located in St. Lucie County, Florida (the "DESL Project" or "Project"). Duke Energy North America ("DENA") has formed DESL to permit, construct, own, and operate the Project. Expected to achieve commercial operation in June 2003, the Project will supply capacity and energy for sale at wholesale to other utilities and power marketers in Florida.

DESL is seeking a determination of need for the DESL Project pursuant to Section 403.519, Florida Statutes. As demonstrated in this Exhibit, the Project satisfies all of the criteria for a need determination in Section 403.519, and all relevant criteria under Rule 25-22.081, Florida Administrative Code.

ES.1 Description of the Applicant

DESL is the applicant for the proposed Project and the primarily affected utility for the Commission's determination of need. DESL was formed in 1999 as a Delaware limited liability corporation, and exists as a wholly owned subsidiary of DENA. The DESL Project will be developed by DENA and will be owned and operated by DESL. DENA is a wholly owned subsidiary of Duke Energy Corporation ("Duke Energy") engaged in the development, acquisition, and management of competitive generation projects throughout North America. DENA is a leading developer of natural gas-fired generation in North America. As of March 2000, DENA has over 4,400 MW in operation, 4,500 MW under construction, and 14,800 MW in various stages of development.

DENA has retained the services of qualified experts to assist in the permitting, design, procurement, and construction of the Project. CH2MHILL is the lead consultant on permitting the Project under the Site Certification Act. Duke/Fluor Daniel ("D/FD") will serve as DENA's engineering/procurement/construction ("EPC") contractor and operator. Natural gas for the Project will be supplied by Florida Gas Transmission Company ("FGT") through an existing contract with Citrus Trading Corporation, and through other suppliers, and possibly other natural gas pipelines. Fort Pierce Utilities Authority ("FPUA") will supply reclaimed water for cooling system purposes.

ES.2 Description of the Project

The Project will be located in St. Lucie County, Florida on a 67-acre site that is currently zoned industrial and has historically been used as pasture land. The Project is scheduled for commercial operation in June 2003 with an 18-month construction schedule. The Project's basic power generation cycle consists of a 2x1 General Electric ("GE") 7FA-combined cycle design operating on natural gas with duct firing. Reclaimed water from the FPUA will be used to meet the majority of the Project's cooling water needs. DESL has submitted a transmission interconnection study request to Florida Power & Light Company ("FPL") to determine the right-of-way path and interconnection voltage for the Project.

The Project, which will have an equivalent availability factor of 94.8 percent, represents a highly reliable source of electric generation to serve the Peninsular Florida wholesale market. The Project will have a net plant output of 608 MW at ISO (59° F and 60% relative humidity) (598 MW summer, 636 MW winter) when operating with duct firing. The Project will have a net plant output of 497 MW at ISO (483 MW summer, 528 MW winter) when operating without duct firing. The Project is a highly efficient means of converting natural gas into electricity. With duct firing at ISO, the Project will have a net plant heat rate of 7,351 Btu/kWh (HHV). Without duct firing at ISO, the Project's net plant heat rate will be 7,096 Btu/kWh (HHV). The Project's output and its efficiency in converting natural gas to electricity will provide low-cost capacity and energy supply alternatives to Peninsular Florida's retail serving utilities. Moreover, the Project's efficiency, its utilization of natural gas, and its utilization of reclaimed water will also have positive impacts on the environmental profile of Peninsular Florida's generation.

The estimated direct capital cost of the Project is $210 million. Duke Energy Capital will finance the Project, and therefore, the Project will not require financial commitment from ratepayers or any other Peninsular Florida residents.

ES.3 Need for the DESL Project

Capacity and energy from the Project is needed to assist other Peninsular Florida utilities to meet minimum reserve margins, to ensure reliability and maintain service that would otherwise be interrupted, and to provide energy and capacity at lower costs. The DESL Project will provide Peninsular Florida residents, utilities, and power marketers a new source of electric generation to meet the state's growing need for electric generation. New generation supplied by the Project is shown to be very reliable, highly efficient, low cost, and environmentally friendly.

The Project is needed to help meet Peninsular Florida's goal of reducing emissions and benefiting the environment. The Project will utilize natural gas - a clean burning domestically produced fuel source - for combustion. The Project will employ best available control technology ("BACT") to efficiently convert natural gas to electricity and minimize emissions.

The Project is consistent with the strategic goals of the Commission and Peninsular Florida. The utilization of natural gas is consistent with the goals of reducing emissions and encouraging reliance on domestically produced fuels. The Project will help to diversify the generation portfolio of Peninsular Florida. The Project enhances a competitive wholesale environment that will ultimately result in cost savings to Florida ratepayers. The Project will provide infrastructure to FPUA to extend the life of current wastewater treatment facilities and reduce the costs of new facilities when installed.

The DESL Project is consistent with the positive economic benefits desired by the State and St. Lucie County. The Project will bring an influx of capital, spending, and taxes that will benefit the State and St. Lucie County. The Project will also increase revenues for the FPUA through the purchase of reclaimed water that will serve the Project.

ES.4 Cost-Effectiveness of the Project

Based on detailed evaluations and numerous analyses, the DESL Project is the most cost-effective generating addition for DESL and Peninsular Florida. The DESL Project was reviewed against eight other supply-side alternatives, and was shown to be the most cost-effective generation addition. The supply-side alternatives evaluated represent the most reliable, cost-effective generation additions that exist on the market today.

The cost-effectiveness analyses conducted on the DESL Project included screening analysis, review of several vendors for equipment, detailed hourly electricity market, transmission system and plant operating cost simulations, and strategic considerations. Van Horn Consulting ("VHC") of Orinda, California and LCG Consulting ("LCG") of Los Altos, California performed the analyses and evaluations. The detailed hourly costs and projected electricity system operations were developed by applying LCG's UPLAN models, including the UPLAN Network Power Model ("NPM"). The UPLAN model utilized energy forecasts, peak demands, fuel prices, transmission system conditions and generation additions to determine the operation of the DESL Project over a ten year period. The analysis and evaluations show that the Project is the most cost-effective supply alternative and would result in lower electricity costs for Peninsular Florida's customers. Furthermore, the DESL Project will enhance the reliability of Peninsular Florida's electric system and reduce environmental impacts in the region, thereby providing additional benefits.

ES.5 Conservation Measures Taken or Reasonably Available

As a wholesale merchant utility, DESL is not in a position to, and does not directly engage in, end-user energy conservation programs. Thus, as the Commission has recognized in other need determination proceedings regarding wholesale merchant utilities, DESL's conservation obligations are limited. However, by utilizing state-of-the-art, high efficiency generation technology and natural gas as fuel, the Project contributes directly and significantly to achieving the overall goals of the Florida Energy Efficiency and Conservation Act ("FEECA"). The Project will have a primary energy conversion efficiency of approximately 48.0 percent, which is significantly better than almost all existing utility generating capacity in Florida, and better than most cogeneration facilities. The Project is expected to displace older, less efficient oil-fired generation and thus will contribute directly to the express statutory goal of conserving expensive resources, especially petroleum fuels. See §§ 366.81, 366.82 (2), Fla. Stat. (1999). Moreover, the Project is expected to displace less-efficient gas-fired units, and thus will increase the efficient use of natural gas in the State. In addition, by providing a highly cost-effective generating facility, wholesale electricity consumers will receive proper market signals in order to compare the relative cost-effectiveness of electric supply with electric demand conservation measures.

ES.6 Consequences of Delay

Delaying the Project will adversely affect the reliability of Peninsular Florida's bulk power supply system, the availability of adequate electricity at a reasonable cost, and Florida's environment. Delay will also deprive St. Lucie County and Peninsular Florida of the positive economic benefits that the Project affords.

Delaying the Project will result in potential lower reserve margins for Peninsular Florida. Such delays in turn will increase the probability that power supply resources available to Peninsular Florida will be insufficient to maintain reliable service. The reserve margin for Peninsular Florida is projected to remain close to the Commission's minimum acceptable criteria. With the retail-serving Investor Owned Utilities ("IOUs") dependent on load management and interruptible customers, nearly half of the state's existing reserve margin (as of January 1, 1999) is <u>not</u> comprised of generation resources. For every day that the Project's operation is delayed, the probability of brownouts and blackouts in Peninsular Florida is greater than it should be, and greater than it would be, with the Project in operation. The DESL Project would increase the generation in the state by 608 MW or approximately 1.5 percent of current generation. The Project will be a very reliable source of generation with an equivalent availability factor of 94.8 percent. The DESL Project would allow Florida utilities to purchase power and continue to serve customers that otherwise would be interrupted or subject to load controls.

Delaying the Project will delay the availability of cost-effective power to the other utilities in Peninsular Florida and their retail customers. The Project will increase competition within the state in the wholesale market and help reduce Peninsular Florida's wholesale power price.

Delaying the Project also will deprive the State of environmental benefits. The DESL Project is a high-efficiency, state-of-the-art, natural gas-fired, combined cycle electric generating facility. Because of its high efficiency and use of clean burning natural gas, the Project's impacts on the environment will be minimized. Based on the modeling of hourly electricity system operations, the Project will displace production from older, less efficient generators that produce more emissions. Delaying the Project will prolong the utilization of the older, less efficient generators and eliminate the reductions in air pollutant emissions that will result from the Project's high efficiency and use of clean natural gas fuel. Delay would also prolong the disposal of effluent by the FPUA into deep injection wells on a barrier island and postpone the efficient use of such effluent in the Project's operations.

Finally, delaying the Project will deprive St. Lucie County and Peninsular Florida of economic benefits. The economic benefits associated with the Project's high paying salaries and influx of monies during construction and operation will be lost or delayed. Moreover, the tax revenue benefits that St. Lucie County will receive will be reduced if the Project is delayed.

ES.7 Conclusion

DESL has addressed all of the criteria the Commission is to consider when deciding whether to grant a determination of need for an electrical power plant including: system reliability and integrity; the need for adequate electricity at a reasonable cost; cost effectiveness; and conservation. DESL has demonstrated that the Project meets these criteria and represents a cost-effective quality addition to Peninsular Florida's generation resources.

1.0 Introduction

The Commission's determination of need pursuant to Section 403.519, Florida Statutes, is part of the comprehensive permitting process for the Project under the Florida Electrical Power Plant Siting Act, Sections 403.501 through 403.518, (the "Siting Act"). Under Section 403.519, Florida Statutes, the Commission is to consider the following issues when making its decision whether to grant a determination of need for a power plant subject to the Siting Act:

1. the need for electric system reliability and integrity;
2. the need for adequate electricity at a reasonable cost;
3. whether the proposed plant is the most cost-effective alternative available;
4. conservation measures taken by, or reasonably available to, the affected utility or utilities which might mitigate the need for the proposed plant; and
5. other matters within the Commission's jurisdiction which the Commission deems relevant to its determination.

DESL's Petition and Exhibits demonstrate that the Project satisfies all relevant criteria set forth in Section 403.519, Florida Statutes, and Rule 25-22.081, Florida Administrative Code.

The Project will provide a power supply resource with proven, reliable, highly efficient, highly available, and environmentally conscious technology. As a wholesale power plant offering capacity and energy to other utilities in Peninsular Florida at negotiated market based prices, the Project also provides a cost-effective power supply alternative for meeting the needs of other utilities in Peninsular Florida. No utility is obligated to buy the output of the Project. The Project will contribute significantly to the reliability of the power supply system in Peninsular Florida, to lowering the cost of generation, to enhanced efficiency and electricity generation in Peninsular Florida, and to improvements in the environmental profile of power generation in this state.

Section 2 of these Exhibits describes the applicant and the management structure of the Project, and its participants. Section 3 describes technical details of the Project, including the site, generating technology, operational reliability and related information, major systems, associated facilities, fuel supply, and the Project's construction and permitting schedules. Section 4 describes the Project's consistency with the power supply needs of Peninsular Florida. Section 5 describes the cost-effectiveness of the Project. Section 6 describes conservation measures taken or reasonably available to the Project. Finally, Section 7 addresses the adverse consequences that delaying the Project would have on power supply reliability, power supply costs, Florida's environment, and the St. Lucie County area.

2.0 The Applicant

The applicant and primarily affected utility for this determination of need is DESL. This section describes the organization and ownership structure of the Project, explains why DESL is a proper applicant, and describes the Project's merchant power plant function.

2.1 Summary of the Project Structure

Figure 2-1 displays the organizational structure for the DESL Project, which will be owned and operated by DESL. DESL is an electric utility under Section 366.02 (2), Florida Statutes, regulated by the Commission. In addition, DESL is a FERC jurisdictional, FERC regulated public utility under the Federal Power Act. DESL will generate electric capacity and energy at the Project and sell that output at wholesale to other Florida utilities and power marketers. DESL is a wholly owned subsidiary of Duke Energy (NYSE: DUK).

DENA, which is also a wholly owned subsidiary of Duke Energy, is the developer and manager of the Project, and is responsible for negotiating the various contracts, managing the permitting approvals, and contracting for the design, procurement, and construction of the facilities. Financing will be provided by DESL through Duke Energy Capital. D/FD will design, engineer, procure, and construct the Project as DENA's EPC contractor. CH2MHILL is providing environmental consulting services for the Project and will coordinate the Site Certification Application. A portion of the natural gas for the Project will be supplied by Citrus Trading Corporation, through the FGT pipeline, pursuant to a long-term firm supply contract with DESL. DESL is continuing to evaluate additional options for gas supply and transportation.

2.2 Duke Energy Corporation

Duke Energy was formed in 1997 by the merger of Duke Power Company ("Duke Power") and PanEnergy Corporation. Duke Power began operations nearly 100 years ago in North and South Carolina, and continues to provide reliable electric service.

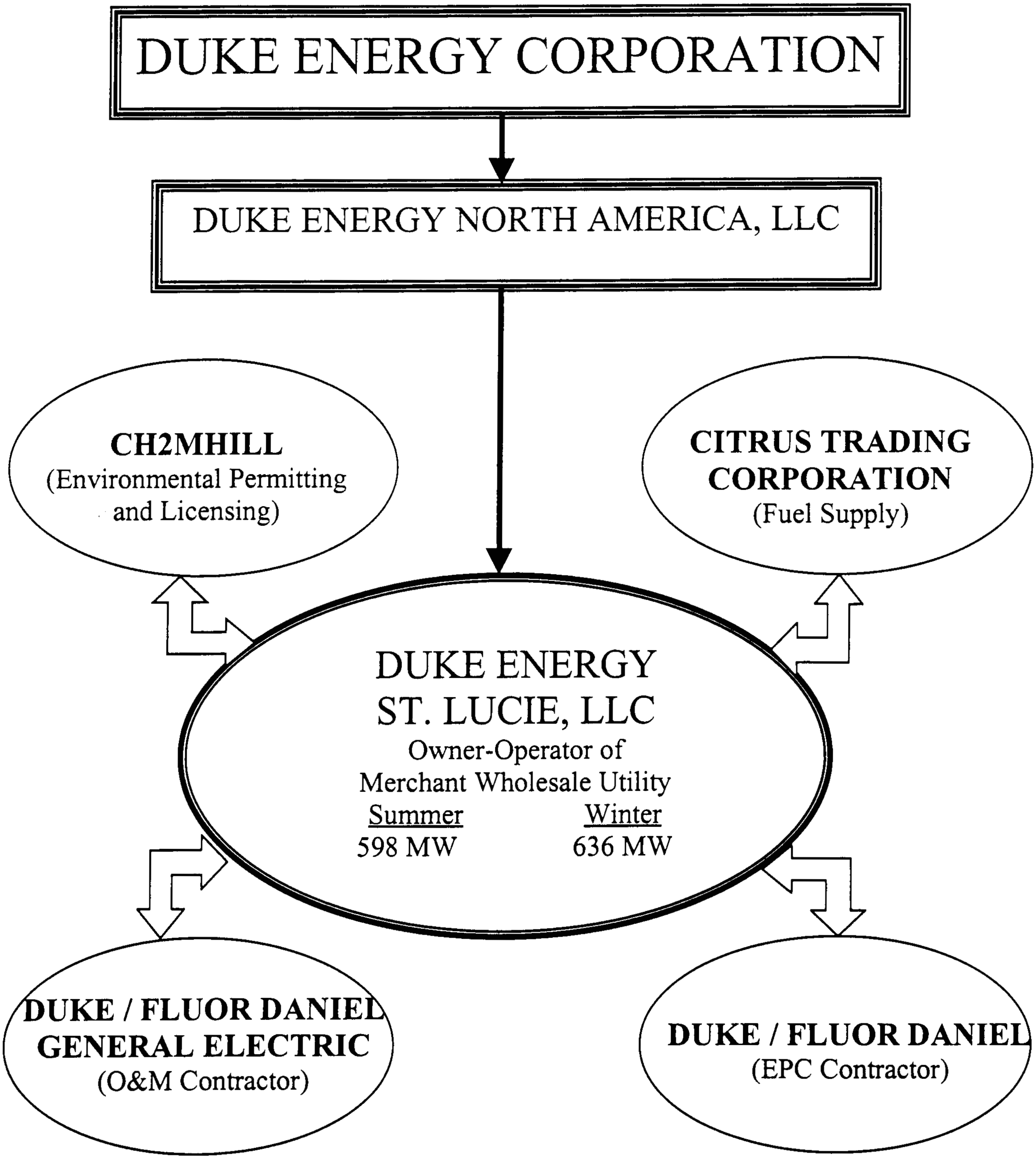


Figure 2-1: Duke Energy St. Lucie Project Structure

Duke Energy is a global energy company with more than $30 billion in assets. Duke Energy companies provide electric service to over 2 million customers; operate pipelines that deliver 10 percent of the natural gas consumed within the United States and market electricity, natural gas, and natural gas liquids. Duke Energy, through DENA has over 4,400 MW of merchant generation in operation, 4,500 MW under construction, and 14,800 MW in various stages of development. Duke Energy is the seventh largest energy company in the world. The corporate headquarters are located in Charlotte, North Carolina. For the past two decades, Duke Energy has been recognized annually by industry experts for operating the nation's most efficient fossil-fueled power plant system. Duke Energy also has the distinction of being the only three-time winner of the prestigious Edison Award, presented annually by the Edison Electric Institute to the nation's best electric utility. In addition, Duke Energy is regularly recognized for the high level of customer service and environmental commitment it brings to its operations.

Duke Energy and its subsidiaries have been active in Florida since the mid-1980's. Duke Engineering & Services ("DE&S") has provided Florida utilities with permitting, design, engineering and construction services for more than a decade including work with nuclear facilities. DE&S also provided services in Florida after Hurricane Andrew. Duke Energy Trading and Marketing ("DETM") helps utility customers more efficiently meet their wholesale electricity and natural gas needs. Crescent Resources, the company's property development subsidiary, has approximately 4 million square feet of commercial and office space built, planned, or under development in Florida. Duke Energy, teamed with the Williams Companies, is developing a new natural gas pipeline that will serve the power projects and other Florida customers.

As displayed in Figure 2-2, Duke Energy's focus is to serve the entire energy value chain to benefit the customer. Duke Energy's customers benefit from our comprehensive integration of energy and energy-related services. Figure 2-3 displays the current organization of the Duke Energy business units.

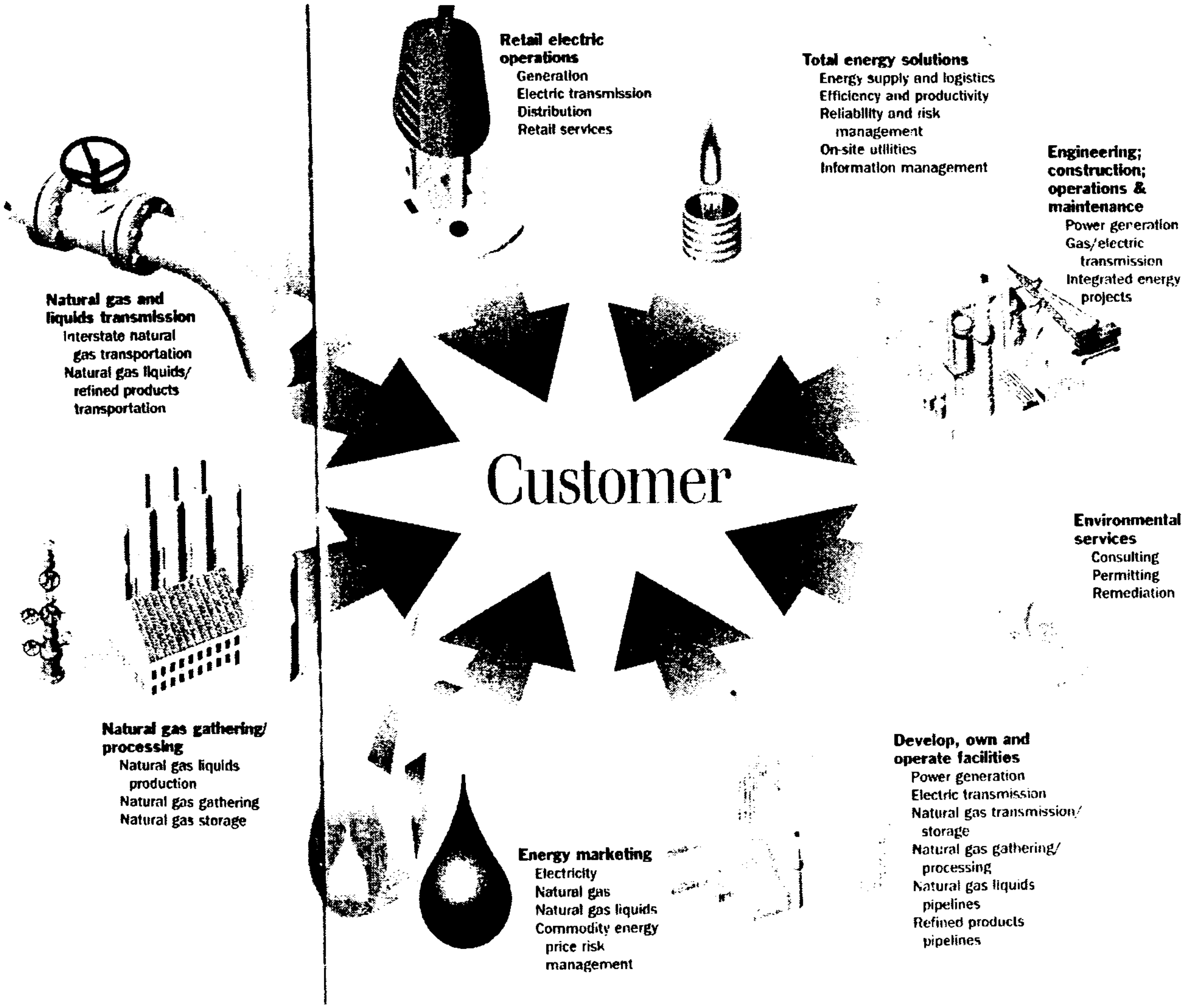


Figure 2-2: Duke Energy serves the entire energy value chain

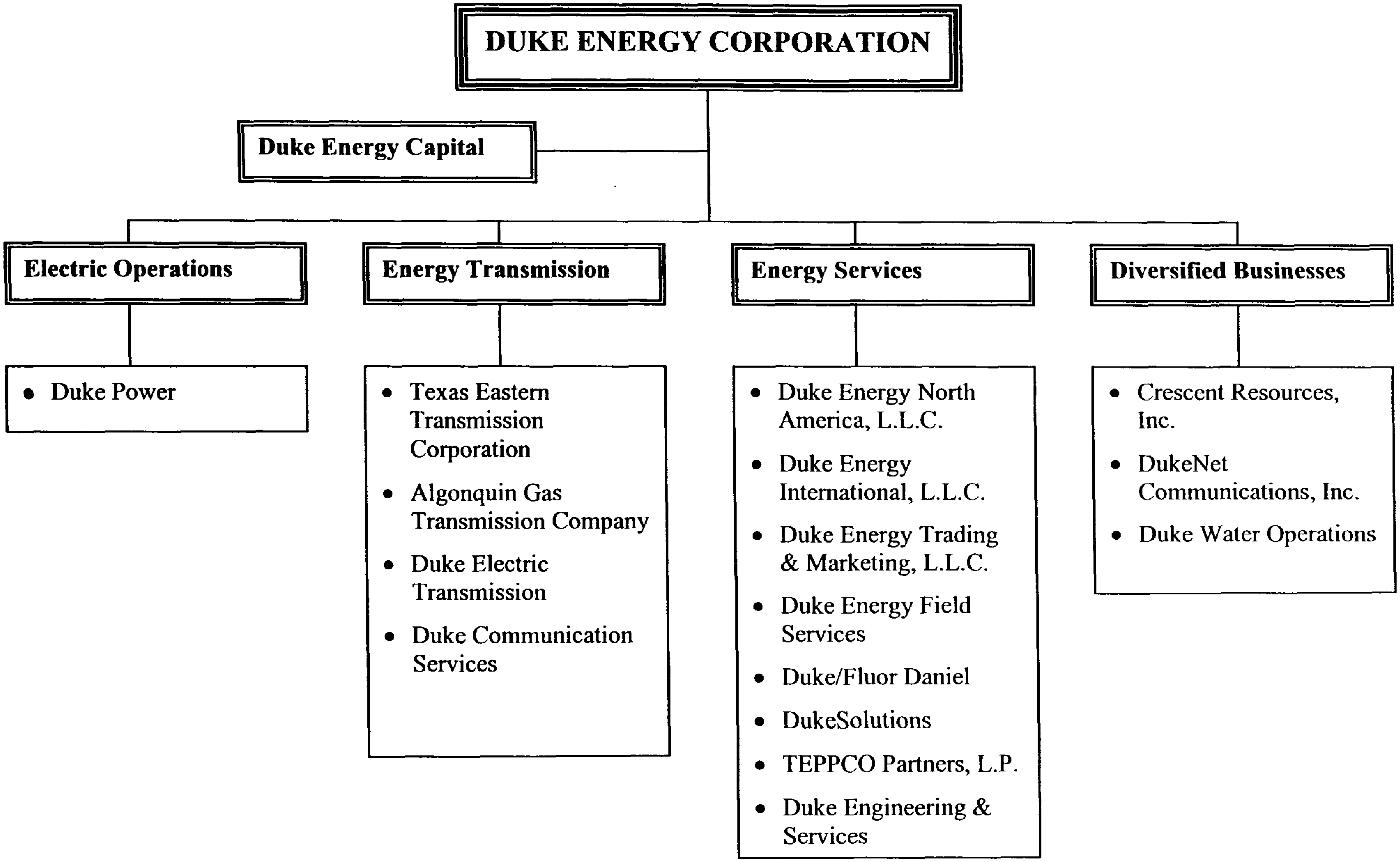


Figure 2-3: Duke Energy Corporation Business Units

2.3 Duke Energy North America, L.L.C.

DENA, a wholly owned subsidiary of Duke Energy, is a leading developer, owner and manager of wholesale electric generation projects throughout the United States. DENA is engaged in the business of developing and acquiring power plants to be operated as wholesale "merchant" power plants selling power to wholesale customers for resale. DENA is the developer of the DESL Project. Pursuant to agreements with several experienced contractors, DENA is arranging for the permitting of the Project, for the engineering/procurement/construction of the Project, for the Project's fuel supply, for the Project's water supply, and for other services necessary to bring the Project to commercial operation.

Set forth below are brief summaries of some of DENA's currently operating assets, projects under construction, and projects that are in the late stages of development. As of March 2000, DENA has 4,400MW in operation, 4,500 MW under construction, and 14,800 MW in various stages of development. DENA has steadily grown since its inception in 1997 to a company with over $3 billion in assets and strong projected growth expectations. Figure 2-4 displays the geographic location of projects in operation or under construction.

DENA has selected five existing facilities, six facilities under construction, and three proposed facilities in late stages of development that demonstrate the quality projects DENA manages.

2.3.1 Currently Operating Generation Assets

DENA currently has several projects in operation throughout the United States. The following paragraphs briefly describe the operating assets.

Moss Landing Power Plant: The Moss Landing Power Plant is located on the Monterey Bay in California. The units built in 1967 and 1968, total 1,478 MW of capacity. The Moss Landing facility has undergone several upgrades in recent years, and has operated as one of the most efficient power plants in United States. DENA anticipates adding additional facilities at this location, pending California Energy Commission ("CEC")

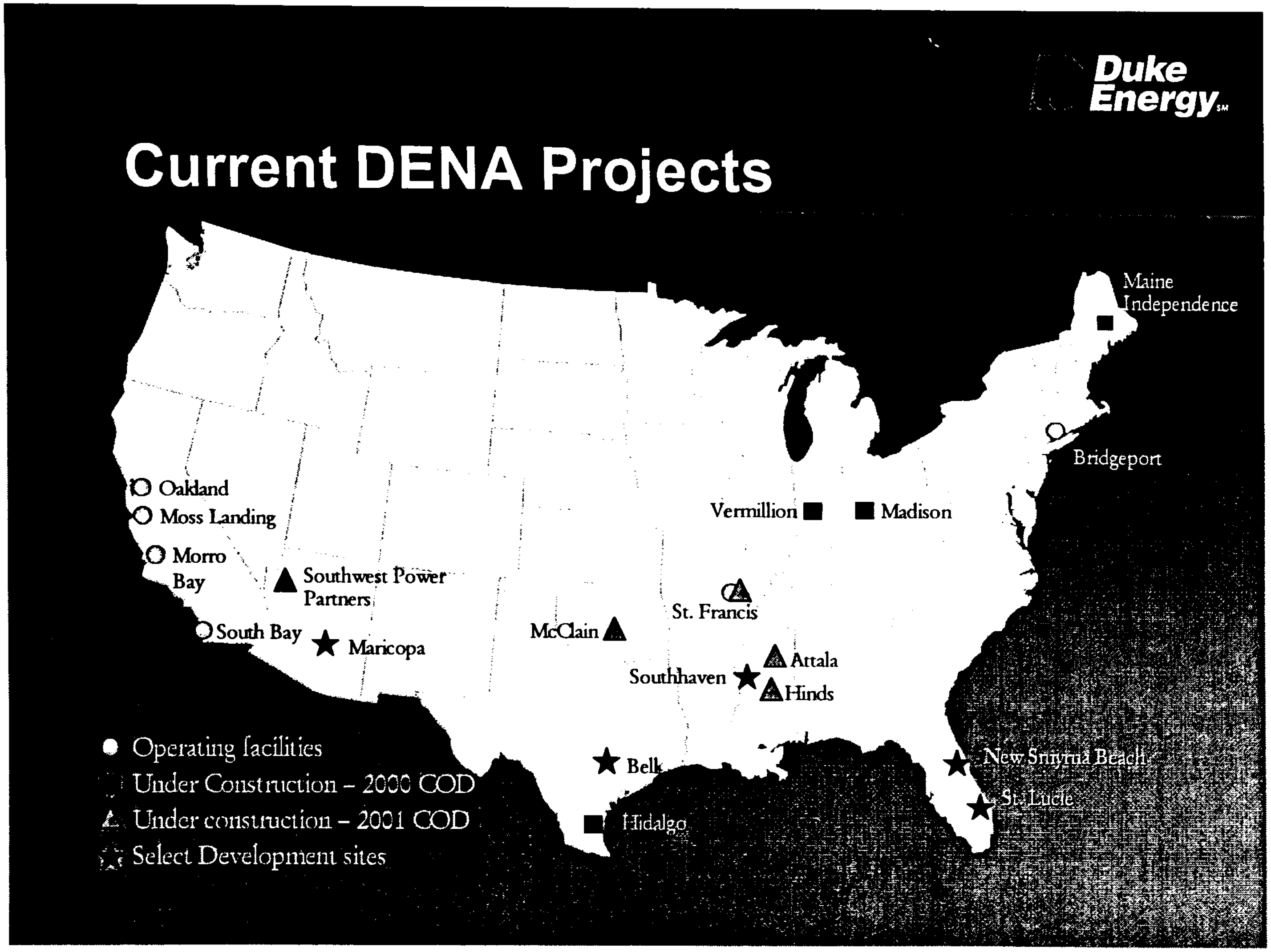


Figure 2-4: Sample of DENA Projects in Operation, Under Construction, and in Development

approval. The units operate on natural gas in simple cycle operation. DENA purchased these facilities in 1998.

Morro Bay Power Plant: The Morro Bay Power Plant is located about 100 miles south of Moss Landing in the city of Morro Bay, California. The plant's four units have 1,002 MW of capacity and were built between 1953 and 1963. The plant has undergone substantial upgrades in recent years to improve efficiency and reduce emissions. The plant utilizes clean burning natural gas in a simple cycle operation. DENA purchased these facilities in 1998.

South Bay Power Plant: In April, 1999, DENA finalized a 10-year lease agreement with the Port of San Diego to operate and eventually replace its 706 MW South Bay Power Plant located in the City of Chula Vista. Under the terms of the agreement, the Port purchased the plant from San Diego Gas & Electric Company. DENA will be responsible for the payment of principal and interest on the bonds issued by the Port to purchase the facility. At the end of the lease, DENA will assume ownership of the plant's air permits and use them for the replacement power plant to be built in the area. San Diego Gas and Electric employees working at the plant will work as DENA's contractors under a two-year operating and maintenance agreement. Similar to DENA's other plants in the state, all output is sold through the Power Exchange ("PX") based upon price.

Associated Electric Cooperative Project: DENA and DETM have entered into an agreement with Associated Electric Cooperative, Incorporated ("AECI"), the nation's second largest power cooperative, to construct two 250 MW gas-fired combined cycle facilities in southeastern Missouri. The first 250 MW, Phase I, has just entered commercial operation and Phase II is targeted for commercial operation in the summer of 2001. The project provides additional capacity to AECI and merchant energy to the region.

Bridgeport Power Project: DENA developed one of the first merchant power plant facilities in the Northeast. Construction of the 500 MW gas fired combined cycle power generation plant in Bridgeport, Connecticut began in October 1997. Phase one began operation in mid-1998; phase two entered operation in July of 1999. In addition to DENA, which is the majority owner in the facility, participants in the project include: The United Illuminating Company, a New Haven, Connecticut based electric utility, which has a minority ownership position in the project; and Siemens Power which was responsible for development, construction, and operations. DETM provides the fuel for the project and markets the power from the plant.

2.3.2 Projects Under Construction

DENA currently has four projects under construction in the United States that are similar to the proposed DESL Project and are listed below. DENA has two additional facilities under construction that will operate as simple cycle plants and are listed below.

Maine Independence Station Project: Construction of the 500 MW gas-fired, combined cycle facility in Veazie, Maine on the Penobscot River began in October 1998. The plant is being constructed on a site used by Bangor Hydro-Electric Company's Graham Station, an oil-fired plant that was retired in 1993. It is anticipated that the new plant will produce approximately 95 percent less air emissions per megawatt hour generated and approximately 95 percent less heated water into the Penobscot River than an oil-fired unit. D/FD is the turnkey contractor for the engineering, procurement, and construction of the plant. DETM will provide the fuel for the plant and market the electricity output on the wholesale market.

Hidalgo Energy Project: Construction of the 500 MW gas-fired, combined cycle facility located in Edinburg, Texas began in March 1999. The facility is DENA's first major wholesale merchant power plant in Texas and is expected to be operational in the summer of 2000. Similar to other DENA projects, D/FD serves as the turnkey contractor for the engineering, procurement and construction of the Hidalgo facility. DETM will provide fuel and market the output on the wholesale market. Public Utilities of Brownsville has acquired a 21.5 percent ownership interest in the Project to meet the needs of its future growth.

Hinds Energy Project: The Duke Energy Hinds Project is a 500 MW GE 7FA 2x1 combined cycle project currently under construction in Hinds County, Mississippi. The site is located within the city limits of Jackson, the state capital. The facility is designed to burn only natural gas. In September 1999, the Mississippi Public Service Commission granted Duke Energy Hinds its Certificate of Public Convenience and Necessity. In January 2000, the project received the necessary environmental permits from the Mississippi Department of Environmental Quality. The plant is scheduled to go into commercial operation in May 2001.

McClain Energy Project: The Duke Energy McClain Project is a 500 MW GE 7FA 2x1-combined cycle project currently under construction in McClain County, Oklahoma. The plant is located south of Oklahoma City, Oklahoma. The facility will be designed to burn natural gas and will use reclaimed water from Oklahoma City and the City of Moore. The McClain Project has received its final air permit. The plant will go into commercial operation in June 2001.

Madison Project: The Duke Energy Madison Project is a 640 MW GE 7EA 8x0-simple cycle project currently under construction in Madison County Ohio. The Project is scheduled to enter commercial operation in June 2000.

Vermillion Project: The Duke Energy Vermillion Project is a 640 MW GE 7EA 8x0-simple cycle project currently under construction in Vermillion County Indiana. The Project is scheduled to enter commercial operation in June 2000.

2.3.3 Projects in Development

DENA currently has several projects under development in the United States similar to the proposed DESL Project. The following are a sample of the similar projects.

New Smyrna Beach Project: Duke Energy New Smyrna Beach LTD, L.L.P. and the Utility Commission of the City of New Smyrna Beach ("UCCNSB") have obtained a determination of need from the Commission for a 500 MW 2x1 GE 7FA combined cycle facility. The Florida Supreme Court is currently reviewing the Commission's determination of need as a result of an appeal from FPL, FPC, and TECO. Once the Florida Supreme Court has issued a final decision, the Governor and Cabinet will rule on the site certification and land use issues. UCCNSB will have entitlement to 30 MW of the output of the facility. The remaining 484 MW will be marketed to other investor and municipally owned utilities and electric cooperatives on the open wholesale market. D/FD will be the turnkey contractor for engineering, procurement, and construction of the facility. Citrus Trading Company will provide fuel on FGT's pipeline for this project, while DETM will market the output on the wholesale market.

Bell Energy Project: The Duke Energy Bell Project is planned as a 500 MW GE 7FA 2x1-combined cycle facility currently under development in Bell County, Texas. The facility will be designed to burn natural gas and will use reclaimed water as its primary cooling source.

Southhaven Energy Project: The Duke Energy Southhaven Project is planned as a 640 MW GE 7EA 8x0 simple cycle facility currently under development in Desoto County, Mississippi. The Project will provide wholesale power into the Entergy and TVA subregion.

2.4 Duke Energy St. Lucie, L.L.C.

DESL is the owner of, and has operational responsibility for, the DESL Project. DESL is the applicant for the Commission's determination of need and is the utility primarily affected by this petition. DESL was formed in 1999 as a Delaware limited liability corporation, and exists as a wholly owned subsidiary of DENA.

DESL is an electric utility under Section 366.02 (2), Florida Statutes. DESL also is a public utility under Section 201 of the Federal Power Act. The FERC is currently reviewing the DESL Rate Schedule No. 1, which will permit DESL to enter into negotiated wholesale power sales agreements with willing utility purchasers. A copy of the application filed at FERC is included in Appendix A for reference.

Moreover, DESL is an exempt wholesale generator ("EWG") under the Public Utility Holding Company Act of 1935. FERC is currently reviewing DESL's application as an EWG. As an EWG, DESL is prohibited by the Public Utility Holding Company Act of 1935 from making retail sales of electricity from the Project directly, and may only sell power to wholesale purchasers. DESL's forecast models indicate that its wholesale sales will be made to other utilities and power marketers for use in Peninsular Florida. A copy of DESL's application for EWG status is provided in Appendix A for reference.

2.5 Description of the Service Contracts for the St. Lucie Project

DENA, serving as the developer for DESL, has negotiated several contracts to provide services for the Project. The major contracts are summarized below.

2.5.1 Environmental Permitting

DENA has retained CH2MHILL to provide environmental services in permitting the Project through the Siting Act process. CH2MHILL is headquartered in Greenwood Village, Colorado with regional offices in Gainesville, Jacksonville, Tampa, Orlando, and Deerfield Beach, FL. CH2MHILL is a leading consultant providing environmental services to the energy industry.

2.5.2 Natural Gas

Citrus Trading Corporation, through an existing contract, will supply a portion of the natural gas for the Project. The natural gas will be delivered on a firm basis through a new 1-mile pipeline lateral, from FGT's Ft. Pierce South Station to the Project Site. The lateral will be permitted and constructed by FGT through FGT's Phase VI FERC filing. DESL will also consider interconnecting with the other proposed natural gas pipelines to provide fuel diversity and reliability and is continuing to evaluate other options for fuel supply.

2.5.3 Water Supply

DESL is in the final stages of negotiations with FPUA for the supply of reclaimed water as the primary source of cooling water for the Project. The FPUA currently discharges the reclaimed water into a deep injection well at its Water Reclamation Facility, which is located on a barrier island. During periods of low reclaimed water supply, if necessary, DESL will draw from a 5.0 million gallon on-site reclaimed water storage pond and/or be supplied groundwater from wells that draw from the Upper Floridan Aquifer.

2.5.4 EPC Contract

D/FD will serve as DESL's EPC contractor for the Project. D/FD has significant experience with the GE 7FA equipment and GE steam turbine equipment, making it a valuable member of the project team. D/FD will require up to 18 months for the construction of the DESL Project from construction mobilization to commercial operation.

2.5.5 O&M Contract

D/FD will also serve as DESL's operations and maintenance contractor for the Project through a long-term contract. DENA has secured long-term service agreements with GE to maintain certain portions of the facility.

2.6 Description of a Merchant Power Plant

A merchant power plant is an electric generating facility that produces power for the express purpose of selling electricity into the wholesale electricity market. Buyers in the wholesale electricity market includes municipalities, cooperatives, investor-owned utilities, and power marketers. The wholesale market *does not* include residential, commercial, or industrial customers in a utility's existing service territory.

The Energy Policy Act of 1992 ("EPACT") opened the national wholesale electricity market to competition. Indeed, the primary purpose of the Energy Policy Act of 1992 was to encourage and promote *wholesale competition* in the electric industry throughout the United States. By law, wholesale competition exists in all 50 states. This wholesale market – which involves the buying and selling of electricity at high voltage on a bulk basis – is the market DESL proposes to enter in Florida. DESL's efforts are not related to, nor part of, any effort to deregulate the Florida retail electricity market.

As noted by the Commission, a merchant plant is "a power plant with no rate base and no captive retail customers." In re: Joint Petition for Determination of Need for an Electrical Power Plant in Volusia County by the Utilities Commission, City of New Smyrna Beach, Florida, and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P., 99 F.P.S.C. 3:401, 407, Docket No. 981042-EM, Order No. PSC-99-0535-FOF-EM (March 22, 1999). A merchant plant differs from a traditional "rate-based" plant in that the costs of a rate-based plant are recovered through rates charged to the utility's captive customers. If, after a rate-based plant is constructed, lower cost power becomes available, the utility nevertheless remains entitled to recover the costs of its plants through its rates. Hence, the utility's ratepayers, rather than its shareholders, bear the risks associated with potential obsolescence. Similarly, absent a finding of imprudence, a utility is permitted to recover the fixed and operating costs of its rate-based plant, even if these costs are higher than originally projected or if the plant fails to operate as well as projected.

In sharp contrast, a merchant plant has no rate base and no captive ratepayers. A merchant plant simply offers its capacity and energy to potential wholesale customers, who are free to purchase or decline to purchase capacity and energy offered by the merchant plant. An economically rational purchasing utility will only enter into an agreement to purchase electric capacity or energy from a merchant plant if the costs of that capacity or energy are lower than the costs of alternatives otherwise available to the utility, e.g., generation from its own power plants or purchases from others. If the cost of power from the merchant plant is higher than the costs of other alternatives, a purchasing utility will simply choose not to buy the merchant plant's output. In such circumstances, the unrecovered costs of the merchant plant will be borne by the plant's owners, but will not be borne by any Florida ratepayers. The same result will occur if the merchant plant incurs cost overruns or fails to operate as efficiently or reliably as projected – the merchant plant owners, rather than any ratepayer, bear all of the capital, operating, technology, fuel procurement and market risks associated with the power plant. Consequently, if the merchant plant's economics are favorable, other utilities and power marketers will purchase its output and enjoy cost savings. If the plant turns out not to be economic, Florida's ratepayers will incur no financial harm. For these reasons, a merchant plant can only benefit other utilities and their ratepayers.

There exist today several generating units throughout the United States that are considered merchant power plants. Companies such as DENA, FPL Group (parent company of FPL), Florida Progress (parent company of FPC), TECO Energy (parent company of TECO), Southern Company, and Pacific Gas & Electric ("PG&E") are a few of the participants in this emerging market. These, and other companies, are building new state-of-the art power plants or are buying existing power plants formerly owned by utility companies. These activities underscore the fact that leading players in the power industry are routinely moving outside of their historical operating areas into the wholesale power market across North America. Generating facilities that operate as merchant plants currently exist in Florida, and others, including the Duke New Smyrna and Okeechobee Projects, are planned for the future.

3.0 Description of the St. Lucie Project

This section describes the DESL Project, including the Project's location, site arrangement, major systems and facilities, associated facilities, capital costs and project financing, fuel supply, performance estimates, operations and maintenance cost estimates, projected operational reliability, and construction schedule.

3.1 Project General Description

The basic power generation cycle for the DESL Project will consist of two GE 7FA natural gas fired combustion turbines, two 3-stage heat recovery steam generators ("HRSG"), selective catalytic reduction ("SCR"), a single steam turbine, condensor, three electrical generators, three main step-up transformers, and two exhaust stacks. The Project will require additional facilities within the site including an integrated control room and administration building/warehouse, mechanical draft cooling towers, demineralization tank, neutralization tank, auxiliary substation, reclaimed water storage pond, and storm water detention pond.

The unit will be designed to operate on natural gas fuel that offers numerous advantages over other fossil fuels. DENA will maintain BACT to meet the permitting requirements of the project.

3.2 Site Location

The proposed project is located in St. Lucie County, Florida. Figures 3-1 through Figure 3-3 depict the site and surrounding communities in greater detail.

3.2.1 Nearest Incorporated Cities

The nearest incorporated cities are Port St. Lucie and Fort Pierce, Florida. The site is approximately 5 miles southwest of Fort Pierce, Florida and approximately 1 mile north of Port St. Lucie.

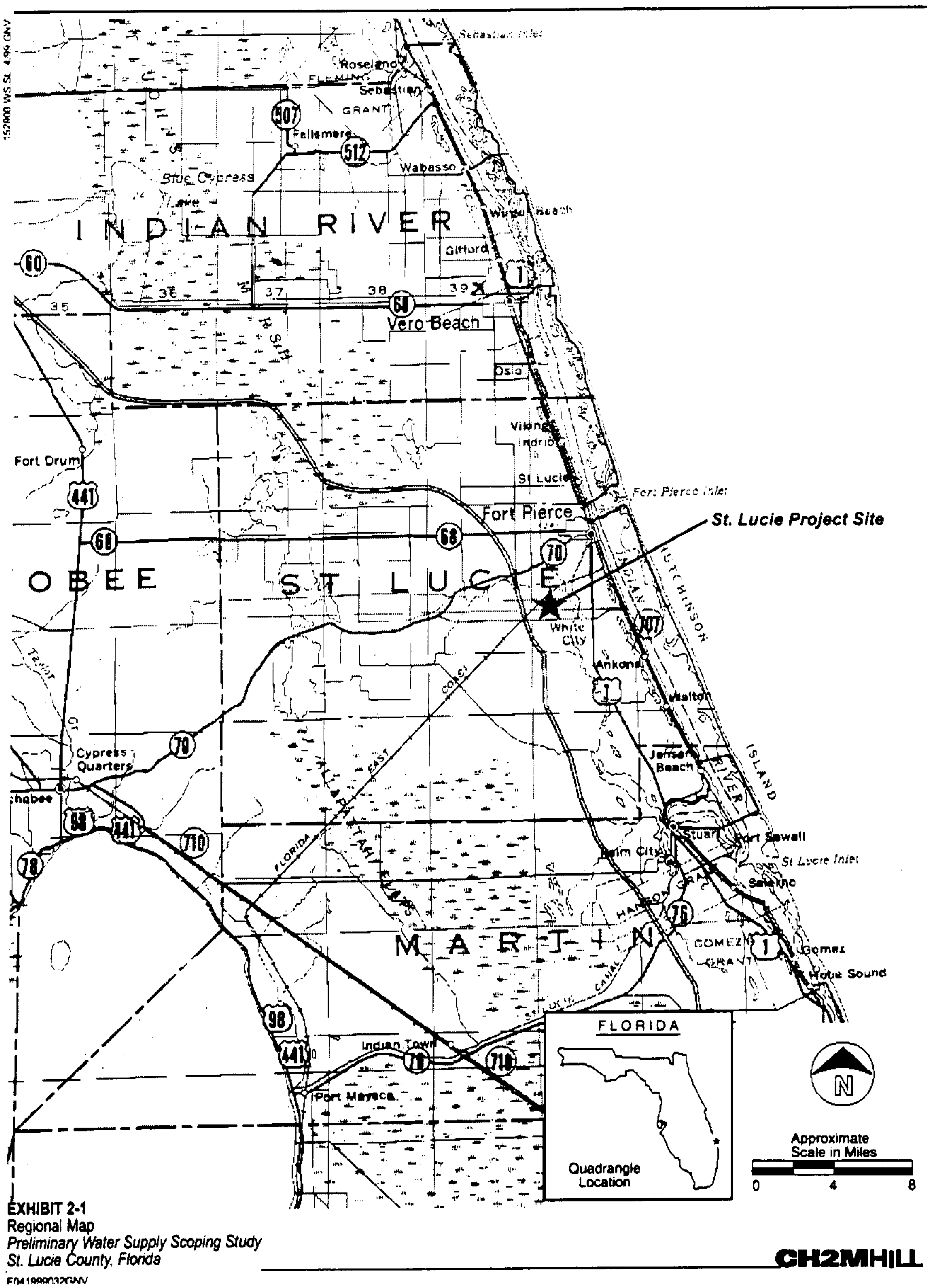


Figure 3-1: State of Florida Map with Site Located

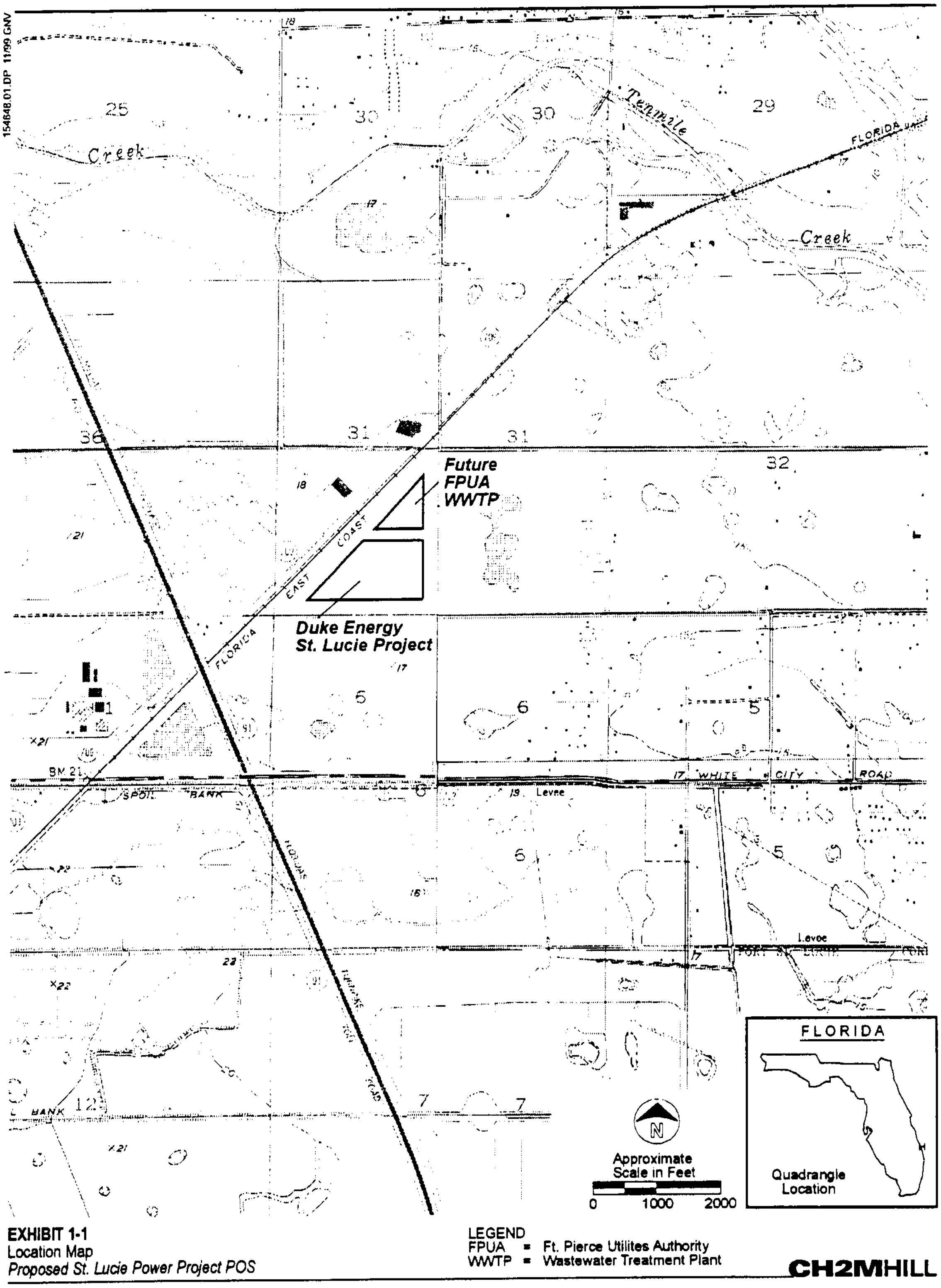


Figure 3-2: Proposed Duke Energy St. Lucie Site

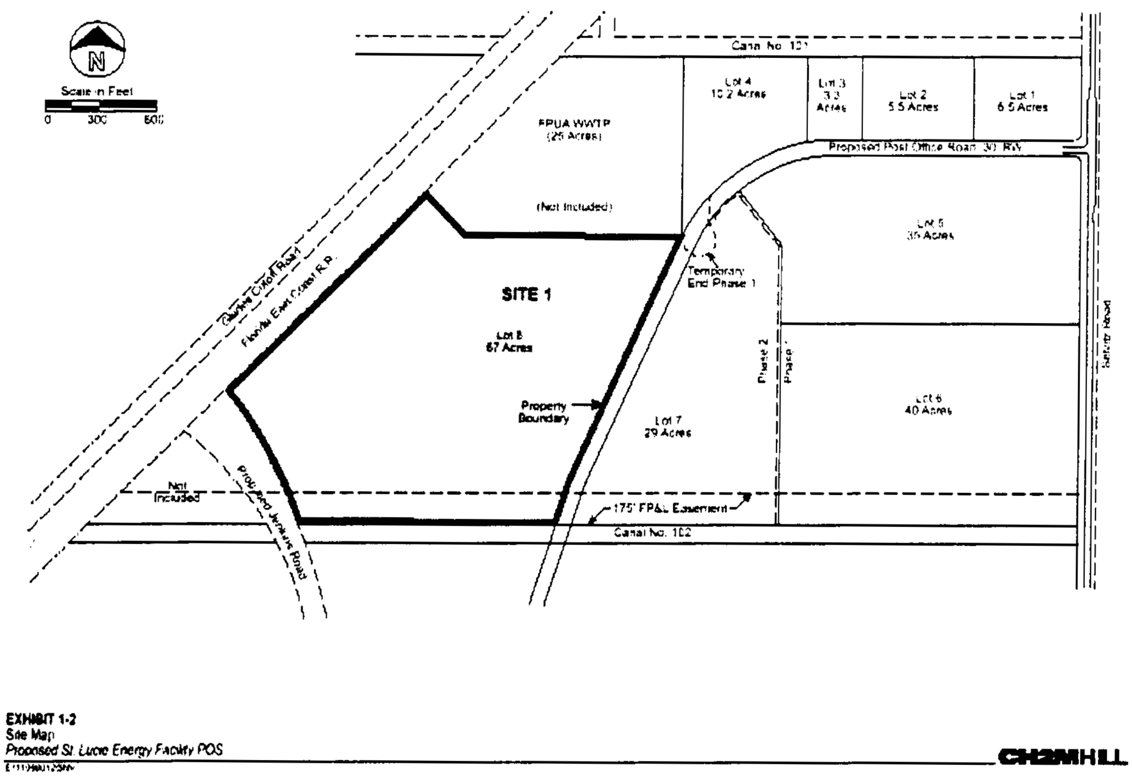


Figure 3-3: Site Location and surrounding lots

3.2.2 Longitude and Latitude (Northeast Property Corner)

Longitude: 80 degrees, 22 minutes, 24.9 seconds

Latitude: 27 degrees, 23 minutes, 8.6 seconds

3.2.3 UTMs (Northeast Property Corner, NAD 27)

3029147.2 m North

561936.5 km East

3.2.4 Section, Township, Range

South ½ of Section 31, Township 35 South, Range 40 East, St. Lucie County, Florida, said portion being more particularly described as Lot 8 of the Midway Industrial Park.

3.3 Description of the Proposed Site

The Project site is located east and north of the intersection of the Florida East Coast Railroad and Canal No. 102, respectively, in St. Lucie County, Florida. The site is legally described as the South ½ of Section 31, Township 35 South, Range 40 East, St. Lucie County, Florida. This site is also described as Lot 8 of the Midway Industrial Park. The site's current land use plan is industrial with zoning for heavy industrial. The site will require rezoning approval from the County Commission, which DESL has discussed with the County. The site is currently outside the City limits of Fort Pierce and consists of approximately 67 acres adjacent to the proposed Fort Pierce Utilities Authority's Mainland WRF.

The site historically was used as grazing land for cattle and tomato fields. Figure 3-4 indicates the location of the proposed site and the associated infrastructure within the area.

3.4 Site Arrangement

Figure 3-5 provides the general arrangement of the power plant on the proposed site indicating the layout of the combustion turbines, steam turbine, substation facilities, exhaust stacks, cooling tower, stormwater retention pond, reclaimed water storage pond, site access road, and associated equipment.

3.5 Commercial Operation

The Project is proposed for commercial operation by June 1, 2003 with a construction schedule of 18 months. The schedule for commercial operation is dependent upon receiving all regulatory approvals prior to December 1, 2001.

3.6 Nameplate Generating Capacity

The nameplate rating of the DESL Project is estimated to be approximately 608 MW at ISO conditions with full duct firing. The exact rating of the unit will depend upon equipment operation.

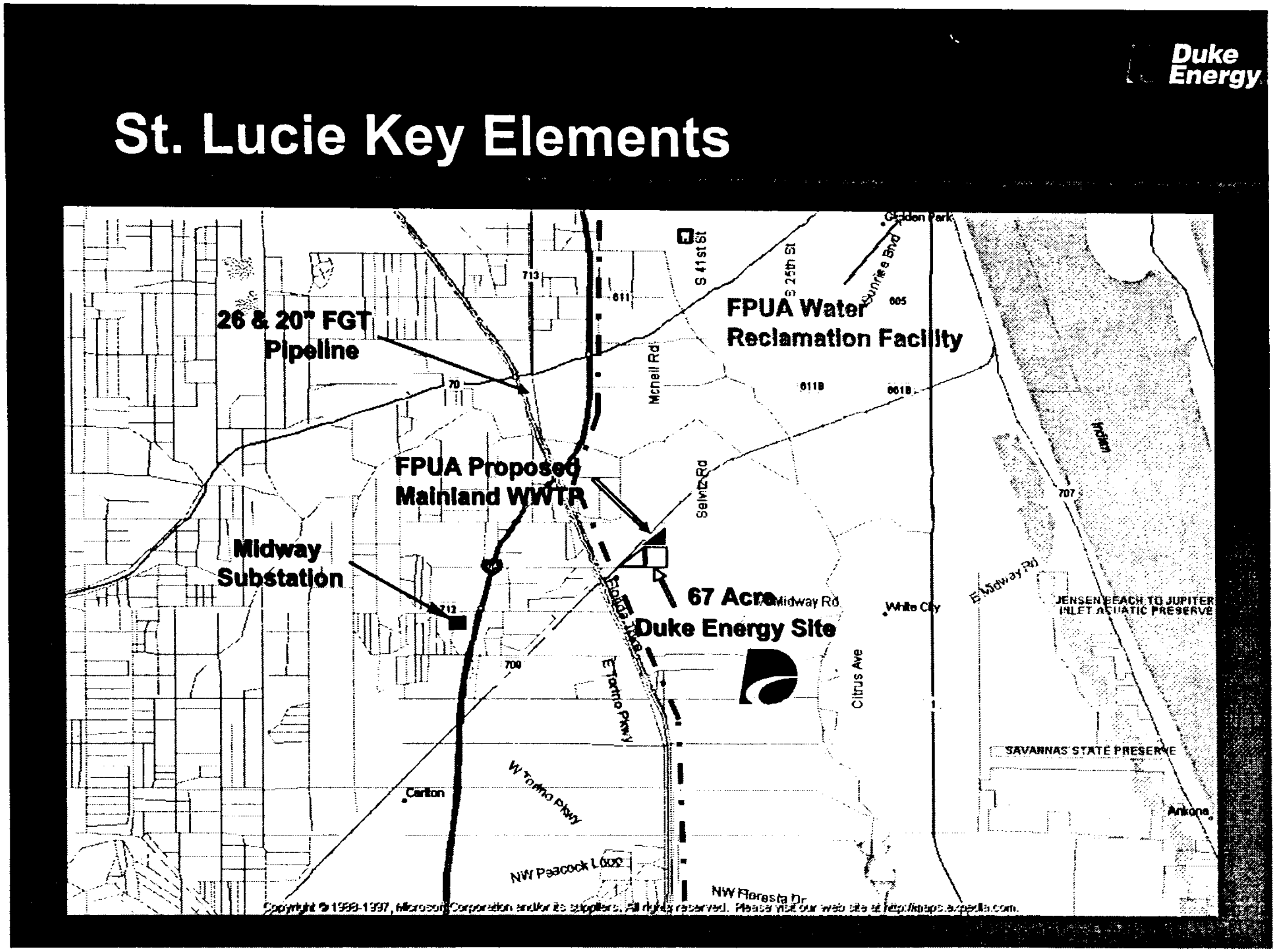
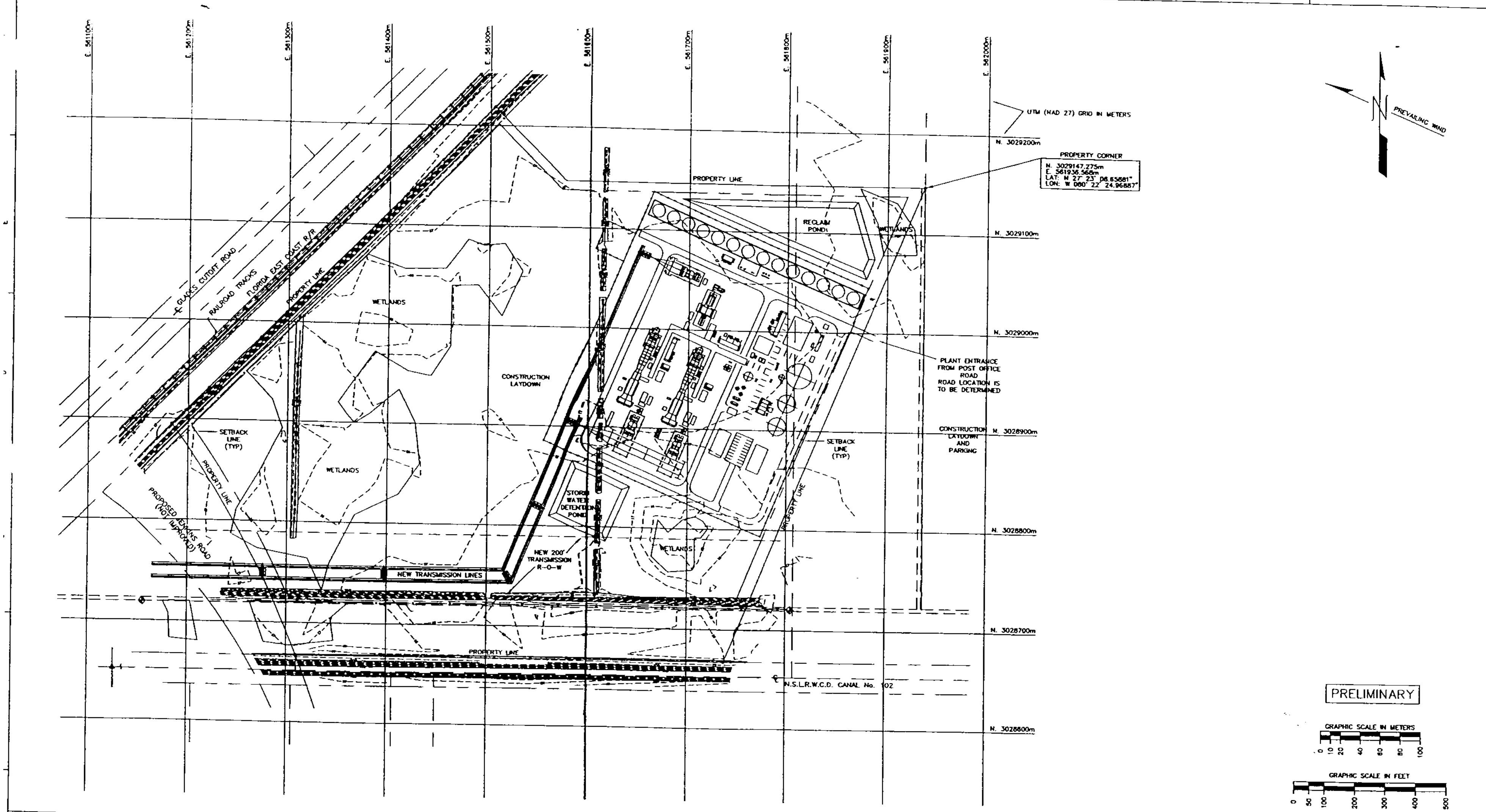


Figure 3-4: Key Elements affecting the siting of the Duke Energy St. Lucie Project



REV.	DATE	REVISION DESCRIPTION	DRWN / CHK.	LAYO / MECH	CIVIL / ELEC	ENGM / PROJ
0	3/21/00	ISSUED FOR AIR PERMIT APPLICATION	DE / DB			

DWG.NO.	REFERENCE DRAWINGS
605216-0-PP-5-2	PROPOSED PLOT PLAN
605216-0-PP-5-3	POWER TRAIN AND COOLING TOWER ELEVATION
	USGS MAP - FORT PIERCE NW, FLA.
	USGS MAP - FORT PIERCE, FLA.
	HARTMAN & ASSOCIATES, INC. TOPOGRAPHIC SURVEY

DUKE/FLUOR DANIEL

DRAWN BY D. EBERSOLE
CHECKED BY D. BROWN
LAYOUT APPROVAL D. BROWN
MECHANICAL APPROVAL K. LIN
CIVIL APPROVAL A. YU
ELECTRICAL APPROVAL K. SANFORD
ENGINEERING MANAGER L. JOACHIM
PROJECT DIRECTOR J. MACKEY

DUKE ENERGY ST. LUCIE L.P.
ST. LUCIE ENERGY FACILITY
FORT PIERCE, FLORIDA

PROPOSED SITE PLAN

SCALE 1" = 150'-0" 605216-0-PP-5- -1-0

MANUAL CHANGES MADE - YES ☐ NO ☐ DWG. FILE UPDATED - YES ☐ NO ☐ MODEL UPDATED - YES ☐ NO ☐

CADD FILE No. 605216-5-1-0 CONTRACT PKG. WRK. PKG. DIST. CODE

3.7 Description of the Major Systems and Facilities

3.7.1 Power Island

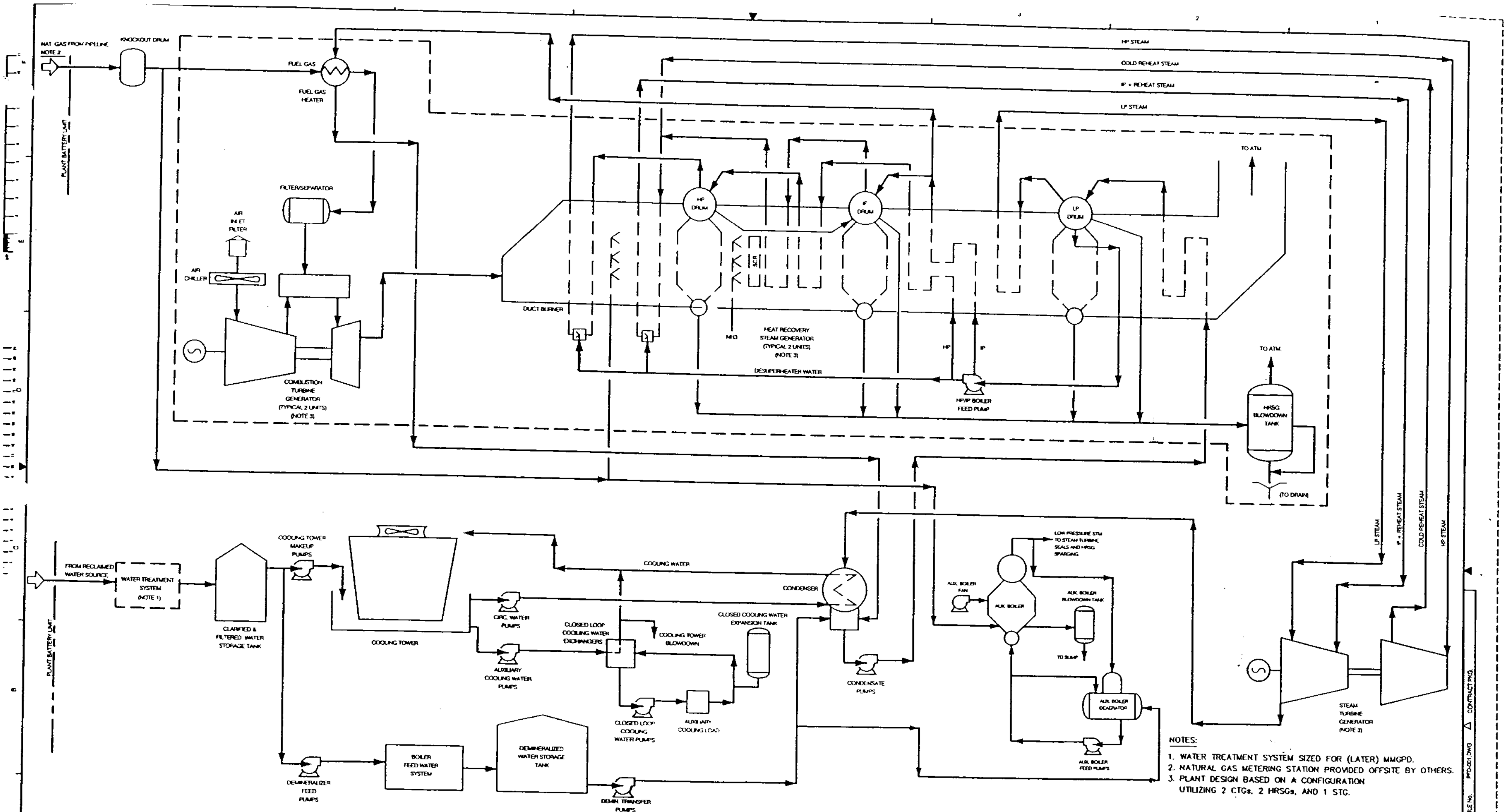
The power island for the Project will consist of two GE 7FA combustion turbines, two combustion turbine electrical generators, two HRSGs with duct firing capabilities, two SCRs, a steam turbine, steam turbine electric generator, cooling tower and condensor, two exhaust stacks, and associated balance of plant equipment. Figure 3-6 displays the schematic process flow diagram for the Project.

3.7.2 Cooling System

Process and makeup water for the cooling system will be primarily supplied by reclaimed water from FPUA's WRF. Wastewater from the Project and FPUA's excess reclaimed water will be discharged via a deep injection well located at the proposed FPUA Mainland WRF. Figures 3-7 through 3-10 provide the preliminary water balances for the Project.

DENA and FPUA are in the final stages of negotiations for a contract to supply process water for the Project. The Project will require the addition of a reclaimed water pipeline that will be permitted, designed, procured, constructed, owned and operated by the FPUA. The permitting of the pipeline will be handled outside of the Project Site Certification Application process. Water used for cooling the facility will be reclaimed water that the FPUA is currently discharging into a deep injection well on a barrier island. The Project will utilize reclaimed water from the FPUA WRF to the maximum extent possible. FPUA has historically had an annual average of 5.8 MGD of reclaimed water available. If duct firing is utilized 10 hours a day, DESL's demand would equate to 6.0 MGD. The utilization of duct firing will depend on market demand and water availability.

Reclaimed water is produced by taking municipal wastewater that enters the WRF along with other wastewater then applying biological treatment, filtration, settling and disinfection. The utilization of the reclaimed water provides a method of beneficially reusing the water, and, because DESL will purchase the water, provides FPUA with a



NOTES:

1. WATER TREATMENT SYSTEM SIZED FOR (LATER) MMGPD.
2. NATURAL GAS METERING STATION PROVIDED OFFSITE BY OTHERS.
3. PLANT DESIGN BASED ON A CONFIGURATION UTILIZING 2 CTGs, 2 HRSGs, AND 1 STG.

REV.	DATE	REVISION DESCRIPTION
A	[illegible]	ISSUED FOR PERMIT APPLICATION
B	[illegible]	ISSUED FOR PERMIT APPLICATION

DUKE/FLUOR DANIEL

DRAWN BY: S. BACA
CHECKED BY: S. DEVONE
PROJECT DIRECTOR: J. MACKEY

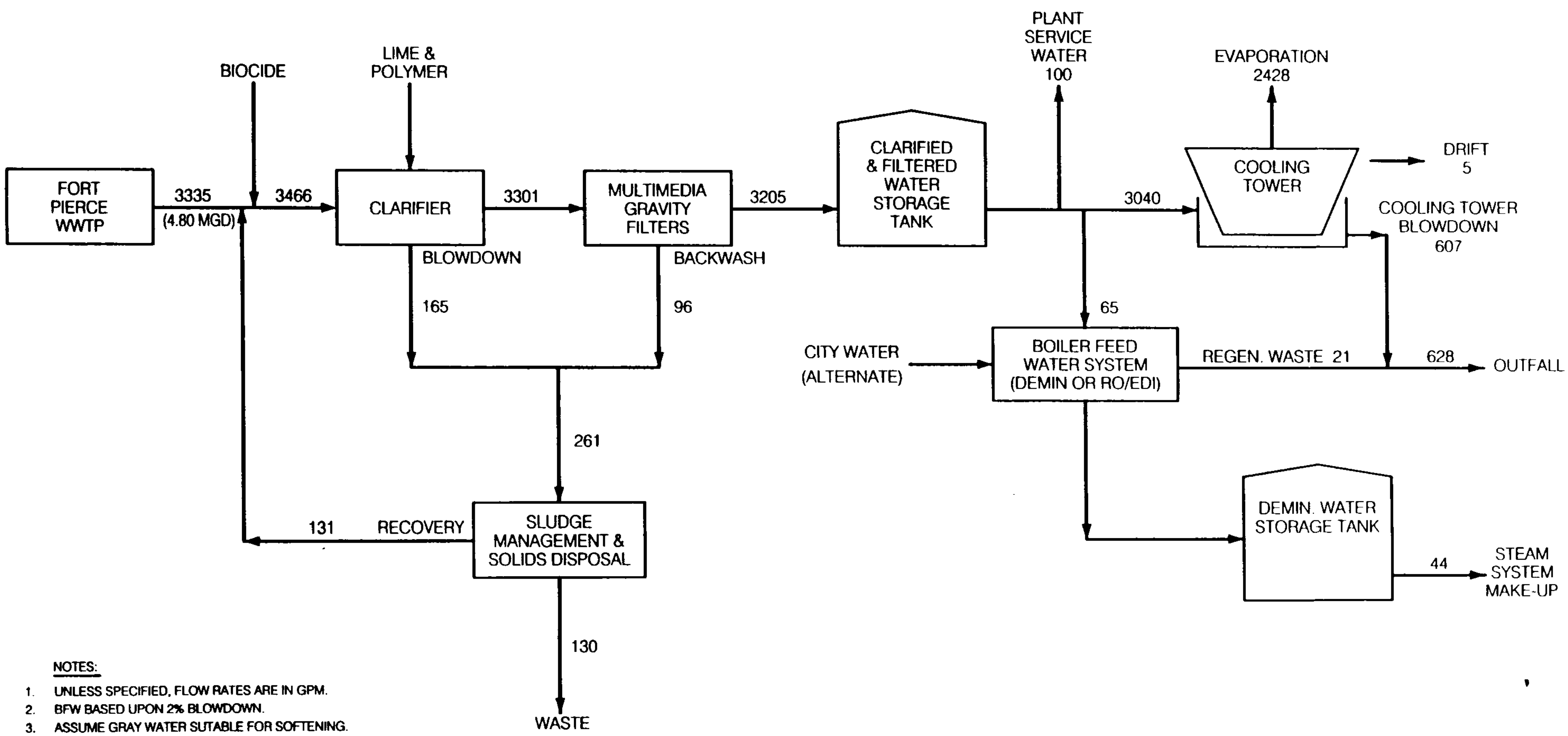
ST. LUCIE ENERGY FACILITY
DUKE ENERGY ST. LUCIE, L.L.C.
FT. PIERCE, FLORIDA

PROCESS FLOW DIAGRAM

SCALE: NONE 605216– 0 –ME–4– FD – 1 – B

MANUAL CHANGES MADE - YES ☐ NO ☐ DWG FILE UPDATED - YES ☐ NO ☐ MODEL UPDATED - YES ☐ NO ☐

ANNUAL AVG. CASE (75°F, 72% R.H.) WITHOUT DUCT FIRED...INLET CHILLER ON



NOTES:

1. UNLESS SPECIFIED, FLOW RATES ARE IN GPM.
2. BFW BASED UPON 2% BLOWDOWN.
3. ASSUME GRAY WATER SUTABLE FOR SOFTENING.
4. ASSUME COOLING TOWER OPERATING AT 5 CYCLES.

REV	DATE	REVISION DESCRIPTION
A		ISSUED FOR PERMIT APPLICATION

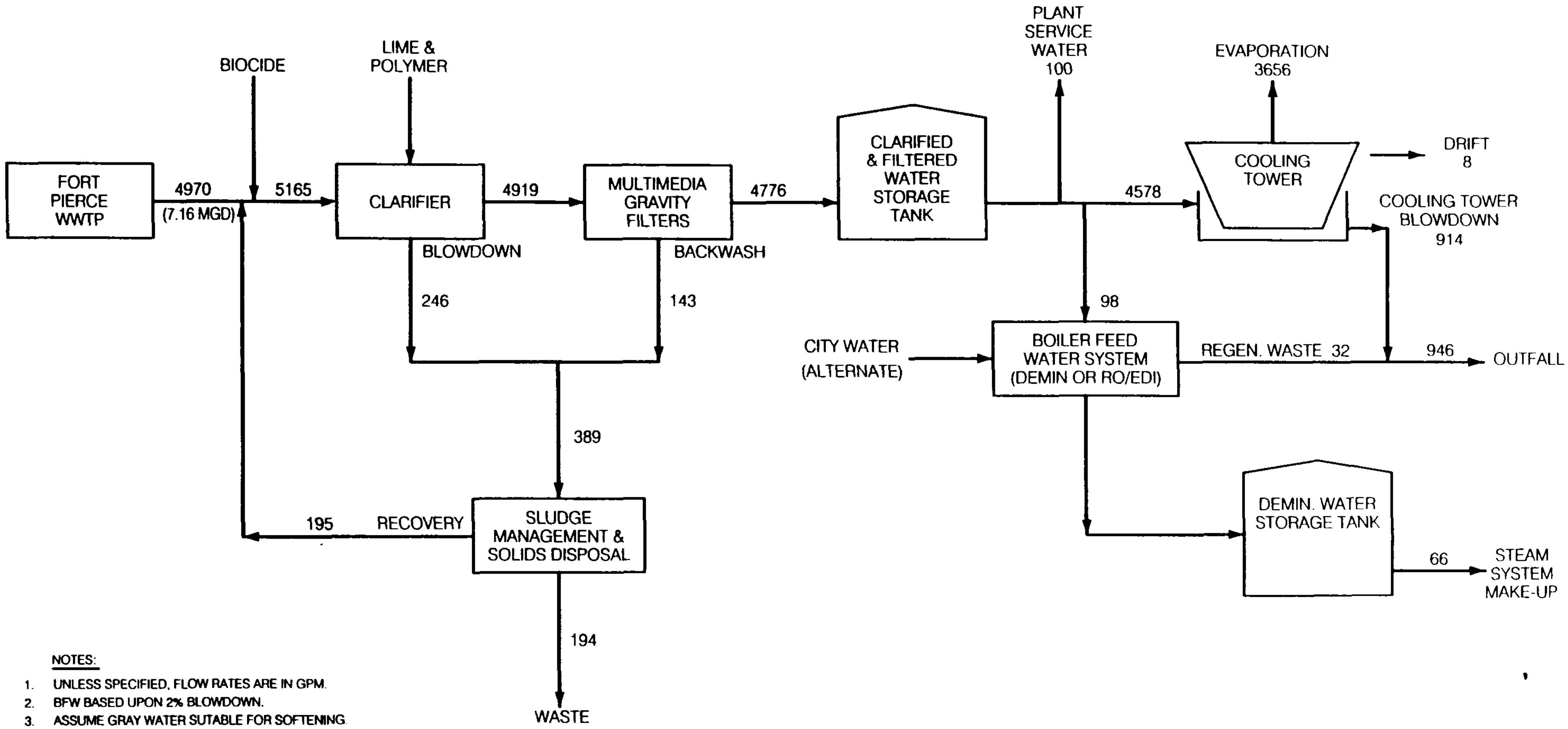
DUKE/FLUOR DANIEL

ST. LUCIE ENERGY FACILITY
DUKE ENERGY ST. LUCIE, L.L.C.
FT. PIERCE, FLORIDA

WATER BALANCE AND BLOCK FLOW DIAGRAM

NONE 605216-0-PD-4-SK-6-A

ANNUAL AVG. CASE (75°F, 72% R.H.) FULL DUCT FIRED, INLET CHILLER ON



NOTES:

1. UNLESS SPECIFIED, FLOW RATES ARE IN GPM.
2. BFW BASED UPON 2% BLOWDOWN.
3. ASSUME GRAY WATER SUTABLE FOR SOFTENING.
4. ASSUME COOLING TOWER OPERATING AT 5 CYCLES.

REV	DATE	REVISION DESCRIPTION
A		ISSUED FOR PERMIT APPLICATION

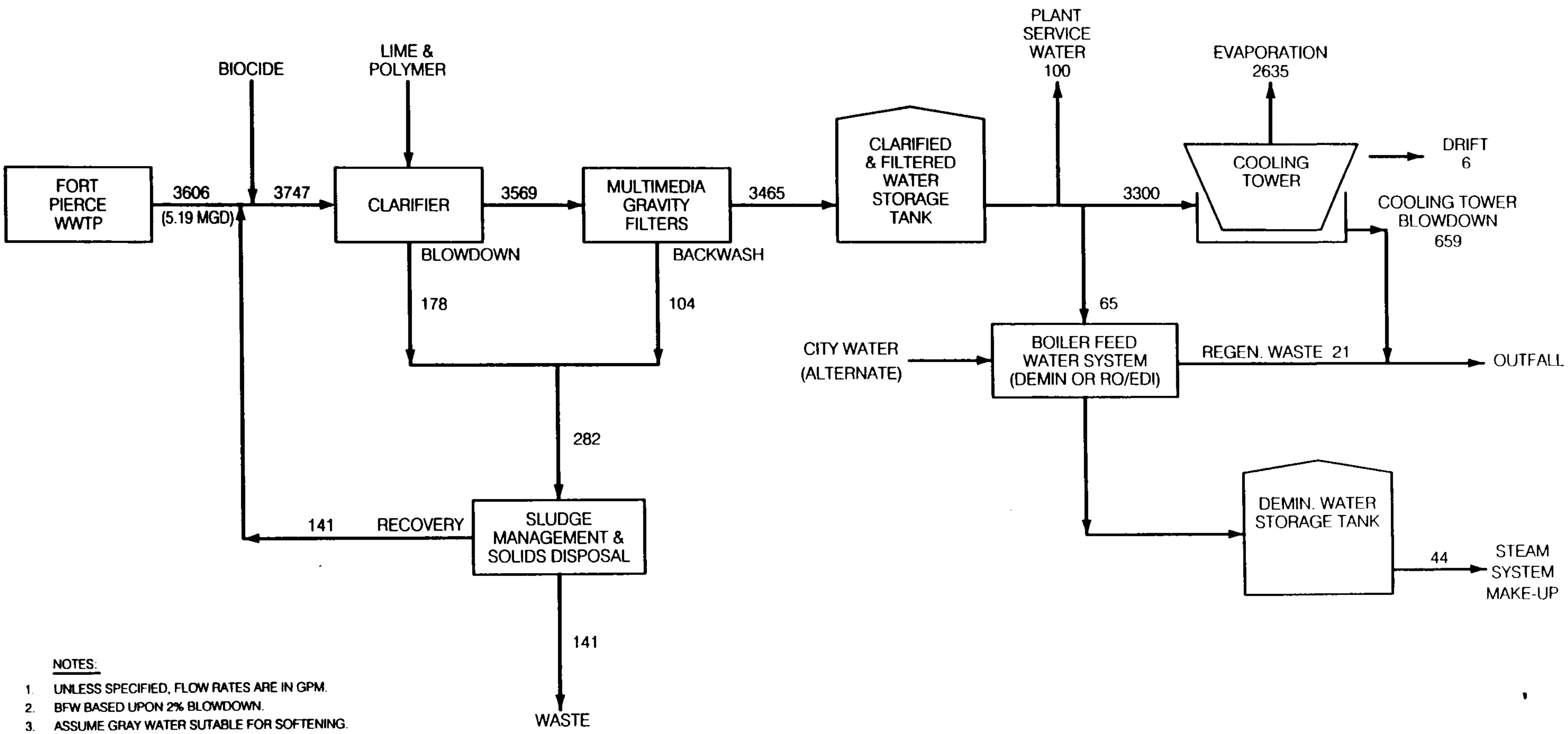
DUKE/FLUOR DANIEL

ST LUCIE ENERGY FACILITY
DUKE ENERGY ST LUCIE L L C
FT PIERCE, FLORIDA

WATER BALANCE AND BLOCK FLOW DIAGRAM

NONE 605216-0-PD-4-SK-5-A

DAILY MAX. CASE: (101° F, 40% R H), WITHOUT DUCT FIRED, INLET CHILLER ON



NOTES:

1. UNLESS SPECIFIED, FLOW RATES ARE IN GPM.
2. BFW BASED UPON 2% BLOWDOWN.
3. ASSUME GRAY WATER SUTABLE FOR SOFTENING.
4. ASSUME COOLING TOWER OPERATING AT 5 CYCLES.

REV	DATE	REVISION DESCRIPTION
A		ISSUED FOR PERMIT APPLICATION
B		ISSUED FOR PERMIT APPLICATION

DUKE/FLUOR DANIEL

S. BACA
R. JANJUA
J. MACKEY

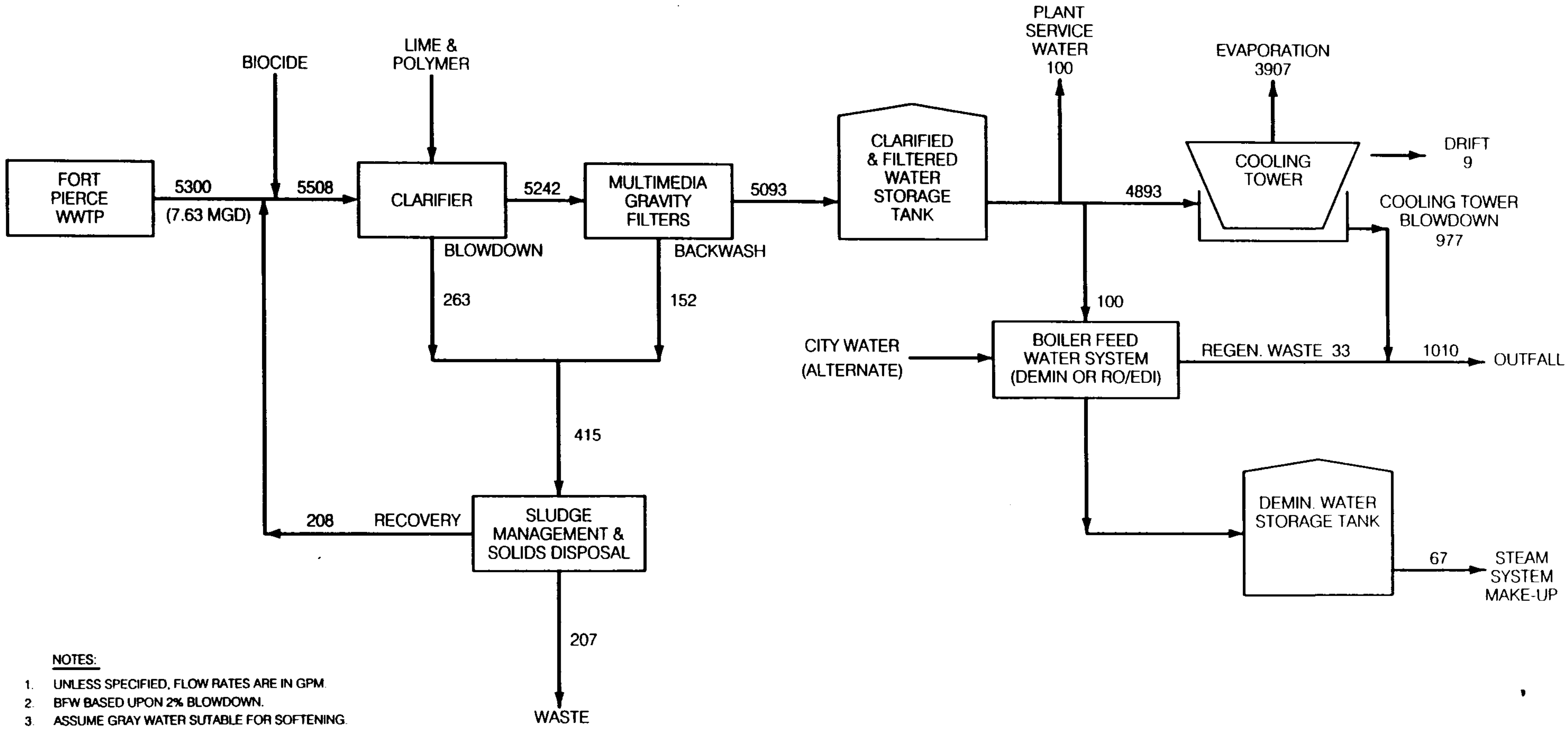
ST. LUCIE ENERGY FACILITY
DUKE ENERGY ST. LUCIE, L.L.C.
FT. PIERCE, FLORIDA

WATER BALANCE AND BLOCK FLOW DIAGRAM

NONE 605216–0–PD–4– SK –4–B

MANUAL CHANGES MADE - YES NO DWG FILE UPDATED - YES NO MODEL UPDATED - YES NO

DAILY MAX. CASE: (101°F, 40% RH), FULL DUCT FIRED, INLET CHILLER ON



NOTES:

1. UNLESS SPECIFIED, FLOW RATES ARE IN GPM.
2. BFW BASED UPON 2% BLOWDOWN.
3. ASSUME GRAY WATER SUTABLE FOR SOFTENING.
4. ASSUME COOLING TOWER OPERATING AT 5 CYCLES

REV	DATE	REVISION DESCRIPTION
A		ISSUED FOR PERMIT APPLICATION
B		ISSUED FOR PERMIT APPLICATION

DUKE/FLUOR DANIEL

ST LUCIE ENERGY FACILITY
DUKE ENERGY ST LUCIE L L C
FT PIERCE, FLORIDA

WATER BALANCE AND
BLOCK FLOW DIAGRAM

NONE 605216-0-PD-4-SK-3-B

revenue stream. The Project will rely on backup groundwater wells for periods of emergencies and low reclaimed water supply.

3.7.3 Duct Firing

Duct firing is a process in which burners are placed in the first stage of the HRSG where natural gas is burned to increase the exhaust temperature of the combustion turbine. The increase in exhaust temperature provides higher heat transfer capabilities, thus producing more steam for use in a larger steam turbine. The increased steam in the steam turbine will produce more power, thus more electricity. The steam turbine and generator must be increased in size over the conventionally sized equipment. The DESL Project will generate 608 MW of capacity at isometric conditions (ISO, 59°F, 60 percent relative humidity) when operating with full duct firing, and will generate 497 MW of capacity at ISO when not implementing duct firing. Details of the Project's output and heat rate at various load and ambient conditions are provided in Section 3.10 and 3.11.

3.7.4 Emission Controls

The DESL Project will utilize natural gas as its only fuel source. Natural gas is a very clean burning fuel in comparison to other fossil fuels. Natural gas does not contain significant amounts of sulfur or ash, therefore eliminating large components of emissions. DESL is proposing to utilize Dry Low NO_x combustors and SCR to minimize the emissions from the Project. Dry Low NO_x combustors are utilized to minimize the formation of NO_x in the combustion process in the gas turbine. SCR is post combustion emission control equipment that utilizes ammonia to react with the NO_x in a catalyst bed that reduces the NO_x emissions.

3.7.5 Fuel Supply

Citrus Trading Corporation will supply a portion of the Project's gas to DESL on a firm basis, pursuant to a long-term contract through the FGT pipeline system. The initial term of the contract is for 20 years. After the initial 20-year term, the gas supply contract is renewable from year to year. If the contract is terminated, DENA, DESL's agent for the gas contract, has the right to acquire Citrus's gas transportation capacity on FGT's system. DESL is continuing to evaluate additional options for natural gas supply.

The DESL Project will require approximately 3,533 MMBtu/hr (HHV) for the project operating at full load in the summer without utilizing duct firing and 4,508 MMBtu/hr (HHV) when utilizing duct firing. Winter fuel requirements will be approximately 3,727 MMBtu/hr (HHV) operating at full load without duct firing and 4,654 MMBtu/hr (HHV) when utilizing duct firing. Fuel oil for the facility will not be utilized and therefore fuel oil storage tanks will not exist on the site.

The Project will require approximately 1 mile of 12-inch pipe from the FGT's existing Ft. Pierce South Station to the Project site. The permitting, design, procurement, and construction of the pipeline will be coordinated by FGT through its Phase VI filing. FGT Phase VI operation is anticipated for the spring of 2003. Discussions between FGT and DENA have already occurred to determine the feasibility of supplying firm transportation to the facility. FGT indicates that there are no apparent impediments to incorporating the Project into the current system. The capital and operating costs of the lateral will be rolled into the firm transportation and commodity charges through FGT.

3.7.6 Substation and Transmission

The DESL Project will be interconnected to the FPL Midway substation at either 230 kV or 500 kV. The Midway substation currently has nine 230 kV lines and three 500 kV lines interconnected. Figure 3-11 displays the current transmission system surrounding the FPL Midway substation. DENA and FPL are currently evaluating the interconnection of the Project into the FPL Midway substation. Figures 3-12 through 3-14 indicate a preliminary one-line diagram for the facility.

The Project will require the addition of 2.8 miles of transmission lines from the primary side of the main step-up transformers to the FPL Midway substation. DESL anticipates that the transmission will follow an existing FPL right of way into the Midway substation. This path will minimize environmental impacts. The transmission facilities will be subject to permitting as directly associated facilities under the Power Plant Siting Act.

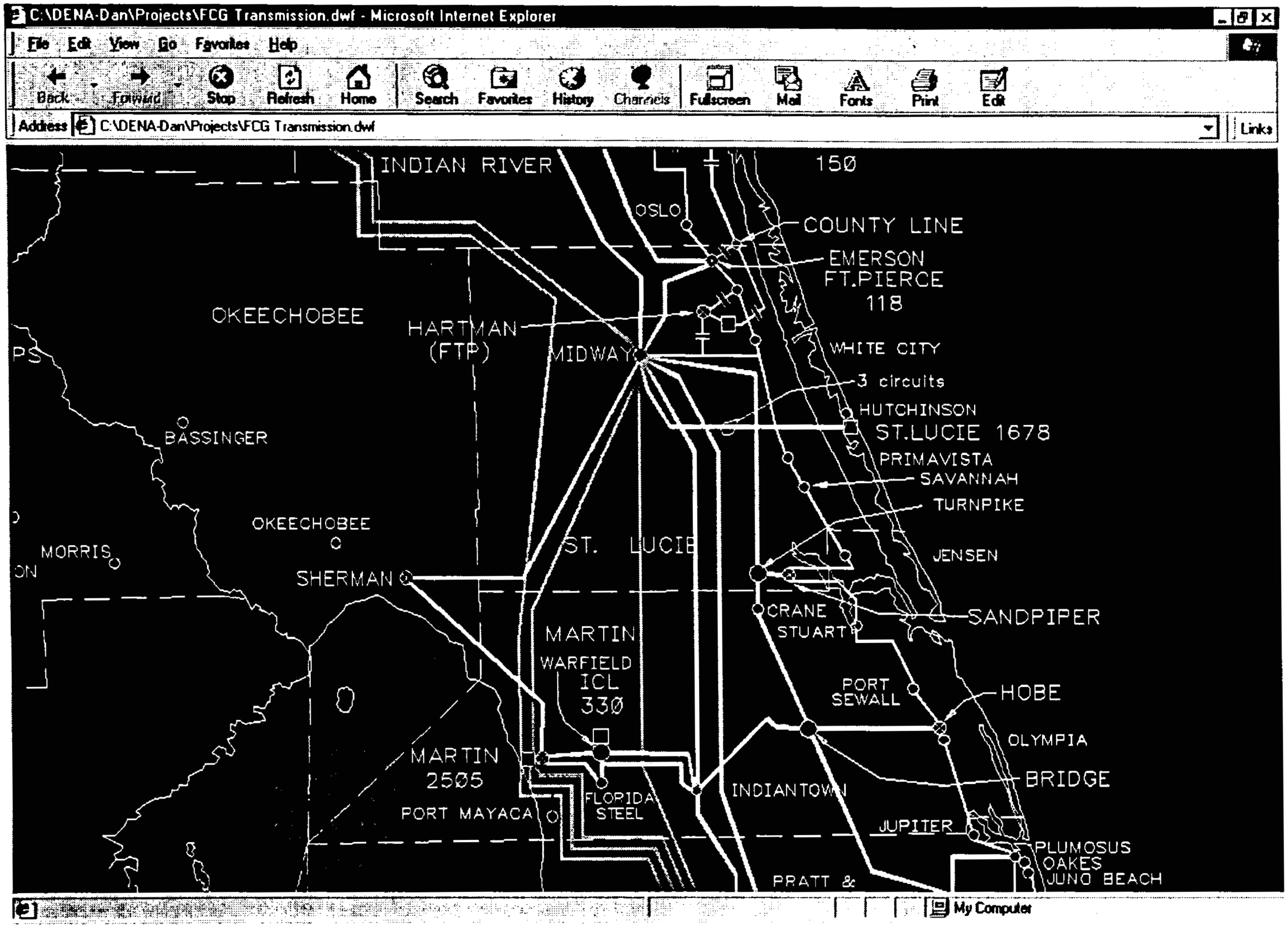
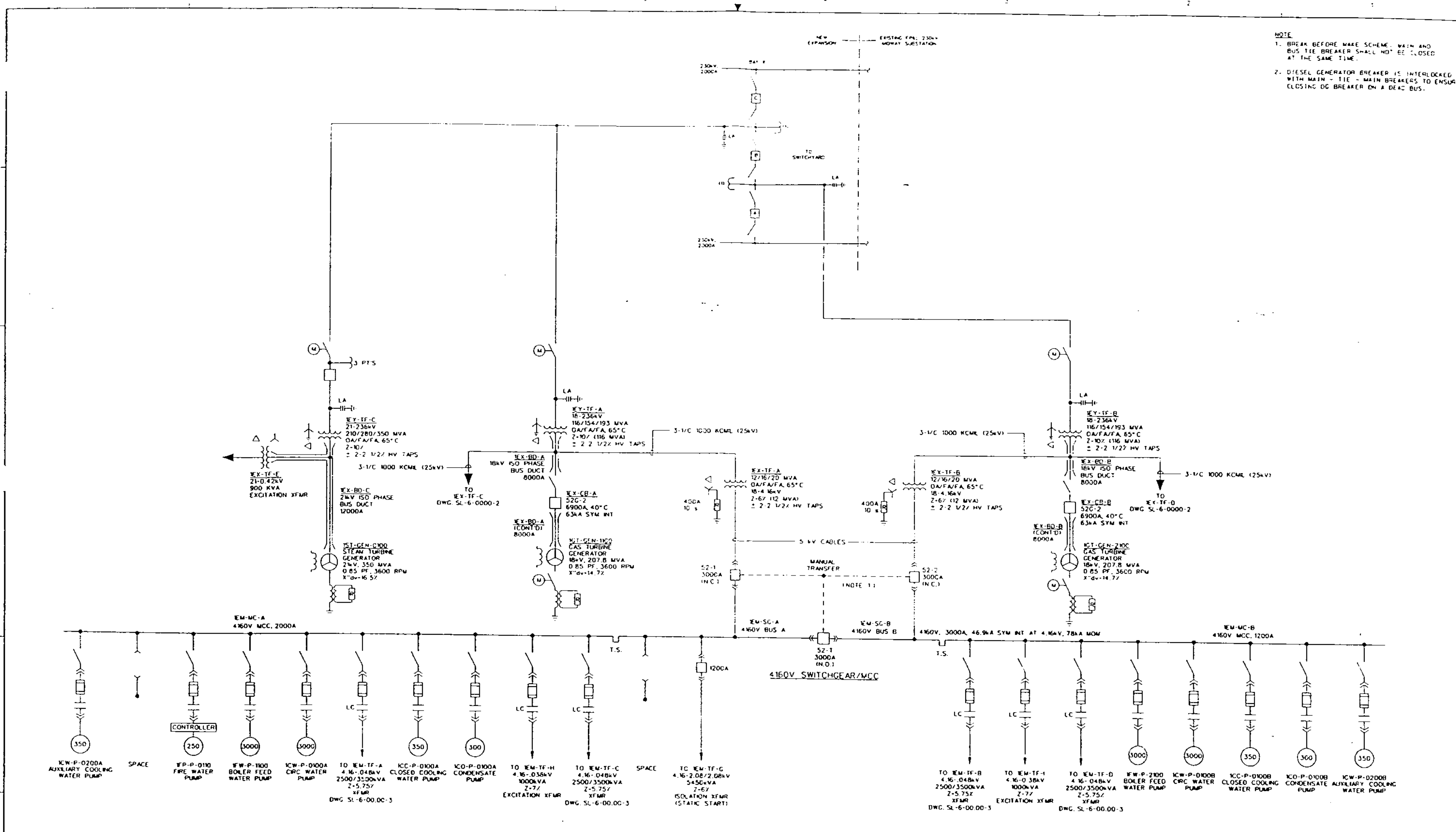


Figure 3-11: Transmission System Surrounding the Site.



REV.	DATE	REVISION DESCRIPTION	DRWN CHK.	LAYO PIPE	CIVIL ELEC	ENGM PROJ
A	3/1/00	ISSUED FOR REVIEW	VF			

DUKE/FLUOR DANIEL

DRAWN BY: V. FLORES — REB 1/19/00

K. SANFORD

DUKE ENERGY NORTH AMERICA
ST. LUCIE GENERATING STATION

ELECTRICAL
OVERALL ONE LINE DIAGRAM

SCALE: NONE — 605216 - 1 - SL - 6 - 00 00 - 1 - A

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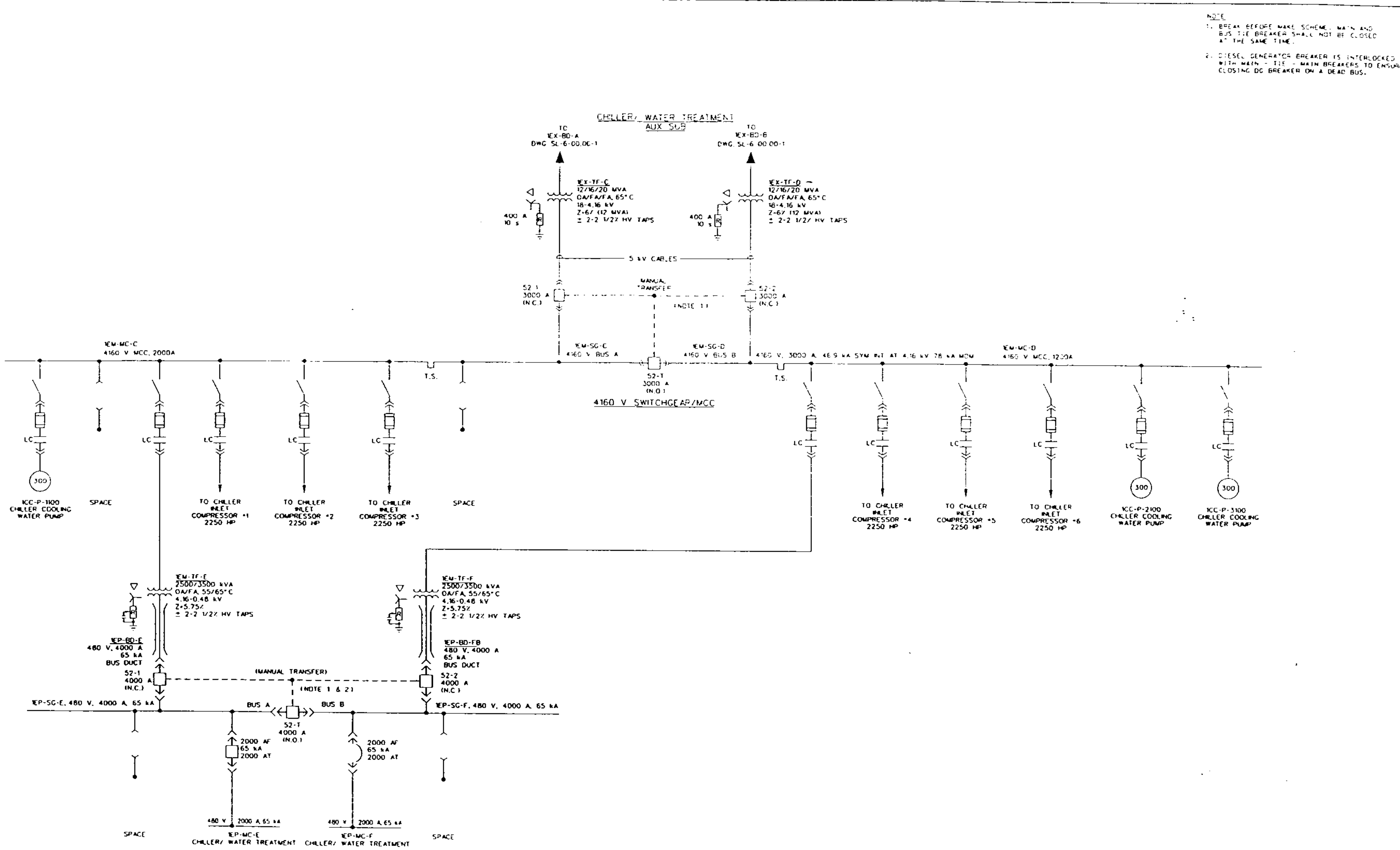

REV.	DATE	REVISION DESCRIPTION	DRWN CHK.	LAYO PIPE	CIVL ELEC	ENGM PROJ
A	3/2/00	ISSUED FOR REVIEW	VF			

REV.	DATE	REVISION DESCRIPTION	DRWN CHK.	LAYO PIPE	CIVL ELEC	ENGM PROJ	DWG NO.	REFERENCE DRAWINGS

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CHECKED BY:
ELECT LAYOUT APPROVAL:
PIPING LAYOUT APPROVAL:
CIVIL APPROVAL: N/A
ELECTRICAL APPROVAL: K. SANFORD
ENGINEERING MANAGER:
PROJECT DIRECTOR:

DUKE ENERGY NORTH AMERICA
ST. LUCIE GENERATING STATION

ELECTRICAL
OVERALL ONE LINE DIAGRAM
CHILLER/WATER TREATMENT AUX SUBSTATION

SCALE	CONTRACT NUMBER	UNIT No.	DOC. TYPE	SUBJECT CODE	SEQ No.	REV.
NONE	605216	1	SL	6	00.00	2	A

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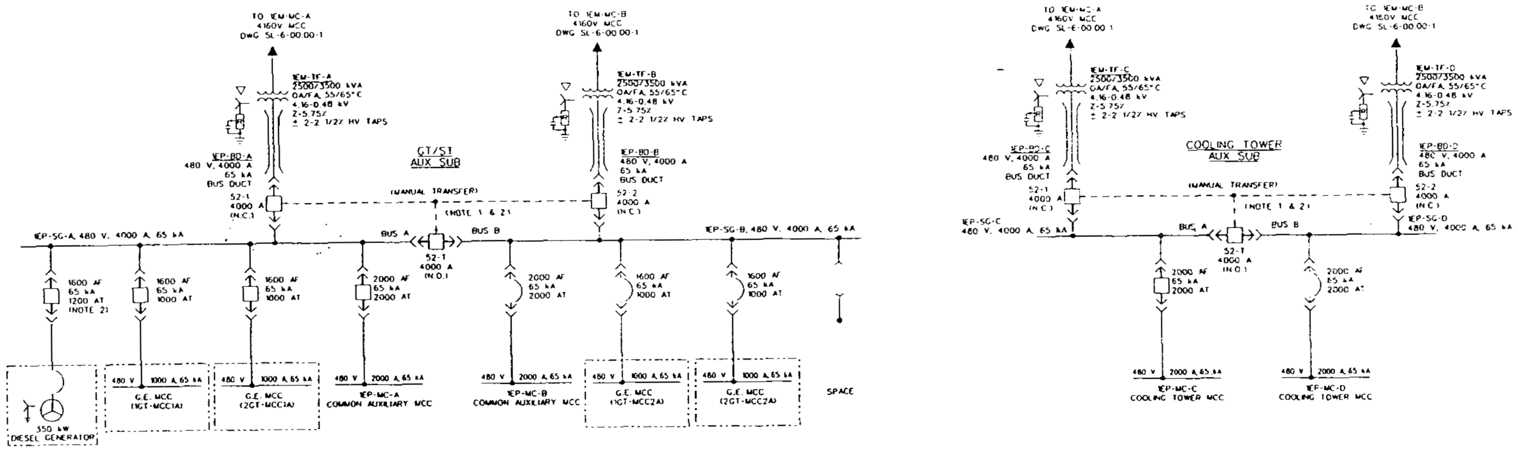
DIST. CODE WRK. PKG. CADD FILE No. 00002.DGN CONTRACT PKG.

ELECT20.0.DGN 1-02
Plot User $$$USERNAME$$$ Plot Date & Time $$$SYTIME$$$
$$DGNSPEC$$$$$$$$$$$$$$$$$$$$$$$$$$$

NOTE

1. BREAK BEFOR MAKE SCHEME. MAIN AND BUS TIE BREAKER SHALL NOT BE CLOSED AT THE SAME TIME.



REV.	DATE	REVISION DESCRIPTION	DRWN / CHK.	LAYO / PIPE	CIVIL / ELEC	ENGM / PROJ	REV.	DATE	REVISION DESCRIPTION	DRWN / CHK.	LAYO / PIPE	CIVIL / ELEC	ENGM / PROJ	DWG.NO.	REFERENCE DRAWINGS
A	3/2/00	ISSUED FOR REVIEW	VF												

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DRAWN BY: V. FLORES
CHECKED BY:
ELECT. LAYOUT APPROVAL:
PIPING LAYOUT APPROVAL:
CIVIL APPROVAL: N/A
ELECTRICAL APPROVAL: K. SANFORD
ENGINEERING MANAGER:
PROJECT DIRECTOR:

DUKE ENERGY NORTH AMERICA
ST. LUCIE GENERATING STATION

ELECTRICAL
OVERALL ONE LINE DIAGRAM

SCALE: NONE — CONTRACT NUMBER 605216 - UNIT No. 1 - DOC TYPE SL - 6 - SUBJECT CODE 00.00 - SEQ No. 3 - REV. A

Plot User $$$$USERNAME$$$$ Plot Date & Time $$$$SYTIME$$$$$$$$

•DATE•TIME• MANUAL CHANGES MADE - YES ☐ NO ☐ DWG. FILE UPDATED - YES ☐ NO ☐ MODEL UPDATED - YES ☐ NO ☐

CADD FILE No. 00003.DGN — WRK. PKG. — DIST. CODE — CONTRACT PKG.

ELEC170_0.DGN 1:0

3.8 Capital Cost of the DESL Project

The direct capital cost estimate for the DESL Project is based upon the current competitive generation market and includes assumptions about the future from D/FD. The estimated direct construction cost of the DESL Project is \$210 million (\$345 per kW). The estimate includes the direct transmission interconnection facilities (step-up transformer, switchgear, and conductor to the bus at the Midway substation). Capital costs for the one-mile natural gas lateral from the Ft. Pierce meter station to the project will be included in the rates from FGT, and not expensed to DESL.

3.9 Project Financing

DENA intends to finance the Project through Duke Energy Capital, thereby eliminating the need to issue debt or secure long-term power supply agreements. This Project will not impose any financial burden, now or in the future, on Florida ratepayers.

3.10 Net Plant Output

The DESL Project is projected to have a full load net plant output of 608 MW during operation at ISO (59 °F and 60% relative humidity) utilizing duct firing. Table 3-1 summarizes the Project's net plant output and heat rates for several ambient conditions and operating assumptions.

3.11 Net Plant Heat Rate

The Project represents very efficient electric generation that minimizes environmental impacts. The Project is projected to have a full load net heat rate of 7,096 Btu/kWh (HHV) during operation at ISO with no duct firing. The heat rate of the unit is 7,351 Btu/kWh (HHV) when duct firing is employed at ISO, during which the output of the unit reaches 608 MW. The unit will have a net thermal operating efficiency of 48 percent, which will be among some of the highest thermal efficiencies for generating units in the state. The estimated net plant heat rate for the St. Lucie Project for several ambient temperatures and operating levels are included in Table 3-1.

St Lucie Energy Facility
Duke Energy of North America
Fort Pierce, Florida

Duke/Fluor Daniel
Contract 06-605216
January 27, 2000
SLD, rev. 2

Estimated Plant Performance and Emissions Data
2 x 1 Combined Cycle Plant with Chiller and Duct Firing with 3.5 ppmvd NOx @ 15% O2
Two General Electric Model PG7241(FA) Combustion Turbine Generators
Two Duct Fired Heat Recovery Steam Generators
One Condensing Reheat Steam Turbine Generator

	Maximum	Max. Avg.	Aver. Amb.	Aver. Min.	Minimum	Maximum	Max. Avg.	Aver. Amb.	Aver. Min.	Minimum
Combustion turbine load	100% with Duct Firing					100%				
Ambient temperature (°F)	101	82	74.6	66.8 (7)	27	101	82	74.6	66.8 (7)	27
Relative humidity (%)	40	77.3	72	73.5	81	40	77.3	72	73.5	81
Mechanical Chiller Operation	On	On	On	Off	Off	On	On	On	Off	Off
Duct Firing Temperature (F)	1290	1285	1275	1290	1260	N/A	N/A	N/A	N/A	N/A
Net plant power output (kW)	598 108	606 187	610 051	599 290	636 103	482 587	490 573	497 489	485 935	527 532
Net CTG power output (kW)	323 436	331 187	333 941	318 134	355 044	321 414	328 968	332 387	317 754	356 495
Net STG power output (kW) (8)	274 672	275 000	276 110	281 156	281 059	161 173	161 605	165 102	168 181	171 037
Net plant heat rate, LHV basis (btu/kWh)	6 789	6 870	6 789	6 640	6 592	6 595	6 700	6 607	6 414	6 366
Net plant heat rate, HHV basis (btu/kWh)	7 536	7 626	7 536	7 370	7 317	7 320	7 437	7 333	7 120	7 066
CTG heat input, LHV basis (mmbtu/h)	3 183	3 287	3 287	3 117	3 358	3 183	3 287	3 287	3 117	3 358
Duct burner heat input, LHV basis (mmbtu/h)	878	878	855	863	835	0	0	0	0	0
CTG fuel flow rate (lb/h) - total for 2 CTGs + duct burners	194 167	199 141	198 052	190 287	200 508	152 187	157 171	157 171	149 042	160 578
Stack exhaust gas flow (lb/h) - total for 2 stacks	7 148 000	7 298 000	7 294 000	6 976 000	7 538 000	7 108 000	7 254 000	7 254 000	6 934 000	7 498 000
Stack exhaust gas composition (by volume)										
- Nitrogen + argon	74.24%	74.55%	74.59%	74.11%	75.12%	74.98%	75.30%	75.30%	74.87%	75.82%
- Oxygen	10.39%	10.42%	10.47%	10.33%	10.78%	12.53%	12.51%	12.51%	12.47%	12.71%
- Carbon dioxide	4.74%	4.77%	4.74%	4.76%	4.66%	3.76%	3.81%	3.81%	3.77%	3.77%
- Water	10.63%	10.26%	10.20%	10.80%	9.44%	8.73%	8.38%	8.38%	8.89%	7.70%
NOx as NO2 (lb/h) - total for 2 stacks (2)	58	59	58	57	59	35	36	36	34	36
CO (lb/h) - total for 2 stacks (3)	272.7	279.2	277.2	267.4	279.8	194.7	201.2	201.2	190.8	205.7
UHC as CH4 (lb/h) - total for 2 stacks (4)	74.8	75.4	74.2	73.4	74.0	28.1	28.6	28.6	27.4	29.5
VOC as CH4 (lb/h) - total for 2 stacks	27.29	27.28	26.57	26.81	25.95	0.00	0.00	0.00	0.00	0.00
SOx as SO2 (lb/h) - total for 2 stacks (5)	19.3	19.7	19.6	18.9	19.8	13.8	14.3	14.3	13.5	14.6
Particulates (lb/h) - total for 2 stacks	33	33	32	32	32	18	18	18	18	18
NH3 (lb/h) - total for 2 stacks	43	44	44	42	45	43	43	43	42	45
Stack velocity (ft/s) - based on a 18 ft. diameter stack	65.4	66.7	66.5	63.3	68.4	65.8	67.1	66.9	63.6	69.0
Stack temperature (°F)	187	188	186	182	185	198	199	197	191	197

	Maximum	Max. Avg.	Aver. Amb.	Aver. Min.	Minimum	Maximum	Max. Avg	Aver. Amb.	Aver. Min.	Minimum	ISO Fired	ISO Unf.
Combustion turbine load	75% (7)					60% (7)					100%	100%
Ambient temperature (°F)	101 (9)	82 (10)	74.6 (10)	66.8	27	101	82	74.6	66.8	27	59 (7)	59 (7)
Relative humidity (%)	40	77.3	72	73.5	81	40	77.3	72	73.5	81	60	60
Mechanical Chiller Operation	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
Duct Firing Temperature (F)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1280	N/A
Net plant power output (kW)	340 073	363 474	372 722	381 418	413 796	287 812	306 459	314 777	322 471	350 214	608 066	496 968
Net CTG power output (kW)	205 094	223 337	230 313	237 236	266 926	163 432	178 007	183 513	189 642	213 364	326 949	327 644
Net STG power output (kW) (8)	134 979	140 137	142 409	144 182	146 870	124 380	128 452	131 264	132 829	136 850	281 117	169 324
Net plant heat rate, LHV basis (btu/kWh)	6 890	6 797	6 747	6 706	6 594	7 195	7 138	7 073	7 020	6 916	6 623	6 392
Net plant heat rate, HHV basis (btu/kWh)	7 648	7 544	7 489	7 443	7 319	7 986	7 923	7 851	7 793	7 677	7 351	7 096
CTG heat input, LHV basis (mmbtu/h)	2 343	2 470	2 515	2 558	2 728	2 071	2 187	2 226	2 264	2 422	3 177	3 177
Duct burner heat input, LHV basis (mmbtu/h)	0	0	0	0	0	0	0	0	0	0	850	0
CTG fuel flow rate (lb/h) - total for 2 CTGs + duct burners	112 053	118 134	120 254	122 305	130 471	99 025	104 598	106 465	108 256	115 826	192 573	151 914
Stack exhaust gas flow (lb/h) - total for 2 stacks	5 338 000	5 542 000	5 628 000	5 706 000	5 972 000	4 878 000	5 000 000	5 056 000	5 126 000	5 396 000	7 103 000	7 062 000
Stack exhaust gas composition (by volume)												
- Nitrogen + argon	74.16%	73.98%	74.55%	74.88%	75.75%	74.24%	74.03%	74.58%	74.92%	75.80%	74.59%	75.33%
- Oxygen	12.48%	12.33%	12.44%	12.49%	12.55%	12.74%	12.48%	12.56%	12.61%	12.70%	10.49%	12.57%
- Carbon dioxide	3.67%	3.72%	3.74%	3.76%	3.85%	3.55%	3.65%	3.69%	3.71%	3.78%	4.74%	3.73%
- Water	9.69%	9.97%	9.27%	8.87%	7.85%	9.47%	9.84%	9.17%	8.76%	7.72%	10.18%	8.37%
NOx as NO2 (lb/h) - total for 2 stacks (2)	25	27	27	28	30	22	24	24	25	26	57	34
CO (lb/h) - total for 2 stacks (3)	143.4	151.2	154.0	156.7	167.1	126.6	133.8	136.2	138.6	148.2	267.7	194.3
UHC as CH4 (lb/h) - total for 2 stacks (4)	21.2	22.0	22.3	22.6	23.5	19.3	19.8	20.0	20.3	21.2	73.2	27.9
VOC as CH4 (lb/h) - total for 2 stacks	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	26.43	0.00
SOx as SO2 (lb/h) - total for 2 stacks (5)	10.2	10.7	10.9	11.1	11.9	9.0	9.5	9.7	9.8	10.5	19.1	13.8
Particulates (lb/h) - total for 2 stacks	18	18	18	18	18	18	18	18	18	18	32	18
NH3 (lb/h) - total for 2 stacks	32	33	34	34	36	29	30	30	31	32	43	42
Stack velocity (ft/s) - based on a 18 ft. diameter stack	48.2	50.2	50.7	51.3	53.7	43.7	44.8	45.1	45.7	48.1	64.3	64.8
Stack temperature (°F)	179	181	179	179	182	174	174	173	173	176	182	193

NOTES:
1) Final approval from DENA is required for the emissions limits to be listed in the air permit.
2) NOx emissions are based on the ppmvd value indicated in the table. The GE guarantee point is 9 ppmvd @ 15% O2.
3) CO emissions are based on a GE guarantee of 9 ppmvd.
4) UHC emissions are based on a GE guarantee of 7 ppmvd.
5) SOx emissions are based on firing pipeline quality natural gas with a maximum sulfur content of 2 grains/100 scf.
6) Plant Performance estimated by Thermoflow GTMaster Software Program ver. 9.1
7) Chiller is not operating below 70F or at partial load.
8) Gross steam turbine output is 290 MW for all 100% load cases with duct firing.
9) HP Steam pressure was reduced to 1450 psia at HPT stop valve in order for the steam cycle calculation to balance.
10) HP Steam pressure was reduced to 1600 psia at HPT stop valve in order for the steam cycle calculation to balance.

F:\Duke Energy PS\06605216 St Lucie\Systems\3 press HRSG\[2x1 xls]Emiss Summary

Table 3-1: Net Plant Output and Heat Rates for the Duke Energy St. Lucie Project.

3.12 Operations and Maintenance

The DESL Project will be operated and maintained by the D/FD operations and maintenance group. This group has significant experience with the power island for the Project and will insure a reliable facility. DENA has retained GE under a long term service agreement to provide O&M services for the two combustion turbines and steam turbine. The O&M cost estimates are based upon a unit operating life of 30 years and a baseload capacity factor. The O&M costs have been broken down into two components, variable costs and fixed costs.

3.12.1 Operating Assumptions

The following assumptions were utilized in preparing the cost estimates for the O&M expenses for the DESL Project:

- Natural Gas will be the source of fuel.
- The units will operate with dry low NO_x combustors and will utilize SCR for NO_x control.
- Combustion turbine generator ("CTG") and steam turbine generator ("STG") maintenance will be provided through DENA/GE long-term service agreement.
- Spare parts for the CTG, STG, and HRSG are estimated on a base load facility.
- Inspections for the combustion turbines, steam turbines, and HRSG's are required every 8,000 hours of operation or 400 starts.
- Minor overhauls are required every 24,000 hours of operation or 900 starts.
- Major overhauls are required every 48,000 hours of operation or 2,400 starts
- Costs for deminerilized cycle makeup water and cooling tower process water are included.
- Twenty-five (25) staff members have been included for the facility.

3.12.2 Fixed O&M Estimates

The DESL Project is projected to have a fixed O&M expense of $20.72 kW-yr. Fixed operating costs are costs that will be incurred whether or not the project operates, and includes wages and wage related overhead, inspections, overhauls, and general facility maintenance.

3.12.3 Variable O&M estimates

The DESL Project is projected to have a variable O&M expense of $0.35/MWh for the facility in 2003. Variable O&M costs include items that are only required when the facility is operating such as chemicals, lubricants, water, and consumables.

3.13 Operational Reliability

The Project is expected to have an equivalent availability factor of 94.8 percent; with a forced outage factor of 1.5 percent and a planned outage rate of 3.7 percent. The project is estimated to operate at intermediate to base load over the initial 30-year period. The 3.7 percent planned outage factor is an average of the maintenance that takes place over the life of the combustion turbines in the first 30 years of operation. Based upon recommendations from the manufacturer, the turbines must undergo routine maintenance that will require the units to be taken offline. The combustion turbines will undergo annual inspections every 8,000 hours of operation, require minor overhauls every 24,000 hours of operation, and require major overhauls every 48,000 hours of operation.

3.14 Emissions

The DESL Project will burn natural gas only in the combustion turbines and duct burners for generating electricity. Natural gas is the cleanest burning fossil fuel with flue gas being the only byproduct of combustion. Because natural gas is a low sulfur, low ash fuel, the impact to the environment is minimized. DESL is currently in the process of drafting its Site Certification Application to the Florida Department of Environmental Protection ("FDEP") for its permit to operate the facility. DESL will meet BACT levels for emissions. The limits anticipated for the Project are displayed in Table 3-1, but have not been approved by the EPA or FDEP and are subject to further modifications.

3.15 Schedule

The schedule for the DESL Project is based upon an 18-month construction period. The construction of the facility needs to begin by December 1, 2001 for a June 1, 2003 commercial operation date. This schedule takes into consideration the significant experience that D/FD has with the equipment and power island that the Project will utilize. Figure 3-15 outlines the construction schedule for DESL.

St. Lucie Energy Facility
Combined Cycle with 290 MW Steam Turbine Generator
Management Level Schedule

ID	Task Name	Duration	Start	Finish
1	**Development/Preliminary Engineering**	**633 days**	**6/1/99**	**11/1/01**
2	Development Team Assigned	0 days	11/1/99	11/1/99
3	Option of Land	0 days	6/1/99	6/1/99
4	Air Permit Application Submittal	0 days	6/1/00	6/1/00
5	Limited Notice to Proceed Phase	39.2 wks	2/1/01	11/1/01
6	DENA Board Approval	8.8 wks	9/3/01	11/1/01
7	EPC Contract Awarded	1 day	11/1/01	11/1/01
8	**Procurement**	95.4 wks	2/1/01	11/29/02
9	**Detail Engineering**	43.4 wks	11/1/01	8/30/02
10	**Purchase/Delivery Major Equipment**	**435 days**	**4/1/01**	**11/29/02**
11	STG Full Release	0 days	4/1/01	4/1/01
12	CTGs (1 & 2) Full Release	0 days	8/1/01	8/1/01
13	Transformers	325 days	9/3/01	11/29/02
14	**Receive Environmental Permit**	0 wks	1/1/02	1/1/02
15	**Field Move-In**	0 wks	1/1/02	1/1/02
16	**Construction**	**261 days**	**2/1/02**	**2/1/03**
17	Site Preparation	12.6 wks	2/1/02	4/30/02
18	Foundations and Undergrounds	13.2 wks	5/1/02	7/31/02
19	Receive/Erect CTG Package #1	22 wks	8/1/02	1/1/03
20	Receive/Erect CTG Package #2	21.8 wks	9/3/02	1/31/03
21	Receive/Erect STG	17.4 wks	8/1/02	11/29/02
22	Receive/Erect HRSG #1	17.4 wks	8/1/02	11/29/02
23	Receive/Erect HRSG #2	17.4 wks	9/3/02	1/1/03
24	Receive/Erect Cooling Tower	17.6 wks	9/2/02	1/1/03
25	Receive/Erect Aux. Equipment	17.4 wks	8/1/02	11/29/02
26	Erect BOP Mechanical/Electrical	17.8 wks	10/1/02	1/31/03
27	Fuel Gas Available	0 wks	1/1/03	1/1/03
28	Water Available	0 wks	1/1/03	1/1/03
29	Mechanical Completion - BOP	0 wks	2/1/03	2/1/03
30	**Start-up/Check-out**	17 wks	2/3/03	5/30/03
31	**Commercial Operation**	0 wks	6/1/03	6/1/03

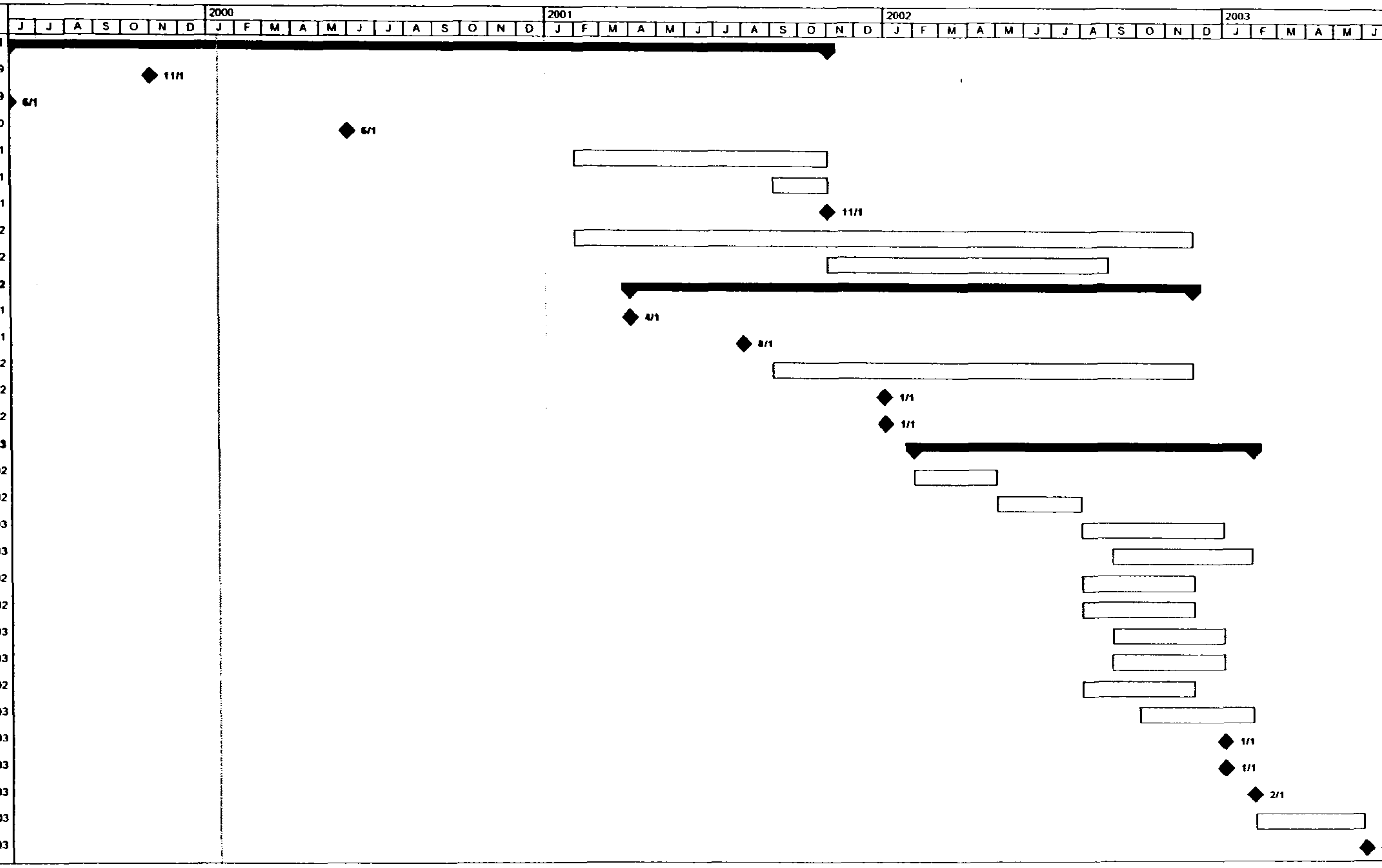

Figure 3-15: Construction Schedule for the Project.

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4.0 Need for the DESL Project

The DESL Project is designed to provide total net generation capacity of 598 MW in the summer and 636 MW in the winter. This additional capacity will significantly increase the reliability of power supply in Peninsular Florida, will insure that adequate electricity is provided to Peninsular Florida at reasonable costs, and will meet the power supply needs of DESL.

4.1 Reliability Need of Peninsular Florida

In evaluating the reliability need of Peninsular Florida, DESL addressed Peninsular Florida's demand for electric power, its existing power supply resources, its reserve margins, and its need for new generation resources.

4.1.1 Demand for Electric Power

Peninsular Florida's peak demands for summer and winter are increasing at one of the fastest growth rates in the United States. Based on the Florida Reliability Coordinating Council's ("FRCC[1]") 1999 Regional Load and Resource Plan, total summer peak demand is forecasted to grow from 36,788 MW in the summer of 1999 to 44,066 MW in the summer of 2008, an average annual growth rate of 2.0 percent. The FRCC's forecasted total summer peak demand growth is only 50 percent as high as actual growth from 1989 to 1998 of 3.96 percent. If growth continues at the historical rate of 3.96 percent, Peninsular Florida's total summer peak demand will reach 52,180 MW in 2008. Peninsular Florida's total winter peak demand exhibits a similar trend with FRCC forecasts projecting a total winter peak demand of 48,441 MW in 2008, which reflects an annual average growth rate of 2.15 percent from the forecasted 39,989 MW 1999 winter peak demand. Peninsular Florida's historical annual average growth rate for total winter peak demand has been 2.31 percent over the last ten years. If growth for total winter peak demand continues at the historical rate of 2.31 percent, Peninsular Florida's total

[1] The Florida Reliability Coordinating Council is responsible for coordinating power supply reliability in Peninsular Florida for the North American Reliability Council (NERC). The most recent planning summary conducted by the FRCC is the "1999 Regional Load and Resource Plan." Published during 1999, this report summarizes current utility resources, planned generating additions for the next ten years, retirements, demand side programs, unit rating changes, and projected peak demands and energy growth through the year 2008. The FRCC 1999 Regional Load and Resource Plan was utilized in addressing the reliability need for the DESL Project.

winter peak demand will reach 49,112 MW in 2008. Table 4-1, summarized from the FRCC 1999 Regional Load and Resource Plan, provides the historical and forecast for summer and winter peak demand.

Net energy for load is also projected to grow significantly over the next ten years. As displayed in Table 4-2, the FRCC forecasts that net energy for load will increase from 186,374 GWH in 1999 to 227,645 GWH in 2008, an annual average growth rate of 2.25 percent. This growth rate is conservative when compared to Peninsular Florida's historical net energy for load growth rate, which averaged 3.24 percent over the nine year period from 1989 to 1998.

4.1.2 Peninsular Florida's Existing Generation Resources

As of January 1, 1999, Peninsular Florida's total generating capacity was 39,128 MW for the winter and 37,338 MW for the summer. Table 4-3 summarizes the total existing capacity grouped by retail serving utility, non-utility generator, and exempt wholesale generator.

Currently, the generation supply in Peninsular Florida has several units that are more than 25 years old. Although the equivalent availability information for specific units throughout Florida is not of public record, the equivalent availability of units deteriorates with time if utilities are not willing to spend the capital to keep these units highly reliable. Units that do not warrant capital expenditures to maintain a high reliability are, generally, older, more costly units that are not utilized for extended periods of use. Figure 4-1 segregates the total capacity by primary fuel and equipment type for Peninsular Florida units into age groups. Figure 4-1 displays Peninsular Florida's dependence on a significant supply of older generation.

The Project will provide Peninsular Florida with a new, highly reliable generating unit that is needed to balance Peninsular Florida's dependence on older generation resources. As discussed in Section 3.13, the availability of the DESL Project is estimated to have an equivalent availability factor of 94.8 percent. This high equivalent availability assures that the Project will contribute to improving the reserve margins and reliability of the Peninsular Florida power supply system.

Table 4-1: Summer and Winter Peak Demand Forecasts

1999
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL

HISTORY AND FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	SUMMER PEAK DEMAND - (MW)				WINTER PEAK DEMAND - (MW)					ENERGY		
YEAR	ACTUAL PEAK DEMAND (MW)				YEAR	ACTUAL PEAK DEMAND (MW)				YEAR	NET ENERGY FOR LOAD (GWH)	LOAD FACTOR (%)
1989	26,608				1989 / 90	29,170				1989	141,021	60.07%
1990	27,238				1990 / 91	24,978				1990	142,490	55.76%
1991	27,662				1991 / 92	28,179				1991	146,786	60.58%
1992	28,930				1992 / 93	27,215				1992	147,728	58.29%
1993	29,748				1993 / 94	28,149				1993	153,269	58.82%
1994	29,321				1994 / 95	32,618				1994	159,353	62.04%
1995	31,801				1995 / 96	34,552				1995	168,982	59.14%
1996	32,315				1996 / 97	34,762				1996	173,327	57.26%
1997	32,924				1997 / 98	30,932				1997	175,534	57.64%
1998	37,153				1998 / 99	35,907				1998	187,868	57.72%
YEAR	TOTAL PEAK DEMAND (MW)	INTER-RUPTIBLE LOAD (MW)	LOAD MANAGE-MENT (MW)	FIRM PEAK DEMAND (MW)	YEAR	TOTAL PEAK DEMAND (MW)	INTER-REPTIBLE LOAD (MW)	LOAD MANAGE-MENT (MW)	FIRM PEAK DEMAND (MW)	YEAR	NET ENERGY FOR LOAD (GWH)	LOAD FACTOR (%)
1999	36,788	1,225	1,540	34,023	1999 / 00	39,989	1,173	2,839	35,977	1999	186,374	59.25%
2000	37,541	1,247	1,591	34,703	2000 / 01	40,928	1,184	2,925	36,819	2000	190,955	60.59%
2001	38,223	1,265	1,578	35,380	2001 / 02	41,865	1,178	2,894	37,793	2001	195,687	60.67%
2002	38,959	1,265	1,537	36,157	2002 / 03	42,808	1,193	2,866	38,749	2002	200,060	60.43%
2003	39,781	1,284	1,509	36,988	2003 / 04	43,726	1,200	2,863	39,663	2003	204,884	60.36%
2004	40,593	1,296	1,493	37,804	2004 / 05	44,651	1,215	2,870	40,566	2004	209,492	60.29%
2005	41,433	1,317	1,478	38,638	2005 / 06	45,553	1,226	2,877	41,450	2005	214,094	60.25%
2006	42,398	1,334	1,467	39,597	2006 / 07	46,600	1,239	2,885	42,476	2006	218,611	60.21%
2007	43,252	1,352	1,457	40,443	2007 / 08	47,502	1,233	2,895	43,374	2007	223,179	59.98%
2008	44,066	1,348	1,452	41,266	2008 / 09	48,441	1,248	2,907	44,286	2008	227,645	59.91%

Table 4-2: Forecasted Net Energy for Load

FRCC REGION
HISTORY AND FORECAST
ENERGY USE BY CUSTOMER TYPE - GWH
AS OF JANUARY 1, 1999

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	RURAL & RESIDENTAL			COMMERCIAL			INDUSTRIAL			STREET & HIGHWAY LIGHTING	OTHER SALES	TOTAL SALES	RESALE	UTILITY USE & LOSSES	NEL
YEAR	GWH	CUSTOMERS	KWH/CUST	GWH	CUSTOMERS	KWH/CUST	GWH	CUSTOMERS	KWH/CUST	GWH	GWH	GWH	GWH	GWH	GWH
1989	62,263	5,191,812	11,993	43,237	618,010	69,962	16,633	26,681	623,384	501	3,503	126,137	0	14,884	141,021
1990	65,022	5,354,736	12,143	44,819	633,799	70,715	16,676	26,065	639,761	508	3,576	130,600	0	11,890	142,490
1991	66,787	5,484,780	12,177	45,796	645,580	70,938	16,650	25,020	665,471	538	3,736	133,508	0	13,278	146,786
1992	67,008	5,584,028	12,000	45,888	660,642	69,459	16,646	24,690	674,190	552	3,796	133,890	0	13,838	147,728
1993	70,488	5,709,685	12,345	48,080	676,150	71,109	16,524	24,962	661,962	535	3,877	139,503	0	13,766	153,269
1994	74,128	5,833,171	12,708	50,454	691,625	72,951	17,025	25,964	655,718	562	4,007	146,177	0	13,176	159,353
1995	78,667	5,955,574	13,209	52,100	705,921	73,804	17,687	25,660	689,299	586	4,165	153,205	0	15,777	168,982
1996	81,047	6,066,709	13,359	53,086	720,371	73,693	18,338	25,523	718,516	600	4,278	157,349	0	15,978	173,327
1997	80,727	6,185,747	13,051	55,643	737,205	75,478	18,707	25,936	721,263	620	4,536	160,233	0	15,301	175,534
1998	88,200	6,309,119	13,980	59,052	755,690	78,143	19,560	26,994	724,593	614	4,603	172,029	0	15,839	187,868
89-1998 % AAGR	3.95%	2.19%	1.72%	3.52%	2.26%	1.24%	1.82%	0.13%	1.69%	2.29%	3.08%	3.51%	0.00%	0.69%	3.24%
1999	86,784	6,432,939	13,491	58,626	772,370	75,904	19,259	26,998	713,322	639	4,665	169,973	0	16,400	186,374
2000	89,141	6,559,408	13,590	60,320	788,526	76,497	19,639	27,187	722,367	658	4,789	174,546	0	16,409	190,955
2001	91,402	6,685,699	13,671	62,041	804,892	77,080	19,894	27,428	725,339	677	4,919	178,933	0	16,754	195,687
2002	93,708	6,809,302	13,762	63,708	820,982	77,600	20,128	27,678	727,220	697	5,045	183,286	0	16,774	200,060
2003	96,033	6,930,494	13,857	65,301	836,863	78,030	20,502	27,806	737,325	718	5,169	187,724	0	17,160	204,884
2004	98,337	7,049,891	13,949	66,900	852,392	78,485	20,818	27,919	745,671	739	5,305	192,099	0	17,393	209,492
2005	100,623	7,166,968	14,040	68,448	867,633	78,891	21,193	28,046	755,626	760	5,438	196,461	0	17,632	214,094
2006	102,921	7,283,304	14,131	69,992	882,695	79,294	21,550	28,145	765,673	782	5,564	200,810	0	17,801	218,611
2007	105,160	7,399,732	14,211	71,551	897,811	79,695	21,930	28,338	773,864	804	5,692	205,136	0	18,043	223,179
2008	107,460	7,516,636	14,296	73,133	912,927	80,108	22,138	28,536	775,793	828	5,823	209,382	0	18,264	227,645
99-2008 % AAGR	2.40%	1.74%	0.65%	2.49%	1.88%	0.60%	1.56%	0.62%	0.94%	2.92%	2.49%	2.34%	0.00%	1.20%	2.25%

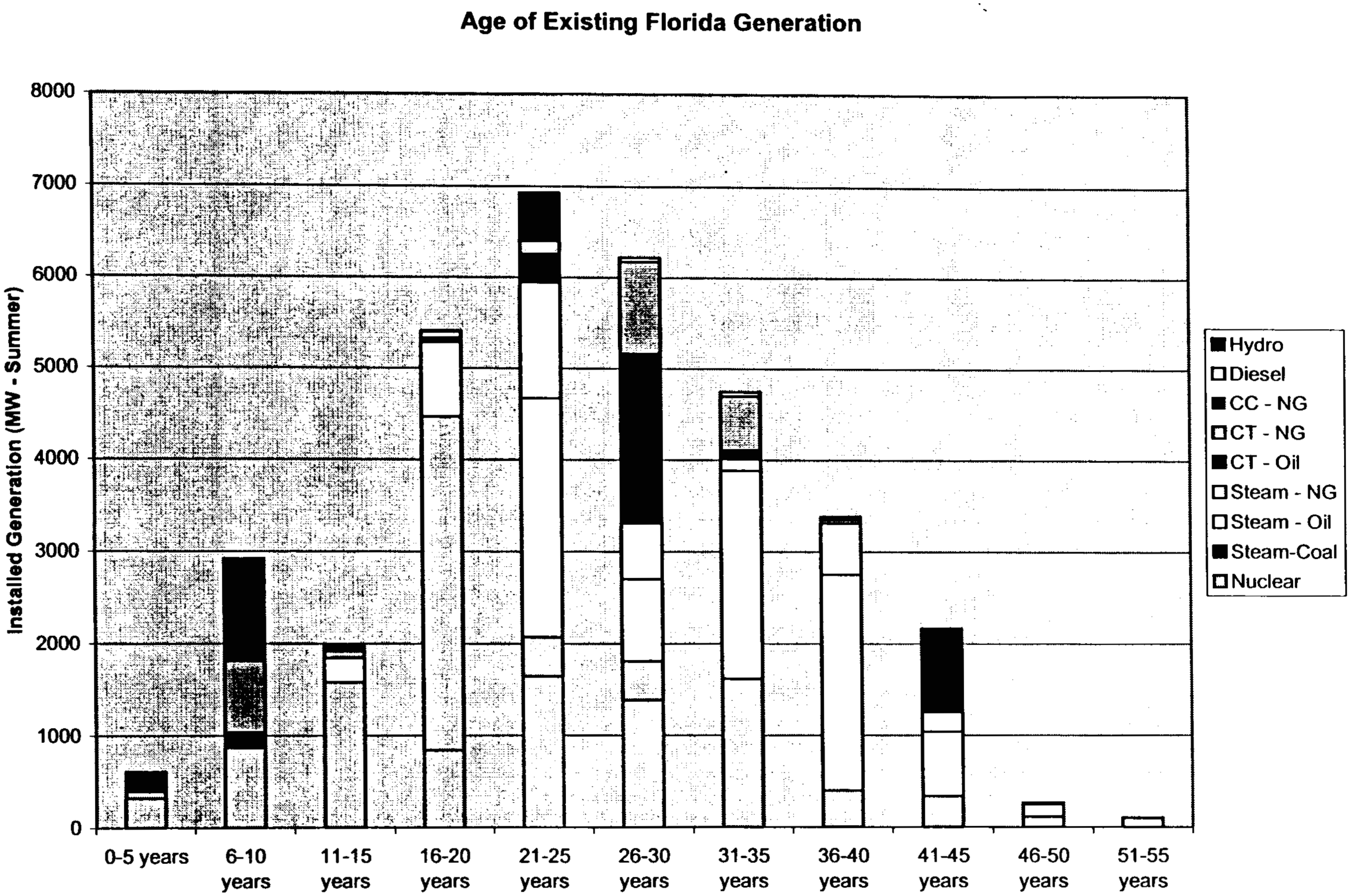

Figure 4-1: Current Age of Generators in Florida.

Table 4-3: Existing Capacity in Peninsular Florida

1999
REGIONAL LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
SUMMARY OF EXISTING CAPACITY
AS OF JANUARY 1, 1999

	NET CAPABILITY - MW	
RETAIL SERVING UTILITIES	SUMMER	WINTER
FLORIDA KEYS ELECTRIC COOPERATIVE ASSOCIATION, INC.	22	22
FLORIDA MUNICIPAL POWER AGENCY	453	478
FLORIDA POWER CORPORATION	6,962	7,727
FLORIDA POWER & LIGHT COMPANY	16,326	16,783
FORT PIERCE UTILITIES COMPANY	119	119
GAINESVILLE REGIONAL UTILITIES	550	563
CITY OF HOMESTEAD	60	60
JEA	2,628	2,733
UTILITY BOARD OF THE CITY OF KEY WEST	52	52
KISSIMMEE UTILITY AUTHORITY	172	189
CIT OF LAKELAND	625	660
CITY OF LAKE WORTH UTILITIES	95	105
UTILITIES COMMISSION OF NEW SMYRNA BEACH	24	24
OCALA ELECTRIC UTILITY	11	11
ORLANDO UTILITIES COMMISSION	1,632	1,689
REEDY CREEK IMPROVEMENT DISTRICT	48	49
SEMINOLE ELECTRIC COOPERATIVE, INC.	1,291	1,345
CITY OF ST. CLOUD	22	21
CITY OF TALLAHASSEE	490	508
TAMPA ELECTRIC COMPANY	3,433	3,587
CITY OF VERO BEACH	150	155
	35,165	36,880
NON-UTILITY GENERATING FACILITIES		
FIRM	2,076	2,129
NON-FIRM	97	119
	2,173	2,248
EXEMPT WHOLESALE GENERATORS		
	0	0
TOTAL FRCC EXISTING CAPACITY:	**37,338**	**39,128**

Data Source:
1999 Regional Load and Resource Plan
Florida Reliability Coordinating Council

4.1.3 Peninsular Florida's Reserve Margins

The FRCC has set a minimum planned reserve margin of 15 percent as the planning criteria to meet demands with sufficient reliability. The Commission has also established a minimum planned reserve margin of 15 percent. See Fla. Admin. Code Rule 25-6.035 (1). On November 29, 1999, the Commission approved a stipulation by Florida's investor-owned retail serving electric utilities to adopt a 20 percent minimum reserve margin for 2004. See In re: Generic Investigation into the Aggregate Electric Utility Reserve Margins Planned for Peninsular Florida. Docket No. 981890. With the implementation of the 20 percent reserve margin, Florida's generation reserves are below the minimum planning threshold.

Peninsular Florida's reserve margin is forecasted to remain very close to the minimum planned reserve margin over the forecasted period according to the FRCC 1999 Regional Load & Resource Report as displayed in Table 4-4. The reserve margin projections provided in Table 4-4 are heavily dependent upon interruptible loads, demand-side control measures, and planned unit additions. Indeed, load management and direct load control currently represent about *50* percent of the reserves in Peninsular Florida's reserve margin. If interruptible loads and load management were not implemented at the time of peak demand, Peninsular Florida's reserve margin would fall significantly below the minimum 15/20 percent criteria. In the year 2003, the forecasted summer reserve margin is just 12 percent without utilizing load management and direct load control measures. For the winter of 2004, the forecasted reserves without implementing load management and load controls will be just 8 percent. This leaves little margin to spare in the event of a cold front like the winter of 1989, outages of a couple large units, forecasting errors, and/or new additions not completed on time. Peninsular Florida will be short by approximately 3,800 MW of capacity in 2004, if load management and interruptible controls are not utilized.

4.1.4 The Need for New Generation Resources

The FRCC Load and Resource Plan indicates that Peninsular Florida needs approximately 11,400 MW of new installed capacity in order to maintain minimum reserve margins over the 1999 to 2008 time period. This estimate assumes that load

Table 4-4: Reserve Margin as reported in 1999 Regional FRCC Load and Resource Plan

1999
LOAD AND RESOURCE PLAN
FLORIDA RELIABILITY COORDINATING COUNCIL
SUMMARY OF CAPACITY, DEMAND, AND RESERVE MARGIN
AT TIME OF SUMMER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
YEAR	INSTALLED CAPACITY (MW)	NET CONTRACTED FIRM INTERCHANGE (MW)	PROJECTED FIRM NET TO GRID FROM NUG (MW)	TOTAL AVAILABLE CAPACITY (MW)	TOTAL PEAK DEMAND (MW)	RESERVE MARGIN W/O EXERCISING LOAD MANAGEMENT & INT (MW)	% OF PEAK	FIRM PEAK DEMAND (MW)	RESERVE MARGIN WITH EXERCISING LOAD MANAGEMENT & INT. (MW)	% OF PEAK
1999	36,125	1,640	2,076	39,841	36,788	3,053	8%	34,023	5,818	17%
2000	36,518	1,755	2,076	40,349	37,541	2,808	7%	34,703	5,646	16%
2001	38,065	1,682	2,076	41,823	38,223	3,600	9%	35,380	6,443	18%
2002	39,675	1,658	2,055	43,387	38,959	4,428	11%	36,157	7,230	20%
2003	40,864	1,566	2,055	44,484	39,781	4,703	12%	36,988	7,496	20%
2004	41,301	1,566	2,055	44,921	40,593	4,328	11%	37,804	7,117	19%
2005	42,162	1,566	2,045	45,772	41,433	4,339	10%	38,638	7,134	18%
2006	42,731	1,566	1,912	46,208	42,398	3,810	9%	39,597	6,611	17%
2007	44,179	1,566	1,906	47,651	43,252	4,399	10%	40,443	7,208	18%
2008	44,893	1,566	1,891	48,350	44,066	4,284	10%	41,266	7,084	17%

SUMMARY OF CAPACITY, DEMAND, AND RESERVE MARGIN
AT TIME OF WINTER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
YEAR	INSTALLED CAPACITY (MW)	NET CONTRACTED FIRM INTERCHANGE (MW)	PROJECTED FIRM NET TO GRID FROM NUG (MW)	TOTAL AVAILABLE CAPACITY (MW)	TOTAL PEAK DEMAND (MW)	RESERVE MARGIN W/O EXERCISING LOAD MANAGEMENT & INT (MW)	% OF PEAK	FIRM PEAK DEMAND (MW)	RESERVE MARGIN WITH EXERCISING LOAD MANAGEMENT & INT. (MW)	% OF PEAK
1999/01	37,803	1,772	2,129	41,704	39,989	1,715	4%	35,977	5,727	16%
2000/01	39,497	1,694	2,129	43,320	40,928	2,392	6%	36,819	6,501	18%
2001/02	41,549	1,671	2,129	45,349	41,865	3,484	8%	37,793	7,556	20%
2002/03	43,225	1,566	2,108	46,899	42,808	4,091	10%	38,749	8,150	21%
2003/04	43,539	1,566	2,108	47,213	43,726	3,487	8%	39,663	7,550	19%
2004/05	44,461	1,566	2,098	48,125	44,651	3,474	8%	40,566	7,559	19%
2005/06	45,245	1,566	1,965	48,776	45,553	3,223	7%	41,450	7,326	18%
2006/07	46,670	1,566	1,959	50,195	46,600	3,595	8%	42,476	7,719	18%
2007/08	47,634	1,566	1,944	51,144	47,502	3,642	8%	43,374	7,770	18%
2008/09	47,624	1,566	1,944	51,134	48,441	2,693	6%	44,286	6,848	15%

management and interruptible customers will continue to request interruption at peak load. However, the forecasted need for an additional 11,400 MW of new installed capacity assumes that the forecast for peak demand over the planning horizon is sound. In fact, the forecast for summer peak demand is forecasted to increase at only somewhat over half the rate of the actual historical growth rate from 1989 to 1998.

Figure 4-2 displays the FRCC's current and planned generating capacity by generating technology and primary fuel type for the 1999 through 2008 time period. Many of the generation additions planned to maintain the reserve margin over the next ten years have not received need determinations from the Commission or received certification under the Siting Act. The process of bringing a generating facility to commercial operation is very time intensive with several hurdles to clear before commercial operation. With the reserve margin so close to the minimum criteria, a delay in a single project could result in significant impacts on the reliability of electricity in Florida.

The Project will increase Florida's effective reserve margin in several ways. The additional capacity supplied by the Project (598 MW summer, 636 MW winter) will improve reliability and reduce Peninsular Florida's exposure to outages. For example, in an extreme event (major transmission lines lost, cold weather spells, several large units trip or on outage, etc.) approximately 600 MW of load will be served that otherwise would be interrupted. The Project, therefore, would enable Florida retail serving utilities to maintain service to approximately 125,000 to 210,000 residential customers (at a coincident peak demand of 3 to 5 kW per household) during such conditions. While the current methodology of calculating reserve margins in the state excludes non-firm capacity, the capacity of the Project in fact will be available to meet the energy needs of Florida utilities. The high equivalent availability of the DESL Project will also serve to increase the reliability of the Peninsular Florida Grid. The DESL Project will utilize state of the art technology to ensure the project is highly reliable and can be counted on for dependable service when requested.

According to the FRCC's 1999 Regional Load & Resource Plan, dated July, 1999, without the DESL Project, Peninsular Florida's summer reserve margins in 2003

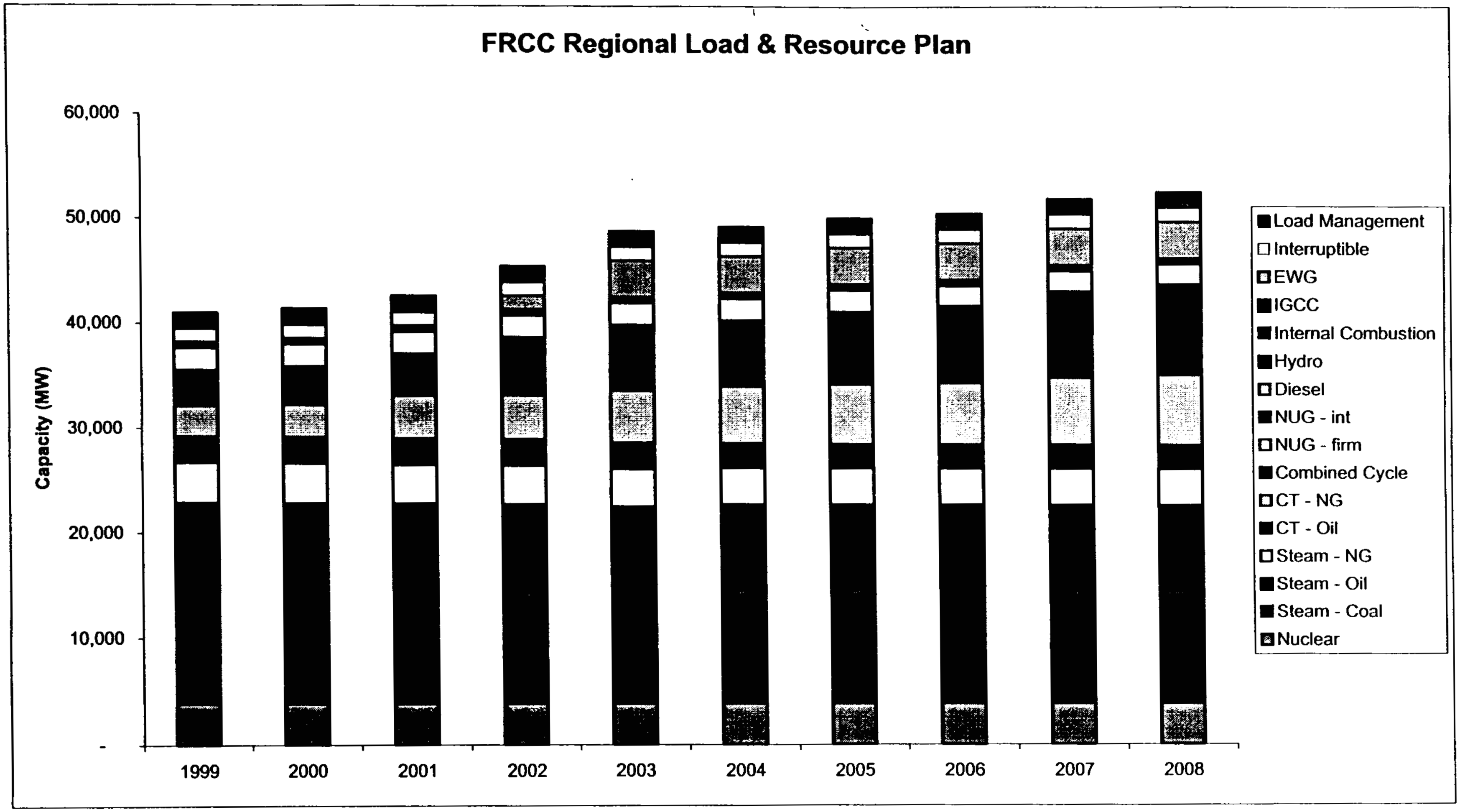

Figure 4-2: FRCC Regional Load & Resource Plan as of January 1, 1999 with planned additions, retirements, and modifications.

through 2008 will rage from 9 percent to 12 percent, without exercising load management and interruptible capabilities. The 9 to 12 percent summer reserve margin (3,810 MW to 4,703 MW) is also significantly dependent upon interchange and NUG capacity. If this generation was removed from the reserve margin, Peninsular Florida could not maintain service to its ratepayers. The Project would increase the installed generation physically located in Florida by approximately 1.41 percent for the summer period.

Similarly, based on data presented in the FRCC's 1999 Regional Load & Resource Plan, without the DESL Project, Peninsular Florida's winter reserve margins in 2003/2004 through 2008/2009 will range from 6 percent to 8 percent, without exercising load management and interruptible capabilities. The 6 to 8 percent winter reserve margin (2,693 MW to 3,642 MW) is also significantly dependent upon interchange and NUG capacity. If this generation was removed from the reserve margin, Peninsular Florida could not maintain service to its ratepayers. The Project would increase the installed generation physically located in Florida by approximately 1.41 percent for the winter period.

Power produced by the Project will be sold in the wholesale market to other utilities and power marketers for use in Peninsular Florida. The LCG model forecasts that all, or virtually all of the sales from the Project over the 2003-2012 period are expected to be to other utilities and power marketers for use in Peninsular Florida (i.e., within the FRCC region), on the basis of the relative economics of the Project and other Peninsular Florida generation facilities. It is unlikely that power produced from the Project will be consumed outside Florida. In Georgia, Alabama and Mississippi, the wholesale market clearing price for electricity is typically lower than in Florida and the cost of fuel transportation to these states is less than in Florida. In addition, electricity generated in Florida would have to incur the expense of being wheeled through the State to the other markets, an expense that electricity generated in those markets would avoid. Moreover, transmission export capability at the Georgia/Florida interface is limited. The site of the Project was chosen to best accommodate sales to the Florida wholesale market, i.e. Peninsular Florida's other utilities and power marketers.

4.1.4.1 LCG's UPLAN Model

The studies of the Project's operations prepared for DESL by VHC and LCG were developed using the UPLAN model. A detailed description of this integrated modeling system is included in Appendix B to the Exhibit, with a brief summary provided below. UPLAN is a state-of-the-art electricity market model that simulates both the behavior of the market participants and the physical structure of the electric system in a regional electricity market. UPLAN's Network Power Model ("NPM") is an Optimal Power Flow ("OPF") and hourly electricity market model that simulates generation, transmission and power markets and addresses issues related to power plant and transmission system operations, economic efficiency, market prices and market share, environmental concerns and the impacts of regulation and competition in interconnected electricity markets. The model simulates the hourly operation of individual generating units, and the hourly dispatch and delivery of electricity to determine both forward and real time or wholesale spot prices for energy and ancillary services. The model closely tracks the large number of factors that affect the supply and consumption of energy using each area's protocols within the large interconnected electrical network. In this case, UPLAN has been applied as a tool to test the cost-effectiveness, operations and reliability impacts of the Project by simulating the FRCC with and without the Project.

UPLAN has been used extensively throughout North America and abroad by public and private clients to examine investment decisions, operating strategies, cost-effectiveness, fuel switching impacts, asset values for merchant plants, nodal, zonal and regional market prices and price volatility, transmission congestion, system reliability, competitive market bidding, stranded costs, portfolio optimization, simulation of ISO/PX operations, and to conduct merger & market power studies. Among the agencies that have relied upon UPLAN model analyses are the Missouri Public Service Commission, the California Public Utilities Commission, the California Energy Commission, the Montana Consumers' Council and the Montana Public Utilities Commission, the Utah Division of Public Utilities, the Western Power Exchange, the Federal Energy Regulatory Commission and the Ohio Public Utilities Commission.

UPLAN has been applied to simulate the restructured, multi-area power market in California, to develop regional pooling models for New England and the PJM Pool, and to provide a municipal power marketing model for Michigan. UPLAN has also been used to evaluate deregulation alternatives for reliability regions within North America, Europe, Asia and Africa.

In addition, UPLAN has been used to conduct competitive market assessments within the NERC regions of the United States and to forecast market clearing prices in all the reliability regions that make up the North American Electric Reliability Council. These assessments include evaluations of the financial viability of new market entrants, and the costs and revenue requirements to recover annual carrying charges on fixed capital investments. UPLAN capabilities to model electricity market prices, unit and system operations and power flows, and benchmarking of its results have been published in the Electricity Journal.[3]

4.2 The Need for Adequate Electricity at a Reasonable Cost

In evaluating Peninsular Florida's need for electricity at a reasonable cost, DESL addressed the cost of electric power in Peninsular Florida and the Project's anticipated impact on wholesale power costs.

4.2.1 Peninsular Florida Residential and Wholesale Power Prices

Figure 4-3 displays the 1998 residential rates by region and how the prices compare across the nation. Florida's residential rates, while not as high as some regions in the United States, are higher than average. Resource Data Institute's studies indicate Florida's average residential electric rate is $70.90/MWh, $3.68/MWh above the national average of $67.22/MWh. Florida's wholesale rate for 1998 was $45.18/MWh on average, the highest among all of the NERC regions. The wholesale rate is approximately 38 percent higher than the national average.

[3] "How to Incorporate Volatility and Risk in Electricity Price Forecasting," The Electricity Journal, May 2000, pp 65-75.

Retail Rates by NERC Region, 1998
Ranked by Retail Rate $/MWh

NERC Region	Retail Sales MWH	Retail Rate $/MWh	Wholesale Rate $/MWh	Net Generation MWh
ECAR	496,315,966	59.84	29.40	528,256,618
ERCOT	259,647,204	62.00	38.93	237,486,598
FRCC	177,336,605	70.90	45.18	167,909,847
MAAC	230,585,572	85.25	33.68	222,508,127
MAIN	230,313,716	65.80	30.24	221,765,988
MAPP	143,419,612	57.82	27.90	155,315,092
NPCC	232,715,777	102.89	35.35	170,508,568
SERC	684,539,871	59.14	41.68	745,028,287
SPP	192,213,364	56.87	31.35	186,169,095
WSCC	565,243,685	68.05	25.69	566,661,227
[N/A]	13,186,605	114.40	25.24	7,707,284
Grand Total	3,225,517,977	67.22	32.76	3,209,316,731

Source: RDI POWERdat

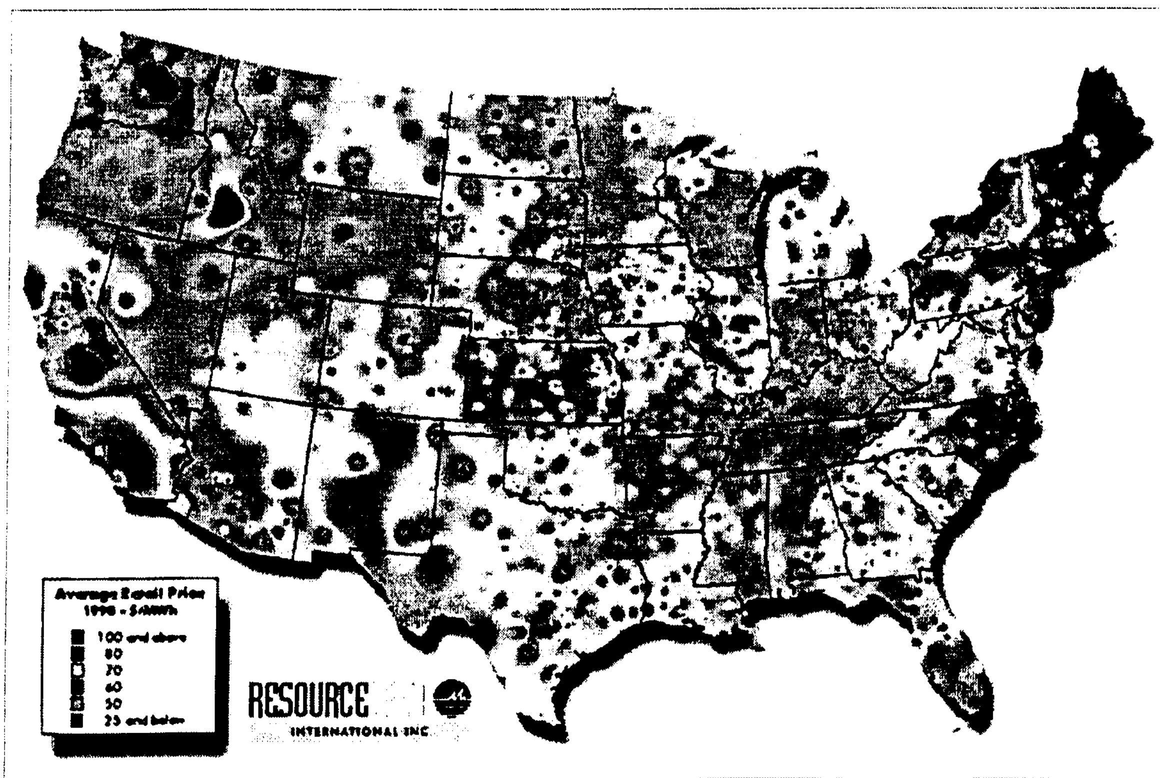

Figure 4-3: 1998 Average Retail Electric Rates - $/MWh

The Project should help to reduce these rates for Florida by providing another competitive wholesale power supply alternative to Florida utilities. The reductions in rates should occur, as utilities are able to purchase power cheaper than they can produce it. The savings will be passed on to their customers through the fuel and purchase power adjustment portions of their bill.

4.2.2 Impact of Project on Peninsular Florida's Wholesale (and Retail) Power Costs

The Project's direct construction costs and heat rate compare very favorably to those of other proposed power plants in Florida based on ten-year site plan information and other filings with the Commission. The Project's low heat rate, high efficiency and other operating characteristics will enable DESL to offer its power production at wholesale prices below the costs of operating higher cost existing resources and, therefore, the Project's power will be attractive for purchase by power marketers and load serving utilities. The detailed analyses performed by Van Horn Consulting and LCG Consulting for DESL demonstrate the cost-effectiveness of the Project, which is projected to operate at high capacity factors. The results show that the presence and operation of the Project will assist in suppressing wholesale, and, in turn, retail power prices in Florida.

4.3 Power Supply Needs of DESL

DESL is committed to operating the Project in a manner that will provide reliable, competitively priced, environmentally clean power in the Florida wholesale power market without risk to Florida's retail electric customers. DESL is developing the Project consistent with the policies of the Commission and the FERC to increase wholesale competition, so that electric consumers will achieve the benefits of competitively priced power generation. DESL, therefore, needs the Project to participate as a competitive supplier in the Florida wholesale power market. Adding the Project to Florida's generation fleet will ensure a more robust and competitive wholesale power market in this state.

4.4 Strategic Considerations

The Project is consistent with strategic factors that may be considered when determining to build a power plant, both from the perspective of DESL and the State. The Project will be fueled by domestically produced natural gas rather than an imported fuel that may be subject to interruption due to political unrest or other events.

The Project has a low installed cost and a highly efficient heat rate, assuring its long-term economic viability. As a merchant plant constructed solely at the expense of DESL, the Project will provide power with no risk to Florida electric retail serving utilities and will impose no obligation on either Florida electric customers or utilities. The Project will likely also contribute to reducing the consumption of fuel oil for electric generation in Florida.

The Project will help to maintain a diverse generation mix of capacity for the Florida market. Figure 4-4 displays Florida's generation mix of currently operating units as of January 1, 1999. Peninsular Florida's current generation capacity has over 48 percent of its generation made up of units that are older than 25 years and over 68 percent that is older than 20 years. The technology and reliability of these units are nearing the end of their economic life. The DESL Project will introduce a new reliable source of efficient generation into this older system. In addition to the foregoing, the Project presents a number of other benefits that should be strategically considered.

4.5 Environmental Efficiency

The Project is consistent with the environmental efficiency goals of Peninsular Florida. The Project's high efficiency, clean burning natural gas design maximizes power output while minimizing the environmental impact.

The fuel source for the Project will be natural gas. Natural gas is the cleanest burning of the fossil fuels and is the fuel source of choice for most new generation projects. The reason natural gas is such a clean burning fuel is the near absence of sulfur and particulate matter in its constituents. With natural gas fuel, the exhaust from a combined cycle power plant is significantly reduced over other fossil fuels.

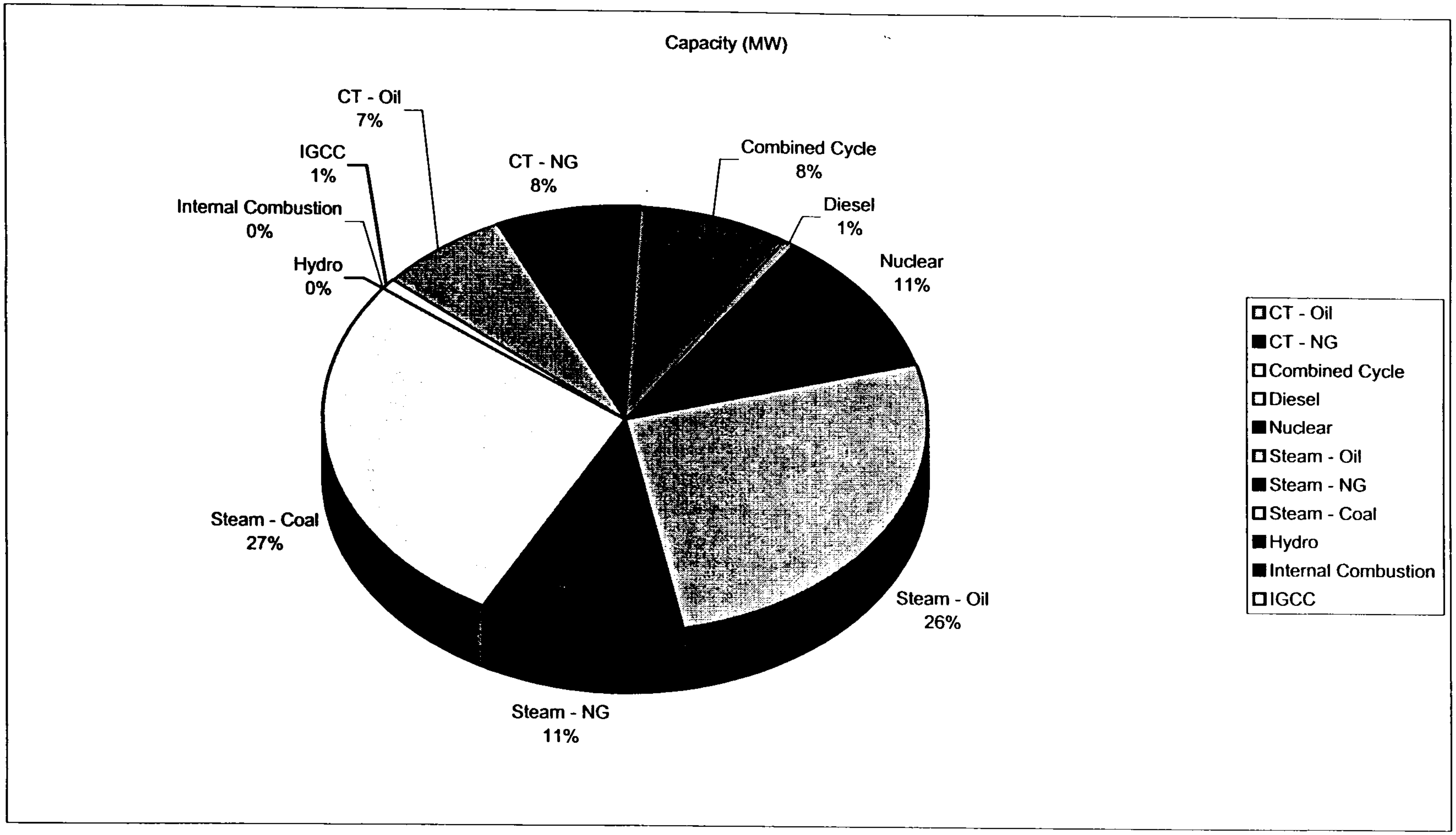

Figure 4-4: Peninsular Florida Utility Capacity as of January 1, 1999.

As displayed in Figure 4-5, the emissions per unit of electric output from the Project will be one of the lowest in the state. The Project will be required to receive all environmental and building permits prior to starting construction. Table 4-5 displays the potential permits that may be required for the Project. The permitting process will ensure that the Project is environmentally sound and represents the best method of adding generation for Peninsular Florida.

The Project is designed to use reclaimed water produced by FPUA for cooling water purposes. The reclaimed water is produced by FPUA at its water reclamation facility ("WRF"), which is located on a barrier island. Use of reclaimed water will minimize the use of ground water resources and, thus, comports with the goals of the South Florida Water Management District to use reclaimed water when available. FPUA currently discharges the reclaimed water to a deep injection well on the barrier island where the WRF is located. DESL will provide FPUA with the necessary infrastructure to convey the reclaimed water from the barrier island to the Project site. Not only will this minimize the deep well injection of reclaimed water on the barrier island, it will provide infrastructure to assist the FPUA in relocating its water reclamation facility from the barrier island to its proposed mainland site.

The DESL Project is consistent with the FEECA goals of maximizing energy efficiency and minimizing environmental impacts. The high efficiency of the Project will produce fewer emissions for every kilowatt of electrical energy produced compared to current generation in Peninsular Florida.

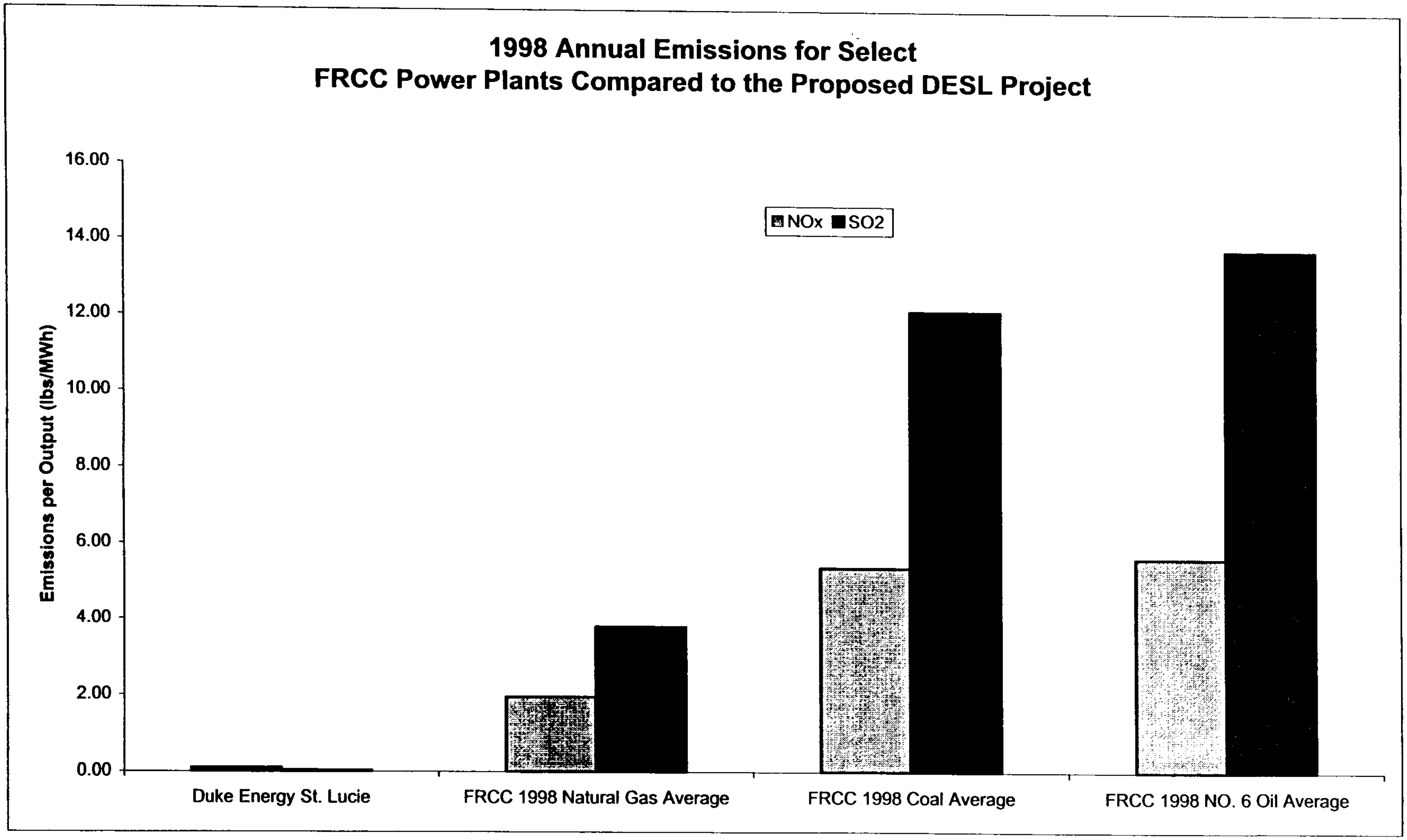

Figure 4-5: 1998 Annual Emissions for select FRCC Power Plants Compared to the Proposed DESL Project

Table 4-5: Environmental Permits

Major Potentially Applicable Environmental Regulations and Licensing Considerations

Federal

1. Air: NAAQS (EPA 40 CFR 50)
2. Air: PSD (EPA 40 CFR 52.21)
3. Air: NSPS (EPA 40 CFR 60, Subpart GG)
4. Wastewater, including Storm Water: NPDES (EPA 40 CFR 423, 122)
5. Dredge and Fill (USACE Section 404 (33 U.S.C. §1344; 33 CFR 320-330)
6. Stack Height (FAA 14 CFR 77; EPA 40 CFR 51)
7. Endangered Species (USFWS 50 CFR 17)
8. Fuel Use Act (DOE 42 U.S.C. §8311; 10 CFR 501)
9. NEPA (42 U.S.C. §§4321-4370; CEQ 40 CFR 1500-1517)

State

1. Power Plant Siting Act (FDEP 403.501-403.518, F.S.; Ch. 62-17, F.A.C.)
2. Permits (FDEP Ch. 373 and 403, F.S.; Ch. 62-4, F.A.C.)
3. Storm Water Discharge (FDEP Ch. 403, F.S.; Ch. 62-25, F.A.C.)
4. Water Policy (FDEP Ch. 373 and 403, F.S.; Ch. 62-40, F.A.C.)
5. Sampling and Analysis: Quality Assurance (FDEP Ch. 373, 376, and 403, F.S.; Ch. 62-160, F.A.C.)
6. Air: AAQS (FDEP Ch. 403, F.S.; Ch. 62-204, F.A.C.)
7. Air: PSD (FDEP Ch. 403, F.S.; Ch. 62-212.400, F.A.C.)
8. Air: NSPS (FDEP Ch. 403, F.S.; Ch. 62-296, F.A.C.)
9. Surface Water Discharge: Surface Water Quality Standards (FDEP Ch. 403, F.S.; Ch. 62-302, F.A.C.)
10. Environmental Resource Permitting and Construction (FDEP Ch. 120, 373, and 403, F.S.; Ch. 62-330, -341, -343, F.AC.)
11. Ground Water Standards (FDEP Ch. 403, F.S.; Ch. 62-520, F.A.C.)
12. Wellhead Protection (FDEP Ch. 403, F.S.; Ch. 62-520, F.A.C.)
13. Water Well Permitting and Construction (FDEP Ch. 373, F.S.; Ch. 62-532, F.A.C.)
14. Reuse of Reclaimed Water (FDEP Ch. 403, F.S.; Ch. 62-610, F.A.C.)
15. Wastewater Discharge: Wastewater Facility Permitting (FDEP Ch. 403, F.S.; Ch. 62-620, F.A.C.)
16. Wastewater Discharge: Pretreatment Requirements (FDEP Ch. 403, F.S.; Ch. 62-625, -650, -660, F.A.C.)
17. Solid Waste (FDEP Ch. 403, F.S.; Ch. 62-701, F.A.C.)
18. Oil/Water Separator: Used Oil Management (FDEP Ch. 403, F.S.; Ch. 62-710, F.A.C.)
19. Hazardous Waste (FDEP Ch. 403, F.S.; Ch. 62-730, F.A.C.)
20. Underground Storage Tank Systems (FDEP Ch. 376, F.S.; Ch. 62-761, F.A.C.)
21. Aboveground Storage Tank Systems (FDEP Ch. 376, F.S.; Ch. 62-761, F.A.C.)

22. Natural Gas Transmission Pipeline Siting (FDEP Ch. 403, F.S.; Ch. 62-807, F.A.C.)
23. Electric and Magnetic Fields (FDEP Ch. 403, F.S.; Ch. 62-814, F.A.C.)
24. Endangered/Threatened Wildlife Species (FGFWFC Ch. 372, F.S.; Ch. 39-27, F.A.C.)
25. Preservation of Native Flora of Florida (FDOA, Ch. 581, F.S.)
26. Archaeology/Historical (FDOS Ch. 267, F.S.; Ch. 1A, F.A.C.)
27. Access Road/Highway/Railroad (FDOT Ch. 14, F.A.C.)
28. Stack Height (FDOT Ch. 330, 333, and 334, F.S.; Ch. 14-60.009, F.A.C.)
29. Land Use: FDCA Coastal Zone Areas (Ch. 380, Part II, Ch. 380.23, F.S.); Environmentally Endangered Land (Ch. 259, F.S.); Areas of Critical Concern (Ch. 380, F.S.); Aquatic Preserves (Ch. 258, Part II, F.S.); State Parks, Recreation Areas, and Wilderness Areas (Ch. 375, F.S., Ch. 258, F.S.); National Forests, National Wildlife Refuges, and State Wildlife Management Areas (Ch. 372, F.S.); Indian Reservations (Ch. 285, F.S.)

Regional

1. Permits Required: Organization and Procedure (SFWMD Ch. 40E-1, F.A.C)
2. Consumptive Water Use, Well Construction: (SFWMD Ch. 40E-2, -3, F.A.C)
3. Environmental Resource Permits: Surface Water Management Systems (SFWMD Ch. 40E-4, -40, -42, -400, F.A.C.)
4. Works of District (SFWMD Ch. 40E-6, F.A.C.)
5. Ground Water Withdrawal: Minimum Levels (SFWMD Ch. 40E-8, F.A.C.)
6. Construction Dewatering: Noticed General Permit (SFWMD Ch. 40E-22, F.A.C.)
7. Water Resource Caution Area (SFWMD Ch. 40E-23, F.A.C.)
8. Land Use: Regional Comprehensive Policy Plan (ECFRPC, Ch. 29F-19, F.A.C.)

Local

1. Land Use: Local Government Comprehensive Planning Act of 1975 with Amendments (Ch. 163, F.S.); St. Lucie County
2. Noise: St. Lucie County Ordinance
3. Well Construction: St. Lucie County Code
4. Environmental Protection: St. Lucie County Code
5. Wetlands: St. Lucie County Code
6. Well-Field Protection: St. Lucie County Code
7. Storage of Hazardous Substances: St. Lucie County Code
8. Tree Removal: St. Lucie County Code
9. Construction Permits, including Setbacks and Height Restrictions

4.5.1 Consistency with Other Proposed Generation Additions

The Project's advanced technology, natural gas-fired combined cycle design is consistent with the type of capacity being planned by many other Peninsular Florida utilities and utilities in North America. Several utilities are planning similar projects based on the technology's environmental efficiency, the low operating costs, low installation costs on $/kW basis, relatively low fuel costs, and unit reliability. Several other facilities are planned with gas-fired simple cycle configurations that would allow the facilities to convert to combined cycle if desired and permitted. Also, several utilities are repowering older generation units by adding new gas fired turbines in place of the conventional boilers. As displayed in Table 4-6, 95 percent of the planned additions, as identified in the 1999 Ten-Year Site Plans, comprise gas-fired electric generation.

4.5.2 Benefits to the St. Lucie Area

St. Lucie County and its surrounding area will benefit from the Project. The Project will contribute to economic growth in the county and provide many new jobs both directly and indirectly. During construction (an 18-month time frame) the Project will employ on average 150 workers' with peak construction manpower estimated at 300 workers. The workforce is projected to increase revenues in the County significantly during the construction period based on standard multiplier effects, where the goods and services required will increase from the new jobs and from the resulting increased spending and economic activity in the area. Accounting for the economic multiplier effects, over $200 million of increased earnings would result from the construction of the Project during 2002 and 2003. After commercial operation of the units, the St. Lucie Economic Development Council estimates that the Project will increase revenues in the County by about 2.5 the annual payroll of the plant staff. Thus, an estimated annual plant operating payroll of about $1.5 million will add about $3.7 million in increased earnings to the local economy each year on an ongoing basis. The Project will also bring a significant tax base to the County *without* a significant additional impact to existing infrastructure in the community.

Table 4-6: Planned and Proposed FRCC Additions

COMPARISON OF PENINSULAR FLORIDA
PLANNED AND PROPOSED GENERATING UNITS

PLANNED & PROPOSED UTILITY/UNIT	IN-SERVICE YEAR	CAPACITY SUMMER MW	CAPACITY WINTER MW	FUELS PRIMARY	FUELS ALTERNATE	HEAT REATE (Btu/Kwh)	EQUIVALENT AVAILABILITY FACTOR %	TOTAL INSTALLED COST ($/KW)	DIRECT CONSTRUCTION COST ($/KW)	TECHNOLOGY TYPE
FPC/HINES 1 (1)	1999	470	505	GAS	NO. 2	6,962	91	$ 600	NOT REPORTED	COMBINED CYCLE
TALLAH/PURDOM 8	2000	233	262	GAS	NO. 2	6,940	NR	$ 483	$ 434	COMBINED CYCLE
FPC/INTRCSS 12-14	2000	240	282	GAS	NO. 2	13,272	91	NOT REPORTED	NOT REPORTED	COMBUSTION TURBINE
JEA KENNEDY CT 7	2000	149	186	GAS	NO. 2	11,120	97	NOT REPORTED	$ 261	COMBUSTION TURBINE
FPL/MARTIN 1&2	2001	149	181	GAS	NO. 2	10,450	98	$ 371	$ 324	
GVLLE/J.R. KELLY	2001	110	110	GAS	NO. 2	7,880	84	$ 375	$ 364	COMBINED CYCLE
KUA-FMPA CANE ISLAND 3	2001	244	267	GAS	NO. 2	6,815	92	$ 430	$ 320	COMBINED CYCLE
JEA BANCY CT 1-3	2001	149	186	GAS	NO. 2	11,120	97	NOT REPORTED	$ 264	COMBUSTION TURBINE
DUKE/NSBPP (2)	2002	476	548	GAS	NONE	6,832	96	N/A	$ 325	COMBINED CYCLE
FPL/FT MYERS (3)	2002	930	1,073	GAS	NONE	6,830	96	$ 557	$ 503	COMB. CYCLE/REPOWER
FPL/SANFORD 4(3)	2002	566	671	GAS	NONE	6,860	96	$ 716	$ 591	COMB. CYCLE/REPOWER
FPL/SANFORD 5(3)	2002	566	671	GAS	NONE	6,860	96	$ 690	$ 591	COMB. CYCLE/REPOWER
SEC/HARDEE 3	2002	488	572	GAS	NO. 2	6,170	93	$ 412	$ 378	COMBINED CYCLE
LKLAND McINTSH 5	2002	337	384	GAS	NO. 2	6,523	91	$ 671	$ 671	COMBINED CYCLE
JEA NORTHSID 1-2	2002	265	265	PET. COKE	COAL	9,946	90	NOT REPORTED	$ 658	CIRCULATING FLUID BED
OKEECHOBEE (4)	2003	514	561	GAS	NO. 2	6,775	93	NOT REPORTED	$ 330	COMBINED CYCLE
DUKE ENERGY ST. LUCIE	2003	598	636	GAS	NONE	7,300	95	NOT REPORTED	$ 345	COMBINED CYCLE
FPL/FT.MYERS 13&14	2003	149	181	GAS	NO. 2	10,450	98	$ 379	$ 324	COMB. CYCLE/REPOWER
FPC/HINES 2	2004	495	567	GAS	NO. 2	680	91	NOT REPORTED	NOT REPORTED	COMBINED CYCLE
LKLAND McINTSH 4	2004	238	238	COAL	PET. COKE	8,776	74	$ 664	$ 664	CIRCULATING FLUID BED
FPL/MARTIN 5&6	2006	394	429	GAS	NO. 2	6,346	96	$ 679	$ 485	COMBINED CYCLE
FPC/HINES 3	2006	495	567	GAS	NO. 2	6,800	91	NOT REPORTED	NOT REPORTED	COMBINED CYCLE
FPL/Unsited	2007	394	429	GAS	NO. 2	6,830	96	$ 784	$ 552	COMBINED CYCLE
KUA-FMPA CANE ISLAND 4	2007	72	82	GAS	NO. 2	11,959	96	$ 447	$ 291	COMBUSTION TURBINE
FPL/UNSITED	2008	394	429	GAS	NO. 2	6,830	96	$ 798	$ 552	COMBINED CYCLE
FPL/UNSITED	2009	394	429	GAS	NO. 2	6,830	96	$ 813	$ 552	COMBINED CYCLE

(1) FPC HINES 1 DATA IS BASERD ON PROJECTED CAPITAL INVESTMENT OF $300,000,000 / NOMINAL CAPACITY OF 500 MW SHOWN IN 1996 TYSP
(2) DUKE/NSBPP DATA IS BASED ON INFORMATION FROM NEED DTERMINATION FILING, AND INCLUDES THE COST OF DIRECTLY ASSOCIATED TRANSMISSION LINES
(3) FOR COMPARABILITY TO THE OTHER VALUES SHOWN HERE, THE COST FOR FPL's REPOWERING PROJECTS IS SHOWN ON THE BASIS OF DOLLARS PER KW OF INCREMENTAL CAPACITY. UNLIKE FPL's 1998 TEN YEAR SITE PLAN, FPL's 1999 TEN YEAR SITE PLAN PRESENTED COST DATA ON THE BAIS OF DOLLARS PER KW OF TOTAL CAPACITY AT THE REPOWERED FT. MYERS AND SANFORD STATIONS
THE TOTAL INSTALLED COST PER KW OF TOTAL CAPACITY, AS SHOWN IN FPL's TEN YEAR SITE PLAN, WAS $367/KW FOR FT. MYERS AND $392/KW FOR SANFORD
(4) OKEECHOBEE GENERATING COMPANY DATA IS BASED ON INFORMATION FROM NEED DETERMINATION FILING

5.0 Cost-Effectiveness of the DESL Project

The DESL Project is the most cost-effective alternative available for meeting the future power supply needs of Florida's retail serving utilities and their retail electric customers. The Project is also the most cost-effective alternative available to DESL for meeting its anticipated wholesale sales obligations.

This section of the Exhibit describes in detail the methodology and models employed by DESL to evaluate the cost-effectiveness of the Project. The section then sets forth the results of the cost-effectiveness analysis and concludes that the Project will provide cost-effective power to Peninsular Florida.

5.1 Cost-Effectiveness Methodology

DESL has evaluated the cost-effectiveness of the Project using several different methodologies including screening analyses, detailed electricity market and production cost simulations, and strategic considerations. The methodology utilized for the Project's determination of cost-effectiveness is outlined below.

Initially, DESL reviewed several supply-side alternatives to determine the most cost-effective method of providing additional generating capacity for Peninsular Florida. The supply-side alternatives were developed from numerous projects reviewed by DENA and estimates of cost and performance supplied by D/FD. DESL also evaluated the feasibility of demand-side programs to mitigate the need for the proposed project.

A screening analysis performed by VHC was also utilized to evaluate potential generation alternatives. While this analysis does not delve into the many complexities of analyzing how a particular power plant would be dispatched, it provides a tool to eliminate alternatives that would not demonstrate economic justification under any likely scenario. In the screening analysis conducted by DESL and VHC, capital costs, fuel costs, fixed operations costs, and variable operations costs were considered. These costs are generically identified as the "busbar costs". In the screening analysis, "busbar costs" were compared for a range of potential annual generation output levels for the unit, as measured by the annual capacity factor. This type of assessment provides a solid foundation for decisions on DESL's Project compared to other supply alternatives.

In addition to screening analysis, detailed electricity market simulations were conducted by VHC and LCG using UPLAN, a dynamic computer model, to determine the Project's cost effectiveness. These simulations were also used to demonstrate how the Project would dispatch in the Florida electricity market, its effects on wholesale market prices, fossil fuel consumption emissions and overall electric system reliability, as well as to calculate the generation that would be displaced from more expensive generating units otherwise needed to serve the Florida market. .

5.2 Supply-side Alternatives

DESL has conducted a thorough review of the supply-side alternatives available to meet Peninsular Florida needs. DESL limited its review to supply-side alternative technologies that are currently operating in a reliable manner and could be potentially built in Florida.

5.2.1 Combined Cycle Alternatives

DESL reviewed several combined cycle configurations to determine the most cost-effective, reliable source of generation utilizing combustion turbines with a steam turbine. Several vendors were closely evaluated by DENA and D/FD to determine the most cost-effective vendor for a large purchase initiative. Due to significant savings associated with a long-term contract with GE, DENA has managed to save significantly on the cost of 7FA combustion turbines. DENA and D/FD have teamed together with reference plant designs to also reduce the costs associated with the engineering, procurement, and construction of these facilities. Three D/FD reference plant designs utilizing GE 7FA combustion turbines in combined cycle operation were analyzed:

- 2 x 1 General Electric 7FA Combined Cycle w/o Duct Firing (Table 5-1)
- 2 x 1 General Electric 7FA Combined Cycle w/ Duct Firing (Table 5-2)
- 4 x 2 General Electric 7FA Combined Cycle w/o Duct Firing (Table 5-3)

All units analyzed are based upon greenfield projects located in Peninsular Florida and operating on natural gas. The cost and performance characteristics listed in Tables 5-1 through 5-3 assumes intermediate to baseload generation. The emission controls for the combustion turbine are assumed to operate with dry low NO_x combustors and SCR.

Table 5-1:
Cost and Performance Characteristics
of a 2 x 1 GE 7FA CC w/o Duct Firing

Direct Capital Cost	$172,000,000	
O&M Cost		
Fixed, $/kW-yr	21.05	
Variable, $/MWH	0.36	
Equivalent Availability		
Equivalent Forced Outage Rate	1.0 percent	
Planned Maintenance Outage Rate	3.7 percent	
Number of Starts	25 starts	
Construction Period, months	18 months	
Net Plant Output / Net Plant Heat Rate (1) (2)	Summer (95 °F)	Winter (27°F)
100 percent of Full Load	460 / 7,200	535 / 7,050
75 Percent of Full Load	360 / 7,600	420 / 7,200
50 Percent of Full Load	260 / 8,250	310 / 7,850
Minimum Load	60 percent	60 percent

(1) Net Plant Output @ 1.5 percent degradation (MW).
(2) Net Plant Heat Rate @ 1.5 percent degradation (HHV) Btu/kWh

Table 5-2:
Cost and Performance Characteristics
of a 2 x 1 GE 7FA CC w/ Duct Firing

Direct Capital Cost	$ 210,000,000	
O&M Cost		
Fixed, $/kW-yr	20.72	
Variable, $/MWH	0.35	
Equivalent Availability		
Equivalent Forced Outage Rate	1.5	
Planned Maintenance Outage Rate	3.7	
Number of Starts	25	
Construction Period, months	18 months	
Net Plant Output / Net Plant Heat Rate (1) (2)	Summer (95 °F)	Winter (27°F)
100 percent of Full Load (Duct fired)	602 / 7,536	636 / 7,317
100 percent of Full Load (Unfired)	483 / 7,320	528 / 7,066
75 Percent of Full Load (Unfired)	340 / 7,648	414 / 7,319
60 Percent of Full Load (Unfired)	288 / 7,986	350 / 7,677
Minimum Load	60 percent	60 percent

(1) Net Plant Output @ 1.5 percent degradation (MW).
(2) Net Plant Heat Rate @ 1.5 percent degradation (HHV) Btu/kWh
(3) Duct fired output and heat rate are based on firing to maintain a steam turbine output of 290 MW

Table 5-3:
Cost and Performance Characteristics
of a 4 x 2 GE 7FA CC w/o Duct Firing

Direct Capital Cost	$304,000,000	
O&M Cost		
Fixed, $/kW-yr	20.05	
Variable, $/MWH	0.35	
Equivalent Availability		
Equivalent Forced Outage Rate	1.5	
Planned Maintenance Outage Rate	3.7	
Number of Starts	50	
Construction Period, months	18 months	
Net Plant Output / Net Plant Heat Rate (1) (2)	Summer (95 °F)	Winter (27°F)
100 percent of Full Load	920 / 7,200	1,070 / 7,050
75 Percent of Full Load	720 / 7,600	840 / 7,200
50 Percent of Full Load	520 / 8,250	620 / 7,850
Minimum Load	60 percent	60 percent

(1) Net Plant Output @ 1.5 percent degradation (MW).
(2) Net Plant Heat Rate @ 1.5 percent degradation (HHV) Btu/kWh

5.2.2 Simple Cycle Alternatives

DESL has reviewed several simple cycle configurations to determine the most cost-effective, reliable source of generation utilizing combustion turbines for generation. As indicated in the previous section, due to significant savings associated with a long-term contract with GE, DENA has managed to save significantly on the cost of 7EA and 7FA combustion turbines. Furthermore, the teaming of DENA and D/FD on reference plant designs reduces the costs associated with the engineering, procurement, and construction of these facilities. Two D/FD reference plant designs utilizing GE 7EA combustion turbines in simple cycle were analyzed and two simple cycle designs with GE 7FA's:

- 8 x 0 General Electric 7EA Simple Cycle (Table 5-4)
- 4 x 0 General Electric 7EA Simple Cycle (Table 5-5)
- 2 x 0 General Electric 7FA Simple Cycle (Table 5-6)
- 4 x 0 General Electric 7FA Simple Cycle (Table 5-7)

All units analyzed are based upon greenfield projects located in Peninsular Florida operating on natural gas. The cost and performance characteristics listed in Tables 5-4 through 5-7 assume peaking to intermediate operation with 2,500 hours of operation annually. The emission controls for the combustion turbine are assumed to operate with Dry Low NO_x combustors.

5.2.3 Pulverized Coal Alternative

Cost and performance estimates for an 800 MW subcritical pulverized coal ("PC") unit were prepared for this need determination petition. For purposes of this analysis, the fuel used is a typical eastern coal. The cost estimate includes cost for the addition of a scrubber to control SO_2 emissions. Cost and operating characteristics are summarized in Table 5-8.

Table 5-4:
Cost and Performance Characteristics
of a 8 x 0 GE 7EA Simple Cycle

Direct Capital Cost	$ 184,000,000	
O&M Cost		
Fixed, $/kW-yr	21.20	
Variable, $/MWH	0.30	
Equivalent Availability		
Equivalent Forced Outage Rate	2.0	
Planned Maintenance Outage Rate	1.3	
Number of Starts	120	
Construction Period, months	13 months	
Net Plant Output / Net Plant Heat Rate (1) (2)	Summer (95 °F)	Winter (27°F)
100 percent of Full Load	560 / 13,200	710 / 11,900
75 Percent of Full Load	420 / 14,500	530 / 13,200
50 Percent of Full Load	270 / 17,000	350 / 15,800
Minimum Load	60 percent	60 percent

(1) Net Plant Output @ 1.5 percent degradation (MW).
(2) Net Plant Heat Rate @ 1.5 percent degradation (HHV) Btu/kWh

Table 5-5:
Cost and Performance Characteristics
of a 4 x 0 GE 7EA Simple Cycle

Direct Capital Cost	$ 114,000,000	
O&M Cost		
Fixed, $/kW-yr	24.05	
Variable, $/MWH	0.33	
Equivalent Availability		
Equivalent Forced Outage Rate	2.25	
Planned Maintenance Outage Rate	1.3	
Number of Starts	120	
Construction Period, months	12 months	
Net Plant Output / Net Plant Heat Rate (1) (2)	Summer (95 °F)	Winter (27°F)
100 percent of Full Load	280 / 13,200	355 / 11,900
75 Percent of Full Load	210 / 14,500	265 / 13,200
50 Percent of Full Load	135 / 17,000	175 / 15,800
Minimum Load	60 percent	60 percent

(1) Net Plant Output @ 1.5 percent degradation (MW).
(2) Net Plant Heat Rate @ 1.5 percent degradation (HHV) Btu/kWh

Table 5-6:
Cost and Performance Characteristics
of a 2 x 0 GE 7FA Simple Cycle

Direct Capital Cost	$ 122,000,000	
O&M Cost		
Fixed, $/kW-yr	22.50	
Variable, $/MWH	0.30	
Equivalent Availability		
Equivalent Forced Outage Rate	2.25	
Planned Maintenance Outage Rate	2.4	
Number of Starts	80	
Construction Period, months	12 months	
Net Plant Output / Net Plant Heat Rate (1) (2)	Summer (95 °F)	Winter (27°F)
100 percent of Full Load	300 / 11,050	370 / 10,390
75 Percent of Full Load	225 / 12,150	275 / 11,425
50 Percent of Full Load	150 / 13,850	185 / 12,950
Minimum Load	60 percent	60 percent

(1) Net Plant Output @ 1.5 percent degradation (MW).
(2) Net Plant Heat Rate @ 1.5 percent degradation (HHV) Btu/kWh

Table 5-7:
Cost and Performance Characteristics
of a 4 x 0 GE 7FA Simple Cycle

Direct Capital Cost	$ 184,000,000	
O&M Cost		
Fixed, $/kW-yr	20.75	
Variable, $/MWH	0.30	
Equivalent Availability		
Equivalent Forced Outage Rate	2.0	
Planned Maintenance Outage Rate	2.4	
Number of Starts	80	
Construction Period, months	13 months	
Net Plant Output / Net Plant Heat Rate (1) (2)	Summer (95 °F)	Winter (27°F)
100 percent of Full Load	600 / 11,050	740 / 10,390
75 Percent of Full Load	450 / 12,150	550 / 11,425
50 Percent of Full Load	300 / 13,850	370/ 12,950
Minimum Load	60 percent	60 percent

(1) Net Plant Output @ 1.5 percent degradation (MW).
(2) Net Plant Heat Rate @ 1.5 percent degradation (HHV) Btu/kWh

Table 5-8: Cost and Performance Characteristics of a 800 MW Pulverized Coal		
Direct Capital Cost	$728,000,000	
O&M Cost		
Fixed, $/kW-yr	19.26	
Variable, $/MWH	1.82	
Equivalent Availability		
Equivalent Forced Outage Rate	5.0 percent	
Planned Maintenance Outage Rate	7.7 percent	
Number of Starts	15	
Construction Period, months	39 months	
Net Plant Output / Net Plant Heat Rate (1) (2)	Summer (95 °F)	Winter (27°F)
100 percent of Full Load	796 / 9,850	800 / 9,825
75 Percent of Full Load	597 / 9,928	600 / 9,902
50 Percent of Full Load	398 / 10,460	400 / 10,433
Minimum Load	254 / 12,516	254 / 12,516

(1) Net Plant Output @ 1.0 percent degradation (MW).
(2) Net Plant Heat Rate @ 1.0 percent degradation (HHV) Btu/kWh

5.2.4 Renewable

Several renewable technologies are being implemented in different regions of the United States. Florida's location, geology, and characteristics eliminate several renewable technologies, such as geothermal and wind generation. Solar generation has promising characteristics for Florida. However, solar generation currently is not capable of producing large amounts of output and is too costly for merchant generation at this time.

5.2.5 Waste-to-Energy

Waste technologies were not reviewed in-depth because of the permitting requirements, lack of availability of adequate fuel sources, and relative small generation capacities of these technologies.

5.2.6 Nuclear

Nuclear units around the U.S. are facing severe environmental, safety, and stranded cost issues that make the addition of this resource unlikely. Although there has not been a new nuclear station built in the U.S. for several years, Table 5-9 provides a rough estimate of nuclear power plant costs and operating characteristics.

Table 5-9:
Cost and Performance Characteristics
of a 1,250 MW Nuclear Fission Generator

Direct Capital Cost	$ 3,625,000,000	
O&M Cost		
Fixed, $/kW-yr	76.5	
Variable, $/MWH	10.8	
Equivalent Availability		
Equivalent Forced Outage Rate	4.0 percent	
Planned Maintenance Outage Rate(3)	7.9 percent	
Construction Period, months	56 months	
Net Plant Output / Net Plant Heat Rate (1) (2)	Summer (95 °F)	Winter (27°F)
100 percent of Full Load	1,250 / 9,750	1,300 / 9,700
75 Percent of Full Load	938/ 9,800	950/ 9,775
50 Percent of Full Load	625 / 10,200	650 / 10,200
Minimum Load	50 percent	50 percent

(1) Based upon a three year operating cycle.

5.3 Demand-side Alternatives

DESL does not serve *retail* customers directly, therefore DESL will not be in a position to implement demand-side alternatives such as load controls and interruptible rates. DESL reviewed cost estimates and economic viability of demand-side alternatives proposed in recent need determination proceedings involving the Kissimmee Utility Authority and Florida Municipal Power Agency (Cane Island Unit 3), and the City of Lakeland (McIntosh Unit 5). Both Cane Island Unit 3 and City of Lakeland McIntosh Unit 5 were determined to be more cost-effective than demand-side programs. The DESL Project is estimated to have a heat rate and a direct construction cost on a \$/kW basis similar to that of Cane Island and McIntosh. Therefore, it is reasonable to conclude that the Project would be more cost-effective than demand-side alternatives if such alternatives were available for implementation.

5.4 Request for Proposals

Although Rule 25-22.082, Florida Administrative Code, requires investor-owned electric utilities to evaluate supply-side alternatives to their next generating units by issuing Requests for Proposals ("RFP") prior to filing a petition for determination of need, the Commission has determined that Rule 25-22.082 does not apply to merchant wholesale utilities such as DESL. See In re: Petition for Determination of Need for an Electrical Power Plant in Okeechobee County by Okeechobee Generating Company, L.L.C., Docket No. 991462-EU, Order No. PSC-99-2438-PAA-EU (December 13, 1999). Accordingly, DESL has not issued a RFP prior to filing this petition. However, as indicated throughout this Exhibit, DESL has extensively reviewed other supply-side alternatives and has determined that the Project is the most cost-effective alternative for Peninsular Florida and for DESL.

5.5 Screening Analysis

Screening analysis was performed to determine the potential supply-side alternatives that could become the most cost-effective addition for the DESL Project. The screening analysis considered the capital costs, fixed operating costs, fuel costs, and variable operating costs for several types of facilities over a range of operating conditions. The cost and operating characteristics were developed from the supply-side alternatives reviewed in subsections 5.2.1 through 5.2.6. The busbar analysis is only an estimate of the cost to generate electricity "to the bus" and does not include costs such as transmission or general administration. Figure 5-1 displays the busbar operating costs of the alternatives identified based upon anticipated operating conditions. Figure 5-2 presents the ranges of costs that result from different annual capacity factors for each type of generating unit.

The screening analysis indicates that a combined cycle technology is the most cost-effective over a broad range of annual capacity factors and that this technology is clearly the most cost-effective generating technology to add at this time in Peninsular Florida.

5.6 Electricity Market and Cost Evaluations

VHC and LCG conducted detailed modeling of the Peninsular Florida electricity market to determine the cost-effectiveness and reliability of the DESL Project. To perform this evaluation, VHC and LCG utilized the UPLAN integrated electricity market model, , which is also described in Appendix B. The UPLAN-NPM is a state-of-the-art competitive electricity market model that simulates both the behavior of the market participants and the physical structure of the electric system in a regional electricity market. UPLAN-NPM is a multi commodity, multi area optimal power flow (MMOPF) model. It has been developed specifically to take into account transmission network constraints, operating characteristics of plants and transmission congestion that may arise in serving projected loads. The system simulates the energy and ancillary services markets, as well as the participants' trading behavior. It then establishes internally consistent forward prices for all market segments, and uses the resources selected in the forward market in an optimal power flow algorithm to determine the hourly real-time prices and generating unit operations.

UPLAN-NPM has been used extensively in all regions of Canada and the United States and in many countries overseas. In addition to evaluating the cost-effectiveness of

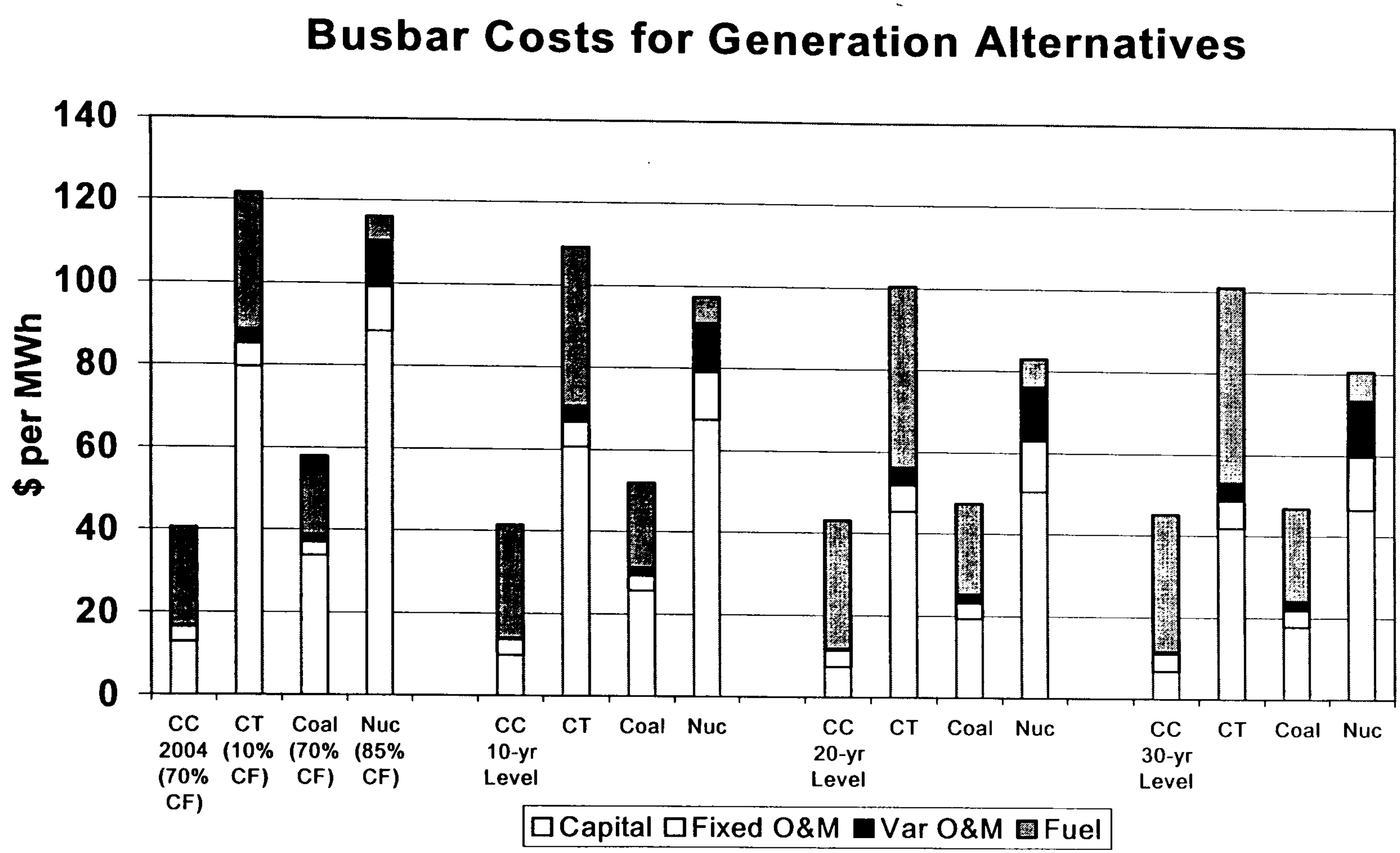

Figure 5-1: Screening Analysis Comparison of Busbar Cost Components for Alternative Generating Technologies

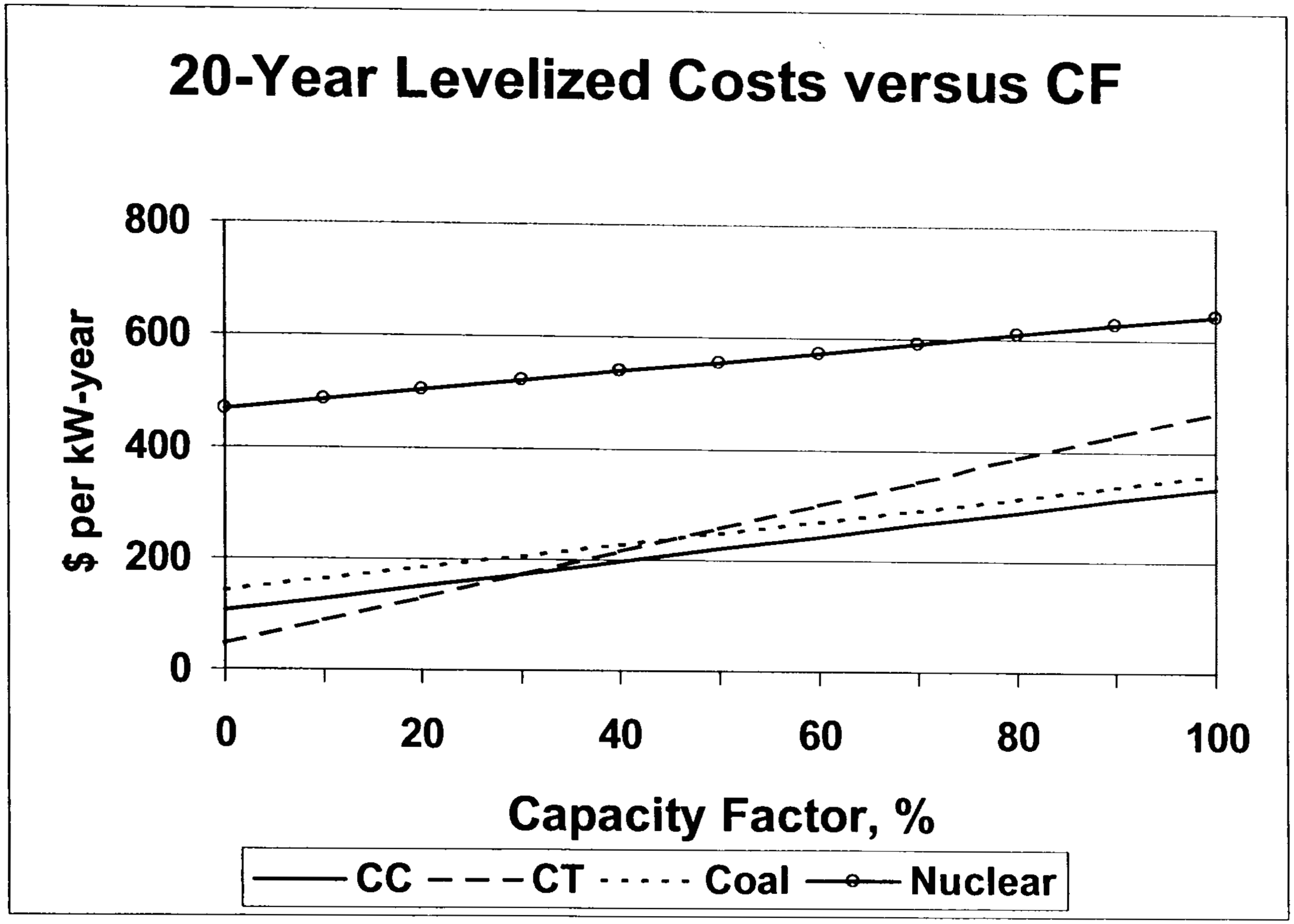

Figure 5-2: Screening Analysis Comparison of 20 Year Levelized Busbar Costs For Different Capacity Factors

investment and operating decisions and forecasting market prices, UPLAN also addresses the uncertainties of the marketplace, the potential for stranded costs, the impact of emission constraints and new entrants, and the existence of market power. The model has undergone extensive public review and testing. It has been extensively tested through the simulation of the California PX/ISO, PJM, NEPOOL and other U.S. markets, and it has been benchmarked to actual prices in evolving competitive markets. The results of benchmarking UPLAN have been published in the Electricity Journal.[4]

5.6.1 Load and Energy Forecast

DESL reviewed the 1999 FRCC Regional Load and Resource Plan and utilized the forecast for peak demand and net energy for load in the UPLAN model. The load and energy forecast presented in the 1999 FRCC Regional Load & Resource Plan was utilized as the Base Case projection. Currently the 1999 FRCC Regional Load and Resource Plan is indicating that demand and energy will only increase at a rate which is only about 50 percent of the historical growth rates. Table 5-10 indicates the annual demand and energy forecast, if historical growth rates were applied.

5.6.2 Fuel Forecast

The utilities' fuel forecasts in the 1999 Ten-Year Site Plans and Supplemental Data Requests were reviewed by DESL and VHC. These forecasts display large variations among the utilities' forecasts of fuel prices on a nominal basis over the planning horizon. Hence, the use of the utilities' forecasts of fuel prices with such wide variations is likely to lead to anomalous results, biased toward those utilities forecasting lower fuel prices. Furthermore, the time horizon for VHC's detailed electricity market analysis extends out to the year 2012, beyond the utility forecasts. Therefore, VHC developed a set of forecasts of fuel prices for Florida for use in the UPLAN model. This set of forecasts relies on the utilities' coal price forecasts in the 1999 Ten-Year Site Plans and on data from the Energy Information Administration's ("EIA") forecasts of coal price

[4] "How to Incorporate Volatility and Risk in Electricity Price Forecasting", The Electricity Journal, May

Table 5-10: Forecast of Demand and Energy Projections based upon historical growth rates

DESL PROJECTION

HISTORY AND FORECAST WITH HISTORICAL GROWTH RATES

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	SUMMER PEAK DEMAND - (MW)					WINTER PEAK DEMAND - (MW)					ENERGY	
YEAR	ACTUAL PEAK DEMAND (MW)				YEAR	ACTUAL PEAK DEMAND (MW)				YEAR	NET ENERGY FOR LOAD (GWH)	LOAD FACTOR (%)
1989	26,608				1989 / 90	29,170				1989	141,021	60.07%
1990	27,238				1990 / 91	24,978				1990	142,490	55.76%
1991	27,662				1991 / 92	28,179				1991	146,786	60.58%
1992	28,930				1992 / 93	27,215				1992	147,728	58.29%
1993	29,748				1993 / 94	28,149				1993	153,269	58.82%
1994	29,321				1994 / 95	32,618				1994	159,353	62.04%
1995	31,801				1995 / 96	34,552				1995	168,982	59.14%
1996	32,315				1996 / 97	34,762				1996	173,327	57.26%
1997	32,924				1997 / 98	30,932				1997	175,534	57.64%
1998	37,153				1998 / 99	35,907				1998	187,868	57.72%
YEAR	TOTAL PEAK DEMAND (MW)	INTER-RUPTIBLE LOAD (MW)	LOAD MANAGE-MENT (MW)	FIRM PEAK DEMAND (MW)	YEAR	TOTAL PEAK DEMAND (MW)	INTER-REPTIBLE LOAD (MW)	LOAD MANAGE-MENT (MW)	FIRM PEAK DEMAND (MW)	YEAR	NET ENERGY FOR LOAD (GWH)	LOAD FACTOR (%)
1999	38,586	1,225	1,540	35,821	1999 / 00	36,942	1,173	2,839	32,930	1999	193,991	57.39%
2000	40,073	1,247	1,591	37,235	2000 / 01	38,366	1,184	2,925	34,257	2000	201,471	57.39%
2001	41,619	1,265	1,578	38,776	2001 / 02	39,846	1,178	2,894	35,774	2001	209,240	57.39%
2002	43,224	1,265	1,537	40,422	2002 / 03	41,382	1,193	2,866	37,323	2002	217,308	57.39%
2003	44,890	1,284	1,509	42,097	2003 / 04	42,978	1,200	2,863	38,915	2003	225,688	57.39%
2004	46,621	1,296	1,493	43,832	2004 / 05	44,635	1,215	2,870	40,550	2004	234,390	57.39%
2005	48,419	1,317	1,478	45,624	2005 / 06	46,356	1,226	2,877	42,253	2005	243,428	57.39%
2006	50,286	1,334	1,467	47,485	2006 / 07	48,144	1,239	2,885	44,020	2006	252,815	57.39%
2007	52,225	1,352	1,457	49,416	2007 / 08	50,000	1,233	2,895	45,872	2007	262,564	57.39%
2008	54,239	1,348	1,452	51,439	2008 / 09	51,928	1,248	2,907	47,773	2008	272,688	57.39%

escalation beyond 2008. Because coal contracts and prices are usually specific to each plant, VHC adopted each utility's own forecasts for its own coal plants. However, because natural gas wellhead prices and oil prices are largely set by market conditions that affect all plants burning those fuels in Florida, DESL utilized natural gas and oil price projections based on EIA's most recent available forecasts for these fuels.[5] In addition, prices of natural gas and petroleum products can have significant seasonal variations. For this reason, VHC has projected prices of oil and natural gas by month. The monthly projections are consistent with the annual average forecasts and are based on historic price behavior. Because each utility's annual coal price forecast was used, the monthly prices for coal are assumed to be equal to the projected annual averages. The specific forecasts of fuel prices developed for the UPLAN analysis of the FRCC electricity market are presented below. The Project also assumed that a new natural gas pipeline, as well as FGT expansions, would be in service to Florida by the time the Project comes on line in June 2003, thus, relieving current constraints on natural gas flows during summer months.

5.6.2.1 Coal Price Forecast

VHC reviewed the utilities' forecasts of coal prices for the 1999 to 2008 period and determined that they were reasonable for the purposes of modeling the dispatch of coal-fired generating units. Because coal is very unit specific and existing long-term contracts influence the price, VHC used the utilities' forecasts of coal prices for the 1999 to 2008 period. For coal prices in the years 2009 to 2015, VHC applied escalation factors from EIA's Annual Energy Outlook 2000 (AEO2K).[6] The coal prices VHC used are presented in Table 5-11.

[5] The use of EIA data and forecasts from its "Annual Energy Outlook 2000" provides consistent data from an independent source.
[6] Source: AEO2K, Supplemental Data, Table 15, Energy Prices by sector and source, steam coal prices to electric generators, Census District 5, South Atlantic.

Table 5-11						
Coal Fuel Price Forecast – Nominal Dollars ($/MMBtu)						
	FP&L	FPC	TECO	JEA	OUC	KUA
1999	1.72	NA	1.72	1.40	1.81	1.73
2000	1.71	NA	1.77	1.40	1.77	1.76
2001	1.75	NA	1.82	1.41	1.80	1.79
2002	1.82	NA	1.87	1.41	1.85	1.83
2003	1.89	NA	1.91	1.42	1.90	1.87
2004	1.97	NA	1.96	1.42	1.96	1.91
2005	2.04	NA	2.00	1.43	2.01	1.96
2006	2.08	NA	2.05	1.43	2.09	2.00
2007	2.13	NA	2.10	1.43	2.18	2.03
2008	2.18	NA	2.15	1.44	2.30	2.08
2009	2.21	NA	2.18	1.46	2.33	2.11
2010	2.29	NA	2.26	1.52	2.42	2.19
2011	2.38	NA	2.35	1.57	2.51	2.27
2012	2.43	NA	2.40	1.61	2.57	2.32
2013	2.49	NA	2.45	1.64	2.62	2.37
2014	2.54	NA	2.50	1.68	2.68	2.42
2015	2.64	NA	2.60	1.74	2.78	2.52

5.6.2.2 Natural Gas Price Forecast

After reviewing the utilities' differing forecasts for prices of natural gas and determining that the disparities among the forecasts would create unrealistic results (since they represent different assumptions about future market conditions), VHC utilized a consistent forecast of natural gas prices that would allow for sensible dispatch of gas-fired generating units within FRCC. VHC utilized EIA's forecast of delivered gas prices to electric generating units in the South Atlantic census region. VHC derived monthly price forecasts using historic data. Table 5-12 displays these monthly price forecasts. These natural gas price forecasts were utilized in the UPLAN model for FRCC generating units burning natural gas.

5.6.2.3 Oil Price Forecast

EIA's forecast of oil prices for electric utility end users in Census District 5 (South Atlantic) are presented in Tables 5-13 and 5-14 for No. 6 Fuel Oil and No. 2 Fuel Oil, respectively.[7] VHC derived monthly price forecasts using historic data. These oil price forecasts were utilized in the UPLAN electricity market model for those FRCC generating units burning oil as their primary or secondary fuel.

[7] Table 8, EIA's AEO2K Reference Case. Oil prices for years 2000 and 2001 were adjusted to reflect oil price escalation rates in EIA's April 2000 short-term forecast.

Table 5-12

Natural Gas Prices, Nominal Dollars ($/MMBtu)

	Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec	Annual Average
2000	3.25	2.71	2.71	2.75	2.83	2.70	2.76	2.57	2.51	2.67	2.88	3.13	2.79
2001	3.20	2.67	2.68	2.71	2.79	2.66	2.72	2.54	2.48	2.63	2.84	3.09	2.75
2002	3.34	2.79	2.79	2.82	2.91	2.77	2.83	2.64	2.58	2.74	2.96	3.22	2.87
2003	3.39	2.83	2.83	2.86	2.95	2.81	2.87	2.68	2.62	2.78	3.00	3.27	2.91
2004	3.50	2.92	2.93	2.96	3.06	2.91	2.97	2.77	2.71	2.88	3.10	3.38	3.01
2005	3.70	3.09	3.10	3.13	3.23	3.08	3.14	2.93	2.87	3.04	3.28	3.57	3.18
2006	3.95	3.30	3.30	3.34	3.44	3.28	3.35	3.13	3.05	3.24	3.50	3.81	3.39
2007	4.14	3.45	3.46	3.50	3.61	3.44	3.51	3.28	3.20	3.40	3.67	3.99	3.55
2008	4.39	3.66	3.67	3.71	3.83	3.64	3.72	3.47	3.39	3.60	3.89	4.23	3.77
2009	4.56	3.80	3.81	3.85	3.97	3.78	3.87	3.61	3.52	3.74	4.04	4.39	3.91
2010	4.74	3.96	3.96	4.01	4.13	3.94	4.02	3.75	3.67	3.89	4.20	4.57	4.07
2011	4.99	4.16	4.17	4.21	4.35	4.14	4.23	3.95	3.86	4.09	4.42	4.81	4.28
2012	5.22	4.36	4.36	4.41	4.55	4.34	4.43	4.14	4.04	4.29	4.63	5.04	4.48
2013	5.50	4.59	4.59	4.64	4.79	4.56	4.66	4.35	4.25	4.51	4.87	5.30	4.72
2014	5.79	4.83	4.84	4.89	5.05	4.81	4.91	4.58	4.48	4.75	5.13	5.58	4.97
2015	6.05	5.05	5.06	5.11	5.28	5.03	5.14	4.79	4.68	4.97	5.36	5.84	5.20

Table 5-13

No. 6 Fuel Oil Prices, Nominal Dollars ($/MMBtu)

	Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec	Annual Average
2000	3.83	3.72	3.65	3.90	4.00	3.91	3.87	3.82	3.73	3.98	3.91	3.75	3.84
2001	3.40	3.30	3.24	3.47	3.55	3.47	3.44	3.40	3.31	3.54	3.47	3.33	3.41
2002	3.21	3.12	3.06	3.27	3.35	3.27	3.24	3.20	3.12	3.33	3.28	3.14	3.22
2003	3.30	3.21	3.15	3.36	3.45	3.37	3.34	3.29	3.21	3.43	3.37	3.23	3.31
2004	3.39	3.30	3.24	3.46	3.55	3.46	3.43	3.39	3.31	3.53	3.47	3.32	3.41
2005	3.51	3.41	3.35	3.58	3.67	3.58	3.55	3.51	3.42	3.65	3.59	3.44	3.52
2006	3.65	3.55	3.48	3.72	3.81	3.73	3.69	3.65	3.56	3.80	3.73	3.57	3.66
2007	3.78	3.67	3.61	3.85	3.95	3.86	3.82	3.77	3.68	3.93	3.86	3.70	3.79
2008	3.91	3.79	3.73	3.98	4.08	3.99	3.95	3.90	3.80	4.06	3.99	3.82	3.92
2009	4.04	3.93	3.86	4.12	4.22	4.12	4.09	4.03	3.94	4.20	4.13	3.96	4.05
2010	4.17	4.05	3.98	4.25	4.36	4.26	4.22	4.17	4.06	4.34	4.26	4.08	4.18
2011	4.32	4.19	4.12	4.40	4.51	4.40	4.37	4.31	4.20	4.49	4.41	4.23	4.33
2012	4.45	4.33	4.25	4.54	4.65	4.54	4.51	4.45	4.34	4.63	4.55	4.36	4.47
2013	4.62	4.49	4.41	4.71	4.83	4.72	4.68	4.62	4.51	4.81	4.73	4.53	4.64
2014	4.79	4.66	4.58	4.89	5.01	4.89	4.85	4.79	4.67	4.99	4.90	4.69	4.81
2015	4.97	4.83	4.74	5.07	5.19	5.07	5.03	4.96	4.84	5.17	5.08	4.87	4.98

Table 5-14

No. 2 Fuel Oil Prices, Nominal Dollars ($/MMBtu)

	Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec	Annual Average
2000	5.15	5.14	4.98	5.04	5.01	4.85	4.80	4.93	5.05	5.19	5.12	4.88	5.01
2001	5.18	5.16	5.00	5.07	5.03	4.87	4.82	4.95	5.07	5.21	5.14	4.91	5.03
2002	5.33	5.31	5.15	5.22	5.18	5.02	4.96	5.10	5.22	5.36	5.30	5.05	5.18
2003	5.56	5.54	5.37	5.44	5.40	5.23	5.17	5.31	5.44	5.59	5.52	5.27	5.40
2004	5.73	5.71	5.54	5.61	5.57	5.40	5.33	5.48	5.61	5.77	5.69	5.43	5.57
2005	5.93	5.92	5.74	5.81	5.76	5.59	5.52	5.67	5.81	5.97	5.90	5.62	5.77
2006	6.17	6.16	5.97	6.04	6.00	5.81	5.75	5.90	6.05	6.21	6.14	5.85	6.00
2007	6.40	6.38	6.19	6.26	6.22	6.03	5.96	6.12	6.27	6.44	6.36	6.07	6.22
2008	6.66	6.64	6.44	6.52	6.47	6.27	6.20	6.37	6.53	6.70	6.62	6.31	6.48
2009	6.98	6.96	6.75	6.83	6.78	6.57	6.50	6.67	6.84	7.03	6.94	6.62	6.79
2010	7.18	7.16	6.95	7.03	6.98	6.76	6.68	6.87	7.04	7.23	7.14	6.81	6.99
2011	7.41	7.39	7.16	7.25	7.20	6.98	6.89	7.08	7.26	7.45	7.36	7.02	7.20
2012	7.68	7.66	7.43	7.52	7.46	7.23	7.15	7.34	7.53	7.73	7.63	7.28	7.47
2013	7.96	7.93	7.69	7.79	7.73	7.49	7.40	7.61	7.79	8.00	7.91	7.54	7.74
2014	8.24	8.22	7.97	8.07	8.00	7.76	7.67	7.88	8.07	8.29	8.19	7.81	8.01
2015	8.57	8.55	8.29	8.39	8.33	8.07	7.98	8.19	8.40	8.62	8.52	8.12	8.34

5.6.3 Peninsular Florida Resource Additions

Resource additions for Peninsular Florida were derived from the 1999 FRCC Regional Load and Resource Plan and market information. While several of the resource additions have not been approved by the Commission or DEP at this time, to be conservative, all planned additions were included in the resource additions in the UPLAN electricity market simulation model runs. Generating characteristics for these units were based upon information supplied in the Ten-Year Site Plans and updated estimates from DESL and D/FD.

5.6.4 Peninsular Florida Retirements

DESL utilized the identified retirements in the 1999 FRCC Regional Load and Resource Plan in the UPLAN model over the planning horizon. Retirements after the 2008 time period were not modeled, although after 2008 there is significant capacity from units that would have been operating more than 40 years.

5.6.5 Peninsular Florida Capacity Reratings

Several capacity reratings were outlined in the 1999 Ten-Year Site Plans. These modifications were incorporated into the UPLAN electricity market model.

5.6.6 Economic Evaluations

DESL evaluated Peninsular Florida's need for power utilizing LCG's UPLAN electricity market model. Results of the analyses indicate that the DESL Project is the most cost-effective addition to meet growth. The model assumptions stated previously were utilized in the base case evaluation to determine the cost-effectiveness of the Project.

5.6.6.1 UPLAN Model Evaluations

The Project, with its low production costs, is projected to dispatch approximately 75 percent of the time. The dispatch assumes economically rational, cost minimizing behavior by Florida's retail-serving utilities, which will only buy power from the Project when it is cost-effective for them to do so.

5.7 Cost-Effectiveness to Peninsular Florida Electric Utilities and Their Customers

DESL's analyses demonstrate that the Project will be cost-effective to Peninsular Florida. The Project will provide a cost-effective option for retail-serving utilities to obtain needed capacity and energy for resale to their customers. Review of the Ten-Year Site Plan information in other filings with the Commission indicate that the Project's direct construction costs and its heat rates compare favorably with those of other new gas-fired combined cycle power plants proposed for Florida.

As discussed in Section 4.2 of the Exhibit, Resource Data Institute studies indicate that Florida's wholesale electricity rate is approximately 38% higher than the national average. The presence of the DESL Project will assist to suppress wholesale power prices in Peninsular Florida.

Assuming rational, cost-minimizing behavior by Florida's retail-serving utilities, it is reasonable to conclude that these utilities will only buy power from the Project when it is cost-effective, i.e., when it is less expensive for them to buy power from the Project than to generate it themselves or to buy from another supplier. Reasonably assuming that the cost of power purchased from the Project is passed directly through to the purchasing utilities' ratepayers, such purchases will necessarily be cost-effective to those ratepayers.

The Project is also cost-effective because it will not expose retail ratepayers to the risks associated with new traditional utility projects. In the event a traditional utility constructed a project that, for whatever reason, was not cost-effective to operate or could not reliably operate, its retail customers would still have to pay costs associated with its construction. If, for whatever reason the DESL Project does not operate, the investors of Duke Energy would carry the burden of these costs, not the retail customers of Peninsular Florida.

5.8 Cost-Effectiveness to DESL

The Project represents the most cost-effective alternative available to DESL for meeting its projected wholesale power commitments. As discussed in the previous sections, DESL conducted detailed evaluations of the supply-side resources identified in subsections 5.2.1 through 5.2.6 against the Project. These evaluations clearly indicate that the most cost-effective economic choice for DESL and Peninsular Florida is a gas fired combined cycle facility. This is supported by the fact that other Florida utilities are planning to add several thousand MW of similar capacity and that a gas fired combined-cycle unit is the technology of choice for the majority of new power plant capacity planned in the United States.

6.0 Conservation Measures Taken or Reasonably Available

As a wholesale merchant utility, DESL is not in a position to, and does not directly engage in, end-user energy conservation programs. Thus, DESL's conservation obligations are limited. See In re: Joint Petition for Determination of Need for an Electrical Power Plant in Volusia County by the Utilities Commission, City of New Smyrna Beach, Florida, and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P., 99 F.P.S.C. 3:401, 439, Docket No. 981042-EM, Order No. PSC-99-0535, FOF-EM (March 22, 1999). However, DESL's evaluation shows that the Project meets the overall goals of FEECA. The Project will employ state-of-the-art, high-efficiency, combined cycle generation technology. The Project will have a thermal energy conversion efficiency of approximately 48 percent. Table 6-1 demonstrates the Project's conversion efficiency is significantly higher than existing utility generating capacity in Florida today. Indeed, the Project will be over 40 percent more efficient than more than half of the existing generating fleet in Peninsular Florida.

As demonstrated in Section 5, the Project's direct construction costs and highly efficient heat rate compare very favorably with those of other new gas-fired combined cycle power plants proposed in Florida. Based on electricity market and cost modeling and other analyses, DESL estimates that the Project will displace generation from less efficient gas-fired units and thus will result in an increase in the efficiency of natural gas use. The Project is also expected to displace older, less efficient oil-fired generation, thus, it will contribute to the express statutory goals in Sections 366.81 and 366.82 (2), Florida Statutes, of conserving expensive resources, especially petroleum fuels. Because of the Project's efficiencies, future cost-effective conservation measures would likely displace older, less-efficient generation, rather than the capacity and energy available from the Project.

Table 6-1: Comparison of the DESL Project with Existing FRCC Capacity

Plant Name	Name Plate Capacity MW	Heat Rate Btu/kWh	Thermal Efficiency
Cane Island Power Park	120	NA	NA
Cane Island Power Park	40	NA	NA
Crystal River	890	NA	NA
Hansel	55	NA	NA
Hansel	18	NA	NA
J.R. Kelly	49	NA	NA
Stock Island	38	NA	NA
Martin (FLPL)	1,224	7,172	47.6
Combined Cycle 1 - RCID	35	7,483	45.6
Combined Cycle 1 - RCID	9	7,540	45.3
Tiger Bay	218	7,738	44.1
Lauderdale	1,043	7,739	44.1
McIntosh-Fl	448	7,956	42.9
Larsen Memorial	147	9,260	36.8
St. Johns River Power	1,358	9,273	36.8
Crystal River North #4-5	1,479	9,382	36.4
Sebring Phillips	38	9,485	36.0
Putnam (FLPL)	580	9,510	35.9
Vero Beach Municipal	158	9,623	35.5
Fort Myers	558	9,632	35.4
Seminole (SECI)	1,429	9,668	35.3
Crystal River South #1-2	964	9,744	35.0
Anclote	1,112	10,000	34.1
Turkey Point	804	10,017	34.1
Scherer #4	891	10,108	33.8
Cape Canaveral	804	10,165	33.6
Big Bend	1,823	10,184	33.5
McIntosh-Fl #3	146	10,194	33.5
University of Florida Project	43	10,270	33.2
P.L. Bartow	494	10,284	33.2
Martin (FLPL)	1,727	10,338	33.0
Riviera	621	10,407	32.8
Hardee Power Station - SEC1	349	10,555	32.3
Manatee	1,727	10,573	32.3
Henry D King	6	10,759	31.7
Northside	861	10,779	31.7
Sanford (FLPL)	1,028	10,783	31.6
Port Everglades	1,255	10,810	31.6
St. Lucie	1,573	10,926	31.2
St. Lucie #2	127	10,926	31.2
Deerhaven	326	11,060	30.8
Turkey Point	1,520	11,064	30.8
Gannon	1,302	11,092	30.8
Key West Internal Combustion & Gas Turbines	56	11,490	29.7
Suwannee River	147	11,764	29.0
Polk	326	11,887	28.7
Southside	232	12,144	28.1
J.R. Kelly	75	12,677	26.9
Cutler (FLPL)	237	12,776	26.7
Henry D King	120	12,784	26.7
G.W. Ivey	59	12,826	26.6
Bayboro	227	13,252	25.7
Deerhaven	123	13,312	25.6
Intercession City	800	13,541	25.2
Debary	861	13,648	25.0
Suwannee River	184	13,831	24.7
J.D. Kennedy	150	13,976	24.4
Larsen Memorial	70	14,637	23.3
McIntosh-Fl	5	15,112	22.6
McIntosh-Fl	27	15,149	22.5
Fort Myers	744	15,398	22.2
G.E. Turner	181	15,440	22.1
P.L. Bartow	223	15,543	22.0
Higgins	153	15,596	21.9
Hookers Point	233	16,029	21.3
Big Bend	176	16,414	20.8
Avon Park	68	16,992	20.1
Lauderdale	822	17,538	19.5
Port St. Joe	19	18,386	18.6
Port Everglades	411	18,839	18.1
Rio Pinar	19	19,378	17.6
Northside	248	21,310	16.0
Gannon	18	21,680	15.7
J.D. Kennedy	169	40,231	8.5
Weighted Average for FRCC		**10,754**	**31.2**
DESL Project		**7,096**	**48.1**

7.0 Consequences of Delay

Delaying the construction and operation of the DESL Project will adversely affect the reliability of the Peninsular Florida bulk power supply system, the availability of adequate electricity at a reasonable cost, and the environment of Florida. Project delay also will have adverse consequences for St. Lucie County.

7.1 Reliability Consequences of Delay

Delay of the DESL Project will deprive Peninsular Florida of a very reliable source of generation, as discussed in Section 4.1. Moreover, as shown in Section 4.1.1, if the Project is not constructed and brought into commercial operation in 2003 as planned, the benefits of reliability will be lost. Indeed, Florida's retail electric ratepayers will be exposed to greater risks of service interruption than they would experience if the Project were built as planned by DESL.

7.2 Power Supply Costs of Delay

The DESL Project will allow the existing retail-serving Peninsular Florida utilities to reduce the costs of supplying power to their customers by offering those utilities another source of capacity and energy in lieu of less efficient generation or purchase contracts. This flexibility, associated with the capacity of the Project, would be eliminated if the DESL Project is delayed or not constructed.

7.3 Environmental Consequences of Delay

The DESL Project is a high-efficiency, state-of-the-art natural gas-fired, combined cycle electric generating facility. Because of its high efficiency and use of clean burning natural gas, the Project's impacts on the environment will be minimized. Based upon electricity market and cost modeling, the Project will displace production from older, less-efficient generators that produce more emissions. Based on the detailed market and operational simulations, projected usage of coal and fuel oil is reduced by the operation of the DESL Project.

The reduction in oil and coal combustion for electric generation will provide significant benefits to Florida's environment by lowering the total emissions in Florida. Moreover, regardless of the type of primary fuel displaced, the Project's operations will result in significant fuel savings due to its higher efficiency of converting fuel into energy.

The Project is also planning to utilize reclaimed water as its main cooling source. This wastewater stream is currently discharged into a deep injection well at the FPUA WRF on South Hutchinson Island – a barrier island, with the Indian River as its only backup option for discharge. The Project represents a beneficial reuse of valuable water resources and will reduce the potential for discharging into the Indian River.

If the Project is not constructed and brought into commercial operation in 2003 as planned, these environmental benefits will be lost, and pollution from electric generation in Florida will be significantly greater than it otherwise would be.

7.4 Positive Economic Impacts on St. Lucie County

The DESL Project will have positive economic impacts in St. Lucie County and Peninsular Florida. The St. Lucie County area will benefit significantly, both during the construction phase and over the 30 year operating life. During the construction period the project will employ an average of 150 workers, with peak construction manpower estimated to be 300 workers. An average of 150 project workers is estimated to generate 224 additional jobs during the 18 month construction period. These direct and indirect jobs created during construction will bring economic benefits to local residents of St. Lucie county. As a result of this increased economic activity during the construction period, the multiplier effect of the Project is estimated to increase earnings in the area by an imputed value of over $200 million (constant 2000 $) in 2003. Each year's delay in construction of the Project would reduce the net present value of area earnings by over $25 million. Thus, a delay in completing construction of the plant from 2003 until 2010 would result in a loss in the net present value of lost earnings of about $175 million for the St Lucie county/area.

The Project will employ approximately 25 people during operation with an estimated annual payroll of $1.5 million. These 25 jobs will create a multiplier effect causing an additional 72 new permanent jobs to be created in St. Lucie County. The economic effect of these 25 jobs will be to increase county/area earnings for all industries by about $3.5 million per year. Delaying the plant's operation until 2010 would result in a loss in net present value (NPV) of almost $19 million (constant 2000 $), and this NPV loss would grow during each year of delay.

The Project will also add a significant tax base to the County. This tax base has very positive impacts with little additional infrastructure required to support the facility. The Project is also providing a revenue source for FPUA through the purchase of its reclaimed water that is currently discharged into a deep injection well. Besides these significant earnings losses, there would be substantial losses in property tax revenue for St. Lucie county if the Project were to be delayed.

Thus, if the Project is not constructed and brought into commercial operation in 2003, as planned, these positive economic benefits to St. Lucie County will be lost or postponed.

8.0 Conclusion

DESL has addressed all of the criteria the Commission is to consider when deciding whether to grant a determination of need for an electrical power plant including: system reliability and integrity; the need for adequate electricity at a reasonable cost; cost effectiveness; and conservation. DESL has demonstrated that the Project meets these criteria and represents a cost-effective quality addition to Peninsular Florida's generation resources. Thus, DESL's petition for need determination should be granted.

9.0 Appendices

Appendix A- FERC Applications for EWG status and Market Rates

- FERC application for St. Lucie Exempt Wholesale Generator status as defined in section 32 of PUHCA.
- FERC filing for tariffs for market-based power sales and reassignment of transmission capacity.

Appendix B- Summary of LCG Consulting's UPLAN integrated electricity market model.

Appendix A
DESL's EWG and Market Based Rate Filings

Pleadings
Duke St. Luci
D7885 0012
CC: LFE, CCDt
GS

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Duke Energy St. Lucie, LLC | Docket No. EG00-132-000

NOTICE OF APPLICATION FOR COMMISSION DETERMINATION
OF EXEMPT WHOLESALE GENERATOR STATUS

(April 19, 2000)

Take notice that on April 17, 2000, Duke Energy St. Lucie, LLC (Duke St. Lucie) filed an application with the Federal Energy Regulatory Commission (the Commission) for determination of exempt wholesale generator status pursuant to Section 32 of the Public Utility Holding Company Act of 1935, as amended, and Part 365 of the Commission's Regulations.

Duke St. Lucie is a Delaware limited liability company that will be engaged directly and exclusively in the business of owning and operating all or part of one or more eligible facilities to be located in St. Lucie County, Florida. The eligible facilities will consist of an approximately 608 MW gas-fired, combined-cycle electric generation plant and related interconnection facilities. The output of the eligible facilities will be sold exclusively at wholesale.

Any person desiring to be heard concerning the application for exempt wholesale generator status should file a motion to intervene or comments with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). The Commission will limit its consideration of comments to those that concern the adequacy or accuracy of the application. All such motions and comments should be filed on or before May 10, 2000, and must be served on the applicant. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection or on the Internet at http://www.ferc.fed.us/online/rims.htm (please call (202)208-2222 for assistance).

David P. Boergers
Secretary

DICKSTEIN SHAPIRO MORIN & OSHINSKY LLP
2101 L Street NW • Washington, DC 20037-1526
Tel (202) 785-9700 • Fax (202) 887-0689

April 17, 2000

The Hon. David P. Boergers
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: Application of Duke Energy St. Lucie, LLC for Determination of Exempt Wholesale Generator Status, Docket No. EG00- 132-000

Dear Mr. Boergers:

Pursuant to Section 32 of the Public Utility Holding Company Act of 1935 and 18 C.F.R. 365 of the Commission's regulations, Duke Energy St. Lucie, LLC hereby submits for filing an original and fourteen copies of its Application for Determination of Exempt Wholesale Generator Status. A filing fee is not required because Duke Energy St. Lucie, LLC will be a public utility under the Federal Power Act. Also enclosed is a 3.5 inch diskette containing a Notice of Filing in Word Perfect format.

Two additional copies are enclosed to be date-stamped and returned to the undersigned via our messenger. Thank you for your attention to this matter.

Sincerely,

Christopher C. O'Hara

Larry F. Eisenstat
Gretchen Schott
Christopher C. O'Hara

Attorneys for Duke Energy St. Lucie, LLC

Enclosures

1177 Avenue of the Americas • 41st Floor • New York, New York 10036-2714
Tel (212) 835-1400 • Fax (212) 997-9880
http://www.dsmo.com

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Duke Energy St. Lucie, LLC	)))	Docket No. EG00-___-000

APPLICATION FOR DETERMINATION OF EXEMPT WHOLESALE GENERATOR STATUS

Pursuant to Section 32 of the Public Utility Holding Company Act of 1935, as amended, ("PUHCA")[1] and Part 365 of the Rules and Regulations of the Federal Energy Regulatory Commission (the "Commission"),[2] Duke Energy St. Lucie, LLC ("Duke St. Lucie") hereby applies for a determination by the Commission that it is an exempt wholesale generator ("EWG"). In support thereof, Duke St. Lucie states:

I. CORRESPONDENCE AND COMMUNICATIONS

All communications and correspondence regarding this Application should be sent to the following persons who are authorized to receive service:

Larry F. Eisenstat
*Christopher C. O'Hara
Dickstein Shapiro Morin & Oshinsky LLP
2101 L Street NW
Washington, D.C. 20037
Tel: (202) 785-9700
Fax: (202) 296-6216

*Brent C. Bailey
Vice President and General Counsel
Duke Energy St. Lucie, LLC
5400 Westheimer Court
Houston, TX 77251-1642
Tel: (713) 627-5307
Fax: (713) 627-5550

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[1] 15 U.S.C. § 79z-5a.

[2] 18 C.F.R. Part 365.

* Persons designated to receive service hereunder.

II. DESCRIPTION OF DUKE ST. LUCIE

A. Duke St. Lucie's Ownership Structure

Duke St. Lucie is a limited liability company organized and existing under the laws of the State of Delaware. Duke St. Lucie is a wholly-owned subsidiary of Duke Energy North America, LLC, a limited liability company organized and existing under the laws of the State of Delaware and, in turn, an indirect, wholly-owned subsidiary of Duke Energy Corporation ("Duke Energy").

B. Duke St. Lucie's Proposed Activities

1. The Facility

Duke St. Lucie will develop, own and operate a gas-fired, combined-cycle electric generation plant with a nominal capacity of approximately 608 MW located in St. Lucie County, Florida (the "Facility"). The Facility is expected to begin commercial operations in the summer of 2003. The Facility will be comprised of generation facilities and related real and personal property and equipment necessary to the generation of electricity including two combustion turbines, two heat recovery steam generators, a steam turbine, and associated supporting systems.

The Facility will also include related transmission interconnection facilities necessary to effect the sale of electricity to Duke St. Lucie's wholesale power purchaser(s). The Facility will be interconnected with transmission facilities owned and operated by Florida Power and Light Company ("FPL") at its Midway substation. The interconnection facilities which Duke St. Lucie may own to interconnect with the transmission facilities of FPL may include step-up transformers and short lengths of transmission lines.

2. Duke St. Lucie's Power Sales

Duke St. Lucie intends to operate the Facility as a merchant plant and will sell energy and capacity generated by the Facility exclusively at wholesale,[3] either through bilateral agreements or through a power exchange.[4] Duke St. Lucie may also purchase power and resell it at wholesale to third parties.[5]

3. Other Activities

Duke St. Lucie may sell at wholesale ancillary services available from the Facility which are incidental to, and by-products of, the Facility's operations as a wholesale power generator.[6] In addition, Duke St. Lucie might also from time to time reassign excess transmission capacity, consistent with the Commission's requirement that such reassignment of excess transmission capacity be limited to the extent that such transmission capacity was originally obtained for the purpose of effecting a specific wholesale sale of electric energy.[7] Duke St. Lucie may also resell its excess gas supplies and assign its excess transportation capacity, consistent with the Commission's EWG precedent that such sales may be made only if such gas supplies and transportation were originally contracted for in order to operate the EWG's facility.[8] Duke St. Lucie may also trade emission allowances

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[3] Contemporaneously with this filing, Duke St. Lucie filed an application pursuant to Section 205 of the Federal Power Act for acceptance of a market-based rate schedule for wholesale sales.

[4] The Commission has determined that sales to a power exchange are considered wholesale sales for EWG purposes. *See Southern California Edison Co.,* 80 FERC ¶ 61,262 (1997).

[5] An EWG is permitted to resell at wholesale power that it has not generated. *See CNG Power Services Corp.*, 69 FERC ¶ 61,002 (1994).

[6] *See, e.g., Duke Energy Oakland, LLC,* 83 FERC ¶ 61,304 (1998); *Sithe Framingham, LLC,* 83 FERC ¶ 61,106 (1998).

[7] *See CNG Power Services Corp.*, 71 FERC ¶ 61,026, at 61,103-04 (1995).

[8] *See Selkirk Cogen Partners, L.P.*, 69 FERC ¶ 61,037, at 61,168-69 (1994).

consistent with the Commission's limitation that an EWG may only engage in such trading so long as the emission allowances were originally obtained in the normal course of operating the EWG's facility.[9]

In addition, Duke St. Lucie may engage in project development activities associated with the Facility. Such project development activities ("Development Activities") may include, but are not necessarily limited to, the following activities: due diligence; site investigations; feasibility studies; preliminary design and engineering; licensing and permitting; negotiation of asset and land acquisitions; negotiation of contractual commitments with lenders, equity investors, governmental authorities and other project participants and such other activities as may be necessary to financially close on eligible facilities; negotiation of power sales contracts; equipment purchases; fuel supply; engineering, construction, interconnection, and related matters; preparation and submission of bid proposals; and development of financing programs related to owning and operating the Facility and/or additional electric generation facilities that satisfy the criteria for EWG status.

III. DUKE ST. LUCIE REPRESENTATIONS REGARDING EXEMPT WHOLESALE GENERATOR STATUS

Consistent with Section 365.3 of the Commission's regulations,[10] Duke St. Lucie makes the following representations in order to demonstrate that it satisfies the requirements for EWG status.

[9] *See UGI Development Co.*, 89 FERC ¶ 61,192 (1999).

[10] 18 C.F.R. § 365.3.

A. Duke St. Lucie will be engaged directly and exclusively in the business of owning or operating, or both owning and operating, all or part of one or more eligible facilities ("Eligible Facilities")[11] and selling electric energy at wholesale. The Facility, as described above, satisfies the definition of Eligible Facilities. Duke St. Lucie's proposed sale of energy and capacity at wholesale through bilateral contracts or a power exchange satisfies the "selling electricity at wholesale" requirement under Section 32(a)(2) of PUHCA.[12]

Duke St. Lucie's proposed potential sale of ancillary services resulting from the Facility's operation will not jeopardize its EWG status. Consistent with FERC precedent, Duke St. Lucie's sales of ancillary services available from the Facility are an incidental by-product of Duke St. Lucie's wholesale generation business and will not violate the EWG exclusivity requirement.[13] Nor will Duke St. Lucie's proposed sale of excess gas supplies and transportation capacity or proposed trading of emission allowances violate the EWG exclusivity requirement. Consistent with Commission precedent, Duke St. Lucie's proposed excess gas supplies and transportation capacity sales and emission allowance trading are incidental to Duke St. Lucie's involvement in the wholesale electric generation

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[11] The term "Eligible Facilities" has the meaning ascribed to it in Section 32(a)(2) of PUHCA. 15 U.S.C. § 79z-5a(a)(2).

[12] 15 U.S.C. § 79z-5a.

[13] *See, e.g., Duke Energy Oakland, LLC,* 83 FERC ¶ 61,304 (1998); *Sithe Framingham, LLC,* 83 FERC ¶ 61,106 (1998).

business.[14] Likewise, Duke St. Lucie's proposed Development Activities, as described in Section II.B.3, are consistent with FERC precedent as permissible incidental activities and will not jeopardize Duke St. Lucie's EWG status.[15]

B. Duke St. Lucie will not make any retail sales, foreign or otherwise.

C. As described in Section II.B.1 above, the Facility will be interconnected with FPL's transmission facilities through interconnection facilities owned by Duke St. Lucie which are necessary for the Facility to transmit the electricity it generates to its power purchaser(s).[16] Duke St. Lucie will not own any transmission facilities other than those interconnection facilities necessary for the Facility to effect the sale of electric energy at wholesale to its power purchaser(s).

D. There are no lease arrangements involving the Facility.

E. Duke St. Lucie is an affiliate ("Affiliate")[17] or an associate company ("Associate Company")[18] of the following electric utility companies ("Electric Utility

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[14] *See UGI Development Co.*, 89 FERC ¶ 61,192 (1999) (regarding emission allowances); *Selkirk Cogen Partners, L.P.*, 69 FERC ¶ 61,037 (1994) (regarding sales of excess gas supplies and transportation capacity).

[15] *See Coastal Nejapa Ltd.*, 71 FERC ¶ 61,081 (1995).

[16] *See* 15 U.S.C. § 79z-5a(a)(2).

[17] The term "Affiliate" has the meaning ascribed to it in Section 2(a)(11) of PUHCA. 15 U.S.C. § 79b(a)(11).

[18] The term "Associate Company" has the meaning ascribed to it in Section 2(a)(10) of PUHCA. 15 U.S.C. § 79b(a)(10).

Company")[19] located in the United States: Duke Energy, which generates, transmits, distributes and sells energy in parts of North Carolina and South Carolina where it has franchised service territories.[20]

F. No rate or charge for, or in connection with, the construction of the Facility or for electric energy produced by the Facility was in effect under the laws of any State on October 24, 1992.

G. No portion of the Facility will be owned or operated by an Electric Utility Company that is an Affiliate or Associate Company of Duke St. Lucie.

H. In accordance with Section 365.3(a)(1) of the Commission's Regulations,[21] a sworn statement, executed by a representative legally authorized to bind Duke St. Lucie attesting to the facts and representations presented herein to demonstrate Duke St. Lucie's eligibility for EWG status, is attached.

I. In accordance with Section 365.3(a) of the Commission's Regulations,[22] a copy of this application was concurrently served upon the U.S. Securities and Exchange Commission, the Florida Public Service Commission, the North Carolina Utilities Commission and the South Carolina Public Service Commission.

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[19] The term "Electric Utility Company" has the meaning ascribed to it in Section 2(a)(3) of PUHCA. 15 U.S.C. § 79b(a)(3).

[20] Duke Energy operates its franchised utility business as Duke Power, a division of Duke Energy, and its electric transmission business, as Duke Electric Transmission, another division of Duke Energy.

[21] 18 C.F.R. § 365.3(a)(1).

IV. CONCLUSION

Duke St. Lucie will be engaged directly and exclusively in the business of owning and operating Eligible Facilities and selling electric energy at wholesale. Accordingly, Duke St. Lucie respectfully requests that the Commission determine that Duke St. Lucie is an EWG within the meaning of Section 32 of PUHCA.

Respectfully submitted,

Cliff COIL

Larry F. Eisenstat
Gretchen Schott
Christopher C. O'Hara
Dickstein Shapiro Morin & Oshinsky LLP
2101 L Street NW
Washington, D.C. 20037
Tel: (202) 785-9700
Fax: (202) 887-0689

Attorneys for Duke Energy St. Lucie, LLC

Dated: April 17, 2000

[22] 18 C.F.R. § 365.3(a).

State of Texas)
) SS
Harris County)

VERIFICATION

I, Brent C. Bailey, being duly sworn, attest that I am Vice President & General Counsel for Duke Energy St. Lucie, LLC and that as such I am legally authorized to bind Duke Energy St. Lucie, LLC to the facts and representations in the foregoing application. I have read the foregoing application of Duke Energy St. Lucie, LLC and I affirm that the facts, representations and statements set forth therein are true and correct to the best of my knowledge and belief.

Brent C. Bailey

Brent C. Bailey

I do hereby certify that on this 14th day of April ~~March~~, 2000, Brent C. Bailey, personally appeared before the undersigned Notary and made oath to the foregoing.

Christine S Schoppe

Notary

My Commission Expires:

CHRISTINE S. SCHOPPE
Notary Public, State of Texas
My Commission Expires
9/15/02

CERTIFICATE OF SERVICE

I hereby certify that the foregoing Application of Duke Energy St. Lucie, LLC for Determination of Exempt Wholesale Generator Status was served this 17th day of April, 2000, by first-class mail, postage prepaid, upon the following:

Secretary
U.S. Securities and Exchange Commission
450 5th Street, N.W.
Washington, D.C. 20549

Secretary
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0850

Secretary
North Carolina Utilities Commission
P.O. Box 29510
Raleigh, NC 27626-0510

Secretary
South Carolina Public Service Commission
P.O. Drawer 11649
Columbia, South Carolina 29211

Christopher C. O'Hara

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Duke Energy St. Lucie, LLC	)	Docket No. EG00-___-000

NOTICE OF APPLICATION FOR COMMISSION
DETERMINATION OF EXEMPT WHOLESALE GENERATOR STATUS

Take notice that on April __, 2000, Duke Energy St. Lucie, LLC (Duke St. Lucie) filed an application with the Federal Energy Regulatory Commission (the Commission) for determination of exempt wholesale generator status pursuant to Section 32 of the Public Utility Holding Company Act of 1935, as amended, and Part 365 of the Commission's Regulations.

Duke St. Lucie is a Delaware limited liability company that will be engaged directly and exclusively in the business of owning and operating all or part of one or more eligible facilities to be located in St. Lucie County, Florida. The eligible facilities will consist of an approximately 608 MW gas-fired, combined-cycle electric generation plant and related interconnection facilities. The output of the eligible facilities will be sold exclusively at wholesale.

Any person desiring to be heard concerning the application for exempt wholesale generator status should file a motion to intervene or comments with the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426, in accordance with 385.211 and 385.214 of the Commission's Rules of Practice and Procedure. The Commission will limit its consideration of comments to those that concern the adequacy or accuracy of the application. All such motions and comments should be filed on or before ________________ and must be served on the applicant. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection or on the Internet at http://www.ferc.fed.us/online/rims.htm (call 202-208-2222 for assistance).

David P. Boergers
Secretary

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Duke Energy St. Lucie, LLC | Docket No. ER00-2225-000

NOTICE OF FILING

(April 20, 2000)

Take notice that on April 17, 2000, Duke Energy St. Lucie, LLC (Duke St. Lucie), tendered for filing pursuant to Section 205 of the Federal Power Act an application for an order accepting its rates of filing, determining of rates to be just and reasonable, and granting certain waivers and preapprovals.

Duke St. Lucie is developing an approximately 608 MW generation facility located in St. Lucie County, Florida. Under its proposed FERC Electric Tariff No. 1, Duke St. Lucie seeks to sell energy and capacity, as well as ancillary services, at market-based rates. Duke St. Lucie also seeks authority to sell, assign, or transfer transmission rights that it may acquire in the course of its marketing activities.

Any person desiring to be heard or to protest such filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission s Rules of Practice and Procedure (18 CFR 385.211 and 385.214). All such motions and protests should be filed on or before May 8, 2000. Protests will be considered by the Commission to determine the appropriate action to be taken, but will not serve to make protestants parties to the proceedings. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection. This filing may also be viewed on the Internet at http://www.ferc.fed.us/online/rims.htm (call 202-208-2222 for assistance).

Linwood A. Watson, Jr.
Acting Secretary

DICKSTEIN SHAPIRO MORIN & OSHINSKY LLP
2101 L Street NW • Washington, DC 20037-1526
Tel (202) 785-9700 • Fax (202) 887-0689

April 17, 2000

The Hon. David P. Boergers
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: *Duke Energy St. Lucie, LLC,*
Docket No. ER00-___-000
2225

Dear Mr. Boergers:

Duke Energy St. Lucie, LLC ("Duke St. Lucie") hereby submits for filing an original and five (5) copies of the Application of Duke St. Lucie for authorization for market-based rate sales. Please acknowledge receipt of this filing by date stamping the two (2) additional enclosed copies and returning them to the undersigned via our messenger.

Documents Submitted:

Application of Duke Energy St. Lucie, LLC for Order Accepting Rates for Filing, Determining Rates to be Just and Reasonable, and Granting Certain Waivers and Pre-Approvals

Included with this filing are the following attachments:

1. Duke St. Lucie's FERC Electric Tariff No. 1 (Description: Market-Based Rate Tariff);

2. Duke St. Lucie's Code of Conduct; and

3. Notice of Filing suitable for publication in the *Federal Register* together with a copy of the Notice on a 3½" diskette.

Expected Service Commencement and Effective Date:

Duke St. Lucie seeks blanket authority to sell at market-based rates power that it generates from its facility or that it acquires in the market, and therefore, Duke St. Lucie requests an effective date sixty (60) days from the date of this filing, in accordance with Section 35.3 of the Commission's regulations.[1]

Names and Addresses of those to whom the Tariff was mailed:

None.

Requisite Agreements:

No agreements are required for the filing of this Tariff.

Communications and Correspondence:

Please direct all communications and correspondence concerning this filing to:

Larry F. Eisenstat
* Christopher C. O'Hara
Dickstein Shapiro Morin
& Oshinsky LLP
2101 L Street NW
Washington, DC 20037
Tel.: (202) 785-9700
Fax: (202) 887-0689

*Brent C. Bailey, Esq.
Vice President and General Counsel
Duke Energy St. Lucie, LLC
5400 Westheimer Court
Houston, Texas 77251
Tel.: (713) 627-5307
Fax: (713) 627-5550

Thank you for your attention to this matter.

Respectfully submitted,

Larry F. Eisenstat
Gretchen Schott
Christopher C. O'Hara

Attorneys for Duke Energy St. Lucie, LLC

[1] 18 C.F.R. § 35.3(a) (1999).

* Persons designated to receive service hereunder.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Duke Energy St. Lucie, LLC	)	Docket No. ER00-___-000

**APPLICATION OF DUKE ENERGY ST. LUCIE, LLC
FOR ORDER ACCEPTING RATES FOR FILING,
DETERMINING RATES TO BE JUST AND REASONABLE,
AND GRANTING CERTAIN WAIVERS AND PRE-APPROVALS**

Pursuant to Section 205 of the Federal Power Act ("FPA")[1] and Part 35 of the regulations of the Federal Energy Regulatory Commission ("Commission"),[2] Duke Energy St. Lucie, LLC ("Duke St. Lucie") hereby requests the Commission to accept for filing the attached market-based rate tariff, FERC Electric Tariff No. 1,[3] governing the sale of energy and capacity at wholesale, the sale of ancillary services, and the sale, assignment or transfer of transmission capacity that Duke St. Lucie may possess. Duke St. Lucie's sales of energy, capacity, or ancillary services will be either from the approximately 608 megawatt generation facility to be developed, owned, and operated by Duke St. Lucie in St. Lucie County, Florida or that Duke St. Lucie purchases in the market. Duke St. Lucie also requests that the Commission grant such waivers and preapprovals as have been granted previously by the Commission to other entities selling power at market-based rates, as more

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[1] 18 U.S.C. § 824d.

[2] 18 C.F.R. §§ 35 *et seq.* (1999).

[3] *See* Attachment 1.

fully set forth herein. Pursuant to Section 35.3 of the Commission's regulations,[4] Duke St. Lucie requests an effective date sixty (60) days from the date of filing.

I. CORRESPONDENCE AND COMMUNICATIONS

The following persons are authorized to receive service and communications regarding this Application:

Larry F. Eisenstat
*Christopher C. O'Hara
Dickstein Shapiro Morin
& Oshinsky LLP
2101 L Street NW
Washington, DC 20037
Tel: (202) 785-9700
Fax: (202) 887-0689

*Brent C. Bailey
Vice President and General Counsel
Duke Energy St. Lucie, LLC
5400 Westheimer Court
Houston, Texas 77251
Tel: (713) 627-5307
Fax: (713) 627-5550

II. BACKGROUND

A. Description of Duke St. Lucie

Duke St. Lucie is a limited liability company organized and existing under the laws of the State of Delaware. Duke St. Lucie is a wholly-owned subsidiary of Duke Energy North America, LLC, a limited liability company organized and existing under the laws of the State of Delaware and, in turn, an indirect, wholly-owned subsidiary of Duke Energy Corporation ("Duke Energy"). Duke Energy is a North Carolina corporation that generates, transmits, distributes and sells energy in parts of North Carolina and South Carolina where it has franchised service territories.[5]

---

[4] 18 C.F.R. § 35.3.

* Persons designated to receive service hereunder.

[5] Duke Energy operates its franchised utility business as Duke Power, a division of Duke Energy, and its electric transmission business as Duke Electric Transmission, another division of Duke Energy.

B. Description of the Facility

Duke St. Lucie will develop, own and operate a gas–fired, combined-cycle electric generation plant with a nominal capacity of approximately 608 MW located in St. Lucie County, Florida (the "Facility"). The Facility is expected to begin commercial operations in the summer of 2003. The Facility is also seeking exempt wholesale generator status under Section 32(a)(2) of the Public Utility Holding Company Act of 1935, as amended ("PUHCA").[6]

The Facility will be comprised of generation facilities and related real and personal property and equipment necessary for the generation of electricity, including two combustion turbines, two heat recovery steam generators, a steam turbine, and associated supporting systems. The Facility will also include related transmission interconnection facilities necessary to effect the sale of electricity to Duke St. Lucie's wholesale power purchaser(s). The Facility will be interconnected with transmission facilities owned and operated by Florida Power and Light Company ("FPL") at its Midway substation. The interconnection facilities which Duke St. Lucie may own to interconnect with the transmission facilities of FPL may consist of step-up transformers and short lengths of transmission lines.

C. Sales of Energy, Capacity, Ancillary and Other Services

Through this Application, Duke St. Lucie seeks blanket approval to make wholesale sales of firm and non-firm energy and capacity from the Facility, or that is purchased on the market, at negotiated rates under the terms of its proposed FERC

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[6] 15 U.S.C. § 79z-5a(a)(2). Contemporaneously with this filing, Duke St. Lucie is filing an Application for Determination of Exempt Wholesale Generator Status.

Electric Tariff No. 1. Such sales may be long or short-term and may be effectuated through bilateral contracts or any power exchange that may develop.

Duke St. Lucie also seeks authority to sell at market-based rates the following ancillary services, which are ancillary services under Order No. 888:[7] Regulation and Frequency Response Service, Energy Imbalance Service, Spinning Reserve Service, and Supplemental Reserve Service.[8] Consistent with the requirements set forth by the Commission in *Avista Corporation*, 87 FERC ¶ 61,223 (1999) and as set forth in its proposed FERC Electric Rate Tariff No. 1, Duke St. Lucie will utilize an Internet-based OASIS-like site in order to provide information about, and to enable purchasers to request and make bids for, ancillary services, and will adhere to the Commission's reporting requirements.[9] As set forth in *Avista*, Duke St. Lucie's market-based rate authority will not apply to the following transactions:

- sales to a regional transmission organization ("RTO"), such as an independent system operator or a transco where the RTO cannot self-supply but instead depends on third parties for such services;

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[7] *See Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036, *clarified*, 76 FERC ¶ 61,009 and 76 FERC ¶ 61,347 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998)(hereinafter "Order No. 888").

[8] The Commission has previously determined that services which do not constitute ancillary services under Order No. 888, which would include, among other services, blackstart service and load following service, do not require separate authorization and may be sold at market-based rates pursuant to the Commission's grant of blanket approval to sell energy and capacity at market-based rates. *See, e.g., Duke Energy Oakland, LLC,* 84 FERC ¶ 61,186, at 61,960 & n.10 (1998); *AES Redondo Beach, LLC*, 83 FERC ¶ 61,358, at 62,446, *order on reh'g*, 85 FERC ¶ 61,123 (1998).

[9] *Avista*, 87 FERC at 61,883-84. The world wide web address will be provided to the Commission prior to the commencement of sales of these ancillary services.

- sales to any traditional, franchised public utilities affiliated with Duke St. Lucie;
- sales where the underlying transmission service is on the system of any public utility affiliated with Duke St. Lucie; and
- sales to any public utility that is purchasing the ancillary services to satisfy its obligation to provide ancillary services to third parties.[10]

Finally, Duke St. Lucie seeks blanket authority to sell, assign or transfer any transmission capacity that it may acquire in the course of its power sales activities consistent with the Commission's limitations.[11] Accordingly, Duke St. Lucie will reassign transmission capacity it may acquire at a price not to exceed the higher of: (1) the original transmission rate charged to Duke St. Lucie, (2) the transmission provider's maximum stated transmission rate at the time of the sale, assignment, or transfer to a customer, or (3) Duke St. Lucie's opportunity cost, capped at the transmission provider's cost of expansion at the time of the sale to the eligible customer.[12] Duke St. Lucie will not recover opportunity costs in connection with reassignments without making a filing under Section 205 of the Federal Power Act.

III. THE COMMISSION SHOULD GRANT MARKET-RATE AUTHORIZATION

A. Legal Standard

Section 205 of the FPA requires that all rates and charges made, demanded, or received by any public utility for the sale of electric energy subject to the Commission's

[10] *Id.* at 61,883 n.12.

[11] *Enron Power Marketing, Inc.*, 81 FERC ¶ 61,277 (1997); *Commonwealth Edison Co.*, 78 FERC ¶ 61,312, at 62,335-36 (1997).

[12] *Id.*

jurisdiction be "just and reasonable" and not "unduly discriminatory or preferential."[13] Market-based rates are just and reasonable if the seller demonstrates that it and its affiliates (1) do not have market power in generation; (2) do not have, or have adequately mitigated, market power in transmission; and (3) do not control any other barrier to market entry. The Commission also considers whether there is evidence of reciprocal dealing or affiliate abuse.[14] As demonstrated below, Duke St. Lucie satisfies each of the Commission's criteria.

B. Generation Market Power

A seller with generation assets that seeks market-based rate authority must demonstrate that neither it, nor its affiliates, have generation market power in the geographic or product markets in which the seller intends to compete. The Commission no longer requires, however, a seller with generation assets built after July 9, 1996 to show that it lacks generation market power. Section 35.27 of the Commission's regulations provides in relevant part that:

> [A]ny public utility seeking authorization to engage in sales for resale of electric energy at market-based rates shall not be required to demonstrate any lack of market power in generation with respect to sales from capacity for which construction has commenced on or after July 9, 1996.[15]

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[13] 16 U.S.C. § 824d.

[14] *See, e.g., Duke Power, a Division of Duke Energy Corporation, Duke Solutions, Inc.*, 84 FERC ¶ 61,235, at 62,200 (1998); *Heartland Energy Servs., Inc.*, 68 FERC ¶ 61,223, at 62,062 (1994); *Kansas City Power & Light Co.*, 67 FERC ¶ 61,183, at 61,556-58 (1994).

[15] 18 C.F.R. § 35.27(a).

Since construction of Duke St. Lucie's Facility has not yet commenced, Duke St. Lucie satisfies the July 9, 1996 date requirement.[16] Thus, the Facility constitutes new capacity under the Commission's regulations and Duke St. Lucie will not have, nor is it required to demonstrate its lack of, generation market power.

Duke St. Lucie's affiliates also lack generation market power. Duke St. Lucie is an affiliate of Duke Energy.[17] The Commission has previously determined that Duke Energy and its affiliates lack generation dominance.[18] None of Duke Energy's affiliates currently owns or controls any generation assets located within the State of Florida, although one affiliate, Duke Energy New Smyrna Beach Power Company, Ltd., LLP ("Duke New Smyrna"), is in the process of developing an approximately 500 MW generation facility in Florida. In 1998, the Commission approved Duke New Smyrna's

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[16] Construction of Duke St. Lucie's Facility is scheduled to begin on or about December 1, 2001.

[17] As noted, contemporaneously with this filing, Duke St. Lucie is filing an application seeking exempt wholesale generator ("EWG") status under Section 32(a)(2) of PUHCA. Pursuant to Section 365.4 of the Commission's regulations, Duke St. Lucie is deemed an EWG during the pendency of its application. 18 C.F.R. § 365.4. Accordingly, Duke St. Lucie has employed the meaning of the term "affiliate" ascribed to it in Section 2(a)(11) of PUHCA. 15 U.S.C. § 79b(a)(11). *See Morgan Stanley Capital Group Inc.*, 72 FERC ¶ 61,082, at 61,437 (1995).

[18] *See Oswego Harbor Power, LLC*, 88 FERC ¶ 61,219 (1999) (addressing the application of Duke Energy Merchants, LLC); *Duke Power Company, Duke/Louis Dreyfus LLC, and Duke Energy Marketing Corporation*, 86 FERC ¶ 61,026 (1999); *Duke Power, a Division of Duke Energy Corporation, Duke Solutions, Inc.*, 84 FERC ¶ 61,235 (1998)("*Duke Solutions*"); *Duke Power Company and PanEnergy Corporation*, 79 FERC ¶ 61,236, at 62,037-38 (1997); *Duke/Louis Dreyfus LLC*, 73 FERC ¶ 61,309 (1995), *order on reh'g*, 75 FERC ¶ 61,261 (1996); *see also Lyke-Duke/Louis Dreyfus, Ltd.*, 77 FERC ¶ 61,115, at 61,444 & n.3 (1996); *PanEnergy Trading and Market Services, LLC*, Letter Order, Docket No. ER96-2921 (1996) (unpublished) (PanEnergy's name was subsequently changed to Duke Energy Trading and Marketing, L.C.C.).

request for market-based rate authority.[19] Thus, Duke St. Lucie's affiliation with Duke Energy does not create generation dominance concerns.

C. Ancillary Service Market Power

The Commission has previously determined that, where a seller that seeks authority to sell ancillary services at market-based rates is unable to perform a reliable market power analysis in order to show that the seller lacks market power with respect to each ancillary service, the seller will be permitted to charge flexible rates for ancillary services if it (1) utilizes an Internet-based site providing information regarding, and enabling purchasers to conduct, ancillary service transactions, and (2) complies with the Commission's market monitoring reporting requirements.[20]

Duke St. Lucie is currently unable to perform a reliable market power analysis. There is no RTO or ISO operating within the State of Florida; nor is there any sort of power exchange pursuant to which energy, capacity, or ancillary services is sold. As such, Duke St. Lucie is unable to obtain the factual data relating to the ancillary service capabilities of other suppliers necessary to perform a reliable market power analysis.

As stated earlier and as set forth in its proposed FERC Electric Tariff No. 1, Duke St. Lucie agrees to utilize an Internet-based OASIS-like site in accordance with the

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[19] *Duke Energy New Smyrna Beach Power Company, Ltd., LLP,* 83 FERC ¶ 61,316, *reh'g denied,* 84 FERC ¶ 61,308 (1998)(also new capacity under the Commission's regulations).

[20] Specifically, the Commission requires the Internet-based site to post the types of services available and their offering prices, to permit customers to request and make bids for services, and to include information about accepted and denied requests and the reasons therefor. The Commission also requires sellers to file with the Commission one year after the Internet-based site is operational and at least every three years thereafter a report detailing the seller's activities in the ancillary services market. *Avista,* 87 FERC at 61,884.

Commission's requirements and to comply with the Commission's reporting requirements. Therefore, Duke St. Lucie's request to make sales of ancillary services at market rates should be granted.

D. Transmission Market Power

Duke St. Lucie does not possess any transmission market power. As noted above, the Facility will be interconnected with transmission facilities owned and operated by FPL, and Duke St. Lucie will not own, operate or control transmission facilities other than those limited facilities described above that are necessary to interconnect the Facility with FPL.

Moreover, Duke St. Lucie's affiliates do not have transmission market power. The Commission has previously determined that, when an affiliate of a transmission-owning public utility seeks authorization to charge market-based rates and the affiliated transmission-owning public utility has on file with the Commission an open access transmission tariff, any concerns about transmission market power are mitigated.[21] Although Duke Energy owns transmission facilities, it has on file with the Commission an open access transmission tariff.[22] Accordingly, Duke St. Lucie satisfies the Commission's transmission market power standard for approval of market-based rates.

E. Other Barriers To Entry

A seller seeking market-based rate authority must show that neither it nor its affiliates can erect any other barriers to market entry. In this regard, the Commission has evaluated the following factors: ownership of generation sites; control over key inputs into

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[21] *See, e.g., Cataula Generating Co.*, 79 FERC ¶ 61,261 (1997).

[22] Docket No. OA96-46-000; *see Pacific Gas & Elec. Co.*, 77 FERC ¶ 61,025 (1996).

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generation;[23] and affiliation with, or ownership of, interstate natural gas pipelines and local natural gas distribution systems.[24]

Neither Duke St. Lucie, nor its affiliates, have the ability to erect barriers to entry. Although Duke Energy has an affiliated gas transportation pipeline project under development in the State of Florida,[25] there are competing gas pipelines in the state. The Facility's natural gas requirements will be served by Florida Gas Transmission Company, not a Duke St. Lucie affiliate. Moreover, if Duke Energy's pipeline affiliates were to deny, delay, or require unreasonable terms, conditions, or rates for natural gas service to a competitor of Duke St. Lucie in the bulk power markets,[26] a competitor can file a

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[23] *Tucson Electric Power Co.*, 80 FERC ¶ 61,236, at 61,898 (1997) (identifying "key input to power plant construction, generation or transportation" as the applicable standard for examining possible barriers to entry); *see also Heartland*, 68 FERC at 62,062 ("the Commission [has] determined that affiliation with a major engineering firm and construction firm could not be used to erect barriers to entry because there were a large number of such firms operating on a national basis").

[24] *See Duke Solutions*, 84 FERC at 62,200 (addressing concerns regarding Duke Energy's ownership of natural gas pipelines).

[25] Buccaneer Gas Pipeline Company, L.L.C. is a joint pipeline development of Duke Energy and of Williams, not an affiliate. *See* Docket Nos. CP00-14-000, CP00-15-000, and CP00-16-000.

[26] As a result of Duke Power Company's merger with PanEnergy, Duke Energy became affiliated with four natural gas pipeline companies: Texas Eastern Transmission Corporation, Algonquin Gas Transmission Company, Trunkline Gas Company, and Panhandle Eastern Pipe Line Company. In approving the Duke Power Company-PanEnergy merger, the Commission examined the potential for exercising vertical market power by combining PanEnergy's pipeline subsidiaries with Duke Power Company's electric generation and transmission facilities. The Commission held that there are sufficient alternate pipelines capable of serving the merged company's current and future gas-fired competitors in the relevant geographic markets. *Duke Power Co.*, 79 FERC at 62,039. It is worth noting that, on March 29, 1999, Duke Energy, through its wholly owned subsidiaries, PanEnergy Corp. and Texas Eastern Corporation, divested Panhandle Eastern Pipe Line Company, Trunkline Gas Company, and additional storage related to those systems to CMS Energy Corporation. In addition, Duke Energy indirectly owns 37.5% of Maritimes & Northeast Pipeline, LLC, which was placed into service December 1, 1999. On March 14, 2000, Duke Energy announced that it had completed its acquisition of East Tennessee Natural Gas Company from El Paso Energy Corporation.

complaint with the Commission that could result in the suspension of Duke St. Lucie's market-based rate authority.[27]

E. Affiliate Abuse and Reciprocal Dealing

Duke St. Lucie intends to sell at wholesale energy, capacity, and ancillary services pursuant to FERC Electric Tariff No. 1 to other Duke Energy affiliates that do not have franchised electric service territories, consistent with Commission precedent that permits entities to make market-based sales to other related-entities that are not electric utilities with franchised service territories.[28] Duke St. Lucie will not make any wholesale power sales to any affiliated public utility with a franchised electric service area except pursuant to a separate filing with the Commission under Section 205 of the Federal Power Act. Therefore, with this restriction, sales to affiliates by Duke St. Lucie pursuant to its proposed FERC Electric Tariff No. 1 do not raise affiliate abuse concerns.

The Commission is also concerned with the ability of an applicant for market-based rates to conduct business with an affiliated franchised public utility in ways that result in a transfer of benefits from the affiliated public utility and its ratepayers to the applicant and its shareholders.[29] Such concerns are not at issue here, however, because, consistent with Commission precedent, Duke St. Lucie agrees to comply with the attached Code of

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[27] *Duke Solutions*, 84 FERC at 62,200.

[28] *See, e.g., USGen Power Services, L.P.*, 73 FERC ¶ 61,302, at 61,846 (1995)(power sales transactions undertaken by any of the non-traditional affiliates at the expense of other non-traditional affiliates simply results in an allocation of revenues among the "non-regulated" affiliates); *see also Duke Energy Moss Landing, LLC*, Docket Nos. ER99-1127-000 and ER99-1128-000 (Order Feb. 24, 1999), slip op. at 3 & n.4; *Edison Mission Marketing & Trading, Inc.*, 86 FERC ¶ 61,072 (1999).

[29] *See Heartland*, 68 FERC at 62,062; *Morgan Stanley Capital Group, Inc.*, 69 FERC ¶ 61,175 (1994).

Conduct.[30] The Code of Conduct requires Duke St. Lucie to separate its personnel and business activities from Duke Energy to the extent possible, prohibits the disclosure of confidential information by Duke Energy to Duke St. Lucie, and requires Duke St. Lucie to take any transmission services from Duke Energy under its open access transmission tariffs. The Code of Conduct also protects Duke Energy's captive customers by imposing restrictions on sales of non-power goods and services to, and purchases from, Duke St. Lucie. The Code of Conduct submitted by Duke St. Lucie complies with the Commission's requirements.[31]

IV. REQUESTS FOR WAIVERS OF CERTAIN COMMISSION REGULATIONS AND CERTAIN BLANKET AUTHORIZATIONS AND APPROVALS

Duke St. Lucie requests the same waiver of FERC rules and filing requirements previously granted to other generating entities whose market-based rates have been determined to be just and reasonable and accepted for filing by the Commission. Specifically, Duke St. Lucie requests that the Commission:

1. waive the provisions of Subparts B and C of Part 35 of the Commission's regulations, with the exception of sections 35.12(a), 35.13(b), 35.15 and 36.16;

2. waive the accounting and reporting requirements of Parts 41, 101, and 141 of the Commission's regulations;

3. waive the full requirements of Part 45 of the Commission's regulations, except as limited by prior Commission orders; and

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[30] *See* Attachment 2.

[31] *Oswego Harbor Power, LLC*, 88 FERC at 61,724; *see also Rockingham Power*, 86 FERC ¶ 61,337 (1999); *Duke Energy New Smyrna Beach Power Company, Ltd., LLP*, 83 FERC at 62,290.

4. grant blanket approval of all future issuances of securities and assumptions of liability subject to objection by any interested party, pursuant to Part 34 of the Commission's regulations.

Consistent with the Commission's previous orders granting blanket market-based rate authority, Duke St. Lucie requests that it be permitted to file umbrella service agreements for short-term transactions (one year or less) within thirty days after the date of commencement of short-term service, to be followed by quarterly transaction summaries of specific sales. Duke St. Lucie further requests that for longer-term transactions (longer than one year) it be permitted to file the actual service agreement within thirty days after commencement of service. Duke St. Lucie intends to make separate filings of long-term transaction service agreements apart from filings of short-term transaction summaries and short-term umbrella service agreements.

Also consistent with the Commission's prior orders, Duke St. Lucie commits to either: (1) inform the Commission of any material change in status concerning the relevant representations set forth in this application; or (2) report such changes in the updated market analysis filed every three years by Duke Energy.

A draft Notice of Filing is provided as an attachment, as well as in electronic format on diskette.[32]

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[32] *See* Attachment 3.

V. CONCLUSION

For the foregoing reasons, Duke St. Lucie respectfully requests that the Commission accept its FERC Electric Tariff No. 1 for filing with an effective date sixty (60) days from the date of filing this application. Duke St. Lucie further requests that the Commission grant its requests for waivers and blanket approvals as set forth above.

Respectfully submitted,

Larry F. Eisenstat
Gretchen Schott
Christopher C. O'Hara
Dickstein Shapiro Morin & Oshinsky LLP
2101 L Street, NW
Washington, D.C. 20037
Tel: (202) 785-9700
Fax: (202) 887-0689

Attorneys for Duke Energy St. Lucie, LLC

Dated: April 17, 2000.

ATTACHMENT 1

DUKE ENERGY ST. LUCIE, LLC

MARKET-BASED RATE TARIFF

DUKE ENERGY ST. LUCIE, LLC
FERC ELECTRIC TARIFF NO. 1
(MARKET-BASED RATE TARIFF)

1. Availability. Duke Energy St. Lucie, LLC ("Duke St. Lucie") makes available under this Tariff:

   (a) electric capacity and energy for wholesale sales to purchasers with whom Duke St. Lucie has contracted;

   (b) Regulation and Frequency Response Service, Energy Imbalance Service, Operating Reserve-Spinning Reserve Service, and Operating Reserve-Supplemental Reserve Service, as defined by Order No. 888, to purchasers with whom Duke St. Lucie has contracted; and

   (c) Reassignment of Transmission Capacity to customers with whom Duke St. Lucie has contracted.

2. Applicability. This Tariff is applicable to: all wholesale sales of electric capacity or energy; all sales, except as provided in Paragraph 3, of Regulation and Frequency Response Service, Energy Imbalance Service, Operating Reserve-Spinning Reserve Service, and Operating Reserve-Supplemental Reserve Service; and all reassignments of Transmission Capacity by Duke St. Lucie.

3. Additional Requirements for Ancillary Service Transactions. This Tariff does not authorize the following ancillary services transactions:

   - sales to a regional transmission organization ("RTO"), such as an independent system operator or a transco, where the RTO is dependent on third parties for such services;

   - sales to any affiliate of Duke St. Lucie that is a public utility with a franchised service territory;

   - sales where the underlying transmission service is on the transmission system of a public utility owning transmission facilities that is an affiliate of Duke St. Lucie; or

   - sales to a public utility that is purchasing the ancillary services to satisfy its obligation to provide ancillary services to third parties.

Additional information regarding the availability of ancillary services is available through the following Internet Site for Ancillary Services: http:____________. This Internet Site should be used for transacting in ancillary services.

4. Duration. This Tariff shall continue in effect until terminated or changed and such termination or change becomes effective in accordance with any applicable regulatory requirements.

5. Rates. All sales of capacity, energy, and ancillary services shall be made at rates established by agreement between the purchaser and Duke St. Lucie.

6. Other Terms and Conditions. All other terms and conditions shall be established by agreement between the purchaser and Duke St. Lucie, provided that any reassignment of Transmission Capacity is subject to the terms and conditions established by the FERC for reassignment of Transmission Capacity.

7. Reassignment of Transmission Capacity. Duke St. Lucie may reassign transmission capacity that it has reserved for its own use at a price not to exceed the highest of (i) the original transmission rate paid by Duke St. Lucie; (ii) the applicable transmission provider's maximum stated firm transmission rate on file at the time of the transmission reassignment; or (iii) Duke St. Lucie's own opportunity costs capped at the applicable transmission provider's cost of expansion at the time of the sale to the eligible customer. Duke St. Lucie will not recover opportunity costs in connection with reassignments without making a filing under Section 205 of the Federal Power Act. Except for the price, the terms and conditions under which the reassignment is made shall be the terms and conditions governing the original grant by the transmission provider. Transmission capacity may only be reassigned to a customer eligible to take service under the transmission provider's open access transmission tariff or other transmission rate schedules. Duke St. Lucie will report the name of the assignee in its quarterly reports.

8. Prohibited Affiliate Sales. No sale may be made pursuant to this Tariff to any affiliate of Duke St. Lucie with a franchised service territory, unless such sale is pursuant to a separate filing approved by the Commission under Section 205 of the Federal Power Act.

9. Code of Conduct. All transactions under this Tariff shall be subject to the Code of Conduct of Duke St. Lucie.

10. Modifications. Duke St. Lucie may unilaterally apply to the Commission or other regulatory agency having jurisdiction for a modification of this Tariff under Section 205 of the Federal Power Act and the regulations promulgated under that Act.

11. Effective Date. This Tariff is effective __________ [date established by the Commission].

ATTACHMENT 2

DUKE ENERGY ST. LUCIE, LLC
CODE OF CONDUCT

Duke Energy St. Lucie, LLC ("Duke St. Lucie") has established this Code of Conduct to govern its relationship with Duke Power (a division of Duke Energy Corporation), Duke Electric Transmission (a division of Duke Energy Corporation), and any other electric utility with a franchised service territory that is an affiliate of Duke St. Lucie (collectively the "Franchised Affiliates"):

1. To the maximum extent practicable, all operating employees of Duke St. Lucie will function independently from the operating employees of the Franchised Affiliates.

2. Duke St. Lucie will maintain its books and records separately from those of the Franchised Affiliates.

3. Transmission and ancillary services provided by the Franchised Affiliates to Duke St. Lucie, if any, will be provided under the transmission provider's open access tariff utilizing the transmission provider's OASIS site.

4. Sales of any non-power goods and services by the Franchised Affiliates to Duke St. Lucie shall be priced at the higher of the Franchised Affiliates's cost or the market price for such goods or services. Any non-power goods or services provided by Duke St. Lucie to the Franchised Affiliates shall be priced at a level that does not exceed market price.

5. No employee of the Franchised Affiliates shall directly or indirectly provide any market information to any employee of Duke St. Lucie unless such information is disclosed simultaneously to the public. Market information includes, but is not limited to, any communication concerning the power or transmission business, present or future, positive or negative, concrete or potential. Shared employees in a support role are permitted, but they may not serve as an improper conduit of market information.

6. Duke St. Lucie shall not act a broker for the Franchised Affiliates.

ATTACHMENT 3

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Duke Energy St. Lucie, LLC	)	Docket No. ER00-

NOTICE OF FILING

Take notice that on April __, 2000, Duke Energy St. Lucie, LLC ("Duke St. Lucie") tendered for filing pursuant to Section 205 of the Federal Power Act an application for an order accepting its rates of filing, determining of rates to be just and reasonable, and granting certain waivers and preapprovals.

Duke St. Lucie is developing an approximately 608 MW generation facility located in St. Lucie County, Florida. Under its proposed FERC Electric Tariff No. 1, Duke St. Lucie seeks to sell energy and capacity, as well as ancillary services, at market-based rates. Duke St. Lucie also seeks authority to sell, assign, or transfer transmission rights that it may acquire in the course of its marketing activities.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. 385.211 and 385.214). All such motions or protests should be filed on or before ________________. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection or on the Internet at http://www.ferc.fed.us/online/rims.htm (call 202-208-2222 for assistance).

David Boergers
Secretary

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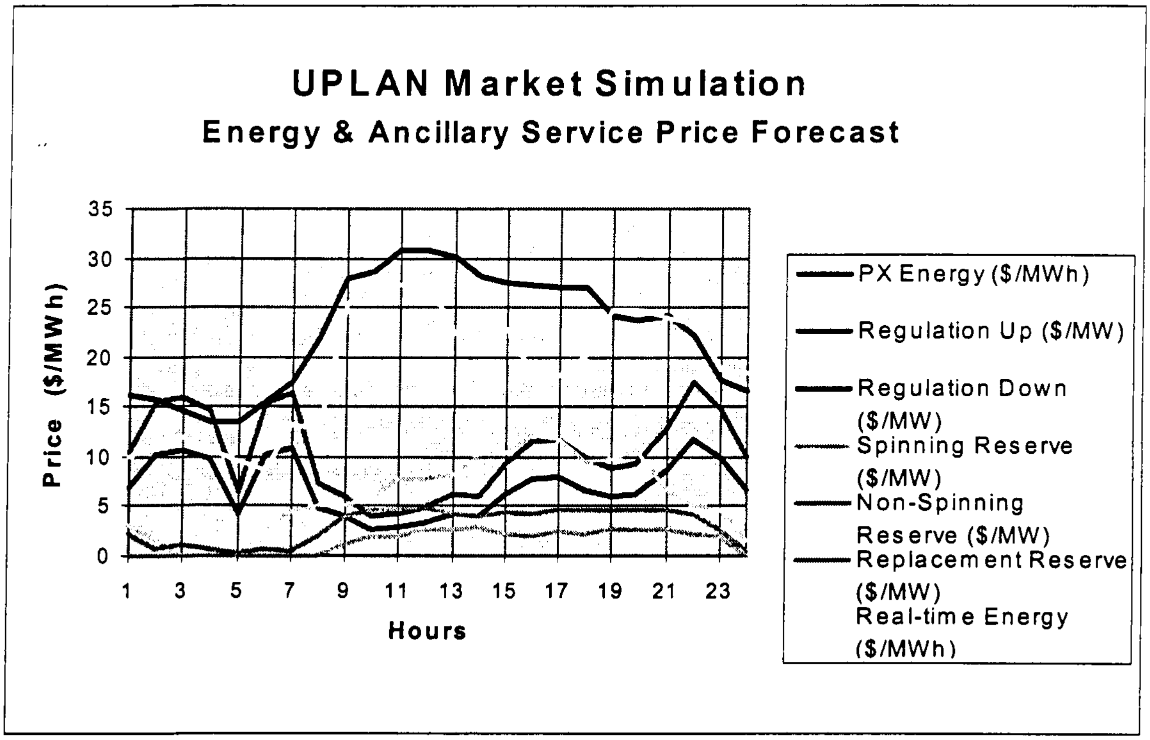
Appendix B

Summary of LCG's UPLAN Integrated Electricity Market Model.

Duke Energy St. Lucie, LLC
Petition for Determination of Need

for the Duke Energy St. Lucie Generating Project



LCG Consulting
4962 El Camino Real, Suite 112 Los Altos, CA 94022
Tel: 650-962-9670 Fax: 650-962-9615 Website: http://www.energyonline.com

Description of UPLAN System

UPLAN: The Network Power Model (NPM)

UPLAN Network Power Model (UPLAN-NPM), a Multi commodity, Multi area Optimal Power Flow (MMOPF) model, has been developed specifically to evaluate utility restructuring and to forecast market prices under competition. The objective of the MMOPF model is to simulate electricity trades and maximize the profits from the trades, taking into account network constraints, operating characteristics of plants and transmission congestion. The system simulates the energy and ancillary markets as well as the participants' trading behavior. It then establishes internally consistent forward prices for all market segments, and uses the resources selected in the forward market in an optimal power flow algorithm to determine the hourly real-time prices and unit operation.

UPLAN-NPM has been used extensively in all regions of Canada and the United States and in many countries overseas. A description of recent market evaluations and regulatory studies may be obtained from LCG. In addition to forecasting market prices, UPLAN also addresses the uncertainties of the marketplace, the potential for stranded costs, the impact of emission constraints and new entrants, and the existence of market power. The model has undergone extensive public review and testing. The results of benchmarking UPLAN have been published in the Electricity Journal[1].

Overview

UPLAN Network Power Model (NPM) is a state-of-the-art competitive electricity market model that simulates both the behavior of the market participants and the physical structure of the electric system in a regional energy market. It carries out the simulation in two steps:

[1] "How to Incorporate Volatility and Risk in Electricity Price Forecasting", The Electricity Journal, May 2000, pp65-75.

- **Electricity Market Simulation:** UPLAN-NPM simulates the behavior of the suppliers, customers and power marketers in the electricity market and determines the forward prices of energy and ancillary services. UPLAN-NPM allows different segments of the regional market to operate using their respective market protocols.

- **Real Time Dispatch and Optimal AC Power Flow:** UPLAN-NPM simulates the hourly generator operation, electricity dispatch and delivery to determine the real time or spot prices, using the optimal AC power flow (OPF) model and comprehensive data describing loads, generators and the transmission system. The model incorporates large-scale optimization techniques to model the physical system and its constraints, subject to economic market behavior.

The model determines locational spot prices, forward prices, ancillary service prices, options values (volatility), congestion prices (TCC, CMS) and many other indices applied to accurately assess the market and evaluate buy/sell and hedging strategies[2]. The NPM incorporates the latest developments in the theory and practice of competitive electricity models and operating models. It has been extensively tested through the simulation of the California PX/ISO, PJM, NEPOOL and other U.S. markets, and it has been benchmarked to actual prices in the evolving markets.

Electricity Market Model

The electricity market model simulates the energy and ancillary services markets, including regulation, spinning reserves, non-spinning reserves and replacement or capacity reserves. The model simulates participants' behavior using either user-specified bidding strategies or bids internally developed in the program, based on rational bidding. The model recognizes that different segments of the interconnected region may have different market protocols.

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[2] Rajat K. Deb, LCG Consulting, Los Altos, California, "Forecasting Competitive Electricity Prices Using the UPLAN System", Technical Report 1999.

The electricity market model contains an auction or bidding model that allows users to develop competitive bidding strategies and evaluate the impacts on the participants. It is possible for a generator in a competitive market to bid its short-run marginal cost (MC), but this runs the risk that the market price will be insufficient to recover long-run total costs. But, by bidding much higher than the MC, the generator runs the risk of losing market share. Since the short-run electricity demand and supply are relatively inelastic, low market prices may force some generators to be retired, creating shortages, which in turn drives up future prices. UPLAN can adjust the bids so that the resulting prices are sufficient for the market to be economically viable. In the long run, however, if prices go up, new players will be attracted to the market, and the added generation will drive prices down until it ceases to be profitable to make new additions. Figure 1 illustrates a 24-hour forecast of energy and ancillary service prices produced by UPLAN Market Model and the real-time prices generated by UPLAN OPF model.

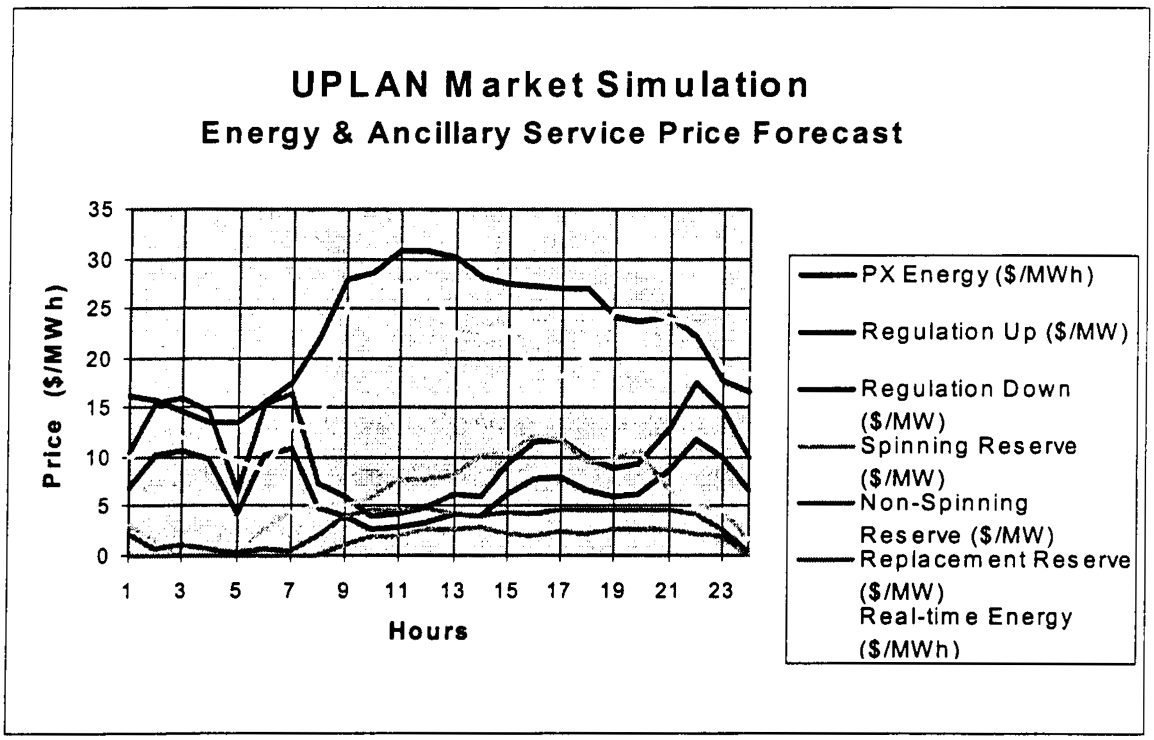

Figure 1. UPLAN Market Simulation

To determine the forward prices, the electricity market model in UPLAN optimizes the returns from all the trades by taking into consideration all the resource constraints. To meet the short-term economic viability requirements, bidders may choose the option of adjusting the bids over a period of time by an amount over the bidders' marginal cost, as allowed by supply and demand elasticity in the simulated markets. The economic viability criteria may produce ideal prices under competitive bidding.

The Real-time Dispatch Model

The optimal power flow model of the UPLAN system is one of the most important modules. It is used for simulating the real-time prices in the competitive power markets. The electricity market simulation model selects resources available to meet the anticipated demand plus necessary ancillary services more efficiently and determines the forward or ex ante Market Clearing Prices (MCP). Then, the real-time dispatch model, an Optimal AC Power Flow (OPF)[3] model, simulates the actual system dispatch and determines the real and reactive power flow in each hour. Any energy imbalances, voltage quality or congestion problems are mitigated by the OPF re-dispatch algorithm. Thus, the electricity prices determined by the real-time simulation may be different from the forward prices, due to several reasons cited below.

- Some scheduled generators may not be available due to forced outages.
- Loads may be higher/lower due to forecasting errors.
- Transmission may not be possible due to congestion.
- Additional generation may be necessary for voltage support, outages, or congestion management, etc.

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[3]
- Rajat K. Deb, LCG Consulting, Los Altos, California, "Optimal Power Flow (OFP) Algorithm of UPLAN-E: Theory and Application", technical report, 1997
- Joydeep Mitra, LCG Consulting, Los Altos, California, "Incorporating the DC Flow Model in the Decomposition-Simulation Method", research paper, 1997
- IEEE Power Engineering Society, "Optimal Power Flow: Solution Techniques, Requirements, and Challenges" Tutorial No. 96 TP 111-0, 1996
- Allen J. Wood and Bruce F. Wollenberg, "Power Generation and Control" Section 13.5 Security Constrained Optimal Power Flow, 1996

UPLAN reports transmission charges, costs of voltage support, generator income, power flows and sub-regional interchanges. In addition, the market model, in combination with the dispatch model, can accurately forecast the ancillary service prices and risk premiums. To capture the uncertainties and the risks, the UPLAN Volatility Model simulates a large number of scenarios using Monte Carlo sampling.

The Major Components of the UPLAN System

The UPLAN program is a system of models and modules designed to simulate the individual aspects of the power system and to provide custom analysis required by a user. The UPLAN integrated system consists of the following functional components of the UPLAN Integrated System

- Forward Market Model for energy and ancillary services auctions and bilateral sales.
- The Real time Dispatch Model using AC Optimal Power Flow (OPF) for congestion management and real-time prices.
- The Volatility Model for asset valuation, bidding strategies, options valuation and risk management.
- The Merchant Plant .Model for assessment of new entrants and their impact on future prices.

All the sub-models of UPLAN draw upon the Network Power Model, which provides the market analysis and simulation, dispatch and load flow. The Windows-based UPLAN system provides flexible access to the various modules and allows users to have as many modules open at a time as are needed.

Network Display Module and Data Editing

UPLAN-NPM is a sophisticated model capable of performing large-scale system optimizations for a regional electricity market. Due to the extensive features of the model and the size of its databases, it may seem to be a daunting task to try to grasp the model in its entirety. To make the task of accessing and understanding the bulk of the underlying data, LCG Consulting has built a graphical interface, referred to as the "network map." This module, which is accessed through the transmission editor, links together all of the information that is required to run a scenario. This geographically-based front end provides an intuitive means to access and revise all generation, load and transmission data at any level of detail. It also provides a means for the dynamic evaluation of the energy market by allowing changes to the underlying market database and providing quick detection and elimination of erroneous data. The following sections illustrate some of the features of the mapping capabilities, and, thereby, some of the functionality of UPLAN itself.

Network Map Display

In Figure 2, the UPLAN database for the Florida Reliability Coordinating Council region is graphically displayed using the "Network Map". Each line represents a transmission link between two nodes (buses) representing the locations of generators, major substations for loads, or transformers. By zooming into the area of interest, pointing and clicking on a bus or transmission line, UPLAN users can retrieve detailed records of the generators, loads, transmission characteristics, flowgate constraints and other related data, then display and edit the embedded data.

Each "node" on the map, often referred to as a "bus", is graphically encoded to display the characteristics of the market to which it belongs, and provides linkages with the underlying database. Thus, a simple glance at the map indicates which nodes are associated with a particular demand bus, with generation injection, or with a capacitor, reactor or transformer. Individual nodes can be brought quickly into focus on the network map by using a drop-down list.

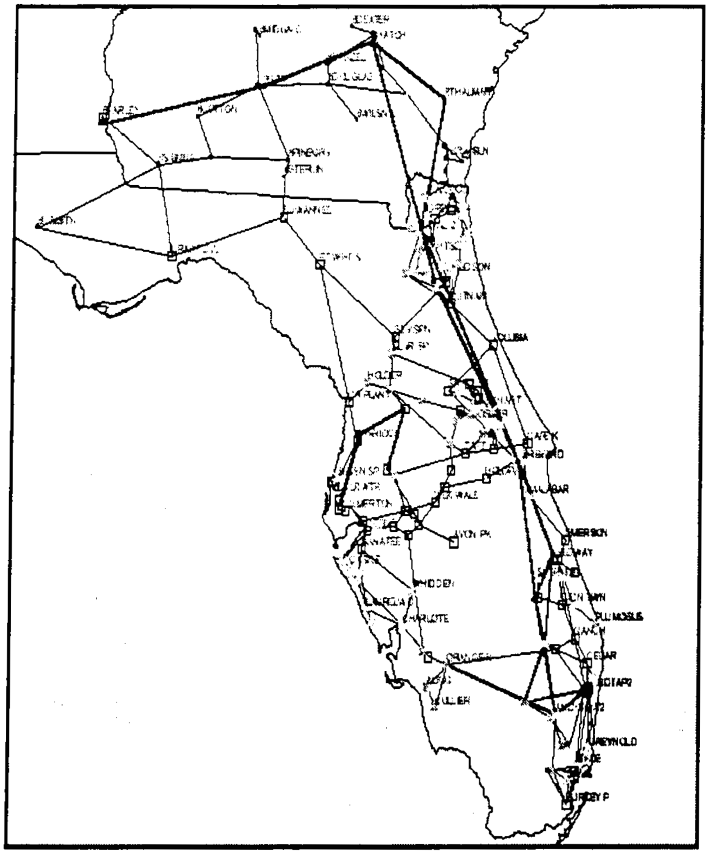


Figure 2. A Global View of the Network Map

The Transmission Interface Limits

An interface is a line or set of lines that connects two regions within the transmission area. Often, limits will be placed on the amount of energy allowed to travel from one region to another, for the purposes of system security or congestion management. Additionally, a wheeling charge may be associated with the transfer of energy. Using the Network Map, a user can bring up the Interfaces dialog box showing all the interfaces in the database, along with those lines that are part of the interface, the capacities (to and from) and any associated wheeling charges. These are illustrated in Figure 3. For a geographical look at any particular interface, the user may click the View button on the Windows-based computer screen.

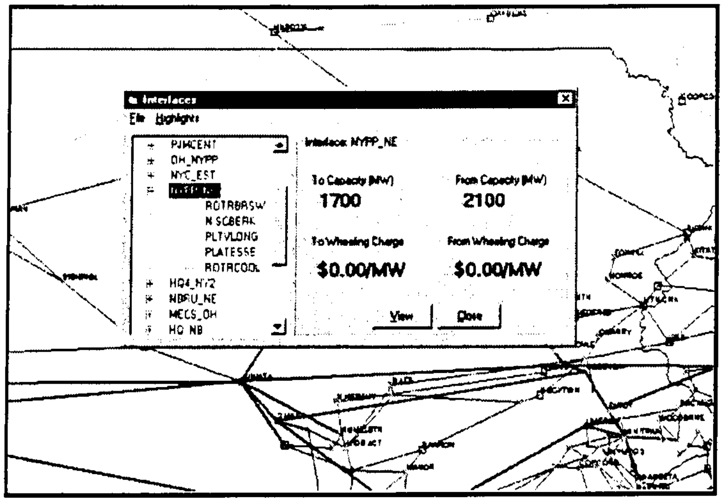


Figure 3. Transmission Interfaces

Defining the Energy Market

UPLAN is a truly multi-area system model. In the current example, hundreds of nodes consisting of demand centers and generation injection points create interconnected markets. Sometimes this granularity is excessive when analyzing sub-markets within the overall system. In this case, regions or "zones" may be defined, thereby allowing the user to limit his or her focus and to aggregate results to zonal or regional levels. For instance, the flows between different zones can be very informative in revealing imports and exports for possible trading applications. The "Network Map" allows users to define a zone or market region simply by moving the cursor around the geographic area. The Network Map will display the nodes included in the region and the users can further modify the zone using a drop-down menu. The zones may be user-assigned for analysis purposes and do not affect the physical simulation of the system.

Merchant Plant Model

Electricity prices are significantly influenced by the structure of the electricity market as it evolves over time. In a truly competitive environment, marketers will offer new products; new participants will find it attractive to participate in the market, and thus new financial instruments will become available for risk management. In the presence of liquidity and price discovery, the arbitrage between various energy products and their derivatives will be eliminated over time, and equilibrium prices will be established. Determination of the evolving market's structure, as inefficient plants are placed on stand-by or shut down, and new players enter the market, is essential for forecasting the long-term prices of various energy products. For example, the incorporation of new entrants under tightening emission constraints poses an analytical challenge that requires the comprehensive capabilities of the UPLAN Merchant Plant Model. Figure 4 presents a functional overview of the model and its capabilities.

The Merchant Plant Addition (MPA) Model has been developed within UPLAN to determine the timing, location and capacity of the new entrants most likely to participate and succeed in a competitive electricity market. In addition, existing thermal generating units may need to be replaced or refurbished to improve their efficiency or to meet emission limits.

The Merchant Plant Addition model uses a non-linear decomposition algorithm to perform the following tasks:

- It searches the transmission network to determine those nodes where the revenues from the projected market prices can support new entrants. Out of the resulting selected set of nodes, some are used as potential sites for locating new capacity additions.
- The MPA retires those units that are not economically viable, after testing whether refurbishment intended to improve total efficiency or achieve desired emission characteristics leads to a viable unit.

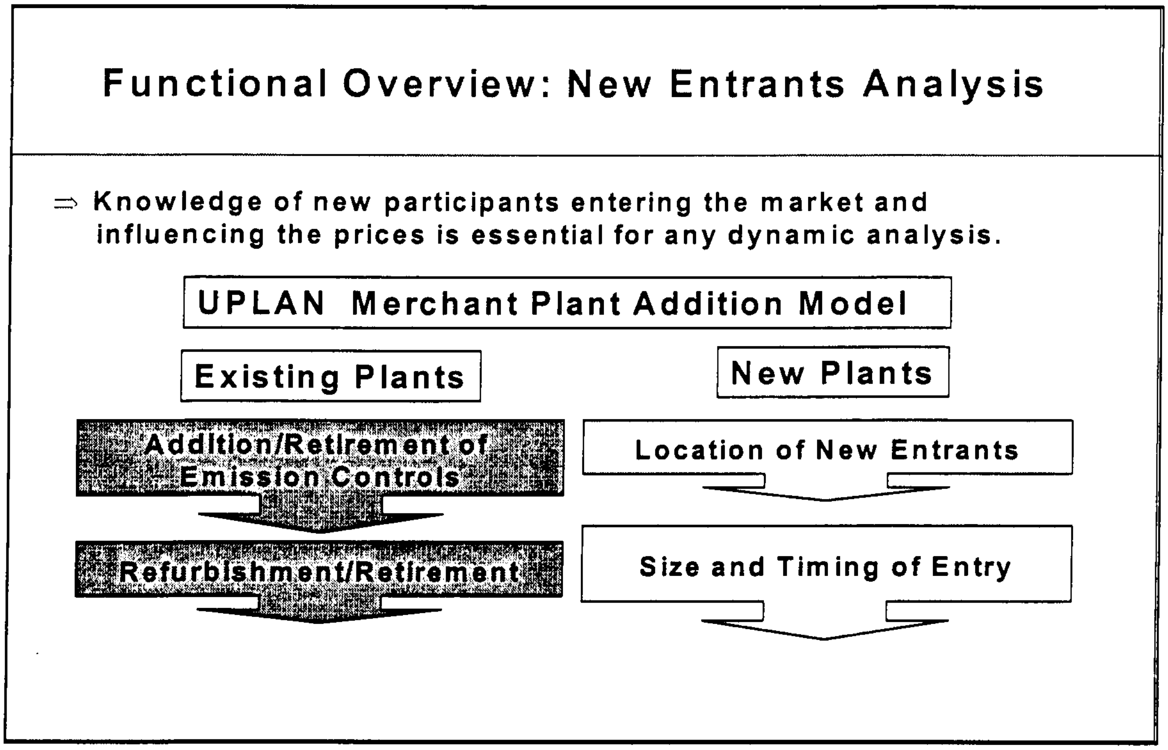


Figure 4. Merchant Plant Model Functionality Description

- The MPA model determines the optimal timing and capacity of new entrants that meet specified investment criteria in terms of rate of return and financial risk.

- The volatility analysis can be used to simulate boom and bust situations for new entrants, to illuminate the effects of uncertainty on key market drivers, and to analyze their impacts on the profitability of new entrants and existing units.

Applied together, UPLAN system models can evaluate the physical operations, reliability, market prices, economics and cost-effectiveness of future energy products and physical assets operating within the highly integrated energy, electricity and transmission marketplaces.

UPLAN APPLICATIONS

1. Background

In 1989, UPLAN was adapted to simulate daily competitive market behavior in the UK electricity grid, in order to plan the privatized electrical industry in the United Kingdom (UK). In 1991, UPLAN was used to model a competition-based national pool for Iberdrola, S.A., the largest utility in Spain. Over the last decade in the United States, UPLAN has been applied to simulate the restructured, multi-area power market in. all of the reliability regions within North America. UPLAN has also been used internationally to evaluate deregulation alternatives for countries in Europe, Asia, Australia and Africa.

In addition, UPLAN has been used to conduct competitive market assessments and to forecast market clearing prices in all the reliability regions that make up the North American Electric Reliability Council. These assessments include evaluations of the financial viability of new market entrants, and the costs and revenue requirements to recover annual carrying charges on fixed capital investments.

UPLAN has been extensively tested in more than 100 prior studies and regulatory filings involving competitive market analysis and integrated resource planning. Hence, the UPLAN series of models has become one of the most widely applied integrated system software products now being used in the United States. Its capabilities to model electricity market prices, unit and system operations and power flows, and the benchmarking of UPLAN results have recently been published in the Electricity Journal.[4]

[4] "How to Incorporate Volatility and Risk in Electricity Price Forecasting," The Electricity Journal, May 2000, pp 65-75.

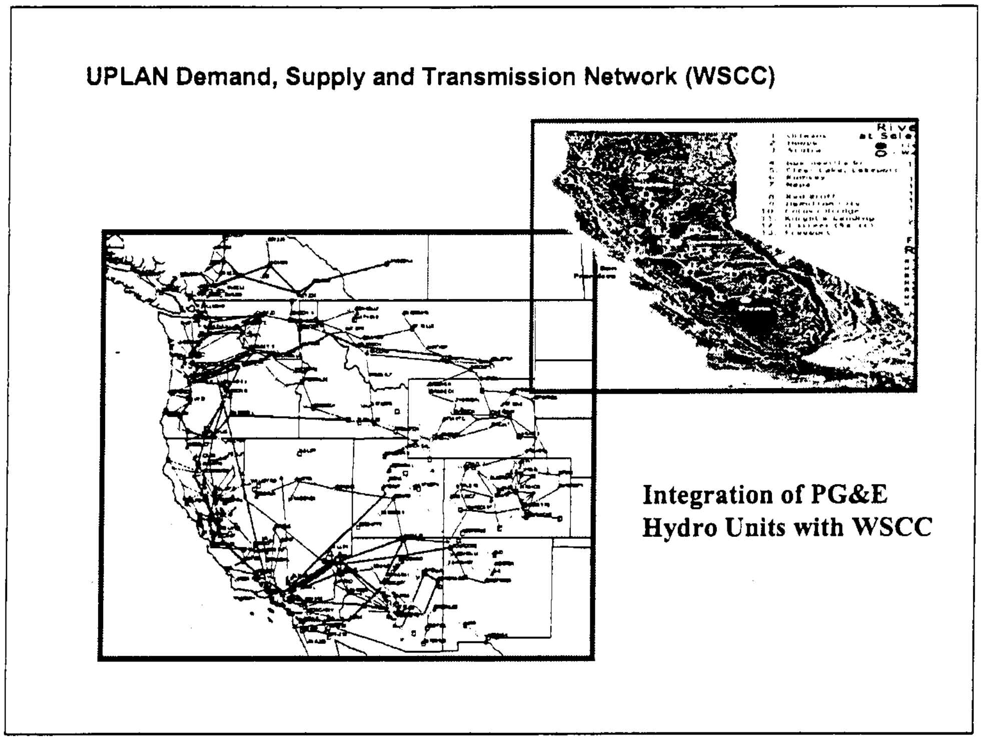
2. Recent Regulatory Studies Using UPLAN

Although most of the UPLAN studies for private clients are proprietary in nature, the following is a partial list of relevant regulatory studies conducted using UPLAN. Most of these studies fall within the general category of electricity regional market analyses. However, the coverage of issues within these studies is quite broad. For example, these studies examine optimized plant operations, forecast Market Clearing Prices (MCP) and Nodal Spot Prices (NSP) for different demand areas, evaluate specific assets, assess stranded costs, project market price volatilities, and analyze transmission access and congestion pricing across critical interfaces. In addition to projecting prices in multi-area electricity markets, UPLAN is eminently suitable for regional integrated generation and transmission reliability and cost-effectiveness analyses and can perform detailed dynamic studies of power plant operations, bidding strategies and physical situations affecting generators and transmission lines.

Among the public studies performed with the UPLAN modeling system are the following:

- **Impact of Divestiture of PG&E Hydroelectric Power Plants. CPUC Study to Satisfy the California Environmental Quality Act (CEQA). March '00 - Present Client: California Public Utility Commission, San Francisco, California**

  UPLAN is currently being used for the CPUC's CEQA study to examine the prospective divestiture of PG&E's hydroelectric generators located throughout northern California. One of the largest studies undertaken by the California Public Utilities Commission, this study analyzes the impact of auctioning PG&E's hydroelectric generators to multiple owners. UPLAN is used to simulate regional energy market and optimal power flows within the WSCC under 75 distinct hydro conditions and under various divestiture cases.



UPLAN simulates hydro schedules and operations (run of river, controlled generation, & pumped storage), discharge strategies, transmission congestion, spot and forward prices for energy and ancillary services. The project is developing and examining selected scenarios and numerous cases such as:

- Base case projections of California and WSCC regional markets, incorporating a schedule of operations for the numerous hydroelectric generators in the WSCC region. The simulated water values for power generation will be initially determined by the UPLAN Hydro Scheduler, as a first approximation.
- Competitive market strategies that produce zonal market and nodal clearing prices for existing California energy markets (day ahead, hour ahead, real time) and California ancillary service markets (regulation/AGC, spinning reserves, non-spinning reserves and replacement/operating reserves)

- Hydro plant optimized schedules developed by applying UPLAN's rational expected equilibrium pricing strategy for bidding into energy and ancillary services markets.
- Alternative scenarios based on different assumptions for major scenario parameters, in order to identify and select critical market variables for detailed uncertainty analyses.
- An examination of the potential to exert market power affecting power system operations and prices.

- **FirstEnergy Corp. on behalf of Ohio Edison Co., Cleveland Electric Illuminating Company and the Toledo Edison Company for Approval of Their Transition Plans and For Authorization to Collect Transition Revenues, 1999 – 2000.**
  Client: First Energy Corp. Columbus, Ohio
  Ohio Public Utility Commission Docket Nos. 99-1212-EL-ETP, 99-1213-EL-ATA, 99-1214-EL-AAM.

  The study develops electricity price forecasts for the East Central Reliability Council region of the United States and projects the performance of generating units using UPLAN. In addition, LCG is providing support for FirstEnergy's responses to discovery and interrogatory questions.

- **Competitive Energy Market Analysis for the State of Montana, 1997 - 1998**
  Client: Montana Consumers' Council, Helena, Montana
  Docket D97.7.91 – PacifiCorp Electric Utility Restructuring Transition Plan

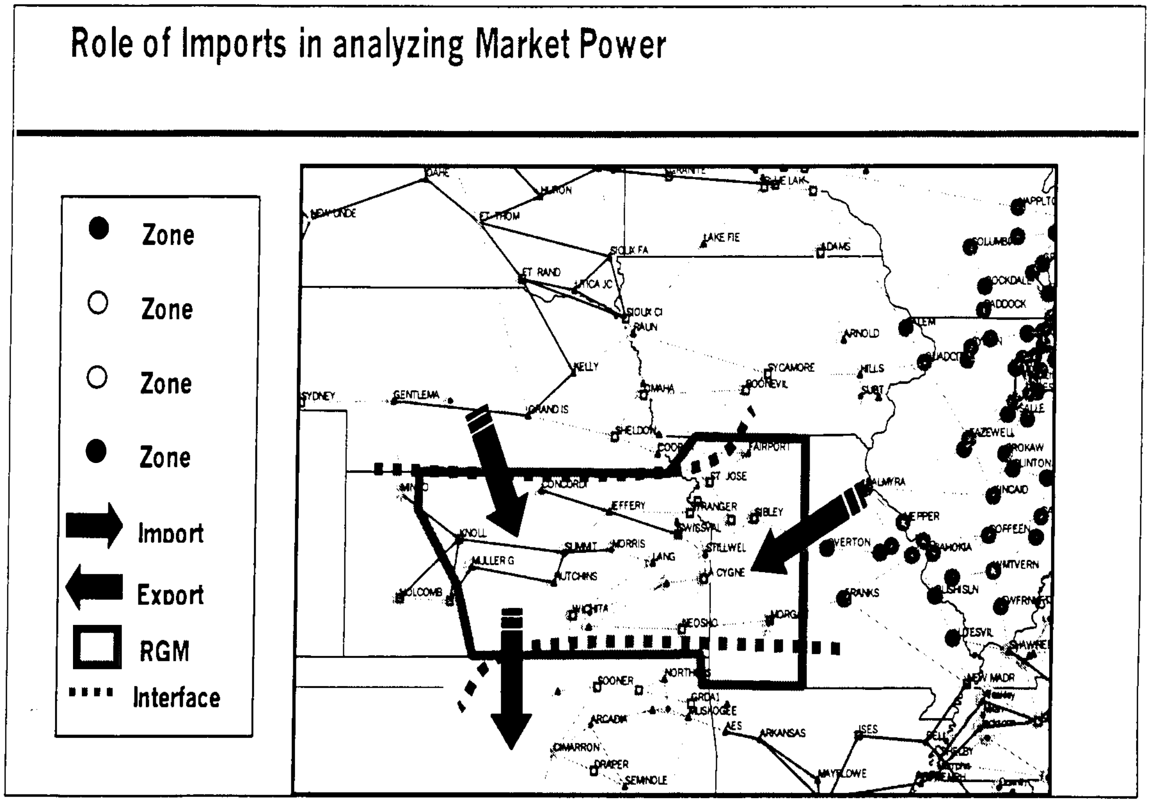
  Using UPLAN, LCG analyzed and filed expert testimony on stranded assets and the impact of the competitive market structure on generation costs, total net revenue, system average costs, and MCPs in the IndeGO region and the state of Montana. Detailed information on generating plants, (e.g. capacity factors, energy, costs, revenues and variable costs) classified by company and fuel type was reported for each generating unit in the state. LCG also provided the Montana Consumers' Council with a competitive assessment of IndeGO energy prices.

- **Retail Electricity Market Analysis for Utah Consumers, 1998**
  Client: State of Utah, Division of Public Utilities, Salt Lake City, Utah
  ED96-999-01 Market Power Study of PacifiCorp.

  By applying the UPLAN modeling system, LCG aided the Division of Public Utilities in its study of the impact of introducing competition to set retail generation prices. LCG provided a range of projected market clearing prices based on a range of alternative assumptions for electricity generation products in the Western Systems Coordinating Council (WSCC) region on an hourly, monthly and annual basis over a designated time period. In addition, other issues such as generator performance, transmission congestion and the potential for market power were also analyzed.

- **Western Resources Inc./Kansas City Power & Light Merger Application Investigation, 1998**
  Client: Missouri Public Service Commission, Jefferson City, Missouri
  Case No. EM-97-515 Missouri PSC, Utility Division

  UPLAN was used to examine market power issues associated with the prospective merger of two utilities. UPLAN addressed issues related to the measurement and duration of market power and how best to mitigate market power with respect to the proposed merger of Kansas City Power & Light and Western Resources. LCG conducted the UPLAN analysis and provided testimony on behalf of the Missouri Public Service Commission.

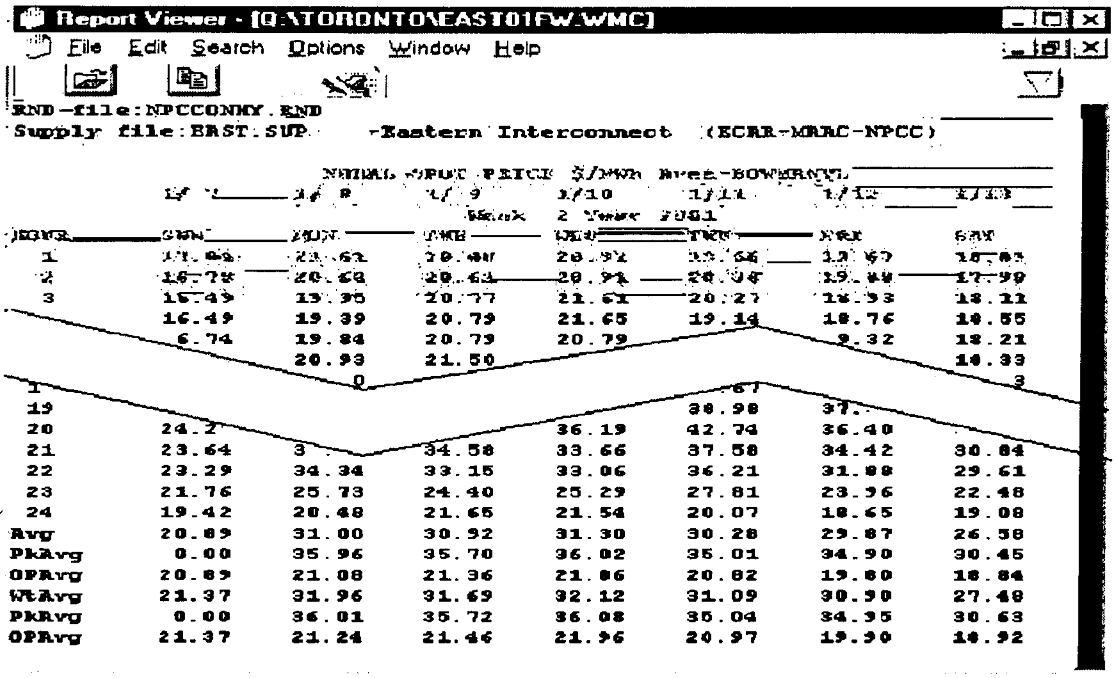


- **Analysis of California Electricity Market Restructuring Proposals, 1995-1998.
Client: California Energy Commission, Sacramento, California
Docket No. EC96-19-001 & ER96-1663-001**

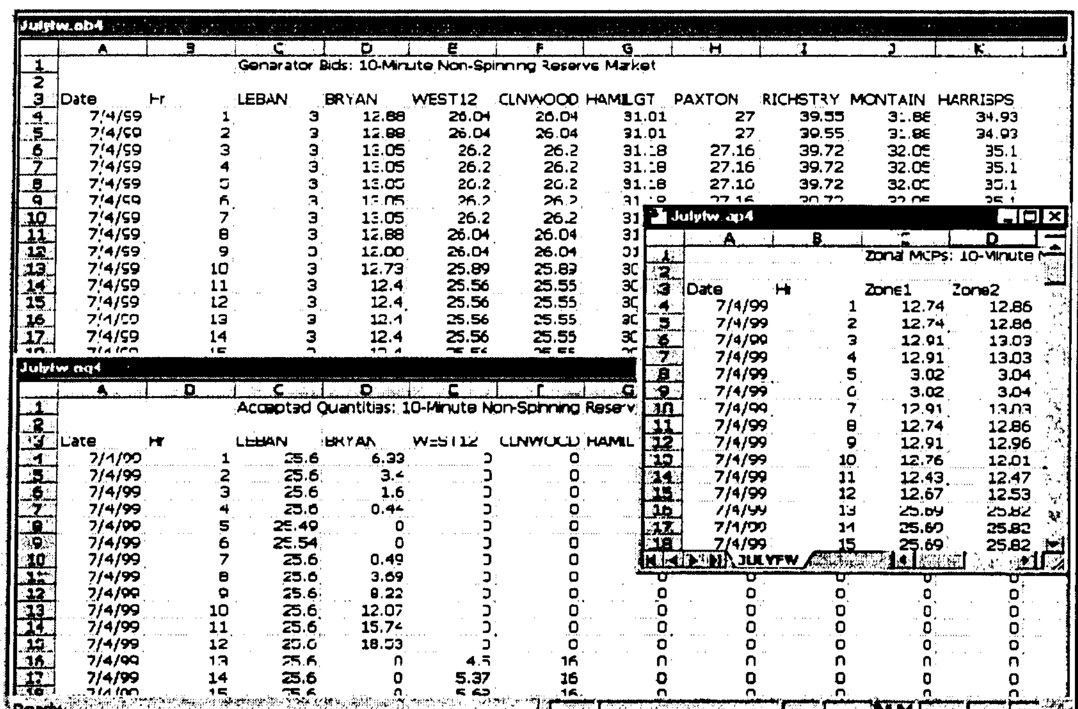
UPLAN was applied to assist the CEC in its analysis of the electric power industry during the period when proposals were being developed and debated to restructure the California electricity market to operate within a competition-based framework. LCG used its proprietary software, the UPLAN Network Power Model, to evaluate the costs, operations, and power market configurations of the Western Region under the leading restructuring proposals. The analysis was used as a basis for the WEPEX filing to FERC to create California's new market structure, and later, for Phase II of the stranded cost and RMR analyses for Southern California Edison, San Diego Gas & Electric and Pacific Gas & Electric. The RMR evaluation for reliability must-run units and its implications for stranded costs was performed using UPLAN. In addition, LCG provided the CEC with a competitive price forecast for 1997 and 1998.

Market Price Report

Nodal Spot Prices and Zonal Sellers' and Buyers' Market Clearing Prices



Ancillary Service Reports



- **Preparation of an Environmental Impact Report (EIR) 1997 for the California Public Utilities Commission, 1995-1996**
  Client: California Public Utilities Commission
  Docket No. ER96-1663-001

The UPLAN- NPM system and its associated database for generation, transmission and loads was applied to assist the California Public Utilities Commission in preparing the Environmental Impact Report required by Decision 95-12-063 for the proposed restructuring of the electric utility industry in California. CPUC Docket No. D96-12-075.

- **Market Power Analysis for UtilitCorp's FERC Merger Filing, April 2000**
  Client: Hogan & Hartson, Washington, D.C.
  Federal Energy Regulatory Commission Docket No. ER91-569-009

UPLAN was used to analyze the effect of transmission congestion on the potential of market power in the electric generation markets served by Entergy. Market power refers to the ability of the sellers or a group of sells to raise the market prices significantly above what would exist under fully competitive conditions, and to maintain the increase for a significant period of time. This results in additional profits for the company exercising market power.