BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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In re: Petition for Determination of Need of Hines Unit 2 Power Plant Docket No.: 001064-EI Submitted for Filing: October 18, 2000

FLORIDA POWER CORPORATION'S THIRD REQUEST FOR CONFIDENTIAL CLASSIFICATION

Florida Power Corporation ("FPC" or the "Company"), pursuant to Section 366.093, <u>Fla.</u> <u>Stats.</u>, and Rule 25-22.006, F.A.C., requests confidential classification of certain documents provided the Staff in response to Staff's Request for Documents to FPC. Those documents are identified by bates numbers FPC001-019, FPC032, FPC040, FPC148-149, FPC154-155, FPC173-177, FPC178-210, FPC212-233, FPC234, FPC235-251, and FPC296-299. These documents have been provided by FPC to Staff in FPC's response to Staff's Request for Documents and they are being filed under seal with the Florida Public Service Commission ("PSC" or the "Commission") because they contain proprietary, confidential business information which has not been made public.

Introduction

FPC's confidential documents fall into one of four categories: confidential bidder information (bates numbers FPC-001-019, FPC212, FPC234, and FPC235-251), third party proprietary information (bates numbers FPC040, FPC148-149, FPC154-155, and FPC173-177), proprietary contract information (bates numbers FPC032, FPC178-210, and FPC213-233), and confidential management information (FPC296-299). We will address each category in turn.

The Confidentiality of the Bids

In its RFP, the Company provided for the confidentiality of the bids it received in response to its RFP (along with any other information provided by the bidders during the course

DOCUMENT NUMBER-DATE 13237 OCT 188 FPSC-RECORDS/REPORTING of the Company's evaluation of their proposals). Two bidders submitted proposals for FPC's consideration. Both bidders requested confidential treatment for the terms of their proposals. As a result, the Company has treated the bidders' proposals as private, confidential information and the Company has not disclosed them to the public.

The documents bearing bates numbers FPC-001-019, FPC212, FPC234, and FPC235-251 contain information provided by the bidders in response to FPC's RFP that the bidders designated as confidential. Accordingly, FPC has treated the information as confidential, has restricted access to the information within the Company to those who needed the information to perform their responsibilities for the Company, and has not made the information public. (Aff. of Michael D. Rib, pp. 2-3).

The Company requested confidential classification of the bids and bidder information identified in FPC's evaluation of the bids in its request for confidential classification filed with the Commission on August 7, 2000. On October 16, 2000, an Order was entered granting FPC's request for confidential classification with respect to the bidders' information and FPC's evaluation of the bids. The documents identified by bates number in the preceding paragraph contain the same information and, for the same reasons provided in its earlier request for confidential classification, the supporting affidavit of Michael D. Rib, and now the Order granting that earlier request, as well as the affidavit of Michael D. Rib in support of FPC's Third Request for Confidential Classification filed herewith, FPC requests confidential classification for these documents.

Third Party Proprietary Information

The documents bearing bates numbers FPC040, FPC148-149, and FPC154-155 contain sensitive, proprietary information provided to FPC by FPC's equipment supplier and potential

gas transportation suppliers for the Hines 2 power unit. The documents with bates numbers FPC173-177 contains proprietary modeling formats belonging to one of FPC's system model providers. In both cases, the information is not public and FPC, pursuant to its understanding with the providers of this information, has treated and continues to treat the information as confidential. FPC requests confidential classification for the documents bearing bates numbers FPC040, FPC148-149, FPC154-155 and FPC173-177 because they contain confidential, sensitive proprietary business information belonging to third parties who provided the documents or information to FPC with the express understanding that it would be kept confidential.

Subsection 366.093(1) provides that "any records received by the Commission which are shown and found by the Commission to be proprietary confidential business information shall be kept confidential and shall be exempt from [the Public Records Act]." Proprietary confidential business information means information that is (i) intended to be and is treated as private, confidential information by the Company, (ii) because disclosure of the information would cause harm, (iii) either to the Company's ratepayers or the Company's business operations, and (iv) the information has not been voluntarily disclosed to the public. § 366.093(3), <u>Fla.Stats.</u>

Public disclosure of this proprietary third party information would harm the Company and its ratepayers. This information, or information like it, is frequently obtained or used during the course of the Company's operations and it is necessary to the efficient and effective operation of the Company's system. (Id., ¶ 9). Public disclosure of the information could undermine the ability of the Company to obtain the information in the future or cause the suppliers to impose even more restrictive terms on the receipt and use of such information. (Id.). Such disclosure might subject the Company to claims by the third party providers as well. (Id.). In either event, the Company and its ratepayers will suffer.

For these reasons, access within the Company to such information is restricted to those employees who need the information to perform their responsibilities for the Company. At no time is the information provided to the public. Accordingly, FPC requests confidential classification for the documents bearing bates numbers FPC040, FPC148-149, FPC154-155 and FPC173-177.

Proprietary Contract Information

The documents bearing bates numbers FPC178-210 contain the confidential, proprietary contract data between FPC and its equipment supplier for the Hines 2 power plant. The documents with bates numbers FPC032 and FPC213-233 are detailed financial pro formas containing information that embodies confidential, proprietary contract and variable operation and maintenance information provided to FPC by FPC's equipment supplier. Both sets of documents contain confidential, proprietary information.

As noted above, Section 366.093, <u>Fla. Stats.</u>, provides that proprietary, confidential business information is (i) intended to be and is treated as private, confidential information by the Company, (ii) because disclosure of the information would cause harm, (iii) either to the Company's ratepayers or the Company's business operations, and (iv) the information has not been voluntarily disclosed to the public. § 366.093(3), <u>Fla.Stats</u>. More to the point, contract or bid information the "disclosure of which would impair the efforts of the public utility or its affiliates to contract for goods or services on favorable terms" <u>is</u> specifically defined as proprietary confidential business information. § 366.093(3)(d), <u>Fla.Stats</u>.

The contract and technical terms between FPC and its equipment suppliers fit this statutory definition of proprietary confidential business information. Accordingly, FPC's

documents containing the information, directly or indirectly, are entitled to protection under Section 366.093 and Rule 25-22.006, F.A.C.

The very purpose of FPC's negotiations with its equipment suppliers is to obtain potentially favorable contract terms for FPC and its ratepayers. FPC endeavors at all times to negotiate contract terms that will offer lower cost resources or provide more economic value to FPC and its ratepayers. In order to negotiate and obtain such favorable terms, however, FPC must be able to assure potential suppliers that the terms of their negotiations and contracts will be kept confidential.

Without the assurance of confidentiality for the negotiations and the terms of contracts with suppliers, the utility's "efforts ... to contract for goods or services on favorable terms" will be impaired. §366.093, <u>Fla.Stats</u>. Indeed, if such proprietary contract information is not kept confidential, and potential suppliers know that the negotiations and terms of their contracts or bids are subject to public disclosure, they will be less willing to make concessions on price, delivery, and other contract terms. (Aff. of Michael D. Rib, ¶ 13). Rather than make such concessions known to their competitors or other potential customers, thus impairing their ability to compete or negotiate more favorable terms in the future with other customers, they will refuse to negotiate with the Company on such terms at all. (<u>Id.</u>). Or, suppliers who otherwise would have submitted bids to, or entered into negotiations with, the Company might decide not to do so, if there is no assurance that their proposals would be protected from disclosure. (<u>Id.</u>). In either event, the Company will be able to obtain equipment or services only upon less favorable terms than it otherwise would have if the parties were assured that the terms of their negotiations or contract proposals would remain confidential.

For all these reasons, FPC has treated and continues to treat this information as confidential, especially its proprietary contract information. (Id. \P 12). Access to the information is restricted within FPC to those employees who need the information to perform their duties and responsibilities with the Company. At no time has such proprietary contract information ever been made public. (Id.).

Accordingly, for each of the foregoing reasons, FPC requests confidential classification for the documents bearing bates numbers FPC032, FPC178-210, and FPC213-233 that were produced by FPC in response to Staff's Request for Documents to FPC.

Confidential Management Information

The documents bearing bates numbers FPC296-299 contain confidential, sensitive management information with respect to the proprietary contract information mentioned above and the internal financial assessment of the Hines 2 power plant. This is confidential, proprietary business information.

The public disclosure of such information will harm FPC and its ratepayers. (Id. ¶ 13). Such disclosure will undermine the ability of the Company to make such decisions in the future on behalf of the Company and its ratepayers. No Company would document such proprietary business and financial information for its management if it will be forced to make such information public. (Id.).

The Company certainly treats such information confidentially. Very few employees were involved in the preparation of the document for management, access was restricted to management until a decision was made, and it was not disseminated within the Company after that decision was made. (Id. ¶ 12). It has never been made public. (Id.).

For these reasons, FPC requests confidential classification for the documents bearing bates numbers FPC296-299 that were produced by FPC in response to Staff's Request for Documents to FPC.

Conclusion

Attachment A hereto contains a justification matrix supporting FPC's third request for confidential classification of the confidential documents provided the Staff in response to Staff's Request for Documents to FPC. The confidential information is identified by document, page, and/or line, where appropriate (for example, in place of certain documents in FPC's response to Staff's Request for Documents to FPC, which would contain nothing but blank pages if the proprietary, confidential business information was redacted, FPC has included a single page for the confidential classification). FPC respectfully requests that certain documents provided by FPC in response to Staff's Request for Documents to FPC identified by bates number in this request for confidential classification, which contain confidential, proprietary information, be classified as confidential for the reasons set forth above.

Respectfully submitted this 18^{th} day of October, 2000.

huhd Nath Gary L. Sasso

J. Michael Walls Jill H. Bowman **Carlton Fields** P. O. Box 2861 St. Petersburg, Florida 33731-2861 Telephone: (727) 821-7000 Facsimile: (727) 822-3768

and

Robert A. Glenn Director, Regulatory Counsel Group Florida Power Corporation P.O. Box 2861 St. Petersburg, FL 33731 Telephone: (727) 820-5184 Facsimile: (727) 820-5519

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT a true and correct copy of the foregoing has been furnished by Federal Express to Deborah Hart, Esq., as counsel for the Public Service Commission, and by U.S. Mail to all other interested parties of record as listed below on this 17^{th} of October, 2000.

Attorney 4

PARTIES OF RECORD:

Deborah Hart, Esq. Division of Legal Services Florida Public Service Commission Gunter Building 2540 Shumard Oak Boulevard Tallahassee, FL 32399-0850

Myron Rollins Black & Veatch P.O. Box 8405 Kansas City, MO 64114 Buck Oven Siting Coordination Office Department of Environmental Protection 2600 Blairstone Road Tallahassee, FL 32301

Paul Darst Strategic Planning Department of Community Affairs 2740 Centerview Drive Tallahassee, FL 32399-2100

ATTACHMENT A DOCUMENT **PAGE/LINE** JUSTIFICATION FPC's Response to Staff's §366.093(3)(d). All Request for Documents to This is information concerning FPC, bates numbers the bids in response to the FPC001-019, FPC212, Request for Proposals ("RFP"), the disclosure of FPC234, and FPC235-251 which would impair the utility's efforts to contract for such services on favorable terms. FPC's Response to Staff's \$366.093. All

Request for Documents to FPC, bates numbers FPC040, FPC148-149, FPC154-155, and FPC173- 177		This is third party proprietary information, the disclosure of which would impair the utility's efforts to efficiently and effectively operate its system.
FPC's Response to Staff's	All.	§366.093(3)(d).
Request for Documents to FPC		This is information concerning the contract terms and negotiations with FPC's suppliers, the disclosure of which would impair the utility's efforts to contract for equipment or services on favorable terms
FPC's Response to Staff's	All.	\$366.093.
Request for Documents to FPC		This is proprietary, confidential business information involving FPC's management decisions, the disclosure of which would restrict or preclude full and open discussions and thus result in harm to the utility and its ratepayers.

BATES NOS. FPC 001 – FPC 019 CONFIDENTIAL PURSUANT TO FLORIDA POWER CORPORATION'S REQUST FOR CONFIDENTIAL CLASSIFICATION FILED AUGUST 7, 2000

		RI	ESERVE MAR	GINS			
		-			. •		
		WINTER RM	%	S	UMMER RM	%	
	1999	2000	'00 - '99		1999	2000	'00 - '99
YEAR	TYSP	TYSP	CHANGE	YEAR	TYSP	TYSP	CHANGE
1999 / 00	16	· ·		2000	18	19	1
2000 / 01	17	16	-1	2001	17	18	1
2001 / 02	18	20	2	2002	19	23	4
2002 / 03	24	22	-2	2003	25	26	1
2003 / 04	20	25	5	2004	21	29	8
2004 / 05	22	23	. 1	2005	23	26	3
2005 / 06	19	25	6	2006	19	27	8
2006 / 07	23	21	-2	2007	22	23	1
2007 / 08	20	24	4	2008	18	26	8
2008 / 09	17	20	3	2009		21	
2009 / 10		22	· .	·			

Note: Reserve margin criteria increased from 15% in 1999 to 20% in 2000.

PLANNED ADDITIONS											
1999 TYSP 2000 TYSP											
ADDITION	(MW)	IN-SERVICE	(MW)	IN-SERVICE	COMMENTS						
HEC#1	505	4/99	0		Included in existing system						
System upgrades	91		58		CR upgrades / CT Fogging						
System changes	0		35		Rating changes						
IC #12-14	297	12/00	282	12/00							
HEC#2	567	11/04	567	11/03	1 year acceleration						
HEC#3	567	11/06	567	11/05	1 year acceleration						
HEC#4			567	11/07	new unit						
HEC#5			567	11/09	new unit						
TOTAL NEW	2,027	=	2,643	a							
SR STEAM	-147	12/01	-146	12/03	Delayed 2 yrs						
HIGGINS P1-4	-148	12/03	-134	12/05	Delayed 2 yrs						
RIO PINAR	-18	12/03	-16	12/05	Delayed 2 yrs						
AP P1-2	-64	12/04	-64	12/06	Delayed 2 yrs						
TURNER P1-2	-36	12/04	-32	12/06	Delayed 2 yrs						
TOTAL RETIRE	-413	=	-392	-							
NET PLANNED	1,614		2,251								

Note: Retirement plan in 2000 does not match dismantlement plan.

	ÿ				DEMAND	& ENERG	Ŷ				· · ·	•
		1999			2000	TYSP		2000 TYSP LESS 1999 TYSP (DELTA)				
	WHOLE	LOAD	FIRM	NET	WHOLE	LOAD	FIRM	NET	WHOLE	LOAD	FIRM	NET
	SALE	MGT	LOAD	ENERGY	SALE	MGT	LOAD	ENERGY	SALE	MGT	LOAD	ENERGY
YEAR	(MW)	(MW)	(MW)	(GWh)	(MW)	(MW)	(MW)	(GWh)	(MW)	(MW)	(MW)	(GWh)
1999 / 00	1,575	865	8,221	39,228	1,647	849	8,259	40,846	72	-16	38	1,618
2000 / 01	1,668	859	8,459	40,367	1,731	809	8,528	41,927	63	-50	69	1,560
2001 / 02	1,266	790	8,271	39,525	1,274	744	8,282	41,330	8	-46	11	1,805
2002 / 03	720	743	7,913	40,048	928	701	8,120	42,221	208	-42	207	2,173
2003 / 04	666	713	8,020	40,967	877	673	8,230	43,268	211	-40	210	2,301
2004 / 05	728	690	8,232	41,911	890	652	8,394	44,215	162	-38	162	2,304
2005 / 06	806	670	8,455	42,856	968	635	8,609	45,214	162	-35	154	2,358
2006 / 07	883	652	8,677	43,789	1,046	619	8,820	46,180	163	-33	143	2,391
2007 / 08	963	637	8,900	44,714	1,129	605	9,029	47,066	166	-32	129	2,352
2008 / 09	1,046	623	9,125		1,210	592	9,233	47,945	164	-31	108	
2009 / 10					1,291	580	9,440					

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SCHEDULE 9

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

- (1) PLANT NAME AND UNIT NUMBER:
- (2) CAPACITY a. SUMMER:
 - b. WINTER:
- **TECHNOLOGY TYPE:** (3)
- (4) ANTICIPATED CONSTRUCTION TIMING a. FIELD CONSTRUCTION START-DATE: b. COMMERCIAL IN-SERVICE DATE:
- (5) FUEL a. PRIMARY FUEL: **b.** ALTERNATE FUEL:
- (6) AIR POLLUTION CONTROL STRATEGY:
- (7) COOLING METHOD:
- (8) TOTAL SITE AREA:
- (9) CONSTRUCTION STATUS:
- (10) **CERTIFICATION STATUS:**
- (11)STATUS WITH FEDERAL AGENCIES:
- PROJECTED UNIT PERFORMANCE DATA (12) PLANNED OUTAGE FACTOR (POF): FORCED OUTAGE FACTOR (FOF): EQUIVALENT AVAILABILITY FACTOR (EAF): ASSUMED CAPACITY FACTOR (%): AVERAGE NET OPERATING HEAT RATE (ANOHR):

(13)

INTERCESSION CITY P12 - 14

240 MW 282 MW

COMBUSTION TURBINE

3/1999 12/2000 (EXPECTED)

NATURAL GAS DISTILLATE OIL

DRY LOW NOx COMBUSTION (NATURAL GAS) WATER INJECTION (DISTILLATE OIL)

AIR

165 ACRES

UNDER CONSTRUCTION

SITE PERMITTED

SITE PERMITTED

2.88	%
3.00	%
91.00	%
15.00	%
13,272	BTU/KWH

PROJECTED UNIT FINANCIAL DATA			Reference
BOOK LIFE (YEARS):	25		Only
TOTAL INSTALLED COST (IN-SERVICE YEAR \$/kW	V): 308.51		87,000
DIRECT CONSTRUCTION COST (\$/kW):	281.21		79,300
AFUDC AMOUNT (\$/kW):	27.30		7,700
ESCALATION (\$/kW):	0.00		- 0
FIXED O & M (\$/kW-Yr):	1.40		395
VARIABLE O & M (\$/MWH):	4.35		
K FACTOR:	NO CALCULATIO	N	

FPC 022

SCHEDULE 9

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

- PLANT NAME AND UNIT NUMBER: (1)
- CAPACITY (2) a. SUMMER:
 - **b.** WINTER:
- **TECHNOLOGY TYPE:** (3)
- (4) ANTICIPATED CONSTRUCTION TIMING a. FIELD CONSTRUCTION START-DATE: b. COMMERCIAL IN-SERVICE DATE:
- (5) FUEL
 - a. PRIMARY FUEL: b. ALTERNATE FUEL:
- (6) AIR POLLUTION CONTROL STRATEGY:
- COOLING METHOD: (7)
- (8) TOTAL SITE AREA:
- (9) CONSTRUCTION STATUS:
- (10) **CERTIFICATION STATUS:**
- (11)STATUS WITH FEDERAL AGENCIES:
- (12) PROJECTED UNIT PERFORMANCE DATA PLANNED OUTAGE FACTOR (POF): 4.41 % FORCED OUTAGE FACTOR (FOF): 3.70 % EQUIVALENT AVAILABILITY FACTOR (EAF): 91.00 % ASSUMED CAPACITY FACTOR (%): 70.00 % AVERAGE NET OPERATING HEAT RATE (ANOHR): 7.306 BTU/KWH
- (13) PROJECTED UNIT FINANCIAL DATA BOOK LIFE (YEARS): TOTAL INSTALLED COST (IN-SERVICE YEAR \$/kW): 345.95 DIRECT CONSTRUCTION COST (\$/kW): 292.00 AFUDC AMOUNT (\$/kW): ESCALATION (\$/kW): FIXED O & M (\$/kW-Yr): VARIABLE O & M (\$/MWH): K FACTOR:

HINES ENERGY COMPLEX UNIT #2

495 MW 567 MW

COMBINED CYCLE

8/2000 11/2003 (EXPECTED)

NATURAL GAS DISTILLATE OIL

DRY LOW NOx COMBUSTION with SELECTIVE CATALYTIC REDUCTION

COOLING PONDS

8,200 ACRES

PLANNED

SITE PERMITTED

SITE PERMITTED

Reference
Only
196,154
165,564
21,478
- 9,112
1,418

Deference

2.10 NO CALCULATION

25

37.88

16.07

2.50

SCHEDULE 9

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

- (1) PLANT NAME AND UNIT NUMBER:
- CAPACITY (2) a. SUMMER:
 - b. WINTER:
- TECHNOLOGY TYPE: (3)
- ANTICIPATED CONSTRUCTION TIMING (4) a. FIELD CONSTRUCTION START-DATE: b. COMMERCIAL IN-SERVICE DATE:
- FUEL (5) a. PRIMARY FUEL: **b.** ALTERNATE FUEL:
- AIR POLLUTION CONTROL STRATEGY: (6)
- COOLING METHOD: (7)
- TOTAL SITE AREA: (8)
- CONSTRUCTION STATUS: (9)
- CERTIFICATION STATUS: (10)
- STATUS WITH FEDERAL AGENCIES: (11)

PROJECTED UNIT PERFORMANCE DATA (12) PLANNED OUTAGE FACTOR (POF): FORCED OUTAGE FACTOR (FOF): 91.00 % EQUIVALENT AVAILABILITY FACTOR (EAF): 70.00 % ASSUMED CAPACITY FACTOR (%): 7,306 BTU/KWH AVERAGE NET OPERATING HEAT RATE (ANOHR):

PROJECTED UNIT FINANCIAL DATA (13) 25 BOOK LIFE (YEARS): TOTAL INSTALLED COST (IN-SERVICE YEAR \$/kW): 408.61 329.00 DIRECT CONSTRUCTION COST (\$/kW): 44.74 AFUDC AMOUNT (\$/kW): 34.87 ESCALATION (\$/kW): 2.50 FIXED O & M (/kW-Yr): 2.10 VARIABLE O & M (\$/MWH): NO CALCULATION K FACTOR:

HINES ENERGY COMPLEX UNIT #3

495 MW 567 MW

COMBINED CYCLE

8/2002 11/2005 (EXPECTED)

NATURAL GAS DISTILLATE OIL

DRY LOW NOx COMBUSTION with SELECTIVE CATALYTIC REDUCTION

COOLING PONDS

8.200 ACRES

PLANNED

SITE PERMITTED

4.41 %

3.70 %

SITE PERMITTED

Reference <u>Only</u> 231,682 186,543 25,368 19,771 1,418

- 73 -

SCHEDULE 9

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

HINES ENERGY COMPLEX UNIT #4 PLANT NAME AND UNIT NUMBER: -(1)(2) CAPACITY 495 MW a. SUMMER: 567 MW b. WINTER: COMBINED CYCLE **TECHNOLOGY TYPE:** (3) ANTICIPATED CONSTRUCTION TIMING (4) 8/2004 a. FIELD CONSTRUCTION START-DATE: 11/2007 (EXPECTED) b. COMMERCIAL IN-SERVICE DATE: . . . (5) FUEL NATURAL GAS a. PRIMARY FUEL: DISTILLATE OIL **b.** ALTERNATE FUEL: DRY LOW NOx COMBUSTION AIR POLLUTION CONTROL STRATEGY: (6) with SELECTIVE CATALYTIC REDUCTION COOLING PONDS **COOLING METHOD:** (7) 8,200 ACRES TOTAL SITE AREA: (8) PLANNED (9) CONSTRUCTION STATUS: SITE PERMITTED (10)**CERTIFICATION STATUS:** SITE PERMITTED STATUS WITH FEDERAL AGENCIES: (11) PROJECTED UNIT PERFORMANCE DATA (12) 4.41 % PLANNED OUTAGE FACTOR (POF): 3,70 % FORCED OUTAGE FACTOR (FOF): EQUIVALENT AVAILABILITY FACTOR (EAF): 91.00 % 70.00 % ASSUMED CAPACITY FACTOR (%): 7,306 BTU/KWH AVERAGE NET OPERATING HEAT RATE (ANOHR): Reference PROJECTED UNIT FINANCIAL DATA (13) Only 25 BOOK LIFE (YEARS): 243,413 TOTAL INSTALLED COST (IN-SERVICE YEAR \$/kW): 429.30 186,543 329.00 DIRECT CONSTRUCTION COST (\$/kW): 47.00 26,649 AFUDC AMOUNT (\$/kW): 30,221 53.30 ESCALATION (\$/kW): 1,418 2.50 FIXED O & M (kW-Yr): 2.10 VARIABLE O & M (\$/MWH):

NO CALCULATION

-	74	-	
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K FACTOR:

SCHEDULE 9

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

(1) PLANT NAME AND UNIT NUMBER: -HINES ENERGY COMPLEX UNIT #5 (2) CAPACITY a. SUMMER: 495 MW b. WINTER: 567 MW **TECHNOLOGY TYPE:** (3) COMBINED CYCLE (4) ANTICIPATED CONSTRUCTION TIMING a. FIELD CONSTRUCTION START-DATE: 8/2006 b. COMMERCIAL IN-SERVICE DATE: 11/2009 (EXPECTED) (5) FUEL a. PRIMARY FUEL: NATURAL GAS **b.** ALTERNATE FUEL: DISTILLATE OIL AIR POLLUTION CONTROL STRATEGY: (6) (7) · COOLING METHOD: COOLING PONDS (8) TOTAL SITE AREA: 8,200 ACRES (9) CONSTRUCTION STATUS: PLANNED (10) CERTIFICATION STATUS: SITE PERMITTED (11) STATUS WITH FEDERAL AGENCIES: SITE PERMITTED (12) PROJECTED UNIT PERFORMANCE DATA PLANNED OUTAGE FACTOR (POF): 4.41 % FORCED OUTAGE FACTOR (FOF): 3.70 % EQUIVALENT AVAILABILITY FACTOR (EAF): 91.00 % ASSUMED CAPACITY FACTOR (%): 70.00 % AVERAGE NET OPERATING HEAT RATE (ANOHR): 7,306 BTU/KWH PROJECTED UNIT FINANCIAL DATA (13) BOOK LIFE (YEARS): 25 TOTAL INSTALLED COST (IN-SERVICE YEAR \$/kW): 451.03 DIRECT CONSTRUCTION COST (\$/kW): 329.00 AFUDC AMOUNT (\$/kW): 49.38 ESCALATION (\$/kW): 72.65 FIXED O & M (\$/kW-Yr): 2.50 VARIABLE O & M (\$/MWH): 2.10 K FACTOR: NO CALCULATION

- 75 -

DRY LOW NOx COMBUSTION with SELECTIVE CATALYTIC REDUCTION

> Reference Only 255,734 186,543 27,998 41,193 1,418

FPC 026

2000 Ten-Year Site Plan 2000 Dollars

Hines Hines Hines Hines Hines Hines Inter, City FPC System Retire NET Plant name Repower Repower CT gas CT gas 1GCC Puly, Coal FL BED Bartow Bartow Bartow F Type F Type G Тура Option name Higgins \$ at CC MW Market ("EA") ' ("F") Steam Steam 2000 TYSP Sludy HEM HG HIGCC HPC HFB CTEA CTF HF alternative number SRS RBART BART net CTF CCH2 PVC FLB **3CTEA** RHS BAR3/2 XBAR net BAR3/2 CCM CCG IGCC SUGGESTED alternative number Generation and Fuel 178 567 365 577 800 500 282 567 380 561 225 561 New winter maximum capacity MW 495 323 494 780 500 249 151 516 495 мw 353 516 220 New summer maximum capacity 89 190 288 400 250 141 289 мw 189 269 269 289 New minimum capacity 2 з Unit 3 of 1&2 Number of Units in capacity ralings 1 site 1 of 2 1 1 1 1 no limit no limit 380 1122 450 672 no limit no limit no limit no limit no limit no limit Avaialable Capacity 11.814 10.300 10,614 6.800 6.800 6.787 8.555 9.874 8,060 7.045 Full load net heat rate (x000) (blu/kwh) 11.000 7.850 7.535 9.867 10,704 15.621 13,972 7.850 Minimum load net heat rate (x000) (btu/kwh) 8.855 8.315 3.0 3.0 3.7 3.7 3.7 8.0 7.0 7.0 5.0 5.0 Mature forced outage rate 2.3 4.0 5.0 4.0 1.5 1.5 2.3 23 Maintenance requirement (wks/yr) 3.0 3.0 HS coal IT Gas HS coal IT Gas Firm Gas Firm Gas Firm Gas Firm Gas HS coal fuel name Firm Gas Primary fuel type IT Gas IT Gas HS coal HS coal HS coal Dist. Oil Dist. Oil IT Gas Secondary fuel type fuel name IT Gas IT Gas 2.4 33.4 22,0 20.3 1.4 2.9 existing O&M 2.5 2.5 Incremental Fixed O&M rate (\$/kw/yr) 5.9 2.72 14.4 1,402 1,402 865 19,250 17,634 10,146 407 519 3,247 Incremental Fixed O&M rate (\$000/yr) 2,220 1,525 ٥ 32 0 n/a 32 n/a ova n/a (\$/kw/yr) 32 32 0 32 32 Fixed gas demand cost 18,144 11,680 0 n/a n/a n/a n/a (\$000/yr) 12.144 17,952 0 17,952 18,144 Fixed gas demand cost 65,000 41,843 65,000 (mmbtu/day) 43,505 64,312 64,312 Fixed gas quantity 2,10 0.72 1.28 4.59 4.35 3.77 2.02 2.19 2.41 1.34 2,10 1.96 (\$/mwh) Variable O&M cost 0.70 0.70 0.70 0.70 0.85 0.85 0,85 0.15 0.15 (CF%) 0.60 0.70 0.50 Variable O&M Capacity Factor (check) 17,103 6,842 6,842 4,128 2.875 7.513 1.516 815 Variable O&M cost (check) (\$000/yr) 3.884 7,220 2.304 3,193 Capital Expenditure & Recovery 2 2 3 vears 3 3 3 3 4 4 Design construction duration 165,830 186,430 160,680 718,940 707,610 491,310 80,000 44,808 (\$1000) 173,040 194,155 Generation Costs 20 10 30 30 15 15 20 Construction expenditure (1st year) 20 20 15 60 60 20 25 20 70 70 60 50 50 Construction expenditure (2nd year) % 25 30 35 40 Construction expenditure (3rd year) 30 30 25 25 % 30 20 30 Construction expenditure (4th year) 885 983 284 252 292 329 440 1,246 456 346 Base cost w/o AFUDC (\$/kw) WTR 301 983 272 (\$/kw) NOM. 361 312 351 467 1.343 896 473 Base cost w/o AFUDC 578 Base Incremental cost w/o AFUDC (\$/kw) WTR Additional Information begin 1/2002 begin 3/2004 begin 1/2005 Comments 3 units 1 unit 1 unit 1 unit 2 units 2 units 1 unit 3 units 2 units 1 unit 1 unit Comments High Capital Sensitivity 100,000 56.011 745,308 778,680 527.875 (\$1000) 191,506 210,831 182,413 233,038 176,645 High Generation Costs 322 411 484 1,292 973 1,056 355 315 (S/kw) WTR 505 376 High cost w/o AFUDC Low Capital Sensitivity 437,750 76,000 42.568 157.539 177.109 155.015 579,684 638,600 157,578 159,653 (\$1000) Low Generation Costs 798 876 270 239

278

285

(S/kw) WTR

415

312

425

1.005

TYSP00\$f.xls: tyspoo\$f

Low cost w/o AFUDC

-93

FPC 027

7/19/00

Confidential

Proposed Heat Rate Curves - Hines 2 Half Unit

		V-I	S			•		•							
		Inpl	t-Output Cu	urves	14 - 14 - 14				Incremen	ntal Heat Rate	Curves		Net	leat Rate Cu	rves
	CC:	205.18	204.72												
	CL:	4,6924	4,6808												
	CI:	0.004414	0.004327								· · · ·				
	.	0.001111		· .											
HtRt	Pen Fac	L 1	1												
		2x1 F W	2x1 F S						2x1 F W	2x1 F S		•	2x1 F W	2x1 F S	
	13	265	264		,										
	25	325	324												
	38	387	386												
	50	451	450												
	63	516	514		1										
	75	582	580					75	5299	5276		75	7759	7735	
	88	650	647					88	5410	5384		88	7424	7399	
	100	719	716					100	5520	5492		100	7186	7161	
	113	789	786					113	5630	5600		11:	7013	6987	
	125	861	857					125	5741	5708		12	6886	6859	
	138	934	930					138	5851	5817		13	6792	6765	
	150	1008	1004					150	5961	5925	· .	15) 6722	6695	
	163	1084	1080					163	6072	6033		16	3 6672	6644	
	175	1162	1156					17	6182	6141		-17	5 6637	6608	
	188	1240	1234					18	6292	6249		18	3 6614	6584	
	200	1320	1314					20	6403	6358		20	0 6601	6570	
	213	1402	1395					21	6513	6466		21	3 6596	6564	
	225	1484	1477					22	5 6624	6574		22	5 6597	6564	
	238	1569	1560					23	6734	6682		23	8 6605	6570	
	250	1654	1645					25	6844	6790	•	25	0 6617	6581	
	200	1741	1732					26	3 6955	6898		26	3 6633	6597	
	203	1920	1810					27	5 7065	7007		27	5 6652	6615	
	210	1029	1019					28	8 7175	7115		28	8 6675	6637	
	200	2010	1998				•	30	7286	7223		30	0 6701	6661	

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FPC 028

Revenue requirement - based on Corporate WACC

(\$000s)	2030	End of Plant Life						
	2001	2002	2003	2004	2005	2006	2007	2008
Rate Base (year end)					· · · ·			
Gross Electric Plant	\$100,000	\$ 100,000	\$100,000	\$100,000	\$100,000	\$100,000	\$100,000	\$ 100,000
Less ADIT	(643)	(3,022)	(5,034)	(6,718)	(8,105)	(9,222)	(10,212)	(11,202
Less accumulated depreciation	(3,333)	(6,667)	(10,000)	(13,333)	(16,667)	(20,000)	(23,333)	(26,667
Equals total rate base	96,024	90,311	84,966	79,949	75,228	70,778	66,455	62,131
Interest Expense	3,220	3,061	2,879	2,709	2,549	2,398	2,254	2,112
Net Income	6,469	6,149	5,784	5,442	5,121	4,818	4,529	4,243
Income Taxes	4,062	3,862	3,632	3,418	3,216	3,026	2,844	2,665
Revenue Requirement on Rate Base	13,751	13,071	12,296	11,569	10,886	10,242	9,627	9,020
Depreciation Expense	3,333	3,333	3,333	3,333	3,333	3,333	3,333	3,333
Property Taxes	2,060	2,069	2,047	2,024	1,997	1,968	1,937	1,903
Depreciation and Property: lax Expenses and the set	5,393	5,402	5,380	5,357	5,330	5,301	5,270	5,236
Fixed Cost Revenue Requirements	\$ 19,144	\$ 18,474	\$ 17.676	\$ 16,926	\$ 16,216	\$ 15,544	\$ 14.897	\$ 14,257

ATWACC	8.62%
NPV of Revenue Requirements	142,792
Total Initial Cost	100,000
NPV of Rev. Reg. / Initial Cost	1.428
- or - "K Factor"	

2007	
	2008
55.0%	55.0%
45.0%	45.0%
100%	100%
12.00%	12.00%
7.30%	7.30%
6.60%	6.60%
3.29%	3.29%
9.89%	9.89%
	55.0% 45.0% 100% 12.00% 7.30% 6.60% 3.29% 9.89%

的复数自然交通 法自然法的公式运行部									
Property Taxes		2001	2002	2003	2004	2005	2006	2007	2008
Property tax millage rate (Max @ 30 mils) - Osceola	•	· · · · · · · · · · · · · · · · · · ·							
County	2.50% escalation	\$ 20.60	\$ 21.40	\$ 21.94	\$ 22.48	\$ 23.05	\$ 23.62	24.21	\$ 24.82

Rev req

FPC 029

kfactor30a.xls

neu-2	

马士 计的数据

	VALU	JE DEFERRA	L CALCUL	ATIONS U	SING PSC M	ETHODOL	OGY - DOC	CKET 891049	-EU, ORDE	R 23623		
	Thereat									1		
	DESCRI	TION OF S	TUDY:		FILE: VAL_E	DEF						
 	1991 Pulve	rized Coal @S	ITE FPC								REV: 09/16/9	1
	KCLEN	ENCE DESI	GN							[DISK: GEB90)05
	CAPACITY	PAYMENTS	BASED O	N INPUT A	SSUMPTION	IS & ENTR	Y VARIABI	LES				
								•				
	ENTRY VA	ARIABLES:		DESCRIPT	ION				CALCULATE	D VALUES BA	SED ON INPUTS	
		2003	Base year	of study					(1+ip)/(1+r) =		0.947706	
	K =	1.35880567	K Factor(N	Aid year)- P.	V. of carry'g	chrg's			((1+ip)/(1+r))	^L =	0.261123	
	-		for \$1 in ra	ate base for e	econ. life of p	lant.			1-(1+ip)/(1+r)	=	0.052294	
		\$372.1	\$/KW - To	otal cost, dire	ect + AFUDC	, in 1/2003 S	5.		1-((1+ip)/(1+r	·))^L =	0.738877	
	On =	\$4.33	\$/KW/Yr -	Fixed O&M	4 costs in 1/20	003 \$.				1		
		1.20	\$/MWH -	Variable O&	M costs in 1/	2003 \$.			In=	\$372.13	\$/kw -Installed costs	of the
	ip =	3.30%	Annual eso	calation rate	of plant costs						plant in in-service y	ear 2003 \$.
	io =	3.30%	Annual esc	clation rate f	or O & M cos	sts.			On=	\$4.40	S/KW/YI - Midyear	Fix O&M cost 20
	r =	9.00%	Util. disco	Util. discount rate							S/MWH - Midyear	Var. O&M cost 20
	L =	25	Years - Econo	omic life of pla	nt.				VACm =	\$3.93	\$/kw/mo - Value of	avoiding plant
	n =	2003	Inservice year	r of deferred un	lit					\$47.13	for one month in 200	03.
	cf =	65.0%	Capacity fact	or of avoided u	nit						(capital costs and fix	ed O&M)
	C =	1.0	Risk factor as	signed to plant					PV of CC =	\$463.90	P.V. of the carry cos	ts of
		1.00	Factor to be u	ised for O & M							plant in 2003 S.	
		25	Number of	years for V	alue deferral	calc.			PV of OM	= \$147.08	P.V. of O&M	in 2003 \$.
	OT ITTOL ITTO	CALCENT ATT										
	OUTPUIS	CALCULATE	D FOR 25	YEARS OF	AVOIDANC	E:	COG-2_103	3				·.
	1	2	3	4	5	6	7	8	9	10	11	12
			<-VALUE of	f DEF PAYME	NTS->	<	EARL	Y CAPACITY P	AYMENTS -		>	
	CONTRA 1 GT		(Method	5a)					(Method 5)	o)		
	CONTRACT	PERIOD		Starting	Jan-03		Starting	Jan-02		Starting	Jan-01	
									-			and the second s
			0&M	CAPITAL	TOTAL	0&M	CAPITAL	TOTAL	0&M	CAPITAL	TOTAL	0&M
	YEAR	MONTHS	\$/KW/MO	\$/KW/MO	\$/KW/MO	\$/K.W/MO	\$/KW/MO	\$/KW/MO	\$/KW/MO	\$/KW/MO	\$/KW/MO	\$/KW/MO
									-			
1	• 2003	Jan - Dec.	0.95	2.98	3.93	0.88	2.78	3.65	0.82	2.59	3.41	0.76
2	2004	Jan - Dec.	0.98	3.08	4.06	0.91	2.87	3.78	0.85	2.67	3.52	0.79
3	2005	Jan - Dec.	1.01	3.18	4.19	0.94	2.96	3.90	0.87	2.76	3.63	0.82

Page 1

Hines 2

Revenue requirement - based on Corporate Framework Energy Supply WACC

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(\$000s)															
	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Rate Base (year end)															A 949 700
Gross Electric Plant	ş -	\$ -	\$ - \$	•	\$ 203,132	\$ 207,323	\$ 226,255	\$ 233,852	\$ 234,041	\$ 234,450	\$ 238,903	\$ 241,895	\$ 242,100	\$ 248,507	\$ 248,796
Less accomulated depreciation	-	:		:	201.778	197.387	206.914	204.760	195,189	185.819	180.257	173.069	163.144	158,892	148,568
	-				201,770		2007011	20 .,. 00							
Interest Expense	0	0	0	0	942	5,527	5,794	5,733	5,465	5,203	5,047	4,846	4,568	4,449	4,160
Net Income	0	0	0	0	2,462	14,449	15,146	14,988	14,288	13,602	13,195	12,669	11,942	11,631	10,875
Income Taxes	<u> </u>	0	0	0	1,540	9,074	9,512	30 124	28 726	27 347	26 528	25 470	7,500	23.384	21,865
neverne negulation of hate base	<u></u>				4,343	23,043	30,431	30,134	20,720	21,041	20,920	20,470	24,010	20,004	211000
Direct Non-Fuel O&M	0	0	0	0	654	4.248	4.157	7.924	4,330	4,381	9,979	4,186	4,706	8,164	4,910
Fully Allocated Site Costs	1916 Ball	CALE	IN THE REAL PROPERTY OF THE	EV:NON	IN PACE COR	N. C.		3144U 77 19	20. SANDA	Why we want	ISTNER GR	an sealann se	MONT -		
Fully Allocated Overheads	Ĵ.O.	.	0	0	0.0	0	0	201	Si to o	56° o	o.	o		Ö.	0
Depreciation Expense	0	0	0	0	1,354	8,582	9,405	9,750	9,759	9,780	10,014	10,181	10,196	10,593	10,612
Dismantlement Expense	0	0	0	0	41	257	257	257	257	257	257	257	257	257	257
Taxes other than income	0	0	0	0	628	3,778	4.025	4,283	3,980	3,884	4,175	3,781	3,686	3,874	3,545
Operating Expenses (, et)	0	_0	0	0	2,678	16,866	17,844	22,214	18,327	18,302	24,426	18,405	18,846	22,888	19,324
*	_														
Non-funi Revenue Requirements	<u>] </u>	\$ -	\$ - \$	-	\$ 7,627	\$ 45,915	\$ 48,296	\$ 52,349	\$ 47,053	\$ 45,649	\$ 50,954	\$ 43,875	\$ 42,856	\$ 46,272	\$ 41,189
	9 . .														
Fua Expense 25. 1	3 5 -	Ş -	\$ - \$	-	\$ 11,964	\$ 65,804	\$ 65,804	\$ 67,069	\$ 67,069	\$ 68,124	\$ 68,124	\$ 68,805	\$ 69,493	\$ 70,188	\$ 70,890
· · · · ·															
	ion Netherl		A BOARD AND		4-01-02	Sector 20		Standard		AL CELEWING	1 9 078	S-102/6805	5-117 349	3-116.460-	\$ 112.079
			De in it.				the second second		法 建設設備			- THE PROVE		1000	
									**************************************					a Mari di Cala di Al Dala da Maria di Polanci da cala	nine finant desinging for the Soldan Star 2 Long off.
Total \$/MWh	#D!V/0	#DIV/0!	#DIV/01	#DIV/01	\$ 35,64	\$ 36.95	\$ 37.74	\$ 39.50	\$ 37.74	\$ 37.63	\$ 39.38	\$ 37.27	\$ 37.16	\$ 38.52	\$ 37.07
Capacity \$/MWh	#DIV/01	#DIV/01	#DIV/01	#DIV/01	\$ 13.87	\$ 15.19	\$ 15.97	\$ 17.31	\$ 15.56	\$ 15.10	\$ 16.85	\$ 14,51	\$ 14.17	\$ 15.30	\$ 13.62
Fuel \$/MWh	#DIV/01	#DIV/01	#DIV/01	#DIV/0!	\$ 21.76	\$ 21.76	\$ 21.76	\$ 22.18	\$ 22.18	\$ 22.53	\$ 22.53	\$ 22.76	\$ 22.98	\$ 23.21	\$ 23.45
Total \$/MWh in 1997 Dollars			#DIV/01	#DIV/01	\$32.28	\$32.81	\$32.85	\$33.71	\$31.58	\$30.87	\$31.68	\$29.39	\$28.72	\$29.19	\$27.54
Average over life			#DIV/01												
Original Capacity Factor	0%	0%	0%	0%	65%	65%	65%	65%	65%	65%	65%	65%	55%	65%	65%
Unginal Forecast GWN Production	0	0			550	3,024	3,024	3,024	3,024	3,024	3,024	3,024	3,024	3,024	3,024
After-tax WACC	•		9.0%												
			0.075												
														-	
Non-fuel Revenue Requirements			\$ - \$) - · -	\$ 7,627	\$ 45,915	\$ 48,296	\$ 52,349	\$ 47,053	\$ 45,649	\$ 50,954	\$ 43,875	\$ 42,856	\$ 46,272	\$ 41,189
NPV @ 9% in 2001			398,730				. t.								
			343,178		\$ 6,932	\$ 41,409	\$ 43,882	\$ 44,168	\$ 42,465	\$ 41,011	\$ 40,718	\$ 39,432	\$ 37,892	\$ 37,851	\$ 36,022
				•											
Fuel Savings					3,746	42,245	45,514	44,498	40,251	43,105	41,678	41,678	41,678	41,678	41,678
NPV @9% of Fuel Savings			375,113						-						
							· · · · ·						<i>i</i>		
First five years fuel Sav NPV			131,823		•						-				
FRSC IIVE YIS IN MFY			100,003												
Oct 98 Fuel Savinas					4.601	28 850	33.566	38.812	39,200	39,592	39.988	40.388	40 792	41,200	41,617
					-,	20,000		00,012		00,002	22,000	10,000			11,072
				•					· .						
									•			X .			
• •										1	2	3	4	<u>5</u>	6
· · · ·												1			
										185,819	180,257	173,069	163,144	158,892	148,568
								1997 - 1997 -		0%	0%	0%	0%	0%	0%
											0	0	0	0	0
													0.001		
12/14/99 8·35 AM							Rev red					FPC	. 031	enth	seff2 vie
														- epin	

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BATES NO. FPC 032 CONFIDENTIAL PURSUANT TO FLORIDA POWER CORPORATION'S REQUST FOR CONFIDENTIAL CLASSIFICATION FILED AUGUST 7, 2000

rower block 2 C	WILF ROW 4	Upgrade	Without Row	4 Upgrade
Ambient Temp.	Net Output (kW)	Net Heat Rate (Btu/kWhr)	Net Output (kW)	Net Heat Rate (Btu/kWhr)
20	578,950	6,092	541,900	6,090
20	584 895	6,050	544,040	6,080
	576 395	5,946	545,430	6,075
40 57	553 685	5,938	553,685	5,938
57	534 105	5,935	534,105	5,935
12	506,400	5,969	506,400	5,969
90	000,400	5978	498 704	1978 978 P
95	1943-490: 049 min	5988	1491,008	5 988 S

Power Block 2 CT Performance Data



Proposed Residential LM Strategy Plan

Exis	ting Program	- Close to N	ew LM Installa ne of occupar	ations, Grand ncy change b	lfather Existi eginning Apr	ng j] 2001)
(Remove	existing parti	cipanto de m	-		LM Saving (at the Ge	s in MW nerator)
· · · ·		Veer and Pa	articipants		Winter	Summer (Aug)
		real-end i	Turnover	Total	(Jan)	
Year	Additions	Cancels	0	472,629		460
1999	4,500	25,000	0	447,629	842	400
2000	0	25,000	65 466	370,973	801	411
2000	0	11,191	45 212	316,486	668	348
2007	0	9,274	-45,212	277 716	573	303
2002	0	7,912	-30,857	2/1,10	505	267
2003		6,943	-27,077	243,030	446	236
2004		6,092	-23,760	213,843		208
2005		5,346	-20,850	187,648	347	184
2006		4 691	-18,296	164,661		162
2007	0	4 117	-16,054	144,490	300	143
2008	0	2 612	-14,088	126,790	270	126
2009	0	3,012	-12.362	111,258	238	
2010	0	3,170				

in the Control of Heating & WH during Winter Months Only										
New Winte	er LM Option	LM Saving (at the Ge	s in MW nerator)							
ſ		Year-end Pa	rticipants	Total	Winter (Jan)	Summer (Aug)				
Vaar	Additions	Cancels	Turnover	0						
1000	0	0	0	5,000	0	0				
2000	5,000	0	24 550	35,125	11	0				
2000	5,625	50	16 955	57,978	80	0				
2007	6,250	351	11 572	75,845	132	0				
2003	6,875	580	10 154	92,740	173	0				
2004	7,500	/50	8,910	108,223	212					
2005	7,500	927	7,819	121,834	247					
2006	6,875	1,002	6,861	133,727	278					
2007	6,250	1,210	6,020	144,035	305					
2008	5,625	1,337	5,283	152,878	329					
2009	5,000	1,440	4,636	160,485	349					
2010	4,500	1,525								

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				Now 1 M Wint	ter Only Opti	on
Tota	LM Program	= Existing L	M Program +	NGM FINI HILL		
•		÷			LM Saving (at the Ge	s in MW nerator)
			rticinants		Winter	Summer
		Year-end Pa	Turnover	Total	(Jan)	(Aug)
Year	Additions	Cancels	0	472,629		460
1999	4,500	25,000	0	452,629	842	400
2000	5,000	25,000	-40,916	406,097	813	
2001	5,625	0.626	-28,258	374,464	748	
2002	6,250	9,020	-19,286	353,561	705	267
2003	6,875	7 701	-16,923	336,436	678	
2004	7,500	7,7020	-14,850	322,066	657	208
2005	7,500	6 428	-13,031	309,482	640	184
2006	6,875	5 910	-11,435	298,388	625	167
2007	6,250	5 454	-10,034	288,525	611	143
2008	5,625	5 053	-8,805	279,667	599	176
2009	5,000	4 699	-7,726	271,743	587	140
2010	4,500	4,000				

F	Ten Year	Site Plan
	(April	1999)
t	Winter	Summer
	(Jan)	(Aug)
ł	875	457
ŀ	865	450
ł	860	403
ł	790	341
ł	743	297
l	713	262
	690	231
	670	204
	652	2 180
	63	7 159
	62	3 140
	60	g 123

FPC 034

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		mer Repower	gins Kepower	rtow #1or #2 Repower	now #3 Repower		lidized Bed	Iverized Coal	est 501G 1x1 CC	est. 501FC 2x1 CC	est. 501FC 2x1 CC	nes Unit #2		nee linit 40	7FA Simple Cycle	3 7FA Simple Cycle	3 7EA Simple Cycle	3 /EA Simple Cycle					
		N. Gas	N. Gas	N. Gas	N. Gas	Coal	Coal	Coal	N. Gas	Distillate	N. Gas	Distillate	N. Gas	Distillate	IV. Cas	2	Distillate	N. Gas	Туре	Fuel	1		
		248	127	274	574	577	200	800	366	545	567	545	567	185	178		0 26	88.9	MW	Winter			
	1010	010	118	248	536	494	500	800	323	473	496	473	496	161	151	0.4	V 7L	74 7	WW	Summer	Capacity	Estimated Ca	
	467	771	102	196	1555	<u>985</u>	500	008	145	1 5 5	155	1005	1152	173	164	2.40	01.0	2 1 2	MW,	Average		pital Cost Rang	T-11- 11
	88,000	000,00	00,001	100,171	171 000	000 C09	477 100	100,100	161,200	1012,101	100,000	160,000	160 700	49.800	49,800	30,700	30,700	000,14		Canital C		e for Alternative	
	368	439	465	000	2001	1707	NC N	400	300	341	010	200	200	788	303	365	376	WAVE		Def			
	000,08	51,000	000,18	100,000	360,000	425,000	000,020	148,000	178,000	178,000	000,661	000,661	100,000	15,100	45 100	28,600	28,600	\$1,000					
	102,000	62,000	107,000	195,000	725,000	512,500	756,000	169,000	205,000	205,000	170,000	170,000	00,10	1,100	51 700	33.300	33,300	\$1,000	ngiH	Cabiat Cost M	anital Cost D		
	335	418	310	270	1,046	850	775	430	349	335	312	299	261	<u>c17</u>	246	340	351	\$/kw	Low	- Bu			
į	427	508	410	351	1,354	1,025	945	491	403	386	334	320	299	515		205	408	\$/kw	High				

Supply-Side Alternatives

FPC 309

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Rocha, James R. /goc,openmail

From:	McKeage, Mark D. /goc,openmail
Sent:	Friday, May 26, 2000 12:16 PM
To:	Rocha, James R. /goc,openmail
Subject:	Difference between GulfBase & No Hines 2

Jim,

Please see attached.

Also, you may note that the year 2000 is slightly different than was included in the numbers I sent you during the RFP. This is due to the fact that PHB and I found an error in that year-I had neglected to include FPC's purchase from Lakeland. It affects the year 2000 only, and affects all cases equally, so no harm.

fear	GulfBase	NoHines2	Difference
2000	1,193,127	1,193,127	0
2001	1,240,870	1,240,870	0
2002	1,157,956	1,155,364	-2,592
2003	1,227,334	1,233,231	5,897
2004	1,233,324	1,284,136	50,812
2005	1,317,811	1,361,553	43,742
2006	1,324,769	1,359,966	35,197
2007	1,431,651	1,474,534	42,883
2008	1,446,962	1,471,865	24,903
2009	1,505,475	1,536,685	31,210
2010	1,463,414	1,507,941	44,527

Mark D. McKeage Mark D. McKeage, PE

Principal Engineer

Integrated Resource Planning & Forecasting Financial Services Division Florida Power Corporation One Power Plaza - MAC BB3G 263 13th Avenue South St. Petersburg, Florida 33701-5511 external voice: (727) 826-4393 internal voice: 7-230-4393 external fax: (727) 826-4333 internal fax: 7-230-4333

COMPONENTS OF WINTER PEAK DEMAND

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			7		JAN	UARY	2000	FORE	CAST						
	Regressed			Non-Disp.	Total							Total			
	Firm		Potential	DSM	Retail							System			Total
	Retail	Retail	Total	&	before		WH	OLESAL			Company	before	Total	LM, VR	System
Үеаг	Unadj.	IS/CS	Relat	SS Cogen	DLC	REA	BULK	MUNI	IS	Total	Use	DLC	IS/CS	& SBG	Firm
2000	8,004	312	8,316	-423	7,893	626	771	236	14	1,647	30	9,570	+326	-985	8,259
2001	8,176	292	8,468	-444	8,024	588	924	205	14	1,731	30	9,785	-306	-951	8,528
2002	8,346	290	8,636	-468	8,158	605	459	196	14	1,274	30	9,472	-304	-886	8,282
2003	8,514	314	8,828	-495	8,333	558	153	203	14	928	30	9,291	-328	-843	8,120
2004	8,682	315	8,997	-523	8,474	503	153	206	14	877	30	9,381	-329	-821	8,230
2005	8,845	320	9,165	-552	8,613	525	153	198	14	890	30	9,533	-334	-805	8,394
2006	9,002	323	9,325	-582	8,743	600	153	200	14	968	30	9,741	-337	-794	8,609
2007	9,155	328	9,483	-613	8,870	676	153	203	14	1,046	30	9,946	-342	-784	8,820
2008	9,303	331	9,634	-643	8,991	755	153	206	14	1,129	30	10,150	-345	-775	9,029
2009	9,449	334	9,783	-672	9,111	833	153	209	14	1,210	30	10,351	-348	-769	9,233
2010	9,597	336	9,933	-701	9,232	912	153	212	14	1,291	30	10,553	-350	-763	9,440

					JAI	NUARY	1999	FORE	CAST	Г					
	Regressed			Non-Disp.	Total							Total			
	Firm		Potential	DSM	Retail	· · · ·						System			Total
	Retail	Retail	Total	8	before		WH	OLESALE		_	Company	before	Total	LM, VR	System
Year	Unadj.	IS/CS	Retail	SS Cogen	DLC	REA	BULK	MUNI	15	Total	Use	DLC	IS/CS	& SBG	Firm
2000	8,018	312	8,330	-399	7,931	604	755	215	0	1,574	- 30	9,535	-312	-1003	8,220
2001	8,188	300	8,488	-424	8,064	566	905	. 197	0	1,668	30	9,762	-300	-1003	8,459
2002	8,357	297	8,654	-450	8,204	636	450	180	0	1,266	30	9,500	-297	-932	8,271
2003	8,524	299	8,823	-478	8,345	537	0	182	0	719	30	9,094	-299	-883	7,912
2004	8,689	296	8,985	-508	8,477	481	0	184	0	665	30	9,172	-296	-857	8,019
2005	8,852	298	9,150	-538	8,612	554	0	174	0	728	30	9,370	-298	-840	8,232
2006	9,014	300	9,314	-569	8,745	630	0	176	0	806	30	9,581	-300	-826	8,455
2007	9,177	302	9,479	-599	8,880	705	0	178	0	883	30	9,793	-302	-814	8,677
2008	9,340	304	9,644	-628	9,016	783	0	160	O	963	30	10,009	-304	-805	8,900
2009	9,504	306	9,810	-657	9,153	863	0	182	0	1,045	30	10,228	-306	+798	9,124
2010	9,669	308	9,977	-686	9,291	842	0	184	0	1,026	30	10,347	-308	-790	9,249

1			JAI	NUARY 2	000 FO	RECAS	Tvs	JANUA	RY 1	1999 F	ORECAS	T			
	Regressed			Non-Disp.	Total							Total			
	Firm		Potential	DSM	Retaii		:					System			Total
	Retail	Relait	Total	&	before		WH	OLESALE			Company	before	Total	LM, VR	System
Year	Unadj.	IS/CS	Retail	SS Cogen	DLC	REA	BULK	MUNI	IS	Total	Use	DLC	IS/CS	& SBG	Firm
2000	-14	0	-14	-24	-38	22	16	21	14	73	0	35	-14	18	39
2001	-12	-8	-20	-20	-40	22	19	8	14	63	0	23	-6	52	69
2002	-11	-7	-18	-18	-36	-32	9	16	14	8	0	-28	-7	- 46	11
2003	-10	15	5	-17	-12	21	153	21	14	209	0	197	-29	40	208
2004	-7	19	12	-15	-3	22	153	22	14	212	0	209	-33	36	211
2005	-7	22	15	-14	1	-29	153	24	14	162	0	163	-36	35	162
2006	-12	23	11	-13	-2	-30	153	24	14	162	0	160	-37	32	154
2007	-22	26	4	-14	-10	-29	153	25	: 14	163	0	153	-40	30	143
2008	-37	27	-10	-15	-25	-28	153	26	14	166	0	141	-41	30	129
2009	' -5 5	28	-27	-15	-42	-30	153	27	14	165	0	123	-42	29	109
2010	-72	28	-44	-15	-59	70	153	28	14	265	0	206	-42	27	191

FPC 035

COMPONENTS OF SUMMER PEAK DEMAND

			2		JAN	UARY	2000	FORE	CAST						
	Regressed			Non-Disp.	Totai							Total			
	Firm		Potential	DSM	Retail			•				System			Total
	Retail	Retail	Total	&	before		WH	OLESALE			Company	before	Tolal	LM, VR	System
Year	Unadj.	IS/CS	Retail	SS Cogen	DLC	REA	BULK	MUNI	15	Total	Use	DLC	IS/CS	& SBG	Firm
2000	7,013	313	7326	-355	6971	239	771	253	14	1277	30	8,278	-327	-512	7,439
2001	7,173	294	7467	-368	7099	183	924	222	14	1343	30	B.472	-308	-463	7,701
2002	7,330	291	7621	-381	7240	184	459	209	14	867	30	8,137	-305	-400	7,431
2003	7,487	314	7801	-395	7406	121	153	218	14	506	30	7,942	-328	-356	7,258
2004	7,641	315	7956	-410	7546	48	153	221	14	436	30	8,012	-329	-322	7,361
2005	7,790	321	8111	-425	7686	54	153	211	14	433	30	8,149	-335	-291	7,522
2006	7,934	325	8259	-441	7818	112	153	214	14	493	30	8,341	-339	-265	7,737
2007	8,074	329	8403	-456	7947	171	153	217	14	555	30	8,532	-343	-242	7,947
2008	8,211	332	8543	-471	8072	231	153	220	14	618	30	8,720	-346	-222	8,152
2009	8,348	335	8683	-486	8197	291	153	223	14	681	30	8,908	-349	-205	8,354
2010	8,487	337	8824	-492	8332	353	153	226	14	747	30	9,109	-351	-189	8,569

JANUARY 1999 FORECAST															
	Regressed			Non-Disp.	Total			•				Total			
	Firm		Potential	DSM	Retail	•						System			Total
	Retail	Retail	Total	8	before		WH	OLESALE			Company	before	Total	LM, VR	System
Year	Unadj.	IS/CS	Retail	SS Cogen	DLC	REA	BULK	MUNI	IS	Total	Use	DLC	IS/CS	& SBG	Firm
2000	7,083	313	7,396	-353	7,043	216	755	226	0	1,197	30	8,270	-313	-498	7,459
2001	7,254	301	7,555	-366	7,189	160	905	211	0	1,276	30	8,495	-301	-453	7,741
2002	7,423	298	7,721	-379	7,342	214	300	191	0	705	30	8,077	-298	-394	7,385
2003	7,590	300	7,890	-393	7,497	98	0	191	0	289	30	7,816	-300	-353	7,163
2004	7,755	297	8,052	-408	7,644	25	0	194	0	219	30	7,893	-297	-321	7,275
2005	7,919	299	8,218	-423	7,795	82	0	183	0	265	30	8,090	-299	-293	7,498
2006	8,083	301	8,384	-439	7,945	140	σ	186	0	326	30	8,301	-301	-269	7,731
2007	8,248	303	8,551	-454	8,097	199	0	189	Q	388	30	8,515	-303	-248	7,964
2008	8,412	305	8,717	-468	8,249	259	0	192	۵	451	30	8,730	-305	-230	8,195
2009	8,578	307	8,885	-483	8,402	319	0	194	0	513	30	8,945	-307	-215	8,423
2D10	8,744	309	9,053	-497	8,556	382	0	197	O	579	30	9,165	-309	-202	8,654

			JAI	NUARY 2	000 FC	RECAS	Tvs	JANUA	RY	1999 F	ORECAST	ſ			
	Regressed			Non-Disp.	Total							Total			
	Firm		Potential	DSM	Retail							System			Total
	Retail	Retail	Total	8	before		WH	OLESAL	Ē		Company	before	Total	LM, VR	System
Year	Unadj.	IS/CS	Retail	SS Cogen	DLC	REA	BULK	MUNI	IS	Total	Use	DLC	IS/CS	& SBG	Firm
2000	-70	0	-70	-2	-72	23	16	27	14	80	0	8	-14	-14	-20
2001	-81	-7	-88	-2	-90	23	19	11	14	67	· 0	-23	-7	-10	-40
2002	-93	-7	-100	-2	-102	-30	159	18	14	162	0	60	-7	-6	46
2003	-103	14	-89	-2	-91	23	153	° 27	14	217	0	126	-28	-3	95
2004	-114	18	-96	-2	-98	23	153	27	14	217	0	119	-32	-1	86
2005	-129	22	-107	-2	-109	-28	153	28	14	168	0	59	-36	2	24
2005	-149	24	-125	-2	-127	-28	153	28	14	167	0	40	-38	4	£
2007	-174	26	-148	-2	-150	-28	153	28	14	167	0	17	-40	6	-17
2008	-201	27	-174	-3	-177	-28	153	28	14	167	0	-10	-41	8	-43
2009	-230	28	-202	-3	-205	-28	153	29	14	168	D	-37	-42	10	-69
2010	-257	28	-229	5	-224	-29	153	29	14	168	0	-56	-42	13	-85

FPC 036



FPC Need Determination

Current Perspective

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Key Issues

Hines Site Need Block Size **Contract** Duration Self-Build Costs Basis of Analysis Fuel Scenario Initial Screening **Detailed** Analysis FPC Tx Impact **Contract Options** Non-Price Attributes

Current Thinking

Offered to Bidders 530 MW in 11/03 Flexible Flexible Refined Estimate

NPV Revenue Requirements FGT Supply (Base) ProVIEW Optimization ProSym/Pro-Forma Study Short List Proposals Valuation Adjustment Non-Numeric Analysis

LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY 2000 SERC RATINGS, COGENERATION = 991231 JANUARY 2000 LONG-TERM FORECAST (S000101) Bulk Power Sales included in Demand & Energy Forecast

2000 Ten-Year Site Plan Analysis * Future Capacity Additions for 20 % RM * Base Case

		WINTER 00/01	WINTER 01/02	WINTER 02/03	WINTER 03/04	WINTER 04/05	WINTER 05/06	WINTER 06/07	WINTER 07/08	WINTER 08/09	WINTER 09/10
		Jan-2001	Jan-2002	Jan-2003	Jan-2004	Jan-2005	Jan-2006	Jan-2007	Jan-2008	Jan-2009	Jan-2010
Existing FPC Capacity	MW	8,267	8,590	8,607	8,607	9,028	9,028	9,445	9,349	9,916	9,916
New FPC Capacity	MW	323	17	D	567	0	567	0	567	0	567
Retired FPC Capacity	MW	0	0	0	146	0	150	96 🦛	t Q	o	0
Total Installed Capacity	MW	8,590	8,607	8,607	9,028	9,028	9,445	9,349	9,916	9,916	10,483
Firm Purchase Capacity	MW	469	469	469	469	479	479	479	479	479	479
Firm QF Purchase Capacity	MW	831	831	818	818	818	818	813	798	689	548
Seasonal Purchase Capacity	MW	0	0	0	0	0	٥	0	0	0	0
Capacity on Scheduled Maintenance	MW	0	O.	0	0	0	0	0	0	o	0
Firm Sale of Capacity	MW	٥	e	0	0	0	0	O	. 0	o	0
Total Available Capacity	MW	9,890	9,907	9,894	10,315	10,325	10,742	10,641	11,193	11,084	11,510
Potential Total Relail Demand	мw	8,468	8,636	6,828	8,997	9,165	9,325	9,483	9,634	9,763	9,933
Wholesale (REA)	MW	894	911	558	503	525	600	676	755	833	912
Wholesale (Butk Power)	MW	632	167	167	167	167	167	167	167	167	167
Wholesale (Municipal)	. MW	205	196	203	206	198	200	203	206	209	212
Total Wholesale Demand	MW	1,731	1,274	928	877	890	968	1,046	1,129	1,210	1,291
Company Use	MW	30	30	30	30	30	30 -	30	30	30	30
Potential Total System Demand	MW	10,229	9,940	9,786	9,904	10,085	10,323	10,559	10,793	11,023	11,254
Non-Dispatchable DSM and Self-Service OF	MW	444	468	495	523	552	582	613	643	672	701
Normal Weather Demand (Before Load Control)	MW	9,785	9,472	9,291	9,381	9,533	9,741	9,946	10,150	10,351	10,553
Normal Weather Reserves (Before Load Control)	MW	105	435	603	935	792	1,002	695	1,043	733	957
Normal Weather Reserve Margin (Before Load Control)	*	1.1%	4.6%	6.5%	10.0%	8.3%	10.3%	7.0%	10.3%	7.1%	9.1%
Normal Weather Load Management	MW	833	771	730	707	688	674	661	650	641	632
Normal Weather Demand (After Load Management)	MW	8,952	8,701	8,561	• 8,674	8,845	9,067	9,285	9,499	9,710	9,921
Normal Weather Reserves (After Load Management)	MW	938	1,206	1,333	1,641	1,480	1,675	1,356	1,693	1,374	1,589
Normal Weather Reserve Margin (After Load Management)	*	10.5%	13.9%	15.6%	18.9%	16.7%	18.5%	14.6%	17.8%	14.1%	16.0%
Normal Weather Interruptible Load	MW	306	304	328	329	334	337	342	345	348	350
Normal Weather Voltage Reduction	MW	118	115	113	114	117	120	123	125	128	131
Normal Weather Demand (After All Load Control)	 MW 	8,528	8,282	8,120		8,384	8,610	8,820	9,029	9,234	9,440
Normal Weather Reserves (After All Load Control)	MW	1,362	1,625	1,774	2,084	1,931	2,132	1,821	2,163	1,850	2,070
Normal Weather Reserve Margin (After All Load Control)	*	16.0%	19.6%	21.9%	25.3%	23.0%	4 24.8%	20.6%	24.0%	20.0%	21.9%
Normal Weather Reserves (After All Load Control) Required For 20 %	MW	1,706	1,656	1,624	1,646	1,679	1,722	1,764	1,806	1,847	1,888
Normal Weather Reserves (After All Load Control) Above 20 %	м₩	-344	-32	150	43B	252	410	57	358	3	182
Normal Weather "DLC" Reserve Margin Contribution	%	92.3%	73.2%	66.0%	55.2%	59.0%	53.0%	61.9%	51.8%	60.4%	53.8%

Note: Suwannee River Steam Units 1-3 Retired 12/31/2003 Higgins Peakers P1-P4 Retired 12/31/2005 Rio Pinar Peaker P1 Retired 12/31/2005 Avon Park Peakers P1-P2 Retired 12/31/2006 Turner Peakers P1-P2 Retired 12/31/2006

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LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY 2000 SERC RATINGS, COGENERATION = 991231 JANUARY 2000 LONG-TERM FORECAST (S000101) Bulk Power Sales Included in Demand & Energy Forecast

2000 Ten-Year Site Plan Analysis * Future Capacity Additions for 20 % RM * Base Case

		SUMMER 00	SUMMER 01	SUMMER 02	SUMMER 03	SUMMER 04	SUMMER 05	SUMMER 06	SUMMER 07	SUMMER 08	SUMMER 09
		Aug-2000	Aug-2001	Aug-2002	Aug-2003	Aug-2004	Aug-2005	Aug-2006	Aug-2007	Aug-2008	Aug-2009
Existing FPC Capacity	MW	7,553	7,553	7,817	7,834	7,834	8,186	8,185	8,546	8,468	8,963
New FPC Capacity	MW	Ó	264	3.5.17 T	0	495 495	· 0	495	0	495	0
Retired FPC Capacity	MW	Û	0	0	0	1431 15	0	135	78 22	0	0 5
Total Installed Capacity	MW	7,553	7,817	7,834	7,834	8,186	8,186	8,546	8,468	8,963	8,963
Firm Purchase Capacity	MW	469	469	469	469	469	479	479	479	479	479
Firm QF Purchase Capacity	MW	831	831	818	818	818	818	818	813	798	689
Seasonal Purchase Capacity	MW	0	. 0	. 0	0	0	0	0	0	o	0
Capacity on Scheduled Maintenance	MW	0	0	0	0	O	0	0	0	0	o
Firm Sale of Capacity	MW	0 '	0	0	0	0	0	0	0	0	o
Tolal Available Capacity	_ <u>MW</u> _	8,853	9,117	9,121	9,121	9,473	9,483	9,843	9,760	10,240	10,131
Potential Total Retail Demand	MW	7,326	7,467	7,621	7,801	7,956	8,111	8,259	8,403	8,543	8,683
Wholesale (REA)	MW	392	489	490	121	48	54	112	171	231	291
Wholesale (Bulk Power)	MW	632	632	167	167	167	167	167	167	167	167
Wholesale (Municipal)	MW	253	222	209	218	221	211	214	217	220	223
Total Wholesale Demand	MW	1,277	1,343	867	506	436	433	493	555	618	681
Company Use	MW	30	30	30	30	30	30	30	30	30	30
Potential Total System Demand	MW	8,633	8,840	8,518	8,337	8,422	8,574	8,782	8,988	9,191	9,394
Non-Dispatchable DSM and Self-Service QF	MW	355	368	361	395	410	425	441	456	471	486
Normal Weather Demand (Before Load Control)	MW	8,278	a 3472 U	8,137	7,942	9, 7, 8,012	8,149	8,341	8,532	8,720	8,908
Normal Weather Reserves (Before Load Control)	MW	575	645	985	1,179	1,461	1,335	1,502	1,228	1,519	1,222
Normal Weather Reserve Margin (Before Load Control)	ં જુ કે	6.9%	7.6%	12.1%	-14.8%	18.2%	16.4%	18.0%	14.4%	17.4%	13.7%
Normal Weather Load Management	MW	512	463	400	356	322	291	265	242	222	205
Normal Weather Demand (After Load Management)	MW	7,766	8,009	7,736	7,586	7,690	7,857	8,078	8,290	8,498	8,703
Normal Weather Reserves (After Load Management)	MW	1,087	1,108	1,385	1,536	1,783	1,628	1,767	1,470	1,742	1,427
Normal Weather Reserve Margin (After Load Management)	%	14.0%	13.8%	17.9%	20.2%	23.2%	20.7%	21.9%	17.7%	20.5%	16.4%
Normal Weather Interruptible Load	MW	327	308	305	328	329	335	339	343	346	349
Normal Weather Voltage Reduction	MW	0	0	0	0	0	0	0	0	0	٥
Normal Weather Demand (After All Load Control)	- MW	n 1 ⁶ 7,439	7,701	7,431	an 7,258 . 1	-26±7 7,361 22	······································	7,737	7,947	8,152	8,354 😹
Normal Weather Reserves (After All Load Control)	MW	1,414	1,416	1,690	1,864	2,112	1,961	2,108	1,813	2,086	1,776
Normal Weather Reserve Margin (After All Load Control)	106.%	19.0%	18.4%	- 22.7%	25.7% 4	28.7%	26.1%	27.2%	22.8%	25.6%	21.3%
Normal Weather Reserves (After All Load Control) Required For 20 %	. MW	1,488	* 1,540	1,486	1,452	1,472	1,504	1,547	1,589	1,630	1,671
Normal Weather Reserves (After All Load Control) Above 20 %	MW	-74	-124	204	412	639	456	559	223	457	105
Normal Weather "DLC" Reserve Margin Contribution	%	59.3%	54.4%	41.7%	36.7%	30.8%	31.9%	28.7%	32.3%	27.2%	31.2%

BATES NOS. FPC 040 CONFIDENTIAL PURSUANT TO FLORIDA POWER CORPORATION'S REQUST FOR CONFIDENTIAL CLASSIFICATION FILED AUGUST 7, 2000

LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY 1998 SERC RATINOS, COGENERATION = 181231 JANUARY 1999 LONG-TERM FORECAST (S361208) Bulk Power Sales (GPC, OPC, SECI & MEAG) included in Domand & Energy Forecast 1999 Tern-Year Site Plan

			WINTER 18/99	WINTER 99/00	WANTER 00/01	WINTER 01/02	WINTER 02/03	WINTER 03/04	WINTER 04/05	WINTER 05/05	WINTER 05/07	WINTER 07/08
			Jan-1999	Jan-2000	Jan-2001	Jan-2002	Jan-2003	Jan-2004	Jan-2005	Jan-2006	Jan-2007	Jan-2008
	Evising FPC Cenadity	MW	8.232	8.265	8.305	8,620	8,473	8,473	8,397	B,774	8.774	9,341
	New FPC Canacity	MM	0	a	297	0	0	0	567	•	567	. 0
	Retired FPC Canacity	MW	0	. 0	0	147	0	168	100	0	0	0
	Total Installed Capacity	MW	8,232	8,265	8,603	8,473	6,473	8,307	8,774	8,774	9,341	9,341
	Firm Purchase Capacity	MW	469	469	459	469	469	469	479	479	479	479
	Firm QF Purchase Capacity	MW	831	831	831	831	831	631	831	831	631	831
	Sentonal Purchase Capacity	MW	0	0	a a	a	0	- 0	D	G	D	o
	Cepacity on Scheduled Maintenance	MW	D	· • •	0	0	0	٥	٥	a	0	0
	Firm Sale of Cepacity	MW	25	0	0	0	٥	0	. 0	o	0	o
	Total Available Capacity	MW	9,507	9,565	\$,903	9,773	9,773	9,607	10,084	10,084	10,651	10,651
	Potential Total Betall Demand	MW	8.165	£.330	8.488	8.654	6,823	8,985	9,150	9,314	9,479	5,644
	Wholesels (REA)	MW	669	754	866	936	537	481	554	630	705	783
. `	Wholevale (Bulk Power)	MW	605	605	605	150	0	٥	. 0	0	Ð	٥
	Wholesale (Municipal)	MW	253	216	197	180	183	185	174	175	178	180
	Total Wholesale Demand	MW	1,527	1,575	1,668	1,266	720	668	728	806	883	963
	Wholesale (Interruptible)	MW	0	0	C.	· 0	0	O	a	0	0	o
	Company Use	MW	30	30	30	30	30	30	30	30	30	30
	Potantial Total System Demand	MW	9,723	9,935	10,188	9,950	9,573	9,681	9,908	10,150	10,392	10,637
	Non-Dispatchable DSM and Self-Service QF	MW	378	399	424	450	478	508	538	569	599	528
	Normal Weather Demand (Before Load Control)	MW	9,345	8,538	9,762	9,500	9,095	9,173	9,370	9,581	9,793	10,009
	Normal Weather Interruptible Load	MW	322	312	300	297	299	296	298	300	302	304
	Normal Weather Load Management	MW	895	889	886	817	773	746	725	709	694	682
	Normal Weather Voltage Reduction	MW	112	114	117	115	110	111	114	117	120	123
	Normal Weather Demand (After Load Management)	MW	8,450	8,547	4,876	8,683	8,322	8,427	8,644	8,872	9,099	9,327
	Normal Weather Demand (After All Load Control)	MW	8,016	3,221	8,459	8,271	7,913	8,029	8,232	8,455	8,677	8,300
	Normal Weather Reserves (Befree Load Control)	MW	162	29	141	273	678	434	714	503	858	542
	Normat Weather Reserve Margin (Before Load Control)	*	1.7%	8.3%	1.4%	2.5%	7.5%	4.7%	7.6%	5.2%	8.8%	6.4%
-	Normal Weather Reserves (After Load Management)	MWY	1,057	918	1,027	1,090	1,451	1,380	1,440	1,212	1,552	1,324
	Normal Weather Reserve Margin (After Load Management)	· %	12.5%	10.6%	11.5%	12.5%	17.4%	\$4.0%	16.7%	13.7%	17.1%	14.2%
	Normal Weather Reserves (After All Load Control)	MW	1,491	1,344	1,444	1,502	1,860	1,587	1,852	1,629	1,974	1,751
	Normal Weather Reserve Margin (After All Load Control)	*	18.6%	18,3%	17,1%	18.2%	23.5%	19.8%	22.5%	19.3%	22.7%	19.7%
ļ ,	iormal Weather Reserves (After All Load Control) Required For 15 %	MW	1,202	1,233	1,269	1,241	1,187	1,203	1,235	1,268	1,302	1,335
]	Normal Weather Reserves (After All Load Control) Above 15 %	MW	289	111	175	261	673	384	617	361	672	416
1	Normal Weather "DLC" Reserve Margin Contribution	*	69.1%	97.8%	90,2%	\$1.5%	63.5%	72.7%	81.4%	69,1%	56.5%	63.3%

FPC 041

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LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY 1995 SERC RATINGS, COGENERATION = 181221 JANUARY 1995 LONG-TERM FORECAST (S981208) Bulk Power Sales (GPC, OPC, SEC: & MEAG) included in Demand & Energy Forecast 1999 Ten-Year Sile Plan

		SUMMER SS Aug-1999	SUMMER 00 Aug-2002	SUMMER 01 Aug-2001	SUMMER 02 · Aug-2002	SUMMER 03 Aug-2003	SUMMER 04 Aug-2004	SUMMER 05 Aug-2005	SUMMER DS Aug-2006	SUMMER 07 Aug-2007	SUMMER DB
	1 mat	7 /49	7.510	7510	7 776	7.631	7.631	7,488	7,895	7,895	8,390
Existing FPG Capacity	MVY	1,403	0	749	0		0	495	U	495	0
New FPG Gapacity	MYT.	ч л	0	0	145		543	68	0	0	o · (
Retired FPC Cepacity	MVY	2 450	7 5 1 9	7 750	7 631	7 631	7.488	7,695	7,895	6,390	8,390
Tetal Installed Capacity	MVV	/,409	1,310	469	469	469	469	479	479	479	479
Firm Purchase Capacity	8499 1.004	497	403	403	831	831	831	835	631	831	831
Film OF Functions Capacity	LEAL		631		0	0	0	0	G	O	0
Seasonal Putchase Capacity	877			-	0	0	0	0	G	· 0	. o
Capacity on Scheduled Mankenance	MARK .	25	۵ ۵	0	0		٥	0	D	0	O
Table Available Capacity	MILL	8 744	6 610	9.059	8,931	8,931	8,758	9,205	9,205	9,700	9,700
ton Available Capacity								4.319		R 551	8 717
Potential Total Retail Demand	MW	7,234	7,396	7,555	7,721	7,890	8,052	0,210	540	199	259
Wholesale (REA)	MW	299	366	460	314	¥B	25	12	.40	0	0
Wholesale (Bulk Power)	MW	880	605	605	150	0			195	184	197
Wholesale (Municipal)	MW	279	226	211	190	191	194	103	105	388	451
Total Wholesale Demand	MW	1,458	1,197	1,276	854	269	219	203	0	0	0
Wholesale (Interruptible)	MW	0	•	0	0				30	30	30
Company Use	ww	30	30	30	30	30	30	UL CLAR	8,730	8 969	A 198
Potential Total System Demand	MW	8,722	8,623	8,861	8,695	\$,209	8,301	8,214	430	454	458
Non-Dispatchable DSM and Self-Service QF	MW	342	353	366	378	393	405	423	439	424	400
Normal Weather Demand (Before Load Control)	. WM	6,380	8,270	8,495	8,226	7,816	7,893	8,090	8,300	8,515	8,730
Normal Weather Interruptible Load	MW	324	313	301	298	300	297	299	301	303	305
Normal Weather Load Management	MW	502	498	453	394	353	321	293	269	243	230
Normal Weather Voltage Reduction	MW	0.	. o	C	. 0.	0	a	a	0	o	. 0
Normal Weather Domand (After Load Management)	MW	7,875	7,772	8,042	7,832	7,463	7,572	7,797	8,031	8,267	8,500
Normal Weather Demand (After All Load Control)	MW	7,554	7,459	7,741	7,534	7,163	7,275	7,498	7,739	7,964	8,195
Normal Weather Reserves (Before Load Control)	MW	364	540	564	705	1,115	895	1,115	905	1,185	970
Normal Westner Reserve Margin (Before Load Control)	*	4.3%	\$.5%	6.8%	8,6%	14.3%	11.3%	13.4%	10.9%	13.9%	11.1%
Normal Weather Reserves (After Load Management)	MW	665	1,038	1,017	1,095	1,468	1,216	1,408	1,174	1,433	1,200
Normal Weather Reserve Margin (Alter Load Management)	*	11.0%	13.4%	12.6%	\$4.0%	19.7%	16.1%	18.1%	14.6%	17.3%	14,2%
Normal Weather Reserves (After All Load Control)	MW	1,190	1.351	1,318	1,397	1,768	1,513	1,707	1,475	1,730	1,303
Normal Weather Reserve Margin (After All Load Control)	*	18,3%	18,1%	17.0%	11.5%	24.7%	20.8%	22.8%	19.1%	21.8%	18.4%
Normal Weather Reserves (After All Load Control) Required For 20 %	MW	1,511	1,492	1,548	1,507	1,433	1,455	1,500	1,546	1,593	1,639
Normal Weather Reserves (After All Load Control) Above 20 %	MM	-321	-141	-230	-110	335	58	207	-71	143	-134
Normal Weather "DLC" Reserve Margin Contribution	*	69.4%	60.0%	57.2%	49.5%	38.9%	40,8%	34.7%	38.6%	31.(76	33.275

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FLORIDA POWER CORPORATION NET MAXIMUM DEPENDABLE GENERATING CAPACITY EFFECTIVE BEGINNING JANUARY 1, 2000

NOTE: These are preliminary ratings to be used in the EIA-411 filing on 2/15/00.

Г	1	WINTER C	APABILITY	SUMMER O	CAPABILITY	DERATION					
	UNIT	UNIT MW	PLANT MW	UNIT MW	PLANT MW	(%)					
NUCLEAR STEAM											
Crystal River	3	782*	782	765*	765	2.1739					
FOSSIL STEAM						• •					
Anclote	1	522	1044	498	993	4.5977					
	2	522	· · · · · · · · · · · · · · · · · · ·	495		5.1724					
Bartow	1	123	452	121	444	1.6260					
	- 2	121		119		1.6529					
	3	208	1	204		1.9231					
Crystal River South	1	373	842	369	833	1.0724					
	2	469		464		1.0661					
Crystal River North	4	717	1449	697	1414	2.7894					
	5	732		717		2.0492					
Suwannee	1	33	146	32	143	3.0303					
	2	32		31		3.1250					
	3	81		80		1.2346					
COMBUSTION TURBINES											
Avon Park	P1 & P2	32 ea.	64	26 ea.	52	18.7500					
Bartow	P1 to P3	53 ea.	159	46 ea.	138	13.2075					
Bartow	P4	60 ea.	60	49 ea.	49	18.3333					
Bayboro	P1 to P4	58 ea.	232	46 ea.	184	20.6897					
DeBary	P1 to P6	65 ea.	390	54 ea.	324	16.9231					
DeBarv	P7 to P9	93 ea.	279	80 ea.	240	13.9785					
DeBary	P10	93	93	79	79	15.0538					
Higgins	P1&P2	32 ea.	64	27 ea.	54	15.6250					
Higgins	P3 & P4	35 ea.	70	34 ea.	• 68	2.8571					
Intercession City	P1 to P6	61 ea.	366	49 ea.	294	19.6721					
Intercession City	P7 to P10	94 ea.	376	88 ea.	352	6.3830					
Intercession City	P11	170	170 .	143	143	15.8824					
Rio Pinar	P1	16	16	13	13	18.7500					
Suwannee	P1 & P3	67 ea.	134	55 ea.	110	17.9104					
Suwannee	P2	67	67	54	54	19.4030					
Turner	P1 & P2	16 ea.	32	13 ea.	26	18.7500					
Turner	P3	82	82	65	65	20.7317					
Turner	P4	80	80	63	63	21.2500					
University of Florida Cogen	P1	41	41	35	35	14.6341					
COMBINED CYCLE						· · · ·					
Hines	1	529	529	482	482	8.8847					
Tiger Bay	1	223	223	207	207	7.1749					
						•					
NUCLEAR STEAM (91.7806%)			782		765						
FOSSIL STEAM			3933		3827						
COMB. TURBINES			2775		2343						
COMBINED CYCLE			752		689						
SYSTEM TOTAL *			8242	· · ·	7624						
la Sar	s Serif	LSL ≪ ∲ ¥ 10 ₹	BX U		· · · · · · · · · · · · · · · · · · ·	<i>2. 1</i> ≈ 2 € % , *68	A* 83 3 29 17 9	= ©	•• <u>∆</u> •	Ja Promot	
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		Scheduled	Baseload	Baseload		Intermediate	Baseload & intermediate	Peaking	Total	QF On-Peak	Baseloa Isternedi
	Month	Maintenance	Plants	Contracts	QF Contracts	Resources	Resources	Resources	Resources	Reduction	Resource
1	Jan-00		3,150	463	\$31	2,374	6,824	2,827	3,651	-106	\$,0 33
2	Feb-00	-162	3,150	469	831	2,374	6,824	2,827	9,651	-106	6.039
3	Mar-00	-1,299	3,150	469	831	2,374	8,824	2,827	9,651	-106	6,086
	Apr-00	-1332	3,069	469	831	2,262	6,631	2,188	8,319	-106	5,979
5	May-00	0	3,110	469	831	2,262	6,672	2,188	8,860	-106	5,963
6	Jun-00	0	3.110	469	831	2,262	6,672	1,950	8,622	-106	5,973
.7	Jul-00		3,110	469	831	2,262	8,672	1,950	8,822	-106	5,973
	Aug-00	•	3,024	469	931	2,262	6,586	1,950	9,538	-106	5,891
9	Sep-00	0	3,110	463	831	2,262	6,672	2,045	8,717	-108	5,969
10	Oct-00	-487	3,110	469	831	2,262	6,672	2,188	8,860	-106	5,983
Ħ .	Nov-00		3,191	469	831	2,374	6,865	2,188		-106	6,195
12	Dec-00	-115	3,191	469	831	2,374	6,865	J,124	9,989	-106	6,064
13	Jan-01	o	3,191	469	831	2,374	C, 865	3,124	9,589	-106	6,060
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		B.d	Scheduled	Baseload	Baseload	OF Contracts	Intermediate Recourses	Intermediate - Resources	Peaking Resources	Total Resources	GF On-Peak Reduction	Intermediate Besources
	-	MONI	Maniferration	<u>rians</u>	Comilaria.	: Ger Germania	Tiesculors		11,304,000			
	1	00-nsL	0	3,150	469	- \$31	2,374	6,824	2,827	9,651	106	6,033
.	2	Feb-00	-162	3,150	469	631	2,374	6,824	2,827	9.651	-106	6,039
. 6	3	Mar-00	-1,299	. 3,150	469	831	2,374	6,824	2,827	9,601	-106	6,086
	4	Apr-00	-1,332	3,069	463	831	2,262	6,631	2,188	8,813	-100	6.961 B
8		May-00		3,110	463	831	2,482	8,072	2,100 1,950	8,000	-108	5 973
			U	3,10	169	971	2,202	6,672	1950	8 522	-106	5.973
		Aug-00	V	3 024	489	931	2 262	8.586	1.950	8,536	-106	5,891
2	3	Sep-00	0	3.110	469	801	2,262	8,672	2,045	8,717	-106	5,969
13	10	Dat-00	-487	3,110	463	831	2,262	6,672	2,189	8,860	-106	5,983
14	11	Nov-00	-884	3,191	469	831	2,374	6,865	2,188	9,053	-106	6,185
15	12	Dec-00	-115	3,191	469	631	2,374	6,865	3,124	9,589	-106	6,064
		.lan.01		3 191	469	871	2 374	. 885	3.124	9.389	-106	6.060
	18 M							£.968				6.056
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			Scheduled	Baseload	Baseload	07.0	Intermediate	Intermediate	Peaking	Total	GF On-Peak	intermediate
		Monin	Maintenance	Plants	Contracts	Contracts	Hesources	Hesources	Hesources	Hesources	Hediction	Hesources
•	1	Jan-00	0	3,150	469	831	2,374	6,824	2,827	9,651	-106	6,033
<u>.</u>	2	Feb-00	-162	3,150	469	831	2,374	6,824	2,827	9,651	-106	6,039
	3	Mar-00	-1,299	3,150	469	831	2,374	6,824	2,827	9,651	-106	6,086
		Apr-00	-1,332	3,069	469	801	2,262	6,631	2,188	8,819	-106	5,979
	6	May-CO	0	3,110	469	831	2,282	6,672	2,188	8,860	-106	ð,963 (
	<u>8</u>	Jun 00	0	3,110	469	831	2,262	8,672	1,850	8,622	-106	5.973
		Jul-00	· · · · · · · · ·	3,110	463	831	2,252	, K,672	1,300	8,522	-105	5,973
		Aug-Uu Sec.00		3,029	403	6 31 911	2.202	6,300	2 045	9,338	-106	5,851 K 969
	10	Get-00	-497	3,110	469	811	2 262	8,672	2,010	8,860	-106	5,303
3	11	Nov-00	-884	3.191	469	831	2.374	6,865	2,188	9.053	-106	6,185
6	12	Deo-00	-115	3,191	465	831	2,374	6,865	3,124	9,989	-106	6,064
											·	
	13	Jan-01		3,191	469	#31	2,374	6,865	3,124	9,989	-106	6,060
44		I Summer	Analysis 🗶	NormalLoad	🖌 Normal Caj	pacity / Nor	mai L&C 🔏 N	ormal RM 🔏 (Iormal 24-MO	K TMY Load	1 🔏 TMY U 🚺	
De	51 4 -	\$ G 4	NytoShapes 👻	> > 🗆		A + .1	• <u>A</u> • 🔳	🖽 🖬	6			
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***	(3	<u>*</u>]	Schedul	ed Mainten	ance						C
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		****		•••••••••						·····		
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								Elaseload &				Baseload &
		Month	Scheduled Maintenance	Baseload Plants	Baseload Contracts	OF Contracts	Intermediate Resources	Resources	Peaking Resources	Total Resources	QF On Peak Reduction	Resources
											1	
	1	Jan-08		3,150	463	#31	2,374	6,824	2,827	3,651	-106	\$,033
	2	Feb-00	-182	3,150	469	831	2,374	6,824	2,827	3,801	-108	6,003
		Ane 00	-1233	3,000	103	011	2,317	8,029	2,027	9,001 D 019	-106	5,020
	8	Mau-00	-, aue	3.110	469	801	2 262	6.672	2,188	8.860	-106	5,963
	8	Jun-60	0	3,110	463	831	2262	8,672	1,950	8.622	-106	5,973
	7	Jul-00	0	3,110	469	831	2,262	6,672	1,950	8,622	-106	5,973
L	•	Aug-60	0	3,024	463	931	2,262	6,588	1,950	8,536	-108	5,891
	9	Sep-00	0	3,110	463	831	2,262	6,672	2,045	8,717	-106	5,369
<u>.</u>	10	Oot-00	-487	3,110	469	831	2,262	6,672	2,188	8,860	-106	5,993
	n .	Nov-00		3,191	469	831	2,374	6,865	2,188	9,053	-106	6,185
1.1	12	□eo-00	-115	3,191	469	801	2,374	5,865	3,121	9,589	-106	6,064
1	n	Jan-01	0	3,191	469	831	2,374	6,865	3,124	9,989	-106	6,060
l.,	Hun							£ 968	2/24	0 400		
.		NA INY LOA	O X IMY LBC	V Extreme to		MALOL A EX	Teme KM X	Maroya Y k	NG LOVE YWI	<u>a km /</u>	. 12	
h an	• •	Rs (5) #	AytoShapes +	ノノロ	 ○ ④ ④ ④ ● 	. °•- <u>∕</u>	• <u>A</u> ·=	== 1 ; U				
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Fossil Steam Plant Rating Summary

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· ·	2000 1	YSP	Г		1999 Baselin	ne Ratings	
L	Winter	Summer	-	Base Winter	Peak Winter	Base Summer	Peak <u>Summer</u>
ANC - 1	522	498		512	512	507	507
ANC - 2	522	495		522	522	502	502
BAR - 1	123	121		116	116	113	113
BAR - 2	121	119	•	117	117	113	113
BAR-3	208	204		210	210	207	207
CRY-1	383	379		386	386	381	381
CRY-2	479	474		480	480	469	469
CRY-4	722	712		724	724	704	704
CRY - 5	732	717		734	734	714	714
SUW - 1	33	32		34	34	33	33
SUW - 2	32	31		33	33	32	32
SUW - 3	81	80		85	85	85	85
Subtotal	3,958	3,862		3,953	3,953	3,860	3,860
UF	41	35		44	44	36	36
TIG	223	207		240	240	200	200
HEC - 1	529	482		505	505	470	470
Subtotal	793	724		789	789	706	706
CRY - 3	782	765		782	782	765	765
TOTAL	5,533	5,351		5,524	5,524	5,331	5,331
Ref to TYSP		•		(9)		(20	Ŋ

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Peaking Unit Ratings

	2000 SI	ERC	1999 Wint	er Ratings			. 1999 Sum	mer Ratings		
	Win.	Sum.	WB@40	WP@40	WB@32	WP@32	SB@90	SP@90	SB@95	SP@95
GAS PEAKERS							<u> </u>			
AVP - 1	32	26	32	. 34	33	34	24	29	19	24
BAP - 2	53	46	53	53	54	54	46	46	46	46
BAP-4	60	49	58	58	59	62	49	49	49	49
DEP-7	93	80	91	99	91	98	76	83	69	76
DEP - 8	93	80	91	99	89	96	76	83	69	76
	03	.00	01	00	. 01	08	76	83	60	76
	30	27	30	33	31	34	25	26	24	25
	32	21	30	.00	31	24	25	20	24	25
HGP - Z	32	21	30	33	31	34	20	20	24	20
HGP - 3	35	34	35	35	30	30	31	33	29	31
HGP - 4	35	34	35	35	36	30	31	33	29	31
ICP - 7	94	88	89	93	91	98	83	85	81	83
ICP - 8	94	88	- 89	93	91	98	83	85	81	83
ICP - 9	94	88	89	93	91	98	83	85	81	83
ICP - 10	94	88	89	93	91	98	83	85	81	83
SUP - 1	67	55	63	67	65	68	49	54	44	49
SUP - 3	67	55	63	67	65	68	49	54	44	49
SUBTOTAL	1,068	945	1,028	1,084	1,045	1,110	889	939	839	889
L.O. PEAKERS							•			
AVP - 2	. 32	26	32	34	33	34	24	29	19	24
BAP - 1	53	46	53	53	54	54	46	46	46	46
BAP - 3	53	46	53	53	54	54	46	46	46	46
BYP - 1	58	46	56	58	58	60	44	47	41	44
BYP-2	58	46	56	58	58	60	. 44	47	41	44
BYP - 3	58	46	56	58	58	60	44	47	41	44
BYP-4	58	46	56	58	58	60	44	47	41	44
DEP - 1	65	54	59	65	61	67	49	54	44	49
DEP-2	65	54	59	65	61	67	49	54	44	49
DEP - 3	65	54	59	65	61	67	49	54	44	49
DEP-4	65	54	59	65	61	67	49	54	44	49
DEP - 5	65	54	59	65	61	67	49	54	44	49
DEP-6	65	54	59	65	61	67	49	54	44	49
DEP - 10	93	79	91	99	89	96	76	83	69	76
ICP - 1	61	49	58	58	62	62	47	47	47	47
ICP . 2	61	49	58	58	62	62	47	47	47	47
ICP - 3	61	40	58	58	62	62	47	47	47	47
ICP - 4	61	40	58	58	62	62	47	47	47	47
ICP - 5	61	40	58	58	62	62	· 47	47	47	47
ICP - 6	61	40	58	58	62	62	47	47	47	47
	170	40	169	168	172	172	143	143	1/2	142
	10	145	100	100	172	10	145	140	143	12
CIID 9	10	13	10	67	ee.	19	13	54		51
	46	04	40	49	47	10	10	45	40	12
	10	13	10	10	1/	19	13	10	11	13
	10	13	10	10	1/	19	13	13		13
TUP - 3	82	65	76	82	78	84	61	65	57	61
TUP - 4	80	63	76	82	78	84	. 61	65	57	61
SUBTOTAL	1,666	1,363	1,586	1,662	1,644	1,717	1,299	1,370	1,228	1,299
TOTAL	2,734	2,308	2,614	2,746	2,689	2,827	2,188	2,309	2,067	2,188
Delta from SERC			120	-12			120	-1		

			Baseline Rat	ings			Peak Weathe	r Adjusted Ra	atings	
	SERC		Base	Peak	Base	Peak	Base	Peak	Base	Peak
	Winter	Summer	Winter	Winter	Summer	Summer	Winter	Winter	Summer	Summer
Gas Units	1,068	945	1,028	1,084	889	939	1,045	1,110	839	889
Oil Units	1,666	1,363	1,586	1,662	1,299	1,370	1,644	1,717	1,228	1,299
TOTAL	2,734	2,308	2,614	2,746	2,188	2,309	2,689	2,827	2,067	2,188

JANUARY 2000 LONG-TERM FORECAST (S000101)

Normal Weather

Bulk Power Sales Included

		REGRESSED		•	NON-DISP.	TOTAL						TOTAL				RECT LOAD CON	NTROL PROGRAW	9		(USED)	FIRM	(AVAILABLE)	TOTAL
		FRM		POTENTIAL	DSM	RETAL		WHO	ESALE			SYSTEM			····			·	TOTAL		SYSTEM		IS/CS plus
		RETAL	RETAIL	TOTAL	1 3.5,	BEFORE					CO.	BEFORE	WHUSE	TOTAL	RESIDENTIAL	COMMERCIAL	STANOBY	TOTAL DLC	LOAD CONTROL	VOLTAGE	AFTER	VOLTAGE	VOL TAGE
65150H		UNACJ.	6/03	RETAL	COGEN	LCAD CONTROL	REA	BULK	MUNI	TOTAL	USE	LOAD CONTROL	B	15/CS	LOAD MGT.	LOAD MGT.	GENERATION	PROGRAMS	CAPABLITY	REDUCTION	LOAD CONTROL	REDUCTION	REDUCTION
SEASON	MUNIH	(MINI)	(MIN)	(0,000)	(MAN)	(MNN)	(MIN)	(MM)	(MMM)	(MM)	(1111)	04043	(MIV)	(MANY)	(nnn)	(MIN)	(MW)	(MIN)	0400	. (MW)	(MIV)	(0.00)	
WIN TER 99/00	Jan-2000	8,004	312	8,316	423	7,893	750	632	230	1,647	30	9,570	14	325	849	. 0	21	870	1,195	115	8,259	115	441
WINTER 99/00	Feb-2000	6,888	312	7,200	410	6,790	778	525	185	1,485	30	8,309	14	326	701	0	21	722	1,048	0	7,251	100	
WINTER 99/00	Mar-2000	6,076	312	6,308	361	6,007	289	474	191	954	30	6,991	14	326	543	0	21	564	990	. 0	6,101	86	
SUMMER 00	Apr-2000	5,635	313	5,948	304	5,644	15	479	182	676	30	6,350	14	327	265	215	21	328	966	0	5,695	79	
SUMMER 00	May-2000	6,452	313	6,765	329	6,435	172	555	205	\$33	30	7,399	14	327	350	24	22	405	733	٥	5,556	92	
SUMMER 00	Jun-2000	5,790	313	7,103	343	6,750	235	632	239	1,165	30	7,955	14	327	449	25	22	497	824	đ	7,132	98	
SUMMER 00	Jul-2000	8,957	313	7,290	347	6,933	351	632	233	1,216	30	8,179	14	327	444	26	22	492	- 819	Q	7,360	101	
SUMMER 00	Aug-2000	7,013	313	7,326	355	5,971	392	632	253	1,277	30	8,278	14	327	454	25	23	512	839	. 0	7,439	103	327
SUMMER DO	Sep-2000	5,525	313	6,938	348	6.592	244	632	223	1,099	30	7,721	14	327	408	25	23	455	783	0	6,938	98	
SUMMER OU	00-2000 Nav 2000	6,053	314	6,307	320	6,047	17	5200	183	750	30	6,927	14	328	249	21	23	253	21	0	6,206	85	
WINTER 00/01	Nov-2000	5,423	314	5,737	305	5,376	143	4/4	100	/81	30	6,187	14	329	367	0	23	410	/36	0	5,448	76	
	000-2000			0,01		1.11	337			1,000	. ~	7,743	14	320	-05	U	2	400	615		0,927		
WINTER 00/01	Jan-2001	8,175	292	8,498	444	8,024	894	632	205	1,731	30	9,795	14	305	909	0	24	833	1,139	t18	8.528	119	424
WIN TER DO/DI	Feb-2005	7,036	293	7,329	432	6,897	888	530	170	1,589	30	8,515	14	307	670	٥	24	694	1,001	0	7,514	103	
WIN FER 00/01	Mar-2005	5,207	293	6,500	403	6,097	382	474	174	1,030	30	7,157	14	307	\$15	٥	24	\$36	845	•	6,311	87	
SUMMER 01	Apr-2001	5,764	. 293	6,057	315	5,741	137	484	157	m	. 30	6,548	14	307	259	19	25	303	510	0	5,938	62	
SUMMER 01	May-2001	5,599	293	6,692	341	6,551	301	555	181	1,047	30	7,626	14	307	325	22	25	372	579	0	5,949	96	
SUMMERUS	Jun-2001	6,945	233	7,238	355	6,863	365	632	209	1,225	30	6,139	14	307	403	- 23	. 25	451	758		7,390	101	
SUMAERO	JU-2001	7,125	24	7420	354	7,001	44/	632	202	1281	30	8,3/2	14	308	396	23	20	446	754	0	7,017	105	
SUMMER 01	Sen-2001	6778	294	7.070	300	8712	331	632	105	1,543	30	7,900	14	306	414	23	20	403	217	ů	7,703	100	308
SUMMER 01	03-2001	6 191	294	6495	302	6 153	91	565	165	823	30	7,005		308	217	10	20		570		6435	80	
WIN TER 01/02	Nov-2001	5,535	294	5,830	394	5,448	278	474	151	903	30	6,379	14	308	350	0	25	385	593	0	5,585	79	
WIN TER 01/02	Dec-2001	6,601	294	6,895	429	8,467	657	576	187	1,430	30	7,927	14	308	429	0	27	455	753	0	7,164	99	
					· .																		
WINTER 01/02	Jan-2002	6,345	290	8,636	458	8,168	911	167	195	1,274	30	9,472	14	304	744	٥	27	771	1,275	115	6,262	115	419
WIN TER 01/02	Feb-2002	7,182	291	7,473	455	7,017	901	157	165	1,237	30	6,264	14	305	617	•	27	644	945	0	7,335	101	
SULAIED M	M8F-2002	2,332 6,000	201	6,52/	428	6,199	.3/7	167	108	713	30	6,942	14	305	474	8	27	501	805	0	6,136	5	
SUMMER UZ	Max-2002	5,00 6 764	20	7.034	303	5,601	130	15/	140	444	30	7 267	14	304	218		20	202	539		5,758	80	
SUMMER 02	Jun-2002	7.007	290	7 397	399	7.019	375	157	107	742	30	7,203	14	304	2/3	20	20	321	200		0,728	93	
SUMMER 02	Jul-2002	7,292	290	7.572	372	7,200	447	167	189	803	30	6.033	14	304	335	21	29	385	236	0	7 344	101	
SUMMER 02	Aug-2002	7,330	291	7,621	381	7,240	490	157	209	857	30	8,137	14	305	351	21	29	400	705	0	7.431	102	305
SUMMER 02	Sep-2002	5,924	291	7215	372	6,843	322	167	184	573	30	7,545	14	305	305	20	29	. 355	551	٥	6,005	95	
SUMMER 02	O⊐-2002	5,327	251	5,519	345	6,272	75	157	156	401	30	6,703	14	305	185	17	25	231	5.35	0	6,167	85	
WINTER 02/03	Nov-2002	5,647	282	5,939	410	5,529	259	157	145	593	30	5,142	14	305	335	0	29	354	570	٥	5,471	76	
WIN TER 02/03	Dec-2002	5,731	292	7,025	454	6,572	670	167	175	1,012	30	7,614	14	305	402	0	30	431	737	0	5,677	95	
WANTED MUM			24							-					-		-						
WINTER 02/03	Fab.2003	7 307	314	7.641	499	7 158	556	157	203	328	30	9,271	14	328	701	0	30	730	1.09	113	5.120	113	441
WIN TER 02/03	Mar-2003	5,453	314	5,777	454	6.323	3	157	173	343	30	6,695	14	328	447	0	30	477	HCE.		5 691	82	
SUMMER 03	Apr-2003	5,015	314	5,330	343	5,987	0	157	152	320	30	8,337	14	328	1997	15	31	234		0	5,775	81	
SUMMER 03	May-2003	5,998	314	7,202	358	5,934	a	167	177	334	30	7,208	14	329	235	18	31	295	513	0	6,595	91	
SUMMER 03	Jun-2003	7 249	314	7,553	382	7,181	э	157	205	372	30	7,583	14	328	294	19	31	344	572	0	6,911	95	
SUMMER 03	Jui-2003	7,438	314	7,752	395	7,395	77	167	197	441	30	7,637	14	329	232	19	32	342	\$~)	0	7,167	99	
SUMMER 03	Aug-2003	7,497	314	7,801	395	7,405	121	157	218	505	30	7,942	14	329	305	19	32	355	94	0	7258	100	329
SUMMER 03	Sep-2003	7.073	315	7,398	305	7,002	c	167	192	356	30	7,391	14	329	298	19	32	318	-417	÷ ÷	6,744	93	
SUMMER 03	Dct-2003	5,452	315	6,777	350	6,417	э	157	154	332	30	6,779	14	329	152	15	33	210	5.62	3	6,240	87	
WIN IER 03/04	Nov-2003	5,759	315	5,075	430	5,637	Û	157	151	319	30	5,995	14	330	319	0	33	352	Ф.;	0	5,304	74	
WIN TER 03/04	De: 2003	5,857	315	7,183	482	6,701	303	167	192	552	30	7,363	14	330	304	0	33	417		0	5,636	32	
MN TER 03/04	Jan-2004	0.692	315	8.997	523	8.474	503	157	205	. 877	30	9.381	54	323	673	. 0	33	707	: *	114	8,231	114	443
WIN TER 03/04	Fet-2004	7.471	315	7,785	511	7.275	503	157	174	944	30	8.149	14	329	559	0	33	592		5	7,229	100	
WIN TER 03/04	Mar -2004	5.501	315	5,907	482	5,425	3	157	175	343	30	6,799	14	330	429	0	34	453	5.7	0	6,005	54	
SUMMER 04	Acr -2004	5,14D	315	6,455	358	5.097	C	157	152	222	30	6,449	14	323	165	14	34	214	4	2 ^{- 1}	5,905	82	
SUMMER 04	May-2004	7,030	315	7,345	383	5,992	c	157	175	315	30	7,338	14	329	203	15	34	259		9	6,750	93	
SHAMER 04	Ju-2004	7,338	315	7,713	397	7,315	c	157	207	374	30	7,720	14	323	250	17	35	311	54	,	7,090	. 98 .	
SUMMER 04	Jrg-2004	7,591	315	7,905	401	7,505	2	157	20C	35 4	30	7,904	14	329	257	17	35	309	**	;	7,255	100	
SUMMER 04	Aug-2004	7,641	315	7,958	410	7,515	39	197	2.	435	30	0.012	14	329	239	17	35	322	57 ×	÷ .	7.351	102	323
SPIMMER 04	Set 2004	7,219	315	7,534	401	7,133		157	194	<i></i>	30	7,524	14	330	235	15	35	209		`	6,505	\$5	

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JANUARY 2000 LONG-TERM FORECAST (S000101)

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Normal Weather

Buik Power Sales Included

			REGRESSED			NON-DISP.	TOTAL						TOTAL			1	DIRECT LOAD CON	TROL PROGRAM	5		MSED)	FEM	(AVAILABLE)	TOTAL
			FRM		POTENTIAL	DSM	RETAL		WHO	LEŠALE			SYSTEM							TOTAL		SYSTEM		E/CS plus
			RETAL	RETAL	TOTAL	4 53.	SEFORE					CO.	BEFORE	WHILSE	TOTAL	RESIDENTIAL	COMMERCIAL	STANDBY	TOTAL DLC	LOAD CONTROL	VOLTAGE	AFTER	VOLIAGE	VOL MAGE RECIVICION
			UNADJ.	5/03	RETAL	COGEN	LOAD CONTROL	rea	BULK	MJN1	TOTAL	USE	LOAD CONTROL	8	IS/CS	LOAD MGT.	LOAD MGT.	GENERATION	PROGRAMS	CAPABLIIT	ALLOCION	COALCONIROL	ADD CHOIL	ALD GUILDIN
	SEASON	MONTH	(MM)	(MW)	(MW)	(MNA)	(MW)	(MIW)	(MIV)	(MW)	(MM)	(MW)	(MVV)	(MW)	(MN)	(MW)	(MAR)	(4444)	(MYY) 407	(MYY) 572	(111)	# 379	89.1	
	SUMMER 04	0:::-2004	6,595	316	6.911	375	5,535	0	167	157	335	30	6,901	54	330	14.3		 	343	574	0	5,394	76	
	WINTER 04/05	Nov-2004	5,967	317	6,184	457	5,717		167	153	321	30	6,069	14	331	30/	ň	36	407	738	0	6,677	93	
	WINTER 04/05	Dec-2004	8,996	317	7,313	511	6,602	232	10/	104	204	30	7,415			5.1	-							
	WINTER OVOS	Jan-2005	8.645	320	9,155	552	8,513	525	167	199	890	30	9,533	14	334	652	ő	35	698	1,022	117	8,354	117	451
	WINTER DAUDS	Fab-2005	7.612	321	7.933	540	7,393	520	167	173	860	30	8,253	14	335	541	0	35	578	913	0	7,371	102	
	WINTER 04/05	Mar-2005	6,714	321	7.035	512	8,523	0	167	174	342	30	6.695	14	335	415	0	37	452	787	0	6,109	85	
	SUMMER 05	Apr-2005	6,253	320	6.579	373	8,205	ø	167	151	319	30	6,555	14	334	148	12	37	195	530	Û	6,025	64	
	SUMMER 05	May-2005	7,167	320	7,487	398	7,089	٥	157	177	344	30	7,453	94	334	184	14	39	235	\$70	0	6,653	95	
	SUMMER 05	Jun-2005	7.542	320	7.852	412	7,450	0	167	198	355	30	7,945	14	334	229	15	36	282	815	Q	7229	100	
	SUMMER 05	Jul-2005	7,739	320	8,058	415	7,543	7	157	190	365	30	8,038	14	334	227	15	38	290	614	0	7,423	102	275
	SUMMER 05	Aug-2005	7,790	321	8,111	425	7,585	- 54	167	211	433	30	8,149	14	335	238	- 15	38	291	826	0	7,522	104	345
	SUMMER 05	Sep-2005	7,359	321	7,690	415	7.254	0	157	191	359	. 30	7,653	14	335	208	15	39	262	597	0	7,000	50	
	SUMMER 05	0:::-2005	8,724	321	7,045	391	6,854	٥	187	165	333	30	7,017	14	335	125	12	39	1//	512	0	5,474	30	
	WANTER 05/06	Nov-2005	5,971	322	6,293	497	5,795	6	157	152	320	30	5,145	14	335	297	0	35	399	0/2		8783	94	
	WINTER 05/05	Dec-2005	7,120	322	7,442	541	6,901	239	167	181	567	30	7,518	. 14	335	350	a	29	336	745	Ų	0,100		
	MANTER OF OF	100 2006	0.000	377	6.775	602	8743	600	187	200	968	30	9,741	14	337	635	. 0	. 39	674	1,011	120	8,510	120	457
	WAN JER 03/05	Eab.2005	2 747	324	8075	571	7.500	595	167	175	939	30	8,459	14	336	525	0	40	505	204	¢	7,565	104	
	WINTER 0505	Mar-2005	5834	324	7,158	542	5.515	0	157	177	344	30	6,990	14	338	403		40	443	785	0	5,209	05	
	SUMMER 05	Apr-2005	5.375	324	6,699	385	6,310	٥	157	154	321	30	8,651	14	339	129	11	40 .	181	519	o	6,142	65	
	SUMMER 05	May-2005	7299	324	7,623	413	7210	. Q	157	179	345	30	7,585	14	339	162	13	41	215	554	a	7,032	97	
	SUMMER 05	Jun-2005	7,652	324	8,005	428	7 578	0	157	200	367	30	7,975	14	339	202	13	41	257	595	a	7,381	102	
	SUMMER 05	Jul-2006	7,992	324	8,205	432	7,774	65	157	193	425	30	8,225	14	336	200	14	41	255	\$93	0	7,536	105	220
	SUMMER 05	Aug-2005	7,934	325	8,259	441	7,918	112	167	214	493	30	6,341	14	339	210	14	42	- 265	604	0	7,73/	107	738
	SUMMER 05	Sep-2005	7,495	325	7,829	432	7,398	0	167	154	351	30	7,779	14	339	194	13	42	239	578	0	120	 	
	SUMMER 08	0::1-2005	6,948	325	7,173	405	8,767	0	167	168	335	30	7,132	54	339	111	11	42	104	503	с С	6,651	78	
	WIN TER 05/07	Nov-2005	5,072	325	5,397	529	5,859	0	167	155	322	30	8,221	14	. 339	289	0	42	307	772	0	8939	95	
	WINTER 05/07	Dec-2005	7,241	325	7,555	572	6,994	296	157	183	545	30	7,570	14	3.54	350	v			132	-	6,000		
	WANTED DONT	Jan-2007	9 155	328	9.483	613	6.670	676	157	203	1,045	30	9,945	14	342	819	0	42	- 851	1,003	123	6,820	123	455
e e	WINTER 05/07	Fan-2007	7 679	328	9207	801	7,606	672	167	179	1,019	30	8,555	14	342	513	` o	43	555	898	0	7,755	107	
	WNIER 09/07	Mar-2007	6.950	329	7278	572	5,705	22	157	180	369	30	7,105	54	342	393	۵.	43	435	778	0	6.327	56	
	SUMMER 07	Apr-2007	5,489	328	5,815	404	6412	a	157	156	323	30	6,765	14	342	114	10	44	157	509	. 0	6255	87	
	SUMMER 07	May-2007	7,429	328	7,755	423	7,327	0	157	181	348	30	7,705	14	342	143	12	- 44	199	541	٥	7,155	99	
	SUMMER 07	Jun-2007	7,917	328	8,145	443	7,702	10	167	203	381	30	8,113	14	342	178	. 12	- 44	235	577	٥	7,535	104	
	SUMMER 07	Jul-2007	8.021	329	8.350	447	7,903	122	167	195	485	30	8,418	14	343	177	12	. 44	234	577	• 0	7,941	108	~~~
	SUMMER 07	Aug-2007	0.074	329	6,403	455	7 947	171	167	217	555	30	8,532	14	343	185	12	45	242	585	0	7,947	109	343
	SUMMER 07	Sep-2007	7,527	329	7 555	447	7.509	٥	157	197	354	30	7,903	54	343	162	12	45	219	. 552	0	7,341	101	-
	SUMMER 07	ಿ≍-2007	6,959	329	7238	422	6,675	0	\$67	170	337	30	7243	14	343	98	10	45	153	496	0	5.141	34	
	WN 1ER 07/08	Nov-2007	8,171	329	5,500	558	5,912	8	157	157	324	30	5,295	- 14	343	281	a .	45	320	730		7.092	58	
	WIN TER 07/08	Dec-2007	7,358	329	7,597	502	7,065	354	157	185	707	30	7,822	14	343	342	a .	-0	301	730	v	7,002		•
		Inc. 2008	0.307	724	0.631	843	ROOM	755	157	205	1.129	30	10,150	14	345	605	a	45	550	\$95	125	9.029	125	470
	WIN TER OTING	Fac-2009	8005	331	8337	531	7,705	754	157	181	1,107	30	8,843	14	345	502	0	45	547	892	0	7,951	110	
	WINTER 07/09	Mar-2008	7.952	331	7,393	503	6,790	73	157	182	422	30	7,242	14	345	384	٥	45	430	. 775	a	5,457	90	
	SUMMER OF	Apr-2009	6.598	331	5323	419	5.510	0	167	158	325	a 30	6,9%5	14	345	100	9	47	158	501	0	6,364	8)	•
	SUMMER OF	May-2008	7,554	331	7.995	444	7,441	ΰ	167	184	352	30	7,823	14	345	125	10	47	164	529	٥	7,294	101	
	SUMMER OF	Jun-2008	7,950	332	82%2	458	7,624	58	157	205	432	30	6285	14	345	157	11	47	215	552	0	7,724	107	
	SUMMER 09	Jut-2009	8,157	332	6,493	453	8.025	181	167	199	547	30	8,503	14	345	. 155	11	49	215	551	0	8.042	111	748
	SUMMER OF	Aug-2009	8,211	352	9543	471	8,072	231	167	220	518	30	9,720	14	345	153	11	48	222	569	. 0	6,152	112	
	SUMMER OF	Sec-2008	7,757	332	9.082	452	7,527	0	157	7 199	355	30	0,023	14	345	143	11	49	202	548	5	7,475	103	
	SUMMER 09	Ora-2008	7,097	332	7419	437	5,382	0	157	172	340	30	7,352	14	345	87		48	144	490		5,552	35	
	WIN TER 09/09	Nov-2006	9 6,257	337	3533	599	5.011	0	157	7 159	325	30	5,357	14	345	274	0	45	322	000	5	7.945	100	
	WIN TER OBOS	C+0-200	3 7,474	330	7.907	532	7,175	414	L 15	7 188	769	x	7,974	14	347	334	٥	48	362	779	U	1293		
		سرب الرا				177	A +++	87	3 (*	7 200	121		0 10351	14	338	597	9	49	541	999	128	\$,234	128	475
	WINTER OFFICE	367-200	, y,ead	ت در مربر	8 N	524	7 105		- 10		1.18	2 3	9.017	14	- 348	491	0	43	540	1998	э	9,129	112	
	MINIER OF CHI	F 40-2002	e 0.132	ادرو ⊷∹۲	26.27	100	5875	12	4 117		475	30	7,391	14	348	375	0	49	424	772	9	6.508	22	
	AND A REAL FOR ALL	211.000	= 7.743 = 3.704	يور ميچ	1743	310	5.505	0	15	7. 160	327	3	5.9%	14	348	69	9	. 50	:47	495	0	5,371	ж	
	SUMMER D-	Mar. 200	g 7940	Te	મહત્વ	450	7,555	54	15	7 105	409	r , 30	c 7 <i>.</i> 933	14	349	111	3	50	171	519	0	7,474	1(3)	
	ST.MMER D	1:5-2151	6 6063	12	9499	473	7,345	10	7 15	7 209	493	3	0,455	14	349	139	30	50	199	546	ð	7,910	102	
			,																					
																				म	PC 051			7/19/00 45 12 14 754
	1/1C 2000 ×15	D-SP. 63												\$	18-24-21-21-3		•	1.00		T.	10 001			

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JANUARY 2000 LONG-TERM FORECAST (S000101)

Normal Weather

ويعتدون والارتجاب الأخداقات

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Bulk Power Sales Included

		REGRESSED			NON-DISP,	TOTAL						TOTAL				RECT LOAD CO	NTROL PROGRAM	s .		NSEDI	FEM	(AVAILABLE)	TOTAL	
		FRM		POTENTIAL	DSM	RETAL		WHO	LESALE			SYSTEM							TOTAL.		SYSTEM		IS/CS plus	ŧ
		RETAL	RETAL	TOTAL	6 35.	BEFORE					CO.	REFORE	WHESE	TOTAL	RESIDENTIAL	COMMERCIAL	STANDBY	TOTAL DLC	LOAD CONTROL	VOLTAGE	AFTER	VOLTAGE,	VOLTAGE	,
		UNADJ.	6/03	RETAL	COGEN	LOAD CONTROL	REA	BULK	MUNI	TOTAL	USE	LOAD CONTROL	. 15	8/05	LOAD MGT.	LOAD MOT.	GENERATION	PROGRAMS	CAPABLITY	REDUCTION	LOAD CONTROL	REDUCTION	REDUCTION	N
SEASON	MONTH	0.000	0.04	(0.000)	(MW)	(11/1)	(MVV)	(MW)	6MM)	(4511)	(ANY)	(Why	(MIN)	(111)	(MVA)	(404)	(1111)	0.000	(8.00)	(MYY)	(MVM)	0.4949		
SUMMER 09	Jul-2009	8,293	335	8,628	477	8,151	240	167	202	510	30	8,791	14	349	138	10	51	196	547	. 0	6243	113		
SUMMER 09	Aug-2009	8,348	335	6,683	486	8,197	291	187	223	681	30	8,908	14	349	144	10	51	205	554	O	8,354	115	· 3	12
SUMMER OF	Sep-2009	7,895	335	8,221	477	7,744	32	157	202	401	30	8,175	14	349	125	10	51	187	\$36	a	7,539	105		
SUMMER 09	Cct-2009	7205	335	7,540	451	7,069	D	167	175	343	30	7,482	14	349	75	ອຼ	52	135	485	. D	6,977	57		
WINTER 09/10	Nov-2009	6,355	335	5,701	617	6,084	0	167	161	325	30	6,442	14	349	268	۵	51	319	658	0	5,774	81		
WINTER 09/10	Dec-2009	7,591	336	7,927	601	7,255	474	167	190	832	30	8,128	14	350	327	o	52	378	728	. 0	7,399	102		
WINTER 09/10	Jan-2010	9,597	335	9,933	701	9232	912	167	212	1,291	30	10,553	14	350	580	a	52	632	982	131	9,440	131	4	81
WINTER 09/10	Feb-2010	8,259	335	8,595	687	7,909	912	157	185	1,255	30	1204	14	350	481	0	52	\$33	963	0	8,321	114		
WINTER 09/10	Mar-2010	7,285	335	7,621	655	6,955	177	167	195	530	30	7,525	14	350	357	D	52	419	769	0	5,755	94		
SUMMER 10	Apr-2010	5,619	336	7,155	445	6,710	٥	167	162	330	30	7,070	14	350	78	7	53	138	436	0	8,582	S1		
SUMMER 10	May-2010	7,908	337	8,145	469	7,575	114	167	189	471	30	8,177	14	351	98	8	53	159	510	D	7,685	105		
SUMMER 10	Jun-2010	8,217	337	8.554	482	8,072	157	157	212	535	30	8,538	14	351	122	8	53	184	535	0	8,103	112		
SUMMER 10	Jul-2010	8,431	337	8,765	485	8 283	301	157	205	574	30	8,967	14	351	121	۹.	53	163	\$34	0	8,453	115		
SUMMER 10	Aug-2010	8,487 -	337	8,824	492	8,332	353	157	226	747	30	9,109	14	351	127	9	53	199	540	٩	8,559	118	3	51
SUMMER 10	Sep-2010	8,017	337	8,354	482	7,872	79	167	205	452	30	8,354	14	351	153	9	53	172	523	0	7,830	109		
SUMMER 10	Oct-2010	7,325	337	7,852	455	7,207	0	167	177	345	30	7,562	14	351	67 ·	7	53	127	478	D	7,104	95		
WINTER 10/11	Nov-2010	6,465	338	5,003	621	6,182	0	157	163	330	30	6,542	14	352	262	٥	52	314	665	D	5,875	82		
WINTER 10/11	Dec-2018	7,710	338	9,048	653	7,395	536	167	192	895	30	0,311	54	352	320	D	52	372	724	0	7,587	105		

JANUARY 2000 FORECAST (S000102) High Retail Scenario

Bulk Power Sales Included

		TOTAL	DIRECT LC	DAD CONTROL P	ROGRAMS		TOTAL	(USED)	FIRM	(AVAILABLE)
		BEFORE	RESIDENTIAL	OTHER DLC	TOTAL DLC	INTERR.			AFTER	VOLTAGE
SEASON	MONTH	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)
WINTER 99/00	Jan-2000	9,692	8 49 .	21	870	326	1,196	116	8,380	116
WINTER 99/00	Feb-2000	8,410	701	21	722	326	1,048	D	7,362	101
WINTER 99/00	Mar-2000	7,077	543	21	564	326	890	· O	6,187	86
SUMMER 00	Apr-2000	6,428	285	42	328	327	655	o	5,773	81
SUMMER 00	May-2000	7,493	360	46	406	327	733	0	6,760	94
SUMMER 00	Jun-2000	8,055	449	47	497	327	824	0	7,232	100
SUMMER 00	Jul-2000	8,282	444	48	492	327	819	0	7,463	103
SUMMER 00	Aug-2000	8,382	464	48	512	327	839	. 0	7,543	104
SUMMER 00	Sep-2000	7,818	408	48	455	327	783	0	7,035	97
SUMMER 00	Oct-2000	6,913	249	44	293	328	621	0	6,292	87
WINTER 00/01	Nov-2000	6,263	387	23	410	328	738	٥	5.524	77
WINTER 00/01	Dec-2000	7,839	465	23	488	328	816	0	7,023	97
WINTER 00/01	Jan-2001	9,913	809	24	833	306	1,139	. 120	8,654	120
WINTER 00/01	Feb-2001	8,621	670	24	694	307	1,001	0	7,620	105
WINTER 00/01	Mar-2001	7,247	515	24	539	307	846	0	6,401	89
SUMMER 01	Apr-2001	6,631	259	43	303	307	610	0	6,021	84
SUMMER 01	May-2001	7,727	325	.47	372	307	679	0	7,048	97
SUMMER 01	Jun-2001	8,244	403	48	451	307	758	0	7,486	103
SUMMER 01	Jui-2001	8,481	395	49	446	308	754	o	7,726	106
SUMMER 01	Aug-2001	8,582	414	49	463	305	771	0	7,811	107
SUMMER 01	Sep-2001	8,002	361	48	409	308	717	D	7,285	100
SUMMER 01	Oct-2001	7,097	217	45	262	308	570	0	6.526	90
WINTER 01/02	Nov-2001	6,475	359	26	385	308	693	0	5,782	80
WINTER 01/02	Dec-2001	8,047	429	27	455	308	763	0	7,284	100
WINTER 01/02	Jan-2002	9,631	744	27	771	304	1,075	117	8,439	117
WINTER 01/02	Feb-2002	8,416	617	27	644	305	949	o	7,467	103
WINTER 01/02	Mar-2002	7,055	474	27	501	305	806	0	6,249	87
SUMMER 02	Apr-2002	6,431	218	45	262	304	566	0	5,864	81
SUMMER 02	May-2002	7,478	273	48	321	304	625	0	6,853	94
SUMMER 02	Jun-2002	7.924	340	49	388	304	692	0	7.231	99
SUMMER 02	Jul-2002	8,170	336	50	385	304	689	0	7,481	103
SUMMER 02	Aug-2002	8.275	351	50	400	305	705	0	7 569	104
SUMMER 02	Sep-2002	7.675	306	49	356	305	661		7 014	97
SUMMER 02	Oct-2002	6.819	185	46	231	305	536	- n · .	6 283	87
WINTER 02/03	Nov-2002	5 254	335	29	364	306	670	0	5 592	79
WINTER 02/03	Dec-2002	7 753	402	- 30	431	305	737	0	7.015	70
	000-2002		772	00	-31	960	191		(,010	37
WINTER 02/03	Jan-2003	9,475	701	30	730	328	1,058	115	8,301	115
WINTER 02/03	Feb-2003	8,232	581	30	612	328	940	0	7.292	101
WINTER 02/03	Mar-2003	6,828	447	30	477	325	805	0	6.023	84

JANUARY 2000 FORECAST (S000102) High Retail Scenario Bulk Power Sales Included

	31		TOTAL	DIRECT LO	DAD CONTROL P	ROGRAMS		TOTAL	(USED)	FIRM	(AVAILABLE)
			BEFORE LOAD CONTROL	RESIDENTIAL	OTHER DLC	TOTAL DLC	INTERR.	LOAD CONTROL CAPABILITY	VOLTAGE	AFTER	VOLTAGE
	SEASON	MONTH	(MW)	(MW)	(MW)	(MW)	(MW)	_(MW)	(MW)	(MW)	(MVY)
	SUMMER 03	Apr-2003	5,461	188	46	234	328	562	0	5,899	82
	SUMMER 03	May-2003	7,353	235	49	285	328	613	٥	6,740	93
	SUMMER 03	Jun-2003	7,737	294	50	344	328	672	0	7,065	98
	SUMMER 03	Jul-2003	7,996	292	51	342	328	670	o	7,326	101
	SUMMER 03	Aug-2003	8,102	305	51	355	328	684	0	7,418	102
	SUMMER 03	Sep-2003	7,541	268	50	316	329	647	0	6,894	95
	SUMMER 03	Oct-2003	6,914	162	48	210	329	539	0	6,375	83
	WINTER 03/04	Nov-2003	6,146	319	33	352	330	682	- O	5,464	76
	WINTER 03/04	Dec-2003	7,578	384	33 .	417	330	747	0	6,831	95
	WINTER 03/04	Jan-2004	9,636	673	33	707	329	1,036	118	8,482	118
	WINTER 03/04	Feb-2004	8,354	559	33	592	329	921	0	7,443	103
	WINTER 03/04	Mar-2004	6,984	429	34	463	330	793	Û	5,191	85
	SUMMER 04	Apr-2004	5,624	166	48	214	329	543	0	6,081	85
	SUMMER 04	May-2004	7,542	209	50	259	329	588	0	6,954	96
	SUMMER 04	Jun-2004	7,936	260	51	311	329	540	a	7,296	101
	SUMMER 04	Jui-2004	8,127	257	52	309	329	635	0	7,469	103
	SUMMER 04	Aug-2004	8,236	269	52	322	329	651	0	7,585	104
	SUMMER 04	Sep-2004	7,734	236	52	288	330	618	. O	7,116	98
	SUMMER 04	Oct-2004	7,091	143	49	192	330	522	0	6,569	91
	WINTER 04/05	Nov-2004	6,248	307	36	343	331	674	C	5,574	78
	WINTER 04/05	Dec-2004	7,635	371	36	407	331	738	0	6,897	95
	WINTER 04/05	Jan-2005	9,819	652	36	688	334	1,022	121	8,677	121
	WINTER 04/05	Feb-2005	8,524	541	36	578	335	913	. 0	7,612	105
	WINTER 04/05	Mar-2005	7,104	415	37	452	335	787	0	6,317	83
	SUMMER 05	Apr-2005	6,753	146	50	196	334	530	0	6,223	87
	SUMMER 05	May-2005	7,693	184	52	236	334	570	٥	7,123	98
	SUMMER 05	Jun-2005	8,088	229	53	282	334	616	0	7,472	103
	SUMMER 05	Jul-2005	8,288	227	53	280	334	514	0	7,673	106
	SUMMER 05	Aug-2005	8,401	238	54	291	335	626	0	7,774	107
	SUMMER 05	Sep-2005	7,890	208	53	262	335	597	0	7,293	101
	SUMMER 05	Oct-2005	7,231	126	51	177	335	512	0	6,719	93
•	WINTER 05-05	Nov-2005	6,368	297	39	336	336	672	٥	5,696	80
	WINTER 05:06	Dec-2005	7,785	360	39	399	336	735	G j	7,053	93
	WINTER 05-05	Jan-2005	10.091	835	39	674	337	1,011	124	8,955	124
	WINTER 05.06	Feb-2006	8.765	526	40	566	338	904	O	7,861	103
	WINTER 05-06	Mar-2005	7.248	403	40	443	338	781	0	6,467	90
	SUMMER 05	Apr - 2005	6.905	129	52	181	338	519	0	5,386	89
	SUMMER 06	May-2005	7,870	162	54	216	338	554	0	7,315	101
	SUMMER 06	Jun-2006	8.275	202	54	257	338	595	0	7,681	106

lysp2000.xls TYSP High Load

Page 2 of 4

7/19/00 @ 12.14 F'M

FPC 054

JANUARY 2000 FORECAST (S000102) High Retail Scenario

Bulk Power Sales included

2	,	TOTAL	DIRECT LC	DAD CONTROL P	ROGRAMS		TOTAL	(USED)	FIRM	(AVAILABLE)
SEASON	MONTH	BEFORE LOAD CONTROL (MW)	RESIDENTIAL LOAD MGT. (MW)	OTHER DLC PROGRAMS (MW)	TOTAL DLC PROGRAMS (MW)	INTERR. LOAD	LOAD CONTROL CAPABILITY (MW)	VOLTAGE REDUCTION (MW)	AFTER LOAD CONTROL (MW)	VOLTAGE REDUCTION
SUMMER 05	Jui-2006	8,537	200	55	255	338	593	0	7.944	109
SUMMER 06	Aug-2006	8,651	210	55	265	339	604	0	8.047	111
SUMMER 06	Sep-2006	8.070	184	55	239	339	578	٥	7.492	103
SUMMER D6	Oct-2006	7,396	511	53	164	339	503	0	6,893	95
WINTER 06/07	Nov-2006	6.447	289	42	331	339	670	0	5,777	81
WINTER 06/07	Dec-2006	7,945	350	42	393	339	732	٥	7,214	100
WINTER 06/07	Jan-2007	10,303	619	42	661	342	1,003	127	9,172	127
WINTER 06/07	Feb-2007	8,957	513	43	556	342	898	٥	8,058	111
WINTER 06/07	Mar-2007	7,368	393	43	436	342	778	0	6,590	92
SUMMER 07	Apr-2007	7,014	114	54	167	342	509	0	6,505	90
SUMMER 07	May-2007	7,994	143	56	199	342	541	. 0	7,454	103
SUMMER 07	Jun-2007	8,418	178	56	235	342	577	0	7,841	108
SUMMER 07	Jul-2007	8,732	177	57	234	343	577	٥	8,155	112
SUMMER 07	Aug-2007	8,848	185	57	242	343	585	e	8,263	114
SUMMER 07	Sep-2007	8,200	162	57	219	343	562	0	7,533	105
SUMMER 07	Oct-2007	7,512	95	55	153	343	496	0	7,016	97
WINTER 07/08	Nov-2007	6,568	281	45	326	343	669	0	5,899	82
WINTER 07/08	Dec-2007	8,152	342	45	387	343	730	0	7,422	102
WINTER 07/08	Jan-2008	10,577	605	46	650	345	995	131	9,450	131
WINTER 07/08	Feb-2008	9,205	502	46	547	345	892	0	8,313	114
WINTER 07/08	Mar-2008	7,557	384	45	430	345	775	٥	6,782	94
SUMMER 08	Apr-2008	7,166	100	56	156	345	501	٥	6,665	93
SUMMER 08	May-2008	8,171	126	58	184	345	529	0	7,642	105
SUMMER 08	Jun-2008	8,653	157	58	216	346	562	0	8.091	11)
SUMMER 08	Jui-2008	8,981	156	59	215	346	561	0	8,420	116
SUMMER 08	Aug-2008	9,100	163	59	222	346	568	0	8,532	117
SUMMER 08	Sep-2008	8,380	143	59	202	346	545	0	7,832	108
SUMMER 08	Oct-2008	7,677	37	57	144	346	490	0	7.187	99
WINTER 08/09	Nov-2008	6,671	274	48	322	346	665	0	6,003	84
WINTER 08/09	Dec-2008	8,342	334	43	382	347	729	٥	7,613	105
WINTER 08/09	Jan-2009	10,827	592	49	641	348	989	134	9.703	134
WINTER 08/09	Feb-2009	9,420	491	49	540	348	888	0	8.532	117
WINTER 08/09	Mar-2009	7,733	375	49	424	348	772	¢	5.960	96
SUMMER 09	Apr-2009	7,302	89	58	147	348	495	0	6.808	94
SUMMER 09	May-2009	\$,352	111	60	171	348	519	۰.	7.863	108
SUMMER 09	Jun-2009	8.869	139	60	199 .	349	548	0	8.321	114
SUMMER 09	Jui-2009	9,213	138	61	198	349	547	٥	8,665	119
SUMMER 09	Aug-2009	9,333	144	61	205	349	554	0	8.779	120
SUMMER 09	Sep-2009	8.575	125	61	187	349	536	0	8.039	111

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JANUARY 2000 FORECAST (S000102) High Retail Scenario Bulk Power Sales Included

•		TOTAL	DIRECT LO	DAD CONTROL P	ROGRAMS			(USED)	FIRM	(AVAILABLE)
		BEFORE	RESIDENTIAL	OTHER DLC	TOTAL DLC	INTERR.	TOTAL LOAD CONTROL	VOLTAGE	AFTER	VOLTAGE
		LOAD CONTROL	LUAD MGI.	PRUGRAMS	PROGRAMS	LUAD	CAPABILIT	REDUCTION	LOAD CONTROL	REDUCTION
SEASON	MONTH	(MW)	(MW)	(MVV)	(MW)	(MYV)	(MVV) *	(MWY)	(MVV)	(MVV)
SUMMER 09	Oct-2009	7,825	76	60	136	349	485	0	7,340	101
WINTER 09/10	Nov-2009	6,784	268	51	319	349	668	0	6,116	85
WINTER 09/10	Dec-2009	8,542	327	52	378	350	728	0	7,813	108
WINTER 09/10	Jan-2010	11,087	580	52	632	350	982	138	9,957	138
WINTER 09/10	Feb-2010	9,657	481	52	533	350	883	o	8,774	120
WINTER 09/10	Mar-2010	7,921	367	52	419	350	769	o	7,152	99
SUMMER 10	Apr-2010	7,450	78	60	138	350	488	ο,	6,962	97
SUMMER 10	May-2010	8,616	98	61	159	351	510	0	8,105	112
SUMMER 10	Jun-2010	9,101	122	61	184	351	535	0	8,566	118
SUMMER 10	Jui-2010	9,463	.121	62	183	351	534	0	8,929	122
SUMMER 10	Aug-2010	9,588	127	62	189	351	540	0	9,048	124
SUMMER 10	Sep-2010	8,805	111	61	172	351	523	0	8,281	114
SUMMER 10	Oct-2010	7,992	67	60	127	351	478	0	7,514	104
WINTER 10/11	Nov-2010	6,920	262	52	314	352	666	-0	6,254	87
WINTER 10/11	Dec-2010	8,768	320	52	372	352	724	0	8,044	111

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JANUARY 2000 FORECAST (S000103) Low Retail Scenario Bulk Power Sales Included

		TOTAL	DIRECT LC	DAD CONTROL P	ROGRAMS			(USED)	FIRM	(AVAILABLE)
		SYSTEM					TOTAL		SYSTEM	
		BEFORE	RESIDENTIAL	OTHER DLC	TOTAL DLC	INTERR.	LOAD CONTROL	VOLTAGE	AFTER	VOLTAGE
		LOAD CONTROL	LOAD MGI.	PROGRAMS	PROGRAMS	LOAD	CAPABILITY	REDUCTION	LOAD CONTROL	REDUCTION
SEASON	MONTH	(MW)	(MW)	. (MW)	(MW)	(MVY)	(MAA)	(MW)	(MW)	(MVV)
WINTER 99/00	Jan-2000	9,360	849	21	870	326	1,196	112	8,052	112
WINTER 99/00	Feb-2000	8,124	701	21	722	326	1,048	0	7,075	98
WINTER 99/00	Mar-2000	6,824	543	21	564	326	890	٥	5,934	83
SUMMER 00	Apr-2000	6,191	285	42	328	327	655	٥	5,536	77
SUMMER 00	May-2000	7,222	360	45	405	327	733	0	6,469	90
SUMMER 00	Jun-2000	7,772	449	47	497	327	824	۵	6,948	96
SUMMER 00	Jul-2000	7,991	444	48	492	327	819	0	7,172	99
SUMMER 00	Aug-2000	8,089	464	48	512	327	639	0	7,250	100
SUMMER 00	Sep-2000	7,541	408	48	456	327	783	0	6,758	94
SUMMER 00	Oct-2000	6,659	249	44	293	328	621	o	6,038	84
WINTER 00/01	Nov-2000	6,020	387	23	410	328	738	0	5,281	74
WINTER 00/01	Dec-2000	7,550	465	23	488	328	816	0	6,734	93
WINTER 00/01	Jan-2001	9,550	809	. 24	833	306	1,139	115	8,296	115
WINTER 00/01	Feb-2001	8,309	670	24	694	307	1,001	0	7,308	101
WINTER 00/01	Mar-2001	6,971	515	24	539	307	546	0	6,125	85
SUMMER 01	Apr-2001	6,372	259	43	303	307	610	a	5,762	80
SUMMER 01	May-2001	7,431	325	47	372	307	679	0	6,752	93
SUMMER 01	Jun-2001	7,933	403	48	451	307	758	O	7,175	99
SUMMER 01	Jui-2001	8,162	398	49	446	308	754	0	7,407	102
SUMMER Of	Aug-2001	8,261	414	49	463	308	771	0	7,490	103
SUMMER 01	Sep-2001	7,699	361	45	409	308	717	0	6,982	96
SUMMER 01	Oct-2001	6,819	217	45	262	308	570	٥	6,248	97
WINTER 01/02	Nov-2001	6,207	359	26	385	308	693	D	5,514	. 77
WINTER 01/02	Dec-2001	7,728	429	27	455	308	763	0	6,965	95
WINTER 01/02	Jan-2002	9,229	744	27	771	304	1.075	112	8.043	112
WINTER 01/02	Feb-2002	8.071	617	27	644	305	949	0	7,122	98
WINTER 01/02	Mar-2002	6,750	474	27	501	305	806	0	5,944	82
SUMMER 02	Apr-2002	6.142	218	45	262	304	566	o	5,575	78
SUMMER 02	May-2002	7,149	273	• 48	321	304	625	0	6,524	90
SUMMER 02	Jun-2002	7,578	340	49	388	304	692	o	6,885	95
SUMMER 02	Jul-2002	7,815	336	50	385	304	689	0	7,126	55
SUMMER 02	Aug-2002	7,918	351	50	400	305	705	0	7,212	9 9
SUMMER 02	Sep-2002	7,337	306	49	356	305	661	. 0	6,676	92
SUMMER 02	Oct-2002	5,509	185	46	231	305	536	0	5,973	83
WINTER 02/03	Nov-2002	5,934	335	29	364	306	670	0	5,263	74
WINTER 02/03	Dec-2002	7,372	402	30	431	306	737	0	6,635	3 2
		•								
WINTER 02/03	Jan-2003	8,992	701	30	730	328	1.058	109	7,825	109
WINTER 02/03	Feb-2003	7,817	581	30	612	328	940	0	6.877	95
WINTER 02/03	Mar-2003	5,462	447	30	477	328	. 305	0	5.657	ε.

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Page 1 of 4

JANUARY 2000 FORECAST (S000103) Low Retail Scenario

Bulk Power Sales Included

	r	TOTAL	DIRECT LO	DAD CONTROL P	Rograms		TOTAL	(USED)	FIRM	(AVAILABLE)
		BEFORE LOAD CONTROL	RESIDENTIAL	OTHER DLC PROGRAMS	TOTAL DLC PROGRAMS	INTERR. LOAD	LOAD CONTROL CAPABILITY	VOLTAGE REDUCTION	AFTER LOAD CONTROL	VOLTAGE REDUCTION
SEASON	MONTH	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)
SUMMER 03	Apr-2003	6,114	188	46	234	328	562	0	5,552	78
SUMMER 03	May-2003	6,957	236	49	285	328	613	0	6,344	88
SUMMER 03	Jun-2003	7,321	294	50	344	328	672	0	6,649	92
SUMMER 03	Jul-2003	7,569	292	51	342	328	670	0	6,899	95
SUMMER 03	Aug-2003	7,673	305	51	356	328	684	0	6,989	97
SUMMER 03	Sep-2003	7,135	268	50	318	329	647	0	6,458	90
SUMMER 03	Oct-2003	6,542	162	48	210	329	539	0	6,003	84
WINTER 03/04	Nov-2003	5,753	319	33	352	330	682	0	5,081	71
WINTER 03/04	Dec-2003	7,124	354	33	417	330	747	٥	6,377	89
WINTER 03/04	Jan-2004	9,061	673	33	707	329	1,035	110	7,915	110
WINTER 03/04	Feb-2004	7,870	559	33	592	329	921	Û	6,949	96
WINTER 03/04	Mar-2004	6,548	429	34	453	330	793	D	5,755	80
SUMMER 04	Apr-2004	6,211	166	48	214	329	543	0	5,668	79
SUMMER 04	May-2004	7,070	209	50	259	329	588	0	6,482	90
SUMMER 04	Jun-2004	7,440	260	51	311	329	640	0	6,800	94
SUMMER 04	Jui-2004	7,617	257	52	309	329	638	. 0	6,979	96
SUMMER 04	Aug-2004	7,724	269	52	322	329	651	0	7,073	98
SUMMER 04	Sep-2004	7,250	236	52	288	330	618	0	6,632	92
SUMMER 04	Oct-2004	6,648	143	49	192	330	522	0	6,125	85
WINTER 04/05	Nov-2004	5,820	307	36	343	331	674	0 -	5,146	72
WINTER 04/05	Dec-2004	7,126	371	36	407	331	738	. 0	6,385	89
WINTER 04/05	Jan-2005	9,175	652	36	688	334	1,022	112	8,041	112
WINTER 04/05	Feb-2005	7,971	541	36	578	335	913	0	7,059	98
WINTER 04/05	Mar-2005	6,617	415	37	452	335	787	D	5,830	81
SUMMER 05	Apr-2005	6,288	146	50	196	334	530	0	5,758	80
SUMMER 05	May-2005	7,163	184	52	236	334	570	0.	6,593	91
SUMMER 05	Jun-2005	7,531	229	53	282	334	616	0	6,915	96
SUMMER 05	Jul-2005	7,717	227	53	280	334	614	٥	7,102	95
SUMMER 05	Aug-2005	7,826	238	54	291	335	626	0	7,199	99
SUMMER 05	Sep-2005	7,346	205	53	262	335	597	0	6,749	94
SUMMER 05	Oct-2005	6,733	126	51	177	335	512	C	6,221	87
WINTER 05/06	Nov-2005	5,871	297	- 39	336	336	672	o	5,199	73
WINTER 05/06	Dec-2005	7,197	360	39	399	336	735	0	6,462	90
WINTER 05/06	Jan-2006	9,342	635	39	674	337	1.011	114	8,216	114
WINTER 05/05	Feb-2006	8,122	526	40	566	338	904	0	7,218	100
WINTER 05/06	Mar-2006	6,681	403	40	443	338	751	0	5,900	82
SUMMER 05	Apr-2006	6,365	129	52	181	338	519	0	5.846	82
SUMMER 06	May-2006	7,252	162	54	216	338	554	0	6,698	93
SUMMER 06	Jun-2006	7.625	202	54	257	338	595	0	7,031	97

JANUARY 2000 FORECAST (S000103) Low Retail Scenarlo

Bulk Power Sales Included

		TOTAL	DIRECT LO	DAD CONTROL P	Rograms			[USED]	FIRM	(AVAILABLE)
		SYSTEM		:		:	TOTAL		SYSTEM	
		BEFORE	RESIDENTIAL	OTHER DLC	TOTAL DLC	INTERR.	LOAD CONTROL	VOLTAGE	AFTER	VOLIAGE
		LOAD CONTROL	LOAD MGT.	PROGRAMS	PROGRAMS	LOAD	CAPABILITY	REDUCTION	LOAD CONTROL	REDUCTION
SEASON	MONTH	(MW)	(MW)	(MVV)	(MW)	(MW)	(MVV)	(MVY)	(MW)	(MVV)
SUMMER 06	JUF-2006	7,871	200	55	255	338	593	0	7,278	101
SUMMER 06	Aug-2006	7,981	210	55	265	. 339	604	. 0	7,377	102
SUMMER 06	Sep-2006	7,437	184	55	239	339	578	0	5,859	95
SUMMER 06	Oct-2006	6,816	111	53	164	339	503	D	6,313	88
WINTER 06/07	Nov-2005	5,919	289	42	331	339	670	0	5,249	74
WINTER 06/07	Dec-2005	7,316	350	42	393	339	732	0	6,585	91
WINTER 06/07	Jan-2007	9,505	619	42	661	342	1,003	117	8,385	117
WINTER 06/07	Feb-2007	8,273	513	43	556	342	898	0	7,374	102
WINTER 06/07	Mar-2007	6,764	393	43	436	342	778	O D	5,986	84
SUMMER 07	Apr-2007	6,437	114	54	167	342	509	. 0	5,928	83
SUMMER 07	May-2007	7,335	143	56	199	342	541	0	6,795	94
SUMMER 07	Jun-2007	7,725	178	56	235	342	577	0	7,148	99
SUMMER 07	Jul-2007	8,021	177	57	234	343	577	0	7,444	103
SUMMER 07	Aug-2007	8,133	185	57	242	343	585	0	7,548	104
SUMMER 07	Sep-2007	7,524	162	57	219	343	562	Ċ	6,962	96
SUMMER 07	Oct-2007	6,894	98	55	153	343	496	o	6,398	89
WINTER 07/08	Nov-2007	5,965	281	45	326	343	669	0	5,296	74
WINTER 07/08	Dec-2007	7,433	342	45	387	343	730	0	6,703	93
WINTER 07/08	Jan-2008	9,665	605	46	650	345	995	119	8,550	119
WINTER 07/08	Feb-2008	8,423	502	46	547	345	892	٥	7,531	104
WINTER 07/08	Mar-2008	6,868	384	46	430	345	775	. 0	6,093	85
SUMMER 08	Apr-2008	6,505	100	56	156	345	501	0	6,004	84
SUMMER 08	May-2008	7,416	125	55	184	345	529	Q	6,887	95
SUMMER 08	Jun-2008	7,860	157	58	216	345	562	0	7,298	101
SUMMER 08	Jul-2008	8,166	156	59	215	346	561	0	7,605	105
SUMMER 08	Aug-2008	8,281	163	59	222	346	568	. Q	7,713	105
SUMMER D8	Sep-2008	7,607	143	59	202	346	548	0	7,059	95
SUMMER 08	Oct-2008	6,968	87	57	144	346	490	0	6,478	90
WINTER 08/09	Nov-2008	6,008	274	48	322	346	668	0	5,340	75
WINTER 08/09	Dec-2008	7.552	334	• 48	382	347	729	D	6,823	95
WINTER 08/09	Jan-2009	9,823	592	49	641	348	959	121	6,713	121
WINTER 08/09	Feb-2009	8,560	491	49	540	348	585	o	7,672	106
WINTER 08/09	Mar-2009	6,975	375	49	424	348	772	0 .	6,202	86
SUMMER 09	Apr-2009	6.574	89	55	147	348	495	0	6,030	85
SUMMER 09	May-2009	7.550	111	60	171	348	519	0	7,031	97
SUMMER 09	Jun-2009	7.994	139	60	199	349	548	. 0	7,445	103
SUMMER 09	Jul-2009	8,316	138	61	198	349	547	. 0	7,768	107
SUMMER 09	Aug-2009	8,430	144	61	205	349	554	٥	7.876	109
SUMMER 09	Sep-2009	7.722	126	61	157	345	536	۵.	7,186	99

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17

Page 3 of 4

JANUARY 2000 FORECAST (S000103) Low Retail Scenario

Buik Power Sales Included

	•	TOTAL	DIRECT LC	AD CONTROL PI	ROGRAMS		70711	(USED)	FIRM	(AVAILABLE)
		SYSTEM BEFORE LOAD CONTROL	RESIDENTIAL	OTHER DLC	TOTAL DLC	INTERR.	LOAD CONTROL CAPABILITY	VOLTAGE	AFTER LOAD CONTROL	VOLTAGE
SEASON	MONTH	(MW)	(MW)	(MW)	(MW)	(MW)	_(MW)	(MW)	(MW)	(MW)
SUMMER 09	Oct-2009	7,045	76	60	136	349	485	0	6,560	91
WINTER 09/10	Nov-2009	6,061	268	51	319	349	668	0	5,393	76
WINTER 09/10	Dec-2009	7,679	327	52	378	350	728	0.	6,950	96
WINTER 09/10	Jan-2010	9,991	580	52	632	350	982	124	8,685	124
WINTER 09/10	Feb-2010	8,718	481	52	533	350	883	0	7,835	108
WINTER 09/10	Mar-2010	7,094	367	52	419	360	769	0	6,325	88
SUMMER 10	Apr-2010	6,653	78	60	135	350	488	0	6,165	86
SUMMER 10	May-2010	7,705	98	61	159	351	510	0	7,194	100
SUMMER 10	Jun-2010	6,143	122	61	184	351	535	· • •	7,608	105
SUMMER 10	Jui-2010	8,480	121	62	183	351	534	0	7,945	110
SUMMER 10	Aug-2010	8,599	127	52	189	351	540	0	8,059	111
SUMMER 10	Sep-2010	7,871	111	61	172	351	523	a	7,347	102
SUMMER 10	Oct-2010	7,137	57	60	127	351	478	0	6,659	93
WINTER 10/11	Nov-2010	6,148	262	52	314	352	666	0	5,482	77
WINTER 10/11	Dec-2010	7,846	320	52	372	352	724	D	7.122	99

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Page 4 of 4

		Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	540-00	0c1-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-G1	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
	Baseload Plants (Summer and Winter TYSP Ratings)					-			-	·						I							<u>1</u>	<u></u>	
	Crystal River 1	383	383	383	379	379	379	379	379	379	379	383	383	383	353	353	379	379	379	379	379	379	379	383	383
	Crystal River 2	479	479	479	474	474	474	474	474	474	474	479	479	503	503	503	498	498	498	498	498	495	498	503	503
- 1	Crystal River 4	722	722	722	712	729	729	729	729	729	729	739	739	739	739	739	729	729	729	729	729	729	729	739	739
	Crystal River 5	732	732	732	717	717	717	717	717	717	717	732	732	732	732	732	717	717	717	717	717	717	717	732	732
	Crystal River 3	: 782	782	782	765	765	765	765	765	765	765	782	782	782	782	782	765	765	765	765	765	765	765	782	782
	University of Florida Cogen	41	41	41	35	35	35	35	35	35	35	41	41	41	41	41	35	35	35	35	35	35	35	41	41
	Baseload Contracts (Firm Purchase Canacity)																				I	L			I
	UPS Purchase from Southern Company	409	409	409	409	409	409	409	∡∩9	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409
- 21	TECO Purchase for Sebrion Load	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	50	60	50	50	60	60	60
•	OF Contracts																		1				· · · ·		
		40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	06	40	40	40	40
}					45		45				45		45		45	15		45	45	15	15			45	15
ł		42	42	13	47		42	42	42	42	42	42	12	42	42		42	13	12	12	13	12	13		12
ł		13	13	13	13	13	13	13	13	13	13	13	13	13	. 13	13	- 13	+3			13	13	13		44
	BAT COUNTY RES REC				11														11		<u> </u>			<u> </u>	
.	LFC MADISUN (APP)	9		9	8	. 9				9	9	9	-		<u>"</u>		9		9	<u> </u>		[*]	<u> </u>	<u> </u>	<u> </u>
·	LFC JEFFERSON (APP)	9	9	9		9	9	9	9	9		9	9		<u> </u>				8				9		
	LAKE COUNTY RES REC	13	. 13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
	PASCO COUNTY RES REC	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
	DADE COUNTY RES REC	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
	CARGILL	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
	LAKE COGEN	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	.110	110	110	110
	PASCO COGEN	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109
	ORLANDO COGEN	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79
	RIDGE GENERATING STA	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
	EL DORADO (APP)	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114
	ROYSTER (PPP)	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
	MULBERRY (PPP)	79	79	79	79	79	79	79	79	79	79	79	79	79	75	79	79	79	79	79	79	79	79	75	79
i	CFR-BIOGEN (ORANGE CD)	74	. 74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	1 74	74	74	74	1 74	74	\$ 74
	US AGRICHEM	6	6	6	6	6	6	6	6	6	6	5	6	6	s · 6	6	6	6	5 6	6	3 6	5 6	6 6	1	5 1
1	Intermediate Resources (Summer and Winter TYSP Ratings)																								
	Anciote 1	522	522	522	498	498	498	498	498	498	498	522	522	522	522	522	498	498	493	493	498	498	498	523	2 522
	Anciote 2	522	522	522	495	495	495	495	495	495	495	522	522	522	527	522	495	495	5 495	495	5 495	495	495	527	522
	Bartow 1	123	123	123	121	121	121	121	121	121	121	123	123	123	123	123	121	121	121	121	121	121	121	12:	123
•	Bartow 2	121	121	121	119	119	119	119	119	119	119	121	121	121	121	121	119	119	119	119	115	119	119	121	121
	Bartow 3	208	208	208	204	204	204	204	204	204	204	208	208	208	205	208	204	204	1 204	204	204	204	204	205	205
	Suvannee River 1	33	33	33	32	32	32	32	32	32	32	33	33	33	33	33	32	32	2 32	32	2 32	32	32	. 3	3 33
	Suwannes River 2	32	32	32	31	31	31	31	31	31	31	32	32	37	37	2 32	31	31	1 31	31	31	31	31	3	2 3.
	Suwannee River 3	- 81	51	51	50	30	50	60	80	80	50	81	61	81	81	81	50	80	80	50	30 30	90 80	30	, "S	1 3
	Tiger Bay Cogen	223	223	223	207	207	207	207	207	207	207	223	223	223	22:	223	207	207	7 207	207	207	207	207	22	3 22
	Hines Energy Complex 1	529	529	529	432	482	452	482	482	452	482	529	529	529	529	529	482	482	z 452	482	2 452	432	2 432	2 52	52
	Hines Energy Complex 2	0	0	0	0		0	0	0	0	0	0	0		0 0	0) c	0	0 0	0			2 0	1	0
	Hines Energy Complex 3	0	0	0	0	- C	0	0	0	6)	0						0 0		0 0	, , ,		1	0
1	Hines Energy Complex 4			1	0	+	0													1	0 0			1	0
	Higes Energy Complex 5																		0 0		Di f		3 6	; 	
	Finite Chargy Complex o								1						1			1	<u>-</u> -	1	1	1	<u> </u>		-1
	Gas Peaking Resources (Summer and Winter TYSP Ratings)																								
	Avon Park P1	32	32	32	25	26	26	26	26	25	26	26	32	2 32	2 3	2 32	2	5 26	8 26	5 20	5 21	5 20	3 26	i 2	5 37
	Bartow P2	53	53	53	46	46	46	46	46	48	46	46	53	53	9 5	3 53	3 46	3 48	5 48	3 46	5 46	5 40	5 46	; 4	6 5
	Bartow P4	60	60	60	49	49	49	49	49	45	49	49	60	60	6	0 60	45	49	9 49	49	9 49	9 49	49	4	9 6
	Debary P7	93	93	93	80	50	85	85	55	35	5 80	50	93	3 93	3 93	3 93	3 80	50 50	0 55	5 55	5 8	5 24	5 50	<u>ه</u> ار	0 5
	Debary PS	93	93	93	30	50	35		85	35	5 30	30	93	3 93	3 93	3 93	3 80	50	0 35	5 5	5 3	5 8	5 80	3 2	0 9
	Debary PS	93	93	93	50	30	35	55	35	35	5 50	30	93	3 93	3 9	3 93	3 30) St	0 35	5 5	5 3	5 5	5 5	3 8	0 6
	Higgins P1	32	32	32	2 27	2	27	27	27	27	27	27	/ 32	2 37	z 3.	z 32	2 27	7 2	7 27	27	7 2	7 2	7 . 2	7 2	7 3
	Higgins P2	32	32	32	2 27	27	27	27	27	27	27	27	37	2 3	z 3.	2 37	2 27	7 27	7 27	27	7 2	7 2	7 27	7 2	7 3
	Higgins P3	35	35	35	34	34	34	34	34	34	34	34	35	5 39	5 3	5 39	5 34	1 34	4 34	34	4 3	1 3	4 34	1 3	4 3

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Hingins P4	35	35	35	34	34	34	34	34	34	34	34	35	35	35	35	34	34	34	34	34	34	34	34	35
Interression City P7	94		94	80		and in		81	illinin aa	80	50			94	94	80	80		85	85	88	80	80	
Interession City P8		94	94	80	80			RA	AR	80	50		94	94		80	50	85	8.9	8.4	83	50	801	94
Interession City P					80						80					80	80		24			80	80	
Intercession City Ps						60	64									80	80	44	28			80		
Intercession City P10											~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~							90			•0	80		
		v										24									00			
intercession City P13												94												
Intercession City P14																							80	
Suwannee River P1	67	6/	67				50					67	6/	87	6/				50	55		50	50	67
Suwannee River P3	67	57	67	55	55	55	55	55	55	55	55	<u>67</u>	67	67	57	55	55	55	55	55	55	55	55	57
Ratings											· ·													
Aven Park P2	32	32	32	25	26	26	25	26	25	26	25	324	32	32	32	26	25	26	26	25	25	26	25	32
Bartow P1	53	53	53	45	45	46	46	45	46	46	46	53	53	53	53	48	46	45	46	45	45	45	46	53
Bartow P3	53	53	53	46	45	46	45	46	46	46	45	53	53	53	53	45	48	AR	46	46	46	AR	45	53
Butter D1	53	58	58	46		48	45	46	40	46	40	58	58	59	54	46	48	46	45	46	46	40	46	
Baybord P1			50				48	48			40							40				40	45	
Bayoolo P2				40			40				40	50					40	40	40			40	40	
Bayboro P3			53	46	48	46	46	46	46	46	46		53	53		45	45	46	46	40	46	40	46	
Bayboro P4	53	55	58	46	46	46	46	46	46	46	46	58	53	58	58	46	46	46	46	46	46	46	46	53
Debary P1	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	
Debary P2	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	6
Debary P3	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P4	65	65	65	54	54	54	54	54	54	54	. 54	65	65	65	65	54	54	54	54	54	54	54	54	6
Debary P5	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P6	65	. 65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P10	93	93	93	79	79	84	54	84	54	79	79	93	93	93	93	79	79	84			\$4	79	79	93
Intercession City P1	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	61
Intercession City P2	61	· 61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	6
Intercession City P3	61	51	61	49	49	. 49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	6
Intercession City P4	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	6
Intercession City P5	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	6
Intercession City P6	61	61	61	49	49	49	49	49	49	49	49	51	51	61	61	49	49	49	49	49	49	49	49	6
Intercession City P11	170	170	170	143	143		0		0	143	143	170	170	170	170	143	143		0	0		143	143	17
Rio Pinar P1	16	16	16	-13	13	13	13	13	13	13	13	16	16	16	16	13	13	13	13	13	13	13	13	1
Stywarnes River P7	57	67	57	54	54	54	54	54	54	54	54	#7	67	67	67	67	54	54	54	54	54	54	54	
Turner Di	16	16	16	+	43	12	- 12	12	+2	+2		16	16	16	16	42	12	+2		+2				
	10	10	10		13	47		13	13	42	10	10	10	10	45	44	د. د.	47					13	
	10		. 60		13		13	13	13	13			10	70		13	13	13	13	33				
lumer P3		32		60	00			65	60								00 ~~~						~~~~	3.
Turner P4		30		63	63	6.3	63	63	63	63	63	80	30		30		63	63	63	63	63	63	63	5
Total Baseload Plants	3,139	3 139	3,139	3,082	3,099	3,099	3,099	3,099	3,099	3,099	3,156	3,156	3,180	3,130	3,130	3,123	3,123	3,123	3,123	3,123	3,123	3,123	3,180	3,13
Total Baseload Contracts	469	469	469	469	469	469	469	469	469	469	469	469	459	469	469	469	469	469	469	459	469	469	469	40
Total GF Contracts	531	531	531	531	831	531	531	531	831	831	831	531	531	831	831	831	831	8 31	\$31	531	831	831	831	5
Total Intermediate Resources	2,394	2,394	2.394	2,269	2,269	2,269	2,269	2,269	2,269	2,259	2,394	2,394	2,394	2,394	2,394	2,269	2,269	2,269	2,269	2,269	2,269	2,269	2,394	2.39
Total Gas Peaking Resources	1.065	1 065	1 068	913	<u>\$</u> 13	960	960	960	960	913	913	1,350	1,350	1.350	1,350	t,153	1,153	1,200	1,200	1.200	1,200	1,153	1,153	1.3
Total Light Oil Peaking Resources	1.566	1 555	1,665	1,363	1,363	1,225	1,225	1,225	1.225	1,363	1,363	1,666	1,665	1,666	1,666	1,410	1,363	1,225	1,225	1,225	1,225	1,363	1,363	1,66
Total Available Resources	9.567	9 567	9.567	8,927	8,944	8,853	8.853	8,853	8,853	8,944	9,126	9,866	9,590	9.890	9,890	9,255	9,208	9,117	9,117	9,117	9,117	9,208	9,390	9.89
	\$ 267												9 5 60											

*	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03
Baseload Plants (Summer and Winter TYSP Ratings)		L	l	l :				L							<u> </u>	<u></u>	1		· · ·	I			I	
Crystal River 1	400	400	400	396	396	396	396	396	396	396	400	400	400	400	400	396	396	396	396	396	396	396	400	400
Crystal River 2	503	503	503	495	498	498	498	498	498	498	503	503	503	503	503	498	498	498	498	498	495	495	503	503
Costal River 4	739	739	739	779	779	779	779	779	779	779	739	739	739	739	739	779	779	779	779	779	779	779	739	730
Costal River 5	737	732	732	717	717	717	717	717	717	717	732	732	712	732	732	717	717	717	717	717	717	717	792	737
Costal River 3	. 782	787	782	765	765	765	765	765	765	765	782	782	782	782	782	765	765	765	765	765	765	765	787	787
Liniversity of Florida Cogen	3 102	41	41	705		25		700	35	25	- 102	41	41	102	41	25		700	25			100	41	102
Baseload Contracts (Figs Purchase Capacity)			1	~	~			~		~					4 1		~	33	<u> </u>	3	33	<u> </u>	+1	41
100 Dumbase from Southare Company	400	400	400	400	400	400	400	400	400		400	400	400	400	400	400	400		1	(00	450	400	400	
TECO Burghase for Sching Land	403 604	405	408	403	403	403	409	403	403	403	403	403	403	409	409	409	409	409	405	409	409	409	409	409
OE Contrade		~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~				N	00		60		8	00	80	60	<u> </u>	00	00	00	00	60			60	ьо
	40																		I					
FINELLAS CORES REC 1	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
FINELLAS CO RES REC 2	13	15	13	15	15	13			===	13	15	15	15	15	15		15	15	15	15	15	15	15	15
IIMBER ENERGY 1	13	13	13	0	0	0	0		0		0	0	0	0	0	•	0	0	0	0	0	0	0	0
BAT COUNTY RES REC		31	11	11	11	11		11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
L=G MADISON (APP)	- 9		8	9	9	9	9	9	9		9	9	9			9		9			9	9	9	9
LFC JEFFERSON (APP)	9	9	9	<u></u>	9	9	9	9	9	9	9	°	9	9	9	9	9	9	9	9	9	9	<u>و</u>	9
LAKE COUNTY RES REC	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	. 13	13	13	13	13	13	13	13	13
PASCO COUNTY RES REC	23	23	23	23	23	23	Z3	23	23	23	Z3	23	23	23	23	Z3	23	23	23	23	23	23	23	23
DADE COUNTY RES REC	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
CARGILL	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
LAKE COGEN	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
PASCO COGEN	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109
ORLANDO COGEN	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	: 79	79	79	79
RIDGE GENERATING STA	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
EL DORADO (APP)	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114
ROYSTER (PPP)	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
MULBERRY (PPP)	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	75	79	79	75	79	79	79
CFR-BIOGEN (ORANGE CO	. 74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	. 74	74	74	1 74	74	74	74	74	74
US AGRICHEN	1 6	6	5	6	6	6	6	6	6	6	6	5	6	6	6	6	6	<u> </u>	36	6	(<u> </u>	5 6	6	5 5
Intermediate Resources (Summer and Winter TYSP Ratings)		,	,					,							,		,					,		
Anciote 1	522	522	522	495	498	498	498	498	498	495	522	522	522	522	522	493	498	495	498	498	495	495	522	522
Anciote 2	522	522	522	495	495	495	495	495	495	495	522	522	522	522	522	495	495	495	5 495	495	495	495	522	522
Bartow 1	123	123	123	121	121	121	121	121	121	121	123	123	.123	123	123	121	121	121	121	121	121	121	123	123
Bertow 2	121	121	121	119	119	119	119	119	119	119	121	121	121	121	121	119	119	115	119	119	115	119	121	121
Bartow 3	208	208	205	204	204	204	204	204	204	204	208	208	208	205	205	204	204	204	204	204	204	204	208	203
Suwannee River 1	33	33	33	32	32	32	32	32	32	32	33	33	33	33	33	32	32	37	2 32	32	32	32	33	33
Suwannee River 2	32	32	32	31	31	31	31	31	31	31	32	32	32	32	32	31	31	31	31	31	31	31	32	32
Suwannee River 3	81	81	81	30	80		80	50	50	80	31	81	81	81	81	80	80	50	50	80	50	50	- 81	51
Tiger Bay Cogen	223	223	223	207	207	207	207	207	207	207	223	223	223	223	223	207	207	207	207	207	207	207	223	3 223
Hines Energy Complex 1	529	529	529	482	432	482	482	452	482	482	529	529	529	529	529	482	482	452	432	432	482	2 492	529	529
Hines Energy Complex 2	0		0		0	0	(0	0	0	0	0 0	0	0	0	0	0	1 0	0 0	. 0) (567	7 567
Hines Energy Complex 3	0	0	0		0	0	0	0	0	0	0	0	0	0	0 0	0	0		0 0	0	1			
Hines Energy Complex 4	0		0		0 0	•		0	0	0	0	0 0	0		0	0	0		0 0	0) (0 0		a (
Hines Energy Complex 5	0	0	0 0) C	0	0	(0 0	0	0	0	0 0	C	(0 0	0	0 0	(0 0	0			0	
Gas Peaking Resources (Summer and Winter TYSP Ratings)																								
	<u> </u>		J						r			·	T ~	J ~	J ~									
Avon Park P1	32	32	32	Z0	25	26	26	26		25		32		32	32		26	20	26	26				32
Barlow P2	53		53	46	46	46	46	46	46	46	46	53	53	5	53	46	46	4	46	46	4	46	40	53
Bartow P4	60	60	60	49	49	49	49	49	49	49	49	60	60	60	60	49	49	4	49	49	49	49	49	* 60
Debary P7	93	93	93	30		\$5 	35	85		30	30	93	93	93	93	50	80		5 5			3 50	80	<u>, 93</u>
Debary PS	93	93	93		80	85		85	85	80	50	93	93	92	93	50	50	8	5 85	85		5 30		9
Debary PS	93	93	93	\$ 80	03 1	5		5 35	35	50		93	93	93	93		50	8	5 85	- : : : 35	5 8	5 8	8	9
Higgins P1	32	37	2 32	2 27	27	27	27	27	27	27	27	32	32	37	32	27	27	2	7 27	27	2	7 2	2	7 3
Higgins P2	2 32	3	2 32	27	27	27	2	27	27	27	27	32	32	33	2 . 32	27	27	Z	7 27	27	2	7 2	2	7 33
Higgins P	3 35	35	5 35	34	34	1 34	34	4 34	34	34	34	1 35	35	35	35	34	34	34	34	34	3	4 3	34	4 35

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Higgins P4	35	35	35	34	34	34	34	34	34	34	34	35	35	35	35	34	34	34	34	34	34	34	34	35
Intercession City P7	94	94	94	80	80	88	85	85		80	80	94	94	94	94	80	80	88	88	88	85	80	80	94
Intercession City P8	94	94	94	80	80	88	88	85	83	80	80	94	94	94	94	80	80	85	88	88	83	80	80	<u>94</u>
Intercession City P9	94	94	94	80	80	88		55	85	80	80	94	94	94	94	80	80	88	88	88	83	80	80	94
Intercession City P10	94	94	94	80	80	88	85	85	85	80	80	94	94	94	94	80	80	83	83	66	53	80	80	
Intercession City P12	94	94	94	80	80	80	80	80	80	80	80	94	94	94	94	80	80	80	80	80	80	30		94
Intercession City P13	y 94	94	94	- 80	80	80	80	80	80	80	80	94	94	94	94	80	80	80	80	80	80		50	94
Intercession City P14	94	94	94	80	80	80	08	80	80	08	80	94	94	94	94	80	80	50	80	80	80		80	94
Suwannee River P1	57	67	67	55	55	55	55	55	55	55	55	67	67	67	67	55	55	55	55	55	55	55	55	67
Suwannee River P3	67	67	57	55	55	55	55	55	55	55	55	67	67	67	67	55	55	55	55	55	55	55	55	67
Light Oil Peaking Resources (Summer and Winter TYSP																								
Ralings)					76	26	26	76	26	26	26	97	37	32	32	26	26	26	26	26	25	26	26	32
Avon Faik F2		57	52	48		46	46	45	48	45	46	53	53	53	53	46	45	46	45	46	45	46	46	53
Dation Fil	- 63	57		45	46	46	46	45	46	45	46	53	53	53	53	45	46	45	45	46	46	46	46	53
Dailow F3 Dathara D4		5.4	50	48	45	45	46	46	46	46	45	58	58	58	58	45	46	46	45	46	45	45	46	58
Daybord P 1				48	48	45	46	46	46	46	46	58	58	58	53	46	45	46	46	45	46	46	45	53
Bayboro F2		53	58	46	45	48	46	45		46	46	58	58	58	58	45	46	46	46	46	46	45	46	58
Baytorio F3	58	53	58	45	46	45	46	46	46	45	45	58	58	58	58	46	46	45	46	46	45	46	45	53
Dahary P1	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P2	65	65	65	54	54	54	54	54	54	54	54	65	65	65	55	54	54	54	54	54	54	54	54	65
Debay P3	65	65	65	54	54	54	54	54		54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P4	65	65	85	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary PS	65	65	65	54	54	54	54	54	54	54	54	65	65	55	65	54	54	54	54	54	54	54	54	65
Debary P6	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P10	93	53	93	79	79	04	84	\$4	64	79	79	93	93	93	93	79	79	54	54	- 34	34	79	79	92
Intercossion City P1	- 61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	61
Intercession City P2	51	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	6
Intercession City P3	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	6
Intercession City P4	61	61	61	49	49	49	49	49	49	49	49	-61	51	61	61	49	49	49	49	49	49	49	49	е
Intercession City P5	61	61	61	49	49	49	49	49	49	49	49	61	61	51	61	49	49	49	49	49	49	49	49	
Intercession City P6	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	(
Intercession City P11	170	170	170	143	143	0	0	0	0	143	143	170	170	170	170	143	143	0	.0		<u>.</u>	143	143	1
Rio Pinar P1	16	16	16	13	13	13	13	13	13	13	13	16	16	16	16	13	13	13	13	13	13	13	13	
Suwannes River PZ	67	67	67	67	54	54	54	54	54	54	54	67	67	67	67	67	54	54	54	54	54	54	54	<u> </u>
Tumer P1	16	16	16	13	13	13	13	13	13	13	13	16	16	16	16	13	13	13	13	13	13	13	.13	
Turner P2	. 16	18	16	13	13	13	13	13	13	13	13	16	16	16	16	13	13	13	13	13	13	13	13	
Tumer P3	32	52	82	82	65	65	65	£5	65	65	65	8Z	82	\$2	32		65	65	65	65	65	65	65	
Tumer P4	20	30	80	80	63	63	63	63	53	63	63	80	50	80	30		63	63	63	53	63	63	63	
<u>Total Baseload Plants</u>	3,197	3,197	3,197	3,140	3,140	3,140	3,140	3,140	3,140	3,140	3,197	3,197	3,197	3,197	3,197	3,140	3,140	3,140	3,140	3,140	3,140	3,140	3,197	3,
Total Baseload Contracts	469	459	469	469	459	469	469	469	469	469	469	459	469	469	469	469	459	469	469	469	469	469	469	
Total QF Contracts	\$31	831	831	818	5 18	313	\$18	313	. 513	\$18	818	318	\$15	\$15	518	513	318	818	518	\$18	313	813	818	
Total Intermediate Resources	2,394	2,394	2,394	2,269	2,269	2,269	2,269	2,259	2,269	2,269	2,394	2,394	2,394	2,394	2,394	2,269	2,269	Z,269	Z.269	2,269	2,269	2,269	2,951	
Total Gas Peaking Resources	1,350	1,350	1,350	1,153	1,153	1,200	1,200	1,200	1,200	1,153	1,153	1,350	1,350	1,350	1,350	7,153	1,153	1,200	1,200	1,200	1,200	1,153	1,100	-
Total Light Oil Peaking Resources	1,666	1,666	1,665	1,410	1,363	1,225	1,225	1,225	1,225	1,353	1,363	1.666	1,666	1.666	1,656	1,410	1,363	1,225	1.225	1,225	1,225	5.00	1,303	
Total Available Resources	9,907	9,907	9,907	9,259	9,212	9,121	9,121	9,121	9,121	9,212	9,394	9,894	9.394	9,894	9,594	9,259	9,212	9,121	9,121	9.121	9,121	9,212	9,961	

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	Jan-04	Feb-04	Mar-04	Acr-04	May-04	Jun-04	Jul-04	Aug-04	Sec-04	Oct-04	Nov-04	Dec-04	Jan-05	Fab-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
Baseload Plants (Summer and Winter TYSP Ratings)		l	1			1				<u> </u>]			l I				1	1			L			
Crystal River 1	400	400	400	396	395	396	396	395	395	396	400	400	400	400	400	395	396	395	396	396	396	396	400	400
Coeld Birer 2	503	503	503	499	AOA	408	108	498	408	408	503	503	503	503	503	408	408	408	408	498	498	495	503	507
Costal River 4	730	720	770	770	770	770	770	770	770	770	720	720	730	730	730	770	770	720	770	720	770	770	730	77
Citystal Niva 4	733	733	733	747	747	747	747	747	747	747	735	739	739	739	735	747	747	747	747	747	7+7	747	700	73
	132	132	132	707							732	132	132	134	134		1			///	111		132	13
Crystar River 3	3762	182	102	105	/05	100	/00	/05	765	/65	/82	/82	/82	/82	/82	/65	/65	/65	/65	/65	/65	/65	102	/3
University of Florida Cogen	41	41	41	35	35	35	35	35	35	35	41	41	41	41	<u> 41</u>	35	35	35	35	35	35	35	41	4
Baseload Contracts (Firm Purchase Capacity)		r	<u>.</u>			<u> </u>			r	· · · · · · · · ·			,		, 		.			·	· · · · · · · · · · · · · · · · · · ·	.		,
UPS Purchase from Southern Company	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	405	409	409	409	40
TECO Purchase for Sebring Load	60	60	60	60	50	60	60	60	60	60	60	60	70	70	70	70	70	70	70	70	70	70	70	74
<u>QF Contracts</u>						<u>.</u>																		
PINELLAS CO RES REC 1	40	40	40	40	40	. 40	40	40	40	40	40	- 40	40	40	40	40	40	40	40	40	40	40	40	40
PINELLAS CO RES REC 2	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	i 15	i, 15	15	15	15
TIMBER ENERGY 1	0	0	0 0	· 0	0	0	0	0	. 0	0	0	0	0	0	0			0	0) () 0	0	0	
BAY COUNTY RES REC	11	11	11	11	11	11	11	11	11	. 11	-11	11	11	11	11	11	11	11	11	1	11	11	11	1
LFC MADISON (APP)	9	s	9	9	· 9	9	9	9	9	9	9	9	9	9	8	5	a s	9 9	9	1 1	9 9	, <u> </u>	9	1
LFC JEFFERSON (APP)	9	g	9 9	9	. 9	9	9	9	9	g	9	R	9	9	9	<u> </u> ;					9 9	1	,	,
LAKE COUNTY RES REC	13	13	1 13	13	13	13			13	13	47	13	12		17			1 17			1 17	1 1-	1 17	1
PASCO COUNTY BES BEC	73	71	77					273		27	27				77							7	77	
DADE COUNTY DES DEC									43	47	43							23			2 23			
DADE COUNTY RES REC	43	44	43 	L 43	EP		t# 	EP	43	4.1	43	43	43	43	43	4	4	43	4	4	43	43	43	⁴
CARGIL	13	12	13	15	13	10	15	15	15	15	er er	15	15	15	15	12	12	15			15	15	15	
LAKE COGEN	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	11	110	110	110	11
PASCO COGEN	109	105	109	109	109	109	109	109	109	109	. 109	109	109	109	109	109	9 105	9 109	105	10	9 109	109	109	10
ORLANDO COGEN	1 79	79	79	79	79	79	79	79	79	79	79	79	79	75	79	79	75	79	79	7	9 ' 79	1 79	79	7
RIDGE GENERATING STA	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	4	0 40	0 40	40	0 4	0 40	+ 40	/ 40	4
EL DORADO (APP)	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	4 114	4 114	114	4 11-	4 114	1 114	114	11
ROYSTER (PPP)	31	31	1 31	31	31	31	31	31	31	31	31	31	31	31	31	3	1 31	1 31	3.	1 3	1 31	1 31	31	. з
MULBERRY (PPP)	79	79	9 79	79	79	79	79	79	79	79	79	75	79	75	79	7	9 79	9 75	71	9 7	9 79	ə 79	3 79	1 7
CFR-BIOGEN (ORANGE CO	74	74	4 74	74	74	74	74	74	74	74	74	74	74	74	74	1 7.	4 74	4 74	4 74	4 7	4 74	4 7/	4 74	1
US AGRICHEM	6		5 6	6	- 5	6	6	6		5 6	6	6	5 6		5 6	5	6 (6 (5 (6	6 (6	5 (5
Intermediate Resources (Summer and Winter TYSP Ratings)										·					^			-L						
Anclote 1	522	523	2 522	493	498	493	498	495	498	498	522	522	2 522	527	522	49	3 495	3 495	49:	3 49	3 493	3 49	s 52:	2 5
Anclote 2	522	522	2 522	495	495	495	495	495	495	495	522	522	522	522	522	49	5 49	5 495	49	5 49	5 495	5 49	5 527	2 57
Bartow 1	123	123	3 123	121	121	121	121	121	121	121	123	123	123	123	123	12	1 12	1 121	12	1 12	1 121	1 12	1 12	17
Battow 2	121	121	121	119	119	119	119	119	110	119	121	121	121	171	121	110	110	110	4.10	11	0 110	111	171	12
Bartow	20.9	201	208	204	204	204	204	204	204	204	208	204	204	201	209	20	4 70	4 204		4 20	4 304	1 20	205	1
Surgence Piget							204	204	204	204	200		200	200	200	20		20	20	4 <u>- 2</u> 7	204	204	200	
Sowarate River 1		<u> </u>		<u> </u>						, <u> </u>				<u> </u>	(<u></u>	·			<u></u>		<u></u>	<u></u>	<u>'</u>
Suwannee River 2		·····						<u> </u>				<u> </u>	<u></u>	<u> </u>	<u> </u>	·						<u></u> '	<u></u>	<u>'</u>
Suwannee River 3	1	4	0	°	0	0	0	0		0	°	<u> </u>	<u>'</u>	' <u> </u>	<u> </u>	' '		0 0	<u>ا</u>	۹	0	<u>, 1 (</u>	1	·
Tiger Bay Cogen	223	223	3 223	207	207	207	207	207	207	207	223	223	223	223	3 223	20	7 207	7 207	20	7 20	7 207	/ 207	/ 223	3 2
Hines Energy Complex 1	529	529	9 529	432	482	482	432	482	482	2 482	529	529	529	529	529	45	2 43	Z 43	2 45	2 45	2 48	2 48	2 525	3 5
Hines Energy Complex 2	567	567	7 567	495	495	495	495	495	495	5 495	567	567	567	567	567	49	5 49	5 495	5 49	5 49	5 49	5 49	5 567	7 5
Hines Energy Complex 3		1	0 0	0	0	0	0	0		0 0	0) (0 0	2	0	0	0	0	0	0	0 557	7 5
Hines Energy Complex 4	C		0 0	0	0	0	0	0		0 0	0	() (0 0	2	0	0 0		0	0	0	0 0	0
Hines Energy Complex 5	i C	1	0 0	0	0	· 0	0	0 0	(0 0	0) (3	0	0 4	D	0	0	0	0 +	0
Gas Peaking Resources (Summer and Winter TYSP Rational															1									
			1	· · · · · ·	-			1		<u></u>		1	<u>.</u>	·	-	<u></u>	<u>,</u>	<u></u>					4	<u>.</u>
Avon Park P1	32	3	2 32	26	26	26	26	26	26	5 26	26	34	2 32	3	2 37	2 2	6 2	6 20	6 2	6 2	6 2	õ <u>2</u>	5 2f	5
Bartow P2	2 53	5:	3 53	46	46	46	46	46	40	5 46	45	53	3 53	5	3 53	4	6 4	6 4	5 4	6 4	6 4	6 4	5 46	5
Bartow P4	60	5	0 60	49	49	49	49	49	49	9 49	49	60	50 60	5	0 60	0 4	9 4	9 49	9 4	9 4	9 4	9 4	9 41	9
Debary P7	93	9	3 93	30	30	35	35	5 85	8	5 30	30	93	3 93	3 93	3 93	3 3	0 5	0 ಜ	5 8	5 . 8	5 8	5 5	0 3/	0
Debary PS	93	9	3 93	80	50	35	85	5 .85	8	5 30	50	9:	3 93	9	3 93	3 3	0 3	0 3	5 8	5 5	5 5	5 8	0 5	0
Debary PS	93	9	3 93	30	30	\$5	. 25	5	5	5 30	30	9	3 93	3 5	3 93	3 3	0 3	0 3	5 .8	5 5	5 8	5 8	.0 S	.0
Higgins P1	32	3	2 32	2 27	27	27	27	27	2	7 27	27	3	2 32	2 3	2 3	2 2	7 2	7 2	7 Z	7 2	7 2	7 7	7 2	17
Higgins P2	2 32	2 I	2 32	27	27	27	27	27	2	7 27	27	3	2 37	3	2 3	2 7	7 7	7 2	7 7	7 7	7 7	7 7	7 7	7
Hissing 97			5 34	1 2	1 24	14		24		1 24		3				1	4 7	4 7	1 7		4 7	4	4 7	4
i iiggita r			-1	. ~	1 ~	, ~	. ~	-		- I	1 34	1 3	-,	- 1 - ^{- 2}	-1 -2	-, J	-i •	- I - S	-	~l *	~, °	-	-1 3	- I · · ·

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							4 34	4 3	4 34	34	35	35	35	5 35	34	34 80	88	88	88		80	80	94
Higgins P4 3	5 3	5 3	5 34	3	4 34	3	8 8	8	8 80	80	94	94		4 94	80	80	88	85	58		80	80	94
Intercession City P7 9	4 9	4 5	4 80		0 0	3	8 8	3	8	80	94	1 <u>94</u>	9	4 94	80	80	8	88	83	89	80	80	94
Intercassion City PS	4 9	4		<u>}</u>	30 B	8	58 8	8	33 B	0 84	<u> </u>	4	9	4 94	80	80		8	83	80	30	0 50	94
Intercession City P9	4 6	4	4 0	1	50	8	63	3	88 8	<u>• </u>		4 94	4 6	94 94	80	0 50	3	3 80	80	80	3	0 80	94
Intercession City P10	4	P4			80 2	0	80 8	50	80 8			4 9	4	94 94	1 8	0 8	8 0	0 8	<u> </u>	8	8	0 8	0 94
Intercession City P12	×	94	al 8	d	80 8	io i	80 8	80	80 8			4 9	4 9	94 94	4 8	0 8	0	0 8		5 5	5 5	5 5	5 67
Intercession City P13 S			<u>al</u> 8	0	80 4	50	80	80	80	SU		37 5	7	57 6	7 5	5 5	5		5 5	5 5	5 5	5 5	5 67
Intercession City P14	94	57	67	5	55	55	\$5	55	55		55 0	57 6	57	67 6	7	5 5	5	<u>- اح</u>		-1	_ _		
Suwannee River P1	87	57	67	*5	55	55	55	55	50		-1											26	25 32
Suwannee River P3	<u></u>	<u>- </u>											201	72 3	2	26	26	26	26	26		45 4	6 53
Light Oil Peaking Resources (Summer and Winter TYSP					28	26	26	26	26	26	26	32	53	53 53	53	46	46	45	46	45	45	46	16 53
Ratings) Avon Park P2	32	32	32	48	46	46	46	46	48	45	46	53		53	53	45	46	46	46	46	40	45	46 53
Barlow F1	53	53	53	45	45	46	46	46	46	46	46	53	58	58	58	46	46	46	46	40	46	46	46 58
Barlow P3	53	53	58	45	46	46	46	46	46	46	46	58	58	58	58	46	46	46	46	45	45	46	46 53
Bayboro P1	58	58	50	46	45	46	46	46	45	46	40	53	58	58	58	46	46	46	46	45	46	45	45 58
Bayboro P2	58	-50	58	46	46	46	46	46	46	46	40	58	58	58	58	46	45	46	40	54	54	54	54 65
Bayboro P3	53	53	58	46	46	46	45	46	46	46	54	65	65	65	65	54	54	54	24	54	54	54	54 65
Bayboro P4	58			54	54	54	54	54			54	65	65	65	65	54	-54	54		54	54	54	54 65
Debary P1	65	- 85	65	54	54	54	54	54		- 64	54	65	65	65	65	54	54		54	54	54	54	54 65
Debary P2	65	- 65	65	54	54	54	54	54	54	54	54	65	65	65	65	54		54	54	54	54	54	54 65
Debary P3			65	54	54	54	54		- 54		54	65	65	65	65		- 54	-54	54	54	54	54	54 65
Debary P4		65	65	54	54	54	54			54	54	65	65	65	65		70		64	84	84	79	79 93
Debary P5	- 65	65	65	54	54	54	54	54		79	79	93	93	93	93		49	49	49	49	49	49	49 61
Debary Po		93	93	79	79	64	84	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49 61
Debaty Pit	61	61	61	49	49	49		49	49	49	49	61	61	61	- 61	49	49	49	49	49	49	49	49 0
Intercession City P2	51	61	61	49	49	49	49	49	49	49	49	61	61	61		49	49	49	49	49	49	49	49 6
Intercassion City P3	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49		49 6
Intercession City P4	61	61	61	49		49	49	49	49	49	49		- 61	61	61	49	49	49	49	49	49	143	143 17
Intercession City P5	61	61	61	49	49	49	49	49	49	49	49	61	470	170	170	143	143	0	0	0		13	13
Intercession City P6	61	61	- 61	49			illini il	0	.0	143	143	1/0		16	16	13	13	13	13	- 13	54	54	54
Intercession City P11	170	170	170	43	13	13	13	13	13	13	- 13		67	67	67	67	54	54	54			13	13
Rio Pinar P1	16	16		57	54	54	54	54	54	54	54		16	16	16	13	13	13				13	13
Suwarnee River P2	67	67			13	13	13	13	13	13	13		16	16	16	13	13	13	13		- 55	65	65
Tumer P1	16	16	10	13	13	13	13	13	13				8Z	82	32	32	65	65		63	63	63	63
Turnet P2	16	10		52	65	65	65	65	65			80	30	80	30	30	63						2407 31
Turner P3	82			30	63	63	63	63							7 107	3 140	3,140	3,140	3,140	3,140	3,140	3,140	3,13/
Turner P4						3140	3.140	3,140	3,140	3,140	3,197	3,197	3,197	3,197	3.131					470	479	479	479
	3,197	3,197	3,197	3,140	3,140	3,140						460	479	479	479	479	479	479	479	4/5		+	
Total Baseload Plants			460	469	469	469	469	469	469	469	469					818	313	\$18	\$15	518	515	313	
Total Baseload Contracts	469	469	403				813	815	813	518	818	818	518	813					2.671	2 621	2,621	2,621	3.382 3
	\$15	515	\$13	518	318	313				7.671	2 815	2,815	2,815	2,815	Z,815	2,621	2,621	2,621	2,021			4.157	1 153
Total QF Contracts	2.845	2 315	2,815	2,621	2.621	2,621	2,621	2,621	2,621	2,021			4 75 7	1 350	1 350	1,153	1,153	1,200	1,200	1,200	1.200	1,153	
Total Intermediate Resources	4,019	ļ			1 1 52	1.200	1,200	1,200	1,200	1,153	1,153	1,350	1,350				1 787	1.225	1,225	1,225	1,225	1,363	1,363
T + + C Beaking Resources	1,350	1,350	1,350	1,153	1,133				1 275	1,363	1,363	1,666	1,666	1,668	1,666	1,410						0.574	10 392 11
Total Gas Meaking Resources	1,656	1,666	1,666	1,410	1,363	1,225	1,225	1,225	·	 				10 775	10 375	9,621	9,574	9,453	9,433	9,483	9,483	9,5/4	10.322
Total Light Oil Peaking Resources			+		0.574	9.47	9,473	9,47	3 9,473	9,564	9,815	10,315	10,325	10,323				L	l				
	10,315	10,31	5 10,315	9,611	9,564	3,474			J	1		1											
Total Available resources	L	L.																					

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	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-05	Jul-06	Aug-05	Sep-06	Oct-05	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Anr-07	May-07	Jun 67	Jul-07	Aug_07	500-07	001-07	Nov-07	Dec-07
Baseload Plants (Summer and Winter TYSP Ratings)			1					1	1 .				· 1				,				Cap-ar			
Crystal River 1	400	400	400	395	396	396	396	396	396	396	400	400	400	400	400	395	705	306	208	706	206	2001	4001	400
Crystal River 2	503	503	503	498	498	498	498	498	498	498	503	503	503	503	503	408	409	409	408	409	409	409	507	
Crystal River 4	739	739	739	729	729	779	779	779	729	779	739	730	730	730	710	770	770	770	770	770	430	720		
Crystat River 5	732	732	73Z	717	717	717	717	717	717	717	732	712	732	777	733	717	717	747	747	747	717	747	735	
Crystal River 3	+ 782	782	782	765	765	765	765	765	765	765	787	782	792	787	782	700	705	765	717	717	707	717	732	
University of Florida Cogen	41	41	41	25		25	76	200	105		- 102	102	102	102	102	100	105	705	105	/65	, 705	100	/62	13
Baseload Contracts (Firm Purchase Capacity)			1	37		<u>~</u>			35		41	41	41	41	41	35		35	35	35	35	35	41	4
LIPS Purchase from Southern Company	400	400	1 400	400	400			1 400		1												.	,×	
TECO Bustone for Sobilar Land	70		403		403	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409
OF Contracts	10	1	<u>'</u> '	10	/4		/0	1 70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
	40	1 40							r				· · · · ·									,,		
	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
FINELLAS CORES REC 2	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
			0	0	0	0		0	0	0	0	0	0	Û	0	0	0	0	0	0	0	0	0	
BAT COUNTY RES REC	11	11	11		11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	. 11	1
LFC MADISON (APP)	9	9	9	9	9		9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	
LFC JEFFERSON (APP)	9	9	9	9	9	9	9	9	. 9	9	9	9	9	ទ	9	9	9	9	g	9	9	9	9	
LAKE COUNTY RES REC	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	1.
PASCO COUNTY RES REC	23	23	23	23	23	Z3	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	Z3	23	2
DADE COUNTY RES REC	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	4
CARGILL	15	15	15.	15	15	· 15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	1
LAKE COGEN	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	11
PASCO COGEN	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	10
ORLANDO COGEN	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	7
RIDGE GENERATING STA	40	40	40	- 40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	4
EL DORADO (APP)	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	11
ROYSTER (PPP)	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	3
MULBERRY (PPP)	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	7
CFR-BIOGEN (ORANGE CO)	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	7
US AGRICHEM	6	ί ε	6 6	6	6	6	. 6	6	6	6	6	6	0	0	0	0	0	0	Ð	0	0	0	0	
Intermediate Resources (Summer and Winter TYSP Ratings)		.																						
Anciote 1	\$22	522	522	493	493	493	498	498	498	498	522	522	522	522	522	498	498	493	493	495	498	493	522	52
Anciole 2	522	522	522	495	495	495	495	495	495	495	522	522	522	522	522	495	495	495	495	495	495	495	522	52
Barlow 1	123	123	123	121	121	121	121	121	121	121	123	123	123	123	123	121	121	121	121	121	121	121	123	12
Barlow 2	121	121	121	119	119	119	119	119	119	119	121	121	121	121	121	119	119	119	119	119	119	119	121	12
Bartow 3	203	208	205	204	204	204	204	204	204	204	203	203	203	205	208	204	204	204	204	204	204	204	203	20
Suwannee River 1	0	0	0	0	0	0	0	0	0	.0	0	0	0	0	0	0	0	0	0	0	0	0	. 0	
Suwannee River 2	0	0	¢	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	,	0	
Suwannee River 3	0	0	0	0	0	0	0	0	0	0	0	0	0	o	0	0	0	0	0	0	0	0	- 0	
Tiger Bay Cogen	223	Z23	223	207	207	207	207	207	207	207	223	223	223	223	223	207	207	207	207	207	207	707	223	
Hines Energy Complex 1	529	529	529	452	432	482	432	432	482	482	529	529	529	529	529	482	482	482	452	482	482	452	529	52
Hines Energy Complex 2	567	567	567	495	495	495	495	495	495	495	567	567	567	567	567	495	495	495	495	495	495	495	567	55
Hines Energy Complex 3	567	567	567	495	495	495	495	495	495	495	567	567	567	567	567	495	495	495	495	495	405	495	567	56
Hines Energy Complex 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1 0	0					567	50
Hines Energy Complex 5	0	0	0	0	0	0	0	G	0	0	0	0	0		0	0				0				
Gas Peaking Resources (Summer and Winter TVSD Davis and						I		1	1	1			I		1				l		l	1	<u> </u>	Alana
So toking resources (Sommer and Winder (TSP Raungs)			,			,	<u></u>																	
Avon Park P1	32	32	32	26	26	26	26	26	26	25	26	32	0	0	0	0	0	C	0	0	0	0	0	
Bartow P2	53	53	53	46	46	46	46	46	46	46	45	53	53	53	53	46	45	46	46	46	46	46	45	5
Bartow P4	-50	50	60	49	49	49	49	49	49	49	49	60	60	60	60	49	49	49	49	49	49	49	49	e
Debary P?	93	93	93	50	30	35	85	\$5	85	80	20	93	93	93	93	50	30	. 35	. 55	35		30	30	
Debary P3	93	93	93	\$0	30	\$5	85	35	35	30	80	93	93	93	93	50	50	85	85	85		30	50	ş
Debary PS	93	93	93	50	30	35	35	85	55	50	30	93	93	93	93	80	50	55	35	35	85	50	50	
Higgins P1	0	C	0	0	0	0	. 0	0	0	0	0	0	0	0	0	0	0	0	0	0			0	
Higgins P2	- 0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		0 1	0	
Higgins P3	0	0	C	0	0	0	0	a	0	0	0	0	0	0	0	0	0	0	0	0	0		1 0	
									·	· · · · · · · · · · · · · · · · · · ·			A		·		· · · · ·				1	- L	1	

Page 7 of 12

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Higgins P4	0	0	0	0	0	0	0	0	0	0	0	0	0	D	0	0	0	0	0	0	٥	0	0	0
Intercession City P7	94	94	94	80	80	88	88	88	85	80	80	94	94	94	94	80	80	88	83		88	80	80	94
Intercession City P3	94	54	94	80	80	88	88	88	83	80	80	94	94	94	94	80	80	88	83	83	88	50	80	94
Intercession City P9	94	94	94	80	80			85	88	80	80	94	94	94	94	80	80	88	83	88	83	80	80	94
Intercession City P10	94	94	84	80	80	85	88	85		80	80	94	94	94	94	80	80	85	88	88	55	80	80	94
Intercession City P12	94	94	94	80	80	80	80	80	80	80	80	94	94	94	94	80	80	80	80]	80	80	80	80	94
Intercession City P13	v 94	94	94	80	80	80	80	80	50	80	80	94	94	94	94	80	80	80	80	80	108	80	80	94
Intercession City P14		94	94	50	80	80	80	80	<u>50</u>	50	80	94	94	94		80	80	80	80	80	80	80	80	
Suwannee River P1	67	87	67	55		55	55	- 55	55	55	55	67	67	67	67	55	55	55	55	55	55	55	55	67
Siavannee River P3	67	57	57	55	55	55			55	55	45	57	67	67	57	55	55	55			54		55	
Light Oil Peaking Resources (Summer and Winter TYSP				<u> </u>		<u> </u>		<u> </u>														<u>~</u> _		
Ralings)											1													
Aven Park P2	32	32	32	26	25	26	26	26	26	26	26	62	0	0	0	0	0	0	0	0	0	0	0	0
Bartow P1	53	53	53	46	45	46	45	46	46	45	45	53	53	53	53	45	46	46	46	46	45	45	46	53
Bartow P3	53	53	53	45	46	46	46	45	46	45	45	53	53	53	53	46	46	45	45	45	46	45	45	53
Bayboro P1	55	58	58	46	46	46	46	46	46	45	46	53	58	58	58	46	46	46	46	45	46	45	46	58
Bayboro P2	58	58	58	48	46	46	45	46	46	46	46	58	58	58	53	46	46	46	45	45	46	46	46	58
Bayboro P3	58	58	58	46	46	46	45	45	46	46	46	58	58	58	58	46	46	46	45	46	46	46	45	53
Bayboro P4	58	58	58	46	46	45	46	46	46	45	46	58	58	58	53	46	46	46	46	46	46	45	46	53
Debary P1	65	65	65	54	54	54	54	54	54	54	54	65	65	65		54	54	54	54	54	54	54	54	65
Debary P2	65	65	85	54	54	54	54	54	54	54	54	85	65	65	65	54	54	54	54	54	54		54	65
Debary P3	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P4	65	65	85	54	54	54	54		54	54	54	65	65	65	65	- 54	54	54		54	54	54	54	
Dehary PS	65		55	54		54	54	54	54	54	54	65	65	55		54	54	54	54	54	54	54	54	
Dehay PS			65			54	54	54		54		65	8	85	65		54		54	54	54	54	54	65
Debay P10				79	70					79	79	~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~				79	79	*4	84		84	79	79	
Internetion City Pt	81	81			40	40	40	40	40	49	49	61		60		AD	49		OK.	40	404	49	401	
Interestion City P1						40	40	40	40	40	40							40	40	43			49	
Intercession City P2				40		49	45	49	45		49		01			49	43	45	43	49	45	40	43	
Intercession City P3	01			49	49	49	49	49	49	49	49	61	01			49	49	49	45	49	49	49	49	
intercession City P4				49	49	43	49	49	49	43		01	61			49	49	43	49	49	49	49	49	
Intercession City P5	61		61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	6
intercession City P6	01		61	49	49	49	49	49	49	49	49	01	61	61	. 61	49	49	49	49	49	49	49	49	61
Intercession City P11	170	170	170	143	143	G			0	143	143	170	170	170	170	143	143	D	0	0	D	143	143	170
Rio Pinar P1	0	0	0	. 0	0	0	0	0	0	°		0	0	0	0	0	0	0	0	0	0	0	0	
Suwannee River P2	67	67	67	67	54	54	54	54	54	54	54	67	67	67	67	67	54	54		54	54	54	54	67
Turner P1	16	16	16	13	13	13	13	13	13	13	13	16	0	0	0	0	0	0	0	0	0	0	0	
Turner P2	16	16	16	13	13	13	13	13	13	13	13	16	0	0	0	0	0	0	0	0	0	0	0	
Turner P3	32	82	52	5Z	65	65	55	65	65	65	65	\$2	3Z	32	32	32	65	65	65	65	65	65	65	
Turner P4	80	30	80	50	63	63	53	63	63	63	63	50	80	80	30	50	63	63	63	63	63	63	63	30
Total Baseload Plants	3,197	3,197	3,197	3,140	3,140	3,140	3,140	3,140	3,140	3,140	3,197	3,197	3,197	3,197	3,197	3,140	3,140	3,140	3,140	3,140	3,140	3,140	3,197	3,19
Total Baseload Contracts	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	47
Total QF Contracts	818	818	\$18	818	818	\$18	. 313	\$18	818	\$15	\$15	818	813	813	813	\$13	813	\$13	813	813	\$13	813	813	S1:
Total Intermediate Resources	3,332	3,382	3,382	<u>3,116</u>	3,175	3,118	3,116	3,116	3.116	3,116	3,382	3,382	3,382	3,332	3,382	3,116	3,116	3,116	3,116	3,116	3,116	3,116	3,949	3,949
Total Gas Peaking Resources	1,216	1,216	1,216	1,031	1,031	1,075	1,075	1.073	1,078	1,031	1,031	1,216	-1,154	1,154	1,184	1,005	1.005	1,052	1,052	1,052	1,052	1,005	1,005	1,13
Total Light Oil Peaking Resources	1,650	1,550	1,650	1,397	1,350	1.212	1,212	1,212	1.212	1,350	1,350	1,650	1,536	1,536	1,586	1,345	1,298	1,160	1,160	1,160	1,150	1,293	1,293	1,58
Total Available Resources	10,742	10,742	10,742	9,931	9,934	9,843	9,843	9,343	9,843	9,934	10,257	10,742	10,641	10,641	10,641	9,595	9,851	9,760	9,760	9,760	9,760	9,851	10,741	11,20

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-	1 100 00	Esh 08	Here CR	A	Mary DR	h 00	hel of	1 4	C	0.000	New Or	Dec 00	h- 00	Cab an I	No. 00	4-1 00	Nov 00	hun 00 1	1.1.00	1	E 00	0-1-00	Nov on 1	D 00
Paraland Plants (Summar and Wilster TYPE Parks and	380-00	1	mar-uo	Apr-00	may-on	Jun-os	JUI-08	AUS-00	399-08	000	NDA-na	D-8C-00	Jan-ua	Ped-03	Mar-Us	Apr-us	May-08	Jun-09	Jui-09	Angva	Sep-Us	UCI-US [104-03 [I	Dec-03
Baseroad Flands (administrand Winter, 175P Raungs)		J						r																
Crystal River 1	400	400	400	396	396	396	396	396	396	396	400	400	400	400	400	396	396	395	396	398	395	396	400	400
Crystat River 2	503	503	503	490	498	495	498	498	493	498	503	503	503	503	503	498	498	495	498	498	498	498		50.
Crystal River 4	(39	/39	739	729	729	729	/29	729	729	729	739	739	739	739	/39	729	729	729	729	729	729	729		13
Crystai River 5	132	732	132	/1/			/1/			71/	/32	732	732	732	732	- 11/	717	/17	/17	/1/	717	717	/32	73
Crystal River 3	y 782	/82	782	765	765	765	765	765	765	765	782	752	782	782	782	765	765	765	765	765	, 765	765	782	73
University of Florida Cogen	41	41	41	35	35	35	35	35	35	35	41	41	41	41	41	35	35	35	35	35	35	35	41	4
Baselola Convacis (Firm Purchase Capacity)		1						r		r	,						,				,	,		
UPS Purchase from Southern Company	409	409	409	. 409	409	409	409	409	409	409	. 409	409	409	409	409	409	409	409	409	409	409	409	409	409
TECO Purchase for Sebring Load	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
<u>QF Contracts</u>						,					,								,Â			<u> </u>	<u> </u>	
PINELLAS CO RES REC 1	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
PINELLAS CO RES REC 2	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	1!
TIMBER ENERGY 1	0	0	0	Ç	0	0	0	0	0	0	0	0	0	0	0	0	Ď	0	0	0	0	0	O	(
BAY COUNTY RES REC	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	1
LFC MADISON (APP)	9	9 9	9	9	9	9	9	9	9	9	9	9	9	8	9	9	9	9	9	9	9 9	9	9	
LFC JEFFERSON (APP)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9 9	9	9	
LAKE COUNTY RES REC	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	1
PASCO COUNTY RES REC	23	23	23	23	23	23	23	Z3	23	23	23	23	23	23	23	23	23	23	23	23	3 23	23	23	2
DADE COUNTY RES REC	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	4
CARGILL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		0 0	, 0	0	
LAKE COGEN	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	11
PASCO COGEN	109	109	109	109	109	109	109	109	109	109	109	109	Ó	0	0	ō	0	0	0	0	0 0	0	0	
ORLANDO COGEN	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	7
RIDGE GENERATING STA	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	2
EL DORADO (APP)	114	114	114	114	114	114	114	114	• 114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	11
ROYSTER (PPP)) 31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	1	0	0	
MULBERRY (PPP)	y 79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	9 79	79	79	
CFR-BIOGEN (ORANGE CO	74	5 74	74	74	74	74	74	74	74	74	74	.74	74	74	74	74	74	74	74	74	4 74	4 74	74	
US AGRICHEM	4 0	0 0	0	0	0	0	0	0	0	0	0	0	0 0	0	0	0		0	0) (0 0	0 0	0	
Intermediate Resources (Summer and Winter TYSP Ratings)										·							L			1	1	·		
Anciote 1	522	2 522	522	498	498	498	498	498	498	498	522	522	522	522	522	495	493	493	493	49	3 495	493	522	.5:
Anciote 2	522	522	522	495	495	495	495	495	495	495	522	522	522	522	522	495	495	495	495	49	5 495	5 495	522	5:
Bartow 1	123	123	123	121	121	121	121	121	121	121	123	123	123	123	123	121	121	121	121	121	1 121	1 121	123	1:
Bartow 2	121	121	121	119	119	119	119	119	119	119	121	121	121	121	121	119	119	119	119	119	9 119	119	121	1
Bartow 3	205	3 203	208	204	204	204	204	204	204	204	208	205	205	203	205	204	204	204	204	204	1 204	204	205	2
Suwannee River 1	0	0 0	0 0	0	0	0	0	0	0	0	0		0	0	0	0						0	0	
Suwannee River 2		0	0	0	0	0	0	0		0	0		0 0		0						n	0		
Stwanpes River 3	0		0	0	0		0	0			0												- 0	
Tiger Bay Cogen	223	223	223	207	207	207	207	207	207	207	223	221	223	227	773	207	207	207	207	203	7 707	7 207	773	2
Hines Energy Complex 1	529	529	529	487	482	487	452	437	437	457	579	529	529	529	579	457	4.97	497	497	497	2 497	2 457	579	
Hines Energy Complex 2	567	7 557	557	495	495	405	405	405	495	405	567	567	557	567	557	405	405	405	405	40	5 405	5 405	567	5
Hines Energy Complex 3	557	7 567	567	495	495	405	495	495	405	495	567	567	557	567	567	405	405	405	404	40	5 10	5 405	557	<u> </u>
Hines Energy Complex 4	567	7 567	587	495	495	405	405	495	405	405	567	567	557	567	567	405	405	405	405	40	5 40	5 405	667	<u> </u>
Hines Energy Complex 5													1			435						430	507	\vdash
Thirds Ellipsyy Complex 3		·	1	L	· · ·			<u>'</u>	<u> </u>	<u> </u>			′ <u> </u>	L			<u>'} '</u>	<u> </u>	<u> </u>	1	<u> </u>	<u> </u>		L.
Gas Peaking Resources (Summer and Winter TYSP Ratings)					10040																			
Avon Park P1		0 0	0 0	0	0	0	0	0	0	D	0	0	0 0	0	0	. 0	0 0	0 0			0 0	0 0	0	
Bartow P2	2 53	3 53	3 . 53	46	46	46	45	46	46	45	. 45	53	53	53	53	46	46	5 46	3 46	5 41	6 40	5 46	46	
Barlow P4	4 60	0 60	60	49	49	49	49	49	49	49	49	60	60	60	60	49	49	3 49	49	4	9 4	9 49	49	
Debary P7	7 93	3 93	3 93	30	80	\$5	35	85	. 35	30	30	93	3 93	93	93	\$0	50	. 85	5 85	5 8	5 8	5 30	20	
Debary PS	93	3 93	3 93	30	· 80	\$5	35	5 35	35	20	50	93	3 93	. 93	93	. 30	30	35	5 85	5 3	5 8	5 80	50	
Debary PS	9 93	3 93	3 93	80	50	. 55	- 25	\$ \$5	. 85	50	50	93	3 93	93	93	30	50		5 85	5 3	5 8	5 80	20	
Higgins P1	1 (0 0	0 0		0	0	c	0 0	0	0	0		0 0	0	0	(0 0			0	0 0	1 0	
Higgins P2	2 0	0 0	0 0	0	0	0	0	0 0	c	> 0	0		0	0	0	. (0 0	0 0			0	0 0	0	
Higgins P.	3 0	0 0	0 0	1	0	0		0 0	0		0			0	0						0	0 0	1 0	<u> </u>
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Higgins P4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Intercession City P7	94	94	94	80	80		88	83		80	80	94	94	94	94	80	80	85	83	85	85	80	80	94
Intercession City P8	94	94	94	50	80	86	65	65	65	50	80	94	94	94	94	80	80	88	85	88	88	80	80	94
Intercession City P9	94	94	94	80	80		85	85	85	80	80	94	.94	94	94	80	80	85	83		83	50	80	94
Intercession City P10	94	94	94	80	80	88	85	85	85	80	50	94	94	9 4	94	80	80	83	33	88	£3	80	80	94
Intercession City P12	94	94	94	80		80	80	80	- 80	80	80	94	94	9 4	94	80	80	80	80	80	80	80	80	94
Intercession City P13	· y 94	94	94	80	80	80	80	80	80	80	- 80	94	94	94	94	80	80	80	80	80	80	80	80	94
Intercession City P14	94	94	94	80	80	80	80	80	80	80	80	94	94	94	94	80	80	80	80	80	80	80	80	94
Suwannee River P1	67	67	67	55	55	55	55	55	55	55	55	67	67	67	67	55	55	55	55	55	55	55	55	67
Suwannee River P3	67	67	67	55	55	55	55	- 55	55	55	- 55	67	67	67	67	55	55	55	55	55	55	55	55	67
Light Oil Peaking Resources (Summer and Winter TYSP																								
Aven Park P2	ol	d	d		ام	ام	ام		ol	<u>اہ</u>	ما	7 0/				<u></u>	പ		d		d		d	
Bartow D1	57	57	- 63		46	45	46	45	46	46	. 45	52	52	52	53		46		46	45	46			
Batow P1	- 53			40	40	40	40	40	40	40	40	50	53		53	40	40	46	40	40	40	40		
Balluw P3	20	50		40	40	40	40		40	40	40			55	50	40	40	40	40	40	40			
Baytoro P1	50		00	40	40	40	40	40	40	40	40	56	50	50	00	40	45	40	40	40	40	40	40	23 E0
Bayboro P2				40	40	40	40	40	40	40	40				50	40	40	40	40	40	40	40	401	50
Baysoro P3		50		40	40	40	40	40	40	40	40		50		50	40	40	40	40	40	40	40	40	
Baytoro P4	100		50	40	40	40	40	40	40	40	40	00	20			40 E4	40	40	40	40	40	40 EA	40	
Dobay P1				54						====								54	54	54	84			
Debary P2		ec	00 #5	54	54	54	54	54	P4	54		ec									54			60
Decary P3	65	65	65	54	54	54	54	54	54	54	54	50	55			64	54	54		54	54	54	54	67
					54	54			54		54		65								54			65
Debay P3	85	85		54	54	54	54		54		54							54						65
Dabay Po	~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~	02		70	70					70	70			07		70	70		84			70	70	67
Internetion City Pt	81		81	40	40		40	40	40	40	13	81	81	55	61	40	40	80	AQ	40	40	10	49	
Interession City P1	51		81	40		40	43	49	40	40	49	51	51			40	49	49	40	49	49	49		51
Interestion City P2	61	61	61	40		49		40	40	40		61	RI		10	49	40	49	49	49		49	49	61
Interession City P3	81			40	40	40	49	40	49		40	61	61	61	61	49	49	40		40	40			
Intercession City P4	10	61	61	49	49	49	49	49	 49	49	40	61		81	61	49	40	49		43	49	49	49	6
Intercession City P5	61	61	61	49	49	49	49	49	49	49	49	61	. 61		61	49	49	49	49	49	49	49	49	8
Interression City P11	170	170	170	143	143					143	143	170	170	170	170	143	143				 0.011010	147	143	17
Rio Pinar P1						· <u>·····</u>	0	0	n	0									0	0	0			<u> </u>
Sinvance River P7	67	67	67	57	54	54	54		54	54	54	57	57	57	67	67	54	54	54	54	54	54		6
Turner P1					0			· 0					0				0		0					
Timer P2	0			0				0	ů	0			0				0		0					
Turner P3	87	87	87	87		65	85	65	65	65	65		87		82	87	65	65	65	65	55	65		
Tume Pá	30	30	80	30				5	57	3	50	80	80	30					5	57				80
	~~~~~										3								03	. 03				1
Total Baseload Plants	3,197	3,197	3,197	3,140	3,140	3,140	3,140	3,140	3,140	3,140	3,197	3,197	3,197	3,197	3,197	3,140	3,140	3,140	3,140	3,140	3,140	3,140	3,197	3,197
Total Baseload Contracts	479	479	479	479	479	479	479	479	- 479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	47
Total QF Contracts	798	793	798	795	798	798	795	793	798	793	795	798	639	639	639	639	559	639	639	- 639	658	653	658	65
Total Intermediate Resources	3,949	3,949	3,949	3,611	3,611	3,611	3,611	3,611	3,611	3,611	3,949	3,949	3,949	3,949	3,949	3,611	3.611	3,611	3,611	3,611	3,611	3,611	4,516	4,51
Total Gas Peaking Resources	1,134	1,184	1,184	1,005	1,005	1,052	1,052	1,052	1,052	1,005	1,005	1,184	1,184	1,184	1,184	1.005	1.005	1,052	1,052	1,052	1.052	1,005	1.005	1.18
Total Light Oil Peaking Resources	1,586	1,536	1,588	1,345	1,298	1,160	1,160	1,150	1,160	1,298	1,298	1,586	1,586	1,586	1,586	1,345	1.298	1,160	1,160	1,160	1,160	1.298	1,298	1,58
To <u>tal Available Resources</u>	11,193	11,193	11,193	10,378	10,331	10,240	10,240	10,240	10,240	10,331	10,726	11,193	11,084	11,034	11.034	10.269	10 222	10,131	10,131	10,131	10,100	10,191	11,153	11.62
	L	L					1	L	L		i		L					L	L	L		L	/	1

	.lan_10	Feb-10	Mer-10	Anr-10	May-10	Jun-10	Jui-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10		Comments	
Baseload Plants (Summer and Winter TYSP Rating≤)		·					1	<u> </u>		1	L				
Crystai River 1	400	400	400	396	396	396	395	395	395	396	400	400	~~~~~	Turbine upgi	rade 12/2001
Crystal River 2	503	503	503	498	498	498	498	498	495	498	503	503		Turbine upg	rade 12/2000
Crystal River 4	739	739	739	729	729	729	729	729	729	729	739	739		Turbine Upg	rade: 4/2000
Crystal River 5	73Z	732	732	717	717	717	717	717	717	717	732	732			
* Crystal River 3	782	782	782	765	765	765	765	765	765	765	782	782	1		
University of Florida Cogen	41	41	41	35	35	35	35	35	35	35	41	41			
Baseload Contracts (Firm Purchase Capacity)															
UPS Purchase from Southern Company	409	409	409	409	409	0	0	· 0	0	0	0	0		Contract Ex	pires 8/2010
TECO Purchase for Sebring Load	70	70	70	70	70	70	70	70	70	70	70	70		Contract Ex	pires 3/2011
QF Contracts															
PINELLAS CO RES REC 1	40	40	40	40	40	40	40	40	40	40	40	40		4/1/83	Contract
PINELLAS CO RES REC 2	15	15	15	15	15	15	15	15	15	15	15	15		5/1/86	Contract
TIMBER ENERGY 1	0	0	0	G	0	0	0	0	0	0	0	0		7/1/88	Contract Expires 4/2002
BAY COUNTY RES REC	11	11	11	11	11	11	11	11	11	11	11	11		4/1/83	Contract
LFC MADISON (APP)	9	9	9	9	8	8	9	9	9	9	Ş	9		9/1/89	Contract
LFC JEFFERSON (APP)	9	9	9	9	9	9	9	9	9	9	9	9		8/1/90	Contract
LAKE COUNTY RES REC	13	13	13	13	13	13	13	13	13	13	13	13		9/1/90	Contract
PASCO COUNTY RES REC	23	23	23	23	23	23	Z3	23	23	23	23	23		3/1/91	Contract
DADE COUNTY RES REC	43	43	43	43	43	43	43	43	43	43	43	43		11/1/91	Contract
CARGILL	0	0	0	0	0	0	0	٥	0	0	0	0		10/1/92	Contract Expires 1/2008
	5	0	0	0	0	D	0	0	0	0	0	0		7/1/93	Contract Expres 1/2010
PASCO COGEN	0	0	G	0	0	0	C	0	0	D	0	0		7/1/93	Contract Expires 1/2009
ORLANDO COGEN	79	79	79	79	79	79	79	79	79	79	79	79		10/1/93	Contract
RIDGE GENERATING STA	40	40	40	40	40	40	40	40	40	40	40	40		5/1/94	Contract
EL DORADO (APP)	114	114	114	114	114	114	114	114	114	114	114	114	· ·	7/1/94	Contract
ROYSTER (PPP	}	0	0		1 0	0	0	0	0	0	0	e		7/1/94	Contract Expires 9/2009
MULBERRY (PPP	79	79	79	79	79	79	79	79	79	79	79	79		7/1/94	Contract
CFR-BIOGEN (ORANGE CO	74	74	74	74	74	74	74	74	74	74	74	74	1	6/1/95	Contract
US AGRICHEN		0			,	0	0	0	0	0	0	0	1	1/1/97	Contract Expires 1/2007
Intermediate Resources (Summer and Winter TYSP Ratings)		L	1	L	1	1									
Anciate 1	522	2 522	522	493	493	495	495	498	493	493	522	522	1		
Anciote 2	522	522	522	495	495	495	495	495	495	495	522	522	1		
Bartow	123	123	123	121	121	121	121	121	121	121	123	123	1		
Bariow	2 121	121	121	119	119	119	119	119	119	119	121	121	1		
Barlow	205	203	205	204	204	204	204	204	204	204	203	203			
Situation Brief	1			1		0	0	0	0	0	0	0	1	Unit Refire	ment 12/31/2003
Suparanae River 2	,			1		0	0	0	. 0	0	0		1	Unit Retire	ment 12/31/2003
Summore Parer 1			1	1	,	0	0	0	0	0	0		1	Unit Refire	ment 12/31/2003
Suwanico nuon c				201	2 201	207	707	207	207	207	223	223			1
liger Bay Coger		224	E24	201	200	437	487	497	487	432	579	579	1 .		
Hines chergy Complex	502	7 523	52		- 40	405	495	405	495	495	567	567	1	Unit Addit	on 11/2003
Hittes Energy Complex 2	2 50	507	50	45	40	435	405	405	405	495	567	567	4	Unit Additi	on 11/2005
Hines Energy Complex :	5 56	1 30/	50	49	49.	495	495	435	433	400	567	5,67		Unit Addib	on 15/2007
Hines Energy Complex 4	4 56		56	49	49	495	493	493	493	495	100	507	4	Doit Addit	on 11/2009
Hines Energy Complex	5 55	7 567	<u> 55</u>	49	- 49:	- 445	495	495	495	1 493	301	1	J	Giviridore	and the second s
Gas Peaking Resources (Summer and Winter TYSP Ratings)															
Avon Park P	1	0 (	2	5	0	0 0	0	0	0		0	1	]	Unit Retire	ement 12/31/2006
Barlow P	2 5	3 5:	5	3 4	6 4	5 45	46	46	46	46	46	53			
Bartow P	4 6	0 60	6	4	9 4	9 49	49	49	49	49	45	60	1		
Debary P	7 9	3 9:	3 9	3 3	0 3	0 35	85	35	.55	30	80	93	7	iniet fogge	ng installed 5/2000 (Jun, Jul, Aug & Sep)
Debary P	3 9	3 9	3 9	3 8	0 3	0 85	.85	85	85	50	50	9:	3	Intet loggi	ng Installed 5/2000 (Jun, Jul, Aug & Sep)
Dehary P	9 9 9	3 9	3 9	3 3	0 3	0 35	\$5	85	35	50	80	9	จ	Intel foggi	ng installed 5/2000 (Jun, Jul, Aug & Sep)
Hispine D	1	0	0	0	<del>d</del>		0	0					5	Unit Retire	ement 12/31/2005
	2	0	0	ol	0	0 0	1 0	1	1			,	5	UnitRetire	amon( 12/31/2005
	1	0		0	0		1	1 0	1		1 0	,	5	Unit Retire	ement 12/31/2005
Higgins P	-	<u> </u>	۲ <u>۱</u>	۳۱	~1	<u> </u>	·	1	.L	1	-l			- مستخمست	

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Page 11 of 12

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Higgins P4	0	C	0	0	0	0	0	0	0	0	c	0		Unit Retireme	nt:12/31/2005		
Intercession City P7	94	94	94	80	80	85	85	85	85	80	80	94		Iniet fogging (	(Jun, Jul, Aug &	Sep)	
Intercession City P8	94	94	94	80	80	88		88	85	80	80	94		iniet fogging	(Jun, Jul, Aug &	Sep)	
Intercession City P9	94	94	94	80	80	85	85	88		80	80	94		Infet logging	(Jun, Jui, Aug &	Sep)	
Intercession City P10	94	94	94	80	80			85		80	80			Inlet fogging	(Jun, Jul, Aug &	Sep)	
Intercession City P12	94	94	94	80	80	80	80	80	80	80	80	94		Commercial	operation 12/200	0	
v Intercession City P13	94	94	94	80	80	80	80	80	80	80	80	94		Commercial	operation 12/200	10	
Intercession City P14	94	94	94	80	80	80	80	80	80	80	80	94		Commercial	operation 12/200	0	
Suwannee River P1	67	67	67	55	55	55	55	55	55	55	55	67					
Suwannee River P3	67	67	67	55	55	- 55	55	. 55	55	55	55	67					
Light Oil Peaking Resources (Summer and Winter TYSP Ratings)																	
Avon Park P2	0	0	0	0	0	0	0	0	<b>*</b> 0	0	0	0		Unit Retirem	ent 12/31/2006		
Bartow P1	53	53	53	46	45	46	46	46	46	46	46	53					
Bartow P3	53	53	53	45	46	46	46	45	46	45	45	53					
Bayboro P1	55	58	58	48	46	46	46	45	45	45	45	58					
Bayboro P2	58	58	58	46	46	46	45	46	46	45	45	58					
Bayboro P3	55	58	58	46	46	45	46	46	46	45	46	58					<u>.</u>
Bayboro P4	55	58	58	46	46	45	46	46	45	46	46	58			· · ·		
Debary P1	65	65	65	54	54	54	54	54	54	54	54	65				······	
Debary P2	65	65	65	54	54	54	54	- 54	54	54	54	65					
Debary P3	65	65	65	54	54	54	54	54	54	54	54	65					
Debary P4	65	65	65	54	54	54	54	54	54	54	54	65					
Debary P5	65	65	65	54	54	54	54	54	54	- 54	54	65					
Debary P6	65	65	65	54	54	54	54	54	54	54	54	65					,
Debary P10	93	93	93	79	79	84		84	84	79	79	93		Inlet logging	installed 5/2000	i (Jun, Jul, Au	j& Sep)
Intercession City P1	61	61	61	49	49	49	49	49	49	49	49	61					
Intercession City P2	61	61	61	49	49	49	49	49	49	49	49	61			· · · · · · · · · · · · · · · · · · ·		
Intercession City P3	61	61	61	49	49	49	49	49	49	49	49	61					
intercession City P4	61	51	61	49	49	49	49	49	49	49	49	61				· · · · ·	
Intercession City P5	61	61	61	49	49	49	49	49	49	49	49	61					
Intercession City P6	. 61	61	61	49	49	49	49	49	49	49	49	61					
Intercession City P11	170	170	170	143	143	a	0	0	0	143	143	170		Southern su	mmer ownershi	a (Jun throug)	(Sep)
Rio Pinar P1	0	0	0	. 0	0	0	0	0	0	0	0	0		Unil Retiren	ient 12/31/2005		
Suwannee River P2	67	. 67	67	67	54	54	54	54	54	54	54	67					
Turner Pt	0	0	0	0	0	0	0	0	0	0	0	0		Unit Retiren	nent 12/31/2005		
Turner P2	0	0	0	0	0	0	0	0	0	0	0	0		Unit Retiren	nent 12/31/2005		
Turner P3	82	\$2	32	82	65	65	65	65	65	65	65	52					
Tumer P4	30	50	50	50	63	63	63	63	63	63	63	80		<u> </u>			<u></u> .
<u>Total Baseload Plants</u>	3,197	3,197	3,197	3,140	3,140	3,140	3,140	3,140	3,140	3,140	3,197	3,197				=	
Total Baseload Contracts	479	479	479	479	479	70	70	70	70	70	70	70					
Total QF Contracts	543	543	548	543	548	548	548	543	548	548	548	543					
Total Intermediate Resources	4,516	4.516	4,516	4,106	4,105	4,106	4,106	4,106	4,106	4,106	4,516	4,516					
Total Gas Peaking Resources	1,184	1 154	1,154	1,005	1,005	1,052	1,052	1,052	1,052	1,005	1,005	1,134					
Total Light Oil Peaking Resources	1,586	1.586	1,536	1,345	1,293	1,160	1,160	1,160	1,160	1,298	1,298	1,536					
Total Available Resources	11,510	11 510	11,510	10,623	10,576	10,076	10,075	10,075	10,076	10,167	10,634	11,101					
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#### LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY 2000 SERC RATINGS, COGENERATION = 991231 JANUARY 2000 LONG-TERM FORECAST (S000101) Builk Power Sales included in Demand & Energy Forecast

## 2000 Ten-Year Site Plan Analysis * Future Capacity Additions for 20 % RM * Base Case

)			WINTER 00/01	WINTER 01/02	WINTER 02/03	WINTER 03/04	WINTER 04/05	WINTER 05/06	WINTER 06/07	WINTER 07/08	WINTER 08/09	WINTER 09/10
			Jan-2001	Jan-2002	Jan-2003	Jan-2004	Jan-2005	Jan-2006	Jan-2007	Jan-2008	Jan-2009	Jan-2010
	Existing FPC Capacity	MW	8,267	8,590	8,607	8,607	9,028	9,028	9,445	9,349	9,916	9,916
	New FPC Capacity	MW 🛔	323	11 17 AV	0	667	* o	587	0	.567	0	567
	Retired FPC Capacity	MW	0	0	o	146	0	150	96	0	0	0
	Total Installed Capacity	MW	8,590	8,607	8,607	9,028	9,028	9,445	9,349	9,916	9,916	10,483
	Firm Purchase Capacity	MW	469	469	469	469	479	479	479	479	479	479
	Firm QF Purchase Capacity	MW	831	831	818	818	818	818	813	798	689	548
	Seasonal Purchase Capacity	WW	0	0	<b>o</b> :	0	0	0	0	0	0	0
	Capacity on Scheduled Maintenance	MW	0	o	0	0	0	0	ο	0	0	0
	Firm Sale of Capacity	MW	0	0	. 0	0	0	0	0	0	0	0
	Total Available Capacity	MW	9,890	9,907	9,894	10,315	10,325	10,742	10,641	11,193	11,084	11,510
	Potential Total Retail Demand	MW	8,468	8,636	8,828	8,997	9,165	9,325	9,483	9,634	9,783	9,933
	Wholesale (REA)	MW	894	911	558	503	525	600	676	755	833	912
	Wholesale (Bulk Power)	MW	632	167	167	167	167	167	167	167	167	167
	Wholesale (Municipal)	MW	205	196	203	206	198	200	203	206	209	212
	Total Wholesale Demand	MW	1,731	1,274	928	877	890	968	1,046	1,129	1,210	1,291
	Company Use	MW	30	30	30	30 .	30	30	30	30	30	30
	Potential Total System Demand	MW	10,229	9,940	9,786	9,904	10,085	10,323	10,559	10,793	11,023	11,254
	Non-Dispatchable DSM and Self-Service QF	MW	444	468	495	523	552	582	613	643	672	701
	Normal Weather Demand (Before Load Control)	MW	9,785	9,472	9,291	9,381	9,533	9,741	9,946	10,150	10,351	10,553
	Normal Weather Reserves (Before Load Control)	MW	. 105	435	603	935	792	1,002	695	1,043	733	957
	Normal Weather Reserve Margin (Before Load Control)	2 %	2 <b>1 1 %</b> +	4.6%	6.5%	10.0%	8.3%	10.3%	7.0%	10.3%	7.1%	9.1%
	Normal Weather Load Management	MW	833	771	730	707	688	674	661	650	641	632
	Normal Weather Demand (After Load Management)	MW	8,952	8,701	8,561	8,674	8,845	9,067	9,285	9,499	9,710	9,921
	Normal Weather Reserves (After Load Management)	MŴ	938	1,206	1,333	1,641	1,480	1,675	1,356	1,693	1,374	1,589
	Normal Weather Reserve Margin (After Load Management)	%	10.5%	13.9%	15.6%	18.9%	16.7%	18.5%	14.6%	17.8%	14.1%	16.0%
	Normal Weather Interruptible Load	MW	306	304	328	329	334	337	342	345	348	350
	Normal Weather Voltage Reduction	MW	118	115	113	114	117	120	123	125	128	131
	Normal Weather Demand (After All Load Control)	MW	8,528	8,282	8,120	8,231	8,394	.8,610	8,820	9,029	9,234	9,440
	Normal Weather Reserves (After All Load Control)	MW	1,362	1,625	1,774	2,084	1,931	2,132	1,821	2,163	1,850	2,070
	Normal Weather Reserve Margin (After All Load Control)	%	16.0%	19.6%	21.9%	25.3%	23.0%	24.8%	20.6%	24.0%	20.0%	21.9%
	Normal Weather Reserves (After All Load Control) Required For 20 %	MW	1,706	1,656	1,624	1,646	1,679	1,722	1,764	1,806	1,847	1,888
	Normal Weather Reserves (After All Load Control) Above 20 %	MW	-344	-32	150	438	252	410	57	358	з	182
	Normal Weather "DLC" Reserve Margin Contribution	%	92.3%	73.2%	66.0%	55.2%	59.0%	53.0%	61.9%	51.8%	60.4%	53.8%

Note: Suwannee River Steam Units 1-3 Retired 12/31/2003 Higgins Peakers P1-P4 Retired 12/31/2005 Rio Pinar Peaker P1 Retired 12/31/2005 Avon Park Peakers P1-P2 Retired 12/31/2006 Turner Peakers P1-P2 Retired 12/31/2006

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#### LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY 2000 SERC RATINGS, COGENERATION = 991231 JANUARY 2000 LONG-TERM FORECAST (S000101) Bulk Power Sales included in Demand & Energy Forecast

# 2000 Ten-Year Site Plan Analysis * Future Capacity Additions for 20 % RM * Base Case

		SUMMER 00	SUMMER 01	SUMMER 02	SUMMER 03	SUMMER 04	SUMMER 05	SUMMER 06	SUMMER 07	SUMMER 08	SUMMER 09
		Aug-2000	Aug-2001	Aug-2002	Aug-2003	Aug-2004	Aug-2005	Aug-2006	Aug-2007	Aug-2008	Aug-2009
Existing FPC Capacity	MW	7,553	7,553	7,817	7,834	7,834	8,186	8,186	8,546	8,468	8,963
New FPC Capacity	MW	0	284 1 2	1442.01765.8344	Ð	495	0	495		495	0
Retired FPC Capacity	MW	0	. 0	0	0	143	o	135	78	0	0
Total Installed Capacity	MW	7,553	7,817	7,834	7,834	B,186	8,186	8,546	8,468	8,963	8,963
Firm Purchase Capacity	MW	469	469	469	469	469	479	479	479	479	479
Firm QF Purchase Capacity	MW	831	831	B18	818	818	818	818	813	798	689
Seasonal Purchase Capacity	MW	0	0	0	O	0	0	0	O	٥	0
Capacity on Scheduled Maintenance	MW	0	0	Ó	0	0	0	0	0	0	0
Firm Sale of Capacity	MW	0	0	0	0	0	0	0	0	0	σ
Total Available Capacity	MW	8,853	9,117	9,121	9,121	9,473	9,483	9,843	9,760	10,240	10,131
Potential Total Retail Demand	MW	7,326	7,467	7,621	7,801	7,956	8,111	8,259	8,403	8,543	8,663
Wholesale (REA)	MW	392	489	490	121	48	54	112	171	231	291
Wholesale (Buik Power)	MW	632	632	167	167	167	167	167	167	167	167
Wholesale (Municipal)	мw	253	222	209	218	221	211	214	217	220	223
Total Wholesale Demand	MW	1,277	1,343	867	506	436	433	493	555	618	681
Company Use	M₩	30	30	30	30	30	30	30	30	30	30
Potential Total System Demand	MW	8,633	8,840	8,518	8,337	8,422	8,574	8,782	8,988	9,191	9,394
Non-Dispatchable DSM and Self-Service QF	MW	355	368	381	395	410	425	441	456	471	485
Normal Weather Demand (Before Load Control)	MW	8,278	8,472	8,137		8,012	8,149	8,341	8,532	8,720	8,908
Normal Weather Reserves (Before Load Control)	MW	575	645	985	1,179	1,461	1,335	1,502	1,228	1,519	1,222
Normal Weather Reserve Margin (Before Load Control)	<b>%</b>	6.9%? 5	7,6%	12.1%	14.8%	18.2%	16.4%	18.0%	14.4%	17.4%	13.7%
Normal Weather Load Management	MW	512	463	400	356	322	291	265	242	222	205
Normal Weather Demand (After Load Management)	MW	7,766	8,009	7,736	7,586	7,690	7,857	8,076	8,290	8,498	8,703
Normal Weather Reserves (After Load Management)	MW	1,087	1,108	1,385	1,536	1,783	1,626	1,767	1,470	1,742	1,427
Normal Weather Reserve Margin (After Load Management)	%	14.0%	13.8%	17.9%	20.2%	23.2%	20.7%	21.9%	17.7%	20.5%	16.4%
Normal Weather Interruptible Load	MW	327	308	305	328	329	335	339	343	346	* 349
Normal Weather Voltage Reduction	MW	. 0	0	0	0	0	0	0	0	0	0
Normal Weather Demand (After All Load Control)	MW	. 77,439	7,701	7,431	7,258	7,361	7,522	7,737	7,947	8,152	8,354
Normal Weather Reserves (After All Load Control)	MW	1,414	1,416	1,690	1,864	2,112	1,961	2,106	1,813	2,088	1,776
Normal Weather Reserve Margin, (After All Load Control)	4	19.0%	18.4%	22.7%	25.7%	28.7%	26.1%	27.2%	22.8%	25.6%	21.3%
Normal Weather Reserves (After All Load Control) Required For 20 %	MM	1,468	1,540	1,486	1,452	1,472	1,504	1,547	1,589	1,630	1,671
Normal Weather Reserves (After All Load Control) Above 20 %	MW	-74	-124	204	412	639	456	559	223	457	105
Normal Weather "DLC" Reserve Margin Contribution	%	59.3%	54.4%	41.7%	36.7%	30.8%	31.9%	28,7%	32.3%	27.2%	31.2%

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#### LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY 2000 SERC RATINGS, COGENERATION = 991231 JANUARY 2000 LONG-TERM FORECAST (S000101) Buik Power Sales included in Demand & Energy Forecast

## 2000 Ten-Year Site Plan Analysis * Future Capacity Additions for 20 % RM * No Peaker Retirements

71			WINTER 00/01	WINTER 01/02	WINTER 02/03	WINTER 03/04	WINTER 04/05	WINTER 05/06	WINTER 06/07	WINTER 07/08	WINTER 08/09	WINTER 09/10
			Jan-2001	Jan-2002	Jan-2003	Jan-2004	Jan-2005	Jan-2006	Jan-2007	Jan-2008	Jan-2009	Jan-2010
	Existing FPC Capacity	MW	8,267	8,590	8,607	8,607	9,028	9,028	9,035	9,602	9,602	10,169
	New FPC Capacity	MW	323 1	12	0	667 3	0	12:12:12:45	567 ····	0	; ; 567	132
	Retired FPC Capacity	MW	0	0	Ó	146	0	0		0	0	0
	Total Installed Capacity	MW	8,590	8,607	8,607	9,028	9,028	9,035	9,602	9,602	10,169	10,301
	Firm Purchase Capacity	MW	469	469	469	469	479	479	479	479	479	479
	Firm QF Purchase Capacity	MW	831	831	818	818	818	818	813	798	689	548
	Seasonal Purchase Capacity	мw	0	0	0	D	0	. 0	0	O	o	O
	Capacity on Scheduled Maintenance	MW	0	0	· 0	0	0	0	0	0	0	0
	Firm Sale of Capacity	MW	o	0	o	0	0	0	0	0	0	0
	Total Available Capacity	MW	9,890	9,907	9,894	10,315	10,325	10,332	10,894	10,879	11,337	11.328
	Potential Total Retail Demand	MW	8,468	8,636	8,828	8,997	9,165	9,325	9,483	9,634	9,783	9,933
	Wholesale (REA)	MW	894	911	558	503	525	600	676	755	833	912
	Wholesale (Bulk Power)	MW	632	167	167	167	167	167	167	167	167	167
	Wholesale (Municipal)	MW	205	196	203	206	198	200	203	. 206	209	212
	Total Wholesale Demand	MW	1,731	1,274	928	877	890	968	1,046	1,129	1,210	1,291
	Company Use	MW	30	30	30	30	30	30	30	30	30	30
	Potential Total System Demand	MW	10,229	9,940	9,786	9,904	10,085	10,323	10,559	10,793	11,023	11,254
	Non-Dispatchable DSM and Self-Service QF	MW	444	468	495	523	552	582	613	643	672	701
	Normal Weather Demand (Before Load Control)	MW	. A. 18,745	· 2 · · 9,472	∰	9,381 😨 🕖	9,533	8,741	9,946	10,150	10,351	10,553
	Normal Weather Reserves (Before Load Control)	MW	105	435	603	935	792	592	948	729	986	775
	Normal Weather Reserve Margin (Before Load Control)	<b>%</b>	1.1%	4,6%	6.5%	10.0%	8,3%	6.1%	9.5%	7.2%	9.5%	7.3%
	Normal Weather Load Management	MŴ	833	771	730	707	668	674	661	650	641	632
	Normal Weather Demand (After Load Management)	MW	8,952	8,701	8,561	8,674	8,845	9,067	9,285	9,499	9,710	9,921
	Normal Weather Reserves (After Load Management)	MW	938	1,206	1,333	1,641	1,480	1,265	1,609	1,379	1,627	1,407
	Normal Weather Reserve Margin (After Load Management)	%	10.5%	13.9%	15.6%	18.9%	16.7%	14.0%	17.3%	14.5%	16.8%	14.2%
	Normal Weather Interruptible Load	MW	306	304	328	329	334	337	342	345	348	350
	Normal Weather Voltage Reduction	MW	118	115	113	114	117	120	123	125	128	131
	Normal Weather Demand (After All Load Control)	× MW	8,528	8,282	8,120	8,231	8,394	8,610	8,820	9,029	9,234	9,440
	Normal Weather Reserves (After All Load Control)	MW	1,362	1,625	1,774	2,084	1,931	1,722	2,074	1,849	2,103	1,888
	Normal Weather Reserve Margin (After All Load Control)	- 4	16.0%	19.6%	21.9%	25.3%	23.0%	20.0%	23.5%	20.5%	22.8%	20.0%
Nor	mai Weather Reserves (After All Load Control) Required For 20 %	MW	1,706	1,656	1,624	1,646	1,679	1,722	1,764	1,806	1,847	1,888
	Normal Weather Reserves (After All Load Control) Above 20 %	мw	-344	-32	150	438	252	0	310	44	256	Ð
	Normal Weather "DLC" Reserve Margin Contribution	%	92.3%	73.2%	66.0%	55.2%	59,0%	65.7%	54.3%	60.6%	53.1%	59.0%

Note: Suwannee River Steam Units 1-3 Retired 12/31/2003 Higgins Peakers P1-P4 Retired 12/31/2005 Rio Pinar Peaker P1 Retired 12/31/2005 Avon Park Peakers P1-P2 Retired 12/31/2006 Turner Peakers P1-P2 Retired 12/31/2006

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#### LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY 2000 SERC RATINGS, COGENERATION = 991231 JANUARY 2000 LONG-TERM FORECAST (S000101) Bulk Power Sales included in Demand & Energy Forecast

# 2000 Ten-Year Site Plan Analysis * Future Capacity Additions for 20 % RM * No Peaker Retirements

		SUMMER 00	SUMMER 01	SUMMER 02	SUMMER 03	SUMMER 04	SUMMER 05	SUMMER 06	SUMMER 07	SUMMER 08	SUMMER 09
		Aug-2000	Aug-2001	Aug-2002	Aug-2003	Aug-2004	Aug-2005	Aug-2006	Aug-2007	Aug-2008	Aug-2009
Existing FPC Capacity	MW	7,553	7,553	7,817	7,834	7,834	8,185	8,186	8,185	8,681	8,681
New FPC Capacity	MW	0	264	17	o	485	0	0	495	0	495
Retired FPC Capacity	MW	. 0	0	0	0	143	0	0	0	0	.0
Total Installed Capacity	MW	7,553	7,817	7,834	7,834	8,186	8,186	8,186	8,681	8,681	9,176
Firm Purchase Capacity	MW	469	469	469	469	469	479	479	479	479	479
Firm QF Purchase Capacity	MW	831	831	818	818	818	818	818	813	798	689
Seasonal Purchase Capacity	MW	0	.0	0	0	0	0	0 .	O	0	0
Capacity on Scheduled Maintenance	MW	0	a	0	0	G	0	0	0	0	O
Firm Sale of Capacity	мw	0	0	0	0	0	0	0	0	0	0
Total Available Capacity	MW	8,853	9,117	9,121	9,121	9,473	9,483	9,483	9,973	9,958	10,344
Potential Total Retail Demand	MW	7,326	7,467	7,621	7,801	7,956	8,111	8,259	8,403	8,543	8,683
Wholesale (REA)	MW	392	489	490	121	48	54	112	171	231	291
Wholesale (Bulk Power)	MW	632	632	167	167	167	167	167	167	167	167
Wholesale (Municipal)	MW	253	222	209	218	221	211	214	217	220	223
Total Wholesale Demand	MW	1,277	1,343	867	506	436	433	493	555	618	681
Company Use	MW	30	30	30	30	30	30	30	30	30	30
Potential Total System Demand	wм	8,633	8,840	8,518	8,337	8,422	8,574	8,782	8,988	9,191	9,394
Non-Dispatchable DSM and Self-Service QF	MW	355	368	381	395	410	425	441	456	471	486
Normal Weather Demand (Before Load Control)	MW	0,278	8,472	6,137,	7,942	8,012	8,149	8,341	8,532	8,720	8,908
Normal Weather Reserves (Before Load Control)	MW	575	645	985	1,179	1,461	1,335	1,142	1,441	1,237	1,435
Normal Weather Reserve Margin (Before Load Control)	%	8.9% si	7.6%	12.1%	14.8%	18.2%	16.4%	13.7%	16.9%	14.2%	16.1%
Normal Weather Load Management	мw	512	463	400	356	322	291	265	242	222	205
Normal Weather Demand (After Load Management)	MW	7,766	8,009	7,736	7,586	7,690	7,857	8,076	8,290	8,498	8,703
Normal Weather Reserves (After Load Management)	MW	1,087	1,108	1,385	1,536	1,783	1,626	1,407	1,683	1,460	1,640
Normal Weather Reserve Margin (After Load Management)	%	14.0%	13.8%	17.9%	20.2%	23.2%	20.7%	17.4%	20.3%	17.2%	18.8%
Normal Weather Interruptible Load	MW	327	308	305	328	329	335	339	343	346	1 349
Normal Weather Voltage Reduction	MW	0	0	0	0	0	0	0	0	0	0
Normal Weather Demand (After All Load Control)	MW	- <b>7,439</b> 🔨	7,701	7,431	7,258	7,361	7,522	. 7,737	7,947	8,152	8,354
Normal Weather Reserves (After All Load Control)	MW	1,414	1,416	1,690	1,864	2,112	1,961	1,746	2,026	1,806	1,989
Normal Weather Reserve Margin (After All Load Control)	%	19.0%	18.4%	22.7%	25.7%	28.7%	26.1%	22.6%	25.5%	22.1%	23.8%
Normal Weather Reserves (After All Load Control) Required For 20 %	MW	1,488	1,540	1,486	1,452	1,472	1,504	1,547	1,589	1,630	1,671
Normal Weather Reserves (After All Load Control) Above 20 %	MW	-74	-124	204	412	639	456	199	436	175	318
Normal Weather "DLC" Reserve Margin Contribution	%	59.3%	54.4%	41.7%	36.7%	30.8%	31.9%	34.6%	28.9%	31.5%	27.8%

#### LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY 2000 SERC RATINGS, COGENERATION = 991231 JANUARY 2000 LONG-TERM FORECAST (S000101) Builk Power Sales Included in Demand & Energy Forecast

## 2000 Ten-Year Site Plan Analysis * Without Future Capacity Additions for 20 % RM * With Retirements

[		WINTER 00/01	WINTER 01/02	WINTER 02/03	WINTER 03/04	WINTER 04/05	WINTER 05/06	WINTER 06/07	WINTER 07/08	WINTER 08/09	WINTER 09/10
		Jan-2001	Jan-2002	Jan-2003	Jan-2004	Jan-2005	Jan-2006	Jan-2007	Jan-2008	Jan-2009	Jan-2010
Existing FPC Capacity	MW	8,267	8,590	8,607	8,607	8,461	8,461	8,311	8,215	8,215	B,215
New FPC Capacity	MW	323 W	17 17 18	0	· · · · · · · · · · · · · · · · · · ·	0	0	0	0	0	0
Retired FPC Capacity	MW	0	0	0	146	0	150	96	0	0	0
Total Installed Capacity	MW	8,590	8,607	8,607	8,461	8,461	8,311	8,215	8,215	8,215	8,215
Firm Purchase Capacity	MW	469	469	469	469	479	479	479	479	479	479
Firm QF Purchase Capacity	MW	831	831	818	818	818	818	813	798	689	548
Seasonal Purchase Capacity	MW	0	0	<b>0</b>	0	o	0	0	0	0	0
Capacity on Scheduled Maintenance	MW	. 0	0	0	0	0	0	0	0	0	Û
Firm Sale of Capacity	MW	0	0	0	0	0	0	0	0	0	Ó
Total Available Capacity	MW	9,890	9,907	9,894	9,748	9,758	9,608	9,507	9,492	9,383	9,242
Potential Total Retail Demand	MW	8,468	8,636	8,828	8,997	9,165	9,325	9,483	9,634	9,783	9,933
Wholesate (REA)	MW	894	911	558	503	525	600	676	755	, 833	912
Wholesale (Bulk Power)	MW	632	167	167	167	167	167	167	167	167	167
Wholesale (Municipal)	MW	205	196	203	206	198	200	203	206	209	212
Total Wholesale Demand	мw	1,731	1,274	928	877	890	968	1,046	1,129	1,210	1,291
Company Use	MW	30	30	30	30	30	30	30	30	30	30
Potential Total System Demand	MW	10,229	9,940	9,786	9,904	10,085	10,323	10,559	10,793	11,023	11,254
Non-Dispatchable DSM and Self-Service QF	MW	444	468	495	523	552	582	613	643	672	701
Normal Weather Demand (Before Load Control)	X MW	9,785	9,472	9,291	9,381	9,533	9,741	9,946	10,150	10,351	10,553
Normal Weather Reserves (Before Load Control)	MW	. 105	435	603	368	225	-132	-440	-658	-968	-1,311
Normal Weather Reserve Margin (Before Load Control)	. %	1.1%	4.5%	6.5%	3.9%	2.4%	1.4%	-4.4%	-6.5%	-9.4%	-12.4%
Normal Weather Load Management	MW	833	771	730	707	688	674	661	650	641	632
Normal Weather Demand (After Load Management)	MW	8,952	8,701	8,561	8,674	8,845	9,067	9,285	9,499	9,710	9,921
Normal Weather Reserves (After Load Management)	MW	938	1,206	1,333	1,074	913	541	222	-8	-327	-679
Normal Weather Reserve Margin (After Load Management)	%	10.5%	13.9%	15.6%	12.4%	10.3%	6.0%	2.4%	-0.1%	-3.4%	-6.8%
Normal Weather Interruptible Load	MW	306	304	328	329	334	337	342	345	348	350
Normal Weather Voltage Reduction	MW	118	115	113	114	117	120	123	125	128	131
Normal Weather Demand (After All Load Control)	MW	8,528	8,282	8,120	8,231	8,394	8,610	8,820	9,029	9,234	9,440
Normal Weather Reserves (After All Load Control)	MW	1,362	1,625	1,774	1,517	1,364	998	687	462	149	-198
Normal Weather Reserve Margin (After All Load Control).	%	16.0%	19.6%	21.9%	18.4%	16.3%	11.6%	7.8%	5.1%	1.6%	-2.1%
Normal Weather Reserves (After All Load Control) Required For 20 %	MW	1,706	1,656	1,624	1,646	1,679	1,722	1,764	1,806	1,847	1,888
Normal Weather Reserves (After All Load Control) Above 20 %	MW	-344	-32	150	<b>-129</b>	-315	-724	-1,077	-1,343	-1,698	-2,086
Normal Weather "DLC" Reserve Margin Contribution	%	92.3%	73.2%	66.0%	75.8%	83.5%	113.3%	164.0%	242.3%	751.2%	-562.0%

Note: Suwannee River Steam Units 1-3 Retired 12/31/2003 Higgins Peakers P1-P4 Retired 12/31/2005 Rio Pinar Peaker P1 Retired 12/31/2005 Avon Park Peakers P1-P2 Retired 12/31/2006 Turner Peakers P1-P2 Retired 12/31/2006

#### LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY 2000 SERC RATINGS, COGENERATION = 991231 JANUARY 2000 LONG-TERM FORECAST (S000101) Bulk Power Sales Included in Demand & Energy Forecast

# 2000 Ten-Year Site Plan Analysis * Without Future Capacity Additions for 20 % RM * With Retirements

	<del>, ````````````````````````````````````</del>	SUMMER 00	SUMMER 01	SUMMER 02	SUMMER 03	SUMMER 04	SUMMER 05	SUMMER 06	SUMMER 07	SUMMER 08	SUMMER 09
		Aug-2000	Aug-2001	Aug-2002	Aug-2003	Aug-2004	Aug-2005	Aug-2006	Aug-2007	Aug-2008	Aug-2009
Existing FPC Capacity	MW	7,553	7,553	7,817	7,834	7,834	7,691	7,691	7,556	7,478	7,478
New FPC Capacity	MW	0	264., 104	2. S. 17 . S. N	0		O	0	0	0	D
Retired FPC Capacity	MW .	0	0	. Ö	0	1, 2, 143	0	135	78	0	0
Total Installed Capacity	MW	7,553	7,817	7,834	7,834	7,691	7,691	7,556	7,478	7,478	7,478
Firm Purchase Capacity	MW	469	469	469	469	469	479	479	479	479	479
Firm QF Purchase Capacity	MW	.831	831	818	818	818	818	818	813	798	689
Seasonal Purchase Capacity	MW	O	0	0	0	0	0	0	0	0	0
Capacity on Scheduled Maintenance	MW	Ö	0	0	0	0	0	0	0	0	0
Firm Sale of Capacity	MW	0	Ô	0	0	0	0	0	0	0	0
Total Available Capacity	MW	8,853	9,117	9,121	9,121	8,978	8,988	8,853	8,770	8,755	8,546
Potential Total Retail Demand	MW	7,326	7,467	7,621	7,801	7,956	8,111	8,259	8,403	8,543	8,683
Wholesale (REA)	MW	392	489	490	121	48	54	112	171	, 231	291
Wholesale (Bulk Power)	MW	632	632	167	167	167	167	167	167	167	167
Wholesale (Municipal)	MW	253	222	209	218	221	211	214	217	220	223
Total Wholesale Demand	MW	1,277	1,343	867	506	436	433	493	555	618	681
Company Use	MW	30	30	30	30	30	30	30	30	30	30
Potential Total System Demand	MW	8,633	8,840	8,518	8,337	8,422	8,574	8,782	8,988	9,191	9,394
Non-Dispatchable DSM and Self-Service QF	MW	355	368	381	395	410	425	441	456	471	486
Normal Weather Demand (Before Load Control)		8,274	8.10 8,472	<b>8,137</b>	7,942	8,0121	8,149 \	8,341	8,532	8,720	8,908
<ul> <li>Normal Weather Reserves (Before Load Control)</li> </ul>	MW	575	645	985	1,179	966	840	512	238	34	-263
Normal Weather Reserve Margin: (Before Load Control)	<b>*</b>	6.9%	7.6%	12.1%	14.8%	12.1%	10.3%	6.1%	2.8%	0.4%	-3.0%
Normal Weather Load Management	MW	512	463	400	356	322	291	265	242	222	205
Normal Weather Demand (After Load Management)	MW	7,766	8,009	7,736	7,586	7,690	7,857	8,076	8,290	8,498	8,703
Normal Weather Reserves (After Load Management)	MW	1,087	1,108	1,365	1,536	1,288	1,131	777	480	257	-58
Normal Weather Reserve Margin (After Load Management)	%	14.0%	13.8%	17.9%	20.2%	16.7%	14.4%	9.6%	5.8%	3.0%	-0.7%
Normal Weather Interruptible Load	MW	327	308	305	328	329	335	339	343	346	349
Normal Weather Voltage Reduction	MW	<u> </u>	0	0	0	0	0	0	0	0	0
Normal Weather Demand (After All Load Control)	MW .	7,439	1	. 7,431	7,258	S 7,361	7,522	7,737	7,947	8,152	8,354
Normal Weather Reserves (After All Load Control)	MW	1,414	1,416	1,690	1,864	1,617	1,466	1,116	823	603	291
Normal Weather Reserve Margin (After All Load Control)	1 S 🗧 🐐	19,0%	18.4%	5 <b>22.7%</b> v	25.7%	22.0%	19.5%	14.4%	10.4%	7.4%	3.5%
Normal Weather Reserves (After All Load Control) Required For 20	% MW	1,488	<b>1,540</b>	1,486	1,452	1,472	1,504	1,547	1,589	1,630	1,671
Normal Weather Reserves (After All Load Control) Above 20 %	MW	-74	-124	204	412	144	-39	-431	-767	-1.028	-1,380
Normal Weather "DLC" Reserve Margin Contribution	%	59.3%	54.4%	41.7%	36.7%	40.2%	42.7%	54.1%	71.1%	94.3%	190.3%

#### LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY 2000 SERC RATINGS, COGENERATION = 991231 JANUARY 2000 LONG-TERM FORECAST (S000101) Bulk Power Sales included in Demand & Energy Forecast

# 2000 Ten-Year Site Plan Analysis * Without Future Capacity Additions for 20 % RM * No Retirements

			WINTER 00/01	WINTER 01/02	WINTER 02/03	WINTER 03/04	WINTER 04/05	WINTER 05/06	WINTER 06/07	WINTER 07/08	WINTER 08/09	WINTER 09/10
1			Jan-2001	Jan-2002	Jan-2003	Jan-2004	Jan-2005	Jan-2006	Jan-2007	Jan-2008	Jan-2009	Jan-2010
	Existing EPC Capacity	MW	8.267	8,590	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607
	New FPC Capacity	MW	J / 323 (	17. 17. 2011	0	N42 140:07	ឹច	8 Ot	0	\$331 Q C	0	0
	Retired FPC Capacity	MW	0	0	0	0	0	0	0	0	0	0
	Total installed Capacity	MW	8,590	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607
	Firm Purchase Capacity	MW	469	469	469	469	479	479	479	479	479	479
	Firm OF Purchase Capacity	MW	831	831	818	818	818	818	813	798	689	548
	Seasonal Purchase Capacity	MW	0	0	0	σ	0	D	0	0	0	0
	Capacity on Scheduled Maintenance	MW	C C	o	0	0	o	0	0	0	0	D
	Firm Sale of Capacity	мw	0	0	0	0	0	0	σ	Ð	0	0
	Total Available Capacity	MW	9,890	9,907	9,894	9,894	9,904	9,904	9,899	9,884	9,775	9,634
	Potential Total Retail Demand	MW	8,468	8,636	8,828	8,997	9,165	9,325	9,483	9,634	9,783	9,933
	Wholesale (REA)	MW	894	911	558	503	525	600	676	755	833	912
	Wholesale (Bulk Power)	MW	632	167	167	167	167	167	167	167	167	167
	Wholesale (Municipal)	MW	205	196	203	206	198	200	203	206	209	212
	Total Wholesale Demand	MW	1,731	1,274	928	877	890	968	1,046	1,129	1,210	1,291
	Company Use	MW	30	30	30	30	30	30	30	30	30	30
	Potential Total System Demand	MW	10,229	9,940	9,786	9,904	10,085	10,323	10,559	10,793	11,023	11,254
	Non-Dispatchable DSM and Self-Service QF	MW	444	468	495	523	552	582	613	643	672	701
	Normal Weather Demand (Before Load Control)	MW	9,785	9,472	8,291	<b>9,381</b>	9,533	9,741	9,946	10,150	10,351	10,553
	Normal Weather Reserves (Before Load Control)	MW	105	435	603	514	371 	164	-48 	-266 2000 - 1 - 2000 - 2000 - 2000 - 2000 - 2000 - 2000 - 2000 - 2000 - 2000 - 2000 - 2000 - 2000 - 2000 - 2000 - 20	-576	-919
:	Normal Weather Reserve Margin (Before Load Control)	÷ %	1.1%	4.6%	Sec. 5%	5.5%	3.9%	· 3. ( 17% · · ·		-2,6%	-5.6%	-8.1%
	Normal Weather Load Management	MW	833	771	730	707	688	674	661	650	641	632
	Normal Weather Demand (After Load Management)	MW	8,952	8,701	8,561	8,674	8,845	9,067	9,285	9,499	9,710	9,921
	Normal Weather Reserves (After Load Management)	MW	938	1,206	1,333	1,220	1,059	837	614	384	65	-287
	Normal Weather Reserve Margin (After Load Management)	%	10.5%	13.9%	15.6%	14.1%	12.0%	9.2%	6.6%	4.0%	0.7%	-2.9%
	Normal Weather Interruptible Load	MW	306	304	328	329	334	337	342	345	348	350
	Normal Weather Voltage Reduction	MW	118	115	113	114	117	120	123	125	128	131
	Normal Weather Demand (After All Load Control)	MW	8,528	8,282	8,120	8,231	.8 <b>,394</b> (5	8,610	8,820	9,029	9,234	9,440
	Normal Weather Reserves (After All Load Control)	MW	1,362	1,625	1,774	1,663	1,510	1,294	1,079	854	541	194
.	Normal Weather Reserve Margin (After All Load Control)	%	16.0%	19.6%	21.9%	20.2%	18.0%	15.0%	12.2%	9.5%	5.9%	2.1%
Nor	rmal Weather Reserves (After All Load Control) Required For 20 %	MW	1,706	1,656	1,624	1,646	1,679	1,722	1,764	1,806	1,847	1,888
	Normal Weather Reserves (After Ali Load Control) Above 20 %	MW	-344	-32	150	17	-169	-428	-685	-951	-1,306	-1,694
	Normal Weather "DLC" Reserve Margin Contribution	%	92.3%	73.2%	66.0%	69.1%	75.4%	87.4%	104.4%	131.1%	206.6%	5/4.1%

Note: Suwannee River Steam Units 1-3 Retired 12/31/2003 Higgins Peakers P1-P4 Retired 12/31/2005 Rio Pinar Peaker P1 Retired 12/31/2005

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Avon Park Peakers P1-P2 Retired 12/31/2006 Turner Peakers P1-P2 Retired 12/31/2006

FPC 079
#### LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY 2000 SERC RATINGS, COGENERATION = 991231 JANUARY 2000 LONG-TERM FORECAST (\$000101) Bulk Power Sales included in Demand & Energy Forecast

# 2000 Ten-Year Site Plan Analysis * Without Future Capacity Additions for 20 % RM * No Retirements

			STIMMED 04	SUMMER 02	SUMMER 03	SUMMER 04	SUMMER 05	SUMMER 06	SUMMER 07	SUMMER 08	SUMMER 09
		Aun-2000	Aug-2001	Aug-2002	Aug-2003	Aug-2004	Aug-2005	Aug-2006	Aug-2007	Aug-2008	Aug-2009
	N/14/	7 653	7 553	7.817	7.834	7,834	7,834	7,834	7,834	7,834	7,834
Existing FPC Capacity	MUN MUN	7,555	294		0	0	0	Last Voide A	0	o o	0
New FPC Capacity	10100 B.65A/		- 6040348:#270-222227 - 0	alaasa ni taataa G	O	ANS: 0 1014	o	0	· · · · · · · · · · · · · · · · · · ·	0	0
Rebred FPC Capacity	1VIVV	7 553	7 817	7 834	7.834	7.834	7,834	7,834	7,834	7,834	7,834
Total Installed Capacity	MAA	7,555	460	469	469	469	479	479	479	479	479
Firm Purchase Capacity	MVV	409	403	818	818	818	818	818	813	798	689
Firm QF Purchase Capacity	MW	631	031	0	0	0	0	٥	0	0	0
Seasonal Purchase Capacity	MVV	U	0	0	ň	· 0	0	0	0	D	o
Capacity on Scheduled Maintenance	MVV	0	0	0	ů		. 0	0	0	0	0
Firm Sale of Capacity	MVV	0	0 447	0 101	G 121	9.121	9,131	9,131	9,126	9,111	9,002
Total Available Capacity	MVV	8,853	9,111	7 624	7 805	7 956	8.111	8.259	8,403	8,543	8,683
Potential Total Retail Demand	MVV	7,326	1,401	400	121	48	- 54	112	171	231	291
Wholesale (REA)	MIN	392	409	450	167	167	167	167	167	167	167
Wholesale (Bulk Power)	WW	632	032	200	218	221	211	214	217	220	223
Wholesale (Municipal)	MW	253	222	203	506	436	433	493	555	618	681
Total Wholesale Demand	MW	1,277	1,343	30	30	30	30	30	30	30	30
Company Use	MW	30	30	30	9 3 3 7	8 4 2 2	8.574	8.782	8,988	9,191	9,394
Potential Total System Demand	MW	8,633	8,640	0,010	205	410	425	441	456	471	486
Non-Dispatchable DSM and Self-Service QF	MW MV	355	368	0 6 9 7	2 942	. 012	8 149	8.341	8.532	8,720	8,908
Normal Weather Demand (Before Load Control):	77838-222 MW	8,2/8	SUN AS <b>NO NO N</b> O NO	~~ q,1⇒/ ∩DE	1 170	4 100	983	790	594	390	93
Normal Weather Reserves (Before Load Control)	<b>MW</b> National States of the States	5/5 121-22-27	640	903	44.95	1100	12.1%	9.5%	7.0%	4.5%	1.0%
Normal Weather Reserve Margin (Before Load Contr	ol)	6.9%	X 1 . X . X . 8 / / / /	12.1%		200 · · · · · · · · · · · · · · · · · ·	201	265	242	222	205
Normal Weather Load Management	MW	512	463	400	300	7 600	7 957	8.075	8 290	8,498	8,703
Normal Weather Demand (After Load Management)	MW	7,766	8,009	7,736	1,500	1,030	1,007	1.055	836	613	298
Normal Weather Reserves (After Load Management)	· MW	1,087	1,108	1,385	1,535	1,431	1,214	13.1%	10.1%	7.2%	3.4%
Normal Weather Reserve Margin (After Load Manageme	ent) %	14.0%	13.8%	17.9%	20.2%	10.0%	10.274	10.17	343	346	349
Normal Weather Interruptible Load	MW	327	306	305	328	329	330	339	0	0	0
Normal Weather Voltage Reduction	MW	9	0	<u>,                                     </u>	0				7 847	8 152	8.354
Normal Weather Demand (After All Load Control)	e and Ma	7,439	7,701	7,431	7,258	Six 7,261	1,522	~~	1 170	0,00	647
Normal Weather Reserves (After All Load Control)	MV	1,414	1,416	1,690	1,864	1,760	1,609	1,394	1,113	44 9%	7 7%
Normal Weather Reserve Margin (After All Load Con	trol) %	19.0%	18.4%	22.7%	25,7%	23.9%	21.4%	0. 18.0%	14.8%	1.070	1.871
Normal Weather Reserves (After All Load Control) Required	Far 20 % MW	t,488	1,540	1,486	1,452	1,472	1,504	1,547	1,589	1,000	-1 024
Normal Weather Reserves (After All Load Control) Above	20 % MV	-74	-124	204	412	287	104	-153	-411	-0/2	85.6%
Normal Weather "DLC" Reserve Margin Contribution	%	59.3%	54.4%	417%	36.7%	37.0%	38.9%	43.3%	49.0%	03,376	00.078

7'19/07 @ 12 18 PM

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#### LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY 1998 SERC RATINGS, COGENERATION = 981231 JANUARY 1999 LONG-TERM FORECAST (S981208) Bulk Power Sales (GPC, OPC, SECI & MEAG) included in Demand & Energy Forecast

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### 1999 Ten-Year Site Plan

	w	INTER 99/00	WINTER 00/01	WINTER 01/02	WINTER 02/03	WINTER 03/04	WINTER 04/05	WINTER 05/08	WINTER 06/07	WINTER 07/08
		Jan-2000	Jan-2001	Jan-2002	Jan-2003	Jan-2004	Jan-2005	Jan-2006	Jan-2007	Jan-2008
Existing FPC Canacity	MW	8,265	8,306	8,620	8,473	8,473	8,307	8,774	8,774	9,341
New EPC Capacity	MW	0	297. 4.	Ð	່ບໍ່	0	667	0	567	0
Retired EPC Canarity	MW	0	0	SAT 15	0	168	100	0	D	0
Total installed Capacity	MW	8,265	8,603	8,473	8,473	8,307	8,774	8,774	9,341	9,341
Firm Purchase Canacity	MW	469	469	469	469	469	479	479	479	479
Firm OF Purchase Capacity	MW	831	831	831	831	831	831	831	831	831
Seasonal Purchase Capacity	MW	0	0	D	0	0	0	0	0	0
Capacity on Scheduled Mainlenance	MW	D	0	0	0	0	O	σ	D	0
Firm Sale of Canacity	MW	0	0	0	O	0	0	G	0	0
Total Available Capacity	MW	9,565	9,903	9,773	9,773	9,607	10,084	10,084	10,651	10,651
Potential Total Retail Demand	MW	8,330	8,488	8,654	8,823	8,985	9,150	9,314	9,479	9,644
Wholesale (REA)	.MW	754	866	936	537	481	554	630	705	783
Wholesale (Buik Power)	MW .	605	605	150	a	0	0	0	٥	0
Wholesale (Municipal)	MW	216	197	180	183	185	174	176	178	, 180
Total Wholesale Demand	MW	1,575	1,668	1,266	720	666	728	806	883	963
Company Use	MW	30	30	30	30	30	30	30	30	30
Potential Total System Demand	MW	9,935	10,186	9,950	9,573	9,681	9,908	10,150	10,392	10,637
Non-Dispatchable DSM and Self-Service QF	MW	399	424	450	478	508	538	569	599	628
Normal Weather Demand (Before Load Control)	MW	9,536		9,500		9,473	9,370	9,581	9,793	10,008
Normal Weather Reserves (Before Load Control)	MW	29	141	273	678	434	714	503	858	642
Normal Weather Reserve Margin (Before Load Control)	· %	0.3%	14%	2.9%	7.5%	e : : : : : : : : : : : : : : : : : : :	7,6%	5.2%	8.8%	6.4%
Normal Weather Load Management	MŴ	889	886	817	773	746	726	709	694	582
Normal Weather Demand (After Load Management)	MW	8,647	8,876	8,683	8,322	8,427	8,644	8,872	9,099	9,327
Normal Weather Reserves (After Load Management)	MW	918	1,027	1,090	1,451	1,180	1,440	1,212	1,552	1,324
Normal Weather Reserve Margin (After Load Management)	%	10.6%	11.6%	12.6%	17.4%	14.0%	16.7%	13.7%	17.1%	14.2%
Normal Weather Interruptible Load	MW	312	300	297	299	296	298	300	302	304
Normat Weather Voltage Reduction	MW	114	117	115	110	111	114	117	120	123
Normal Weather Demand (After All Load Control)	MW	8,221	8,459	6,271	7,913	8,020	0,232	8,455	8,677	8,900
Normal Weather Reserves (After All Load Control)	MW	1,344	1.444	1,502	1,860	1,587	1,852	1,629	1,974	1,751
Normal Weather Reserve Margin (After All Load Control)	- <b>X</b>	16:3%		18.2%	23,5%	19.8%	22.5%	19.3%	22.7%	19.7%
Normal Weather Reserves (After All Load Control) Required For 15 %	MW	1,233	1,269	1,241	1,187	1,203	1,235	1,268	1,302	1,335
Normal Weather Reserves (After All Load Control) Above 15 %	MW	111	175	261	673	384	617	361	672	416
Normal Weather "DLC" Reserve Margin Contribution	%	97.8%	90.2%	81.8%	63.5%	72.7%	61.4%	69 1%	56.5%	63.3%

FPC 081

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#### LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY 1998 SERC RATINGS, COGENERATION = 981231 JANUARY 1999 LONG-TERM FORECAST (S981208) Bulk Power Sales (GPC, OPC, SECI & MEAG) included in Demand & Energy Forecast

### 1999 Ten-Year Site Plan

		SUMMER 00	SUMMER 01	SUMMER 02	SUMMER 03	SUMMER 04	SUMMER 05	SUMMER 05	SUMMER 07	SUMMER 08
		Aug-2000	Aug-2001	Aug-2002	Aug-2003	Aug-2004	Aug-2005	Aug-2006	Aug-2007	Aug-2008
Existing FPC Capacity	MW	7,510	7,510	7,776	7,631	7,631	7,488	7,695	7,895	8,390
New FPC Capacity	MW	0	249	0	0.	• 0	495	0	495	0
Retired FPC Capacity	MW	a	0	145	0	143-5 143	88	0	0	0
Total Installed Capacity	MW	7,510	7,759	7,631	7,631	7,488	7,895	7,895	8,390	8,390
Firm Purchase Capacity	MW	469	469	469	469	469	479	479	479	479
Firm QF Purchase Capacity	MW	831	831	831	831	. 831	831	831	831	831
Seasonal Purchase Capacity	MW	0	. 0	D	0	0	0	0	0	0
Capacity on Scheduled Maintenance	MW	0	0	0	0	0	0	Q	0	0
Firm Sale of Capacity	MW	0	0	0 .	0	0	0	· 0 ·	D	0
Total Available Capacity	MW	8,810	9,059	8,931	8,931	8,788	9,205	9,205	9,700	9,700
Potential Total Retail Demand	MW	7,396	7,555	7,721	7,890	8,052	8,218	8,384	8,551	8,717
Wholesale (REA)	MW	366	460	514	88	25	82	140	199	259
Wholesale (Bulk Power)	MW	605	605	150	0	0	0	0	Q	U
Wholesale (Municipal)	MW	226	211	190	191	194	163	185	189	192
Total Wholesale Demand	MW	1,197	1,276	854	289	219	265	325	388	451
Company Use	MW	30	30	30	30	30	30	30	30	30
Potential Total System Demand	MW	8,623	8,861	8,605	8,209	8,301	8,513	8,739	8,969	9,198
Non-Dispatchable DSM and Self-Service QF	MW	353	366	379	393	408	423	439	454	468
Normal Weather Demand (Before Load Control)	. 2 MW	B 270	8,495	8,228	7,816	₹ <b>7,893</b>	8,090	<b> 6,300</b>	8,515	8,730
Normal Weather Reserves (Before Load Control)	MW	- 540	564	705	1,115	895	1,115	905	1,185	970
Normal Weather Reserve Margin (Before Load Control)	14	6.5%	6.6%	8.6%	14.14.3%	11.3%	13.8%	10.8%	13.9%	11.1%
Normal Weather Load Management	. MW	498	453	394	353	321	293	269	248	230
Normal Weather Demand (After Load Management)	MW	7,772	8,042	7,832	7,463	7,572	7,797	8,031	8,267	8,500
Normal Weather Reserves (After Load Management)	MW	1,038	1,017	1,099	1,468	1,216	1,408	1,174	1,433	1,200
Normal Weather Reserve Margin (After Load Management)	%	13.4%	12.6%	14.0%	19.7%	16.1%	18.1%	14.6%	17.3%	14.1%
Normal Weather Interruptible Load	MW	313	301	298	300	297	299	301	303	305
Normal Weather Voltage Reduction	MW	0	0	0	0	0	00	0	0	0
Normal Weather Demand (After All Load Control)	MW .	7.459	7,741	7,534	7,163	7,275	7,498	7,730	7,964	8,195
Normal Weather Reserves (After All Load Control)	MW	1,351	1,318	1,397	1,768	1,513	1,707	1,475	1,736	1,505
Normal Weather Reserve Margin (After All Load Control)	. 1	18.1%	17.0%	18.5%	24.7%	20.8%	22,8%	19.1%	21.8%	18.4%
Normal Weather Reserves (After All Load Control) Required For 20 %	WM	1,492	1,548	1,507	1,433	1,455	1,500	1,546	1,593	1,639
Normat Weather Reserves (After All Load Control) Above 20 %	MW	-141	-230	-110	335	58	207	-71	143	-134
Normal Weather "DLC" Reserve Margin Contribution	%	60.0%	57.2%	49.5%	36.9%	40.8%	34.7%	38.6%	31.7%	35.5%

FPC 082

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#### LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY

### 2000 TYSP (DRAFT) vs. 1999 TYSP

	WINTER 99/00	WINTER 00/01	WINTER 01/02	WINTER 02/03	WINTER 03/04	WINTER 04/05	WINTER 05/06	WINTER 06/07	WINTER 07/08
	Jan-2000	Jan-2001	Jan-2002	Jan-2003	Jan-2004	Jan-2005	Jan-2006	Jan-2007	Jan-2008
Existing FPC Capacity MV	/ #REFI	-39	-30	134	134	721	254	671	8
New FPC Capacity MV	#REF!	26	17	0	567	-567	567	-567	567
Retired FPC Capacity MV	/ #REFI	0	-147	0 *	-20	-100	150	96	o
Total Installed Capacity MV	/ #REFI	-13	134	134	721	254	671	8	575
Firm Purchase Capacity MV	/ #REFI	0	0	O	0	0	0	0	0
Firm QF Purchase Capacity MV	#REFI	0	0	-13	-13	-13	-13	-18	-33
Seasonal Purchase Capacity M	/ #REFi	ο.	0	0	0	D	0	0	0
Capacity on Scheduled Maintenance MV	/ #REFI	0	0	0	0	0	0	0	O
Firm Sale of Capacity MN	#REFI	0	0	0	0	0	O	D	0
Total Available Capacity MI	V #REF!	-13	134	121	708	241	658	-10	542
Potential Total Retail Demand Mi	V #REF!	-20	-18	5	12	15	11	4	-10
Wholesale (REA) MI	V #REF!	28	-25	21	22	-29	-30	-29	-28
Wholesale (Bulk Power) Mi	V #REF!	27	17	167	167	167	167	167	167
Wholesale (Municipal) M	V #REF!	8	16	20	21	24	24	25	26
Total Wholesale Demand Mi	V #REF!	63	8	208	211	162	162	163	166
Company Use M	V #REFI	0	0	0	0	0	0	0	σ
Potential Total System Demand M	V #REFI	43	-10	213	223	177	173	167	156
Non-Dispatchable DSM and Self-Service QF M	V #REF!	20	18	17 .	15	14	13	14	15
Normal Weather Demand (Before Load Conirol)	V REFL.	21	<b>-28</b> (A.S.)	198	208		180	153	141
Normal Weather Reserves (Before Load Control) M	v #REFI	-36	162	-75	501	78	. 499	-164	401
Normal Weather Reserve Margin (Befdre Load Control)	Titles PREFI St	-0.4%	1.7%	6-1.0% US	8.2%	0.7%	5.0%	-1.8%	3.9%
Normal Weather Load Management M	V #REF!	-53	-46	-43	-39	-38	-35	-33	-32
Normal Weather Demand (After Load Management) M	V #REF!	76	18	239	247	201	195	186	172
Normal Weather Reserves (After Load Management) M	V #REF!	-89	116	-118	461	40	463	-196	369
Normal Weather Reserve Margin (After Load Management) 9	#REFI	-1.1%	1.3%	-1.9%	4.9%	0.1%	4.8%	-2.5%	3.6%
Normal Weather Interruptible Load M	V #REF!	6	7	29	33	36	37	40	41
Normal Weather Voltage Reduction M	V #REFI	1	0	3	3	3	3		2
Normal Weather Demand (After All Load Control)	Y CON FRET	3 69	11	3	211	162	155	143	129
Normal Weather Reserves (After All Load Control) M	N #REFI	-82	123	-86	497	79	503	-153	412
Normal Weather Reserve Margin (After All Load Control)	#REFI	() -11% ()	1.5%	··· 1.4	5.5%	0.5%	5.5%	-2.1%	4.3%
Normal Weather "DLC" Reserve Margin Contribution	#REF!	2.1%	-8.6%	2.5%	-17.5%	-2.4%	-16.1%	5.3%	-11.5%

FPC 083

### LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY

### 2000 TYSP (DRAFT) vs. 1999 TYSP

		SUMMER 00	SUMMER 01	SUMMER 02	SUMMER 03	SUMMER 04	SUMMER 05	SUMMER 06	SUMMER 07	SUMMER 08
Existing FPC Capacity	MW	43	43	A1	203	202	AUg-2005	AUG-2006	Aug-2007	Aug-2008
New FPC Capacity	MW	0	15	17	0	405	-495	405	405	70
Retired FPC Capacity	MW	0	0	-145	0 4		-88	135	-485	495
Total Installed Capacity	MW	43	58	203	203	698	201	651	78	E73
Firm Purchase Capacity	MW	0	0	0	200	0	201	0	10	0
Firm QF Purchase Capacity	MW	0		-13	-13	-13	-13	-13	-18	33
Seasonal Purchase Capacity	мw	O	0	0	0	0	0	-15	0	
Capacity on Scheduled Maintenance	MW	0	0	0	0	0	0	0	0	0
Firm Sale of Capacity	мw	D	D	0	0	0	0	ů.	0	0
Total Available Capacity	MW	43	58	190	190	685	278	638	60	540
Potential Total Retail Demand	MW	-70	-88	-100	-89	-96	-107	•125	-148	-174
Wholesale (REA)	MW	26	29	-24	23	23	-28	-28	-28	-28
Wholesale (Bulk Power)	MW	27	27	17	167	167	167	167	167	167
Wholesale (Municipal)	мw	27	11	19	27	27	28	29	28	28
Total Wholesale Demand	MW	80	67	13	217	217	168	168	167	167
Company Use	MW	0	0	O	0	ο	0	0	0	0
Potential Total System Demand	MW	10	-21	-87	128	121	61	43	19	-7
Non-Dispatchable DSM and Self-Service QF	MW	2	22	2	2	2	2	2	2	3
Normal Weather Demand (Before Load Control)	MW,	8	-23	-80	128	119	59	41	17	-10
Normal Weather Reserves (Before Load Control)	MW	35	81	280	64	568	220	597	43	549
Normal Weather Reserve Margin (Before Load Control)	1	0.4%	1.0%	3.5%	0.6%	6.9%		7,1%	0.5%	6.3%
Normal Weather Load Management	MW	14	10	6	3	1	-2	-4	-6	-8
Normal Weather Demand (After Load Management)	MW	-6	-33	-96	123	118	60	45	23	-2
Normal Weather Reserves (After Load Management)	MW	49	91	286	68	567	218	593	37	542
Normal Weather Reserve Margin (After Load Management)	%	0.6%	1.2%	3.9%	0.6%	7.1%	2.6%	7.3%	0.4%	6.4%
Normal Weather Interruptible Load	мw	14	7	7	28	32	36	38	40	41
Normal Weather Voltage Reduction	MW	0	0	00	0	·0	0	0	0	0
Normal Weather Demand (After All Load Control)	MW	20	40 1	-103	95	86	1 24	1. <b>1</b>	47	-43
Normal Weather Reserves (After All Load Control)	MW	63	98	293	96	599	254	631	77	583
Normal Weather Reserve Margin (After All Load Control)	%	0.9%	1.4%	4.2%	1.0%	7.8%	3.3%	8.1%	1.0%	7.2%
Normal Weather "DLC" Reserve Margin Contribution	%	-0.7%	-2.8%	-7.8%	-0.2%	-10.0%	-2.7%	-10.0%	0.5%	-8.3%

															1. S.	A	AP 201	Renned Westher		1. 681.00	3	
						- *								1.5%								
							Number of S.				Surained 3			EDC Incluin			8t.	Tore DLC				
		Scheduled	Baseload	Baselowi		fer metale	intermediate	Peaking	Total	QF Cn-Peek	(mermediate	Peaking	Operating	Recordes	Total Peak	Bupply	Reserve	IS/CS and	Firm Peak	•	Total Reserve	
	Month	Maintenançe	Plants	Contracts	QF Canincia	Respurces	Resurces	Resources	Recourtes	Reduction	Recurses	Recourse	Requirements	EFOR	Before CLC	Variance	Margin	VOL Reil)	Aller DLC	Total Variance	Margen	
<b>1</b> .	Jan-08	· •	3,159	469	81	2,994	6,843	2,734	2,567	-106	8,945	2,626	341	-495	8,578	3	4.33%	1,111	1,299	1,308	13.83%	
z	Feb-00	-162	3,139	469	\$51	2,394	6,633	2,734	9,567	-106	6,052	2,823	341	-446	8,208	1,007	13,20%	1,044	7,261	2,144	29.53%	1
3	Mar-00	-1,299	3,139	469	#21	2,304	6,633	2,734	8.567	-106	6,058	2,438	341	-383	8,391	1,277	18 26%	890	6,101	2,167	35.52%	
4	Apr-02	-1,332	3,062	459	\$31	2,250	8,651	2.276	8.927	-108	5,994	2,129	281	. 34	6,390	1,245	13 61%	\$55	5,695	1,900	\$3.38%	
. 5	May-00	•	1,099	468	(11)	2,268	6,068	2,276	8,944	-108	5,956	2,171	291	-420	7,390	1,545	20.66%	733	8,966	2,278	34.17%	
	Jun-00	•	2,099	468	831	2,299	8,668	2,185	8,853	-106	5,958	2,061	201	-415	7,956	817	11.20%	824	7,132	1,721	24, 13%	
	10-00		1,050	400		2,250	6,956	2,185	1,153	-100	3,959	2,085	251	-415	. 178	674	1 24%		7,340	1,483	20.25%	
	East.M	•	3,000		101	1,250	1,000	2,143	1.05	-106	5,956	2,001	271	-618	9,2/8	373		<	7,639	1,414	17.01%	
10	00.00	-457	3 099	458	611	2 248	4.454	2 276		-108	5 175	2,087	291	-364	# 877	1,132	21 APC		8 776	2 241	38.77%	
11	Nov-00	-854	2,156	469	811	2,334	6,850	2.276	8.126	-108	6.197	2.181	271	-382	6.187	2,055	11.72%	736	5.446	2.794	51,25%	
12	Dec-00	-115	3,158	468	631	2,384	6,850	3,016	1,205	-106	8,054	2,900	341	-445	7,743	2,008	21.83%	816	6.827	2,824	40.78%	
-																						
11	Jener	•	3,187	40	101	2,394	6,674	3,816	1,196	-192	6,675	2,894	. 341	-01	8,785	105	1.87%	1,257	. 0,000	\$,942	13.97%	
	140-01	-167	· 3,180	+03		2,394	4.4/4	3,018	1,80	-100	6,080	2,000	241	-463	8,315	1,206	14,185	1,001	7,314	2,204	20.00	
- 13	Ancas	-301	1,100	440	837	7.765	8.407	4 689	4,000	-108	4.040	- 1.400		-177	r,137	2.04	4L 1876		6.016	2,078	17.47%	
. 13	stand 1		3,779		ar.	2.300	6.693	2,516	3 374		E 009	1		.364	7,8%	794	10 104	474		د مب د اه د	20 64 64	
12	Jun-O1		3,173	40	#31	2,260	6,612	2.425	1.117	-108	1.973	2.316	281	-00	8,136	976	12 03%	754	7.340	1,737	23.54%	
18	14-01	•	3,123	482	821	2,200	6.692	2,425	8,117	-106	5,573	2,310	291	-430	1.372	748	8,80%	754	7,417	1,500	18.68%	
24	Aug-#1		3,125	488	471	2,260	6,012	2,425	8,117	-108	8,973	2,216	291	-438	8,472	845	7.61%	771	7,701	1,418	18.39%	
21	Sep-D1	e	3,123	469	124	2,269	6.632	2,425	8,117	-105	5,973	2,314	251	-130	7,900	1,217	15.41%	717	7,145	1,834	26.10%	
22	Oct-01	-428	3,123	. 489	831	2,269	8.682	2.516	8,204	-108	5,995	2,418	281	-400	7,008	1,572	22.48%	570	6,435	2,145	33,32%	
23	Nov-01	-1,467	3,100	489	831	2,384	6,874	2.516	8,365	-105	6,204	2,425	201	-364	6,379	1,544	24.20%	633	5,666	2,237	39.34%	
24	Dec-01	-1,152	3,180	469	·~. #11	2,3%	8,874	2.016	8,000	-106	6,123	2,814	341	-408	7,827	811	10,23%	763	7,194	1,574	21,98%	
- 28	210-02	•	2.197	468	831	2.394	6.899	2,016	9,397	-106	6,013	2,099	341	473	8,473	435	4.57%	1.134	6.212	1,625	13.575	
26	Feb-02	0	3,197	465	\$31	2,394	6,891	3,016	8,907	-108	6,068	2.894	341	473	8,254	7,623	18.00%	140	7,335	2.572	35.00%	
27	Mar-02	-941	3,197	459	831	2.394	6,691	- 3,016	8,907	-106	6,128	2,911	341	-422	6,942	2,024	29.18%	806	6,136	2,830	48,13%	
20	Apr-02	-1,101	3,140	469	818	2,299	8,595	2.563	8,258	-108	6,016	2,469	291	-378	6,325	1,634	28.99%	566	5,758	2,400	41.66%	
29	May 02	-484	3,140	469	818	2,209	6.696	2,51	9,212	-108	5,952	2,414	231	-108	7,353	1,375	18,70%	625	6,728	2,000	28.73%	
30	Jun-02	0	3,140	469	516	2,268	6,695	2,425	8,121	-106	5,978	2,317	201	-431	7,791	1,331	17.0015	692	7,008	2023	28.50%	
31	14-02	0	2,140	463	<b>818</b>	2,298	6,694	2.425	8,121	-108	5,878	2,317	251	-131	8,033	1,988	12.54%	658	7,344	1,777	24.20%	
72	Aug-01	•	3,148	483	#18	2,249	8,696	2,429	8,121	-194	5,978	2317	291	-431	8,127	<b>Bitd</b>	12,19%	705	7,431	1,696	22.74%	
22	Sep-02	•	3,140	458	\$18	2,268	6,690	2.425	1,121	-106	5,574	2,317	291	-411	2,548	1,575	20 87%	641	6,685	1,234	32.47%	
	08.02	-401	2,140	409	818	2,200	4 6 10	2,514	1.212	-106	3,987	2,415	201	-400	6,700	1,508	23.45%	536	8,167	2000	38.83%	
	Dec 02	-717	3,187	444	418	1764	6.670	2.516	1.00	-104	6,110	2.414			7.814	1.448	37.58%	777	2,417	2 2 2 2 2 2 2 2 2 2 2 2 2 2 2 2 2 2 2 2	11 57%	
			-										••••	-								
37	Jan-83	• `	3,197	489	618	2,394	6,878	1.018	9,294	-196	8,978	2,844	. 341	473	9,291	682)	4.49%	1,171	8,129	1,774	21.43%	
	Feb-03		3,197	400	818	2,394	6,078	3.016	8,854	-108	6,076	2,694	341	-473	8,078	1,817	22.49%	540	7,138	2,758	38.61%	
	9447-00		1,197	467	818	2,394	6,678	1,016	9,894	-106	6,076	2,896	301	-473	6,096	3,196	41.17%	805	5.891	6,003	47.145	
~	-pus		3,140	457		2,00	4,6.40	2.564	4 3 4 1	-100	4.879	2.455		-1.50	8,007 7,708	204		302	1//5	3,004	92.01% 18.05m	
	100.00		3 140			2 288	6.696	3475		-106	6 978	2 317	201		7 583	1.438	27.00%	472	8.845	7 7 10	11 80%	
			1.140	445		2 300	6.005	2475	6 121	-104	5 878	2 317	201		7 817	1 764	14 1.011	470	1 187	1 854	97 27%	
44	Aug 41	•	1,146		\$18	2,753	8,896	2.425	8,121	-106	5,975	1317	201	-431	7,942	1.179	14.45%	644	7.154	1.864	25.44%	. 1
45	5-0-03		3,140	468	ant	2.260	6.656	2.425	8,121	-106	5,976	1,217	291	-431	7,581	1,730	23.41%	647	6,744	2.377	35.25%	
-46	00-03		3,140	462	312	2,269	6,656	2,518	8,212	-106	5,972	2,407	291	-436	6,778	2,434	35.90%	538	6,240	2,972	47.63%	
47	Nov-03		3,197	451	216	2.961	7.445	2.516	9,961	-106	6,690	2,297	291	-477	5,965	3,976	66.42%	682	5,304	4,657	87.81%	
48	Cec-02		3, 197	459	810	2.961	7,445	3.016	10,461	-106	6,620	2,890	341	-505	7,383	3,078	41.69%	747	5.836	1.625	\$7.85%	
·	مق مورد		3,197	. 40		2.010	7.395	1.816	10.316		6.488	2 482	341	-497	1.341	424		1.114	4.231	2.004	25.32%	
50	Feb-D4	•	3,197	453	415	2.815	1,254	1.018	10,315	-106	6,480	2,892	341	497	4,149	2,166	25 55%	921	7.228	1,087	42.71%	
51	Mar-D4		2,197	469	815	2,815	7,296	1.016	10,315	-106	6.480	2,892	341	-487	6,796	3,517	91.73%	793	6.005	4,310	71.76%	
52	Apr-04		1,140	468	816	2.521	7,048	2.563	9,611	-106	6.308	2,442	291	-458	6,448	3,162	48 04%	540	5,506	3,705	82,73%	
53	May-OI		3,140	469	818	2.521	7,048	2.516	8,564	-106	6,310	2,402	291	-455	7,236	2,226	20.32%	566	6,750	2,814	41 68%	
54	.hm-04		3,140	458	818	2.821	1.048	2.425	8,473	-106	8,314	2.312	291	-150	7,720	1.753	22.71**	\$40	7,080	2,393	33.60%	
55	J <b>₩</b> -04		3,140	459	818	2.621	7,048	2.425	8,473	-106	6,314	2,312	- 291	-450	7,904	1,560	19.45**	636	7,256	2,207	30.58%	
- 56	Aug 44	4	3,140	469	818	1,521	7,545	2.425	8,473	-106	6,314	2512	291	-156	8,012	1,481	18.34%	651	7.361	2,112	28.62%	
57	Sep-64		3,140	469	818	2.671	7.04E	2.425	6,473	-108	6,314	2312	291	-450	7,524	1,848	25.90%	618	4.506	2,567	37.18%	
58	Oct-04		3,140	469	818	2.621	7.04ê	2.516	8,564	-108	6,310	2,402	291	-455	6,901	2,664	34.60%	\$22	6.375	3,186	49.94%	
58	Nov-04		3,197	469	£18	2815	1.29%	2.546	. 9,815	-106	6,550	2.399	291	-168	6,068	3,747	\$1.78°s	\$74	3.394	4,421	83.97%	
60	Dec-04		3,197	469	818	2,8%	1 299	2.016	10,315	-106	6,480	2.892	341	-497	7,415	2,900	30 12%	734	4.477	3,638	54.50%	
<b>6</b> 7	Jan 45		3,197	479	816	2,675	7,308	3.916	10,325	-196	6,499	2,692	341	-197	8,533	782	8.31%	1,139	8.394	1,931	22.01%	
\$2	F#9-D5		3,197	479	\$10	2.875	· 30+	3996	10,325	-106	6,480	2.842	341	497	8,253	2,042	24 63%	\$13	1 271	2,954	40.06%	
63	Mar-05		3, 197	479	818	2,815	1.874	3.44	10.325	-105	6,490	2.692	341	457	6,395	1,430	49 75*,	787	4,:0d	4,717	69.04%	
64	Apr-05		3,140	479	· 818 ·	2.621	256	2 <b>34</b> 3	9.621	106	6.318	2,449	.251	-458	6,555	3,066	46 78°.	530	5.,25	3,596	55.69%	
65	1,ºay-05		3,140	478	918	2,821	<i>.</i> **	5-14	\$.\$74	105	4,320 -	2.402	251	-455	7,463	2,111	28.29*+	570	5,450	2,681	38.90%	
64	Inder AL		3 140	479	816	2 42*		2.124	8.457	106	5,324	2 3 17	251	455	7.645	1.534	20.6***	618	1,200	7 254	11 18%	

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27.75% 17 8815 7.473 2060 ..... 3 140 -7.054 ..... . .... ..... .... --490 4 014 144 414 478 818 -108 Aug-05 Sep-05 Oct-05 -3,140 818 2,621 7,058 1.00 8,485 -196 -108 8,326 **** 221 -458 8,149 7,853 7,017 ..... ----*** .... 1 941 ..... 7,058 6,505 34,40% ..... 3,140 416 2,621 7,058 2,425 8,483 8,324 9 112 291 291 -150 -155 1.811 -647 478 3,058 ----3,140 818 2,821 7,058 2,516 8,574 -108 6,320 2,402 2.557 M 44% 513 Nor-05 3,197 11 3,342 7,878 2,516 10,382 -106 7,104 2.391 291 -500 6,148 4,246 68,09% 672 5,474 4.818 -341 72 Dec-05 3,157 419 818 7,576 3,016 10,482 -106 7,053 2,984 -526 7,518 1.374 44.88% 735 6,783 4,108 60.58% Jan - 76 878 7,176 12,742 -196 7,848 2.736 341 -618 3,761 8,463 1,992 2,273 1,171 8,818 2.132 26,77% 1,197 -3,382 2,886 -----7,545 Feb-08 3,197 478 816 3,362 7,875 2,866 10,742 -106 7,040 2,736 341 -519 25.64% 101 2.177 47 00% 341 Mar-08 3,197 818 3,382 7,576 2,668 10,742 -106 7,040 8,798 2,736 -518 6,890 8,561 1,752 63.68% 781 6,208 4,534 73.02% 291 6,142 7,032 7,381 Apr-OS 3,140 818 1.118 7,553 2,428 8,961 2.308 -478 1,320 49 85% 518 3,438 62 (7% 478 -108 -108 -108 -108 -108 7,553 7,653 7,563 7,563 7,553 7,553 May-Di 3,140 478 618 3,116 2.361 8,534 8,363 1,000 2,292 291 -475 -470 7,508 7,978 8,229 8,341 7,770 7,122 2,348 30.95% 554 2,802 41.27% 3,140 3,140 3,140 3,140 3,140 6,604 6,804 6,804 6,804 6,804 Jun Of 818 3,116 2,290 2,177 1.668 23.42% 585 2.443 23.37% 291 291 291 291 291 291 291 m Jui-08 Aug-86 Sep-05 2,118 3,516 3,916 3,118 2,290 2,290 2,290 2,290 8,843 8,843 8,843 8,843 8,843 8,843 7,636 7,737 7,201 8,629 878 878 2.172 -478 -478 -470 -478 -483 -483 1,814 18.67% 5634 2,207 28.91% 479 1,502 2,064 2,802 2,172 13.81% 2,105 27.22% 171 26.54% 571 2,642 36.69% 479 818 49 88% 3,116 2,361 -106 -106 8,800 870 0a-08 3,140 479 858 7,553 2,762 Nov-OE Dec-OE 7,110 6.221 5,551 3,197 818 3.342 7,878 2.381 10,257 2,258 4.036 \$4,55% 670 4,708 64,78% 470 3,197 478 818 3.342 7,876 2,006 10,742 -106 7,040 2,736 341 1,670 3,072 40.05% 722 6,839 3,804 54.62% 8,320 7,758 6,327 6,250 7,185 Jan-87 Fob-87 Mar-87 9,944 8,855 7,105 895 1,996 LHX 72.95% 1,821 2,884 38.63% 5,197 2,110 18,641 10,841 7,038 2,841 341 341 341 281 291 291 9,128 896 778 529 641 577 4778 813 813 3,382 7,971 3,197 7,871 2,770 7,036 7,038 2,641 37.18% 478 3.362 10.841 3,536 48,75% 4,314 3,842 3,197 478 613 3,342 7,871 2,770 68.18% 8,896 8,851 8,780 8,780 Aur-07 May-07 Jun-01 Jul-07 Aug-87 Sep-07 Oct-07 Nex-07 Dec-07 1,140 1,140 1,140 1,140 1,140 1,140 1,140 1,140 1,140 1,140 1,147 813 3.116 7,548 7,548 2,350 6,796 6,798 2.777 3,133 48.30% 64 22% 479 6,785 7,705 8,113 8,418 8,532 7,903 7,903 8,294 7,622 478 813 3,115 2,188 2,145 27.84% 2,666 37,48% 2,006 7,538 2,224 479 813 813 3,116 7,548 7,548 7,548 7,548 7,548 8,438 8,438 2,212 6,801 1,847 1,342 20.30% 28.515 6,801 6,801 6,801 517 545 91 479 1,116 2,212 2,096 15.04% 1,818 21.47% 2,115 3,115 3,116 3,116 3,116 3,549 2.212 8,798 8,795 2,094 291 281 1,228 14.39% 7,947 7,941 1,013 22.81% a 413 873 2.212 1,857 23.49% 562 2,418 32.94% 479 478 6,794 7,851 8.961 10.741 2,165 291 291 241 495 6,747 2,104 2,303 2,607 36.02% 48,00% 813 813 4,445 3,386 70.59% **000** 730 5,827 5,114 80.68% 478 2,770 11,208 7,542 2,674 43.28% 7,082 4,718 56.04% 478 815 341 341 345 18,130 8,643 7,242 1,128 9,625 2,163 23.96% Jan 64 Feb-08 Mar 68 Aar 68 May 68 Jan 68 Ja 3,197 470 798 3,549 1,43 2,778 11,195 7.567 2,654 1,843 10.25% 97 ÷ 3,197 3,197 475 798 798 2,949 3,949 3,811 8,423 2,770 11,193 11,193 7,567 2,634 2,350 26.57% 7,851 3.242 40.76% 842 775 501 529 542 541 6,467 6,364 7,294 473 8,423 2,770 7,597 2.834 3,951 54.58% 4,728 13.06% 8.028 10,378 10,331 10,240 10,240 3,140 3,140 3,140 3,140 3,140 3,140 3,140 3,140 3,140 3,197 3,197 794 2,350 2,359 7,296 2.225 291 291 6,085 7,829 3,512 51.18% 4,014 G. 07% 478 32.06% 3,037 101 478 3,811 1,257 2.508 41.64% 7948 7948 3,411 8,028 8,028 2,212 7,261 2,089 291 8,208 8,603 1,954 20.54% 7,724 2,515 32.56% 102 103 478 479 2.212 7,261 291 1,837 18,02% 8,042 2,197 27.32% 3,815 2,212 10,248 478 479 796 799 8,825 2,026 1,261 7,261 2,045 2.089 291 281 8,726 1,539 17.42% 568 548 8,152 2,010 2,754 21.01% 104 105 8.073 3,216 27.62% 7,478 36.90% 3,811 3,811 3,849 3,849 475 479 478 7548 7548 7548 2,303 10,331 1,257 2,178 7,352 2,979 40.52% 490 555 6,562 3,468 50.56% 8.025 281 106 107 1,423 8,423 2,303 10,726 7.636 251 6,367 4,158 61.45% 5,690 5,027 HI 21% 2,634 7,974 720 7,245 11,183 7,567 541 3,218 40.36% 3.948 64.48% 108 1,117 886 772 495 , 108 Jan-09 3,197 3,197 679 6412 630 635 1,949 8,314 2,778 11,664 7,458 2,634 341 -643 -545 -545 -597 -498 -493 -493 -493 -493 -493 -493 18,351 733 7.66% 8,234 1,850 28.83% . -106 -108 -108 -106 -106 -106 -106 -106 -106 Jan-09 Faty-08 Max-09 Apr-08 May-08 Jun-09 110 478 3,949 6,314 2,770 11,064 7,452 2.634 341 341 8,017 2,066 22.92% 8,128 2,854 36.34% 3.197 3.140 3.140 479 3.949 8,314 2,770 11,084 7,458 2,634 7,361 3,701 50.17% 6,608 4,475 87.72% m 112 479 478 613 633 3,611 3,611 7,918 2,350 10.248 7,145 2,225 291 291 4,965 3,303 47 42% 8,471 3,794 58.68% 113 7,819 7,148 7,893 2,278 27.86% 519 7,474 2,748 36,76% 2,178 2,069 2,589 2,589 2,089 2,089 2,178 3,140 3,140 3,140 3,148 3,148 3,140 3,611 2,212 479 479 10,131 10,131 291 281 1,673 7,910 2,221 114 62.9 7,818 7,152 8,458 18,78% 548 547 536 536 485 25.08% 1,340 1,323 1,825 2,729 Jul 09 Aug-09 Sep-08 7,152 1.711 15.24% 6,243 1,847 22.69% 429 3,611 7,819 115 13.72% 23.54% 36.58% 1,778 2,461 3,214 4,254 7,638 . 675 6249 654 3,611 3,611 7,913 2,212 10,131 7,152 291 291 291 8,908 21.26% 478 7,648 10,100 8,175 32.21% 2,212 7,121 04-05 3,140 479 458 1.611 7,858 2,303 10,191 7,1+7 7,462 6,877 48 07% Nov-09 Dec-09 3,197 479 658 4,516 8,050 2,303 11,153 -106 -108 8,040 2,165 291 -551 -577 6,412 4,711 73 12% 868 728 5,774 5,378 10 15% 3,197 478 658 4,516 1,150 2,770 11,620 7,870 2,676 341 8,128 3,492 42.97% 7,399 4,220 57 041 -679 -577 -577 -526 1,113 683 769 488 479 4,516 2,778 11,518 11,510 -186 -106 2,626 2,626 341 18,555 957 1.07% 2,448 2,478 21.33% 125 Jan-18 3,197 548 6,740 7,140 2.306 3.945 25 05% 1.321 3,189 341 1.204 7.525 38 325 Faib- 10 3,197 479 548 4,516 8,740 2,770 7,950 52,95% 6,756 4,754 2,536 341 291 70 37% Mar-10 3, 197 479 548 4,518 4,108 4,108 4,108 4,108 4,108 4,108 4,108 4,108 4,516 4,516 8,740 2,770 11,510 -106 -106 7,860 3,553 4,041 Apr-10 3,140 479 648 8,273 2,350 10,623 7,480 2,218 7,070 50 26% 6,582 61 40% 124 May-10 Jun-10 Jul-10 810 575 125 1140 478 548 8,273 2,303 10,576 -105 -105 -105 -105 -105 -105 -105 -105 7,442 2,172 281 281 525 520 520 528 528 525 551 577 6.177 2,398 28 34% 7,666 2,909 37 85% 2,062 3,140 70 548 7,864 2.212 10.076 7,077 8.636 1,438 18.85% 8,103 1,873 24 35% 126 3,140 3,149 3,149 3,149 3,149 3,140 3,197 2,212 2,212 1,213 2,252 2,303 2,303 70 78 544 548 10,076 7,077 291 291 1,089 12 12-534 6,453 1,623 19.20% 7,844 7,884 7,884 7,884 8,331 8,331 8.987 Aug-10 7,577 9,109 967 18.61% 548 8,568 1,998 17.58% 128 2,082 2,172 2,145 2,826 1,722 2,585 4,091 2,790 10,075 251 251 251 251 7,017 8,354 20 42% 521 7,630 2,246 28 68% 70 70 70 70 548 548 548 Sep-10 7,073 7,521 7,491 7.582 6.542 8.311 34 08% 478 7,104 3,063 43.12% Cest-10 Nov-10 130 62 54% 23 57% 5,876 7,547 4,757 10,634 686 724 80 55°-131 46.32% 3.197 Dec-10 2 7 20

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	WINTER PEAK (JANUARY)										
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	
Total Available Resources Without Load Mgmt. *	9,651	9,989	10,006	10,006	10,421	10,431	10,431	10,998	10,998	10,998	
Scheduled Maintenance	0	0	0	• 0	0	0	0	0	0	0	
Qualified Facility (QF) Contractually-Allowed On-Peak Capacity Reduction	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106	
Total Supply Capability	9,545	9,883	9,900	9,900	10,315	10,325	10,325	10,892	10,892	10,892	
Total Demand (before DLC) for Mild Weather Peak	(8,841)	(9,035)	(8,674)	(8,324)	(8,479)	(8,564)	(8,717)	(8,879)	(9,041)	(9,204	
Supply Variance	704	848	1226	1576	1836	1761	1608	2013	1851	1688	
Supply Reserve Margin (%)	8.0%	9.4%	14.1%	18.9%	21.7%	20.6%	18.4%	22.7%	20.5%	18.3%	
Total DLC (Including IS/CS)	687	667.	637	624	612	608	605	604	603	602	
Total Variance	1391	1515	1863	2200	2448	2369	2213	2617	2454	2290	
Total Reserve Margin (%)	17.1%	18.1%	23.2%	28.6%	31.1%	29.8%	27.3%	31.6%	29.1%	26.6%	
Total Demand (before DLC) for Normal Weather Peak	(9,591)	(9,784)	(9,424)	(9,074)	(9,229)	(9,314)	(9,466)	(9,628)	(9,790)	(9,953	
Supply Variance	(46)	99	476	826	1086	1011	859	1264	1102	939	
Supply Reserve Margin (%)	-0.5%	1.0%	5.1%	9.1%	11.8%	10.9%	9.1%	13.1%	11.3%	9.4%	
Total DLC (Including IS/CS)	1084	1050	991	959	936	923	913	905	898	892	
Total Variance	1038	1149	1467	1785	2022	1934	1772	2169	2000	1831	
Total Reserve Margin (%)	12.2%	13.2%	17.4%	22.0%	24.4%	23.0%	20.7%	24.9%	22.5%	20.2%	
Total Demand (before DLC) for TMY Peak	(9,737)	(9,933)	(9,588)	(9,247)	(9,414)	(9,505)	(9,660)	(9,816)	(9,970)	(10,121	
Supply Variance	(192)	(50)	312	653	901	820	665	1076	922	771	
Supply Reserve Margin (%)	-2.0%	-0.5%	3.3%	7.1%	9.6%	8.6%	6.9%	11.0%	9.2%	7.6%	
Total DLC (Including IS/CS)	1084	1050	991	959	936	923	913	905	898	892	
Total Variance	893	1001	1303	1612	1837	1742	1578	1981	1820	1663	
Total Reserve Margin (%)	10.3%	11.3%	15.2%	19.5%	21.7%	20.3%	18.0%	22.2%	20.1%	18.0%	
Total Demand (before DLC) for Extreme Weather Peak	(10,965)	(11,158)	(10,798)	(10,448)	(10,603)	(10,688)	(10,841)	(11,002)	(11,165)	(11,327	
Supply Variance	(1420)	(1275)	(898)	(548)	(288)	(363)	(516)	(110)	(273)	(435	
Supply Reserve Margin (%)	-13.0%	-11.4%	-8.3%	-5.2%	-2.7%	-3.4%	-4.8%	-1.0%	-2.4%	-3.8%	
Total DLC (Including IS/CS)	1299	1258	1183	1141	1112	1094	1080	1068	1058	1049	
Total Variance	(121)	(17)	285	593	824	731	564	958	785	614	
Total Reserve Margin (%)	-1.2%	-0.2%	3.0%	6.4%	8.7%	7.6%	5.8%	9.6%	7.8%	6.09	

* Normal Weather Plant Ratings

				W	INTER PEA	K (JANUAR	<i>(Y)</i>			
4) 4) Childreithe D	2000	2001	2002	2003	2004	2005	2006	2007	2008	2000
Spinning Reserves	(191)	(191)	(191)	(191)	(191)	(191)	(191)	(191)	(101)	/101
Load Pollowing	(150)	(150)	(150)	(150)	(150)	(150)	(150)	(151)	(150)	(15)
Reduction	0	0	0	0	0	0	0	(100)	(100)	(100
Remainder of Available Resources	9,204	9,542	9,559	9,559	9,974	9,984	9,984	10,551	10,551	10,55
Total Demand (before DLC) for Mild Weather Peak	(8,841)	(9,035)	(8,674)	(8,324)	(8.479)	(8,564)	(8 717)	(8 870)	(0.041)	10 204
Supply Variance	363	507	885	1235	1495	1420	1267	1672	1510	(9,204
Remaining Supply Reserve Margin (%)	4.1%	5.6%	10.2%	14.8%	17.6%	16.6%	14.5%	18.8%	16 7%	14 69
Total DLC (Including IS/CS)	687	667	. 637	624	612	608	605	604	603	602
Total Variance	1050	1174	1522	1859	2107	2028	1872	2276	2113	1940
Remaining Total Reserve Margin (%)	12.9%	14.0%	18.9%	24.1%	26.8%	25.5%	23.1%	27.5%	25.0%	22 70
Total Demand (before DLC) for Normal Weather Peak	(9,591)	(9,784)	(9,424)	(9,074)	(9,229)	(9,314)	(9,466)	(9.628)	(9 790)	19 953
Supply Variance	(387)	(242)	135	485	745	670	518	923	761	598
Remaining Supply Reserve Margin (%)	-4.0%	<b>-2</b> .5%	1.4%	5.3%	8.1%	7.2%	5.5%	9.6%	7.8%	6.0%
Total DLC (including IS/CS)	1084	1050	991	959	936	923	913	905	898	892
Total Variance	697	808	1126	1444	1681	1593	1431	1828	1659	1490
Remaining Total Reserve Margin (%)	8.2%	9.3%	13.4%	17.8%	20.3%	19.0%	16.7%	21.0%	18.7%	16.4%
Total Demand (before DLC) for TMY Peak	(9,737)	(9,933)	(9,588)	(9,247)	(9,414)	(9,505)	(9,660)	(9.816)	(9.970)	(10.121
Supply Variance	(533)	(391)	(29)	312	560	479	324	735	581	430
Remaining Supply Reserve Margin (%)	-5.5%	-3.9%	-0.3%	3.4%	6.0%	5.0%	3.4%	7.5%	5.8%	4 39
Total DLC (including IS/CS)	1084	1050	991	959	936	923	913	905	898	892
Total Variance	552	660	962	1271	1496	1401	1237	1640	1479	1322
Total Domand (befan DLO) for Extension (%)	6.4%	7.4%	11.2%	15.3%	17.6%	16.3%	14.1%	18.4%	16.3%	14.3%
Total Demand (Derore DLC) for Extreme Weather Peak	(10,965)	(11,158)	(10,798)	(10,448)	(10,603)	(10,688)	(10,841)	(11,002)	(11,165)	(11.327
Supply Variance	(1761)	(1616)	(1239)	(889)	(629)	(704)	(857)	(451)	(614)	(776
Remaining Supply Reserve Margin (%)	-16.1%	-14.5%	-11.5%	-8.5%	-5.9%	-6.6%	-7.9%	-4.1%	-5.5%	-6.9%
I otal DLC (Including IS/CS)	.1299	1258	1183	1141	1112	1094	1080	1068	1058	1049
Total Variance	(462)	(358)	(56)	252	483	390	223	617	444	273
Kemaining Total Reserve Margin (%)	-4.8%	-3.6%	-0.6%	2.7%	5.1%	4.1%	2.3%	6.2%	4.4%	2 7%

			, ,	WIN	NTER PEAK	(JANUAR)	0			
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Actual Forced Outages (5.5% EFOR)	(459)	(478)	(479)	(479)	(502)	(502)	(502)	(533)	(533)	(533)
Remainder of Available Resources	8,745	9,064	9,080	9,080	9,472	9,482	9,482	10,018	10,018	10,018
		(0.005)	(0.07.0)	(0.00.0)	(9.470)	(0 504)	(0 717)	(9.970)	(9.041)	(9 204)
Total Demand (before DLC) for Mild Weather Peak	(8,841)	(9,035)	(8,674)	(8,324)	(0,4/9)	(0,004)	(0,717)	1120	077	814
Supply Variance	(96)	29	406	/ 50	993	910	- 705	1139	10.8%	8.8%
Remaining Supply Reserve Margin (%)	-1.1%	0.3%	4.7%	9.1%	11.7%	10.7%	0.0%	12.0%	602	602
Total DLC (Including IS/CS)	687	667	637	624	612	608	600	4742	1590	1417
Total Variance	591	696	1043	1380	1605	1526	13/1	1/43	1000	16 5%
Remaining Total Reserve Margin (%)	7.2%	8.3%	13.0%	17.9%	20.4%	19.2%	16.9%	21.1%	10.7%	10.070
Total Demand (before DLC) for Normal Weather Peak	(9,591)	(9,784)	(9,424)	(9,074)	(9,229)	(9,314)	(9,466)	(9,628)	(9,790)	(9,955)
Supply Variance	(846)	(720)	(344)	6	243	168	16	390	228	CO
Remaining Supply Reserve Margin (%)	-8.8%	-7.4%	-3.6%	0.1%	2.6%	1.8%	0.2%	4.1%	2.3%	0.7%
Total DLC (Including IS/CS)	1084	1050	991	959	936	923	913	905	898	892
Total Variance	238	330	647	965	1179	1091	929	1295	1126	957
Remaining Total Reserve Margin (%)	2.8%	3.8%	7,7%	11.9%	14.2%	13.0%	10.9%	14.8%	12.7%	10.6%
Total Demand (before DLC) for TMY Peak	(9,737)	(9,933)	(9,588)	(9,247)	(9,414)	(9,505)	(9,660)	(9,816)	(9,970)	(10,121
Supply Variance	(992)	(868)	(508)	(167)	59	(23)	(177)	202	48	(103
Remaining Supply Reserve Margin (%)	-10.2%	-8.7%	-5.3%	-1.8%	0.6%	-0.2%	-1.8%	2.1%	0.5%	-1.0%
Total DLC (Including IS/CS)	1084	1050	991	959	936	923	913	905	898	892
Total Variance	92	182	483	792	994	900	736	1107	946	789
Remaining Total Reserve Margin (%)	1.1%	2.0%	5.6%	9.6%	11.7%	10.5%	8.4%	12.4%	10.4%	8.6%
Total Demand (before DLC) for Extreme Weather Peak	(10,965)	(11,158)	(10,798)	(10,448)	(10,603)	(10,688)	(10,841)	(11,002)	(11,165)	(11,327
Supply Variance	(2220)	(2094)	(1718)	(1368)	(1131)	(1206)	(1359)	(984)	(1147)	(1309
Remaining Supply Reserve Margin (%)	-20.2%	-18.8%	-15.9%	-13.1%	-10.7%	-11.3%	-12.5%	-8.9%	-10.3%	-11.6%
Total DLC (Including IS/CS)	1299	1258	1183	1141	1112	1094	1080	1068	1058	104
Total Variance	(921)	(836)	(534)	(227)	(19)	(112)	(279)	84	(89)	(25)
Remaining Total Reserve Margin (%)	-9.5%	-8.4%	-5.6%	-2.4%	-0.2%	-1.2%	-2.9%	0.8%	-0.9%	-2.5

3

	WINTER PEAK (JANUARY)											
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009		
Worst-Case Forced Outages (9.7% EFOR)	(810)	(843)	(844)	(844)	(885)	(885)	(885)	(940)	(940)	(940)		
Remainder of Available Resources	8,394	8,699	8,715	8,715	9,089	9,099	9,099	9,611	9,611	9,611		
Total Demand (before DLC) for Mild Weather Peak	(8,841)	(9.035)	(8.674)	(8,324)	(8,479)	(8,564)	(8,717)	(8,879)	(9,041)	(9,204)		
Supply Variance	(447)	(336)	41	391	610	535	382	732	570	407		
Remaining Supply Reserve Margin (%)	-5.1%	-3.7%	0.5%	4.7%	7.2%	6.3%	4.4%	8.2%	6.3%	4.4%		
Total DLC (Including IS/CS)	687	667	637	624	612	608	605	604	603	602		
Total Variance	240	331	677	1014	1222	1143	988	1336	1173	1010		
Remaining Total Reserve Margin (%)	2.9%	4.0%	8.4%	13.2%	15.5%	14.4%	12.2%	16.1%	13.9%	11.7%		
Total Demand (before DLC) for Normal Weather Peak	(9,591)	(9,784)	(9,424)	(9,074)	(9,229)	(9,314)	(9,466)	(9,628)	(9,790)	(9,953)		
Supply Variance	(1197)	(1085)	(709)	(359)	(140)	(215)	(367)	(17)	(179)	(342)		
Remaining Supply Reserve Margin (%)	-12.5%	-11.1%	-7.5%	-4.0%	-1.5%	-2.3%	-3.9%	-0.2%	-1.8%	-3.4%		
Total DLC (Including IS/CS)	1084	1050	991	959	936	923	913	905	898	892		
Total Variance	(113)	(35)	282	599	796	708	546	888	719	550		
Remaining Total Reserve Margin (%)	-1.3%	-0.4%	3.3%	7.4%	9.6%	8.4%	6.4%	10.2%	8.1%	6.1%		
Total Demand (before DLC) for TMY Peak	(9,737)	(9,933)	(9,588)	(9,247)	(9,414)	(9,505)	(9,660)	(9,816)	(9,970)	(10,121)		
Supply Variance	(1343)	(1233)	(873)	(532)	(324)	(406)	(560)	(205)	(359)	(510)		
Remaining Supply Reserve Margin (%)	-13.8%	-12.4%	-9.1%	-5.8%	-3.4%	-4.3%	-5.8%	-2.1%	-3.6%	-5.0%		
Total DLC (Including IS/CS)	1084	1050	991	959	936	923	913	905	898	892		
Total Variance	(259)	(183)	118	427	611	517	352	700	539	382		
Remaining Total Reserve Margin (%)	-3.0%	-2.1%	1.4%	5.1%	7.2%	6.0%	4.0%	7.9%	5.9%	4.1%		
Total Demand (before DLC) for Extreme Weather Peak	(10,965)	(11,158)	(10,798)	(10,448)	(10,603)	(10,688)	(10,841)	(11,002)	(11,165)	(11,327)		
Supply Variance	(2571)	(2459)	(2083)	(1733)	(1514)	(1589)	(1742)	(1391)	(1554)	(1716)		
Remaining Supply Reserve Margin (%)	-23.4%	-22.0%	-19.3%	-16.6%	-14.3%	-14.9%	-16.1%	-12.6%	-13.9%	-15.1%		
Total DLC (Including IS/CS)	1299	1258	1183	1141	1112	1094	1080	1068	1058	1049		
Total Variance	(1272)	(1201)	(900)	(592)	(402)	(495)	(662)	(323)	(496)	(666)		
Remaining Total Reserve Margin (%)	-13.2%	-12.1%	-9.4%	-6.4%	-4.2%	-5.2%	-6.8%	-3.2%	-4.9%	-6.5%		

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Total Available Resources Without Load Mgmt.	8,536	8,785	8,802	8,802	9,147	9,157	9,157	9,652	9,652	9,652
Scheduled Maintenance	0	0	. 0	0	0	0	0	0	0	0
Qualified Facility (QF) Contractually-Allowed On-Peak Capacity	(400)	(400)	(406)	(400)	(400)	(400)	(400)	(400)	(400)	(400)
Reduction	(100)	(100)	(100)	(100)	(100)	(106)	(106)	(106)	(106)	(106)
Total Supply Capability	8,430	8,679	8,696	8,696	9,041	9,051	9,051	9,546	9,546	9,546
Total Domand (before DLC) for Mild Weather Beak	(8 220)	(8 206)	(9.046)	(7 692)	(7.926)	(7.026)	(9.070)	(9.220)	(9.400)	(9.562)
Fotal Demand (Defote DLC) for mild Weather Feak	201	283	660	1013	1205	1125	072	1207	(0,400)	(0,002)
Supply Variance	2.4%	3.4%	8 1%	13 2%	15 4%	14 2%	12 0%	15.0%	13.6%	11 5%
Total DLC (Including IS/CS)	761	711	658	626	596	575	556	541	528	517
Total Variance	962	994	1308	1638	1800	1699	1528	1848	1674	1501
Total Reserve Margin (%)	12.9%	12.9%	17.7%	23.2%	24.9%	23.1%	20.3%	24 0%	21.3%	18.7%
Total Demand (before DLC) for Normal Weather Peak	(8,328)	(8,495)	(8,145)	(7.782)	(7.935)	(8.025)	(8,178)	(8.338)	(8,499)	(8.661)
Supply Variance	102	184	551	914	1106	1026	873	1208	1047	885
Supply Reserve Margin (%)	1.2%	2.2%	6.8%	11.7%	13.9%	12.8%	10.7%	14.5%	12.3%	10.2%
Total DLC (Including IS/CS)	819	762	701	663	629	604	582	564	548	535
Total Variance	920	946	1252	1577	1735	1630	1455	1771	1595	1420
Total Reserve Margin (%)	12.3%	12.2%	16.8%	22.2%	23.7%	22.0%	19.2%	22.8%	20.1%	17.5%
Total Demand (before DLC) for TMY Peak	(8,482)	(8,656)	(8,326)	(7,977)	(8,143)	(8,237)	(8,389)	(8,542)	(8,692)	(8,841)
Supply Variance	(52)	23	369	719	898	<b>814</b>	661	1004	853	704
Supply Reserve Margin (%)	-0.6%	0.3%	4.4%	9.0%	11.0%	9.9%	7.9%	11.8%	9.8%	8.0%
Total DLC (Including IS/CS)	819	762	701	663	629	604	582	564	548	535
Total Variance	767	785	1071	1382	1527	1418	1244	1568	1401	1239
Total Reserve Margin (%)	10.0%	10.0%	14.0%	18.9%	20.3%	18.6%	15.9%	19.7%	17.2%	14.9%
Total Demand (before DLC) for Extreme Weather Peak	(8,470)	(8,637)	(8,287)	(7,924)	(8,078)	(8,167)	(8,320)	(8,480)	(8,642)	(8,803)
Supply Variance	(40)	42	409	772	963	884	731	1066	904	743
Supply Reserve Margin (%)	-0.5%	0.5%	4.9%	9.7%	11.9%	10.8%	8.8%	12.6%	10.5%	8.4%
Total DLC (Including IS/CS)	840	782	718	677	642	615	592	572	556	542
Total Variance	* 800	823	1126	1449	1604	1499	1323	1638	1459	1284
Total Reserve Margin (%)	10.5%	10.5%	14.9%	20.0%	21.6%	19.8%	_17.1%	20.7%	18.0%	15.5%

* Normal Weather Plant Ratings

tysp2000.xis/Summer Analysis

	SUMMER PEAK (AUGUST)											
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009		
Spinning Reserves	(191)	(191)	(191)	(191)	(191)	(191)	(191)	(191)	(191)	(191)		
Load Following	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)		
Baseload Contract Contractually-Allowed On-Peak Capacity	•		0			•						
Reduction	, U	U	U	U	U		Ū	U	0	0		
Remainder of Available Resources	8,139	8,388	8,405	8,405	8,750	8,760	8,760	9,255	9,255	9,255		
Total Demand (before DLC) for Mild Weather Peak	(8,229)	(8,396)	(8,046)	(7,683)	(7,836)	(7,926)	(8,079)	(8,239)	(8,400)	(8,562)		
Supply Variance	(90)	(8)	359	722	914	834	681	1016	855	693		
Remaining Supply Reserve Margin (%)	-1.1%	-0.1%	4.5%	9.4%	11.7%	10.5%	8.4%	12.3%	10.2%	8.1%		
Total DLC (Including IS/CS)	761	711	658	626	596	575	556	541	528	517		
Total Variance	671	703	1017	1347	1509	1408	1237	1557	1383	1210		
Remaining Total Reserve Margin (%)	9.0%	9.1%	13.8%	19.1%	20.8%	19.2%	16.4%	20.2%	17.6%	15.0%		
Total Demand (before DLC) for Normal Weather Peak	(8,328)	(8,495)	(8,145)	(7,782)	(7,935)	(8,025)	(8,178)	(8,338)	(8,499)	(8,661)		
Supply Variance	(189)	(107)	260	623	815	735	582	917	756	594		
Remaining Supply Reserve Margin (%)	-2.3%	-1.3%	3.2%	8.0%	10.3%	9.2%	7.1%	11.0%	8.9%	6.9%		
Total DLC (Including IS/CS)	819	762	701	663	629	604	582	564	548	535		
Total Variance	629	655	961	1286	1444	1339	1164	1480	1304	1129		
Remaining Total Reserve Margin (%)	8.4%	8.5%	12.9%	18.1%	19.8%	18.0%	15.3%	19.0%	16.4%	13.9%		
Total Demand (before DLC) for TMY Peak	(8,482)	(8,656)	(8,326)	(7,977)	(8,143)	(8,237)	(8,389)	(8,542)	(8,692)	(8,841)		
Supply Variance	(343)	(268)	78	428	607	523	370	713	562	413		
Remaining Supply Reserve Margin (%)	-4.0%	-3.1%	0.9%	5.4%	7.5%	6.3%	4.4%	8.3%	6.5%	4.7%		
Total DLC (Including IS/CS)	819	762	701	663	629	604	582	564	548	535		
Total Variance	476	494	780	1091	1236	1127	953	1277	1110	948		
Remaining Total Reserve Margin (%)	6.2%	6.3%	10.2%	14.9%	16.4%	14.8%	12.2%	16.0%	13.6%	11.4%		
Total Demand (before DLC) for Extreme Weather Peak	(8,470)	(8,637)	(8,287)	(7,924)	(8,078)	(8,167)	(8,320)	(8,480)	(8,642)	(8,803)		
Supply Variance	(331)	(249)	118	481	672	593	440	775	613	452		
Remaining Supply Reserve Margin (%)	-3.9%	-2.9%	1.4%	6.1%	8.3%	7.3%	5.3%	9.1%	7.1%	5.1%		
Total DLC (Including IS/CS)	840	782	718	677	642	615	592	572	556	542		
Total Variance	509	532	835	1158	1313	1208	1032	1347	1168	993		
Remaining Total Reserve Margin (%)	6.7%	6.8%	11.0%	16.0%	17.7%	16.0%	13.3%	17.0%	14.4%	12.0%		

				SU	MMER PEA	K (AUGUS	T)			
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Actual Forced Outages (5.5% EFOR)	(398)	(412)	(413)	(413)	(432)	(432)	(432)	(459)	(459)	(45)
Remainder of Available Resources	7,741	7,976	7,992	7,992	8,318	8,328	8,328	8,796	8,796	8,79
Total Demand (before DLC) for Mild Weather Peak	(8,229)	(8,396)	(8,046)	(7,683)	(7,836)	(7,926)	(8,079)	(8,239)	(8,400)	(8,562
Supply Variance	(488)	(420)	(54)	309	482	402	249	557	396	234
Remaining Supply Reserve Margin (%)	-5.9%	-5.0%	-0.7%	4.0%	6.2%	5.1%	3.1%	6.8%	4.7%	2.79
Total DLC (including IS/CS)	761	711	658	626	596	575	556	541	528	51
Total Variance	273	291	604	935	1078	977	805	1098	924	75
Remaining Total Reserve Margin (%)	3.7%	3.8%	8.2%	13.2%	14.9%	13.3%	10.7%	14.3%	11.7%	9.3
Total Demand (before DLC) for Normal Weather Peak	(8,328)	(8,495)	(8,145)	(7,782)	(7,935)	(8,025)	(8,178)	(8,338)	(8,499)	(8,66
Supply Variance	(587)	(519)	(153)	210	383	303	150	458	297	13
Remaining Supply Reserve Margin (%)	-7.1%	-6.1%	-1.9%	2.7%	4.8%	3.8%	1.8%	5.5%	3.5%	1.6
Total DLC (Including IS/CS)	819	762	701	663	629	604	582	564	548	53
Total Variance	231	243	548	873	1012	907	732	1022	845	67
Remaining Total Reserve Margin (%)	3.1%	3.1%	7.4%	12.3%	13.9%	12.2%	9.6%	13.1%	10.6%	8.2
Total Demand (before DLC) for TMY Peak	(8,482)	(8,656)	(8,326)	(7,977)	(8,143)	(8,237)	(8,389)	(8,542)	(8,692)	(8,84
Supply Variance	(741)	(680)	(334)	15	175	91	(61)	254	104	(4
Remaining Supply Reserve Margin (%)	-8.7%	-7.9%	-4.0%	0.2%	2.2%	fatter 1.1%	-0.7%	3.0%	1.2%	-0.5
Total DLC (Including IS/CS)	819	762	701	663	629	604	582	564	548	53
Total Variance	78	. 83	367	678	804	695	521	818	652	49
Remaining Total Reserve Margin. (%)	1.0%	1.0%	4.8%	9.3%	10.7%	9.1%	6.7%	10.3%	8.0%	5.9
Total Demand (before DLC) for Extreme Weather Peak	(8,470)	(8,637)	(8,287)	(7,924)	(8,078)	(8,167)	(8,320)	(8,480)	(8,642)	(8,803
Supply Variance	(729)	(661)	(295)	68	240	161	8	316	154	(7
Remaining Supply Reserve Margin (%)	-8.6%	-7.7%	-3.6%	0.9%	3.0%	2.0%	0.1%	3.7%	1.8%	-0.19
Total DLC (Including IS/CS)	840	782	718	677	642	615	592	572	556	54
Total Variance	111	121	423	745	882	776	600	888	710	53
Remaining Total Reserve Margin (%)	1.5%	1.5%	5.6%	10.3%	11.9%	10.3%	7.8%	11.2%	8.8%	6.5

				S	UMMER PE	AK (AUGUS	T)		······	<u> </u>
Worst-Case Forced Outgres (9.7% EEOD)	2000	2001	2002	2003	2004	2005	2006	2007	2008	2000
Remainder of Available Resources	(702)	(726)	(728)	(728)	(761)	(761)	(761)	(809)	(800)	2003
	7,437	7,662	7,677	7,677	7,988	7,998	7.998	8 445	8 445	
Total Demand (before DLC) for Wild Working and								01110	0,770	0,4
Poter Demand (Derore DLC) for mild weather Peak	(8,229)	(8,396)	(8,046)	(7,683)	(7,836)	(7,926)	(8.079)	(8 239)	(8.400)	19 56
Remaining Supply Variance	(792)	(734)	(369)	(6)	152	72	(81)	206	45	(11
Total DLO (Instanting Supply Reserve Margin (%)	-9.6%	-8.7%	-4.6%	-0.1%	1.9%	0.9%	-1.0%	2.5%	0.5%	1
Total DLC (including IS/CS)	761	711	658	626	596	575	556	541	528	-1.4
Remaining Total Persons Manual (1)	(31)	(23)	289	619	748	647	476	747	573	
Total Demand (before Di C) for Normal Weather Bert	-0.4%	-0.3%	3.9%	8.8%	10.3%	8.8%	6.3%	9.7%	7 3%	5.0
Sumity Veria	(8,328)	(8,495)	(8,145)	(7,782)	(7,935)	(8,025)	(8,178)	(8.338)	(8 499)	(8.66
Remaining Supply Variance	(891)	(833)	(468)	(105)	53	(27)	(180)	107	(54)	(21
Total Di C (Including 10/00)	-10.7%	-9.8%	-5.7%	-1.3%	0.7%	-0.3%	-2.2%	1.3%	-0.6%	-2.5
Total DEC (including IS/CS)	819	762	701	663	629	604	582	564	548	-2.0
Remaining Total Persons Morgin (4)	(72)	(71)	233	558	683	577	403	671	495	31
Total Demand (before DLC) for TMX Boot	-1.0%	-0.9%	3.1%	7.8%	9.3%	7.8%	5.3%	8.6%	6.2%	30
Sumply Verlage	(8,482)	(8,656)	(8,326)	(7,977)	(8,143)	(8,237)	(8,389)	(8.542)	(8 692)	/8.84
Remaining Supply Variance	(1045)	(994)	(649)	(300)	(154)	(238)	(391)	(96)	(247)	(0,04
Total DLC (Including 19/00)	-12.3%	-11.5%	-7.8%	-3.8%	-1.9%	-2.9%	-4.7%	-1.1%	-2.8%	-4.5
Total DEC (Including IS/CS)	819	762	701	663	629	604	582	564	548	53
Remaining Total Reserve Marrin (%)	(226)	(232)	52	363	475	366	192	468	301	13
Total Demand (before DLC) for Extrome Margin (%)	-3.0%	-2.9%	0.7%	5.0%	6.3%	4.8%	2.5%	5.9%	3.7%	17
Supply Verianae	(8,470)	(8,637)	(8,287)	(7,924)	(8,078)	(8,167)	(8,320)	(8,480)	(8 642)	(8.80)
Remaining Supply Variance	(1033)	(975)	(610)	(247)	(90)	(169)	(322)	(35)	(197)	(35)
Total DLC (Including (%)	-12.2%	-11.3%	-7.4%	-3.1%	-1.1%	-2.1%	-3.9%	-0.4%	-2.3%	
Total Veriana	840	782	718	677	642	615	592	572	556	54'
Remaining Total Passaria Marria (0)	(193)	(194)	107	430	552	446	271	538	359	18.
(%)	-2.5%	-2.5%	1.4%	5.9%	7.4%	5.9%	3.5%	6.8%	4.4%	22

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#### Normal Weather

Bulk Power Sales Included

				x					NON-DISP.	TOTAL	DIRECT LO	DAD CONTROL P	ROGRAMS			(USED)	FIRM	(AVAILABLE)
		POTENTIAL		WHO	LESALE			POTENTIAL	DSM	SYSTEM					TOTAL		SYSTEM	
		TOTAL					<b>CO</b> .	TOTAL	& S.S.	BEFORE	RESIDENTIAL	OTHER DLC	TOTAL DLC	INTERR.	LOAD CONTROL	VOLTAGE	AFTER	VOLTAGE
(e) ( <b>or</b> - con		RETAIL.	REA	BULK	MUNI	TOTAL	USE	SYSTEM	COGEN	LOAD CONTROL	LOAD MGT.	PROGRAMS	PROGRAMS	LOAD	CAPABILITY	REDUCTION	LOAD CONTROL	REDUCTION
SEASON	MONTH	(MW)	(MW)	(MW}	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)
WINTER 99/00	Jan-2000	8,330	779	631	220	1,630	30	9,990	399	9,591	735	23	758	326	1,084	0	8,507	115
WINTER 99/00	Feb-2000	7,619	778	524	178	1,480	30	9,129	386	8,743	559	23	583	326	909	0	7,834	105
WINTER 99/00	Mar-2000	6,771	289	473	172	934	30	7,735	352	7,383	396	23	419	326	745	٥	6,638	89
SUMMER 00	Apr-2000	5,791	0	478	176	654	30	6,475	295	6,180	282	43	326	327	653	0	5,527	77
SUMMER 00	May-2000	6,617	173	555	199	927	30	7,574	322	7,252	353	47	400	327	727	0	6,525	90
SUMMER 00	Jun-2000	7,154	294	631	220	1,145	30	8,329	338	7,991	423	49	473	327	800	0	7,191	99
SUMMER 00	Jul-2000	7,284	351	631	223	1,205	30	8,519	343	8,176	440	50	490	327	817	0	7,359	102
SUMMER 00	Aug-2000	7,396	392	631	232	1,255	30	8,581	353	8,328	442	50	492	327	819	0	7,509	103
SUMMER 00	Sep-2000	7,111	244	631	211	1,086	30	8,227	344	7,883	390	49	439	327	766	0	7,117	97
SUMMER 00	Oct-2000	6,295	-0	555	170	725	30	7,050	316	6,734	236	45	281	328	609	0	6,125	85
WINTER 00/01	Nov-2000	6,163	142	473	157	772	30	6,965	357	6,608	322	24	347	328	675	٥	5,933	81
WINTER 00/01	Dec-2000	7,329	567	550	208	1,325	30	8,684	414	8,270	621	25	646	328	974	0	7,296	103
WINTER 00/01	Jan-2001	8,488	870	631	189	1,690	30	10,208	424	9,784	710	26	736	314	1,050	0	8,734	117
WINTER 00/01	Feb-2001	7,762	863	529	163	1,555	30	9,347	409	8,938	535	26	562	314	876	0	8,062	107
WINTER 00/01	Mar-2001	6,896	358	473	154	985	30	7,911	372	7,539	376	26	401	314	715	0	6,824	91
SUMMER 01	Apr-2001	5,911	113	483	150	746	30	6,687	304	6,383	257	46	303	314	617	0	5,766	80
SUMMER 01	May-2001	6,756	277	565	153	995	30	7,781	333	7,448	319	50	369	314	683	0	6,765	93
SUMMER 01	Jun-2001	7,308	360	631	169	1,160	30	8,498	350	8,148	360	52	432	315	747	0	7,401	101
SUMMER 01	Jul-2001	7,440	423	631	171	1,225	30	3,695	355	8,340	394	52	447	315	762	0	7,578	104
SUMMER 01	Aug-2001	7,555	465	631	180	t,276	30	3,361	366	8,495	395	52	447	315	762	0	7,733	106
SUMMER 01	Sep-2001	7,263	307	631	164	1,102	30	8,395	356	8,039	346	52	397	315	712	0	7,327	100
SUMMER 01	Oct-2001	6,427	67	565	136	768	- 30	7,225	326	6,899	206	47	254	315	569	0	6,330	87
WINTER 01/02	Nov-2001	6,271	254	473	130	857	30	7.158	377	6,781	299	27	325	315	641	0	6,140	84
WINTER 01/02	Dec-2001	7,461	643	575	161	1,379	30	8,870	438	8,432	576	27	602	316	918	0	7,514	105
WINTER 01/02	Jan-2002	8,654	893	167	130	1,190	30	9.874	450	9,424	653	27	680	311	991	c	8,433	114
WINTER 01/02	Feb-2002	7,913	886	167	119	1,172	30	9,115	434	8,681	493	27	520	311	831	. 0	7,850	105
WINTER 01/02	Mar-2002	7,029	359	167	107	633	30	7,692	395	7,297	346	27	374	311	685	0	6,612	89
SUMMER 02	Apr-2002	6,038	112	167	98	377	30	6.445	315	6,130	215	49	264	311	575	0	5,555	77
SUMMER 02	May-2002	6,904	293	167	117	577	30	7,511	345	7,165	268	53	321	311	632	0	5,534	90
SUMMER 02	Jun-2002	7,467	359	167	126	652	30	8,149	362	7,787	320	54	374	311	635	0	7,102	97
SUMMER 02	Jui-2002	7,503	428	167	128	723	30	8,356	368	7,988	333	55	388	312	700	0	7,288	100
SUMMER 02	Aug-2002	7,721	472	167	134	773	30	8,524	379	8,145	334	55	389	312	701	0	7,444	102
SUMMER 02	Sep-2002	7,422	306	167	123	596	30	3.048	368	7,680	293	54	347	312	659	·	7,021	96
SUMMER 02	Oct-2002	6,566	57	167	107	331	30	6.927	338	6,589	175	50	226	312	538	٥	6,051	84
WINTER 02/03	Nov-2002	6.387	251	167	104	522	30	6,939	399	6,540	230	29	309	312	621	0	5,919	81
WINTER 02/03	Dec-2002	7,602	652	167	115	934	30	3.565	464	8,102	541	30	571	313	884	0	7,218	101
	Jan 2002 -	8 473	122	167	00	600	חר	9 55 2	478	9 074	£16	20	EAE	213	050	n .	8 115	115
WINTER 02/03	Eab-2003	9,023 8,068	400	167		684		8.787	461	8 3 2 1	466	30	496	313	809	n	7 512	101
WINTER 02/03	Mar-2003	7 165	-21	167	81	24.5	30	7 443	419	7 024	307	30	357	313	670	Л	6 354	86
	Miai-2003	7,700		.07		240				1,04.1		~~		0.0			0,004	00

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7/19/00 @ 12-23 PM

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### Normal Weather

#### **Bulk Power Sales Included**

				<b>y</b> .					NON-DISP.	TOTAL	DIRECT LO	DAD CONTROL P	ROGRAMS	. ·		(USED)	FIRM	(AVAILABLE)	
		POTENTIAL		WHO	LESALE			POTENTIAL	DSM	SYSTEM					TOTAL		SYSTEM		
		TOTAL					<b>CO</b> .	TOTAL	& S.S.	BEFORE	RESIDENTIAL	OTHER DLC	TOTAL DLC	INTERR.	LOAD CONTROL	VOLTAGE	AFTER	VOLTAGE	
		RETAIL	REA	BULK	MUNI	TOTAL	USE	SYSTEM	COGEN	LOAD CONTROL	LOAD MGT.	PROGRAMS	PROGRAMS	LOAD	CAPABILITY	REDUCTION	LOAD CONTROL	REDUCTION	
SEASON	MONTH	(MW)	(MW)	(MW)	(MW)	(MW) .	(MW)	(MW)	(MW)	(MW)	. (MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	
SUMMER 03	Apr-2003	6,170	o	167	74	241	30	6,441	326	6,115	186	52	238	313	551	0	5,564	77	
SUMMER 03	May-2003	7,055	0	167	79	246	30	7,331	357	6,974	232	56	288	313	601	0	6,373	88	
SUMMER 03	Jun-2003	7,631	o	167	86	253	30	7,914	376	7,538	278	57	335	314	649	0	6,889	95	
SUMMER 03	Jul-2003	7,770	· 0	167	85	252	30	8,052	381	7,671	289	58	347	314	561	0	7,010	97	
SUMMER 03	Aug-2003	7,890	0	167	88	255	30	8,175	393	7,782	291	58	349	314	663	0	7,119	98	
SUMMER 03	Sep-2003	7,585	- 0	167	82	249	30	7,864	382	7,482	256	57	313	314	627	0	6,855	94	
SUMMER 03	Oct-2003	6,709	0	167	75	242	30	6,981	350	6,631	154	53	207	314	521	0	6,110	85	
WINTER 03/04	Nov-2003	6,507	0	167	72	239	30	5,776	421	6,355	267	33	300	314	614	0	5,741	79	
WINTER 03/04	Dec-2003	7,745	178	167	83	428	30	8,203	491	7,712	520	33	552	315	867	0	6,845	96	
WINTER 03/04	Jan-2004	8,985	- 461	167	. 94	722	30	9,737	508	9,229	593	33	626	310	936	0	8,293	112	
WINTER 03/04	Feb-2004	8,215	461	167	87	715	30	8,960	490	8,470	448	. 33	481	310	791	0	7,679	103	
WINTER 03/04	Mar-2004	7,295	0	167	77 -	244	30	7,569	444	7,125	314	34	348	310	658	0	6,467	87	
SUMMER 04	Apr-2004	6,294	Q	167	71	238	30	6,562	338	6,224	164	55	219	310	529	0	5,695	79	
SUMMER 04	May-2004	7,198	٥	167	79	246	30	7,474	371	7,103	205	59	264	310	574	. 0	6,529	90	
SUMMER 04	Jun-2004	7,787	0	167	86	253	30	8,070	390	7,680	245	60	305	310	615	0	7,065	97	
SUMMER 04	Jul-2004	7,929	ά α	167	86	253	30	8,212	396	7,816	255	61	316	311	627	0	7,189	99	
SUMMER 04	Aug-2004	8,052	6	167	88	261	30	8,343	408	7,935	257	61	318	311	629	0	7,306	101	
SUMMER 04	Sep-2004	7,740	0	167	84	251	30	8,021	397	7,624	226	60	286	311	597	0	7,027	96	
SUMMER 04	Oct-2004	6,846	0	167	75	242	30	7,118	363	6,755	136	56	192	311	503	0	6,252	86	
WINTER 04/05	Nov-2004	6,620	O	167	73	240	30	6,890	444	6,446	258	36	293	311	604	0	5,842	50	
WINTER 04/05	Dec-2004	7,881	189	167	83	439	30	8,350	519	7,831	503	36	539	311	850	0	6,981	98	
WINTER 04/05	Jan-2005	9,150	486	167	19	672	30	9,852	538	9,314	575	36	611	312	923	0	8,391	113	
WINTER 04/05	Feb-2005	8,365	481	167	19	667	30	9,062	519	8,543	434	36	470	312	782	٥	7,761	104	
WINTER 04/05	Mar-2005	7,429	o	167	18	185	30	7,644	470	7,174	304	37	341	312	653	0	6.521	88	
SUMMER 05	Apr-2005	6,423	o	167	17	184	30	6,637	350	6,287	145	58	203	312	515	0	5,772	30	
SUMMER 05	May-2005	7,346	0	167	18	185	30	7,561	384	7,177	181	62	243	312	555	. 0	6.622	91	
SUMMER 05	Jun-2005	7,948	0	167	18	185	30	8,163	404	7,759	216	63	280	313	593	· 0	7,166	. 95	
SUMMER 05	Jul-2005	8,092	0	167	18	185	30	8,307	410	7,897	225	64	289	313	602	C	7.295	100	
SUMMER 05	Aug-2005	8,218	15	167	18	200	30	8,448	423	8.025	227	- 64	291	313	604	· 0	7.421	102	÷.,
SUMMER 05	Sep-2005	7,899	0	167	18	185	30	8,114	41	7.703	199	53	263	313	576	0	7.127	95	
SUMMER 05	Oct-2005	6,935	0	167	17	184	30	7,200	376	6.824	120	60	179	313	492	0	6.332	83	
WINTER 05/05	Nav-2005	6,738	0	167	17	134	30	6,952	467	6,485	250	39	288	313	601	Ċ Ó	5.384	81	
WINTER 05/06	Dec-2005	8,022	200	167	17	384	30	8,436	546	7.890	489	39	528	314	842	٥	7.045	99	
WINTER 05/06	Jan-2006	9,314	513	167	11	691	30	10,035	569	9,466	560	39	599	314	913	0	8.553	116	9
WINTER 05/06	Feb-2005	8,515	509	167	11	687	30	9,232	548	8.634	423	40	462	314	776 .	o	7.908	106	60
WINTER 05/06	Mar-2006	7,561	0	167	11	178	30	7,769	496	7,273	296	40	336	314	650	ο.	5.623	89	ū
SUMMER 06	Apr-2006	6.552	· · o	167	11	178	30	6,760	362	6,398	128	61	189	314	503	0	5.895	82	Ā
SUMMER 06	May-2006	7,494	0	167	11	178	30	7,702	398	7.304	159	65	224	314	538	0	6,766	93	, <b>14</b>
SUMMER 06	Jun-2005	8.108	· 0	167	11	178	30	8,316	419	7.897	191	66	257	315	572	0	7 325	101	

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#### Normal Weather

#### **Bulk Power Sales Included**

				*					NON-DISP.	TOTAL	DIRECT LO	DAD CONTROL P	ROGRAMS		,	(USED)	FIRM	(AVAILABLE)
		POTENTIAL		WHO	LESALE			POTENTIAL	DSM	SYSTEM					TOTAL		SYSTEM	
-		TOTAL					CO.	TOTAL	& S.S.	BEFORE	RESIDENTIAL	OTHER DLC	TOTAL DLC	INTERR.	LOAD CONTROL	VOLTAGE	AFTER	VOLTAGE
5		RETAIL	REA	BULK	MUNI	TOTAL	USE	SYSTEM	COGEN	LOAD CONTROL	LOAD MGT.	PROGRAMS	PROGRAMS	LOAD	CAPABILITY	REDUCTION	LOAD CONTROL	REDUCTION
SEASON	MONTH	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)
SUMMER 06	Jul-2006	8,256	0	167	11	178	30	8,464	425	8,039	199	67	266	315	581	0	7,458	103
SUMMER 06	Aug-2006	8,384	25	167	11	203	30	8,617	439	8,178	200	67	267	315	582	0	7,595	104
SUMMER 06	Sep-2006	8,059	0	167	11	178	30	8,267	425	7,841	176	67	242	315	557	0	7,284	100
SUMMER 06	Oct-2006	7,127	0	167	11	178	30	7,335	389	6,946	105	63	158	315	483	0	6,463	89
WINTER 06/07	Nov-2006	6,856	0	167	11	178	30	7,064	491	6,573	243	42	285	315	600	0	5,973	82
WINTER 06/07	Dec-2006	8,164	209	167	11	387	30	8,581	574	8,007	477	42	519	316	835	o	7,172	100
WINTER 06/07	Jan-2007	9,479	540	167	11	718	30	10,227	599	9,628	546	42	589	316	905	0	8,723	118
WINTER 06/07	Feb-2007	8,666	536	167	11	714	30	9,410	577	8,833	412	43	455	316	771	o	8,062	105
WINTER 06/07	Mar-2007	7,694	0	167	11	178	30	7,902	522	7,380	289	43	332	315	648	0	6,732	91
SUMMER 07	Apr-2007	6,682	S. 0	167	11	178	30	6,890	374	6,516	113	64	177	316	493	0	6,023	84
SUMMER 07	May-2007	7,643	0	167	11	178	30	7,851	411	7,440	141	68	209	316	525	o	6,915	95
SUMMER 07	Jun-2007	8,270	0	167	11	178	30	8,478	433	8,045	168	69	238	317	555	0	7,490	103
SUMMER 07	Jul-2007	8,420	0	167	11	178	30	8,628	440	8,188	175	70	246	317	563	o	7,625	105
SUMMER 07	Aug-2007	8,551	33	167	11	211	30	8,792	454	8,338	176	70	247	317	564	0	7,774	107
SUMMER 07	Sep-2007	8,219	0	167	11	178	30	8,427	441	7,986	155	70	225	317	542	0	7,444	102
SUMMER 07	Oct-2007	7,268	C	167	11	178	30	7,476	402	7,074	93	66	159	317	476	0	6,598	91
WINTER 07/05	Nov-2007	6,976	0	167	11	178	30	7,184	513	6,671	237	45	282	318	600	0	6,071	83
WINTER 07/08	Dec-2007	8,306	220	167	11	398	30	8,734	601	8,133	467	45	512	318	830	0	7,303	102
WINTER 07/08	Jan-2008	9,644	566	167	11	744	30	10,418	628	9,790	534	45	580	318	898	o	8,892	120
WINTER 07/08	Feb-2008	8,816	560	167	11	738	30	9,584	605	8,979	403	46	449	318	767	0	8,212	110
WINTER 07/08	Mar-2008	7,828	o	167	11	178	30	8,036	547	7,489	282	46	328	318	646	0	6,843	93
SUMMER 08	Apr-2008	6,810	0	167	11	178	30	7,018	385	6,633	99	67	167	318	485	0	6,148	85
SUMMER 08	May-2008	7,792	0	167	11	178	30	8,000	424	7,576	124	71	195	319	514	0	7,062	97
SUMMER 08	Jun-2008	8,430	0	167	11	178	30	8,638	447	8,191	148	73	221	319	540	0	7,651	105
SUMMER 03	Jui-2008	8,584	0	167	11	178	30	8,792	454	8,338	155	73	228	319	547	0	7,791	107
SUMMER 08	Aug-2008	8,717	42	157	11	220	30	3,967	468	8,499	156	74	229	319	548	0	7,951	109
SUMMER 08	Sep-2008	8,379	0	167	11	178	30	8,587	455	8,132	137	73	210	319	529	0	7,603	104
SUMMER 08	Oct-2008	7,408	0	167	11	178	30	7,616	415	7,201	82	69	151	319	470	0	6,731	93
WINTER 08/09	Nov-2003	7,095	D	167	11	178	30	7,303	535	6,765	231	48	279	320	599	0	6,169	85
WINTER 08/09	Dec-2008	8,445	230	167	- 11	408	30	8,886	627	8,259	457	48	505	320	825	0	7,434	104
WINTER 08/09	Jan-2009	9,810	592	167	11	770	30	10,610	657	9,953	523	49	572	320	592	o	9,061	123
WINTER 08/09	Feb-2009	5,965	587	167	11	765	30	9,763	633	9,130	395	49	444	320	764	. 0	8,366	112
WINTER 08/09	Mar-2009	7,962	0	167	11	178	30	8,170	572	7,598	276	49	325	320	645	. 0	6,953	94
SUMMER 09	Apr-2009	6,941	٥	167	11	178	30	7,149	396	6,753	88	71	158	320	478	D	6.275	87
SUMMER 09	May-2009	7,942	0	167	11	178	30	8,150	437	7,713	109	74	184	321	505	0	7.208	99
SUMMER 09	Jun-2009	8.592	0	167	11	178	30	8,800	461	8.339	131	76	207	321	528	. 0	7.811	107
SUMMER 09	Jul-2009	8,749	0	167	11	178	30	8,957	468	8,489	136	76	213	321	534	0	7.955	109
SUMMER 09	Aug-2009	8.885	51	167	11	229	30	9,144	483	8,661	137	77	214	321	535	0	5,125	111
SUMMER 09	Sep-2009	8.540	0	167	11	178	30	8,748	469	8.279	121	76	197	321	518	0	7.761	105
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#### Normal Weather

### Bulk Power Sales Included

										NON-DISP.	TOTAL	DIRECT LC	DAD CONTROL P	ROGRAMS			(USED)	FIRM	(AVAILABLE)
			POTENTIAL		WHO	LESALE			POTENTIAL	DSM	SYSTEM			<u></u>		TOTAL		SYSTEM	
;			TOTAL	mg#Rebbin				<b>co</b> .	TOTAL	& S.S.	BEFORE	RESIDENTIAL	OTHER DLC	TOTAL DLC	INTERR.	LOAD CONTROL	VOLTAGE	AFTER	VOLTAGE
2			RETAIL	REA	BULK	MUNI	TOTAL	USE	SYSTEM	COGEN	LOAD CONTROL	LOAD MGT.	PROGRAMS	PROGRAMS	LOAD	CAPABILITY	REDUCTION	LOAD CONTROL	REDUCTION
	SEASON	MONTH	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)
	SUMMER 09	Oct-2009	7,551	0	167	11	178	30	7,759	428	7,331	72	72	144	321	465	0	6,865	95
,	WINTER 09/10	Nov-2009	7,215	0.	167	11	178	30	7,423	557	6,866	226	51	277	322	599	0	6,267	86
,	WINTER 09/10	Dec-2009	8,591	240	167	11	418	30	9,039	654	8,385	448	51	499	322	821	0	7,564	106

······································	100.00	Eab 00	Mar 00	Apr.00	May-00	tun-00	Jul 00	Aug.00	Sen-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01
Read and Director (Duran and Winter Game Defense)	3419-00	C50-00	mareov		may-ou	5411-00		Aug-ou	Separ						I			I	I	t			
Daseroad Plants (Summer and Winter Dase Rapitos)	245	785	795	791	381	381	381		381	381	345	355	386	336	386	381	381	381	381	295	381	351	386
Crystal River 1	300	480	480	469	401	493	493	493	493	493	504	504	504	504	504	493	493	493	493	493	493	493	504
Crystal River 2	704	704	724	704	721	721	721	721	721	721	741	741	741	741	741	721	721	721	721	721	721	721	741
Crystal River 4	724	724	724	714	714	714	714	714	714	714	734	734	734	734	734	714	714	714	714	714	714	714	734
Crystal River 5	734	740	704	714	765	765	765	765	765	765	782	782	782	782	782	765	765	765	765	765	765	765	782
Crystal River 3	762	/82	102	765	705	103	200	765	703	705	102		44			36	36	36	36	36	36	36	44
University of Florida Cogen	44	44	44	30	30			30	30													L	
Baseload Contracts (Firm Purchase Capacity)	400	400	400	400	400	400	400	400	4001	400	409	409	409	409	409	409	409	409	409	409	409	409	409
UPS Purchase from Southern Company	409	409	409	409	409	409	409	409	409	403	403	- 403 601	60	60	60	50	60	60	60	60	60	60	60
TECO Purchase for Sebring Load	60	50	60	60	60	60	60	DU	00	60	00	00	00										
<u>QF Contracts</u>					40		40		40	40	40	40	40	40	40	أمه	40	40	40	40	40	40	40
PINELLAS CO RES REC 1	40	40	40	40	40	40	40	40	40	40	40		15	15	15	15	15	15	15	15	15	15	15
PINELLAS CO RES REC 2	15	15	15	15	15	15	15	15	15	10				13		13	13	13	13	13	13	13	13
TIMBER ENERGY 1	13	13	13	13	13	13	13	13	13	13		13	13	13				- 11	11	11	11	11	11
BAY COUNTY RES REC	11	11	11	11	11	11	11																9
LFC MADISON (APP)	9	9	9	9	9	9	9			9	a	9		9						-		9	
LFC JEFFERSON (APP)	9	9	9	9	9	9	9	9		9	9	9		43				- 13	11	13	13	13	
LAKE COUNTY RES REC	13	13	13	13	13	13	13	13	13	13	13	13	13			221	22	23	21	23	23	23	23
PASCO COUNTY RES REC	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	42	42		43	47	43	43
DADE COUNTY RES REC	43	43	43	43	43	43	43	43	43	43	43	43	43	43	40	45				15	15	15	15
CARGILL	15	15	15	15	15	15	15	15	15	15	15	15	15	15	110	10	110	110	110	110	110	110	110
LAKE COGEN	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	100	109	100	109	109	109	109	109
PASCO COGEN	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	70	70	701		79	70	79	79
ORLANDO COGEN	79	79	79	79	79	79	79	79	79	79	19		/9	/9	19	/5	13	40	A	40	40	40	40
RIDGE GENERATING STA	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	114	114	114	114	114	114	114
EL DORADO (APP)	114	114	114	114	114	114	114	114	114	114	114	114								31	31	31	31
ROYSTER (PPP)	31	31	31	31	31	31	31	31	31	31	31	31	31	31	20	70	70	70	70	70	79	79	79
MULBERRY (PPP)	79	75	79	79	79	79	79	79	79	79	79	.79	74	73	74	73	74	74	74	74	74	74	74
CFR-BIOGEN (ORANGE CO	/4	14	14		14	/4	/4	/4		(4			<u> </u>				6		<u> </u>			5 6	6
USAGRICHEN	6	8	6	5 6	5 6	6	5	6	b	6		•				ļ	۳ <u>، ۱</u>		l'	1	1	1	·
Intermediate Resources (Summer and Winter Base Ratings)					ļ						547	E 4 7	£17	547	512	507	507	507	50	7 507	50	7 507	512
Anciole	512	512	512	2 507	507	507	507	507	507	507	512	512	512	512	512	507	507	507	50	50	50	502	522
Anciole 2	2 522	522	522	2 502	2 502	502	2 502	502	502	502	522	522	522	522	522	502	302	502		2 302		1173	116
Barlow	1 116	116	116	113	113	113	113	113	113	113	116	116	116	110	110	113	113	113			1	1 417	117
Bartow	2 117	117	117	113	3 113	113	113	113	113	113	11/	11/	11/	11/	11/	113	113	113	20	7 203	20	207	210
Barlow	3 210	210	210	207	207	207	207	207	207	207	210	210	210	210	210	207	207	207	20	201	20	201	34
Suwannee River	1 34	34	34	4 33	3 33	33	3 33	33	33	33	34	34	34	34	34	33	33	33					37
Suwannee River	2 33	3 33	3 33	3 33	2 32	32	32	32	32	32	33	33	3	3	33	32		32					33
Suwannee River	3 85	5 85	5 85	5 8	5 85	85	5 85	85	85	35	85	85	8	8	8	85		35	20	0 20	20	200	240
Tiger Bay Coge	n 240	240	240	200	200	200	200	200	200	200	240	240	240	240	240	200	200	200	20	20	47	470	505
Hines Energy Complex	1 505	5 50	5 505	5 47	470	470	470	470	470	470	505	505	50	50	50	470	4/0	4/0	4/	4/	4/	4/0	
Hines Energy Complex	2 0		0 0	0	0 0	1	0 0	0		0							0		<u> </u>	0	<u></u>		1 0
Hines Energy Complex	3 (	0		0	0 0		0 0	0		0		1 (	)	0	0	<u>, , , , , , , , , , , , , , , , , , , </u>	<u> </u>	<u> </u>	1	<u> </u>	<u> </u>	<u>vi</u>	<u> </u>
Gas Peaking Resources (Summer Base Rating @ 95*F.						•									1								
Spring/Fall Base Rabing @ 90"F. Winter Peak Rating @ 32"F)	1 3	4 3	4 3	4 2	4 24	19	9 19	19	24	24	24	4 34	4 3	4 3	4 3	4 24	24	19	1	9 1	9 2	4 24	24
Avon Park P	2 6	4 5	4 5	4 4	6 44	4	6 46	4	4	46	4	5 54	4 5	4 5	4 5	4 40	45	46	5 4	6 4	6 4	6 46	46
Barlow P		2	2	2 - 4	4		4	40	44	49	4	6	2 6	2 6	2 6	2 49	49	49	4	19 4	9 4	9 49	3 49
Bartow P	7 6				6 74		2 7	1.1.1.7	2 74	76	7	5 9	8 9	8 9	8 9	8 70	5 75	72	2	2 7	2 7	6 76	5 76
Depart P				. 7	61 7	+ +	2 7	7	2 70	5 76	7	6 9	s 9	3 9	8 9	8 7	5 76	7	2	2 7	2 7	6 78	5 76
Debary H	3 3	4	4 7	<u> </u>	5 7		4 2		4 2	5 20		5	4 3	4 3	4 3	4 2	5 25	24	4	24 2	4 2	5 25	5 25
Higgins F					5 2		4 2		4 2	5 2		5 3	4	4 3	4 3	4 2	5 25	24	4 3	24 2	4 2	5 25	25
Higgins F	4			4	2			2		1 2	1	1 1	6 7	6 3	6 3	6 3	1 31	29	9	29 2	9	11 31	31
Higgins F	3 3	3		3	3	2		2	3		<u> </u>	1	6 7	6 3	6 3	6 3	1 31	29		29 2	19	11 31	31
Higgins P	<u>عا</u> 3	- J	- jo		n a	ч ×	- 2	' L	- J		1 3		- I		·	-1	1		1				<u> </u>

tysp2000.xis : Normal Capacity

Page 1 of 12

FPC 099

7 19:00 @ 12 25 PM

	Jan-00	Feb-00	Mac-00	Apr-00	May-00	Jun-00	Jui-00	Aug-00	Sep-00	Oct-00	Nov-60	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01
Intercession City P7	98	98	98	83	83	84	84	84	83	83	83	98	93	. 98	98	83	83	84	84	84	83	83	83
Intercession City P8	98	98	98	83	83				83	83	83	98	98	98	98	83	83	84	84	84	. 83	83	83
Intercession City P9	98	93	98	83	<u>5</u> 3	84	84	84	83	83	83	98	98	. 98	98	83	83	84	- 84		83	83	83
Intercassion City P10	98	98	98	83	83	64	84	84	<b>8</b> 3	83	83	98	98	98	98	83	83	84	84	84	83	83	83
Intercession City P12	0	0	0	0	0	0	0	0	0	0	0	99	99	99	99	83	83	83	83	83	63	83	83
Intercession City P13	<u> </u>	0	0	0	0	0	0	0	0	0	0	99	- 99	99	99	83	83	83	83	83	' 83	\$3	83
Intercession City P14	0	0	0	0	G	0	0	<u> </u>	0	0	0		• 99	99	99	83	83	83	83	83	83	83	\$3
Suwannee River P1	68	63	68	49	49	44	44	44	49	49	49	68	68	68	58	49	49	44	44	44	49	49	49
Suwannee River P3	58	63	63	49	49	44	44	44	49	49	49	68	68	63	68	49	49	44	44	44	49	49	49
Light Oil Peaking Resources (Summer Base Rating @ 95°F. Spring/Fall Base Rating @ 90°F. Winter Peak Rating @ 32°F)															<u> </u>								
Avon Park P2	34	34	34	24	24	19	19	19	24	24	24	34	34	34	34	24	24	19	19	19	24	24	24
Bartow P1	54	54	54	46	45	46	45	46	46	45	46	54	54	54	54	46	46	46	46	46	45	46	45
Bartow P3	54	54	- 54	46	45	46	46	46	46	46	45	54		54	54	46	46	46	46	46	46	45	46
Bayboro P1	60	60	60	44	44	41	41	41	44	- 44	44	60	60	60	60	44	44	41	41	41	44	44	
Bayboro P2	60	60	60	44	44	41	41	41	44	44	44	60	60	60	60	44	44	41	41	41	44	44	
Bayboro P3	60	60	60	44	44	41	41	41	44	44	44	60	60	60	60	44	44	41	41	41	44	44	
Bayboro P4	60	60	50	44	44	41	41	41	44	44	- 44	60	60	60	60	44	44	41	41	41	44	44	44
Debary P1	67	67	67	49	49	- 44	44	44	49	49	49	67	67	67	67	49	49	44	44	. 44	49	49	49
Debary P2	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44	49	49	49
Debary P3	67	67	57	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44	49	49	49
Debary P4	67	67	67	49	49	44	44	44	49	49	49	67	67	67	<del>6</del> 7	49	49	44	44	44	49	49	49
Debary P5	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44	49	49	49
Debary P6	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44	49	49	49
Debary P8	96	96	96	. 76	76	72	72	72	76	76	76	96	95	96	96	76	76	72	72	72	76	76	76
Debary P10	96	96	96	76	76	72	72	72	76	75	76	96	96	96	96	76	76	72		72	76	76	75
Intercession City P1	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47	47	47	47
Intercession City P2	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47	47	47	47
Intercession City P3	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	. 47	47	47	47	47	47	47	47
Intercession City P4	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47	47	47	47
Intercession City P5	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	· 47	47	47	47	47	47
Intercession City P6	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47	47	47	47
Intercession City P11	172	172	172	143	143		0	0	0	143	143	172	172	172	172	143	143	0			0	143	143
Rio Pinar P1	19	19	19	13	13	11	11	11	13	13	13	19	19	19	19	13	13	11	11	11	13	13	13
Suwannee River P2	. 63	63	63	51	51	48	43	45	51	51	51	68	63	68	68	63	51	45	45	43	51	51	51
Turner P1	19	19	19	13	13	11	11	11	13	13	13	19	19	19	19	19	13	. 11	11	11	13	13	13
Turner P2	19	19	19	13	13	11	11	11	13	13	13	19	19	19	19	19	13	11	11	11	13	13	13
Turner P3	84	84	84	61	61	57	57	57	61	61	61	84	84	84	- 54	84	61	57	57	57	61	61	61
Turner P4	54	54	34	61	61	57	57	57	61	61	61	84	84		. 84	-84	61	57	57	57	61	61	51
Total Baseload Plants	3,150	3,150	3,150	3.069	3,110	3,110	3,110	3,024	3,110	3,110	3,191	3,191	3,191	3,191	3,191	3,110	3,110	3,110	3,110	3,024	3,110	3,110	3,191
Total Baseload Contracts	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469
Total QF Contracts	831	831	831	831	831	\$ 531	331	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831
Total Intermediate Resources	2,374	2,374	2,374	2.262	2,262	2,262	2,262	2,262	2,262	2,262	2,374	2,374	2,374	2,374	2,374	2,262	2,262	2,262	2,252	2,262	2,262	2,262	2.374
Total Gas Peaking Resources	1,014	1,014	1.014	813	813	789	789	789	813	813	81:	3 1,311	1,311	1,311	1,311	1,062	1,062	1,038	1,038	1,038	1,052	1,062	1,06
<u>Total Light Oil Peaking Resources</u>	1,81	1,813	1,813	1.375	1,375	1,160	1,160	1,160	1,232	1,375	1,37	5 1,813	1,813	1.813	1.813	1,450	1,375	1,160	1,160	1,160	1,232	1,375	1,37
Total Available Resources	9,65	9,651	9.651	8.819	8,360	8,622	8,622	8,536	8,717	8,860	9.05:	3 9.959	9,989	9,989	9,989	9,154	9,109	8,871	8,871	8,785	8,966	9,109	9,302

	Dec-01	Jan.02	Feb-02	Mar-07	Apr-02	May-02	Jun-82	Jul-02	Aug.02	Sen-02	001-02	Nov-02	Dec 02	120.03	Eab 07	Mar.07	Apr 07	Have 0.3	hun 02	- Iul 02	4100 07 1	Fan 07	0 1 0 7
Baseload Plants (Summer and Winter Base Patients)						mey-or					OCI-OZ		Dave	Jan-03		mai+03	Apr-03	May-03   .	un-es	101-03	Aug-03	Sep-us	001-03
Costd Piver 1	386	402	403	403	398	30.81	108	308		2091	30.8	402	403	407	403	403	208	208	708	200	Int	leoc.	200
Costal River 2	504	504	504	504	493	493	493	493	493	000	493	504	504	504		403	330	407	402	250	402	402	
Costal River &	741	741	741	741	721	721	721	721	721	721	721	741	741	741	741	741	721	704	701	433	493	490	
Constal Piver 5	734	734	734	734	. 714	714	714	714	714	714	744	794	774	734	791	741	721	721		721	721	721	
Crystal Pover 3	7.52	782	782	782	765	765	765	765	765	765	765	787	792	793	782	7.34	714	7 14	714	714	765	714	705
Lioiuarrity of Elorida Cenan	44	102		102			700		26	20		- 102	- 102		102	102		- 103	103	105		- 103	
Baseload Contracts (First Buseload Conscient)		1	**		<u>, 30</u>			30	<u> </u>					**		44	106	30	36	30]	30	35	36
LICE Durchase Capacity	400	4001	400	4001	400	400	4001	400	400	4001	400	4001	400	400									
OPS Porchase itom Southern Company	403	403	403	405	405	403	403	405	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409
IECO Purchase for Septing Load	60	00	60	50	- 60	60		50	501	60	60]	60	60	60	60	60	60	60	60	60	60	60	50
<u>QF Contracts</u>																<u> </u>							<u> </u>
PINELLAS CO RES REC 1	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40]	40	40	40	40	40	40	40	40
PINELLAS CO RES REC 2	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
TIMBER ENERGY 1	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	. 13	13	13	13	13	13	13	13
BAY COUNTY RES REC	11	11	11	11	11	11	11	11	11	11	11	. 11	11	11	11	11	11	11	11	11	11	11	11
LFC MADISON (APP)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
LFC JEFFERSON (APP)	9	9	9	9	9	9		9	9	9	9	9	. 9	9	9	9	9	9	9	9	e	9	9
LAKE COUNTY RES REC	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
PASCO COUNTY RES REC	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
DADE COUNTY RES REC	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
CARGILL	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
LAKE COGEN	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
PASCO COGEN	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109
ORLANDO COGEN	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79
RIDGE GENERATING STA.	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	· 40	40	40	40	40	40	40	40
EL DORADO (APP)	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114
ROYSTER (PPP)	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
MULBERRY (PPP)	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79
CFR-BIOGEN (ORANGE CO)	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74
USAGRICHEM	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Intermediate Resources (Summer and Winter Base Ratings)																						¹	
Anciole 1	512	512	512	512	507	507	507	507	507	507	507	512	512	512	512	512	507	507	507	507	507	507	507
Anciole 2	522	522	522	522	502	502	502	502	502	502	502	522	522	522	522	522	502	502	502	502	502	502	502
Bartow 1	115	116	116	116	113	113	113	113	113	113	113	116	116	115	116	115	113	113	113	113	113	113	113
Bartow 2	117	117	117	117	113	113	113	113	113	113	113	117	117	117	117	117	113	113	113	113	113	113	113
Bartow 3	210	210	210	210	207	207	207	207	207	207	207	210	210	210	210	210	207	207	207	207	207	207	207
Suwannee River 1	34	34	34	34	33	33	33	33	33	33	33	34	34	34	34	34	33	33	33	33	33	33	33
Suwannee River 2	33	33	33	33	32	32	32	32	32	32	32	33	33	33	33	33	32	32	32	32	32	- 32	32
Suwannee River 3	85	5 85	85	85	85	85	85	85	85	85	85	85	85	85	85	\$5	35	85	85	85		85	
Tiger Bay Cooen	240	240	240	240	200	200	200	200	200	200	200	240	240	240	240	240	200	200	200	200	200	200	200
Hines Energy Complex 1	505	505	505	505	470	470	470	470	470	470	470	505	505	505	505	505	470	470	470	470	470	470	470
Hines Energy Complex 7			0	0	0							0									470		
Hines Energy Complex 2			0		0				0			0											
Gas Peaking Resources (Summer Base Rating @ 95°F		1		1		1 • *			۲ <u> </u>			۲ <u>ــــــــــــــــــــــــــــــــــــ</u>			۲ <u> </u>		<u>۹</u>			1			
Spring/Fall Base Rating @ 90°F. Winter Peak Rating @ 32°F)				·	( 19 S																		
Avon Park P1	34	34	34	34	24	24	19	19	19	24	24	24	34	34	34	34	24	24	19	19	19	24	24
Bartow P2	54	54	54	54	46	46	46	46	46	46	46	46	54	54	54	54	46	46	46	46	45	46	46
Barlow P4	62	2 62	62	62	49	49	49	49	49	49	49	49	62	62	62	62	49	49	49	49	49	49	49
Debary P7	95	98	98	98	76	76	72	72	2 72	76	76	76	98	98	95	98	76	76	.72	72	72	76	76
Debary PS	98	5 98	- 98	· 98	76	76	72	72	2 72	76	76	76	95	98	98	95	76	76	72	72	72	76	76
Higgins P1	34	4 34	34	34	25	25	24	24	24	25	25	25	34	34	34	34	25	25	24	24	24	25	25
Higgins P2	34	4 34	34	34	25	25	24	24	24	25	25	25	34	34	34	34	25	25	24	24	24	25	25
Hianins P3	36	6 36	36	36	31	31	29	29	29	31	31	31	35	36	36	36	31	31	29	25	. 29	31	31
Higgins P4	36	5 35	36	36	31	31	29	29	29	31	31	31	36	36	36	36	31	31	29	29	29	31	31

	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03
Intercession City P7	98	98	98	93	83	83	84	84	84	83	83	83	93	98	95	98	83	83	84	84	84	83	\$3
Intercession City P8	98	98	98	95	83	83	84	84	84	83	83	83	98	98	98	98	83	83	84	84	84	83	83
Intercession City P9	98	93	98	98	83	83	84	84	84	83	\$3	83	95	98	98	98	83	83	\$4	84	84	83	83
Intercession City P10	98	98	93	98	83	83	84	84		83	\$3	83	98	98	95	.98	83	83		84	84	83	83
Intercession City P12	99	99	99	99	83	83	83	83	83	83	83	83	99	99	99	99	83	83	83	83	, 83	83	83
Intercession City P13	× 99	99	99	99	83	83	83	83	83	83	83	83	99	99	99	99	83	83	83	83	83	83	83
Intercession City P14	99	99	99	99	83	83	83	83	83	83.	83	83	99	99	99	99	83	83	83	83	83	83	83
Suwannee River P1	68	65	65	68	49	49	44	44	44	49	49	49	68	68	65	68	49	49	44	44	44	49	49
Suwannee River P3	68	68	63	68	49	49	44	44	44	49	49	49	68	68	63	63	49	49	44	44	44	49	49
Light Oil Peaking Resources (Summer Base Rating @ 95°F. Sorino/Fall Base Rating @ 90°F. Winter Peak Rating @ 32°F1															÷								
Avon Park P2	34	34	34	34	24	24	19	19	19	24	24	24	34	34	34	34	24	24	19	19	19	24	24
Bartow P1	54	54	54	54	46	46	46	46	46	46	46	46	54	54	54	54	45	46	46	45	46	46	46
Bartow P3	54	54	54	54	46	45	46	46	46	46	45	46	54	54	54	54	46	46	45	46	46	46	46
Bayboro P1	60	60	60	60	44	44	41	41	41	44	44	44	60	60	60	60	44	44	41	41	41	44	44
Bayboro P2	60	60	60	60	44	44	41	41	41	44	44	44	60	60	60	60	44	44	41	41	41	44	44
Bayboro P3	60	00	60	60	44	44	41	41	41	44	44	44	60	60	60	60	44		41	41	41	44	44
Bayboro P4	60	50	60	60	44	44	41	41	41	44	44	44	60	60	60	60	44	44	41	41	41	44	44
Debary P1	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44	49	49
Debary P2	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	. 49	49	44	44	44	49	49
Debary P3	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44	49	49
Debary P4	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44	49	49
Debary P5	67	67	67	67	49	49	44	44	44	49	49	49	67	. 67	67	67	49	49	44	44	44	49	- 49
Debary P6	67	67	67	67	49	49	44	44	44	49	49	49	67	67	57	67	49	49	44	44	44	49	49
Debaty P8	96	96	96	96	76	76	72	72	72	76	76	76	96	96	96	96	76	76	72	72	72	76	76
Debary P10	96	96	96	96	76	76	72	72	72	76	76	76	96	96	96	96	76	76	72	72	72	76	76
Intercession City P1	62	62	62		47	. 47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47	47	47
Intercession City P2	62	62	62	52	47	47	47	47	47	47	47	47	<u>52</u>	62	62	. 62	47	47	47	47	47	47	47
Intercession City P3	62	62		62	41	47		41	47	47	47	47		62	62		4/	47	41	47	47	4/	41
intercession City P4	62	62	62	62	41	47	47	47	47	47	41	47	62	62	02	62	4/	47	47	4/	4/	4/	4/
Intercession City P5	62	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	4/	47	47	47	47	47
interession City P1	172	172	172	172	143	143		0	0		143	143	172	172	172	172	143	143					143
Bin Dinar Pi	19	- 19	19	19	13	13	11	11	11	13	13	13	19	19	19		13	13	11	11	11	13	143
Stwappee Biver P2	65	68	68	68	68	51	48	48	48	51	51	51	68	68	68	63	68	51	43	45	43	51	51
Turner Pt	19	19	19	19	19	13	11	11	11	13	13	13	19	19	19	19	19	13	11	11	11	13	13
Turner P2	19	19	19	19	19	13	11	11	11	13	13	13	19	19	19		19	13	11	11	11	13	13
Turner P3	84	84	84	84	84	61	57	57	57	61	61	61	84	84	84	84	84	. 61	57	57	57	61	61
Turner P4	84	84	-84	34	84	61	57	57	57	61	61	61	84	54	\$4	84	84	61	57	57	57	61	61
Total Baseload Plants	3,191	3,205	3,205	3,208	3,127	3,127	3,127	3,127	3,041	3,127	3,127	3,208	3,208	3,208	3,208	3,208	3,127	3,127	3,127	3,127	3,041	3,127	3,127
Total Baseload Contracts	469	469	469	469	469	469	469	469	459	469	469	469	469	469	469	469	469	469	469	469	469	469	469
Total QF Contracts	831	\$31	831	\$31	831	534	531	831	831	831	831	831	831	\$31	\$31	831	\$31	831	831	831	831	\$31	831
Total Intermediate Resources	2,374	2,374	2.374	2.374	2,262	2,262	2,262	2,262	2,262	2,262	2,262	2,374	2,374	2.374	2.374	2,374	2,252	2,262	2,262	2,262	2,262	2,262	2,262
Total Gas Peaking Resources	1,311	1,311	1,311	1.311	1,062	1,052	1,038	1,038	1,038	1,062	1,062	1,062	1,311	1.311	1.311	1,311	1,052	1,062	1,038	1,038	1,038	1,062	1,062
Total Light Oil Peaking Resources	1.813	1,813	1,513	1.813	1,450	1,375	1,160	1,160	1,160	1,232	1,375	1,375	1,813	1,813	1.813	1,813	1,450	1,375	1,160	1,160	1,150	1,232	1,375
Total Available Resources	9,989	10.006	10.006	10,006	9,201	9,126	8,888	8,888	\$,802	8,983	9,126	9,319	10.006	10.006	10.006	· 10.005	9,201	9,126	8,888	8.883	3,802	8,953	9.125

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Page 4 of 12

N N	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	.Jan-05	Feb-05	Mar-05	Anr-05	May-05	Jun_05	.lui-05	Aun.05	Sen .05
Baseloud Plants (Summer and Winter Base Rations)																							2000
Crystal River 1	403	403	403	403	403	398	398	398	398	312	398	398	403	403	403	403	403	398	398	305	398		368
Crystal River 2	504	504	504	504	504	493	493	493	493	493	493	493	504	504	504	504	504	403	493	402	402	403	402
Crystal River 4	741	741	741	741	741	721	721	721	721	721	721	721	741	741	741	741	7/1	721	721	721	701	721	721
Costal Pilor S	734	734	734	734	734	714	714	714	714	714	714	714	724	734	724	724	794	714	744	721	725	721	741
Corplet Pines 2	3 782	782	792	782	782	765	765	765	765	714	765	74	702	7.04	7.04	704	734	714	714	714	1714	714	714
	192	102	102	102	102	201		201	705	105	703	/05	/02	102	/02	102	102	765	705	765	/65	765	765
Chiversity of Fionda Cogen	44		44	44	44			30		36	36	36	44	44	44	44	44	36	35	36	36	36	36
	400	4001							(aal								·						
UPS Purchase from Southern Company	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409
TECO Purchase for Sebring Load	60	60	60	60	60	60	60	60	60	60	<u>60</u>	60	60	60	70	70	70	70	70	70	70	70	70
<u>QF Contracts</u>												<u>г т</u>					·						<u> </u>
PINELLAS CO RES REC 1	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
PINELLAS CO RES REC 2	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
TIMBER ENERGY 1	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
BAY COUNTY RES REC	11	11	11	11	11	11			11	11	11	11	11	. 11	11	11	11	11	11	11	11	11	11
LFC MADISON (APP)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	و	9	9	9
LFC JEFFERSON (APP)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
LAKE COUNTY RES REC	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
PASCO COUNTY RES REC	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
DADE COUNTY RES REC	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
CARGILL	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
LAKE COGEN	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
PASCO COGEN	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109
ORLANDO COGEN	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	- 79	79	79	79	79
RIDGE GENERATING STA.	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
EL DORADO (APP)	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	.114	114	114	114
ROYSTER (PPP)	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
MULBERRY (PPP)	79	79	79	79	79	79	79	79	79	. 79	79	79	79	79	79	79	79	79	79	79	79	79	79
CFR-BIOGEN (ORANGE CO)	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74
US AGRICHEM	6	6	6	5	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Intermediate Resources (Summer and Winter Base Ratings)																							
Anciote 1	512	512	512	512	512	507	507	507	507	507	507	507	512	512	512	512	512	507	507	507	507	507	507
Anciote 2	522	522	522	522	522	502	502	502	502	502	502	502	522	522	522	522	522	502	502	502	502	502	502
Bartow 1	116	115	116	116	116	113	113	113	113	113	113	113	116	116	116	115	115	113	113	113	113	113	113
Barlow 2	117	117	117	117	117	113	113	113	113	113	113	113	117	117	117	117	117	113	113	113	113	113	113
Barlow 3	210	210	210	210	210	207	207	207	207	207	207	207	210	210	210	210	210	207	207	207	207	207	207
Suwannee River 1	0	0	0	0	0	0	0	0	0	0	Û	0	0	6	0	0	0	0	. 0	0	0	0	0
Suwannee River 2	2 0	0	0	0	0	0	0	0	0	0	0	0	0	(	C	0	0	0	0	0	0	- 0	0
Suwannee River 3	0	0	0	0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	0	0	0	0
Tiger Bay Coger	240	240	240	240	240	200	200	200	200	200	200	200	240	240	240	240	240	200	200	200	200	200	200
Hines Energy Complex 1	505	505	505	505	505	470	470	470	470	470	470	470	505	505	505	505	505	470	470	470	470	470	470
Hines Energy Complex 2	2 567	567	567	567	567	495	495	495	0	495	495	495	567	567	567	567	567	495	495	495	495	495	495
Hines Energy Complex 3	3 0	0	0	0	0	8	0	0	0	0	0	0	0	0	0	0	0	0	0	. 0	0	0	0
Gas Peaking Resources (Summer Base Rating @ 95*F.		1		1	·		i		·	h		·			4				•		1	l	
Spring/Fall Base Rating @ 90°F, Winter Peak Rating @ 32°F)		r		1		1								r	r				r		·		
Avon Park P1	24	34	34	34	34	24	24	19	19	. 19	24	24	24	34	34	34	34	24	24	19	19	19	24
Bartow P2	2 46	54	54	54	54	46	46	46	46	46	46	46	46	54	54	54	54	46	46	46	46	46	46
Bartow P4	49	62	62	62	62	49	49	49	49	49	49	49	49	62	62	62	62	49	49	49	49	49	49
Debary P7	7 76	98	98	98	98	76	76	72	72	72	76	76	. 76	98	98	98	93	76	76	72	72	72	76
Debary PS	76	95	93	98	93	76	76	72	72	72	76	76	76	98	98	93	93	76	76	72	72	72	76
Higgins P1	1 25	34	34	34	34	25	25	24	24	24	25	25	25	34	34	34	34	25	25	24	24	24	25
Higgins P2	2 25	34	34	34	34	25	25	24	24	24	25	25	25	34	34	34	34	25	25	24	24	24	25
Higgins P	3 31	36	36	36	36	31	31	29	29	29	31	31	31	36	36	36	36	31	31	29	29	29	31
Higgins P4	4 31	36	36	36	36	31	31	29	29	29	31	31	31	36	36	36	36	31	31	29	29	29	31

Page 5 of 12

FPC 103

7.19.00 @ 12:25 PM

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	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jui-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05
Intercession City P7	83	98	98	98	98	83	83	84	64		83	83	\$3	98	98	98	98	83	83	84	84	84	83
Intercession City P8	83	98	96	98	98	83	83	84	84	84	83	83	83	98	98	98	98	83.	83	84	84	84	83
Intercession City P9	83	98	98	98	98	83	83	84	84	84	83	83	83	98	98	98	98	83	83	34	84	84	83
Intercession City P10	83	98	98	98	93	83	83	84	84		83	53	83	98	98	98	98	83	83	84	84		83
Intercession City P12	83	99	99	99	99	83	83	83	83	83	83	63	83	99	99	99	99	63	83	83	1 83	83	83
Intercession City P13	× 83	99	99	99	99	83	83	83	83	83	83	83	83	99	99	99	99	83	83	83	83	83	83
Intercession City P14	. 83	99	99	99	99	83	83	83	83	83	83	83	83	99	99	99	99	83	83	83	83	83	83
Suwannee River P1	49	68	68	68	68	49	49	44	44	44	49	49	49	68	68	68	68	49	49	44	44	44	49
Buwannee River P3	49	63	63	68	63	49	49	44	44	44	49	49	. 49	68	68	68	63	49	49	44	44	44	49
Light Oil Peaking Resources (Summer Base Rating @ 95°F,																							
Avon Park P2	24	34	34	34	34	24	24	19	19	19	24	24	24	34	34	34	34	24	24	101	19	19	24
Bartow P1	45	54	54	54	54	46	46	46		45	46	46	45	54	54	54	54	46	45	45	46	45	45
Bartow P3	46	54	54	54	54	46	46	46	- 46	46	46	46	46	54	54	54	54	45	46	45	46	45	45
Bayboro Pt	44	60	60	60	60	44	44	41	41	41	44	44	44	60	60	60	60		44	41	41	41	
Bayboro P?	44	60	60	60	60	44	44	41	41	41	44	44	44	60	60	60	60		44	41	41		
Bayboro P3	44	60	60	60	60	44	44	41	41	41	44	44	44	60	60	60	60		44	41	41	41	
Bayboro P4	44	60	60	60	60	- 44	44	41	41	41	44	44	44	60	60	60	60	44		41	41	41	44
Debary P1	49	67	67	67	67	49	49	44		44	49	49	49	67	67	67	67	49	49	44	44	44	49
Debary P2	49	67	67	67	67	49	49	44	- 44	44	49	49	49	67	67	67	67	49	49	44	44	44	49
Debary P3	49	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44	49
Debary P4	49	67	67	67	67	49	49	44	- 44	44	49	49	49	67	67	67	67	49	49		44	44	49
Debary P5	49	67	67	67	67	49	49	44	44	44	49	49	49	. 67	67	67	67	49	49	44	44	44	, 49
Debary P6	49	67	67	57	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	- 44	44	44	49
Debary P3	76	96	96	95	96	76	76	72	72	72	76	76	76	96	96	96	96	76	76	72	72	72	76
Debary P10	76	96	96	96	96	76	76	72	72	72	76	76	76	96	96	96	96	76	76	72	72	72	76
Intercession City P1	47	62	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47	47
Intercession City P2	47	62	\$2	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47	47
Intercession City P3	47	62	62	62	62	47	47	47	47	47	47	47	. 47	62	62	62	62	47	47	47	47	47	47
Intercession City P4	47	62	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47	47
Intercession City P5	47	62	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47	47
Intercession City Pf	5 47	62	<i>6</i> 2	62	62	47	47	47	47	47	47	47	47	52	62	62	62	47	47	47	47	47	47
Intercession City P11	143	172	172	172	172	143	143			0		143	143	172	172	172	172	143	143	0	0	Ģ	Ó
Rio Pinar P1	13	19	19	19	19	13	13	11	11	11	13	13	. 13	19	19	19	19	13	13	t1	11	11	13
Suwannee River P2	2 51	63	65	68	65	68	51	48	48	48	51	51	51	- 68	63	63	68	53	51	48	48	48	51
Turner P1	1 13	19	19	19	- 19	19	13	11	11	11	13	13	13	19	19	19	19	19	13	11	11	11	13
Turner P2	2 13	.19	19	19	19	19	13	11	11	11	13	13	13	19	19	19	19	19	13	11	11	11	13
	3 51	34	- 84	84	84	84	61	57	57	57	61	61	61	84	- 84	84	84	84	61	57	57	57	61
Turner P4	4 61	- 84	84	84	84	84	61	57	57	57	· 61	61	61	84	84	84	84	84	61	57	57	57	61
Total Baseload Plants	3,208	3,208	3,208	3,208	3,205	3,127	3,127	3,127	3,127	3,041	3,127	3 127	3,208	3,208	3,208	3,208	3,203	3,127	3,127	3,127	3,127	3,041	3,127
Total Baseload Contracts	469	469	469	469	469	469	469	469	469	469	469	469	469	469	479	479	479	479	479	479	479	479	479
Total QF Contracts	831	831	831	831	\$31	● 534	831	831	831	\$31	531	831	831	831	. 831	831	831	831	831	331	831	831	531
Total Intermediate Resources	2,789	2,759	2,789	2,789	2,789	2,607	2,607	2,607	2,112	2,607	2,607	2,607	2,789	2,789	2,789	2,739	2,789	2,607	2,607	2,607	2,607	2.607	2,607
Total Gas Peaking Resources	1.062	1,311	1,311	1,311	1,311	1,062	1,062	1,038	1,038	1,038	1,062	1,062	1,062	1,311	1,311	1,311	1,311	1,062	1,062	1,038	1,038	1.038	1.062
Total Light Oil Peaking Resources	1,375	1,813	1,813	1,813	1,813	1,450	1,375	1,160	1,160	1,160	1,232	1,375	1,375	1,813	1,813	1,813	1,813	1,450	1,375	1,160	1 160	1,150	1.232
Total Available Resources	9.734	10,421	10,421	10,421	10,421	9,546	9,471	9,233	8,738	9.147	9,328	9.471	9,734	10,421	10,431	10,431	10,431	9,556	9,481	9,243	9.243	9.157	9,338

Page 6 of 12

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State       State <th< th=""><th></th><th>Oct-05</th><th>Nov-05</th><th>Dec-05</th><th>Jan-06</th><th>Feb-06</th><th>Mar-06</th><th>Apr-06 h</th><th>lay-06</th><th>Jun-06</th><th>Jui-06</th><th>Aug-06</th><th>Sep-06</th><th>Oct-06</th><th>Noy-06</th><th>Dec-06</th><th>Jan-07</th><th>Feb-07 N</th><th>ar-07</th><th>Apr-07</th><th>May-07</th><th>Jun-07</th><th>Jul-07 A</th><th>ug-07</th></th<>		Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06 h	lay-06	Jun-06	Jui-06	Aug-06	Sep-06	Oct-06	Noy-06	Dec-06	Jan-07	Feb-07 N	ar-07	Apr-07	May-07	Jun-07	Jul-07 A	ug-07	
Charatter         Construct         Construct <t< th=""><th>Baseload Plants (Summer and Winter Base Ratings)</th><th></th><th></th><th></th><th></th><th>- · · ·</th><th></th><th></th><th></th><th></th><th></th><th></th><th> t.</th><th></th><th></th><th></th><th></th><th></th><th></th><th></th><th></th><th></th><th></th><th></th></t<>	Baseload Plants (Summer and Winter Base Ratings)					- · · ·							t.												
Constrained A Distant D	Crystal River 1	398	403	403	403	403	403	398	398	398	398	312	398	398	403	403	403	403	403	398	398	398	398	312	
Cogardines         Fib	Crystal River 2	493	504	504	504	504	504	. 493	493	493	493	493	493	493	504	504	504	504	504	493	493	493	493	493	
Constrained         Fiel	Crystal River 4	721	741	741	741	741	741	721	721	721	721	721	721	721	741	741	741	741	741	721	721	721	721	721	
Changer into and and and any and any and any and any and any and any any and any	Crystal River 5	714	734	734	734	734	734	714	714	714	714	714	714	714	734	734	734	734	734	714	714	, 714	714	714	
University of produce as 30         41         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64         64        64         64	Crystal River 3	765	782	782	782	782	782	765	765	765	765	765	765	765	782	782	782	782	782	765	765	765	765	765	
Beache Control         Beache	University of Florida Copen	36	44	44	44	44	44	36	36	36	. 36	36	36	36	44	44	44	44	44	36	36	36	36	36	
UP PACHASE BRONDA Groups       40       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000       000	Baseload Contracts (Firm Purchase Capacity)		ł.		I					L	f	I							· · · · ·				L-		
TROP Markan Is Steps Los         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P <th>UPS Purchase from Southern Company</th> <th>409</th>	UPS Purchase from Southern Company	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	
OF Controls         Non-Line	TECO Purchase for Sebring Load	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	
PHILLAS CORENESC       14       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64       64<	QF Contracts	LL	i		L		I		¹	I			L	· · ·	t	l and the second	I	l		L L	····· '	í	l		
methods consistency       11       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       16       16	PINELLAS CO RES REC 1	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	
Tradem Servery         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11         11	PINELLAS CO RES REC 2	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	
BAY COARTYRESPEC       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11       11<	TIMPER ENERGY 1	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	
LIGLADENCE MOPP, IA 6 0, IA 7,	BAY COUNTY RES REC	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	
UPG_REFERENT VERT         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I         I <thi< th=""> <thi< th=""> <thi< th=""></thi<></thi<></thi<>	EC MADISON (ADD)	9			9	9	9	9	9	9	9		9	9	9	9	9	9	9	9	9	e	S	9	
LUEG COLATY PESSING: 03 01 01 01 01 01 01 01 01 01 01 01 01 01	LEC JEFFFRSON (APP)	9		9	9	9	9	9	9		9		9	9	9		9	9	9	9	9	9	9	9	
PRECONSIDING         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23         23	LAKE COUNTY RES REC	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13.	13	
DADE         CONTY RESIDE         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -	PASCO COUNTY RES REC	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	
LARGEL       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15	DADE COUNTY RES REC	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	
LARG COORD       Lin       TIO	CARGIL	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	
PASCO COGE       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100	LAKE COGEN	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	
ONAMOD COGAN       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       19       10       10	PASCO COGEN	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	
PRIDCE GENERATING STA       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40 <t< th=""><th>ORI ANDO COGEN</th><td>79</td><td>79</td><td>79</td><td>79</td><td>79</td><td>79</td><td>79</td><td>79</td><td>79</td><td>79</td><td>79</td><td>79</td><td>79</td><td>79</td><td>79</td><td>79</td><td>79</td><td>79</td><td>79</td><td>79</td><td>79</td><td>79</td><td>79</td></t<>	ORI ANDO COGEN	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	
International Business       International Base       Inter	RIDGE GENERATING STA	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	
ROYSTER       (PFP)       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31		114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	
MALBERRY (PPP)       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78       78 <th>BOYSTER (PPP)</th> <th>31</th>	BOYSTER (PPP)	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	
CFR-BLOGEN (JPA/NGE CO)       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74       74      <	MULL BERRY (PPP)	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	
USAGRUCHAM       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       6       7       7       7       7       7       7       7       7       7       7	CER-BLOGEN (ORANGE CO	74	74	74	74	74	74	74	74	74	74	74	74	74	74	· 74	74	74	74	74	74	74	74	74	
Intermediate Restances       Anciola 1       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512 <th colspa<="" th=""><th>USAGRICHEM</th><th>6</th><th>6</th><th>6</th><th>6</th><th>6</th><th>6</th><th>6</th><th>6</th><th>6</th><th>6</th><th>6</th><th>6</th><th>6</th><th>6</th><th>6</th><th>6</th><th>6</th><th>6</th><th>6</th><th>6</th><th>6</th><th>6</th><th>6</th></th>	<th>USAGRICHEM</th> <th>6</th>	USAGRICHEM	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Andola 1       507       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       507       507       507       507       507       507       507       507       507       507       507       507       507       507       507       507       507       507       507       507       507       507       507       507       507       507       507       507       507       507       507       507       507       507       507       507       507       507       507       507       507       507       507       507       507       507	Intermediate Resources (Summer and Winter Base Ratings)	<u> </u>	1		1		1 1						1				L1			11					
Anciole Z       502       552       552       552       552       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550       550	Anciole	507	512	512	512	512	512	507	507	507	507	507	507	507	512	512	512	512	512	507	507	507	507	507	
Industry I       113       116       116       116       116       116       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113	Anciale	502	522	522	522	522	522	502	502	502	502	502	502	502	522	522	522	522	522	2 502	502	502	502	502	
Bartow 2       113       117       117       117       117       117       117       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113       113	Barlow	113	116	116	116	116	116	113	113	113	113	113	113	113	115	116	116	116	116	113	113	113	113	113	
Link Har	Bation	113	117	117	117	117	117	113	113	113	113	113	113	113	117	117	117	117	117	113	113	113	113	113	
Landow         Landow <thlandow< th=""> <thlandow< th=""> <thlandow< th="" th<=""><th>Partour</th><th>3 207</th><th>210</th><th>210</th><th>210</th><th>210</th><th>210</th><th>207</th><th>207</th><th>207</th><th>207</th><th>207</th><th>207</th><th>207</th><th>210</th><th>210</th><th>210</th><th>210</th><th>210</th><th>207</th><th>207</th><th>207</th><th>207</th><th>207</th></thlandow<></thlandow<></thlandow<>	Partour	3 207	210	210	210	210	210	207	207	207	207	207	207	207	210	210	210	210	210	207	207	207	207	207	
Suvannee River Z       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0 <th< th=""><th>Suwannee River</th><th>1 0</th><th>0</th><th></th><th>0</th><th>0</th><th>0</th><th></th><th>0</th><th>0</th><th>0</th><th>0</th><th>0</th><th>0</th><th>0</th><th>0</th><th>0</th><th>0</th><th></th><th>0 0</th><th>0</th><th>0</th><th>0</th><th>0</th></th<>	Suwannee River	1 0	0		0	0	0		0	0	0	0	0	0	0	0	0	0		0 0	0	0	0	0	
Survance River 3         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0         0	Sitwannaa Pivar	2 0			n	0	0	0	0	0	0	D	0	0	0	0	0	0	(		0	0	- 0	0	
Tiger Bay Cogen         200         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240         240	Sumannee River	3 0					0		0	0	0	0		0	0	0	0			0 0	Ð	0	0	0	
Hines Energy Complex 1       470       505       505       505       505       505       505       505       505       505       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       470       4	Tiner Bay Cone	200	240	240	240	240	240	200	200	200	200	200	200	200	240	240	240	240	240	200	200	200	200	200	
Hines Energy Complex 2       495       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       567       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       4	Lines Energy Complex	1 470	505	504	505	505	505	470	470	470	470	470	470	470	505	505	505	505	505	5 470	470	470	470	470	
Hines Energy Complex 3       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       567       567       567       567       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       <	Lines Energy Complex	2 495	567	557	567	567	567	495	495	495	495	495	495	495	567	567	567	567	567	7 495	495	495	495	495	
Gas Peaking @ 90*F.         Spring/Fail Base Rating @ 90*F.       Spring/Fail Base Rating @ 90*F.       Spring/Fail Base Rating @ 90*F.         Avon Park P1       24       24       34       34       34       24       24       19       19       19       19       24       24       24       34       34       24       24       19       19       19       19       24       24       24       34       34       24       24       19       19       19       19       24       24       24       34       34       24       24       19       19       19       19       24       24       24       34       34       24       24       19       19       19       19       19       24       24       24       34       34       24       24       19       19       19       19       19       19       19       19       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       <	Hints Energy Complex	3 0	0				0	0	0	0	0	0	0	0	567	567	567	567	567	7 495	495	495	495	495	
Spring/Fall Base Rating @ 90°F, Winter Peak Rating @ 12°F)         Avon Park P1       24       24       34       34       34       34       24       24       19       19       19       19       24       24       24       34       34       24       24       19       19       19       19       24       24       24       34       34       24       24       19       19       19       19       24       24       24       34       34       24       24       19       19       19       24       24       24       34       34       34       24       24       19       19       19       19       24       24       24       24       24       24       24       34       34       34       24       24       19       19       19       19       19       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24 </th <th>Gas Peaking Resources (Summer Base Rating @ 95°F</th> <th>1</th> <th><u>ا ا</u></th> <th></th> <th>ٽ _آ</th> <th></th> <th>1 A A</th> <th></th> <th>-</th> <th>· · · · ·</th> <th></th> <th>L</th> <th>1</th> <th></th> <th></th> <th>·</th> <th><u>ا ما</u></th> <th></th> <th></th> <th></th> <th>L</th> <th>1</th> <th>I</th> <th></th>	Gas Peaking Resources (Summer Base Rating @ 95°F	1	<u>ا ا</u>		ٽ _آ		1 A A		-	· · · · ·		L	1			·	<u>ا ما</u>				L	1	I		
Avon Park P1       24       24       34       34       34       34       24       24       19       19       19       19       24       24       24       34       34       24       24       24       24       34       34       24       24       19       19       19       19       24       24       24       34       34       24       24       24       19       19       19       19       24       24       24       34       34       34       24       24       19       19       19         Bartow P2       46       46       54       54       54       54       54       54       54       54       54       54       54       46       46       46       46       46       46       46       46       46       46       46       46       46       46       46       46       46       46       46       46       46       46       46       46       46       46       46       46       46       46       46       46       46       46       46       46       46       46       46       46       46       46       46 <th< th=""><th>Spring/Fall Base Rating @ 90°F, Winter Peak Rating @ 32°F)</th><th></th><th></th><th></th><th>,</th><th></th><th>,,</th><th>,</th><th></th><th></th><th></th><th></th><th><u></u></th><th></th><th></th><th>, <b></b></th><th>,</th><th><u> </u></th><th></th><th></th><th></th><th></th><th></th><th></th></th<>	Spring/Fall Base Rating @ 90°F, Winter Peak Rating @ 32°F)				,		,,	,					<u></u>			, <b></b>	,	<u> </u>							
Bartow P2       46       46       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       56       56       56       56       56       56       56       56       56       56       56       56       56       56       56       56       56       56       56	Avon Park P	1 24	24	34	34	34	34	24	24	- 19	19	19	24	24	24	34	34	34	34	4 24	24	19	19	19	
Bartow P4       49       49       62       62       62       62       62       62       63       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49       49	Bartow P	2 46	46	54	1 54	54	54	46	45	46	46	46	46	46	46	54	54	54		4 46	46	46	46	46	
Debary P7       76       98       98       98       98       97       76       76       76       76       76       76       76       76       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98	Bartow P	4 49	49	63	2 62	62	62	49	49	49.	49	49	49	49	49	62	62	62	63	2 49	49	49	49	49	
Debary P3         76         76         93         93         76         76         72         72         72         72         76         76         98         98         98         98         76         76         72         72         72         72         72         76         76         98         98         98         98         76         76         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72         72	Debary P	7 76	76	98	898	98	98	76	76	72	72	72	76	76	76	98	98	98	98	8 76	76	72	72	72	
Higgins P1 25 25 34 34 34 34 25 25 24 24 24 25 25 25 34 34 34 32 25 24 24 24 25 25 34 34 34 34 35 25 25 24 24 24 24	Debary P	9 76	75	9	5E 55	98	98	76	76	. 72	72	72	76	76	76	93	. 93	98	98	8 76	76	. 72	72	72	
	Higgins P	1 25	25	3	4 34	34	34	25	25	24	24	24	25	25	25	34	34	34	34	4 25	25	24	24	24	
Higgins P2 25 25 34 34 34 34 25 25 24 24 24 24 25 25 25 34 34 34 25 25 24 24 24	Higgins P	2 25	25	3	4 34	34	34	25	25	24	24	24	25	25	25	34	- 34	34	34	4 25	25	24	24	24	
Higgins P3 31 31 35 36 36 36 31 31 29 29 29 31 31 31 36 36 36 31 31 29 29 29	Higgins P	3 31	31	3	5 36	36	35	31	31	29	29	29	31	31	31	. 36	36	36	36	5 31	31	- 29	29	29	
Higgins P4 31 31 36 36 36 37 36 31 31 29 29 29 31 31 31 36 36 36 31 31 29 29 29	Higgins P	4 31	31	3	6 36	34	36	31	31	29	29	29	. 31	31	31	36	36	36	36	5 31	31	29	29	29	

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Page 7 of 12

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Intercession City P7	83	83	98	98	98	98	83	83	84	84	84	83	83	83	98.	98	98	95	83	83	84		
Intercession City P8	83	83	98	98	98	98	83	<b>8</b> 3	84	84	84	83	83	83	98	95	98	93	83	83	84	84	84
Intercession City P9	53	83	98	98	95	93	83	83	44	84	84	83	83	83	98	98	98	95	83	83	84	\$4	
Intercession City P10	83	83	98	98	98	93	83	83	84	84	84	83	83	83	<b>98</b>	98	95	98	83	83		84	84
Intercession City P12	83	83	99	99	99	99	83	83	83	83	83	83	83	63	99	99	99	99	83	83	' 83	83	83
Intercession City P13	3 83	83	99	99	99	99	83	83	83	83	83	83	83	83	99	99	99	99	83	83	83	83	83
Intercession City P14	83	83	99	99	99	99	83	83	83	83	83	83	83	83	- 99	99	99	99	83	83	83	83	83
Suwannee River P1	49	49	63	68	68	68	49	49	44	44	44	49	49	49	68	68	63	63	49	49	44	44	44
Suwannee River P3	49	49	58	68	63	68	49	49	44	44	44	49	49	. 49	68	68	53	68	49	49	44	44	44
Light Oil Peaking Resources (Summer Base Rating @ 95°F, Spring/Fall Base Rating @ 90°F, Winter Peak Rating @ 32°F)																							
Avon Park P2	24	24	34	34	34	34	24	24	19	19	19	24	24	24	34	34	34	34	24	24	19	19	19
Barlow P1	46	46	54	54	54	54	46	46	46	46	46	46	46	46	54	54	54	54	46	46	46	46	46
Barlow P3	46	46	54	54	54	54	46	46	46	46	46	46	46	46	54	54	54	54	46	45	46	46	46
Bayboro P1	44	44	60	60	60	60	.44	44	41	41	41	44	44	44	60	60	60	60	44	44	41	41	41
Bayboro P2	44	44	60	60	60	60	44	44	41	41	41	44	44	. 44	60	60	60	60	44	44	41	41	41
Bayboro P3	44	44	60	60	60	60	44	44	41	41	41	44	. 44	44	60	60	60	60	44	44	41	41	41
Bayboro P4	44	44	60	60	60	60	44	44	41	41	41	44	44	44	60	60	60	60	44	44	41	41	41
Dabary P1	49	49	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44
Debary P2	49	49	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44
Debary P3	49	49	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44
Dabary P4	49	49	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44
Debary P5	49	49	57	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	- 44
Dabary P6	49	49	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44
Debary P8	76	76	96	96	96	96	76	76	72	72	72	76	76	76	96	96	96	96	76	76	72	72	72
Debary P10	76	76	96	96	96	96	76	76	72	72	72	76	76	76	96	96	96	96	76	76	72	72	72
Intercession City P1	47	47	62	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47
Intercession City P2	47	47	62	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47
Intercession City P3	47	47	62	62	62	62	47	4/	4/	47	47	47	47	47	62	62	62	62	47	47	47	47	47
Intercession City P4	4/	4/		62	62	62	4/	4/	4/	4/	4/	41	4/	47	62	62	62	52	47	47	47	47	47
Intercession City P5	47	47	62	62	62	62	47	47	4/	4/	47	47	47	47	62	62	62	62	47	47	47	47	47
Intercession City Pe	4/	4/	172	172	472	172	4/	4/	4/	47	4/	4/	4/	4/	170	62	62	62	4/	4/	47	4/	4/
Intercession City P11	143	143	10	1/2	10	10	143	143		11		13	143	143	1/2	1/2	1/2	1/2	143	143			
Rio Final Fi	51	51	63	65	63	68	63	51	48			51	51	51	63	[] 63	13	13	69	13		48	
Turner Di		13	19	19	19	19	19	13	11	11	11	13	13	13	19	19	10	19	10	13		11	
Turner P	13	13	19	19	19	19	19	13	11		11	13	13	13	19	19	19	19	19	13			11
Turner P2	61	61	84	84	84	84		61	57	57	57	61	61	61	64		84	84	84	61	57	57	57
Turner Pé	61	61	84	64	84	84	84	61	57	57	57	61	61	61	54	84		84	54	61	57	57	57
Total Baseload Plants	3,127	3,208	3,208	3,208	3,208	3,208	3,127	3,127	3,127	3,127	3,041	3,127	3,127	3,208	3,208	3,205	3,203	3,205	3,127	3,127	3,127	3,127	3,041
Total Baseload Contracts	479	479	479	479	479	479	479	479	479	479	479	479	. 479	479	479	479	479	479	479	479	479	479	479
Tutal QF Contracts	831	831	831	831	531	• 531	831	831	531	831	831	831	831	831	831	831	831	831	831	<b>5</b> 31	831	\$31	831
Total Intermediate Resources	2,607	2,789	2,789	2,789	2,789	2,789	2,607	2,607	2,607	2,607	2,607	2.607	2,607	3,356	3,356	3,356	3,356	3,356	3,102	3,102	3,102	3,102	3,102
Total Gas Peaking Resources	1.062	1,062	1,311	1,311	1,311	1,311	1,062	1,062	1,038	1,038	1,038	1.062	1,062	1,052	1,311	1,311	1,311	1,311	1,062	1,062	1,038	1.038	1,038
Total Light Oil Peaking Resources	1,375	1,375	1,813	1,813	1,813	1,813	1,450	1,375	1,160	1,160	1,160	1.232	1,375	1,375	1,813	1,813	1,813	1,813	1,450	1,375	1,150	1,160	1,160
Total Available Resources	9.481	9,744	10,431	10,431	10,431	10,431	9,556	9,481	9,243	9,243	9,157	9,338	9,481	10,311	10,998	10,995	10,998	10,995	10,051	9,976	9,738	9,738	9,652

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approximate frame. Change and and a series of a	× .	Sep-07	Oct-07	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Noy-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09
Operation         Mit         Mit        Mit         Mit         Mi	Baseload Plants (Summer and Winter Base Ratings)				l I		ł.																	
Open Nord         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60         60        60        60 <t< td=""><td>Crystal River 1</td><td>398</td><td>398</td><td>403</td><td>403</td><td>403</td><td>403</td><td>403</td><td>398</td><td>398</td><td>398</td><td>398</td><td>312</td><td>398</td><td>398</td><td>403</td><td>403</td><td>403</td><td>403</td><td>403</td><td>398</td><td>398</td><td>398</td><td>393</td></t<>	Crystal River 1	398	398	403	403	403	403	403	398	398	398	398	312	398	398	403	403	403	403	403	398	398	398	393
Openatione         Openatione         Pio	Crystal River 2	493	493	504	504	504	504	504	493	493	493	493	493	493	493	504	504	504	504	504	493	493	493	493
Cysee hand         Ye         Ye        Ye        Ye <t< td=""><td>Crystal River 4</td><td>721</td><td>721</td><td>741</td><td>741</td><td>741</td><td>741</td><td>741</td><td>721</td><td>721</td><td>721</td><td>721</td><td>721</td><td>721</td><td>721</td><td>741</td><td>741</td><td>741</td><td>741</td><td>741</td><td>721</td><td>721</td><td>721</td><td>721</td></t<>	Crystal River 4	721	721	741	741	741	741	741	721	721	721	721	721	721	721	741	741	741	741	741	721	721	721	721
Desire for each of a set	Crystal River 5	714	714	734	734	734	734	734	714	714	714	714	714	714	714	734	734	734	734	734	714	1 714	714	714
Underwy the basis of and	Crystal River 3	* 765	765	782	782	782	782	782	765	765	765	765	765	765	765	782	782	782	782	782	765	765	765	765
Buttery Control Constant of Source Control Ge         Source Contro Ge         Source Control Ge         S	University of Florida Cogen	36	36	44	44	44	44	44	36	36	36	36	36	36	36	44	44	44	44	44	36	36	36	35
Pipe Arban to model model and point         etc.	Baseload Contracts (Firm Purchase Capacity)		1		LI		· ·	l		1			I			1		i		·				
TROPAGALAR SERVICE         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P         P	UPS Purchase from Southern Company	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	[60]	409	lens.
D2 Convert       NPLLADEC       <	TECO Purchase for Sebring Load	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70		70
PHELLAGO DEBNEC 1       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40       40	QF Contracts									1										·				
Impulsion of Res Res     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10     10	PINELLAS CO RES REC 1	40	40	40	40	40	40	40	40	40	40	40	40	40	40	مه	40	∡∩l	40	40	401	40	401	40
Number Delawar         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10         10	PINELLAS CO RES REC 2	15	15	15	15	15	15	15	15	15	15	15	15	15		15	15	15	40	+ 5	40		40	15
BAY COUNTYRESK       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O      <	TIMBER ENERGY 1	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	12				42		
UPLANDEXA	BAY COUNTY RES REC	11	11	11	11	11		11	11	11	11	- 11		11	11		11	11		- 13		11		
Dec persones no.       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D       D <thd< th="">       D       <thd< th="">      &lt;</thd<></thd<>															'			<u>├'</u>		<u>-</u>		;]	<u>;</u>	
Line County Kasses         Si									s	3							9				9			
PARCOC CULVY UNDER IDE       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I       I <td></td> <td>13</td> <td>13</td> <td>13</td> <td>13</td> <td>13</td> <td>13</td> <td>13</td> <td>13</td> <td>13</td> <td>17</td> <td>12</td> <td>13</td> <td></td> <td></td> <td>12</td> <td>13</td> <td>12</td> <td></td> <td></td> <td>+2</td> <td></td> <td></td> <td></td>		13	13	13	13	13	13	13	13	13	17	12	13			12	13	12			+2			
Dubbe Conversion         Ta	PASCO COUNTY RES BEC	23	- 23	23	23	23	23	23	23	23	27	22	23			27	93	22		13	13			
Loc or MARL       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       15       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16       16	DADE COUNTY RES REC	43	43	43	43	43	41	43	43	43	43	43	43	43		43	10			42	43			
LAUS COOCH 170 170 170 170 170 170 170 170 170 170		15	15	15	15	15	15	15		15	45	15	15				45	15	40	40	40	43		
PRSDC COCID:       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100       100		110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110		110	110
ORMADD COORD       C1       C1 <thc1< th="">       C1       C1</thc1<>	PASCO COCEN	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	100	100	100	100	100	100	100
RDGE GENDATINGESS.       60       61       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       60       6	OBLANDO COGEN	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	70	70	- 70	70	70	70	70
LEDOKADD       LeDokADD <th< td=""><td>RIDGE GENERATING STA</td><td>40</td><td>40</td><td>40</td><td>40</td><td>40</td><td>40</td><td>40</td><td>40</td><td>40</td><td>40</td><td>40</td><td>40</td><td>40</td><td>40</td><td>40</td><td>40</td><td>40</td><td></td><td>40</td><td>/3</td><td>19</td><td></td><td></td></th<>	RIDGE GENERATING STA	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40		40	/3	19		
HONGING (PP)       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3       3 <t< td=""><td>F DORADO (APP)</td><td>114</td><td>114</td><td></td><td>114</td><td>114</td><td>114</td><td>114</td><td>114</td><td>114</td><td>114</td><td>114</td><td>114</td><td>114</td><td>114</td><td>114</td><td>114</td><td>114</td><td>114</td><td>114</td><td>114</td><td>114</td><td></td><td>+14</td></t<>	F DORADO (APP)	114	114		114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114		+14
MALABORY (PPC)       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70       70 <td>BOYSTER (PPP)</td> <td>31</td> <td></td> <td>31</td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td>	BOYSTER (PPP)	31	31	31	31	31	31	31	31	31	31	31	31	31	31		31							
CFR-BIOCEN (OPAN-0C CO 2 P 2 7 2 7 2 7 2 7 2 7 2 7 7 7 7 7 7 7	MULBERRY (PPP)	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	74	79	70	79	70	70	
Lis AGRICAREM Lis AGRICAREM Lis AGRICARE Lis AREADOM Lis AGRICAREM Lis AREADOM	CER-BIOGEN (ORANGE CO)	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	73	74	74	74
Intermedial Resource (Jummer and Winter Anne Reform)       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O       O		6			6	6	5	6	6	6	6								<u> </u>					
Anchole       507       507       512       512       512       512       512       507       507       507       507       507       507       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       512       <	Intermediate Resources (Summer and Winter Base Ratings)	1			<u>ا ا</u>					[]		1	۳ ۱		1			<u>ا ا ا ا</u>		<u> </u>	<u> </u>		<u> </u>	°
Andolog       Ord       Ord <thord< th="">       Ord       Ord       <t< td=""><td>Aprila 1</td><td>507</td><td>507</td><td>512</td><td>512</td><td>512</td><td>512</td><td>512</td><td>507</td><td>507</td><td>507</td><td>507</td><td>507</td><td>507</td><td>507</td><td>512</td><td>512</td><td>512</td><td>512</td><td>512</td><td>507</td><td>507</td><td>507</td><td>507</td></t<></thord<>	Aprila 1	507	507	512	512	512	512	512	507	507	507	507	507	507	507	512	512	512	512	512	507	507	507	507
Markow	Anctota 2	502	502	522	522	522	522	522	502	502	502	502	502	502	502	512	577	572	522	572	502	507	507	
Line       Line <thline< th="">       Line       Line</thline<>	Bactow 1	113	113	116	116	115	116	116	113	113	113	113	113	113	113	116	116	116	115	116	502	112	113	
Control       Contro       Control       Control	Bartow 2	113	113	117	117	117	117	117	113	113	113	113	113	113	113	117	117	117	117	417	113	113	442	113
Buranne River 1       C       CR       CR <td>Barlow 3</td> <td>207</td> <td>207</td> <td>210</td> <td>210</td> <td>210</td> <td>210</td> <td>210</td> <td>207</td> <td>207</td> <td>207</td> <td>207</td> <td>207</td> <td>207</td> <td>207</td> <td>210</td> <td>210</td> <td>210</td> <td></td> <td>210</td> <td>207</td> <td>207</td> <td>207</td> <td></td>	Barlow 3	207	207	210	210	210	210	210	207	207	207	207	207	207	207	210	210	210		210	207	207	207	
Ochrame River 2       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0	Sturantee River 1			0		0						0				210				210	207	201		
Sumane River 3       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0       0	Siwannea Rivar 2	,		0		0	0	0						n		<u> </u>		,						<u> </u>
Image Bay Cope       200       240       240       240       240       240       240       240       240       240       240       240       240       240       240       240       240       240       240       240       240       240       240       240       240       240       240       240       240       240       240       240       240       240       240       240       240       240       240       240       240       240       220       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200       200	Silvannea Rivar 2		0	0		0	n	0	0					n	<u> </u>		0							
Hines Energy Complex 1       210       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       110       1	Tigar Boy Coner	200	200	240	240	240	240	240	200	200	200	200	200	200	200	240	240	240	240	240	200	200	200	
Integrating bender       Ind       Ind </td <td>Hines Energy Complex 1</td> <td>470</td> <td>470</td> <td>505</td> <td>505</td> <td>505</td> <td>505</td> <td>505</td> <td>470</td> <td>470</td> <td>470</td> <td>470</td> <td>470</td> <td>470</td> <td>470</td> <td>505</td> <td>505</td> <td>505</td> <td>504</td> <td>505</td> <td>470</td> <td>470</td> <td>470</td> <td>470</td>	Hines Energy Complex 1	470	470	505	505	505	505	505	470	470	470	470	470	470	470	505	505	505	504	505	470	470	470	470
Hines Energy Complex 3       455       567       567       567       567       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       495       4	Hines Energy Complex 1	495	495	567	567	567	567	567	495	495	495	405	495	470	4/0	557	567	567	500	567	4/0	470	410	4/0
Gas Peaking Resources (Summer Base Rating @ 37*F)         Avon Park P1       24       24       24       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34	Hines Energy Complex 2	495	495	567	567	567	567	567	495	495	495	495	495	495	495	567	5,67	567	567	507	435	455 A04	495	495
Spring/Fall Base Rating (a) 90°F. Winter Peak Rating (b) 32°F)         Avon Park P1       24       24       24       24       24       19       19       19       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24       24	Gas Peaking Resources (Summer Base Rating @ 95°F				1		L. <b>P.</b> ²⁰⁰ L		[	1		1			1			1	307		1 400	400		
Avon Park P1       24       24       24       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34       34	Spring/Fall Base Rating @ 90°F, Winter Peak Rating @ 32°F)																							<u></u>
Barlow P2       46       46       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54       54	Avon Park P1	24	24	24	34	34	34	34	24	24	19	19	19	24	24	24	34	34	34	34	24	24	19	19
Barlow P4       49       49       49       52       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       62       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63       63	Bartow P2	46	46	46	54	54	54	54	46	46	46	45	46	46	46	46	54	54	54	54	46	46	46	46
Debary P7       76       76       76       76       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98       98	Bartow P4	49	49	49	62	62	62	62	49	49	49	49	49	49	49	49	62	62	62	62	49	49	49	49
Debary P9       76       76       76       76       76       76       76       76       76       98       91       95       95       772       772         Hiogins P1       25       25       25       34       34       34       34       25       25       24       24       24       25       25       34       34       34       24       24       24       25       25       34       34       34       25       24       24       24       25       25       34       34       34       25       24       24       24       25       25       34       34       34       25       25       24       24       24       25       25       34       34       34       25       25       24       24       24       25       25       34       34       34       25       25       24       24       24       25       25       34       34       34       25       25       24       24       24       25       25       34       34       34       25       25       24       24       24       24       25       25       34       34 <td< td=""><td>Debary P7</td><td>7 76</td><td>76</td><td>76</td><td>98</td><td>98</td><td>98</td><td>98</td><td>76</td><td>76</td><td>72</td><td>72</td><td>72</td><td>76</td><td>76</td><td>76</td><td>98</td><td>98</td><td>98</td><td>98</td><td>76</td><td>76</td><td>72</td><td>72</td></td<>	Debary P7	7 76	76	76	98	98	98	98	76	76	72	72	72	76	76	76	98	98	98	98	76	76	72	72
Higgins P1       25       25       25       34       34       34       34       25       25       24       24       24       25       25       34       34       34       25       25       24       24       24       25       25       34       34       34       34       25       25       24       24       24       25       25       34       34       34       25       25       24       24       24       25       25       34       34       34       25       25       24       24       24       25       25       34       34       34       25       25       24       24       24       25       25       25       34       34       34       25       25       24       24       24       25       25       25       34       34       34       25       25       24       24       24       24       25       25       34       34       34       25       25       24       24       24       24       24       25       25       25       34       34       34       34       25       25       24       24       24       24	Debary PS	76	76	76	98	98	98	95	76	76	72	72	72	76	76	76	98	98	98	98	. 75	76	72	72
Higgins P2       25       25       25       24       34       34       24       24       24       25       25       34       34       34       25       25       24       24       24       24       25       25       34       34       34       25       25       24       24       24       24       25       25       34       34       34       25       25       24       24         Higgins P3       31       31       36       36       36       36       31       31       29       29       29       31       31       36       36       31       31       29       29       29       31       31       36       36       31       31       29       29       29       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31       31	Higgins P1	25	25	25	34	34	34	34	25	25	24	24	24	25	25	25	34	34	34	34	25	25	24	24
Higgins P3       31       31       36       36       36       36       31       31       29       29       29       29       31       31       36       36       31       31       29       29         Higgins P3       31       31       36       36       36       36       31       31       29       29       29       31       31       36       36       35       31       31       29       29         Higgins P4       31       31       36       36       36       36       36       36       36       31       31       29       29       29       31       31       36       36       36       31       31       29       29       29       31       31       36       36       36       31       31       29       29         Higgins P4       31       31       36       36       36       36       36       36       31       31       29       29       29       31       31       31       36       36       36       31       31       29       29         Higgins P4       31       31       36       36       36	Higgins P2	2 25	25	25	i 34	34	34	34	25	25	24	24	24	25	25	25	34	34	34	34	25	25	24	24
Higgins P4 31 31 36 36 36 36 36 31 31 29 29 29 31 31 31 36 36 36 36 31 31 29 29	Higgins P	3 31	31	31	36	36	36	36	31	31	29	29	29	31	31	31	36	36	36	36	31	31	29	29
	Higgins P ²	4 31	31	31	36	36	36	36	31	31	29	29	29	31	31	31	36	36	36	36	31	31	29	29

Page 9 of 12

**FPC 107** 

7.19/00 @ 12:25 PM

>	Sep-07	Oct-07	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jui-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jui-09
Intercession City P7	83	83	83	98	98	98	98	83	83	84	84		83	83	83	95	98	98	98	83	83	84	34
Intercassion City P8	83	83	83	98	98	95	98	83	83		54	84	83	53	83	98	98	98	98	83	83	84	84
Intercession City P9	83	83	83	98	98	98	98	83	83	84	84	84	83	83	\$3	98	98	98	98	83	83	84	\$4
Intercession City P10	83	83	83	98	98	98	98	83	83			84	. 83	83	83	98	98	98	98	83	83	84	84
Intercession City P12	83	83	83	99	99	99	99	83	83	83	83	83	83	83	83	99	99	99	99	83	, 83	83	- 83
Intercession City P13	83	83	83	99	99	99	99	83	83	83	<b>5</b> 3	83	63	83	83	99	- 99	99	99	83	83	83	83
Intercession City P14	83	83	83	99	99	99	99	83	83	83	83	83	83	83	53	99	99	99	99	83	83	83	83
Suwannee River P1	49	49	49	68	58	68	68	49	49	44	44	44	49	49	49	68	68	68	68	49	49	44	44
Suwannee River P3	49	49	49	65	63	68	68	49	49	44	44	44	49	49	49	68	68	58	63	49	49	44	44
Light Oil Peaking Resources (Summer Base Rating @ 95°F. Spring/Fall Base Rating @ 90°F. Winter Peak Rating @ 33°F.																							
Avon Park P2	24	24	24	34	34	34	34	24	24	19	19	19	24	24	24	34	34	34	34	24	24	19	19
Barlow P1	46	45	46	54	54	54	54	46	46	46	46	46	45	46	46	54	54	54	54	46	46	46	45
Bartow P3	46	46	46	54	54	54	54	46	46	46	46	46	46	46	46	54	54	54	54	46	45	45	45
Bayboro P1	44	- 44	44	60	60	60	60	44	44	41	41	41	44	44	44	60	60	60	60	44	44	41	41
Bayboro P2	44	44	44	60	60	60	60	44	44	41	41	41	44	44	44	50	60	60	60	44	44	41	41
Bayboro P3	44	44	44	60	60	60	60	44	44	- 41	41	41	44	44	44	60	60	60	60	44	44	41	41
Bayboro P4	44	44	44	60	60	60	60	- 44	44	41	41	41	44	44	44	60	60	60	60	44	44	41	41
Debary P1	49	49	49	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44
Debary P2	49	49	49	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44
Debary P3	49	49	49	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44
Debary P4	49	49	49	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44
Debary P5	49	49	49	67	67	67	67	49	49	44	44	- 44	49	49	49	67	67	67	67	49	49	44	' 44
Debary P6	49	49	49	67	67	67	67	49	49	44	44	- 44	49	49	49	67	67	67	67	49	49	44	44
Debary P8	76	76	76	96	96	96	96	76	76	72	111111111111111111111111111111111111111	72	76	76	76	96	96	95	96	76	76	72	72
Debary P10	76	76	76	96	96	96	96	76	76	72		72	76	76	76	96	96	96	96	76	76	72	72
Intercession City P1	47	47	47	62	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47
Intercession City P2	47	47	47	62	62	52	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	. 47
Intercession City P3	47	47	47	62	52	62	62	47	47	47	47	47	47	47	47	62	62	62	52	47	47	47	47
Intercession City P4	47	47	47	62	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47
Intercession City P5	47	47	47	62	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47
Intercession City P6	47	47	47	62	52	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47
Intercession City P11	0	143	143	172	172	172	172	143	143	0	0		0	143	143	172	172	172	172	143	143	0	0
Rio Pinar P1	13	13	13	19	19	19	19	13	13	11	11	11	13	13	13	19	19	19	19	13	13	11	11
Suwannee River P2	51	51	51	68	68		68	65	51	48	43	48	51	51	51	68	68	68	53	63	51	48	43
Turner P1	13	13	13	19	19	. 19	19	19	13	11	11	11	13	13	13	19	19	19	19	19	13	11	11
Turner P2	13	13	13	19	19	19	19	19	13	11	11	11	13	13	13	19	19		19	19	13	11	
Turner P3	61	61	61	84		84	84		61	5/	5/	5/	61	- 61	61	84	84		84	84	61		5/
Turner P4	61	51	61	84		- 84	84	84	61	5/	5/	5/	61	61	61	84	- 54	84	54		61		57
<u>Total Baseload Plants</u>	3,127	3,127	3,203	3,208	3,203	3,203	3,208	3,127	3,127	3,127	3,127	3,041	3,127	3,127	3,208	3,208	3,208	3,208	3,208	3,127	3,127	3,127	3,127
Total Baseload Contracts	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479
Total QF Contracts	\$31	831	631	831	831	• 331	831	831	831	831	831	831	831	831	831	831	831	831	831	831	\$31	831	831
Total Intermediate Resources	3,102	3,102	3,356	3,356	3,356	3,356	3,356	3,102	3,102	3,102	3,102	3,102	3,102	3,102	3,356	3,356	3,356	3,355	3,356	3,102	3,102	3,102	3,102
Total Gas Peaking Resources	1.062	1,062	1,062	1,311	1,311	1,311	1,311	1,062	1,062	1.038	1,038	1,038	1,062	1,062	1,062	1,311	1,311	1,311	1,311	1,062	1.062	1,038	1,038
Total Light Oil Peaking Resources	1.232	1,375	1,375	1,813	1,813	1,813	1,813	1,450	1,375	1,160	1,160	1.160	1,232	1,375	1,375	1,813	1,813	1,813	1,813	1,450	1,375	1,160	1,160
Total Available Resources	9,833	9,976	10,311	10,998	10,998	10,998	10,998	10,051	9,976	9.738	9,738	9.652	9,833	9,976	10,311	10,998	10,998	10,998	10,998	10,051	9.976	9.738	9,738

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	Aug-09	Sep-09	Oct-09	NOY-09	Dec-09		Comments	
Baseload Plants (Summer and Winter Base Ratings)							Decaleday	6 Mix in August the to FOD Limitation
Crystal River 1	312	398	398	403	403		Turhine upp	ada 12/01
Crystal River 2	493	493	493	504	504		Turbine upgr	ade 4/00
Crystal River 4	721	721	721	741	741		Turbine upgr	ade 4/00
Crystal River 5	714	714	714	734	734		Turbine upge	ade 5/99
S Crystal River 3	765	765	765	782	782		Turbine upga	ade 10/99
University of Florida Cogen	36	36	36	44	44			
Baseload Contracts (Firm Purchase Capacity)								
UPS Purchase from Southern Company	409	409	409	409	409			
TECO Purchase for Sebring Load	70	70	70	70	70			· · · · · · · · · · · · · · · · · · ·
OF Contracts								
PINELLAS CO RES REC 1	40	40	40	40	40		4/1/83	Contract
PINELLAS CO RES REC 2	- 15	15	15	15	15		6/1/86	Contract
TIMBER ENERGY 1	13	13	13	13	13		7/1/85	Contract
BAY COUNTY RESPEC	11	11	11	11	11		4/1/88	Contract
							9/1/89	Contract
						<u> </u>	5/1/00	Contract
		47	47	10	40	<u> </u>	0/1/00	
		13	13	13	13		9/1/90	Contract
PASCO COUNTY RES REC	23	23	23	23	23		3/1/91	Contract
DADE COUNTY RES REC	43	43	43	43	43		11/1/91	Contract
CARGILL	15	15	15	15	15		10/1/92	Contract
	110	110	110	110	110		7/1/93	Contract
PASCO COGEN	109	109	109	109	109		7/1/93	Contract
ORLANDO COGEN	79	79	79	79	79		10/1/93.	Contract
RIDGE GENERATING STA	40	40	40	40	40	<u> </u>	5/1/94	Contract
EL DORADO (APP	114	114	114	114	114	I	7/1/94	Contract
ROYSTER (PPP	31	31	31	31	31		7/1/94	Contract
MULBERRY (PPP	79	79	79	79	79		7/1/94	Contract
CFR-BIOGEN (ORANGE CO	74	74	74	74	74		6/1/95	Contract
US AGRICHEM	6	6	6	6	6		1/1/97	Contract
Intermediate Resources (Summer and Winter Base Ratings)								
Anciote	507	507	507	512	512	[		
Anciole	502	502	502	522	522			· · ·
Barlow '	113	113	113	116	116			
Bartow	2 113	113	113	117	117	1		
Barlow	3 207	207	207	210	210	ļ		
Suwannee River	1 0	0	0	0 0			UnitRetirez	nept 11/03
Siwannee River	2 0	0		0			Unit Retirer	nent 11/03
Siwannee River						<u> </u>	UnitRetirer	nent 11/03
Tiner Ray Code	200	200	200	240	240	1		l service serv
Hines Energy Complex	470	470	470	505	505			
nines chergy complex	4/0	405	40	500			LINI AND	1
Hines Energy Complex	493	493	450	507	507	<u> </u>	Linit Additio	n 11/05
Hines Energy Complex :	493	493	49:	207 207	1 201	L	LINI ADDIN	111/00
Spring/Fall Base Rating @ \$0°F. Winter Peak Rating @ 32°F)								
Avon Park P	1 19	24	24	24	34	<u>.</u>	1	1
Bartow P	2 45	46	46	46	54		1	
Barlow P.	49	49	49	49	62		1	
Dehary P	72	76	76	76	98	. ·	Iniet loggin	installed 5/00 (Jun, Jul & Aug)
Dabasy (	7	75	71	75	0.0	1	Intel Incoin	n installed 5/00 (Jun.,kil & Aun)
Lioualy F	1 24	25	24		24			
		2		2		<u> </u>	+	
Higgins P	4 <u>24</u>	2		23		<u> </u>		·
Higgins P	<u>عام 2</u>	31	3	31	36	<u>'</u>	· · ·	
Higgins P	4  25	≠µ 31	1 31	H 31	1 36	ij –	1	

×

	Aug-09	Sep-09	Oct-09	Nov-09	Dec-89	r	Commente	
Intercession City P7	84	83	83	83	04		iniat foaning (	
Intercession City P8	84	63	83	83	98		Inlet focoine (	
Intercession City PS	64	83	83	83	. 98		Intel fonding (	
Intercession City P10	84	83	83	83	98		Iniet focolne f	kin . Ki & Alimi
Intercession City P12	83	83	63	83	99		Commercial o	peration 12/00
3 Intercession City P13	83	83	83	83	99		Commencial o	peration \$2/00
Intercession City P14	83	83	83	83			Commercial o	oeralian 12/00
Suwannee River Pt	44	49	49	49	68			
Siwannes River P3	44	49	49	49	68			
Light Oil Peaking Resources (Summer Base Rating @ \$5°F.				L		L		
Spring/Fall Base Rating @ 90°F, Winter Peak Rating @ 32°F)					r			100 million 100
Avon Park P2	19	24	24	24	34	<u> </u>	· ·	· · · · · · · · · · · · · · · · · · ·
Barlow P1	46	46	46	46	54			
Barlow P3	46	46	46	46	54	·	· ·	
Bayboro P1	41	44	44	44	60			
Bayboro P2	41	44	44	44	60		· · · · ·	
Bayboro P3	41	44	44	44	60			
Bayboro P4	41	44	44	44	60			
Debary P1	44	49	49	49	67		-	
Debary P2	44	49	49	49	67			
Debary P3	44	49	49	49	67		<b>└──</b> ┤-	
Debaty P4	44	49	49	49	67		-	
Debary P5	44	49	49	49	67		-	
Debay Po	444	43	45	49	6/			
Debay Pil	72	76	76	76	96		INIST TOGGING IN	istalled 5/00 (Jun: Jul & Aug)
Intercession City P1	A7	47	47	10	30		Innacio90iu3:iu	Islaned 5/00 (Jun, Jul & Aug)
Interession City P	47	47	47	47	62		i -	
Intercession City P3	47	47	47	47	67			
Intercession City P4	47	47	47	47	62		<u>   </u>	
Interession City P5	47	47	47	47	62		<u>├</u> ─── <u></u>	
Intercession City P6	47	47	47	47	52			
Intercession City P11	0		143	143	172		Southernisurn	mar sumarchie This Pennah Sault
Rig Pinar P1	11	13	13	13	19	<u>`</u>	Contributi Sult	ine switestip (Juli 20 Dugit Sep)
Suwannee River P2	48	51	51	51	58		┟╼╾╸╴╴┨╴	
Turner P1	11	13	13	13	19			
Tumer P2	11	13	13	13	19		<u> </u> -	
Turner P3	57	61	61	61	84			
Turner P4	57	61	61	61	84			
Total Baseload Plants	3 041	3 127	3 127	3 208	3 208			
				0,200	0,200	· .	· ·	
Total Baseload Contracts	479	479	479	479	479			
Total QF Contracts	831	831	831	831	831			
Total Intermediate Resources	3,102	3,102	3,102	3,356	3,356			
Total Gas Peaking Resources	1,035	1,062	1,062	1,062	1,311			
Total Light Oil Peaking Resources	1,160	1,232	1,375	1,375	1,813			
Total Available Resources	9,652	9,833	9,976	10,311	10,998			

7/19/00 @ 12:25 PM

#### LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY 1999 SERC RATINGS, COGENERATION = 981231 JUNE 1999 FORECAST (\$990503) Bulk Power Sales included in Demand & Energy Forecast

# Hines 2 in 11/2003 : Normal Weather Analysis with Capacity @ "Base" Ratings

						·						
			WINTER 99/00	WINTER 00/01	WINTER 01/02	WINTER 02/03	WINTER 03/04	WINTER 04/05	WINTER 05/06	WINTER 06/07	WINTER 07/08	WINTER 08/09
9 /			Jan-2000	Jan-2001	Jan-2002	Jan-2003	Jan-2004	Jan-2005	Jan-2006	Jan-2007	Jan-2008	Jan-2009
	Existing FPC Capacity	MW	8,351	8,351	8,689	8,706	8,706	9,121	9,121	9,121	9,688	9,688
	New FPC Capacity	MW	0	338	34 17 5 64	0	.567	0	O	567	0	o
	Retired FPC Capacity	MW	0	0	0	0	152	0	0	0	٥	0
	Total Installed Capacity	MW	8,351	8,689	8,706	B,706	9,121	9,121	9,121	9,688	9,688	9,688
	Firm Purchase Capacity	MW	469	469	469	469	469	479	479	479	479	479
	Firm QF Purchase Capacity	MW	831	831	831	831	831	831	831	831	831	831
	QF Contractually-Allowed On-Peak Capacity Reduction	MW	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)
	Seasonal Purchase Capacity	MW	٥	0	0	0	0	0	0	0	· 0	0
	Capacity on Scheduled Maintenance	MW	0	0	0	0	0	0	0	0	0	0
	Firm Sate of Capacity	MW	0	0	0	o	0	G	G	· 0	0	0
	Total Available Capacity	MW	9,545	9,883	9,900	9,900	10,315	10,325	10,325	10,892	10,892	10,892
	Potential Total Retail Demand	MW	8,330	8,488	8,654	8,823	8,985	9,150	9,314	9,479	9,644	9,810
	Wholesale (REA)	MW	779	870	893	433	461	486	513	540	566	592
	Wholesale (Bulk Power)	MW	631	631	167	167	167	167	167	167	167	167
	Wholesate (Municipal)	MW	220	189	130	99	94	19	11	11	11	11
	Total Wholesale Demand	MW	1,630	1,690	1,190	699	722	672	691	718	744	770
	Company Use	MW	30	30	30	30	30	30	30	30	30	30
	Potential Total System Demand	MW	9,990	10,208	9,874	9,552	9,737	9,852	10,035	10,227	10,418	10,610
	Non-Dispatchable DSM and Self-Service QF	WW	399	424	450	478	508	538	569	599	628	657
43.	Normal Weather Demand (Before Load Control)	MW	9,591	8,784	········	9,074	9,229	9,314	9,466	9,924	9,790	9,953
	Normal Weather Reserves (Before Load Control)	MW	-46	99	476	826	1,086	1,011	859	1,264	1,102	939
	Normal Weather Reserve Margin (Before Load Control)	1. %	-0.5%	1.0%	25.1%	9.1%	11.8%	10.8%	9,1%	13.1%	11.3%	9.4%
	Normal Weather Load Management	MW	758	736	680	646	626	611	599	589	580	572
	Normal Weather Demand (After Load Management)	MW	8,833	9,048	8,744	8,428	8,603	8,703	8,867	9,039	9,210	9,381
	Normal Weather Reserves (After Load Management)	MW	712	835	1,156	1,472	1,712	1,622	1,458	1,853	1,682	1,511
	Normal Weather Reserve Margin (After Load Management)	%	8.1%	9.2%	13.2%	17.5%	19.9%	18.6%	16.4%	20.5%	18.3%	16.1%
	Normal Weather Interruptible Load	MW	326	314	311	313	310	312	314	316	318	320
	Normal Weather Voltage Reduction	MW	0	0	0 Alan dahalikkaan 2. stalinta kanka saa	0	0	0	0	0	0	C
	Normal Weather Demand (After All Load Control)	MW	8,507	8,734	8,433	8,115	8,293	8,391	8,553	8,723	8,892	9,061
	Normal Weather Reserves (After All Load Control)	MW	1,038	1,149	1,467	1,785	2,022	1,934	1,772	2,169	2,000	1.831
N.	Normal Weather Reserve Margin (After All Load Control)	1	12.2%	13.2%	17.4%	22.0%	24.4%	23.0%	20.7%	24,9%	22.5%	20.2%
N	ormal Weather Reserves (After All Load Control) Required For 15 %	MW	1,276	°1,310	1,265	1,217	1,244	1,259	1,283	1,309	1,334	1,359
	Normal Weather Reserves (After All Load Control) Above 15 %	MW	-238	-161	202	568	778	675	489	860	666	472
	Normal Weather "DLC" Reserve Margin Contribution	%	104.4%	91.4%	67.6%	53.7%	46.3%	47.7%	51.5%	41.7%	44.9%	48.7%

### **FPC 111**

### LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY 1999 SERC RATINGS, COGENERATION = 981231 JUNE 1999 FORECAST (S990503)

#### Bulk Power Sales Included in Demand & Energy Forecast

### Hines 2 in 11/2003 : Normal Weather Analysis with Capacity @ "Base" Ratings

9	· · · · · · · · · · · · · · · · · · ·		SUMMER 00	SUMMER 01	SUMMER 02	SUMMER 03	SUMMER 04	SUMMER 05	SUMMER 06	SUMMER 07	SUMMER 08	SUMMER 09
			Aug-2000	Aug-2001	Aug-2002	Aug-2003	Aug-2004	Aug-2005	Aug-2006	Aug-2007	Aug-2008	Aug-2009
	Existing FPC Capacity	MW	7,236	7,236	7,485	7,502	7,502	7,847	7,847	7,847	8,342	8,342
	New FPC Capacity	MW	0	249	6 17 (i · · ·	ວ່	495	0	0	495	0	0
	Retired FPC Capacity	MW	0	0	0	0	150	0	0	0	0	0
	Total Installed Capacity	MW	7,236	7,485	7,502	7,502	7,847	7,847	7,B47	8,342	8,342	8,342
	Firm Purchase Capacity	MW	469	469	469	469	469	479	479	479	479	479
	Firm QF Purchase Capacity	MW	831	831	831	831	831	831	831	831	831	831
	QF Contractually-Allowed On-Peak Capacity Reduction	MW	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)
	Seasonal Purchase Capacity	ŃW	0	0	0	٥,	٥	0	0	0	0	0
	Capacity on Scheduled Maintenance	MW	0	0	0	0	0	0	C	0	. 0	0
	Firm Sale of Capacity	MW	0	0	0	0	Q	0	0	0	0	0
	Total Available Capacity	MW	8,430	8,679	8,696	8,696	9,041	9,051	9,051	9,546	9,546	9,546
	Potential Total Retail Demand	MW	7,396	7,555	7,721	7,890	8,052	8,218	8,384	8,551	8,717	8,885
	Wholesale (REA)	MW	392	465	472	0	6	- 15	25	33	42	51
	Wholesale (Bulk Power)	MW	631	631	167	167	167	167	167	167	167	167
	Wholesale (Municipal)	MW	232 ·	180	134	88	88	18	11	, <b>11</b> ,	11	11 :
	Total Wholesale Demand	MW	1,255	1,276	773	255	261	200	203	211	220	229
	Company Use	MW	30	30	30	30	30	30	30	30	30	30
	Potential Total System Demand	MW	8,681	8,861	8,524	8,175	8,343	8,448	8,617	8,792	8,967	9,144
l	Non-Dispatchable DSM and Self-Service QF	MW	353	366	379	393	408	423	439	454	468	483
	Normal Weather Demand (Before Load Control)	. MW	0,328	8,495	8,145		7,935	8,025	6,178	8,338	8,499	8,661
	Normal Weather Reserves (Before Load Control)	MW	102	<b>184</b>	551	914	1,106	1,026	873	1.208	1,047	885
·	Normal Weather Reserve Margin (Before Load Control)	- <b></b>	2. 6: <b>1.2%</b>	2.2%	6.8% Sr S	A1.7%	13.9%	12.8%	/:): 10,7%	14.5%	12.3%	10.2%
	Normal Weather Load Management	MW	492	447	389	349	318	291	267	247	229	214
	Normal Weather Demand (After Load Management)	мw	7,836	8,048	7,756	7,433	7,617	7,734	7,911	8,091	8,270	8,447
	Normal Weather Reserves (After Load Management)	MW	593	631	940	1,263	1,424	1,317	1,140	1,454	1,276	1,099
	Normal Weather Reserve Margin (After Load Management)	%	7.6%	7.8%	12.1%	17.0%	18.7%	17.0%	14.4%	18.0%	15.4%	13.0%
	Normal Weather Interruptible Load	MW	327	315	312	314	311	313	315	317	319	321
	Normal Weather Voltage Reduction	MW	0	0	0	0	0 Sectore and the sector	0	0	0	0	0
	Normal Weather Demand (After All Load Control)	MW	7,509	7,733	7,444	7,119;;	7,306	7,421	7,596	7,774	7,951	8,126
	Normal Weather Reserves (After All Load Control)	MW	920	946	1,252	1,577	1,735	1,630	1,455	1,771	1,595	1,420
	Normal Weather Reserve Margin (After All Load Control)	%	12.3%	12.2%	16.8%	22.2%	23.7%	22.0%	19.2%	22.8%	20.1%	17,5%
Nor	mal Weather Reserves (After All Load Control) Required For 20	% MW	1,502	1,547	1,489	1,424	1,461	1,484	1,519	1,555	1,590	1,625
,	Normal Weather Reserves (After All Load Control) Above 20 %	MW	-581	-601	-237	153	274	145	-64	217	5	-206
	Normal Weather "DLC" Reserve Margin Contribution	%	89.0%	80.6%	56.0%	42.1%	36.3%	37.1%	40.0%	31.8%	34.4%	37.7%

Honoral Weather

														6.5%	8.7%				Total DLC				
		6 1. d 1. d	Busied	Bazelord		iniamediata	Section 4	Pesking	Total	OF On-Pask	Bandoof & Injermediate Resources	Peaking Resources	Operating Requirements	FPC Available Resources EFOR	FPC Available Resources EFOR	Total Peak Before DLC	Supply Variance	Supply Reserve Margin	(Including IS/CS and Vall. Red.)	Firm Peak Alter DLC	Total Variance	Talai Resen Margin	**
	Month	Maintenance	Plants	Contracts	QF Contracts	Resources	Resources	Resources	POR CALCULAR OF				141	-458	419	8,591	- 44	0.63%	1,084	8,597	1,144	12.45%	
			3 150	463	831	2,374	6,824	2,827	9,551	-106	6,033	3714	341	-450	-794	4,743	746	£53%	500	7,834	1,855	21.12%	
-1	Jan-99	+162	3,150	469	831	2,374	6.824	2,827	8,651	-106	6.046	2,730	341	-344	-684	7.383	968	13.12%	745	. 6,636	1,714	35,45%	
4	Mar-00	-1,299	3,150	469	631	2,374	6.824	2,627	8,641	-106	5,978	2,103	281	-340	-600	6,180	1.307	21.15%	127	4.525	2,335	35.78%	, · ·
Å.	Apr-00	-1,332	3,069	459	631	2,297	8,631	2,144	8,850	-108	5,963	2,084	291	-415	-733	7,252	1,608	22.1/%	800	7.181	1,430	12.20%	, - ₁
5	MAY-00	٥	3,110	469	831	2,262	6,612	1 950	8.522	-106	5,973	1,849	291	-403	-7 10	7,991	631	5.45%	A17	1,350	1,262	17.15%	,
6	Jun-00	` ۵	3,110	459	831	2,262	6,514	1.950	8.622	-195	5,973	1,849	291	-403	-710	8,1/8	208	2.49%	818	7,508	1,026	12.67%	•
7	Jul-00	٥	3,110	459	631	1 267	6.546	1,350	8,536	-106	5,681	1,850	291	-398	-102	7 547	114	10.58%	766	7,117	1,806	22.48%	•
8	Aug-00	8	3,024	463	101 101	2 263	. 6.672	2,945	6.7 17	-106	5,968	1,643	281	-406	-/12	6,734	1.538	24.34%	808	6,125	2,246	38.70%	•
9	Sep-00	0	3,110	469	831	2 262	6,572	2,188	8,660	-106	5,943	2,091	281	-378	-656	6.604	1,561	23.62%	675	\$,833	2,236	37.54%	•
10	04-09	-487	3,110	469	831	2,374	6,565	2,155	8,053	-106	6,165	2,094	201	-472	-\$32	6,270	1,604	19.40%	674	7,296	2,578	35.33%	•
11	Nov-DQ	-654	3,191	459	431	2,374	6.685	3,124	3,949	-106	6,064	3,000					215	2.10%	1,050	8,734	1,255	14.379	ń
12	Dec-00	-[15	3.131					2,124	3,363	-106	6,060	3,005	341	-478	443	1.734	844	2.00%	828	8,062	1,760	21.637	<b>K</b>
13	Jan-01	٥	3,191	469	431	2 104	6,385	3,124	9,949	-106	6,066	3,007	341	-468	-124	7.539	1,948	25.35%	715	. 6,824	2,664	28.057	<b>5</b> · ·
14	Feb-01	-167	3,191	453		2.374	6.565	3,124	8,389	-106	6,040	3,011	341	-373	454	6,343	1,705	25.71%	617	5,766	2,122	40.281	*
15	Mar-01	-501	3,191	463	831	2.262	4.572	2,612	9,184	-105	5,965	2,419	201	-345	-679	7,446	855	11.48%	663	6,765	1,536	22.74	×.
16	Apr-01	-1,096	3,110	469	831	2,262	6,672	2,437	8,109	-106	3,966	2,01	291	-416	-734	. 8,148	723	8.87%	747	7,401	1,470	18,69	
17	May-01		3 119	469	<b>6</b> 31	2,252	6,572	2,199	8,871	-106	2,900	2 085	291	-416	-734	8,340	631	4.36%	742	7,578	1,282	13.64	
18	104-01		3,110	469	431	2,252	8,672	2,198	8,871	-108	5.645	2,096	281	-412	-726	8,425	. 290	3.41%	162	7,733	1,002	22.37	- s
19	400-01		3,024	469	831	2,262	6,585	2,198	8,785	-106	5,350	2,169	281	-472	-744	8,039	827	11.53%	712	6 330	2,151	33.87	1%
21	Sep-01	٥	3,110	469	\$31	2,262	8,672	2,234	0,100	-106	5,978	2,335	281	-395	-697	6.349	1,582	22.63%		6.140	1,695	27.81	196
22	004-01	-628	3,110	469	\$31	2,262	6,672	2,437	8.307	-106	6,198	2,347	291	-358	-634	6,781	1,054	10.0976	118	7.514	1,323	17.61	1%
23	Nov-01	-1,457	3,191	469	431	2,374	4 165	3,124	1,949	-196	6,107	3,020	341	-415	-731	1412						18.6	-
24	Dec-01	-1.152	3,181	469	831	2,314				-906	6.076	3,004	341	-478	444	9,424	542	4.18%	801	7 850	2,156	21.4	7%
- 24	100-02		3,208	469	831	2,374	6,182	3,124	19,006	-106	6.076	3,004	341	-479	-844	8,681	1,325	15.26%	685		2.453	37.0	3%
26	Fals-02	8	3,205	468	\$31	2,374	6,842	3,124	10.008	-106	6,115	3,017	341	-427	-153	1,257	1,766	24.25%	476	5.555	2,545	45.8	2%
27	Mar-02	-841	3,208	469	\$31	2,374	6,842	3,144	8.201	-105	6.012	2,419	291	-374	-660	6,130	1.478	20.60%	532	4,534	2.104	32.2	55
26	Apr-02	-1,101	3,127	468	431	2,262	1.643	2,437	9,126	-106	5,949	2,336	291	-404	-712	7,100	1.101	14.13%	645	7,102	1.766	25.1	15%
25	May-02	-454	3,127	469	831	2.262	6,649	2,199	8,858	+106	5,979	2,094	281	-417	.736	7,944	900	11.261	6 · 700	7.24	1,596	21.9	14%
з	Jun-02	0	3,127	408	A11	2.262	5,543	2,199	6.855	-106	5,978	2,094	201		-728	8,145	657	1.96%	701	7,44	1,35	1 11.3	24%
3	1 1-02	0	1,127	459	11	2,262	5,503	2,199	1,192	-106	5,857	2,995	) ant 291	423	-745	7.640	1,303	16.879	N 650	7.62	1.96	2 273	13%
3	2 Aug-02		3,041	469	431	2,262	4,649	2,294	8,983	-106	5,8/3	2,10	241	-387	-701	6,508	1,536	29.341	K · 534	6.05	2.4/4	1 464 1 45	44%
3	3 Sep-04		3,127	469	831	2,252	. <b>6,64</b> 9	2,437	8,126	-106	6.183	2.33	291	-402	-109	8,540	2.071	31.671	Ng 621	5,01	2.00	L 21	.78%
3	5 Nov-03	-708	3.208	459	831	2,374	6,862	2,437	8,318	-106	6,105	3.014	4 341	-440	-775	8,102	1,192	14.7 1	* **				
3	5 Dec-02	2 -712	3,208	469	<b>631</b>	2,374	6,642	3,124				3.00	4 341	-479	-444	5,074	852	10.27	% 358	8,11	5 1,43	1 20	2016
			1 204	465	831	2,32	6,642	3,124	10,006	-106	6,076	1.00	4 341	-479	-844	1.321	1,625	20.25	¥ \$29	7,51	2 249		444
3	7 Jan-0.	, v	3,208	469	531	2.37-	6,882	3,124	10,006	-109	6.075	3.00	4 341	-479	, -au	1 7,924	2,862	42.45	<b>% 6</b> 70	6.34	4 3,63	12 · 41	36%
-	a result a kasa		3,208	465	a a a a a a	2,37	6.842	3,124	10,000	-106	5,966	2,40	3 251	-435	-764	6 6,115	3,046	50.47	156 201 IN 501	6.3	2,7	SI 43	
	a Apr-Q	3	3.127	465	131	2.26	2 6,640	2,314	8,126	-196	5,968	2,32	5 291	I -430	-754	9 6.9/4	4,194	17.90	N 543		1,9	99 25	LQ1% .
	At May-	23	3,127	46	9 631	2.25	2 8,600	2,199	8,555	-105	5,979	2,05	H 291	-41	-73	6 7.53	1, 1,217	15.34	55. 561	7.0	10 1, <b>1</b>	76 .26	.79%
	42 Jun-8	33	3,127	46	9 831	2.20	7 6.649	2,199	8,635	-106	5.979	2,04	14 291	1 -41	, -rs		1,020	13.10	P% 663	7,1	18 1,6	43 27	1.64%
	۵-اب ده	3	3,121	r. 46 . 46	9 831 • 831	2.2	2 8,603	2,193	6,802	-106	5,487	2,01	45 20°	1 -41-	1 -74	5 7.46	2 1,501	20.0	E% 627	5.6	55 2.1	.28 31	1.05%
	44 Aug-	e3 e	2,641		a 831	2,2	5.645	2.294	8,983	-108	5.975	i. 2,1	68 AP	, ,	a .75	.6.63	1 2,495	\$ 37.6	3% \$21	6,1	10 3,0	16 41	1.36%
	45 Sep-	03	3,12	7 46	3 83	1 2,2	62 6,685	2,437	9,126	- 106	5,969	2,1	29 29 71 78	1 46	4 4	6.35	5 1,371	8 53.1	7% 814	. s	41 3.9	AG 10	2.54%
	45 Qci-	03	3.72	a - 16		1 2,7	4 7,29	7 2,437	9,734	-104	6,503	2 . 2,3	as 34	1 -50	2 -64	15 2.71	2 2,704	35.1	3% 667	6.1	45 3.1	# <b>*</b> . *	<i>L.C.</i> 7%
	47 Nov-	-03 -03	3.20	4	59 53 ⁻	1 2,7	LB 7,29	7 3.124	10.421	-10						4 9 9	1.18	2 12.9	2% \$34	s 42	80 21	128 2	5.66%
	~6 Dec	~	-,				13 7.25	7 3,124	10,421	1 -10	• • •	4 25	NG 19	n -54	· •	5 141 15	a 1.95	1 23.0	3% 78	1, 1 <i>1</i>	178 2.3	142 3	5.71%
	AAL EA	-04 0	3,20	16 44 			43 7.29	7 3,124	10.42	1 -10	6.47	4 2.5	NG 246	n - 24 		85 7.12	5 3,29	46.2	LGYL 65		167 J.S	854 6	j1.14%
	50 Feb	-04	3,20	15 4	60 64 68 63	1 27	19 7,29	7 3,124	19,42	1 -10	6 6,47	4 2,5	NG 24	an -4	54 - 8	6.2	3,32	2 53.3	7% S2	9 SJ	125 3.1	451 . #	17.62%
	51 Mar	4	3.20		60 A3	1 2,4	67 7,03	4 2,512	9,546	- 10	6 6,28	v 2.3	105 2	91 -4	49 -7	93 7,11	2,36	a ja ja ja	34% 57	4 6,	529 . 2.	- SHL	10.03%
	52 Apr-	-04	3.14	27 4	49 83	ji 2.6	jo7 7,03	4 2,457	9,471	-10	6 6,30	N 2.	uso 2	91 -4	34 -7	69 7.5	M 1.55	SJ 20.3	22% 61	<b>5</b> 7.	965 Z.	549	21.55%
	al May	-04	2.12	27 4	.59 63	ai 2.0	107 7,93	2.19	3,21	3 -10	NG 0.31 NG 6.81	15 2.	096 2	91 -4	09 ·7	7.8	16 82	2 11.3	79% 62	u 1.	،1, 1644 1. 2015	.441	25.18%
	54 Jun	а а	3.1	27 4	45 (Ga	31 2.	112 6.53	39 2.19	6,73	a	4 4.22	21 2.	AS1 2	91 .4		161 7,9	15 1.2	12 15.	2/% 62 16% 44		027 2	301	32.75%
	56 Aug	-04 0	3,0	41 4	163 E	31 2,	607 <b>6,3</b> -	4 2,19	10	A -10	6 5,34	06 2.	184 2	i9i -4	ы <b>з</b> 🤤	779 7.6	24 1,70	un 22	2078 34 215 54		252 3	218	51.48%
	57 Sec	-04	' 3.1	27 .	459 - &	31 2.	607 1.0	н <u>са</u> 14 247	7 9.47	-1ú	of 8,3	20 2	.325 2	291 -	ы ен	193 6.7	10 2.7 11 / 12	ng 46. NA 51.		ы 5	M2 1	192	66.63%
	58 Dc	1-04	. 3.1	27	469 5	31 2	807 7.0	97 243	7 9.73	4 -16	66 6.5	62 [′] 2	,321 2	291 -	164 1	010 8.4							
				208	-159 2	ມາ 2																	

60	Dec-04		3.	208	469	831	2.788	7,297	3,124	10,421	-106	6.474	2,999	341	-502	-685	7,831	2,580	33.67%	850	6.941	3,440	48.27%
61	Jan-05	0	3,	204	478	431	2,749	7,207	3,124	10,431	-106	8,684	2,999	341	-362	-445	8,314	1,117	11.50%	923	8,381	2,049	24.31%
62	Feb-05		3,	205	478	831	2,749	1,307	3,124	10,431	-106	8,484	2,899	341	-502	-845	8,543	1,855	22.19%	782	7,761	2,670	34.41%
63	MAI-05		· 3,	294	478	<b>#31</b>	2,749	7,207	3,124	10,431	-196	6,464	2,899	341	-502	-845	7,174	3,257	45.40%	653	6,521	3,910	58.96%
64	Apr-05		3,	127	478	A31 ²	2,607	7,044	2.512	8,556	-105	6,307	2,395	291	-454	-868	6,257	3,263	\$2.00%	\$15	5,772	3,784	65.55%
65	May-05		3	127	479	831	2,607	7,044	2,437	8,481	-108	8,310	2,325	291	-448	-793	2,177	2,304	32.10%	\$55	8,622	2,158	43.16%
66	Jug-05		3	127	479	831	2.607	7.044	2,199	8.243	-106	6.329	2.090	291	-436	-768	7,750	1.484	58.12%	593	7,168	2.076	28.17%
	hut of			177	478	831	2 507	7 044	2 199	9 243	-106	6 320	2 090	291	-436	744	7 897	1.348	17.04%	802	7.285	1.64	26 70%
											100	6 997	3 681	-		781	4 076	4 417	14 1006	804	7.474	1714	22.200
68	Aug-05	•	. 3	,041	478	<b>1</b> 11	2,607	6,836	4,189	8,137	-100	1.00	2,001	401			<b>U</b> ,063	1,146			1,461	4,1.00	21.167
69	Sap-05		3,	127	479	831	2,607	7.044	2,294	9,138	-106	8,318	2,184	201	-414	-7.0	1,105	1,633	21.23%	916	7.127	2,211	31.02%
70	Oci-85		3.	.127	479	831	2,607	7.044	2.437	9,481	-105	\$,310	2,325	291	-449	-783	6,624	2.697	34.94%	467.	6.332	3,148	48.73%
71	Nov-05		3	,298	478	431	2,789	7,307	2,437	8,744	-106	6,662	2,321	291	-464	-\$18	6,485	3,259	\$0.25%	601	5,644	3,860	45.81%
72	Dac-05		3.	208	478	831	2,748	7,307	3,124	10,431	-106	6,484	2,989	341	-502	-885	7,890	2,541	32.21%	142	7,048	3,343	48.01%
71	Jan-06	•	1	208	478	441	2,744	1,301	3,124	18,631	-198	6,464	1,000				3,499		14.1378	858 ····	6,333	1,0/6	41.89%
74	Fab-08		3	,205	478	931	2,738	7,307	3,124	10,431	-106	6,494	2,999	341	-502	-445	8,684	\$,747	20.12%	776	7,908	2,523	31.81%
75	Mar-05		. 3	,205	479	431	2,789	7,307	3,124	10,431	-108	6,484	2,999	341	-502	-445	7,273	3,154	43.42%	650 ·	6,623	3.808	ST 49%
76	Apr-06		3.	.127	479	631	2,607	7,044	2.512	8,556	-106	4,307	2,399	291	-454	-800	6,396	3, 158	48.36%	\$03	5,495	3,661	\$2.10%
71	May-06		3	.127	479	831	2,607	7,044	2,437	8,441	-106	6,319	2,325	291	-449	-793	7,304	2,177	29.81%	538	6,766	2,715	40.13%
76	Jun-06		3	127	478	831	2,607	7.044	2,199	8,243	-106	6,320	2,090	291	-434	-769	7,897	1,348	17.04%	\$72	7,325	1,018	26.14%
79	Jul-06		3	,127	479	831	2,607	7,044	2,199	9.243	-106	\$,325	2,090	291	-436	-768	8,039	1,294	14.97%	581	7,458	1,784	23.83%
80	Aug-06		3	.041	478	831	2,607	6,358	2,199	8,157	-105	6,237	2,081	291	-432	-761	8,178	875	11.87%	542	7,596	1,561	20.55%
	Sec.06			177	479	831	2 607	7.044	2,294	8.334	-106	6,316	214	291	-442	-779	7.841	1.497	19.09%	557	7.284	2.054	28.21%
	0-1-05			+77	470	131	2 607	7 944	2 437	B 451	-106	6.310	2.325	291	-448	-793	1.848	2 515	36.50%	- 443	1.43	3.016	46 70%
					(10		3 760	7	2 417	10.311	-106	7 106	2313	201	-195	473	6 573	1734	56 AT%	400	4 973	4 334	77 675
63	Nor-Ob		3		4/9	101	3,330	e jare	2.431	19.011			2,213			4.4		4 6 6 4			8.813 8.438		12.46 M
64	Dec-96		3	205	479	#31	3,356	7,874	2,126	10,936	-196	1,92/	2,991	341	-013	-940	8,007	2,501	3/	444	1,1/2	3,129	10.33%
85	Jan-07	و		208	473	831	3,356	7,674	3,124	10,895	-106	7,027	2,891	341	-533	-840	5,624	1,270	14.23%	805	4,723	2,375	26.08%
86	E-6-01			208	479	831	3 356	7.874	3.124	10,895	-105	7.927	2.591	341	-533	-840	6.833	2.165	24.51%	πι	8.962	2.836	36.42%
	14			104	(78		3 368	7	5 124	10 998	-105	7 077	2 981	341	-513	مع	7.340	3 611	49 02%	<b>648</b>	6 732	4 768	63 36%
Br	Martor				*/*			1,014	2,444	10,000	-105		2 363	204	-44.5		A 518	1 616	64 7646			4.034	44 994
25	Apr-07			,127	478	<b>1</b> 01	3,102	7,558	2.312	10,031	-140	0,701	2.332	. 201			9,3 19 7, 4 19	3,505				4,424	
49	May-07		. ,	1,127	479	121	3,102	1,538	2,437	3,370	-106	6,783	2.315	201	-	-441	1,440	2.3.99	34.03%	123	6,813	3,061	4.25
₽a	Jun-07		- 3	1,127	479	631	3,102	7,539	2,199	8,738	-106	6,794	2.083	291	-464	-817	8,045	3,683	21.04%	<b>2</b> 22	7,499	2,247	30.00%
ទេ	Jui-07		3	1,127	479	431	3,102	7,538	2,199	8,738	-106	6,794	2,083	291	-464	-817	8,168	1,550	18.93%	563	7,625	2,112	27.70%
92	Aug 07	٩	3	1,041	478	831	3,102	7,453	2,199	8,652	-196	6,712	2,084	291	-458	-404	8,338	1,314	15.75%	364	7,774	1,377	24.15%
83	Sep-07		3	1,127	478	831	3,102	7,539	2.294	8,833	-106	6,790	2,177	291	-469	-827	7,946	1,847	23, 13%	542	7,446	2,349	32.09%
94	Oct-07		3	1,127	479	831	3,102	7,538	2.437	9,976	-106	5.745	2,318	281	-477	-841	7,974	2.902	41.92%	478	6,588	3,378	\$1.19%
95	Nov-07		1	,208	478	431	3,356	7,574	2,437	10,311	-106	7,106	2,313	291	-495	-673	0,671	3,640	54.56%	500	6,071	4.240	69.43%
96	Dec-07		2	1,204	478	431	3,355	7,874	3,124	10,998	-106	7,027	2.99 t	341	-633	-840	8,133	2.865	35.23%	830	7,303	3,695	50.58%
				+																			
97	Jen-08	9	-	3,206	478	433	3,336	7,874	3,124	10,396	+199	6,84	2,301	241			3,130	1,698	12.34%			2,106	23.94FA
	Fab-QB		1	3,208	479	831	3,356	7,874	3.124	10,968	-196	7,027	2,991	341	-533	-940	8,978	2,015	22.49%	767	4,212	2,786	33.92%
99	Mar-06		1	3.205	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-840	7,458	3,509	45.06%	646	6,843	. 4,155	60.72%
100	Apr-08		:	3,127	479	431	3,102	7,539	2,512	10.051	-106	6,781	2,382	291	-481	-145	6,633	3,418	51.53%	485	8,148	3,903	63.48%
101	May-08		:	3, 127	479	<b>631</b> ·	3, 192	7,538	2,437	8,976	-106	6,785	2,318	291	-477	-841	1,578	2,450	31.66%	514	7.062	2,914	41.27%
102	Jan-Då		:	3.127	479	<b>83</b> 1	3,102	7,539	2,199	9,735	-106	6,794	2,053	291	-464	-817	4, 191	1,547	18.66%	540	7,631	2,957	27.21%
103	80-IuL			3, 127	479	431	3,102	7,539	2,199	8,738	-106	6,794	2,043	291	-464	-417	8,336	1,400	15.79%	547	7,791	1,947	24.98%
104	Aug-08	٥		1.041	673	431	3,192	7.453	2,199	9,652	-106	6,712	2,084	291	-458	-808	4,499	1,153	13.56%	548	7,951	1,701	21.38%
105	Scolle	-		1 127	479	831	3,102	7.539	2.294	9,433	-106	5.750	2,177	291	-463	-827	8,132	1,701	20.92%	\$29	7,603	2,730	28.32%
					170		7 107	7 410	3 437	B 476	-105	£ 785	2318	291	477	-841	7 201	2 775	34 54 5	470	4731	3 745	48 71%
100	021-04			3, 147	4/8		3,102	1,000	2,437		-100	7.44	2.313	201	406		8 7.54	3.6.13	63.24W	£0.9	6.488	4.443	
107	Nev-08			3,208	479	831	3.356	7,8/4	2.437	10,411	- 108	r, we	2,316	201			0./ 40	4,343	32.37%	300	1,103	4,142	BY . 14 B
105	Dec-08			3,208	479	431	3,356	1,5/4	3.124	10,896	- 100	1,421	6,5991		-111	-9-0	8,698	6.138	33.18%	643	(,4.94	3,364	47.34%
109	Ph.eet	٥		3 208	479	831	3,356	7.574	1.124	10.834	+196	7,927	2,991	341	-533	-840	8,853	1,845	10.50%	862	8,061	1,837	21.38%
	d - 00	•			170	471	3 364	7 874	3.124	10 994	-106	7 077	2 941	341	-611	-940	9.130	1.668	20 46%	764	1 366	2 632	31.45%
110	FaD-US			3.000	4/3			1,074	2.124	40,000	-100	3 0.11	1.001	341			7 508	3.400	44 75%	6.4 <b>6</b>		4.048	** ***
111	Mar 09			3,201	4/8	831	3.350	2,8/4	3.124	10,100	- 100	1,044	2.001								0,000		
112	Ар-09			3,127	479	431	3, 102	7,538	2312	10.031	-120	6,781 5	2,392				0.7 65				0,210	4.170	
113	May-08			3.127	478	831	3,102	7,639	2.437	9,975	-106 🏔	6,785	2,316	201	-4/1	-641 -	1,113	2.263	20.34%	909	7,208	2.764	38.40%
114	Jun-09		· ·	3.127	478	#31	3,102	7.538	2,199	9,738	+106	6,794	2,043	291	-454	-617	6,339	1,399	- 16.77%	524	7,811	1.826	24.66%
115	80-Iuk		:	3.127	479	831	3,192	7,538	2.189	9,738	-106	6,794	2,043	291	-464	-817	3,469	1,248	34.23%	\$34	7.855	1,782	22.41%
116	Aug-09		:	3,041	478	831	3,102	7,453	2,188	8,652	-146	6,712	2,044	291	-459	-808	8,661	991	11.44%	535	8,126	1,526	18.77%
117	Sep-09			3,127	478	831	3,102	7,539	2.294	9,633	-106	6,799	2,177	291	-469	-427	6.279	1,554	16.77%	518	7,761	2.072	25.69%
114	Qc1-09			3.127	479	831	3,102	7.539	2.437	9,976	+106	6,785	2,316	291	-477	-841	7,331	2.645	36 04%	465	5.866	3.110	45.30%
119	Nov-09			3.205	479	\$31	3,356	7,874	2.437	10.311	-106	7,106	2,313	251	-495	-673	5,366	3,445	50 17%	599	6.257	4,044	\$4.53%
	0-4.00			3 208	479	831	3.355	7.574	3.124	10.938	-108	7,027	2,991	341	-533	-940	8.385	2.613	31 16%	- 821	.7.564	3.434	45.40%
120															-							-	

2000-2001 Resource Assessment Normal Weather Forecast (S990503) Monthly Peaks with Actual Resources (5.5% EFOR with No Market Purchases)

MW



Total Peak Before DLC	Firm Peak After DLC
Scheduled Maintenance	FPC Available Resources EFOR
Baseload & Intermediate Resources	Peaking Resources
Total DLC (Including IS/CS and Volt. Red.)	Coperating Requirements
#### TMY Weather

#### Bulk Power Sales Included

		TOTAL	DIRECT LO	DAD CONTROL P	ROGRAMS		ΤΟΤΑΙ	(USED)	FIRM	(AVAILABLE)	
		REEORE	RESIDENTIAL	OTHER DI C	TOTAL DLC	INTERR	LOAD CONTROL		AFTER	VOITAGE	
		LOVDCONTROL	LOAD WOT	BROGRAMS	BROGRAMS	LOAD	CARABUITY	REDUCTION		BEDUCTION	
SELEON	NONTH	LOAD CONTROL	LUAD MGT.	PROGRAMS	(AUA/)	(1440)	(AAAA	ANA		ALLOUTION	
SEASON	MONTH	(20164)	(mvr)	(10144)	(MAA)	(10044)	(IMAA)	(MAA)	(waxa)	(max)	
WINTER 99/00	Jan-2000	9,737	735	23	758	326	1,084	C	8,652	115	
WINTER 99/00	Feb-2000	8,413	559	23	583	326	909	. 0	7,505	105	
WINTER 99/00	Mar-2000	6,939	396	23	419	326	745	0	6,194	69	
SUMMER 00	Apr-2000	6,202	282	43	326	327	653	D	5,550	77	
SUMMER 00	May-2000	7,670	353	47	400	327	727	0	6,942	.90	
SUMMER 00	Jun-2000	8,129	423	49	473	327	800	0	7,329	99	
SUMMER 00	Jul-2000	8,295	440	50	490	327	817	0	7,478	102	
SUMMER 00	Aug-2000	8,482	442	50	492	327	819	٥	7,653	103	
SUMMER 00	Sep-2000	7,728	390	49	439	327	766	0	6,961	97	-
SUMMER 00	Oct-2000	7,018	236	45	281	328	609	0	6,409	85	• '
WINTER 00/01	Nov-2000	5,971	322	24	347	328	675	0	5,297	81	
WINTER 00/01	Dec-2000	7,883	621	25	646	328	974	0	6,909	103	
WINTER 00/01	Jan-2001	9,933	710	26	736	314	1,050	0	8,682	117	
WINTER 00/01	Feb-2001	8,620	535	26	562	314	876	0	7,745	107	
WINTER 00/01	Mar-2001	7,090	376	26	401	314	715	0	6,375	91	
SUMMER 01	Apr-2001	6,411	257	46	303	314	617	0	5,793	80	
SUMMER 01	May-2001	7,909	319	50	369	314	683	0	7,226	83	
SUMMER 01	Jun-2001	8,295	380	52	432	315	747	٥	7,548	101	
SUMMER 01	Jul-2001	8,479	394	52	447	315	762	0	7,718	104	
SUMMER 01	Aug-2001	8,656	395	52	447	315	762	· 0	7,893	106	
SUMMER 01	Sep-2001	7,879	346	52	397	315	712	· 0	7,167	100	
SUMMER 01	Oct-2001	7,196	206	47	254	315	569	0	6,628	87	
WINTER 01/02	Nov-2001	6,139	299	27	326	315	641	о. С	5,498	84	
WINTER 01/02	Dec-2001	8,037	576	27	602	316	918	0	7,118	105	
WINTER 01/02	Jan-2002	9,588	653	27	680	311	991	O	8,597	114	
WINTER 01/02	Feb-2002	8,379	493	27	520	311	831	0	7,548	105	
WINTER 01/02	Mar-2002	6,849	346	27	374	311	685	0	6,164	89	
SUMMER 02	Apr-2002	6,177	215	49	264	311	575	0	5,601	77	
SUMMER 02	May-2002	7,679	268	58	321	311	632	Đ	7,047	90	
SUMMER 02	Jun-2002	7,959	320	54	374	311	685	D	7,274	97	
SUMMER 02	Jul-2002	8,161	333	55	385	312	700	o	7,461	100	
SUMMER 02	Aug-2002	8,326	334	55	389	312	701	٥	7,625	102	
SUMMER 02	Sep-2002	7,527	293	54	347	312	659	0	6,865	96	
SUMMER 02	Oct-2002	6,906	175	50	226	312	538	0	6,368	84	
WINTER 02/03	Nov-2002	5,900	280	29	309	312	621	0	5,279	81	
WINTER 02/03	Dec-2002	7.711	541	30	571	313	884	0	6,827	101	
							· · · · · · · · · · · · · · · · · · ·				
WINTER 02/03	Jan-2003	9,247	616	30	646	313	959	0	8,288	110	
WINTER 02/03	Feb-2003	8,032	456	30	496	313	809	. 0	7,223	101	
WINTER 02/03	Mar-2003	6,573	327	30	357	313	670	0	5,903	36	

#### TMY Weather

#### Bulk Power Sales Included

		SYSTEM	DIRECT LO	DAD CONTROL P	ROGRAMS		TOTAL	(USED)	FIRM	(AVAILABLE)
		REFORE	RESIDENTIAL	OTHER DI C	TOTAL DLC	INTERR	LOAD CONTROL	VOLTAGE	AFTED	VOLTAGE
		LOAD CONTROL	LOAD MGT.	PROGRAMS	PROGRAMS	LOAD	CAPABILITY	REDUCTION		REDUCTION
SEASON	MONTH	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	/MW)	(MOW)
SUMMER 03	Apr-2003	6.172	186	52	238	313	551	0	5 621	(MVV) 77
SUMMER 03	May-2003	7.533	232	56	288	313	601	0	6.032	68
SUMMER 03	.kin-2003	7.724	278	57	335	314	649		7 075	. 95
SUMMER 03	Jul-2003	7.867	289	58	347	314	661	. 0	7 205	97
SUMMER 03	Aug-2003	7,977	291	58	349	314	553	0	7314	27
SUMMER 03	Sap-2003	7.329	256	57	313	314	627	0	6 701	94
SUMMER 03	Oct-2003	6,963	154	53	207	314	521	0	6 442	85
WINTER 03/04	Nov-2003	5,712	267	33	300	314	614	0	5.098	79
WINTER 03/04	Dec-2003	7,319	520	33	552	315	867	0	6,451	96
WINTER 03/04	Jan-2004	9,414	593	33	626	310	936	0	8,478	112
WINTER 03/04	Feb-2004	8,200	448	33	481	310	791	· 0 ·	7,408	103
WINTER 03/04	Mar-2004	6,677	314	34	348	310	658	0	6,019	87
SUMMER 04	Apr-2004	6,296	164	55	219	310	529	٥.	5,767	79
SUMMER 04	May-2004	7,711	205	59	264	310	574	٥	7,137	90
SUMMER 04	Jun-2004	7,884	245	60	305	310	615	0	7,269	97
SUMMER 04	Jul-2004	8,038	255	61	316	311	627	0	7,411	99
SUMMER 04	Aug-2004	8,143	257	61	318	311	629	0	7,514	101
SUMMER 04	Sep-2004	7,472	226	60	286	311	597	o	6,875	96
SUMMER 04	Oct-2004	7,103	136	56	192	311	503	• •	6,600	86
WINTER 04/05	Nov-2004	5,800	258	36	293	311	604	0	5,196	80
WINTER 04/05	Dec-2004	7,434	503	36	539	311	850	. 0	6,584	98
WINTER 04/05	Jan-2005	9,505	575	36	611	312	923	0	8,583	113
WINTER 04/05	Feb-2005	8.287	434	36	470	312	782	C	7,504	104
WINTER 04/05	Mar-2005	6,722	304	37	341	312	653	o	6,069	88
SUMMER 05	Apr-2005	6.367	145	58	203	312	515	0	5,852	80
SUMMER 05	May-2005	7,822	181	62	243	312	555	0	7,268	91
SUMMER 05	Jun-2005	7,970	216	63	280	313	593	0	7,375	98
SUMMER 05	Jul-2005	8.135	225	64	289	313	602	0	7,533	100
SUMMER 05	Aug-2005	8.237	227	64	291	313	604	- 0	7,633	102
SUMMER 05	Sep-2005	7,542	199	- <b>6</b> 3	263	313	576	0	6,966	98
SUMMER 05	Oct-2005	7.130	120	60	179	313	492	0	6,687	83
WINTER 05/06	Nov-2005	5.831	250	. 39	28\$	313	601	٥	5,230	81
WINTER 05/06	Dec-2005	7.477	489	39	528	314	842	0	6,635	89
WINTER 05/05	Jan-2006	9.660	560	39	599	314	913	٥	8,747	116
WINTER 05/06	Feb-2006	8 436	423	40	462	314	776	C	7,659	106
WINTER 05/05	Mar-2005	6.814	296	40	336	314	650	0	6,164	89
SUMMER 06	Apr-2006	6 480	128	61	189	314	503	0	5,977	82
SUMMER D6	May-2006	7.983	159	65	224	314	538	0	7,445	93
SUMMER D6	Jun-2006	8 112	191	66	257	315	572	0	7.540	101

FPC 117

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#### TMY Weather

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#### Bulk Power Sales Included

		TOTAL	DIRECT LC	DAD CONTROL P	ROGRAMS		TOTAL	(USED)	FIRM	(AVAILABLE)	
		BEFORE	RESIDENTIAL	OTHER DLC	TOTAL DLC	INTERR.	LOAD CONTROL	VOLTAGE	AFTER	VOLTAGE	
		LOAD CONTROL	LOAD MGT.	PROGRAMS	PROGRAMS	LOAD	CAPABILITY	REDUCTION	LOAD CONTROL	REDUCTION	
SEASON	MONTH	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	
SUMMER 06	Jul-2006	8,286	199	67	266	315	581	0	7,705	103	
SUMMER 06	Aug-2006	8,389	200	67	267	315	582	0	7.807	104	
SUMMER 06	Sep-2006	7,667	176	67	242	315	557	0	7,110	100	
SUMMER 06	Oct-2006	7,305	105	63	168	315	483	0	6,821	89	
WINTER 06/07	Nov-2006	5,907	243	42	285	315	600	. 0	5,308	82	
WINTER 06/07	Dec-2005	7,577	477	42	519	316	835	0	6,741	100	
WINTER 06/07	Jan-2007	9,816	546	42	589	316	905	0	8,911	118	
WINTER 06/07	Feb-2007	8,588	412	43	455	316	771	0	7,817	108	
WINTER 06/07	Mar-2007	6,910	289	43	332	316	648	0	6,262	91	
SUMMER 07	Apr-2007	6,595	113	64	177	316	493	0	6,102	84	
SUMMER 07	May-2007	8,144	141	68	209	316	525	0	7,619	95	
SUMMER 07	Jun-2007	8,256	168	69	238	317	555	o	7,702	103	
SUMMER 07	Jul-2007	8,439	175	70	246	317	563	· 0	7,876	105	
SUMMER 07	Aug-2007	8,542	176	70	247	317	564	0	7,978	107	
SUMMER 07	Sep-2007	7,794	155	70	225	317	542	0	7,252	102	
SUMMER 07	Oct-2007	7,431	93	66	159	317	476	0	6,955	91	
WINTER 07/08	Nov-2007	5,987	237	45	282	318	600	٩.	5,388	83	
WINTER 07/08	Dec-2007	7,680	467	45	512	318	830	C	6,851	102	
WINTER 07/08	Jan-2008	9,970	534	45	580	318	898	D	9,072	120	
WINTER 07/08	Feb-2008	8,734	403	46	449	318	767	0	7,967	110	
WINTER 07/08	Mar-2008	7,005	282	46	328	318	646	D	6,359	93	
SUMMER 08	Apr-2008	6,709	99	67	167	318	485	0	6,224	85	
SUMMER 08	May-2008	8,302	124	71	195	319	514	. 0	7,788	97	
SUMMER 08	Jun-2008	8,397	148	. 73	221	319	540	0	7,857	105	
SUMMER 08	Jui-2008	8,589	155	73	228	319	547	0	8,042	107	
SUMMER 08	Aug-2008	8,692	156	74	229	319	545	٥	8,144	109	
SUMMER 08	Sep-2008	7,919	137	73	210	319	529	0	7,391	104	
SUMMER 08	Oct-2003	7,555	82	69	151	319	. 470	0	7,035	93	
WINTER 08/09	Nov-2008	6,065	231	48	279	320 .	599	o	5,456	85	
WINTER 08/09	Dec-2008	7,780	457	• 48	505	320	825	0	6,955	-104	
WINTER 08/09	Jan-2009	10,121	523	49	572	320	892	0	9,229	123	
WINTER 08/09	Feb-2009	8,880	395	49	444	320	764	0	8,116	112	
WINTER 08/09	Mar-2009	7,096	276	49	325	320	645	0	6,451	<b>54</b> ·	
SUMMER 09	Apr-2009	6,820	85	71	158	320	478	Ο.	6,342	87	
SUMMER 09	May-2009	8,457	109	74	184	321	505	0	7,952	99	
SUMMER 09	Jun-2009	8,535	131	76	207	321	528	0	8.008	107	
SUMMER 09	Jul-2009	B,737	136	76	213	321	534	0	8.203	109	
SUMMER 09	Aug-2009	3,841	137	77	214	321	535	0	8.306	111	
SUMMER 09	Sep-2009	8,043	121	76	197	321	518	. 0	7,526	106	

FPC 118

#### TMY Weather

## Bulk Power Sales Included

		TOTAL	DIRECT LC	AD CONTROL PR	ROGRAMS			(USED)	FIRM	(AVAILABLE)
		SYSTEM			· · · · · · · · · · · · · · · · · · ·		TOTAL		SYSTEM	
	•	BEFORE	RESIDENTIAL	OTHER DLC	TOTAL DLC	INTERR.	LOAD CONTROL	VOLTAGE	AFTER	VOLTAGE
		LOAD CONTROL	LOAD MGT.	PROGRAMS	PROGRAMS	LOAD	CAPABILITY	REDUCTION	LOAD CONTROL	REDUCTION
SEASON	MONTH	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MM/)
SUMMER 09	Oct-2009	7,677	72	72	144	321	465	0	7.211	()
WINTER 09/10	Nov-2009	6,142	226	51	277	322	599	o	5 543	86
WINTER 09/10	Dec-2009	7,881	448	51	499	322	821	0	7,060	106

FPC 119

#### LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY

#### 1999 SERC RATINGS, COGENERATION = 981231

#### JUNE 1999 FORECAST (S990506)

#### Bulk Power Sales Included in Demand & Energy Forecast

# Hines 2 in 11/2003 : "TMY" Weather Analysis with Capacity @ "Base" Ratings

		WINTER 99/00	WINTER 00/01	WINTER 01/02	WINTER 02/03	WINTER 03/04	WINTER 04/05	WINTER 05/06	WINTER 06/07	WINTER 07/08	WINTER 08/09
		Jan-2000	Jan-2001	Jan-2002	Jan-2003	Jan-2004	Jan-2005	Jan-2006	Jan-2007	Jan-2008	Jan-2009
Existing FPC Capacity	мw	8,351	8,351	8,689	8,706	8,706	9,121	9,121	9,121	9,688	9,688
New FPC Capacity	MW	. 0	538		o	× 1567	0	0		0	0
Retired FPC Capacity	мw	0	. 0	0	0	5, S 152 14	0	0	0	0	0
Total Installed Capacity	MW	8,351	8,689	8,706	8,706	9,121	9,121	9,121	9,688	9,688	9,688
Firm Purchase Capacity	MW	469	469	469	469	469	479	479	479	479	479
Firm QF Purchase Capacity	MW	. 831	831	831	831	831	831	831	831	831	831
QF Contractually-Allowed On-Peak Capacity Reduction	MW	(106)	(106)	(106)	(106)	(106)	(106)	(105)	(106)	(106)	(105)
Seasonal Purchase Capacity	MW	0	0	0	0	٥	O	0	0	0	0
Capacity on Scheduled Maintenance	MW	0	0	0	0	D	0	· 0	0	0	0
Firm Sale of Capacity	MW	0	0	0	0	0	0	0	O	0	Đ
Total Available Capacity	MW	9,545	9,883	9,900	9,900	10,315	10,325	10,325	10,892	10,892	10,892
TMY Weather Damand ¹ (Before Load Control)	MW	9,737	9,933	9,588	9,247	9,414	9,605	9,660	9,816	9,970	10,121
TMY Weather Reserves (Before Load Control)	MW	-192	-50	312	653	901	820	665	1,076	922	771
TMY Weather Reserve Margin (Before Load Control)	1/2	2.0%	-0.5%	ALL	7.1%	9.6%	8.6%	6.9%	11.0%	9.2%	7,6%
TMY Weather Load Management	MW	758	736	680	646	626	611	599	589	580	572
TMY Weather Demand (After Load Management)	MW	8,978	9,196	8,908	8,601	8,788	8,895	9,061	9,227	9,390	9,549
TMY Weather Reserves (After Load Management)	WM	567	687	992	1,299	1,527	1,430	1,264	1,665	1,502	1,343
TMY Weather Reserve Margin (After Load Management)	%	6.3%	7.6%	11.1%	15.1%	17.4%	16.1%	14.0%	18.0%	16.0%	14.1%
TMY Weather Interruptible Load	MW	326	314	311	313	310	312	314	316	318	320
TMY Weather Voltage Reduction	MW	0	0	D	0	0	0	0	0	0	C
TMY Weather Demand (After All Load Control)	MW	8,652	8,882	8,597	8,288	8.478	8,583	8,747	8,911	9,072	-9,229
TMY Weather Reserves (After All Load Control)	MW	893	1,001	1,303	1,612	1,837	1,742	1,578	1,981	1,820	1,663
TMY Weather Reserve Margin (After All Load Control)		10.3%	Cab: 11.3%	152%	19.5% No	21,7%		18.0%	22.2%	20.1%	18.0%
TMY Weather Reserves (After All Load Control) Required For 15 %	MW	1,298	1,332	1,290	1,243	1,272	1,287	1,312	1,337	1,361	1,384
TMY Weather Reserves (After All Load Control) Above 15 %	MW	-405	-332	14	369	565	455	266	644	459	279
TMY Weather "DLC" Reserve Margin Contribution	%	121.5%	105.0%	76.0%	59.5%	50.9%	53.0%	57.8%	45.7%	49.3%	53.6%

## FPC 120

1 6

# LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY

#### 1999 SERC RATINGS, COGENERATION = 981231

#### JUNE 1999 FORECAST (S990506)

Bulk Power Sales Included in Demand & Energy Forecast

# Hines 2 in 11/2003 : "TMY" Weather Analysis with Capacity @ "Base" Ratings

	_						and the second se				
		SUMMER 00	SUMMER 01	SUMMER 02	SUMMER 03	SUMMER 04	SUMMER 05	SUMMER 06	SUMMER 07	SUMMER 08	SUMMER 09
·		Aug-2000	Aug-2001	Aug-2002	Aug-2003	Aug-2004	Aug-2005	Aug-2006	Aug-2007	Aug-2008	Aug-2009
Existing FPC Capacity	MW	7,236	7,236	7,485	7,502	7,502	7,847	7,847	7,847	8,342	8,342
New FPC Capacity	MW	٥	249	17 2 2	0	495	0	. 0	495	D	0
Retired FPC Capacity	MW	0	o	. 0	0	, (r160 - 23	· 0	· 0	0	0	٥
Total Installed Capacity	MW	7,236	7,485	7,502	7,502	7,847	7,847	7,847	8,342	8,342	8,342
Firm Purchase Capacity	MW	469	469	469	469	469	479	479	479	479	479
Firm QF Purchase Capacity	мw	831	831	831	831	831	831	831	831	831	831
QF Contractually-Allowed On-Peak Capacity Reduction	WW	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)
Seasonal Purchase Capacity	MW	0	0	0	0	0	0	0	· 0	0	0
Capacity on Scheduled Maintenance	MW	0	O	0	0	0	0	0	0	0	0
Firm Sale of Capacity	MW	0	0	0	0	0	0	0	Ō	0	0
Total Available Capacity	MW	8,430	8,679	8,696	8,696	9,041	9,051	9,051	9,546	9,546	9,546
TMY Weather Demand) (Before Load Control)	MW	8;482	8,659	8,328	7,977	8,143(4)	8,237	8,389	8,542	8,692	8,841
TMY Weather Reserves (Before Load Control)	MW	-52	23	369	719	898	814	661	1,004	<b>853</b>	704
TMY Weather Reserve Margin (Before Load Control) +) ://	Цý.,	-0.6%	×_0.3%	4.4%	9.0%	11.0%	9.9%	7.9%	11.8%	9.8%	8.0%
TMY Weather Load Management	MW	492	447	389	349	318	291	267	247	229	214
TMY Weather Demand (After Load Management)	мw	7,990	8,208	7,937	7,628	7,825	7,946	8,122	8,295	8,463	8,627
TMY Weather Reserves (After Load Management)	MW	440	470	759	1,068	1,216	.1,105	929	1,251	1,082	918
TMY Weather Reserve Margin (After Load Management)	%	5.5%	5.7%	9.6%	14.0%	15.5%	13.9%	11.4%	15.1%	12.8%	10.6%
TMY Weather Interruptible Load	MW	327	315	312	314	311	313	315	317	319	321
TMY Weather Voltage Reduction	MW	0	0	0	0	0		0		0	- 0 8 va
TMY Weather Demand (After All Load Control)	MW-	663	7,893	7	7,314	7,514514	SKE 7,633	7,807	7,978	8,144	8,306
TMY Weather Reserves (After All Load Control)	MW	767	785	1,071	1,382	1,527	1,418	1,244	1,568	1,401	1,239
TMY Weather Reserve Margin, (After All Load Control)	2	10.0%	10.0%	14.0%	18.9%	20.3%	77.0 18.6%	15.9%	197%	5- 17.2% av	14.9%
TMY Weather Reserves (After All Load Control) Required For 20 %	мw	1,533	1,579	1,525	1,463	1,503	1,527	1,561	1,596	1,629	1,661
TMY Weather Reserves (After All Load Control) Above 20 %	мw	-766	-793	-454	-81	24	-109	-318	-28	-227	-422
TMY Weather "DLC" Reserve Margin Contribution	%	106.8%	97.1%	65.5%	48.0%	41.2%	42.6%	46.8%	36.0%	39.1%	43.2%

6

#### Extreme Weather

#### Bulk Power Sales Included

		TOTAL	DIRECT LC	AD CONTROL P	Rograms			(USED)	FIRM	(AVAILABLE)
		SYSTEM	<del></del>				TOTAL		SYSTEM	
		BEFORE	RESIDENTIAL	OTHER DLC	TOTAL DLC	INTERR.	LOAD CONTROL	VOLTAGE	AFTER	VOLTAGE
		LOAD CONTROL	LOAD MGT.	PROGRAMS	PROGRAMS	LOAD	CAPABILITY	REDUCTION	LOAD CONTROL	REDUCTION
SEASON	MONTH	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)
WINTER 99/00	Jan-2000	10,965	950	23	973	326	1,299	0	9,666	133
WINTER 99/00	Feb-2000	9,996	833	23	856	326	1,182	0	8,814	121
WINTER 99/00	Mar-2000	8,490	691	23	714	325	1,040	0	7,450	104
SUMMER 00	Apr-2000	6,290	301	43	344	327	671	0	5,619	79
SUMMER 00	May-2000	7,379	379	47	426	327	753	D	6,626	92
SUMMER 00	Jun-2000	8,129	453	49	502	327	829	Q	7,300	100
SUMMER 00	Jul-2000	8,315	502	50	551	327	878	0	7,437	103
SUMMER 00	Aug-2000	8,470	463	50	513	327	840	0	7,630	105
SUMMER 00	Sep-2000	8,019	426	49	475	327	802	0	7,217	99
SUMMER 00	Oct-2000	6,854	271	45	316	328	644	0	6,210	86
WINTER 00/01	Nov-2000	7,589	444	24	468	328	796	0	6,753	94
WINTER 00/01	Dec-2000	9,447	958	25	983	328	1,311	0	8,136	118
WINTER 00/01	Jan-2001	11,158	918	26	944	314	1,258	0	9,900	136
WINTER 00/01	Feb-2001	10,191	797	26	824	314	1,138	0	9,053	124
WINTER 00/01	Mar-2001	8,646	656	26	682	314	996	o	7,650	106
SUMMER 01	Apr-2001	6,493	274	46	320	314	634	0	5,859	51
SUMMER 01	May-2001	7,575	343	50	393	314	707	0	6,868	95
SUMMER 01	Jun-2001	8,285	407	52	459	315	774	ò	7,511	103
SUMMER 01	Jul-2001	8,480	450	52	502	315	817	0	7,663	106
SUMMER 01	Aug-2001	8,637	414	52	467	315	782	. 0	7,855	108
SUMMER 01	Sep-2001	8,176	377	52	429	315	744	0	7,432	102
SUMMER 01	Oct-2001	7,019	237	47	284	315	599	C	6,420	89
WINTER 01/02	Nov-2001	7,762	414	27	440	315	755	0	7,007	97
WINTER 01/02	Dec-2001	9,610	890	27	917	316	1,233	0	8,377	121
WINTER 01/02	Jan-2002	10,798	846	27	872	311	1,183	o	9,615	132
WINTER 01/02	Feb-2002	9,934	736	27	763	311	1,074	٥	8,860	121
WINTER 01/02	Mar-2002	8,404	607	27	634	311	945	0	7,459	104
SUMMER 02	Apr-2002	6,240	230	49	279	311	590	0	5,650	79
SUMMER 02	May-2002	7,292	288	\$53	341	311	652	0	6,640	92
SUMMER 02	Jun-2002	7,924	343	54	397	311	708	٥	7,216	99
SUMMER 02	Jul-2002	8,128	380	55	434	312	746	o	7,382	102
SUMMER 02	Aug-2002	8,287	351	55	406	312	718	٥	7,569	104
SUMMER 02	Sep-2002	7,817	320	54	374	312	686	0	7,131	98
SUMMER 02	Oct-2002	6,709	202	50	252	312	564	0	6,145	85
WINTER 02/03	Nov-2002	7,521	387	29	417	312	729	0	6,792	94
WINTER 02/03	Dec-2002	9,279	838	30	868	313	1,181	0	8,098	. 117
WINTER 02/03	Jan-2003	10,448	798	30	828	313	1,141	0	9,307	128
WINTER 02/03	Feb-2003	9,573	696	30	726	313	1,039	· 0	8,534	117
WINTER 02/03	Mar-2003	8.131	574	30	605	313	918	0	7,213	100

FPC 122

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#### Extreme Weather

#### Bulk Power Sales Included

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		TOTAL	DIRECT LC	DAD CONTROL P	ROGRAMS		TOTAL	(USED)	FIRM SYSTEM	(AVAILABLE)
		BEFORE	RESIDENTIAL	OTHER DLC	TOTAL DLC	INTERR.	LOAD CONTROL	VOLTAGE	AFTER	VOLTAGE
		LOAD CONTROL	LOAD MGT.	PROGRAMS	PROGRAMS	LOAD	CAPABILITY	REDUCTION	LOAD CONTROL	REDUCTION
SEASON	MONTH	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)
SUMMER 03	Apr-2003	6,224	198	52	250	313	563	. 0	5,661	79
SUMMER 03	May-2003	7,100	249	56	305	313	615	0	6,482	90
SUMMER 03	Jun-2003	7,675	297	57	354	314	568	0	7,007	96
SUMMER 03	Jul-2003	7,810	330	58	388	314	702	. 0	7,108	99
SUMMER 03	Aug-2003	7,924	305	58	363	314	677	0	7,247	100
SUMMER 03	Sep-2003	7,618	279	57	337	314	651	0	6,967	96
SUMMER 03	Oct-2003	6,751	177	53	230	314	544	0	6,207	86
WINTER 03/04	Nov-2003	7,336	371	33	403	314	717	0	6,619	92
WINTER 03/04	Dec-2003	8,889	806	33	839	315	1,154	0	7,735	112
WINTER 03/04	Jan-2004	10,603	769	33	802	310	1,112	0	9,491	130
WINTER 03/04	Feb-2004	9,722	670	33	703	310	1,013	0	8,709	119
WINTER 03/04	Mar-2004	8,232	554	34	587	310	897	O	7,335	102
SUMMER 04	Apr-2004	6,335	175	55	230	310	540	. 0	5,795	81
SUMMER 04	May-2004	7,231	220	59	279	310	589	0	6,642	. 92
SUMMER 04	Jun-2004	7,818	262	60	322	310	632	0	7,186	99
SUMMER 04	Jul-2004	7,957	291	61	352	311	663	0	7,294	101
SUMMER 04	Aug-2004	8,078	269	61	331	311	642	0	7,436	102
SUMMER 04	Sep-2004	7,761	247	60	307	311	618	0	7,143	- 98
SUMMER 04	Oct-2004	6,875	156	56	212	311	523	0.	6,352	. 88
WINTER 04/05	Nov-2004	7,428	358	36	394	311	705	0	6,723	93
WINTER 04/05	Dec-2004	9,008	782	36	818	311	1,129	· 0	7,879	113
WINTER 04/05	Jan-2005	10,688	746	36	782	312	1,094	0	9,594	131
WINTER 04/05	Feb-2005	9,796	650	. 36	687	312	999	o	8,797	121
WINTER 04/05	Mar-2005	8,281	537	37	574	312	886	0	7,395	103
SUMMER 05	Apr-2005	6,397	154	58	212	312	524	0	5,873	82
SUMMER 05	May-2005	7,304	194	62	256	312	568	0	6,736	93
SUMMER D5	Jun-2005	7,896	231	63	295	313	608	0	7,288	100
SUMMER 05	Jul-2005	8,037	257	64	321	313	634	0	7,403	102
SUMMER 05	Aug-2005	8,167	238	64	302	313	615	0	7,552	104
SUMMER 05	Sep-2005	7,840	217	<b>6</b> 3	281	313	594	٥	7,246	100
SUMMER 05	Oct-2005	6,944	137	60	197	313	510	. 0	6,434	89
WINTER 05/06	Nov-2005	7,467	348	39	387	313	700	0	6,767	94
WINTER 05/06	Dec-2005	9,068	762	39	801	314	1,115	0	7,953	114
WINTER 05/05	Jan-2006	10,841	727	39	766	314	1,080	0	9,761	134
WINTER 05/06	Feb-2006	9,937	634	40	673	314	987	٥	8,950	123
WINTER 05/06	Mar-2006	8,381	524	40	564	314	878	٥	7,503	104
SUMMER 06	Apr-2006	6.508	136	61	197	314	511	٥	5.997	83
SUMMER 06	May-2006	7.431	171	65	236	314	550	0	6.881	95
SUMMER 05	Jun-2006	8.035	204	66	270	315	585	. 0	7,450	102

FPC 123

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#### Extreme Weather

#### Bulk Power Sales Included

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		TOTAL	DIRECT LC	DAD CONTROL P	ROGRAMS			(USED)	FIRM	(AVAILABLE)
		SYSTEM	<u></u>				TOTAL		SYSTEM	
		BEFORE	RESIDENTIAL	OTHER DLC	TOTAL DLC	INTERR.	LOAD CONTROL	VOLTAGE	AFTER	VOLTAGE
		LOAD CONTROL	LOAD MGT,	PROGRAMS	PROGRAMS	LOAD	CAPABILITY	REDUCTION	LOAD CONTROL	REDUCTION
SEASON	MONTH	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)
SUMMER 06	Jul-2006	8,179	227	67	294	315	609	0	7,570	105
SUMMER 06	Aug-2006	8,320	210	67	277	315	592	0	7,728	106
SUMMER 06	Sep-2006	7,977	192	67	258	315	573	0	7,404	102
SUMMER 05	Oct-2005	7,066	121	63	184	315	499	0	6,567	91
WINTER 06/07	Nov-2006	7,555	339	42	381	315	696	Ο,	6,859	95
WINTER 06/07	Dec-2006	9,184	744	42	786	316	1,102	0	8,082	116
WINTER 06/07	Jan-2007	11,002	710	42	752	316	1,068	0	9,934	136
WINTER 06/07	Feb-2007	10,085	619	43	662	316	978	0	9,107	125
WINTER 06/07	Mar-2007	8,487	512	43	555	316	871	0	7,616	105
SUMMER 07	Apr-2007	6,625	120	64	184	316	500	0	6,125	85
SUMMER 07	May-2007	7,567	151	68	219	316	535	0	7,032	97
SUMMER 07	Jun-2007	8,182	180	69	249	317	566	0	7,616	105
SUMMER 07	Ju!-2007	8,328	200	70	270	317	587	0	7,741	107
SUMMER 07	Aug-2007	8,480	185	70	255	317	572	0	7,908	109
SUMMER 07	Sep-2007	8,123	169	70	239	317	556	0	7,567	104
SUMMER 07	Oct-2007	7,194	107	65	173	317	490	0:	6,704	93
WINTER 07/08	Nov-2007	7,653	331	45	376	318	694	0	6,959	96
WINTER 07/08	Dec-2007	9,311	728	45	773	318	1,091	0	8,220	118
WINTER 07/08	Jan-2008	11,165	695	45	740	318	1,058	0	10,107	138
WINTER 07/08	Feb-2008	10,232	606	46	652	318	970	0	9,262	127
WINTER 07/08	Mar-2008	8,596	501	46	547	318	865	0	7,731	107
SUMMER 08	Apr-2008	6,744	106	67	173	318	491	0	6,253	87
SUMMER 08	May-2008	7,703	133	. 71	204	319	523	. 0	7,180	99
SUMMER 03	Jun-2008	8,329	159	73	231	319	550	0	7,779	107
SUMMER 08	Jul-2005	8,475	176	73	250	319	569	. 0	7,909	109
SUMMER 08	Aug-2008	8,642	163	74	237	319	556	0	8,086	111
SUMMER 08	Sep-2008	8,269	. 149	73	222	319	541	0	7,728	106
SUMMER 08	Oct-2008	7,322	- 94	69	163	319	482	. 0	6,840	95
WINTER 08/09	Nov-2008	7,749	324	48	372	320	692	0	7,057	98
WINTER 08/09	Dec-2008	9,436	714	• 48	762	320	1,032	0	8,354	120
WINTER 08/09	Jan-2009	11,327	681	49	729	320	1,049	0	10,278	. 141
WINTER 08/09	Feb-2009	10,382	594	49	643	320	963	0	9,419	129
WINTER 08/09	Mar-2009	8,705	491	49	540	320	860	0	7,845	109
SUMMER 09	Apr-2009	6,863	93	71	164	320	484	Ο.	6,379	88
SUMMER 09	May-2009	7,839	117	74	192	321	513	0	7,326	101
SUMMER 09	Jun-2009	8,477	140	76	216	321	537	0	7,940	109
SUMMER 09	Jul-2009	8,629	156	76	232	321	553	0	8,076	111
SUMMER 09	Aug-2009	. 8,803	144	77	221	321	542	o	8,261	113
SUMMER 09	Sep-2009	8.415	132	76	205	321	529	<b>o</b>	7,886	108

FPC 124

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#### Extreme Weather

#### Bulk Power Sales Included

		TOTAL	DIRECT LC	DAD CONTROL P	ROGRAMS			(USED)	FIRM	(AVAILABLE)
		SYSTEM					TOTAL		SYSTEM	
		BEFORE	RESIDENTIAL	OTHER DLC	TOTAL DLC	INTERR.	LOAD CONTROL	VOLTAGE	AFTER	VOLTAGE
		LOAD CONTROL	LOAD MGT.	PROGRAMS	PROGRAMS	LOAD	CAPABILITY	REDUCTION	LOAD CONTROL	REDUCTION
SEASON	MONTH	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)
SUMMER 09	Oct-2009	7,451	83	72	155	321	476	0	6,975	96
WINTER 09/10	Nov-2009	7,847	317	51	368	322	690	0	7,157	99
WINTER 09/10	Dec-2009	9,563	700	51	752	322	1,074	0	8,489	121

## FPC 125

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#### LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY

#### 1999 SERC RATINGS, COGENERATION = 981231

#### JUNE 1999 FORECAST (\$990506)

#### Bulk Power Sales Included in Demand & Energy Forecast

# Hines 2 in 11/2003 : "Extreme" Weather Analysis with Capacity @ "Base" Ratings

		WINTER 99/00	WINTER 00/01	WINTER 01/02	WINTER 02/03	WINTER 03/04	WINTER 04/05	WINTER 05/06	WINTER 06/07	WINTER 07/08	WINTER 08/09
		Jan-2000	Jan-2001	Jan-2002	Jan-2003	Jan-2004	Jan-2005	Jan-2006	Jan-2007	Jan-2008	Jan-2009
Existing FPC Capacity	MW	8,351	8,351	8,689	8,706	8,706	9,121	9,121	9,121	9,688	9,688
New FPC Capacity	мw	0	338	17	0	567	0	0	567	0	0
Retired FPC Capacity	мw	0	0	0	0	152	0	0	0	O	· 0
Total Installed Capacity	мw	8,351	8,689	8,706	8,706	9,121	9,121	9,121	9,688	9,688	9,688
Firm Purchase Capacity	MW	469	469	469	469	469	479	479	479	479	479
Firm QF Purchase Capacity	MW	831	831	831	831	831	831	831	831	831	831
QF Contractually-Allowed On-Peak Capacity Reduction	MW	(106)	(106)	(105)	(106)	(106)	(106)	(106)	(106)	(106)	(106)
Seasonal Purchase Capacity	мw	0	0	0	0	0	• 0	0	0	0	0
Capacity on Scheduled Maintenance	MW	0	0	0	0	0	0	٥	G	0	0
Firm Sale of Capacity	MW	0	0	٥	0	0	0	0	٥	0	0
Total Available Capacity	мw	9,545	9,883	9,900	9,900	10,315	10,325	10,325	10,892	10,892	10,892
Extreme Weather Demand (Before Load Control)	MW	10,965	11,158	10,798	10,448	10,603	10,688	10,841	11,002	11,165	11,327
Extreme Weather Reserves (Before Load Control)	мw	-1,420	-1,275	-898	-548	-288	-363	-516	-110	-273	-435
Extreme Weather Reserve Margin (Before Load Control)	%	-13.0%	-11.4%	-8.3%	-5.2%	-2.7%	-3.4%	-4.8%	-1.0%	-2.4%	-3.8%
Extreme Weather Load Management	WM	973	944	872	828	802	782	766	752	740	729
Extreme Weather Demand (After Load Management)	мw	9,992	10,214	9,926	9,620	9,801	9,906	10,075	10,250	10,425	10,598
Extreme Weather Reserves (After Load Management)	мw	-447	-331	-26	280	514	419	250	642	467	294
Extreme Weather Reserve Margin (After Load Management)	%	-4.5%	-3.2%	-0.3%	2.9%	5.2%	4.2%	2.5%	6.3%	4.5%	2.8%
Extreme Weather Interruptible Load	MW	326	314	311	313	310	312	314	316	318	320
Extreme Weather Voltage Reduction	MW	0	0	0	0	• 0	0	0	0	٥	- 0
Extreme Weather Demand (After All Load Control)	MW	9,666	9,900	9,615	9,307	9,491	9,594	9,761	9,934	10,107	10,278
Extreme Weather Reserves (After All Load Control)	MW	-121	-17	285	593	824	731	564	958	785	614
Extreme Weather Reserve Margin (After All Load Control)	%	-1.2%	-0.2%	3.0%	6.4%	8.7%	7.6%	5.8%	9.6%	7.8%	6.0%
Extreme Weather Reserves (After All Load Control) Required For 15 %	мw	1,450	1,485	1,442	1,396	1,424	1,439	1,464	1,490	1,516	1,542
Extreme Weather Reserves (After All Load Control) Above 15 %	мw	-1,571	-1,502	-1,157	-803	-600	-708	-900	-532	-731	-927
Extreme Weather "DLC" Reserve Margin Contribution	%	-1076.7%	-7488.5%	414.5%	192.4%	135.0%	149.7%	191.5%	111.5%	134.8%	170.8%

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#### LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY

#### 1999 SERC RATINGS, COGENERATION = 981231

#### JUNE 1999 FORECAST (S990506)

#### Bulk Power Sales included in Demand & Energy Forecast

# Hines 2 in 11/2003 : "Extreme" Weather Analysis with Capacity @ "Base" Ratings

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		SUMMER 00	SUMMER 01	SUMMER 02	SUMMER 03	SUMMER 04	SUMMER 05	SUMMER 06	SUMMER 07	SUMMER 08	SUMMER 09
		Aug-2000	Aug-2001	Aug-2002	Aug-2003	Aug-2004	Aug-2005	Aug-2006	Aug-2007	Aug-2008	Aug-2009
Existing FPC Capacity	MW	7,236	7,236	7,485	7,502	7,502	7,847	7,847	7,847	8,342	8,342
New FPC Capacity	MW	0	249	17	0	495	0	0	495	0	0
Retired FPC Capacity	MW	0	0	O	0	150	0	· 0	0	. 0	0
Total Installed Capacity	MW	7,236	7,485	7,502	7,502	7,847	7,847	7,847	8,342	8,342	8,342
Firm Purchase Capacity	мw	469	469	469	469	469	479	479	479	479	479
Firm QF Purchase Capacity	MW	831	831	831	831	831	831	831	831	831	831
QF Contractually-Allowed On-Peak Capacity Reduction	MW	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)
Seasonal Purchase Capacity	MW	0	0	0	0	0	D	0	0	0	0
Capacity on Scheduled Maintenance	мw	0	0	0	0	0		0	0 11	0	0
Firm Sale of Capacity	MW	0	0	0	0	0	0	0	0	0	0
Total Available Capacity	MW	8,430	8,679	8,696	8,696	9,041	9,051	9,051	9,546	9,546	9,546
Extreme Weather Demand (Before Load Control)	MW	8,470	8,637	8,287	7,924	8,078	8,167	8,320	8,480	8,642	8,803
Extreme Weather Reserves (Before Load Control)	MW	<b>-40</b>	42	409	772	963	884	731	1,066	904	743
Extreme Weather Reserve Margin (Before Load Control)	%	-0.5%	0.5%	4.9%	9.7%	11.9%	10.8%	8.8%	12.6%	10.5%	8.4%
Extreme Weather Load Management	MW	513	467	406	363	331	302	277	255	237	221
Extreme Weather Demand (After Load Management)	MW	7.957	8,170	7,881	7,561	7,747	7,865	8,043	8,225	8,405	8,582
Extreme Weather Reserves (After Load Management)	MW	473	508	814	1,135	1,293	1,186	1,008	1,321	1,140	963
Extreme Weather Reserve Margin (After Load Management)	%	5.9%	6.2%	10.3%	15.0%	16.7%	15.1%	12.5%	16.1%	13.6%	11.2%
Extreme Weather Interruptible Load	MW	327	315	312	314	311	313	315	317	319	321
Extreme Weather Voltage Reduction	MW	0	0	0	0	0	0	0	Q	0	0
Extreme Weather Demand (After All Load Control)	MW	7,630	7,855	7,569	7,247	7,436	7,552	7,728	7,908	8,086	8,261
Extreme Weather Reserves (After All Load Control)	MW	800	823	1,126	1.449	1,604	1,499	1,323	1,638	1,459	1,284
Extreme Weather Reserve Margin (After All Load Control)	%	10.5%	10.5%	14.9%	20.0%	21.6%	19.8%	17.1%	20.7%	18.0%	15.5%
Extreme Weather Reserves (After All Load Control) Required For 20 %	MW	1,526	1,571	1,514	1.449	1,487	1,510	1,546	1,582	1,617	1,652
Extreme Weather Reserves (After All Load Control) Above 20 %	MW	-726	-748	-388	0	117	-12	-223	57	-158	-368
Extreme Weather "DLC" Reserve Margin Contribution	%_	105.1%	94.9%	63.7%	46.8%	40.0%	41.0%	44.8%	34.9%	38.1%	42.2%

FPC 127

														3.5%	8.7%							
	- Manih	Scheduled Maintenance	Baseload Plans	Baseload Contracts	OF Contricu	intermediate Resources	Baneload & Intermediate Resources	Peaking Resources	Total Resources	QF On Peak Reduction	Baseload & Internediale Resources	Peaking Resources	Operating Requirements	FPC Available Resources EFOR	FPC Available Resources EFOR	Total Peak Before DLC	Supply Variance	Supply Reserve Margin	Total DLC (Including ISICS and Velt, Red.)	Firm Peek. Aher DLC	Total Venance	Total Rase Marcin
	dan-00		2 156	459	831	2 374	6 824	2 127	1.651	-105	6 613	2712	345		-010	10.046	-1.314	-11.22%	1 228		-11	
2	Feb-00	-162	3,150	469	531	2.374	6.824	2,627	8,661	-105	6,039	2,714	345	460	-794	8,995	-607	-5.07%	1,102	1,014	675	7.65%
3	Mar-00	-1,299	3,150	469	21	2,374	6,024	2,627	9,651	-105	6,005	2,730	341	-386	-604	8,460	-138	-1.63%	1,040	7,460	902	12.11%
4	Apr-00	-1,332	3,069	459	831	2,262	6,691	2,188	8,619	-108	5,978	2,103	291	-340	-600	6,290	C, 197	10.03%	671	5,619	1,858	33.25%
5	May-00	. 0	3,110	463	ិនា	2,252	6,672	2,108	8,850	-105	5,963	2,084	291	-415	-733	7,378	1,451	20.07%	753	6,626	2,234	33.72%
6	Jun-0)	0	3,110	469	831	2,262	6,672	1,950	6,622	-105	5,973	1,049	291	-403	-710	6,129	493	6.05%	829	7,300	1,322	13.11%
	10-00	•	2,110	469	814	2 767	6.002	1,950	8,022	-106	5,8/3	1,042	201	-103	-702	0,315	307	3.00/m	0/0	7,437	1,139	15.57%
	500-00	0	3 110	469	531	2 262	6.672	2.045	5717	-108	5,969	1,943	291	-405	-719	8019	695	8 70%	802	7,217	1.500	20.75%
a	Cct-00	-437	3,110	469	531	2,262	6,672	2,108	8,860	-106	5,963	2,091	291	-369	-606	6,054	1,519	22.16%	644	6,210	2,153	34.84%
1	Navido	-084	3,191	469	331	2,374	6,665	2,165	2063	-105	6.185	2.094	221	-378	-868	7,589	580	7.64%	796	6,793	1,376	20.25%
Z	Dec-00	-115	3, 191	469	831	2.374	6,005	3,124	2,989	-105	6,064	3,006	341	-472	-632	8,447	427	4.52%	1,311	ą 136	1,735	21.37%
3	Jan-01	٥	3,181	469	831	2,374	4,065	3,124	5,906	-106	6,060	3,005	341	-678	-843	15,168	-1, 168	-10.46%	1,210	8,908		8.80%
4	Fob-Q1	-167	3, 191	459	E31	2,374	6,855	3,124	2,959	-106	5,066	3,007	341	-463	-627	10,191	-369	1825	1,138	8.063	762	5 49%
5	Mar-01	-501	3, 191	463	<b>E</b> 31	2,374	6,865	3,124	2,509	-105	6,050	2011	341	-460	-794	E 646	842	£ 74%	995	7,650	1,635	24.03%
s -	Apr-01	-1,095	3,110	469	831	2.252	6,672	2.512	9,184	-\$05	5,995	2,419	291	-573	-665	6.493	1,595	24.56%	534	5,659	2,229	33.05%
7	May 01	-306	3,110	453	- 531	2,262	6.672	2 437	8,109	-105	5,965	2,341	201	-303	-0/9 -734	1,3/3	-40	2 61%	707 · 724	6,655 7,614	1,435	20.55%
19	301-01	ő	3,110	459	21	2.252	6.672	2 199	2,071	-105	5,963	2,095	291	415	-734	5,490	391	4.01%	817	7,653	1,207	15.76%
20	Aug-01	0	3,624	459	831	2,262	6,586	2,199	8,785	-108	5,660	2,098	291	-412	-726	K 637	148	1.71%	782	7,865	\$25	11.82%
21	Sep-01	٥	3,110	459	<b>331</b>	2.262	6,672	2,294	8,965	-105	5,959	2,189	291	-422	-744	0,175	790	A 85%	744	7,432	1,536	20.63%
22	001-01	-623	3,110	463	531	2.262	6,672	2,437	8,109	-106	5,979	2,338	291	-366	-697	7,019	1.462	20.53%	500	6,420	2,061	32.11%
23	Nov-01	-1,457	2,191	469	531 	2,374	6,855	2,437	2,302	-105	6,196	2,347	291	-369	-534	7,762	73	0.94%	755	7.007	623	11.62%
24	Dec-01	-1,152	2,191	469	531	23/4	6000	2.124	8,909	-100	6,307	7,050	. 341 .	-415	÷(3)	2,010	-773	-0.04%	1,213	5,3//	460	5 4976
ສ ‴	Jan-02	•	3,248	458	831	2,374	6,862	1,124	10,005	-106	. 6,076 6,076	3,004	341	-479 -479	-844	10,798	-792	-7.33%	1,183	1,015	301	4.67%
	POD-UZ	-941	3,200	403	601 1711	2,3/4	6.772	3 124	10,006	-105	5115	3.017	341	407	.753	6414		7 57%	545	2,000	1,005	24.343
2	Apr-32	-1.101	1 127	463	831	2,262	6.009	2.512	8,201	-105	6,012	2,419	281	-374	-650	6,240	1,850	29.01%	590	5.660	2.460	43,359
9	May-02	-454	3,127	469	231	2.252	6.009	2,437	8,126	-108	5,909	2,335	231	-404	-712	7,252	1,350	12.51%	462	6,640	2,012	30.149
ю	310-32	0	3,127	469	<b>\$</b> 21	2,262	6,689	2,199	8,863	-105	5,979	2,004	291	-417	-735	7,924	964	12.15%	208	7,216	1.671	23,169
11	Jul-02	٥	1 127	469	នា	2,262	6,689	2, 199	8,963	-106	5,979	2,094	221	-417	-736	8,125	760	23%	746	7,322	1,505	20.409
12	Aug-02	•	3,041	463	101	2,262	6.603	2,120	8,802	-106	3,007	2,005	291	-413	-728	6,207	515	621%	715	7,560	1,202	16.289
9 11	Dep-02	-611	3,127	469	991	2,252	6 689	2,437	0,903	-108	5.004	2 328	201		-743	6 209	1,100	27.07%	664	7,131 R 145	1,224	20.975
3	Nev-02	-705	3,205	469	501	2,374	6.822	2,437	2319	-105	6,123	2,336	291	412	-708	7,521	1,090	14.45%	729	6,792	1.819	26.769
35.	Dec-32	-712	3,205	459	<b>\$31</b>	2374	6,852	3,124	10,005	-105	6,105	3,014	341	-440	-775	9,279	15	0.15%	1,181	5,093	1, 195	14.77
37	Jan-03		3,208	469	631	2,374	6,982	3,124	10,006	-105	6,075	3,004	341	-479	-844	10,448	-442	4.23%	1,141	9,307		7.51%
z	Feb-03		3,205	469	531	2,374	5.822	3,124	10,005	-105	5,076	3,004	341	-479	-344	2,573	433	4.52%	1,039	6,534	1.472	17.251
39	Mar-03		3.205	459	<b>6</b> 1	2 374	6.32	3 124	10,005	-105	6,076	3,034	341	479	-844	8,131	1,675	23.06%	915	7,213	2,793	32725
40	Apr-23		3,127	469	531	2,262	5.529	2.512	8,201	-105	5,965	2,403	291	435	-765	6,224	2,977	47.53%	563	5,661	3,540	2 541
41	May-03		2,127	469	511 674	2,262	6.020	2,437	3,120 p.800	-100	5,363	2,004	291	-430	-738	7,100	1 213	15.000	615	2 012	2,044	40.795
	101-73		3 127	459	21	2.45	6.653	2,199	233	-105	5,579	2.094	291	-417	-736	7,810	1.075	13.675	702	7,108	1.774	25.03
44	Aug-03	٩	3,041	459	801	2,262	6,603	2,199	8,802	-106	5,697	2,095	291	-413	-728	7,924	878	11.00%	677	7,247	1,555	21.46
که	Sec-33		3, 127	469	<b>2</b> 11	2.262	6,589	2,294	6,983	-106	5,975	2,168	291	-421	-745	7,815	1,355	17.92%	861	6,967	2.015	23.93
46	Oct-33		3,127	465	531	2.252	5,009	2437	\$ 125	-105	5,969	2,329	291	-430	-759	5,751	2.375	35 10%	544	6,207	2,919	47.03
47	Nov-33		3,203	265	53 I	2,783	7,297	2,437	8,734	-195	6,552	2,321	291	-464	-815	7,336	2,398	32.69%	217	6.619	3,115	47.07
	Dec-03		3,208	463	<u>ع</u> ار 1	2,758	7,297	3,124	10.421	-105	6,474	2,929	341	-502	-855	6.659	1.532	17.23%	1,154	7,735	2,606	54.73
45	Jan-84	ð	3,208	. 469	831	2,789	7,297	3,124	10,421	-196	<b>3</b> ,474	2,999	341	-502	-655	10,603	-182	-1,72%	1,112	8,401	300	3.795
N)	Feb -4		3,205	433	531	2,785	1,297	3,124	10,421	-106	6.474	2,995	341	-502	-365	9,722	4999	7.19%	1,013	3,709	1,712	19.69
51	44 <b>-</b> 5-2		3,208	453	921 ·	2,759	7,227	3,124	10,421	-105	6474	2999	341	-502	-555 -914	6,232	2,189	2559%	- 597 640	7,225	1,065	42.05
2	للور، بوريد مشير بيريد		3,127	4935 167	201 	2.657	7.034	2,512	8.946	-105	4 334	2.354	401 201	-024 0440	-309	7 231	2 240	3) 944 3) 944	540	8,040 8,642	3.751	42.17
بد د	ينز-يونيهم الاشتروبال		3 127	433		2.927	7.034	2.199	9,213	-106	6,310	2.090	291	436	-769	7.818	1.415	10 09%	632	7,105	2.047	23 49
55	ورد ال		3,127	-52	51	2 112	6.529	2 199	8,738	-105	5,825	2.095	291	-409	721	7,967	781	9 81%	63	7,294	1,444	1979
58	Aug-04	٥	3,041	469	801	2,607	6,948	2,198	8 147	-106	6,227	2,091	291	-412	-761	8,678	1,669	13.23%	642	7,416	1,710	23.60
57	Sep-04		3,127		21	2,577	7,034	2,294	9,328	-135	6,305	2,134	291	-442	.772	7,761	1.557	20,19%	616	7, 143	2.155	3559
58	Det#)4		3.127	فنزاه	121	2.9)7	7.934	2,437	2,471	-105	6,300	2.325	291	-445	-723	6,875	2.595	37 76%	523	6,352	2,115	42 1 1
55	1.0.4		3,205	-445	21	2 755	1,237	2,437	2,734	-105	6.552	2.321	291	-464	-518	7.425	2,305	31.04%	705	6,723	2011	44 75

Extraste Weather

FPC 128

<b>60</b>	Dec-04		3,205	459	801	2,769	7,297	3,124	10,421	-108	6.474	2,999	341	-502	-855	8008	1,413	15.59%	1,129	7,679	2.542	32.25%
ត	Jan-05		1 205	479	831	276	7.307	3 124	10.421	-106	6.494	2 999	341	-502		10 688	.257	-2 484	1 094			
62	Fab-05	•	1,205	479	831	2,759	7.307	3.124	10.431	-105	6.404	2,999	361	602		9795	535	6476	000	a, ana 19 707	1.6%	B (470
63	Mar-05		3,205	479	531	2,789	7,307	1.124	10.431	-106	6.404	2,909	341	-602	-035	8.261	2 150	25.97%		7 196	3.035	41.05%
64	Apr-05		3,127	479	631 ⁷	2,607	7,044	2,512	8,555	-106	6,307	2,399	231	-464	-800	6.397	3 159	49.30%	524	5.873	3.653	19 72%
66	Nay-05		3,127	479	231	2,607	7,044	2,437	2,451	-106	6,310	2.325	291	-449	-723	7.304	2 177	29.81%	568	6736	2 745	40.75%
66	Jun-05		3,127	479	631	2,607	7,044	2,199	9,243	-105	6.320	2.090	291	-435	-769	7,895	1.347	17.05%	605	7.265	1.954	26.81%
67	Jul-05		3,127	479	231	2,607	7.044	2,199	9,243	-105	6,320	2,090	291	-436	-769	8,037	1,206	15.00%		7.413	1.839	24 25 5
68	Aug-05	•	3.041	479	801	2.607	6.958	2 199	8.157	-10.6	6.237	2.091	291	-432	-761	8.167	200	12.12%		7 447	1 404	25 254
63	Sep-05		3.127	479	831	2.607	7.044	2.294	9,338	-106	6.316	2 154	291	442	.779	7.840	1.498	1211%	504	7 248	2.097	20.024
70	Oct-05		1.127	479	531	2.807	7.044	2,437	8.401	-108	6.310	2.325	291	419	-723	6.944	2.637	35.64%	E10	5414	3047	47 3/04
71	Nav-05		3.205	479	535	2 729	7.307	2.437	9 744	-105	6552	2 321	291	454		2 467	2 277	30.49%	200	6.787	3 077	41.00%
72	Dec 05		1205	479	E31	2,759	7.307	1 124	10.431	-106	6.464	2,999	341	-502	-896	8055	1 363	15.07%	1 116	2 05 1	2.478	
						-											.,					
73	Jan-05	۵.	3,208	478	<b>#</b> 11	2,789	7,307	3,124	14,431	-105	6,404	2,399	341	-502	-805	10,841	-416	-1.78%	1,000 .	8,761	676	8.00%
74	Feb-05		3,205	479	531	2,769	7,307	3,124	10,431	-105	6,464	2,369	341	-502	-866	9,937	494	4.97%	<b>9</b> 87	6,960	1,481	16.55%
75	M#-05		3,205	479	231	2,769	7,307	1,124	10,431	-106	6,404	2,999	341	-602	-855	8391	2,060	24.45%	578	7 503	2.920	39.02%
76	Apr-06		3,127	479	831	2,507	7,044	2.512	2,565	-106	6,307	2,399	291	464	-800	6,508	3,048	40.03%	511	5,997	3,659	59.36%
π	May-06		3,127	479	301	2,607	7,044	2,437	9,431	-106	6,310	2,325	231	-449	-793	7,431	2,060	27.5.9%	55-0	6,051	2,600	\$7.79%
76	Jun-05		3,127	479	831	2,607	7,014	Z, 199	9,243	-106	6,320	2,090	291	436	-789	8,005	1,208	15.03%	555	7,450	1,793	24.07%
79	JU -05		3,127	479	531	2,607	7,044	2,199	9,243	-105	6.320	2,090	291	-436	-759	8,179	1,054	13.00%	809	7,570	1,672	22 0.9%
80	Aug-06	٥	3,041	479	<b>3</b> 31	2,607	6,958	2,199	8,157	-108	6,237	2,691	291	-402	-761	6,220	837	10.04%	\$92	7,728	5,428	18.49%
ยา	Sep-06		3,127	479	831	2,607	7,044	2.294	9,338	-105	6,316	2,104	291	-412	-779	7,977	1,351	17.00%	673	7,404	1,934	26.13%
62	0=1-36		3,127	479	531	2,607	7,044	2,437	8,451	+105	6,310	2,325	291	-449	-793	7,065	2.415	34.10%	499	6,557	2,914	44.37%
83	Nov-96		1205	479	831	3,256	7,874	2.437	10,311	-108	7,108	2,313	221	-495	-873	7,465	2,756	35.49%	695	6,858	3,462	50.32%
54	Dec-06		3,208	479	<b>\$</b> 31	3,365	7,574	3,124	10,995	-105	1,027	2,991	345	-\$33	-940	â 184	1,014	18 75%	1,102	5,052	2.915	35.00%
85	Jan-07	8	1,208	479	831	126	7.874	3,124	10,958	-105	7.027	2.991	341	-633	-848	11,662	4.1	4.85	1.655	* 514	1 444	18 71%
116	Feb-07		3,215	479	831	3,365	7,674	3 124	10,598	-106	7,027	2.991	341	-533	-940	10,065	913	9.05%	978	2.107	1.691	20.76%
87	Mar-07		3,208	479	531	3,356	7.674	1.124	10,998	-106	7,027	2,991	341	433	-940	8.437	2.611	29.59%	571	7.616	3.352	44.40%
	Apr-07		3,127	479	831	3,102	7,539	2.512	10,051	-106	6,791	2.392	291	-431	-848	6.625	1.426	\$1.71%	500	6 125	3.925	64 11%
19	May-07		3,127	479	231	1,102	7,539	2.437	2,978	-106	6,705	2,310	291	-477	-041	7,567	2.409	31.04%	535	7.012	2.944	41.67%
93	JUN-07		3,127	479	501	3,102	7,539	2 199	9,735	-105	5,794	2,083	291	-454	-817	6,162	1.566	19.01%	565	7,615	2 122	27.87%
91	JU-07		3,127	479	<b>431</b>	3,102	7,539	2, 199	9,738	-105	6,794	2,003	251	-454	-817	6,326	1,410	18.93%	567	7,741	1.997	26.79%
92	Aug-07	0	3,041	478	431	3,102	7,453	2,198	9,852	-164	4712	2,084	291	-458	-808	8,480	1,172	13.82%	\$72	7,80 8	1,744	22.00%
63	Sep-07		3.127	478	631	3,102	7.539	2,294	8,533	-106	6,790	2,177	291	-453	-527	B.123	1,710	21.05%	558	7,567	2,265	23.94%
54	Col-07		3, 127	479	<b>5</b> 31	3,102	7,539	2,437	5.975	-106	6,706	2,318	291	477	-841	7, 194	2,752	32.67%	493	6,704	2,272	40 00%
54	Nov-07		3,236	479	831	3,368	7,874	2.437	10.311	-105	7,106	2,313	291	495	-823	7,663	2,665	34.73%	694	6.969	3.362	45 17%
96	Dec-07		3,203	479	531	3,555	7,574	3,124	10,995	-106	7,027	2991	341	-633	-940	£311	1,657	15.12%	1,081	6,220	2.778	33.00%
~					-		7		<b>68.008</b>	105	7	3.001	-									
97	Jan-Ge		1,208	473	801	3,216	1,6/4	3,124	10,990	-100	7,027	2,001		-043		. 11,100	-167	-1.30%	1,036	10,107		LETY
30	Feb-05		200	4/3	601	3,300	7,024	3,124	10.336		1,027	2.00	341	435		10,2.32	700	1.460	8/0	2.252	1,/36	10.74%
	M2-05		3,200	4/9	531	1,20	7,074	1.44	P2.300	- 100	7,027	2.991	341	-335	-940	. 6.240	242	21.3476	800	7,731	3,251	42.20%
100	Aprile		3,127	4/9	ະ 	1,102	7,539	2,512	0.078	-100	6,701	2.342	201	-01	-343	Q./44.	1,30/	-	441	123	3,798	60.75%
101	NAY-US		3,127	4/9		3,102	7,558	2.007	6 13P		6,704	2,318	201		-041	1,103	22/3	21.51%	54.5	7,100	2,790	30.50%
102	101-00		3,127	473		1,102	7,553	2,103	6 776	100	6.704	2,000	201			4.20	1,408	12.01%		1,002	1,303	40.10%
103	30485		3,127	479		1.102	7,535	2.139	1/35	-100	6.750	2003	201		-217	0,4/3	1,250	14.00%	598	7,909	1,628	23 11%
104	5.00	•	3 127	479	231	3 102	7.539	2 254	2:02	-106	6,790	2 177	291	463	-307	8,959 8,259	1.554	15.91%	641 ·	1,728	1,363	77 24%
100	0-1.0*		3 127	479	231	3 103	7.640	2 417	5 276	108	6.7%	2 918	291	477	.941	7 500	244	35744	493	8 945	1 135	AL 954
100	beres .		3 318	479		3 46.0	7 874	2 417	1.00		2 106	2 349	201	464		7 740	2,007	33.0494		1.040	7,130	40.00%
107	Decals		1 208	479	201	3 35 5	7 574	3 124	40 G28	105	7.007	2,991	343	673		0.435	1400	10.000	1.0972	1,101 B 364	2.644	
	200.40		0,200		<b></b>	-,													1,000		200	31.00 %
109	Jan-09	۰	3,208	479	831	3,356	7,874	3,124	10.998	-106	7,627	2, 981	341	-533	-948	11,327	-121	-2.00%	1,049	10,278	720	7.81%
110	Fab-09		1205	479	<b>\$31</b>	3,356	1.274	3,124	19,228	105	7,027	2.99t	341	-523	-940	10,362	616	5 52%	953	2419	1,579	15.76%
111	Mar-09		3,203	479	21	3,356	7,374	3.124	10.325	-105	7,027	2,991	341	-673	-940	8,705	2,293	25.34%	362	7,5%	3,153	43 19%
112	Apr-09		3,127	479	31	3,102	7,539	2.512	16-661	-106	6,781	2,332	291	-461	-345	6,853	3, 158	48.45%	484	5,379	1,672	57.56%
313	May-09		1 127	479	ສາ	3,102	7,539	2437	1,375	105 🛦	6,765	2,318	291	477	-841	7,539	2 137	27.26%	513	7,226	2,660	35.17%
114	Jun-Qi		3,127	479	21	3,102	7,539	2 197	à 128	106	6 794	2,003	291	-464	-\$17	8477	1,251	14 87%	537	1,990	1,797	22.54%
115	تتبه ال		3.127	479	<b>531</b>	3,102	7,629	2.135	1. M	1-1-35	6,794	2,063	291	-464	517	5,629	1,109	12.35%	563	5.075	1,051	20.57%
116	Aug-09		3,041	479	831	3,102	7,453	2,198	9 652	-106	6,712	2,084	291	-45.9	-805	6,603	**	2.64%	\$42	8,261	1,390	16.83%
117	Sep-09		3,127	479	231	3,102	7,539	2.224	2/03	195	5,790	2,177	291 -	453	-27	8415	1,410	16 25%	525	7,335	1,947	24 6:54
118	Oci-39		3.127	479	531	3,102	7,632	2.427	1.15	1-75	6,765	2,315	291	,477	-041	7,451	2,525	33 C.9%	475	6.575	3,001	43 03%
119	Nov-)j		1,208	479	831	3,256	7,274	2,437	N 211	-105	7,106	2,313	231	495	-873	7,047	2,454	31 4/24	960	6.197	3,154	44.07%
120	Dec-33		3.208	479	\$31	3,365	7.874	3.124	1	105	7,027	2,991	341	-533	-54-)	5.563	1,435	15-01%	1,074	ಲ್ಲೆ ಸಮ	2,509	29.55%

#### Mild Weather

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#### Bulk Power Sales Included

		TOTAL	DIRECT LO	DAD CONTROL P	Rograms			(USED)	FIRM	(AVAILABLE)	
		SYSTEM					TOTAL	1.	SYSTEM		
		BEFORE	RESIDENTIAL	OTHER DLC	TOTAL DLC	INTERR.	LOAD CONTROL	VOLTAGE	AFTER	VOLTAGE	
		LOAD CONTROL	LOAD MGT.	PROGRAMS	PROGRAMS	LOAD	CAPABILITY	REDUCTION	LOAD CONTROL	REDUCTION	
SEASON	MONTH	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	
WINTER 99/00	Jan-2000	8,841	338	23	361	326	687	O	8,154	105	
WINTER 99/00	Feb-2000	8,060	321	23	344	326	670	0	7,390	96	
WINTER 99/00	Mar-2000	6,779	305	23	328	325	654	0	6,125	- 81	
SUMMER 00	Apr-2000	6,104	286	43	329	327	656	o .	5,448	76	
SUMMER 00	May-2000	7,164	305	47	352	327	679	0	6,485	89	
SUMMER 00	Jun-2000	7,896	405	49	454	327	781	0	7,115	97	
SUMMER 00	Jul-2000	8,078	342	50	392	327	719	0	7,359	100	
SUMMER 00	Aug-2000	8,229	384	50	434	327	761	0	7,468	102	
SUMMER 00	Sep-2000	7,788	365	49	414	327	741	C	7,047	96	
SUMMER 00	Oct-2000	6,651	225	45	270	328	598	0	6,053	84	
WINTER 00/01	Nov-2000	6,073	299	24	. 323	328	651	0	5,422	74	
WINTER 00/01	Dec-2000	7,628	331	25	356	328	684	0	6,944	. <b>94</b> .	
WINTER 00/01	Jan-2001	9,035	326	26	353	314	667	0	8,368	108	
WINTER 00/01	Feb-2001	8,256	307	26	333	314	647	D	7,609	98	
WINTER 00/01	Mar-2001	6,935	289	26	315	314	629	0	6,306	84	
SUMMER 01	Apr-2001	6,306	260	46	307	314	621	¢	5,685	79	
SUMMER 01	May-2001	7,360	276	50	326	314	640	0	6,720	92	
SUMMER 01	Jun-2001	8,052	364	52	416	315	731	0	7,321	100	
SUMMER 01	Jul-2001	8,243	307	52	359	315	674	0	7,569	103	
SUMMER 01	Aug-2001	8,396	344	52	396	315	711	0	7,685	105	
SUMMER 01	Sep-2001	7,944	324	52	375	315	690	0	7,254	99	
SUMMER 01	Oct-2001	6,815	197	47	244	315	559	0	6,256	86	
WINTER 01/02	Nov-2001	6,245	278	27	304	315	619	0	5,626	77	
WINTER 01/02	Dec-2001	7,790	305	Z7	332	316	648	0	7,142	97	
WINTER 01/02	Jan-2002	8,674	299	27	326	311	637	0	8,037	104	
WINTER 01/02	Feb-2002	7,998	282	27	309	311	620	0.	7,378	96	
WINTER 01/02	Mar-2002	6,693	266	27	293	311	604	0	6,089	81	
SUMMER 02	Apr-2002	6,054	218	49	267	311	578	٥	5,476	76	
SUMMER 02	May-2002	7,078	232	• ⁶³	284	311	595	0	6,483	89	
SUMMER 02	Jun-2002	7,691	307	54	360	311	671	0	7,020	96	
SUMMER 02	Jul-2002	7,891	259	55	314	312	626	0	7,265	95	
SUMMER 02	Aug-2002	8,046	291	55	346	312	658	0	7,388	101	
SUMMER 02	Sep-2002	7,585	275	54	329	312	641	0	6,944	÷ \$5	
SUMMER 02	Oct-2002	6,506	168	50	218	312	530	٥	5,976	83	
WINTER 02/03	Nov-2002	6,004	259	29	289	312	601	.0	5,403	74	
WINTER 02/03	Dec-2002	7,459	286	30	315	313	623	0	6,831	93	
WINTER 02/03	Jan-2003	8,324	261	30	311	313	624	٥	7,700	100	
WINTER 02/03	Feb-2003	7,637	265	30	295	313	608	0	7,029	<b>S</b> 2	
WINTER 02/03	Mar-2003	6,420	251	30	281	313	594	D	5,826	78	

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#### Mild Weather

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## Buik Power Sales Included

		TOTAL	DIRECT LC	DAD CONTROL P	ROGRAMS			(USED)	FIRM	(AVAILABLE)
		SYSTEM			· · · · · · · · · · · · · · · · · · ·		TOTAL		SYSTEM	
		BEFORE	RESIDENTIAL	OTHER DLC	TOTAL DLC	INTERR	LOAD CONTROL	VOLTAGE	AFTER	VOLTAGE
		LOAD CONTROL	LOAD MGT.	PROGRAMS	PROGRAMS	LOAD	CAPABILITY	REDUCTION	LOAD CONTROL	REDUCTION
SEASON	MONTH	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)
SUMMER 03	Apr-2003	6,038	188	52	240	313	553	0	5,485	76
SUMMER 03	May-2003	6,865	200	56	256	313	569	· •	6,316	87
SUMMER 03	Jun-2003	7,443	266	57	323	314	637	· 0	6,806	93
SUMMER 03	Jui-2003	7,573	225	58	283	314	597	Ο.	6,976	95
SUMMER 03	Aug-2003	7,683	253	58	312	314	626	0	7,057	97
SUMMER 03	Sep-2003	7,387	240	57	297	314	611	0	6,776	93
SUMMER 03	Oct-2003	6,548	147	53	200	314	514	0	6,034	83
WINTER 03/04	Nov-2003	5,819	247	33	280	314	594	0	5.225	72
WINTER 03/04	Dec-2003	7,069	273	33	306	315	621	Đ	6,448	88
WINTER 03/04	Jan-2004	8,479	269	33	302	310	612	0	7,857	102
WINTER 03/04	Feb-2004	7,786	254	33	268	310	598	. 0	7,188	94
WINTER 03/04	Mar-2004	6,521	241	34	274	310	584	0	5,937	79
SUMMER 04	Apr-2004	6,148	166	55	221	310	531	0	5,617	78
SUMMER 04	May-2004	7,015	177	59	236	310	546	0 -	6,469	89
SUMMER 04	Jun-2004	7,584	234	60	295	310	605	0	6,979	96
SUMMER 04	Jul-2004	7,719	199	61	259	311	570	• <b>0</b> •	7,149	98
SUMMER 04	Aug-2004	7,836	224	61	285	311	596	0	7,240	99
SUMMER 04	Sep-2004	7,529	212	60	272	311	583	0	6,946	95
SUMMER 04	Oct-2004	6,671	129	56	186	311	497	0	6,174	85
WINTER 04/05	Nov-2004	5,910	238	36	274	311	585	0	5,325	73
WINTER 04/05	Dec-2004	7,188	264	36	299	311	610	0	6,578	89
WINTER 04/05	Jan-2005	8,554	260	36	295	312	608	0	7,956	103
WINTER 04/05	Feb-2005	7,860	246	36	282	312	594	0	7,266	95
WINTER 04/05	Mar-2005	6,570	233	37	270	312	582	0	5,988	80
SUMMER 05	Apr-2005	6,211	147	58	205	312	517	0	5,694	79
SUMMER 05	May-2005	7,089	156	62	218	312	530	0	6,559	90
SUMMER 05	Jun-2005	7,663	207	63	270	313	583	0	7,080	97
SUMMER 05	Jui-2005	7,800	175	64	239	313	552	Q	7,248	99
SUMMER 05	Aug-2005	7,926	197	<u>5</u> 4	262	313	575	0	7,351	101
SUMMER 05	Sep-2005	7,608	187	• 63	250	313	563	0	7.045	97
SUMMER 05	Oct-2005	6,741	114	60	174	313	487	0	6,254	86
WINTER 05/06	Nov-2005	5,950	231	39	270	313	583	0	5,367	74
WINTER 05/06	Dec-2005	7,249	256	39	295	314	609	0	6,640	90
WINTER 05/06	Jan-2006	8,717	252	39	291	314	605	о с.	8,112	105
WINTER 05/06	Feb-2006	8,001	239	40	278	314	592	D	7,409	97
WINTER 05/06	Mar-2006	6,670	226	40	266	314	580	0	6,090	82
SUMMER 06	Apr-2006	6,321	129	61	191	314	505	0	5,816	81
SUMMER 05	May-2006	7,216	138	65 .	203	314	517	0	6,699	92
SUMMER 05	Jun-2006	7,802	182	- 66	249	315	564	0	7.238	99

#### Mild Weather

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# Bulk Power Sales Included

		TOTAL SYSTEM	DIRECT LO	DAD CONTROL P	ROGRAMS		TOTAL	(USED)	FIRM	(AVA	(LABLE)	
		BEFORE	RESIDENTIAL	OTHER DLC	TOTAL DLC	INTERR	LOAD CONTROL	VOLTAGE	AFTER	vo	LTAGE	
		LOAD CONTROL	LOAD MGT.	PROGRAMS	PROGRAMS	LOAD	CAPABILITY	REDUCTION	LOAD CONTROL	RED	UCTION	
SEASON	MONTH	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	. (	MW)	
SUMMER 06	Jul-2006	7,941	155	67	222	315	537	0	7,404	·	101	
SUMMER 06	Aug-2006	8,079	174	67	241	315	556	0	7,523		103	
SUMMER 06	Sep-2005	7,746	165	67	231	315	546	0	7,200		99	
SUMMER 06	Oct-2006	6,862	101	63	163	315	478	0	6,384		88	
WINTER 06/07	Nov-2005	6,038	225	42	256	315	581	0	5,457		75	
WINTER 06/07	Dec-2006	7,365	248	42	291	316	607	0	6,758	• . • • .	92	•
WINTER 06/07	Jan-2007	8,879	245	42	288	316	604	0	8,275	s. 1	108	
WINTER 06/07	Feb-2007	8,150	232	43	275	316	591	0	7,559		99	
WINTER 06/07	Mar-2007	6,777	220	43	263	316	579	0	6,198		83	. 1
SUMMER 07	Apr-2007	6,439	114	54	178	316	494	0	5,945		83	
SUMMER 07	May-2007	7,352	121	68	190	316	506	0	6,846	•	94	
SUMMER 07	Jun-2007	7,949	161	69	230	317	547	0	7,402		101	
SUMMER 07	Jul-2007	8,091	136	70	207	317	524	0	7,567		104 .	
SUMMER 07	Aug-2007	8,239	154	70	224	317	541	0	7,698		105	
SUMMER 07	Sep-2007	7,891	145	70	215	317	532	0	7,359		101	
SUMMER 07	Oct-2007	6,990	89	66	155	317	472	0	6,518		90	
WINTER 07/08	Nov-2007	6,136	219	45	264	318	582	0	5,554		76	
WINTER 07/08	Dec-2007	7,491	242	45	287	318	605	°.	6,886		94	
WINTER 07/08	Jan-2008	9,041	239	45	285	318	603	. 0	8,438	•	110	
WINTER 07/08	Feb-2008	8,297	227	46	273	318	591	0	7,706		101	
WINTER 07/08	Mar-2008	6,885	215	46	261	318	579	. 0	6,306		85	
SUMMER 08	Apr-2008	6,557	101	67	168	318	486	0	6,071		84	
SUMMER 08	May-2008	7,488	107	71	178	319	497	. 0	6,991		96	
SUMMER 08	Jun-2008	8,095	142	73	215	319	534	0	7,561		104	
SUMMER 08	2008-انىل	8,240	120	73	194	319	513	٥	7,727		106	
SUMMER 08	Aug-2008	8,400	135	74	209	319	528	Ο.	7,872		108	
SUMMER 03	Sep-2008	8,037	128	73	201	319	520	D .	7,517		103	
SUMMER 08	Oct-2008	7,118	78	69	147	319	466	0	6,652		92	
WINTER 08/09	Nov-2008	6,233	213	48	261	320	581	0	5,652		7 <u>8</u>	
WINTER 08/09	Dec-2008	7,617	235 .	48	285	320	605	0	7,012		95	
WINTER 08/09	Jan-2009	9,204	234	49	282	320	602	0	8,602		113	
WINTER 08/09	Feb-2009	8,447	222	49	270	320	590	0	7,857		103	
WINTER 08/09	Mar-2009	6,995	210	49	259	320	579	0	6,416		86	
SUMMER 09	Apr-2009	6,676	89	71	159	320	479	0	6,197		86	
SUMMER 0S	May-2009	7,625	95	74	169 .	321	490	٥	7,135		98 .	
SUMMER 09	Jun-2009	8,244	125	76	201	321	522	0	7,722		106	
SUMMER 09	Jui-2009	8,392	106	76	182	321	503	0	7,889		108	
SUMMER 09	Aug-2009	8,562	119	77	196	321	517	0	8,045		110	
SUMMER 09	Sep-2009	8.184	113	76	189	321	510	· O	7,674		105	

FPC 132

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#### Mild Weather

#### Bulk Power Sales Included

		TOTAL	DIRECT LO	DAD CONTROL P	Rograms			(USED)	FIRM	(AVAILABLE)
		SYSTEM		1998 - 1998 - 1999 - 1998 - 1998 - 1998 - 1998 - 1998 - 1998 - 1998 - 1998 - 1998 - 1998 - 1998 - 1998 - 1998 -			TOTAL		SYSTEM	
		BEFORE	RESIDENTIAL	OTHER DLC	TOTAL DLC	INTERR.	LOAD CONTROL	VOLTAGE	AFTER	VOLTAGE
	•	LOAD CONTROL	LOAD MGT.	PROGRAMS	PROGRAMS	LOAD	CAPABILITY	REDUCTION	LOAD CONTROL	REDUCTION
SEASON	MONTH	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)
SUMMER 09	Oct-2009	7,247	69	72	141	321	462	0	6,785	94
WINTER 09/10	Nov-2009	6,330	209	51	260	322	582	0	5,748	79
WINTER 09/10	Dec-2009	7,743	231	51	282	322	604	0	7,139	97

FPC 133

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#### LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY

#### 1999 SERC RATINGS, COGENERATION = 981231

#### JUNE 1999 FORECAST (S990507)

#### Bulk Power Sales Included in Demand & Energy Forecast

# Hines 2 in 11/2003 : "Mild" Weather Analysis with Capacity @ "Base" Ratings

		WINTER 99/00	WINTER 00/01	WINTER 01/02	WINTER 02/03	WINTER 03/04	WINTER 04/05	WINTER 05/06	WINTER 06/07	WINTER 07/08	WINTER 08/09
		Jan-2000	Jan-2001	Jan-2002	Jan-2003	Jan-2004	Jan-2005	Jan-2006	Jan-2007	Jan-2008	Jan-2009
Existing FPC Capacity	MW	8,351	8,351	8,689	8,706	8,706	9,121	9,121	9,121	9,688	9,688
New FPC Capacity	MW	0	1. 338	A 17	0	567	0	0	-607	0	o
Retired FPC Capacity	MW	. 0	0	0	0	15242-35	0	0	0	0	0
Total Installed Capacity	MW	8,351	8,689	8,706	8,706	9,121	9,121	9,121	9,688	9,688	9,688
Firm Purchase Capacity	мw	469	469	469	469	469	479	479	479	479	479
Firm QF Purchase Capacity	MW	831	831	831	831	831	831	831	831	831	831
QF Contractually-Allowed On-Peak Capacity Reduction	MW	(106)	(106)	(106)	(106)	(106)	(106)	(105)	(106)	(106)	(106)
Seasonal Purchase Capacity	MW	0	٥	o	0	0	0	0	0.	0	ο.
Capacity on Scheduled Maintenance	MW	0	0	0	0	0	0	0	0	0	. 0
Firm Sale of Capacity	MW	0	0	٥	0	0	0	0	٥	٥	0
Total Available Capacity	MW	9,545	9,883	9,900	9,900	10,315	10,325	10,325	10,892	10,892	10,892
Mild Westher Demand (Before Load Control)	MW	8,841	9,035	8,874	8,324	8,479	8,564	87174	8,879	9,041	9,204
Mild Weather Reserves (Before Load Control)	MW	704	648	1,226	1,576	1,836	1,761	1,608	2,013	1,851	1,688
Mild Weather Reserve Margin (Before Load Control)	15	8.0%	9.4%	14.1%	18.9%	21.7%	20.6%	18.4%	22.7%	120.5%	18.3%
Mild Weather Load Management	MW	361	353	326	311	302	296	291	288	285	262
Mild Weather Demand (After Load Management)	мw	8,480	8,682	8,348	8,013	8,177	8,268	8,426	8,591	8,756	8,922
Mild Weather Reserves (After Load Management)	MW	1,065	1,201	1,552	1,887	2,138	2,057	1,899	2,301	2,136	1,970
Mild Weather Reserve Margin (After Load Management)	%	12.6%	13.8%	18.6%	23.5%	26.1%	24.9%	22.5%	26.8%	24.4%	22.1%
Mild Weather Interruptible Load	MW	326	314	311	313	310	312	314	316	318	320
Mild Weather Voltage Reduction	MW	0 20-20-00-00-00-00-00-00-00-00-00-00-00-0	0	0	0	0	0	0	0	0	0
Mild Weather Demand (After All Load Control)	MW	8,154	8,368	8,037	7,700	ANU 7 867	7,956	8,112	8,275	8,438	8,602
Mild Weather Reserves (After All Load Control)	MW	1,391	1,515	1,863	2,200	2,448	2,369	2,213	2.617	2.454	2,290
Mild Weather Reserve Margin (After All Load Control)		AN, 17,1%	18.1%	23.2%	1) 28.6% J5	(31.1%)	29,8%	21.3%	31.6%	29.1%	26.6%
Mild Weather Reserves (After All Load Control) Required For 15 %	MW	1,223	1,255	1,206	1,155	1,180	1,193	1,217	1,241	1,266	1,290
Mild Weather Reserves (After All Load Control) Above 15 %	MW	168	259	657	1,044	1,268	1,176	997	1,375	1,188	1,000
Mild Weather "DLC" Reserve Margin Contribution	%	49.4%	44.0%	34.2%	28.3%	25.0%	25.7%	27.4%	23.1%	24.6%	26.3%

FPC 134

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## LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY

#### 1999 SERC RATINGS, COGENERATION = 981231

#### JUNE 1999 FORECAST (S990507)

Bulk Power Sales Included in Demand & Energy Forecast

# Hines 2 in 11/2003 : "Mild" Weather Analysis with Capacity @ "Base" Ratings

		SUMMER 00	SUMMER 01	SUMMER 02	SUMMER 03	SUMMER 04	SUMMER 05	SUMMER 06	SUMMER 07	SUMMER 08	SUMMER 09
		Aug-2000	Aug-2001	Aug-2002	Aug-2003	Aug-2004	Aug-2005	Aug-2006	Aug-2007	Aug-2008	Aug-2009
Existing FPC Capacity	MW	7,236	7,236	7,485	7,502	7,502	7,847	7,847	7,847	8,342	8,342
New FPC Capacity	MW	0	249	17	Ō	495 20.0	0	Q	495	G	0
Retired FPC Capacity	MW	0	0	٥	0	160	0	0	0	0	0
Total Installed Capacity	MW	7,236	7,485	7,502	7,502	7,847	7,847	7,847	8,342	8,342	8,342
Firm Purchase Capacity	MW	469	469	469	469	469	479	479	479	479	479
Firm QF Purchase Capacity	мw	831	831	831	831	831	831	831	831	831	831
QF Contractually-Allowed On-Peak Capacity Reduction	MW	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)
Seasonal Purchase Capacity	MW	o	0	0	0	<b>o</b> .	· 0 ·	O	0	. 0	o ,
Capacity on Scheduled Maintenance	MW	0	0	0	0	0	0	0	0	0	0
Firm Sale of Capacity	MW	0	0	0	0	0	0	0	0	0	0
Total Available Capacity	MW	8,430	8,679	8,696	8,696	9,041	9,051	9,051	9,546	9,546	9,546
Mild Weather Demand (Before Load Control)	NW.	8,229	8.396	8,046	7,683,75	7,838!	7,926	8,079	8,239	8,400	8,502
Mild Weather Reserves (Before Load Control)	MW	201	283	650	1,013	1,205	1,125	972	1,307	1,146	984
Mild Weather Reserve Margin (Before Load Control)	37	2.4%	3.4%	8.1%	13.2%	15:4%	142%	12:0%	¥8,9%	13.6%	11.5%
Mild Weather Load Management	MW	434	396	346	312	285	262	241	224	209	196
Mild Weather Demand (After Load Management)	MW	7,795	8,000	7,700	7,371	7,551	7,664	7,838	8,015	8,191	8,366
Mild Weather Reserves (After Load Management)	мw	635	679	996	1,324	1,489	1,386	1,213	1,531	1,355	1,180
Mild Weather Reserve Margin (After Load Management)	%	8.1%	8.5%	12.9%	18.0%	19,7%	18.1%	15.5%	19.1%	16.5%	14.1%
Mild Weather Interruptible Load	мw	327	315	312	314	311	313	315	317	319	321
Mild Weather Voltage Reduction	MW	0	0	0	0	0	0	0		0	
Mild Weather Demand, (After All Load Control)	MW	7,468	7,685	7,388 31 1	7,057	7 240	No. 7 Notes -	7.523	7,698	7 872	8,045
Mild Weather Reserves (After All Load Control)	MW	962	994	1,308	1,638	1,800	1,699	1,528	1,848	1,674	1,501
Mild Weather Reserve Margin (After All Load Control)	34	12.9%	12.9%	A 97.7%	23.2%		23.1%	20.3%	24.0%	21:3% 9 1	18.7%
Mild Weather Reserves (After Ali Load Control) Required For 20 %	MW	1,494	1,537	1,478	1,411	1,448	1,470	1,505	1,540	1,574	1,609
Miid Weather Reserves (After All Load Control) Above 20 %	MW	-531	-543	-170	227	352	229	23	308	99	-108
Mild Weather "DLC" Reserve Margin Contribution	%	79.1%	71.6%	50,3%	38.2%	33.1%	33.8%	36.4%	29.3%	31.5%	34.5%

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																		•	Total DLC			
	Month	Scheduled Haintenance	Baselood Plants	Baseload Contracts	QF Contracts	intermotiste Resources	Banalosi & Intermediate Resources	Peaking Resources	Totai Resources	OF On-Peak Reduction	Baseload & Intermediate Resources	Paaking Resources	Operating Requirements	FFC Available Resources EFOR	FPC Available Resources EFOR	Total Pask Balons DLC	Supply Variance	Supply Reserve Margin	(including IB/CS and Volt. Red.)	Firm Peak Alter DLG	Total Variance	Total Rosan Margin
1	66-nat		3,150	463	831	2,374	6,824	2,827	8,651	-106	6,033	2,712	341	-458	-810	8.641	810	8.16%	447	6.154	1.407	14.36%
Z	Feb-00	-162	3,150	468	831	2,374	6,824	2,827	8.651	-106	6.039	2,714	341	-450	-794	8,060	1,428	17.73%	670	7,390	2,099	28.40%
3	Mar-00	-1,299	3,150	469	431	2,374	5,824	2.427	8,651	-196	6,086	2,730	241	-365	-884	8,778	1,573	23.20%	654	6,125	2,227	36.35%
4	Apr-00	-1,332	3,069	460	831	2,262	6.631	2,188	8,819	+106	5,978	2,193	291	-340	-609	E, 104	1,363	22.46%	656	5,448	2,038	37.44%
5	Mey-00	٥	3,110	463	631	2,262	5,572	2.168	8,460	-106	5,963	2,084	291	-616	-733	7,164	1,696	21.07%	678	6,485	2,375	36.63%
6	Jun-00	٥	3,110	463	431	2,262	6,672	1,850	8.622	-106	5,973	1,849	291	-403	-710	7,896	726	8.19%	781	7,115	1,507	21.18%
7	Jui-00	0	3,110	459	831	2,262	8,672	1,950	8,622	-106	5,873	1,649	291	-403	-710	8,078	544	6.73%	719	7,358	(,263	17.16%
	Aug-00	0	3,024	469	831	2,262	6,586	1,850	8,538	-106	5,831	1,850	291	-396	-702	1,220	307	3.73%	761	7,468	1,068	14.30%
8	54p-00	0	3,110	459	831	2,262	8,672	2,945	6,717	-106	5,969	1,943	291	-408	-714	7,768	929	11.83%	741	7,047	5,670	23.71%
10	New 00	-467	3,110	463	431	2,252	6,672	2,108	8.053	-108	5,963	2,981	201	-388	-606	8,631	1,722	23.8476	1446 ·	6,953	2,320	31.33%
	Deci00	-115	3 191	469	831	7 374	6 565	3 124	6 9.89	-106	6.064	3 006	341	472	417	7 678	2 745	79.44%	644	8.844	2,14(	47 104
	010-00	-112		403		4.414	4,005			-,		3.500				1.000	2,24			6.944	.2.8.90	44.1878
13	Jan-01	¢	3,191	469	101	2,374	6,865	3,124	8,349	-106	6,060	3,005	341	-478	40	8,035	854	10.56%	647	8,368	1,621	18.37%
14	Fab-Q1	-157	3,181	463	431	2.374	6,465	3,124	8.953	-106	6,066	3,007	341	-468	-827	8,256	1,566	18.97%	647	7,608	2,213	29.09%
15	Mar-01	-501	3, 191	469	831	2,374	8.865	3,124	8.949	+106	6,000	3,011	341	-450	-796	6,835	2,653	38.61%	629	6,306	3,182	50.46%
16	Apr-01	-1.096	3,110	469	831	2,262	6,572	2,512	9,184	-106	3,003	2,419 .	201	-3/3	-151	6,306	1,782	28.26%	621	\$,665	2,403	42.26%
	May Q1	-505	3,110	463	531	2,262	6,672	2,437	8,199	-108	2,506	2,341	281	-345	-478	7,560	M3	12.81%	640	6.729	1,583	23.56%
10	300-01		3.110	468	431	2.24	6,672	4,199 7,100	4.871	-106	5,3%3	2,005	201	. 4610	-714	8,032	818	19.17%	131	7.321	1,348	21.16%
24	300-015 Auto 01		3,110	460	474	2,202	8,8/4 8 140	2,100	8,671	-100	6.800	2,096	201	-419	-7.54	8,243	344	1.01%	8/4	7,368	1,362	17.29%
21	Sep-01		3,110	453	831	2 267	\$ 672	2,294	1.966	-106	5.959	2 189	201	-422	34	7.944	1.022	17 87%	690	7 754	1,200	71.40%
22	Oct-01	-628	3,110	469	\$31	1.263	6.572	2,437	9,109	-108	5.979	2,338	291	-385	-447	4.815	1.565	24.45%	654	6.256	2,225	35.57%
23	Nev-01	-1.457	3.191	469	831	2.374	6.665	2.437	8,302	-106	6.156	2.347	291	-358	-634	6.245	1.590	25.46%	610	5.626	2.204	39.27%
24	Dec-01	-1.152	3,191	469	431	2,374	6,865	3,124	8.945	-106	6,107	3,020	341	-415	-731	7,789	1.947	13.44%	641	7.142	1.665	21,73%
			-																			
25	Jan-62	•	3,204	459	435	2,374	6,842	3,124	18,005	-106	8,078	2,004	341	-479		8,674	1,332	15.30%	637	6,037	1,969	24.45%
25	Fab-02	8	3,208	463	\$31	2.3/4	8.842	3,124	10,006	-108	8,0/5	2,004		-4/3	-944	1,398	2,004	43.11%	625	1,3/8	2.628	35.62%
21 -	Mat-02	-341	3,208	4440			8,842	3,649	0.2015	-105	6,113	2,011	341	-914	-123	- a ASA	4,3(4	33.0478	474	6.008	2.0/6	40.00%
20	- May 07	-1.501	3.127	408	821 821	2 262	8,649	2.437	6.126	-106	5.849	2.314	291	-404	-712	7.078	1.664	22, 10%	505	8.483	2,824	- 33 31%
30	Jun-02		3.127	453	<b>1</b> 21	2,262	6,549	2,199	6.854	-106	5.978	2.094	-291	-417	-736	7.691	5.197	15.56%	<b>67</b> 1	7.020	1.864	26.61%
31	Jul-07	-	3 177	459	831	2 262	5 5AS	2.159	8.858	+106	5.979	2.054	291	-417	-734	7.691	997	12 63%	676	7 265	1,622	27 33%
22	Aug-02		3.041	463	431	2,262	6.603	2,199	8,402	-196	5,897	2,085	291	-413	-728	1,048	756	8.39%	658	7.344	1.414	18,125
33	Sep-02	9	3.127	469	431	2,262	6.649	2.294	6,943	-106	5.575	2,146	291	-423	-745	7,585	1,304	18.43%	641	6.844	2.038	29.36%
34	Oct-02	-60 1	3.127	468	431	2,257	6,648	2.437	9,126	- 106	5.994	2,334	291	-397	-701	6,506	2,019	31.03%	\$30	5,976	2.549	42.65%
35	Nov-02	-708	3.208	469	831	2,374	6,642	2.437	8,318	-106	8, 163	2.336	291	-402	-709	8,004	2.607	43.42%	601	5,403	3,298	59.37%
36	Dec-02	-712	3.208	459	431	2.374	6.842	3.124	10,006	-106	8,105	3.014	341	-440	-775	7,458	1,835	24.60%	628	6,831	2,483	36.07%
77	[ea.03	۵	9 208	459		2 334	6 817	3 124	10.006	-106	6 876	3 004	541	478		8 174	1 697	20 71%	574	7 784	1 144	-
1.4	Eab.01	•	1 208	469	431	2 174	4 14 7	3 124	10 008	-106	6 076	3 004	341	476		7 637	2 360	31.02%		2 028	3 477	43 34%
34	444-07	•	3 204	459	41	2374	6 847	1.124	10.004	-106	6 076	3.004	341	-478		6.420	3 546	55 85%		6 8 76 .	4 180	71 144
-10	Apr-03		3.127	469	831	2.262	6.649	2.512	9,291	-108	5,968	2,403	291	-435	-746	8,034	3.163	52.38%	553	5.445	3,714	57.76%
41	May-03		3,127	459	831	2,262	6.649	2.437	9,126	-106	5,969	2,329	291	-430	-758	8,805	2,241	32.55%	568	6.318	2,810	44.49%
42	Jun-03		3,127	453	431	2,262	8.659	2.199	8.855	-106	5,979	2.094	291	-417	-734	7,443	1,445	19.41%	637	6.805	2.041	30.58%
43	101-03		3,127	468	431	2,262	6.549	2,189	8.455	-106	5.978	2,084	291	-417	-736	7,573	1.315	17.36%	597	6,976	1,811	27.49%
44	Aug-03	4	3,041	453	631	2,262	6,603	2,158	8,802	-106	\$,887	2,095	291	-413	-726	7,643	1,118	14.56%	626	7,057	1,744	24.71%
45	Sep-03		3,127	459	831	2,262	5.685	2.294	8.953	-106	5,975	2,185	291	-423	-745	7,387	1,596	21.61%	611	6,776	2,207	32.57%
. 46	Oct-03		3.127	469	831	2,262	6,689	2.437	9,126	-106	5,968	2,329	291	-630	-758	6,548	2.578	38.37%	514	6,034	3,082	51,24%
41	Nov-03		3.208	469	431	2,768	7,287	2,437	9,734	-106	6,552	2,321	291	-464	-618	5,819	3.915	87.28W	594	\$.225	4,509	M 30%
48	Dec-03		3,208	469	431	2.789	7.267	3.124	10.421	-106	6,474	2,999	341	-502	-845	7,044	3,352	47 A2%	621	8,448	3,973	\$1.52%
49	Jan-94		3.208	469	431	2.789	7,297	3,124	10.421	-105	. 8,474	2,999	341	-592	-445	1,475	1,942	22.90%	\$12	7.867	2.556	32.47%
50	Fab-04		3 208	469	631	2,769	7,297	3,124	19,421	-106	5.474	2,998	341	-502	-665	1.766	2.635	33.64%	598	7.188	3,233	44.97%
51	Mar-04		3,208	469	831	2,789	7.297	3.124	10.421	-106	5.474	2.999	341	-502	-485	6,521	3,900	59.51%	584	5,537	4.444	75.54%
52	Apr-04		3.127	469	431	2.607	7.034	2.512	8,548	-106	6,297	2,399	291	-454	-600	6,148	3,398	\$5.27%	531	5,617	3.829	61.96%
53	May-04		3.127	462	531	2,607	7.034	2,437	9,4T1	-106	6,300	2.325	291	-449	-793	7,015	2.456	35.01%	546	6,469	3,002	45.40%
51	Jun-04		3.127	469	431	2,607	7,034	2.199	9,233	-108	6,310	2,090	291	-436	-768	7,584	1.649	21.74%	605	6,979	2,253	32 28%
55	Jul-04		3.127	465	431	2.112	6.539	7.199	4.738	-106	5.835	2.095	291	-408	-721	7,718	1.018	13 20%	570	7,148	1,589	22.23
56	Aug-04		3,041	469	431	2,607	6,946	2,199	8,147	-196	6,227	2,095	221	-432	-761	7,836	1,311	16.73%	596	7,240	1,505	28.33%
ŝ7	Sep-04		3.127	469	431	2.607	7.034	2.294	9.326	-106	8,306	2.154	291	-442	-779	7,529	1.799	23 69%	. 563	6,945	2,362	34.28%
58	Oci-04		3.127	469	531	2,607	7.034	2.437	8.471	-106	6.300	2.325	291	-448	-783	8,671	2.600	41 \$7%	497	6,174	3,297	53.40%
59	Nov-04		3.208	459	<b>4</b> 31	2,789	1.297	2.437	\$.734	-106	5.552	2.121	291	-454	-818	5,810	3.824	64.70%	585	5.325	4,409	82.80%

FPC 136

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60	Dec-04		3,208	469	831	2,789	7,297	3,124	10,421	-106	8,474	2,999	341	-502	-645	7,188	3,233	44.80%	#16	6,578	3,843	54.43%
61	Jan-05	4	3,204	478	431	2,749	7,307	3,124	10,431	-106	6,484	2,969	341	-642	-885	8,564	1,147	21.40%	604	7,958	2,475	31.11%
62	Feb-05		3,206	478	831	2,748	7,307	3.124	10,431	-100	6,464	2,999	341	-\$0Z	-865	7,860	2,571	32,71%	584	7,266	3, 165	43.56%
ស	Mar-05		3.294	479	431	2,769	7.307	3.124	10.431	-106	6.464	2,999	341	-502	-445	6.570	3.661	SE 77%	547	6 644	443	74 184
81	Am.05		3 127	479	A31 ×	3 607	7 044	7 517		-104	6 107	3 108	201		-		3.7.4	61 M				
						2.001			4,000	-100	<b>0,001</b>	6,000	- 441			9,419	3,343	93-WE 20	- 817	3,034	3,862	61.82%
65	May-05		3,127	478	831	2,607	7,944	2,437	8,481	-106	6,310	2,325	291	-449	-793	7,088	2,382	33.74%	\$30	6.550	2.822	44.55%
66	Jun-DS		3,127	479 .	831	2,607	7,044	2,199	8,243	-106	6,329	2,090	291	-436	-768	7,663	1,540	20.61%	\$63	7,060	2.163	30.55%
67	20-ئىدار		3.127	479	831	2.607	7.044	2,199	8,243	-106	6.320	2,090	281	-436	-788	7.800	1443	18.49%	669	7 748	1 895	77 578
~	A	•					* ***															
80	wind-co	v	3,041	4/8	8-3 I	2,007	6,536	2,189	<b>1</b> ,137	-168	8,231	2,001	201	-6.12	-/#1	7,829	1,231	13.53%	373	7,251	1,805	24.55%
69	5ep-05		3,127	479	631	2,607	7,044	2.294	8,338	-106	6,316	2,164	291	-442	-778	7,608	1,730	22,74%	563	7,045	2,293	32.55%
70	Oct-05		3,127	479	831	2,607	7,044	2,437	8,481	-106	6,310	2,325	291	-648	-783	6.741	2,740	40.86%	447	6,254	3.227	\$1.58%
71	Nov-05		3.205	479	#31	2,789	7.307	2.437	9.744	-106	6 562	2.321	291	-454	-818	5 850	3.764	61 76%	641	4 107	4 177	
	D					3.744	7														4	01-0170
14	Dec-US		منعرد	4/3	531	2,100	106	3,124	10,451	-108	8,494	2,306	241	-302	-665	7,244	3,162	43,80%	608	6,649	3,791	\$7.08%
27	1	•	3.000	474		7 744	7 307	1 124	10 431	108		1 854	141						***	· ·		
		•					1,000			-100							1,414	18.0030		4,114	2,318	21.27%
74	Feb-06		3.208	479	431	2,789	7,347	3,124	50,431	-308	6,484	2,999	341	-602	-485	8,001	2,430	30.37%	542	7,408	3.022	43.78%
75	Mar-06		3,208	479	431	2,769	7,307	3,124	10,431	-106	6,484	2,899	341	-502	-445	6,670	3,761	56.38%	540	6,090	4,361	71.26%
76	Apr-06		3,127	478	631	2,607	7.044	2,512	9,556	-106	6,307	2,399	291	-454	-800	8,321	3,235	81.18%	505	5.816	3.740	64.29%
77	May-05		3 127	479	\$31	7 607	7 644	2 437	8 441	-106	6310	2 3 25	291		.793	7 718	2 366	11 194	617		1 741	44 6764
																					6.186	41.8278
/6	Jun 96		3.12/	4/9	831	2,991	7.044	2,149	8.243	-106	6.240	2,090	2011	-1.30	-/68	7.492	1,441	18.46%	364	7,236	2,004	27.59%
79	Jul-06		3,127	478	831	2,607	7.944	2,199	9.243	-105	6,320	2,090	291	-438	-769	7,941	1,302	18.38%	\$37	7,404	1.838	24.43%
80	Aug-05	٥	3,641	479	831	2,607	6,958	2,189	8,157	-106	6,237	2,091	261	-432	-761	8,978	1,076	13.34%	556	7.521	1.434	21,72%
81	540-05		3 127	479	831	2 607	7.044	2 294	8 338	-106	6316	2.154	291	-442	.778	7.746	1 597	20 555	SAR	7 200	7 134	78 70%
									0.000													
82	061-06		3,127	4/8	841	2,007	7,044	2,437	3,481	-108	010	2,323	21	-443	-183	8,862	2.619	34.17%	478	6,384	3,097	48.52%
83	Nor-06		3,208	479	121	3,356	7,874	2,437	10,311	-106	7,108	2,313	291	-495	-473	8,038	4,271	70.77%	581	5,457	4,854	88.95%
64	Dec-06		3.205	478	A31	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-840	7,365	3,633	49.33%	647	6,756	4,240	62.73%
#5	Jan-07	0	3,208	479	431	3,356	7,674	3,124	10,998	-106	7,027	2,991	341	433	.440	8,879	2,118	21.47%	654	8,275	2,721	32.90%
86	Fad-OT		3,208	478	831	3,356	7,874	3,124	10,898	-106	7,027	2.891	341	-533	-840	8,150	2.848	34.94%	581	7.550	3,439	45.50%
67	Mar-07		3 265	478	431	3 356	7.574	3,124	10.045	-106	7.077	2 941	341	.533	-040	6.777	4 771	67 78%	676	6 188	4 800	TT 45.4
							* / **															
60	API-VI		3,147	4/8	6-21	3,102	1,308	6.312	19,431	- 1946		6,326	201		-946	4,438	4,012	30.1076	-	8,943	4,196	63.05%
49	May-07		3.127	479	435	3,102	7,539	2,437	8,876	- 106	4,745	2.318	291	-477 -	-841	7,352	2,624	35.66%	506	4,846	3,130	45.71%
90	Jun-07		3,127	479	631	3.102	7,538	2,139	8,738	-106	6,794	2,043	291 ·	-464	-617	7,948	1,789	22.50%	547	7,402	2,336	31.56%
#1	70-اد ا		1.127	479	831	3,102	7,539	2,196	8,738	-106	6,794	2,043	291	-464	-517	6,091	1,547	20.35%	524	7.557	2.170	28.68%
82	Aug 07	۵	3.041	478	431	3 102	7.453	2.195	8 857	-106	6.712	2.054	291		308	A 234	1 413	17 15%	641	7 534	1 464	74 3.ak
		-					7 634								437	7.000						
33	249-01		3.141	4/3	834	a. 194	(,	2.234	8,830		<b>4</b> ,7 <b>4</b>	2.07	a.		-84	1.001	1.042		142	2,350	2,474	23.82%
54	Oct-07		3,127	479	831	3, 102	7,538	2,437	8,976	-106	6,785	2.318	291	-477	-841	6,960	2,914	. 42.72%	472	6.614	3,458	53.04%
95	Nav-07		3,208	479	831	3,356	7,874	2,437	10.311	-106	7,106	2,313	291	-495	-473	6,136	4,175	68.04%	582	5,554	4,757	85.64%
96	Sec-07		3,208	479	831	3,356	7.874	3,124	10,995	-106	7,027	2,991	341	-533	-843	7,491	3,507	46.42%	605		4 112	59.72%
S7	Jon-06	e	3,208	479	<b>4</b> 31	3,356	7,874	3,124	10,998	-106	7,027	2,581	341	433	-842	8,041	1,857	21.85%	803	6,438	2,560	30.34%
95	Fab-05		3.208	479	831	3.356	7,874	3,124	10,998	-106	7.027	2,991	341	-533	-840	8,297	2,701	32.55%	50 t	7.396	3 292	42.71%
44	Mar 408		3 208	479	831	3 356	7 874	3 174	10 994	-106	7 027	7 991	361	-633	-945	6 AA5 ·	4 113	59 74%	570	6 104	4 607	74.414
																					4,002	
100	Арі-Са		3.121	4/8	631	3,102	1,558	2,512	10,051	-106	0.741	£,384	201	-4.81	~848	8,397	3,414	\$3.29%	446	6,071	3,940	65.56%
101	May-06		3,127	479	#31	3,102	7,539	2,437	\$,976	-106	6,785	2,318	291	-477	-641	7,488	2,458	33.23%	487	6,391	2.965	42.70%
102	Jun-08		3.127	479	831	3,102	7,539	2,199	9,734	-105	6,794	2,083	291	-464	-817	8,095	1,543	29.29%	\$34	7.561	2,176	28.78%
103	80-iut.		3.127	478	831	3, 102	7.539	2,199	9.734	-196	6,794	2.083	291	-464	-117	8,240	1.494	14.17%	513	1.121	2 0 10	26.01%
	Aug. 14		7 8-1	470	817	1 107	7 457	9 104	1653	-104	4 717	2 044	207	.458		8 405	4 959	14 8000	630		4.900	
104	Andere		3,041			4.044		4 130	0,014		W,1 10						34234	14.003	148	1,674	1,/89	42.61%
105	5ep-06		3.127	475	831	3,102	1,238	2,294	9,633	-189	8.790	2.1/7	201	-404	-	8.937	1,796	22.35%	520	7,517	2316	39.61%
106	Oct-08		3.127	479	#31	3,102	7,539	2,437	9,978	-106	6,785	2.314	291	-477	-141	7.118	2,858	40.15%	458	6,652	3,324	49.97%
107	Nev-08		3,295	479	431	3,356	7,874	2.437	10,311	-106	7,106	2,313	291	-495	-673	6.233	4,078	65.43%	581	5.652	4.658	87.45%
108	Dec DB		1 705	179		3 156	7 874	3 124	10 898	-106	7 027	2 991	341	-413	-840	7 6 17	3 341	44 36%	605	2017	1 044	
							.,													1.014		
105	Jan-05		3,294	479	#31	3.356	7,374	3,124	10,958	-166	7,927	2,891	341	-533	-840	9,204	1,794	18.48%	692	8,602	2.366	27.86%
	5	•				3 3 6 8	7.074		to oak	108	1 027	3 894	344	.613		4 4 4 7	2661	10 104		1.00		
110	rep-49		3.408	418	831 	3,330	1,8/4	4,164	10,200	- 108	1.021	2,521					4,331	۲۵۹۹ نج		1.001	3, 143	JH.73%
	Mat-08		3.205	479	831	3,356	7,874	3,124	10.998	- 106	1.027	2,991	341	-533	-840	6.985	4,003	57.23%	578	6,416	4,542	71.42%
112	Apr-09		3.127	479	831	3,102	7,539	2,512	10,051	-106	6.781	2,392	201	-481	-643	6,676	3,375	\$0.55%	478	6.197	3.854	62.20%
113	Max-09		3.127	479	631	3,102	7,539	2.437	9.976	-106	*6.785	2.318	291	-477	-\$41	7.625	2,351	30.83%	490	7,135	2.041	39.41%
	h		3			5 (07	7 510	3 100	6 778	. 104	5 744	2 (10.2	201	-161		8 744	1.444	18 1.74	674	1 1 2 2	2.6-4	36.165
114	308-0S		3.128	418	144	3.142		4.189	a, 138	- 646	4.85	2,003				4.44	1,404	18.16%	****	1.144	2.915	an. 10%
115	Jul-09		3 127	-179	. 831	3.102	7,539	2,189	8,738	- 106	6,794	2,083	291	-464	-817	8.392	1,346	18.03%	503	7,869	1.849	Z3 44%
118	Aug-09	8	3,041	478	831	3,192	7,453	2,198	8,652	-106	6.712	2,084	291	-453	-609	8.562	1,099 .	12,73%	\$17	8,045	1,607	19.97%
117	Sep-09		3.127	479	831	3.102	7,538	2,294	9.833	- 106	6.790	2,177	291	-469	-827	8.184	1,549	20.15%	510	7.674	2,158	28 13%
1.10	0:1.09		3 127	474	A31	3 102	7 538	2.437	9.876	- 106	6.745	2.318	281	-677	-841	7.747	2,729	37 66%	487	4 745	1 101	47.01%
						2.265		1	10.311	105	3 106	2313	30.0			4 334	3.081					
119	Nov-09		3 205	1/9	631	3.356	(,114	2.431	10.311	- 100	7.100	2.313		-433	-013	9.30	3,301	62.65% ·	362	3./48	4,563	/9 3/%
120	Ouc-09		3.308	479	\$31	3.356	7,874	3.124	10.998	-106	7.027	2,001	341	-633	-040	7,743	3,255	42.04%	604	7,138	3.859	54 07%

**FPC 137** 

5.2.1.1 Financial

# FINANCIAL ASSUMPTIONS FOR 2000 10 Year Site Plan and IRP BASE CASE VALUES

	Base year 2000	10.1	
	CED Locate	10 Year Sile Plan Values	<u>.</u> .
	CER Inputs		
•	DISCOLDUTE DATE	0.570/	
9	DISCOUNTRATE	8.23%	
10	REAL DISCOUNT RATE	5.53%	
11	FED INC TAX RATE	38.58%	
12	INFLATION RATE	3.00%	
13	AFUDC RATE	8.53%	1
14	CAPITALIZED INT DEBT RATE	7.0%	
15	DEBT STRUCTURE BOOK	45.00%	
16	DEBT STRUCTURE FOR TAX	100.00%	
17	DESIRED RETURN ON RATE BASE	9.75%	
18	ITC RATE	0.0%	
19	LONG TERM DEBT INT RATE	7.0%	
20	COST OF CAP ESC RATE (Coal)	2.5%	
21	COST OF CAP ESC RATE (C.T.)	2.5%	
22	COST OF CAP ESC RATE (C.C.)	2.5%	
23	COST OF CAP ESC RATE (Transm & Substa)	2.5%	
24	COST OF CAP ESC RATE (Distrib)	2.5%	
	,		
26	PRV Innuts		
20	I KV mpuis		
<b>70</b>	FUEL COST ESCALATION Augleon 100%	NI/A	. ••
20	FUEL COST ESCALATION (Nuclear 100%)	N/A	
29	FUEL COST ESCALATION (Coal)		
30	FUEL COST ESCALATION (OII)	IN/A	
31	FUEL COST ESCALATION (Gas)	N/A	
32	ENERGY COST ESCALATION	N/A	
33	FIXED COST ESCALATION	2.5%	
34	VARIABLE COST ESCALATION	3.0%	
35	REVENUE DISCOUNT RATE	8.53%	
36	SALES DISCOUNT RATE	0.00%	
37	WEIGHTED COST OF CAPITAL	9.75%	
38	CONSTRUCTION ESCALATION (Coal)	2.5%	4
39	CONSTRUCTION ESCALATION (C.T.)	2.5%	4
40	CONSTRUCTION ESCALATION (C.C.)	2.5%	
41	LEVELIZED CHARGE RATE (Coal)	13.77%	
42	LEVELIZED CHARGE RATE (C.T.)	13.88%	
43	LEVELIZED CHARGE RATE (C.C.)	14.35%	
			· ·
45	DSV Inputs		
47	BASE REVENUE ESCALATION	0.0%	
48	CUSTOMER COST ESCALATION	3.0%	
40	DSM FXPENSE ESCALATION	3.0%	
47 :	Dom Exi Ende Edoxextion	5.070	
£1	Mama CENERAL INELATION (CPI)	3 0%	
51	Memo GENERAL INFLATION (CFI)	3.5%	
52	Memo GDP PRICE Index	2.378	
		Page Case Can Structure	
		Base Case Cap Structure	
		45 000/ 7 009/	2 1 50/
56	Long Term Debt	45.00% 7.00%	3.13%
57	Preferred Stock	0.00% 8.00%	0.00%
58	Common Stock	55.00% 12.00%	6.60%
59		Composite	9.750%
60		Debt Tax Deductible	1.22%
61		After-Tax Discount Rate	8.53%
63	Federal Income Tax Ra	te	35.00%
64	State Income Tax Rate	· · · ·	5.50%
· . 1		FPC 130	

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# 5.2.1.2 Fuel Forecast

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	COAL FO	RECAST			0001			OIL FOREC	AST					
	CRYSTAL	1-2			CRYSTAL 4-5			#6 FUEL OIL			#2	FUEL OIL	Oil	
	(includes 5	% Pet. Col	ke)										Transport	
		9	MMBTU			\$/MMBTU		\$/MMBTU					•	
	BTU/LB	/	AVG. I	NCRE.	BTU/LB	AVG.	INCRE.	•	1.0%	1.50%	2.50% .2-	.5%	\$/N	MBtu
Jan-00		12500	1.630	1.550	12500	1.950	1.610		2.97	2.96	2.93	5.36	Suw #6	
Feb-00		12500	1.630	1.550	12500	) 1.950	1.610		3.10	3.09	3.06	5.71	2.50%	0.50
Mar-00		12500	1.630	1.550	12500	) 1.950	1.610		3.01	2.99	2.96	5.52	1%	0.65
Apr-00		12500	1.630	1.550	12500	1.950	1.610		2.92	2.91	2.88	5.31	#2 Qil	
May-00		12500	1.630	1.550	12500	1.950	1.610		2.83	2.82	2.79	5.09	Anciote	0.13
Jun-00		12500	1.630	1.550	12500	1.950	1.610	•	2.76	2.75	2.72	4.92	Avon Park	0.21
Jul-00		12500	1.630	1.550	12500	1.950	1.610		2.68	2.67	2.65	4.82	Bartow	0.20
Aug-00		12500	1.630	1.550	12500	1.950	1.610		2.62	2.61	2.59	4.76	Bayboro	0.20
Sep-00		12500	1.630	1.550	1250	0 1.950	1.610	-	2.57	2.56	2.54	4.78	Crystal R	0.23
Oct-00		12500	1.630	1.550	1250	0 1.950	1.610		2.53	2.52	2.49	4.49	Debary	0.30
Nov-00		12500	1.630	1.550	1250	D 1.950	) 1.610		2.48	2.47	2.45	4.70	Higgins	0.09
Dec-00		12500	1.630	1.550	1250	0 1.950	1.610		2.44	2.43	2.41	4.83	Hines*	0.34
2001		12500	1.650	1.570	1250	0 1.930	1.650	· .	2.69	2.59	2.43	4.76	Int.City	0.11
2002		12500	1.670	1.590	1250	0 1.920	1.680		2.65	2.56	2.40	4.74	Rio P	0.23
2003		12500	1.690	1.610	1250	0 1.940	1.710		2.65	2.56	2.40	4.77	Suwannee	0.24
2004		12500	1.710	1.640	1250	0 1.960	1.740		2.67	2.58	2.42	4.81	Turner	0.27
2005		12500	1.730	1.660	1250	0 1.910	) 1.770		2.71	2.61	2.45	4.89		
2006		12500	1.770	1.690	1250	0 1.930	1.800		2.77	2.67	2.50	4.99	I.05%Sulfur	-
2007		12500	1.790	1.710	1250	0 1.950	1.830		2.83	2.73	2.56	5.10	Add \$.15/mm	btu
2008		12500	1.820	1.740	1250	0 1.990	1.860		2.89	2.79	2.61	5.21	for any new #	2 oil sites
2009		12500	1.840	1.770	1250	0 2.020	1.890		2.96	2.85	2.67	5.31	plus transport	t

Escalation rates : Coal :+ 1.0%/yr after 2009 Oil : +1.0%/yr after 2009 Heat Content : #6 oil - 6.5 Mbtu/bbl #2 oil - 5.8 Mbtu/bbl

FPC 141

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# NATURAL GAS SUPPLY AND VARIABLE TRANSPORTATION COST

(\$/MMBTU)

	REGULAR	PREMIUM	TIGER		VARIABLE FT					
	SUPPLY	SUPPLY	SUPPLY		FGT	FGT	FGT	GulfStr	Sonat	
	COST	COST	COST		U of F	IC	O-FGT	FTS	Suwan	
Jan-00	\$2.35	\$3.35	\$2.29		\$0.22	\$0.22	\$0.12	\$0.00	\$0.19	
Feb-00	\$2.49	\$3.49	\$2.29		\$0.22	\$0.22	\$0.12	\$0.00	\$0.19	
Mar-00	\$2.51	\$3.51	\$2.29		\$0.22	\$0.22	\$0.12	\$0.00	\$0.19	
Apr-00.	\$2.57	\$3.57	\$2.29		\$0.22	\$0.22	\$0.12	\$0.00	\$0.19	
May-00	\$2.60	\$3.60	\$2.29	1.1.1	\$0.22	\$0.22	\$0.12	\$0.00	\$0.19	
Jun-00	\$2.61	\$3.61	\$2.29	1	\$0.22	\$0.22	\$0.12	\$0.00	\$0.19	
Jul-00	\$2.62	\$3.62	\$2.29		\$0.22	\$0.22	\$0.12	\$0.00	\$0.19	
Aug-00	\$2.63	\$3.63	\$2.29		\$0.22	\$0.22	\$0.12	\$0.00	\$0.19	
Sep-00	\$2.64	\$3.64	\$2.29		\$0.22	\$0.22	\$0.12	\$0.00	\$0.19	
Oct-00	\$2.67	\$3.67	\$2.29		\$0.22	\$0.22	\$0.12	\$0.00	\$0.19	
Nov-00	\$2.78	\$3.78	\$2.29	1	\$0.22	\$0.22	\$0.12	\$0.00	\$0.19	
Dec-00	\$2.90	\$3.90	\$2.29		\$0.22	\$0.22	\$0.12	\$0.00	\$0.19	
2001	\$2.59	\$3.59	\$2.38	]	\$0.23	\$0.23	\$0.13	\$0.00	\$0.20	
2002	\$2.63	\$3.63	\$2.48		\$0.23	\$0.23	\$0.13	\$0.09	\$0.20	
2003	\$2.71	\$3.71	\$2.58		\$0.23	\$0.23	\$0.13	\$0.09	\$0.20	
2004	\$2.80	\$3.80	\$2.68		\$0.23	\$0.23	\$0.13	\$0.09	\$0.20	
2005	\$2.88	\$3.88	\$2.79		\$0.23	\$0.23	\$0.13	\$0.09	\$0.20	
2006	\$2.94	\$3.94	\$2.90		\$0.24	\$0.24	\$0.14	\$0.10	\$0.21	
2007	\$3.01	\$4.01	\$3.01	1 .	\$0.24	\$0.24	\$0.14	\$0.10	\$0.21	
2008	\$3.07	\$4.07	\$3.13		\$0.24	\$0.24	\$0.14	\$0.10	\$0.21	
2009	\$3.14	\$4.14	\$3.26		\$0.24	\$0.24	\$0.14	\$0.10	\$0.21	

INTERRUPTIBLE TRANSPORTATION						
U of F	IC	O-FGT	GT Gulfstr SONAT			
\$0.39	\$0.39	\$0.29	\$0.00	\$0.70		
\$0.39	\$0.39	<b>\$</b> 0.2 <del>9</del>	\$0.00	\$0.70		
\$0.39	\$0.39	\$0.29	\$0.00	\$0.70		
\$0.39	\$0.39	\$0.29	\$0.00	\$0.60		
\$0.67	\$0.67	\$0.57	\$0.00	\$0.60		
\$0.67	\$0.67	\$0.57	\$0.00	\$0.60		
\$0.67	\$0.67	\$0.57	\$0.00	\$0.60		
\$0.67	\$0.67	\$0.57	\$0.00	\$0.60		
\$0.67	\$0.67	\$0.57	\$0.00	\$0.60		
\$0.47	\$0.47	\$0.37	\$0.00	\$0.60		
\$0.47	\$0.47	\$0.37	\$0.00	\$0.70		
\$0.47	\$0.47	\$0.37	\$0.00	\$0.70		
\$0.55	\$0.55	\$0.45	\$0.00	\$0.65		
\$0.60	\$0.60	\$0.50	\$0.30	\$0.65		
\$0.60	\$0.60	\$0.50	\$0.30	\$0.65		
\$0.60	\$0.60	\$0.50	\$0.30	\$0.65		
\$0.60	\$0.60	\$0.50	\$0.30	\$0.65		
\$0.61	\$0.61	\$0.51	\$0.30	\$0.65		
\$0.61	\$0.61	\$0.51	\$0.30	\$0.65		
\$0.61	\$0.61	\$0.51	\$0.30	\$0.65		
\$0.61	\$0.61	\$0.51	\$0.30	\$0.65		

Post 2009 escalation rate for Regular and Premium Supply Costs = 1.0% per year Post 2009 thru 12/31/10 escalation rate for Tiger Supply Costs = 4% per year

FPC 142

# 5.2.1.4 Generation Technology

# Confidential

# 2000 Ten-Year Site Plan

# Confidential

2000 Dollars

			· · · · · · · · · · · · · · · · · · ·			
Plant name		Hines	Hines	Hines	Inter. City	FPC System
Option name		F Type	F Type	G Type	CT gas	CT gas
•			Market		("EA")	("F")
Study		2000 TYSP	2000 TYSP	2000 TYSP	2000 TYSP	2000 TYSP
Alternative		CCH2	CCM	CCG	3CTE	CTF
Generation and Fuel						
New winter maximum capacity	MW	567	567	365	282	178
New summer maximum capacity	MW	495	495	323	249	151
New minimum capacity	MW	289	289	190	141	89
Number of units in capacity ratings		1 . 1 .	1	1	3	1 1
Available capacity		no limit	no limit	no limit	no limit	no limit
		*				
Full load net heat rate ( x000 )	(btu/kwh)	6.800	6.800	6.787	11.814	10.614
Minimum load net heat rate ( x000 )	(btu/kwh)	7.850	7.850	7.535	15.621	13.972
	1					
Mature forced outage rate	%	3.7	3.7	3.7	3.0	3.0
Maintenance requirement	(wks/yr)	2.3	2.3	2.3	1.5	1.5
Primary fuel type	fuel name	Firm Gas	Firm Gas	Firm Gas	IT Gas	IT Gas
Secondary fuel type	fuel name	IT Gas	IT Gas	IT Gas	Dist. Oil	Dist. Oil
					•	
ncremental Fixed O&M rate	(\$/kw/yr)	2.5	2.5	2.4	1.4	2.9
ncremental Fixed O&M rate	(\$000/yr)	1,402	1,402	865	407	519
			•			
Fixed gas demand cost	(\$/kw/yr)	32	32	32	n/a	n/a
Fixed gas demand cost	(\$000/yr)	18,144	18,144	11,680	n/a	n/a
Fixed gas quantity	(mmbtu/day)	65,000	65,000	41,843		]
/ariable O&M cost	(\$/mwh)	2,10	· 2.10	1.96	4.35	3.77
/ariable O&M Capacity Factor (check)	(CF%)	0.70	0.70	0.70	0,15	0.15
/ariable O&M cost (check)	(\$000/yr)	6,842	6,842	4,128	1,516	815
Capital Expenditure & Recovery				4	· · · · · · · · · · · · · · · · · · ·	
			-	2	2	
	years	3	5 NA	NA.	2	NA
Projected conversion downlime	monins (\$1000)	105 020	196 420	160 680	80.000	44 808
	(\$1000)	165,630	100,430	15	30	30
construction expenditure (1st year)	70	15	13	10	30	70
construction expenditure (2nd year)	70	. 60	00	25	10	1
construction expenditure (3rd year)	70	25	20	25		
Construction expenditure (4th year)	76					
lase cost w/o AFUDC	(\$/kw) WTR	292	329	440	284	252
Base cost w/o AFUDC	(\$/kw) NOM.	312	351	467	301	272

FPC 144

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Cost Estimate Worksheet: Impact of Staged CC Construction

Original Investigations: Hines 2 Cost Impact

For CT's Staged In-Service (\$2000)

Original Power Block Cost Estimate	\$166 Million
Estimated Impact on Power Block Cost *	20%

Potential Cost Impact @ 20% Project	\$ 33 Million
Potential Cost Impact (Mitigated) **	\$ 20 Million

Estimated Impact for a "Market" Combined Cycle

For CT's Staged In-Service (\$2000)

Current Power Bloc	\$186 Million			
Potential Cost Impo	\$ 20 Million			
- · · · · · · · ·	• - · · · · ·		· · · · · · · · · · · · · · · · · · ·	

Resultant Total Cost of Power Block

\$206 Million

* Note: Based on B&V conceptual studues for Hines 2 development.

** Note: The planning estimate for mitigation of cost impact is based on advance planning and contract development anticipating staged installation.

Printed 5/10/00 staged_cc_cost.xls

# 6.1.1 Financial



# BATES NOS. FPC 148 – FPC 149 CONFIDENTIAL PURSUANT TO FLORIDA POWER CORPORATION'S REQUST FOR CONFIDENTIAL CLASSIFICATION FILED AUGUST 7, 2000

# FINANCIAL ASSUMPTIONS FOR 2000-10 Year Site Plan and IRP BASE CASE VALUES

		•	
	Base year 2000	10 Vaan Sito Dian Valuus	
	CEP locuts	to rear one rian varues	
	C EK liputs		
9	DISCOUNT RATE	8 539.	
in.	REAL DISCOUNT RATE	5 53%	
11	EED INC TAY BATE	29 5994	
13	NELATION DATE	3 1004	
12	A FUDC DATE	2.0070 9.570/	
13		0.3370 7.00/	
14	CAPITALIZED INT DEBT RATE	1.0%	
12	DEBT STRUCTURE BOOK	45.00%	
10	DEBT STRUCTURE FOR TAX	100.00%	
17	DESIRED RETURN ON RATE BASE	9.75%	
18		0.0%	
19	LONG TERM DEBT INT RATE	7.0%	
20	COST OF CAP ESC RATE (Coal)	2.5%	
21	COST OF CAP ESC RATE (C.T.)	2.5%	
22	COST OF CAP ESC RATE (C.C.)	2.5%	
23	COST OF CAP ESC RATE (Transm & Substa)	2.5%	
24	COST OF CAP ESC RATE (Distrib)	2.5%	
		• • • • • • • •	
26	PRV Inputs	•	
		· · ·	
28	FUEL COST ESCALATION (Nuclear 100%	N/A	
29	FUEL COST ESCALATION (Coal)	N/A	
30	FUEL COST ESCALATION (Oil)	N/A	
31	FUEL COST ESCALATION (Gas)	N/A	
32	ENERGY COST ESCALATION	N/A	
33	FIXED COST ESCALATION	2.5%	
34	VARIABLE COST ESCALATION	3.0%	
35	REVENUE DISCOUNT RATE	8.53%	
36	SALES DISCOUNT RATE	0.00%	
37	WEIGHTED COST OF CAPITAL	9.75%	
38	CONSTRUCTION ESCALATION (Coal)	2.5%	
39	CONSTRUCTION ESCALATION (C.T.)	2.5%	
40	CONSTRUCTION ESCALATION (C.C.)	2.5%	
11	LEVELIZED CHARGE RATE (Coal)	13 77%	
17	LEVELIZED CHARGE RATE (COL)	13.88%	
47	I = VELIZED CHARGE RATE (C.T.)	14 35%	
43		14,0070	
45	DSV Inputs		•
	bov mpad		
17	BASE REVENUE ESCALATION	0.0%	
47	CUSTOMER COST ESCALATION	3.0%	
10	DSM EVPENSE ESCALATION	3.0%	
47	DIM EXICUSE ESCREATION	5.078	
51	Memo GENERAL INFLATION (CPI)	3 0%	
57	Vamo GDP PRICE Index	7.5%	
2-	Memo GDT TIGCE Maex	2.578	
	÷	Base Case Cap Structure	
21	· · · · · ·		
20	Long lerm Debt		%a
57	Preferred Stock	0.00% 8.00% 0.00	%
58	Common Stock	55.00% 12.00% 6.60	%
59		Composite 9.750	%
60		Debt Tax Deductible 1.22	%
61		After-Tax Discount Rate 8.53	6
			_

63 64

Federal Income Tax Rate	35.00%	FPC 150
State Income Tax Rate	5.50%	

6/11/2000

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3.15% 0.00%

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Avon Park	P2_	6985	
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Bartow	G2	STREET	
Bartow	GJ		
Bartow	P1		
Bartow	P2	S 100	
Bartow	P3		
Bartow	P4	S. S. S. S.	
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Bayboro	Pt		
Bayboro	P2	1	
Bayboro	P3	S. 1. 11.	
Bayboro	P4	1.51685te	
Cargill	G1		
Crystal River	G1		
Crystal River	G2		Charlana Alba
Crystal River	G3	5040	
Crystal River	G4		
Crystal River	G5	1.0000	
Dade County	G1		
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FPC 151

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Intercession City		P10			1			
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US Agri-Chem	(	31		250	(î.).			
Univ. of Florida	(	3•		152	e.			
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FPC 152

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## 12/14/99

#### K-Factor for Standard Offer Contract and Value of Deferral

- S5 Mill contingency included. AFDAC included ✓
- 25 years **V**
- Property taxes included 1.7%, not escalated, no AFDAC
- Payroll taxes excluded
- ✓ 55% Eq @ 12.0% + 45% D @ 7.3% = ATWACC
- ✓ 5 year contract (standard offer)
- ✓ 2.5% escalation
- Zero capital additions
- ✓ 2004 Jan in service for first full year
- ✓ Zero O&M
- ✓ No transmission or substation

#### 0&M

- Payroll taxes excluded
- 3.1% escalation ✓
- ✓ Variable
- ✓ Fixed

Fuel 6,975 Heat Rate @ 65% average dispatch

# BATES NOS. FPC 154 – FPC 155 CONFIDENTIAL PURSUANT TO FLORIDA POWER CORPORATION'S REQUST FOR CONFIDENTIAL CLASSIFICATION FILED AUGUST 7, 2000



# Build Vs Purchase Power

Paul Pender, Manager Financial & Investment Analysis (612) 330-7769

EEI System Planning Committee San Francisco, California September 25, 1991

75

FPC 156

## Independent Power Producers (IPP's)

- Facilitated because of utility unwillingness or inability to build due to experience during last construction cycle with;
  - Prudency disallowances
  - Escalating construction costs
  - High financing costs

### Entities involved Independent Power Producers

Generation facilities (not QF) that are frequently subsidiaries of utilities, non-utilities or independent publicly-held companies not subject to traditional regulation

# Power Purchase Contract Key Factors

- Financial leverage
   The lender will extend credit to
   the IPP on 85-90% of the project
   based on the power purchase contract
- Assignment of risk Credit to the IPP is granted based on credit worthiness of the utility that is purchasing power

## Entities Involved Cost of Capital Tax Rate of 40%

	IPP		Traditional Utilit	
	% of Total Capital	% Cost	% of Total Capital	% Cost
Debt Preferred Stock Common Equity	85 0 15	6.6 - 16	50 6 44	5.4 9.5 12.5
Weighted Cost of Capital		8.0		8.8
*• After Tax	-	· .		

# Build Vs Purchase Power Why?

- Avoid large capital outlay
- Reduce risk of not being included in rate base
- Cost advantages
- Supply diversity

## Financial Impact

- Bondholder
- Equity Investor (Shareholder)

The company's credit protection is eroded by additional fixed obligations

ميم معهد اليوريون الإلواديو أرادهم

"While transfer of capacity ownership to thirdparty generators can lower costs, reduce regulatory risks, ... this supply option entails specific risks that must be accounted for in S&P's evaluation of credit quality.*

## Rating Agency Response Standard & Poor's

*Take-or-pay obligations are treated by S&P as debt equivalents. With take-and-pay contracts the minimum fixed payment under the contract is reflected in S&P's calculation of the utility's fired charge coverage: Funds from operations + .est + capacity payment / (interest + capacity payments)

Rating Agency Response Moody's

"In our view, the practice of imputing debt obligations for purchase power contracts constitutes a better measurement of the real financial burden being undertaken by the company.*

1

## Total Cost of Purchase Contract Step 1

Present value of future purchase contract obligations * (equity ratio/debt ratio) = equity financing required to restore original capital structure

### Total Cost of Purchase Contract Step 1 - Example Dolars in minors

Year	PV Purchase Contract	Equity Ratio	Deb( Ratio	Equity Financing Required
1	\$200	60%	40%	\$300
2	187	-	•	280
3	173	•	-	259
4	157	•	•	235
5	140	•	•	210
6	121	-		182
7	101	•	-	151
8	79	-	-	118
9	55	•	•	82
10	29	•	•	43

**FPC 158** 

Equity financing required * Debt ratio = Amount normally financed with debt

....

Year	Equity Financing Required	Debi Ratio	Amount Normally Debt Financed
1 -	\$300	40%	\$120
2	280	•	112
3	259	•	103
4	235	•	0.0
5	210	•	<b>D A</b>
6 /	182	•	73
7	151	•	61
8	118	•	47
9	82	•	33
10	43	-	17

Total Cost of Purchase Contract Step 3

Amount normally financed with debt * (Cost of equity - Cost of debt) = Excess return

# Total Cost of Purchase Contract Step 3 - Example

Amo

Year	Amount Normally Debt Financed	Equily Cost	Debi Cost	Excess Return
1	\$120	12.5%	9.0%	\$4.20
2	112	•	-	3.92
3	103	•	•	3.62
4	94	•	-	3.29
5	84	•	-	2.94
8	73	•	-	2.55
7	51	•	•	2.12
8	47	-	■ 1	1.66
9	33	•	•	1.15
10	17	•	•	0.60

# Total Cost of Purchase Contract Step 4

(Amount normally debt financed * Cost

of equity) * (Tax rate/1-tax rate) =

Excess taxes

# Total Cost of Purchase Contract Step 4 - Example

Year	Amouni Normaliy Debt Financed	Equity Cost	Tax Rale	Excess Texes
1	\$120	12.5%	40%	\$10,00
2	112	•	•	9.34
3	103	•	•	8.52
4	94	•	-	7.84
5	84	-	•	6.99
6	73	•	•	6.06
7	61	-	•	5.05
8	47	•	٠	3.94
9	33	-	-	2.74
10	17	-	•	1,43

## Excess return + Excess taxes =

Total PV incremental return adjustment

# Step'5 - Example

Year	Excess Return	Excess Taxes	Total PV Incremental Return Adjustment
1	\$4,20	\$10.00	\$13.03
2	3.92	9.34	11.17
3	3.62	8.62	9.45
4	3.29	7.84	7.89
5	2.94	6.99	6 4 5
6	2.55	6.06	5 13
7	2.12	5.05	3.92
8	1.66	3.94	2.81
9	1.15	2.74	1 79
10	0.60	1.43	0.86

# Total Cost of Purchase Contract Step 6

Nominal cost + Total PV incremental return adjustment = Total contract cost

# Total Cost of Purchase Contract Step 6 - Example

Year	PV Purchase Contract	Total PV Incremental Return Adjustment	Total Contract Cost
1	\$200	\$13.03	\$262
2	187	11.17	•
3	173	9.45	
4	157	7.89	
5	140	6.45	
6	121	5.13	
7	101	3.92	
8	79	2.81	
9	55	1,79	
10	29	0.85	
	-	4	

## Bondholder Concerns Summary

## Purchase Contracts = Increased Debt

# Financial Impact Equity Investor

High power purchases limits the company's ability to meet shareholders' return expectations

# Calculation of the True Cost of a Capacity Purchase Method 3 - Capitalized Capacity Payments

inual Capacity Pmt 33 Icalation rate: 0.0% Intract Term (yrs): 10 Isk Factor: 100%		Cost of Debt:9.0Debt rat;c:40.0Equity return:12.5		
Effective tax rate:	40 000%	COC - before tax	11.10%	
Interest Coverage ratio	4.47	COC - after tax:	9.66%	

	Capacity	Present	Implicit	Compensating	Added
Year	Payment	Value	Interest	Equity	Rev Regumt
1	32,549	200.000	20.000	120.000	14 200
2	32.549	187.451	18.745	. 112.471	13 309
3	32.549	173.647	17,365	104,188	12 329
. 4	32.549	158.463	15.846	95.078	11 251
5	32.549	141.760	14,176	85.056	10.065
6	32.549	123.387	12.339	74.032	8 760
7	32.549	103.176	10,318	61,906	7 326
8	32.549	80.945	8.094	48.567	5 747
9	32.549	56,490	5.649	33 894	4 011
10	32.549	29.590	2,959	17 754	2 101
NPV	202 955				61 705
		Orig	ginal Contract	PV:	200.000
		Tot	al PP Contrac	t Cost:	281,705

Percent Increase in Revenue Requirement:

30.40%

Note: NPV is calculated using the after-tax cost of capital

•<u>-</u>*2

ar Lees

12.12

10001-24

Of course, at least initially, this restructuring will be done largely at the expense of its investors. Point is shareholders may absorb some of the fixed expedded costs that cannot be reduced, such as a aprilon of the company's \$54 million lease payment associated with PV units 1 & 2 (\$76 million of this leave is the rates.

It is important to accognize that PNM may eventually be a threat to berrounding regions. A large part of the utility's significant excess reserves are not recoverable from the payers. Capacity out of rate base totals 365mw, holuding a 105mw purchased power contract. Since his investment has already been written down and represents a drag on cash flow. PNM can justify marketing it at only a small premium over man ginal cost. This could present a problem for other utilities in surrounding areas.

The Arizona utilities are also vumerable to competitive threats from surrounding areas like, Utah and New Mexico. A particularly vumerable utility in the Southwest is ruscon Electric Power Company. TEP also has surplus reserves, high rates and nonearing assets. Like PNM, TEP must rely heavily on wholesale interchange markets, given the large amount of surplus reserves. Furthermore, about 198mw of TEP's Springerable unit 2 coal plant is out of rate base, and a

certain portion of the lease of Springerville up has been disallowed. The company also ha industrial lead with a 9% concentration oad :r the mining industry, which could , lefit tron self-generation. However, unlike, NM, which is taking steps to allow it to low rates eventually. TEP is sé financially distra fed that it has limited flexibility to lower ra 5 Like PNM, TEP has excess reserves appeassets out of rate base and could also controute to the reduction of regional market rate ret its long-term competitive vider the present structure is questionability able

Addic Service Co.'s (PSCO) has the lowest rate pructure in its immediate area. Also, capacity needs are modest. While it will have some small rate needs over the intermediate term, its low cost rate structure should not change significantly industrial load and wholesale load exposure is not that significant. The only threat to Colorado would be from comparies to its south that have assets out of rate base and hus may be able to sell power only slightly above margin to gain load. Debroah Godsmith, C.F.A.

(212, 208-1394

A WAY STATES

*Figures based on Typical Residential, Compercial, and Industrial Bills:Edison Electric Institute.

# **BUY VERSUS BUILD DEBATE REVISITED**

The debate over purchased power, or the "buy versus build" controversy, will likely continue to rage as state utility regulators grapple with the implications of the National Energy Policy Act of 1992. As part of this sweeping legislation, state regulators must consider the potential impact on utilities' cost of capital from purchasing power.

Table 1 Determining the risk factor	
The Visk factor chosen is a fa analysis of qualitative risk	unction of a subjective (not erbitrary) - s
Market	head for power
	Economics
Oberating	Performance standards
	Reliability
	Discarchabp//v
	Control over maintenance
	Flexibility and diversity
Regulatory	Preapprova:
	Paquiatory (ecover) mechanisms
	Regulatory out clause
	الاختباب بالمراجع فإبران المتحد المتعاف فكاثب كالمدار

Compared with the last baseload construction cycle, which is universally acknowledged to have been a disaster for investor-owned utilities, buying power from others appears substantially less risky than building new capacity. However, the electric utility industry's entire approach to supply-side resource additions has undergone radical transformation, to the point where it is now impossible to generalize about whether utility bondholders are better off if their utility buys or builds. The important thing is that both resource strategies have inherent risks. S&P employs a methodology for evaluating the benefits and risks of purchased power, and for adjusting a purchasing utility's reported financial statements to allow for more meaningful comparisons with traditional utilities.

### BENEFITS OF PURCHASING POWER

Buying power may be the best choice for a utility that faces increasing demand. Moreover purchasing may be the least risky course. The benefits of purchasing can be quite compelling. For example, utilities that purchase avoid the risks of significant construction cost overruns or that the plant might never be finished at all. They also may avoid the associated financial stress caused by regulatory lag typical in building programs.

In addition, utilities that purchase power avoid risking substantial capital. There are many examples of utilities that have failed to earn a full return on and of capital employed to build a plant. Furthermore, purchased power may contribute to fuel-supply diversity and flexibility, and may be cheaper, at least over the short run Utilities that meet demand expectations with a portfolio of supply-side options also may be better able to adapt to future demand uncertainty, given the specter of retail transmission access

Nevertheless, in the buy-versus-build debate it is important that appropriate comparisons are made. A properly designed building program may avoid many of the risks associated with the

### 26 STANDARD & POOR'S CREDITWEEK

150 The same with a straight

JUNE 21, 1993

CHEDIT COMMENTS

Unfortubate baseload program of the 1970s and early 1950s. A utility could

- Butid a plant using a treed-price, turnkey construction contract;
- Construct with a modular approach, adding small units incrementally as demand expectations solidify,
- Optain regulatory preapproval.
- Receive a cash return on construction work
   In progress to ease financing stress; and
- Finance the asset with a large portion of equity, providing a cushion for bondholders



## PURCHASES ARE NOT RISK-FREE

Regardless of whether a utility buys or builds, adding capacity means incurring risk. To the extent that there are any risks with purchased power, bondholders are directly threatened because there is no equity layer to protect them. Utilities are not compensated for any risks they assume in purchasing power. At best, purchased power is recovered dollar-for-dollar as an operating expense, so there is no markup to reward equity holders for taking risks.





FPC 163

When a utility enters into a long-term purchased power contract with a fixed-cost component, it takes on financial risk. Heavy fixed long-term contractual arrangements representat least in part-off-balance-sheet debt equivalents Utilities need to take these financial exter nalities' into account so that buy and build options are evaluated on a level playing field

5&P has developed a methodology to quantify this financial risk and adjust financial statements to make traditional utilities and purchasing utilittes comparable. S&?'s approach is unique because it folds our qualitative analysis into our quantitative methodology. S&P begins by determuning the potential off-balance-sheet obligation. This is done by calculating the present value of the capacity payments to be made over the life of the contract, discounted at 10%. The capacity payment is the fixed portion of the purchased power expense. It covers fixed costs, including debt service, depreciation, and a return on equity S&P is concerned about the total fixed payment. not simply the debt service portion, the utility is obligated to pay the whole amount, not just a part. This means S&P is relatively indifferent to how the nonutility generator is capitalized, except in the extreme case where vast overleveraging threatens the viability of the project.

In virtually all cases, S&P has access to—and utilizes—actual capacity payments. In the rare instance where they are not available or where capacity and energy payments are not broken out—such as in an energy-only contact—S&F will estimate the capacity payment.

5&P does not stop with the potential debt equivalent. S&P recognizes that not all obligations have the same characteristics. What is true of other off-balance-sheet liabilities also is true of purchased power some are more firm and therefore more debt-like than others.

This concept of the difference in the relative debt characteristics of purchased power obligations can be illustrated by using the concept of a risk spectrum (see chart 1). A risk spectrum is simply a range from 0% to 100%. Obligations on the low end of the scale would have fewer debtlike characteristics and would be considered less firm than the obligations judged to fall on the high end of the scale. This spectrum is important because the place where an obligation falls on the scale—what S&P calls the risk factor—will determine what portion of the obligation 5&P will add to a unity's reported debt. For example, if S&F determines that the risk factor for an obligation is 20%, S&P adds 20% of the potential debt equivalent to reported debt.

Different off-balance-sheet obligations have different risks (see chart 2, which shows various types of off-balance sheet obligations and where 50P believes they might fall on the risk spectrum scale). Sale/leasebacks of major plants are viewed as the virtual equivalent of debt, due to the strategic importance of these major electric generating facilities and the "hell-or-high-water" nature of the lease commutments

Obligations under take-or-pay contracts, which are unconditional as to both acceptance and availability of power, are considered quite firm. The extreme care would be a unit-specific tirm take-or-pay arrangement. Fiere, the risk factor might be as high as 70%-80%. Take-and-pay contracts, which require copacity payments only if power is available, are considered the least dect-like of the three types of obligations listed in chart 2 because take-and-pay capacity payments are conditional. In practice, the risk factors for take-and-pay performance contracts are generally in the 10%-20% range, although some may beas righ as 50%.

#### DETERMINING THE RISK FACTOR

How does 5&P determine the risk factor or the place where an obligation falls on the risk spectrum? 5&P's assessment of the risk factor reflects our analysis of the risks a utility incurs when

ABC Power Co. adjustment to ca (Mil 5 at year-end 1992)	oitai structure Originai	cagita.	Å2,45%	ed cap tar	
	52	ruclure		structure	
	5	*/o	2	3.	
Dept	1 400	54	1 400	45	
Adjustment to dect			265	4	} 58
Preferred sigck	200	ą	200	÷	
Common equity	1 220	38	1 000	72	

purchasing power under contract. This depends on a qualitative analysis of market, operating, and regulatory risks. It also depends on S&P's evaluation of the extent to which these risks are borne by the utility. The analysis is subjective, but not arbitrary (see table 1 for some of the key factors under each broad risk category). Depending on circumstances, the utility may bear substantial risks, or it may have successfully shifted risks to either the ratepayers or to the nonutility generaror provider of the power.

- Lower risk factors would be appropriate if:
- The power is economic and needed,
- True performance standards exist,
- A project has operated reliably,
- The unlity has a say in the scheduling of maintenance and retains control over dispatch,
- A contract is preapproved by regulators,
- Capacity payments are recovered through a fuel-clause type mechanism, and
- A regulatory out clause passes disallowance risk to the power seller

### Table 3

ABC Power Co. adjustment to gratex interest coverage

			g orstak		Ad. greist
			CI COV		nt c0v
Net income		:20		306	
ncome taxes		55	300	.27	
Glarest expense			115 = 754	114	- 21.
Prelax availabin		300			
Public attac heternozze transt	led dans - 506	- Tillen	745	•2	

The absence of these qualitative risk mitigators would lead toward the higher end of the risk spectrum and a higher risk factor

### ADJUSTMENTS TO FINANCIAL STATEMENTS

Once S&P has determined what the nsk factor is through a qualitative evaluation. S&P then adjusts ine unling a maneral statements. The procedure to adjust debt is to take the present value of nuture capacity payments discounted at 10%. The 10% discount factor was chosen to approximate a utility's average cost of capital. The result—the potential debt equivalent—would be multiplied by the risk factor. That result would be added to the utility's reported debt. To adjust the traditional pretainterest coverage ratio. S&P would take 10% of the adjustment to debt. A typical example of the adjustment process is shown below. A STATE AND A STATE AN

#### ABC POWER CO. EXAMPLE

To illustrate the financial adjustments, consider the hypothetical example of ABC Power Cobuying power from XYZ Cogeneration Venture. Under the terms of the purchased power contract, annual capacity payments made by ABC Power start at \$115 million in 1993, rise by \$5 million per year to \$135 million by 1997, and remain fixed through the expiration of the purchased power contract in 2023. The net present value of these obligations over the life of the contract discounted at 10% is \$1.3 billion.

In the case of XYZ. S&P chose a 20% risk factor, which, when multiplied by the potential debt equivalent, resulted in a figure of \$265 million. The risk factor is chosen based on qualitative analysis of the purchased power contract itself and the extent to which market, operating, and regulatory risks are borne by the utility.

Table 2 shows the adjustment to ABC Power's capital structure. S&P takes \$265 million, which is the net present value of the future capacity payments multiplied by a 20% risk factor, and adds it to ASC Power's actual debt of \$1.4 billion at year-end 1992. As illustrated in table 2, ABC Power's adjusted debt leverage is 58%, up from 54%.

Table 3 illustrates that ABC Power's pretax interest coverage for 1992, without adjusting for off-balance-sheet obligations, was 2.6 times (x), which is calculated by dividing the sum of net income, income taxes, and interest expense by interest expense. To adjust for the XYZ capacity payments, the 5265 million debt adjustment is multiplied by a 10% interest rate to arrive at \$27 million. When this is added to both the numerator and denominator, adjusted pretax interest coverage falls to 2 3x.

#### EFFECT ON RATINGS

The purchased power issue is somewhat complex, but S&P strongly believes that certain purchased power contracts are less risky than others, and that these subtle differences must be factored into the analysis. S&P combines qualitative analysis with the traditional present value approach. The result is an adjustment to debt that is understandable and useful, particularly in the regulatory process, since the adjusted ratios S&P derives are the ones on which S&P ratings are based.

#### **FPC 164**

#### STANDARD & POOR'S CREDITWEEK

JUNE 21, 1993

Second CREDIT COMMENTS BEEN AS A CONTRACT OF

Over the past tew years, several ratings have been lowered due to purchased power obligations. In other cases, S&P did not raise ratings Shill others are lower than they might otherwise be swing to purchased power liabilities.

S&P anticipates some rating downgrades of electric utilities over the next couple of years mowever, much will depend on how utilities and regulators respond to 5&P's analysis.

Utilines can offset purchased power liabilities in several ways including higher returns on equity or higher equity components in capital structures. Another possibility might be some type of incentive return mechanism.

As competition increases in the electric utility industry, power supply strategies will grow more complex. Consequently, a utility's purchased power obligations must be evaluated in a broader framework than the one this article addresses. The simple truth is that a utility can build all of its own plants, finance them with a balanced mix or equity and debt, put them into rate base without a disallowance, and still find itself in trouble it its rates are not competitive. Consequency, the buyversus-build debate must be viewed within the larger context of a utility's competitive position.

There are many benefits to purchasing power-Indeed, purchasing may be the least risky strategy, but it is not risk-free. S&P's methodology quantifies the risks by explicitly recognizing the key qualitative factors of markets, operations, and regulation. S&P analyzes contracts to determine who is taking the risk: the nonutility generator, the utility, or the ratepayer. S&P recognizes that these adjustments must be viewed within the larger context of a utility's competitive position. *Curtis Moulton* 

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# **R**EMAND-SIDE MANAGEMENT GAINS MOMENTUM

Over the past year, the move to Demand-Side Management (DSM) has gathered momentum as investor-owned utilities attempt to meet the demand for power without incurring the financing stress, and subsequent regulatory scrutiny, associated with new plant construction. Moreover, regulatory pressures have motivated utilities to pursue this path for an additional attribute: environmental benefits

DSM is the reduction of electric consumption through behavior modification. This can be achieved by inducing customers to avail themselves of energy-efficient technologies, or by curtailing 'shifting energy usage from periods of high to low demand. Utilities must and resources to meet high, or peak, demand. DSM is often addressed through an Integrated Resource Planning (IRP), or Least Cost Planning (LCP), ph cess whereby utilities and regulators jointly evaluate all available demand- and supply-side option (including purchased power)

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pressure if DSM programs do Prospectively, SJ may come under not deliver th promised economic savings. In Electric Co. finds itself in this Commonwee Cutility has been the focus of recent position. T Erts alleging rate escalation due to inmedia res DSM The northeast is sprinkled with efficien. addin hal examples, since utilities in this part of funtry embarked on aggressive DSM pro-:he is under more favorable economic condi-'ns Although reserve margins subsequently veiled in the attermath of the recession several

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#### DSM AS A RESOURCE OPTION

DSM was conceived as a resource alternative to a construction. It was to offer benefits such as

- Reducing costs of incremental resources (either built or saved).
- Avoiding financial/regulatory risks associated with construction,
- Meeting environmental objectives,
- Offering the fixibility to match resources incrementally with load, and
- Diversifying programs to mitigate asset concentration.

However, as conservation gained broad public and political appeal, regularies embraced DSM for its noneconomic benefits. Consideration of environmental externalities has become mandatory in many jurisdictions. However, pollution mitigation may not be efficiently addressed by individual state regulators and may diplicate efforts by other agencies. Monetizing externalities raises the price of electricity to consumers. The same is true of discounting the cost of DSM programs to give them an advances. Furthers

FPC 165

# BATES NOS. FPC 173 – FPC 177 CONFIDENTIAL PURSUANT TO FLORIDA POWER CORPORATION'S REQUST FOR CONFIDENTIAL CLASSIFICATION FILED AUGUST 7, 2000

# BATES NOS. FPC 178 – FPC 210 CONFIDENTIAL PURSUANT TO FLORIDA POWER CORPORATION'S REQUST FOR CONFIDENTIAL CLASSIFICATION FILED AUGUST 7, 2000

# 6.1.4.2 Expansion Resources Financials

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# BATES NOS. FPC 212 – FPC 251 CONFIDENTIAL PURSUANT TO FLORIDA POWER CORPORATION'S REQUST FOR CONFIDENTIAL CLASSIFICATION FILED AUGUST 7, 2000



#### ELECTRIC, GAS & WATER UTILITIES

Of course, at least initially, this restructuring will be done largely at the expense of its investors. PNM's shareholders may absorb some of the fixed embedded costs that cannot be reduced, such as a portion of the company's \$84 million lease payments associated with PV units 1&2 (\$76 million of this lease is in rates).

It is important to recognize that PNM may eventually be a threat to surrounding regions. A large part of the utility's significant excess reserves are not recoverable from rate payers. Capacity out of rate base totals 365mw, including a 105mw purchased power contract. Since this investment has already been written down and represents a drag on cash flow, PNM can justify marketing it at only a small premium over marginal cost. This could present a problem for other utilities in surrounding areas.

The Arizona utilities are also vulnerable to competitive threats from surrounding areas like, Utah and New Mexico. A particularly vulnerable utility in the Southwest is Tuscon Electric Power Company. TEP also has surplus reserves, high rates and nonearning assets. Like PNM, TEP must rely heavily on wholesale interchange markets, given the large amount of surplus reserves. Furthermore, about 198mw of TEP's Springerville unit 2 coal plant is out of rate base, and a certain portion of the lease of Springerville unit 1 has been disallowed. The company also has 34% industrial load with a 9% concentration of load in the mining industry, which could benefit from self-generation. However, unlike PNM, which is taking steps to allow it to lower rates eventually, TEP is so financially distressed that it has limited flexibility to lower rates. Like PNM, TEP has excess reserves and assets out of rate base and could also contribute to the reduction of regional market rates. Yet its long-term competitive viability under the present structure is questionable.

Public Service Co.'s (PSCO) has the lowest rate structure in its immediate area. Also, capacity needs are modest. While it will have some small rate needs over the intermediate term, its low cost rate structure should not change significantly. Industrial load and wholesale load exposure is not that significant. The only threat to Colorado would be from companies to its south that have assets out of rate base and thus may be able to sell power only slightly above margin to gain load. Deborah Goldsmith, C.F.A.

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*Figures based on Typical Residential, Commercial, and Industrial Bills/Edison Electric Institute.

# **BUY VERSUS BUILD DEBATE REVISITED**

The debate over purchased power, or the "buy versus build" controversy, will likely continue to rage as state utility regulators grapple with the implications of the National Energy Policy Act of 1992. As part of this sweeping legislation, state regulators must consider the potential impact on utilities' cost of capital from purchasing power.

#### Table 1 Determining the risk factor

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Opera

Regula

The risk factor chosen is a function of a subjective (not arbitrary) analysis of qualitative risks.

t i i i	Need for power
	Economics
ing	Performance standards
5	Reliability
	Dispatchability
	Control over maintenance
	Flexibility and diversity
torv	Preapproval
	Manual Annual

Regulatory recovery mechanisms Regulatory out clause

Compared with the last baseload construction cycle, which is universally acknowledged to have been a disaster for investor-owned utilities, buying power from others appears substantially less risky than building new capacity. However, the electric utility industry's entire approach to supply-side resource additions has undergone radical transformation, to the point where it is now impossible to generalize about whether utility bondholders are better off if their utility buys or builds. The important thing is that both resource strategies have inherent risks. S&P employs a methodology for evaluating the benefits and risks of purchased power, and for adjusting a purchasing utility's reported financial statements to allow for more meaningful comparisons with traditional utilities.

#### BENEFITS OF PURCHASING POWER

Buying power may be the best choice for a utility that faces increasing demand. Moreover, purchasing may be the least risky course. The benefits of purchasing can be quite compelling. For example, utilities that purchase avoid the risks of significant construction cost overruns or that the plant might never be finished at all. They also may avoid the associated financial stress caused by regulatory lag typical in building programs.

In addition, utilities that purchase power avoid risking substantial capital. There are many examples of utilities that have failed to earn a full return on and of capital employed to build a plant. Furthermore, purchased power may contribute to fuel-supply diversity and flexibility, and may be cheaper, at least over the short run. Utilities that meet demand expectations with a portfolio of supply-side options also may be better able to adapt to future demand uncertainty, given the specter of retail transmission access.

Nevertheless, in the buy-versus-build debate it is important that appropriate comparisons are made. A properly designed building program may avoid many of the risks associated with the

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unfortunate baseload program of the 1970s and early 1980s. A utility could:

- Build a plant using a fixed-price, turnkey construction contract;
- Construct with a modular approach, adding small units incrementally as demand expectations solidify;
- Obtain regulatory preapproval;
- Receive a cash return on construction work in progress to ease financing stress; and
- Finance the asset with a large portion of equity, providing a cushion for bondholders.



#### **PURCHASES ARE NOT RISK-FREE**

Regardless of whether a utility buys or builds, adding capacity means incurring risk. To the extent that there are any risks with purchased power, bondholders are directly threatened because there is no equity layer to protect them. Utilities are not compensated for any risks they assume in purchasing power. At best, purchased power is recovered dollar-for-dollar as an operating expense, so there is no markup to reward equity holders for taking risks.



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When a utility enters into a long-term purchased power contract with a fixed-cost component, it takes on financial risk. Heavy fixed charges reduce a utility's financial flexibility, and long-term contractual arrangements represent at least in part—off-balance-sheet debt equivalents. Utilities need to take these "financial externalities" into account so that buy and build options are evaluated on a level playing field.

S&P has developed a methodology to quantify this financial risk and adjust financial statements to make traditional utilities and purchasing utilities comparable. S&P's approach is unique because it folds our qualitative analysis into our quantitative methodology. S&P begins by determining the potential off-balance-sheet obligation. This is done by calculating the present value of the capacity payments to be made over the life of the contract, discounted at 10%. The capacity payment is the fixed portion of the purchased power expense. It covers fixed costs, including debt service, depreciation, and a return on equity. S&P is concerned about the total fixed payment, not simply the debt service portion: the utility is obligated to pay the whole amount, not just a part. This means S&P is relatively indifferent to how the nonutility generator is capitalized, except in the extreme case where vast overleveraging threatens the viability of the project.

In virtually all cases, S&P has access to—and utilizes—actual capacity payments. In the rare instance where they are not available or where capacity and energy payments are not broken out—such as in an energy-only contact—S&P will estimate the capacity payment.

S&P does not stop with the potential debt equivalent. S&P recognizes that not all obligations have the same characteristics. What is true of other off-balance-sheet liabilities also is true of purchased power: some are more firm and therefore more debt-like than others.

This concept of the difference in the relative debt characteristics of purchased power obligations can be illustrated by using the concept of a risk spectrum (see chart 1). A risk spectrum is simply a range from 0% to 100%. Obligations on the low end of the scale would have fewer debtlike characteristics and would be considered less firm than the obligations judged to fall on the high end of the scale. This spectrum is important because the place where an obligation falls on the scale—what S&P calls the risk factor—will determine what portion of the obligation S&P will add to a utility's reported debt. For example, if S&P determines that the risk factor for an obligation is 20%, S&P adds 20% of the potential debt equivalent to reported debt.

Different off-balance-sheet obligations have different risks (see chart 2, which shows various types of off-balance sheet obligations and where S&P believes they might fall on the risk spectrum scale). Sale/leasebacks of major plants are viewed as the virtual equivalent of debt, due to the strategic importance of these major electric generating facilities and the "hell-or-high-water" nature of the lease commitments.

Obligations under take-or-pay contracts, which are unconditional as to both acceptance and availability of power, are considered quite firm. The extreme case would be a unit-specific purchase of expensive nuclear capacity under a

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firm take-or-pay arrangement. Here, the risk factor might be as high as 70%-80%. Take-and-pay contracts, which require capacity payments only if power is available, are considered the least debt-like of the three types of obligations listed in chart 2 because take-and-pay capacity payments are conditional. In practice, the risk factors for take-and-pay performance contracts are generally in the 10%-20% range, although some may be as high as 50%.

#### DETERMINING THE RISK FACTOR

How does S&P determine the risk factor or the place where an obligation falls on the risk spectrum? S&P's assessment of the risk factor reflects our analysis of the risks a utility incurs when

Table 2	
ABC Power Co. adjustment to capital structure	
(Mil. \$ at year-end 1992)	_

(	Origina	Adjuste	ed capital structure			
	\$	%	\$	%		
Debt	1,400	54	1,400	49	1	
Adjustment to debt	· <u> </u>		265	9	1 28	
Preferred stock	200	8	200	7		
Common equity	1,000	38	1,000	35		

purchasing power under contract. This depends on a qualitative analysis of market, operating, and regulatory risks. It also depends on S&P's evaluation of the extent to which these risks are borne by the utility. The analysis is subjective, but not arbitrary (see table 1 for some of the key factors under each broad risk category). Depending on circumstances, the utility may bear substantial risks, or it may have successfully shifted risks to either the ratepayers or to the nonutility generator provider of the power.

Lower risk factors would be appropriate if:

- The power is economic and needed,
- True performance standards exist,
- A project has operated reliably,
- The utility has a say in the scheduling of maintenance and retains control over dispatch,
- A contract is preapproved by regulators,
  Capacity payments are recovered through a
- fuel-clause type mechanism, and
- A regulatory out clause passes disallowance risk to the power seller.

#### Table 3 ABC Power Co. adjustment to pretax interest coverage (Mil. \$ year-end 1992) Orig. pretax

	Orig. pretax			
	int, cov.	int. cov.		
Net income	120	300		
Income taxes	65 <u>300</u>	+27		
Interest expense	115 $115 = 2.6x$	115 = 2.3x		
Pretax available	300	+27		
Interest associated with adjusted debt = \$	265 million x 10%			

The absence of these qualitative risk mitigators would lead toward the higher end of the risk spectrum and a higher risk factor.

#### ADJUSTMENTS TO FINANCIAL STATEMENTS

Once S&P has determined what the risk factor is through a qualitative evaluation, S&P then adjusts the utility's financial statements. The procedure to adjust debt is to take the present value of future capacity payments discounted at 10%. The 10% discount factor was chosen to approximate a utility's average cost of capital. The result—the potential debt equivalent—would be multiplied by the risk factor. That result would be added to the utility's reported debt. To adjust the traditional pretax interest coverage ratio, S&P would take 10% of the adjustment to debt. A typical example of the adjustment process is shown below.

#### ABC POWER CO. EXAMPLE

To illustrate the financial adjustments, consider the hypothetical example of ABC Power Co. buying power from XYZ Cogeneration Venture. Under the terms of the purchased power contract, annual capacity payments made by ABC Power start at \$115 million in 1993, rise by \$5 million per year to \$135 million by 1997, and remain fixed through the expiration of the purchased power contract in 2023. The net present value of these obligations over the life of the contract discounted at 10% is \$1.3 billion.

In the case of XYZ, S&P chose a 20% risk factor, which, when multiplied by the potential debt equivalent, resulted in a figure of \$265 million. The risk factor is chosen based on qualitative analysis of the purchased power contract itself and the extent to which market, operating, and regulatory risks are borne by the utility.

Table 2 shows the adjustment to ABC Power's capital structure. S&P takes \$265 million, which is the net present value of the future capacity payments multiplied by a 20% risk factor, and adds it to ABC Power's actual debt of \$1.4 billioft at year-end 1992. As illustrated in table 2, ABC Power's adjusted debt leverage is 58%, up from 54%.

Table 3 illustrates that ABC Power's pretax interest coverage for 1992, without adjusting for off-balance-sheet obligations, was 2.6 times (x), which is calculated by dividing the sum of net income, income taxes, and interest expense by interest expense. To adjust for the XYZ capacity payments, the \$265 million debt adjustment is multiplied by a 10% interest rate to arrive at \$27 million. When this is added to both the numerator and denominator, adjusted pretax interest coverage falls to 2.3x.

#### EFFECT ON RATINGS

The purchased power issue is somewhat complex, but S&P strongly believes that certain purchased power contracts are less risky than others, and that these subtle differences must be factored into the analysis. S&P combines qualitative analysis with the traditional present value approach. The result is an adjustment to debt that is understandable and useful, particularly in the regulatory process, since the adjusted ratios S&P derives are the ones on which S&P ratings are based.

Over the past few years, several ratings have been lowered due to purchased power obligations. In other cases, S&P did not raise ratings. Still others are lower than they might otherwise be owing to purchased power liabilities.

S&P anticipates some rating downgrades of electric utilities over the next couple of years. However, much will depend on how utilities and regulators respond to S&P's analysis.

Utilities can offset purchased power liabilities in several ways, including higher returns on equity or higher equity components in capital structures. Another possibility might be some type of incentive return mechanism.

As competition increases in the electric utility industry, power supply strategies will grow more complex. Consequently, a utility's purchased power obligations must be evaluated in a broader framework than the one this article addresses. The simple truth is that a utility can build all of its own plants, finance them with a balanced mix of equity and debt, put them into rate base without a disallowance, and still find itself in trouble if its rates are not competitive. Consequently, the buyversus-build debate must be viewed within the larger context of a utility's competitive position.

There are many benefits to purchasing power. Indeed, purchasing may be the least risky strategy, but it is not risk-free. S&P's methodology quantifies the risks by explicitly recognizing the key qualitative factors of markets, operations, and regulation. S&P analyzes contracts to determine who is taking the risk: the nonutility generator, the utility, or the ratepayer. S&P recognizes that these adjustments must be viewed within the larger context of a utility's competitive position. *Curtis Moulton* 

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# **DEMAND-SIDE MANAGEMENT GAINS MOMENTUM**

Over the past year, the move to Demand-Side Management (DSM) has gathered momentum as investor-owned utilities attempt to meet the demand for power without incurring the financing stress, and subsequent regulatory scrutiny, associated with new plant construction. Moreover, regulatory pressures have motivated utilities to pursue this path for an additional attribute: environmental benefits.

DSM is the reduction of electric consumption through behavior modification. This can be achieved by inducing customers to avail themselves of energy-efficient technologies, or by curtailing/shifting energy usage from periods of high to low demand. Utilities must add resources to meet high, or peak, demand. DSM is often addressed through an Integrated Resource Planning (IRP), or Least Cost Planning (LCP), process whereby utilities and regulators jointly evaluate all available demand- and supply-side options (including purchased power).

At present, DSM plays a minor role in assessing the total credit quality of an issuer, although there have been two ratings actions where DSM was cited as a contributing factor. Georgia Power Co.'s January 1992 upgrade reflected material reductions in capital requirements achieved through IRP. Potomac Electric Power Co.'s August 1990 downgrade took note of a return on equity (ROE) penalty levied in response to what regulators deemed a subpar commitment to DSM.

Prospectively, S&P believes that utility ratings may come under pressure if DSM programs do not deliver their promised economic savings. Commonwealth Electric Co. finds itself in this position. The utility has been the focus of recent media reports alleging rate escalation due to inefficient DSM. The northeast is sprinkled with additional examples, since utilities in this part of the country embarked on aggressive DSM programs under more favorable economic conditions. Although reserve margins subsequently swelled in the aftermath of the recession, several utilities' DSM programs have become virtually impossible to halt.

S&P maintains that DSM can enhance credit strength if it is truly economic compared to other alternatives and is used as part of a balanced approach to resource planning. However, experience is beginning to raise red flags for this resource option, which had initially appeared to be a panacea for meeting incremental power needs. Recall that nuclear power, at its inception, was touted as being "too cheap to meter." Furthermore, embedded costs of unneeded DSM programs may put utilities at a competitive disadvantage in the advent of retail wheeling. The passage of the 1992 Energy Policy Act legalized wholesale wheeling; most industry participants feel that retail wheeling is inevitable. In fact, it is currently being explored in New Mexico and Michigan.

#### DSM AS A RESOURCE OPTION

DSM was conceived as a resource alternative to plant construction. It was to offer benefits such as:

- Reducing costs of incremental resources (either built or saved),
- Avoiding financial/regulatory risks associated with construction,
- Meeting environmental objectives,
- Offering the flexibility to match resources incrementally with load, and
- Diversifying programs to mitigate asset concentration.

However, as conservation gained broad public and political appeal, regulators embraced DSM for its noneconomic benefits. Consideration of environmental externalities has become mandatory in many jurisdictions. However, pollution mitigation may not be efficiently addressed by individual state regulators and may duplicate efforts by other agencies. Monetizing externalities raises the price of electricity to consumers. The same is true of discounting the cost of DSM programs to give them an advantage. Further-

STANDARD & POOR'S

# CREDIT ISSUES FOR UTILITY PURCHASERS

"There are indeed benefits to purchasing power, but there are also risks that are too often overlooked." The debate over purchased power continues to rage in the utility industry, and S&P has been at the forefront of efforts to analyze the issue. What are the merits of purchasing power versus utility construction of electric generating plants? It is impossible to generalize about whether utility bondholders are better off if their utility buys or builds. The important thing is that both resource strategies have inherent risks.

Purchased power is usually touted as a virtually risk-free alternative to costly plant construction. As we shall see, there are indeed benefits to purchasing power, but there are also risks that are too often overlooked. Only by thoroughly examining the risks--as well as the benefits--can a utility choose correctly. And only by evaluating both buying and building can an investor know what he is getting into.

The "buy versus build" controversy has been around for a long time--as long as purchasing power has been an option. In the past, when utilities built new plants, they typically built more capacity than they needed and sold excess power to their neighbors. The contracts under which this power was sold were timed to expire when the selling utility needed the power to meet its growing native load.

#### TO BUY OR BUILD?

In this article, S&P tackles the debate over the pros and cons of utilities purchasing power rather than building their own plants. The initial focus is on the benefits associated with purchased power. But the risks will also be examined, since S&P believes that utilities are absorbing significant market, operating, regulatory, and financial risks when they enter into long-term purchased power contracts with nonutility generators. S&P will also present here its method of adjusting a utility's financial statements to capture the off-balance sheet obligations associated with purchased power.

#### **BIRTH OF THE NUG**

The enactment of the Public Utilities Regulatory Policies Act (PURPA) in 1978 gave birth to a new provider of electricity: the nonutility generator, or NUG. Congress intended to spur the development of cogeneration and small power producers by providing incentives that included exemption from utility regulation and a requirement that utilities buy electricity from qualifying facilities (QFs) at avoided cost. A QF is a cogenerator or small power producer that is certified by the Federal Energy Regulatory Commission (FERC) as meeting the operating and efficiency standards required by PURPA. Avoided cost is an estimate of the incremental costs that the utility would have incurred absent the purchase from the QF.

A second type of nonutility generator is the independent power producer (IPP), which does not have the same rights under PURPA as a QF. IPPs are not automatically granted a full avoided cost standard for rate setting and have no legislated right to sell power. Their success hinges solely on their competitiveness.

Up to 50% of generating capacity needed over the next 20 years could be built by nonutility generators, according to some estimates. These aggressive estimates assume that the Public Utility Holding Company Act of 1935 (PUHCA) will be amended to exempt IPPs from certain regulatory entanglements associated with the act. S&P's current estimate is that Congress will enact a comprehensive energy bill in 1992. It will include an exemption from PUHCA for IPPs and will also mandate open access transmission for wholesale transactions. Because of these changes, the future will be completely wide open to competition in generation.

#### **BENEFITS OF PURCHASED POWER**

Why are so many deciding to buy so much? The decision to shun new generating plant investment is not difficult to understand, in view of the politicized and occasionally recalcitrant regulatory environments with which some utilities have had to contend to recover their investment. The first benefit is avoidance of construction risk. Buying instead of building will allow the purchasing utility to avoid the risk that a plant under construction will incur significant cost overruns or might never be finished at all. A purchasing utility "Utilities are not compensated for any risks they assume in purchasing power." only begins paying for power once the NUG plant achieves performance hurdles outlined in the power purchase contract.

Second, utilities can avoid financial deterioration that is typical in multiyear construction programs and is caused by regulators' reluctance to allow a full cash return on construction work in progress. A third benefit to purchasing is that if timed correctly, a utility's rates will rise concurrent with or close to the time it begins making purchased power payments. Thus, an important incentive to purchase capacity is the reduction of regulatory lag. In most states, it has been easier to recover purchased power expense than to rate base a new plant.

Other benefits of purchased power are power supply flexibility and diversity. These benefits arise mainly from the fact that most NUG projects are small relative to a utility's total supply base. So there is little concentration risk. Lastly, a utility that avoids investing in generating plant while continuing to depreciate existing plants will see a shift in its asset mix over time. With ongoing new investment in transmission and distribution, the proportion of total assets in the less risky segments of the business will increase.

#### **MARKET RISKS**

To the extent that there are any risks with purchased power, bondholders are directly threatened, because there is no equity cushion to insulate them. Utilities are not compensated for any risks they assume in purchasing power. At best, purchased power is recovered dollar-for-dollar as an operating expense, so there is no markup to reward equity holders for taking risks.

S&P's methodology to evaluate the risks inherent in a purchased power strategy is divided into two basic parts: qualitative and quantitative. The two parts are closely related. In the qualitative area, S&P is interested in three key areas: market risk, operating risk, and regulatory risk. In the quantitative area, S&P addresses financial risks associated with purchased power and how these risks are incorporated into the rating process.

The market risks in purchasing power stem from the fact that a utility enters into a long-term contract to buy power without assurance that it will be able to sell the power. Even a cursory analysis of the last construction cycle demonstrates that utilities are not very good at forecasting demand for electricity. Given that regulators get very upset when a utility procures too much power, there is a major risk to utilities if demand falls short of expectations. The utility also accepts the risk that the power may not be economic over time. In the increasingly competitive electric utility industry, a utility's cost of power is critical to its success. To the extent that contracted power becomes uneconomic relative to other sources of supply, the utility may suffer a loss of customers, sales, and earnings.

#### **OPERATING RISKS**

There are also operating risks in purchasing power. Erecting a power plant is much more difficult today than it was 10 years ago due to heightened environmental awareness. This means that a lot of contracted NUG capacity may never actually come on line. Purchasing utilities try to compensate for this by accepting more bids for power than they actually need. If a significantly greater percentage of contracted purchased power fails to materialize, the utility may be required to accelerate its own construction activities at a late date, thereby resulting in greater cost than previously anticipated and a greater risk of regulatory disallowance. The utility has an obligation to serve, but the NUG does not.

Will NUG plants operate well? The data suggest that there is not much difference in availability between utility plants and NUG plants. But there are lingering doubts. Any discrepancy in quality may not be known until plants begin to age. Another operating risk faced by the purchasing utility is loss of control over its supply sources. The utility may or may not control a NUG plant's operations and dispatch and may have no say in when the unit is taken down for routine maintenance. These factors can have an important influence on a utility's efficiency and reliability. Control over dispatch is particularly important. It is bad enough that a utility has to pay minimum capacity payments regardless of the economics of the power purchased. But it is worse if the utility cannot decline delivery of uneconomic energy.

The benefits associated with a diverse and flexible fuel supply were discussed earlier. Obviously, the opposite would be a risk. S&P pays particular attention to natural gas-fired NUGs. S&P believes that natural gas will play an increasingly important role in electric generation in the U.S., and that superior drilling and recovery technologies will keep gas prices relatively low for the foreseeable future. Moreover, natural gas combustion technologies are pretty straightforward. Nevertheless, overreliance on any one fuel is a risk, and nearly three-quarters of independent power projects in development are fired with natural gas. "The first financial risk is the potential for liquidating rate base." The independent power industry argues that since regulators allow the passthrough of purchased power expense to a utility's customers, there is no risk to the purchasing utility. S&P agrees that one-for-one recovery of the expense helps mitigate the risk. But there remains the chance that regulators will disallow purchased power costs--either capacity costs or energy costs, and either prospectively or retroactively.

CREDIT COMMENT

The risk that the purchasing utility may have to absorb regulatory disallowances could be reduced by the existence of a "regulatory out" clause in the power purchase contract. Under this clause, disallowance risk is passed to the NUG. Whether or not a regulatory out provision reduces risk for the utility depends on specific language in the contract. Further, these provisions have not yet been tested in the courts.

Another important factor when considering regulatory risk is a state-by-state analysis of the mechanics of recovering purchased power expense. For example, S&P believes that disallowance risk is reduced if purchased power capacity charges are recovered from customers in a separate adjustment mechanism like a fuel clause rather than through base rates. This way, there is little or no delay in beginning to recover the charges, since no general rate filing is needed, and it is also easier to track the expense and be assured that there are adequate revenues to cover the charge.

One of the ways to mitigate disallowance risk is through a comprehensive integrated resource planning process hosted by the state regulators. In these elaborate procedures, all supply- and demand-side options are considered within a common framework to obtain a least-cost mix. Certain states like Nevada have instituted preapproval programs for resource planning that alleviate the risk of regulatory scrutiny after the fact. Legislation in Nevada precludes disallowance of future capacity once the resource plan has been approved by the commission. This does not preclude the potential for cost overrun penalties, but it is a step toward ensuring that capacity additions will not be classified as unnecessary after the investment has already been made. In the end, S&P's evaluation of regulatory risk is a state-bystate effort, encompassing the entire regulatory, legislative, and judicial arenas.

#### **FINANCIAL RISKS**

The first financial risk is the potential for liquidating rate base. Equity investors, in particular, are alarmed about this phenomenon. The idea is that since utilities are allowed a return on depreciated investment (or rate base), their earnings will decline to the extent that rate base declines. If a utility is not building new generating plant, yet continues to depreciate existing generating investment, then its depreciation will exceed new capital investment, and its rate base and earnings will erode.

But debt quality may not necessarily be affected. S&P recognizes that declining rate base will be gradual and that spending on transmission and distribution will continue, so rate base will not disappear altogether. And if depreciation exceeds new investment, that need not be alarming, since it means that cash flow is strong relative to needs. What is critical is what the utility does with its cash flow. A shrinking utility does not threaten bondholders to the extent that the utility reduces debt as its assets contract. Done in proportion, key relationships like cash flow to debt and cash flow coverage of interest will stay relatively constant.

The bigger concern with declining rate base is how management will react when faced with a scenario of slow earnings growth or declining earnings. Historically, the typical response has been nonutility diversification. S&P has never been a big fan of diversification because of concerns about management pursuing greater risk in search of greater returns.

The second and more important area of financial risk stems from the fact that in a purchased power arrangement, the purchasing utility enters into a long-term contract with a fixed-cost component. These long-term contractural arrangements are, at least in part, off-balance sheet debt equivalents. S&P is really concerned with firm long-term contracts, not spot purchases. And, as a practical matter, overall purchased power risk is usually not significant until purchased power exceeds 10%-15% of capacity.

The fixed or capacity portion of the purchased power payment covers a NUG's fixed costs, including debt service, depreciation, and a return on equity. The total fixed capacity payment is of concern, not simply the debt service portion. This is because the utility is obligated to pay the whole thing, not just a part.

By capturing the entire fixed payment in its analysis, S&P is not focused on the extent to which the NUG is leveraged. Whether a NUG is capitalized with 70% or 90% debt makes little difference in the capacity payments. There may be a difference in the NUG's financial viability.



That is, highly leveraged NUGs are inherently less creditworthy than less leveraged NUGs. And their financial health may affect their reliability. But this is better analyzed within an overall evaluation of a utility's fuel and power supply risk.

#### TAKE-OR-PAY VS. TAKE-AND-PAY

There are two basic types of purchased power contracts: take-or-pay and take-and-pay. Takeor-pay contracts are unconditional as to both acceptance and availability of power. That is, the utility is obligated to make capacity payments all



the time, whether or not the plant is able to produce power. Thus, if the plant cannot produce, the utility has to make the capacity payment and still go elsewhere and pay for replacement power.

Alternatively, take-and-pay contracts require capacity payments only if power is available. Virtually all NUG power is sold under take-and-pay contracts that contain conditional provisions, such as those that include a minimum performance standard measured against actual operating availability. If performance of the NUG plant falls below the contract minimums, capacity payments are lowered. If performance is chronically poor, the take-and-pay contract is usually cancellable.

As a practical matter, contract provisions vary widely, so it is not always easy to clearly distinguish between a conditional and an unconditional contract. Thus, whether capacity payments represent debt under take-or-pay or take-andpay contracts is a murky issue. What is true of purchased power is true of other off-balance sheet obligations—that some are more firm, and therefore more debt-like, than others.

#### **RISK SPECTRUM**

The difference in the relative debt characteristics of off-balance sheet obligations can be illustrated through the concept of a risk spectrum (see figure 1). Obligations on the left hand of the spectrum would have fewer debt-like characteristics and would be considered less firm than the obligations judged to fall on the right-hand side. This spectrum is important because the place where an obligation falls on the scale--the risk factor--will determine what portion of the obligation S&P will add to a utility's reported debt. For example, if S&P considers that the risk factor for any particular obligation is 50%, it will add 50% of that obligation to reported debt.

#### **OFF-BALANCE SHEET OBLIGATIONS DIFFER**

Different off-balance sheet obligations have different risks. Figure 2 shows various types of offbalance sheet obligations and where S&P believes they might fall on the scale--their risk factors. Sale/leasebacks of major plants are viewed as virtually the equivalent of debt, due to the strategic importance of these major electric generating facilities and the "hell-or-high-water" nature of the lease commitments. Take-or-pay obligations are considered quite firm, given the general unconditional nature of a utility's obligation to make capacity payments. Take-and-pay contracts are considered least debt-like of the three types of obligations listed in figure 2 because take-andpay capacity payments are conditional. It is important to keep in mind that while all of these obligations have fixed charges associated with them that will impact a utility's day-to-day fixed charge burden, the executory nature of the lease or contractural relationship may allow S&P to view an obligation as something short of a total debt equivalent.

#### ATTRIBUTES DECREASING THE RISK FACTOR

Where take-and-pay contracts fall on the risk spectrum-their risk factor-depends on a qualitative analysis of the purchased power contract itself, and the extent to which market, operating, and regulatory risks are borne by the utility. What are some of the attributes of these qualitative factors that would allow S&P to arrive at a relatively low risk factor? In the area of market risk, the risk factor would be reduced to the extent that the power is economic relative to alternatives. Secondly, risk would be lower if the project's energy rate was indexed to the purchasing util-

"Once S&P has determined what the risk factor is through a qualitative evaluation, it then adjusts the utility's financial statments."

ity's other sources of power, so that the purchased power's economics would not decline over time.

In the area of operating risk, the risk factor would tend to be lower where a contract contains true performance standards, such as a minimum capacity factor of 80% and a total cutoff of capacity payments below a certain level of availability. If the utility retains control over the NUG's scheduling of maintenance and dispatch, risk would also be lower. Another attribute contributing to lower risk would be project diversity, since concentrations of purchased power exposure are more significant than aggregate exposure.

Lessening regulatory risk would be: a regulatory out clause, complete recovery of the capacity charge through a fuel clause type mechanism rather than base rates, and a state regulatory environment that supports and encourages utilities to purchase power. The absence of these qualitative risk mitigators would lead one toward the higher end of the risk spectrum and a higher risk factor. S&P would expect that, as a practical matter, the risk factor for take-and-pay obligations would range between 10%-50%.

#### ADJUSTMENTS TO FINANCIAL STATEMENTS

Once S&P has determined what the risk factor is through a qualitative evaluation, it then adjusts the utility's financial statements. The procedure to adjust debt would be to take the net present value of future capacity payments discounted at 10%. The 10% discount factor was chosen to approximate a utility's average cost of capital. The result--the potential debt equivalent--would be multiplied by the risk factor. That result would be added to the utility's reported debt. To adjust the traditional interest coverage ratio, S&P would take 10% of the adjustment to debt. A typical example of the adjustment process is shown below.

#### CONSUMERS POWER EXAMPLE

Table 1 shows the annual capacity payments that Consumers Power Co. is scheduled to make to the Midland Cogeneration Venture (MCV). Based on 90% availability, they rise to \$369 million in 1995, where they remain for the duration of the 35-year contract. The net present value of these obligations over the life of the contract discounted at 10% is \$3.383 billion.

In the case of MCV, S&P chose a 30% risk factor, which, when multiplied by the potential debt equivalent, resulted in a figure of \$1.015 billion. The risk factor is chosen based on qualitative

Table 1			
Consumers P	ower adjustment to debt		
(Mil. \$ Year-e	ind 1990)		
•	Off-balance sheet obligation payments		
1991	\$284	Net present value of	
1992	\$299	obligations at 10% =	\$3,38
1993	\$328	Multiplied by risk factor	X 30
1994	\$355	Adjustment to debt	\$1,0
1995-2025	\$369 per year		

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analysis of the purchased power contract itself and the extent to which market, operating, and regulatory risks are borne by the utility. In the Consumers Power example, S&P chose the 30% risk factor for several reasons. First, there is some

#### Table 2 Consumers Power adjustment to capital structure (Mil. \$ Year-end 1990) Original capital Adjusted capital structure structure Debt 3,435 65 3435 54 } 70 Adjustment to debt 1,015 --16 Preferred stock 170 3 170 3 Common stock 32 27 1.720 1,720

risk because of concentration-MCV will represent 15% of Consumers' capacity. In addition, while regulatory peace is beginning to emerge, it it too early to say that Michigan utility regulators are fully supportive of MCV. Consumers Power is not currently recovering the full capacity payment, because Michigan regulators are allowing recovery based on deliverability rather that availability.

On the other hand, the MCV capacity payments are not viewed as total debt equivalents, because there is a fuel clause in Michigan for the energy payments and a regulatory out clause covering the energy portion of the contract. In addition, S&P is comfortable with the Michigan pool controlling dispatch and believes that the performance standards in the contract render it truly conditional.

Table 2 shows the adjustment to Consumers' capital structure. We take \$1.015 billion, which is the net present value of the future capacity payments multiplied by a 30% risk factor, and add it to Consumers' actual debt of \$3.435 billion at 1990 year end. As is evident to the table, Consumers' adjusted debt leverage is 70%, up from 65%.

Table 3 illustrates that Consumers' pretax inter-

Table 3 Consumers Powe	er adjust	tment to pretax interest	coverage
(พก. จารสา-เกม	1330)	Original pretax interest coverage	adjusted pretax interest coverage
Net income	\$34		700
Income taxes	403	$\frac{700}{2.66x}$	+101 = 2,20
Interest expense	<u>263</u>	263	263
Pretax available	700		+101

est coverage for 1990, without adjusting for offbalance sheet obligations, was 2.66 times (x), which is calculated by dividing the sum of net income, income taxes, and interest expense by interest expense. To adjust for the MCV capacity payments, the \$1.015 billion debt adjustment is multiplied by a 10% interest rate to arrive at \$101 million. When this is added to both the numerator and denominator, adjusted pretax interest coverage falls to 2.2x.

NOVEMBER 1991 5

S&P can make similar adjustments to two other traditionally important ratios—funds from operations interest coverage and funds from operations to average total debt. The results of these adjustments are shown in Table 4.

#### EFFECT ON RATINGS

Will S&P lower bond ratings to reflect its focus on the risks in purchased power? Going forward, S&P would expect some rating downgrades over the next couple of years. However, where purchases represent less than 10%-15% of a utility's capacity, the quantitative adjustments will not make much difference to the ratios, and the incremental financial risk may be offset by the qualitative benefits of purchasing power.

Even where purchases are more significant, downgrades may or may not be appropriate, depending on the response to S&P's analysis by utilities and their regulators. It is not S&P's role to simply sit in judgment. Rather, it intends to work closely with both utilities and regulators to help identify the appropriate risk factor to apply to a utility's off-balance sheet obligations. Moreover, S&P will work with interested parties to design

usted ratios	
1990 original	1990 adjusted
65%	70%
2.66x	2.20x
2.71x	2.23x
13%	10%
	usted ratios 1990 original 65% 2.66x 2.71x 13%

ways to offset purchased power risks. These offsets could take several forms, including higher returns on equity, higher equity components in capital structures, incentive return mechanisms for purchasing, or laws or regulations that would eliminate disallowance risk.

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#### ELECTRIC GAS & WATER UTILITIES

Of course, at least initially, this restructuring will be done largely at the expense of its investors. PNM's shareholders may absorb some of the fixed embedded costs that cannot be reduced, such as a portion of the company's \$84 million lease payments associated with PV units 1&2 (\$76 million of this lease is in rates).

It is important to recognize that PNM may eventually be a threat to surrounding regions. A large part of the utility's significant excess reserves are not recoverable from rate payers. Capacity out of rate base totals 365mw, including a 105mw purchased power contract. Since this investment has already been written down and represents a drag on cash flow, PNM can justify marketing it at only a small premium over marginal cost. This could present a problem for other utilities in surrounding areas.

The Arizona utilities are also vulnerable to competitive threats from surrounding areas like, Utah and New Mexico. A particularly vulnerable utility in the Southwest is Tuscon Electric Power Company. TEP also has surplus reserves, high rates and nonearning assets. Like PNM, TEP must rely heavily on wholesale interchange markets, given the large amount of surplus reserves. Furthermore, about 198mw of TEP's Springerville unit 2 coal plant is out of rate base, and a certain portion of the lease of Springerville unit 1 has been disallowed. The company also has 34% industrial load with a 9% concentration of load in the mining industry, which could benefit from self-generation. However, unlike PNM, which is taking steps to allow it to lower rates eventually, TEP is so financially distressed that it has limited flexibility to lower rates. Like PNM, TEP has excess reserves and assets out of rate base and could also contribute to the reduction of regional market rates. Yet its long-term competitive viability under the present structure is questionable.

Public Service Co.'s (PSCO) has the lowest rate structure in its immediate area. Also, capacity needs are modest. While it will have some small rate needs over the intermediate term, its low cost rate structure should not change significantly. Industrial load and wholesale load exposure is not that significant. The only threat to Colorado would be from companies to its south that have assets out of rate base and thus may be able to sell power only slightly above margin to gain load.

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*Figures based on Typical Residential, Commercial, and Industrial Bills/Edison Electric Institute.

# **BUY VERSUS BUILD DEBATE REVISITED**

The debate over purchased power, or the "buy versus build" controversy, will likely continue to rage as state utility regulators grapple with the implications of the National Energy Policy Act of 1992. As part of this sweeping legislation, state regulators must consider the potential impact on utilities' cost of capital from purchasing power.

#### Table 1

#### Determining the risk factor

The risk factor chosen is a function of a subjective (not arbitrary) analysis of qualitative risks.

mainel	Economics
Operating	Performance standards Reliability Dispatchability Control over maintenance Flexibility and diversity
Regulatory	Preapproval Regulatory recovery mechanish Regulatory out clause

Compared with the last baseload construction cycle, which is universally acknowledged to have been a disaster for investor-owned utilities, buying power from others appears substantially less risky than building new capacity. However, the electric utility industry's entire approach to supply-side resource additions has undergone radical transformation, to the point where it is now impossible to generalize about whether utility bondholders are better off if their utility buys or builds. The important thing is that both resource strategies have inherent risks. S&P employs a methodology for evaluating the benefits and risks of purchased power, and for adjusting a purchasing utility's reported financial statements to allow for more meaningful comparisons with traditional utilities.

#### BENEFITS OF PURCHASING POWER

Buying power may be the best choice for a utility that faces increasing demand. Moreover, purchasing may be the least risky course. The benefits of purchasing can be quite compelling. For example, utilities that purchase avoid the risks of significant construction cost overruns or that the plant might never be finished at all. They also may avoid the associated financial stress caused by regulatory lag typical in building programs.

In addition, utilities that purchase power avoid risking substantial capital. There are many examples of utilities that have failed to earn a full return on and of capital employed to build a plant. Furthermore, purchased power may contribute to fuel-supply diversity and flexibility, and may be cheaper, at least over the short run. Utilities that meet demand expectations with a portfolio of supply-side options also may be better able to adapt to future demand uncertainty, given the specter of retail transmission access.

Nevertheless, in the buy-versus-build debate it is important that appropriate comparisons are made. A properly designed building program may avoid many of the risks associated with the

#### ELECTRIC, GAS & WATER UTILITIES

firm take-or-pay arrangement. Here, the risk factor might be as high as 70%-80%. Take-and-pay contracts, which require capacity payments only if power is available, are considered the least debt-like of the three types of obligations listed in chart 2 because take-and-pay capacity payments are conditional. In practice, the risk factors for take-and-pay performance contracts are generally in the 10%-20% range, although some may be as high as 50%.

#### DETERMINING THE RISK FACTOR

How does S&P determine the risk factor or the place where an obligation falls on the risk spectrum? S&P's assessment of the risk factor reflects our analysis of the risks a utility incurs when

Table 2			
ABC Power Co. adjustment	t to	capital	structure
(Mil. \$ at year-end 1992)			

	Ori	ginal capital structure	Adjuste	ed capital structure	
	\$	%	\$	%	
Debt	1,400	54	1,400	49	1 50
Adjustment to debt			265	9	58
Preferred stock	200	8	200	7	
Common equity	1,000	38	1,000	35	

purchasing power under contract. This depends on a qualitative analysis of market, operating, and regulatory risks. It also depends on S&P's evaluation of the extent to which these risks are borne by the utility. The analysis is subjective, but not arbitrary (see table 1 for some of the key factors under each broad risk category). Depending on circumstances, the utility may bear substantial risks, or it may have successfully shifted risks to either the ratepayers or to the nonutility generator provider of the power.

Lower risk factors would be appropriate if:

- The power is economic and needed,
- True performance standards exist,
- A project has operated reliably,
- •The utility has a say in the scheduling of maintenance and retains control over dispatch,
- A contract is preapproved by regulators,
- Capacity payments are recovered through a fuel-clause type mechanism, and
- •A regulatory out clause passes disallowance risk to the power seller.

 Table 3

 ABC Power Co. adjustment to pretax interest coverage

 (Mil. \$ year-end 1992)

 Orig. pretax

 int. cov.

 Net income
 120
 300

 Income taxes
 65
 300
 +27

	120				000		
ncome taxes	65	300			+27		
nterest expense	115	115	=	2.6x	115	=	2
retax available	300				+27		
nterest associated with adjusted debt	= \$265 million x 109	6					

The absence of these qualitative risk mitigators would lead toward the higher end of the risk spectrum and a higher risk factor.

#### ADJUSTMENTS TO FINANCIAL STATEMENTS

Once S&P has determined what the risk factor is through a qualitative evaluation, S&P then adjusts the utility's financial statements. The procedure to adjust debt is to take the present value of future capacity payments discounted at 10%. The 10% discount factor was chosen to approximate a utility's average cost of capital. The result—the potential debt equivalent—would be multiplied by the risk factor. That result would be added to the utility's reported debt. To adjust the traditional pretax interest coverage ratio, S&P would take 10% of the adjustment to debt. A typical example of the adjustment process is shown below.

#### ABC POWER CO. EXAMPLE

To illustrate the financial adjustments, consider the hypothetical example of ABC Power Co. buying power from XYZ Cogeneration Venture. Under the terms of the purchased power contract, annual capacity payments made by ABC Power start at \$115 million in 1993, rise by \$5 million per year to \$135 million by 1997, and remain fixed through the expiration of the purchased power contract in 2023. The net present value of these obligations over the life of the contract discounted at 10% is \$1.3 billion.

In the case of XYZ, S&P chose a 20% risk factor, which, when multiplied by the potential debt equivalent, resulted in a figure of \$265 million. The risk factor is chosen based on qualitative analysis of the purchased power contract itself and the extent to which market, operating, and regulatory risks are borne by the utility.

Table 2 shows the adjustment to ABC Power's capital structure. S&P takes \$265 million, which is the net present value of the future capacity payments multiplied by a 20% risk factor, and adds it to ABC Power's actual debt of \$1.4 billion at year-end 1992. As illustrated in table 2, ABC Power's adjusted debt leverage is 58%, up from 54%.

Table 3 illustrates that ABC Power's pretax interest coverage for 1992, without adjusting for off-balance-sheet obligations, was 2.6 times (x), which is calculated by dividing the sum of net income, income taxes, and interest expense by interest expense. To adjust for the XYZ capacity payments, the \$265 million debt adjustment is multiplied by a 10% interest rate to arrive at \$27 million. When this is added to both the numerator and denominator, adjusted pretax interest coverage falls to 2.3x.

#### **EFFECT ON RATINGS**

Adj. pretax

int. cov.

3x

The purchased power issue is somewhat complex, but S&P strongly believes that certain purchased power contracts are less risky than others, and that these subtle differences must be factored into the analysis. S&P combines qualitative analysis with the traditional present value approach. The result is an adjustment to debt that is understandable and useful, particularly in the regulatory process, since the adjusted ratios S&P derives are the ones on which S&P ratings are based. unfortunate baseload program of the 1970s and early 1980s. A utility could:

- Build a plant using a fixed-price, turnkey construction contract;
- Construct with a modular approach, adding small units incrementally as demand expectations solidify;
- Obtain regulatory preapproval;
- Receive a cash return on construction work in progress to ease financing stress; and
- Finance the asset with a large portion of equity, providing a cushion for bondholders.



#### PURCHASES ARE NOT RISK-FREE

Regardless of whether a utility buys or builds, adding capacity means incurring risk. To the extent that there are any risks with purchased power, bondholders are directly threatened because there is no equity layer to protect them. Utilities are not compensated for any risks they assume in purchasing power. At best, purchased power is recovered dollar-for-dollar as an operating expense, so there is no markup to reward equity holders for taking risks.



When a utility enters into a long-term purchased power contract with a fixed-cost component, it takes on financial risk. Heavy fixed charges reduce a utility's financial flexibility, and long-term contractual arrangements representat least in part-off-balance-sheet debt equivalents. Utilities need to take these "financial externalities" into account so that buy and build options are evaluated on a level playing field.

S&P has developed a methodology to quantify this financial risk and adjust financial statements to make traditional utilities and purchasing utilities comparable. S&P's approach is unique because it folds our qualitative analysis into our quantitative methodology. S&P begins by determining the potential off-balance-sheet obligation. This is done by calculating the present value of the capacity payments to be made over the life of the contract, discounted at 10%. The capacity payment is the fixed portion of the purchased power expense. It covers fixed costs, including debt service, depreciation, and a return on equity. S&P is concerned about the total fixed payment, not simply the debt service portion: the utility is obligated to pay the whole amount, not just a part. This means S&P is relatively indifferent to how the nonutility generator is capitalized, except in the extreme case where vast overleveraging threatens the viability of the project.

In virtually all cases, S&P has access to---and utilizes-actual capacity payments. In the rare instance where they are not available or where capacity and energy payments are not broken out-such as in an energy-only contact-S&P will estimate the capacity payment.

S&P does not stop with the potential debt equivalent. S&P recognizes that not all obligations have the same characteristics. What is true of other off-balance-sheet liabilities also is true of purchased power: some are more firm and therefore more debt-like than others.

This concept of the difference in the relative debt characteristics of purchased power obligations can be illustrated by using the concept of a risk spectrum (see chart 1). A risk spectrum is simply a range from 0% to 100%. Obligations on the low end of the scale would have fewer debtlike characteristics and would be considered less firm than the obligations judged to fall on the high end of the scale. This spectrum is important because the place where an obligation falls on the scale—what S&P calls the risk factor—will determine what portion of the obligation S&P will add to a utility's reported debt. For example, if S&P determines that the risk factor for an obligation is 20%, S&P adds 20% of the potential debt equivalent to reported debt.

Different off-balance-sheet obligations have different risks (see chart 2, which shows various types of off-balance sheet obligations and where S&P believes they might fall on the risk spectrum scale). Sale/leasebacks of major plants are viewed as the virtual equivalent of debt, due to the strategic importance of these major electric generating facilities and the "hell-or-high-water" nature of the lease commitments.

Obligations under take-or-pay contracts, which are unconditional as to both acceptance and availability of power, are considered quite firm. The extreme case would be a unit-specific purchase of expensive nuclear capacity under a 🕨

JUNE 21, 1993

27

STANDARD & POOR'S CREDITWEEK

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Over the past few years, several ratings have been lowered due to purchased power obligations. In other cases, S&P did not raise ratings. Still others are lower than they might otherwise be owing to purchased power liabilities.

S&P anticipates some rating downgrades of electric utilities over the next couple of years. However, much will depend on how utilities and regulators respond to S&P's analysis.

Utilities can offset purchased power liabilities in several ways, including higher returns on equity or higher equity components in capital structures. Another possibility might be some type of incentive return mechanism.

As competition increases in the electric utility industry, power supply strategies will grow more complex. Consequently, a utility's purchased power obligations must be evaluated in a broader framework than the one this article addresses. The simple truth is that a utility can build all of its own plants, finance them with a balanced mix of equity and debt, put them into rate base without a disallowance, and still find itself in trouble if its rates are not competitive. Consequently, the buyversus-build debate must be viewed within the larger context of a utility's competitive position.

There are many benefits to purchasing power. Indeed, purchasing may be the least risky strategy, but it is not risk-free. S&P's methodology quantifies the risks by explicitly recognizing the key qualitative factors of markets, operations, and regulation. S&P analyzes contracts to determine who is taking the risk: the nonutility generator, the utility, or the ratepayer. S&P recognizes that these adjustments must be viewed within the larger context of a utility's competitive position.

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# DEMAND-SIDE MANAGEMENT GAINS MOMENTUM

Over the past year, the move to Demand-Side Management (DSM) has gathered momentum as investor-owned utilities attempt to meet the demand for power without incurring the financing stress, and subsequent regulatory scrutiny, associated with new plant construction. Moreover, regulatory pressures have motivated utilities to pursue this path for an additional attribute: environmental benefits.

DSM is the reduction of electric consumption through behavior modification. This can be achieved by inducing customers to avail themselves of energy-efficient technologies, or by curtailing/shifting energy usage from periods of high to low demand. Utilities must add resources to meet high, or peak, demand. DSM is often addressed through an Integrated Resource Planning (IRP), or Least Cost Planning (LCP), process whereby utilities and regulators jointly evaluate all available demand- and supply-side options (including purchased power).

At present, DSM plays a minor role in assessing the total credit quality of an issuer, although there have been two ratings actions where DSM was cited as a contributing factor. Georgia Power Co.'s January 1992 upgrade reflected material reductions in capital requirements achieved through IRP. Potomac Electric Power Co.'s August 1990 downgrade took note of a return on equity (ROE) penalty levied in response to what regulators deemed a subpar commitment to DSM.

Prospectively, S&P believes that utility ratings may come under pressure if DSM programs do not deliver their promised economic savings. Commonwealth Electric Co. finds itself in this position. The utility has been the focus of recent media reports alleging rate escalation due to inefficient DSM. The northeast is sprinkled with additional examples, since utilities in this part of the country embarked on aggressive DSM programs under more favorable economic conditions. Although reserve margins subsequently swelled in the aftermath of the recession, several utilities' DSM programs have become virtually impossible to halt.

S&P maintains that DSM can enhance credit strength if it is truly economic compared to other alternatives and is used as part of a balanced approach to resource planning. However, experience is beginning to raise red flags for this resource option, which had initially appeared to be a panacea for meeting incremental power needs. Recall that nuclear power, at its inception, was touted as being "too cheap to meter." Furthermore, embedded costs of unneeded DSM programs may put utilities at a competitive disadvantage in the advent of retail wheeling. The passage of the 1992 Energy Policy Act legalized wholesale wheeling; most industry participants feel that retail wheeling is inevitable. In fact, it is currently being explored in New Mexico and Michigan.

#### DSM AS A RESOURCE OPTION

DSM was conceived as a resource alternative to plant construction. It was to offer benefits such as:

- Reducing costs of incremental resources (either built or saved),
- Avoiding financial/regulatory risks associated with construction,
- Meeting environmental objectives,
- •Offering the flexibility to match resources incrementally with load, and
- Diversifying programs to mitigate asset concentration.

However, as conservation gained broad public and political appeal, regulators embraced DSM for its noneconomic benefits. Consideration of environmental externalities has become mandatory in many jurisdictions. However, pollution mitigation may not be efficiently addressed by individual state regulators and may duplicate efforts by other agencies. Monetizing externalities raises the price of electricity to consumers. The same is true of discounting the cost of DSM programs to give them an advantage. Further-

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# THE CREDIT PICTURE

	Males Interest Rates, Money Fla	ws, and	l Other	Finan	icial V	<b>ariable</b>	5 5	Receiver 6	11		41 - 44 4 41	r ha harry			ļ
		1999:2	1999:3	1 <b>9</b> 30:4	2000:1	2000:2	2000:3	1998	1999	2000	2001	2002	 ? 2003	3 2004	•
)r	niornal Ratas (Porcant, NSA)											-	-		
F	ederal Funds Rate	4.75	5.00	5.37	5.50	5.60	5.50	5.35	4.89	5.50	5.50	5.60	5.50	5.50	
P	Iscount Refe	4.50	4.80	4.87	5.00	5.00	5.00	4.82	4.62	5.00	5.00	6.00	5.00	5.00	
	3-Month	4.57	4.77	5.11	5.15	5.14	. 5.15	4.90	4.74	5.15	5.14	5 13	5 13	5 13	•
	8-Month	4.76	4.96	5.34	5.43	5,43	5 44	5.02	4.01	5.43	5.42	5.41	5.42	5.41	
•	1-YBAI 9-Vear	4.88	5.16	5.40	5.47	5.47	5.48	5.05	5.03	5.47	5.48	5.44	5.44	5.44	
	3-Year	5.35	5.71	6.75	5.70	5.61	0.50 5.64	5.14	5.30	5.68	5.51	- 5.5)	5.52	5.51	
	5-Year	5.44	5.77	5,90	5.94	5.B1	5.72	5.15	5.50	5.77	5,58	5.61	5.59	5.68	
	10-Year	5.54	5.88	5.93	5.95	5.82	5.71	5.26	5.56	5.77	5.00	5.68	5.68	5.71	
5	bon-Term Rales on:	5.80	6-04	6.17	5.17	6.05	5.92	5.58	5.84	5.88	5.78	5.87	5,87	5.89	
	3-Month Treasury Bills	4.45	4.65	4.98	5.01	5.01	5.02	4.78	4.62	5.01	5,00	4.89	5.00	4.89	
	6-Month Treasury Bills	4.58	4.78	5.13	5.21	5.21	5.22	4.83	4.73	5.21	5,20	5.20	5.20	5.20	
	3-Monin Leige CDS	4.88	5.38	5.59	5.50	5.60	5.56	5.47	5.21	5.57	5.63	5.58	5.58	5.58	
	3-Month Prime Comm. Paper	4.86	5.23	5.40	5.50	6.53	5.49	5.34	5.08	5.50	5.56	5.51	5.51	3.00 5.52	
	Prime Commercial Loans	7.75	8.10	8.37	8.50	8.50	8.50	8.35	7.00	8.50	8.50	8.60	8.50	8.50	
Lo	AUIO INSIBIL LAS. @ LOMM: BRAKS	8.30	8.44	8.50	8.63	8.75	8.82	8.54	5,40	5.76	8,92	9.01	9,04	8.08	
	Seasoned AAA Corporate Bonds	6.93	7.33	7.18	7.20	6.94	6.70	6.63	6.97	6.84	6.46	6.43	6.44	6.53	
	Seasoned BAA Corporate Bonds	7,74	8.10	7.97	7.91	7.66	7,41	7.22	7.80	7.55	7.11	7.11	7.08	7.18	
7		7.30	7.76	7.78	7,76	7.40	7.13	5.91	7.48	7.30	5.84	6.80	6.73	6.80	•
	Bond Index of 20 G.O. Munis.	5.21	5,56	5.72	5.78	5.68	5.54	5.09	5.39	5.58	5.23	5.32	5.31	5.09	
M	ungage Rates Conventional Mon. Commit (a) Fill Mon Bate on Loans Closed	7.21	7. <b>8</b> 1	7.92	7.82	7.65	7.44	6.95	7,45	7.53	6.94	6.87	6.92	6.95	
	New Hamas	6.92	7.16	7.72	7.86	7.82	7.68	7.08	7.18	7.72	7.21	7.05	7.09	7.12	
	Existing Homes	7.13	7.58	7.73	7.87	7.82	7.66	7.10	7.35	7.72	7,19	7.02	7.06	7.09	
~	TIN-District Cost of Funds	4.49	4.56	4.66	4.77	4.87	4.95	4.86	4.57	4,90	5.16	5.31	6.39	5.44	
He	Norve Aggregates (Billions of dollar	<b>(8)</b>													
TO	18) Adderves Addurd Bargani Chappen	43.74	42.05	40.96	40.69	40-50	40.43	44.60	40.95	40.44	40.94	41.99	43.47	45.16	
No	nborrowed Reserves	43.50	41.77	40.57	40.32	40.25	+U.7 40.04	44.48	40.57	40.12	40.70	41.81	3.2 ⊿3.20	3.8 45.00	
Bo	trowed Reserves	0.15	0.28	0.40	0.37	0.25	0.39	0.12	0.40	0.33	0.24	0.19	D.17	0.16	
He	CASE DECENTES	42.51	40.92	39.87	39.61	39.43	39.36	43.01	30.67	39.38	39.89	40.85	42.42	44.1	
Fre	ba Receivas	1.08	0.85	0.70	0,71	0.82	0.68	1.47	0.70	0.74	0.81	0.86	0.88	0.89	
Mc	enetary Aggregates (Billions of dolla	rs) (b)													
Mt		1104.8	1098.4	1101.5	1101.8	1106.0	1113.1	1087.6	1101.5	1121.5	1160.1	1208.8	1267.5	1332.2	
r	Annual Percent Change	3.5	-2.3	1.1	0.1	1.5	2.6	1.8	1.3	1.8	3.4	4.2	4.6	5.1	
č	heckable Deposits	616.3	598.9	585.6	591.7	589.0	525.D 588.0	623.3	585.6	588.3	595.9	611.7	633.6	673.2 658.0	
M2		4504.8	4561.1	4615.2	4669, 1	4723.6	4778 4	4363.5	4615.2	4836.2	5088.3	5313.3	5574.4	5850.5	
МЭ	Annual Percent Change	5.8	5.1	4.8	4.8	4,8	4.8	B.5	5.8	4.8	4,8	8.4 5.00cc	4.9	5.0	
	Annual Percont Change	5.8	5.6	5.7	5.4	5.2	5.3	10.9	6.2	5.3	5.2	1328.0	7694.7 5 0	BCB5.2 5.1	
M1	Velocity (GDP/M1)	8.28	8.45	8.55	8.62	8.68	8.74	8.11	8,39	8.71	8.87	8.85	0.00	9.02	
M2	Annual Percent Change	•0.3	8.3	4.9	3.2	<b>3.3</b>	2.7	4.6	3.4	3,8	1.8	0,8	0.6	0.1	
1416	Annual Percent Change	•2.4	0.7	1.2	-1.4	2.03	0.5	-1.7	-1.0	-0.1	2.04	0.0	2.05	2.05	
Qu	tetanding Credit					••••		•••	•	•					
C B	Loans al Commercial Banks	959.0	871.3	887.7	1002.3	1014.3	1025.2	949.5	887.7	1036.9	1097.A	1160 3	1229.1	1298.2	
, ⁷	Annual Percent Change	2.4	5.2	6.9	6.1	4.0	4.4	11.8	4.0	6.0	5.0	5.7	5.9	5.6	
L'ar	nsumer Credit Quistanding	1347.8	1369.7	1384.8	1419.0	1439.7	1457.0	1274.0	1361.1	1447.2	1512.7	1567.8	1633.5	1716.5	
Mai	Norge Loans • All issuers	5883.4	6010.3	7.5 6120.6	6247.2	5.7 6363.3	4.9 6478.2	3.4 5580.2	6129.6	5.5 6581,2	7060.3	.3.4 7534.4	4.7	5.9 6418.1	
P	Annual Parcant Change	10.6	8.9	8.2	7.9	7.6	7.4	10.0	B,7	7.5	7.1	8.7	6.0	5.4	
Sic	ck Markal (NSA)	•													
SM	² Index of SOD Common Stocks	1329.8	1342.2	1315.0	1347.4	1365.5	1420.2	1084.3	1311.5	1409.9	1503.5	1617.6	1805.1	1959.2	
Divi	idend-Price Rallo - S&P 500	1.24	1.24	3.57	1.58	1.60	1.57	1.48	1.34	1.57	1.62	1.62	1.54	1 48	
Pric	rungs per Shara - S&P 500 (\$) Se-Eernings Bailo	12.59 34 ƙ	12.93 32.7	71.81	11.70 27 A	13.08	13.85 28 0	37.71 27 A	18.29	52.88 28 6	58,34 26.7	82 16	64.58 28 8	65,58 30.2	
a. C	ommilment rate is for 30-year, 80% m	ortnane loa	n		A-1.U	61:0	20.0	~	<b>1</b>		F. 1. 1	1997 a. b.	20.0		

 Demonstration and a purpose and a mongage to C. Annual numbers are journ-quaner numbers.

FPC 269

# INFLATION AND EMPLOYMENT

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TABLES Prices, Wages, and Product	, Wages, and Productivity												
	1999:2	1998:3	1999:4	2000:1	. 2000:2	2000:3		1999	2000	2001	2002		لانتشار میلاد. 2004 م
Chain-Weighted Price Indexes Percent	thénge !	SAAD)		-	••••••							~	
GDP (Implicit brice deflator)	1 A	60000	1.0								. –		-
GDP (Chain-wi. index)	1.3	1.0	1.4	1.0	1.9	1,5	12	1,4	1,4	1.5	1.7	2.0	2.1
Domestic Demand	1.9	1.6	1.6	1.0	1.3	7.2	07	1.0	1.4	1.0	1.0	2.0	2.1
Consumption	2.2	1.9	1.8	1.8	1.5	1.5	0.9	1.6	1.7	1.7	2.2	24	C.U G.A
Durables	•1.0	-2.0	-3.6	-1.7	-1.2	+1.1	-2.4	-2.7	-1.9	-0.9	-0.3	0.0	0.0
Molor Venicles and Parts	0.3	2.5	-3.6	0.4	0.4	0.0	-0.6	•0.1	-0.2	-0.1	0.4	0.9	0.8
Light Venicles	-0.2	•0.9	-0,2	0.6	0.5	0.0	-0.7	-0.3	0.0	•Q.3	0.2	0.9	0.8
LBIS Now Tracks	-1.3	-1.3	-0.5	0.3	<b>D.</b> 3	-0.1	-0.7	-0.0	-0.3	•0.4	0.0	0.5	0,6
Other	0,9	-0.6	0.1	0.8	0,8	0.1	-0.7	0.4	0.4	0.0	0.5	1.1	1.1
Furniture and Appliances	1.J	5.C	*8.5 - 6.6	0.1	0,1	0.0	-8.7	0.2	-0.4	0.1	0.5	0.7	0.8
Computers	.127	10.6	.170	-33.4	-3.0	-3.2	-70.0	•5.¥	-4.3	-2.9	-2.0	-1.8	-1.7
Olhar	-4.6	-3.6	-2.1	-63,4	-25.0	-0.8	-30.2	*23.2	.21.2	-20.5	-16.3	•14.8	14.3
Other Durables	1.2	-4.1	2.2	-0.6	0.7	0.9	-0.7	-1.7	0.7	1.3	ΨU.1 1 E	17	U.1
Nondurablas	5.1	2.9	3.0	1.8	1,1	1.0	0.1	2.3	2.1	1.7	2.5	2.5	2.6
Food and Beverages	1.2	2.1	2.3	2.5	2.3	2.1	1.7	2.1	2.2	2.3	2.6	2.7	2.6
Clothing and Shoes	3.9	-4.2	-4.4	-2.2	-0.7	0.3	-2.1	-2.2	-17	1.0	1.7	1.6	1.4
Gaspline and Oll	68.3	24.8	21.0	4.7	•6.5	•9.2	-11.5	9.1	8.0	•3.7	-0.2	0.4	0.6
	14.0	24.5	3.4	7,6	-3.8	-5.8	-9,2	-0.6	4.4	-0.8	2.5	3.1	3.2
Sadices	1,1	3.0	4.3	2.2	2.2	2.4	2.0	4.1	2.7	2.6	3.3	3.3	<b>3</b> .1
Ноцбіля	30	2.2 201	2.3	2,6	2.2	2.2	2.1	2.1	2.3	2.3	2.6	2.0	2.9
Housebold Operation	-0.0	10	2.4	∠.0 1.£	2.0	2.0	3.2	2.0	2.0	2.0	2.6	3.0	3.1
Electricity	0.6	1.1	15	26	33	27	-1.0	-0.0	21	1 3	1.3	1.7	1.6
Natural Ĝas	-1.4	18.5	21.3	8.6	-4.6	-9.0	-2.1	1.7	5.2	-3.6	20	21	1.4
Other	-1.2	•0.7	-0.3	-0,1	0.4	0.9	0.5	0.1	0.0	1.1	1.5	1.8	1 8
Transportation	2.3	0.0	1.0	1.8	1,3	2.5	1.1	1.0	1.5	2.7	2.9	3.1	9.1
Madical	1.6	2.2	2.2	2.6	2.3	2.6	2.3	2.5	2.4	2,7	3.1	5.4	3.4
Ulber Services	1.3	2.8	2.5	3.0	2.5	1.9	2.2	2.0	2.5	2,1	2.5	2.7	2.7
	-0.1	-0.5	0.4	0.3	0.2	0.0	-0,8	-0.1	0.1	-0.5	-0.3	0.0	-0.1
Fautomen	-1.4	-1.7	-0.7	-13.7	-0.5	-0.6	-1.8	•1.4	-0.8	•1.1	-1.0	-0.7	-0.4
Automobiles	-4.5	-14	-1.7	-1.0	-1.4	-2.0	P.D* 3.0	-2.0	-21	-6.2	•1.8	-1.6	-1.7
New Care	-1.2	-1.3	-0.5	0.3	0.7	-0.1	-07	-0.5	0.1	-0.0	0.2	0.6	0.5
Net Used Cars	3.4	-1.2	-1.4	-1.0	-0.4	0.2	-2.3	•1.3	-0.5	0.2	-0.2	0.4	0.0
Computing Equipment & Software	•8.1	-8.0	-7.2	-B.4	-8.8	-9.2	-12.8	-10.4	-8.3	-10.1	-10.3	-0 A	-0.5
- Other	0.0	0.0	0.5	0.8	1.0	0.9	0.0	0.6	0,6	1.0	1.6	1.6	1.4
Siruciums	2.2	2.0	2.6	3.2	3.6	4,3	3.1	2.5	3.3	2.7	5 ⁴ 1.8	2.6	2.3
Buildings and Diher	3.7	3.3	3.1	2.9	2.7	2.7	3.3	3.7	2.9	2.4	2.6	2.7	2.5
Bublic Luibus	-4,9	-0.3	•0.2	6.7	13.1	16.7	4.1	+2.5	6.5	5.5	-3,7	2.6	1.6
Bacidebuar	0.2	2,3	2.0	1.0	1.7	1.6	1.0	0.0	1.7	1.5	1,0	2.0	2.0
Equipment	.2.0	3.2	3,5	3.3	2.4	1.6	2.6	3.9	2.8	1,5	2.1	2.2	2.1
Structures	37	73	9.6	70.2	-0,4	17	-0.4 D.6	4.0	4.0	1.0	0.0	0.7	0.7
Gov'l Cons. and investment	2.9	3.0	2.2	3.3	17	17	1.5	26	2.5	21	23	2.2	2.1
Federal	0.9	1.3	1.5	5.1	1.2	1.1	1.1	2.9	2.2	2.2	2.4	2.4	2:5
1 Delense	1.0	1.3	1.3	5.0	1.1	0.8	0.8	2.6	2.1	2.0	2.2	2.3	2.3
Consumption	1.5	1.6	1.6	5.0	1.2	0.9	1.2	2.8	2.4	2.2	2.5	2.5	2.6
employee Compensation	0.5	0.2	1.4	12.2	1.4	1.5	2.4	4,3	3.8	4.1	4.0	3.0	4.0
Other	0.0	1,4	0.8	1.1	1,3	0.4	-0,9	1.4	1.0	0.8	1.0	1.3	1.3
li Dyasimani	-15	-07	-0.0	1,5	0,9	0.6	1,7	2.0	1.7	0.9	1.5	1.5	1,5
Nondelense	07	12	•0.2	5.2	1.0	u.1	-1.7	[.] A C	2.1	0,2	0.6	0.7	0.7
Consumption	1.3	1.6	2.1	67	1.3	1.5	29	4.0	31	3.1	27	2.5	2.7
Employee Compensation	1.6	2.3	2.9	11.5	3.0	3.0	3.6	6.8	4.9	5.1	51	47	3.2 A R
Cons. of Fixed Capital	-0.8	-0.4	0.7	0.8	0.4	0.6	-1.0	0.8	0.4	0.2	0.1	0.3	0.3
y. Other	1.8	2.1	1.5	1.3	0.5	0.3	1.6	2.0	1.1	0.8	E.1	1.4	1.4
investment State	•1.4	-0.6	-0.2	-0.1	-0.1	01	-1.0	1.2	-0.2	•0.3	-0.3	-0.1	-D.1
Cincal	4.0	4.0	2.7	2.4	2.0	2.0	1.8	2.5	2.6	2,1	2.2	24	2.4
Consumplian	4.2	4.5	2.9	2.7	2.2	2.2	2.0	2.7	2.9	2.4	2.C	2.7	2.8
	2.5	3.2	3.3	3.6	3.5	3.6	3.5	2.9	3.4	3.7	3.7	3.8	3.8
Other	2.0	5.1	1.2	1.0	0.9	0.8	0.3	1.3	1.1	0.5	0,3	0.6	U.6
No Parent	9.4	11.9	2.3	0.2	-2.0	-2.5	-2,9	2.0	1.8	-1.6	-0.8	0.7	-0.7
E Epuloment	-20	1.3	1.4	1.2	1.1	1.0		1.7	1.3	0.7	D.6	0.9	10
Silichiran	40	-2.J	-(.5) 74	2.1	-2.2	-2.3	-3.8 A e	•2./	-2.2	-2.4	-2.0	-1.0	-1,3
E DORA	0.7	3.0	6-D	2.4	2.3	2.2	2.0	1.J.	2.0 0.0	1.8	1.5	1,8	້-ສ ດ 1
March., excl. Bus. Machines	-0.1	1.2	1.0	U.I - 1 0.1	-0.8	1.2	· c. J	-0.23 -07	0.L	™U.® ⊿D_4	u.2	0.2	0.1
	5.2	5.9	5 N	10	-0.7	-1.2 .2 A	-2.4	0.7	1.7	-0.4 -0.9	0.1	0.1	-0.2
and the set of the set	-1.0	0.6	0.6	2.1	1.0	-0.5	-2.6	-0.4	06	0.4	1.6	1.2	0.5
And the second sec										•			

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FPC 270

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## INFLATION AND EMPLOYMENT

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Prices, Wages, and Produ	ctivity	1 (1) (1) (1) (1) (1) (1) (1) (1) (1) (1			, is a first of the				S. S				
	1999:2	1999;3	1099:4	2000:1	2000:2	2000:3	1998	1999	2000	2001	2002	2003	2004
Consumer Price Indexes (Percent change, SAAR)	· .					-							
All Urban Consumers	3.5	2.6	2.5	2.4	1.9	1.0	1.6	2.2	2.3	2.1	2.6	2.8	2.8
Food	0.9	2.1	2.5	.2.8	2.6	2.3	2.1	2,2	2.4	2.6	2.0	2.0	2.9
Energy	25.5	13.8	13.7	4.8	-2.9	-6.3	•7.9	3.8	5.2	-1.0	0.8	1.2	0,9
Commodillas	66.2	25.3	19.8	5.0	-6.2	•8.9	+1 <b>3.0</b>	8.6	7.9	-3.4	0.0	0.7	G.8
Sarvicas	0.1	4.2	7.7	4.6	0.5	•1.4	-3.2	0.0	2.9	·0.4	1.5	1.7	1.0
Excl. Food & Energy	2.4	1.7	1.7	2.1	2-1	2.5	2.3	2.0	2.1	2.4	2.7	2.0	2.9
Lommoquies	0.6	0.7	-0.5	0.4	0.8	. 1.0	0.6	0.0	0.5	1.1	1.6	1.7	1.5
Services	3.1	2.1	2.6	2.8	2.8	3.2	3.1	2.7	2.8	3.0	3.1	3.4	3.5
Urban Wage & Clerical Workers	3.3	2.9	2.8	2.4	1-8	1.8	1.3	2.2	2.4	2.1	2.6	2.8	2.8
Wages and Productivity in the Nonfarr Percent chance, SAAR)	n Bueinea:	6ector											
ECI for Compensation (a)	4.6	3.4	<b>3</b> .3	3.6	3.6	3.D	3.5	3.1	3.6	3.7	3.6	3.7	3.7
ECI for Wages & Salaries (a)	5.0	3.2	3.4	3.7.	4.1	4.2	4.0	3.4	3.8	<b>3.6</b>	3,7	3.6	3.7
ECI for Benefits (a)	3.9	3.8	3.8	3.4	2.4	3.0	2.5	2.6	3.3	3.4	3.5	3.6	3.7
Compensation per Hour (b)	5.0	4.6	3.5	3.7	3.6	4.0	4.2	4.3	3.9	3.9	3.8	3.9	3.0
Dutput per Hour	0.6	3.8	2.7	0.2	2.1	2.5	2.2	2.8	1.9	2.1	2.1	2.3	2.1
Cyclically Adjusted	2.3	3.2	2.7	3.2	2.7	2.6	2.4	3.3	2.8	2.2	2.0	2.0	2.0
Jolit Labor Costa	4.4	0.7	D.8	3.4	1.4	1.4	2.0	1,4	2.0	1.8	1.6	1,6	1.8
Cyc. Adj. Unit Labor Costs (c)	1.3	0.0	0.0	0,8	0.6	1.1	1.5	0.1	0.6	1.3	٦.6	1.6	1.7
tanulaciuring Output per Hour	4.8	5.3	5.8	1.3	3.7	4.7	4.1	5.3	3.9	4.6	4.7	4.6	4.5
fectors Affecting Inflation and Product	livity									•,			
Civilian Unemoloyment Rate (%)	43	4.2	4.1	41	4,1	4.1	4.5	4.2	4.1	41	43	44	4.5
SDP Gap (%)	-4.2	-4.6	-5.0	-4.5	-4.5	-4.5	-3.6	-4.6	4,5	-4.4	4.2	-4.3	-43
Alnimum Wage (S/hour)	5.15	5.15	5.15	5,15	5,16	5.00	5.15	5.15	5.38	5.76	5.95	6.15	6.36
J.S. Dollar, Trade-Weinhted													
Ex. Bate - DECD (1990=1.000)	1.100	1.084	1.063	1.040	1.033	1.046	1.105	1.078	1.047	1.040	1.008	0.987	0.970
							·		-				

a. Private industry, lixed weights.
b. Nonfarm business sector, weges and salaries of employees, plus employers' contributions for social insurance and private benefit plans, plus estimate of total self-employees, plus employers' contributions for social insurance and private benefit plans, plus estimate of total self-employees, plus employers' contributions for social insurance and private benefit plans, plus estimate of total self-employees, plus employers' contributions for social insurance and private benefit plans, plus estimate of total self-employees, variable weights.
c. Defined as employment cost index for compensation divided by a four-quarter moving average of cyclically adjusted output per hour.

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## INFLATION AND EMPLOYMENT

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	1096:2	1998:3	1999:4	2000:1	2000:2	2000:3	1008	1999	2000	2001	2002	2003	2004
Producer Price Indexes - Slage of Pro- (Percent change, SAAR)	ceasing)			*******			<u></u>				Manager.		
Finished Goode	2.7	3.8	4,9	2.5	Q.8	-0.1	-0.9	1.9	2.3	0.7	1.4	1.6	1.5
Excl. Food & Energy	0.2	0.6	1.8	1.4	1.4	0.0	0,0	1.6	1.2	1.2	1.5	1,6	1.7
Consumer Finished Goods	5.7	5.2	6.3	3.2	0.8	-0.2	-1.0	2.5	3.0	0.7	1.6	1.7	1.6
Food	-2.1	0.3	3.4	2.8	2.3	1.6	-0.2	0.8	2.0	1.5	1,4	1.8	1.8
Energy	27.3	27,8	22.6	-6.9	-4.0	-6.9	-8.8	5.5	8.3	-2.3	0.9	1.3	0.7
U()BI Designation Flateboot Coorte	0.3	1.5	2.7	2.0	. 1.7	1.2	1.8	2.0	1,6	1.4	1.0	1.0	2.0
Producers Finished Godde	U.1	-0.7	D.5	0.5	D.7	0.5	-0.5	0.0	. U.4	ų. <i>r</i>	1.P	1.1	1.1
Interneoiste Materiala, Supplies,			* *					0.7	26		10		
and Componenta Onde Materials for Europat	4.4	0.1	5.0	2.0	0.2	-0.5	•d. 1	U.2	2.0	0.6	1.2	1.5	1.5
	76 7	70.4	40.7			= 6	-	• 6					
мосавана	20.7	30.1	20.7	0.0	-D.3	-3.4	-13.U	1.3	1.1	•Q.0	1.5	1.0	1.2
Producer Price Indexes - Commodity ( (Percent change, SAAR)	anglange	-	•					,					
Total	5.6	. 74	5 A	25	0.0	•0.7	.2.5	1.0	2.0	0.6	14	16	15
Industrial Commodities	7.4	8.3	8.2	2.4	-0.5	-1.2	-2.3	1.5	2.9	0.4	1.4	1.6	1.5
Fuels, Related Prod., Power	50.7	40.3	29.4	6.4	-7.4	-9.9	-12.6	8.1	10.1	-3.1	1.2	1.5	0.6
Coal	1.4	-15.6	4.7	10.2	2.9	<b>9.6</b>	-2.8	-3.6	2.0	2.6	1.8	1.7	1.6
Natural Gas	188.1	132.8	48.7	.7.0	-15.2	-20.7	-19.6	15.7	15.2	-3.7	6.5	5.3	1.1
Electricity	-3.0	0.7	1.5	3.6	3.8	2.5	-1.2	-1.3	2.1	1.5	1.6	1.6	1.5
Utility Natural Gas	5.0	22.3	21.3	7.1	-5.7	-8.9	-3.4	1.6	5.5	-3.2	2.1	2.1	0,2
Demestic Crude Oli (NSA)	453.0	127.9	57.3	14.5	-22.2	-22.0	-37.8	41.4	23.1	-8.2	-2.0	-D,B	-0.B
Petroleum Products	150.8	89.9	61.7	14.6	-12.1	-17.0	-24.6	21.2	20.0	•7,7	-1.7	-0.6	-0.4
Residual Fuela	221.3	155.8	58.1	3.7	-17.9	-15.9	-26.2	18.0	21.3	-6.1	2.8	3.5	1.7
Non-Energy Ind. Commodities	1.0	2.6	2.1	1.6	1.0	0.7	-0.1	0.2	1.5	1.2	1.6	1.6	1.7
Textile Products and Apparel	-1.9	-2.2	· •1.3	-0.4	-0.3	-0.3	0.2	-1.7	-Q.B	0.2	0.8	1.0	0.9
Chemicals and Allied Products	2.2	6.1	3.0	1.6	0,4	•0.1	0.2	-0.1	2.0	1.4	2.2	2.6	2.7
Rubbar and Plastic Products	0.3	1,9	ז.3	1.7	1.3	0.5	-0.5	-0.Z	1.3	1.1	1.2	1.0	1.2
Lumber and Wood Products	5.5	11.8	7.5	2.5	1.2	1.0	-2.8	3.7	4.3	1.5	1.1	1.4	1.1
Puip, Paper, and Products	4.2	7.4	3.0	3.6	2.8	1.7	2.3	1.3	3.4	1.7	2.5	2.6	2./
Metals and Motal Products	0.0	5.3	3.1	3.3	1.2	0.8	-3.0	•2.7	2.0	2.0	1.5	1.9	2.0
wechnery and Equipment	•U.D	-0.1	-0,1	-0.2	0.2	. U.1	-10.00	-0.3	-14,1	0.3	0.0	0.0	0.0
Transportation Eduloment	0.0	-0.6	0.0	0.0 0.7	μ./ Δ α	0.4	-03	0.5	04	0.1	1.2	9.4	1.4
Presendor Care	-0.6	-1.4	-1.4	-0.7 -0.1	0.0	.10	-0.3	-17	-0 B	.0.7	.0.1	0.2	
Other Industrial Commodities	0.4	2.7	5.9	2.2	1,3	1.3	2.4	5.2	2.5	1.8	2.3	2.3	2.2
Farm Products	-3.9	0.6	6.0	4.4	5.2	3.4	-7.4	-6.3	3.6	2.3	4 1.3	1.8	1.6
Processed Foods	-4.3	2.9	3.2	2.7	2,2	1.5	-1,7	-0.1	2.0	· 1.5 ·	1.5	1.6	1.6
Factors Allacting Producer Prices													
Unii Lab. Cosis - Noniarm (% ch)	4.4	0.7	0.8	3.4	1.4	1.4	2.0	1.4	2.0	1.8	1.6	1.6	1.6
Social Insurance Contributions													
as Percent of Wages and Selaries	14.7	14.7	14.6	14.7	14.6	14.5	14.9	14.7	14.6	14.6	14.5	14.5	14.4
S. Doller Exch. Rate - OECD (a)	1.100	1.084	1.053	1.040	1.033	1.046	1.105	1.078	1.047	1.040	1.008	0.087	0.073
Annual Percent Change	9.6	-6.5	-11.1	-4.8	•2.9	5.2	5.0	-2.4	-2.9	-0.6	-3,1	-2.1	•1.4
NP1 - OECD U.S. Trad. Part. (a)	1.065	1.066	1.071	1.077	1.081	1.084	1.076	1,065	1.082	1.098	1.117	1.137	1.156
Annual Percent Change	2.2	0.2	2.1	2.0	1,5	1.3	-0.6	-0.9	1.6	1.5	1,7	1.8	1.6
Nan. Capacity Utilization (%)	78.5	79.5	79.7	78.7	78.4	78.3	80.8	79.5	78.4	78.7	78.5	79.0	78.9
	31.5	33.7	24.0	D11	50.4	40.0	Ø1. I	⊃£.¤	51 <b>0</b> .4	21.4	00.4	92.U	21.2

b. Percent of purchasing agents reporting slower deliveries.

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#### **FPC 272**

#### INFLATION AND EMPLOYMENT

TABLE 5 Energy			<b>编 標為</b>									
Al Lineard C. Bris (L. 1923) ang kamil dan yest meterikan ini ini ini in	1900:2	1989:3	1099:4	2000:1	2000:2	2000:0	1998	1999	2000 2000	2001	2002	,:
Demand for All Fuels			- <b></b>					-				•••••••
Total Energy Demand (Quad. Blu)	91.9	94.2	94.4	94.4	95.0	85.7	91.t	92.8	05.4	97,8	00.5	101.4
Annual Percent Change	5.3	10.2	0.7	-Q.1	2.7	3.0	Ω.5	1.9	2.7	2.5	1.8	1.8
Real GDP (% change)	1,9	4.8	4.8	1.7	3.4	3.6	4.3	3.8	3.4	3.5	3.0	3.2
Wgid. Ind Eng. Dam. (1996=1.0)	1.1	1.1	1.1	1.1	1.2	1.2	1,1	1.1	1.2	1.2	1.2	1.5
Electricity (Qued. Btu)	11.2	11.3	11.5	11.6	11.7	11.8	11.0	11.2	11.7	12.0	12.3	12.6
Coal (Quad. Btu)	2.0	2.0	1.9	1,9	1.9	- 1.9	2.0	1,9	1.9	1.8	1.8	1.7
Natural Gas (Quad. Blu)	17.3	18.3	18.1	18.1	18.2	18.2	17.1	17.7	18.2	18.5	18.8	19.0
Petrolaum (Quad, Btu) Energy-Use Ratios	36.3	36.4	36,4	36.4	36.7	37.1	35.9	36.4	36.9	38.0	38.6	30.2
Million Bill per Capita	337.2	344.8	344.7	343.9	345.5	347.4	338.7	340.1	346.5	352.4	365.8	359.4
Thous. Blu / Chnd. 1996 \$ GDP	10.5	10.6	10.5	10.5	10.4	10.4	10.7	10.5	10.4	10.3	10.2	10, 1
Prices (Dollars per barrel)										. •		
U.S. Balloars' Acquisition Price												
lor Crude Olt - Composite	15.88	19.62	22.64	22.90	21.50	20,16	12.58	17.25	21.03	15.03	18.48	18.31
Annual Percent Change	293.0	147.3	77.3	4.7	-22.3	-22.8	-34.2	37.2	21.9	-10.0	-2.4	-0.9
Domestic	15.08	18.75	22.97	23.59	22.04	20.84	13.19	17.53	21.57	19.38	18.92	18.74
Annual Percent Change	283.5	133.4	83.2	11.3	-23.9	•23.0	-33.0	32.9	23.1	-10.2	-2.4	-0.8
Foreign	15.44	19.51	22.38	22.44	21.14	19.85	12.14	17.06	20.67	18.63	18.19	18.02
Annual Parcent Change	304.4	154.7	73.3	0.0	-21.2	-22.3	-34.8	40.5	21.2	-9.8	-2.4	-0.9
Foreign (Chained 1996 5)	13.60	17.14	19.61	19.58	18.39	17.10	10.83	14.99	17.94	15.82	15.28	14.83
Annual Parcent Change	299.2	152.3	71,4	-0.7	-22.2	-23.5	-35.6	38.5	19.7	-11.3	-4, 1	-2.6
Pricae (Percent change)	ب											
PPI - Fuel and Power	50.7	40.3	29,4	6.4	-7.4	·9.8	-12.5	8.1	10.1	-3.1	1.2	1.5
Coal	1.4	-15.6	4.7	10.2	2.0	9,6	-2.8	-3.6	2.9	2.6	1.8	1.7
Natural Gas	168.1	132.6	49,7	•7.0	-15.2	-20.7	-19.8	15,7	15.2	-3.7	6.5	6.3
Electricity	-3.0	0.7	1.5	3.6	3.8	2.5	-1.2	-1.3	2.1	1.5	1.6	1.6
Utility Natural Gas	5.0	22.3	21.3	7.1	-5.7	-8.9	•3.4	1.8	5.6	-3.2	2.1	2.1
Domesiic Crude Oil (NSA)	453.0	127.0	57.3	14.5	-22.2	-22.0	-37.8	41,4	23.1	-8.2	-2.0	-0.6
Relined Petroleum Products	150.8	89.8	61.7	14. <b>G</b>	-12.1	-17_0	-24.8	21.2	20.9	-7,7	-1.7	-0.8
Residual Fuels	221.3	155.8	58.1	3.7	-17.9	-15.9	-26.2	18.0	21.3	-5.1	2.8	3.5
Producer Price Index - Industrial	7.4	8.3	6.2	2.4	-0.5	-1.2	-2.3	1.5	2.9	0.4	- 1,4	1.6
Pers. Cons. Chained Index - Energy	26.9	15.0	13.3	4.6	-2.9	-5.1	-6.3	3.4	5.3	-1.8	Q.7	1.1
Ganoline	68.3	24.8	21.9	4.7	-6.5	-9.2	-11.5	9.1	8,0	-3.7	-0.2	Q.4
Fuel Oli and Coal	. 14.0	24.6	3.4	7.0	-3.8	-5.8	-9,2	-0.8	4.4	-0.8	2.6	3.1
Electricity	0.6	1.1	1.6	2.8	3.3	2.7	-3.8	-0.5	2.1	1.3	1.3	1.5
Natural Gas	-1.4	18.5	21.3	8.6	-4.6	-9.0	-2.1	1.7	5.2	-3.6	2.0	2.1
Pera, Cons. Chain Type Index	2.2	1.9	1.8	1.8	1.5	1.5	0.0	1.6	1.7	1.7	2.2	2.4

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**Real Personal Consumption (Percent change)** 2.5 Total Consumption 5.1 4.3 5.1 7.1 -1.2 Q. 1 Gasoline 1.3 Fuel OII and Coal 16.1 +11.0 1.0 1.0 Electricity -3.9 11.5 -10.2 Natural Gas 28.8 2.3 0.8 Energy Share of Consumption (%) 4.9 4.0 4.8 **4.**B Chained 1996 Dollars 4.5 4.3 Current Dollars 4.4 Average Miles per Gallon 19.1 19.1 19.1 19.D Imports of Petroleum and Producte Million Barrele per Day 13.2 12.8 12.1 11.0 Billions of Chained 1996 Dollars 82.6 77.7 76.7 85.1 Billions of Current Dollars A7.8

Fadaral

State and Local

Pers. Cons. Chain Type Index

Gasoline Tax (Cents per gallon)

Dom. Energy Supply (Quad. Blu)

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4,4 4.3 4.4 19.1 10.1 19.0 12.8 13.6 12.6 62.7 87.5 81.2 90.3 60.0 63.7 77.7 86.7 89.8 0.94 0.58 Import Bill as Percent of GNP 0.70 0.84 0.92 0.83 0.92 Industrial Production 0.9 Coal Mining (% change) -1.0 13.5 9.1 3.2 -0.2 1.7 9.3 -3.3 Oil and Gas Extraction (% change) 0.8 10.3 7.8 12.8 -1.4 Q.8 1.8 Pipad Gas and Elac. Util. (%ch) 7,0 5.3 6.2 -1.5 2.5

Oil and Natural Gat 34.3 34.7 Nuclear, Hydro and Other 33.Z 34.4 Energy Imports (Quad. Btu) 27.0 28.6 Net Exp. & Inv. Ch. (Quad. Blu) 2.6 1.5 ent ent. 2003

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#### Wieland, Karl H. /goc, openmail

From: Sent: Subject: Lynch, Edward V. /goc,openmail Thursday, March 09, 2000 2:55 PM Wieland, Karl H. /goc,openmail Data Request

Kari,

This is from DRI's The <u>U.S. Economy 25-Year Focus - Winter '99</u> (TREND25YR0299) Ther was no Utility AA Bond series so I'm giving you the 30YR T-Bond and the 30YR Mortgage rate.

Summary of Long Term Projections:

Trend 2.5%	<u>CPI</u> Optimistic 1.7%	Pessimistic 3.5%		
Trend 5.56%	30 YR Treas Optimistic 5.39%	s Bond Pessimistic 6.07% よ.び	•	
Trend 6.91%	30 YR Morte Optimistic 6.55%	gage Rate Pessimistic 7.42%		
$\lambda$				

OV +1% - 0.8 rost of Capital 0 P -0.3 +0.5

Inflation.

wred 3% for CPI 10 in 2.5% for Conchuction

Y

Utilities Rating

Service

Global

# Utility Credit Report

FLORIDA POWER CORP. Analyst: John W. Whitlock, New York (1) 212-438-7678

# Corporate Credit Rating

# Business Profile

strong

Outstanding Rating(s)

Florida Power Corp.	
Sr unsecd debt	
Local currency	A+/Watch Neg
Sr secd debt	
Local currency	AA-/Watch Neg
CP	
Local currency	Watch Neg/A-1+
Pfd stk	
Local currency	A/Watch Neg
Florida Progress Co	rp.
Corp credit rating	A/Watch Neg/A-1
Sr unsecd debt	
Local currency	A/Watch Neg
CP	
Local currency	Watch Neg/A-1
Pfd stk	
Local currency	B88+/Watch Neg

**Corporate Credit Rating History** 

Oct. 23, 1986 A+/A-1+ June 26, 1990 AA-/A-1+

#### **Company Contact**

Pam Saari (1) 727-820-5871



#### RATIONALE

The ratings of Florida Power Corp. and affiliates are on CreditWatch with negative implications, reflecting Carolina Power & Light Co.'s (CP&L) offer to acquire parent Florida Progress Corp. for \$5.3 billion plus the assumption of \$42.7 billion in debt. Florida Progress' credit quality is supported by solid cash flow from its utility subsidiary, Florida Power, partly offset by a weaker financial profile for its nonregulated subsidiary, Electric Fuels Corp.

Florida Power's ratings reflect an above average business position buoyed by demand growth, which is spurred by Florida's vibrant economy, growing population, and diversified fuel mix. These positive credit factors are slightly offset by less supportive regulation and the growing threat of widespread competition in the state. Also, the uncharacteristically high amount of debt used to finance nonregulated activities adversely affects the consolidated entity's financial profile.

The utility's financials have rebounded to previous levels after being held back during the outage at the Crystal River Unit 3 nuclear plant, which returned to service in early 1998. Debt leverage is temporarily higher than normal because of the buyout of the Tiger Bay purchased-power contract and the related 220MW facility. However, the lower capacity charges resulting from the buyout are a long-term credit positive.

Electric Fuels' primary holdings are in the nonregulated rail services, inland marine, and energy and related services units, which are vertically integrated and contribute to Florida Progress' profit picture. Still, the risk profile of these units is greater than the traditional regulated utility business, requiring greater cash flows commensurate with the higher risk.

The cash flow generated from nonregulated investments may allow the parent to reduce the financial leverage and improve the consolidated financial profile. A return to 1997 levels of adjusted funds flow to total debt of more than 25% and adjusted funds flow interest coverage of 4.5 times (x) is possible during the forecast period. However, the consolidated enterprise's credit quality may be affected by Electric Fuels' expansion plans, which will require even greater improvement in credit protection measures.

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		Financial Summary	
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	1998	1997	1996	1995	1994
Gross revenues	2,648.2	2,448.4	2,393.6	2,271.7	2,080.5
Net income from continuing operations	250.1	135.9	238.4	227.0	200.8
Funds from operations (FFO)	659.6	459.5	529.8	524.3	502.0
Net cash flow	503.2	265.6	352.7	333.9	316.2
Capital expenditures	310.2	387.2	217.3	283.4	319.5
Total capital	3,547.6	3,727.7	3,180.8	3,202.2	3,265.4
Adjusted ratios					
Pretax interest coverage (x)	2.79	2.93	3.56	3.33	3.02
Total debt/total capital (%)	56.9	59.7	48.8	48.2	50.9
FFO interest coverage (x)	4.01	3.30	4.64	4.47	4,28
FFO/avg. total debt (%)	25.8	20.7	30.0	28.8	30.1

#### Global Utilities Rating Service

#### Florida Power Corp.

#### Rating Methodology

Florida Power's corporate credit rating is based on the financial and business risk profile analysis of the consolidated enterprise. Florida Power's first mortgage bonds are rated the same as the firm's corporate credit rating. While these bonds are collateralized by utility property, Standard & Poor's ultimate recovery analysis does not project the value of such collateral to exceed substantially the maximum amount of first mortgage bonds that could be outstanding under the terms of the indenture. Therefore, Standard & Poor's does not have the necessary confidence that first mortgage bondholders would receive their principal in a bankruptcy scenario to consider higher secured ratings. Stress cases consider varying percentages of book value for the different utility asset classes based on the quality of each asset class. Nuclear assets are presumed to have no collateral value.

The utility's senior unsecured debt is rated one notch lower than the corporate credit rating because unsecured bondholders are disadvantaged by the presence of first mortgage bonds currently outstanding. In Florida Power's case, less than 35% of total debt outstanding is secured and assets are considered encumbered only up to the amount needed to satisfy the corresponding secured debt actually outstanding.

#### **Business Description**

Florida Power, the regulated subsidiary of Florida Progress (see

November 1999 Utility Credit Report, provides electric service to 1.3 million customers in central and northern Florida. The utility accounted for 80% of assets, 88% of earnings, and 73% of revenues for Florida Progress in 1998. Financing of the nonutility businesses is done at Progress Capital Holdings, which was formed to consolidate Florida Progress' diversified operations into one entity. The principal nonregulated operating subsidiary is Electric Fuels, which engages in coal mining, procurement and transportation, rail car services, and bulk commodities transportation. Progress Capital Holdings' ratings reflect a guarantee by parent Florida Progress.

#### FLORIDA POWER CORP.



#### **Business Profile**

Regulation. Florida Power's retail rates are regulated by the Florida Public Service Commission (PSC), which allows recovery of fuel-adjustment and purchased-power capacity costs, ratemaking incentives for operational efficiency, and accelerated cost recovery. The PSC has been generally supportive of Florida Power, as evidenced by the substantial recovery allowed for the buyout of the Tiger Bay purchased-power contract and acquisition of the facility. Still, the 1999 ruling allowing Duke Energy Corp. to build a merchant power plant serving the town of New Smyrna Beach (pending appeal and Florida Power Plant Siting Board approval) is a credit concern.

Previously, Florida's peninsular geography and transmission constraints helped to isolate the

Standard & Poor's

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#### Florida Power Corp. Global Utilities Rating Service

legulatory agency	Florida Public Service Commission	
itate		
ase period	Eignt months.	
iterim procedures	Selectively.	
uthorized returns (past 12 to 18 mon	[ns]	
Heturn on equity (efectric)	13./5%	· · · · · · · · · · · · · · · · · · ·
Return on equity (gas)	11.3%	
Return on equity (telephone)	132%	
ate base	Average original cost.	
est period	Forecast.	
WIP	Some CWIP included in rate base I	for a partial cash return.
djustment mechanisms	Fuel and purchased-power adjustin of purchased power are reflected t expenses can be recovered withou accelerated recovery of investmen	rent clauses (semiautomatic), both the capacity and energy components hrough the fuel ajustment clause; demand-side management related t filing a base rate case; an oil backout cost adjustment allows ts in projects designed to displace oil-generated capacity.
icentive ratemaking	Demand-side management; plant p recovery factor rule.	performance; rate of return and price cap/index; oil backout cost
ammissioners	Party	Tem
ulia Johnson, Chair	Dernocrat	January 2001
usan F. Clark	Democrat	January 2003
Leon Jacobs, Jr.	Democrat	January 2002
on Garria	Independent	January 2002
Ve Galcia		

Industry Retail Sales (MWh) 1997



Source: Edison Electric Institute

Source: Regulatory Research Associates Inc.

state's investor-owned utilities from competition. However, several other companies are seeking to build plants similar to the Duke/New Smyrna project, which could be the impetus for widespread competition throughout Florida. Still, there has been no grassroots support for electric restructuring legislation in past legislative sessions, given the small industrial base and temperate residential and commercial rates in the state. However, in Standard & Poor's view, additional merchant plant approvals, as well as new proposals, may be a catalyst for comprehensive legislation in Florida during 2000 to 2001.

Florida Power, which does not plan to seek base rate relief for the foreseeable future, is currently authorized a regulatory return on equity (ROE) of 12%, with an allowed range between 11% and 13%. However, the allowed rate of returns for the Florida investor-owned utilities have been under greater PSC scrutiny recently, which could affect the utility in the future. Still, Florida Power is protected by a rate stipulation that does not expire until 2001.

Markets. Florida Power serves about half of Florida's 67 counties, with a population of almost 5 million residing in the service territory. Service is provided in portions of central and north-central Florida and along the west coast of the state, including St. Petersburg and Clearwater, as well as the areas surrounding Walt Disney World, Orlando, Ocala, and Tallahassee. Some of the municipalities in the franchise area have exerted some pressure on the company when negotiating franchise renewal agreements by threatening to exit the system and team up with an independent power producer (IPP). Yet, the company is protected to some degree by the high cost of the distribution plant that would have to be purchased from Florida Power before a municipality could leave.

Florida Power's industrial customers accounted for about 9% of retail electric revenues and 13% of retail kWh sales, lessening its future exposure to potential electric restructuring in Florida. The company's heavy reliance on residential customers (60% of retail electric revenues and 50% of retail kWh sales) helps to quard against fluctuations in economic activity among the diverse customer base. Continued economic growth will likely fuel customer growth of 2% per year and retail kWh sales increases of 3% per year for 2000 and 2001.

Environmental concerns in Florida have limited Florida Power's transmission network, and no new high-voltage lines are likely in the foreseeable future. Combined with capacity constraints at the transmission interface with Georgia Power Co. outside of Florida, the utility has little transmission flexibility. Standard & Poor's is concerned that the lack of transmission could cause

## Global Utilities 3

Rating

Service

bottlenecks during high demand periods, which could lead to price spikes.

**Operations.** To meet its future firm load projected demand, Florida

Power could build an additional 1,000MW of gas-fired, combined-cycle generation at its Hines facility (a 500MW unit went into service in 1998). The ability to

build and place in service gas-fired, combined-cycle plants in a short time gives the company increased flexibility in planning its long-range capacity needs.

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****	1996	1997	1998	1999-2001*	1999-2009*
Population					
Florida	1.7	1.6	1.5	1.5	1.5
Southeast region	1.3	1.2	1.1	1.0	0.9
National	0.9	0.9	0.9	0.8	0.8
Real per capita income (1992 \$)					
Florida	21,894	22,484	23,139	23,526	24,891
Southeast region	19,319	19,848	20,401	20,765	22,008
National	22,183	.22.872	23,477	23,791	25,013
Total employment					·
Florida	3.2	4.2	3.3	1.7	1.9
Southeast region	2.2	2.7	2.4	1.0	1.2
National	2.2	2.6	2.3	1.0	1.1
Unemployment rate					
Florida	5.0	4.7	4.7	5.4	5.4
Southeast region	5.1	4.6	4.4	5.5	5.6
National	5.3	4.8	4.7	5.4	5.4

*Population and total employment estimates represent average annual growth rates for the period. Real per capita income and unemployment rate estimates represent forecasts for the last year in the period. Source: DRI/McGraw-Hill.

	Markı	et Segments	1997 - 1998 - 1998 - 1998 - 1998 - 1998 - 1998 - 1998 - 1998 - 1998 - 1998 - 1998 - 1998 - 1998 - 1998 - 1998 -		
	1998	1997	1996	1995 •	1994
Salar					
Total retail (GWh)	33 387	30.850	30,785	4 29,499	27.675
Residential (%)	49.5	48.9	50.3	50.6	50.1
Commercial (%)	30.0	30.0	28.7	29.2	29.8
Industrial (%)	13.1	13.6	13.7	13.1	12.9
Other (%)	7.4	7.5	7.2	7.1	7.2
Wholesale (GWh)	3,864	2,440	2,708	2,903	2,339
Total sales (GWh)	37,251	33,290	33,493	32,403	30,015
Revenue					
Total retail {mil. \$}	2,390	2,203	2,169	2,074	1,908
Residential (%)	59.6	58.7	59.9	60.4	59.9
Commercial (%)	25.5	25.8	24.8	24.8	25.4
Industrial (%)	9.0	9.4	9.5	9.1	9.1
Other {%}	6.0	6.1	5.8	5.6	5.7
Wholesale (mil. \$)	206	151	159	153	125
Total revenue (mil. \$)	2,596	2,358	2,328	2,227	2,033
Annual sales growth (%)					
Residential	9.6	(2.6)	3.6	7.B	3.7
Commercial	8.0	4.6	2.7	4.4	4.7
Industrial	4.5	(0.9)	9.3	8.0	5.9
Total retail	8.2	0.2	4.4	6.6	4.3
Standard & Poor's retail avg,	2.0	0.6	3.0	3.1	2.6
Wholesale	58.4	(9.9)	(6.7)	24.1	10.4
Total sales growth	11.9	(0.6)	3.4	8.0	4.8
Retail customer growth	2.0	1.7	1.6	2.2	2.4

Source: Navigant Consulting Inc.

🖌 🛛 Florida Power Com.

1997

Global Utilities Rating Service

Florida Power's construction needs for 2000 and 2001 will be about \$550 million, with the majority of the expense targeted for transmission and distribution activity. Free cash flow is expected to cover amply this level of expenditure.

Florida Power's fuel mix is coal 38%, nuclear 15%, gas 7%, oil 20%, and purchased power 20%. The company's coal-fired plants mainly use Appalachian coal delivered by rail and barge and supplied by Florida Progress' subsidiary, Electric Fuels, pursuant to long-term contracts between Florida Power and Electric Fuels. The company's oil needs and gas supply are purchased under contracts and in the spot market from several suppliers with existing contracts sufficient to cover requirements.

A sizable portion of Florida Power's energy needs are provided

by purchased-power contracts with other utilities and qualifying facilities (QF), including a large contract with Southern Co. and several QFs totaling 946MW of capacity, 831MW of which is currently available. The PSC allows recovery of QF contract costs in rates, but the company has attempted to buy out several QF contracts to minimize future capacity payments. The elimination of these uneconomical contracts helps to reduce Florida Power's potential exposure to stranded investment.

For credit protection measures, Standard & Poor's adjusts the debt component of utilities with purchased-power contracts to fully realize the financial impact. The net present value of future annual capacity payments for each contract is discounted by 10% (the estimated cost of capital) to identify the potential debt equivalent that a utility incurs when it enters into a long-term purchased-power contract. A risk factor for each contract is then determined on the basis of a qualitative analysis of the contract's terms and conditions, the ability to recover costs through regulatory means, and operating risks. The potential debt equivalent is multiplied by the risk factor to determine the amount of off-balance-sheet obligations added, which was \$350 million for Florida Power in 1999.

Florida Power meets environmental standards by burning low-sulfur coal and installing low-nitrogen burners at Crystal River Units 1, 2, 4, and 5. Standard & Poor's believes that more stringent guidelines for nitrogen oxide and mercury emissions are likely to be implemented, which could adversely affect coal-burning



Industry Fuel Mix



Source: Edison Electric Institute.

•	1008	1007	1000	1000	
			1330	1,223	1004
Generating capacity					
Owned (MW)	7,727	6,755	7,347	6,526	7,207
Firm purchased (MW)	1,286	1,523	1,495	457	250
Peak demand (MW-summer)	7,444	8,066	8,807	7,128	6,955
Reserve margin (%)	21.1	2.6	0.4	(2.0)	7.2
Peak growth (%)	(7.7)	(8.4)	23.6	2.5	3.4
Arinual load factor (%)	N.A.	N.A.	N.A.	49.8	51.2
FRCC regional reserve margin (%-summer)	7.7	N.A.	N.A.	N.A.	N.A.
Generation by fuel source (%)					
Coal -	37.9	45.3	60.1	39.2	44.0
Dil	19.6	17.8	22.5	12.2	16.1
Gas	6.5	6.5	4.2	3.9	0.0
Nuclear	14,9	0.0	8.6	18.8	18.0
Purchased	21.0	30.5	4.7	26.0	21.9

FRCC---Florida Reliability Coordinating Council. N.A.---Not available.

	Efficience Operating Efficie	y Statistics nev (electric-ret	ail)		
	4.7 F 79 2009 79 1998 1996	1997	1996	1995	19 <b>54</b>
Total customers/employee	283	239	279	241	225
Industry avg.	259	247	233	215	204
Total MWh/total employee	7,044	5,601	6,650	5,600	5,005
Industry avg.	6,781	6,364	6,061	5,558	5,148
Total revenue/total kWh (cents)	7.16	7.14	7.05	7.03	6.89
Industry avg.	7.00	7.14	7,13	7.16	7,19

Source: Navigant Consulting Inc.

## Industry Efficiency Measures



**FPC 279** 

Florida Power Corp.

Global Utilities Rating

Service

Industry Rates (cents/kWh)

Residential

Commercial

Industrial

1993 1994 1995 1996 1997

			, Nucleal oper (1	atting Statistics 998)			
Unit	% owned	Lifetime forced outage rate (%)		2			
Crystal River 3	90.4	21.3					
Unit	Book value (mil. S)	Decomm. basis	Est. decomm. cest (mil. S)	Date of estimate	Total ant. funded (mil. \$)	Annual armt. funded (mil. S)	suffic
Counted Bines 3	996 5	Ernonfield	120 2	19/00	275 2		********

environmental costs to ratepayers in a regulated energy market and its use of natural gas at new plant sites help to mitigate this potential risk. The Crystal River Unit 3 nuclear

electric utilities. However, Florida

Power's ability to pass along

plant has performed well since its return to service in early 1998. The plant ran at 100% capacity for 20 consecutive months before beginning a 45-day scheduled refueling outage at the end of September 1999. The turnaround is largely attributable to the new management team that has been running the facility since 1997.

Florida Power's 90,4% share of Crystal River Unit 3 had a net book value of \$384 million at year-end 1998. Florida Power is licensed to operate the nuclear plant through December 2016 when decommissioning would likely begin. The PSC has determined future decommissioning costs for Crystal River Unit 3 to be about \$2 billion, which is equivalent to \$465 million in 1998 dollars. As of June 1999, Florida Power funded about \$354 million of its estimated decommissioning expense. Florida Power and Dynegy Inc.

have a power marketing alliance

assets and minimizes its risk exposure through Dynegy's expertise in energy marketing. power trading, and risk management. Florida Power's excess physical capacity is sold on a short-term forward (less than three months) basis and spot basis after its native load requirements are met, and the utility has the right to veto any transaction. Any increase in margins resulting from on-system energy trading is credited back to the utility's ratepayers under the fuel-adjustment clause, which reduces the overall energy costs for its customers. Standard & Poor's views Florida Power's decision to use a successful power marketer (Dynegy) and use only excess capacity backed by physical assets to be a sensible lower-risk strategy, which is favorable to credit quality.

that leverages the utility's physical

**Competitive position.** Florida Power's competitive position is enhanced by the small size of its industrial customer class. The primary groups are the phosphate and citrus industries, which reduce the threat of relocation and political opposition. Also, the industrial customers benefit from the current interruptible rate of 4 cents per MWh, which creates a disincentive to seek open competition. Still, the looming presence of planned IPPs could affect the utility's position.

One area that the company has focused on is improving overall system reliability. Residential and commercial customers throughout Florida demand that the service outages be limited in frequency and duration. The company has beefed up its resources dedicated to improving its distribution system, which will position the company favorably when the market transitions from regulation to competition.

Florida Power's biggest investment is the Crystal River Unit 3 nuclear station, with a book value of about \$384 million (excluding nuclear fuel). It represents about 20% of common equity and 10% of net electric plant in service and total capitalization. Crystal River Unit 3 is Florida Power's single largest base load facility, and it represented 8% of 1998's total winter capacity (including purchased power).

		E	nergy Costs (cei	and Rate: nts/kWh)	s (1998)				
Utility	Fuel	Totel variable production	Tatel fixed production	Purchased power	Production end purchased power	Total anergy cost	Residential state	Commercial rute	industrial rate
Florida Power Corp.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	8.62	6.09	4.90
Florida Power & Light Co.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	7.87	6.47	4.99
Gulf Power Co.	1.74	2.33	0.37	3.75	2.80	4.01	6.22	5.17	3.81
Tampa Electric Co.	2.23	2.88	1.42	4.10	4.27	5.52	7.99	6.48	4.48
FRCC region average	1.99	2,60	0.90	3.93	3.54	4.76	7.58	6.05	4.54
Standard & Poor's average	1.50	2.39	1.79	3.95	3.96	5.57	8.67	7.35	5.10

FRCC--Florida Reliability Coordinating Council. N.A.---Not available.





Source: American Gas Association.

🖬 🛛 Florida Power Corp.

#### **Financial Profile**

#### Financial policy: Average

Florida Power's debt leverage is high, but the company continues to make strides to reduce debt to 45% of capitalization. The roll off in 2000 of a portion of the debt associated with the buyout of the Tiger Bay contract and sufficient internal funding for planned capital expenditures provide a platform for the company to achieve its goal. Florida Progress' dividend payout for 1999 is expected to be about 70% of earnings.

**Profitability.** Through the first three quarters of 1999, retail sales were up slightly from the same period in 1998. Solid customer growth was offset by bad weather in 1999, compared with 1998; a heat wave prevailed in Florida during most of June 1999. Full-year earnings will probably be slightly more than in 1998. Still, the utility's ROE is expected to be about 13% for 1999.

Adjusted pretax interest coverage is expected to be about 4.5x. Robust cash flow, cost-containment initiatives, and strong customer sales growth are the expected catalysts.

**Cash flow protection.** The utility's modest capital budget of about \$300 million per year should be ably funded from internal cash generation. Capital spending will be concentrated in large part on transmission and distribution projects.

Cash flow protection measures are expected to remain healthy during the 2000-2001 period. Standard & Poor's expects a retum to prior levels, with funds from operations (adjusted for off-balance-sheet purchased-power obligations) interest coverage of 4.5x and adjusted funds from operations to total average debt of 25% possible.

**Capital structure.** Debt leverage for the utility is high, but the company is committed to improving this measure. The roll off in 2000 of a portion of the debt associated with the buyout of the Tiger Bay contract will help Florida Power meet its goal as will robust regulated cash flow.

The average remaining life of Florida Power's long-term debt is 12.9 years, with an embedded cost of 6.8%. The PSC's approval of accelerated depreciation has reduced the amount of regulatory assets that could have been stranded in a deregulated energy market.

Financial flexibility. Florida Progress' stock is trading at 230% of its book value, in reaction to CP&L's offer to purchase the company. Florida Power has a \$200 million 364-day and a \$200 million five-year revolving credit facility, which are used to back up its \$400 million commercial paper program.

Florida Power has \$585 million in first mortgage bonds outstanding, with maturities through 2023. The utility has registered \$370 million in additional first mortgage bonds but has no plans to issue new first mortgage bonds at this time. The company also has a remaining shelf filing of \$250 million in medium-term notes.

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Global Utilities Rating

Service

Common equity characteristics	as of June 30, 1999
Ticker symbol	FPC
Stock price (S)	41.3125
PE ratio (x)	13.7
Dividend yield (%)	5.3
Market to book (%)	209.7
Dividend to book (%)	11.0
Debt characteristics at fiscal ye	ar ended 1998
Secured debt (%)	35
Unsecured debt (%)	65

Subordinated debt (%)	
Fixed-rate debt (%)	100
Variable-rate debt (%)	
Avg. life of long-term debt (years)	14
Embedded cost of long-term debt (%)	6.6
Debt maturing in five years (mil. \$)	1,284.1

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Arranged	Outstanding	Expiration date	Same-day availability	MAC
400.0	0.0			· · · · · · · · · · · · · · · · · · ·
400.0	0.0	11/99	N.A.	N.A
N.A.				
	Arranged 400.0 400.0 N.A.	Arranged Outstanding 400.0 0.0 400.0 0.0 N.A	Arranged Outstanding data 400.0 0.0 11/99 400.0 0.0 11/99 N.A	Arranged Outstanding date availability 400.0 0.0 400.0 0.0 11/99 N.A. N.A.

MAC-Material adverse change. N.A.-Not available.

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Florida Power Corp.

			Year ended Dec. 3		
	1998	1997	1996	1995	199
Incases statement (mil \$1					
Grace revonue	7 649 2	2 448 4	2 797 6	2 271 7	2 080
Onerting avegages (eval. DDRA)	1 784 2	1 631 6	1 600 9	1 573 4	1 300
Depending expenses (excl. DDoA)	1,704.3	225.0	324.2	1,323,4	761
Depreciation and amontization	347.1	323.5	J24.2	23./	4101.
r retax operating income	518.6	430.9	408.5	434,0	419.
Grass interest expense	136.5	117.3	98.4	104.5	108.4
Pretax income	390.4	205.8	374.2	356.5	315.
AFUDC and deferrals	16.9	9.7	7.5	9.0	10.9
Income taxes	140.3	69.9	135.8	129.5	114.3
Net income from continuing operations	250.1	135.9	238.4	227.0	200.8
Earnings protection			•		
Pretax interest coverage (x)	3.77	4.15	4.73	4.33	3.81
Adjusted pretax interest coverage (x)	2,79	293	3.56	3.33	3.02
Preferred dividend coverane (x)	3 71	4.07	4 34	3 80	3.34
FRITTA interest coverage (v)	6 37	693	8.07	7 14	6 22
	6.9	71	31	40	5/
Al CDC and deterred alcune/earlings ( //)	12.0 -	ćo	J.I	177	10.0
netum on common equity (nominal) (79)	14.5	142.2	12.0	12.2	
Common dividend payout (%)	02.3	143.Z	/3.0	17.00	32.1 Al A
Annual U&M growth (%)	12.7	2.8	0./	(7.0)	N.A
Annual expense growth (excl. DD&A) (%)	9.4	1.9	5.1	8.9	N,A
0&M/revenues (%)	20.8	20.0	19.9	20.8	24.8
Total operating expenses (excl. DD&A)/revenues (%)	67.4	66.6	66.9	67.1	67.3
Balance sheet (mil. S)					
Cash and equivalents	0.0	0.0	0.0	0.8	0.0
Gross plant	6,732.0	6.869.4	6.522.5	6,403,1	6,201.2
Net plant	3.630.5	3.649.5	3.517.1	3,605.1	3,669.2
Total assets	4 928 1	4 900 8	4 264 0	4 284.9	4,284.9
Short-term debr	138.9	181 7	25.4	30.6	90.7
Inna-tarm dabe	1 555 1	1 745 4	1 295 4	1 279 1	1 363 5
Proferred stack	73 5	335	33 6	1785	143 5
	1 820 1	1 767 5	1 825 5	1 754 0	1 667 4
Connuct equity	7 647 8	1,707.3 7777 c	7 190 0	3 707 7	3 765 /
Total capitalization	3,347.0	3,121.1	450.6	3,202.2 AA9.7	A76 (
i oral on-palance-sheet opligations	/40.0		430.0		420.2
Balance sheet ratios (%)					
Short-term debt/total capital	3.9	4.9	0.8 4	1.0	2.8
Long-term debt/total capital	43.8	46.8	40.8 4	39.9	41.8
Preferred stock/total capital	0.9	0.9	1.1	4.3	4.4
Common equity/total capital	51.3	47.4	57.4	54.8	51.1
Adjusted total debt/total capital	56.9	59.7	48.8	48.2	50.9
Debt/EBITDA (x)	2.0	2.4	1.7	1.8	2.2
Cash flow Imit &					
Natincomo	750 1	125.0	238.4	227 1	200.8
	250.1	705.7	2130	227.0	287 0
Depreciation Deformed towns and ITO	301.0	115 71	(22.0)	120 21	
AFUDC and did will	30.3	(13.2)	(32.0)	(23.3)	
Arouc and deterrais	(10.9)	(3.7)	رد. <i>۲</i> ۲	12)	0.0
Uther funds from operations (FFU) adjustments	28.9	42.8	10.7	24./	507/
FFU	659.6	459.5	529.8	324.3	102.0
Preferred dividends	(1.5)	(1.5)	(5.8)	(9.7)	110.1
Common dividends	(154.9)	(192.4)	(171.3)	(180.7)	11/5./
Net cash flow (NCF)	503.2	265.6	352,7	333.9	310.
Working capital changes	89.8	(57.6)	(57.3)	32.8	
Capital expenditures (capex)	(310.2)	(387.2)	(217.3)	(283.4)	(319.5
Discretionary cash flow	282.8	(179.2)	78.1	83.3	[13.6
Cash flow adequacy					
Canex/ave total capital (%)		112	68	8.8	9.
NCF/raney (%)	162 7	69 S	167 3	117.4	99.
FED/aur tatal date /9/ )	26 4	00.0 ר פר	AU 3	37 9	34
Advand CCO (see April 1 to 1971)	30.4	40.J	90.0	72 0	30
Aujusted FrUjavg. total debt (%)	25.8	20.7	30.0	20.0	56
HU interest coverage (x)	5.66	4.76	6.31	3.33	
Definition of the light second s	4.71	חביבי	a 6a	a a 1	-1.2

depletion, and amortization. EBITDA—Earnings EKS™ software by Navigant Consulting Inc. Į.

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Standard & Poor's Global Sector Review • DECEMBER 1999

## Florida Power Corp.

Florida Power Corp. Corporate Credit Rating AA-/Watch Neg/A-1+ **RATIONALE** The ratings of Florida Power Corp. are on CreditWatch with negative implications, reflecting Carolina Power & Light Co.'s offer to acquire parent Florida Progress Corp. for \$5.3 billion plus the assumption of \$42.7 billion in debt. Florida Progress' credit quality is supported by solid cash flow from its utility subsidiary, Florida Power, partly offset by a weaker financial profile for its nonregulated subsidiary, Electric Fuels Corp.

Florida Power's ratings reflect an above-average business position buoyed by demand growth, which is spurred by Florida's vibrant economy, growing population, and diversified fuel mix. These positive credit factors are slightly offset by less supportive regulation and the growing threat of widespread competition in the state. Also, the high amount of debt used to finance nonregulated activities adversely affects the consolidated entity's financial profile.

The utility's financials have rebounded to previous levels after being held back during the outage at the Crystal River Unit 3 nuclear plant, which

#### John W. Whitlock, New York (1) 212-438-7678

returned to service in early 1998. Debt leverage is temporarily higher than normal because of the buyout of the Tiger Bay purchased-power contract and the related 220 megawatts facility. However, the lower capacity charges resulting from the buyout are a long-term credit positive.

Electric Fuels' primary holdings are in the nonregulated rail services, inland marine, and energy and related services units, which are vertically integrated and contribute to Florida Progress' profit picture. Still, these units are riskier than the traditional regulated utility business, requiring greater cash flows commensurate with the higher risk.

The cash flow generated from nonregulated investments may allow the parent to reduce the financial leverage. A return to 1997 levels of adjusted funds flow to total debt of more than 25% and adjusted funds flow interest coverage of 4.5 times (x) is possible during the forecast period. However, the consolidated enterprise's credit quality may be affected by Electric Fuels' expansion plans, which will require even greater improvement in credit protection measures.

#### Florida Power Corp. Financial Statistics

			-Year ended Dec. 3	1	
(Mil. S)	1998	1997	1996	1995	1994
Gross revenues	2,648.2	2,448.4	2,393.6	2,271.7	2,080.5
Net income from cont. operations	250.1	135.9	238.4	227.0	200.8
Funds from operations (FFO)	659.6	459.5	529.8	524.3	502.0
Net cash flow (NCF)	503.2	265.6	352.7	333.9	316.2
Capital expenditures	310.2	387.2	217.3	283.4	319.5
EBIT interest coverage (x)	3.77	4.15	4.73	4.33	3.81
Preferred dividend coverage (x)	3.71	4.07	4.34	3.80	3.34
FFO interest coverage (x)	5.66	4.76	6.31	5.95	5.57
Capital expend./avg. total capital (%)	8.5	11.2	6.8	8.8	9.8
NCF/capital expenditures (%)	162.2	68.6	162.3	117.8	99.0
FFO/avg. total debt (%)	36.4	28.3	40.3	37.9	34.5
Return on common equity (nominal) (%)	13.9	7.5	13.0	12.7	11.4
Total capitalization	3,547.6	3,727.7	3,180.8	3,202.2	3,265.4
Short-term debt (%)	3.9	4.9	0.8	1.0	2.8
Long-term debt (%)	43.8	46.8	40.8	39.9	41.8
Preferred stock (%)	0.9	0.9	1.1	4.3	4.4
Common equity (%)	51.3	47.4	57.4	54.8	51.1

#### Florida Power Corp. Operating Statistics

			—Year ended Dec. 3	1	
	1998	1997	1996	1995	1994
Total sales (GWh)	37,251	33,290	33,493	32,403	30,015
Residential (%)	44.4	45.3	46.2	46.1 -	46.2
Commercial (%)	26.8	27.8	26.4	26.6	27.5
Industrial (%)	11.7	12.6	12.6	11.9	11.9
Wholesale (%)	10.4	7.3	8.1	9.0	7.8
Other (%)	6.7	7.0	6.7	6.4	6.6
Avg. retail revenue (cents/kWh)	0.07	0.07	0.07	0.07	0,07
Retail sales growth (%)	8.27	0.21	4.36	6.59	4.32
Capacity at time of neak (MW)	9.013	8.278	8.842	6,983	7,457
Reserve margin (%)	21.1	2.6	0.4	1.4	9.1

GWh-Gigawatt hours, kWh--Kilowatt hours, MW--Megawatts.



## **BALANCE SHEET STATISTICS FOR ELECTRIC UTILITIES**

For 12 months ended Dec. 31, 1999 (Mil. \$)

Company Name	Gross plant	Net plant	Current assets	Total assets	Short-term • *debt	Long-term debt	OBS debt	Pref. stock	Comm. stock	Total cap.
Wisconsin Public Service Corp.	2,053.6	850.8	186.4	1,409.9	50.4	373.1	0.0	51.2	525.1	999.9
Average AA+	2,053.6	850.8	186.4	1,409.9	50.4	373.1	0.0	51.2	525.1	999.9
Madison Gas & Electric Co.	782.2	297.8	71.1	495.5	27.0	148.6	5.7	0.0	185.7	361.2
Northern States Power Wisconsin	1,240.3	752.8	86.7	907.1	80.8	232.0	0.0	0.0	357.0	669.8
Southern Indiana Gas & Electric Co.	1,362.5	738.9	104.0	894.8	76.6	238.3	0.0	19.3	334.6	668.7
Tampa Electric Co.	4,563.7	2,745.0	306.3	3,322.5	356.0	690.3	32.6	0.0	1,043.1	2,089.4
Average AA	1,987.2	1,133.6	142.0	1,405.0	135.1	327.3	9.6	4.8	480.1	947.3
Central Illinois Public Service Co.	2,733.3	1.472.8	249.6	1,781.8	167.9	493.6	0.0	80.0	534.4	1.275.9
Florida Power & Light Co.	18,005.0	7,821.0	893.0	10,608.0	219.0	2,079.0	1,236.6	226.0	4,793.0	7,317.0
Florida Power Corp.	- 6,993.2	3,651.9	520.7	5,002.5	229.9	1,478.8	781.2	33.5	1,885.0	3,627.2
Indianapolis Power & Light Co.	3,049.5	1,750.4	176.6	2,048.8	49.0	628.0	50.0	59.1	780.5	1,516.6
Northern States Power Co.	9,783.9	4,451.5	1,033.8	9,767.7	1,094.0	3,453.4	198.2	305.3	2,557.5	7,410.2
Otter Tail Power Co.	889.6	503.0	119.9	680.8	5.9	176.4	32.9	33.5	245.7	461.6
San Diego Gas & Electric Co.	4,483.0	2,157.0	843.0	4,366.0	66.0	892.0	260.1	104.0	1,314.0	2,375.0
TECO Energy Inc.	6,064.4	3,627.8	531.8	4,690.1	969.5	1,207.8	32.6	0.0	1,472.5	3,649.8
Union Electric Co.	9,652.7	5,331.8	707.8	7,043.6	11.4	1,816.6	42.7	221.2	2,433.7	4,482.9
Wisconsin Electric Power Co.	6,395.2	3,205.3	645.9	5,052.6	295.5	1,677.6	0.0	30.5	1,880.9	3,884.4
Wisconsin Power & Light Co.	2,508.0	1,241.6	121.5	1,766.1	182.7	414.7	36.5	60.0	599.1	1,256.5
Average AA-	6,414.4	3,201.3	531.3	4,800.7	299.2	1,301.5	242.8	104.8	1,681.5	3,387.1
Alabama Power Co.	12,605,2	7 703.8	848.3	9 6 4 8 7	197.8	3 190.4	101.5	664.5	2,988,9	7.041.5
Allegheny Energy Inc.	8.839.7	5,207,2	709.3	6.852.4	830.8	1,499.0	75.8	229.5	1,695,3	4,254.6
Allegheny Generating Co.	828.9	601.7	7.3	620.9	52.5	148.9	0.0	0.0	154.5	355.9
Alliant Energy Corp.	6,205.7	3.128.3	486.0	6.075.7	492.8	1,512.8	211.9	113.6	2,155.6	4,274.8
Ameren Corp.	13,056.5	7.165.2	879.0	9,177.6	209.0	2,382.9	52.5	300.7	3,089.7	5,982.4
Baltimore Gas & Electric Co.	8,976.2	5.510.1	655.0	7,272.6	652.9	1,956.0	248.5	440.0	2,355.4	5,404.3
Consolidated Edison Co. of New York Inc.	14,991.7	10,606.9	1,378.1	13,682.2	770.4	4,243.1	698.5	249.6	4,393.8	9,656.8
Duke Energy Corp.	30,436.0	20,995.0	6,717.0	33,409.0	782.0	8,683.0	233.7	1,450.0	10,198.0	21,113.0
FPL Group Inc.	19,397.0	9,107.0	1,373.0	13,441.0	464.0	3,478.0	1,236.6	226.0	5,370.0	9,538.0
Georgia Power Co.	16,343.3	9,804.7	1,028.6	12,276.9	792.0	2,688.4	473.3	804.2	3,938.2	8,222.8
Gulf Power Co.	1,887.8	1,065.9	158.2	1,308.5	55.0	367.4	12.8	89.2	422.3	934.0

Source: Financial data from EKS™ software by Navigant Consulting Inc.

43



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## Standard & Poor's RatingsDirect

Analysis

Publication Date: 26-Apr-2000

## Summary: Florida Power Corp.

Contents Rationale

Analyst: John W Whitlock, New York (1) 212-438-7678



#### **Credit Rating:**

AA-/Watch Neg/A-1+

## Rationale 🎰

The ratings on Florida Power Corp. are on CreditWatch with negative implications, reflecting Carolina Power & Light Co.'s offer to acquire parent Florida Progress Corp. for \$5.3 billion plus the assumption of \$4.7 billion in debt. Florida Progress' credit quality is supported by solid cash flow from its utility subsidiary, Florida Power, partly offset by a weaker financial profile for its nonregulated subsidiary, Electric Fuels Corp.

The ratings on Florida Power reflect an above average business position buoyed by demand growth, which is spurred by Florida's vibrant economy, growing population, and diversified fuel mix. These positive credit factors are slightly offset by the changing regulatory and political environment in Florida, which may adversely impact the consolidated business profile of the utility. Also, the uncharacteristically high amount of debt used to finance nonregulated activities adversely affects the consolidated entity's financial profile.

Debt leverage for Florida Power is temporarily higher than normal because of the buyout of the Tiger Bay purchased-power contract and the related 220MW facility. However, the lower capacity charges resulting from the buyout are a long-term credit positive. Still, the high amount of debt leverage pressures consolidated credit protection measures.

Electric Fuels' primary holdings are in the nonregulated rail services, inland marine, and energy and related services units, which are vertically integrated and contribute to Florida Progress' profit picture. Still, the risk profile of these units is greater than the traditional regulated utility business, requiring greater cash flows commensurate with the higher risk.

The cash flow generated from nonregulated investments may allow the parent to reduce the financial leverage and improve the consolidated financial profile. A return to 1997 levels of adjusted funds flow to total debt of more than 25% and adjusted funds flow interest coverage of 4.5 times is possible during the forecast period. However, the consolidated enterprise's credit quality may be affected by Electric Fuels' expansion plans, which will require even greater improvement in credit protection measures.

## Moody's Investors Service

Global Credit Research

## Florida Power Corporation

September 1999

<u>Category</u>	Moody's Rating	First Mortgage Bonds	Δ2
Issuer Rating	A1*	Senior Unsecured Shelf	(P)A3
First Mortgage Bonds	Aa3*	Subordinate	Raal
Senior Unsecured	A1*	Analyst	Phone
Preferred Stock	"a1"*	A. Tucker Hackett/New York	1 212 553 1653
Commercial Paper	P-1*	Scott Solomon/New York	1.2 (2.333.1033
Ult Parent: Carolina Power & Light Compa	INV	Susan D. Abbott/Now York	
Issuer Rating	A3	Jusan D. ADDOLUNEW TOTK	
<ul> <li>Placed under review for possible downgrade on Au-</li> </ul>	zust 23, 1999		

Rating History



#### Operating Statistics

Florida Power Corporation (Statistics in bold type)

Peer Group Median (Statistics in light type)

-	[2]1999		998	19	97	1	996		1995	[3]5-	-Yr.Avg
Revenue (US\$ bil.)	2.7	1.2	2.6	1.1	2.4	1.1	2.4	1.0	2.3	1414.5	[4]6.2
Assets (US\$ bil.)	5.0	2.9	4.9	2.8	4.9	2.7	4.3	2.8	4.3	[4]2.5	[4]3.0
Com. Equity (US\$ bil.)	1.8	0.9	1.8	0.9	1.8	0.9	1.8	0.9	1.8	[4]2.2	(413.6
Op. Margin (%)	14.2	14.8	14.0	15.5	10.1	16.4	13.9	16.1	14.4	15.7	13.4
ROA(%)	5.3	3.7	5.0	3.6	2.7	3.7	5.5	3.8	5.1	3.7	4.6
ROE(%)	14.2	12.2	13.7	11.8	7.6	12.0	12.7	12.5	12.4	12.0	11.6
Div. Payout (%)	133.6	82.8	61.7	85.2	142.0	81.9	71.2	79.0	83.2	82.3	90.0
Pretax Int. Cov. (X)	4.1	3.5	3.7	3.4	2.7	3.5	4.7	3.4	4.3	3.4	3.9
Fxd. Chg. Cov. (X)	4.0	3.0	3.7	2.9	2.6	2.9	4.3	2.9	3.8	2.9	3.6
FFO Int. Cov. (X)	6.5	4.5	6.0	4.5	5.2	4.6	6.6	4.4	6.1	4.4	5.9
FFO % Total Debt	41.6	25.7	40.7	26.2	25.5	26.4	42.0	25.3	40.9	25.3	36.9
RCF % Gross CAPEX	97.3	114.0	172.2	124.6	77.0	128.8	176.6	113.5	121.6	113.8	129.7
Total Cap. (US\$ bil.)	3.6	2.0	3.5	2.0	3.7	2.0	3.2	1.9	3.2	[4]1.7	[4]1.8
TD % Cap.	47.4	49.2	47.8	49.5	51.7	48.8	41.6	49.5	40.9	49.4	45.3
Pfd. Stk. % Cap.	0.9	5.8	0.9	6.0	0.9	5.8	1.1	4.6	0.8	5.4	0.9
Common % Cap.	51.7	44.9	51.3	44.9	47.4	45.4	57.4	45.1	54.8	44.9	52.4
<b>Electric Utility Operating Statistics</b>											
Customer Segmentation			R	esidential	Com	nercial	Indus	trial	Wholesal	e	Total
Revenue (US\$ mil.)		· · · · · · · · · · · · · · · · · · ·		1,424.6	••	608.9	2	14.4	207.	9	2.648.2
Kwh(mil.)				16526		9999	. 4	375	386	4	37251
¢/Kwh				8.6		6.1	-	4.9	5.4	4	7.1
Regional Average				7.9		6.5		4.7	4.1	3	7.6
Competitive Position				Fuol	Ne	n Fuol	Invocto		Total Cas	• Doniou	-1 Cast

 \$ per Mwhr.
 22.03
 3.29
 9.15
 34.47
 34.76

 [1] Competivic Position reflects 1997 figures. [2] For the 12 months ended June 30; Balance sheet items are as of June 30. [3] Five year average 1998-1994. [4] Five year compound annual growth rate.
 Source of the second second

**Opinion** 

#### **Rating Rationale**

Florida Power Corporation (FPC) has retained a Aa3 senior secured rating for a number of years by virtue of its capable management, cost-cutting initiatives, supportive regulation, competitive rates, the state's vibrant economy, and limited instate competition. However, the utility is exposed to nuclear risk through its 90% ownership of the Crystal River nuclear plant and to potential stranded costs from expensive powerpurchase contracts and regulatory assets. In addition, ratings pressure originates in acquisition leverage issued by a new holding company created to purchase FPC.

#### Recent Events

Management announced in August the company will be sold to Carolina Power & Light Company (CP&L, rated A2 sr. sec.) to create the nation's 9th largest utility in terms of generating capacity. The new super regional utility will be headquartered in North Carolina.

New management expects merger-related synergies, driven by cost savings, to exceed \$100 million per annum. Savings will result primarily from elimination of duplicate corporate and administrative programs and operating efficiencies. A substantial portion of these savings will be extracted from FPC.

In addition, revenue enhancements are likely from generation expansion and wholesale marketing opportunities. CP&L intends to use the FPC platform to build gas-fired generating plants in Florida.

#### Rating Outlook

Concern that financial pressure will result from the obligation to service up to \$3.5 billion of acquisition leverage to be issued by a new holding company led Moody's to place the securities on review for potential downgrade. FPC 286

upon .	Type of Debt	Maturity	Moody's Rating		
orida Po	wer Corporation			=	
	Issuer Rating		A1	-	
	4% Cum. Pfd. Stk.		"a1"		
	4.60% Cum. Pfd. Stk. 4.40% Cum. Pfd. Stk.		"a1" "a1"		1
	4.58% Cum. Pfd. Stk.		"a1"	•	1
	7.76% Cum. Pfd. Stk.	• • • • • • • • • • • • • • • • • • •	"a1"	•	
	\$7.08 Cum. Pfd. Stk. 4.75% Pfd. Stk.		"a1" "a1"		:
20%	First Mortgage Bonds	2023	Ăa3		1
25%	First Mortgage Bonds	2022	Aa3 Aa3		
/5% )0%	First Mortgage Bonds First Mortgage Bonds	2008	Aa3		
25%	First Mortgage Bonds	2003	Âa3		
75%	First Mortgage Bonds	2002	Aa3 Aa3		
00% 50%	First Mortgage Bonds Medium Term Notes	1999 2028	Aa3		€ }
10%	Medium Term Notes	2007	Â		
20%	Medium Term Notes	2006	A1 A1		
90% 20%	Medium Term Notes Medium Term Notes	2004	A1		- - -
10%	Medium Term Notes	2002	Âİ		
80%	Medium Term Notes	2001	A1 A1		ļ
					1
tina His	415 Shelf Registration		P-1 (P)Aa3		
Aa2 Aa3 A1 A2	415 Shelf Registration		P-1 (P)Aa3		
Aa2 Aa3 A1 A2 A3 A3 Baa1 9/92	A15 Shelf Registration	nior Secured	P-1 (P)Aa3		
Aa2 Aa3 A1 A2 A3 A3 Baa1 9/92	415 Shelf Registration  tory Peer 9/93 9/94 9/95 Florida Pow er Corporation		P-1 (P)Aa3		
Aa2 Aa3 A1 A2 A3 A3 Baa1 9/92	415 Shelf Registration  tory Peer 9/93 9/94 9/95 Florida Pow er Corporation	nior Secured 9/96 9/97 9/98 Peer Group Average	P-1 (P)Aa3		
Aa2 Aa3 A1 A2 A3 A3 Baa1 9/92	A15 Shelf Registration  tory Peer 9/93 9/94 9/95 Florida Pow er Corporation Editor	nior Secured 9/96 9/97 9/98 Peer Group Average Production Associa	P-1 (P)Aa3		
Aa2 Aa3 A1 A2 A3 3aa1 9/92	A15 Shelf Registration  tory Peer 9/93 9/94 9/95 Florida Pow er Corporation Editor David Veasey	nior Secured 9/96 9/97 9/98 Peer Group Average <u>Production Association Association Secured</u>	P-1 (P)Aa3		
Aa2 Aa3 A1 A2 A3 Baa1 9/92	A15 Shelf Registration  tory Peer 9/93 9/94 9/95 Florida Pow er Corporation Editor David Veasey	nior Secured 9/96 9/97 9/98 Peer Group Average <u>Production Associa</u> John Tzanos	P-1 (P)Aa3		

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## Risks/Weaknesses

- Financial pressure from acquisition debt issued to finance its acquisition by Carolina Power and Light (CPL).
- Exposure to nuclear risk through Crystal River and CPL's nuclear units.
- Above-market purchased-power contracts constrain the company's ability to reduce production costs.
- Merchant plant sponsors continue attempts at inroads in FPC's service territory.
- Potential stranded costs are high for the rating category, but average for investor owned utilities in Florida.
- Significant risks inherent in expanding unregulated activities of parent.
- Parent guarantee of non-regulated subsidiary debt issued by Progress Capital Holdings, a downstream holding company that finances the parent's non-regulated businesses.

## Opportunities/Strengths

- Acquisition by CPL creates critical mass and cost savings opportunities.
- An economically vibrant service territory.
- The lack of political or regulatory support for deregulation in Florida.
- A growing residential customer base drives steady revenue growth.
- Competitive rates within Florida.

#### Company Fundamentals

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On August 23, 1999, Carolina Power & Light Company announced plans to acquire the parent company of Florida Power Corporation (FPC), Florida Progress, in a cash and stock transaction valued at \$8 billion, including the assumption of \$2.7 billion in FPC debt and preferred stock. Under terms of the agreement, Florida Progress shareholders will receive \$54 per share in a combination of cash and a new CPL holding company's common stock (See Management Strategy and Competitive Position for details). Acquisition debt of \$3.5 billion will be issued by a new holding company to finance the acquisition.

Florida Power Corporation is the principal operating subsidiary of Florida Progress Corporation, a diversified energy-related holding company based in St. Petersburg, Florida. As the state's second largest investor-owned utility, FPC provides electric service to more than 1.3 million customers in a 20,000 square-mile service territory encompassing substantial portions of west central and northern Florida, including the fast growing region around Orlando. Electric Fuels Corporation, an energy and transportation company is Florida Progress' other major subsidiary. Progress Capital Holdings, Inc. (PCH), a downstream holding company finances the parent's non-utility businesses. In 1997, the company wrote off its investment in Mid-Continent Life Insurance Company without impacting ratings.

At year-end 1998, FPC comprised approximately 80% of Florida Progress' assets, 73% of its consolidated revenue, and 89% of its net income. Residential and commercial customers contributed 54% and 23% to total electric revenues, respectively, while industrial and wholesale customers each supplied 8%. As demonstrated in the pie chart below, the predominantly residential base of FPC will make a strong complement to CPL's higher mix of commercial and industrial customers. This strategic fit will enhance CPL's plans to expand its electric generation capacity and build a powerful presence in the Southeastern electric and natural gas markets.



Centered on its growing trade and services industries, while further influenced by tourism and agriculture, Florida's economy continues to be among the fastest growing in the nation. During the 1990s, the state's population has grown by nearly 20% and continues to outperform the region and the nation in employment and income growth. As a result, this vibrant service territory appeals to outside utilities, who are interested in constructing merchant plants to serve it.

To date, neither the legislature nor the Florida Public Service Commission (FPSC) has been a forceful advocate for deregulation of electricity markets. Despite political disinterest, FPC's management has taken certain steps in anticipation of eventual electric deregulation and created a national retail energy strategy to position itself for a more competitive marketplace. When competition finally arrives, FPC will be relatively well positioned due to its strong customer base and transmission bottlenecks limiting other utilities access to the state. In addition, CPL will construct new plants in the area to serve load growth.

In an attempt to capitalize on increased wholesale demand, several companies, including Duke Energy Power Services (a subsidiary of Duke Energy), are planning to build cogeneration merchant plants to service wholesale customers within Florida, primarily municipalities. However, the plans of these companies have met significant opposition from the three investor-owned utilities in Florida, who have argued that merchant plants are illegal under the state's complex laws governing power projects, specifically the Florida Power Plant Siting (PPSA) Act.

The PPSA governs the building of new generation involving steam capacity of 75 megawatts or more. Other companies, such as Constellation Power (a subsidiary of Baltimore Gas & Electric), have circumvented the PPSA by proposing to build a combustion turbine plant rather than a combined cycle facility.

On March 5, 1999, the Florida Public Service Commission (FPSC) voted 4 to 1 in favor of allowing Duke Energy Power Services to build a 514 megawatt combined cycle merchant plant in New Smyrna Beach, Florida, thereby setting an important precedent for the development of merchant plants, and indirectly increasing the IOU's competition within Florida. Given the decision by the FPSC to allow Duke Energy Power Services to build a merchant plant in New Smyrna Beach, Moody's anticipates other merchant plants will be built, therefore, further increasing in-state competition for wholesale customers. However, Moody's believes the anticipated increase in wholesale competition is partially mitigated by the growth in demand for wholesale energy. All three Florida utilities have appealed the FPSC's decision to the Florida Supreme Court.

At year-end 1998, FPC's resources for serving load consisted of 9,013 mw of electric power, with 7,727 mw generated by owned facilities and 1,286 mw obtained through purchased power contracts. The pie chart below highlights the combined company's post-merger generation mix, which is more balanced, but retains a higher exposure to nuclear assets.



Power purchased under contract from other utilities and non-utility generators comprise a significant portion of total energy sold by the company. These long-term contracts are above market and constrain the company's ability to reduce production costs and become more competitive. FPC is obligated to purchase approximately 871 mw of power (831 mw is currently available) from qualifying facilities with expiration dates ranging from 2002 to 2025. From other utilities, FPC purchases 455 mw of power, primarily from Southern Company with whom it has a contract to purchase approximately 400 mw through 2010. Ox July 1' cycle : Energ power Energ by the As

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Prior oppor how r Over the past few years, management has made progress in renegotiating these contracts, notably the July 1997 buyout of the 220 mw Tiger Bay cogeneration facility, which is now run as a gas-fired combined cycle generating plant. The FPSC recently approved an amended contract between FPC and El Paso Energy to allow two units to operate at times as merchant plants. The utility will retain first call on the power produced by Mulberry and Orange facilities, which will lose their qualifying facility status. El Paso Energy agreed to reduced capacity payments for the facilities in exchange for the ability to operate them by their power marketing subsidiary.

As the majority owner and operator of the Crystal River Nuclear Plant, FPC continues to retain a significant exposure to nuclear assets. Subsequent to restarting in early February 1998, after an extended outage, Crystal River achieved a capacity factor of 90% vs. an industry average of 76.7%. Because the Nuclear Regulatory Commission is currently designing a new system for evaluating safety of nuclear plants, recent scores for Crystal River are not available.

#### Management Strategy and Competitive Position

#### Acquisition by Carolina Power & Light

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Because size will be important to achieve economies of scale and expand the customer base in a deregulating market, FPC agreed to be acquired by CPL to create the nation's ninth largest electric utility based on generating capacity. The super regional utility will serve nearly 2.7 million customers in a 50,000 squaremile service territory across three states and will have generating capacity of approximately 18,520 megawatts. Combined assets will total \$15.2 billion, while total revenue reaches \$6.7 billion. For a discussion of CPL, please refer to the Global Credit Report published in February 1999.

The new company will be operated out of Raleigh, NC, the headquarters of CP&L. A local office will likely remain open in St. Petersburg, Florida. Richard Korpan will retire as chairman, president, and chief executive officer of Florida Progress and will join CP&L's board of directors. The board will consist of 14 members, 10 from CP&L and 4 from FPC.

According to the pie chart below, new management expects merger-related synergies to range from \$100 to \$175 million on an annual basis, driven primarily by cost savings instead of revenue enhancements. These synergies result primarily from the elimination of duplicate corporate and administrative programs, and from operating efficiencies, including integration of the Crystal River nuclear site with CP&L's three existing nuclear sites. Revenue enhancements are also possible from generation expansion and wholesale marketing opportunities.

\$100 - \$175 Million of Annual Synergies

44%

After the integration is completed, it is anticipated the company will have a combined workforce of approximately 16,000 employees, reflecting a reduction of about seven percent. The company will use a combination of attrition and moderation in hiring to reduce the need for employee separations. At this early stage in the merger process many of these synergies have not been definitively identified; however, a significant portion of these savings will likely be extracted from FPC.

#### Strategy Prior to Acquisition May Change

Prior to the acquisition, FPC's strategy was to capitalize on strengths in its core business, pursue growth opportunities through Electric Fuels, and develop a national retail energy business. It remains to be seen how new management will alter FPC's stated strategy.

14%

20%

**FPC 290** 

**Shared Services** 

Energy Supply

**Energy Delivery** 

Retail

200

**Revenue Synergies** 

As part of a national retail strategy, FPC planned to offer commodity-related products and services, as well as their transportation to the retail customer. Through its marketing and service joint venture with Cinergy and New Century Energies, management targets large national companies in diverse locations and offers energy management services. In addition, its power marketing alliance with Houston-based Dynegy, Inc. (formerly NGC Corporation) enables the company to better market its power supply to utilities and large energy users in Florida and other regions. Dynegy's energy marketing, trading, and risk management skills also help FPC optimize the value of its generation portfolio, while reducing energy costs.

Management's focus on cost controls allows FPC to maintain competitive retail prices by limiting O&M increases to less than inflation, and reducing costs associated with expensive purchased-power contracts. In particular, the Tiger Bay buy-out reduced purchased power commitments by 220 mw or 20%, while saving customers approximately \$2 billion during the period 2008 through 2025. The Pasco Cogen buy-out is expected to save customers \$183 million beginning in 2002. Additional savings come from formation of strategic business units in 1996, and a corporate-wide work process-reengineering program instituted in 1997.

Management continues to grow its non-regulated businesses at Electric Fuels through acquisitions and business expansion. At year-end 1998, Electric Fuels represented approximately 11% of Florida Progress' equity investment and 27% of consolidated revenue. Its business units are energy- related services, inland marine transportation, and rail services. Medium term notes issued by PCH fund business unit operations. Non-regulated businesses include:

- Energy and Related Services This business unit supplies coal to FPC and other utilities and industrial customers through its network of operations. Abnormal weather in 1998 increased the volume of coal transported to FPC and resulted in higher earnings. Continued growth will be driven largely from the expansion of its river terminal operations and related activities.
- Inland Marine Transportation This business unit transports coal, agricultural, and other dry bulk
  commodities through the Ohio and Mississippi rivers. Weak export shipments caused by a strong U.S.
  dollar and warmer winter weather have negatively impacted 1998 earnings. Growth is expected to be
  driven by barge fleet expansion.
- Rail Services This business unit serves the country's major railroads by providing various services. In 1998, the company spent approximately \$200 million for acquisitions and will continue to expand its operations into new markets serving other Class 1 and shortline railroads, as well as private fleet owners.

#### Year 2000—Company Expects to be Ready

Since mid-1997, FPC has been actively preparing for Year 2000 (Y2K) through the replacement and upgrade of computer systems and technologies. Total costs for this program have been estimated between \$15 and \$20 million, \$9.5 million has been incurred and expensed to date. Management plans to complete its Y2K program by the third quarter of 1999 for FPC, and by the fourth quarter of 1999 for Electric Fuels.

## Regulation, Rates, and Restructuring

New management will obtain regulatory approvals for the acquisition in two steps. In early 2000, management expects to receive approval for formation of the new holding company from the SEC, FERC, NRC, NCUC, and SCPSC. By next summer, management expects merger approval from CPL and FPC shareholders, the SEC, FERC, the NRC, and the Department of Justice. Approvals from the FPSC and state commissions in North Carolina and South Carolina are not required, but discussions will be held with these state regulators. CPL will register as a holding company under the Public Utilities Holding Company Act of 1935.

Neither legislators nor regulators are moving quickly to implement retail competition in Florida due to the state's competitive electric rates, small number of industrial customers, and relative physical isolation. The 1999 legislative session in Florida adjourned in April without considering restructuring legislation. The Florida legislature has been monitoring restructuring activities in other states via a working group established in 1997. A comprehensive restructuring bill was introduced in the 1998 session, but was not passed. Di replac service millio base r: has no an allo

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During 1997, the FPSC approved a settlement agreement allowing FPC to recover a portion of replacement fuel costs incurred during Crystal River's extended outage. While Crystal River was out of service, the company spent \$100 million in additional nuclear O&M expenses and approximately \$173 million in fuel replacement costs. Under the settlement agreement, FPC agreed not to seek a change in base rates or the authorized range of its equity return for a four year period ending in 2001. The company has not filed for rate relief since 1992 when the FPSC approved a 12% regulatory return on equity with an allowed ranged between 11% and 13%.

#### Financial Analysis

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The acquisition will be treated as a purchase for accounting purposes. This creates goodwill of \$3.3 billion to be housed at the new holding company. Despite goodwill amortization of \$83 million per year, management expects earnings per share growth of 7-8%. The new entity will continue CPL's dividend policy. The remainder of this report discusses FPC's financial performance and goals as disclosed before the merger.

For the six-month period ended June 30, 1999, Florida Progress' net income increased approximately 12% over the same period in 1998, driven by improved earnings at the utility. FPC earnings increased due to lower amortization of regulatory assets and lower interest expenses for debt refinancings in late 1998. At Electric Fuels, earnings increased due to sales of a coal-based synthetic fuel by the Energy and Related Services group. In addition, the Rail Services and Inland Marine Transportation business units experienced improved operating results during the second quarter of 1999.

Florida Progress' net income increased to \$282 million in 1998, up from \$54 million in 1997, as the company recovered from the extended outage at Crystal River and rebounded from the \$87 million writeoff of Mid-Continent. In addition, strong customer growth at the utility and enhanced earnings from diversified operations bolstered results. At the utility, however, accelerated amortization of regulatory assets, expenditures to increase reliability, and a lump-sum pay increase offset increased revenues attributed to hotter-than-normal weather. These accelerations increased utility operation and maintenance expenses beyond the increases already anticipated because of costs related to operating Tiger Bay. Despite higher operating expenses, pre-tax interest coverage strengthened to 3.7 times from 2.6 times. It had been depressed in 1997 due to expenses related to the Crystal River outage.

Funds from operations interest coverage increased from 5.2 times to 0.20 times as income rebounded from depressed levels in 1997, and accelerated amortization increased in amounts sufficient to offset higher interest expense.

On December 31, 1998, FPC's capital structure improved to approximately 48% debt, 1% preferred stock, and 51% common equity, from 52% debt, 1% preferred, and 47% equity at year-end 1997 as debt declined by \$233 million. However, these figures do not reflect off-balance sheet obligations from above market power- purchase contracts. Prior to the acquisition by CPL, management intended to repay debt in order to achieve its capital structure target of 55% equity. Whether this goal remains is uncertain. At June 30th, the capital structure remained essentially unchanged.

Construction expenditures (excluding the allowance for funds used during construction) totaled approximately \$315 million in 1998, compared to \$387 million in 1997. These expenditures covered distribution lines and the construction of the Hines Energy Complex, a 500 mw gas-fired power plant that began operations in April, 1999. Going forward, the company estimates construction expenditures to total approximately \$885 million from 1999 to 2001, over half of which relate to transmission and distribution expenditures. Production expenditures total \$254 million, including three 100 mw Intercession City peakers scheduled for completion in December 2000. Internally generated funds will finance the capital expenditure program.

## Florida Power Corporation

· · · · · · · · · · · · · · · · · · ·	1998	1997	1996	1995	1994			14.4 × 14.794
INCOME STATEMENT (\$ millions)	·		, ,	,		•		CASH F
Revenue Operating Expense Earnings Before Interest, Taxes, Depr. & Amort.	2,648 2,136 859	2,448 2,131 644	2,394 1,925 793	2,272 1,815 750	2,080 1,661 681	•	•	Funds Fi Preferre Commo
Depreciation and Amortization Earnings Before Interest & Taxes	347 512	326 318	324 468	294 456	262 420	1		Gross C
Other Income Gross Interest Expense Pretax Income	6 136 250	1 117 136	1 98 238	1 104 227	-0 108 201		•	Issuance Refirema
Income Taxes Preferred Dividends Net Income Available for Common Stock	140 2 249	70 2 134	136 6 233	130 10 217	115 10 191			Retirem Net C
Coverage Analysis								Change
EBITDA Interest Coverage EBIT Interest Coverage Pretax Interest Coverage FFO Interest Coverage (FFO-Gross Capital Excenditures) Interest	6.3 3.7 3.7 6.0	5.5 2.7 2.7 5.2	8.1 4.8 4.7 6.6	7.2 4.4 4.3 6.1	6.3 3.9 3.8 5.7			Cash F FFO % FFO % Total [
Coverage Fixed Charge Coverage	2.8 3.7	0.9 2.6	3.4 4.3	2.4 3.8	1.8 3.3	•		Total [
Earnings Analysis								RCF % RCF %
Operating Margin Return on Equity Return on Asset Return on Capital AFLIDC % Net Income	14.0 13.7 5.0 10.6 6.8	10.1 7.6 2.7 6.6 7.2	13.9 12.7 5.5 10.3 3.2	14.4 12.4 5.1 9.9	14.7 11.4 4.5 9.0 5.7		a.	Constru Gross CWIP
BALANCE SHEET (\$ millions)	0.0	7.2	5.2	0.4	0.7			OPERA
Cash and Equivalents Net Plant and Equipment Total Assets	0 3,630 4,928	0 3,650 4,901	0 3,517 4,264	1 3,609 4,285	0 3,669 4,284	•	•	Electri Reside
Current Portion of LT Debt, Leases & Pref. Short-Term Debt Long-Term Debt Total Debt	92 47 1,555 1,694	2 180 1,745 1,927	21 4 1,296 1,322	31 0 1,279 1,310	35 55 1,364 1,454			Comn Indust Whole
Preferred Equity Common Equity Total Capitalization Tangible Capitalization (net worth)	34 1,820 3,548 3,548	34 1,768 3,728 3,728	34 1,826 3,181 3,181	138 1,754 3,202 3,202	144 1,667 3,265 3,265			Comn Indust Whole Particle
Capital Structure								Comm
Retained Earnings Total Debt - Cash and Equivalents Deferred Charges % Common Equity	816 1,694 45.2	763 1,927 42.6	821 1,322 16.0	761 1,309 6.4	724 1,454 6.0	•		Whole Tota
STD + Curr. Portion of LTD, Leases & Pref. % Capitalization Total Debt % Capitalization	3.9 47.8	<b>4.9</b> 51.7	0.8 41.6	1.0 40.9	2.8 44.5			Fuel Po Non-F Investr
Asset Composition								Totc
Net Plant and Equipment % Total Assets Investments % Total Assets Current Assets % Total Assets Deferred Charges % Total Assets	73.7 0.2 9.4 16.7	74.5 0.7 9.5 15.4	82.5 0.3 10.4 6.8	84.2 4.3 8.9 2.6	85.6 3.4 8.6 2.4	•		

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## Florida Power Corporation

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	1998	1997	1996	1995	1994
CASH FLOW STATEMENT (\$ millions)	,		· · ·		
Funds From Operations Preferred Dividends Common Dividends Retained Cash Flow	689 2 153 534	490 2 191 298	555 6 166 384	535 10 181 345	514 10 176 328
Gross Capital Expenditures Free Cash Flow	310 224	387 -89	217 166	283 61	324 4
Issuance of Long-Term Debt Retirement of Long-Term Debt Net Change in Long-Term Debt	144 -259 -115	448 -21 426	0 -47 -47	0 0 0	0 0 0
Retirement of Preferred Equity Net Change in Preferred Equity	. O O	0	-106 -106	0 0	0
Change in Working Capital	-73	67	64	-34	17
Cash Flow Analysis					
FFO % Gross Capital Expenditures FFO % Total Debt Total Debt / FFO Total Debt / (FFO - Gross Capital Expenditures)	172.2 40.7 245.8 447.0	77.0 25.5 392.9 1,867.0	176.6 42.0 238.2 391.4	121.6 40.9 244.8 520.5	101.3 35.3 282.9 765.9
RCF % Gross Capital Expenditures RCF % Total Debt	172.2 31.5	77.0 15.5	176.6 29.0	121.6 26.3	101.3 22.6
Construction Analysis					
Gross Capital Expenditures % Capitalization CWIP % Common Equity	8.7 20.8	10.4 15.8	6.8 7.7	8.9 7.5	9.9 13.3
OPERATING STATISTICS			:		
Market Analysis					
Electric % Total Revenue	100.0	100.0	100.0	100.0	100.0
Residential % Electric Revenue Commercial % Electric Revenue Industrial % Electric Revenue Wholesale % Electric Revenue	53.8 23.0 8.1 7.9	52.8 23.2 8.5 6.3	54,3 22,4 8.6 6.7	55.1 22.7 8.3 6.8	54.9 23.3 8.3 6.0
Residential % Kwh Sales Commercial % Kwh Sales Industrial % Kwh Sales Wholesale % Kwh Sales	44.4 26.8 11.7 10.4	45.3 27.8 12.6 7.3	46.2 26.4 12.6 8.1	46.1 26.6 11.9 9.0	46.2 27.5 11.9 7.8
Residential Price per Kwh Commercial Price per Kwh Industrial Price per Kwh Wholesale Price per Kwh Total Price per Kwh	8.6 6.1 4.9 5.4 7.1	8.6 6.1 5.0 6.3 7.4	8.4 6.1 4.9 5.9 7.1	8.4 6.0 4.9 5.3 7.0	8.2 5.9 4.8 5.3 6.9
Competitive Position					
Fuel Per Mwhr Non-Fuel Per Mwhr Investment Per Mwhr Tatel Cost Per Mwhr	22.0 3.3 9.2 34.5	22.0 3.3 9.2 34.5	0.0 0.0 0.0	0.0 0.0 0.0 0.0	0.0 0.0 0.0 0.0

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evenue (US\$ bil.) ssets (US\$ bil.) om. Equity (US\$ bil.) )p. Margin (%) OA(%) OE(%) <u>iv. Payout (%)</u> retax Int. Cov. (X) retax		2.7 5.0 1.8 14.2 5.3 14.2 133.6 4.1 4.0 6.5 41.6 97.3 3.6 47.4 0.9	1.2 2.9 0.9 14.8 3.7 12.2 82.8 3.5 3.0 4.5 25.7 114.0 2.1 49.2 5.5	2.6 4.9 1.8 14.0 5.0 13.7 61.7 3.7 3.7 6.0 40.7 172.2 3.5 47.8 0.9	1.1 2.8 0.9 15.5 3.6 11.7 85.2 3.4 2.9 4.5 26.2 124.6 2.0 49.5 6.0	2.4 4.9 1.8 10.1 2.7 7.6 142.0 2.7 2.6 5.2 25.5 77.0 3.7 51.7 0.9	1.1 2.7 0.9 16.4 3.7 12.0 81.9 3.5 2.9 4.6 26.4 128.8 2.0 48.8 5.7	2.4 4.3 1.8 13.9 5.5 71.2 4.7 4.3 6.6 42.0 176.6 3.2 41.6 1.1	1.0 2.8 0.9 16.1 3.8 12.5 79.0 3.4 2.9 4.4 25.3 113.5 1.9 49.5 4.6	2.3 4.3 1.8 14.4 5.1 12.4 83.2 4.3 3.8 6.1 40.9 121.6 3.2 40.9 0.8	[4]4.5 [4]2.5 [4]2.3 15.7 3.7 12.0 82.3 3.4 2.9 4.4 25.3 113.8 [4]2.3 49.4 5.3	(4)6.2 (4)3.6 (4)3.6 13.4 4.6 11.6 90.0 3.9 3.6 5.9 36.9 129.7 (4)1.8 45.3 0.9	
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evenue (US\$ bil.) ssets (US\$ bil.) jon. Equity (US\$ bil.) )p. Margin (%) OA(%) OE(%) OE(%) Viv. Payout (%) retax Int. Cov. (X) retax Int. Cov. (X) retax Int. Cov. (X) FO (% Total Debt CF % Gross CAPEX otal Cap. (US\$ bil.) D % Cap. id. Stk. % Cap. ommon % Cap. lectric Utility Operation atomer Segmentation evenue (US\$ mil.) wh(mil.) %Kwh egional Average ompetitive Position reflector per Mwhr. I Competivie Position reflector mpound annual growth rate	ting Statistic 1 1s 1997 figures. [ 2.	2.7 5.0 1.8 14.2 5.3 14.2 133.6 4.1 4.0 6.5 41.6 97.3 3.6 47.4 0.9 51.7 §	1.2 2.9 0.9 14.8 3.7 12.2 82.8 3.5 3.0 4.5 25.7 1140 2.1 49.2 5.5 45.0	2.6 4.9 1.8 14.0 5.0 13.7 61.7 3.7 6.0 40.7 7.72.2 3.5 47.8 0.9 51.3 Random Random Ran	1.1 2.8 0.9 15.5 3.6 11.7 85.2 3.4 2.9 4.5 26.2 124.6 2.0 49.5 6.0 44.9 <b>2:</b> <b>3:</b> <b>4:</b> <b>5:</b> <b>6:</b> <b>4:</b> <b>5:</b> <b>6:</b> <b>4:</b> <b>5:</b> <b>6:</b> <b>6:</b> <b>6:</b> <b>6:</b> <b>6:</b> <b>6:</b> <b>6:</b> <b>7:</b> <b>9:</b> <b>5:</b> <b>6:</b> <b>6:</b> <b>6:</b> <b>6:</b> <b>6:</b> <b>7:</b> <b>9:</b> <b>5:</b> <b>6:</b> <b>6:</b> <b>6:</b> <b>6:</b> <b>6:</b> <b>6:</b> <b>6:</b> <b>6</b>	2.4 4.9 1.8 10.1 2.7 7.6 142.0 2.7 2.6 5.2 25.5 77.0 3.7 51.7 0.9 47.4 Comm	1.1 2.7 0.9 16.4 3.7 12.0 81.9 3.5 2.9 4.6 26.4 128.8 2.0 48.8 5.7 45.4 <b>128.8</b> 5.7 45.4 <b>608.9</b> <b>9999</b> 6.1 <b>6.5</b> <b>9999</b> 6.1 <b>6.5</b> <b>m-Fuel</b> <b>3.29</b> are as of J	2.4 4.3 1.8 13.9 5.5 12.7 71.2 4.7 4.3 6.6 42.0 176.6 3.2 41.6 1.1 57.4 1.6 1.1 57.4 4 1.6 1.1 57.4 1.1 57.4 1.6 1.1 57.4 1.0 9 1.6 1.7 1.2 1.7 1.2 4.7 4.3 6.6 4.2 0 1.7 6.6 4.2 1.6 1.6 1.6 1.6 1.6 1.7 7 1.2 4.7 4.3 6.6 4.2 1.6 1.6 1.7 7 7 1.2 4.7 4.3 6.6 4.2 1.6 1.7 7 7 1.2 4.7 4.3 6.6 4.2 1.7 7 1.2 7 4.7 4.3 6.6 4.2 1.7 7 7 1.2 4.7 4.3 6.6 4.2 1.7 7 1.2 7 4.7 4.3 6.6 4.2 1.7 7 1.2 7 4.7 4.3 6.6 4.2 1.7 7 1.2 7 1.2 7 4.7 4.3 6.6 4.2 1.2 7 1.2 7 4.7 4.3 6.6 4.2 1.2 7 1.2 7 4.7 4.3 6.6 4.2 1.7 7 1.2 7 4.7 4.3 6.6 4.2 1.6 1.7 7 7 4.3 6.6 4.2 1.6 1.7 7 7 1.2 7 4.7 7 1.2 7 4.7 4.3 6.6 4.2 7 4.7 7 4.1 5 7.4 7 4.1 5 7.4 1.6 1.1 5 7.4 1.6 1.1 5 7.4 1.6 1.1 1.5 7.4 1.1 1.7 4.1 1.1 5 7.4 1.0 1.1 1.1 5 7.4 1.1 1.1 1.1 1.1 1.1 1.1 1.1 1.1 1.1 1	1.0 2.8 0.9 16.1 3.8 12.5 79.0 3.4 25.3 113.5 1.9 49.5 4.6 45.1 trial 14.4 375 4.9 4.7 trial 14.4 5.15 Five year	2.3 4.3 1.8 14.4 5.1 12.4 83.2 4.3 3.8 6.1 40.9 121.6 3.2 40.9 0.8 54.8 Wholesal 207. 386 5. 4. Total Con 34.4 average 19	[4]4.5 [4]2.5 [4]2.3 15.7 3.7 12.0 82.3 3.4 2.9 4.4 25.3 113.8 [4]2.3 49.4 5.3 49.4 5.3 49.4 5.3 45.0 9 4 4 5.3 45.0	(4)6.2 (4)3.6 (4)3.6 13.4 4.6 11.6 90.0 3.9 3.6 5.9 36.9 129.7 (4)1.8 45.3 0.9 52.4 4 2,648.2 37251 7.1 7.6 nal Cost 34.76 (4) Five yea	ar 
evenue (US\$ bil.) ssets (US\$ bil.) jon. Kargin (%) OA(%) OE(%) Viv. Payout (%) retax Int. Cov. (X) retax Int. Cov. (X) reto. (X) FO Int. Cov. (X) FO Int. Cov. (X) FO M. Total Debt CF % Gross CAPEX otal Cap. (US\$ bil.) D % Cap. id. Stk. % Cap. ommon % Cap. lectric Utility Operal ustomer Segmentation evenue (US\$ mil.) wh(mil.) "Kwh egional Average ompetitive Position reflect mpound anaual growth rate <b>pinion</b>	ting Statistic	2.7 5.0 1.8 14.2 5.3 14.2 133.6 4.1 4.0 6.5 41.6 97.3 3.6 47.4 0.9 51.7 §	1.2 2.9 0.9 14.8 3.7 12.2 82.8 3.5 3.0 4.5 25.7 114.0 2.1 49.2 5.5 45.0	2.6 4.9 1.8 14.0 5.0 13.7 61.7 3.7 6.0 40.7 172.2 3.5 47.8 0.9 51.3 References of the second	1.1 2.8 0.9 15.5 3.6 11.7 85.2 3.4 2.9 4.5 26.2 124.6 2.0 49.5 6.0 44.9 <b>:sidential</b> 1,424.6 16526 8.6 7.9 Fuel 22.03 ; Balance s	2.4 4.9 1.8 10.1 2.7 7.6 142.0 2.7 2.6 5.2 25.5 77.0 3.7 51.7 0.9 47.4 Comr	1.1 2.7 0.9 16.4 3.7 12.0 81.9 3.5 2.9 4.6 26.4 128.8 2.0 48.8 5.7 45.4 45.4 <b>mercial</b> 608.9 9999 6.1 6.5 <b>m-Fuel</b> 3.29 are as of J	2.4 4.3 1.8 13.9 5.5 12.7 71.2 4.7 4.3 6.6 42.0 176.6 3.2 41.6 1.1 57.4 indus 21 41.6 1.1 57.4 une 30. (3)	1.0 2.8 0.9 16.1 3.8 12.5 79.0 3.4 2.9 4.4 25.3 113.5 1.9 49.5 4.6 45.1 trial 14.4 375 4.9 4.7 nent 9.15 Five year	2.3 4.3 1.8 14.4 5.1 12.4 83.2 4.3 3.8 6.1 40.9 121.6 3.2 40.9 0.8 54.8 Wholesal 207. 386 5. 4. Total Cor 34.4 average 199	[4]4.5 [4]2.5 [4]2.3 15.7 3.7 12.0 82.3 3.4 4.2 25.3 113.8 [4]2.3 4.4 25.3 113.8 [4]2.3 49.4 5.3 49.4 5.3 45.0 [e] 9 4 4 3 3 5 5 3 45.0	(4)6.2 (4)3.6 (4)3.6 13.4 4.6 11.6 90.0 3.9 3.6 5.9 36.9 129.7 (4)1.8 45.3 0.9 52.4 4 52.4 4 5.2 52.4 7.1 7.6 34.76 (4) Five yet	ar

risk through its 90% ownership of the Crystal River nuclear plant and to potential stranded costs from expensive powerpurchase contracts and regulatory assets. In addition, ratings pressure originates in acquisition leverage issued by a new holding company created to purchase FPC.

#### **Recent Events**

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Management announced in August the company will be sold to Carolina Power & Light Company (CP&L, rated A2 sr. sec.) to create the nation's 9th largest utility in terms of genciencies. A substantial portion of these savings will be extracted from FPC.

In addition, revenue enhancements are likely from generation expansion and wholesale marketing opportunities. CP&L intends to use the FPC platform to build gas-fired generating plants in Florida.

#### **Rating Outlook**

Concern that financial pressure will result from the obligation to service up to \$3.5 billion of acquisition leverage to be issued by a new holding company led Moody's to place the securities on review for potential downgrade.

# BATES NOS. FPC 296 - FPC 299 CONFIDENTIAL PURSUANT TO FLORIDA POWER CORPORATION'S REQUST FOR CONFIDENTIAL CLASSIFICATION FILED AUGUST 7, 2000

- Steam turbine annual, minor, and major inspection costs are estimated based on Black & Veatch data. Annual inspections occur every 8,000 hours of operation, minor overhauls occur every 24,000 hours of operation, and major overhauls occur every 48,000 hours of operation.
- The costs for demineralized cycle makeup water and cooling tower raw water are included.
- The variable O&M analysis is based on a repeating maintenance schedule for the CTG and includes replacement and refurbishment costs. The annual average cost is the estimated average cost over the 25 year cycle life.
- O&M costs for the simple cycle 7EA and 7FA are based on a 17.1 percent capacity factor.
- O&M costs for the combined cycle plants a 85 percent capacity factor.

## 6.3 Simple Cycle Combustion Turbine

The simple cycle combustion turbine is a packaged (pre-assembled by vendors) machine consisting of an air compressor, combustor, gas turbine, and electric generator. Figure 6-4 presents a plant flow diagram for a combustion turbine simple cycle unit. Filtered air is drawn through the compressor end of the machine and compressed by the multistage axial compressor. Fuel is mixed with the compressed air and burned in the combustor section. The hot gases then expand through the turbine and are exhausted to the atmosphere. The shaft power produced by the turbine drives the compressor and an electric generator.

Four simple cycle combustion turbines were selected as generating unit alternatives:

- General Electric 7EA (Tables 24 & 25)
- General Electric 7FA (Tables 26 & 27)

The 7EA, and 7FA combustion turbines are heavy-duty industrial combustion turbines. The combustion turbines are dual fueled with specifications for performance and operating costs give for both natural gas and distillate.

#### 6.4 Combined Cycle

A combustion turbine combined cycle unit includes a combustion turbine (air compressor, combustor, gas turbine, and generator), a heat recovery steam generator (HRSG), and a steam turbine. Major components included in the steam cycle are the air-cooled condenser, condensate pumps, deaerator, and boiler feed pumps. Figure 6-3 presents a plant flow diagram for a combustion turbine combined cycle generating unit. The combined cycle is arranged so that hot exhaust gas from the combustion turbine is ducted to the HRSG, where it passes over heat exchanger tubes. Heat from the exhaust gas is transferred to water flowing in the tubes, generating steam. The superheater section of the HRSG provides superheated steam to the steam turbine. Both the steam turbine and combustion turbine drive electric generators, thus the name combines cycle.

A combined cycle unit may be configured in a number of different ways. A typical configuration would include either one or two combustion turbines exhausting to individual HRSGs that provide steam to a single steam turbine.

Four combined cycle units were selected as generating unit alternatives:

- 2 x 1 Westinghouse 501FC (Hines #2)
- (Tables 28 & 29)

(Tables 32)

• 2 x 1 Westinghouse 501F (Hines #2 market price) (Tables 30 & 31)

1 x 1 Westinghouse 501G

The combined cycles all utilize conventional, heavy-duty industrial type combustion turbines. The combined cycles would be dual fueled. Specifications for performance and operating costs are based on baseload operation. The combined cycles assume dry low  $NO_x$  combustors. The units would be located at the Hines Energy Center and would utilize existing common facilities to the extent possible. Adequate natural gas pressure is assumed. Therefore, natural gas compressors are not included.

Notice that two different prices are given for the Westinghouse  $501F 2 \ge 1$  combined cycle alternative at Hines (Hines #2). The first price is based on an agreement that was entered when Hines #1 was procured. This agreement was established before the recent increase in combustion turbine prices. The non-market based price is therefore lower than the market based price. The market price typifies the capital cost of a Westinghouse  $501F 2 \ge 1$  combined cycle installation without the cost savings associated with the established Hines #2 agreement.

#### 6.5 Pulverized Coal

A conventional pulverized coal steam-generating unit receives raw coal that has been pulverized and dried so that about 70 percent would pass through a 200-mesh screen (0.074 millimeter particle size). As shown on the flow diagram on Figure 6-1, the dry pulverized coal is carried on a hot air stream through coal piping to the furnace, where it is ignited and burned in suspension. Waterwalls in the furnace absorb the radiant energy obtained from the combustion process.

Downstream from the furnace, the flue gas flows through steam- and water-cooled convective heat transfer surfaces and then through a regenerative air heater. From the air heater, the flue gas flows through particulate removal and desulfurization equipment before entering the stack and being exhausted to the atmosphere. The superheated steam is delivered to the steam turbine generator. Steam from the turbine exhaust is condensed, heated by steam from turbine extractions, and pumped back to the steam-generating unit.

A 800 MW pulverized coal unit with dry scrubber, electrostatic precipitator, and selective catalytic reduction (SCR) was selected as a solid fueled alternative. The unit is assumed to be the first unit at a site. It is assumed that coal is delivered by rail and cooling is achieved with

4.5

Т	able 28	••••••••••••••••••••••••••••••••••••••		
Estimated Cost and Performance for	Hines Unit #2, 2x	(1 501FC on N	latural Gas	
Total Capital Cost, 1999 \$1,000	160,700			······
Total Capital Cost, 1999 \$/kW	302			······
O&M Cost-Peaking Duty (17.1% CF)	· · ·		······································	
Fixed O&M Cost, 1999 \$/kW-y	2.44		<u>.</u>	
Variable O&M Cost, 1999 \$/MWh	2.04			
Equivalent Availability, %	92			······
Equivalent Forced Outage Rate, %	3.7			
Planned Maintenance Outage, days/year	16		· · · · · · · · · · · · · · · · · · ·	
Startup Fuel (cold start), Mbtu	4296			
Construction Cash Flows (1 st /2 nd //n th year, %)	15/60/25			·····
Construction Period, months	30			•
Net Direct Output and Net Plant Heat Pate (HHV)	NPO	(MW)	NPHR (	Btu/kWh)
Net Plant Output and Net Plant field Rate (IIIIV)	40° F	90° F	40° F	90° F
100 Percent of Full Load	567.2	495.5	6,785	6,823
75 Percent of Full Load	448.9	394.0	7,111	7,354
50 Percent of Full Load	308.5	267.7	7,799	7,894
35 Percent of Full Load	206.3	176.5	9,334	9,586

Tabl	e 29	· ·				
Estimated Cost and Performance for H	lines Unit #2, 2	x1 501FC on	Distillate			
Total Capital Cost, 1999 \$1,000	160,700					
Total Capital Cost, 1999 \$/kW	316					
O&M Cost-Peaking Duty (17.1% CF)			46			
Fixed O&M Cost, 1999 \$/kW-y	2.44		• • • • • • • • • • • • • • •			
Variable O&M Cost, 1999 \$/MWh	2.25		······································	· · · · · · · · · · · · · · · · · · ·		
Equivalent Availability, %	92	· · ·				
Equivalent Forced Outage Rate, %	3.7					
Planned Maintenance Outage, days/year	16					
Startup Fuel (cold start), Mbtu	4120		······································			
Construction Cash Flows (1 ¹¹ /2 nd //n th year, %)	15/60/25	· · · · · · · · · · · · · · · · · · ·				
Construction Period, months	30		· · · · · · · · · · · · · · · · · · ·			
Net Plant Output and Nat Plant Heat Rate (HHV)	NPO	(MW)	NPHR (I	Btu/kWh)		
Net Plant Output and Net Plant fleat Rate (1117)	40° F	90° F	40° F	90° F		
100 Percent of Full Load	545.3	473.3	6,553	6,635		
75 Percent of Full Load	402.3	347.9	7,019	7,135		
50 Percent of Full Load	289.0	249.0	7,633	7,786		
35 Percent of Full Load	193.1	164.7	8,947	9,223		

- Steam turbine annual, minor, and major inspection costs are estimated based on Black & Veatch data. Annual inspections occur every 8,000 hours of operation, minor overhauls occur every 24,000 hours of operation, and major overhauls occur every 48,000 hours of operation.
- The costs for demineralized cycle makeup water and cooling tower raw water are included.
- The variable O&M analysis is based on a repeating maintenance schedule for the CTG and includes replacement and refurbishment costs. The annual average cost is the estimated average cost over the 25 year cycle life.
- O&M costs for the simple cycle 7EA and 7FA are based on a 17.1 percent capacity factor.
- O&M costs for the combined cycle plants a 85 percent capacity factor.

#### 6.3 Simple Cycle Combustion Turbine

The simple cycle combustion turbine is a packaged (pre-assembled by vendors) machine consisting of an air compressor, combustor, gas turbine, and electric generator. Figure 6-4 presents a plant flow diagram for a combustion turbine simple cycle unit. Filtered air is drawn through the compressor end of the machine and compressed by the multistage axial compressor. Fuel is mixed with the compressed air and burned in the combustor section. The hot gases then expand through the turbine and are exhausted to the atmosphere. The shaft power produced by the turbine drives the compressor and an electric generator.

Four simple cycle combustion turbines were selected as generating unit alternatives:

- General Electric 7EA (Tables 24 & 25)
- General Electric 7FA (Tables 26 & 27)

The 7EA, and 7FA combustion turbines are heavy-duty industrial combustion turbines. The combustion turbines are dual fueled with specifications for performance and operating costs give for both natural gas and distillate.

#### 6.4 Combined Cycle

A combustion turbine combined cycle unit includes a combustion turbine (air compressor, combustor, gas turbine, and generator), a heat recovery steam generator (HRSG), and a steam turbine. Major components included in the steam cycle are the air-cooled condenser, condensate pumps, deaerator, and boiler feed pumps. Figure 6-3 presents a plant flow diagram for a combustion turbine combined cycle generating unit. The combined cycle is arranged so that hot exhaust gas from the combustion turbine is ducted to the HRSG, where it passes over heat exchanger tubes. Heat from the exhaust gas is transferred to water flowing in the tubes, generating steam. The superheater section of the HRSG provides superheated steam to the steam turbine. Both the steam turbine and combustion turbine drive electric generators, thus the name combines cycle.

(Tables 32)

A combined cycle unit may be configured in a number of different ways. A typical configuration would include either one or two combustion turbines exhausting to individual HRSGs that provide steam to a single steam turbine.

Four combined cycle units were selected as generating unit alternatives;

•	2 x 1 Westinghouse 501FC (Hines #2)	(Tables 28 & 29)
•	2 x 1 Westinghouse 501F (Hines #2 market price)	(Tables 30 & 31)

1 x 1 Westinghouse 501G

The combined cycles all utilize conventional, heavy-duty industrial type combustion turbines. The combined cycles would be dual fueled. Specifications for performance and operating costs are based on baseload operation. The combined cycles assume dry low  $NO_x$  combustors. The units would be located at the Hines Energy Center and would utilize existing common facilities to the extent possible. Adequate natural gas pressure is assumed. Therefore, natural gas compressors are not included.

Notice that two different prices are given for the Westinghouse  $501F 2 \times 1$  combined cycle alternative at Hines (Hines #2). The first price is based on an agreement that was entered when Hines #1 was procured. This agreement was established before the recent increase in combustion turbine prices. The non-market based price is therefore lower than the market based price. The market price typifies the capital cost of a Westinghouse  $501F 2 \times 1$  combined cycle installation without the cost savings associated with the established Hines #2 agreement.

#### 6.5 Pulverized Coal

A conventional pulverized coal steam-generating unit receives raw coal that has been pulverized and dried so that about 70 percent would pass through a 200-mesh screen (0.074 millimeter particle size). As shown on the flow diagram on Figure 6-1, the dry pulverized coal is carried on a hot air stream through coal piping to the furnace, where it is ignited and burned in suspension. Waterwalls in the furnace absorb the radiant energy obtained from the combustion process.

Downstream from the furnace, the flue gas flows through steam- and water-cooled convective heat transfer surfaces and then through a regenerative air heater. From the air heater, the flue gas flows through particulate removal and desulfurization equipment before entering the stack and being exhausted to the atmosphere. The superheated steam is delivered to the steam turbine generator. Steam from the turbine exhaust is condensed, heated by steam from turbine extractions, and pumped back to the steam-generating unit.

A 800 MW pulverized coal unit with dry scrubber, electrostatic precipitator, and selective catalytic reduction (SCR) was selected as a solid fueled alternative. The unit is assumed to be the first unit at a site. It is assumed that coal is delivered by rail and cooling is achieved with

	Table 28					
Estimated Cost and Performance for	Hines Unit #2, 2x	1 501FC og N	latural Gas			
Total Capital Cost, 1999 \$1,000	160,700					
Total Capital Cost, 1999 \$/kW	302					
O&M Cost-Peaking Dury (17.1% CF)						
Fixed O&M Cost, 1999 \$/kW-y	2.44					
Variable O&M Cost, 1999 \$/MWh	2.04					
Equivalent Availability, %	92					
Equivalent Forced Outage Rate, %	3.7					
Planned Maintenance Outage, days/year	16					
Startup Fuel (cold start), Mbtu	4296					
Construction Cash Flows (1"/2",/n" year, %)	15/60/25					
Construction Period, months	30					
Not Blant Output and Net Blant Heat Bats (HHV)	NPO	(MW)	NPHR (	Bru/kWh)		
(Act Flatt Odiput and Net Flatt Flatt Mate (Filly)	40° F	90° F	40° F	90° F		
100 Percent of Full Load	567.2	495.5	6,785	6,823		
75 Percent of Full Load	448.9	394.0	7,111	7,354		
50 Percent of Full Load	308.5	267.7	7,799	7,894		
35 Percent of Full Load	206.3	176.5	9,334	9,586		

Tabl	e 29			
Estimated Cost and Performance for F	lines Unit #2, 2	x1 501FC on	Distillate	
Total Capital Cost, 1999 \$1,000	160,700		4 6	
Total Capital Cost, 1999 S/kW	316			
O&M Cost-Peaking Dury (17.1% CF)				
Fixed O&M Cost, 1999 \$/kW-y	2.44			
Variable O&M Cost, 1999 S/MWh	2,25		·····	
Equivalent Availability, %	92			
Equivalent Forced Outage Rate, %	3.7			·····
Planned Maintenance Outage, days/year	16		·	
Startup Fuel (cold start), Mbtu	4120			
Construction Cash Flows (1"/2"//n" year, %)	15/60/25			
Construction Period, months	30	· · · · · · · · · · · · · · · · · · ·	· · · · · · · · · · · · · · · · · · ·	
Net Plant Ourout and Net Plant Heat Rate (HHV)	NPO	(MW)	NPHR (I	Btu/kWh)
Not Flatt Output and ther Flatt float Note (INTY)	40° F	90° F	40° F	90° F
100 Percent of Full Load	545.3	473.3	6,553	6,635
75 Percent of Full Load	402.3	347.9	7,019	7,135
50 Percent of Full Load	289.0	249.0	7,633	7,786
35 Percent of Full Load	193.1	164.7	8,947	9,223

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Estimated Cost and Perform	Table 30 nance a 2x1 501FC	on Natural G	as			
Total Capital Cost, 1999 \$1,000	181,200					
Total Capital Cost, 1999 \$/kW	341					
O&M Cost-Peaking Duty (17.1% CF)			· · · · · · · · · · · · · · · · · · ·			
Fixed O&M Cost, 1999 \$/kW-y	2.44					
Variable O&M Cost, 1999 S/MWh	2.04					
Equivalent Availability, %	92					
Equivalent Forced Outage Rate, %	3.7					
Planned Maintenance Outage, days/year	16					
Startup Fuel (cold start), Mbtu	4296					
Construction Cash Flows (1"/2nd//nth year, %)	15/60/25		······································			
Construction Period, months	30					
Net Blast Querut and Net Blast Heat Bate (UUV)	NPO	(MW)	NPHR (	Bru/kWh)		
Net Plant Output and Net Plant fieat Rate (Firty)	40° F	90° F	40° F	90° F		
100 Percent of Full Load	567.2	495.5	6,785	6,823		
75 Percent of Full Load	448.9	394.0	7,111	7,354		
50 Percent of Full Load	308.5	267.7	7,799	7,894		
35 Percent of Full Lond	206.3	176.5	9,334	9,586		

Ta	able 31			· · · · · · · · · · · · · · · · · · ·
Estimated Cost and Performa	nce for a 2x1 501	FC on Distilla	Ite	
Total Capital Cost, 1999 \$1,000	181,200		44	
Total Capital Cost, 1999 S/kW	356		·····	
O&M Cost-Peaking Duty (17,1% CF)				
Fixed O&M Cost, 1999 \$/kW-y	2.44			
Variable O&M Cost, 1999 \$/MWh	2.25			
Equivalent Availability, %	92			
Equivalent Forced Outage Rate, %	3.7			
Planned Maintenance Outage, days/year	16			
Startup Fuel (cold start), Mbtu	4120	· · · · · · · · · · · · · · · · · · ·	· · ·	
Construction Cash Flows (1"/2"d//nth year, %)	15/60/25			
Construction Period, months	30			
Net Blant Quitnut and Net Blant Heat Rate (HHV)	NPO	(MW)	NPHR (	Ini/kWh)
Her Flatt Output and Her Flatt Hour Kate (1117)	40° F	90° F	40° F	90° F
100 Percent of Full Load	545,3	473.3	6,553	6,635
75 Percent of Full Load	402.3	347.9	7,019	7,135
50 Percent of Full Load	289.0	249.0	7,633	7,786
35 Percent of Full Load	193.1	164.7	8,947	9,223

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		E-time to d C-	Table 41	Eng Alternations					
		esumaico Ca	pital Cost Kange	, for Alternatives	i 				
		Capacity				C	apital Cost Ra	nge	
Fuel	Winter	Summer	Average	Capital Co	ost	Low	High	Low	High
Туре	MW	MW	MW	\$1,000	\$/kw	\$1,000	\$1,000	\$/kw	\$/kw
N. Gas	88.9	74.2	81.6	30,700	376	28,600	33,300	351	408
Distillate	92.0	76.4	84.2	30,700	365	28,600	33,300	340	396
N. Gas	178	151	164	49,800	303	45,100	51,700	275	315
Distillate	185	161	173	49,800	288	45,100	51,700	261	299
N. Gas	567	496	531	160,700	302	159,000	170,000	299	320
Distillate	545	473	509	160,700	316	159,000	170,000	312	334
N. Gas	567	496	531	181,200	341	178,000	205,000	335	386
Distillate	545	473	509	181,200	356	178,000	205,000	349	403
N. Gas	366	323	345	156,100	453	148,000	169,000	430	491
Coal	800	800	800	687,040	859	620,000	756,000	775	945
Coal	500	500	500	477,100	954	425,000	512,500	850	1,025
Coal	577	494	536	697,900	1303	560,000	725,000	1,046	1,354
N. Gas	574	536	555	171,000	308	150,000	195,000	270	351
N. Gas	274	248	261	103,000	394	81,000	107,000	310	410
N. Gas	127	118	122	56,000	459	51,000	62,000	418	508
N. Gas	248	230	239	88,000	368	80,000	102,000	335	427
	Fuel Type N. Gas Distillate N. Gas Distillate N. Gas Distillate N. Gas Distillate N. Gas Coal Coal Coal N. Gas N. Gas N. Gas N. Gas	Fuel         Winter           Type         MW           N. Gas         88.9           Distillate         92.0           N. Gas         178           Distillate         92.0           N. Gas         178           Distillate         185           N. Gas         567           Distillate         545           N. Gas         567           Distillate         545           N. Gas         567           Distillate         545           N. Gas         366           Coal         800           Coal         500           Coal         577           N. Gas         574           N. Gas         274           N. Gas         127           N. Gas         248	Estimated Cay           Fuel         Winter         Summer           Type         MW         MW           N. Gas         88.9         74.2           Distillate         92.0         76.4           N. Gas         178         151           Distillate         185         161           N. Gas         567         496           Distillate         545         473           N. Gas         567         496           Distillate         545         473           N. Gas         567         496           Distillate         545         473           N. Gas         366         323           Coal         800         800           Coal         500         500           Coal         577         494           N. Gas         574         536           N. Gas         127         118           N. Gas         248         230	Table 41 Estimated Capital Cost Range           Fuel         Winter         Summer         Average           Type         MW         MW         MW           N. Gas         88.9         74.2         81.6           Distillate         92.0         76.4         84.2           N. Gas         178         151         164           Distillate         185         161         173           N. Gas         567         496         531           Distillate         545         473         509           N. Gas         567         496         531           Distillate         545         473         509           N. Gas         567         496         531           Distillate         545         473         509           N. Gas         366         323         345           Coal         800         800         800           Coal         500         500         500           Coal         577         494         536           N. Gas         574         536         555           N. Gas         274         248         261           N. Gas	Table 41 Estimated Capital Cost Range for Alternatives           Fuel         Winter         Summer         Average         Capital Cost           Type         MW         MW         MW         \$1,000           N. Gas         88.9         74.2         81.6         30,700           Distillate         92.0         76.4         84.2         30,700           N. Gas         178         151         164         49,800           Distillate         185         161         173         49,800           N. Gas         567         496         531         160,700           Distillate         345         473         509         160,700           N. Gas         567         496         531         181,200           Distillate         545         473         509         160,700           N. Gas         5667         496         531         181,200           N. Gas         366         323         345         156,100           Coal         800         800         800         687,940           Coal         500         500         500         477,100           N. Gas         574         536 <t< td=""><td>Table 41Estimated Capital Cost Range for AlternativesFuelWinterSummerAverageCapital CostTypeMWMWMW\$1,000\$/kwN. Gas88.974.281.630,700376Distillate92.076.484.230,700365N. Gas17815116449,800303Distillate18516117349,800288N. Gas567496531160,700302Distillate545473509160,700316N. Gas567496531181,200341Distillate545473509181,200356N. Gas366323345156,100453Coal800800800687,040859Coal500500505171,000308N. Gas574536555171,000308N. Gas274248261103,000394N. Gas12711812256,000459N. Gas24823023988,000368</td><td>Table 41 Estimated Capital Cost Range for Alternatives           Capacity         Construction           Fuel         Winter         Summer         Average         Capital Cost         Low           Type         MW         MW         \$1,000         \$7kw         \$1,000           N. Gas         88.9         74.2         81.6         30,700         376         28,600           Distillate         92.0         76.4         84.2         30,700         365         28,600           N. Gas         178         151         164         49,800         303         45,100           Distillate         185         161         173         49,800         288         45,100           N. Gas         567         496         531         160,700         302         159,000           Distillate         545         473         509         160,700         316         159,000           N. Gas         567         496         531         181,200         341         178,000           Distillate         545         473         509         181,200         356         178,000           N. Gas         366         323         345         156,100</td><td>Table 41 Estimated Capital Cost Range for Alternatives           Capacity         Capital Cost Range for Alternatives           Fuel         Winter         Summer         Average         Capital Cost         Low         High           Type         MW         MW         MW         \$1,000         \$/kw         \$1,000         \$1,000           N. Gas         88.9         74.2         81.6         30,700         376         28,600         33,300           Distillate         92.0         76.4         84.2         30,700         365         28,600         33,300           N. Gas         178         151         164         49,800         303         45,100         51,700           Distillate         185         161         173         49,800         288         45,100         51,700           N. Gas         567         496         531         160,700         316         159,000         170,000           N. Gas         567         496         531         181,200         341         178,000         205,000           N. Gas         566         323         345         156,100         453         148,000         169,000</td><td>Table 41 Estimated Capital Cost Range for Alternatives           Fuel         Winter         Summer         Average         Capital Cost         Low         High         Low           Type         MW         MW         MW         \$1,000         \$7kw         \$1,000         \$1,000         \$7kw           N. Gas         88.9         74.2         81.6         30,700         376         28,600         33,300         340           N. Gas         178         151         164         49,800         303         45,100         51,700         275           Distillate         185         161         173         49,800         302         159,000         170,000         299           Distillate         185         161         173         49,800         302         159,000         170,000         299           Distillate         545         473         509         160,700         316         159,000         170,000         312           N. Gas         567         496         531         181,200         341         178,000         205,000         345           Distillate         545         473         509         181,200         356         178,000</td></t<>	Table 41Estimated Capital Cost Range for AlternativesFuelWinterSummerAverageCapital CostTypeMWMWMW\$1,000\$/kwN. Gas88.974.281.630,700376Distillate92.076.484.230,700365N. Gas17815116449,800303Distillate18516117349,800288N. Gas567496531160,700302Distillate545473509160,700316N. Gas567496531181,200341Distillate545473509181,200356N. Gas366323345156,100453Coal800800800687,040859Coal500500505171,000308N. Gas574536555171,000308N. Gas274248261103,000394N. Gas12711812256,000459N. Gas24823023988,000368	Table 41 Estimated Capital Cost Range for Alternatives           Capacity         Construction           Fuel         Winter         Summer         Average         Capital Cost         Low           Type         MW         MW         \$1,000         \$7kw         \$1,000           N. Gas         88.9         74.2         81.6         30,700         376         28,600           Distillate         92.0         76.4         84.2         30,700         365         28,600           N. Gas         178         151         164         49,800         303         45,100           Distillate         185         161         173         49,800         288         45,100           N. Gas         567         496         531         160,700         302         159,000           Distillate         545         473         509         160,700         316         159,000           N. Gas         567         496         531         181,200         341         178,000           Distillate         545         473         509         181,200         356         178,000           N. Gas         366         323         345         156,100	Table 41 Estimated Capital Cost Range for Alternatives           Capacity         Capital Cost Range for Alternatives           Fuel         Winter         Summer         Average         Capital Cost         Low         High           Type         MW         MW         MW         \$1,000         \$/kw         \$1,000         \$1,000           N. Gas         88.9         74.2         81.6         30,700         376         28,600         33,300           Distillate         92.0         76.4         84.2         30,700         365         28,600         33,300           N. Gas         178         151         164         49,800         303         45,100         51,700           Distillate         185         161         173         49,800         288         45,100         51,700           N. Gas         567         496         531         160,700         316         159,000         170,000           N. Gas         567         496         531         181,200         341         178,000         205,000           N. Gas         566         323         345         156,100         453         148,000         169,000	Table 41 Estimated Capital Cost Range for Alternatives           Fuel         Winter         Summer         Average         Capital Cost         Low         High         Low           Type         MW         MW         MW         \$1,000         \$7kw         \$1,000         \$1,000         \$7kw           N. Gas         88.9         74.2         81.6         30,700         376         28,600         33,300         340           N. Gas         178         151         164         49,800         303         45,100         51,700         275           Distillate         185         161         173         49,800         302         159,000         170,000         299           Distillate         185         161         173         49,800         302         159,000         170,000         299           Distillate         545         473         509         160,700         316         159,000         170,000         312           N. Gas         567         496         531         181,200         341         178,000         205,000         345           Distillate         545         473         509         181,200         356         178,000

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T Estimated Cost and Perform	able 30 ance a 2x1 501F(	C on Natural G	ias			
Total Capital Cost, 1999 \$1,000	181,200					
Total Capital Cost, 1999 \$/kW	341					
O&M Cost-Peaking Duty (17.1% CF)			· · · · · · · · · · · · · · · · · · ·	······		
Fixed O&M Cost, 1999 \$/kW-y	2.44					
Variable O&M Cost, 1999 \$/MWh	2.04			<u> </u>		
Equivalent Availability, %	92		· · · ·			
Equivalent Forced Outage Rate, %	3.7					
Planned Maintenance Outage, days/year	16					
Startup Fuel (cold start), Mbtu	4296			·····		
Construction Cash Flows (1 st /2 ^{ad} //n th year, %)	15/60/25	······································				
Construction Period, months	30		·			
Net Blant Output and Net Blant Heat Pate (HHV)	NPO	(MW)	NPHR (	Btu/kWh)		
Net Plant Output and Net Plant Heat Rate (IIII V)	40° F	90° F	40° F	90° F		
100 Percent of Full Load	567.2	495.5	6,785	6,823		
75 Percent of Full Load	448.9	394.0	7,111	7,354		
50 Percent of Full Load	308.5	267.7	7,799	7,894		
35 Percent of Full Load	206.3	176.5	9,334	9,586		

Table 31				
Estimated Cost and Performance for a 2x1 501FC on Distillate				
Total Capital Cost, 1999 \$1,000	181,200			
Total Capital Cost, 1999 \$/kW	356		· · · · · · · · · · · · · · · · · · ·	
O&M Cost-Peaking Duty (17.1% CF)			4	
Fixed O&M Cost, 1999 \$/kW-y	2.44			
Variable O&M Cost, 1999 \$/MWh	2.25			
Equivalent Availability, %	92			
Equivalent Forced Outage Rate, %	3.7			
Planned Maintenance Outage, days/year	16			
Startup Fuel (cold start), Mbtu	4120			
Construction Cash Flows (1 st /2 nd //n th year, %)	15/60/25			
Construction Period, months	30			
Net Plant Output and Net Plant Heat Rate (HHV)	NPO (MW)		NPHR (Btu/kWh)	
	40° F	90° F	40° F	90° F
100 Percent of Full Load	545.3	473.3	6,553	6,635
75 Percent of Full Load	402.3	347.9	7,019	7,135
50 Percent of Full Load	289.0	249.0	7,633	7,786
35 Percent of Full Load	193.1	164.7	8,947	9,223