LAKELAND ELECTRIC

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COMMISSION CLERK

Director, Office of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850
Attn: Ann Cole

March 29, 2012

120000-OT

Dear Ms. Cole,

Pursuant to Section 186.801, Florida Statutes and Rules 25-22.070-072 of Florida Administrative Code, Lakeland Electric hereby submits 25 printed copies of its 2011 Ten Year Site Plan.

Additionally, I have included a CD containing the TYSP in PDF format, as well as Schedules 1 – 10 in Excel format (as requested per the TYSP Supplemental Data Request #1).

If you have any questions please do not hesitate to contact us.

Sincerely,

John P. Guiseppi
System Planning Section

COM ______
APA ______
ECR ______
GCL 2
RAD 22+CD
SRC ______
ADM ______
OPC ______
CLK 1-original

Enclosure

501 E. Lemon St. ✦ Lakeland, Florida 33801
Phone: 863.834.6300 ✦ Fax: 863.834.6344

Schedule 1
Existing Generating Facilities
As of December 31, 2009

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Plant Name	Unit No.	Location	Unit Type	Fuel Pri	Fuel Alt	Fuel Transport Pri	Fuel Transport Alt	Alt. Fuel Days Use	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen. Max. Nameplate KW	Net Capability Summer MW	Net Capability Winter MW
LARSEN	2	POLK	GT	NG	DFO	PL	TK	28	Nov-62	NA	11,500	10	14
LARSEN	3	POLK	GT	NG	DFO	PL	TK	28	Dec-62	NA	11,500	9	13
LARSEN	8CT	POLK	CT	NG	DFO	PL	TK	5	Jul-92	NA	80,000	76	93
LARSEN	8ST	POLK	CA	WH		NA		0	Apr-56	NA	40,000	29	31
MCINTOSH	1	POLK	ST	NG	RFO	PL	TK	29	Feb-71	NA	90,000	85	85
MCINTOSH	2	POLK	ST	NG	RFO	PL	TK	25	Jun-76	NA	114,700	106	106
MCINTOSH	3	POLK	ST	BIT	NA	RR	NA	0	Sep-82	NA	364,000	205	205
MCINTOSH	5CT	POLK	CT	NG		PL		0	May-01	NA	250,000	212	233
MCINTOSH	5ST	POLK	CA	WH		NA		0	May-02	NA	120,000	126	121
MCINTOSH	D1	POLK	IC	DFO		TK		0	Jan-70	NA	2,500	2.5	2.5
MCINTOSH	D2	POLK	IC	DFO		TK		0	Jan-70	NA	2,500	2.5	2.5
MCINTOSH	GT1	POLK	GT	NG	DFO	PL	TK	2	May-73	NA	20,000	16	19
WINSTON	01 - 05	POLK	IC	DFO	NG	TK	PL	0	Dec-01	NA	12,500	12.5	12.5
WINSTON	06 - 10	POLK	IC	DFO	NG	TK	PL	0	Dec-01	NA	12,500	12.5	12.5
WINSTON	11 - 15	POLK	IC	DFO	NG	TK	PL	0	Dec-01	NA	12,500	12.5	12.5
WINSTON	16 - 20	POLK	IC	DFO	NG	TK	PL	0	Dec-01	NA	12,500	12.5	12.5

WINSTON has (20) 2.5 MW DIESEL PEAKING UNITS

MCINTOS 3 is 364 MW Name Plate, and 40% owned by OUC

Schedule 2.1
History and Forecast of Energy Consumption and Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		Rural and Residential					Commercial	
Year	Population	Members per Household	GWH	Average No. of Customers	Average KWH Consumption Per Customer	GWH	Average No. of Customers	Average KWH Consumption Per Customer
HISTORY:								
2002	234,210	2.54	1,391	92,258	15,077	691	10,809	63,928
2003	236,890	2.54	1,408	93,348	15,083	689	11,097	62,089
2004	243,576	2.58	1,391	94,261	14,757	690	11,296	61,084
2005	247,942	2.58	1,431	96,220	14,872	733	11,493	63,778
2006	253,405	2.57	1,438	98,680	14,572	756	11,832	63,895
2007	253,027	2.52	1,444	100,523	14,365	781	11,898	65,641
2008	252,731	2.51	1,383	100,739	13,729	762	11,913	63,964
2009	253,084	2.52	1,417	100,628	14,082	749	11,837	63,276
2010	253,009	2.51	1,530	100,689	15,195	753	11,806	63,781
2011	254,283	2.52	1,437	100,812	14,254	744	11,786	63,126
FORECAST:								
2012	257,449	2.54	1,407	101,371	13,880	754	11,808	63,855
2013	259,878	2.54	1,413	102,338	13,807	766	11,829	64,756
2014	262,616	2.54	1,423	103,436	13,757	774	11,893	65,080
2015	265,484	2.53	1,434	104,750	13,690	782	11,978	65,286
2016	268,618	2.53	1,452	106,221	13,670	790	12,056	65,528
2017	271,874	2.52	1,468	107,748	13,624	795	12,119	65,599
2018	275,228	2.52	1,485	109,294	13,587	801	12,180	65,764
2019	278,658	2.51	1,504	110,849	13,568	807	12,246	65,899
2020	282,053	2.51	1,521	112,366	13,536	812	12,314	65,941
2021	285,367	2.51	1,539	113,788	13,525	818	12,383	66,058

Schedule 2.2
History and Forecast of Energy Consumption and Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Year	GWH	Industrial Average No of Customers	Average KWH Consumption Per Customer	Railroads and Railways GWH	Street & Highway Lighting GWH	Other Sales to Public Authorities GWH	Total Sales to Ultimate Consumers GWH
HISTORY:							
2002	520	84	6,190,476	0	19	105	2,726
2003	541	88	6,147,727	0	19	103	2,760
2004	534	91	5,868,132	0	20	101	2,736
2005	541	83	6,518,072	0	20	84	2,809
2006	586	87	6,735,632	0	21	87	2,888
2007	615	88	6,988,636	0	21	87	2,948
2008	607	87	6,977,011	0	21	85	2,858
2009	590	85	6,941,176	0	21	83	2,860
2010	581	84	6,916,667	0	21	81	2,966
2011	578	87	6,643,678	0	21	84	2,864
FORECAST:							
2012	603	84	7,178,571	0	21	85	2,870
2013	678	85	7,976,471	0	21	86	2,964
2014	680	85	8,000,000	0	21	86	2,984
2015	681	85	8,011,765	0	21	86	3,004
2016	683	86	7,941,860	0	21	87	3,033
2017	684	86	7,953,488	0	21	87	3,055
2018	686	86	7,976,744	0	21	87	3,080
2019	687	86	7,988,372	0	21	87	3,106
2020	689	87	7,919,540	0	21	88	3,131
2021	690	87	7,931,034	0	21	88	3,156

Schedule 2.3
History and Forecast of Energy Consumption and Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)
Year	Sales for Resale GWH	Utility Use & Losses GWH	Net Energy for Load GWH	Other Customers (Average No.)	Total No. of Customers
HISTORY:					
2002	0	114	2,840	10,583	113,734
2003	0	130	2,890	10,517	115,050
2004	0	146	2,882	10,398	116,046
2005	0	143	2,952	10,206	118,002
2006	0	112	3,000	10,017	120,616
2007	0	120	3,068	9,871	122,380
2008	0	117	2,975	9,685	122,424
2009	0	132	2,992	9,432	121,982
2010	0	151	3,117	9,209	121,788
2011	0	29	2,893	9,078	121,763
FORECAST:					
2012	0	125	2,995	9,009	122,272
2013	0	130	3,094	9,017	123,269
2014	0	131	3,115	9,021	124,435
2015	0	132	3,136	9,027	125,840
2016	0	132	3,165	9,031	127,394
2017	0	133	3,188	9,036	128,989
2018	0	134	3,214	9,039	130,599
2019	0	136	3,242	9,045	132,226
2020	0	136	3,267	9,051	133,818
2021	0	137	3,293	9,055	135,313

Schedule 3.1
History and Forecast of Summer Peak Demand
Base Case

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
HISTORY:									
2002	578	0	578	0	0	0	0	0	578
2003	579	0	579	0	0	0	0	0	579
2004	584	0	584	0	0	0	0	0	584
2005	639	0	639	0	0	0	0	0	639
2006	631	0	631	0	0	0	0	0	631
2007	648	0	648	0	0	0	0	0	648
2008	615	0	615	0	0	0	0	0	615
2009	625	0	625	0	0	0	0	0	625
2010	638	0	638	0	0	0	0	0	638
2011	611	0	611	0	0	0	0	0	611
FORECAST:									
2012	655	0	655	0	0	0	0	0	655
2013	662	0	662	0	0	0	0	0	662
2014	669	0	669	0	0	0	0	0	669
2015	675	0	675	0	0	0	0	0	675
2016	682	0	682	0	0	0	0	0	682
2017	688	0	688	0	0	0	0	0	688
2018	695	0	695	0	0	0	0	0	695
2019	701	0	701	0	0	0	0	0	701
2020	707	0	707	0	0	0	0	0	707
2021	714	0	714	0	0	0	0	0	714

Schedule 3.2
History and Forecast of Winter Peak Demand
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
HISTORY:									
2001/02	694	0	694	0	0	0	0	0	694
2002/03	570	0	570	0	0	0	0	0	570
2003/04	648	0	648	0	0	0	0	0	648
2004/05	680	0	680	0	0	0	0	0	680
2005/06	596	0	596	0	0	0	0	0	596
2006/07	684	0	684	0	0	0	0	0	684
2007/08	710	0	710	0	0	0	0	0	710
2008/09	804	0	804	0	0	0	0	0	804
2009/10	709	0	709	0	0	0	0	0	709
2010/11	612	0	612	0	0	0	0	0	612
FORECAST:									
2011/12	696	0	696	0	0	0	0	0	696
2012/13	699	0	699	0	0	0	0	0	699
2013/14	703	0	703	0	0	0	0	0	703
2014/15	708	0	708	0	0	0	0	0	708
2015/16	713	0	713	0	0	0	0	0	713
2016/17	718	0	718	0	0	0	0	0	718
2017/18	723	0	723	0	0	0	0	0	723
2018/19	727	0	727	0	0	0	0	0	727
2019/20	731	0	731	0	0	0	0	0	731
2020/21	736	0	736	0	0	0	0	0	736

Schedule 3.3
History and Forecast of Annual Net Energy for Load - GWH
Base Case

(1) Year	(2) Total	(3) Residential Conservation	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor %
HISTORY:								
2002	2,726	0	0	2,726	0	114	2,840	44.8%
2003	2,760	0	0	2,760	0	130	2,890	57.9%
2004	2,736	0	0	2,736	0	146	2,882	50.8%
2005	2,809	0	0	2,809	0	143	2,952	49.6%
2006	2,888	0	0	2,888	0	112	3,000	57.5%
2007	2,948	0	0	2,948	0	120	3,068	51.2%
2008	2,858	0	0	2,858	0	117	2,975	47.8%
2009	2,860	0	0	2,860	0	132	2,992	42.5%
2010	2,966	0	0	2,966	0	151	3,117	50.2%
2011	2,864	0	0	2,864	0	29	2,893	47.4%
FORECAST:								
2012	2,870	0	0	2,870	0	125	2,995	49.1%
2013	2,964	0	0	2,964	0	130	3,094	50.5%
2014	2,984	0	0	2,984	0	131	3,115	50.6%
2015	3,004	0	0	3,004	0	132	3,136	50.6%
2016	3,033	0	0	3,033	0	132	3,165	50.7%
2017	3,055	0	0	3,055	0	133	3,188	50.7%
2018	3,080	0	0	3,080	0	134	3,214	50.7%
2019	3,106	0	0	3,106	0	136	3,242	50.9%
2020	3,131	0	0	3,131	0	136	3,267	51.0%
2021	3,156	0	0	3,156	0	137	3,293	51.1%

Schedule 4
Previous Year and 2-Year Forecast of Retail Peak Demand and Net Energy for Load by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2011 Actual		2012 Forecast		2013 Forecast	
Month	Peak Demand MW	NEL GWH	Peak Demand MW	NEL GWH	Peak Demand MW	NEL GWH
January	665	226	697	217	696	239
February	501	194	558	206	557	214
March	434	213	474	226	479	234
April	552	240	508	223	514	231
May	568	264	548	266	555	275
June	609	279	604	281	611	288
July	591	290	655	278	662	284
August	611	298	635	304	642	311
September	563	269	582	289	588	295
October	482	218	543	257	548	264
November	429	198	460	217	460	222
December	383	204	559	231	558	237

Schedule 5
Fuel Requirements

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Fuel Requirements		Units	Actual 2010	Actual 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
(1)	Nuclear		Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal[1]		1000 Ton	366	343	337	383	368	416	379	428	417	398	426	463
(3)	Residual	Total	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(4)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(5)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)		Other	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate	Total	1000 BBL	77	1	0	0	0	0	0	0	0	0	0	0
(9)		Steam	1000 BBL	0	1	0	0	0	0	0	0	0	0	0	0
(10)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CT	1000 BBL	77	0	0	0	0	0	0	0	0	0	0	0
(12)		Other	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	1000 MCF	14142	16123	18836	15041	15771	15076	16979	14917	16722	16162	16958	18430
(14)		Steam	1000 MCF	659	188	1	64	26	44	26	53	10	36	95	133
(15)		CC	1000 MCF	13467	15919	18835	14977	15745	15032	16953	14864	16712	16126	16863	18297
(16)		CT	1000 MCF	16	16	0	0	0	0	0	0	0	0	0	0
(17)	Other (Specify)		Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0

1 Includes Petroleum Coke

Schedule 6.1
Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 2010	Actual 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
(1)	Firm Inter-Region Interchange		GWH	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Nuclear		GWH	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal[1]		GWH	843	821	800	925	892	1007	923	1042	1019	976	1046	1140
(4)	Residual	Total	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(5)		Steam	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CC	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(8)		Other	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(9)	Distillate	Total	GWH	5	1	0	0	0	0	0	0	0	0	0	0
(10)		Steam	GWH	5	1	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWH	5	0	0	0	0	0	0	0	0	0	0	0
(12)		CT	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(13)		Other	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	GWH	1826	2346	2796	2474	2811	2497	2826	2712	2534	2683	2855	2728
(15)		Steam	GWH	56	10	0	4	1	2	1	5	0	4	5	12
(16)		CC	GWH	1769	2336	2796	2470	2810	2495	2825	2707	2534	2679	2850	2716
(17)		CT	GWH	1	0	0	0	0	0	0	0	0	0	0	0
(18)	NUG		GWH	0	0	0	0	0	0	0	0	0	0	0	0
(19)	Renewables	Total	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(20)		Biofuels	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(21)		Biomass	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(22)		Hydro	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(23)		Landfill Gas	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(24)		MSW	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(25)		Solar	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(26)		Wind	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(27)		Other	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(28)	Other (Specify)[2]		GWH	443	-274	-601	-305	-588	-368	-584	-566	-339	-417	-634	-575
(29)	Net Energy for Load		GWH	3117	2893	2995	3094	3115	3136	3165	3188	3214	3242	3267	3293

1 Includes Petroleum Coke.
Intra-Regional Net Interchange[2]

Schedule 6.2
Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 2010	Actual 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
(1)	Firm Inter-Region Interchange		%	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Nuclear		%	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal		%	27.05	28.38	26.71	29.9	28.64	32.11	29.16	32.69	31.71	30.1	32.02	34.62
(4)	Residual	Total	%	0	0	0	0	0	0	0	0	0	0	0	0
(5)		Steam	%	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CC	%	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	%	0	0	0	0	0	0	0	0	0	0	0	0
(8)		Other	%	0	0	0	0	0	0	0	0	0	0	0	0
(9)	Distillate	Total	%	0.16	0	0	0	0	0	0	0	0	0	0	0
(10)		Steam	%	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	%	0.16	0	0	0	0	0	0	0	0	0	0	0
(12)		CT	%	0	0	0	0	0	0	0	0	0	0	0	0
(13)		Other	%	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	%	58.58	81.08	93.36	79.96	90.24	79.62	89.29	85.07	78.84	82.76	87.39	82.84
(15)		Steam	%	1.8	0.35	0	0.13	0.03	0.06	0.03	0.16	0	0.12	0.15	0.36
(16)		CC	%	56.75	80.75	93.36	79.83	90.21	79.56	89.26	84.91	78.84	82.63	87.24	82.48
(17)		CT	%	0.03	0	0	0	0	0	0	0	0	0	0	0
(18)	NUG		%	0	0	0	0	0	0	0	0	0	0	0	0
(19)	Renewables	Total	%	0	0	0	0	0	0	0	0	0	0	0	0
(20)		Biofuels	%	0	0	0	0	0	0	0	0	0	0	0	0
(21)		Biomass	%	0	0	0	0	0	0	0	0	0	0	0	0
(22)		Hydro	%	0	0	0	0	0	0	0	0	0	0	0	0
(23)		Landfill Gas	%	0	0	0	0	0	0	0	0	0	0	0	0
(24)		MSW	%	0	0	0	0	0	0	0	0	0	0	0	0
(25)		Solar	%	0	0	0	0	0	0	0	0	0	0	0	0
(26)		Wind	%	0	0	0	0	0	0	0	0	0	0	0	0
(27)		Other	%	0	0	0	0	0	0	0	0	0	0	0	0
(28)	Other (Specify)[2]		%	1421	-9.47	-20.07	-9.86	-18.88	-11.73	-18.45	-17.75	-10.55	-12.86	-19.41	-17.46
(29)	Net Energy for Load		%	100	100	100	100	100	100	100	100	100	100	100	100

1 Includes Petroleum Coke.
Intra-Regional Net Interchange[2]

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Year	Total Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	QF MW	Total Capacity Available MW	System Firm Summer Peak Demand MW	Reserve Margin before Maintenance MW	% of Peak	Scheduled Maintenance MW	Reserve Margin after Maintenance MW	% of Peak
FORECAST:											
2012	929	0	0	0	929	655	274	42%	0	274	42%
2013	929	0	0	0	929	662	267	40%	0	267	40%
2014	929	0	0	0	929	669	260	39%	0	260	39%
2015	929	0	0	0	929	675	254	38%	0	254	38%
2016	929	0	0	0	929	682	247	36%	0	247	36%
2017	929	0	0	0	929	688	241	35%	0	241	35%
2018	929	0	0	0	929	695	234	34%	0	234	34%
2019	929	0	0	0	929	701	228	33%	0	228	33%
2020	929	0	0	0	929	707	222	31%	0	222	31%
2021	929	0	0	0	929	714	215	30%	0	215	30%

Schedule 7.2
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Year	Total Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	QF MW	Total Capacity Available MW	System Firm Winter Peak Demand MW	Reserve Margin before Maintenance MW	Reserve Margin before Maintenance % of Peak	Scheduled Maintenance MW	Reserve Margin after Maintenance MW	Reserve Margin after Maintenance % of Peak
FORECAST:											
2011/12	975	0	0	0	975	696	279	40%	0	279	40%
2012/13	975	0	0	0	975	699	276	40%	0	276	40%
2013/14	975	0	0	0	975	703	272	39%	0	272	39%
2014/15	975	0	0	0	975	708	267	38%	0	267	38%
2015/16	975	0	0	0	975	713	262	37%	0	262	37%
2016/17	975	0	0	0	975	718	257	36%	0	257	36%
2017/18	975	0	0	0	975	723	252	35%	0	252	35%
2018/19	975	0	0	0	975	727	248	34%	0	248	34%
2019/20	975	0	0	0	975	731	244	33%	0	244	33%
2020/21	975	0	0	0	975	736	239	33%	0	239	33%

Schedule 8
Planned and Prospective Generating Facility Additions and Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
								Const.	Commercial	Expected	Gen. Max.	Net Capability		
	Unit		Unit	Fuel		Fuel Transport		Start	In-Service	Retirement	Nameplate	Summer	Winter	
Plant Name	No.	Location	Type	Pri	Alt	Pri	Alt	Mo/Yr	Mo/Yr	Mo/Yr	KW	MW	MW	Status

No changes at this time

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) Plant Name and Unit Number: No changes at this time

(2) Capacity
a. Summer:
b. Winter:

(3) Technology Type:

(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:

(12) Projected Unit Perfomance Data
Planned Outage Factor (POF):
Forced Outage Factor (FOF):
Equivalent Availability Factor (EAF):
Resulting Capacity Factor (%):
Average Net Operating Heat Rate (ANOHR):

(13) Projected Unit Financial Data
Book Life (Years):
Total Installed Cost (In-Service Year $/kW):
Direct Construction Cost ($/kW):
AFUDC Amount ($/kW):
Escalation ($/kW):
Fixed O&M ($/kW-Yr):
Variable O&M ($/MWH):
K Factor:

Schedule 10
Status Report and Specifications of Proposed Directly Associated Transmission Lines

(1)	Point of Origin and Termination:	No changes at this time
(2)	Number of Lines:	
(3)	Right-of-Way:	
(4)	Line Length:	
(5)	Voltage:	
(6)	Anticipated Construction Timing:	
(7)	Anticipated Capital Investment:	
(8)	Substations:	
(9)	Participation with Other Utilities:	

2012 Ten-Year Site Plan

Electrical Generating Facilities & Associated Transmission Lines

April 2012

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1.0 Introduction

This report contains the 2012 Lakeland Electric Ten-Year Site Plan (TYSP) pursuant to Florida Statutes and as adopted by Order No. PSC-97-1373-FOF-EU on October 30, 1997. The Lakeland TYSP reports the status of the utility's resource plans as of December 31, 2011. The TYSP is divided into the following nine sections: Introduction, General Description of Utility, Forecast of Electrical Power Demand and Energy Consumption, Energy Conservation & Management Programs, Forecasting Methods and Procedures, Forecast of Facilities Requirements, Generation Expansion Analysis Results and Conclusions, Environmental and Land Use Information, and Ten-Year Site Plan Schedules. The contents of each section are summarized briefly in the remainder of this Introduction.

1.1 General Description of the Utility

Section 2.0 of the TYSP discusses Lakeland's existing generation and transmission facilities. The section includes a historical overview of Lakeland's system, and a description of existing power generating and transmission facilities. This section includes tables which show the source of the utility's current 975 MW of net winter generating capacity and 929 MW of net summer generating capacity (as of the end of calendar year 2011).

1.2 Forecast of Electrical Power Demand and Energy Consumption

Section 3.0 of the TYSP provides a summary of Lakeland's load forecast. Lakeland is projected to remain a winter peaking system throughout the planning period. The projected annual growth rates in peak demand for the winter and summer are 0.62 % and 0.96 % percent, respectively, for 2012 through 2021.

Net energy for load is projected to grow at an average annual rate of 1.06% percent for 2012 through 2021. Projections are also developed for high and low load growth scenarios.

1.3 Energy Conservation and Management Programs

Section 4.0 provides descriptions of the existing conservation and energy conservation & management programs. Additional details regarding Lakeland's energy conservation & management programs are on file with the Florida Public Service Commission (FPSC).

Lakeland's current energy conservation & management programs include the following programs for which demand and energy savings can readily be demonstrated:

- Commercial Programs:
  - Commercial Lighting Program.
  - Thermal Energy Storage Program.

Lakeland also currently conducts the following conservation and energy management programs which promote energy savings and efficiency:

- Residential Programs:
  - Energy Audit Program.
  - Public Awareness Program.
  - Speakers Bureau.
  - Informational Bill Inserts.
- Commercial Programs:
  - Commercial Audit Program.

Section 4.0 also contains discussions of Lakeland's solar technology programs. While these types of programs are not traditionally thought of as DSM, they have the same effect of conserving energy normally generated by fossil fuels as DSM programs do by virtue of their avoidance of fossil fuels through the use of renewable energy.

1.4 Forecasting Methods and Procedures

Section 5.0 discusses the forecasting methods used for the TYSP and outlines the assumptions applied for system planning. This section also summarizes the integrated resource plan for Lakeland and provides planning criteria for the Florida Municipal Power Pool, of which Lakeland is a member. The integrated resource plan is fully incorporated in the TYSP and is discussed in further detail in Sections 6 and 7 of this report. Fuel price projections are provided for coal, natural gas, and oil; with brief descriptions of the methodology. Assumptions for the economic parameters and evaluation criteria which are being applied in the evaluation are also included in Section 5.0.

1.5 Forecast of Facilities Requirements

Section 6.0 integrates the electrical demand and energy forecast with the energy conservation & management forecast to determine Lakeland's requirements for the ten-year planning horizon. Application of the reserve margin criteria indicates no need for additional capacity during the current ten year reporting period.

1.6 Generation Expansion Analysis Results and Conclusions

Section 7.0 discusses the current status of any supply-side evaluation being undertaken by Lakeland to identify the best option for its system. It also discusses basic methodology used by Lakeland in its Generation Expansion Planning Process.

1.7 Environmental and Land Use Information

Section 8.0 discusses the land and environmental features of Lakeland's TYSP.

1.8 Ten-Year Site Plan Schedules

Section 9.0 presents the schedules required by the Florida Public Service Commission (FPSC) for the TYSP.

2.0 General Description of Utility

2.1 City of Lakeland Historical Background

2.1.1 Generation

The City of Lakeland was incorporated on January 1, 1885, when 27 citizens approved and signed the city charter. Shortly thereafter the original light plant was built by Lakeland Light and Power Company at the corner of Cedar Street and Massachusetts Avenue. This plant had an original capacity of 50 kW. On May 26, 1891, plant manager Harry Sloan threw the switch to light Lakeland by electricity for the first time with five arc lamps. Incandescent lights were first installed in 1903.

Public power in Lakeland was established in 1904, when foresighted citizens and municipal officials purchased the small private 50 kW electric light plant from owner Bruce Neff for $7,500. The need for an expansion led to the construction of a new power plant on the north side of Lake Mirror in 1916. The initial capacity of the Lake Mirror Power Plant is estimated to have been 500 kW. The plant has since been expanded three times. The first expansion occurred in 1922 with the addition of 2,500 kW; in 1925, 5,000 kW additional capacity was added, followed by another 5,000 kW in 1938. With the final expansion, the removal of the initial 500 kW unit was required to make room for the addition of the 5,000 kW generating unit, resulting in a total peak plant capacity of 12,500 kW.

As the community continued to grow, the need for a new power plant emerged and the Charles Larsen Memorial Power Plant was constructed on the southeast shore of Lake Parker in 1949. The initial capacity of the Larsen Plant Steam Unit No. 4 completed in 1950 was 20,000 kW. The first addition to the Larsen Plant was Steam Unit No. 5 (1956) which had a capacity of 25,000 kW. In 1959, Steam Unit No. 6 was added and increased the plant capacity by another 25,000 kW. Three gas turbines, each with a nominal rating of 11,250 kW, were installed as peaking units in 1962. In 1966, a third steam unit capacity addition was made to the Larsen Plant. This was Steam Unit No.7 having a nominal 44,000 kW capacity and an estimated cost of $9.6 million. This brought the total Larsen Plant nameplate capacity up to a nominal 147,750 kW.

In the meantime, the Lake Mirror Plant, with its old and obsolete equipment, became relatively inefficient and hence was no longer in active use. It was kept in cold standby and then retired in 1971.

As the city continued to grow during the late 1960's, the demand for power and electricity grew at a rapid rate, making evident the need for a new power plant. A site was purchased on the north side of Lake Parker and construction commenced during 1970. Initially, two diesel units with a peaking capacity of a nominal rating 2,500 kW each were placed into commercial operation in 1970.

Steam Unit No. 1, with a nominal rating of 90,000 kW, was put into commercial operation in February 1971, for a total cost of $15.22 million. In June of 1976, Steam Unit No. 2 at Plant 3 was placed into commercial operation, with a nominal rated capacity of 114,707 kW and at a cost of $25.77 million. This addition increased the total capacity of the Lakeland system to approximately 360,000 kW. At this time, Plant 3 was renamed the C. D. McIntosh, Jr. Power Plant in recognition of the former Electric and Water Department director.

On January 2, 1979, construction was started on McIntosh Unit No. 3, a nominal 334 MW coal fired steam generating unit which became commercial on September 1, 1982. The unit was designed to use low sulfur oil as an alternate fuel but an alternate fuel has never been used in the unit. The unit uses a minimal amount of natural gas or #2 diesel oil for flame stabilization during startups. Petroleum Coke has been used as a supplemental fuel to coal based on economics. The plant utilizes sewage effluent for cooling tower makeup water. This unit is jointly owned with the Orlando Utilities Commission (OUC) which has a 40 percent undivided interest in the unit.

As load continued to grow, Lakeland continually studied and reviewed alternatives for accommodating the additional growth. Alternatives included both demand- and supply-side resources. A wide variety of conservation and energy conservation & management programs were developed and marketed to Lakeland customers to encourage increased energy efficiency and conservation in keeping with the Florida Energy Efficiency and Conservation Act of 1980 (FEECA). Changes to the FEECA rules in 1993 exempted Lakeland from conservation requirements, but Lakeland has remained active in promoting and implementing cost-effective conservation programs. These programs are discussed in further detail in Section 4.0.

Although demand and energy savings arose from Lakeland's conservation and energy conservation & management programs, additional capacity was required in the early 1990's. Least cost planning studies resulted in the construction of Larsen Unit No. 8, a natural gas fired combined cycle unit with a nameplate generating capability of 124,000 kW. Larsen Unit No. 8 began simple cycle operation in July 1992, and combined cycle operation in November of that year.

In 1994, Lakeland made the decision to retire the first unit at Larsen Plant, Steam Unit No. 4. This unit, put in service in 1950 with a capacity of 20,000 kW, had reached the end of its economic life. In March of 1997, Lakeland retired, Larsen Unit No. 6, a 25 MW oil fired unit that was also nearing the end of its economic life. In October of 2004, Lakeland retired Larsen Unit 7, a 50MW oil fired steam unit.

In 1999, the construction of McIntosh Unit No. 5 Simple Cycle combustion turbine was completed. The unit was released for commercial operation in May, 2001. Beginning in September 2001, the unit underwent conversion to a combined cycle unit through the addition of a nominal 120 MW steam turbine generator. Construction was completed in Spring 2002 with the unit being declared commercial in May 2002. The resulting combined cycle gross capacity of the unit is 345 MW summer and 360 MW winter.

During the summer of 2001, Lakeland took its first steps into the world of distributed generation with the groundbreaking of its Winston Peaking Station. The Winston Peaking Station consists of 20 quick start reciprocating engines each driving a 2.5 MW electric generator. This provides Lakeland with 50 MW of peaking capacity that can be started and put on line at full load in ten minutes. The Station was declared commercial in late December 2002.

In 2009 Lakeland Electric installed an ammonia injection system using the principle of selective catalytic reduction (SCR) on Unit 3. This being part of a project to provide full flexibility in implementing the Federal Cap and Trade program for nitrogen oxides (NOx) required under the Clean Air Interstate Rule (CAIR).

2.1.2 Transmission

The first phase of the Lakeland 69 kV transmission system was placed in operation in 1961 with a step-down transformer at the Lake Mirror Plant to feed the 4 kV bus, nine 4 kV feeders, and a new substation in the southwest section of town with two step-down transformers feeding four 12 kV feeders.

In 1966, a 69 kV line was completed from the Northwest substation to the Southwest substation, completing the loop around town. At the same time, the old tie to Bartow was reinsulated for a 69 kV line and placed in operation, feeding a new step-down substation in Highland City with four 12 kV feeders. In addition, a 69 kV line was completed from Larsen Plant around the Southeast section of town to the southwest substation. By 1972, 20 sections of 69 kV lines, feeding a total of nine step-down substations, with a total of 41 distribution feeders, were completed and placed in service. By the fall of 1996, all of the original 4 kV equipment and feeders had been replaced and/or upgraded to 12 kV service. By 1998, 29 sections of 69 kV lines were in service feeding 20 distribution substations.

As the Lakeland system continued to grow, the need for additional and larger transmission facilities grew as well. In 1981, Lakeland's first 230 kV facilities went into service to accommodate Lakeland's McIntosh Unit No. 3 and to tie Lakeland into the State transmission grid at the 230 kV level. A 230 kV line was built from McIntosh Plant to Lakeland's west substation. A 230/69 kV autotransformer was installed at each of those substations to tie the 69 kV and 230 kV transmission systems together. In 1988, a second 230 kV line was constructed from the McIntosh Plant to Lakeland's Eaton Park substation along with a 230/69 kV autotransformer at Eaton Park. That line was the next phase of the long-range goal to electrically circle the Lakeland service territory with 230 kV transmission to serve as the primary backbone of the system.

In 1999, Lakeland added generation at its McIntosh Power Plant that resulted in a new 230/69/12kV substation being built and energized in March of that year. The Tenoroc substation, replaced the switching station called North McIntosh. In addition to Tenoroc, another new 230/69/12kV substation was built. The substation, Interstate, went on line June of 1999 and is connected by what was the McIntosh West 230 kV line. This station was built to address concerns about load growth in the areas adjacent to the I-4 corridor which were causing problems at both the 69kV and distribution levels in this area.

In 2001, Lakeland began the next phase of its 230kV transmission system with the construction of the Crews Lake 230/69kV substation. The substation was completed and placed in service in 2001. This project includes two 230kV ties and one 69kV tie with Tampa Electric, a 150MVA 230/69kV autotransformer and a 230kV line from Lakeland's Eaton Park 230kV substation to the Crews Lake substation.

Early transmission interconnections with other systems included a 69 kV tie at Larsen Plant with Tampa Electric Company (TECO), established in the mid 1960s. A second tie with TECO was later established at Lakeland's Highland City substation. A 115 kV tie was established in the 1970s with Progress Energy of Florida (PEF) and Lakeland's West substation and was subsequently upgraded and replaced with the current two 230 kV lines to PEF in 1981. At the same time, Lakeland interconnected with Orlando Utilities Commission (OUC) at Lakeland's McIntosh Power Plant. In August 1987, the 69 kV TECO tie at Larsen Power Plant was taken out of service and a new 69 kV TECO tie was put in service connecting Lakeland's Orangedale substation to TECO's Polk City substation. In mid-1994, a new 69 kV line was energized connecting Larsen Plant to the Ridge Generating Station (Ridge), an independent power producer. Lakeland has a 30-year firm power-wheeling contract with Ridge to wheel up to 40 MW of their power to PEF. In early 1996, a new substation, East, was inserted in the Larsen Plant to the Ridge 69 kV transmission line. Later in 1996, the third tie line to TECO was built from East to TECO's Gapway substation. As mentioned above, in August of 2001, Lakeland completed two 230kV ties and one 69kV tie with TECO at Lakeland's Crews Lake substation. The multiple 230 kV interconnection configuration of Lakeland is also tied into the bulk transmission grid and provides access to the 500 kV transmission network via PEF, providing for greater reliability. At the present time, Lakeland has a total of approximately 124 miles of 69 kV transmission and 28 miles of 230 kV transmission lines in service along with six 150 MVA 230/69 kV autotransformers.

2.2 General Description: Lakeland Electric

2.2.1 Existing Generating Units

This section provides additional detail on Lakeland's existing units and transmission system. Lakeland's existing generating units are located at the two existing plant sites: Charles Larsen Memorial (Larsen) and C.D. McIntosh Jr. (McIntosh). Both plant sites are located on Lake Parker in Polk County, Florida. The two plants have multiple units with different technologies and fuel types. The following paragraphs provide a summary of the existing generating units for Lakeland. Table 2-1 summarizes the environmental considerations for Lakeland's steam turbine generators and Table 2-2 provides other physical characteristics of all Lakeland generating units.

The Larsen site is located on the southeast shore of Lake Parker in Lakeland. The site has three units. The total net winter (summer) capacity of the plant is 151 MW (124 MW). Units 2 and 3, General Electric combustion turbines, have a combined net winter (summer) rating of 27 MW (19 MW). The units burn natural gas as a primary fuel with diesel as a backup. Historically, Larsen Unit No. 5 consisted of a boiler for steam generation and steam turbine to convert the steam to electrical power. When the boiler began to show signs of degradation beyond economical repair, a gas turbine with a heat recovery steam generator, Unit No. 8, was added to the facility. This allowed the gas turbine (Unit No. 8) to generate electricity and the waste heat from the gas turbine to repower the former Unit No. 5 steam turbine in a combined cycle configuration. The former Unit No. 5 steam turbine currently has a net winter (summer) rating of 31 MW (29 MW) and is referred to as Unit No. 8 Steam Turbine from this point on in this document and in the reporting of this unit. The Unit No. 8 combustion turbine has a net winter (summer) rating of 93 MW (76 MW).

The McIntosh site is located in the City of Lakeland along the northeastern shore of Lake Parker and encompasses 513 acres. Electricity generated by the McIntosh units is stepped up in voltage by generator step-up transformers to 69 kV and 230 kV for transmission via the power grid. The McIntosh site currently includes seven units in commercial operation having a total net winter and summer capacity of 774 MW and 755 MW, respectively. Unit CT1 consists of a General Electric combustion turbine with a net winter (summer) output rating of 19 MW (16 MW). Unit No. 1 is a natural gas/oil fired General Electric steam turbine with a net winter and summer output of 85 MW. Unit No. 2 is a natural gas/oil fired Westinghouse steam turbine with a winter and summer output of 106 MW. Unit No. 3 is a 342 MW pulverized coal fired unit owned 60 percent by Lakeland and 40 percent by OUC. Lakeland's share of the unit yields net winter and summer output of 205 MW. Technologies used for Unit 3 are very innovative making it a very environmentally friendly coal unit. Unit No. 3 was one of the first "zero-discharge" plants built, meaning no waste water products leave the plant site untreated. Unit No. 3 also includes a wet flue gas scrubber for SO_2 removal and uses treated sewage water for cooling water. Two small diesel units with a net output of 2.5 MW each are also located at the McIntosh site.

McIntosh Unit No. 5, a Westinghouse 501G combined cycle unit, was initially built and operated as a simple cycle combustion turbine that was placed into commercial operation May, 2001. The unit was taken off line for conversion to combined cycle starting in mid September 2001 and was returned to commercial service in May 2002 as a combined cycle unit with a rating of 354 MW winter and 338 MW summer. The unit is equipped with Selective Catalytic Reduction (SCR) for NO_x control.

Lakeland Electric constructed a 50-megawatt electric peaking station adjacent to its Winston Substation in 2001. The purpose of the peaking plant was to provide additional quick start generation for Lakeland's system during times of peak loads.

The station consists of twenty (20) EMD 20 cylinder reciprocating engines driving 2.5 MW generators. The units are currently fueled by #2 fuel oil but have the capability to burn a mix of 5% #2 oil and 95% natural gas. Lakeland currently does not have natural gas service to the site.

The plant has remote start/run capability for extreme emergencies at times when the plant is unmanned. The station does not use open cooling towers. This results in minimal water or wastewater requirements. Less than three quarters of the six (6) acre site was developed leaving considerable room for water retention.

The engines are equipped with hospital grade noise suppression equipment on the exhausts. Emission control is achieved by Selective Catalytic Reduction (SCR) using 19% aqueous ammonia. The SCR system will allow the plant to operate within the

Minor New Source levels permitted by the Florida Department of Environmental Protection (DEP).

Winston Peaking Station (WPS) was constructed adjacent to Lakeland's Winston Distribution Load Substation. Power generated at WPS goes directly into Winston Substation at the 12.47kV distribution level of the substation and has sufficient capacity to serve the substation loads. Winston Substation serves several of Lakeland's largest and most critical accounts. Should Winston lose all three 69kV circuits to the substation, the WPS can be on line and serving load within ten minutes. In addition to increasing the substation's reliability, this arrangement will allow Lakeland to delay the installation of a third 69kV to 12.47kV transformer by several years and also contributes to lowering loads on Lakeland's transmission system.

2.2.2 Capacity and Power Sales Contracts

Lakeland has no firm power sales contract in place as of December 31, 2011.

Lakeland shares ownership of the C. D. McIntosh Unit 3 with OUC. The ownership breakdown is a 60 percent share for Lakeland and a 40 percent ownership share for OUC. The energy and capacity delivered to OUC from McIntosh Unit 3 is not considered a power sales contract because of the OUC ownership share.

2.2.3 Capacity and Power Purchase Contracts

Lakeland currently has no long term firm power purchase contracts in place as of December 31, 2011.

2.2.4 Planned Unit Retirements

Lakeland currently has no set retirement plans in place for its units due to the current economic conditions of the electric utility industry and the uncertainty that those conditions present. When that is combined with an ample reserve margin, Lakeland deems that its most prudent decision for the moment is to continue to put all expansion and retirement plans into abeyance until market conditions encourage a change.

2.2.5 Load and Electrical Characteristics

Lakeland's load and electrical characteristics have many similarities with those of other peninsular Florida utilities. The peak demand has historically occurred during the winter months. Lakeland's actual total peak demand (Net Integrated) in the winter of 2011/2012 was 612 MW which occurred on January 4th. The actual summer peak in

2011 was 611 MW and occurred on August 12th. Lakeland normally is winter peaking and expects to continue to do so in the future based on expected normal weather. Lakeland's historical and projected summer and winter peak demands are presented in Section 3.0.

Lakeland is a member of the Florida Municipal Power Pool (FMPP), along with Orlando Utilities Commission (OUC) and the Florida Municipal Power Agency's (FMPA) All-Requirements Project. The FMPP operates as an hourly non-firm energy pool with all FMPP capacity from its members committed and dispatched economically together. Commitment and dispatch services for FMPP are provided by OUC. Each member of the FMPP retains the responsibility of adequately planning its own system to meet native loads, obligations and reserve requirements.

2.3 Service Area

Lakeland's electric service area is shown on Figure 2-1 and is entirely located in Polk County. Lakeland serves approximately 246 square miles of which approximately 171 square miles is outside of Lakeland's city limits.

Table 2-1
Lakeland Electric
Existing Generating Facilities
Environmental Considerations for Steam Generating Units

Plant Name	Unit	Particulate	Flue Gas Cleaning		Type
			SO_x	NO_x	
Charles Larsen Memorial	8ST	N/A	N/A	N/A	OTF
C. D. McIntosh, Jr.	1	None	None	None	OTF
	2	None	LS	FGR	WCTM
	3	EP	S	LNB	WCTM
	5ST	N/A	N/A	N/A	WCTM

FGR = Flue gas recirculation
LNB = Low NO_x burners
EP = Electrostatic precipitators
LS = Low sulfur fuel
S = Scrubbed
OTF = Once-through flow
WCTM = Water cooling tower mechanical
N/A = Not applicable to waste heat applications

Source: Lakeland Environmental Staff

Table 2-2a
Lakeland Electric Existing Generating Facilities

Plant Name	Unit No.	Location	Unit Type[3]	Fuel[4] Pri	Fuel[4] Alt	Fuel Transport[5] Pri	Fuel Transport[5] Alt	Alt Fuel Days Use[2]	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen. Max. Nameplate kW	Net Capability Summer MW	Net Capability Winter MW
Charles Larsen Memorial	2	16-17/28S/24E	GT	NG	DFO	PL	TK	---	11/62	Unknown	11,500	10	14
	3		GT	NG	DFO	PL	TK	---	12/62	Unknown	11,500	9	13
	8		CA	WH	---	---	---	---	04/56	Unknown	25,000	29	31
	8		CT	NG	DFO	PL	TK	---	07/92	Unknown	101,520	76	93
Plant Total												124	151

[2]Lakeland does not maintain records of the number of days that alternate fuel is used.

[3]Unit Type

CA	Combined Cycle Steam Part
CT	Combined Cycle Combustion Turbine
GT	Combustion Gas Turbine
ST	Steam Turbine

[4]Fuel Type

DFO	Distillate Fuel Oil
RFO	Residual Fuel Oil
BIT	Bituminous Coal
WH	Waste Heat
NG	Natural Gas

[5]Fuel Transportation Method

PL	Pipeline
TK	Truck
RR	Railroad

Table 2-2b
Lakeland Electric Existing Generating Facilities

Plant Name	Unit No.	Location	Unit Type[3]	Fuel[4] Pri	Fuel[4] Alt	Fuel Transport[5] Pri	Fuel Transport[5] Alt	Alt Fuel Days Use[2]	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen. Max. Nameplate kW	Net Capability Summer MW	Net Capability Winter MW
Winston Peaking Station	1-20	21/28S/23E	IC	NG	DFO	PL	TK	NR	12/01	Unknown	2,500 each	50	50
Plant Total												50	50
C.D. McIntosh, Jr.	D1	4-5/28S/24E	IC	DFO	---	TK	---	NR	01/70	Unknown	2,500	2.5	2.5
	D2		IC	DFO	---	TK	---	NR	01/70	Unknown	2,500	2.5	2.5
	GT1		GT	NG	DFO	PL	TK	NR	05/73	Unknown	26,640	16	19
	1		ST	NG	RFO	PL	TK	NR	02/71	Unknown	103,000	85	85
	2		ST	NG	RFO	PL	TK	NR	06/76	Unknown	126,000	106	106
	3[1]		ST	BIT	---	RR	TK	NR	09/82	Unknown	363,870	205	205
	5		CT	NG	DFO	PL	TK	NR	05/01	Unknown	292,950	213	233
	5		CA	WH	---	---	---	NR	05/02	Unknown	135,000	125	121
Plant Total												755	774
System Total												**929**	**975**

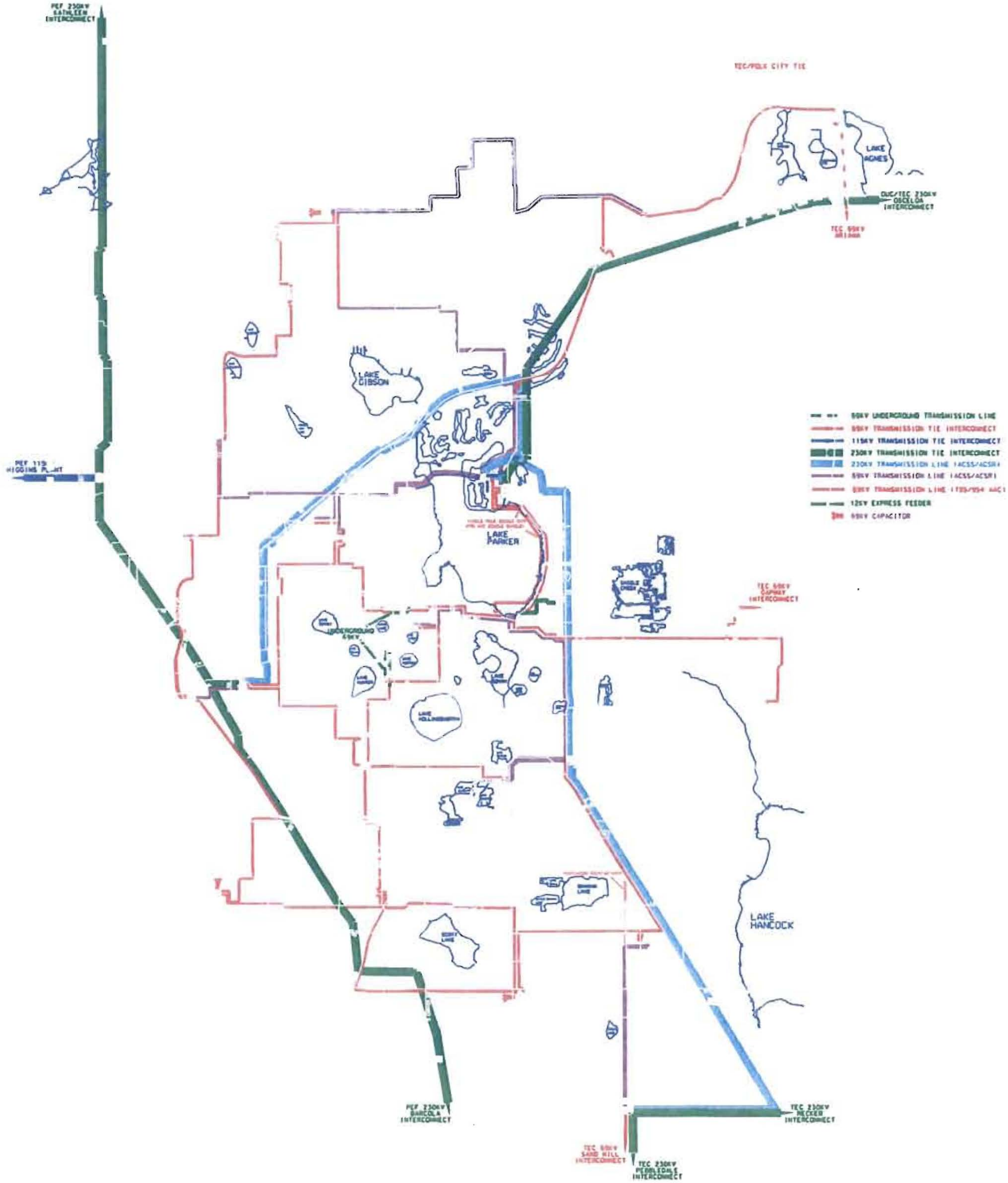
[1]Lakeland's 60 percent portion of joint ownership with Orlando Utilities Commission.
[2]Lakeland does not maintain records of the number of days that alternate fuel is used.

[3]Unit Type
CA Combined Cycle Steam Part
CT Combined Cycle Combustion Turbine
GT Combustion Gas Turbine
ST Steam Turbine

[4]Fuel Type
DFO Distillate Fuel Oil
RFO Residual Fuel Oil
BIT Bituminous Coal
WH Waste Heat
NG Natural Gas

[5]Fuel Transportation Method
PL Pipeline
TK Truck
RR Railroad

LAKELAND ELECTRIC



3.0 Forecast of Electrical Power Demand and Energy Consumption

Annually, Lakeland develops a detailed short-term (1-year) electric load and energy forecast for budget purposes and short-term operational studies. The annual long-term (25-30 years) forecast is developed for use in the Utility's long-term planning studies. The long-term forecasts are used as a key input into Lakeland's Integrated Resource Plan.

Sales and customer forecasts of monthly data are prepared by rate classification or revenue class. Separate forecast models are developed for inside and outside Lakeland's corporate limits for the Residential (RS), General Service (GS), General Service Demand (GSD) and Industrial rate classifications. Monthly forecasts are summarized annually using fiscal period ending September 30th.

Lakeland uses an advanced statistical program called MetrixND (developed by Itron) to assist with the analysis and forecasting of its time series data such as number of customers, energy and demand consumption. MetrixND allows Lakeland to incorporate economic, demographic, price, elasticities, end-use appliance saturations and efficiencies, and various weather variables into the forecast.

Lakeland also uses MetrixLT (developed by Itron), which integrates with MetrixND, and is used for developing long-term system and revenue class hourly load forecasts.

MetrixND and MetrixLT are both established software packages developed by Itron which are widely used throughout the utility forecasting industry.

Many variables are evaluated for the development of the forecast. The variables that proved to be significant and are included in the forecast are: Gross State Product (GSP), non-manufacturing employment, total employment, disposable personal income per household, persons per household, growth in number of households, structural changes (appliance saturation and efficiency trends) as well as weather. Binary variables were also used to explain outliers in historical billing data, trend shifts, monthly seasonality, rate migration between classes, etc…

The economic projections used in this forecast are purchased from Moody's Economy.com. Moody's is one of the leading economic forecasting and consulting firms in the nation and their data is widely used within the electric forecasting industry. This forecast reflects their most current economic outlook at time of forecast development, December 2011.

Additionally, population projections used in this forecast are purchased from the Bureau of Business and Economic Research (BEBR). BEBR is an applied research center in the Warrington College of Business Administration at the University of Florida. BEBR focuses their research on Florida and its local areas. BEBR's population projections are also widely used throughout the electric forecasting industry. This forecast reflects their most recent demographic projections at time of forecast development, June 2011.

The real price of electricity was developed using a 12-month moving average of real average revenue. The historical price data by class, along with the Consumer Price Index (CPI), was used to develop a price forecast for use in the MetrixND modeling structure.

Heating and cooling degree days are variables that attempt to explain a customer's usage behavior as influenced by either hot or cold weather. The industry standard for calculating degree days is: Average Daily Temperature – 65 degrees (base temperature) = Heating or Cooling Degree Day. Example: If the Average Daily Temperature is higher than 65 degrees, then it is a Cooling Degree Day (CDD). Example: 75 (average daily temperature) - 65 = 10 CDD. If the Average Daily Temperature is lower than 65 degrees, then it is a Heating Degree Day (HDD). Example: 55 (average daily temperature) – 65 = 10 (base temperature) HDD.

These heating and cooling degree day variables are used in the forecasting process to correlate electric consumption with weather. The heating and cooling degree days are weighted to capture the impacts of weather on revenue month billed consumption.

The Utility owns and operates seven of its own weather stations. The weather stations are strategically placed throughout the electric service territory to provide the best estimate of overall temperature for the Lakeland service area. All of the models of the forecast are developed using historical 20-year normal weather.

Normal temperatures at time of peak are used for peak modeling. Heating and cooling degree days are calculated for each monthly peak. Then, the weather variables are ranked from the highest to lowest value within each year. Normal peak day HDD and CDD's are then defined as an average across the rankings. The last step is to map the average values back to the month during which the highest HDD or CDD typically occurs.

Historical monthly data was available and analyzed for the 20-year period from Fiscal Years 1990 - 2012. However, after careful evaluation of the data and model statistics, most models were developed using less than a 10-year estimation period.

The techniques employed to generate the forecasts include: econometric and multiple regression modeling, study of historical relationships and growth rates, trend analysis, and exponential smoothing. Lakeland also reviews the forecasts for reasonableness, compares projections to historical patterns, and modifies the results as needed using informed judgment.

The winter peak forecast is developed under the assumption that its occurrence will be on a January weekday. Winter temperatures at peak ranging from 28.5° F to 32.8° F have typically occurred on January to March weekdays between 7 and 8 a.m. Lakeland remains a winter peaking utility through the projected period.

The summer peak forecast is developed under the assumption that its occurrences will be on a July weekday. The summer temperatures at peak ranging from 94.1° F to 96.1° F have typically occurred on weekdays between 3 and 6 p.m.

Lakeland currently does not have any Demand Side Management (DSM); therefore, does not assume any deductions in peak load for the forecast period.

The results of the energy sales forecasts for all revenue classes are added together to create a total sales forecast. A loss-factor of approximately 4.2% (based on historical monthly data) is applied to convert total energy sales into net energy for load (NEL).

3.1 Service Territory Population Forecast

Electric Service Territory Population Estimate

Lakeland Electric's service area encompasses approximately 246 square miles of which approximately 171 square miles are outside the City of Lakeland's corporate limits. The estimated electric service territory population for Lakeland for Fiscal Year 2011 is 254,283 persons.

Population Forecast

Lakeland's electric service territory population is projected to increase at an estimated 1.15% average annual growth rate (AAGR) from Fiscal Year 2012 through Fiscal Year 2021. Polk County's population (Lakeland/Winter-Haven MSA) is growing at 1.57% AAGR for the same 10-year period. Historically, Polk County's population has grown faster than Lakeland's electric service territory population.

3.2 Account Forecasts

Lakeland forecasts the number of monthly electric accounts for the following categories and subcategories:

Residential

- Commercial
  - General Service
  - General Service Demand
- Industrial
  - General Service Large Demand
  - Contract
  - Interruptible
  - ELDC (Extra Large Demand Customer)
- Other
  - Private Area Lighting
  - Roadway Lighting
  - Electric
  - Water
  - Municipal

3.2.1 Residential Accounts

Regression analysis was used to develop the Residential (RS) account forecast using monthly customer data from January 2000 – January 2012. Total RS accounts were projected as a function of the number of households for the Lakeland/Winter-Haven

Metropolitan Statistical Area (MSA). Binary variables were also used to explain outliers in historical billing data and to account for seasonality.

The number of RS accounts for outside the corporate limits was developed using an exponential smoothing share model with historical monthly customer data from May 2004 – January 2012.

Projected AAGR for total RS accounts is 1.3% for Calendar Year 2012- 2021.

3.2.2 Commercial Accounts

General Service Accounts

A regression model was used to develop the General Service (GS) account forecast. The number of new small commercial accounts is a function of total employment for the Lakeland/Winter-Haven Metropolitan Statistical Area (MSA). The forecast model was estimated using historical monthly customer data from January 2003 – January 2012. Binary variables were also used to explain outliers in historical billing data.

The number of GS accounts for inside the corporate limits was developed using an exponential smoothing share model with historical monthly customer data from April 2004 – January 2012.

GS accounts are expected to increase at an AAGR of 0.5% from Calendar Year 2012-2021

General Service Demand Accounts

The forecast for the number of GSD commercial accounts for inside and outside city limits was developed using historical relationships and growth rates. These forecasts were developed outside of MetrixND and later integrated with the Total Account Forecast.

The GSD total account class is expected to grow at a rate of 0.6 % from Calendar Year 2012 to 2021.

3.2.3 Industrial Accounts

The Industrial account category is comprised of those accounts within the General Service Large Demand (GSLD), Interruptible and Extra Large Demand Customer (ELDC) customer classes.

Projections for the Industrial accounts were modeled independently of MetrixND. Special consideration was given to account for new major commercial and industrial development projects that may impact future demand and energy requirements.

3.2.4 Other Accounts

The Other account category is comprised of those accounts within the Municipal, Electric, and Water Departments of the City of Lakeland. This category also includes those accounts for private area and roadway lighting.

Historical data for these classes is very inconsistent and difficult to model. Therefore, the account projections for this category were based on time trends, historical growth rates and relationships. Lakeland also took into consideration any future projects and developments.

These forecasts were developed outside of MetrixND and were later integrated with the other rate class forecasts to generate the Total Account Forecast.

The Other account category is expected to increase at 0.1% AAGR over the 10-year reporting period.

3.2.5 Total Accounts

The Total Account Forecast for Lakeland Electric is the sum of all the individual forecasts mentioned above. Total accounts are expected to increase at 1.1% AAGR over the 10-year reporting period.

3.3 Energy Sales Forecast

Lakeland forecasts monthly energy sales for the following categories and subcategories:

- Residential
- Commercial
  - General Service
  - General Service Demand
- Industrial
  - General Service Large Demand
  - Interruptible
  - ELDC (Extra Large Demand Customer)

- Other
  - Electric
  - Water
  - Municipal
  - Unmetered (Street Lighting)
  - Private Area Lighting
  - Roadway Lighting

3.3.1 Residential Energy Sales

The Residential (RS) energy sales forecast was developed using the Statistically Adjusted End-use (SAE) modeling approach. The SAE approach uses regression models and independent variables that are designed to capture the impacts of changing end-use saturation and efficiency trends as well as economic conditions on long-term residential energy and demand. The models are average use models that use historical monthly energy sales data from January 2005 – January 2012.

The RS average use models for inside and outside Lakeland's corporate limits are driven by disposable personal income per household, the number of persons per household, appliance saturation and efficiency trends, and weather. Binary variables were also used to explain outliers in the historical billing data.

The average use regression model was based on the following average use equation:

$$AvgUse_{y,m} = a + b_1 \times XCool_{y,m} + b_2 \times XHeat_{y,m} + b_3 \times XOther_{y,m}$$

Where:

XCOO*L* = Cooling equipment saturation levels (central, room), cooling equipment efficiency, thermal efficiency, home size (square footage), household income, average persons per household size, energy price and cooling degree days (CDD).

$$XCool_{y,m} = CoolIndex_y \times CoolUse_{y,m}$$

$XCool_{y,m}$	is the estimated cooling energy use in year (y) and month (m).
$CoolIndex_{y,m}$	is the annual index of cooling equipment.

$CoolUse_{y,m}$ is the monthly usage multiplier.

The $CoolIndex_{y,m}$ is calculated as follows:

$$CoolIndex_y = Structural\ Index_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \big/ Eff_y^{Type} \right)}{\left(Sat_{01}^{Type} \big/ Eff_{01}^{Type} \right)}$$

$CoolUse_{y,m}$ is defined as follows:

$$CoolUse_{y,m} = \left(\frac{CDD_{y,m}}{CDD_{01}} \right) \times \left(\frac{HHSize_{y,m}}{HHSize_{01}} \right)^{0.10} \times \left(\frac{HHIncome_{y,m}}{HHIncome_{01}} \right)^{0.20} \times \left(\frac{\Pr ice_{y,m}}{\Pr ice_{01}} \right)^{0.0}$$

XHEAT = Heating equipment saturation levels (resistance, heat pump), heating efficiency, thermal efficiency, home size (square foot), household income, average persons per household size, energy price and heating degree days (HDD).

$$XHeat_{y,m} = HeatIndex_{y,m} \times HeatUse_{y,m}$$

Where:

$XHeat_{y,m}$ is the estimated heating energy use in year (y) and month (m).

$HeatIndex_{y,m}$ is the annual index of heating equipment.

$HeatUse_{y,m}$ is the monthly usage multiplier.

The $HeatIndex_{y,m}$ is calculated as follows:

$$HeatIndex_y = Structural\ Index_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \big/ Eff_y^{Type} \right)}{\left(Sat_{01}^{Type} \big/ Eff_{01}^{Type} \right)}$$

$HeatUse_{y,m}$ is defined as follows:

$$HeatUse_{y,m} = \left(\frac{HDD_{y,m}}{HDD_{01}}\right) \times \left(\frac{HHSize_{y,m}}{HHSize_{01}}\right)^{0.10} \times \left(\frac{HHIncome_{y,m}}{HHIncome_{01}}\right)^{0.20} \times \left(\frac{Price_{y,m}}{Price_{01}}\right)^{0.0}$$

XOTHER = Other equipment saturation levels (water heat, appliances, lighting densities, plug loads), appliance efficiency, household income and average persons per household size. The explanatory variables for other uses are defined as follows:

$$XOther_{y,m} = OtherIndex_{y,m} \times OtherUse_{y,m}$$

The $OtherIndex_{y,m}$ is calculated as follows:

$$OtherIndex_{y} = Structural\ Index_{y} \times \sum_{Type} EI^{Type} \times \frac{\left(Sat_{y}^{Type} \big/ Eff_{y}^{Type}\right)}{\left(Sat_{01}^{Type} \big/ Eff_{01}^{Type}\right)}$$

$OtherUse_{y,m}$ is defined as follows:

$$OtherUse_{y,m} = \times \left(\frac{HHSize_{y,m}}{HHSize_{01}}\right)^{0.10} \times \left(\frac{HHIncome_{y,m}}{HHIncome_{01}}\right)^{0.20} \times \left(\frac{Price_{y,m}}{Price_{01}}\right)^{0.0}$$

The equation used to develop residential energy sales is as follows:

$$ResidentialSales_{y,m} = ResidentialCustomer_{y,m} \times AverageUsePerCustomer_{y,m}$$

The Total Residential Energy Sales Forecast is projected to increase at 1.0% AAGR over the 10-year reporting period.

3.3.2 *Commercial Energy Sales*

The General Service (GS) and General Service Demand (GSD) energy sales forecasts were also developed using the SAE modeling approach. The model framework for the Commercial sector is the same as it is for the Residential model. The econometric equation used to develop Commercial energy sales is as follows:

$$Sales_{y,m} = a + b_{y,m} \times XHeat_{y,m} + b_{y,m} \times XCool_{y,m} + b_{y,m} \times XOther_{y,m}$$

3.3.2.1 *General Service Energy Sales*

GS energy sales were projected for both inside and outside the corporate limits. The GS sales models are driven by: Gross State Product (GSP), weather, and appliance saturations and efficiencies. Binary variables were also used to help explain fluctuations in historical billing data due to rate migrations, billing discrepancies, seasonality, etc... The models are using historical monthly energy sales data from January 2005 – January 2012.

General Service (GS) energy sales are expected to increase at 0.8% AAGR over the 10-year reporting period.

3.3.2.2 *General Service Demand Energy Sales*

GSD energy sales were projected for both inside and outside the corporate limits. Non-residential sales models are driven by: Gross State Product (GSP), weather, and appliance saturations and efficiencies. Binary variables were also used to help explain fluctuations in historical billing data due to rate migrations, billing discrepancies, seasonality, etc... The models are using historical monthly energy sales data from January 2005 – January 2012.

General Service Demand energy sales are expected to increase at 0.8% AAGR over the 10-year reporting period.

3.3.3 *Industrial Energy Sales*

The forecast of Other energy sales is comprised of sales for the Municipal, Electric and Water Departments of the City of Lakeland, private area lighting, roadway lighting, and Un-metered (street lighting) sales. Models are very difficult to develop for these rate classes due to the large fluctuations in the historical billing data. Therefore, the projections for this category were based on historical trends and growth rates. Special consideration was given to account for new projects and developments.

Other energy sales comprise approximately 0.2% of total sales and are expected to increase at 0.7% AAGR over the 10-year reporting period.

3.3.4 Other Sales

Other energy sales are comprised of sales for the municipal, electric and water departments, private area lighting, roadway lighting, and unmetered (street lighting) rate classes. Models are very difficult to develop for these rate classes due to the large fluctuations in the historical billing data. Therefore, the projections for this category were based on historical trends and growth rates. Special consideration was given to account for new projects and developments.

Other energy sales comprise 3.5% of total sales and are expected to increase at 0.7% AAGR over the 10-year reporting period.

3.3.5 Total Sales

The Total Energy Sales Forecast for Lakeland is the sum of the individual forecasts mentioned above. Total energy sales are projected to grow at 0.8% AAGR over the 10-year reporting period.

3.4 Net Energy for Load Forecast

Models are estimated in MetrixND to forecast monthly sales by customer class (Res, GS, GSD, Industrial, Other) and then summed together to create a total sales forecast.

To determine the total net energy for load (NEL) for the system, a loss-factor is applied to the total sales forecast to convert sales into NEL. Electric losses, the measure of the amount of energy lost during the generation, transmission, and distribution of electricity are developed using a historical average. Electric losses are expected to be approximately 4.2% for the 10-year forecast horizon.

NEL is projected to increase at 1.06% AAGR over the 10-year reporting period.

3.5 Peak Demand Forecast

A regression model is estimated in MetrixND to forecast monthly peaks. The model is developed using Itron's SAE modeling approach to ensure we are accounting for end-use appliance saturations and efficiencies that may affect peak. These models are driven by monthly energy coefficients and actual peak-producing weather conditions. The forecast is generated under the assumption of "normal" peak-producing weather conditions.

Historically, Lakeland has been a winter peaking utility and the forecast assumes this will continue over the 10-year forecast horizon.

The 2012 base case forecast for summer peak is 655 MW with winter (2012/2013) expected to be 696 MW. The Total Annual Peak Demand Forecast is expected to increase at approximately 5.0 MW's a year over the 10-year reporting period, or at an AAGR of 0.62%.

3.6 Hourly Load Forecast

Twenty-four hourly regression models were developed in MetrixND to generate the 20-year hourly load forecast. Each of these models relates weather and calendar-conditions (day-of-week, month, holidays, etc.) to load. The un-calibrated hourly load shape is then scaled to the energy forecast and the peak forecast using MetrixLT. The result is an hourly load shape that is calibrated to the system energy and system peak forecasts produced out of MetrixND.

Table 3-1
Historical and Projected
Heating and Cooling Degree Days

YEAR	HDD 65	CDD 65
2002	638	3,404
2003	682	3,336
2004	595	3,184
2005	564	3,200
2006	446	3,487
2007	338	3,492
2008	522	3,110
2009	716	3,141
2010	1,378	3,078
2011	462	3,168
2012	609	3,046
2013	609	3,046
2014	609	3,046
2015	609	3,046
2016	609	3,046
2017	609	3,046
2018	609	3,046
2019	609	3,046
2020	609	3,046
2021	609	3,046

Table 3-2
Historical Monthly Peaks and Date

	2009		2010		2011	
Jan	710	22-Jan	804	11-Jan	665	13-Jan
Feb	703	05-Feb	624	26-Feb	501	14-Feb
Mar	546	03-Mar	645	05-Mar	434	30-Mar
Apr	471	24-Apr	451	24-Apr	552	28-Apr
May	568	11-May	578	03-May	568	12-May
Jun	625	22-Jun	619	16-Jun	609	23-Jun
Jul	601	16-Jul	638	28-Jul	591	25-Jul
Aug	608	11-Aug	621	03-Aug	611	12-Aug
Sep	579	21-Sep	597	13-Sep	563	20-Sep
Oct	587	08-Oct	528	28-Oct	482	11-Oct
Nov	444	01-Nov	435	03-Nov	429	16-Nov
Dec	505	29-Dec	709	14-Dec	383	08-Dec

3.7 Sensitivity Cases

3.7.1 High and Low Load Forecast Scenarios

A forecast is generated based on the projections of its drivers and assumptions at time of forecast development. This base forecast is intended to represent the forecast that is "most likely" to occur.

It should be noted, especially due to current economic conditions, that there may be some conditions that arise that may cause variation from what was expected in the base forecast. For these reasons, a high and low case scenario forecast was developed for customers, energy sales, system net energy for load and peaks. The high and low forecasts were based on variations of the primary drivers including population and economic growth.

Table 3-3 Summer Peak Demand (MW)			
Year	Low	Base	High
2012	652	655	658
2013	657	662	668
2014	662	669	677
2015	666	675	687
2016	671	682	696
2017	675	688	705
2018	679	695	715
2019	683	701	724
2020	688	707	733
2021	692	714	743
AAGR	0.66%	0.96%	1.36%

Table 3-4 Winter Peak Demand (MW)			
Year	Low	Base	High
2012/13	693	696	698
2013/14	694	699	704
2014/15	696	703	711
2015/16	699	708	719
2016/17	701	713	726
2017/18	704	718	734
2018/19	707	723	742
2019/20	709	727	749
2020/21	712	731	756
2021/22	714	736	764
AAGR	0.33%	0.62%	1.01%

Table 3-5 Net Energy for Load (GWH)			
Year	Low	Base	High
2012	2994	2995	3001
2013	3088	3094	3111
2014	3100	3115	3141
2015	3108	3136	3168
2016	3124	3165	3205
2017	3137	3188	3239
2018	3155	3214	3280
2019	3175	3242	3323
2020	3193	3267	3363
2021	3210	3293	3405
AAGR	0.78%	1.06%	1.41%

Model Evaluation and Statistics

The results of the current Fiscal Year 2012 Electric Load and Energy Forecast were reviewed by an outside consultant. Itron was hired to review all sales, customer, peak and energy forecast models for reasonableness and statistical significance. Itron also evaluated and reviewed all key forecast assumptions.

Additionally, the MetrixND software calculates the following list of statistical tests for determining a significant model: Adjusted R-Squared, Durbin Watson Statistic, F-Statistic, Probability (F-Statistic), Mean Absolute Deviation (MAD) and Mean Absolute Percent of Error (MAPE).

4.0 Energy Conservation and Management Programs

Lakeland Electric is committed to the efficient use of electric energy and is committed to providing cost-effective energy conservation and demand reduction programs for all its consumers. Lakeland is not subject to FEECA rules but has in place several Energy Conservation & Management Programs and remains committed to utilizing cost-effective conservation and Energy Conservation & Management Programs that will benefit its customers. Presented in this section are the currently active programs.

This section also includes a brief description of Lakeland's advances in solar technology and a new LED traffic light retrofit program. Lakeland has been a pioneer in the deployment and commissioning of solar energy devices and continues to support and look for opportunities to promote solar energy technologies.

4.1 Existing Energy Conservation and Management Programs

Lakeland has the following energy conservation & management programs that are currently available and address two major areas of energy conservation & management:

- Reduction of energy needs on a per customer basis.
- Movement of energy to off-peak hours when it can be generated at a lower cost.

4.1.1 Non-Measurable Demand and Energy Savings

The programs outlined in this section cannot directly be measured in terms of demand and energy savings, but are very important in that they have been shown to influence public behavior and thereby help reduce energy consumption and generation requirements. Lakeland considers the following programs to be an important part of its objective to cost-effectively reduce energy consumption:

- Residential Programs:
  - Energy Audit Program.
  - Public Awareness Program.
  - Speakers Bureau.
  - Informational Bill Inserts.
- Commercial Programs:
  - Commercial Audit Program.

4.1.1.1 Residential Programs.

4.1.1.1.1 Residential Energy Audits.

The Energy Audit Program promotes the usage of high energy-efficiency appliances in the home and gives the customer an opportunity to learn about other utility conservation programs. The program provides Lakeland with a valuable customer interface and a good avenue for increased customer awareness.

4.1.1.1.2 Public Awareness Program.

Lakeland believes that public awareness of the need to conserve electricity is the greatest conservation resource. Lakeland's public awareness programs provide customers with information to help them reduce their electric bills by being more conscientious in their energy usage.

4.1.1.1.3 Speakers Bureau.

Lakeland holds local group meetings to help inform the public of new energy efficiency technologies and ways to conserve energy in the commercial and residential sectors.

4.1.1.1.4 Informational Bill Inserts.

Monthly billing statements provide an excellent avenue for communicating timely energy conservation information to its customers. In this way, Lakeland conveys the message of better utilizing their electric resources on a regular basis in a low cost manner.

4.1.1.2 Commercial Programs.

4.1.1.2.1 Commercial Energy Audits.

The Lakeland Commercial Audit Program includes educating customers about high efficiency lighting and thermal energy storage devices for customers to consider in their efforts to reduce costs associated with their electric usage.

4.1.2 Energy Conservation and Management Technology Research

Lakeland has made a commitment to study and review promising technologies in the area of energy conservation & management programs. Some of these efforts are summarized below.

4.1.2.1 Direct Expansion Ground Source Heat Pump Study.

In cooperation with ECR Technologies of Lakeland, Lakeland Electric was given the Governor's Energy Award for work in the evaluation and analysis of direct expansion ground source heat pump (GSHP) technology. This technology reduces weather sensitive loads and promotes greater energy efficiency. A study of the demand and energy savings associated with this technology was completed in an effort to establish its cost-effectiveness for new construction, as well as retrofitting the technology to existing homes. The original units were installed in the 1980's and are still in service. There is little customer interest due to the cost of the units. Currently, no new sites are being developed.

4.1.2.2 Whole House Demand Controller Study/Real Time Pricing.

The concept of this technology is to control multiple appliances in the customer's home. The initial study was designed such that when a customers' demand reached a pre-set level, no additional appliances would be allowed to turn on. There has been no customer interest in this program as initially offered.

4.1.2.3 Time-of-Day Rates.

Lakeland is currently offering a time of day program and plans to continue as this makes consumers aware of the variation in costs during the day. To date, there has been limited interest by Lakeland's customers in this demand-side management program.

4.1.3 New Conservation Programs 2011

In keeping with Lakeland Electric's plan to promote retail conservation programs, the utility is continuing the following Energy Efficiency & Conservation Programs during 2011:

Residential

- Insulation rebate - $100 rebate for adding attic insulation to achieve R30 total. Certificate issued to resident at energy audit/visit and redeemed to Insulation Contractor. Can be homeowner installed
- Energy Saving Kits – giveaway at audits contains weather-stripping, outlet gaskets, low flow showerhead, CFL, etc.
- HVAC Maintenance Incentive - $50 rebate for residential customers that have A/C maintenance done.
- Heat Pump Rebate - $250 rebate for installing heat pumps with a SEER of 15 or higher (SEER 14 for package units)
- Compact Fluorescent Lighting – giveaway at audits, up to 3 per residence
- On-line Energy Audit

Commercial

- Energy Audits – rebate of up to $5000 for GSLD, Contract, and Interruptible customers to have audit done by Energy Services Company. Promoted by Account Executives

- Compact Fluorescent/LED Lighting – rebate up to $200 per customer for CFL/LED lighting upgrades
- Vending Miser for commercial customers that install vending miser. Limit of 3 per customer.

Expected Results

- 700 kw demand reduction and over 3,000,000 kwh

4.2 Solar Program Activities

Lakeland Electric views solar energy devices as distributed generators whether they interconnect to the utility grid or not. Solar also contributes to reducing both peak demand and energy linking it to energy conservation & management programs. As such they can potentially fill the much-desired role that an electric utility needs to avoid future costs of building new (and/or re-working existing) supply side resources and delivery systems.

4.2.1 Solar Powered Street Lights.

Distributed generation produces the energy in end use form at the point of load by the customer, thereby eliminating many of the costs, wastes, pollutants, environmental degradation, and other objections to central station generation.

Solar powered streetlights offer a reliable, cost-effective solution to remote lighting needs. As shown in Figure 4-1, they are completely self-contained, with the ability to generate DC power from photovoltaic modules and batteries. During daylight hours solar energy is stored in the battery bank used to power the lights at night. By installing these self sufficient, stand-alone solar lighting products, Lakeland Electric was able to avoid the construction costs related to expansion of its distribution system into remote areas. These avoided costs are estimated to be approximately $40,000.

For 13 years Lakeland had 20 solar powered streetlights in service. Each of these lights offset the need for a traditional 70 watt fixture that Lakeland typically would use in this type of application and displaced the equivalent amount of energy that the 70 watt fixture would use on an annual basis. The primary application for this type of lighting is for remote areas as stated above. In 2006, Lakeland's distribution system was developed in the areas where the solar powered streetlights were installed. Lakeland has chosen to phase-out the solar powered streetlights due to their age. Lakeland installed these 20 lights in mid-1994 in a grant program with the cooperation of the Florida Solar Energy Center (FSEC).

Figure 4-1
Solar Powered Streetlight

4.2.2 Solar Thermal Collectors for Water Heating.

The most effective application for solar energy is the heating of water for residential use. Solar water heating provides energy directly to the end-user and results in a high level of end-user awareness. The sun's energy is stored directly in the heated water itself, reducing the effect of converting the energy to other forms.

During a ten-year pilot program, Lakeland installed and operated 57 solar water heaters in single family homes. Lakeland chose active solar water heaters as well as passive. All units were installed on the roofs of residential customers' homes, i.e. – at the point of consumption. Since this method of energy delivery bypasses the entire transmission and distribution system, there are other benefits than only avoided generation costs.

In Lakeland's program, each solar water heater remained the property of the utility, thereby allowing the customer to avoid the financial cost of the purchase. Lakeland's return on this investment was realized through the sale of the solar generated energy as a separate line item on the customer's monthly bill. This energy device was monitored by using a utility-quality Btu meter calibrated to read in kWh.

One of the purposes of this program was to demonstrate that solar thermal energy can be accurately metered and profitably sold to the everyday residential end-user of hot water. Lakeland Electric's fleet of 57 solar thermal energy generators displaces over 2,000 kWh per year per installation on average. In keeping with the goals of the pilot program, Lakeland will provide the participants with a choice to either:

- assume ownership of the solar heater at no cost (or)
- have the solar heater removed and replaced with a standard electric water heater, also at no cost.

4.2.3 Renewable Energy Credit Trading

Lakeland Electric is also the first utility to successfully trade Renewable Energy Credits (REC's) that were produced by these solar water heaters. In 2004 a cash transaction took place between Lakeland and two REC buyers: Keys Energy Services of Key West and the Democratic National Convention in Boston. Keys Energy needed the REC's for its retail Green Pricing program. The Democratic National Convention used the REC's to offset the emissions produced during that convention.

4.2.4 Utility Expansion of Solar Water Heating Program

During November, 2007 Lakeland Electric issued a Request for Proposals for the expansion of its Residential Solar Water Heating Program. In this solicitation Lakeland sought the services of a venture capital investor who would purchase, install, own, operate and maintain 3,000 – 10,000 solar water heaters on Lakeland Electric customers' residences in return for a revenue-sharing agreement. Lakeland Electric would provide customer service and marketing support, along with meter reading, billing and collections. During December, 2007 a successful bidder was identified and notified. In August 2009, Lakeland Electric approved a contract with the vendor with plans to resume installations of solar water heaters during 2010. Annual projected energy savings from this project will range between 7,500 and 25,000 megawatt-hours. These solar generators will also produce Renewable Energy Credits that will contribute toward Florida's expected mandate for renewable energy as a part of the utility's energy portfolio.

During the summer of 2010 the "Solar for Lakeland" program began installing residential solar water heaters. Under this expanded program the solar thermal energy will be sold for the fixed monthly amount of $34.95. This is the equivalent of 275 kWh of electricity, the amount needed to heat water for an average family of 4 people. All solar heating systems will continue to be metered for customers' verification of solar operation and for tracking green credits for the utility. During the 2010 and 2011 calendar years 99 solar heaters were installed in residential locations under the new program.

4.2.5 Utility-Interactive Net Metered Photovoltaic Systems

This project started as a collaborative effort between the Florida Energy Office (FEO), Florida Solar Energy Center (FSEC), Lakeland Electric, and Shell Solar Industries. The primary objective of this program was to develop approaches and designs that integrate photovoltaic (PV) arrays into residential buildings, and to develop workable approaches to interconnection of PV systems into the utility grid. Lakeland originally installed 3 PV systems, all of which were directly interconnected to the utility grid. These systems have an average nominal power rating of approximately 2.6 kilowatts peak (kwp) and are displacing approximately 2900 kWh per year per installation at standard test conditions.

During 2005 title to these systems was transferred to those homeowners in return for their extended voluntary participation. By the end of 2009 only one of these three original systems was still in operation.

Lakeland owned, operated, and maintained the systems for at least 7 years. FSEC conducted periodic site visits for testing and evaluation purposes. System performance data was continuously collected via telephone modem line during those years. FSEC prepared technical reports on system performance evaluation, onsite utilization, coincidence of PV generation with demand profiles, and utilization of PV generated electricity as a demand-side management option.

After 2011there were a total of 68 PV systems that have been privately purchased in the Lakeland Electric service territory. These systems now generate a total of 357 kw of electric capacity. Lakeland Electric has allowed the interconnection of these systems in "net meter" fashion.

4.2.6 Utility-Interactive Photovoltaic Systems on Polk County Schools

Lakeland was also actively involved in a program called "Portable Power." The focus of the program was to install Photovoltaic Systems on portable classrooms in the Polk County School District. This program included Lakeland Electric, Polk County School District, Shell Solar Industries, Florida Solar Energy Research (FSER) and Education Foundation, Florida Solar Energy Center (FSEC) and the Solar Electric Power Association (SEP), formerly known as the Utility Photovoltaic Group. The program allowed seventeen portable classrooms to be enrolled in former President Clinton's "Million Solar Roofs Initiative." With the installation of the photovoltaic systems 80 percent of the electricity requirements for these classrooms was met.

Along with the photovoltaic systems, a specially designed curriculum on solar energy appropriate to various grade levels was developed. This education package was delivered to the schools for their teachers' use for the instruction of solar sciences. By addressing solar energy technologies in today's public school classrooms, Lakeland is informing the next generation of the environmental and economic need for alternate forms of energy production.

The "Portable Power" in the schools, shown in Figure 4-2, consisted of 1.8kWp photovoltaic systems on 17 portable classrooms. In addition to the educational awareness benefits of photovoltaic programs in schools, there were several practical reasons why portable classrooms were most appropriate as the platforms for photovoltaics. They provided nearly flat roofs and were installed in open spaces, so final orientation is of little consequence. Another reason was the primary electric load of the portable classroom was air conditioning. That load was reduced by the shading effect of the panels on their short stand-off mounts. Most important, the total electric load on the portable classroom was highly coincidental with the output from the PV system. The hot, sunny days which resulted in the highest cooling requirements also produced the maximum PV output.

Of extreme value to the photovoltaic industry, Lakeland Electric, in a partnership with the FSEC, provided on-site training sessions while installing the solar equipment on these school buildings. Attendees from other electric utilities were enrolled and given a hands-on opportunity to develop the technical and business skills needed to implement their own solar energy projects. The training classes covered all aspects of the solar photovoltaic experience from system design and assembly, safety and reliability, power quality, and troubleshooting to distributed generation and future requirements of deregulation.

Figure 4-2
Portable Classroom Topped by PV Panels

Lakeland owned, operated, and maintained the systems on these classrooms. Lakeland monitored the performance and FSEC conducted periodic testing of the equipment. Through the cooperative effort of the partnership, different ways to use a photovoltaic system efficiently and effectively in today's society were evaluated.

As a result of aging, all of the portable classrooms have been retired. And, where shifting populations have caused school officials to relocate some classrooms to schools that are outside Lakeland's service territory, Lakeland has removed the PV systems from those classrooms. Because the equipment is still capable of generating, budgets are being created that will have these systems re-installed on buildings owned by the City of Lakeland.

4.2.7 Integrated Photovoltaics for Florida Residences

Lakeland's existing integrated photovoltaic program supports former President Clinton's "Million Solar Roofs Initiative". The Department of Energy granted five million dollars for solar electric businesses in addition to the existing privately funded twenty-seven million dollars, for a total of thirty-two million dollars for the program. Through the Utility Photovoltaic Group, the investment supported 1,000 PV systems in 12 states and Puerto Rico with hopes to bring photovoltaic systems to the main market. The 1,000 systems were part of the 500,000 commitments received for the initiative to date. The goal was to have installed solar devices on one million roofs by the year 2010. Lakeland helped to accomplish this national goal.

This program provides research in the integration of photovoltaic's in newly constructed homes. Two new homes, having identical floor plans, were built in "side-by-side" fashion. The dwellings were measured for performance under two conditions: occupied and unoccupied. Data is being collected for end-use load and PV system interface. As a research project, the goal is to see how much energy could be saved without factoring in the cost of the efficiency features.

The first solar home was unveiled May 28, 1998, in Lakeland, Florida. The home construction includes a 4 kW photovoltaic system, white tiled roof, argon filled windows, exterior wall insulation, improved interior duct system, high performance heat pump and high efficiency appliances. An identical home with strictly conventional construction features was also built as a control home. The homes are 1 block apart and oriented in the same direction as shown in Figure 4-3. For the month of July 1998, the occupied solar home air conditioning consumption was 72 percent lower than the unoccupied control house. Living conditions were simulated in the unoccupied home. With regard to total power, the solar home used 50 percent less electricity than the air conditioning consumption of the control home. The solar home was designed to provide enough power during the utility peak that it would not place a net demand on the grid. If the solar home produces more energy than what is being consumed on the premises, the output of the photovoltaic system could be sent into the utility grid. The objective was to test the feasibility of constructing a new, single family residence that was engineered to reduce air conditioning loads to an absolute minimum so most of the cooling and other daytime electrical needs could be accomplished by the PV component.

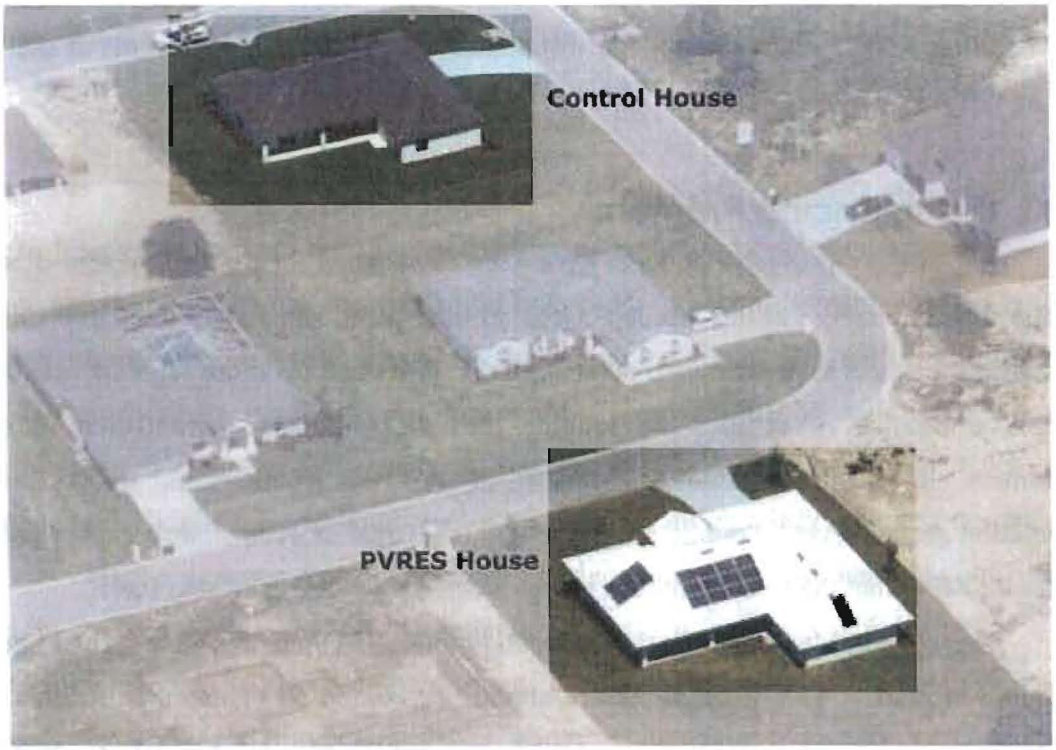


Figure 4-3
Solar House and Control House

4.2.8 Utility-Scale Solar Photovoltaic Program

During November, 2007 Lakeland Electric issued a Request for Proposal seeking an investor to purchase and install investor-owned PV systems totaling 24 megawatts on customer-owned sites as well as City of Lakeland properties. During December, 2007 a successful bidder was identified. In October 2008, Lakeland Electric approved the contract with the vendor. Installation of these PV systems began in 2010. Projected reduction in annual fossil-fuel generation is expected to be 31,800 megawatt-hours. This project will not only offset future energy generation, but will also produce highly valuable Renewable Energy Credits in anticipation of a Florida mandate to produce renewable energy as a part of the utility's overall portfolio.

During 2010 an investor-owned 250kw PV system was installed on the roof of Lakeland's Civic Center. This system became operational during March and produced a total of 425,926 kWh during 2011.

During 2011 a 2.3 megawatt PV system was installed at the Lakeland Linder Airport. This system is interconnected directly to the utility's medium voltage distribution circuit on Hamilton Road. Plans call for the installation of another 3.2 megawatts at that site during 2012.

4.3 Green Pricing Program

Because no long-term budgets have been established for the deployment of solar energy devices, many utilities are dependent on infrequent, somewhat unreliable sources of funding for their solar hardware purchases. To provide for a more regularly available budget, a number of utilities are looking into the voluntary participation of their customers. Recent market studies performed in numerous locations and among diverse population groups reveal a public willingness to pay equal or even slightly higher energy prices knowing that their payments are being directed towards renewable fuels.

The Florida Municipal Electric Association (FMEA) has assembled a workgroup called "Sunsmart". This workgroup is a committee composed of member utilities. Its purpose is to raise environmental awareness and implement "Green Pricing" programs that would call for regular periodic payments from customers who wish to invest in renewables. The Florida Solar Energy Center (FSEC) co-hosts this effort by providing meeting places and website advertising to recruit from statewide responses. A grant from the State of Florida Department of Community Affairs, Florida Energy Office has been appropriated to encourage utility involvement with Green Pricing. Lakeland Electric is an active member of this committee and is investigating the marketability and public acceptance of a Green Pricing Program in its service territory.

4.4 LED Traffic Light Retrofit Program

The City of Lakeland is responsible for the operation and maintenance of 3,411 traffic lights at over 171 intersections. Historically, these traffic signals have used incandescent bulbs which are replaced every 18 months and use approximately 135 watts of electricity per bulb. This amounts to an annual electrical consumption of 1,633,525 kwh for all 12" red and green signals, arrow signals and pedestrian crossing signals.

This project retrofitted the existing bulbs with highly efficient Light Emitting Diodes (LEDs). The LEDs use approximately 10 watts of energy which is more than a

90% decrease in energy consumption as compared to their incandescent counterparts and have a longer life span, up to seven years, which reduces maintenance costs as well.

The Florida Department of Transportation (FDOT) agreed to help fund Lakeland's project to retrofit the signals. The FDOT contributed $50,000 for these new LED traffic lamps on all roadways within Lakeland's city limits. The FDOT views this as a "good neighbor policy" since FDOT depends on city crews to maintain the signals on its roads and highways within the city's limits.

The project began in December, 2002 and was completed in June 2003. The project is expected to save the City of Lakeland $150,000 per year in maintenance and electricity costs.

As a next step, Lakeland Electric added backup power supply equipment at 14 critical intersections earmarked for FDOT-funded LED signals. These improvements were limited to those intersections that are located on state-funded roadways. The UPS systems will improve safety by keeping traffic signals operating during power outages and accidents. Emergency vehicles in Lakeland will see the added benefit of having easier access to desired areas such as fire and medical locations. Lakeland anticipates being one of the first cities in Florida to have the UPS systems applied to the LED signals.

5.0 Forecasting Methods and Procedures

This section describes and presents Lakeland's long-term integrated resource planning process, the economic parameter assumptions, plus the fuel price projections being used in the current evaluation process.

5.1 Integrated Resource Planning

Lakeland selects its capacity resources through an integrated resource planning process. Lakeland's planning process considers energy conservation, and supply-side resources along with the needs of the T&D system. The integrated resource planning process employed by Lakeland continuously monitors supply and energy conservation programs. As promising alternatives emerge, they are included in the evaluation process.

5.2 Florida Municipal Power Pool

Lakeland is a member of the Florida Municipal Power Pool (FMPP) along with the Orlando Utilities Commission (OUC) and the All-Requirements Project of the Florida Municipal Power Agency (FMPA). The three utilities operate as one control area. All FMPP capacity resources are committed and dispatched together from the OUC Operations Center.

The FMPP is not a capacity pool meaning that each member must plan for and maintain sufficient capacity to meet their own individual demands and reserve obligations. Any member of the FMPP can withdraw from FMPP with 1 year written notice. Lakeland, therefore, must ultimately plan to meet its own load and reserve requirements as reflected in this document.

5.3 Economic Parameters and Evaluation Criteria

This section presents the assumed values adopted for economic parameters and inputs used in Lakeland's planning process. The assumptions stated in this section are applied consistently throughout this document. Subsection 5.3.1 outlines the basic economic assumptions. Subsections 5.3.2 and 5.3.3 outline the constant differential fuel forecasts, and base case, high and low.

5.3.1 Economic Parameters

This section presents the values assumed for the economic parameters currently being used in Lakeland's least-cost planning analysis.

5.3.1.1 Inflation and Escalation Rates

The general inflation rate applied is assumed to be 3.0 percent per year based on the US forecasted Producer Price Index. A 2.5 escalation rate is applied to operation and maintenance (O&M) expenses. Fuel price escalation rates are discussed below in Section 5.3.2.

5.3.1.2 Bond Interest Rate

Consistent with the traditional tax exempt financing approach used by Lakeland, the self-owned supply-side alternatives assume 100 percent debt financing. Lakeland's long-term tax exempt bond interest rate is assumed to be 5.5 percent.

5.3.1.3 Present Worth Discount Rate

The present worth discount rate used in the analysis is set equal to Lakeland's assumed bond interest rate of 5.5 percent.

5.3.1.4 Interest During Construction

During construction of the plant, progress payments will be made to the EPC contractor and interest charges will accrue on loan draw downs. The interest during construction rate is assumed to be 5.5 percent.

5.3.1.5 Fixed Charge Rates

The fixed charge rate is the sum of the project fixed charges as a percent of the project's total initial capital cost. When the fixed charge rate is applied to the initial investment, the product equals the revenue requirements needed to offset fixed costs for a given year. A separate fixed charge rate can be calculated and applied to each year of an economic analysis, but it is most common to use a Levelized Fixed Charge Rate that has the same present value as the year by year fixed charged rates. Included in the fix charged rate calculation is an assumed 2.0 percent issuance fee, a 1.0 percent annual insurance cost, and a 6-month debt reserve fund earning interest at a rate equal to the bond interest rate.

5.3.2 Fuel Price Projections

This section presents the fuel price projections for coal, natural gas and oil. This year's fuel price forecast for natural gas has been prepared with the assistance of The Energy Authority (TEA) for Lakeland Electric. The fuel price forecast for solid fuels and oils has been prepared by Lakeland Electric's staff.

5.3.2.1 Natural Gas

Natural gas is a colorless, odorless fuel that burns cleaner than many other traditional fossil fuels. Natural gas can be used for heating, cooling, and production of electricity, and other industry uses.

Natural gas is found in the Earth's crust. Once the gas is brought to the surface, it is refined to remove impurities such as water, sand, and other gases. The natural gas is then transmitted through pipelines and delivered to the customer either directly from the pipeline or through a distribution company or utility. When natural gas reaches its destination through a pipeline, it is sometimes stored prior to distribution.

Table 5-1 Base Case Fuel Price Forecast Summary (Real Price $/MMBtu, No Inflation Added)						
	McIntosh 3 Coal-CAPP Only	IB:CAPP-Blended	Natural Gas[1]	High Sulfur #6 Oil[1]	Low Sulfur #6 Oil[1]	#2 Diesel Oil[1]
2012	4.30	3.80	2.95	13.45	16.78	20.50
2013	4.34	3.80	3.80	13.85	17.18	20.93
2014	4.36	3.80	4.23	14.05	17.38	21.16
2015	4.41	3.90	4.51	14.07	17.40	21.18
2016	4.46	3.90	4.76	14.33	17.66	21.46
2017	4.50	4.00	5.01	14.10	18.43	22.30
2018	4.55	4.00	5.25	15.85	19.18	23.11
2019	4.59	4.00	5.49	16.46	19.79	23.79
2020	4.64	4.10	5.75	17.00	20.33	24.37
2021	4.69	4.10	6.01	17.39	20.72	24.79
Avg. Annual	0.97%	0.85%	8.23%	2.90%	2.37%	2.13%

[1]Prices represent delivered prices

5.3.2.1.1 Natural gas supply and availability

Significant natural gas reserves exist, both in the United States and throughout North American mainland and coastal regions. Natural gas reserves are mostly dependent on domestic production. Increasing production of natural gas from new unconventional sources is contributing to the lack of volatility seen in recent years. Several years of gas prices averaging below $4.00 per MMBtu had not slowed the pace of development of new production in North American fields. However, recent periods when gas has been well below $3.00 per MMBtu potential investors in new gas production have lost interest.

Natural gas reserves exist both in the United States and North American mainland and coastal regions. Natural gas reserves are mostly dependent on domestic production. Increasing demand for natural gas as a fuel for both home and heating and new power generation projects is contributing to the price volatility seen in recent years. Liquefied Natural Gas (LNG) feasibility is currently being explored by two projects proposing pipelines into Florida, and several projects in the Gulf of Mexico along the Louisiana coast.

5.3.2.1.2 Natural gas transportation

There are now two transportation companies serving Peninsular Florida, Florida Gas Transmission Company (FGT) and Gulfstream. Lakeland Electric has interconnections and service agreements with both companies to provide diversification and competition in delivery.

5.3.2.1.2.1 Florida Gas Transmission Company

FGT is an open access interstate pipeline company transporting natural gas for third parties through its 5,000-mile pipeline system extending from South Texas to Miami, Florida.

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

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

FGT's total receipt point capacity is in excess of 3.0 billion cubic feet per day and includes connections with 10 interstate and 10 intrastate pipelines to facilitate transfers of natural gas into its pipeline system. FGT reports a current delivery capability to Peninsular Florida in excess of 2.0 billion cubic feet per day.

5.3.2.1.2.2 Florida Gas Transmission market area pipeline system

FGT's total receipt point capacity is in excess of 3.0 billion cubic feet per day and includes connections with 10 interstate and 10 intrastate pipelines to facilitate transfers of natural gas into its pipeline system. FGT reports a current delivery capability to Peninsular Florida in excess of 2.1 billion cubic feet per day. Lakeland Electric currently has in excess of 28,000 MMBtu / day of firm transportation contracted with FGT for natural gas delivery to Lakeland Electric's generation facilities.

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

FGT is currently marketing its Phase VIII Expansion Project. Phase VIII Expansion Project will consist of approximately 483.2 miles of multi diameter pipeline in Alabama, Mississippi and Florida with approximately 365.8 miles built parallel to existing pipelines. The project will add 213,600 horsepower of additional mainline compression with one new compressor station to be built in Highlands County, Fla. The project will provide an annual average of 820,000 MMbtu/day of additional firm transportation capacity. Currently, Lakeland has no plans to purchase additional pipeline capacity.

5.3.2.1.2.3 Gulfstream pipeline

The Gulfstream pipeline is a 744-mile pipeline originating in the Mobile Bay region and crossing the Gulf of Mexico to a landfall in Manatee County (south Tampa Bay). The pipeline has the capability to supply Florida with 1.1 billion cubic feet of gas per day serving existing and prospective electric generation and industrial projects in southern Florida. Figure 5-1 shows the route for the Gulfstream pipeline. Phase I of the pipeline has been completed and ends in Polk County, Florida. The pipeline will be extended to FP&L's Martin Plant. Construction for the Gulfstream pipeline began in 2001 and was placed in service in May, 2002. Phase II was completed in 2005.

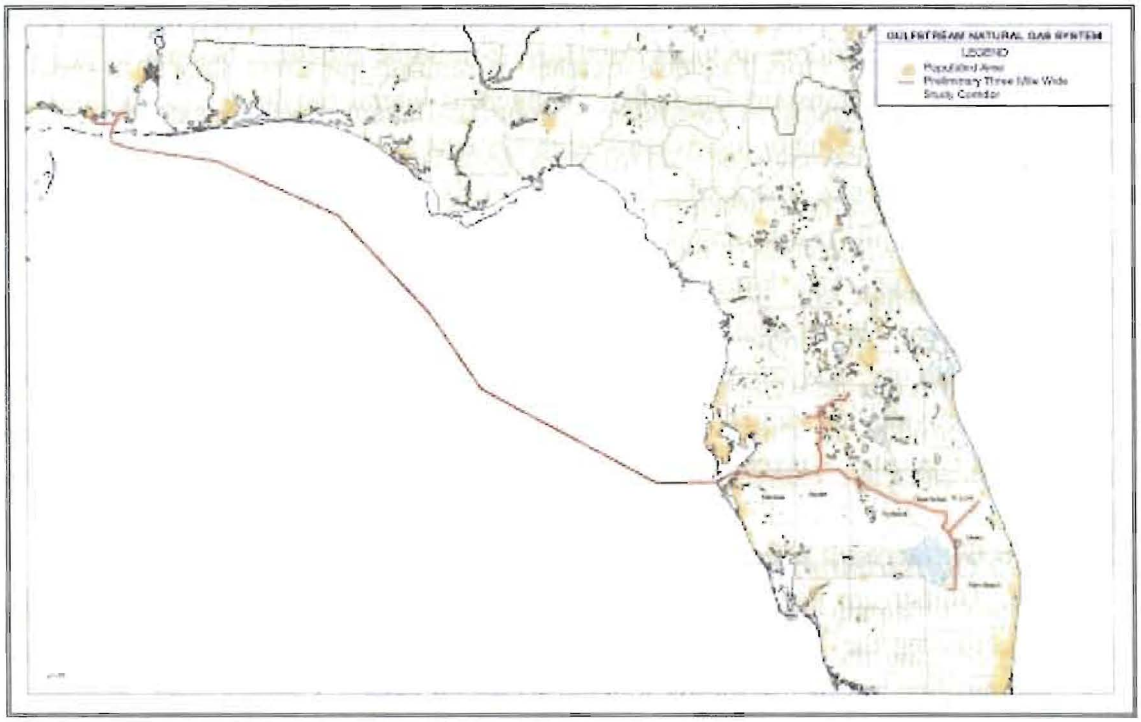


Figure 5-1
Gulfstream Natural Gas Pipeline

5.3.2.1.3 Natural gas price forecast

The price forecast for natural gas is based on historical experience and future expectations for the market. The forecast takes into account the fixed long term contracts that Lakeland has in place for a portion of its gas along with new or spot purchases of gas to meet its needs. The cost of reservation is not included in the price of natural gas in Table 5-1. All other fuel types in the table are delivered prices. As previously stated, natural gas prices have been extremely volatile in recent years. To address this volatility, Lakeland Electric initiated a formal fuels hedging program in 2003. The Energy Authority (TEA), a company located in Jacksonville, FL, is Lakeland's consultant assisting in the administration and adjustment of policies and procedures as well as the oversight of the program.

Lakeland purchases "seasonal" gas to supplement the base requirement and purchase "as needed" daily gas to round out its supply needs.

Natural gas transportation from FGT is currently supplied under three tariffs, FTS-1, FTS-2 and FTS-3. Rates in FTS-1 are based on FGT's Phase II expansion and rates in FTS-2 are based on the Phase III expansion. Rates in FTS-3 are based on the Phase VIII expansion, which went in service April 1, 2011. *NOTE: Lakeland does not currently subscribe to any FTS-3 capacity.* The Phase III expansion was extensive and rates for FTS-2 transportation are significantly higher than FTS-1. Rates for the Phase IV, Phase V, and Phase VI are included in the FTS-2 rate structure. October 1, 2009 FGT filed revised tariff sheets proposing to increase its rates and to make certain changes to terms and conditions of service under the tariff. This rate case settled April 1, 2011. Resulting changes to transportation rates are reflected in Table 5-2. Any other future expansions will be set by the Federal Energy Regulatory Commission (FERC) rate cases.

Table 5-2
Natural Gas Tariff Transportation Rates

	Rate Schedules					
Rates And Surcharges	FGT FTS-1 w/surcharges (cents/DTH)*	FGT FTS-2 w/surcharges (cents/DTH)*	**FGT FTS-3 w/surcharges (cents/DTH)*	FGT ITS-1	Gulfstream FTS-1	Gulfstream FTS-6
Reservation	46.94	71.85	157.91	61.23	55.59	62.00
Usage	2.75	0.93	0.97	0.00	0.02	0.02
Total	49.69	72.78	158.88	61.23	55.61	62.02
Fuel Charge	3.69%	3.69%	3.69%	3.69%	2%	2%

* A DTH is equivalent to 1 MMBtu or 1 MCF
** Lakeland does not currently subscribe to any FTS-3 Capacity

For purposes of projecting delivered gas prices, transportation charges of \$0.69/mmbtu were applied for existing units as this is the average cost for Lakeland to obtain natural gas transportation for those units. This average rate is realized through a current mix of FTS-1, FTS-2 and Gulfstream FTS transportation, including consideration of Lakeland's ability to relinquish FTS-2 transportation and acquire other firm and interruptible gas transportation on the market.

5.3.2.2 Coal

Coal has been used as an energy source for hundreds of years and provided the energy which fueled the Industrial Revolution of the 19th Century and it was a primary fuel of the electric era in the 20th Century. Lakeland's McIntosh Unit #3 is a 365 mega watt coal burning generator that was placed into service in the early 1980's.

5.3.2.2.1 Coal supply and availability

Lakeland's current coal purchase contracts are approximately 50 percent under agreement for calendar 2012 and 20 percent spot purchases. Spot purchases can extend from several months to one year in length. Lakeland maintains a 20 – 30 day coal supply reserve (60,000 – 90,000 tons).

5.3.2.2.2 Coal transportation

McIntosh Unit 3 is Lakeland's only unit burning coal. Lakeland projects McIntosh Unit 3 will burn approximately 700,000 tons of coal per year. The coal sources are located in eastern Kentucky, which affords Lakeland a single rail line haul via CSX Transportation. Lakeland at times may also import a portion of its coal needs from South American sources, primarily from the nation of Columbia. Coal transportation for U.S. rail origins are provided under a contract signed with CSX in late 2008. The contract period is from January 1, 2009 through December 31, 2013.

5.3.2.2.3 Coal price forecast

Currently, Lakeland's term purchase of coal for McIntosh 3 is under one contract which extends through the end of 2012. Lakeland's coal costs will most likely increase due to prevailing market contract positions but may moderate if successful in blending low cost coals from the Illinois Basin market.

5.3.2.3 Fuel Oil

5.3.2.3.1 Fuel oil supply and availability

The City of Lakeland currently obtains all of its fuel oil through spot market purchases and has no long-term contracts. This strategy provides the lowest cost for fuel oil consistent with usage, current price stabilization, and on-site storage. Lakeland's Fuels Section continually monitors the cost-effectiveness of spot market purchasing.

5.3.2.3.2 Fuel oil transportation

Although the City of Lakeland is not a large consumer of fuel oils, a small amount is consumed during operations for backup fuel and diesel unit operations. Fuel oil is transported to Lakeland by truck.

5.3.2.3.3 Fuel oil price forecast

Recent world events appear to have placed oil prices at a new level in the world market. Lakeland has adjusted its oil price forecast to reflect current market pricing and what the anticipated future price may be.

5.3.3 Fuel Forecast Sensitivities

Fuel Forecast Sensitivities Lakeland is not presenting specific forecasted fuel price sensitivities. In the 2005 IRP study, fuel price sensitivity cases were run for natural gas and coal. Natural gas price sensitivity cases included: + $1.00/mmbtu, + $2.00/mmbtu, + $3.00/mmbtu and - $1.00/mmbtu from the base case price forecast. Coal price sensitivities included +/- $0.50/mmbtu from the base case price forecast. No price sensitivities were run on oil fuels as they only make up a very small part of total energy production and cost in the forecast period.

6.0 Forecast of Facilities Requirements

6.1 Need for Capacity

This section addresses the need for additional electric capacity to serve Lakeland's electric customers in the future. The need for capacity is based on Lakeland's load forecast, reserve margin requirements, power sales contracts, existing generating and unit capability and scheduled retirements of generating units.

6.1.1 Load Forecast

The load forecast described in Section 3.0 is used to determine the need for capacity. A summary of the load forecast for winter and summer peak demand for base high, and low projections are provided in Tables 3-3 and 3-4.

6.1.2 Reserve Requirements

Prudent utility planning requires that utilities secure firm generating resources over and above the expected peak system demand to account for unanticipated demand levels and supply constraints. Several methods of estimating the appropriate level of reserve capacity are used. A commonly used approach is the reserve margin method, which is calculated as follows:

$$\frac{\text{system net capacity - system net peak demand}}{\text{system net peak demand}}$$

Lakeland has looked at probabilistic approaches to determine its reliability needs in the past. These have included indices such as Loss of Load Probability (LOLP) and Energy Use Efficiency (EUE). Lakeland has found that due to the strength of its transmission system, assisted LOLP or EUE values were so small that reserves based on those measures would be nearly non-existent. Conversely, isolated probabilistic values come out overly pessimistic calling for excessively high levels of reserves due to approximately 50% of Lakeland's capacity being made up by only two units. As a result, Lakeland has stayed with the reserve margin method based on the equation presented above. When combined with regular review of unit performance at times of peak, Lakeland finds reserve margin to be the proper reliability measure for its system.

Generation availability is reviewed annually and is found to be within industry standards for the types of units that Lakeland has in its fleet, indicating adequate and prudent maintenance is taking place. Lakeland's winter and summer reserve margin target is currently 15%. This complies with the FRCC reserve margin criteria for the FRCC Region. As Lakeland's needs and fleet of resources continue to change through time, reserve margin levels will be reviewed and adjusted as appropriate.

6.1.3 Additional Capacity Requirements

By comparing the load forecast plus reserves with firm supply, the additional capacity required on a system over time can be identified. Lakeland's requirements for additional capacity are presented in Tables 6-1 and 6-2 which show the projected reliability levels for winter and summer base case load demands, respectively. Lakeland's capacity requirements are driven by the base winter peak demand forecasts.

The last column of Table 6-1 indicates that using the base winter forecast, Lakeland will not need any additional capacity in the current ten year planning cycle.

In 2007 Pace Global Energy Services, LLC was contracted by the City of Lakeland's Electric to conduct a risk integrated resource plan ("RIRP") and evaluation of the future resource needs of LE. The study was designed to guide LE in making strategic decisions regarding the timing and type of future build decisions necessary to meet the future load growth in the City of Lakeland and Polk County.

Pace's unique approach to resource planning – Pace RIRP℠ explicitly incorporates market volatility, the relationship between commodity prices for natural gas, coal, power, and the utilities relationship to load, thereby improving traditional IRP approaches. Pace's RIRP℠ approach further analyzes the regulatory and environmental risk elements that subject utilities to a variety of threats that can undermine its attempts at achieving environmental and financial goals while maintaining rate stability and price competitiveness. These specific risk categories include regulatory changes, CO_2 environmental regulatory regimes, market structure changes and increased costs in project development and construction. Pace RIRP℠ allows for evaluating a wide range of portfolios across the complete spectrum of utility risks in an appropriate, logical, and compelling way.

Covering the period from 2008 through 2028 ("Study Period"), the Report included a brief summary of the components of the RIRP that Pace provided LE throughout the process.

These include;

- A review of LE's planning objectives and major risks.
- Pace's Reference Case assumptions that reflect the main fundamental drivers of our market view, as well as the simulation methodology used to develop an integrated market pricing forecast for the relevant power market.
- An assessment of the Supply/Demand balance of LE.
- A review of capacity alternatives available to LE under current regulatory conditions in the state of Florida.
- A presentation of LE's risk profile and portfolio options.

Lakeland received the final report March 17, 2008. As previously mentioned, absent any retirements, Lakeland does not need additional capacity in the current ten year planning horizon. Results of the RIRP did indicate the need for additional capacity shortly beyond the current ten year planning horizon and therefore Lakeland has moved into a second phase of that study to identify the best alternative(s) for Lakeland and its customers based on factors such as least cost, risk avoidance and other strategic concerns. Lakeland has concluded from Phase I of the RIRP that additional fuel diversity is in the best interests of Lakeland and its customers. Possible scenarios include but are not limited to retirements, fuel conversion strategies, fuel diversification strategies, and long term capacity replacement based on fuel savings or combinations of any of these.

As Lakeland expects to continue to be a winter peaking utility, Table 6-1 also indicates that no additional capacity is needed during the summer peak seasons for the current ten year planning cycle.

Table 6-1 Projected Reliability Levels - Winter / Base Case										
					System Peak Demand		Reserve Margin		Excess/ (Deficit) to Maintain 15% Reserve Margin	
Year	Net Generating Capacity (MW)	Net System Purchases (MW)	Net System Sales (MW)	Net System Capacity (MW)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)	Before Interruptible and Load Management (%)	After Interruptible and Load Management (%)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)
2012/2013	975	0	0	975	696	696	40.1	40.1	175	175
2013/2014	975	0	0	975	699	699	39.5	39.5	171	171
2014/2015	975	0	0	975	703	703	38.7	38.7	167	167
2015/2016	975	0	0	975	708	708	37.7	37.7	161	161
2016/2017	975	0	0	975	713	713	36.7	36.7	155	155
2017/2018	975	0	0	975	718	718	35.8	35.8	149	149
2018/2019	975	0	0	975	723	723	34.9	34.9	144	144
2019/2020	975	0	0	975	727	727	34.1	34.1	139	139
2020/2021	975	0	0	975	731	731	33.4	33.4	134	134
2021/2022	975	0	0	975	736	736	32.5	32.5	129	129

Table 6-2
Projected Reliability Levels - Summer / Base Case

Year	Net Generating Capacity (MW)	Net System Purchases (MW)	Net System Sales (MW)	Net System Capacity (MW)	System Peak Demand		Reserve Margin		Excess/ (Deficit) to Maintain 15% Reserve Margin	
					Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)	Before Interruptible and Load Management (%)	After Interruptible and Load Management (%)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)
2012	929	0	0	929	655	655	41.8	41.8	176	176
2013	929	0	0	929	662	662	40.3	40.3	168	168
2014	929	0	0	929	669	669	38.9	38.9	160	160
2015	922	0	0	922	675	675	36.6	36.6	146	146
2016	929	0	0	929	682	682	36.2	36.2	145	145
2017	929	0	0	929	688	688	35.0	35.0	138	138
2018	929	0	0	929	695	695	33.7	33.7	130	130
2019	929	0	0	929	701	701	32.5	32.5	123	123
2020	929	0	0	929	707	707	31.4	31.4	116	116
2021	929	0	0	929	714	714	30.1	30.1	108	108

7.0 Generation Expansion Analysis Results and Conclusions

With the addition of McIntosh 5 in 2002, LE's generation profile shifted towards more exposure to natural gas. Pace recommended that LE attempt to pursue a course of action that attempts to limit its exposure to natural gas and attempts to add additional base load units. This course of action would be very difficult to accomplish give the regulatory and political environment that presently exists in Florida. This course of action is further complicated by the reliance LE must have on third parties to initiate and gain approval for such resources and for LE to successfully contract for equity shares or operating partnerships.

Regardless of the resource plan that LE develops, there is tremendous price risk from the volatility of natural gas that will pervade LE's supply portfolio for the foreseeable future. Robust commodity and price risk management programs are imperative to managing these costs. Proactively managing these risks over the near to medium term through well managed and controlled risk management programs can help LE mitigate the fuel and market volatility risks.

7.1 Supply-Side Economic Analysis

KEY FINDINGS: MARKET RISK

As stated previously LE desires to reduce the expected utility cost and narrow the distribution of possible outcomes. Pace concludes that additional base load capacity is essential in accomplishing that goal. Purchasing or constructing IGCC, nuclear or even renewable capacity is necessary for achieving this outcome.

Of the four base-load capacity resource options available to LE; IGCC appears to be superior, making plan 1[1] (Hold & Buy IGCC) the lowest in expected costs and volatility of possible outcomes. Nuclear power stations reduce both total expected utility cost and volatility of LE's utility cost. Uranium markets have been, and are expected to be more stable than natural gas markets. Therefore, market risk in this portfolio is reduced. The combination of the four baseload options in Plan 9 (Hold & Buy Renew /

[1] Again we note the current situation in Florida where the IGCC projects have either been delayed indefinitely or cancelled outright in response to the regulatory and permitting approval uncertainty.

IGCC / Nuc) provides portfolio performance that is extremely close in terms of reduced volatility of possible outcomes when compared to the status quo risk profile.

However, an additional consideration in procuring nuclear and IGCC capacity is the capital cost risk. Recently, there has been a heavy run up capital costs in completing baseload resources. It is possible that if the costs to complete a nuclear or IGCC facility could escalate far beyond Pace's estimate, fixed costs of these facilities could become stranded or rates could rise to levels that could drive away economic growth in Lakeland.

The combination of additional mid-merit combined-cycle and peaking combustion turbine gas-fired units provides no benefit to LE. Additional assets of these types will not reduce market risk or lower expected system cost. Acquiring additional gas-fired assets does not materially improve LE's risk profile beyond the status quo case.

7.1.1 Operational Risk

In terms of operational risks, modern IGCC and advanced technology next-generation nuclear facilities represent relatively unproven options due to the lack of operating stations in the US. Currently, only two small scale operational IGCC facilities exist in the US (including the nearby facility operated by Tampa Electric Company).

Due to the historical operational problems of current US nuclear fleet, in addition to the advanced technology expected to be used on the next generation of reactors operational risk in being part of the ownership of additional nuclear plants is also unknown. Therefore, it is possible the availability of the unit could be low in the early years of its operational life. In addition, as a minority partner LE would not be the operator of any nuclear facility in which it acquires capacity. The availability of the plant would depend heavily on the primary owner of the facility and the design performance of the nuclear technology. Mitigating part of this concern is the exceptional performance of the nuclear fleets in France, Japan and Korea.

The operational risks of constructing additional CC and CT facilities are minimal; as the operational characteristics of CT and CC generating units are well known to LE. In addition, LE already is the operator of the McIntosh 3 unit, and therefore is fully informed of the operational risks of investing in the remaining capacity.

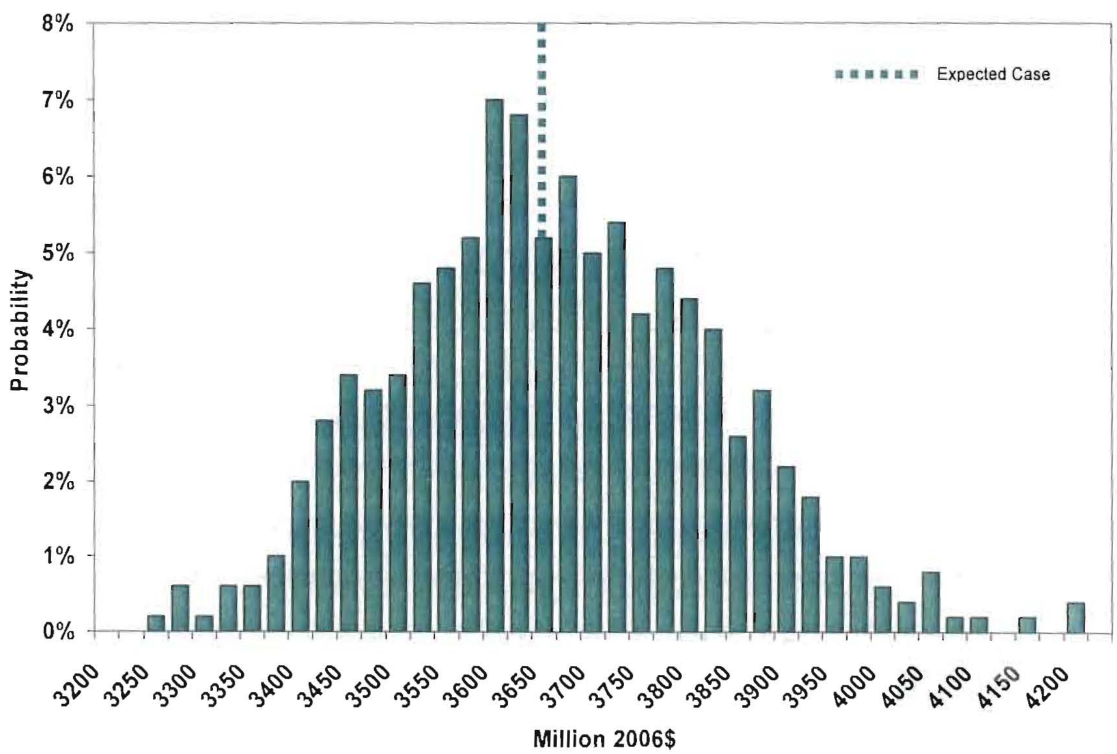
7.1.2 Future Capacity Additions Investment Decisions

Pace's analysis of the resources available to LE suggests that Advanced Nuclear Reactors, Biomass, Municipal Solid Waste, Gas-fired Combined Cycle and Combustion Turbine are available to LE for future development.

LE's status quo option is to maintain with its current resource base, while buying needed energy in the spot FMPP and FRCC markets. This plan results in a risk profile as seen in Exhibit 7.1. This is the risk profile that LE's decisions on future capacity investments should attempt to mitigate and improve.

The final decision on future investment lies with Lakeland Electric, and its views on balancing its primary planning objectives. Balancing competing and sometimes conflicting objectives requires an excellent understanding of current and future market conditions.

Exhibit 7.1: Net Present Value Utility Cost Risk Profile – 2008 - 2028



Note: Assumes a 2.5% Real Discount Rate
Source: Pace

Increasing the utility's base load capacity would reduce total system utility cost as well as cost volatility. Even accounting for the recent run ups in uranium prices, the markets for U_3O_8 and coal are notably lower and less volatile than natural gas and fuel oil. While increasing IGCC and nuclear base load resources reduces volatility and system cost, these base load alternatives in Florida will be extremely difficult to permit and construct and neither can be pursued alone by LE. LE should actively network and engage partnership or equity share participation in potential base load project developments. LE should give strong political support to nuclear and IGCC at the state level. This should be done to prevent the current regimes regulatory push towards a gas-only future. LE should attempt to influence state-level regulators in order to inform them of the risks and costs of their actions as current policies push the state in this direction.

When comparing the IGCC to nuclear build decision, neither type presents a solid case of superiority over the other and ultimately comes down to which technology can be constructed in the state. Both provide stability and reduced utility costs by taking advantage of the coal and uranium markets, respectively. However, nuclear facilities provide lower and more stable energy through a larger capital requirement. When considering regulatory carbon compliance risk, IGCC facilities produce significant amounts of CO_2 and would require significant additional capital to install carbon capture equipment; a technology which remains commercially unproven. On the other hand, capital expense of nuclear facilities is a large unknown due to the lack of any recent history of constructing such facilities on US soil. Furthermore, the utilities in Florida will be hard pressed to have the first nuclear facility online prior to 2020. Therefore, if a nuclear plant is chosen by LE as a future expansion resource, the additional lead time would result in greater volatility due to the time LE would remain exposed to the volatility in the spot energy markets. Given the evolving regulatory conditions in the state of Florida, the nuclear build addition appears the more credible of the two options.

Biomass, Municipal Solid Waste (MSW), or alternative technologies such as plasma gasification may provide options in the future for "base load like" supply, i.e. low price fuels that are similar to the economics of nuclear and IGCC. LE should consider evaluating projects similar to those recently proposed and under construction in the state of Florida. These projects can reduce expected utility cost volatility to levels similar to other base load generation types.

A natural gas-fired capacity expansion future represents the highest-cost, highest-risk outcome for LE. Additional natural gas-fired capacity does not reduce future market and only partially mitigates carbon related regulatory risk. With these resources, LE does not substantially reduce its risk profile beyond the status quo case. This is due to the large amount of gas-fired capacity already in the FMPP and FRCC market that regularly sets the marginal price of energy.

As shown in Section 6 and again in the Tables in Section 9, Lakeland does not have an immediate capacity need in the current ten year planning horizon. This gives Lakeland the ability to continue, in a timely but unhurried manner, its evaluation of resource options along with existing resources and what the proper mix of existing and/or new resources should be, if any. As no final decision has been made at the time of this writing, all resources are assumed available over the planning cycle meaning no planned retirements of existing facilities being proposed for the current ten year planning cycle. The demand and capacity analysis presented in Section 6 indicates that this position is feasible and achievable for the current planning cycle.

7.2 Energy Conservation and Management Programs

Lakeland continues to actively monitor Energy Conservation & Efficiency Options to find the most cost-effective way to meet our customers' needs. Lakeland was able to demonstrate its solar thermal water heating program cost-effective through the use of the PSC approved FIRE model in the 2005 IRP. The main driver for this program being cost-effective is because it has its own self-sustaining rate, meaning there is no revenue loss to the utility and other customers do not subsidize the program. Participants are billed for the thermal energy used at a separate rate from their normal KWH consumption. As a result Lakeland is developing a business plan to present to its management to increase the penetration of its solar thermal hot water program. This program has been highly successful in its R&D stage and should be considered a hybrid between energy conservation & management programs and distributed generation. It should be noted that despite this program being cost-effective, even the most aggressive implementation of this program would not meet all of the future capacity needs of the system.

7.3 Sensitivity Analysis

In Lakeland's normal course of analysis a preferred option would be selected. Lakeland would then perform several sensitivity analyses to measure the impact of important assumptions on the option(s) selected. The sensitivity analyses may include but not be limited to the following:

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

For each sensitivity analysis, a best plan over the planning horizon would be identified. The sensitivity analyses have been performed by Pace over the same planning period used throughout the economic evaluations, with a projection of annual costs and cumulative present worth costs.

7.4 Transmission and Distribution

All options selected would be analyzed for impacts to the transmission and distribution systems and the costs of any upgrades would be factored into the final analysis and decision.

8.0 Environmental and Land Use Information

Lakeland's 2012 Ten-Year Site Plan has no capacity additions in it and thus no additional environmental or land use information is required at this time. All existing units are fully permitted and meet all permitted requirements. Any future additions would comply with all applicable environmental and land use requirements.

9.0 Ten-Year Site Plan Schedules

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

9.1 Abbreviations and Descriptions

The following abbreviations are used throughout the Ten-Year Site Plan Schedules.

Abbreviation	Description
Unit Type	
CA	Combined Cycle Steam Part
GT	Combustion Gas Turbine
ST	Steam Turbine
CT	Combined Cycle Combustion Turbine
IC	Internal Combustion Engine
Fuel Type	
NG	Natural Gas
DFO	Distillate Fuel Oil
RFO	Residual Fuel Oil
BIT	Bituminous Coal
WH	Waste Heat
Fuel Transportation Method	
PL	Pipeline
TK	Truck
RR	Railroad
Unit Status Code	
RE	Retired
SB	Cold Standby (Reserve)
TS	Construction Complete, not yet in commercial operation
U	Under Construction
P	Planned for installation

Table 9-1a
Schedule 1.0: Existing Generating Facilities as of December 31, 2010

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				Fuel		Fuel Transport						Net Capability[1]	
Plant Name	Unit No.	Location	Unit Type	Pri	Alt	Pri	Alt	Alt Fuel Days Use	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen. Max. Nameplate kW	Summer MW	Winter MW
Charles Larsen Memorial	2	16-17/28S/24E	GT	NG	DFO	PL	TK	28	11/62	Unknown	11,500	10	14
	3		GT	NG	DFO	PL	TK	28	12/62	Unknown	11,500	9	13
	8		CA	WH	---				04/56	Unknown	25,000	29	31
	8		CT	NG	DFO	PL	TK	5	07/92	Unknown	101,520	76	93
Plant Total												124	151

[1]Net Normal.

Source: Lakeland Energy Supply Unit Rating Group

Table 9-1a
Schedule 1.0: Existing Generating Facilities as of December 31, 2010

Plant Name	Unit No.	Location	Unit Type[3]	Fuel[4] Pri	Fuel[4] Alt	Fuel Transport[5] Pri	Fuel Transport[5] Alt	Alt Fuel Days Use[2]	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen. Max. Nameplate kW	Net Capability Summer MW	Net Capability Winter MW
Winston Peaking Station	1-20	21/28S/23E	IC	NG	DFO	PL	TK	NR	12/01	Unknown	2,500 each	50	50
Plant Total												50	50
C.D. McIntosh, Jr.	D1	4-5/28S/24E	IC	DFO	---	TK	---	NR	01/70	Unknown	2,500	2.5	2.5
	D2		IC	DFO	---	TK	---	NR	01/70	Unknown	2,500	2.5	2.5
	GT1		GT	NG	DFO	PL	TK	NR	05/73	Unknown	26,640	16	19
	1		ST	NG	RFO	PL	TK	NR	02/71	Unknown	103,000	85	85
	2		ST	NG	RFO	PL	TK	NR	06/76	Unknown	126,000	106	106
	3[1]		ST	BIT	---	RR	TK	NR	09/82	Unknown	363,870	205	205
	5		CT	NG	DFO	PL	TK	NR	05/01	Unknown	292,950	212	233
	5		CA	WH	---	---	---	NR	05/02	Unknown	135,000	126	121
Plant Total												755	774
System Total												**929**	**975**

[1]Lakeland's 60 percent portion of joint ownership with Orlando Utilities Commission.
[2]Lakeland does not maintain records of the number of days that alternate fuel is used.

[3]**Unit Type**		[4]**Fuel Type**		[5]**Fuel Transportation Method**	
CA	Combined Cycle Steam Part	DFO	Distillate Fuel Oil	PL	Pipeline
CT	Combined Cycle Combustion Turbine	RFO	Residual Fuel Oil	TK	Truck
GT	Combustion Gas Turbine	BIT	Bituminous Coal	RR	Railroad
ST	Steam Turbine	WH	Waste Heat		
		NG	Natural Gas		

Table 9-2

Schedule 2.1: History and Forecast of Energy Consumption and Number of Customers by Customer Class

-1	-2	-3	-4	-5	-6	-7	-8	-9
	Rural & Residential					Commercial		
Year	Population	Members per Household	GWh	Average No. of Customers	Average kWh Consumption per Customer	GWh	Average No. of Customers	Average kWh Consumption per Customer
2002	234,210	2.54	1,391	92,258	15,077	691	10,809	63,928
2003	236,890	2.54	1,408	93,348	15,083	689	11,097	62,089
2004	243,576	2.58	1,391	94,261	14,757	690	11,296	61,084
2005	247,942	2.58	1,431	96,220	14,872	733	11,493	63,778
2006	253,405	2.57	1,438	98,680	14,572	756	11,832	63,895
2007	253,027	2.52	1,444	100,523	14,365	781	11,898	65,641
2008	252,731	2.51	1,383	100,739	13,729	762	11,913	63,964
2009	253,084	2.52	1,417	100,628	14,082	749	11,837	63,276
2010	253,009	2.51	1,530	100,689	15,195	753	11,806	63,781
2011	254,283	2.52	1,437	100,812	14,254	744	11,786	63,126
Forecast								
2012	257,449	2.54	1,407	101,371	13,880	754	11,808	63,855
2013	259,878	2.54	1,413	102,338	13,807	766	11,829	64,756
2014	262,616	2.54	1,423	103,436	13,757	774	11,893	65,080
2015	265,484	2.53	1,434	104,750	13,690	782	11,978	65,286
2016	268,618	2.53	1,452	106,221	13,670	790	12,056	65,528
2017	271,874	2.52	1,468	107,748	13,624	795	12,119	65,599
2018	275,228	2.52	1,485	109,294	13,587	801	12,180	65,764
2019	278,658	2.51	1,504	110,849	13,568	807	12,246	65,899
2020	282,053	2.51	1,521	112,366	13,536	812	12,314	65,941
2021	285,367	2.51	1,539	113,788	13,525	818	12,383	66,058

Table 9-3
Schedule 2.2: History and Forecast of Energy Consumption and Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	GWh	Average No. of Customers	Average kWh Consumption per Customer	Railroads and Railways	Street & Highway Lighting GWh	Other Sales to Public Authorities GWh	Total Sales to Ultimate Consumers GWh
2002	520	84	6,190,476	0	19	105	2,726
2003	541	88	6,147,727	0	19	103	2,760
2004	534	91	5,868,132	0	20	101	2,736
2005	541	83	6,518,072	0	20	84	2,809
2006	586	87	6,735,632	0	21	87	2,888
2007	615	88	6,988,636	0	21	87	2,949
2008	607	87	6,977,011	0	21	85	2,859
2009	590	85	6,941,176	0	21	83	2,861
2010	581	84	6,916,667	0	21	81	2,966
2011	578	87	6,643,678	0	21	84	2,864
Forecast							
2012	603	84	7,178,571	0	21	85	2,870
2013	678	85	7,976,471	0	21	86	2,964
2014	680	85	8,000,000	0	21	86	2,984
2015	681	85	8,011,765	0	21	86	3,004
2016	683	86	7,941,860	0	21	87	3,033
2017	684	86	7,953,488	0	21	87	3,055
2018	686	86	7,976,744	0	21	87	3,080
2019	687	86	7,988,372	0	21	87	3,106
2020	689	87	7,919,540	0	21	88	3,131
2021	690	87	7,931,034	0	21	88	3,156

Table 9-4

Schedule 2.3: History and Forecast of Energy Consumption and Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)
Year	Sales for Resale GWH	Utility Use & Losses GWh	Net Energy for Load GWh	Other Customers (Average No.)	Total No. of Customers
2002	0	114	2,840	10,583	113,734
2003	0	130	2,890	10,517	115,050
2004	0	146	2,882	10,398	116,046
2005	0	143	2,952	10,206	118,002
2006	0	112	3,000	10,017	120,616
2007	0	120	3,068	9,871	122,380
2008	0	117	2,975	9,685	122,424
2009	0	132	2,992	9,432	121,982
2010	0	151	3,117	9,209	121,788
2011	0	29	2,893	9,078	121,763
Forecast					
2012	0	125	2,995	9,009	122,272
2013	0	130	3,094	9,017	123,269
2014	0	131	3,115	9,021	124,435
2015	0	132	3,136	9,027	125,840
2016	0	132	3,165	9,031	127,394
2017	0	133	3,188	9,036	128,989
2018	0	134	3,214	9,039	130,599
2019	0	136	3,242	9,045	132,226
2020	0	136	3,267	9,051	133,818
2021	0	137	3,293	9,055	135,313

Table 9-5
Schedule 3.1: History and Forecast of Summer Peak Demand Base Case (MW)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
					Residential		Commercial/Industrial		
Year	Total	Wholesale	Retail	Interrupt.	Load Management	Conservation	Load Management	Conservation	Net Firm Demand
2002	578	0	578	0	0	0	0	0	578
2003	579	0	579	0	0	0	0	0	579
2004	584	0	584	0	0	0	0	0	584
2005	639	0	639	0	0	0	0	0	639
2006	631	0	631	0	0	0	0	0	631
2007	648	0	648	0	0	0	0	0	648
2008	615	0	615	0	0	0	0	0	615
2009	625	0	625	0	0	0	0	0	625
2010	638	0	638	0	0	0	0	0	638
2011	611	0	611	0	0	0	0	0	611
Forecast									
2012	655	0	655	0	0	0	0	0	655
2013	662	0	662	0	0	0	0	0	662
2014	669	0	669	0	0	0	0	0	669
2015	675	0	675	0	0	0	0	0	675
2016	682	0	682	0	0	0	0	0	682
2017	688	0	688	0	0	0	0	0	688
2018	695	0	695	0	0	0	0	0	695
2019	701	0	701	0	0	0	0	0	701
2020	707	0	707	0	0	0	0	0	707
2021	714	0	714	0	0	0	0	0	714

Table 9-6
Schedule 3.2: History and Forecast of Winter Peak Demand Base Case (MW)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
			Retail	Interrupt.	Residential		Comm./Ind.		
Year	Total	Wholesale			Load Management	Conservation	Load Management	Conservation	Net Firm Demand
2002/03	694	0	694	0	0	0	0	0	694
2003/04	570	0	570	0	0	0	0	0	570
2004/05	648	0	648	0	0	0	0	0	648
2005/06	680	0	680	0	0	0	0	0	680
2006/07	596	0	596	0	0	0	0	0	596
2007/08	684	0	684	0	0	0	0	0	684
2008/09	710	0	710	0	0	0	0	0	710
2009/10	804	0	804	0	0	0	0	0	804
2010/11	709	0	709	0	0	0	0	0	709
2011/12	612	0	612	0	0	0	0	0	612
Forecast									
2012/13	696	0	696	0	0	0	0	0	696
2013/14	699	0	699	0	0	0	0	0	699
2014/15	703	0	703	0	0	0	0	0	703
2015/16	708	0	708	0	0	0	0	0	708
2016/17	713	0	713	0	0	0	0	0	713
2017/18	718	0	718	0	0	0	0	0	718
2018/19	723	0	723	0	0	0	0	0	723
2019/20	727	0	727	0	0	0	0	0	727
2020/21	731	0	731	0	0	0	0	0	731
2021/22	736	0	736	0	0	0	0	0	736

Table 9-7
Schedule 3.3: History and Forecast of Annual Net Energy for Load – GWh
Base Case

-1	-2	-3	-5	-6	-7	-8	-9	-10
Year	Total	Residential Conservation	Comm./Ind. Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
2002	2,726	0	0	2,726	0	114	2,840	44.8%
2003	2,760	0	0	2,760	0	130	2,890	57.9%
2004	2,736	0	0	2,736	0	146	2,882	50.8%
2005	2,809	0	0	2,809	0	143	2,952	49.6%
2006	2,888	0	0	2,888	0	112	3,000	57.5%
2007	2,948	0	0	2,948	0	120	3,068	51.2%
2008	2,858	0	0	2,858	0	117	2,975	47.8%
2009	2,860	0	0	2,860	0	132	2,992	42.5%
2010	2,966	0	0	2,966	0	151	3,117	50.2%
2011	2,864	0	0	2,864	0	29	2,893	47.4%
Forecast								
2012	2,870	0	0	2,870	0	125	2,995	49.1%
2013	2,964	0	0	2,964	0	130	3,094	50.5%
2014	2,984	0	0	2,984	0	131	3,115	50.6%
2015	3,004	0	0	3,004	0	132	3,136	50.6%
2016	3,033	0	0	3,033	0	132	3,165	50.7%
2017	3,055	0	0	3,055	0	133	3,188	50.7%
2018	3,080	0	0	3,080	0	134	3,214	50.7%
2019	3,106	0	0	3,106	0	136	3,242	50.9%
2020	3,131	0	0	3,131	0	136	3,267	51.0%
2021	3,156	0	0	3,156	0	137	3,293	51.1%

Table 9-8
Schedule 4: Previous Year and Two Year Forecast of Retail Peak Demand and Net Energy for Load by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Month	Actual		2012 Forecast		2013 Forecast	
	Peak Demand[1] MW	NEL GWh	Peak Demand[1] MW	NEL GWh	Peak Demand[1] MW	NEL GWh
January	665	226	697	217	696	239
February	501	194	558	206	557	214
March	434	213	474	226	479	234
April	552	240	508	223	514	231
May	568	264	548	266	555	275
June	609	279	604	281	611	288
July	591	290	655	278	662	284
August	611	298	635	304	642	311
September	563	269	582	289	588	295
October	482	218	543	257	548	264
November	429	198	460	217	460	222
December	383	204	559	231	558	237

[1]After Load Management, Conservation and Interruptible Load exercised as needed.

Table 9-9
Schedule 5: Fuel Requirements

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Calendar Year										
	Fuel Requirements	Type	Units	2011-Actual	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
(1)	Nuclear		Trillion Btu	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal[1]		1000 Ton	343	337	383	368	416	379	428	417	398	426	463
(3)	Residual	Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(4)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(5)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(6)		Total	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(7)	Distillate	Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(8)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(9)		CT	1000 BBL	1	0	0	0	0	0	0	0	0	0	0
(10)		Total	1000 BBL	1	0	0	0	0	0	0	0	0	0	0
(11)	Natural Gas	Steam	1000 MCF	188	1	64	26	44	26	53	10	36	95	133
(12)		CC	1000 MCF	15,919	18,835	14,977	15,745	15,032	16,953	14,864	16,712	16,126	16,863	18,297
(13)		CT	1000 MCF	16	0	0	0	0	0	0	0	0	0	0
(14)		Total	1000 MCF	16,123	18,836	15,041	15,771	15,076	16,979	14,917	16,722	16,162	16,958	18,430
(15)	Other		Trillion Btu	0	0	0	0	0	0	0	0	0	0	0

[1] Includes Petroleum Coke.

Table 9-10
Schedule 6.1: Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Calendar Year										
	Energy Sources	Type	Units	2011-Actual	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
(1)	Inter-Regional Interchange		GWh	0	0	0	0	0	0	0	0	0	0	0
(2)	Nuclear		GWh	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal[1]		GWh	821	800	925	892	1,007	923	1,042	1,019	976	1,046	1,140
(4)	Residual	Steam	GWh	0	0	0	0	0	0	0	0	0	0	0
(5)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	GWh	0	0	0	0	0	0	0	0	0	0	0
(7)		Total	GWh	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate	Steam	GWh	0	0	0	0	0	0	0	0	0	0	0
(9)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0
(10)		CT	GWh	0	0	0	0	0	0	0	0	0	0	0
(11)		Total	GWh	0	0	0	0	0	0	0	0	0	0	0
(12)	Natural Gas	Steam	GWh	10	0	4	1	2	1	5	0	4	5	12
(13)		CC	GWh	2,336	2,796	2,470	2,810	2,495	2,825	2,707	2,534	2,679	2,850	2,716
(14)		CT	GWh	0	0	0	0	0	0	0	0	0	0	0
(15)		Total	GWh	2,346	2,796	2,474	2,811	2,497	2,826	2,712	2,534	2,683	2,855	2,728
(16)	NUG			0	0	0	0	0	0	0	0	0	0	0
(17)	Hydro			0	0	0	0	0	0	0	0	0	0	0
(18)	Other (Specify)[2]			-274	-601	-305	-588	-368	-584	-566	-339	-417	-634	-575
(19)	Net Energy for Load		GWh	2,893	2,995	3,094	3,115	3,136	3,165	3,188	3,214	3,242	3,267	3,293

[1] Includes Petroleum Coke.
[2] Intra-Regional Net Interchange

Table 9-11
Schedule 6.2: Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Calendar Year										
	Energy Source	Type	Units	2011-Actual	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
(1)	Inter-Regional Interchange		%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(2)	Nuclear		%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(3)	Coal[1]		%	28.38	26.71	29.9	28.64	32.11	29.16	32.69	31.71	30.1	32.02	34.62
(4)	Residual	Steam	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(5)		CC	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(6)		CT	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(7)		Total	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(8)	Distillate	Steam	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(9)		CC	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(10)		CT	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(11)		Total	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(12)	Natural Gas	Steam	%	0.35	0.00	0.13	0.03	0.06	0.03	0.16	0.00	0.12	0.15	0.36
(13)		CC	%	80.75	93.36	79.83	90.21	79.56	89.26	84.91	78.84	82.63	87.24	82.48
(14)		CT	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(15)		Total	%	81.09	93.36	79.96	90.24	79.62	89.29	85.07	78.84	82.76	87.39	82.84
(16)	NUG		%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Hydro		%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Other (Specify)[2]		%	-9.47	-20.07	-9.86	-18.88	-11.73	-18.45	-17.75	-10.55	-12.86	-19.41	-17.46
(18)	Net Energy for Load		%	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00

[1] Includes Petroleum Coke.
[2] Other = Intra-Regional Net Interchange Including Firm Sale to FMPA.

Table 9-12

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

-1	-2	-3	-4	-5	-6	-7	-8	-9	-10	-11	-12
Year	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	Projected Firm Net To Grid from NUG	Total Capacity Available	System Firm Peak Demand	Reserve Margin Before Maintenance[1]		Scheduled Maintenance	Reserve Margin After Maintenance[1]	
	MW	MW	MW	MW	MW	MW	MW	%	MW	MW	%
2012	929	0	0	0	929	655	274	41.8	0	274	41.8
2013	929	0	0	0	929	662	267	40.3	0	267	40.3
2014	929	0	0	0	929	669	260	38.9	0	260	38.9
2015	929	0	0	0	929	675	254	37.6	0	254	37.6
2016	929	0	0	0	929	682	247	36.2	0	247	36.2
2017	929	0	0	0	929	688	241	35.0	0	241	35.0
2018	929	0	0	0	929	695	234	33.7	0	234	33.7
2019	929	0	0	0	929	701	228	32.5	0	228	32.5
2020	929	0	0	0	929	707	222	31.4	0	222	31.4
2021	929	0	0	0	929	714	215	30.1	0	215	30.1

[1] Included exercising Load Management and Interruptible Load.

Table 9-13

Schedule 7.2: Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak

-1	-2	-3	-4	-5	-6	-7	-8	-9	-10	-11	-12
Year	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	Projected Firm Net To Grid from NUG	Total Capacity Available	System Firm Peak Demand	Reserve Margin Before Maintenance[1]		Scheduled Maintenance	Reserve Margin After Maintenance[1]	
	MW	MW	MW	MW	MW	MW	MW	%	MW	MW	%
2012/13	975	0	0	0	975	696	279	40.1	0	279	40.1
2013/14	975	0	0	0	975	699	276	39.5	0	276	39.5
2014/15	975	0	0	0	975	703	272	38.7	0	272	38.7
2015/16	975	0	0	0	975	708	267	37.7	0	267	37.7
2016/17	975	0	0	0	975	713	262	36.7	0	262	36.7
2017/18	975	0	0	0	975	718	257	35.8	0	257	35.8
2018/19	975	0	0	0	975	723	252	34.9	0	252	34.9
2019/20	975	0	0	0	975	727	248	34.1	0	248	34.1
2020/21	975	0	0	0	975	731	244	33.4	0	244	33.4
2021/22	975	0	0	0	975	736	239	32.5	0	239	32.5

[1] Included exercising Load Management and Interruptible Load.

Table 9-14
Schedule 8.0: Planned and Prospective Generating Facility Additions and Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Plant Name	Unit No.	Location	Unit Type	Fuel		Fuel Transport		Const Start	Commercial In-Service	Expected Retirement	Gen Max Nameplate	Net Capability		Status
				Pri.	Alt.	Pri.	Alt.	Mo/Yr	Mo/Yr	Mo/Yr	kW	Sum MW	Win MW	

None At Time of This Filing

Table 9-15
Schedule 9.1: Status Report and Specifications of Approved Generating Facilities

(1)	Plant Name and Unit Number:	N/A
(2)	Capacity:	
(3)	Summer MW	
(4)	Winter MW	
(5)	Technology Type:	
(6)	Anticipated Construction Timing:	
(7)	Field Construction Start-date:	
(8)	Commercial In-Service date:	
(9)	Fuel	
(10)	Primary	
(11)	Alternate	
(12)	Air Pollution Control Strategy:	
(13)	Cooling Method:	
(14)	Total Site Area:	
(15)	Construction Status:	
(16)	Certification Status:	
(17)	Status with Federal Agencies:	
(18)	Projected Unit Performance Data:	
(19)	Planned Outage Factor (POF):	
(20)	Forced Outage Factor (FOF):	
(21)	Equivalent Availability Factor (EAF):	
(22)	Resulting Capacity Factor (%):	
(23)	Average Net Operating Heat Rate (ANOHR):	
(24)	Projected Unit Financial Data:	
(25)	Book Life:	
(26)	Total Installed Cost (In-Service year $/kW):	
(27)	Direct Construction Cost ($/kW):	
(28)	AFUDC Amount ($/kW):	
(29)	Escalation ($/kW):	
(30)	Fixed O&M ($/kW-yr):	
(31)	Variable O&M ($/MWh):	

Table 9-16
Schedule 9.2: Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number:	None in Current Planning Cycle
(2)	Capacity:	
(3)	Summer MW	
(4)	Winter MW	
(5)	Technology Type:	
(6)	Anticipated Construction Timing:	
(7)	Field Construction Start-date:	
(8)	Commercial In-Service date:	
(9)	Fuel	
(10)	Primary	
(11)	Alternate	
(12)	Air Pollution Control Strategy:	
(13)	Cooling Method:	
(14)	Total Site Area:	
(15)	Construction Status:	
(16)	Certification Status:	
(17)	Status with Federal Agencies:	
(18)	Projected Unit Performance Data:	
(19)	Planned Outage Factor (POF):	
(20)	Forced Outage Factor (FOF):	
(21)	Equivalent Availability Factor (EAF):	
(22)	Resulting Capacity Factor (%):	
(23)	Average Net Operating Heat Rate (ANOHR):	
(24)	Projected Unit Financial Data:	
(25)	Book Life:	
(26)	Total Installed Cost (In-Service year $/kW):	
(27)	Direct Construction Cost ($/kW):	
(28)	AFUDC Amount ($/kW):	
(29)	Escalation ($/kW):	
(30)	Fixed O&M ($/kW-yr):	
(31)	Variable O&M ($/MWh):	

Table 9-17 Schedule 10: Status Report and Specifications of Proposed Directly Associated Transmission Lines		
(1)	Point of Origin and Termination:	None planned.
(2)	Number of Lines:	None planned.
(3)	Right of Way:	None planned.
(4)	Line Length:	None planned.
(5)	Voltage:	None planned.
(6)	Anticipated Construction Time:	None planned.
(7)	Anticipated Capital Investment:	None planned.
(8)	Substations:	None planned.
(9)	Participation with Other Utilities:	None planned.