have significant uncertainties. Nonetheless, we believe the extrapolated numbers presented here are informative and allow at least some sense of the potential magnitude of the impacts, and some basis for comparison of the relative magnitude of impacts for the four options.

Extrapolation approach. As noted above, the method we used is a major simplification of the rigorous and data-intensive modeling approach used in detailed studies, and is meant to approximate the possible range of damage costs associated with the options and to aid in comparisons. We used two studies as data sources, EPA's regulatory impact analysis for CAIR (US EPA 2005b) and an ICF 2005 modeling study of two power plants in the Midwest. EPA's study used the Community Multiscale Air Quality (CMAQ) model to estimate $PM_{2.5}$ concentrations across the US resulting from power plant emissions of $PM_{2.5}$ precursors under both a baseline scenario and a reduced SO_2 and NO_x emission scenario (i.e., the CAIR regulatory program) for 2010 and 2015. EPA then performed probabilistic modeling of dose-response for mortality and several kinds of illness, followed by probabilistic valuation modeling of the predicted health effects (that is, estimating a dollar value of health "damages"). ICF used very similar methods and data inputs in its study, except that the Regional Modeling System for Aerosols and Deposition (REMSAD) was used for the photochemical air modeling. EPA's study covered hundreds of power plants in the Eastern US, while ICF's study focused on two specific plants.

For purposes of application in this options comparison, we reviewed the health effects and damage cost results of these studies in conjunction with the associated quantities of SO_2 and NO_x emissions. Our goal was to develop a general approximation of the amount of impacts associated with a given emission quantity (i.e., something roughly parallel to the environmental externality "adders" used by some states in power plant decisions). Achieving this goal is greatly complicated by the fact that emissions of primary $PM_{2.5}$ are not an adequate predictor of downwind $PM_{2.5}$ impacts, and that there are multiple important precursors (including SO_2, NO_x, primary $PM_{2.5}$, VOCs) and other determinants of airborne $PM_{2.5}$. After examining the data from both studies, we decided to use the damage costs per ton of SO_2 plus NO_x as the estimator of regional impacts (rather than damage costs per ton of SO_2 or NO_x alone). These two pollutants are generally the main contributors to regional $PM_{2.5}$ resulting from power plant emissions (as evidenced by EPA's focus of the CAIR regulations only on these two pollutants), and while neither one alone nor the two in combination are expected to be linear with regional $PM_{2.5}$ concentrations, using the sum was considered the better approach (in part based on careful examination and comparison of the various possible estimators, including damage costs per ton SO_2 and damage costs per ton NO_x).

The CAIR analyses provide a look at the overall impact of emission reductions of hundreds of power plants in the Eastern US. Using the CAIR results for 2015 yields an estimator of approximately $20,000 (2003 dollars) of national damage costs from $PM_{2.5}$ health impacts (both morbidity and mortality) per combined ton of SO_2 and NO_x emitted ($100 billion in damage costs using 3 percent discounting, roughly 5.5 million tons of emitted SO_2 plus NO_x). This large-scale, multi-plant analysis provides an aggregate-

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level result, which could be viewed as an averaging over many emission reductions in many different locations. ICF's modeling for two particular Midwest US locations yields an estimator of approximately $30,000 ($33,000 for one location, $26,000 for the other[41]) (2003 dollars) of national damage costs from $PM_{2.5}$ health impacts (morbidity and mortality) per combined ton of SO_2 and NO_x emitted, which indicates the emission location may be somewhat "riskier" than the average derived from CAIR. The proportion of the damage costs accruing in-state in ICF's modeling study ranged from 10 to 20 percent for the two emission locations (both in the same state) Given these two data sets, and the recognition of significant uncertainty in applying these values to other power plants in other locations, we use an order-of-magnitude range of $5,000 to $50,000 per combined ton of SO_2 plus NO_x to extrapolate the potential regional health damage costs for the four options. In-state damage costs would be expected to be substantially lower than the total regional damage costs.

Clearly, Florida is different geographically and has different air quality conditions than the rest of the Eastern US. Florida's air quality is relatively good for $PM_{2.5}$ and other regulated air pollutants, as evidenced by the fact that, unlike most Eastern states, it has no non-attainment counties (see Abt 2004 for examples of projected future $PM_{2.5}$ levels in Florida). However, even though much of what is "downwind" for Florida emissions is ocean, it is clear from the CAIR modeling that Florida emissions of $PM_{2.5}$ precursors affect downwind $PM_{2.5}$ levels in states to the north. Moreover, examination of potentially exposed populations – a critically important determinant of health impacts and damage costs from $PM_{2.5}$ exposures – in proximity to Gainesville and comparison with populations relevant for CAIR (Eastern US average of 164 people per square mile) and for ICF's study in the Midwest US shows similar (or higher) populations for Gainesville, as shown in Figure 6-16, particularly at greater distances where the majority of impacts occur. Moreover, the population surrounding Gainesville skews older than average, which would tend to make the risks from $PM_{2.5}$ exposure higher than the average Eastern US location.

Figure 6-16
Comparison of Population Densities for Deerhaven and Extrapolation Sites

Radius from Facility (miles)	Population (number/mi^2)		
	Deerhaven Site	Site 1, ICF Midwest Study	Site 2, ICF Midwest Study
25	147	153	34
50	109	310	16
75	137	199	21
200	156	54	58
311 (500 km)	179	45	44

Thus, while the damage cost estimators derived above obviously are not a perfect fit for estimating and comparing health damage costs for the four options in Florida, use of the

[41] This relatively small difference, despite the fact that population close to the source is much higher for one site than the other, is consistent with the observation that far-field effects dominate overall $PM_{2.5}$ damage cost estimates.

derived order-of-magnitude range appears to be a reasonable approximation given the data available to work with.

Extrapolation results for $PM_{2.5}$ Damage Costs. The regional damage cost extrapolation results for the 2015 base case are presented in Figure 6-17 for the four options. Considering local generating unit emissions only (that is, excluding non-local emissions from power purchases under the two DSM options), the ranking of the options based on extrapolated regional $PM_{2.5}$ damage costs is the same as the ranking based on estimated local $PM_{2.5}$ impacts: CFB option > IGCC option > DSM/biomass option > DSM/power purchase option. For all options, and especially the two DSM options, the majority of regional $PM_{2.5}$ damage costs result from continued operations of existing GRU units (rather than from a new unit). This baseline for all options is roughly \$10 to \$100 million in estimated damage costs due to emissions from future operations of existing GRU units. Thus, the differences between options appear most pronounced when only the new units are being compared. Impact of regional emissions from power purchases to be added for final report

Figure 6-17
Summary of Extrapolated Regional Health Damage Cost Estimates for $PM_{2.5}$ Exposures for the Four Options

Year/ Scenario	Source	Estimated Annual Regional Damage Costs (millions, $2003 dollars, rounded) [a]			
		CFB	IGCC	DSM plus Biomass	DSM plus Power Purchase
2015/ base case	New unit only	$6 - 60	$4 - 40	$0.5 - 5 + __ [b]	$0 + __ [b]
	All GRU units	$16 - 160	$14 – 140	$10 - 100 + __ [b]	$10 - 100 + __ [b]

[a] Based on generating unit stack emissions of SO_2 and NO_x as estimated by IPM, along with the damage cost estimator range described in text.
[b] Includes non-GRU emissions resulting from power purchases. Results to be added for final report.

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CHAPTER SEVEN
ECONOMIC IMPACT

Introduction

In this section we analyze the socioeconomic impacts of the four main resource options, as discussed in Chapter 1. The four main options are:

- 220 MW CFB plant;
- 220 MW IGCC plant;
- 75 MW Biomass plant; and
- Maximum DSM

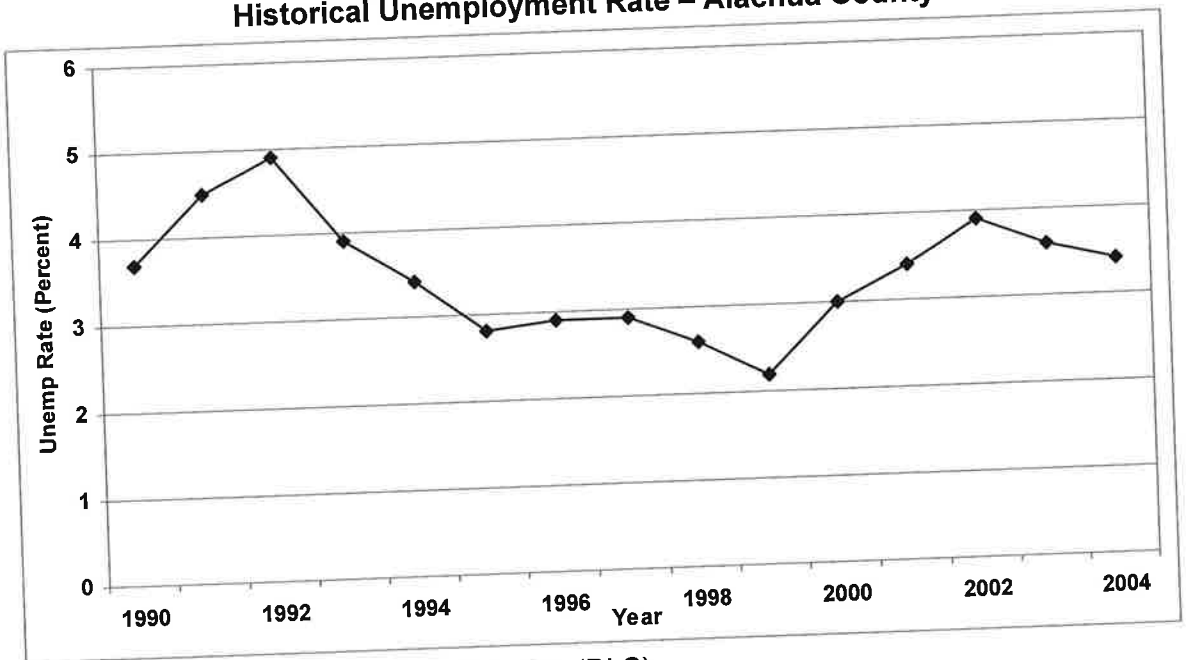
The main socioeconomic impact analyzed in this section is the potential for job creation in the Alachua County. Since all the options involve significant investments to meet future energy demand (including options for demand-side management), they have the potential to create both local as well as regional employment opportunities. Some of these additional employment opportunities will be temporary (for example, for construction of the power plant), while others will be more permanent (for example, for operation and maintenance of the plants once they are constructed).

The section is organized as follows. We first describe the local labor market conditions to determine the potential benefits of these new jobs. We then describe the regional economic model used to estimate the new jobs created. We then describe the methodology used to estimate the jobs. The section ends with the results of the analysis and some concluding thoughts.

Local Labor Market Conditions

Because the IMPLAN model (discussed below) is based on county-level data, the socioeconomic impacts are analyzed for the entire county. As Figure 7-1 below shows, historically, the annual unemployment rate in Alachua County has been quite low in recent years. From a peak of about 5 percent in 1992, the unemployment rate has dropped significantly to about 3.4 percent in 2004. This drop in unemployment is expected given the overall economic boom throughout the country and its effects in Florida in general, and the local economy in particular.

Figure 7-1
Historical Unemployment Rate – Alachua County



Source: Bureau of Labor Statistics (BLS)

Although the unemployment rate in the local economy is not high, creating additional job opportunities can have its advantages. Labor economists argue that local unemployment can be costly not only to the individuals directly affected but also to the regional/national economies. Avoiding the costs of unemployment thus leads to both private benefits (i.e., benefits to individuals directly affected) as well as social benefits (i.e., benefits to the region as a whole). Some of the potential benefits from reducing unemployment discussed in the economic literature are:[42]

- Increased productivity
- Increased individual income
- Reduced poverty
- Reduced criminal activity / policing costs
- Reduced costs of mental and physical health services
- Reduced costs of support services
- Improved life opportunities
- Reduced benefits payments
- Increased tax revenue
- Improved fiscal position

[42] See for example, D. Perkins and P Angley. "Values, unemployment and public policy. The need for a new direction". Discussion Paper, 2003.

A decrease in unemployment implies an increase in worker productivity that leads to an increase in individual incomes. These in turn lead to reductions in poverty and unemployment benefits. Unemployment can also breed higher crime rates that require more public spending in law enforcement activities, social benefits, and state-sponsored health and other support costs. These, along with the added disadvantage of lower tax revenues, have a negative impact on state and Federal fiscal positions. Thus, the jobs created by the four resource options discussed here have the potential to bring in significant socioeconomic benefits to the region as a whole.

Modeling

To estimate the regional economic impacts of the jobs created -- through the indirect and induced multiplier effects – we use the regional economic model IMPLAN. IMPLAN is created and maintained by the Minnesota IMPLAN Group (MIG). The IMPLAN model is a static input-output framework used to analyze the effects of an economic stimulus on a pre-specified economic region, in this case, Alachua county. This model is considered static because the impacts calculated by any scenario in IMPLAN estimate the indirect and induced impacts for one time period (typically a year). The modeling framework in IMPLAN consists of two components – the descriptive model and the predictive model. The descriptive model defines the local economy in the specified modeling region, and includes accounting tables that trace the "flow of dollars from purchasers to producers within the region".[43] It also includes the trade flows that describe the movement of goods and services, both within, and outside of the modeling region (i.e., regional exports and imports with the outside world). In addition, it includes the Social Accounting Matrices (SAM) that trace the flow of money between institutions, such as transfer payments from governments to businesses and households, and taxes paid by households and businesses to governments. The predictive model consists of a set of "local-level multipliers" that can then be used to analyze the changes in final demand and their ripple effects throughout the local economy. These multipliers are thus coefficients that "describe the response of the [local] economy to a stimulus (a change in demand or production)."[44] Three types of multipliers are used in IMPLAN:

- Direct – represents the jobs created due to the investments that result in final demand changes, such as investments needed for build and operate a power plant.
- Indirect – represents the jobs created due to the industry inter-linkages caused by the iteration of industries purchasing from industries, brought about by the changes in final demands.

[43] IMPLAN Pro Version 2.0 User Guide.
[44] *Ibid.*

- Induced – represents the jobs created in all local industries due to consumers' consumption expenditures arising from the new household incomes that are generated by the direct and indirect effects of the final demand changes.

To illustrate these concepts consider the following simplified example. A $10 million investment required to construct the power plant leads to 100 jobs (say) in the construction industry, due to the workers needed to construct the power plant. These jobs are the result of the direct investment and are hence termed as direct jobs in IMPLAN terminology. Because the construction industry is connected to other industries through its inter-industry linkages, the 100 direct jobs create an additional 40 (say) jobs in industries such as wholesale trade, motor vehicle parts and dealers, architectural and engineering services, etc. In the regional economic parlance (and in IMPLAN), these additional jobs are termed indirect jobs. Finally, because the direct and indirect jobs create income for the workers involved, which are then spent on various consumption activities, these expenditures lead to further economic activity and employment in the economy. In IMPLAN, these jobs, say an additional 30, are termed as induced employment and are created in sectors such as food and beverage stores (restaurants and bars), retail outlets, general merchandise stores, hospitals and physician offices, etc. Thus the total number of jobs created by the $10 million investment in this example is 170, out of which 70 jobs are created in "support" industries due to the input-output relationships between economic sectors.

Methodology

We used the IMPLAN model data for the Alachua County to estimate the potential for job creation through the various resource options. In order to estimate the potential for job creation in the regional economy, we first estimated the levels of investments needed for these options. Using data from sources discussed elsewhere in this study, we estimated the total capital and operating and maintenance (O&M) costs for the various options. For example, Chapter 4 discusses the capital costs needed for the three options involving constructing a new power plant. These costs were (2003$):

- 220 MW CFB - $470 million
- 220 MW IGCC - $445 million
- 75 MW CFB for Biomass - $170 million

We assume these investments are made over a four year period to construct the plant under each option, and divide the capital cost equally for an annual average capital cost. These are then entered into the IMPLAN model to estimate the number of workers needed to construct the plant over the 4-year period.

Jobs that will be created due to the operation and maintenance of the plant are estimated using the levelized cost data explained in Chapter 4. In order to estimate the total annual O&M cost, we used the per-unit O&M costs from Chapter 4 (in 2003$/MWh) and assumed a 75 percent capacity factor for the three plant options.[45]

For the 75 MW Biomass plant option, we also model the economic impacts of the different biomass fuel types needed (urban wood waste, forestry residue and energy crops) and the associated transportation costs required to deliver the biomass fuel to the plant.

Cost assumptions for the DSM option – the cost assumptions used for the DSM option were based on the 15 DSM programs discussed in Chapter 3. Tot calculate the total socioeconomic benefits of these programs, we estimated four types of impacts for each program:

1. GRU incentives to residential and commercial customers, which then get invested to buy equipment for DSM and associated labor costs (and hence create jobs in the economy).

2. GRU administrative costs for local personnel and advertising to promote the DSM programs. These investments create local jobs for GRU personnel and the advertising and marketing sector (with corresponding ripple effects through the local economy).

3. Bill savings to residential and commercial customers due to reduced demand for electricity. These savings have a positive effect on the economy because customers then spend their savings on other consumption goods creating additional local economic activity. These consumption expenditures are modeled using the consumption patterns of the median household in Alachua county.

4. GRU lost revenue due to reduced demand for electricity from the grid. The DSM programs result in reduced demand for electricity from the grid, leading to lost revenue for the utility supplying the electricity. The lost revenue creates negative economic impacts as it is associated with resources taken out of the economy. However, the negative effects of this loss are more than offset by the positive effects generated by the bill savings to electricity customers and their subsequent spending of that money on other goods and services.

Once the investment amounts were determined, these were then used in IMPLAN to create the initial perturbations for the appropriate IMPLAN sectors to estimate the local economic impacts for Alachua county.

Results

[45] The capacity factor assumptions will be updated with IPM estimates in the next draft.

Figure 7-2 below presents the estimated job creation potential for the 220 MW CFB plant option.

Figure 7-2
Jobs Created by 220 MW CFB Coal Plant Option

Job Types	Construction Phase	Operation & Maintenance
Direct	1,332	55
Indirect	312	15
Induced	450	30
Total	**2,094**	**100**

Preliminary results, subject to change. Totals may not add due to rounding.
Source: ICF calculations based on IMPLAN model results

Construction jobs are estimated based on the capital cost assumptions for the CFB plant (explained in Chapter 4). The CFB plant is assumed to require $470 million in capital costs. We assume the plant will be constructed over a four year period creating 1,332 construction jobs (direct). These jobs are considered temporary because they will cease to exist after the plant has been constructed. Moreover, these direct jobs create an additional 762 jobs in support industries due to the indirect (312 jobs) and induced expenditures (450 jobs).

Operation and maintenance of the CFB power plant is estimated to create a total of 100 jobs in Alachua county. Out of these, 55 workers are estimated to be directly involved in operation and maintenance of the plant. Additionally, we estimate another 45 jobs will be created in Alachua county due to the indirect (15) and induced effects (30) discussed above. Unlike the construction-related jobs which are considered temporary lasting for 4 years, the jobs created due to the operation of the plant would be permanent, leading to long-term benefits for the local economy in Alachua county.

Figure 7-3 below presents the estimated job creation potential for the 220 MW IGCC plant option.

Figure 7-3
Jobs Created by 220 MW IGCC Plant Option

Job Types	Construction	Operation & Maintenance
Direct	1,261	46

Indirect	295	12
Induced	426	25
Total	**1,983**	**83**

Preliminary results, subject to change. Totals may not add due to rounding.
Source: ICF calculations based on IMPLAN model results

Because the investments needed for the IGCC plant are similar, but smaller, to those for the CFB plant, the local economic impacts for these two options are quite similar. This is true for the 1,983 construction jobs created during the first 4 years only. Moreover, operation and maintenance of the IGCC plant will require an additional 46 workers annually for the life of the plant. These 46 new long-term jobs in Alachua are expected to create an additional 37 jobs due their secondary or ripple effects.

Figure 7-4 below presents the estimated job creation potential for the 75 MW Biomass plant option.

Figure 7-4
Jobs Created by 75 MW Biomass Plant Option

Job Types	Construction	Operation & Maintenance
Direct	482	295
Indirect	113	56
Induced	163	83
Total	**758**	**435**

Preliminary results, subject to change. Totals may not add due to rounding.
Source: ICF calculations based on IMPLAN model results

The total number of construction jobs required for the 75 MW Biomass CFB plant are lower than those for the previous two options. This is because we assume this plant will have a capacity of 75 MW as opposed to 220 MW assumed for the two previous options. As a simplifying assumption, the number of workers needed to construct a power plant is assumed to be directly proportional to the capacity of the plant, thus the total number of direct, indirect, and induced jobs created for this plant is significantly less. Again, we assume these construction jobs will be available for four years, during the construction phase of the plant.

Although the biomass plant is assumed to be smaller in size (and therefore should have less economic impact), the operation and maintenance jobs created for this plant are significantly higher than for the other two plant options. Because running a biomass plant tends to be more labor intensive than some of the other generation technologies, there is potential for more long-term jobs being created in Alachua for the biomass plant option. We estimate there will be a total of 435 jobs created due to the biomass plant. Out of this, there will be 295 workers directly involved in the operation of the plant. Out of this, we estimate 66 new jobs created in the transportation sector to deliver the biomass fuels to the plant, and an additional 229 jobs in sectors that provide the different types of biomass fuels. Moreover, these direct jobs are also likely to create an additional 140 jobs in the Alachua economy due to the indirect and induced effects.

Figure 7-5 below presents the estimated job creation potential for the Maximum DSM option.

Figure 7-5
Jobs Created by Max DSM Option

Job Types	Jobs Created
Direct	1,916
Indirect	308
Induced	295
Total	**2,518**

Preliminary results, subject to change. Totals may not add due to rounding.
Source: ICF calculations based on IMPLAN model results

The DSM option involves 15 different DSM programs for the residential and commercial sectors, discussed in Chapter 3. The job creation potential for the DSM option is modeled using the four types of impacts discussed above. The main distinction between the estimated jobs under DSM with those of the other options discussed above is that the DSM jobs are assumed to be cumulative for the entire life of the programs. Most programs are assumed to start in 2006 and continue until 2025. We first estimate the cumulative investments required for these programs and the cumulative bill savings over the entire period, convert those to a net present value before estimating the total employment impacts of these resources.

The DSM programs are expected to impact more economic sectors in Alachua (and other Florida counties) than the other options. The total number of direct jobs is estimated to be about 1,916. Out of these, HVAC contractors are expected to benefit significantly (244 jobs until 2025) due to the investments needed to purchase equipment for several DSM programs. Additionally, the bill savings for residential and commercial customers that is expected to be funneled back into the local economy is expected to provide a boost to the regional economy and create substantial number of additional jobs. Finally, these direct jobs are expected to ripple through the economy and create more employment opportunities through the indirect and induced effects as shown in the Figure above.

CHAPTER EIGHT
MODELING RESULTS

This chapter presents the results of ICF's analysis. This chapter is organized into ___ sections. The first section discusses revenue requirements. The second discusses emission impacts.

REVENUE REQUIRMENTS

The key results are:

Figure 8-1
Revenue Requirements – Millions 2003$ - Average Across Cases[1]

Year	220 MW CFB	220 MW IGCC	75 MW Biomass Maximum DSM	Maximum DSM
2006	92	92	90	90
2007	92	92	90	90
2008	93	93	90	90
2009	100	100	96	96
2010	114	114	108	108
2011	113	100	108	106
2012	116	103	110	108
2013	120	107	112	110
2014	125	111	112	111
2015	129	116	113	112
2016	135	121	117	116
2017	141	126	121	120
2018	147	132	124	124
2019	153	137	128	128
2020	160	143	132	132
2021	166	149	137	137
2022	172	155	142	142
2023	178	162	147	147
2024	185	169	152	153
2025	191	176	158	158
Total	2719	2497	2388	2377
Average	136	125	119	119

[1]Excludes sunk cost recovery, indirect G&A, taxes.

Figure 8-2
Revenue Requirements[1] – Standard Deviation – Million$

Year	220 MW CFB	220 MW IGCC	75 MW Biomass Maximum DSM	Maximum DSM
2006	6.6	6.6	6.2	6.2
2007	6.7	6.7	6.2	6.2
2008	7.0	7.0	6.4	6.4
2009	7.3	7.3	6.4	6.4
2010	8.6	8.6	7.2	7.2
2011	8.7	7.2	6.2	7.3
2012	9.8	7.9	6.9	8.3
2013	11.3	9.7	7.6	9.4
2014	12.9	11.1	8.5	10.6
2015	15.0	13.1	9.5	12.0
2016	17.1	14.9	11.3	13.8
2017	19.8	17.1	13.3	15.9
2018	22.9	19.7	15.7	18.3
2019	26.5	22.8	18.4	21.0
2020	30.7	26.3	21.3	24.0
2021	33.6	29.0	24.0	26.8
2022	36.9	32.2	26.9	30.0
2023	40.8	35.9	30.2	33.5
2024	45.2	40.3	33.9	37.4
2025	50.2	45.3	37.9	41.8
TOTAL				
Average				

[1]Excludes sunk cost recovery, indirect G&A, taxes.

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Figure 8-3
Revenue Requirements –$ Millions Nominal – Average Across Cases

Year	220 MW CFB	220 MW IGCC	75 MW Biomass Maximum DSM	Maximum DSM
2006	98	98	96	96
2007	101	101	99	99
2008	104	104	101	101
2009	114	114	110	110
2010	134	134	127	127
2011	135	119	130	127
2012	143	126	135	133
2013	150	134	140	138
2014	160	143	144	143
2015	169	152	149	147
2016	181	162	157	155
2017	193	173	165	164
2018	206	184	174	173
2019	219	197	184	183
2020	234	210	194	193
2021	248	224	205	205
2022	263	238	217	217
2023	279	253	230	230
2024	296	270	244	245
2025	313	288	258	259
TOTAL	3740	3425	3259	3245
Average	187	171	163	162

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Figure 8-4
Revenue Requirements – Highest Among Cases Examined – 2003$ - Millions

Year	220 MW CFB	220 MW IGCC	75 MW Biomass Maximum DSM	Maximum DSM
2006	94	94	92	92
2007	96	96	93	93
2008	98	98	95	95
2009	107	107	102	102
2010	126	126	118	118
2011	112	95	122	120
2012	118	99	124	124
2013	124	104	127	128
2014	130	110	129	131
2015	137	115	130	133
2016	147	124	136	139
2017	157	133	143	145
2018	169	143	149	152
2019	181	154	156	158
2020	194	166	163	165
2021	204	175	170	172
2022	215	185	177	180
2023	226	196	185	188
2024	238	207	193	196
2025	251	219	201	204
TOTAL	3123	2746	2806	2836
Average	156	137	140	142

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EMISSIONS

Figure 8-5
CO_2 Emissions – GRU – Average Across Cases

Year	220 MW CFB	220 MW IGCC	75 MW Biomass Maximum DSM	Maximum DSM
2006	64,548,000	64,548,000	64,481,200	64,481,200
2007	65,043,900	65,043,900	64,909,300	64,909,300
2008	65,539,800	65,539,800	65,337,400	65,337,400
2009	65,765,100	65,765,500	65,511,200	65,514,100
2010	63,580,000	63,580,000	63,445,700	63,431,900
2011	94,675,900	89,590,200	52,736,300	53,759,300
2012	94,178,950	88,781,000	52,819,450	54,051,150
2013	93,682,000	87,971,800	52,902,600	54,343,000
2014	91,433,650	85,924,550	52,238,550	53,992,200
2015	89,185,300	83,877,300	51,574,500	53,641,400
2016	85,323,519	81,329,862	49,878,458	51,949,146
2017	81,823,507	78,945,578	48,296,064	50,353,074
2018	78,638,934	76,709,129	46,815,146	48,844,668
2019	75,730,424	74,606,905	45,425,062	47,416,314
2020	73,064,400	72,626,800	44,116,500	46,061,200
2021	70,823,890	70,391,664	43,643,485	45,726,679
2022	68,712,735	68,338,503	43,200,031	45,412,284
2023	66,722,351	66,449,035	42,783,869	45,117,186
2024	64,844,792	64,707,103	42,392,945	44,840,601
2025	63,072,700	63,098,400	42,025,400	44,581,800
TOTAL	1,516,389,853	1,477,825,030	1,034,533,161	1,063,763,902
Average	75,819,493	73,891,252	51,726,658	53,188,195

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Figure 8-6
SO_2 Emissions – GRU – Average Across Cases

Year	220 MW CFB	220 MW IGCC	75 MW Biomass Maximum DSM	Maximum DSM
2006	250,487	250,487	250,389	250,389
2007	249,778	249,778	249,506	249,506
2008	249,070	249,070	248,623	248,623
2009	249,191	249,191	248,586	248,586
2010	34,283	34,283	34,251	34,244
2011	54,299	51,351	40,068	30,403
2012	53,970	50,846	40,146	30,461
2013	53,642	50,340	40,225	30,520
2014	52,270	49,084	39,791	30,134
2015	50,898	47,828	39,358	29,749
2016	48,601	46,296	38,313	28,658
2017	46,536	44,872	37,317	27,644
2018	44,669	43,545	36,368	26,698
2019	42,974	42,304	35,462	25,814
2020	41,427	41,141	34,596	24,983
2021	39,974	39,670	34,195	24,640
2022	38,613	38,333	33,809	24,316
2023	37,337	37,113	33,437	24,009
2024	36,139	35,997	33,078	23,717
2025	35,013	34,973	32,733	23,440
TOTAL	1,709,168	1,686,502	1,580,250	1,436,533
Average	85,458	84,325	79,013	71,827

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Figure 8-7
NO_x Emissions – GRU – Average Across Cases

Year	220 MW CFB	220 MW IGCC	75 MW Biomass Maximum DSM	Maximum DSM
2006	144,264	144,264	144,198	144,198
2007	144,009	144,009	143,839	143,839
2008	143,755	143,755	143,481	143,481
2009	143,957	143,958	143,580	143,582
2010	43,935	43,935	43,874	43,868
2011	54,407	41,088	40,267	38,349
2012	54,637	41,303	40,305	38,494
2013	54,868	41,518	40,344	38,639
2014	54,351	40,996	39,797	38,255
2015	53,833	40,474	39,249	37,870
2016	52,689	39,316	37,997	36,614
2017	51,589	38,225	36,827	35,439
2018	50,532	37,195	35,731	34,336
2019	49,515	36,222	34,699	33,300
2020	48,535	35,299	33,728	32,322
2021	48,125	34,988	33,330	32,010
2022	47,728	34,694	32,954	31,716
2023	47,345	34,415	32,599	31,439
2024	46,975	34,150	32,263	31,177
2025	46,617	33,899	31,945	30,929
TOTAL	1,381,665	1,183,701	1,161,007	1,139,857
Average	69,083	59,185	58,050	56,993

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Figure 8-8
Hg Emissions – GRU – Average Across Cases

Year	220 MW CFB	220 MW IGCC	75 MW Biomass Maximum DSM	Maximum DSM
2006	2.52	2.52	2.52	2.52
2007	2.51	2.51	2.51	2.51
2008	2.50	2.50	2.50	2.50
2009	2.51	2.51	2.50	2.50
2010	2.38	2.38	2.37	2.37
2011	2.17	2.30	2.15	2.11
2012	2.17	2.30	2.15	2.11
2013	2.18	2.30	2.15	2.12
2014	2.14	2.26	2.11	2.08
2015	2.10	2.21	2.07	2.05
2016	2.02	2.13	2.00	1.97
2017	1.95	2.06	1.93	1.91
2018	1.89	2.00	1.87	1.84
2019	1.83	1.94	1.81	1.78
2020	1.77	1.88	1.75	1.72
2021	1.74	1.84	1.73	1.70
2022	1.71	1.81	1.70	1.68
2023	1.68	1.77	1.67	1.65
2024	1.65	1.74	1.65	1.63
2025	1.63	1.71	1.62	1.62
TOTAL	41.04	42.67	40.77	40.37
Average	2.05	2.13	2.04	2.02

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Figure 8-9
Sample Metrics

GRU Option	Average Rate Impacts/Costs	Volatility of Annual Costs	Residual Emissions	Local Economic Impact	Constructional Operational Risk	Capital Investment Cost
Coal CFB						
Coal IGCC						
Gas CC						
"Maximum" DSM – Incremental Short-Term Purchases						

Figure 1-9
Historical Spot Power Prices in FRCC

Period	On-Peak[1] ($/MWh)	Off-Peak ($/MWh)	All-Hours ($/MWh)
2002	40.2	21.9	30.5
2003	52.0	22.7	36.5
2004	58.1	29.4	42.9
2005	85.0	44.3	63.4

Source: Power Market's Week.
[1]On-peak defined as 7:00 AM to 11:00 PM, Monday through Friday.

Figure 1-10
Historical Implied Heat Rates in FRCC

Period	On-Peak[1] (Btu/kWh)	Off-Peak (Btu/kWh)	All-Hours (Btu/kWh)
2002	10,632	5,800	8,071
2003	9,115	3,975	6,391
2004	9,359	4,739	6,910
2005	10,085	5,258	7,527

Source: Power Market's Week (Florida Spot power prices) and Gas Daily (Delivered to Florida City Gate).
[1]On-peak defined as 7:00 AM to 11:00 PM, Monday through Friday.

Figure 1-13
Key FRCC Capacity Assumptions Overview

Parameter	FRCC
Recently Operational Builds 2000-2005 (MW)	18,237
Total Capacity as of July 2005 (MW)	52,452
ICF Firmly Planned Builds (MW) 2006-2007	0
New Builds	Firm builds plus non-firm builds as necessary to meet net peak demand and reserve requirements; mix of unplanned builds endogenously determined based on economics

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FRCC Geographic Scope

- FRCC encompasses Peninsular Florida, east of the Apalachicola River. It is electrically unique because it is a peninsula and is tied to the Eastern Interconnection only on one side. The FRCC is responsible for setting the reliability standards, procedures, and policies that all users of the transmission system must follow when operating in the region.
- The 29 FRCC members comprise six industry sectors: power marketers, generators, non-investor-owned utilities-wholesale, load-serving entities, generating load-serving entities, and investor-owned utilities.

Figure 1-15
GRU Electric Facilities

Source: A Review of Florida Electric Utility 2005 Ten-Year Site Plans, prepared by the Florida Public Service Commission, Division of Economic Regulation, December 2005

GRU Generation Assets

- GRU is the City of Gainesville enterprise arm that has the responsibility to operate and maintain the vertically integrated electric power system.
- Gainesville Regional Utilities (GRU) owns and operates two power plants, the John R. Kelly Generating Station located in downtown Gainesville, and the Deerhaven Generating Station located near the city of Alachua.
- Additionally, a 1.4 % ownership in Florida Power Corporation's Crystal River Unit 3 operated by Progress Energy Florida (PEF) and two internal combustion engines located at Alachua County Southwest Landfill of 1.3 MW provide generating capacity to the GRU system. The landfill is owned by Alachua County.
- An inter-local agreement between the City of Gainesville and Alachua County approved the concept of using landfill gas to power tow internal combustion engine generators. The County granted a special use permit and easement for GRU to operate and access the generators.

Source: A Review of Florida Electric Utility 2005 Ten-Year Site Plans, prepared by the Florida Public Service Commission, Division of Economic Regulation, December 2005

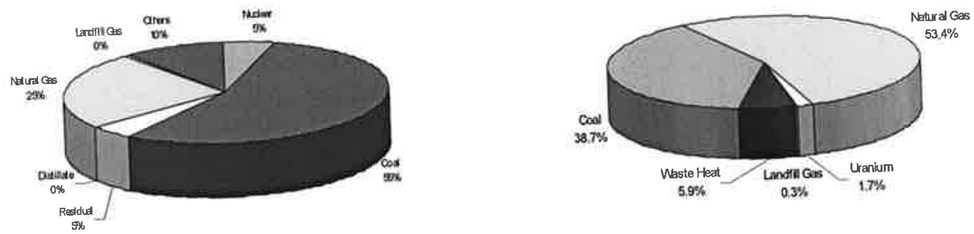
Transmission Network

- GRU's bulk power transmission network consists of a 138 kV loop connecting the following:
  - GRU's 2 generating stations
  - GRU's 9 distribution substations
  - 3 interties with Progress Energy Florida (PEF)
  - An intertie with Florida Power and Light Company (FPL)
  - An interconnection with Clay at Farnsworth Substation, and
  - An interconnection with the City of Alachua at Alachua No.1 Substation
- State Interconnections – The system is currently interconnected with PEF and FPL at four separate points. These include:
  - A 230 kV transmission line interconnection between PEF's Archer Substation and GRU's Parker Substation with 224 MVA of transformation capacity from 230 kV to 138 kV
  - PEF's Idylwild Substation with 2 separate circuits via a 168 MVA 138/69 kV transformer at the Idylwild Substation

- A 138 kV tie between FPL's Bradford Substation and the System's Deerhaven Substation with a thermal capacity of 224 MVA

Source: A Review of Florida Electric Utility 2005 Ten-Year Site Plans, prepared by the Florida Public Service Commission, Division of Economic Regulation, December 2005, pages 5,6,7

Figure 1-16
Generation & Capacity Mix: 2004



Net Energy for load includes utility use & losses

Others = Purchase energy - Starke Contract - Energy Sales

Distillate & Residual are alternate fuel (page 11)

Source: A Review of Florida Electric Utility 2005 Ten-Year Site Plans, prepared by the Florida Public Service Commission, Division of Economic Regulation, December 2005, pages 11, 42

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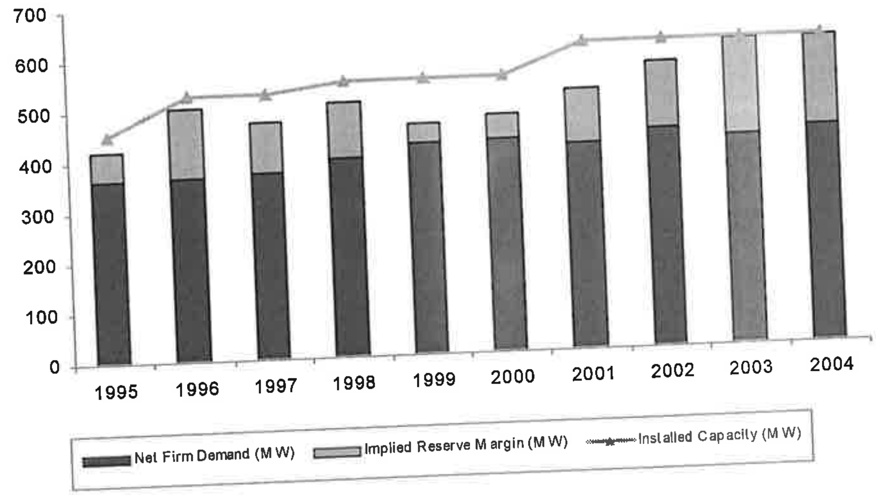
Figure 1-17
Capacity & Demand (MW)



Source: A Review of Florida Electric Utility 2005 Ten-Year Site Plans, prepared by the Florida Public Service Commission, Division of Economic Regulation, December 2005, pages 37, 52

FRCC Planning Reserve Margins

- FRCC has historically required an unenforceable 15 percent installed reserve margin guideline for the FRCC system as a whole.
- In line with the above, GRU uses a planning criteria of 15% capacity reserve margin.
- Investor Owned Utilities in the region are further required to maintain an installed capacity reserve of 20 percent as based on a standing agreement with the Florida Public Services Commission.

Source: A Review of Florida Electric Utility 2005 Ten-Year Site Plans, prepared by the Florida Public Service Commission, Division of Economic Regulation, December 2005, page 49

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Figure 1-18
Overview of FRCC Demand and Capacity Related Assumptions

Annual Average Peak Growth (%) (2004-2014)	Treatment – Base Case	
	FRCC	GRU
2005 Net Internal Peak Demand[1] (MW) Annual Average Peak Growth (%) (2004-2014)	43495 2.52%[2]	458 2.37%[3]
2005 Net Energy for Load[1] (GWh) Annual Average Energy Growth (%) (2004-2014)	227,871 2.46%[2]	2122 2.40%[3]
Target Reserve Margin (%)	15% - 20%	15%
New Builds	Firm builds plus unplanned builds as necessary to meet net peak demand and reliability/reserve requirements; mix of unplanned builds endogenously determined based on economics	
Firm Builds (MW) In Operation 2000-2005 Under Construction 2006 2007 2008 2009 2010 2011 2012 Total 2000-12	17034 809 1957 1075 2714 1246 1987 2390 29212	110 0 0 0 0 0 0 0 220 330

1) FRCC 2005 starting point taken from NERC ES&D and GRU 2005 starting point taken from A Review of Florida Electric Utility 2005 Ten-Year Site Plans, prepared by the Florida Public Service Commission, Division of Economic Regulation, December 2005
2) FRCC annual average growth rate from 2004 Regional Load & Resource Plan for 2004-2013.
3) GRU annual average growth rate from A Review of Florida Electric Utility 2005 Ten-Year Site Plans, prepared by the Florida Public Service Commission, Division of Economic Regulation, December 2005 for 2005-2014.

Figure 1-19
Key Reserve Margin Assumptions Overview

Parameter	Treatment	
	FRCC	GRU
Planning Reserve Margin (%)	Varies between 15% and 20%	15%

Key Reserve Margin Assumptions Overview

- FRCC has historically required an unenforceable 15 percent installed reserve margin guideline for the FRCC system as a whole. GRU also uses a planning criteria of 15% capacity reserve margin.
- Investor Owned Utilities in the region are further required to maintain an installed capacity reserve of 20 percent as based on a standing agreement with the Florida Public Services Commission.
- Going forward, ICF projects a 23 percent planning reserve margin in the near-term and gradually declining to 18 percent by 2014.

Note: Interruptible load is accounted in the Reserve Margin calculation.

Key Transmission Assumptions

- Power will flow on an economic basis subject to transmission limits, as specified by the total transfer capability, and subject to transmission costs and losses. We assume no charges for moving power within FRCC and an approximately $2.50/MWh transmission charge to move power to and from neighboring regions, e.g., Southern. Regions without an ISO / RTO structure and associated "pancaking" may have higher near-term charges for movements to neighboring areas.

- The transmission capacities specified above reflect both simultaneous and non-simultaneous total transfer capabilities (TTC). TTC's represent non-firm transmission capacity used in our modeling to capture energy transfers and are typically higher than the First Contingency Transfer Capabilities (FCTTC) used to model capacity transfers, which capture an "N-0" contingency level.

- Simultaneous (joint) import or export transfers are usually lower than the sum of non-simultaneous transfers. Simultaneous transfer limitations are captured in our modeling by using joint interface capacities for all interconnecting paths to a region and reflects "N-1" contingency levels.

Figure A3-3. Commercial Building Type Baseline Characteristics

	Grocery	Hotel	Hospital	Office	Retail	Restaurant
	Baseline	Baseline	Baseline	Baseline	Baseline	Baseline
Square Feet per Floor	40000	30000	30000	30000	100000	3000
% Window Area (WWA)	5%	33%	50%	50%	6%	10%
Number of Stories	1	4	8	8	1	1
Wall Insulation	13	13	13	13	13	13
Wall Sheathing	2	2	2	2	2	2
Attic Insulation	23	24	15	17	33	21
Window U	0.7	0.7	0.7	0.7	0.7	0.7
Window SHGC	0.78	0.78	0.78	0.78	0.78	0.78
Outdoor Air (ac/h)	0.35	0.5	1.2	2.5	0.5	4
Roof Solar Absorptivity	0.75	0.75	0.75	0.75	0.75	0.75
Cooling Efficiency (EER)	9.21	15	14.75	9.63	8.84	8.68
Fan Type	1	1	1	1	1	1
Duct Loss	0%	0%	0%	0%	0%	0%

Figure A3-3. Commercial Measures – Baseline and Upgrade Characteristics

	Window Treatment		Cool (reflective) rooftops		Installation of Low-E glass or multiple glazed windows		High-efficiency chillers (Existing: 0.85 kW/ton; Baseline: 0.65 kW/ton; Upgrade: 0.45 kW/ton)			Automatic OA reduction control	
	Baseline	Upgrade	Baseline	Upgrade	Baseline	Upgrade	Existing	Baseline	Upgrade	Baseline	Upgrade
Window U	0.75	0.75			0.65	0.45					
Window SHGC	1.035	0.46			0.55	0.35					
Outdoor Air										100% constant	75% variable
Roof Solar Absorptivity			0.95	0.2							
Cooling Efficiency							0.85	0.65	0.45		
Fan Type											
Duct Loss											

	Energy management controls		Improved maintenance and diagnostics		Variable-speed drives		High-efficiency packaged DX A/C (Existing: 8 EER; Baseline: 10 EER; Upgrade: 12 EER)			Unoccupied OA reduction	
	Baseline	Upgrade	Baseline	Upgrade	Baseline	Upgrade	Existing	Baseline	Upgrade	Baseline	Upgrade
Window U											
Window SHGC											
Outdoor Air										Fixed Control	Enthalpy Controled
Roof Solar Absorptivity											
Cooling Efficiency							8	10	12		
Fan Type	Constant Temperature	Variable Temperature			Constant	Variable					
Duct Loss			0%	5%							

Figure A3-4. GRU Cumulative Avoided Costs

Year	NPV Avoided Cost / kWh	NPV Avoided Cost / kW
2006	$0.0643	$0.00
2007	$0.1219	$0.00
2008	$0.1732	$0.00
2009	$0.2189	$0.00
2010	$0.2594	$0.00
2011	$0.2953	$0.00
2012	$0.3166	$1,460.09
2013	$0.3373	$1,460.09
2014	$0.3575	$1,460.09
2015	$0.3771	$1,460.09
2016	$0.3961	$1,460.09
2017	$0.4145	$1,460.09
2018	$0.4323	$1,460.09
2019	$0.4495	$1,460.09
2020	$0.4662	$1,460.09
2021	$0.4822	$1,460.09
2022	$0.4977	$1,460.09
2023	$0.5126	$1,460.09
2024	$0.5270	$1,460.09
2025	$0.5408	$1,460.09
2026	$0.5541	$1,460.09
2027	$0.5668	$1,460.09
2028	$0.5791	$1,460.09
2029	$0.5908	$1,460.09
2030	$0.6021	$1,460.09

Discount Rate: 6.75%
2012 Capital Cost: $2,306.50 / kW
Winter Peak hours: 331
Summer Peak hours: 1377
Off Peak hours: 7052
Source: GRU Strategic Planning

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Figure A3-5 Measure to Program Mapping

Program	Technology Type	Measure
Residential CFL Program		Compact fluorescent lamps (CFLs)
Residential Fridge/Freezer Buyback		Remove 2nd Freezer
		Remove 2nd Refrigerator
Home Performance with Energy Star (Marginally Cost-Effective Measures)		Whole House Fan
		Duct Insulation
Home Performance with Energy Star (Cost-Effective Measures)		Solar gain controls such as exterior shades
		Shade Screens
		Window Film
		Central A/C - various equipment retrofits (EER & tonnage)
		Refrigerant charge testing and recharging
		Air sealing (caulking, weatherstripping, hole sealing)
		Two speed Central AC
		Energy Star or better windows
		Filter cleaning and/or replacement
		Landscape Shading
		Insulated metal or fiberglass doors
Comprehensive Water Heating Program		Pipe Wrap (Elec)
		Water heat tank wraps and bottom boards (Elec)
		Low Flow Showerheads (Elec)
		Faucet Aerators (Elec)
		Vapor-compression cycle
		Heater efficiency upgrades (Elec)
		Heat Trap - Water Lines
Residential Solar Water Heater		Solar Water Heater
Residential Appliance		Energy Star or better refrigerator
		Energy Star or better clothes dryer (Elec)
		Energy Star Clothes Washers - All Electric
		Energy Star Dishwasher - Electric DHW
Residential A/C Rebate, Weatherization, & A/C Tune-Up Program (Marginally Cost-Effective Measures)		Whole House Fan
		Duct Insulation
Residential A/C Rebate, Weatherization, & A/C Tune-Up Program (Cost-Effective Measures)		Solar gain controls such as exterior shades
		Shade Screens
		Window Film
		Central A/C - various equipment retrofits (EER & tonnage)
		Refrigerant charge testing and recharging
		Air sealing (caulking, weatherstripping, hole sealing)
		Two speed Central AC
		Energy Star or better windows
		Filter cleaning and/or replacement
		Landscape Shading
		Insulated metal or fiberglass doors
Residential A/C Direct Load Control		Central AC Direct Load Control
Residential Water Heating Direct Load Control		Water Heating Direct Load Control
Energy Star Homes		14 SEER AC
		8.2 HSPF heat pump
		Programmable Thermostat
		Duct leakage of 4 cfm / 100 sq. ft of conditioned space
		Duct insulation of R-6
		Infiltration of 7 ACH50
		R-30 attic insulation
		R-5 exterior wall sheathing on block walls
		No slab insulation
		U-value: 0.55 and SHGC: 0.35 for windows
		40 gallon electric water heater with 0.93 EF
		ENERGY STAR dishwasher and refrigerator with 3 ENERGY STAR light fixtures

Figure A3-5 Measure to Program Mapping (Continued)

Program	Technology Type	Measure
Commercial Cooling	Chillers	High-efficiency chillers
	Chillers	Energy management controls
	Chillers	Window treatment
	Chillers	Chiller economizers (water side), or air side economizers
	Chillers	Variable-speed drives
	Chillers	Cool (reflective) rooftops
	DX Units	Energy management controls
	DX Units	High-efficiency packaged DX A/C
	DX Units	Window treatment
	DX Units	Variable-speed drives
	DX Units	Cool (reflective) rooftops
	Room AC	Energy management controls
	Room AC	Window treatment
	Room AC	Variable-speed drives
	Room AC	Cool (reflective) rooftops
Commercial Lighting - Exterior	E Incand.	High-intensity discharge lamps (incandescent to hi-pres sodium)
	E Incand.	Outdoor lighting controls for incandescent (photocell/timeclock)
	Fluor	T8 lamps with electronic ballasts (2L4')
	Fluor	Outdoor lighting controls for fluorescent (photocell/timeclock)
	HID	Outdoor lighting controls for HID (photocell/timeclock)
	HID	High-intensity discharge lamps (mercury vapor to hi-pres sodium)
Commercial Lighting - Interior	4' Fluor	T8 lamps with electronic ballasts (2L4')
	4' Fluor	Reflectors for 4' fluorescent
	4' Fluor	Occupancy sensors for 4' fluorescent
	8' Fluor	Reflectors for 8' fluorescent
	8' Fluor	T8 lamps with electronic ballasts (2L8')
	8' Fluor	Occupancy sensors for 8' fluorescent
	8' Fluor	Perimeter dimming for 8' fluorescent
	Exit Signs	LED Exit Signs
	HID	High-intensity discharge lamps (incandescent to metal halide)
Commercial Office Equipment	Copy/Fax	Power management enabling - copier
	Monitors	Network power management enabling - monitor
	Monitors	Power management enabling - monitor
	CPUs	Power management enabling - PC
Grocery and Restaurant Refrigeration Program		Demand defrost electric
		Demand hot gas defrost
		Efficiency compressor motor retrofit
		Floating head pressure controls
		Anti-sweat (humidistat) controls
		Strip curtains for walk-ins
		Night covers for display cases
		Evaporator fan controller for MT walk-ins
		Compressor VSD retrofit
		Refrigeration commissioning
Commercial Ventilation		Premium-efficiency motors
		Variable-speed drives
		CV to VAV conversion
		Unoccupied OA reduction
		Automatic OA reduction control
Commercial Water Heating		Faucet Aerator
		Tank Insulation
		Circulation Pump Timelocks
		Instanteous Water Heater <=200 MBTUH
		Low Flow Showerheads
		Heater efficiency upgrade
		Pipe Insulation

A3-6. Adoption Curve Function

MS_0: Market share of the technology or product in an initial year
C: The product's assumed maximum market share; and
A: A parameter representing "adoptive influence," which influences the speed at which a technology gains share in the market.

$$MS_t = \frac{C}{1 + e^{\left[-At + \ln\left(\frac{1 - MS_0/C}{MS_0/C}\right)\right]}}$$

A3-7 Supply Curves

The levelized costs in each of the supply curves below are for technology costs only, and do not include program incentive or administration costs. Thus, this supply curve should not be compared to the program DSM supply curve shown earlier in this report. Also note that the discount rate and the methodology used is not intended to match IPM's methodology for developing its supply curves of generating or DSM capacity. These curves simply illustrate the amount and cost of DSM available from the various technologies considered.

The levelized or annualized cost of energy or peak demand is calculated for each measure as follows. First, it is necessary to derive the capital recovery rate, or CRR: For consistency with GRU's avoided costs documentation, we have used a discount rate of 6.75% to determine these annualized costs.

CRR = d / [1 – (1 + d)^(-n)]

Where d is the discount rate (6.75%) and n is the effective useful life of the measure. Using the CRR, the levelized cost of energy is:

Levelized cost per kWh = Incremental Measure Cost x CRR / Annual kWh Savings
Levelized cost per kW = Incremental Measure Cost x CRR / Peak Demand Savings

All measures are ranked by ascending levelized cost, with each measure adding to the cumulative total DSM potential (MW or MWh). These curves thus describe, from a purely technology cost standpoint, what amount of economic DSM (TRC>=0.5) is available for a certain cost. The actual cost of delivering these DSM savings through programs would exceed the costs noted here due to the program costs associated with marketing, administration, education, and any engineering services provided.

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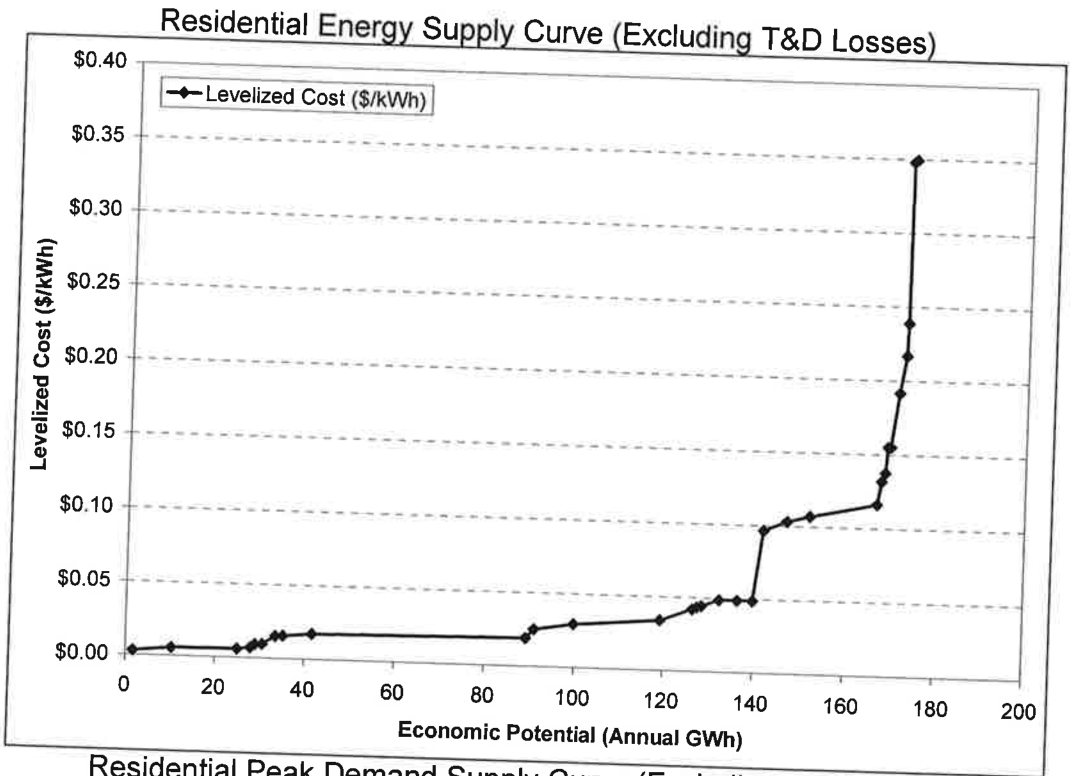
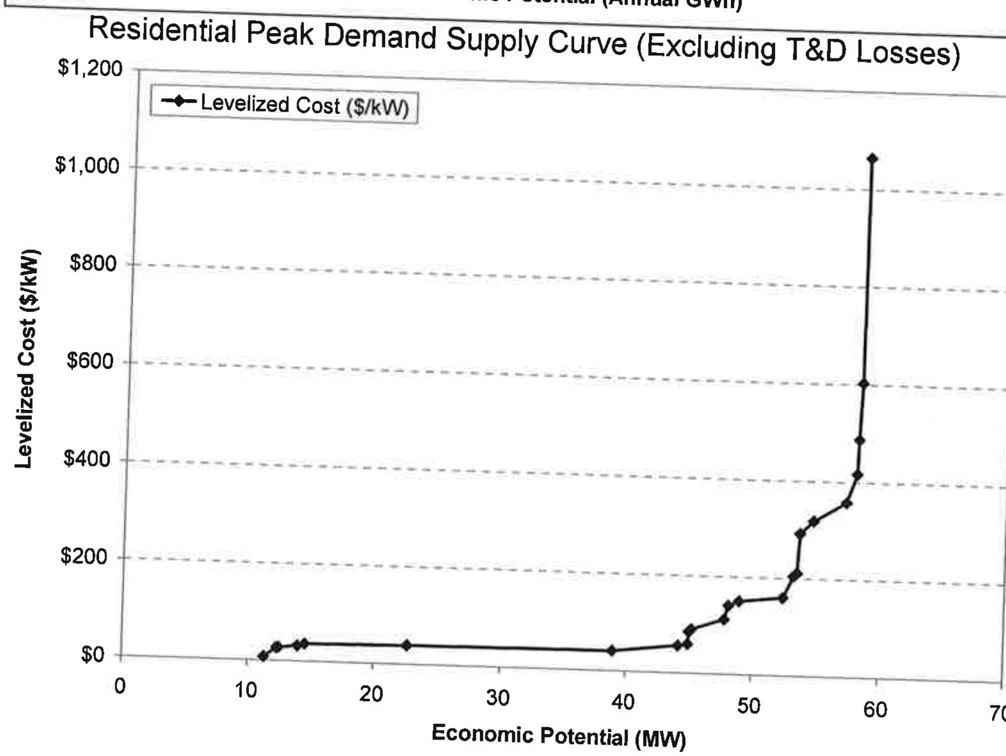
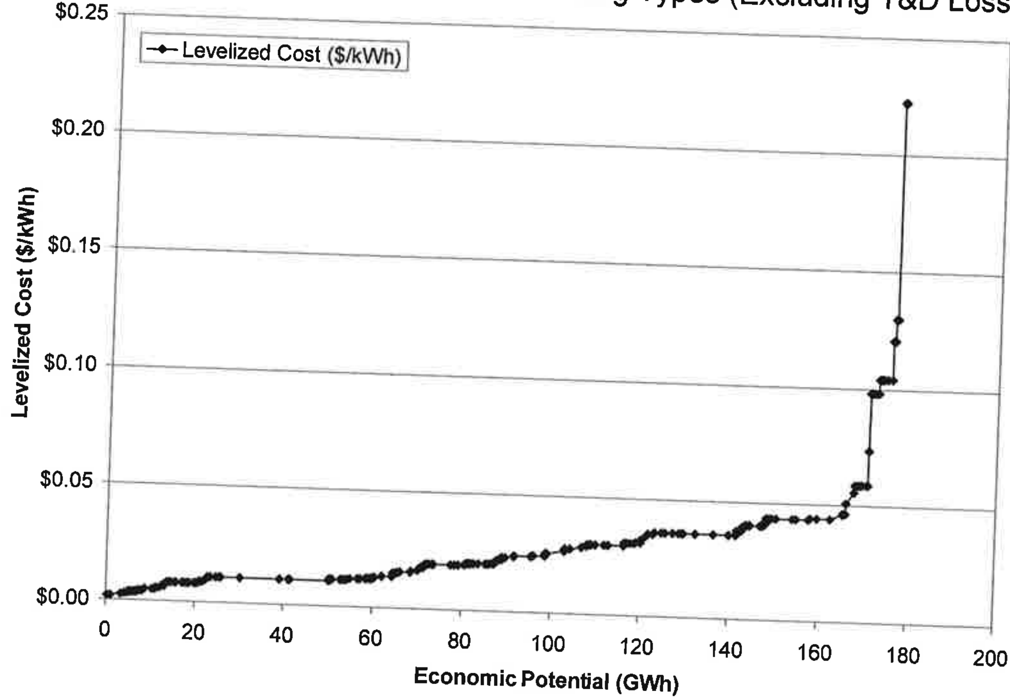
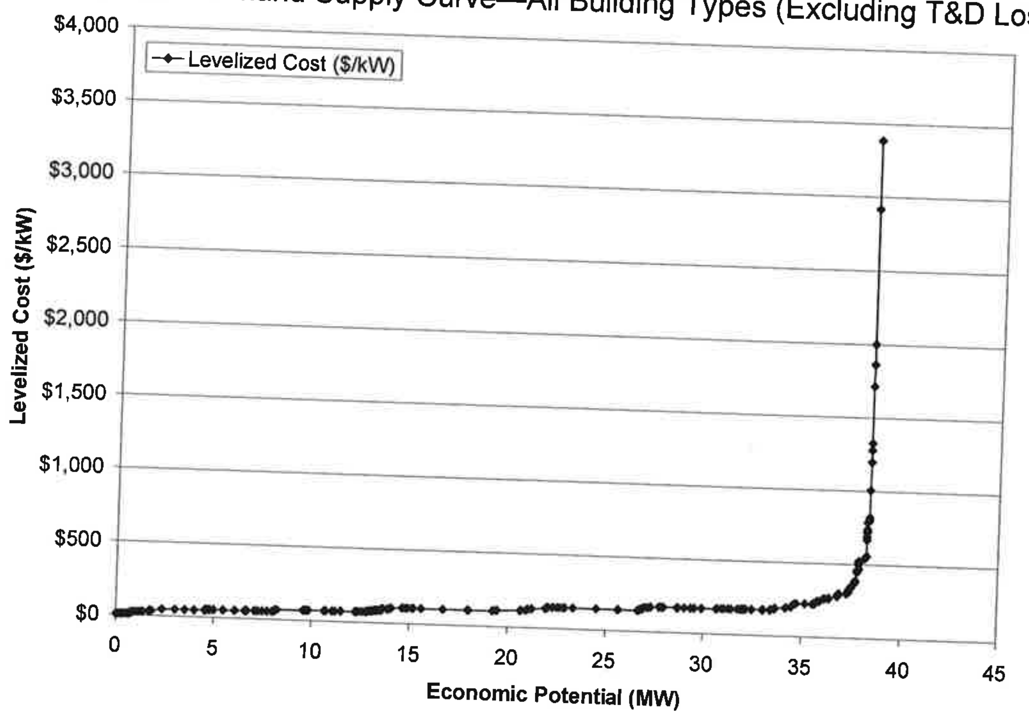

Residential Energy Supply Curve (Excluding T&D Losses)
Levelized Cost ($/kWh)
Levelized Cost ($/kWh)
Economic Potential (Annual GWh)
$0.40
$0.35
$0.30
$0.25
$0.20
$0.15
$0.10
$0.05
$0.00
0
20
40
60
80
100
120
140
160
180
200


Residential Peak Demand Supply Curve (Excluding T&D Losses)
Levelized Cost ($/kW)
Levelized Cost ($/kW)
Economic Potential (MW)
$1,200
$1,000
$800
$600
$400
$200
$0
0
10
20
30
40
50
60
70

Commercial Energy Supply Curve—All Building Types (Excluding T&D Losses)



Commercial Peak Demand Supply Curve—All Building Types (Excluding T&D Losses)



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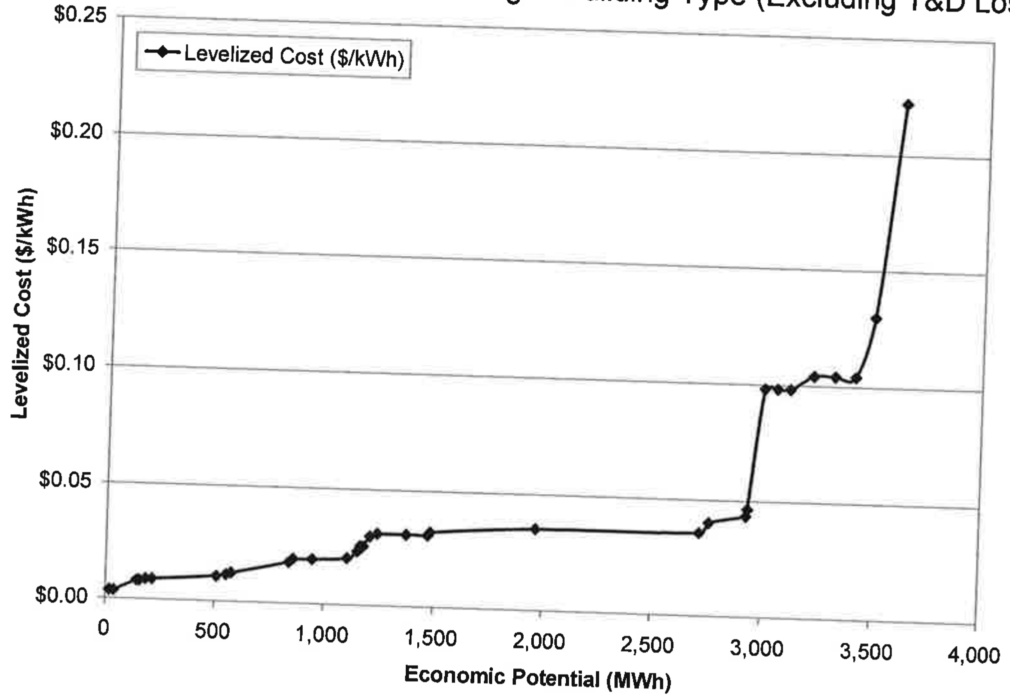
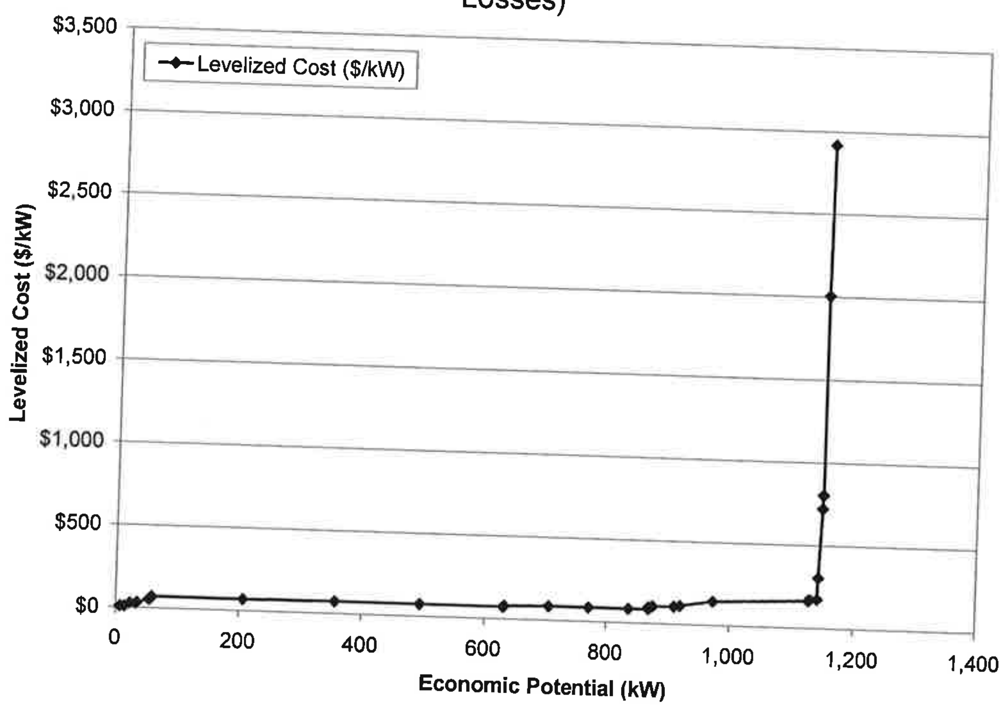
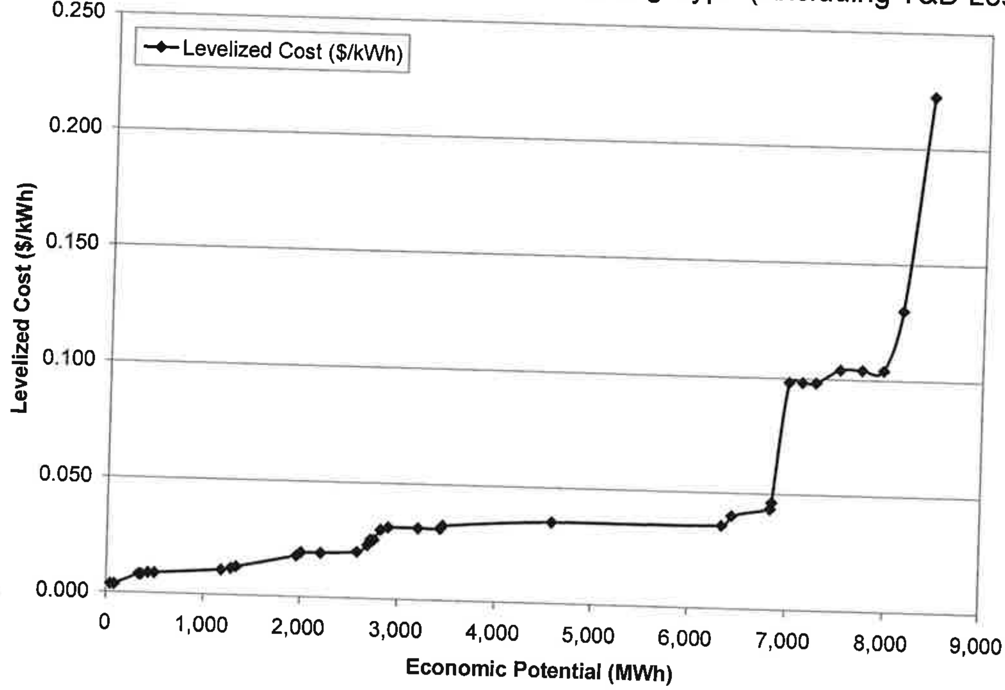
Commercial Energy Supply Curve—Colleges Building Type (Excluding T&D Losses)



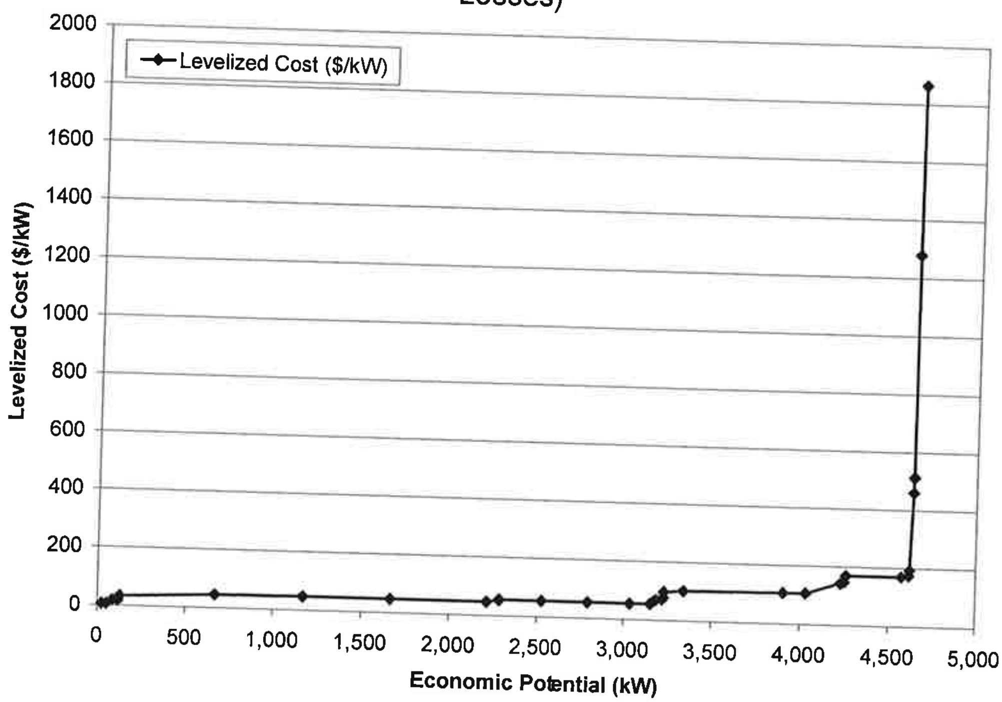
Commercial Peak Demand Supply Curve—Colleges Building Type (Excluding T&D Losses)



Commercial Energy Supply Curve—Schools Building Type (Excluding T&D Losses)



Commercial Peak Demand Supply Curve—Schools Building Type (Excluding T&D Losses)



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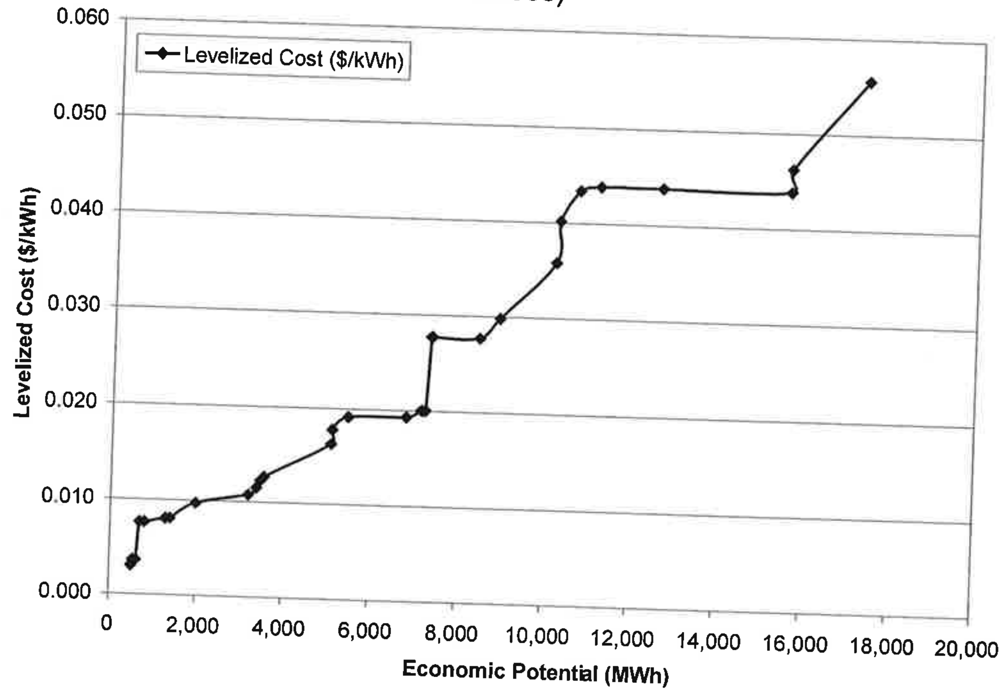
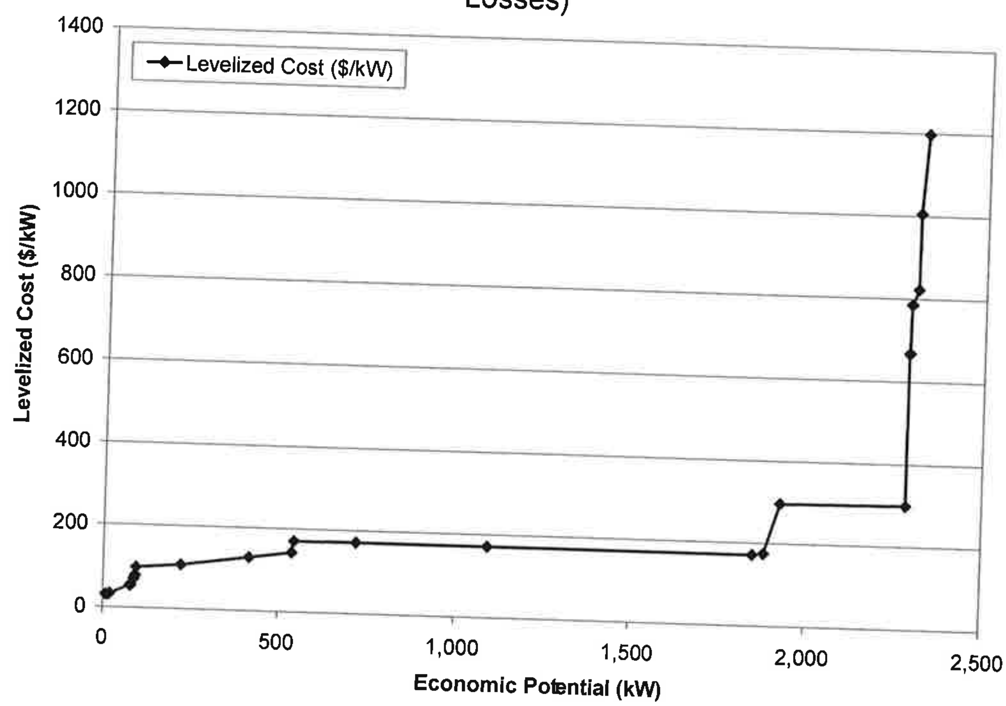
Commercial Energy Supply Curve—Hotels/Motels Building Type (Excluding T&D Losses)



Commercial Peak Demand Supply Curve—Hotels/Motels Building Type (Excluding T&D Losses)



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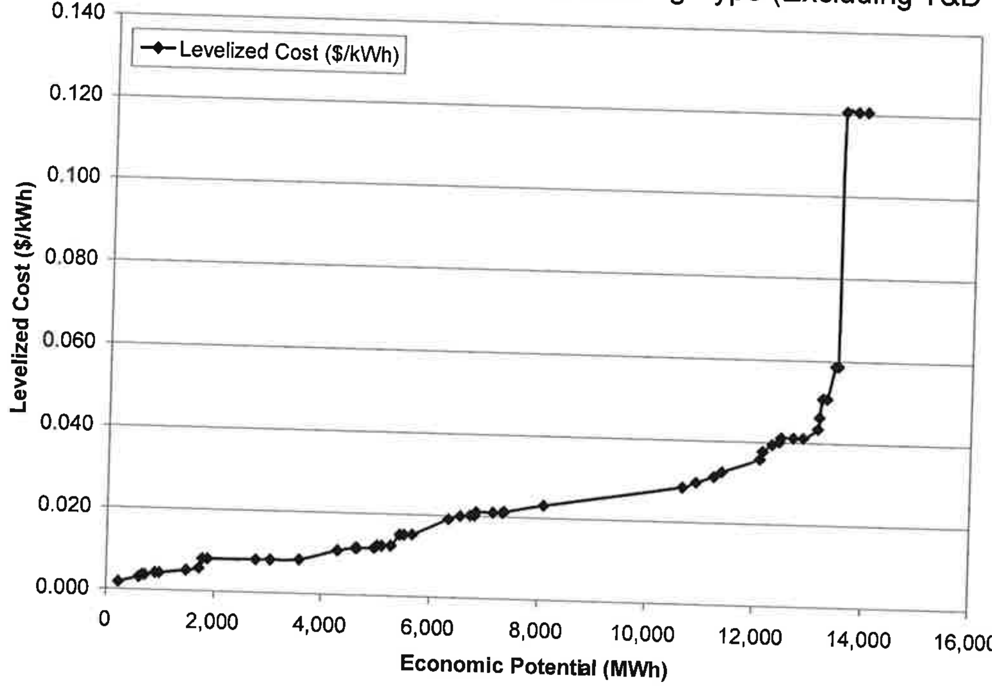
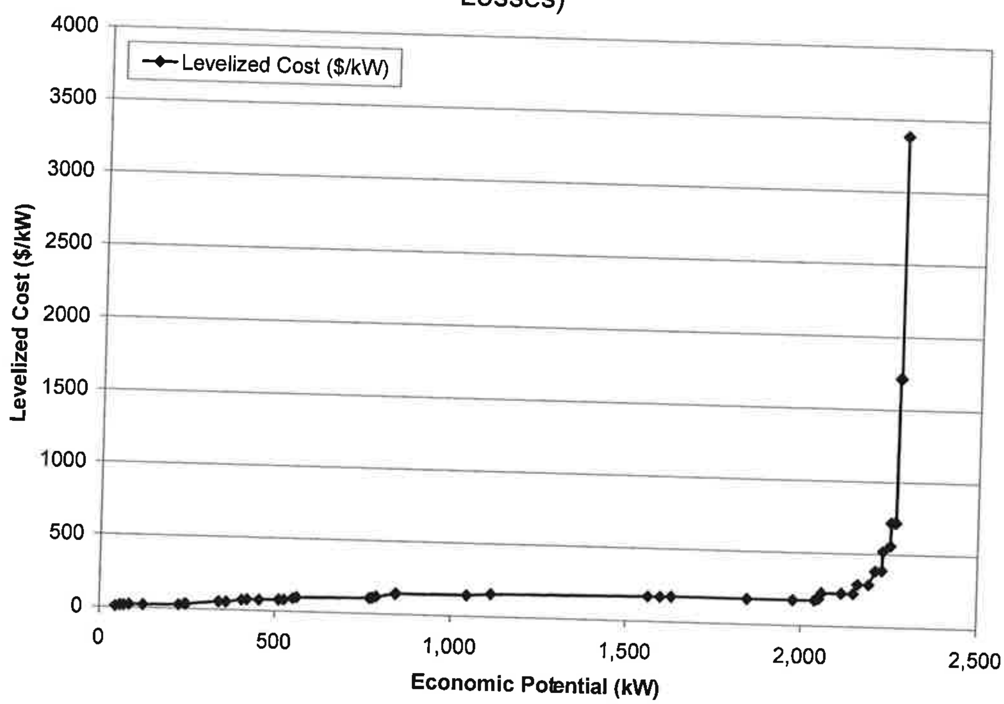
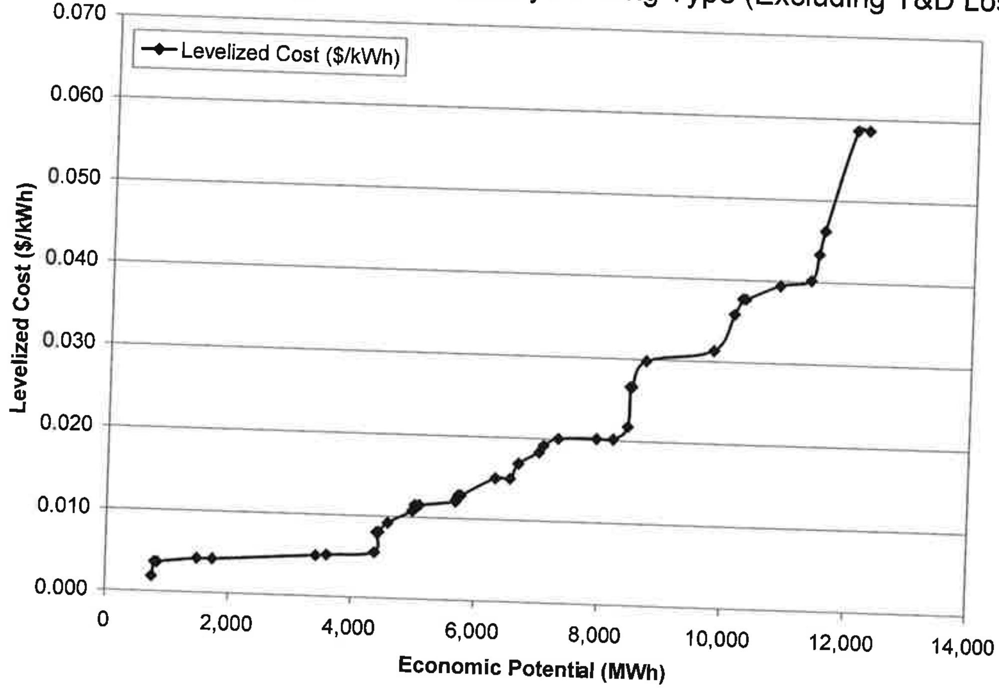
Commercial Energy Supply Curve—Restaurants Building Type (Excluding T&D Losses)



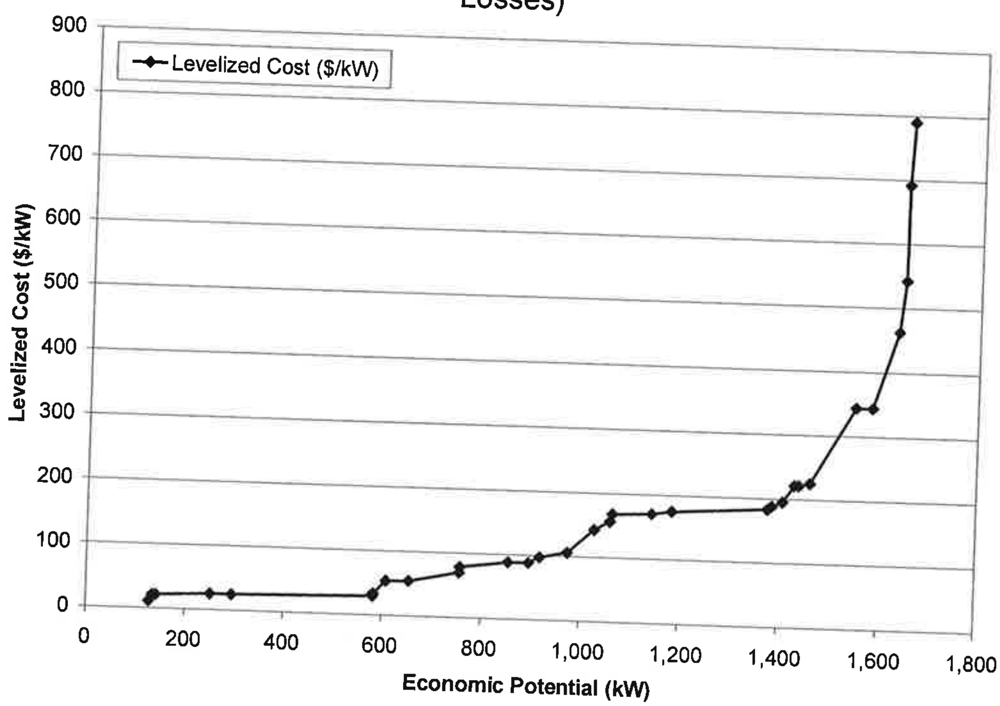
Commercial Peak Demand Supply Curve—Restaurants Building Type (Excluding T&D Losses)



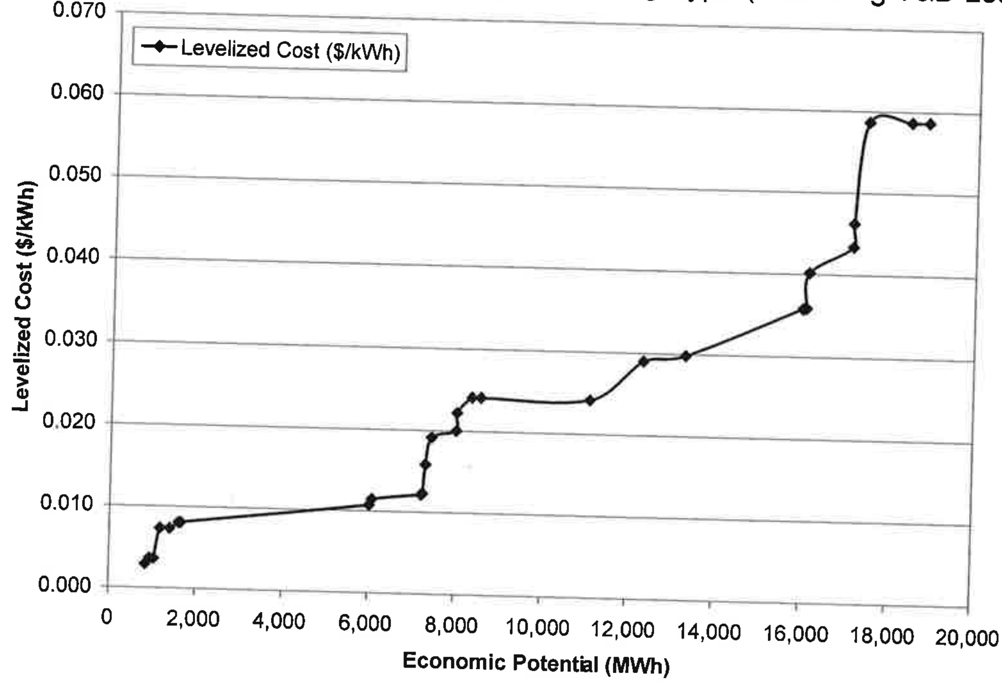
Commercial Energy Supply Curve—Grocery Building Type (Excluding T&D Losses)



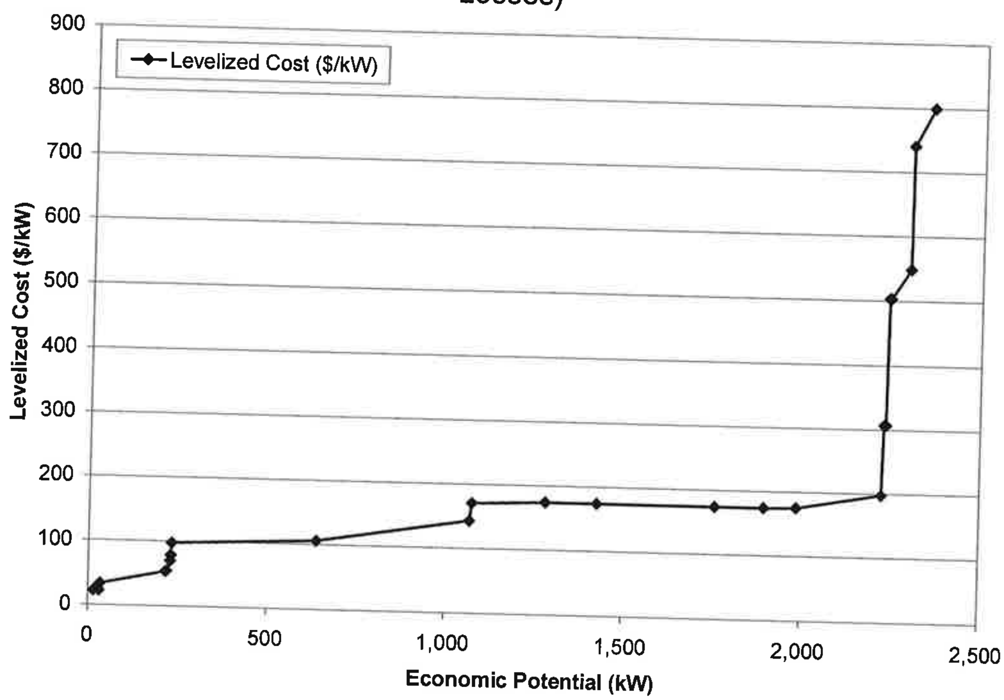
Commercial Peak Demand Supply Curve—Grocery Building Type (Excluding T&D Losses)



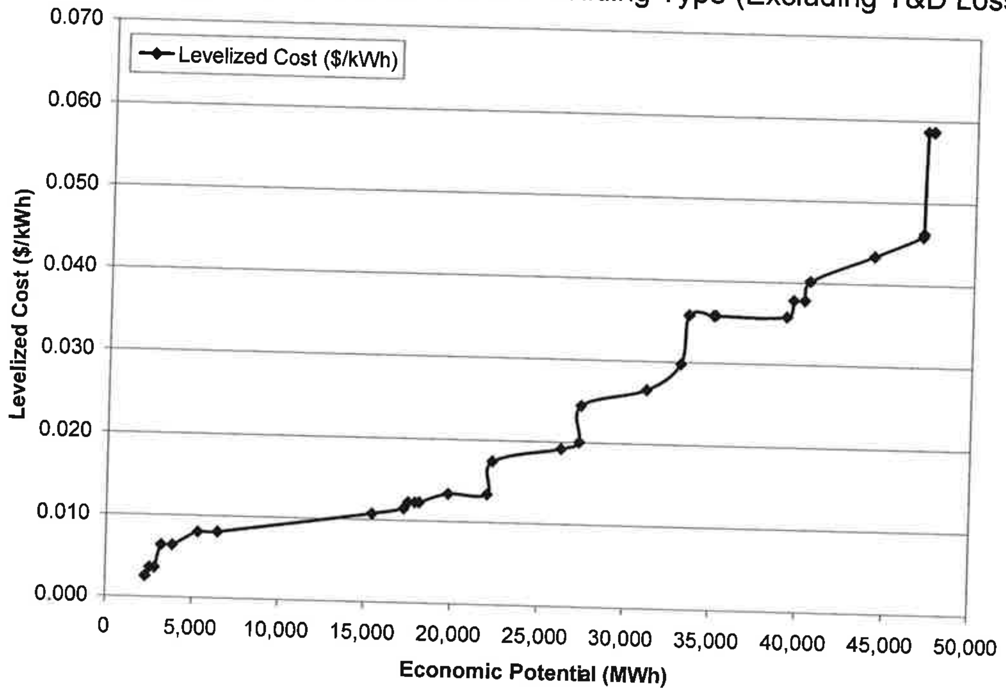
Commercial Energy Supply Curve—Hospital Building Type (Excluding T&D Losses)



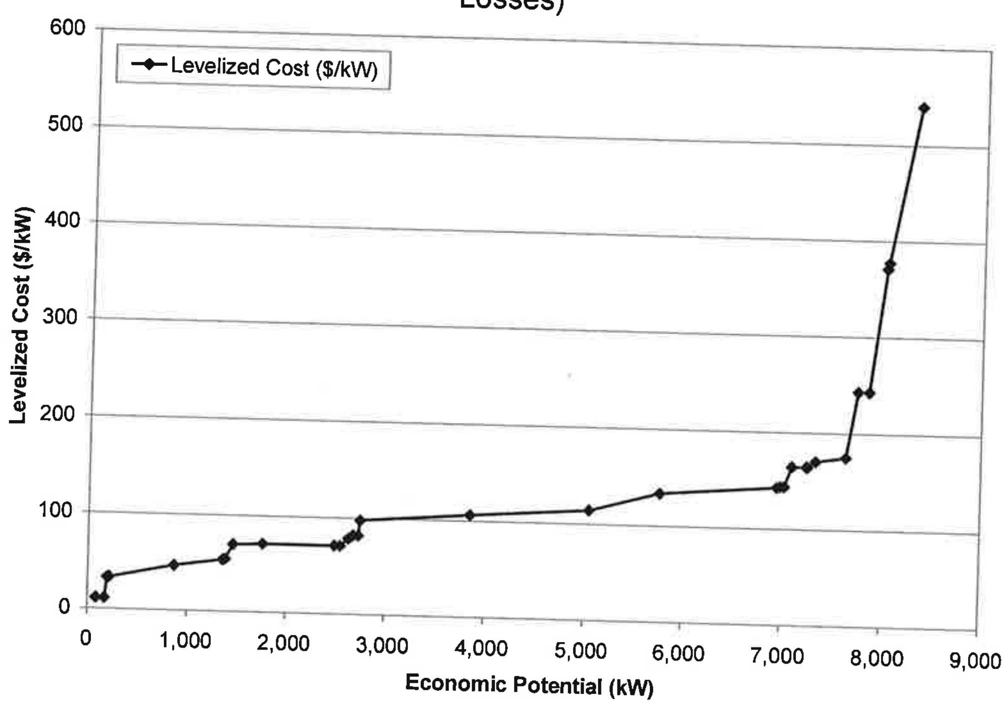
Commercial Peak Demand Supply Curve—Hospital Building Type (Excluding T&D Losses)



Commercial Energy Supply Curve—Offices Building Type (Excluding T&D Losses)



Commercial Peak Demand Supply Curve—Offices Building Type (Excluding T&D Losses)



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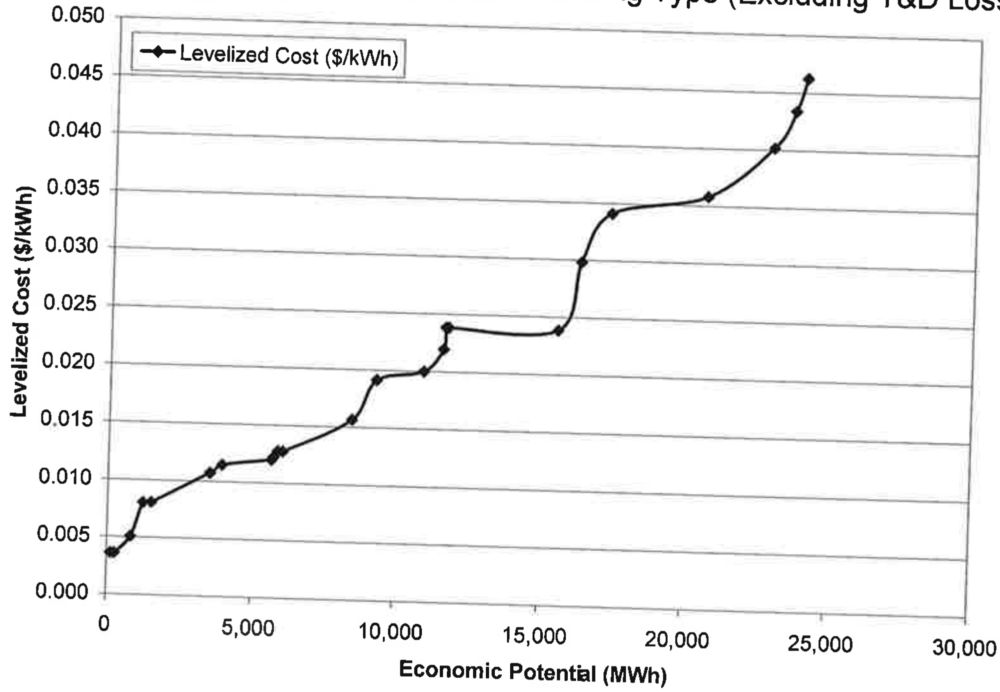
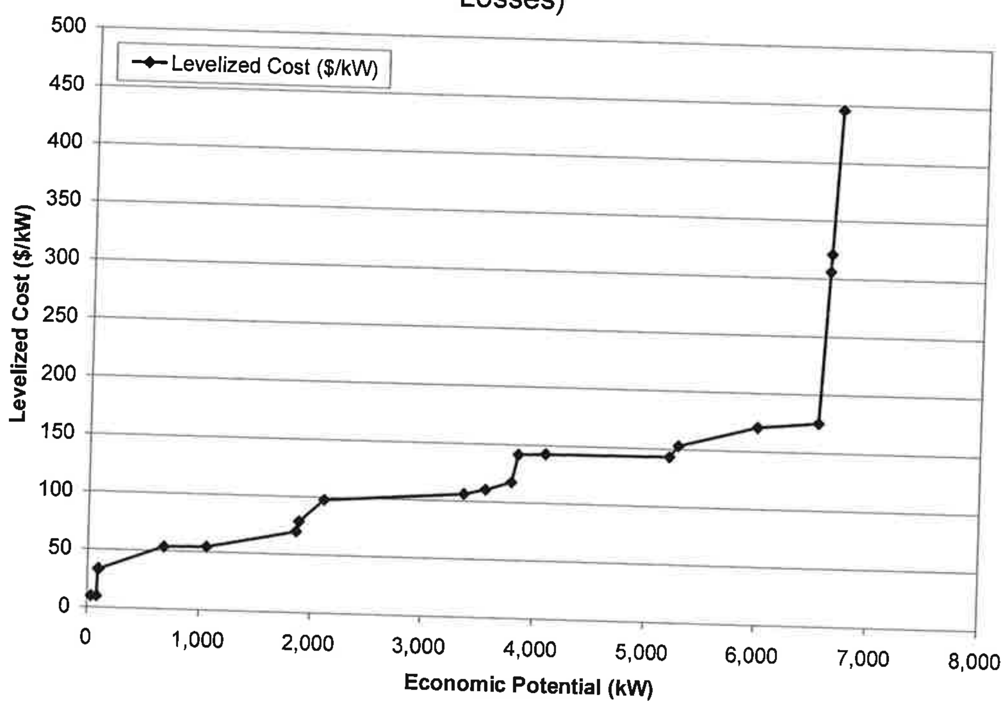
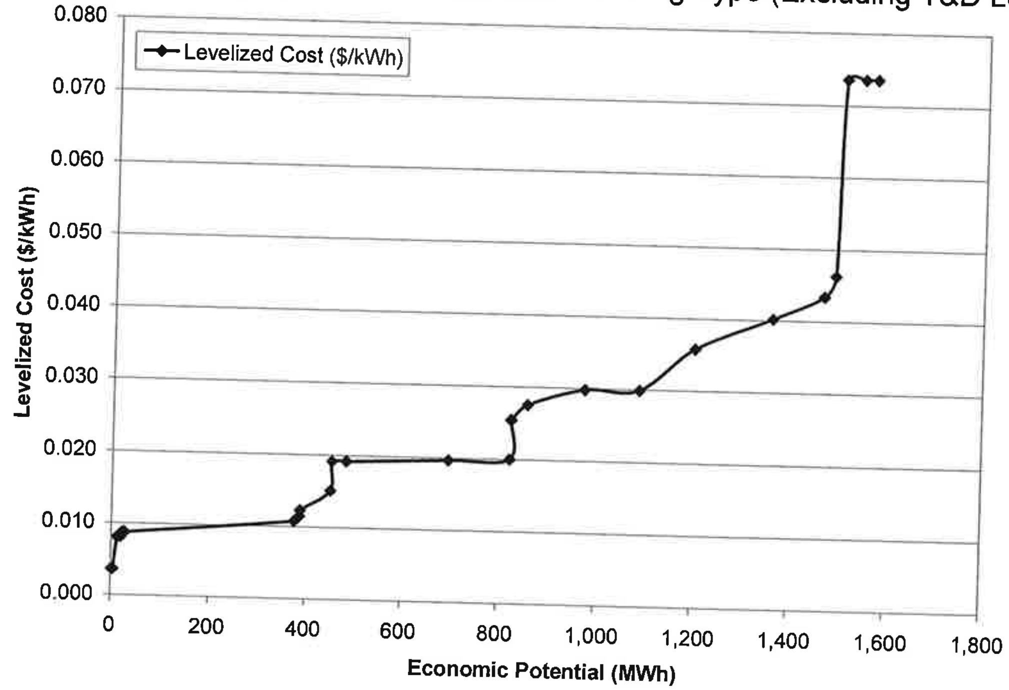
Commercial Energy Supply Curve—Retail Building Type (Excluding T&D Losses)



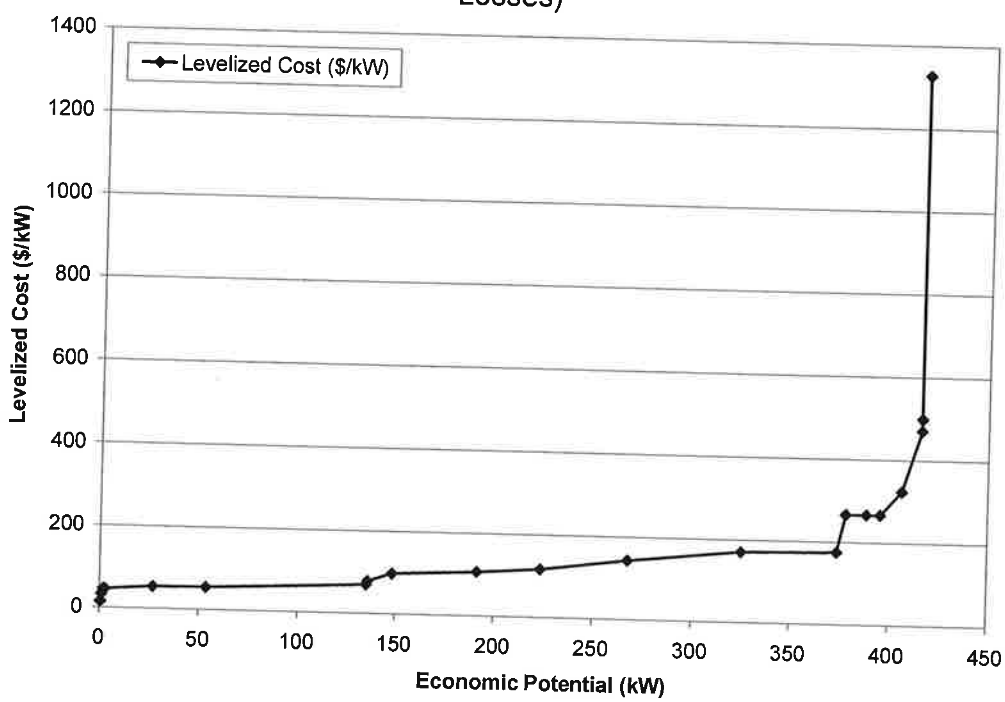
Commercial Peak Demand Supply Curve—Retail Building Type (Excluding T&D Losses)



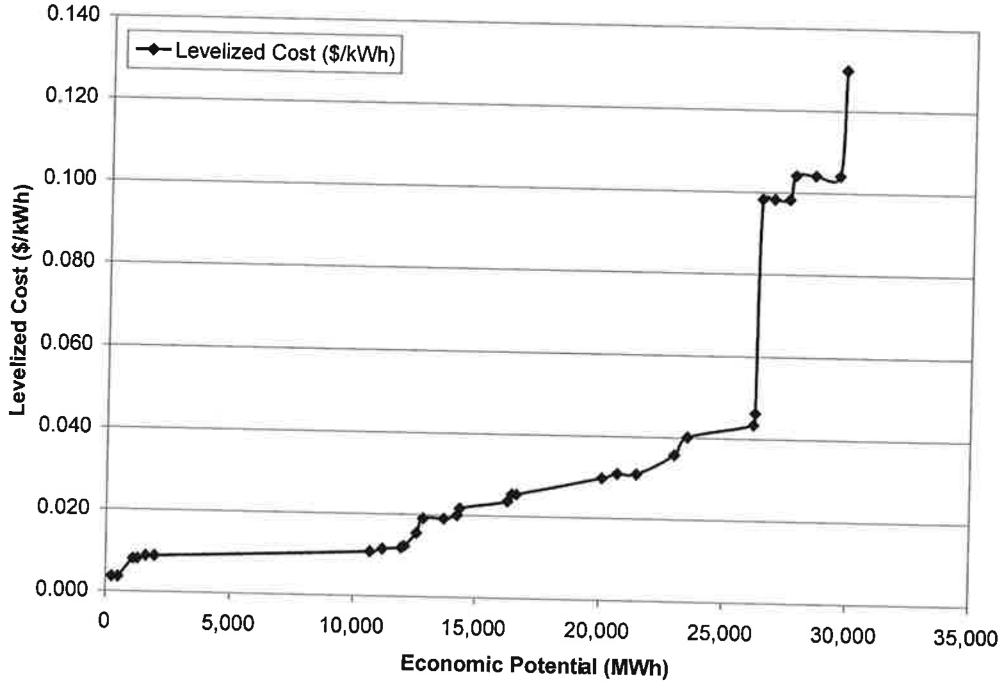
Commercial Energy Supply Curve—Warehouse Building Type (Excluding T&D Losses)



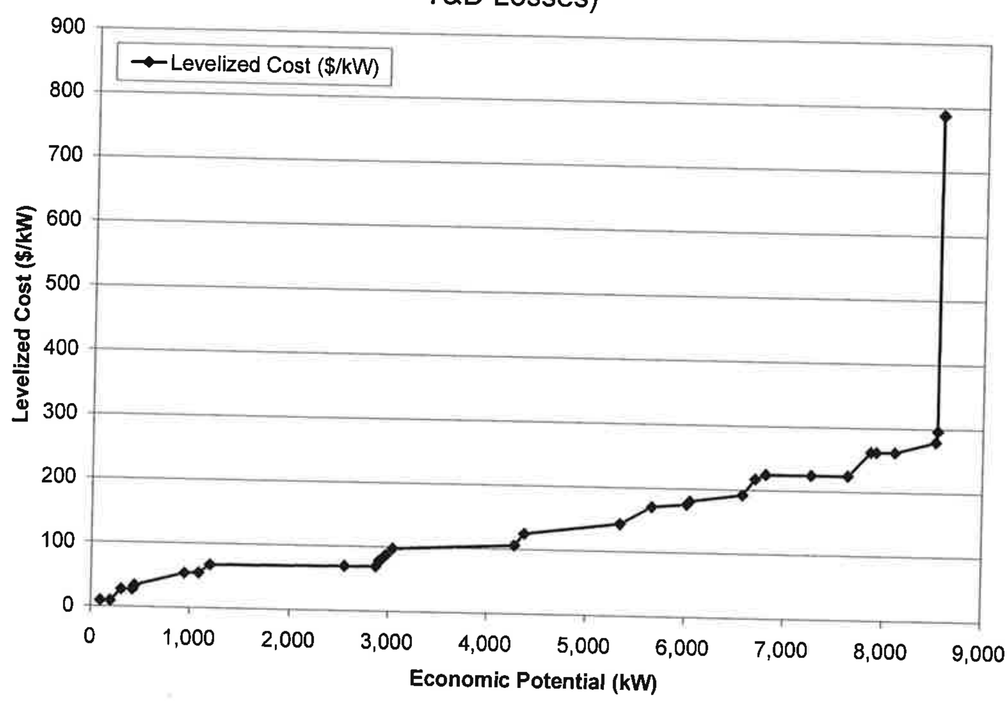
Commercial Peak Demand Supply Curve—Warehouse Building Type (Excluding T&D Losses)



Commercial Energy Supply Curve—Miscellaneous Building Type (Excluding T&D Losses)



Commercial Peak Demand Supply Curve—Miscellaneous Building Type (Excluding T&D Losses)



ATTACHMENT 4
GENERATION OPTIONS AND FINANCING COSTS

New Power Plant Costs

- New Power Plants – New combined cycle plants are assumed to be available at a cost of $626/kW (2003$) in 2006 in FRCC, and new simple cycle units are at a cost of $386/kW (2003$).
    - On an ISO basis, FRCC combined cycle costs are approximately at a 7 percent discount to the U.S. average
    - Costs for gas-fired equipment are generally decreasing modestly in real terms from 2006 through 2025. We assume flat costs in the near term for pulverized coal equipment in real terms.
    - The build mix is determined through economics.
- ICF imposes restrictions on the start dates of model additions to account for the necessary construction/permitting lag times and the commercial acceptance of new technology:
    - LM6000s are allowed to be built in 2006
    - Simple cycle turbines no earlier than 2009
    - Combined cycles and cogeneration units starting in 2009
    - Supercritical coal builds are allowed in 2011, with no coal builds in certain regions in the model such as in New England, large parts of New York and PJM East
    - IGCC are allowed in 2013

Key Plant Performance Assumptions

- New Unit Characteristics - New combined cycles and simple cycle units are assumed to have heat rates (HHV) of 7,100 Btu/kWh and 10,825 Btu/kWh in 2004, respectively. They start at higher levels and improve modestly over time due to the commercial acceptance of the next generation of turbines such as the FB, G and H technology.
- New supercritical coal units are assumed to have a heat rate of approximately 9,888 Btu/kWh and IGCC's heat rate are assumed to be around 7,908 Btu/kWh. For the IGCC unit coming online in 2013 we assume a 7FA-technology power island.

Key Plant Performance Assumptions

- Fossil Plant Availability – Existing plant availability is overall consistent with historical levels.
- Combined cycle units are provided the option to turndown overnight to a minimum level of 50 percent of full load. This decision whether to run at minimum load or to cycle off completely is based on economics.
  - The model considers the cost of start up incurred by turning off overnight and weighs this against losses incurred by operating "out of money", i.e., with a variable cost higher than the energy price.
  - In regions with high off-peak prices, the units will typically choose to turndown to minimum levels. In regions dominated by low variable cost capacity with low off-peak prices, the model will typically cycle the combined cycle units off at night and incur the cost of an additional start. The 50 percent minimum operating level is based on environmental considerations. Low NO_x burners, which are required by BACT and LAER regulations, cannot achieve single digit NO_x levels at low air/fuel mixtures.

Figure 4-12
Key Nuclear Performance Assumptions

Plant	Generator	Capacity	Availability
Turkey Point	3	666	90.3
Turkey Point	4	666	90.2
St. Lucie	1	839	90.7
St. Lucie	2	839	90.0
Crystal River	3	812	90.0
Total / Average		3,822	90.2
Source: ICF			

Key Plant Performance Assumptions

- Nuclear Performance - We assume availabilities consistent with recent historical levels and the improving performance trend. Note that while many units in the nuclear fleet are performing above their historical EFOR we continue to enforce this parameter which is typically 5 to 6 percent.
- Nuclear plants are assumed to operate until their license expires and for an additional 20-year license extension, unless it is economic to retire them earlier.

In review of process contingency risk impacts on IGCC costs, we have updated our view for the 220 MW class. For example, values have been revised from $2,070/kW to $2,200/kW for a Brownfield scenario. In this table, we also show costs for CFB stations that would be designed to maximize the use of biomass in a solid fuel facility. Values are higher than the bituminous-fired CFB due in large part to the larger furnace box requirements.

Figure 5-8
Delivered Natural Gas Price Forecasts[1,2] (Nominal $/MMBtu)

Year	Data	ICF Base Case[3,4]	GRU – IRP[5]
1995	Historical	2.33	2.33
1996	Historical	3.37	3.37
1997	Historical	3.3	3.3
1998	Historical	2.87	2.87
1999	Historical	2.86	2.86
2000	Historical	4.53	4.53
2001	Historical	4.91	4.91
2002	Historical	3.82	3.82
2003	Historical	5.80	5.80
2004	Historical	6.15	6.15
2005	Historical	7.18	7.18
2006	Forecast	10.02	6.50

[1] Assumes 2.63% inflation from 2003 to 2004 dollars, and 2.25 percent per year future general inflation rate.
[2] Assumes all gas commodity contracting is at spot and no financial hedging.
[3] Assumes $0.39 (2003$) for gas transportation/basis premium over Henry Hub Louisiana commodity cost delivered to Florida.
[4] ICF 2006-2008 forecasts are derived from NYMEX Henry Hub natural gas futures traded on 1/5/2006. 2009 is interpolated from 2008 and 2010 ICF forecast. A basis differential derived from GRU's delivered price is applied to this base price.
[5] GRU forecast as of April 2005, Source: A Review of Florida Electric Utility 2005 Ten-Year Site Plans, prepared by the Florida Public Service Commission, Division of Economic Regulation, December 2005.

HOW TO INTERPRET THE GAS PRICE FORECASTS

- These forecasts represent a fundamentals view of gas prices over the long term.
    - They do not incorporate the effects of the hurricanes on natural gas prices. These are expected to reduce production in the near term, with full recovery within two years.
    - Nor do they reflect short term phenomena or speculative behavior by traders