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On Behalf of

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PUBLIC DISCLOSURE

Achievable Energy Efficiency Potential Assessment

Final Study for Georgia Power

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PUBLIC DISCLOSURE

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1 EXECUTIVE SUMMARY

1.1 Background

- The Georgia Public Service Commission, in Docket No. 22449-U issued a June 22, 2006 accounting order that requires Georgia Power Company's 2007 IRP filing to include an assessment of the maximum achievable cost effective potential for energy efficiency programs in its service area.

- The assessment study is to follow the scope and detail used in the May 5, 2005 Assessment of Energy Efficiency Potential in Georgia prepared for the Georgia Environmental Facilities Authority (GEFA).

- Georgia Power retained Nexant, Inc. to conduct the assessment of energy efficiency potential in the Georgia Power Company service area, building upon results of the Company's demand-side management (DSM) measure screening and technical analyses which Nexant had supported over the preceding months. Southern Company Services provided additional support on the study's modeling analyses.

1.2 Assessment Approach

- The assessment of achievable potential was conducted in three sequential steps.
  - Organize input data. Compile final DSM measure screening results and collect service area sales forecast data. Inputs include confidential data such as forecast customer counts and floor space, end-use saturations, end-use unit energy consumption and energy intensity, etc.
  - Estimate energy efficiency potential impacts at end use level. Using economic screening results of 215 discrete measures, Nexant analyzed groups of measures by facility type and end use to estimate technically feasible and economically feasible potential impacts. The groups of measures were modeled in EnerSim to simulate interactive effects of multiple measures affecting space conditioning end uses.

- Estimate theoretically achievable impacts. Following a review of DSM market potential studies and observed program results, Nexant applied plausible market penetration curves to each end use to estimate technically feasible, economically feasible, and potentially achievable energy efficiency impacts

1.3 Definitions of Energy Efficiency Potential

- For symmetry with the GEFA report on Energy Efficiency Potential, this study defines energy efficiency potential as follows:
  - Technical Potential—the quantification of savings that could be realized if energy efficiency measures were applied in all feasible instances, regardless of cost.
  - Economic Potential—the subset of technical potential that is cost-effective from the Total Resource Cost Perspective, without regard to cross subsidies
  - Achievable potential—energy savings that can feasibly be achieved through program and policy interventions. This study estimates theoretically achievable potential for three policy intervention scenarios that correspond to varying levels of incentives provided to end-use consumers:[1]
    - Low incentives—monetary incentives to customers equivalent to 25% of incremental costs of energy efficiency improvements
    - Moderate incentives—monetary incentives to customers equivalent to 50% of incremental costs of energy efficiency improvements
    - Aggressive incentives—monetary incentives to customers equivalent to 100% of incremental costs of energy efficiency improvements

[1] The scenario definitions adopt the nomenclature of the GEFA study to describe varying levels of incentives without consideration of possible connotations of "low," "moderate," and "aggressive" levels of incentives.

- Each scenario includes significant expenditures on incentives to subsidize the purchase of energy-efficiency measures. It should be further noted that this study is based on a number of estimates, including projections of penetration rates which attempt to describe human behavior associated with program structures. It is not possible to know with certainty whether the results can be obtained under the scenarios studied.

1.4 Summary Results

- This assessment presents projections of estimated technical, economic, and achievable potential for the 2007 to 2018 time period. Section 3 presents detailed results.
- Projections of achievable potential by the year 2010 range between 1.7% and 6.2% of electricity sales, and 2.0% and 7.3% of peak demand.[2] Table 1 below presents results for the three policy intervention scenarios.[3]
- Figure 1 and Figure 2 below show projections of theoretically achievable energy sales and peak demand relative to Georgia Power's baseline forecasts.[4] The figures illustrate alternative forecasts that reflect the effects of estimated Low Incentive, Moderate Incentive, and High Incentive impacts on electricity sales and peak demand.

Table 1: Theoretically Achievable Potential—Total Potential and Percent of 2010 Forecast

Load Type	Low Incentive		Moderate Incentive		Aggressive Incentive	
Reduction in Electricity Sales (MWh)	Redacted	1.7%	Redacted	3.3%	Redacted	6.2%
Reduction in Peak Demand (MW)	Redacted	2.0%	Redacted	3.8%	Redacted	7.3%

[2] Throughout this study, "peak demand" signifies the demand for power at the generator level at the time of system peak, except as otherwise noted.
[3] Each scenario estimate of theoretically achievable potential assumes a 2007 start date of full-scale program implementation. Delayed start-up or a measured ramping up to full-scale implementation would lessen the magnitude of theoretically achievable potential in any given future year.
[4] This study analyzed the residential, commercial, and industrial sector forecasts, and not Georgia Power's total forecast, which also includes MARTA and territorial wholesale customers.

Figure 1: Theoretically Achievable Potential (Electricity Sales)

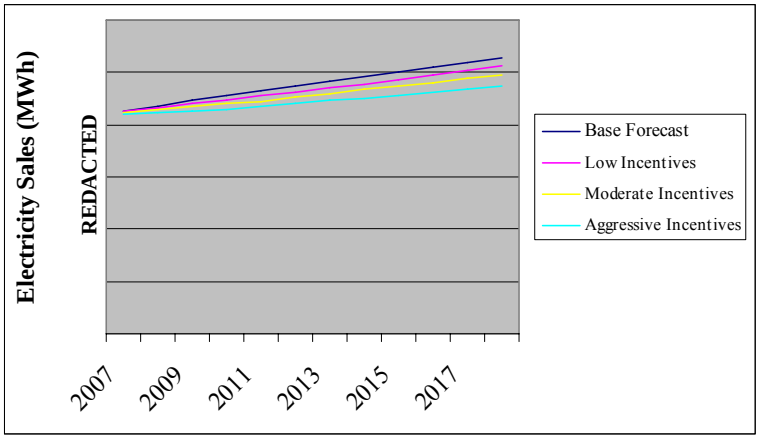


Figure 2: Theoretically Achievable Potential (Peak Demand)

1.4.1 Achievable Potential by Sector

- For the Aggressive Incentive scenario, Figure 3 and Figure 4 illustrate the achievable potential for electricity sales and peak demand impacts by sector.

Figure 3: 2010 Achievable Potential by Sector (Electricity Sales)

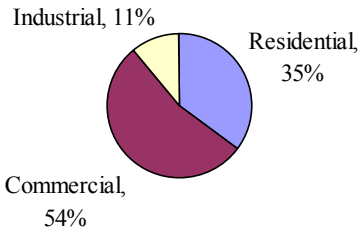
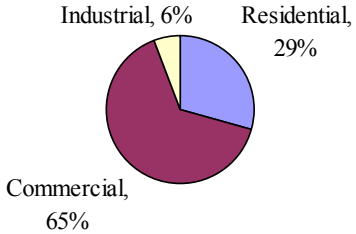


Figure 4: 2010 Achievable Potential by Sector (Peak Demand)



1.4.2 Achievable Potential by End Use

- Figure 5 and Figure 6 illustrate the end uses that comprise the achievable potential (Aggressive Incentive scenario) for electricity sales and peak demand impacts.

Figure 5: 2010 Achievable Potential by End Use (Electricity Sales)

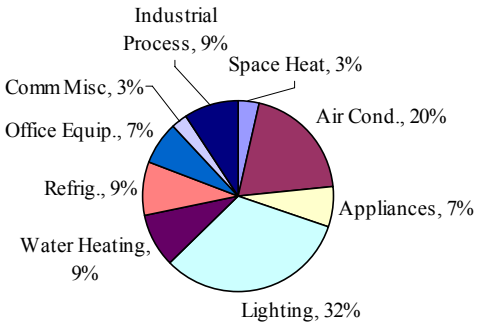
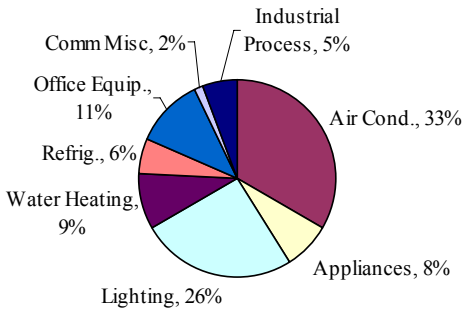


Figure 6: 2010 Achievable Potential by End Use (Peak Demand)



Note: The end-use shares of theoretically achievable potential are based on non-coincident peak demand reductions and do not necessarily match shares sector shares presented in Figure 4.

1.4.3 Achievable Potential Cost-Effectiveness

- Table 2, Table 3, and Table 4 present cost-effectiveness indicators from Total Resource Cost (TRC), Ratepayer Impact Measure (RIM), and Participant Cost Test (PCT) perspectives respectively, of the effects of achievable energy efficiency impacts from 2007 through 2018. The tables present economic indicators for each scenario of theoretically achievable potential.
- Benefits and costs are measured in the following way from TRC, RIM, and PCT perspectives:

- The TRC and RIM perspectives measure benefits as the reductions in costs utilities experience as a result of reduced demand for energy. The PCT measures benefits as the reductions in participants' energy costs plus all incentives received to offset energy-efficiency measure costs.
- TRC perspective costs include all costs incurred to purchase, install, and maintain efficiency technologies, plus administrative costs required to implement energy efficiency programs
- RIM perspective costs include all incentives to encourage purchase, installation, and maintenance of efficiency technologies, plus administrative costs required to implement energy efficiency programs, plus the lost electric utility revenues as a result of reduced energy sales.[5]
- PCT perspective costs include all costs incurred to purchase, install, and maintain efficiency technologies.

- TRC net benefits of between $0.8 and $3.1 billion are theoretically achievable, at a RIM net cost of between $1.3 and $4.9 billion to electricity ratepayers. The RIM net cost indicates the amount that electricity rates would have to increase due to DSM—over and above rate increases that would ordinarily be expected.[6]

- PCT net benefits of between $1.6 and $6.7 billion are theoretically available to participants.

Table 2: TRC Net Benefits and Benefit-Cost Ratios

Scenario	Net Benefits (Billions)	Benefit-Cost Ratio
Low Incentive	$0.8	1.5
Moderate Incentive	$1.8	1.7
Aggressive Incentive	$3.1	1.8

Table 3: RIM Net Benefits and Benefit Cost-Ratios

Scenario	Net Benefits (Billions)	Benefit-Cost Ratio
Low Incentive	-$1.3	0.6
Moderate Incentive	-$2.4	0.6
Aggressive Incentive	-$4.9	0.5

[5] Electric utility revenues are lost when authorized fixed costs are under-recovered due to the effects of DSM on reducing energy sales. Recovery of these authorized fixed costs from remaining energy sales causes rates to increase.

[6] This study does not estimate RIM benefits and costs from a gas utility perspective. To the extent that gas utility lost revenues exceed avoided gas supply costs, as would normally be expected, gas rates would also be adversely affected and would rise above otherwise anticipated increases. Estimated net present value data presented in this assessment are for the period from 2007 through 2018.

Table 4: PCT Net Benefits and Benefit-Cost Ratios

Scenario	Net Benefits (Billions)	Benefit-Cost Ratio
Low Incentive	$1.6	3.1
Moderate Incentive	$3.4	3.4
Aggressive Incentive	$6.7	4.0

- Figure 7, Figure 8, and Figure 9 below illustrate breakdowns of benefits and costs for TRC, RIM, and PCT perspectives for each of the three scenarios.
  - The TRC benefits in each scenario accrue from approximately equal shares of avoided electricity costs and avoided gas costs.
  - The RIM perspective includes benefits and costs only to the electric utility.
  - The PCT net benefits would be substantial even without financial incentives to encourage participation by subsidizing portions of participants' efficiency measure costs.

Figure 7: TRC Benefits and Costs by Scenario

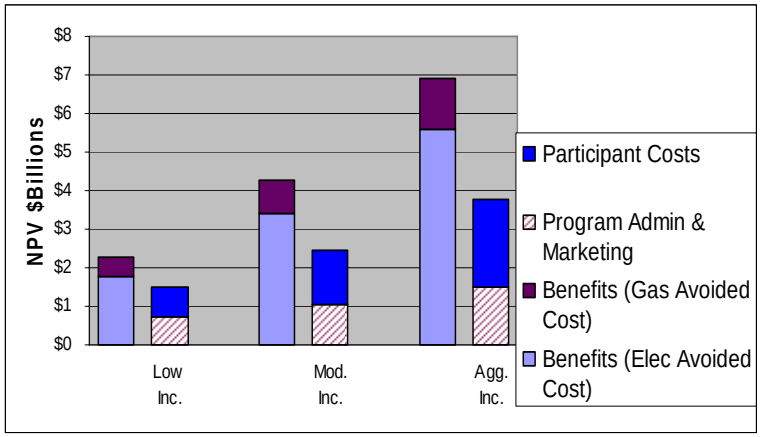
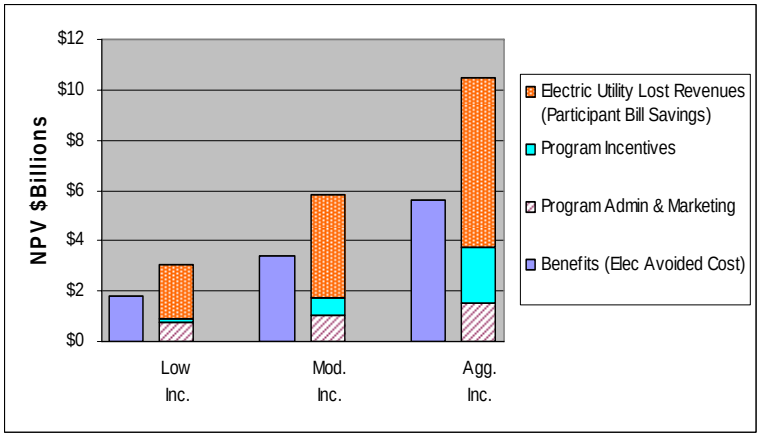
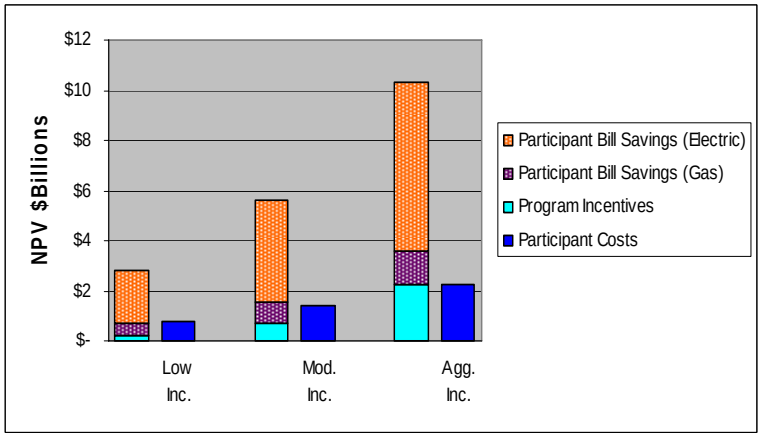


Figure 8: RIM Benefits and Costs by Scenario



Note: The above RIM analysis is only for the electric utility and does not include gas utility RIM results.

Figure 9: PCT Benefits and Costs by Scenario



- Annual DSM program expenditures in each theoretically achievable scenario would be substantial. Table 5 lists the annual expenditures in 2010 associated with each of the scenarios.

Table 5: 2010 Annual Program Expenditures by Scenario ($Millions)

Scenario	Annual Incentives ($MM)	Administrative Costs ($MM)	Total Costs ($MM)
Low Incentive	$29.0	$116.0	$145.0
Moderate Incentive	$125.8	$188.8	$314.6
Aggressive Incentive	$513.9	$342.6	$856.6

- Table 6 indicates the cumulative capacity reductions that are theoretically achievable for each of the scenarios analyzed.[7]

Table 6: Theoretically Achievable Georgia Power Capacity Reductions

Scenario	2018 Capacity Change (MW)
Low Incentive	Redacted
Moderate Incentive	Redacted
Aggressive Incentive	Redacted

1.5 Conclusions

- An apparently significant potential for increased energy efficiency exists in Georgia, where the economy could benefit from effects associated with reduced energy consumption and peak power requirements.

[7] In this table, capacity reductions signify the amount of generation capacity, as opposed to peak demand, that could theoretically be avoided.

- Reductions in energy consumption and peak power requirements occur when energy-efficiency measures or actions are implemented by energy customers, who receive economic benefits directly from reductions in their energy bills. Customers could also benefit from any financial incentives that might be offered by programs intended to accelerate markets for the purchase and installation of high-efficiency measures.

- Per directive of the Georgia Public Service Commission, this study adopts the structure of the Georgia Environmental Facilities Authority's similar study, which examined scenarios of theoretically achievable energy efficiency potential associated with "low" incentives, "moderate" incentives, and "aggressive" incentives. Each scenario involves substantial expenditures on incentives, ranging from $29 million per year to more than $510 million per year by 2010, the fourth year of program implementation. This study also demonstrates, however, that customers are able to realize substantial benefits from increased energy efficiency even without any financial subsidies.

- Economic benefits to the State's retail energy market resulting from energy efficiency improvements made by customers in Georgia Power's service territory could range to as high as $0.8 billion to $3.1 billion.

- If implemented through electric utility programs, the potential benefits of energy efficiency associated with energy reductions ranging from 1.7 percent to 6.2 percent of forecast sales come at a substantial cost to ratepayers. Net costs to electric utility ratepayers could range to as high as $1.3 billion to $4.9 billion. These costs are over and above the cost associated with meeting these demand needs using supply side options. Program costs alone could increase rates as much as $0.9 billion to $3.8 billion. This study does not estimate costs to gas utility ratepayers, who could also experience adverse rate impacts.

1.6 Caveats

- The interpretation of results presented in this study (and in general, all studies of this nature) should include consideration of several important caveats.

- Uncertainties. A key determinant of the potential for achievable energy efficiency savings is the market penetration rate and yet these estimates of customer response represent a substantial source of uncertainty in the projections of achievable potential. The GEFA study, in a similar caveat, noted that "the greatest source of uncertainty in our projections of achievable potential are the estimates of market share growth under each policy scenario."

  The estimated impact of efficient technologies on energy consumption is another key determinant of savings potential, and yet these inputs also have substantial uncertainty. In the near term, while efficient technology options can be reasonably well defined, customer behavior and electricity usage patterns vary widely and can differ significantly from assumptions necessarily made to model "typical" usage profiles. In future years, uncertainties are exacerbated by lack of information about future technology choices. Georgia Power's forecasting models already incorporate the effects of trend increases in end use energy efficiency that reflect historical trends. There is no sound basis, however, for estimating potential impacts of unknown future technologies that are incrementally *even more* efficient than the higher efficiency end uses implicitly incorporated in the forecast. As a result, the availability and magnitude of future impacts are inherently speculative.

- Potential reliability impacts. The uncertainties noted above could result in deterioration of system reliability if estimates of theoretically achievable energy savings were used to justify reductions in the load forecasts used for planning Power Purchase Agreements (PPAs) and capacity construction programs. If estimated energy savings do not materialize, then the planned PPAs and generation resource options—many of which require long lead times to place into operation—might be insufficient to sustain system reliability until recourse to additional (and likely more costly) resource options can be secured.

- Rate impacts. The effect of energy efficiency programs on rates, unlike other effects of energy savings programs, has little uncertainty: energy efficiency programs cause electricity rates to rise faster than they would ordinarily. In addition, the uncertainties noted above that could result in reduced energy savings are not necessarily associated with comparable reductions in program costs and adverse rate impacts. Market

acceptance rates that fail to materialize, for example, reduce incentives and rebate processing costs but do not reduce marketing costs or other fixed costs of program management and reporting. More worrisome, if realized technology impacts are less than estimated impacts, then the impact of *all* of the estimated costs of rebates, processing, marketing, and administration remains but with diminished savings of supply costs. That is, the rate impacts effects could be more adverse than estimated in this study.

2 STUDY APPROACH

2.1 Introduction

- It should be noted that this study is based on a number of estimates, including projections of penetration rates which attempt to describe human behavior associated with program structures. It is not possible to know with certainty that the results can be obtained under the scenarios studied.

2.1.1 Background

- The Georgia Environmental Facilities Authority (GEFA), to better understand the estimated magnitude of achievable energy savings potential in Georgia, commissioned ICF Consulting to conduct a study of technical and economic potential for energy efficiency in the State

- Referencing the GEFA study, the Georgia PSC issued a June 22, 2006 accounting order in Docket No. 22449-U requiring Georgia Power Company's 2007 IRP filing to include an assessment of the maximum achievable cost effective potential for energy efficiency programs in its service area.

2.1.2 Objectives

- In response to the accounting order, Georgia Power subsequently retained Nexant to investigate energy efficiency potential in its service area, defining the following objectives:
  - Expand the scope of DSM measure screening and economic analyses to quantify technical and economic potential for energy efficiency
  - Assess theoretically achievable potential for energy efficiency in scenario analyses corresponding to policy settings in which customers are offered low incentives, moderate incentives, and aggressive incentives

2.2 Approach

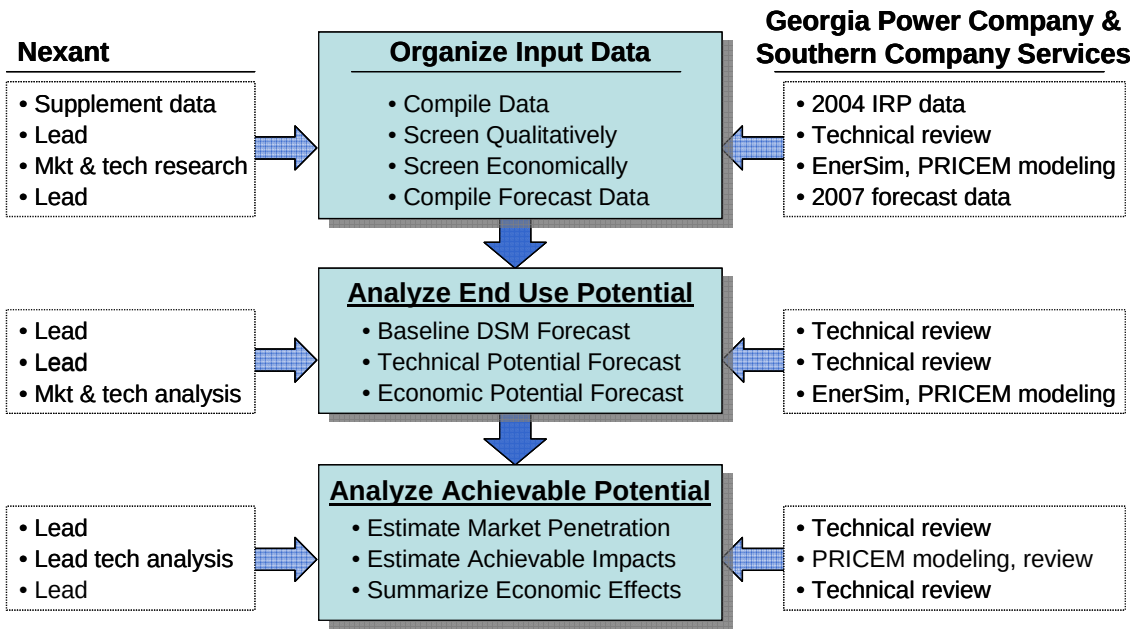
- The central technique in Nexant's approach to projecting estimates of energy efficiency potential is to modify end-use forecast data to reflect substitution of existing and expected energy consumption patterns with higher-efficiency end-use patterns.
- The study followed three sequential steps, which are each described in more detail in the text that follows below. Nexant, Georgia Power, and Southern Company Services staff worked in close collaboration throughout the analysis, to maximize effective use of their combined expertise and analytical tools. Figure 10 illustrates the roles and inputs each party contributed to the analysis.
  - Organize input data. Compile final DSM measure screening results and collect service area sales forecast data. Inputs include confidential data such as forecast customer counts and floor space, end-use saturations, end-use unit energy consumption and energy intensity, etc.
  - Estimate energy efficiency potential impacts at end use level. Using economic screening results of 215 discrete measures, Nexant analyzed groups of measures by facility type and end use to estimate technically feasible and economically feasible potential impacts. The groups of measures were modeled in EnerSim to simulate interactive effects of multiple measures affecting space conditioning end uses.
  - Estimate theoretically achievable impacts. Following a review of DSM market potential studies and observed program results, Nexant applied plausible market penetration curves to each end use to estimate technically feasible, economically feasible, and potentially achievable energy efficiency impacts.

2.2.1 Organize Data Inputs

- To ensure a comprehensive analysis of energy end uses and potentially achievable savings, Nexant's analysis began with a "bottom up" approach that examined measure-specific impacts and cost data. Measure data resulted from several comprehensive screening analyses that Nexant and Georgia Power had jointly conducted

and shared with the DSM Working Group (established by a 2004 ruling of the Georgia Public Service Commission) over the preceding months. The screening analyses included the following key components:

Figure 10: Analysis Inputs and Roles



– Compile and augment comprehensive lists of measures, building upon prior analyses conducted in Georgia and in other states. The measures analyzed in Georgia Power's 2004 IRP provided an initial list, which was supplemented through consideration of other sources, such as the 2005 GEFA report, California's Deemed Energy Efficiency Resource database and the Northwest Power and Conservation Council's Regional Technical Forum database. The final list included almost 550 measures.

- Conduct a qualitative screening to ensure that candidate measures are suitable for the Company's customers, that costs and impacts can be determined with reasonable accuracy, that better measures are not readily available in the marketplace, etc. The qualitative screening analysis, which resulted in a list of about 500 measures, was also discussed in progress with the DSM Working Group.
- For all candidate measures that passed the qualitative screening, the approach updated both cost and impact data for each measure.
  - Nexant conducted market research to update measure costs. The cost data differentiate between type of cost (capital, installation labor, maintenance, etc.) so that cost components can be updated more readily. In this way, retrofit (capital plus installation labor plus incremental maintenance), new construction (incremental capital and maintenance), and burnout costs (incremental capital and maintenance) can be separately evaluated for measures that can be adopted in different implementation modes.
  - Weather-sensitive end uses were analyzed in the EnerSim model, which simulates energy usage in homes and buildings using weather data specific to Georgia Power's service area. Home and building prototypes were modeled for both existing and new dwellings and facilities.
- Conduct economic screening. Southern Company Services conducted the economic analysis of individual measures, utilizing its PRICEM model to identify the avoided energy supply costs associated with measure savings. This analysis resulted in a final list of 95 residential measures and 120 nonresidential measures that were incorporated into the analysis of achievable potential.

- Collect and analyze forecast data. Georgia Power supplied baseline forecast data for residential, commercial, and industrial sectors.

  - The residential forecast data were organized by housing type (single family, multi-family, and manufactured housing) and end use (electric furnace, electric room heating, heat pump heating, gas furnace, gas room,

heating, central air conditioning, heat pump cooling, room air conditioning, dish washers, washers, water heating (electric and gas), cooking (electric and gas), refrigerators (first and second), freezers, dryers (electric and gas), color TVs, lighting, and other).

- The commercial sector forecast was similarly organized by facility type (amusement, education, government, grocery, health, lodging, miscellaneous, office, religious, restaurant, retail, and warehouse) and end use (heating, cooling, water heating, cooking, refrigeration, exterior lighting, interior lighting, office equipment, and miscellaneous).

- The industrial sector forecast was organized by major end use (motors, thermal processes, lighting, other processes, and miscellaneous).

2.2.2 Estimate Energy Efficiency Potential at End Use Level

- The first major task in estimating energy efficiency potential is to construct a baseline DSM forecast that is consistent with the Company's forecast.[8] For example, in the residential sector, the general equation for the DSM baseline forecast is:

Eq. 1: $$Forecast_{BL} = \sum_{i,j,t} HH_{i,t} \times EUS_{i,j,t} \times UEC_{i,j,t}$$

Where:
$HH_{i,t}$ = the number of households of type i in year t
$EUS_{i,j,t}$ = the saturation of end use type j in household type i in year t
$UEC_{i,j,t}$ = the unit energy consumption of end use j in household type i in year t

- Nonresidential sectors followed an analogous methodology tied directly to Georgia Power's forecast.

[8] This study analyzed the residential, commercial, and industrial sector forecasts, and not Georgia Power's total forecast, which also includes MARTA and territorial wholesale customers.

- The next major task is to create an alternative forecast that characterizes the DSM technical potential, which is accomplished by substituting the most efficient technologies at the end use level. Following the residential example above, the general equation is:

Eq. 2: $$Forecast_{TP} = \sum_{i,j,t} HH_{i,t} \times EUS_{i,j,t} \times UEC_{i,j',t}$$

Where:
$HH_{i,t}$ = the number of households of type *i* in year *t*
$EUS_{i,j,t}$ = the saturation of end use type *j* in household type *i* in year *t*
$UEC_{i,j',t}$ = the unit energy consumption of end use *j′* (the most efficient end use technology configuration) in household type *i* in year *t*

  - The technical potential for DSM is the difference between Equation 1 and Equation 2. Special consideration is required in determining UECi,j′,t to incorporate the interactive effects of appliance and envelope measures. All of the measures (with the exception of mutually exclusive measures) affecting a particular energy end use were bundled together as a package of measures and analyzed in the EnerSim simulation model to determine the aggregate effects of all measures acting simultaneously.

- The next task, creating an alternative forecast of "economic" DSM potential (i.e., considering the most efficient measures that pass the TRC test), is conducted similarly. Again following the residential example, the general equation is:

Eq. 3: $$Forecast_{EP} = \sum_{i,j,t} HH_{i,t} \times EUS_{i,j,t} \times UEC_{i,j'',t}$$

Where:
$HH_{i,t}$ = the number of households of type *i* in year *t*
$EUS_{i,j,t}$ = the saturation of end use type *j* in household type *i* in year *t*
$UEC_{i,j'',t}$ = the unit energy consumption of end use *j″* (the most efficient end use technology configuration *that is also economic*) in household type *i* in year *t*

- Similar to the calculation of technical potential, the economic potential for DSM is the difference between Equation 1 and Equation 3. And again, special consideration is required in determining UECi,j″,t to incorporate the interactive effects of appliance and envelope measures. In considering interactive effects of measures contributing to economic DSM potential, only the TRC-passing measures were bundled together for simulation modeling. In this case, however, measures were sequentially added to the EnerSim analyses up until the point at which the *next* measure's net benefits were no longer cost-effective.

2.2.3 Estimate Theoretically Achievable Impacts

- The estimation of theoretically achievable energy efficiency potential requires estimating, among other parameters, the rate at which cost-effective measures might be adopted over time. Because program implementation scenarios have a direct influence over such market penetration rates, Nexant's approach incorporated sets of market penetration curves corresponding to the following implementation scenarios:[9]

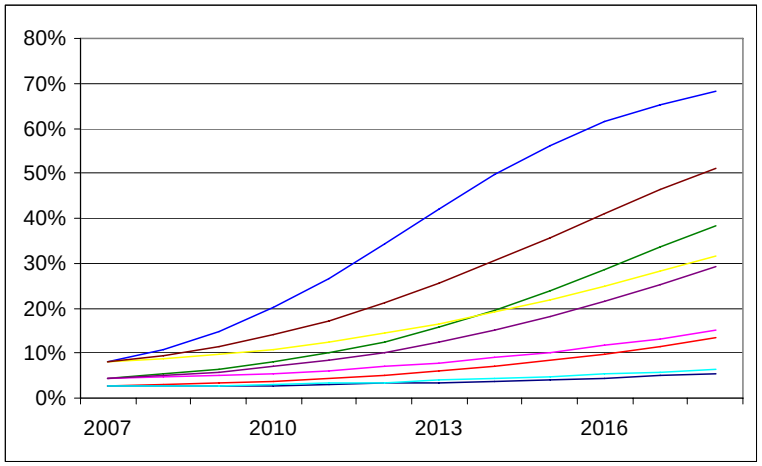
  - "Low" incentives: This scenario assumes market penetration rates projected for financial incentives that subsidize 25% of an energy end-user's incremental measure costs, and a program implementation strategy centered on marketing/outreach tactics.
  - "Moderate" incentives: Market penetration rates are projected for financial incentives that subsidize 50% of an energy end-user's incremental measure costs, and a program implementation strategy that features increased marketing/outreach activities.
  - "Aggressive" incentives: Market penetration rates are projected for financial incentives that subsidize the entire incremental cost of energy efficiency measures, coupled with a program implementation strategy that features much more aggressive marketing, direct outreach, and technical service offerings.

[9] The scenario definitions adopt the nomenclature of the GEFA study to describe varying levels of incentives without consideration of possible connotations of "low," "moderate," and "aggressive" levels of incentives. Each scenario includes significant expenditures on incentives to subsidize the purchase of energy-efficiency measures.

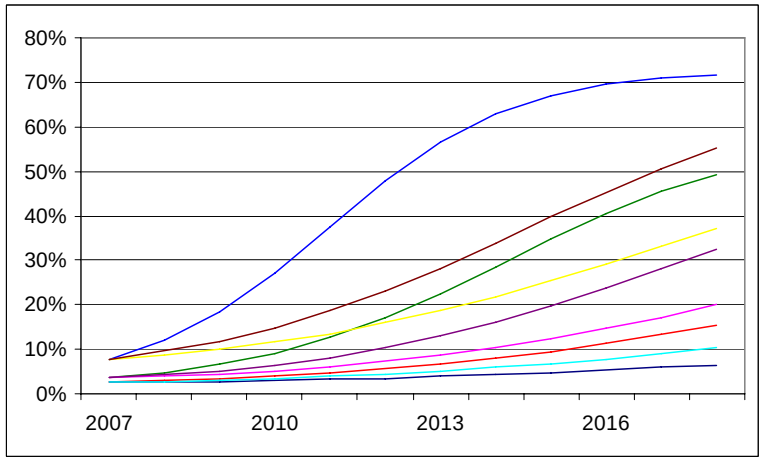
– Figures 11 presents families of market penetration curves utilized in the Nexant analysis. Nexant's market penetration curves differentiate between retrofit opportunities, and market opportunities available when end users are already considering energy technology purchase (e.g., upon natural replacement of equipment that burns out, or in new construction applications). The curves further differentiate penetration rates according to how quickly various technologies are typically adopted into the market.

Figure 11: Market Penetration Curves

11a: Retrofit Opportunities



11:b Turnover/New Construction Opportunities



- For each market segment and end-use combination, Nexant estimated the potential efficiency and costs of future measures serving the same segments and end uses. The measures modeled in the initial year are all available in the marketplace, and costs and impact estimates are relatively well known. Future measures are expected to be available at *approximately* the magnitude of cost and proportionate impacts, but actual impacts and costs

depend on a variety of factors (e.g., new codes and standards, future technology development, commercialization and market acceptance, etc.).

- Administrative costs are estimated as a portion of the overall cost of program implementation (i.e., including incentives). For the low incentive scenario, administrative costs are estimated to have a higher share of overall costs. For the moderate and aggressive incentive scenarios, the administrative costs have a lower share of overall program costs.

- Nexant's approach to estimating achievable potential focused on creating theoretically achievable forecasts of energy consumption, consistent with assumptions embedded in Georgia Power's baseline forecast. To estimate the effects on system supply, Georgia Power modeled the associated capacity effects in PRICEM using 8760 hour load shapes for each end use. By using end use load shapes that are calibrated for diversity among customers, the model calculates avoided electrical supply costs associated with reductions to both energy and peak capacity requirements. Theoretically achievable reductions in peak capacity are an additional model output.

2.2.4 Summarize Estimated Economic Indicators of Theoretically Achievable Energy Efficiency Impacts

- Nexant's economic analyses summarized cost-effectiveness from three perspectives—the Total Resource Cost (TRC), the Ratepayer Impact Measure (RIM), and the Participant Cost Test (PCT) perspectives.

  – The TRC test analyzes cost-effectiveness from a broad societal perspective, which seeks to determine whether the cost of generating and delivering a particular amount of energy is greater or less than the cost of implementing measures or programs to save that amount of energy. Benefits are measured by the avoided costs of utility energy supply (e.g., electrical, gas, and other energy costs, as well as avoided capacity costs). TRC costs include the incremental costs of purchasing, installing, and maintaining energy efficiency measures, plus any administrative costs to implement programs.

- The RIM test analyzes cost-effectiveness from an electricity ratepayer perspective, which seeks to determine whether the effects of energy program implementation would cause electricity rates to go up or go down as compared to a baseline resource plan without the program. Benefits are measured by the avoided costs of electric utility energy supply (e.g., electrical energy costs, as well as avoided capacity costs). RIM costs include any administrative costs to implement programs, plus any direct financial incentives given to customers who implement energy efficiency measures, plus revenues lost as a direct result of the energy efficiency programs.[10]
- The PCT perspective assesses cost-effectiveness to participants, and indicates whether participation in a program would result in net benefits to a customer. Benefits are measured by the reduction in participants' energy costs plus any incentives received to offset energy-efficiency measure costs. Costs include the incremental costs of purchasing, installing, and maintaining energy-efficiency measures.

[10] This study does not estimate RIM benefits and costs from a gas utility perspective. To the extent that gas utility lost revenues exceed avoided gas supply costs, as would normally be expected, gas rates would also be adversely affected and would rise above otherwise anticipated increases.

3 ESTIMATES OF ENERGY EFFICIENCY POTENTIAL

3.1 Introduction and Background

- This section presents estimates of technically feasible and economic potential for energy efficiency savings, followed by estimates of theoretically achievable potential for the period 2007 through 2018.
  - Technical potential and economic potential show the gross potential for energy efficiency savings associated with energy end uses as presently utilized in Georgia Power's service area. Both estimates of savings potential include savings that would occur naturally over time as older devices wear out and are replaced by newer, more efficient, equipment.
  - Nexant's estimates of theoretically achievable energy efficiency savings are net of naturally occurring efficiency improvements, and are consistent with the scenarios described above in Section 2.

3.2 Technical and Economic Potential

- The concepts of technical and economic potential, in use by DSM practitioners since the late 1980s, have often been used to identify the sectors and end uses that appear to be associated with the largest amounts of energy savings potential. The concepts have not been used to represent how much potential *could* be achieved, but simply to focus research efforts on the sectors and end uses that have higher savings potentials.

- To derive estimates of technical and economic potential, technically and economically feasible measures are applied simultaneously to all sectors and end uses. Economically feasible measures are those that have a TRC benefit to cost ratio greater than or equal to 1.0

- Table 7 presents estimates of technically and economically feasible potential.

Table 7: Technically and Economically Feasible Potential (2018)

Load Type	Technical Potential		Economic Potential	
Reduction in Electricity Sales (MWh)	Redacted	31%	Redacted	24%
Reduction in Peak Demand (MW)	Redacted	33%	Redacted	25%

3.2.1 Technically and Economically Feasible Potential by Sector

- Figure 12 and Figure 13 illustrate that the residential and commercial sectors have the largest technically feasible energy savings potential, followed by the industrial sector.
- The majority of technically feasible potential in each sector is also economically feasible.

Figure 12: Technically and Economically Feasible Potential by Sector (Sales)

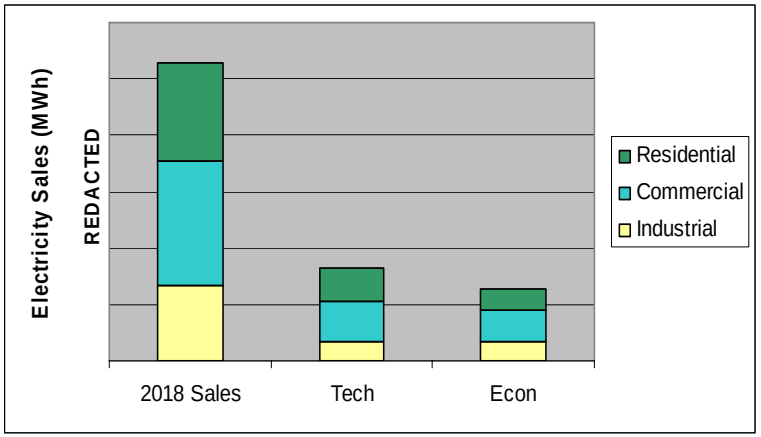
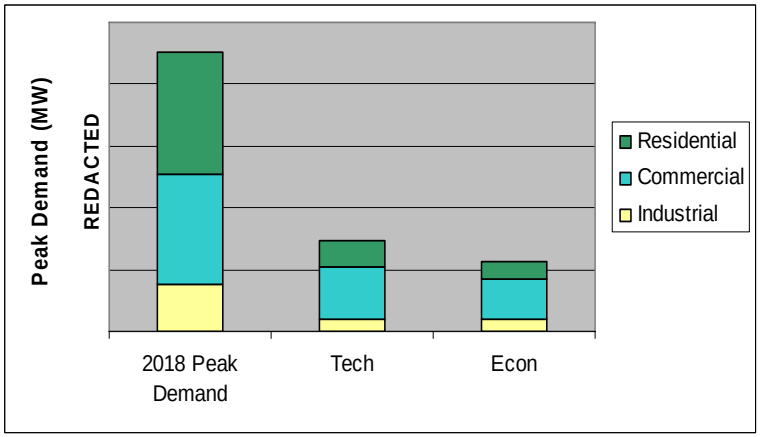


Figure 13: Technically and Economically Feasible Potential by Sector (Peak Demand)



3.3 Theoretically Achievable Potential

- In the context of technically and economically feasible potential savings described above, Table 8 lists theoretically achievable potential (aggressive incentive scenario) in absolute values and in shares of forecast 2018 load.[11]

Table 8: 2018 Theoretically Achievable Potential (Absolute and Percent of 2018 Load)

Load Type	Technical Potential		Economic Potential		Achievable Potential	
Residential						
Reduction in Electricity Sales (MWh)	Redacted	33%	Redacted	22%	Redacted	9%
Reduction in Peak Demand (MW)	Redacted	22%	Redacted	14%	Redacted	6%
Commercial						
Reduction in Electricity Sales (MWh)	Redacted	33%	Redacted	25%	Redacted	11%
Reduction in Peak Demand (MW)	Redacted	49%	Redacted	37%	Redacted	17%
Industrial						
Reduction in Electricity Sales (MWh)	Redacted	26%	Redacted	25%	Redacted	10%
Reduction in Peak Demand (MW)	Redacted	25%	Redacted	25%	Redacted	10%
Total						
Reduction in Electricity Sales (MWh)	Redacted	31%	Redacted	24%	Redacted	10%
Reduction in Peak Demand (MW)	Redacted	33%	Redacted	25%	Redacted	11%

[11] This study analyzed the residential, commercial, and industrial sector forecasts, and not Georgia Power's total forecast, which also includes MARTA and territorial wholesale customers.

- Because long term estimates of energy efficiency savings potential are inherently imprecise, a focus on nearer term estimates is more useful in considering savings that are potentially achievable in the various scenarios. By 2010, Nexant estimates that a range of 1.7% to 6.2% of electricity sales is theoretically achievable, as is a range of 2.0% to 7.3% of peak demand. Table 9 lists estimates of theoretically achievable potential for the year 2010. Figures 14 and 15 illustrate the same information as alternative forecasts.

Table 9: 2010 Theoretically Achievable Potential (Absolute and Percent of 2010 Load)

Load Type	Low Incentive		Moderate Incentive		Aggressive Incentive	
Reduction in Electricity Sales (MWh)	Redacted	1.7%	Redacted	3.3%	Redacted	6.2%
Reduction in Peak Demand (MW)	Redacted	2.0%	Redacted	3.8%	Redacted	7.3%

Figure 14: Theoretically Achievable Potential (Electricity Sales)

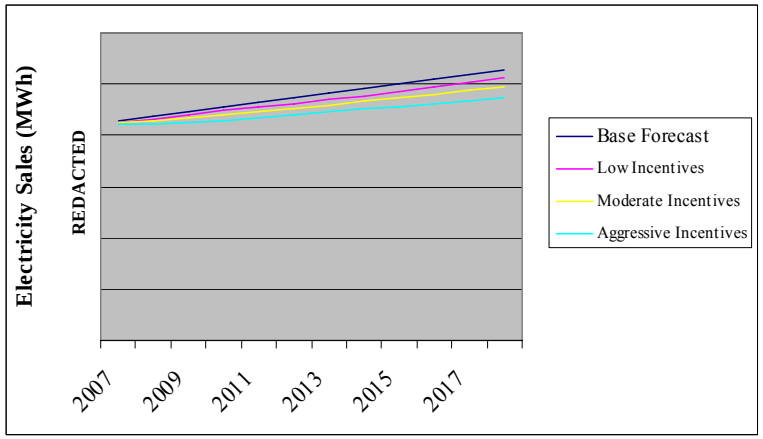
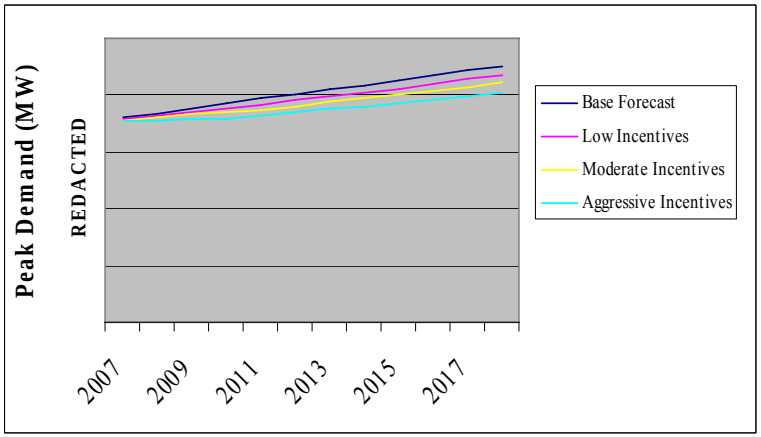


Figure 15: Theoretically Achievable Potential (Peak Demand)



3.3.1 Theoretically Achievable Potential by Sector

- Figure 16 and Figure 17 show the theoretically achievable energy savings potential by sector. The commercial sector accounts for slightly more than half of theoretically achievable energy savings potential, and nearly two-thirds of the peak reduction potential. The residential sector accounts for the majority of the remaining potential for both electricity sales and peak demand reduction.

Figure 16: 2010 Theoretically Achievable Potential by Sector (Electricity Sales)

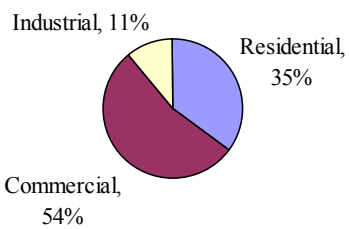
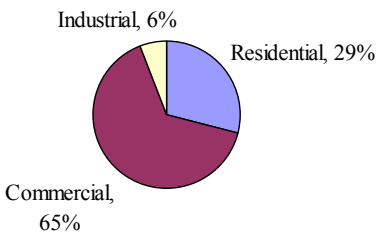


Figure 17: 2010 Theoretically Achievable Potential by Sector (Peak Demand)



3.3.2 Theoretically Achievable Potential by End Use

- A further understanding of theoretically achievable technical potential is aided by consideration of contributing end uses. Figure 18 and Figure 19 illustrate that—in terms of potential savings—the most significant end uses are lighting (more than 30% of potential savings) and space conditioning (more than 20%).

Figure 18: 2010 Theoretically Achievable Potential by Sector and End Use (Electricity Sales)

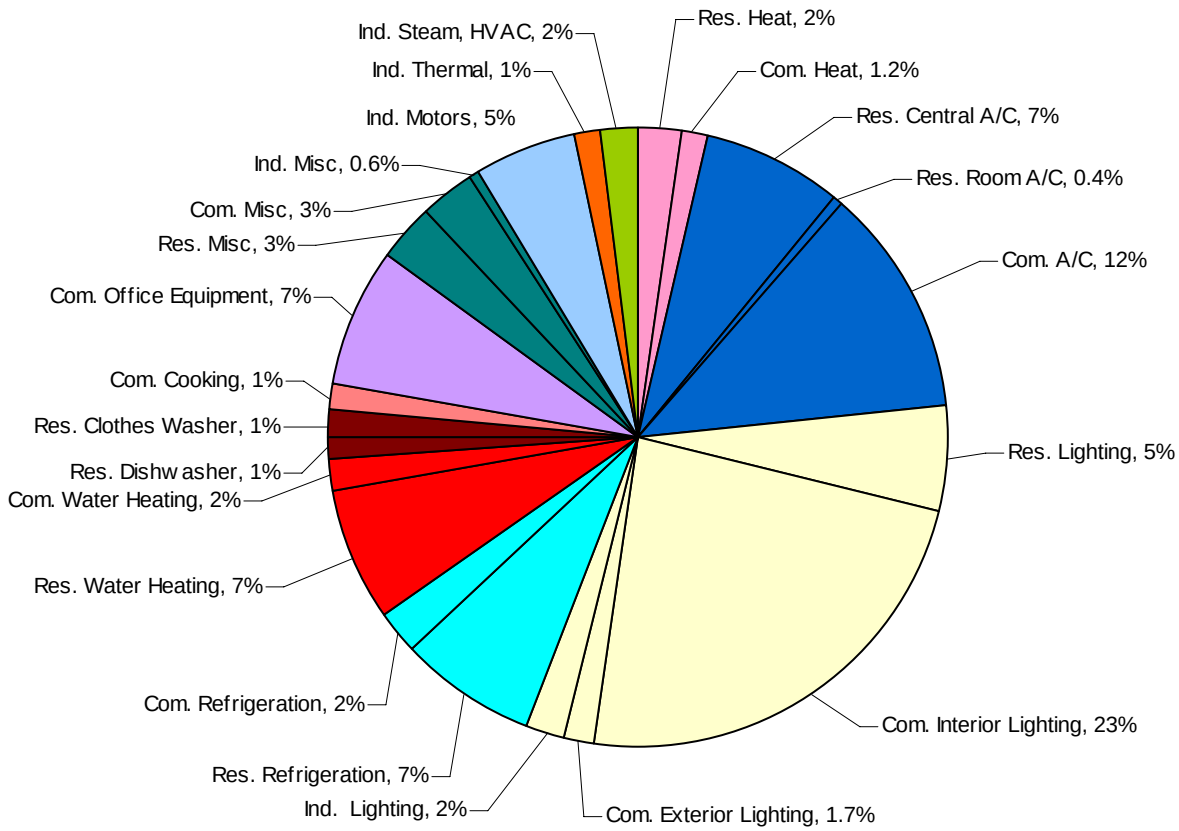
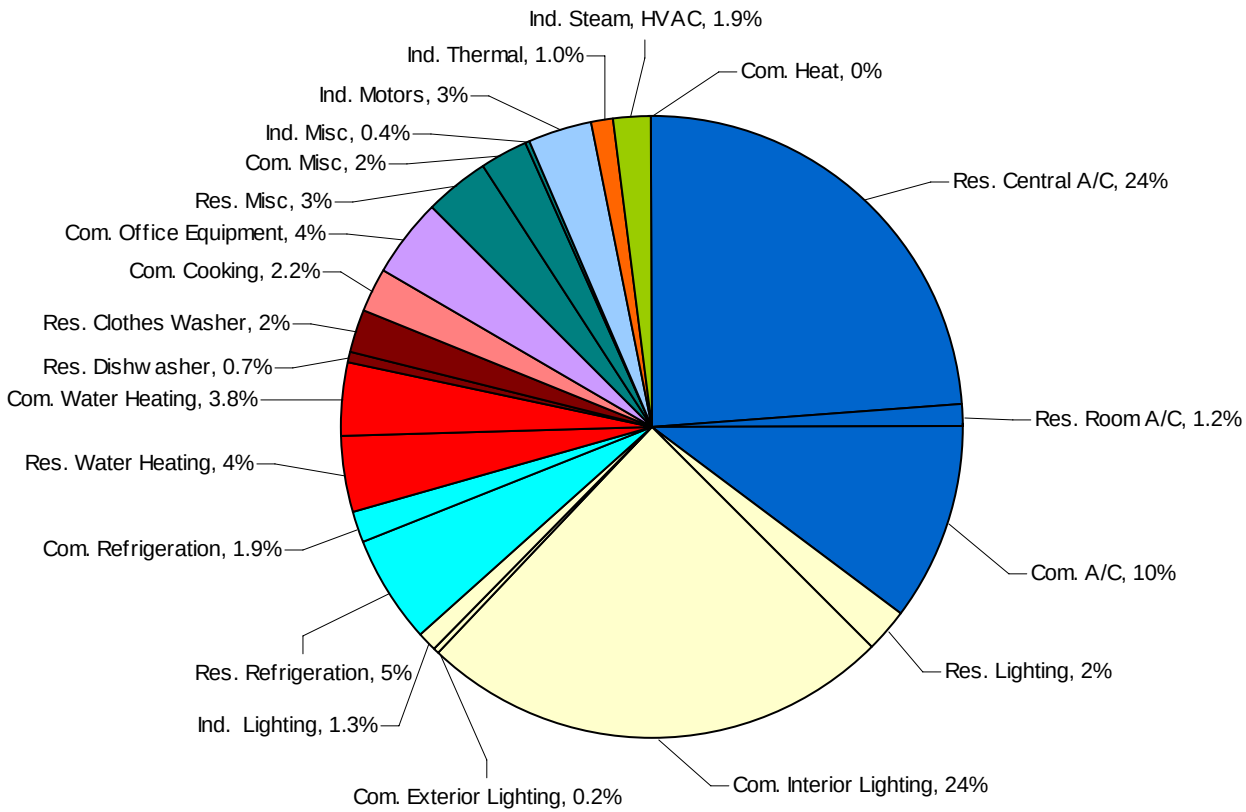


Figure 19: 2010 Theoretically Achievable Potential by Sector and End Use (Peak Demand)



Note: The end-use shares of theoretically achievable potential are based on non-coincident peak demand reductions. The sector totals, as a result, do not necessarily match the sector shares of potential peak demand reduction shown in Figure 19 above.

3.3.3 Cost-Effectiveness of Theoretically Achievable Potential

- The estimated energy savings potential that is theoretically achievable has significant economic benefits to the general economy and many customers served by the Georgia Power Company. The economic benefits, however, would require a significant investment that would come at a cost to all ratepayers.

- Potentially achievable benefits, from programmatic efforts from 2007 through 2018, could range as high as $0.8 billion to $3.1 billion from a Total Resource Cost perspective.[12] Associated costs to electricity ratepayers could range from $1.3 billion to $4.9 billion from the Ratepayer Impact Measure perspective. The RIM net cost indicates the amount that electricity rates would have to increase due to DSM—over and above rate increases that would ordinarily be expected.[13]

- Several types of costs are associated with the scenarios of theoretically achievable potential, including the following:

  - Participant costs—the incremental costs to purchase, install, and maintain energy efficiency measures.
  - Program Incentives—the financial incentives paid by energy efficiency programs to subsidize the purchase of energy efficiency measures
  - Program administration—the administrative, marketing, promotional, and other costs associated with managing programs designed to achieve energy efficiency savings

- Table 10 lists the estimated costs associated with the theoretically achievable scenarios.

[12] *California Standard Practice Manual: Economic Analysis of Demand-Side Program and Projects,* California Public Utilities Commission. San Francisco, CA, October 2001.

[13] This study does not estimate RIM benefits and costs from a gas utility perspective. To the extent that gas utility lost revenues exceed avoided gas supply costs, as would normally be expected, gas rates would also be adversely affected and would rise above otherwise anticipated increases. Estimated net present value data presented in this assessment are for the period from 2007 through 2018.

Table 10: Participant, Program Incentive, and Program Administrative Costs (NPV thousands)

Scenario	Participant Costs	Program Incentives	Program Administration
Low Incentive	$746,750	$186,688	$746,750
Moderate Incentive	$1,396,804	$698,402	$1,047,603
Aggressive Incentive	$2,262,444	$2,262,444	$1,508,296

Total Resource Cost (TRC) Test Perspective

- The Total Resource Cost test considers the costs of an energy efficiency measure or program (incremental measure costs plus program administrative costs) relative to the benefits of avoided energy supply costs.

Ratepayer Impact Measure (RIM) Test Perspective

- The Ratepayer Impact Measure test considers the net impact on utility rates associated with a measure or energy efficiency program. Benefits include avoided energy supply costs. Costs include incentives, program administrative costs, and utility revenues that are lost due to reduced sales and the under-recovery of authorized costs.

Participant Cost Test (PCT) Perspective

- The Participant Cost Test considers the net benefits to customers participating in an energy efficiency program. Benefits include reduced energy costs plus any incentives. Costs include the incremental costs of purchasing, installing, and maintaining energy efficiency measures.

- Figure 20, Figure 21, and Figure 22 show benefits and costs from TRC, RIM, and PCT perspectives of the theoretically achievable scenarios.

Figure 20: TRC Benefits and Costs ($B)

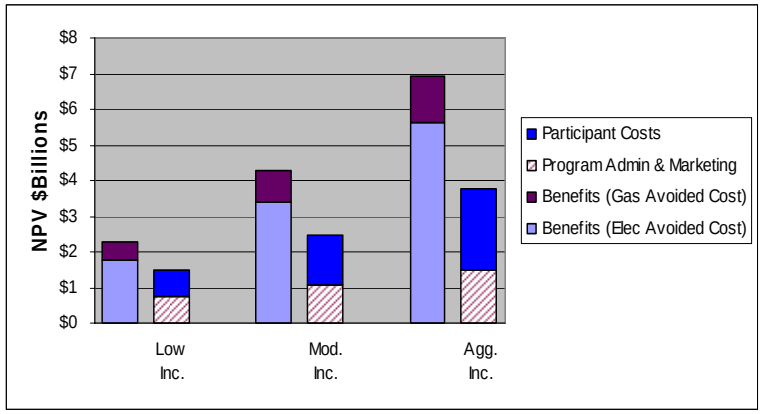
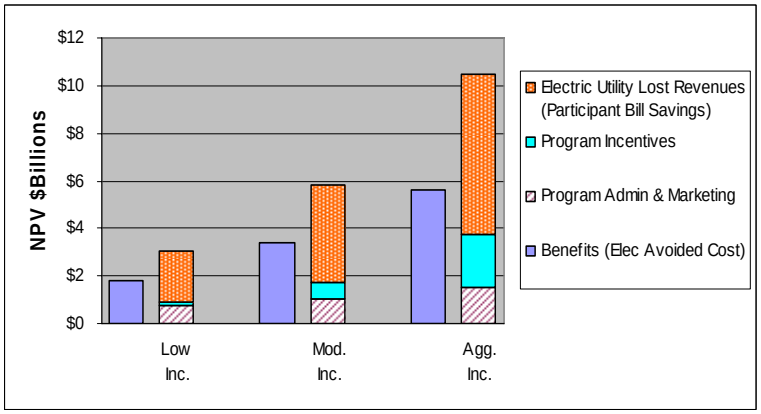
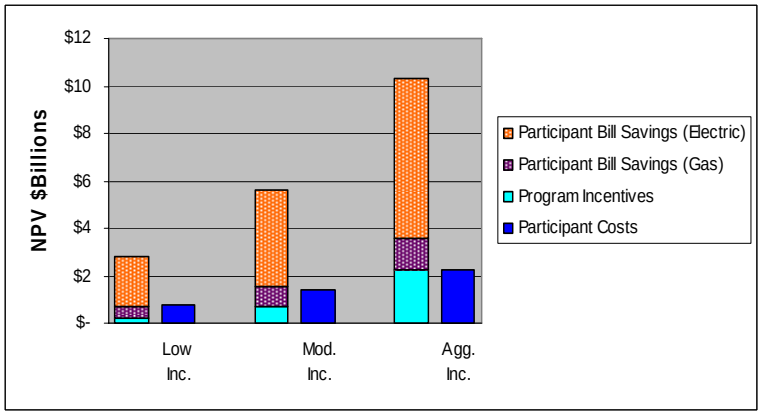


Figure 21: RIM Benefits and Costs ($B)



Note: The above RIM analysis is only for the electric utility and does not include gas utility RIM results.

Figure 22: PCT Benefits and Costs ($B)



- Table 11 lists net economic benefits and benefit-to-cost ratios for each scenario from the TRC, RIM, and PCT perspectives. Table 12 through Table 14 list similar economic indicators by sector and end use for each scenario for the TRC and RIM perspectives.

Table 11: TRC, RIM, and PCT Net Benefits ($B) and Benefit-Cost Ratios

Scenario	TRC		PCT		RIM	
	Net Benefits	BC Ratio	Net Benefits	BC Ratio	Net Benefits	BC Ratio
Low Incentive	$0.8	1.5	$1.6	3.1	-$1.3	0.6
Moderate Incentive	$1.8	1.7	$3.4	3.4	-$2.4	0.6
Aggressive Incentive	$3.1	1.8	$6.7	4.0	-$4.9	0.5

Table 12: TRC and RIM Net Benefits ($MM) and Benefit-Cost Ratios by Sector and End Use (Low Incentive)

Scenario	TRC		RIM	
	Net Benefits	BC Ratio	Net Benefits	BC Ratio
Residential Space Heat	-$18	0.6	-$52	0.4
Residential Central A/C	$237	1.6	-$297	0.4
Residential Room A/C	$2	1.1	-$13	0.4
Residential Lighting	$12	1.3	-$62	0.5
Residential Appliances	-$9	1.0	-$272	0.5
Commercial Heating	$5	1.4	-$24	0.4
Commercial Cooling	$148	1.6	-$194	0.6
Commercial Lighting	$165	2.0	-$64	0.8
Commercial Refrigeration & Cooking	$22	1.7	-$13	0.8
Commercial Office Equipment	$51	2.1	-$140	0.4
Commercial Other	$65	3.7	-$18	0.8
Industrial Process Motors	$68	1.9	-$65	0.7
Industrial Process Thermal	$22	1.3	-$54	0.7
Industrial Other	$8	1.2	-$19	0.8
Total	**$777**	**1.5**	**-$1,286**	**0.6**

Table 13: TRC and RIM Net Benefits ($MM) and Benefit-Cost Ratios by Sector and End Use (Moderate Incentive)

Scenario	TRC		RIM	
	Net Benefits	BC Ratio	Net Benefits	BC Ratio
Residential Space Heat	-$18	0.7	-$83	0.4
Residential Central A/C	$490	1.8	-$523	0.4
Residential Room A/C	$13	1.6	-$19	0.4
Residential Lighting	$48	1.7	-$126	0.5
Residential Appliances	$64	1.2	-$472	0.5
Commercial Heating	$12	1.6	-$44	0.4
Commercial Cooling	$301	1.8	-$362	0.6
Commercial Lighting	$352	2.3	-$118	0.8
Commercial Refrigeration & Cooking	$52	1.9	-$26	0.8
Commercial Office Equipment	$116	2.4	-$279	0.4
Commercial Other	$126	4.6	-$29	0.8
Industrial Process Motors	$155	2.0	-$143	0.7
Industrial Process Thermal	$75	1.4	-$128	0.7
Industrial Other	$27	1.2	-$50	0.7
Total	**$1,813**	**1.7**	**-$2,402**	**0.6**

Table 14: TRC and RIM Net Benefits ($MM) and Benefit-Cost Ratios by Sector and End Use (Aggressive Incentive)

Scenario	TRC		RIM	
	Net Benefits	BC Ratio	Net Benefits	BC Ratio
Residential Space Heat	-$17	0.8	-$130	0.3
Residential Central A/C	$770	1.9	-$1,030	0.3
Residential Room A/C	$13	1.3	-$48	0.3
Residential Lighting	$121	2.0	-$279	0.5
Residential Appliances	$154	1.2	-$989	0.4
Commercial Heating	$16	1.6	-$72	0.4
Commercial Cooling	$505	1.9	-$719	0.6
Commercial Lighting	$659	2.5	-$323	0.8
Commercial Refrigeration & Cooking	$100	2.0	-$72	0.7
Commercial Office Equipment	$223	2.5	-$550	0.4
Commercial Other	$226	5.5	-$59	0.8
Industrial Process Motors	$237	2.1	-$278	0.6
Industrial Process Thermal	$102	1.4	-$247	0.6
Industrial Other	$41	1.3	-$106	0.6
Total	**$3,149**	**1.8**	**-$4,901**	**0.5**

- Table 15 through Table 17 list economic indicators by sector and end use for the PCT perspective, showing the participants' perspective with and without incentives.

Table 15: PCT Net Benefits ($MM) and Benefit-Cost Ratios by Sector and End Use (Low Incentive)

Scenario	PCT (with incentives)		PCT (without incentives)	
	Net Benefits	BC Ratio	Net Benefits	BC Ratio
Residential Space Heat	$34	2.3	$27	2.1
Residential Central A/C	$123	1.7	$76	1.4
Residential Room A/C	$4	1.4	$2	1.2
Residential Lighting	$74	4.5	$69	4.3
Residential Appliances	$252	2.8	$218	2.6
Commercial Heating	$29	6.0	$27	5.7
Commercial Cooling	$290	3.5	$260	3.2
Commercial Lighting	$229	3.8	$208	3.6
Commercial Refrigeration & Cooking	$35	3.1	$31	2.9
Commercial Office Equipment	$191	8.9	$185	8.6
Commercial Other	$81	7.8	$78	7.5
Industrial Process Motors	$133	4.5	$124	4.2
Industrial Process Thermal	$76	2.8	$66	2.6
Industrial Other	$27	2.0	$20	1.8
Total	**$1,577**	**3.1**	**$1,390**	**2.9**

Table 16: PCT Net Benefits ($MM) and Benefit-Cost Ratios by Sector and End Use (Moderate Incentive)

Scenario	PCT (with incentives)		PCT (without incentives)	
	Net Benefits	BC Ratio	Net Benefits	BC Ratio
Residential Space Heat	$65	2.6	$45	2.1
Residential Central A/C	$296	1.9	$129	1.4
Residential Room A/C	$13	2.1	$7	1.6
Residential Lighting	$174	5.5	$155	5.0
Residential Appliances	$516	3.2	$397	2.7
Commercial Heating	$56	6.3	$51	5.8
Commercial Cooling	$569	3.6	$458	3.1
Commercial Lighting	$470	4.1	$394	3.6
Commercial Refrigeration & Cooking	$77	3.4	$61	2.9
Commercial Office Equipment	$395	9.3	$371	8.8
Commercial Other	$153	8.7	$143	8.2
Industrial Process Motors	$299	4.5	$256	4.0
Industrial Process Thermal	$204	3.1	$155	2.6
Industrial Other	$77	2.2	$44	1.7
Total	**$3,364**	**3.4**	**$2,665**	**2.9**

Table 17: PCT Net Benefits ($MM) and Benefit-Cost Ratios by Sector and End Use (Aggressive Incentive)

Scenario	PCT (with incentives)		PCT (without incentives)	
	Net Benefits	BC Ratio	Net Benefits	BC Ratio
Residential Space Heat	$113	3.2	$61	2.2
Residential Central A/C	$703	2.4	$183	1.4
Residential Room A/C	$30	2.2	$5	1.2
Residential Lighting	$400	6.6	$328	5.6
Residential Appliances	$1,109	3.7	$698	2.7
Commercial Heating	$88	6.2	$71	5.2
Commercial Cooling	$1,077	4.1	$725	3.1
Commercial Lighting	$982	4.6	$711	3.6
Commercial Refrigeration & Cooking	$172	3.9	$113	2.9
Commercial Office Equipment	$773	9.9	$686	8.9
Commercial Other	$281	10.2	$250	9.2
Industrial Process Motors	$516	4.8	$381	3.8
Industrial Process Thermal	$349	3.4	$205	2.4
Industrial Other	$147	2.6	$57	1.6
Total	**$6,737**	**4.0**	**$4,474**	**3.0**

3.3.4 Detailed Analysis of Theoretically Achievable Potential

- Congruent with the scope and detail of the 2005 GEFA study, this section presents analytical results of the estimated savings associated with each of the theoretically achievable scenarios.

- Table 18 lists the theoretically achievable potential, in absolute terms and as a share of 2010 load, by sector.

Table 18: Theoretically Achievable Potential Savings by Sector (Absolute and Share of 2010)

Load Type	Low Incentive		Moderate Incentive		Aggressive Incentive	
Residential						
Reduction in Electricity Sales (MWh)	Redacted	1.9%	Redacted	3.5%	Redacted	6.8%
Reduction in Peak Demand (MW)	Redacted	1.3%	Redacted	2.5%	Redacted	4.9%
Commercial						
Reduction in Electricity Sales (MWh)	Redacted	2.2%	Redacted	4.1%	Redacted	8.2%
Reduction in Peak Demand (MW)	Redacted	3.3%	Redacted	6.1%	Redacted	12.3%
Industrial						
Reduction in Electricity Sales (MWh)	Redacted	0.9%	Redacted	1.8%	Redacted	2.5%
Reduction in Peak Demand (MW)	Redacted	0.9%	Redacted	1.8%	Redacted	2.3%
Total						
Reduction in Electricity Sales (MWh)	Redacted	1.7%	Redacted	3.3%	Redacted	6.2%
Reduction in Peak Demand (MW)	Redacted	2.0%	Redacted	3.8%	Redacted	7.3%

Residential Sector—Theoretically Achievable Potential

- For the three scenarios of theoretically achievable savings, the estimated potential for energy efficiency savings in the residential sector ranges from 1.9% to 6.8% of electricity sales, and 1.3% to 4.9% of peak demand by 2010. (See Table 19 below.)

Table 19: Theoretically Achievable Residential Energy Savings (Absolute and Share of 2010 Load)

Load Type	Low Incentive		Moderate Incentive		Aggressive Incentive	
Residential						
Reduction in Electricity Sales (MWh)	Redacted	1.9%	Redacted	3.5%	Redacted	6.8%
Reduction in Peak Demand (MW)	Redacted	1.3%	Redacted	2.5%	Redacted	4.9%

- Figure 23 illustrates scenario residential forecasts net of theoretically achievable energy savings.

Figure 23: Theoretically Achievable Residential Energy and Demand Savings

Figure 23a: Scenario Electricity Sales

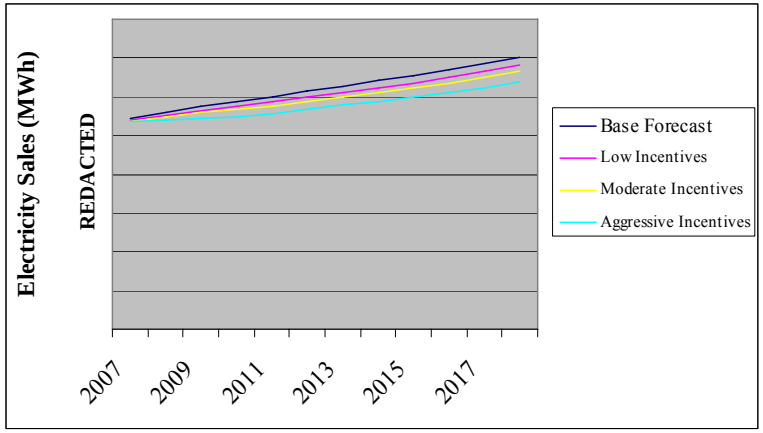
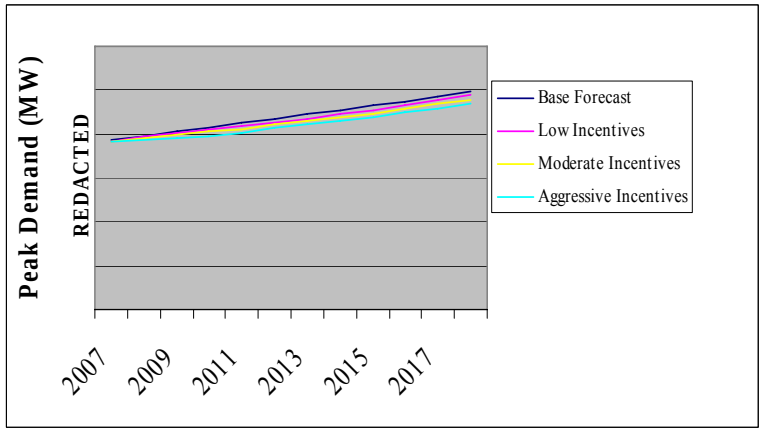


Figure 23b: Scenario Peak Demand



Residential Sector—Theoretically Achievable Potential by End Use

- Figure 24 illustrates theoretically achievable residential energy savings by end use.
- The potential savings of electrical energy are concentrated in four end use categories: air conditioning (22% of potential), refrigerators (20%), water heating (20%), and lighting (16%).
- The potential peak demand savings are much more concentrated in central air conditioning (56% of potential), with lesser amount available from refrigerators (13%) and other end uses. The lower representation of lighting and water heating in potential peak demand savings reflects the fact that usage patterns for these end uses are relatively light during peak demand hours.

Figure 24: 2010 Theoretically Achievable Residential Energy Savings by End Use

Figure 24a: Residential Potential (Electricity Sales)

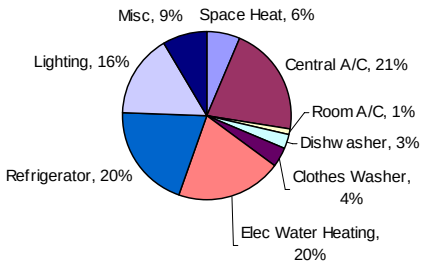
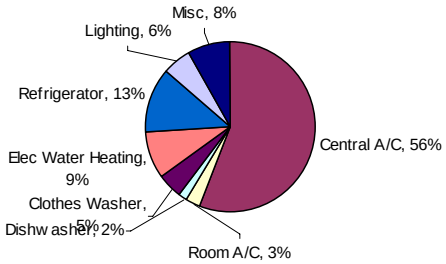


Figure 24b: Residential Potential (Peak Demand)



Residential Sector—Cost-Effectiveness of Theoretically Achievable Potential

- Potentially achievable benefits in the residential sector, from programmatic efforts from 2007 through 2018, could range as high as $0.2 billion to $1.0 billion from a Total Resource Cost perspective. Associated costs to ratepayers could range from $0.7 billion to $2.5 billion from the Ratepayer Impact Measure perspective.

- Table 20 lists the net present value of programs costs associated with the theoretically achievable potential scenarios.

- Table 21 lists the benefits and costs from TRC, RIM, and PCT perspectives of the theoretically achievable scenarios.

- Table 22 through Table 24 lists the benefits and costs from TRC and RIM perspective, by end use, of the scenarios.

- Table 25 through Table 27 lists the benefits and costs from PCT perspective by end use, with and without incentives, illustrating the economic attractiveness of energy efficiency measures even without utility incentives to subsidize initial measure costs.

Table 20: Residential Sector Participant, Program Incentive, and Program Administrative Costs (NPV thousands)

Scenario	Participant Costs	Program Incentives	Program Administration
Low Incentive	$382,443	$95,611	$382,443
Moderate Incentive	$661,231	$330,615	$495,923
Aggressive Incentive	$1,078,637	$1,078,637	$719,091

Table 21: TRC, RIM, and PCT Benefits and Costs of Residential Sector Achievable Scenarios ($B)

Scenario	TRC		PCT		RIM	
	Net Benefits	BC Ratio	Net Benefits	BC Ratio	Net Benefits	BC Ratio
Low Incentive	$0.2	1.3	$0.5	2.3	-$0.7	0.4
Moderate Incentive	$0.6	1.5	$1.1	2.6	-$1.2	0.4
Aggressive Incentive	$1.0	1.6	$2.4	3.2	-$2.5	0.4

Table 22: TRC and RIM Net Benefits ($MM) and Benefit-Cost Ratios for Residential Sector by End Use (Low Incentive)

Scenario	TRC		RIM	
	Net Benefits	BC Ratio	Net Benefits	BC Ratio
Residential Space Heat	-$18	0.6	-$52	0.4
Residential Central A/C	$237	1.6	-$297	0.4
Residential Room A/C	$2	1.1	-$13	0.4
Residential Lighting	$12	1.3	-$62	0.5
Residential Appliances	-$9	1.0	-$272	0.5
Total	**$224**	**1.3**	**-$696**	**0.4**

Table 23: TRC and RIM Net Benefits ($MM) and Benefit-Cost Ratios for Residential Sector by End Use (Moderate Incentive)

Scenario	TRC		RIM	
	Net Benefits	BC Ratio	Net Benefits	BC Ratio
Residential Space Heat	-$18	0.7	-$83	0.4
Residential Central A/C	$490	1.8	-$523	0.4
Residential Room A/C	$13	1.6	-$19	0.4
Residential Lighting	$48	1.7	-$126	0.5
Residential Appliances	$64	1.2	-$472	0.5
Total	**$598**	**1.5**	**-$1,223**	**0.4**

Table 24: TRC and RIM Net Benefits ($MM) and Benefit-Cost Ratios for Residential Sector by End Use (Agg. Incentive)

Scenario	TRC		RIM	
	Net Benefits	BC Ratio	Net Benefits	BC Ratio
Residential Space Heat	-$17	0.8	-$130	0.3
Residential Central A/C	$770	1.9	-$1,030	0.3
Residential Room A/C	$13	1.3	-$48	0.3
Residential Lighting	$121	2.0	-$279	0.5
Residential Appliances	$154	1.2	-$989	0.4
Total	**$1,041**	**1.6**	**-$2,476**	**0.4**

Table 25: PCT Net Benefits ($MM) and Benefit-Cost Ratios for Residential Sector by End Use (Low Incentive)

Scenario	PCT (with incentives)		PCT (without incentives)	
	Net Benefits	BC Ratio	Net Benefits	BC Ratio
Residential Space Heat	$34	2.3	$27	2.1
Residential Central A/C	$123	1.7	$76	1.4
Residential Room A/C	$4	1.4	$2	1.2
Residential Lighting	$74	4.5	$69	4.3
Residential Appliances	$252	2.8	$218	2.6
Total	**$487**	**2.3**	**$391**	**2.0**

Table 26: PCT Net Benefits ($MM) and Benefit-Cost Ratios for Residential Sector by End Use (Moderate Incentive)

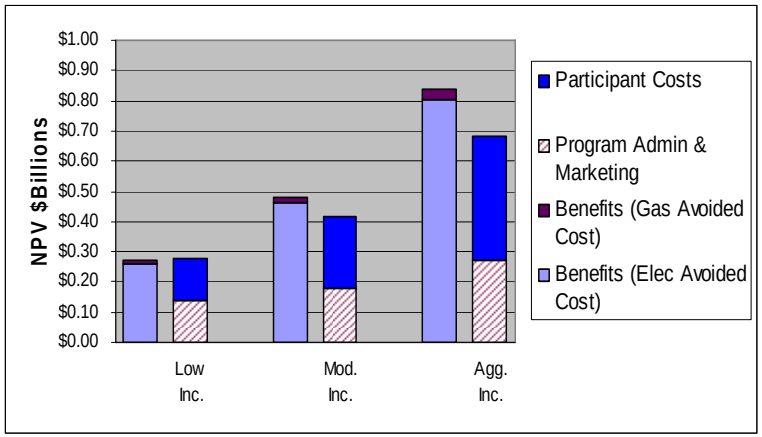
Scenario	PCT (with incentives)		PCT (without incentives)	
	Net Benefits	BC Ratio	Net Benefits	BC Ratio
Residential Space Heat	$65	2.6	$45	2.1
Residential Central A/C	$296	1.9	$129	1.4
Residential Room A/C	$13	2.1	$7	1.6
Residential Lighting	$174	5.5	$155	5.0
Residential Appliances	$516	3.2	$397	2.7
Total	**$1,064**	**2.6**	**$733**	**2.1**

Table 27: PCT Net Benefits ($MM) and Benefit-Cost Ratios for Residential Sector by End Use (Aggressive Incentive)

Scenario	PCT (with incentives)		PCT (without incentives)	
	Net Benefits	BC Ratio	Net Benefits	BC Ratio
Residential Space Heat	$113	3.2	$61	2.2
Residential Central A/C	$703	2.4	$183	1.4
Residential Room A/C	$30	2.2	$5	1.2
Residential Lighting	$400	6.6	$328	5.6
Residential Appliances	$1,109	3.7	$698	2.7
Total	**$2,354**	**3.2**	**$1,275**	**2.2**

- Figure 25 illustrates the breakdown of TRC benefits and costs for residential appliances, including the estimated portion of TRC benefits deriving from avoided gas costs.

Figure 25: TRC Benefits and Costs by Scenario for Residential Appliances



Commercial Sector—Theoretically Achievable Potential

- For the three scenarios of theoretically achievable savings, the estimated potential for energy efficiency savings in the commercial sector ranges from 2.2% to 8.2% of electricity sales, and 3.3% to 12.3% of peak demand by 2010. (See Table 28 below.)

- The commercial sector is analyzed by facility types consistent with Georgia Power Company's forecasting methods. The facility types include: offices, restaurants, retail, grocery, warehouse, education, amusement, healthcare, lodging, public, religious, and miscellaneous.

Table 28: Theoretically Achievable Commercial Energy Savings (Absolute and Share of 2010 Load)

Load Type	Low Incentive		Moderate Incentive		Aggressive Incentive	
Commercial						
Reduction in Electricity Sales (MWh)	Redacted	2.2%	Redacted	4.1%	Redacted	8.2%
Reduction in Peak Demand (MW)	Redacted	3.3%	Redacted	6.1%	Redacted	12.3%

- Figure 26 illustrates scenario commercial forecasts net of theoretically achievable energy savings.

Figure 26: Theoretically Achievable Commercial Energy and Peak Demand Savings

Figure 26a: Scenario Electricity Sales

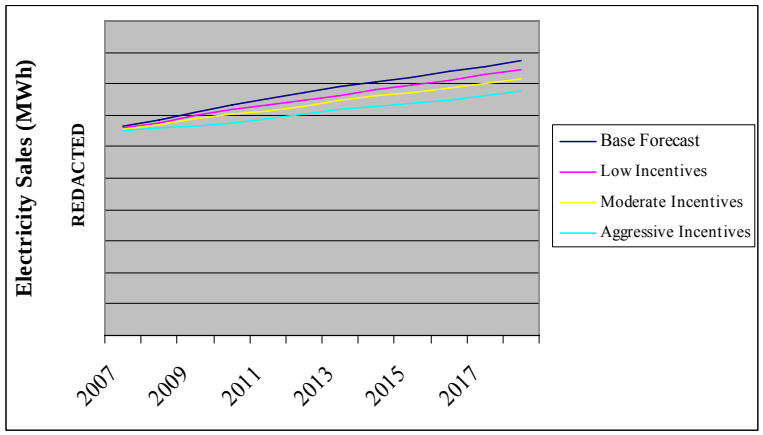
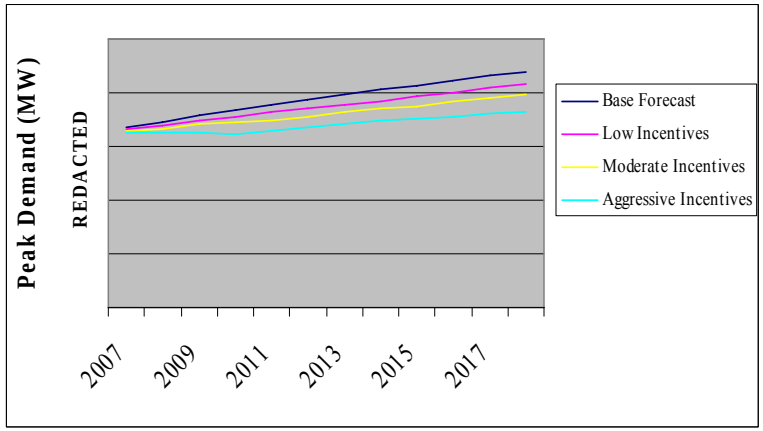


Figure 26b: Scenario Peak Demand



Commercial Sector—Theoretically Achievable Potential by End Use

- Figure 27 and Figure 28 illustrate theoretically achievable commercial energy savings by end use and facility type, respectively.
- Significant end use contributions include: interior lighting (43% of potential), cooling (23%) and office equipment (13%). By facility type, the potential savings of electrical energy is concentrated in offices (31% of potential), followed by retail facilities (15%).

- Similarly, interior lighting (49% of potential), cooling (21%), and office equipment (8%) are the major contributors to estimated achievable potentials. The potential peak demand savings are concentrated in the same facility types—offices (30% of potential), with significant contributing shares from retail facilities (12%), healthcare (11%) and education (11%).

Figure 27: 2010 Theoretically Achievable Commercial Energy and Peak Demand Savings by End Use

Figure 27a: Commercial Potential (Electricity Sales)

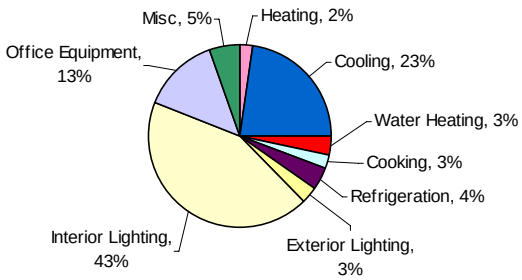


Figure 27b: Commercial Potential (Peak Demand)

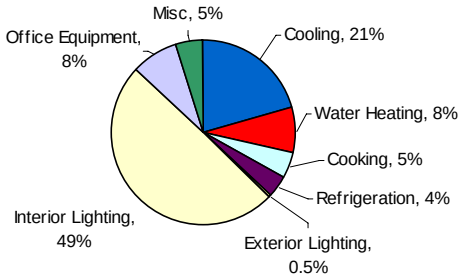


Figure 28: 2010 Theoretically Achievable Commercial Energy and Demand Savings by Facility Type

Figure 28a: Commercial Potential (Electricity Sales)

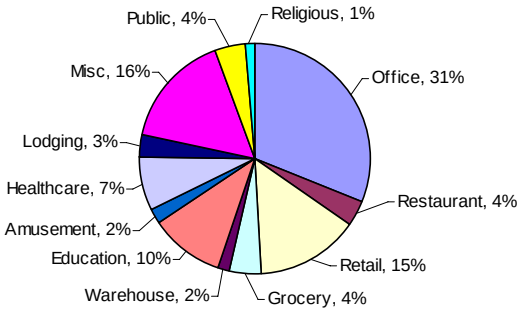
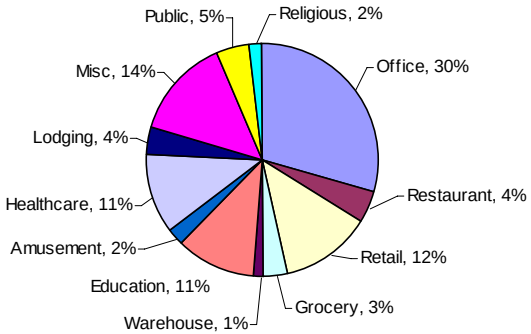


Figure 28b: Commercial Potential (Peak Demand)



Commercial Sector—Cost-Effectiveness of Theoretically Achievable Potential

- Potentially achievable benefits in the commercial sector, from programmatic efforts from 2007 through 2018, could range as high as $0.5 billion to $1.7 billion from a Total Resource Cost perspective. Associated costs to ratepayers could range from $0.5 billion to $1.8 billion from the Ratepayer Impact Measure perspective.

- Table 29 lists the net present value of programs costs associated with the theoretically achievable potential scenarios.

- Table 30 lists the benefits and costs from TRC, RIM, and PCT perspectives of the theoretically achievable scenarios.

- Table 31 through Table 33 lists the benefits and costs from TRC and RIM perspective, by end use, of the scenarios.

- Table 34 through Table 36 lists the benefits and costs from PCT perspective by end use, with and without incentives, illustrating the economic attractiveness of energy efficiency measures even without utility incentives to subsidize initial measure costs.

Table 29: Commercial Sector Participant, Program Incentive, and Program Administrative Costs (NPV thousands)

Scenario	Participant Costs	Program Incentives	Program Administration
Low Incentive	$258,081	$64,520	$258,081
Moderate Incentive	$485,184	$242,592	$363,888
Aggressive Incentive	$815,713	$815,713	$543,809

Table 30: TRC and RIM Benefits and Costs of Commercial Sector Theoretically Achievable Scenarios ($B)

Scenario	TRC		PCT		RIM	
	Net Benefits	BC Ratio	Net Benefits	BC Ratio	Net Benefits	BC Ratio
Low Incentive	$0.4	1.7	$0.8	3.5	-$0.5	0.7
Moderate Incentive	$0.9	1.9	$1.7	3.7	-$0.9	0.7
Aggressive Incentive	$1.3	1.7	$3.4	4.1	-$2.2	0.6

Table 31: TRC and RIM Net Benefits ($MM) and Benefit-Cost Ratios for Commercial Sector by End Use (Low Incentive)

Scenario	TRC		RIM	
	Net Benefits	BC Ratio	Net Benefits	BC Ratio
Commercial Heating	$5	1.4	-$24	0.4
Commercial Cooling	$148	1.6	-$194	0.6
Commercial Lighting	$165	2.0	-$64	0.8
Commercial Refrigeration & Cooking	$22	1.7	-$13	0.8
Commercial Office Equipment	$51	2.1	-$140	0.4
Commercial Other	$65	3.7	-$18	0.8
Total	**$455**	**1.9**	**-$452**	**0.7**

Table 32: TRC and RIM Net Benefits ($MM) and Benefit-Cost Ratios for Commercial Sector by End Use (Moderate Incentive)

Scenario	TRC		RIM	
	Net Benefits	BC Ratio	Net Benefits	BC Ratio
Commercial Heating	$19	2.7	-$38	0.4
Commercial Cooling	$395	2.3	-$280	0.7
Commercial Lighting	$390	2.7	-$80	0.9
Commercial Refrigeration & Cooking	$53	2.0	-$22	0.8
Commercial Office Equipment	-$108	0.6	-$424	0.3
Commercial Other	$130	5.4	-$25	0.9
Total	**$880**	**1.9**	**-$870**	**0.7**

Table 33: TRC and RIM Net Benefits ($MM) & Benefit-Cost Ratios for Commercial Sector by End Use (Aggressive Incentive)

Scenario	TRC		RIM	
	Net Benefits	BC Ratio	Net Benefits	BC Ratio
Commercial Heating	$16	1.6	-$72	0.4
Commercial Cooling	$505	1.9	-$719	0.6
Commercial Lighting	$659	2.5	-$323	0.8
Commercial Refrigeration & Cooking	$100	2.0	-$72	0.7
Commercial Office Equipment	$223	2.5	-$550	0.4
Commercial Other	$226	5.5	-$59	0.8
Total	**$1,729**	**2.3**	**-$1,794**	**0.6**

Table 34: PCT Net Benefits ($MM) and Benefit-Cost Ratios for Commercial Sector by End Use (Low Incentive)

Scenario	PCT (with incentives)		PCT (without incentives)	
	Net Benefits	BC Ratio	Net Benefits	BC Ratio
Commercial Heating	$29	6.0	$27	5.7
Commercial Cooling	$290	3.5	$260	3.2
Commercial Lighting	$229	3.8	$208	3.6
Commercial Refrigeration & Cooking	$35	3.1	$31	2.9
Commercial Office Equipment	$191	8.9	$185	8.6
Commercial Other	$81	7.8	$78	7.5
Total	**$854**	**4.3**	**$790**	**4.1**

Table 35: PCT Net Benefits ($MM) and Benefit-Cost Ratios for Commercial Sector by End Use (Moderate Incentive)

Scenario	PCT (with incentives)		PCT (without incentives)	
	Net Benefits	BC Ratio	Net Benefits	BC Ratio
Commercial Heating	$56	6.3	$51	5.8
Commercial Cooling	$569	3.6	$458	3.1
Commercial Lighting	$470	4.1	$394	3.6
Commercial Refrigeration & Cooking	$77	3.4	$61	2.9
Commercial Office Equipment	$395	9.3	$371	8.8
Commercial Other	$153	8.7	$143	8.2
Total	**$1,720**	**4.5**	**$1,478**	**4.0**

Table 36: PCT Net Benefits ($MM) and Benefit-Cost Ratios for Commercial Sector by End Use (Aggressive Incentive)

Scenario	PCT (with incentives)		PCT (without incentives)	
	Net Benefits	BC Ratio	Net Benefits	BC Ratio
Commercial Heating	$88	6.2	$71	5.2
Commercial Cooling	$1,077	4.1	$725	3.1
Commercial Lighting	$982	4.6	$711	3.6
Commercial Refrigeration & Cooking	$172	3.9	$113	2.9
Commercial Office Equipment	$773	9.9	$686	8.9
Commercial Other	$281	10.2	$250	9.2
Total	**$3,371**	**5.1**	**$2,555**	**4.1**

Industrial Sector—Theoretically Achievable Potential

- For the three scenarios of theoretically achievable savings, the estimated potential for energy efficiency savings in the industrial sector ranges from 0.9% to 2.5% of electricity sales, and 0.9% to 2.3% of peak demand. (See Table 37 below.)

- The industrial sector is analyzed without regard to industry sub-sector (consistent with Georgia Power Company's forecasting methods). Industrial end uses include: motors, thermal processes, other processes, lighting, and other.

Table 37: Theoretically Achievable Industrial Energy Savings (Absolute and Share of 2010 Load)

Load Type	Low Incentive		Moderate Incentive		Aggressive Incentive	
Industrial						
Reduction in Electricity Sales (MWh)	Redacted	0.9%	Redacted	1.8%	Redacted	2.5%
Reduction in Peak Demand (MW)	Redacted	0.9%	Redacted	1.8%	Redacted	2.3%

Industrial Sector—Theoretically Achievable Potential by End Use

- Figure 29 illustrates scenario industrial forecasts net of theoretically achievable energy and peak demand savings.

Figure 29: Theoretically Achievable Industrial Energy and Peak Demand Savings

Figure 29a: Scenario Electricity Sales

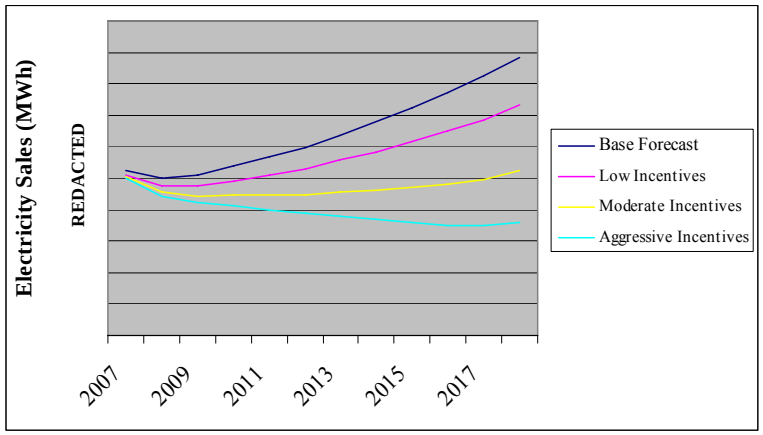
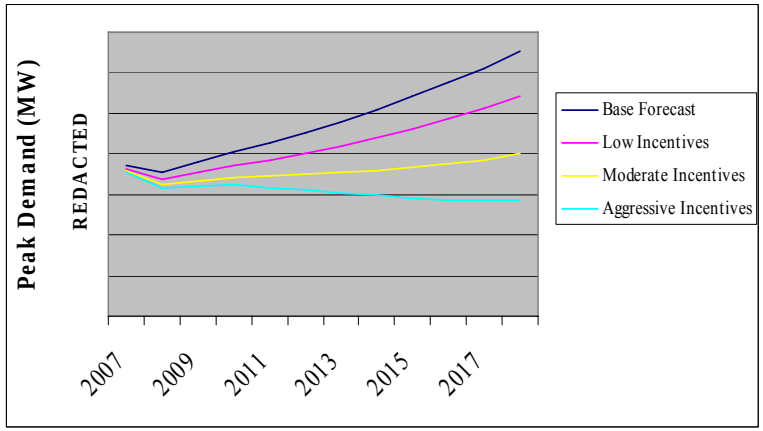


Figure 29b: Scenario Peak Demand



- Figure 30 illustrates theoretically achievable industrial energy savings by end use.
- By end use, the potential savings of electrical energy is concentrated in motor-driven processes (46% of potential), followed by lighting (18%) and other processes (18%).
- The potential peak demand savings are concentrated in the same end uses—motor-driven processes (42% of potential), other processes (24%), and lighting (16%).

Figure 30: 2010 Theoretically Achievable Industrial Energy and Peak Demand Savings by End Use

Figure 30a: Industrial Potential (Electricity Sales)

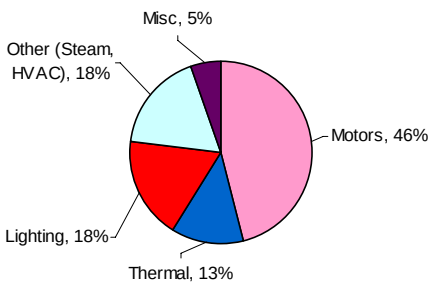
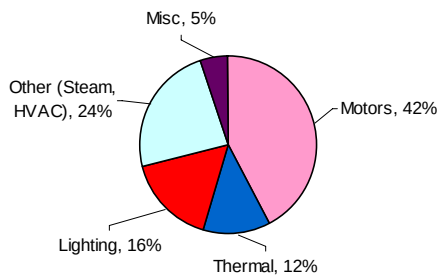


Figure 30b:Industrial Potential (Peak Demand)



Industrial Sector—Cost-Effectiveness of Theoretically Achievable Potential

- Potentially achievable benefits in the industrial sector, from programmatic efforts from 2007 through 2018, could range as high as $0.1 billion to $0.4 billion from a Total Resource Cost perspective. Associated costs to ratepayers could range from $0.1 billion to $0.6 billion from the Ratepayer Impact Measure perspective.

- Table 38 lists the net present value of programs costs associated with the theoretically achievable potential scenarios.

- Table 39 lists the benefits and costs from TRC, RIM, and PCT perspectives of the theoretically achievable scenarios.

- Table 40 through Table 42 lists the benefits and costs from TRC and RIM perspective, by end use, of the scenarios.

- Table 43 through Table 45 lists the benefits and costs from PCT perspective by end use, with and without incentives, illustrating the economic attractiveness of energy efficiency measures even without utility incentives to subsidize initial measure costs.

Table 38: Industrial Sector Participant, Program Incentive, and Program Administrative Costs (NPV thousands)

Scenario	Participant Costs	Program Incentives	Program Administration
Low Incentive	$106,226	$26,557	$106,226
Moderate Incentive	$250,389	$125,194	$187,792
Aggressive Incentive	$368,094	$368,094	$245,396

Table 39: TRC and RIM Benefits and Costs of Industrial Sector Theoretically Achievable Scenarios ($B)

Scenario	TRC		PCT		RIM	
	Net Benefits	BC Ratio	Net Benefits	BC Ratio	Net Benefits	BC Ratio
Low Incentive	$0.1	1.5	$0.2	3.2	-$0.1	0.7
Moderate Incentive	$0.3	1.6	$0.6	3.3	-$0.3	0.7
Aggressive Incentive	$0.4	1.6	$1.0	3.7	-$0.6	0.6

Table 40: TRC and RIM Net Benefits ($MM) and Benefit-Cost Ratios for Industrial Sector by End Use (Low Incentive)

Scenario	TRC		RIM	
	Net Benefits	BC Ratio	Net Benefits	BC Ratio
Industrial Process Motors	$68	1.9	-$65	0.7
Industrial Process Thermal	$22	1.3	-$54	0.7
Industrial Other	$8	1.2	-$19	0.8
Total	**$98**	**1.5**	**-$138**	**0.7**

Table 41: TRC and RIM Net Benefits ($MM) and Benefit-Cost Ratios for Industrial Sector by End Use (Moderate Incentive)

Scenario	TRC		RIM	
	Net Benefits	BC Ratio	Net Benefits	BC Ratio
Industrial Process Motors	$155	2.0	-$143	0.7
Industrial Process Thermal	$75	1.4	-$128	0.7
Industrial Other	$27	1.2	-$50	0.7
Total	**$258**	**1.6**	**-$321**	**0.7**

Table 42: TRC and RIM Net Benefits ($MM) and Benefit-Cost Ratios for Industrial Sector by End Use (Aggressive Incentive)

Scenario	TRC		RIM	
	Net Benefits	BC Ratio	Net Benefits	BC Ratio
Industrial Process Motors	$237	2.1	-$278	0.6
Industrial Process Thermal	$102	1.4	-$247	0.6
Industrial Other	$41	1.3	-$106	0.6
Total	**$380**	**1.6**	**-$631**	**0.6**

Table 43: PCT Net Benefits ($MM) and Benefit-Cost Ratios for Industrial Sector by End Use (Low Incentive)

Scenario	PCT (with incentives)		PCT (without incentives)	
	Net Benefits	BC Ratio	Net Benefits	BC Ratio
Industrial Process Motors	$133	4.5	$124	4.2
Industrial Process Thermal	$76	2.8	$66	2.6
Industrial Other	$27	2.0	$20	1.8
Total	**$236**	**3.2**	**$210**	**3.0**

Table 44: PCT Net Benefits ($MM) and Benefit-Cost Ratios for Industrial Sector by End Use (Moderate Incentive)

Scenario	PCT (with incentives)		PCT (without incentives)	
	Net Benefits	BC Ratio	Net Benefits	BC Ratio
Industrial Process Motors	$299	4.5	$256	4.0
Industrial Process Thermal	$204	3.1	$155	2.6
Industrial Other	$77	2.2	$44	1.7
Total	**$580**	**3.3**	**$454**	**2.8**

Table 45: PCT Net Benefits ($MM) and Benefit-Cost Ratios for Industrial Sector by End Use (Aggressive Incentive)

Scenario	PCT (with incentives)		PCT (without incentives)	
	Net Benefits	BC Ratio	Net Benefits	BC Ratio
Industrial Process Motors	$516	4.8	$381	3.8
Industrial Process Thermal	$349	3.4	$205	2.4
Industrial Other	$147	2.6	$57	1.6
Total	**$1,012**	**3.7**	**$644**	**2.7**

3.4 Conclusions

- An apparently significant potential for increased energy efficiency exists in Georgia, where the economy could benefit from effects associated with reduced energy consumption and peak power requirements.

- Reductions in energy consumption and peak power requirements occur when energy-efficiency measures or actions are implemented by energy customers, who receive economic benefits directly from reductions in their energy bills. Customers could also benefit from any financial incentives that might be offered by programs intended to accelerate markets for the purchase and installation of high-efficiency measures.

- Per directive of the Georgia Public Service Commission, this study adopts the structure of the Georgia Environmental Facilities Authority's similar study, which examined scenarios of theoretically achievable energy efficiency potential associated with "low" incentives, "moderate" incentives, and "aggressive" incentives. Each scenario involves substantial expenditures on incentives, ranging from $29 million per year to more than $510 million per year within the fourth year of program implementation. This study also demonstrates, however, that customers are able to realize substantial benefits from increased energy efficiency even without any financial subsidies.

- Economic benefits to the State's retail energy market resulting from energy efficiency improvements made by customers in Georgia Power's service territory could range to as high as $0.8 billion to $3.1 billion.

- If implemented through electric utility programs, the potential benefits of energy efficiency associated with energy reductions ranging from 1.7 percent to 6.2 percent of forecast sales come at a substantial cost to ratepayers. Net costs to electric utility ratepayers could range to as high as $1.3 billion to $4.9 billion. These costs are over and above the cost associated with meeting these demand needs using supply side options.

Program costs alone could increase rates as much as $0.9 billion to $3.8 billion. This study does not estimate costs to gas utility ratepayers, who could also experience adverse rate impacts.