ENERGY & UTILITIES POLICY COMMITTEE

Thursday, March 11, 2010
8:15AM – 11:00AM
Morris Hall

MEETING PACKET

Larry Cretul
Speaker

Stephen Precourt
Chair

The Florida House of Representatives

General Government Policy Council

Energy & Utilities Policy Committee

Larry Cretul
Speaker

Stephen L. Precourt
Chair

AGENDA

March 11, 2010
8:15 a.m. – 11:00 a.m.
Morris Hall (17 House Office Building)

Opening Remarks by Chair Precourt

Workshop on the following:

PCB EUP 10-03 – Property Assessed Clean Energy

Comments by Commissioner Charles Bronson
Department of Agriculture and Consumer Services

Presentation of the Woody Biomass Economic Study
David Core, Assistant Director, Division of Forestry, Department of Agriculture and Consumer Services

Comments by Representative Ralph Poppell, Chair
Natural Resources Appropriations Committee

Presentation regarding the Forestry Industry and Energy Initiatives at Buckeye Energy Park, Perry, Florida
Clayton W. Bethea, Sustainability Business Manager, Buckeye

Discussion of Pricing for Qualifying Facilities and Renewable Energy Resources
Bob Trapp, Division of Regulatory Analysis, Florida Public Service Commission
Jeffry Pollock, President of J. Pollock, Incorporated representing the Florida Biomass Coalition
Susan Clark, Radey Thomas Yon & Clark

Closing Remarks by Chair Precourt

Adjournment

PCB EUP 10-03

PCB EUP 10-03 SUMMARY
Energy and Wind Damage Resistance Improvements to Real Property

PCB EUP 10-03 relates to financing by local governments for energy efficiency, renewable energy, and wind damage resistance improvements to real property.

The bill creates s. 163.08, F.S., to provide supplemental authority to local governments to finance energy efficiency and renewable energy improvements, and changes or improvements made for the purpose of improving a property's resistance to wind damage for property owners who wish to undertake them. Participation in this financing program is on a voluntary basis.

The bill authorizes local governments to levy non-ad valorem assessments for such improvements, and provides that they may be collected through an assessment, a municipal or county lien, or other lawful method. Local governments may issue debt, payable from the revenues received from the improved property, or any other authorized available revenue source.

The bill authorizes local governments to partner with one or more local governments for the purpose of providing such improvements. A "local government," for purposes of the act, is defined in the bill as "a county, a municipality, or a special district."

Qualified improvements must be affixed to an existing building or facility that is part of the property and must be made by a certified or registered contractor.

The act takes effect on July 1, 1010.

A bill to be entitled

An act relating to energy and wind damage resistance improvements to real property; providing an effective date.

Be It Enacted by the Legislature of the State of Florida:

Section 1. Section 163.08, Florida Statutes, is created to read:

163.08 Supplemental authority regarding improvements to real property.--

(1) Statement of legislative purpose and intent.—

(a) To make energy efficiency and renewable energy improvements, and changes or improvements made for the purpose of improving a property's resistance to wind damage more affordable and assist property owners who wish to undertake them, it is desirable to enable property owners, on a voluntary basis, to finance such improvements with local government assistance.

(b) The Legislature hereby determines that the actions authorized under this act, including the financing therein of qualifying improvements through the execution of financing agreements and the related imposition of voluntary assessments or charges, are reasonable and necessary to serve an important public purpose, and are necessary for the prosperity and welfare of the state and its property owners and inhabitants.

(2) For purposes of this section:

(a) "Local government" means a county, a municipality, or a special district.

(b) "Renewable energy" means electrical, mechanical, or thermal energy produced from a method that uses one or more of the following fuels or energy sources: hydrogen, biomass, as defined in s. 366.91, solar energy, geothermal energy, and wind energy.

(3) A local government may levy a non-ad valorem assessment to fund energy efficiency and renewable energy improvements to residential and nonresidential real property, and changes or improvements made for the purpose of improving a residential or nonresidential real property's resistance to wind damage.

(4) Costs incurred by the local government for such purpose may be collected as a non-ad valorem assessment pursuant to s. 197.3632, a municipal or county lien, or may be collected pursuant to any other lawful method.

(5) Pursuant to this chapter or as otherwise provided by law or pursuant to its home rule power, a local government may partner with one or more local governments for the purpose of providing such improvements.

(6) A local government may issue debt for the purpose of providing such improvements, payable from revenues received from the improved property, or any other available revenue source as authorized by law.

(7) A local government may enter into a financing agreement only with the record owner of the affected property.

(8) Prior to entering into a financing agreement, the local government shall reasonably determine that all property taxes and any other assessments levied on the same bill as property taxes are paid and have not been delinquent for the past three (3) years or the property owner's period of ownership, whichever is less; that there are no involuntary liens such as mechanic's liens on the property; that no notices of default or other evidence of property-based debt delinquency have been recorded during the past three (3) years or the property owner's period of ownership, whichever is less; and that the property owner is then current on all mortgage debt on the property.

(9) Qualifying improvements shall be affixed to an existing building or facility that is part of the property. An agreement between a local government and a qualifying property owner may not cover projects in buildings or facilities under new construction, or construction for which a certificate of occupancy or similar evidence of substantial completion of new construction or improvement has not been issued.

(10) Improvements shall be made by a contractor properly certified or registered pursuant to ch. 489, Part I and Part II, to make the specific energy efficiency, renewable energy, or wind damage resistance improvements, alterations, or installations in the financing agreement. Any work requiring a license under any applicable law shall be performed by an individual holding such license.

(11) No provision in any agreement between a mortgagee or

other lienholder and a property owner or otherwise now or hereafter binding upon a property owner, which allows for acceleration of payment of the mortgage, note or lien or other unilateral modification solely as a result of entering into a financing agreement as provided for in this section, shall be or construed as enforceable.

(12) This section shall be construed to be additional and supplemental to county and municipal home rule authority and not in derogation thereof or a limitation thereon.

Section 2. This act shall take effect July 1, 2010.

Woody Biomass Economic Study

Department of Agriculture and Consumer Services,
Division of Forestry

&

Department of Environmental Protection

Tallahassee, FL
March 01, 2010

Context

- 15.9 million acres of timberland in Florida, with 10.1 million acres in private ownership.

- Wood and wood waste currently contributes 0.6% of the total capacity for electricity generation.

Mandate

- Laws of Florida, Chapter 2008-227, Section 113, pages 125-126 reads: "Woody biomass economic study. – The Department of Agriculture and Consumer Services, in conjunction with the Department of Environmental Protection, shall conduct an economic impact analysis on the effects of granting financial incentives to energy producers who use woody biomass as fuel, including an analysis of effects on wood supply and prices and impacts on current markets and forest sustainability.

Approach

- The University of Florida’s School of Forest Resources and Conservation (SFRC), and Food and Resource Economics Department (FRED) were contracted to complete the needed analysis and prepare two detailed technical reports. These two studies focused on the use of woody biomass fuels for electrical generation and evaluated the potential for Florida’s private timberland contributions to supplying biomass feedstocks under varying scenarios. Renewable electricity generation was used as an example of energy production referenced in the legislation because it is a mature technology with a potential for expansion under enabling legislation.

Definitions (1)

- **Base ORES** – other renewable energy sources (solar, wind, hydropower, and biogenic waste) deployed in Florida to produce electricity at levels currently thought possible by the U.S. Department of Energy, in our reporting 13.5 TWh/yr between 2013 to 2040

- **High ORES** – other renewable energy sources (solar, wind, hydropower, and biogenic waste) deployed in Florida to produce electricity at 2.5 times the levels of base ORES, equal to 33.7 TWh/yr beginning in 2016 until 2040.

Definitions (2)

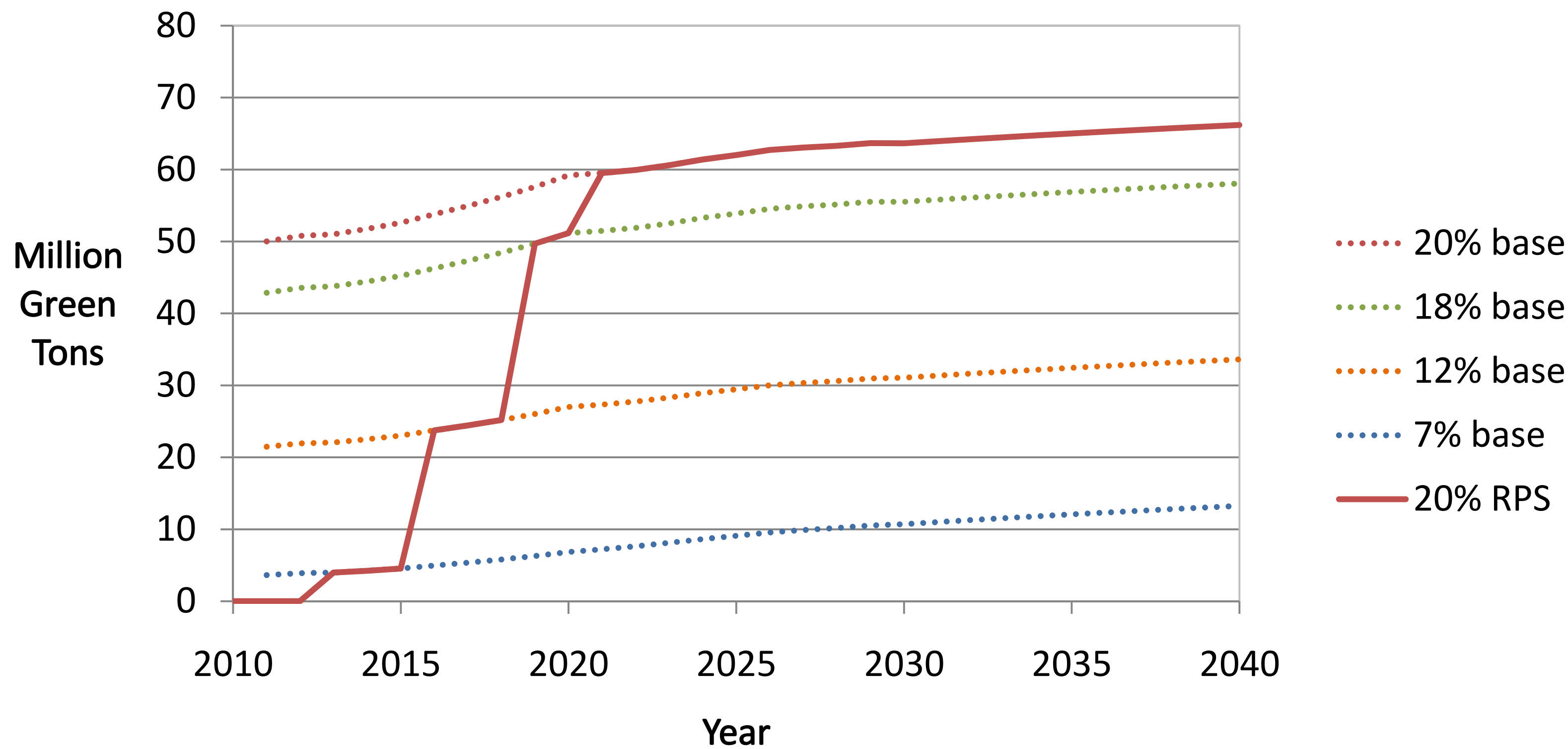
- **Low SREC** – short rotation energy crops (e.g., cottonwood, eucalyptus) planted, by 2033, on 0.6 million acres of non-forested lands in Florida and producing biomass at a rate of 20 green tons per acre per year.

- **High SREC** – short rotation energy crops (e.g., cottonwood, eucalyptus) planted, by 2020, on 1.4 million acres of non-forested lands in Florida and producing biomass at a rate of 32 green tons per acre per year.

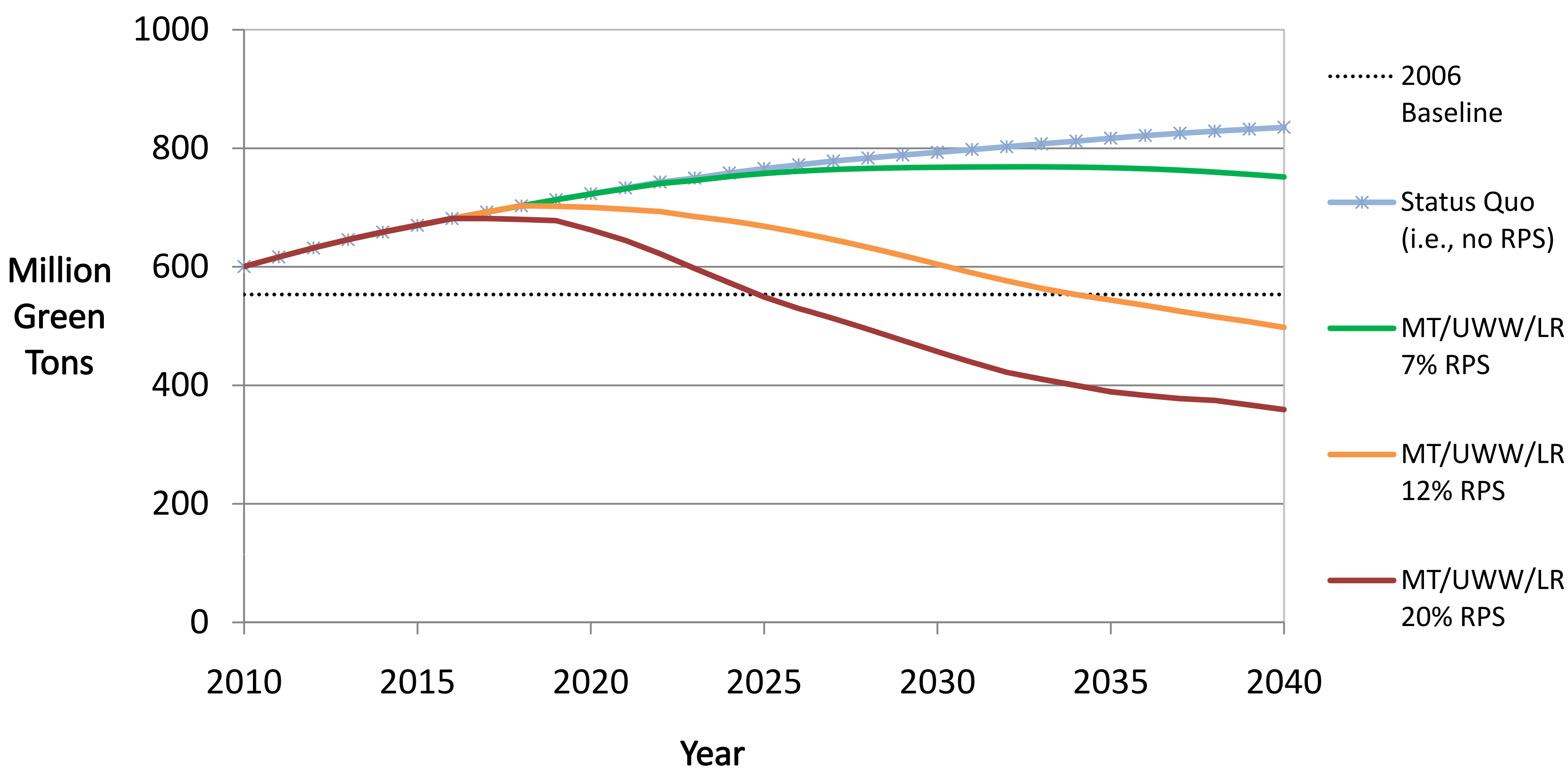
Woody biomass and base other renewable energy sources (ORES) contributions to electricity production in Florida, in the year 2025

	7% RPS		12% RPS		20% RPS	
Woody Biomass	6.3 TWh	2%	20.4 TWh	7%	43.0 TWh	15%
Base other renewable energy sources (ORES)	13.5 TWh	5%	13.5 TWh	5%	13.5 TWh	5%
Total Renewable Electricity	19.8 TWh	7%	33.9 TWh	12%	56.5 TWh	20%
Total Electricity Production	282.5 TWh	100%	282.5 TWh	100%	282.5 TWh	100%

Projected change in demand for woody biomass (merchantable timber, urban wood waste, logging residue, short rotation energy crops) for renewable electricity generation in Florida between 2010 and 2040 under base ORES assumptions. Amounts shown do not include the 20 million tons harvested annually for forest products industry use.



The timber model-generated combined pine and hardwood merchantable timber inventory under varied RPS mandates and <u>base</u> ORES assumptions, 2010 – 2040



Results (1)

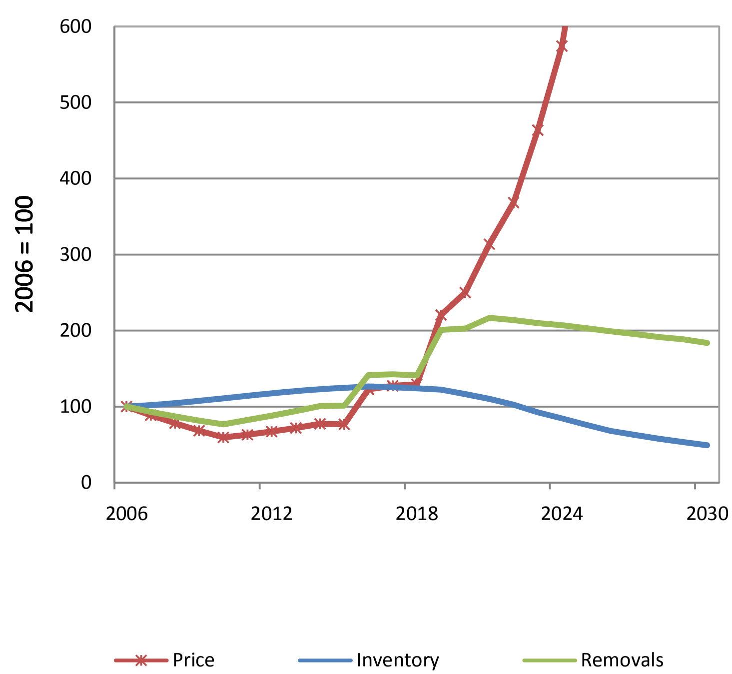
- The economic impact study concluded that tax credits for renewable electricity production, and subsidies for forestry biomass producers would increase the state Gross Domestic Product (GDP), employment and forest sector output while reducing fossil fuel imports, provided feedstock availability can be secured.

Results (2)

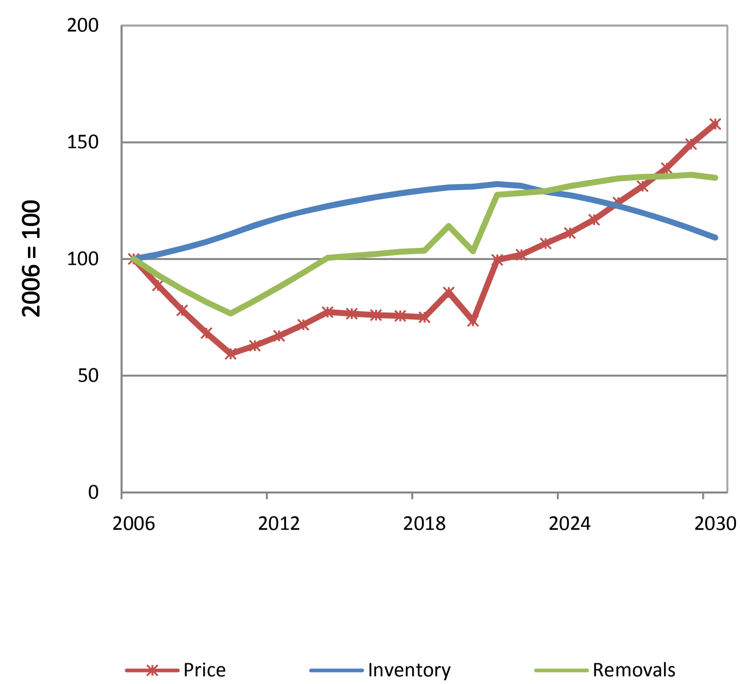
- For a renewable portfolio standard (RPS) <u>greater than</u> 7%, competition for raw material would increase; driving prices up with private timberland owners benefiting.

Effect of short rotation energy crops (SREC) planting on pine roundwood inventory, removals and stumpage prices

0.6 million acres new plantings
Yielding 20 green tons/ac/yr



1.4 million acres new plantings
Yielding 32 green tons/ac/yr



Timber model output for pine roundwood at 20% RPS, <u>base</u> ORES assumptions. Effects of high acreage, high-yielding plantings on the right compared with effects of low acreage, lower yielding plantings on the left

Results (3)

- The study concluded that a 7% RPS (equivalent of 1% to 3% electricity production from wood sources over time) would have little impact to the existing forest products industry and Florida’s forest would remain sustainable, provided merchantable timber (MT), logging residues (LR) and urban wood waste (UWW) were utilized for electricity production, and a strong reforestation program was in place.

Results (4)

- For an RPS <u>greater than</u> 7%, increased reforestation, afforestation and planting of high-yielding short rotation woody crops would be needed to prevent a depletion of forest resources and significant impacts to the existing forest products industry.

Summary

- Currently, harvesting approximately 20 million green tons annually
- 7% RPS would need additional 10 million green tons in 2025, sustainable if MT, UWW, and LR are utilized with a base ORES
- 12% RPS would need an additional 30 million green tons in 2025, sustainable with high SREC and base ORES
- 20% RPS would need an additional 60 million green tons in 2025, to approach sustainability if MT, UWW and LR are utilized with high SREC and base ORES. Alternatively, sustainability can be achieved with 33 million green tons in 2025 if MT, UWW, and LR are utilized with high SREC and high ORES

Woody Biomass Economic Study

Florida Department of Agriculture and Consumer Services, Division of Forestry
Florida Department of Environmental Protection
University of Florida, School of Forest Resources & Conservation
University of Florida, Food & Resource Economics Department

Tallahassee, FL
March 01, 2010

Executive Summary

Florida is made up of nearly 16 million acres of timberland, of which approximately 10 million acres are held by private forest landowners. Over 16 billion dollars of economic return is generated annually by the management and utilization of our state's forest.

In 2008, the Florida Legislature passed legislation requiring the Department of Agriculture and Consumer Services, in conjunction with the Department of Environmental Protection to conduct an economic impact analysis on the effects of granting financial incentives to energy producers who use woody biomass as fuel, including an analysis of the effects on wood supply and prices and impacts on current markets and forest resource sustainability.

The University of Florida's School of Forest Resources and Conservation and the Food and Resource Economics Department were contracted to complete the needed analyses and prepare detailed technical reports. A public forum was held on April 14, 2009, in order to allow conservation groups, forest industry, land managers and other stakeholders to provide input on the methodology for the studies proposed by the UF researchers. These two studies focused on the use of woody biomass fuels for electrical generation and evaluated the potential for Florida's private timberland contributions to supplying biomass feedstocks under varying scenarios. Private lands were chosen due to individual landowners' ability to quickly adapt their management practices to meet market changes.

The study conducted by the UF Food and Resource Economics Department (FRED) analyzed the economic impacts in the state from expanded use of woody biomass as a feedstock for energy production under selected policies and incentives. This study concluded that financial incentives such as renewable energy production tax credits and subsidies for forestry biomass producers would increase state GDP, employment and forest sector output while reducing fossil fuel imports, provided feedstock availability can be secured. The existing wood products manufacturing sector would face higher competition for timber products resulting in higher prices for raw material, while timberland owners would benefit from higher timber prices.

The study conducted by the UF School of Forest Resources and Conservation (SFRC) utilized the Sub-regional Timber Supply (SRTS) model to analyze woody biomass demand, supply and timber prices resulting from implementation of a hypothetical renewable portfolio standard (RPS) in Florida. Currently in Florida, electricity generation from wood and wood waste contributes 0.6% of total capacity. To sustainably achieve 1% to 3% of electricity production from wood sources, logging residues and urban wood waste have to be utilized in addition to merchantable timber along with an enhanced reforestation program. Reforestation must at least keep pace with forest harvest removals. Beyond 3% of electricity generation from wood sources, short rotation energy crops need to make up a larger share of the fuel mix in addition to all other feedstock sources mentioned above. The study concluded that a 7% RPS (equivalent of 1% to 3% electricity production from wood sources over time) would have little impact to the existing forest products industry and Florida's forest would remain sustainable.

Therefore, it appears that a 7% RPS as modeled in the SFRC study would be both feasible without much disruption of timber supply to existing forest products industry, and economically beneficial to the economy of the state, and especially to timber producers and forestry in general. A modest mandate of this kind would facilitate increases in stumpage timber prices landowners receive for their products and increase chances of keeping "forests in forest". Any clean portfolio standard or RPS mandate should also incentivize tree planting including short rotation energy crops establishment on acreage proportional to the magnitude of the mandate. With increased reforestation, afforestation and planting of high-yielding short rotation woody crops on up to 15% of non-forested lands, a 12% and higher RPS could be achieved without depletion of the forest resources of the state, or significant impacts to the existing forest industries.

Introduction

The current report was mandated by the 2008 legislature in House Bill 7135 and signed into law by Governor Crist (Laws of Florida, Chapter 2008-227, Section 113, pages 125-126). The relevant excerpt of the law reads: "Woody biomass economic study. – The Department of Agriculture and Consumer Services, in conjunction with the Department of Environmental Protection, shall conduct an economic impact analysis on the effects of granting financial incentives to energy producers who use woody biomass as fuel, including an analysis of effects on wood supply and prices and impacts on current markets and forest sustainability. The departments shall prepare and submit a report on the results of the analysis to the Governor, the President of the Senate, and the Speaker of the House of Representatives no later than March 1, 2010."

The Florida Division of Forestry (DOF) was designated within the Florida Department of Agriculture and Consumer Services (DACS) as the lead agency for this report. This report focuses on the forest resources of the state, current forest products use, and how granting of financial incentives to energy producers may affect Florida's forest resources and forest industries. The DOF contracted with two teams of researchers at the University of Florida (UF), one at the Food and Resource Economics Department (FRED), and the other at the School of Forest Resources and Conservation (SFRC) to conduct the needed analyses. A public meeting was held in Tallahassee on April 14, 2009, during which forestland owners, forest products industry representatives, conservation organizations, other stakeholders and the public had an opportunity to provide input on the methodology for the studies proposed by the UF researchers. Further stakeholder input was received via a dedicated website between April 15 and May 15, 2009. This report summarizes results of the two technical reports (Hodges et al 2010, and Rossi et al 2010) prepared at the University of Florida at our request. The readers interested in background details, in depth methodology, and results are encouraged to visit www.fl-dof.com where the two technical reports are posted.

Florida has abundant forest resources which are predominantly in private ownership. As of 2007, forests covered 49% of Florida, or 16.9 million acres. Ninety-four percent of that area, or 15.9 million acres is considered available for timber production and classified as timberland. The remainder is largely reserved (e.g., parks and preserves) or unproductive. Softwood forest types occupy 46% of Florida's timberlands, while hardwoods comprise 51%, and non-stocked areas make up the remaining 3%. The longleaf-slash pine forest-type group predominates with 5.6 million acres, or 35% of the timberland. The oak-gum-cypress type group is second in abundance with nearly 3.1 million acres or 19% of the timberland. Non-industrial private forest (NIPF) owners control 63%, or 10.1 million acres, public ownerships are 28%, or nearly 4.5 million acres, while forest products industry ownership is 9% or 1.4 million acres of timberland according to 2007 data. The NIPF ownership is almost equally split between family-owned forests (4.8 million acres) and corporate ownership (5.0 million acres). The NIPF corporate ownership is comprised mainly of Timber Investment Management Organizations (TIMOs) and Real Estate Investments Trusts (REITs).

Florida has thriving forestry and forest products industry sectors with considerable contributions to the state's economy. There are 77 sawmills, pulpwood mills and other primary wood-processing plants operating in the state. The forest products industry uses approximately 20 million green tons of merchantable timber annually. Production of that timber has more than doubled in Florida within the last 60 years, growing from 218 million cubic feet in 1948 to 491 million cubic feet in 2007. Pulpwood, saw logs, veneer logs, composite boards, posts, pilings, and more recently wood pellets are the primary wood products in Florida. The forestry and forest products industry are leading economic sectors in many rural counties in the northern part of the state. Revenue from forestry and related activities is the largest, while the total value added is second only to environmental horticulture among seven leading agricultural industries in Florida. The forestry, wood and paper products industry in Florida has an annual economic impact of $16.7 billion and employs 89,000 persons.

While the legislation referenced the impact of financial incentives to energy producers, such incentives can take various forms, all of which would arguably increase the demand for woody biomass. For purposes of this report, state and federal renewable electricity production tax credits, and the federal biomass crop assistance program (BCAP) were considered in the context of a hypothetical Renewable Portfolio Standard (RPS) for electricity production in Florida. The objective of the report was to answer two questions: (1) what level of biomass utilization for power generation is sustainable in Florida, and (2) what effects do financial incentives to energy producers who use woody biomass as fuel have on the Florida economy, forestry and the existing forest products industry.

In 2007, Florida had 1,048 MW of renewable electricity generation capacity, which was 1.9% of the total, wood and wood waste contributed 354 MW, or 0.6% to that capacity (USDOE 2009b). If a 7% RPS was adopted in Florida today, woody biomass would need to contribute between 1% and 3% of total electricity consumption, for a 12% RPS that share would grow to between 6% and 8%, while for a 20% RPS woody biomass would need to contribute from 14% to 16% of total electricity consumption for the period beginning in 2013 until 2040 (Table 1). However, to sustainably achieve 1% to 3% levels of electricity production from wood sources, logging residues and urban wood waste have to also be utilized in addition to merchantable timber, and reforestation has to keep pace with harvest removals. Beyond 3% of electricity generation from wood sources, short rotation energy crops (SREC) need to fulfill an increasingly larger share of the fuel mix beside all other feedstock sources mentioned above, as described in this report.

Table 1. Woody biomass and base other renewable energy sources (ORES) contributions to electricity production in Florida under a hypothetical 7%, 12% or 20% renewable portfolio standard (RPS) in 2025.

	7% RPS		**12% RPS**		**20% RPS**	
Woody Biomass contribution	6.3 TWh	2%	20.4 TWh	7%	43.0 TWh	15%
ORES contribution	13.5 TWh	5%	13.5 TWh	5%	13.5 TWh	5%
Total renewable electricity	19.8 TWh	7%	33.9 TWh	12%	56.5 TWh	20%
Total electricity production	282.5 TWh	100%	282.5 TWh	100%	282.5 TWh	100%

The amount of woody biomass needed to produce renewable electricity in Florida increases with time due to the projected increases in demand for electricity (Figure 1). Florida currently harvests approximately 20 million green tons of merchantable timber annually. By 2025, a 2% contribution from wood to electricity generation would require an additional 10 million green tons, a 7% contribution would require an additional 30 million green tons, while a 15% contribution would require an additional 60 million green tons of woody biomass beyond what the current forest products industry may need. Assuming current harvest levels for traditional wood products remain the same, such changes would require anywhere from 1.5 to more than four-fold increase in wood output by forestry and allied activities. The four-fold increase would require landscape-scale adjustments in timber and other woody biomass production methods, high and sustained reforestation and afforestation, and infrastructure changes to plant, grow, harvest and transport short rotation woody crops on up to 1.4 million acres of currently non-forested lands.

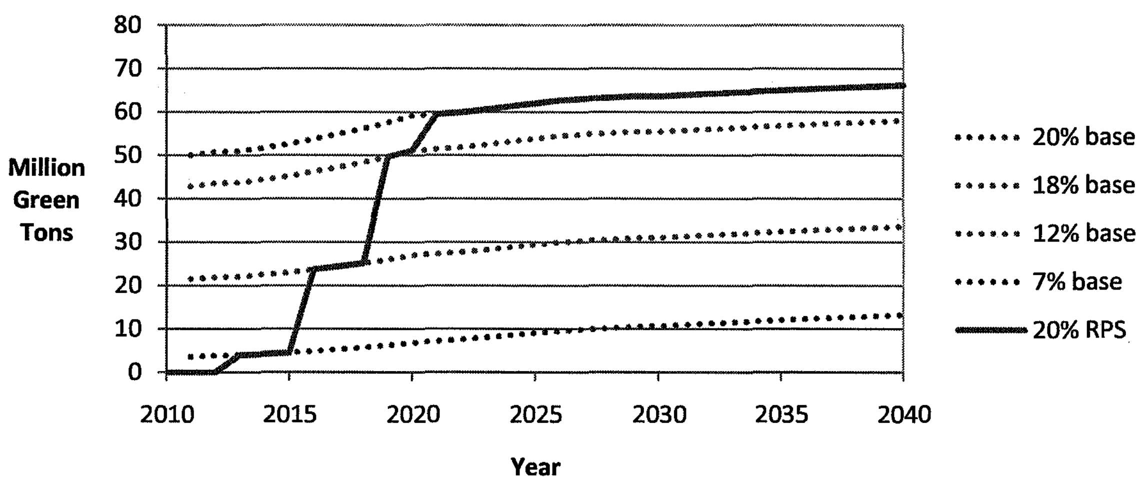


Figure 1. Projected change in demand for woody biomass above 2007 harvest levels of 20 million green tons resulting from a theoretical 20% renewable portfolio standard (solid line), assuming "base" other renewable energy sources (ORES) projection and a step-wise portfolio adoption. Also shown projected amount of woody biomass needed for a hypothetical 7%, 12% or 18% RPS with base ORES assumptions.

The subsequent two chapters of this report summarize the University of Florida's FRED report by Hodges et al 2010, and SFRC report by Rossi et al 2010. The FRED report describes economic impacts which may result from increased wood utilization for renewable electricity production. However, that report did not look at the availability of the woody biomass feedstocks. This task was accomplished by SFRC researchers who modeled woody biomass demand, supply and timber prices scenarios resulting from increased wood utilization for electricity production in Florida as exemplified by a hypothetical adoption of 7%, 12%, or 20% RPS in Florida. The DOF in conjunction with the Department of Environmental Protection (DEP) prepared this final report for the Florida Governor, the President of the Senate, and the Speaker of the House of Representatives, as requested.

University of Florida FRED Report Methods and Findings

Introduction

This study evaluated the economic impacts in the state of Florida from expanded use of woody biomass as feedstock for energy production under selected policies and incentives, as mandated by the Florida legislature in 2008 (HB 7135). The study focused on use of woody biomass fuels for electric power generation, since this is a mature technology with a potential for some expansion under enabling legislation. The models used in this study represent a "snapshot" in time, and do not incorporate a time dimension. However, it is assumed that the estimated economic impacts would occur within a relatively short period of a year or less.

Methods

The analysis was conducted using Input-Output analysis and Social Accounting Matrices (I-O/SAM) for Florida, together with a Computable General Equilibrium (CGE) model of the state's economy. The *Impact Analysis for Planning* (IMPLAN) Professional software and associated databases (Minnesota IMPLAN Group 2007) provided regional information on industry output, value added, employment, personal income, commodity supply and demand, state-local and federal government taxes and spending, capital investment, business inventories, and domestic and foreign trade. The I-O/SAM model was used to generate a snapshot of the Florida economy that served as the starting point for implementation of the CGE model, which finds a solution where all markets are in equilibrium, i.e. supply equals demand. The model was customized to reflect the makeup of the forestry sector (timber production, logging and support services), wood products manufacturing (sawmills, pulp and paper, etc.), and use of biomass fuels as a substitute to fossil fuels (coal, natural gas, oil) for electric power generation. It was assumed that biomass fuels could be provided from domestic and international imports as well as Florida resources, since commodity trade is a feature of the CGE model. Forestry sector production is assumed to include sources such as merchantable timber resources, logging residues, urban wood waste as well as short rotation energy crops.

The impact of increasing biomass fuel supply for electric power generation was simulated over a range of 1 to 80 million green tons annually, at an average composite delivered price of $30 per ton. The upper end of this range represents approximately 26% of current electricity production in Florida, and about 21% of projected generation in the year 2025. These levels can be related to a "clean portfolio standard" considered by the legislature, which would mandate a certain minimum percentage of clean and/or renewable electric power generation sold to final consumers by a given date. Simulations were also conducted to test the effect of a $0.010 to $0.011 per kilowatt-hour state or federal renewable electricity production tax credit, and a 100 percent federal subsidy for biomass fuel producers under the *Biomass Crop Assistance Program* (BCAP). Assumptions about mobility of capital to meet changes in industry output and intermediate commodity demand were tested with different model settings. It may be expected that the results for the mobile capital scenario would hold in the long run, say 10 years or more, while fixed capital would prevail in the short run, subject to limitations on capital movement, especially for highly fixed assets such as forest inventories.

Projected electric power generation in Florida was taken from USDOE Annual Energy Outlook (2009a). The share of generation from conventional efficiency represents 25% thermal efficiency for conversion from wood fuel to electricity with typical stoker-grate furnace technology; high efficiency represents 35% thermal efficiency for advanced gasification combined-cycle technology (Figure 2).

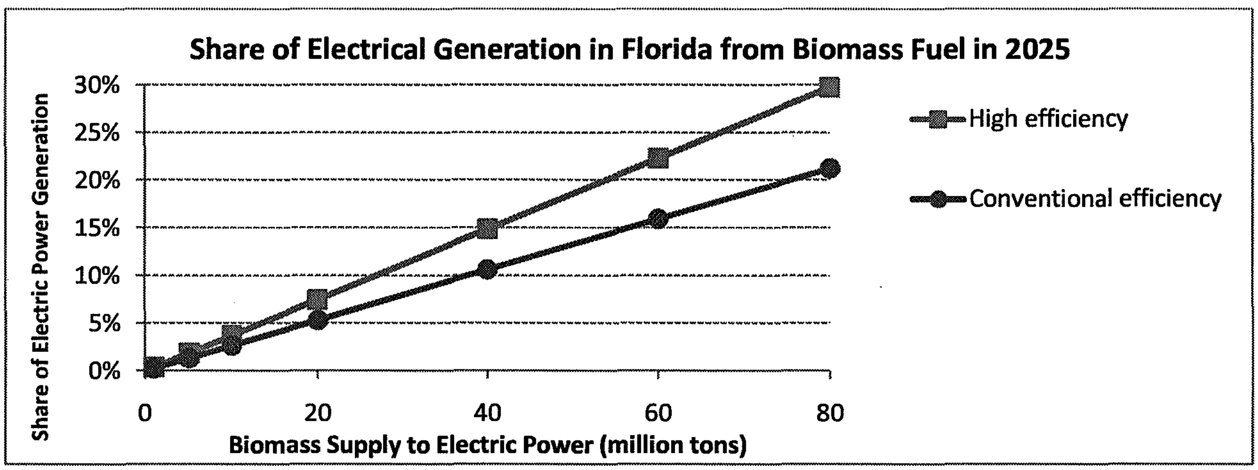


Figure 2. Share of electrical power generation in Florida from biomass fuels under conventional (25%) and high (35%) thermal efficiencies at different levels of biomass supply to power plants in 2025.

Economic Impact Results

It was estimated that increasing biomass use for electric power generation would bring about a relatively small increase in Gross Domestic Product (GDP) of Florida (Figure 3), overall employment, and state government revenues, while modestly decreasing imports of fossil fuels. At the biomass supply level of 40 million tons, with capital assumed to be mobile, GDP would increase by 0.32% above the base level, representing $2.2 billion. Output or sales of the forestry sector would be increased dramatically, about

69% above current levels, to meet new demand for woody biomass fuels. Output of the electric power sector would decrease by up to 0.33% as a result of marginally higher costs for biomass fuels. Under the fixed capital scenario, output of the forest products manufacturing sector would decrease by 6.7% due to competition for the forest resources, and prices for forest commodities may increase by up to 18% in the short run due to competition, but would likely be much lower in the long run as capital resources are reallocated to biofuel production. The relatively modest effects on forest commodity prices observed in the fixed capital CGE analysis, even in the face of a threefold increase in demand, may be attributed to the moderating effect of increased imports, substitution effects, the diverse mix of different biomass resources available, and the fact that commercial timber production in the CGE model represents less than 25% of the total forestry sector.

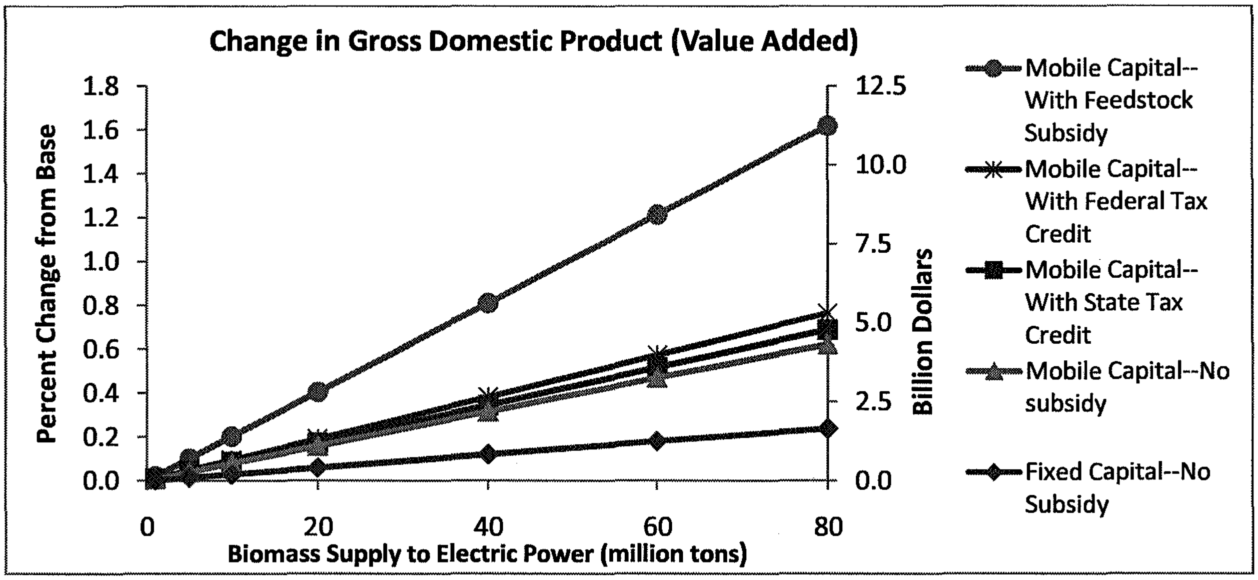


Figure 3. Change in Florida's Gross Domestic Product (GDP) at different levels of biomass supply for electric power generation under differing capital mobility and financial incentives assumptions.

When the CGE model was modified to disaggregate timber production and logging/forestry support services, much larger price effects were observed, with composite prices for timber increasing by 42%, and prices for logging/support services increasing by 143%, for the scenario with 40 million tons biomass supply and fixed capital. The price response was greater for logging/support services than for timber production in this case because logging is the direct supplier to the electric power sector and timber production becomes an indirect input. When the model was further modified to restrict imports of timber and logging/support services, prices for forestry products increased by 150%, and prices for logging/support services increased by 280%. The CGE model predicted also price increases for manufactured wood products anywhere from 0.03% to 4.6% under various model settings.

Imports of fossil fuels would decrease by 2.5%, representing a savings in import purchases of $1.14 billion, while imports of forestry commodities would increase. Employee income would increase by $1.61 billion. Tax revenues to state government would increase by 0.06 percent ($108 million).

Effects of Financial Incentives

Incentives such as a renewable energy production tax credit for electricity generated from biomass, and a subsidy to forestry biomass producers, would further increase forest sector output and state GDP and employment, and reduce imports of fossil fuels. In particular, an electricity production tax credit equivalent to $0.010-0.011 per kilowatt-hour would substantially increase output of the electric power sector, and decrease imports of fossil fuels, while reducing the negative impact of higher electricity prices on all other sectors. However, assuming that the tax credit is unlimited, the state-sponsored incentive would significantly reduce state government revenues by nearly $200 million at the 40 million ton biomass supply level. The 100 percent biomass feedstock federal subsidy to forestry producers would dramatically increase both electric power and forestry commodity output, but would not appreciably affect state government revenues (Figure 4).

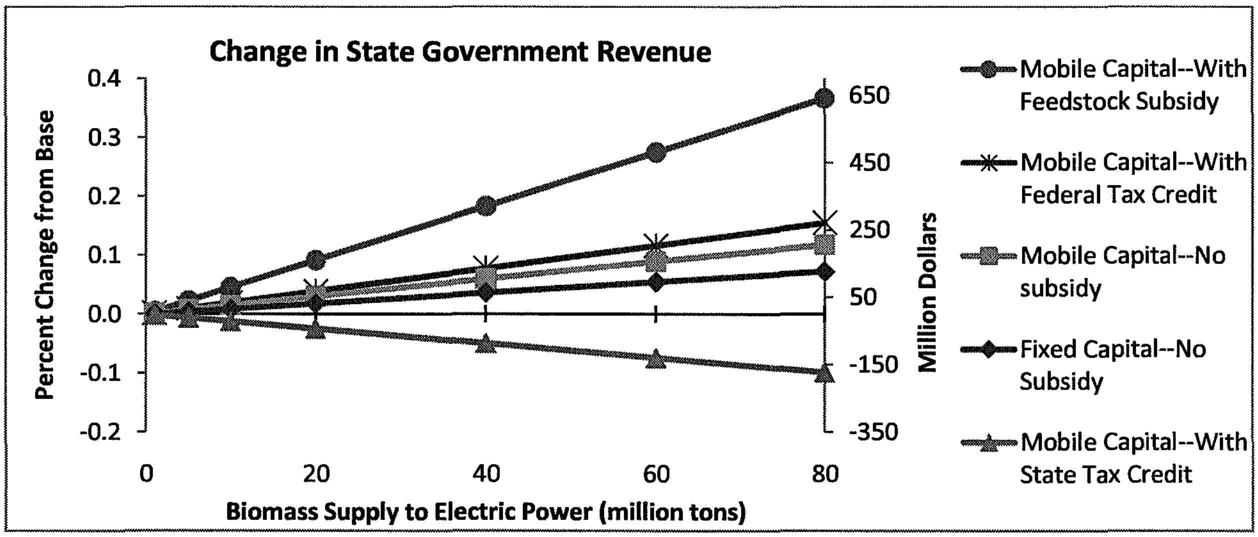


Figure 4. Change in state government revenue at different levels of biomass supply for electric power generation under differing capital mobility and financial incentives assumptions.

Conclusions on Economic Impact and Financial Incentives

Based on these findings, it is concluded that provided feedstock availability can be secured, the various policies and incentives for bioenergy development would have an overall positive impact on the economy of Florida in terms of increased GDP, employment and state government revenues, and decreased imports of fossil fuels. The forestry sector would particularly benefit from increased demand and prices. However, the forest product manufacturing sector would be adversely affected by competition for wood resources and higher prices for material inputs.

The I-O/ SAM and CGE models with mobile capital do not explicitly incorporate any physical capacity limitations on production of a commodity such as biomass fuels. This stands in contrast to bioeconomic models such as the Sub-regional Timber Supply (SRTS) model used in a companion study described below, which dynamically represents timber inventories, forest growth and harvest removals, although without consideration of the effects of domestic or international trade.

University of Florida SFRC Report Methods and Findings

Introduction

This study analyzed woody biomass demand, supply and timber prices resulting from implementation of a hypothetical 20% renewable portfolio standard (RPS) in Florida. Lower RPS mandates at 7% and 12% were also considered. It was assumed that 20% RPS, if passed by the legislature, would be phased-in over time using interim targets of 7% by January 1, 2014, 12% by January 1, 2017, 18% by January 1, 2020, and would be fully implemented at the 20% level by January 1, 2022. It was further assumed that wood resources from Florida and selected counties in southern Alabama and southern Georgia would meet that share of the RPS-imposed demand for electricity generation which cannot be satisfied by other renewable energy sources (ORES) such as solar, wind, hydropower, and biogenic municipal waste. According to U.S. Department of Energy projections, technological constraints and cost would limit the amount of renewable electricity that could be generated from ORES in Florida (Table 1).

Methods

The study estimated bio-economic impacts that a 7%, 12% or 20% RPS mandate would have on the forestry sector in Florida by simulating increased demand for timber resources and modeling the resulting effect on timber stumpage prices, harvests, and inventories of merchantable timber derived from private timberland using Sub-regional Timber Supply (SRTS) model (Abt et al 2000). This study was limited to private timberlands only, partly because of the model employed, which does not model for other types of forest ownership, and partly out of conviction that private landowners could respond quickly to market demands and would not be restrained by other factors influencing forest management decisions on public lands. In order to meet large volume demands of the modeled RPS mandates the pine roundwood category was defined to include pulpwood and small sawtimber size trees between 5.0 and 12.9 inches in diameter. The information generated by SRTS model runs was used to project the allocation of harvested merchantable timber between the forest products industry (FPI) sector and the electric power industry in Florida.

As part of the analysis, several different possible scenarios that represent different woody biomass feedstock source combinations were developed. The SFRC report concluded that for merchantable timber (MT) simulations all hypothetical RPS scenarios modeled had negative impacts on the forest products industry. Therefore, it was assumed that MT alone would not be utilized to satisfy any of the RPS mandates. The first scenario considered in this report is one where MT is augmented with urban wood waste (UWW) and logging residues (LR) as additional sources of woody biomass being used as electricity generation feedstock. The UWW is comprised mainly of large diameter trees typically removed from urban areas. However, this category may also be referred to as "yard trash" in the DEP records. Although the SFRC report used a per capita factor of 0.203 tons per person per year to estimate UWW, the resulting tonnage corresponds very well with a five year average of 3.76 million green tons of "yard trash" received in the DEP registered facilities
http://www.dep.state.fl.us/waste/categories/recycling/SWreportdata/07_data.htm

The LR are derived from the discarded tree tops and tree limbs that are generated during the harvest of MT, and currently mostly left behind in the woods in slash piles or scattered throughout harvested tracts. The next two scenarios are those in which short rotation energy crops (SREC) were added to the first scenario either in "low" or "high" quantities. Given the uncertainty in projecting the amount of Florida's non-forested land that could be converted to SREC in the near future and different potential productivity of these woody crops, the following was assumed. The "SREC_low" scenario is based on unimproved varieties of eucalyptus species planted on up to 0.568 million acres, while "SREC_high" scenario assumed deployment of high-yielding varieties of eucalyptus species tested previously in Florida (Rockwood et al 2006) planted on 1.441 million acres.

Impacts of an RPS on Forest Sustainability

This report considers forest sustainability only in terms of changes to merchantable timber volumes and does not take into account changes in timberland acreage that may take place in the modeled area. This is due to the features of the SRTS model used. As such, these assessments do not provide insights into other aspects of forest sustainability. However, the changes in merchantable timber volume would be crucial to assessments of forest sustainability under any definition.

Comparisons of the simulated effects of the 7% RPS, 12% RPS and 20% RPS and no RPS scenario reveal that only 7% RPS does not lead to merchantable timber volumes decline below 2006 baseline in the modeled time period between 2010 and 2040 (Figure 5). The 12% RPS would diminish the merchantable timber inventory below the 2006 baseline around 2035, while the 20% RPS would do the same starting in approximately 2025. In these runs wood fueled electricity was assumed to be produced from merchantable timber supplemented by urban wood waste and logging residues (no short rotation energy crops), and all runs were under "base" other renewable energy sources assumptions. The negative effects of various RPS mandates on pine roundwood inventory are more pronounced and come sooner (Figure 6) compared with effects on combined merchantable timber inventory discussed before. Still, in the case of the 7% RPS, the pine roundwood inventory does not decline below the 2006 baseline until 2040. However, the levels of pine harvests under 20% or 12% RPS would be below 2006 baseline, and unsustainable, starting in approximately 2022, and 2027, respectively, if only merchantable timber, urban wood waste and logging residues were used for wood-fueled electricity generation.

A closer look at the pine roundwood merchantable timber inventory under the 20% RPS reveals only one sustainable feedstock source combination scenario. Only when merchantable timber augmented with urban wood waste, logging residues and "high" short rotation energy crops are all employed to meet the 20% RPS demand under the "high" ORES assumptions, the pine roundwood inventory stays above the

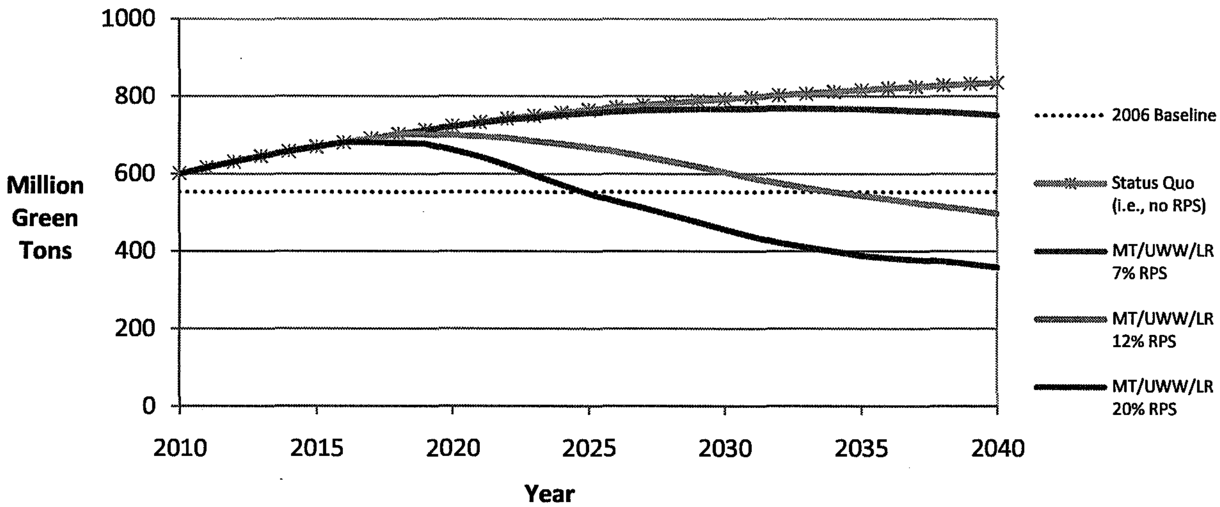


Figure 5. The SRTS model-generated pine and hardwood (combined) merchantable timber inventory. Merchantable timber (MT), urban wood waste (UWW) and logging residue (LR) are used to meet woody biomass demand of a 7%, 12%, or 20% RPS under "base" other renewable energy sources (ORES) assumptions. Also shown are changes in combined pine and hardwood merchantable timber inventory without an RPS mandate and a 2006 baseline.

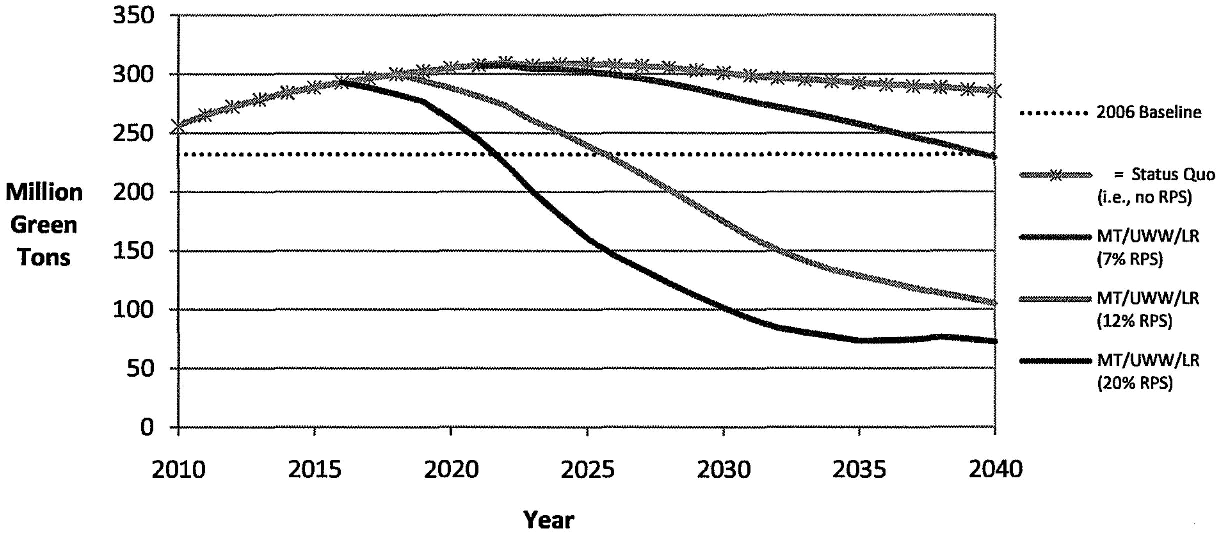


Figure 6. The SRTS model-generated pine roundwood inventory. Merchantable timber (MT), urban wood waste (UWW) and logging residue (LR) are used to meet woody biomass demand of a 7%, 12%, or 20% RPS under "base" other renewable energy sources (ORES) assumptions. Also shown are changes in pine roundwood inventory without an RPS mandate and a 2006 baseline.

2006 baseline level (Figure 7). In that case the amount of biomass feedstock generated in high acreage, high yielding short rotation woody crops plantations plus high contribution of other than wood renewable energy sources (ORES) creates a situation where pine roundwood is unnecessary to meet the 20% RPS demand. In all other considered feedstock combination scenarios, pine roundwood inventory falls quickly below the 2006 baseline and decreases precipitously. In the cases of base ORES without "high" version of short rotation energy crops, pine roundwood inventory declines below the 2006 baseline as early as 2022. This is the year when fully implemented 20% RPS would take effect. Our analyses also showed that reaching the 20% RPS would require very significant redirection of harvested merchantable timber to electricity generation from existing forest products industry under most considered scenarios, as shown for pine roundwood in Figure 8.a-f.

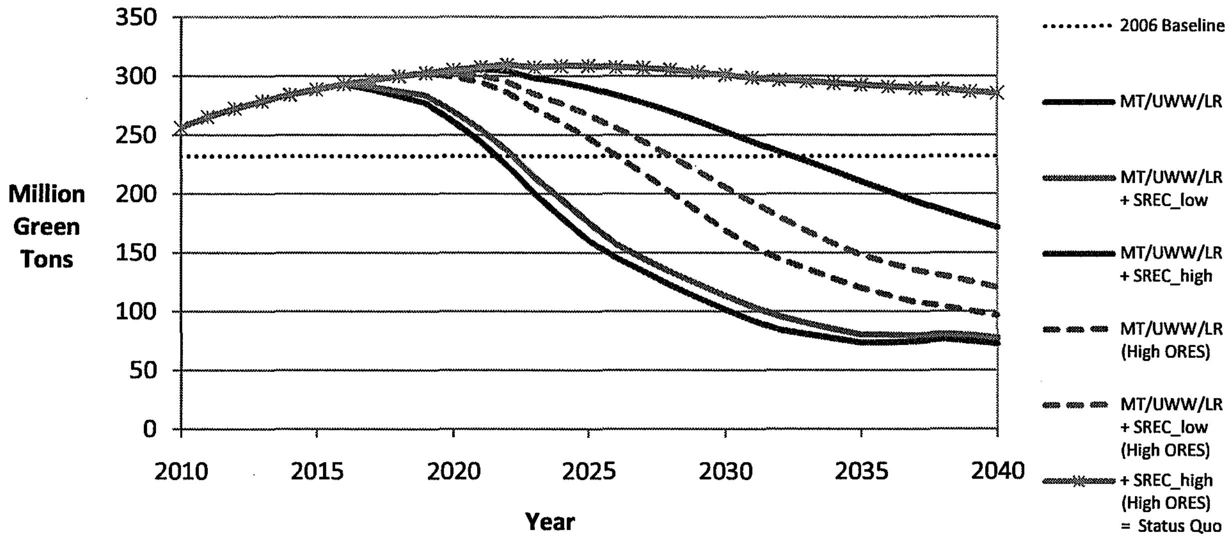


Figure 7. The SRTS model-generated pine roundwood inventory under the 20% RPS mandate. Merchantable timber (MT), urban wood waste (UWW) and logging residue (LR) are augmented with short rotation energy crops (SREC) as indicated in the legend. Base level of other renewable energy sources (ORES) assumed unless otherwise indicated. Changes in pine roundwood inventory without an RPS mandate are equivalent to feedstock scenario of MT/UWW/LR+SREC_high under high ORES assumptions (denoted as Status Quo). Also shown is 2006 pine roundwood baseline.

Generally it was found, that a 12% RPS would also adversely impact the existing forest products industry for all of the base ORES simulations that do not include the SREC_low or SREC_high assumptions as part of that particular feedstock mix. There are little, if any, impacts observed for the high ORES simulations under a 12% RPS. The SREC_high scenario precludes the need for harvesting merchantable timber whatsoever under either a 7% or a 12% RPS in the base or high ORES simulations. Finally, except for the preliminary "merchantable timber only" simulation, all of the 7% RPS projections modeled impart a relatively benign impact on the forest products industry with those under the high ORES assumptions having little, if any, impact at all.

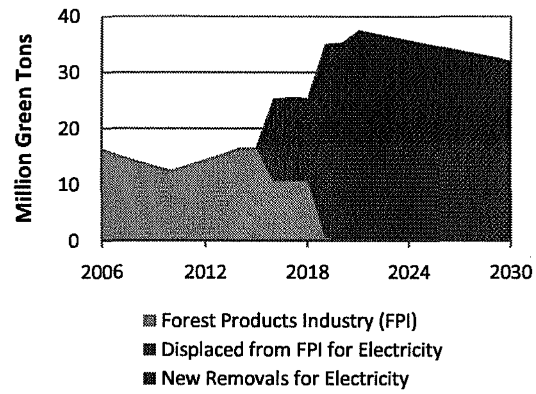


Figure 8.a. Allocation of *Pine Roundwood* 20% RPS, feedstock: MT/UWW/LR.

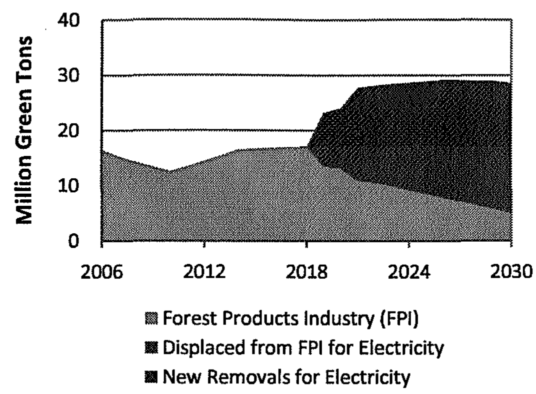


Figure 8.b. Allocation of *Pine Roundwood* RPS, High ORES, feedstock: MT/UWW/LR.

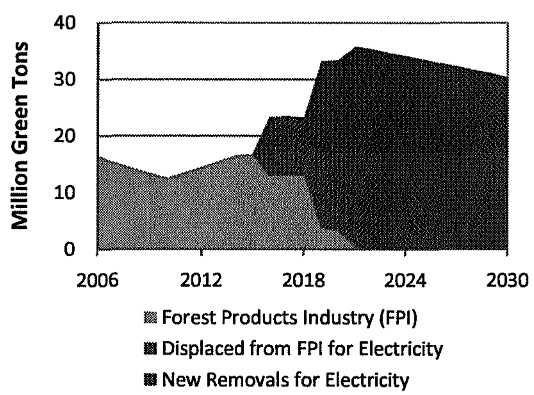


Figure 8.c. Allocation of *Pine Roundwood* 20% RPS, feedstock: MT/UWW/LR+SREC_low.

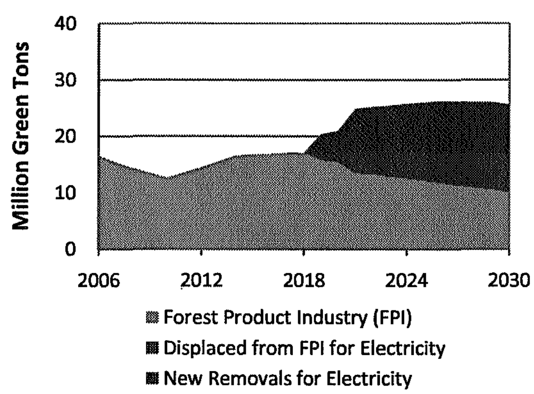


Figure 8.d. Allocation of *Pine Roundwood* 20% RPS, High ORES, feedstock: MT/UWW/LR +SREC_low.

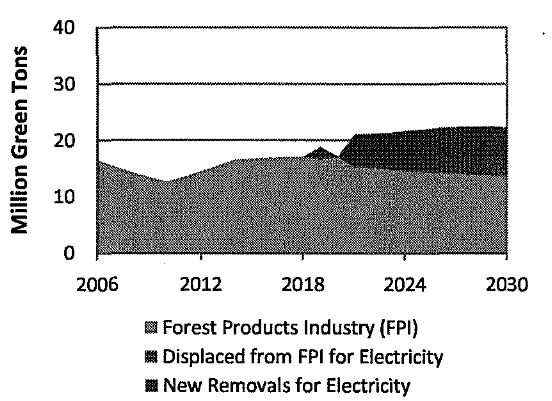


Figure 8.e. Allocation of *Pine Roundwood* 20% RPS, feedstock:MT/UWW/LR+SREC_high.

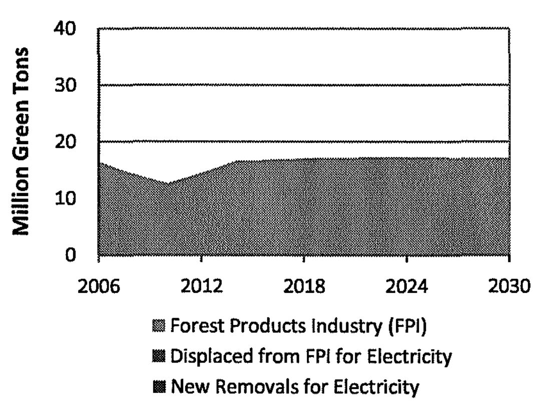


Figure 8.f. Allocation of *Pine Roundwood* 20% RPS, High ORES, feedstock: MT/UWW/LR +SREC_high.

Impact of an RPS on Timber Prices

This study has shown that the effects on stumpage timber prices of a 20% RPS could be quite dramatic, but depend to a large degree on how much short rotation energy crops (SREC) contribute to energy feedstocks, and to a lesser degree on the other renewable energy sources (ORES) development. For example, in the case of MT/UWW/LR+SREC_low feedstock combination scenario with "base" ORES assumptions, by 2025 the stumpage prices for pine pulpwood and small diameter sawtimber were modeled to increase by 500% compared with the prices recorded in 2006. In the same model run pine large sawtimber prices increased by 100% and those of hardwood pulpwood by 150%. In the analogous simulations where SREC_high under base ORES assumptions were used, pine pulpwood and small diameter sawtimber prices increased only slightly by 2025, and there was virtually no effect on prices for pine large sawtimber or hardwood pulpwood compared with 2006 prices. However, in a model run where ORES were assumed "high" and SREC were set to "low", by 2025 prices for pine pulpwood and small sawtimber increased by 100%, prices for large pine sawtimber were virtually unaffected, and prices for hardwood pulpwood increased by 50% compared with 2006 prices. Although price volatility could be disruptive to the existing forest products industry, some of the modeled effects might not be as dramatic in real life. This is mostly due to the fact that the SRTS model employed does not allow for timber imports from outside of Florida and pre-determined neighboring counties in Alabama and Georgia, nor does it account for capital mobilization and substitution effects. It is also worth noting that timberland owners would welcome return of timber prices to their historically much higher levels. With greater returns on investment, more timberland owners would be interested in reforestation of harvested tracts and managing their forests for various uses including bioenergy.

Conclusions on Woody Biomass Supply and Demand

We conclude that in order to achieve a 20% RPS the renewable energy supply intended to meet this demand includes: a strong reforestation and afforestation program, the planting of high-yielding SREC on 15% of Florida farmland or other non-forested lands, and/or other sources of woody biomass not considered here, and/or additional (and significant) amounts of other sources of renewable energy (e.g., wind, solar, biogenic municipal waste) similar to our high ORES scenarios. We projected this latter case by assuming 2.5 times the original estimate of other than woody biomass renewable energy sources. This projection is somewhat hypothetical as the opinions to how much ORES could contribute to the overall RPS differ among experts. The findings from the high ORES scenarios indicate that SREC would still be required to mitigate the impacts of 20% RPS demand on merchantable timber resources. In this case, however, the SREC_high scenario would preclude the need for using any merchantable timber in order to reach the 20% RPS. While the SREC_low scenario appears to approach feasibility as well, the impact on the forest products industry would likely still be adverse in terms of the impact on the price and inventory of pine pulpwood, and the price of pulpwood derived from hardwoods. However, as mentioned before, except for the "merchantable timber only" simulations, all of the 7% RPS projections modeled in this study impart a relatively benign impact on the forest products industry with those under the high

ORES assumptions having little, if any, impact at all. Increases in stumpage prices for timber and other woody biomass would benefit forest landowners and other producers.

Overall Conclusions

The conclusions presented below should be viewed qualitatively rather than quantitatively as many assumptions had to be made in the modeling process, and because of limited predictive powers of models in general, including those employed in the course of preparing the studies for this report.

We conclude that provided woody biomass feedstock availability is secured as discussed in this report, increased woody biomass use for electric power generation in Florida would bring about a modest increase in the state's Gross Domestic Product, employment, and state government revenues, while decreasing total imports, particularly of fossil fuels. For example in 2025, a woody biomass supply level of 40 million tons (equivalent to approximately 10% of electrical power generation, Figure 2), GDP could be increased by 0.32%, representing a $2.2 billion addition to Florida's economy. Such an outcome would require tripling of Florida's wood harvest from the current levels of about 20 million tons. Depending on the level of woody biomass use for electricity generation, output of the forestry sector would have to be increased significantly to meet new demand for woody biomass fuels. This could represent a great economic opportunity for the forestry sector in the state as this would require increased reforestation and afforestation efforts to sustain the bioenergy industry, and would increase the opportunities for existing forest producers and related industries. The largest adverse impact of these policies would be a decrease in output of the forest products manufacturing sector by up to 6.7%, because of competition and increased prices for forest resources.

According to modeling by IMPLAN and CGE (global models), prices for forest timber products may increase approximately 18% in the short-run due to competition for the resource, but would likely be much lower in the long-run if capital is allowed to move freely. However, when CGE model was modified to disaggregate timber production from logging/forestry support services, or further modified to restrict timber and services imports, a 43% to 150% timber price increases were observed. This is somewhat similar to the regional SRTS timber supply model, which predicted timber price increases anywhere from 0% to 150% in some instances, but also 500% in other cases for various timber products depending on the demand and supply assumptions. The CGE model predicted also price increases for manufactured wood products anywhere from 0.03% to 4.6% under various model settings. Imports of fossil fuels into the state would be decreased by up to 2.5%, representing a savings in import purchases of $1.14 billion annually. Employee income would increase by up to $1.61 billion. State government tax revenues would increase by 0.06 percent ($108 million).
The modeling also showed that incentives, such as a state and federal renewable energy production tax credits for electricity generated from biomass equivalent to $0.010 and $0.011 per KWh, respectively, and a 100 percent subsidy to forestry woody biomass producers, would marginally further increase state GDP

and employment. The electricity production tax credit would substantially increase output of the electric power sector, and decrease imports of fossil fuels, while reducing the negative impact of higher electricity prices on all other sectors. The federally sponsored renewable production tax credit would not adversely affect state government revenues. The biomass feedstock federal subsidy to forestry producers would dramatically increase both electric-power and forestry timber output, but would not appreciably affect fossil fuel imports or state government revenues.

Given that physical woody biomass availability is secured as discussed before, it is concluded that the various policies and incentives for bioenergy development that were examined would have an overall positive impact on the economy of Florida in terms of increased GDP, employment and state government revenues, and decreased imports of fossil fuels. The forestry sector would particularly benefit from increased demand and timber prices. However, the forest product manufacturing sector would be subject to increased competition for wood resources with resulting higher prices for material inputs.

Overall, it appears that a 7% RPS as modeled in the SFRC study would be both feasible without much disruption of timber supply to existing forest products industry, and economically beneficial to the economy of the state, and especially to timber producers and forestry in general. A modest mandate of this kind would facilitate increases in stumpage timber prices landowners receive for their products and increase chances of keeping "forests in forest". Any clean portfolio standard or RPS mandate should also incentivize tree planting including short rotation energy crops establishment on acreage proportional to the magnitude of the mandate. With increased reforestation, afforestation and planting of high-yielding short rotation woody crops on up to 15% of non-forested lands, a 12% and higher RPS could be achieved without depletion of the forest resources of the state, or significant impacts to the existing forest industries.

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Acknowledgments

We thank all the individuals and stakeholders who provided input to this report by participating in the public meeting, or providing written comments via the dedicated website or otherwise.

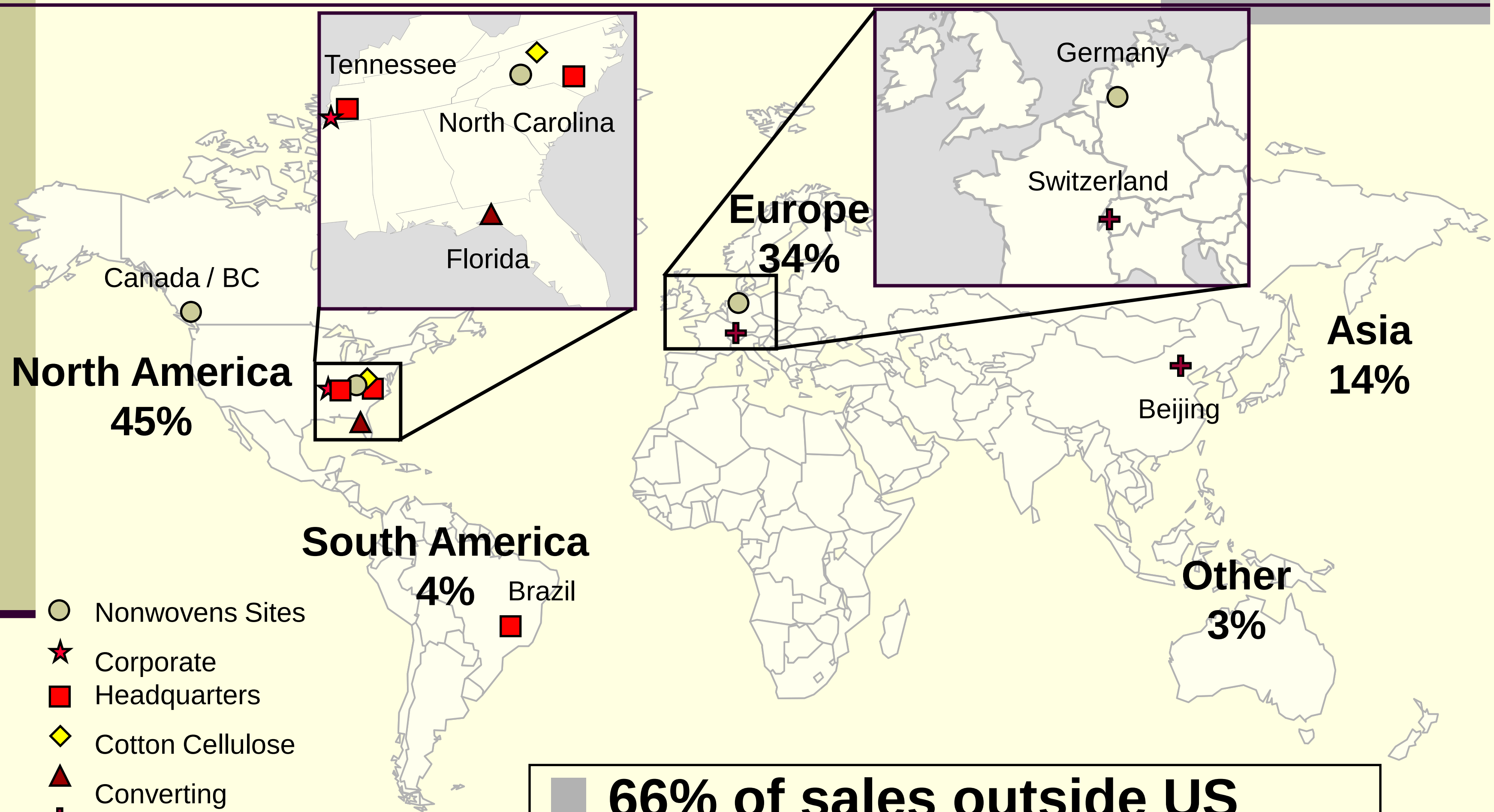
Clayton Bethea
Sustainability Business Manager

Buckeye

Perry, Florida Facility

Geographic Diversity

1,444 Employees



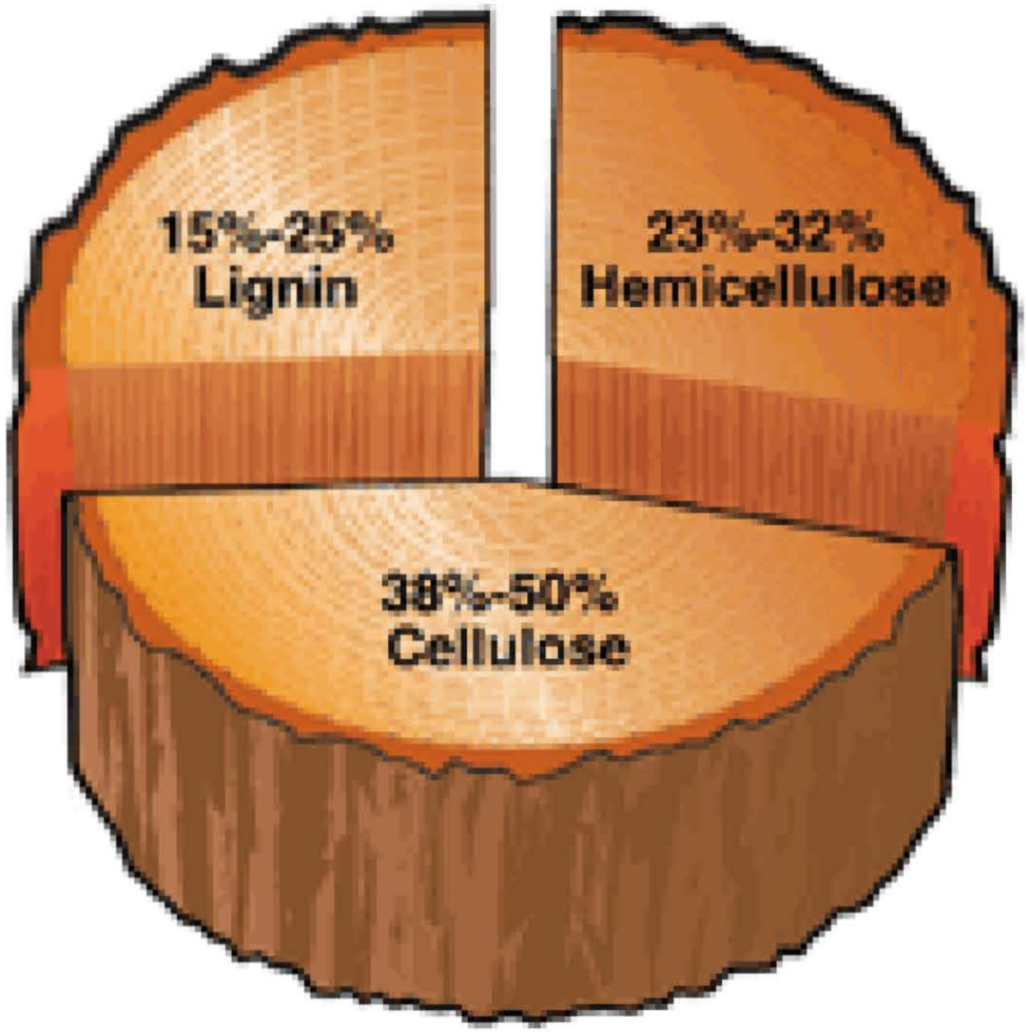
Based on fiscal 2009 Sales

- **66% of sales outside US**
- **78% of sales produced in US**

Perry, Florida Facility

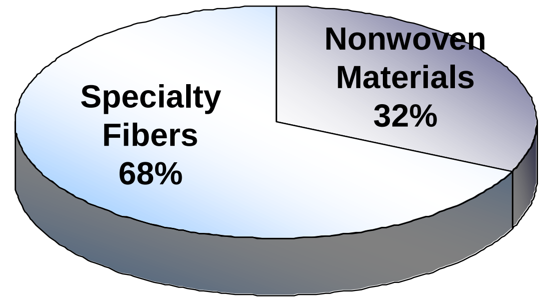
- Established in 1951
- 575 Direct Employees
- 1000 Additional Jobs Tied to Facility
  - Construction/Maintenance
  - Whole Tree Logging Crews
  - Rail Road/Trucking
  - Mill Supplies/etc
- 3,000,000 tons of Biomass converted annually/ Harvested within a 75 mile Radius
- 87% of Energy from Renewable Fuels

Tree Composition



Products

Developed and engineered to enhance products in specialized ways



Specialty Fibers

Nonwoven Materials	Fluff Pulp	Chemical Cellulose	Customized Fibers
32%	**19%**	**32%**	**17%**

Wipes

Baby Diapers

Tire Cord

Ethers (Thickeners)

UltraFiber 500®

Filters

Table Top

Femcare

LCD Screens

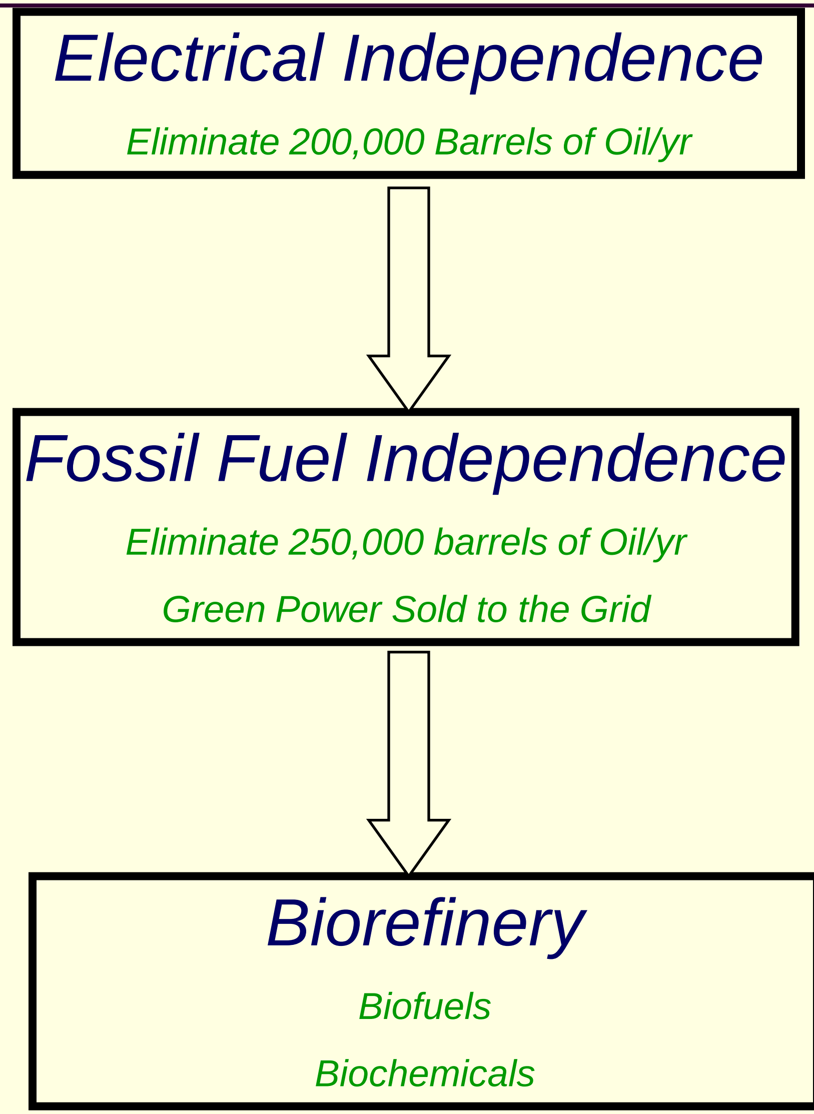
Food Casings

Currency Papers

Other Products

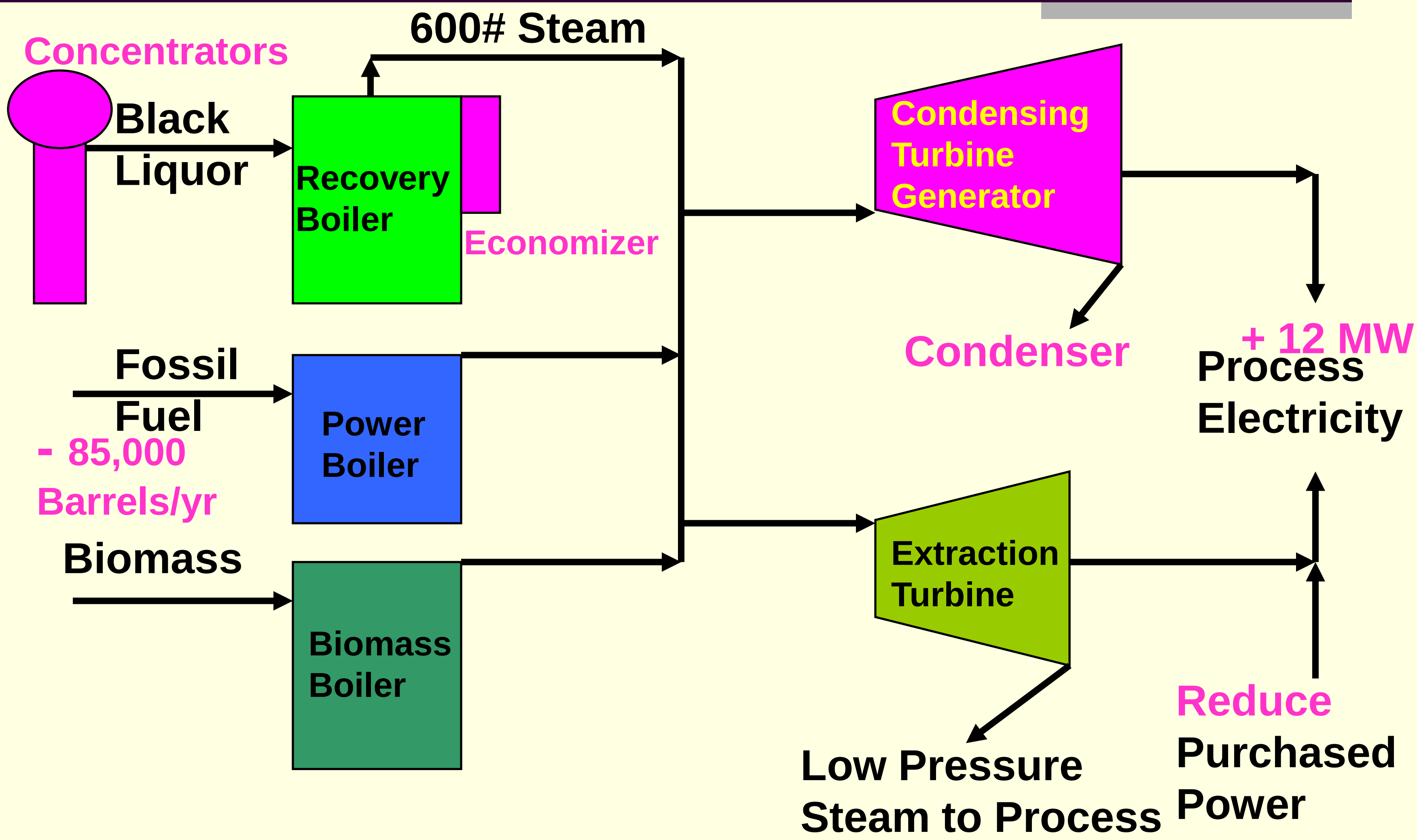
- Turpentine
  - Paints
  - Varnishes
  - Cleaning Agents
  - Fragrances
- Tall Oil
  - Adhesives
  - Rubbers
  - Inks
  - Emulsifiers
  - Soaps
  - Lubricants
- Electricity (40 MW today, 52 MW Sept 2011)

Energy Vision



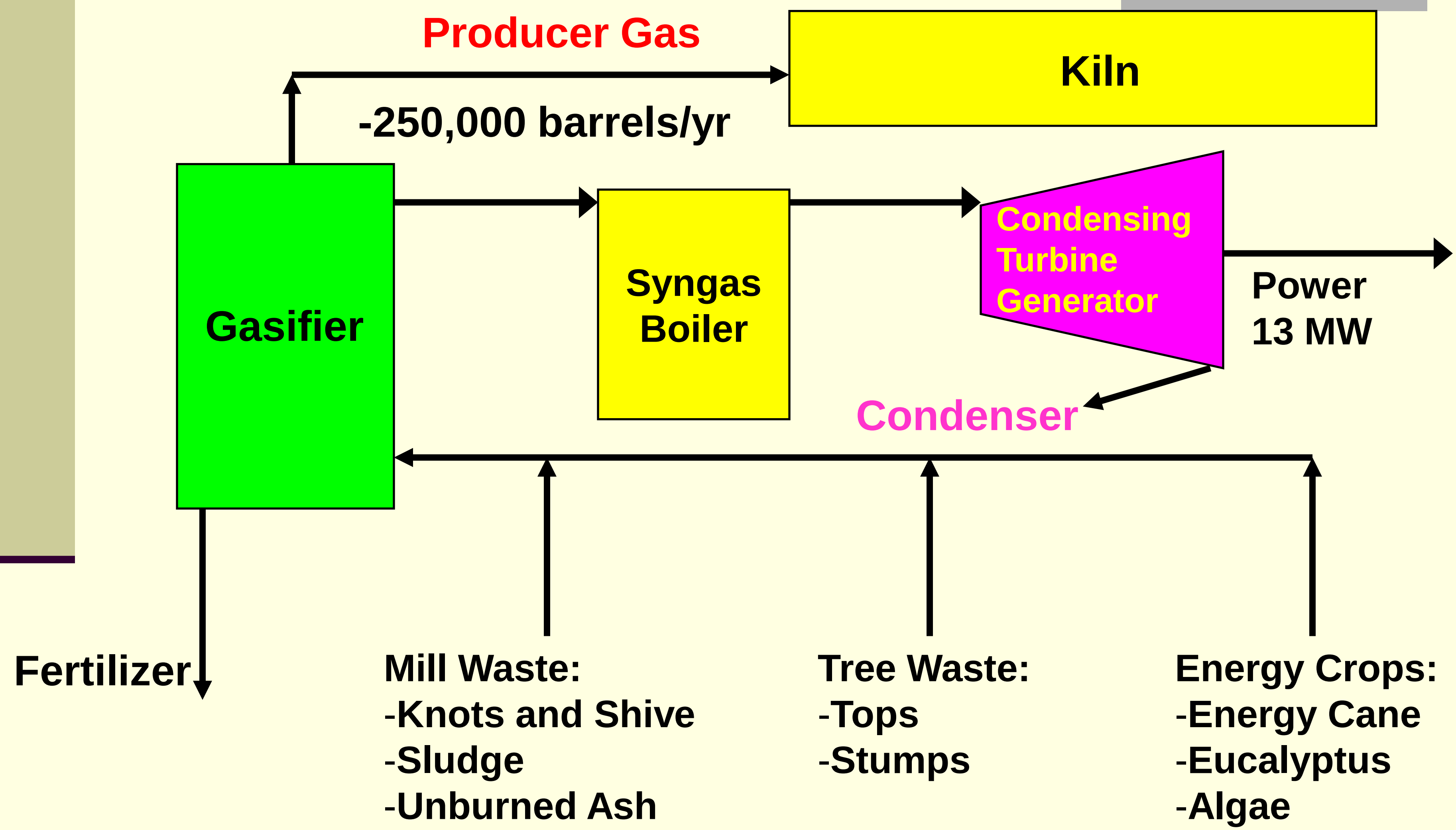
Electrical Independence

Eliminate 200,000 Barrels of Oil/yr



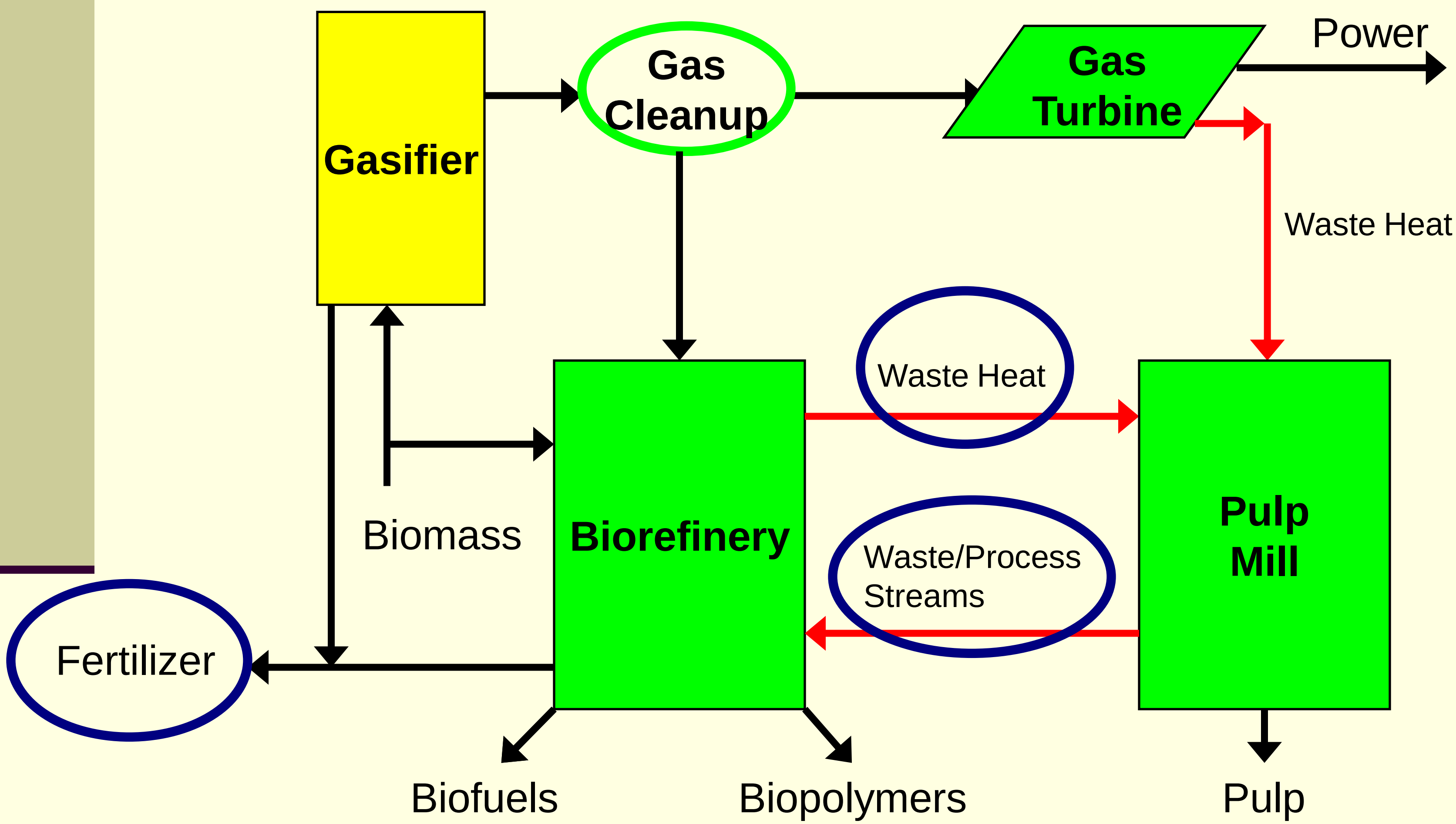
Fossil Fuel Independence

Eliminate 250,000 barrels of Oil/yr
Green Power Sold to the Grid



Biorefinery

Biofuels/Chemicals



Stan Mayfield Cellulosic Biorefinery

Raw Materials

- Agricultural, Forestry and Municipal Residues
- Opportunity streams From Buckeye
- Biomass Production
- Bagasse
- Forest Understory
- Mixed Hardwood Chips

Size: 3-5 tons of cellulosic biomass/day
Estimate 600 tons per year.
3000 gal water/yr, 18 gal/h

If run all the time, 1,750 tons year.

UF-BKI

Partial Saccharification

BKI Waste/Process Stream

→ 200 gal ethanol/day (70,000 gal/yr)

Fuel Ethanol

Lignin
Fertilizer
Co-products

Chemicals, Plastics

Energy Vision

Electrical Independence

Eliminate 200,000 Barrels of Oil/yr

↓

Fossil Fuel Independence

Eliminate 250,000 barrels of Oil/yr

Green Power Sold to the Grid

↓

Biorefinery

Biofuels

Biochemicals

Feedstocks Evaluated

- Whole Tree Harvesting
- Hardwood Whole Tree Chips
- Stumps
- Forest Underbrush
- Knots & Shives
- Densely Planted Pines
- Energy Cane
- Eucalyptus
- Cottonwood
- Switch Grass

Whole Tree Harvesting

Mill Waste: Knots & Shives


Buckeye Energy Park
Buckeye is committed to producing renewable energy.
These test plantings of green energy crops are being evaluated
to determine which are best suited for use in north Florida.
Buckeye's goal is to eliminate the use of fossil fuels at our site
and to provide green energy for others.
For information call 850-584-1275

Alamo Switch Grass
(Panicum Vergatum)

- Grow in wide range of soils & soil moisture
- Can establish by seed & harvest with conventional hay baling equipment
- 10 dry tons/acre/year (4-6’ tall)
- Biomass & Pasture hay for cattle and sheep

Energy Cane (L-79 - 1002)

8/20/09

6/15/09

- 22 dry tons/acre/year
- Grow in wide range of soils & soil moisture
- Fairly easy to establish
- Replant every 5-10 years

Eastern Cottonwood *(Populus deltoides)*

- A Type of Fast Growing Poplar
- Will Grow Across the USA – Best in riverene soils
- Easy to Plant Cuttings
- Freeze Tolerant
- 10 dry Tons/acre/year

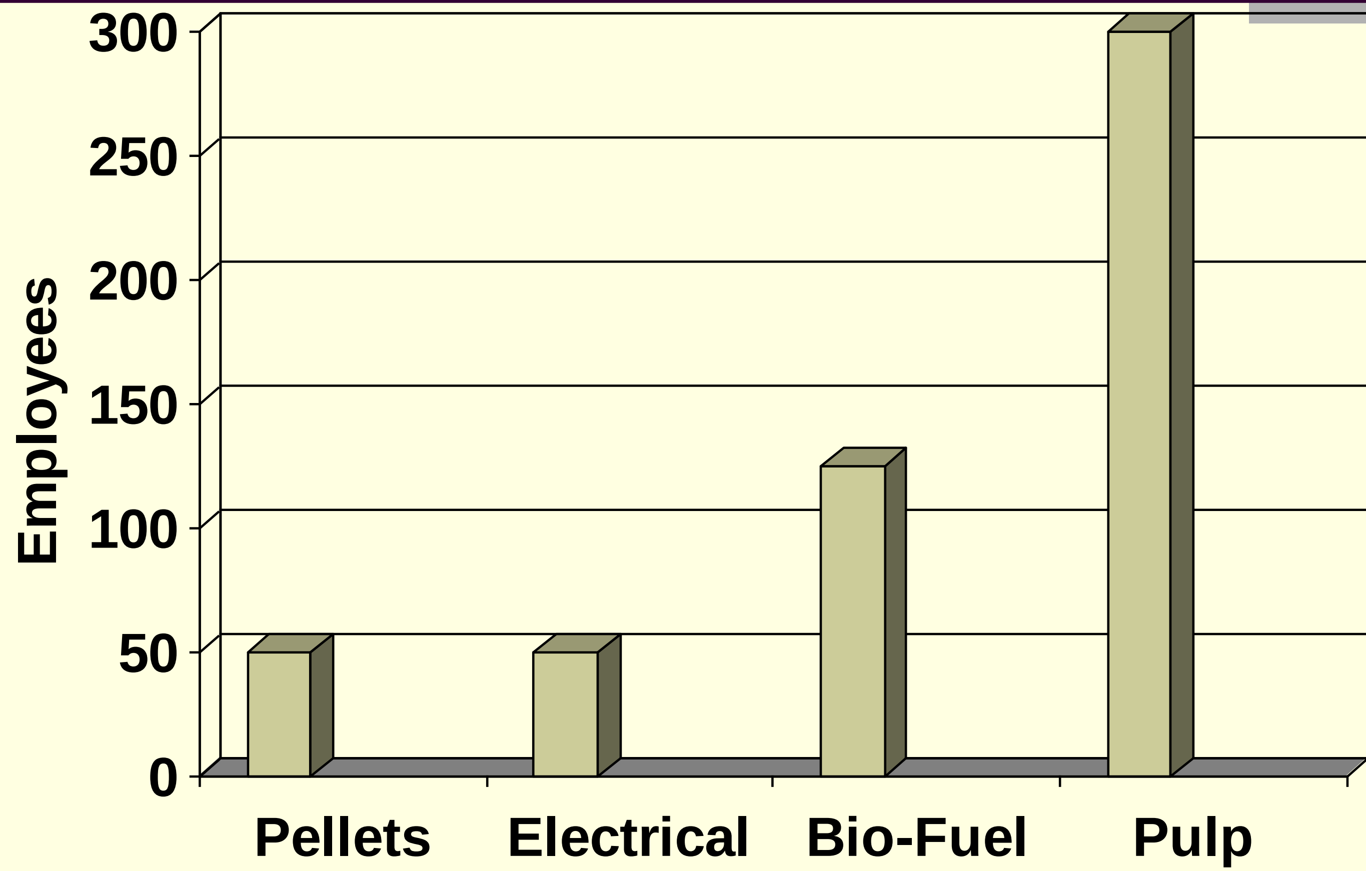
Eucalyptus amplifolia

- 8 years old Eucalyptus and Longleaf Pines in Valdosta, GA
- 30 year Breeding Program by UF
- Believed to be Freeze Tolerant
- Larger Research Trials – BKI & UF
- 14 dry tons/acre/year

Unused Tree Biomass: Stumps

21% of the total tree volume is under ground

of Plant Jobs/Million Tons of Biomass



Conclusions

- Incent Efficient Bioenergy Plants to maximize energy/value per Ton of Biomass.
- Use Urban Biomass Waste, Logging Residuals and Short Rotation Woody Crops
- Incent Biomass Crop Plantings.
- Incent Reforestation and Afforestation.

Questions?

Pricing for
Qualifying Facilities

Bob Trapp
PSC

Florida Public Service Commission

Presentation to the

House Energy & Utilities Committee

from PSC Staff

March 11, 2010

Public Utility Regulatory Policies Act of 1978 (PURPA)

- Part of the National Energy Act of 1978 – intended to encourage conservation of energy and to encourage more efficient use of energy resources by public utilities.

- Purpose – to encourage production of electric power by cogeneration and by small power producers.
  - Cogeneration - the combined production of power and useful heat by the sequential use of energy from one fuel source.
  - Small power producers – facilities generating not more than 80 MW of electric power and which employ renewable resources such as water power, solar energy, wind energy or geothermal energy, or biomass or waste as a primary fuel.

PURPA - Implementation

- The Federal Energy Regulatory Commission (FERC) required to adopt implementing rules within one year.
- FERC rules delegated the implementation of PURPA standards to the states.
- The Florida Legislature enacted PURPA implementation legislation in 1981.

PURPA Requirements

Public utilities must:

- Interconnect with Qualifying Facilities (QF)
  - A QF is an independent producer not primarily engaged in generating or selling electrical power, and meeting other conditions.
- Purchase capacity and energy from FERC-certified QF, and
- Sell electricity, including standby, to QF.

PURPA Requirements (con't)

- The QF bears the cost of interconnection.
- Purchases from the QF may not exceed the utility's full avoided cost.
  - "Full Avoided Cost" is the cost to the electric utility of the electric energy which, but for the purchase from the cogenerator or small power producer, such utility would generate or purchase from another source.
  - A QF is exempt from traditional rate regulation by the states and FERC and has no obligation to demonstrate the reasonableness of its own costs.
- Rates for sale of electricity to the QF must be just, reasonable, and non-discriminatory.

Role of FERC in Determining QF Status

- FERC determines QF status for:
  - Small power production facilities
  - Cogeneration facilities
- A QF can self-certify
  - Must meet certain size and fuel requirements,
  - File with FERC a notice of self-certification
- Or, a QF can be FERC-approved
  - Files application for FERC certification.
- However, in Florida, any electricity produced by any renewable source is deemed a benefit to the public and is considered eligible for a standard offer contract in Florida.

Section 366.051, Florida Statutes

- Authorizes the Public Service Commission to establish guidelines for the purchase and sale of capacity and energy from cogenerators and small power producers.
- Requires that the Commission shall "authorize a rate equal to the purchasing utility's full avoided cost".
- Levelized payments may be authorized with no discounts due to risk factors if adequate security, based on financial stability, is provided.

Determination of Avoided Cost

- The state determines avoided cost for capacity and energy payments.
- A utility's avoided cost rates may differentiate among facilities using various technologies on the basis of the supply characteristics of the different technologies.
- In setting avoided cost rates, a state must account for costs which actually would be incurred by utilities.
- Current debate centers on whether renewable benefits, defined by the Legislature as desirable, should be included in the payment for purchases. If so, how should that amount be quantified?

Recent Legislation

- Section 366.91, F.S.
  - Purchase power contracts must be continuously offered for renewable generators
  - Establishes requirements for net metering
- Section 366.92, F.S.
  - Requires the Commission to submit rules to establish a Renewable Portfolio Standard (RPS) for ratification by the Legislature.
  - Authorizes cost recovery for a total of 110 MW of solar demonstration projects.

Table 1a
Production Cost Ratio For Biomass Generators*
Based on Current Rates

Utility	From Appendix B	All-In Production Cost (¢/kWh)	Restated At 80% (¢/kWh)
FPL	81%	7.0	6.9
PEF	84%	9.0	8.6
TECO	82%	8.0	7.8
Weighted Average	82%	7.6	7.4

** Excluding taxes and fees.*

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Table 2a
Projected Capacity Additions in the FRCC: 2010 to 2018

Resource	MW
Coal	783
Gas	7,794
Nuclear	4,141
Oil	1,673
Total Capacity Additions	14,391

Source: FRCC, 2009 Regional Load & Resource Plan.

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Table 3:
Estimated Cost of Planned Capacity Additions (¢/kWh)

Utility	Plant	Technology	In-Service Year	Revenue Requirement (¢/kWh)
FPL	Desoto	Solar	2010	44.4
FPL	Space Coast	Solar	2010	58.9
FPL	Cape Canaveral	CC	2013	7.5
FPL	Riviera Beach	CC	2014	8.0
FPL	Turkey Point 6	Nuclear	2018[a]	10.5
FPL	Turkey Point 7	Nuclear	2020[a]	11.0
PEF	Suwannee P4	CT	2014	30.2
PEF	Suwannee P5	CT	2015	21.1
PEF	Levy County Unit 1	Nuclear	2016[b]	14.3
PEF	Levy County Unit 2	Nuclear	2017[b]	10.3
TECO	Future CT 1,2,3	CT	2012	38.3
TECO	Future CT 4	CT	2013	31.3
TECO	Future CT 5,6	CT	2013	40.1
TECO	Future CT 7	CT	2014	31.6
TECO	Future CT 8,9	CT	2015	28.3
TECO	Future CT 10, 11	CT	2016	25.7
TECO	Future CC1	CC	2018	10.2

Source: Appendix D
(a) Suspended
(b) Delayed past 2019

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Table 3 – Bar Graph
Estimated Cost of Planned Capacity Additions (¢/kWh)

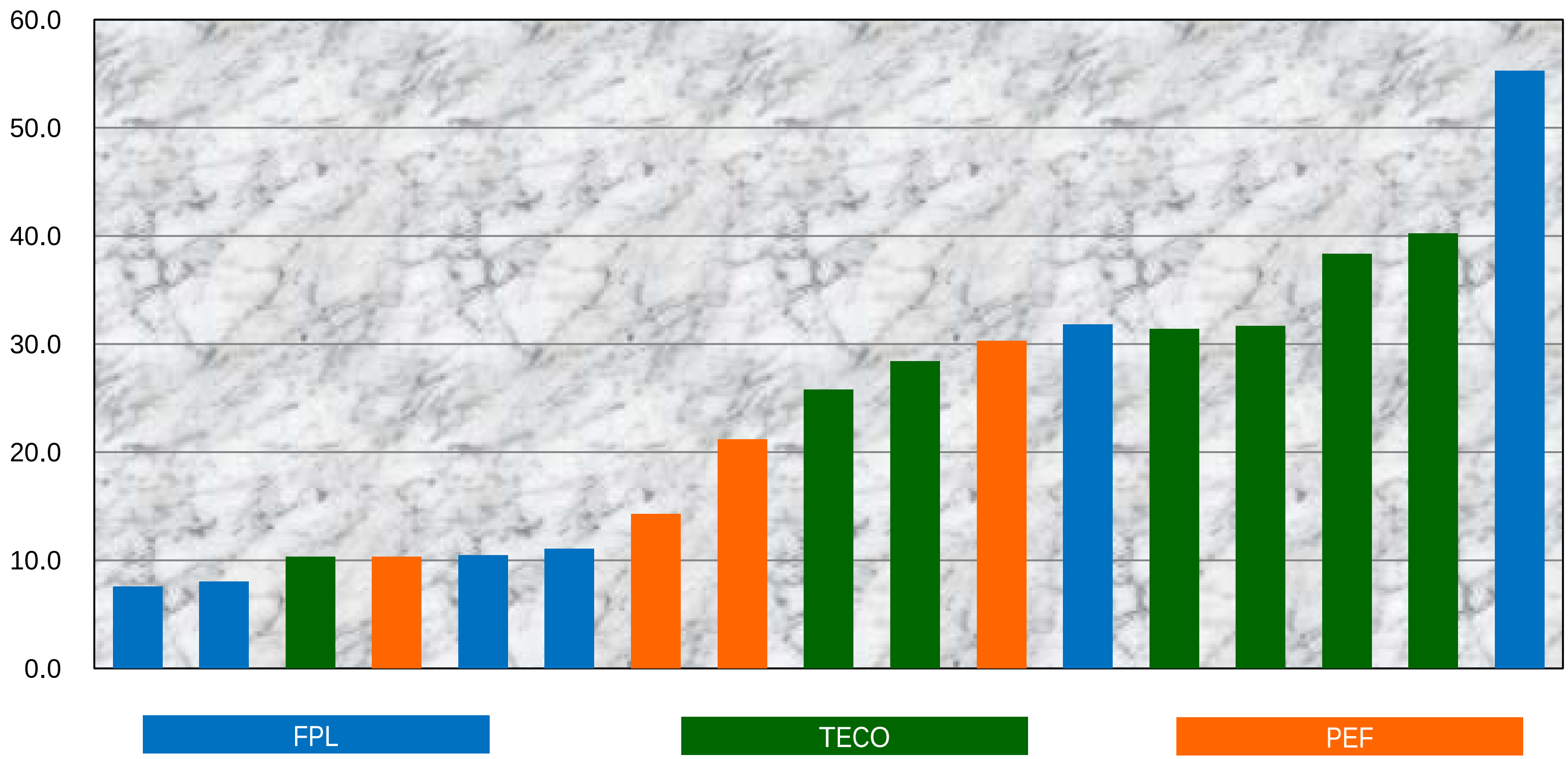

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Table 4
Future Estimated Avoided Cost

Utility	¢ / kWh
PEF	7.3
FPL	7.3
TECO	7.7

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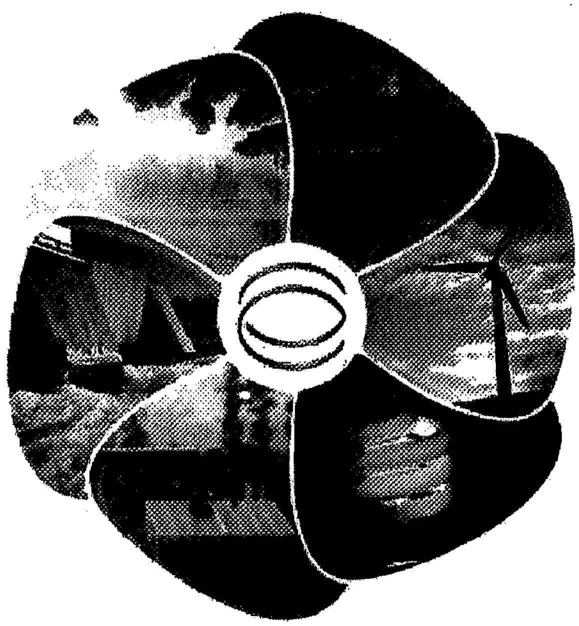
Renewable Energy Pricing Policy

A Report to the Florida Biomass Coalition



March 3, 2010

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GLOSSARY OF ACRONYMS

Term	Definition
DSM	Demand Side Management
FPL	Florida Power & Light Company
FPSC	Florida Public Service Commission
FRCC	Florida Reliability Coordinating Council
IOU	Investor-Owned Electric Utility
kWh	Kilowatt-hour
MW	Megawatt
NYMEX	New York Mercantile Exchange
O&M	Operation and Maintenance
PEF	Progress Energy Florida
QF	Qualifying Facility
TECO	Tampa Electric Company
TYSP	Ten-Year Site Plan For Electrical Generating Facilities and Associated Transmission Lines: January 2009 to December 2018

1. EXECUTIVE SUMMARY

This Report is authored by ***J.Pollock, Incorporated***, an independent firm advising clients in both regulated and competitive markets (see **Appendix A** and www.jpollockinc.com). The objective is to determine whether paying "qualified" local indigenous biomass and waste-heat generators 80% of the current average retail price of electricity (which reflects the cost of producing electricity) is an appropriate policy to encourage further development and deployment of these renewable resources to supply a growing share of the State's electricity needs.[1] The advantages of this pricing mechanism are:

- Greater price transparency than under the current utility Renewable Standard Offer tariffs;
- Less costly than future utility-owned capacity additions; and
- Lower electricity rates to consumers.

Further, it will not require utilities to pay in excess of current avoided cost.

Under current Florida Public Service Commission (FPSC) Rules, non-utility generators are paid based on a utility's avoided cost.[2] While the avoided cost standard is not necessarily unreasonable, the application of this standard through utility Renewable Standard Offer tariffs is a complicated and time-consuming process. Payments for capacity and energy are based on long-term projections of utility capacity needs and the cost to build and operate new generation as well as system incremental costs. These payments are revised annually. System incremental costs are not published, and they change hourly. Thus, there is little or no price transparency. This process means that an independent renewable producer must compete against the entire, existing power system, not just a single avoided unit.

As conditions change, avoided costs also change. The changes can be dramatic if future capacity additions are either accelerated or deferred, or if the generation technology is revised. Probing the utility's future projections requires constant vigilance and may require direct participation in the annual proceedings before the FPSC. The time and expertise required to effectively challenge a utility's avoided unit raises transaction costs and places biomass renewable generators at a decided disadvantage.

Using Retail electricity prices as the basis for full avoided costs is (a) fair, because it recognizes the capacity and energy value contributed by base load and intermediate biomass and waste heat generators; (b) more closely tracks the way that the power system is operated, i.e. as an integrated, multiple plant system rather than as a single unit; and (c) is more transparent and can provide a more stable basis for paying biomass and renewable generators than under the renewable Standard Offer tariff. Greater price transparency means greater certainty for renewable energy producers.

Further, utility costs receive much more scrutiny in contested rate cases than in the annual Renewable Standard Offer tariff proceedings. This is because there is substantial consumer participation in rate matters before the FPSC.[3] Rate cases provide a constructive forum for establishing and resetting the pricing benchmark.

As discussed in this Report, over 80% of the average retail price of electricity is for the recovery of the cost of producing electricity.[4] Production costs include return on plant investment, depreciation, taxes, operation and maintenance (O&M) expense, fuel, energy conservation, purchased power, and environmental remediation costs. The actual percentage of production costs varies among the three major investor-owned utilities (IOU), but they are consistently *above* 80% of the current average retail price. Under this pricing policy, payments to renewable producers may increase or decrease, but the percentage would be fixed and will change only as the utilities' production costs change.

To qualify for the 80% price, biomass producers must operate at annual capacity factors of at least 80%. This is comparable to the performance of base load generation owned and operated by the IOUs. The standard for waste-heat resources is a 63% annual capacity factor because this energy is created from manufacturing operations, and there is a correlation between related manufacturing energy consumption requirements and the renewable electricity produced from waste-heat. This is still comparable to the performance of utility-owned intermediate generation. Thus, both biomass and waste-heat generators can provide firm capacity and energy, and both should receive capacity and energy payments. Further, the less stringent capacity factor for waste-heat generators would not significantly diminish the firmness of the capacity provided. Therefore, paying the entire class of biomass and waste-heat generators 80% of the retail price is a reasonable policy.

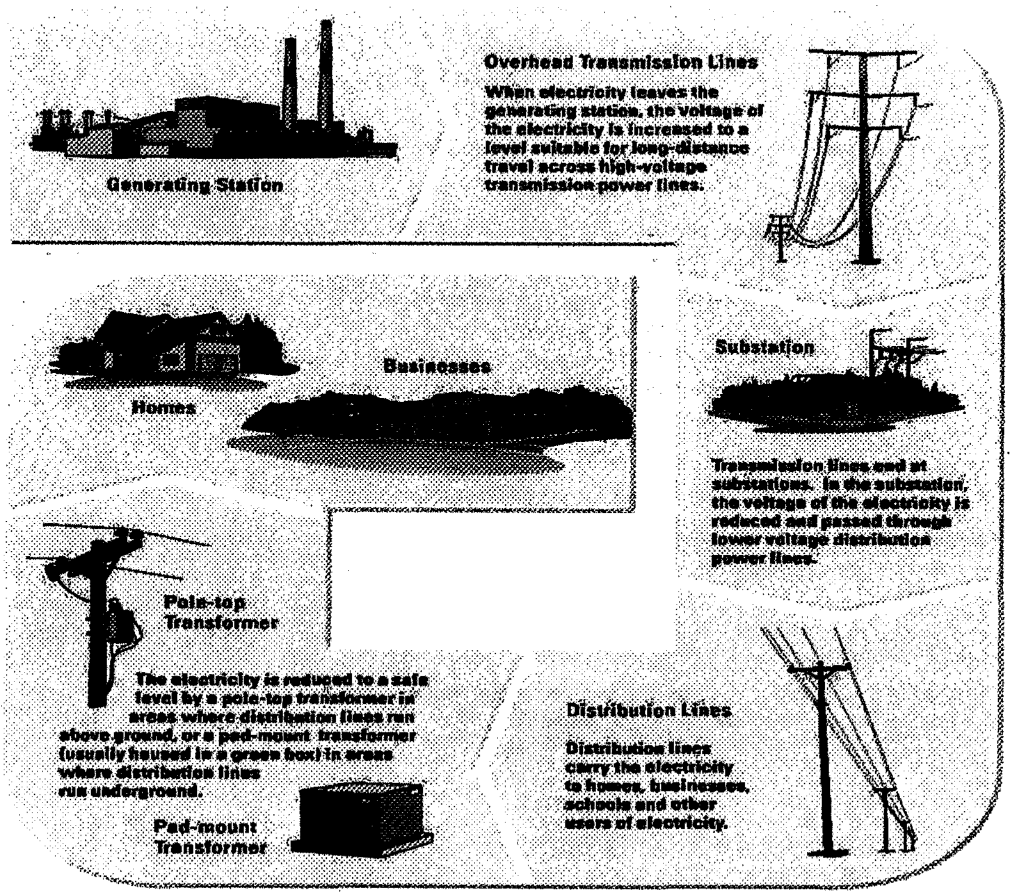
Biomass and waste-heat generation can be integrated into the grid without affecting reliability. Existing biomass and waste-heat resources currently account for over 1,000 MW of generating capacity.[5] Of this amount, electric utilities are purchasing about 447 MW of firm capacity and 628 MW of as-available capacity.[6] Various published reports have identified additional biomass and waste-heat resources that are technically available to supply electricity.[7]

Finally, utility-proposed capacity additions will be more costly than existing capacity. All other things being equal, bringing this new capacity into service will cause rates to increase. Therefore, ***displacing any of these more expensive future utility capacity additions with biomass and waste-heat resources can result in lower rates***.

2. PRICING POLICY

Electric utilities are obligated to provide reliable and safe electricity service to all customers within their exclusive franchise service area at the lowest reasonable cost. In order to provide reliable service, the utility must first produce electric power and energy, and then deliver that electricity to the customer's meter. These basic functions are illustrated in **Figure 1**.

Figure 1: Production and Delivery of Electricity[8]



Production Costs

Production costs refer to those costs incurred to generate (*i.e.* produce) electricity.

Delivery costs, such as transmission and distribution, are excluded. Production includes costs to own, operate and maintain electric generation facilities. Ownership costs include return on investment, depreciation, and income taxes. Operating expenses include fuel, O&M, and taxes other than income. Production costs also include purchased power, investments in environmental equipment (*e.g.* scrubbers, low NOX burners, selective catalytic refiners) and payments to encourage energy conservation.

Under current FPSC regulation, electric utilities are allowed to recover *average* production costs in rates. That is, plant investment and other capital are stated at original cost less depreciation, while operating expenses are based on as-incurred costs.[9]

Some production costs are recovered in the utility's base rates, while others are recovered in one or more of the following cost recovery clauses:

- Fuel and purchased power energy;
- Purchased power capacity (including the recovery of nuclear plant costs);
- Energy conservation (*e.g.* load management, energy efficiency, audits); and,
- Environmental.

Currently, these cost recovery clauses account for between 55% and 64% of the utilities' total cost of service.[10] The FPSC conducts annual reviews of each of the cost recovery clauses. New rates are typically implemented for bills rendered on or after January 1st.

Base rates, however, can only be changed in a rate case or in a limited rate proceeding. A rate case requires the utility to file a rate request application with the FPSC. The FPSC has eight months to review the application and authorize the utility to implement new base rates.

Thus, a utility's production costs are the sum of the costs recovered in base rates, plus the costs recovered in the various cost recovery clauses.

Base Rate Costs

Three major electric rate cases were processed by the FPSC in 2008 and 2009.[11] Under the FPSC's filing requirements, each utility is required to present a cost-of-service study. A cost-of-service study identifies the costs to produce and deliver electricity that are recoverable in base rates. Using the cost studies filed in these cases, we identified the production-related costs. Where necessary, the production costs were adjusted to reflect the costs authorized by the FPSC to be recovered in base rates. This analysis is presented in **Appendix B**.

Cost Recovery Clauses

As previously stated, certain production costs are recovered in separate cost recovery clauses that are reset annually. The assumptions used in this study are based on the rates implemented for electric bills rendered on January 1, 2010. These rates are shown in **Appendix C**. They are particularly noteworthy because the 2010 fuel rates are substantially below the corresponding 2009 rates. These reductions are due to a combination of lower projected fuel costs and large refunds of fuel costs that had been over-collected in 2009.

Summary of Results

Table 1a below summarizes the production cost as a percent of the total cost of providing retail service for each IOU (*i.e.,* Production Cost Ratios). As can be seen, the Production Cost Ratios range from 81% to 84% of the average retail rate. Using 80% as the benchmark would result in an average weighted price per kWh of 7.4¢, as shown below. Thus, using an 80% pricing methodology, biomass producers should be paid 7.4¢ per kWh for all electricity sold to electric utilities.

Table 1a Production Cost Ratio For Biomass Generators* Based on Current Rates			
Utility	**From Appendix B**	**All-In Production Cost (¢/kWh)**	**Restated At 80% (¢/kWh)**
FPL	81%	7.0	6.9
PEF	84%	9.0	8.6
TECO	82%	8.0	7.8
Weighted Average	82%	7.6	7.4

* Excluding taxes and fees.

Because waste-heat resources would be subject to a less stringent performance standard, this could result in a lower capacity value. At most, the reduction in capacity value would not exceed 50%. Removing 50% of the production fixed costs that the FPSC allocates on a peak demand basis would result in the production cost ratios shown in **Table 1b**.

Table 1b Production Cost Ratios For Waste-Heat Generators Based on Current Rates	
FPL	73.4%
PEF	76.1%
TECO	75.0%
Weighted Average	74.4%

As can be seen, the ratios are lower, but the differences are not significant. Further, considering that the production cost ratios for biomass generators are above 80% and that waste-heat generators can provide substantial capacity value, pricing both resources at 80% is reasonable policy.

The prices derived in **Table 1a** will change with the corresponding annual changes in the cost recovery clauses and following a base rate case. As is evident from **Appendix B**, determining the portion of production costs is relatively straight forward and can be readily accomplished in the existing regulatory proceedings.

More importantly, pegging the price of biomass waste-heat resources to a defined percentage of the *average* retail electricity price will treat these producers fairly, provide greater transparency, and encourage additional renewable generation. It will also ensure electric ratepayers are not paying more for these resources than they are currently paying the electric utility for generating electricity and that rates are not increased solely because of this policy.

3. COST OF ALTERNATIVE RESOURCES

Despite recent declining growth, the State will continue to need additional generation capacity to maintain reliability. The Florida Reliability Coordinating Council (FRCC) projects that approximately 14,400 MW of capacity additions are needed through the year 2018, as shown in **Table 2a.**[12]

Table 2a **Projected Capacity Additions in the FRCC: 2010 to 2018 (MW)**	
Coal	783
Gas	7,794
Nuclear	4,141
Oil	1,673
Total Capacity Additions	14,391
Source: FRCC, *2009 Regional Load & Resource Plan.*	

Projected demand growth is also expected to be met with increased conservation, load

Table 2b **Projected Demand Reduction From DSM Programs in the FRCC: 2010 to 2018 (Summer MW)**	
Conservation	1,097
Load Management	567
Interruptible	34
Total Demand Reduction	1,698
Source: FRCC, *2009 Regional Load & Resource Plan.*	

management, and interruptible load. Collectively, these are referred to as Demand Side Management (DSM) programs. As shown in **Table 2b**, DSM programs are projected to reduce future electricity demand by nearly 1,700 MW in 2018. The FPSC recently ordered electric utilities to increase DSM's contribution to reducing future demand by more than 2,600 MW by 2018.[13] Whether the additional goals set by the FPSC can be met cost-effectively has not yet been established.

Future Generation Costs

Future capacity additions reported in the utility's most recent *Ten-Year Site Plan* (TYSP) are shown in **Table 3**. We have estimated the all-in cost of this new capacity on a per kWh basis using the cost parameters provided by the utilities. Where specific costs were not indicated, generic estimates were used.[14] As can be seen in **Table 3**, the per unit cost of future capacity additions will range from 7.5¢ to over 50¢ per kWh. ***These costs are higher than under the proposed transparent pricing policy***. ***Adding more costly generation will increase retail rates***. That is, relying solely on electric utilities to provide future capacity will result in higher future electricity rates. The more costly additions include certain renewable resources and nuclear capacity, both of which are proposed alternatives to reduce Florida's dependence on natural gas. ***However, if the State were to depend on renewable resources that cost no more than the utility's average production cost, rates will either stay the same or decrease.***

Stated differently, having a more transparent pricing policy will not cause rates to increase any faster than the change in each utility's average production costs. Therefore, if biomass and waste-heat resources can be usefully integrated into the electric grid, displacing future, more expensive capacity additions, they can help to mitigate or eliminate future base rate increases.

Table 3: Estimated Cost of Planned Capacity Additions				
Utility	**Plant**	**Technology**	**In-Service Year**	**Revenue Requirement (¢/kWh)**
FPL	Desoto	Solar	2010	44.4
FPL	Space Coast	Solar	2010	58.9
FPL	Cape Canaveral	CC	2013	7.5
FPL	Riviera Beach	CC	2014	8.0
FPL	Turkey Point 6	Nuclear	2018[a]	10.5
FPL	Turkey Point 7	Nuclear	2020[a]	11.0
PEF	Suwannee P4	CT	2014	30.2
PEF	Suwannee P5	CT	2015	21.1
PEF	Levy County Unit 1	Nuclear	2016[b]	14.3
PEF	Levy County Unit 2	Nuclear	2017[b]	10.3
TECO	Future CT 1,2,3	CT	2012	38.3
TECO	Future CT 4	CT	2013	31.3
TECO	Future CT 5,6	CT	2013	40.1
TECO	Future CT 7	CT	2014	31.6
TECO	Future CT 8,9	CT	2015	28.3
TECO	Future CT 10, 11	CT	2016	25.7
TECO	Future CC1	CC	2018	10.2

Source: Appendix D

(a) Suspended[15]
(b) Delayed past 2019

Avoided Cost

Avoided cost is the standard currently used by the FPSC to determine whether alternative generation and DSM resources are more cost-effective for meeting future electricity needs than new utility resources.[16] Federal law requires electric utilities to purchase energy from qualifying facilities (QFs) at avoided cost.[17]

The FPSC has adopted specific rules for quantifying avoided cost. Under these rules, avoided cost is established separately for each utility for non-utility resources that elect to provide energy only when it is available (*i.e.,* "as-available energy") and for resources that can provide both capacity and energy (*i.e.,* "firm capacity"). As-available energy is priced at the host utility's hourly incremental cost. Incremental cost is the cost associated with generation that is displaced by as-available energy.[18]

When firm capacity is provided, the generator is also eligible to receive a capacity payment. The amount of the capacity payment is based on a utility's "avoided unit" and the generator's actual performance. The avoided unit is designated by the FPSC based on each utility's current generation expansion plan.[19] The costs of this "avoided unit" may also be used to establish the energy payments for that portion of the year that the avoided unit is expected to operate. While the capacity payments are published in each utility's Renewable Standard Offer tariffs, the energy payments are determined based on a combination of the energy cost of the avoidable unit and system hourly incremental costs.[20] These are known only on an after-the-fact basis. Thus, energy prices are not transparent. In effect, an independent renewable producer must compete against the entire, existing power system, not just a single avoided unit.

The Renewable Standard Offer tariffs are reviewed and updated annually to reflect changes in each utility's capacity needs as well as the expected costs to construct, operate, and maintain the avoidable capacity. Despite the annual reviews, there is no process for auditing the accuracy of a utility's as-available energy payments. Thus, not only are as-available energy prices not transparent, it is unclear whether the methodology being used is reasonable.

Based on the generation expansion plans identified in **Table 3**, we have estimated the avoided costs for the three IOUs in **Table 4**. They are based on the next gas-fired combined cycle generating unit in each utility's 2009 TYSP. This is the type of generation that could be displaced by qualified biomass and waste-heat resources. The avoided units are assumed to have in-service dates many years from now. Thus, the capacity costs have been discounted.

Table 4 Future Estimated Avoided Cost (¢/kWh)	
PEF	7.3
FPL	7.3
TECO	7.7

As demonstrated in **Part 4** of this Report, the required performance of the former resources is superior to the performance of utility-owned combined cycle generation. Adjustments were made to account for possible delays of planned nuclear capacity.[21] Fuel costs were based on the average closing prices of natural gas futures traded on the NYMEX for 2011 contracts.

As can be seen from **Table 4**, *avoided* costs are comparable to the *average* production costs shown in **Table 1**. Thus, the proposed transparent pricing policy will not result in payments above avoided cost.

4. COMPARABILITY WITH OTHER RESOURCES

Qualified biomass and waste-heat resources are not intermittent; that is, they can operate like a base load generating unit and their productivity is not directly dependent on weather. Further, to qualify a resource must operate at a minimum 80% annual capacity factor for biomass resources and a minimum 63% annual capacity factor for waste-heat resources. This requirement makes biomass and waste-heat a relatively reliable renewable resource capable of displacing future utility capacity additions.[22]

Further, as shown in **Table 5**, the suggested performance standards for biomass and waste-heat resources compare favorably with the average capacity factors for generation currently operating in the FRCC.

Table 5: Five-Year Average Capacity Factor By Fuel Type for Generation Capacity Located in the FRCC

Nuclear	87%
Coal	74%
Gas: Intermediate	51%
Gas: Peaking	5%
Oil	23%
All Other	61%

Source: SNL Financial

As can be seen, the range of average capacity factors for coal and nuclear plants is 74% to 87%. This translates into a weighted average capacity factor of 78%. Thus, the proposed 80% capacity factor performance standard for qualified biomass facilities compares well with the actual performance of nuclear and coal plants. The proposed waste-heat performance standard would make these resources superior to gas-fired intermediate plants.

5. ENDNOTES

[1] "Biomass" means a power source that is comprised of, but not limited to, combustible residues or gases from forest products manufacturing, waste, byproducts, or products from agricultural and orchard crops, waste or co-products from livestock and poultry operations, waste or byproducts from food processing, urban wood waste, municipal solid waste, municipal liquid waste treatment operations, and landfill gas.

"Renewable energy" means electrical energy produced from a method that uses one or more of the following fuels or energy sources: hydrogen produced from sources other than fossil fuels, biomass, solar energy, geothermal energy, wind energy, ocean energy, and hydroelectric power. The term includes the alternative energy resource, waste heat, from sulfuric acid manufacturing operations.

[2] "Avoided cost" is defined in Rule 25-17.210 FAC as: "the incremental costs to the purchasing utility of the electric energy or capacity, or both, which, but for the purchase from a renewable generating facility, such utility would generate itself or purchase from another source."

[3] Consumer participation includes the Office of Public Counsel, the Florida Attorney General, Florida Industrial Power Users Group, and the Florida Retail Federation, among others. Further, the Staff of the FPSC represents all interests.

[4] Gulf Power was not included in this determination because it has not had a litigated rate case within the past several years.

[5] Florida Public Service Commission, *Review of 2009 Ten-Year Site Plans for Florida's Electric Utilities*, October 2009 at 13 (Table 2). This includes biomass, municipal solid waste, and waste-heat capacity.

[6] *Id.* at 14-15.

[7] *Id.* at 15. Also see: Navigant Consulting, *Florida Renewable Energy Potential Assessment Full Report Final Prepared for Florida Public Service Commission, Florida Governor's Energy Office, and Lawrence Berkeley National Laboratory*, December 30, 2008. The technical potential for solid biomass resources ranges from 5,960 MW to over 13,000 MW by 2020 (p14). Additional waste-heat potential of 140 MW was identified (p15).

[8] Source: Power House (http://www.powerhousetv.com/EnergyBasics/INT_000309)

[9] The FPSC uses a projected test year to set rates. This means that the operating expenses included in base rates are those that the utility expects to incur when new base rates are in effect.

[10] See Appendix B.

[11] The three major rate cases are as follows:

Utility	FPSC Docket No.
TECO	080317-EI
FPL	080677-EI and 090130-EI
PEF	090079-EI

J.Pollock was an active participant in all three rate cases. This included providing analysis and expert testimony.

[12] FRCC serves as a regional entity with delegated authority from the North American Electric Reliability Corporation (NERC) for the purpose of proposing and enforcing reliability standards within the FRCC

Region. The area of the State of Florida that is within the FRCC Region is peninsular Florida east of the Apalachicola River. Areas west of the Apalachicola River are within the SERC Region. The entire FRCC Region is within the Eastern Interconnection and is under the direction of the FRCC Reliability Coordinator.

[13] Docket Nos. 080407-EG, 080408-EG, 080409-EG, 080410-EG, 080411-EG, 080412-EG, 0804 I 3-EG (Conservation Goals), *Order No. PSC-09-0855-FOF-EG* Issued December 30, 2009, at 17-22. The quoted amount excludes the goals set for Gulf Power Company, which is not located in the FRCC.

[14] Energy Information Administration, *2009 Annual Energy Outlook Assumptions,* at 89.

[15] The estimated costs were derived from capital costs provided FPSC Order No. PSC-08-0237-FOF-EI, Docket No. 070650-EI at 13.

[16] Avoided costs are also used to measure the cost effectiveness of various conservation programs. The FPSC currently relies primarily on two cost-benefit tests: (1) ratepayer impact measure (RIM) test; and (2) total resource cost (TRC) test. The RIM test provides an indication of any change in rate levels as a result of a conservation program. It provides a measure of the impact of a conservation or energy efficiency program on customers who do not participate. The TRC test is an indicator of the net cost of a conservation and energy efficiency program based on the total costs, including the participant's and utility's costs. In both the RIM and TRC tests, avoided supply costs are integral to establishing cost-effectiveness. Also see endnote 12.

[17] See 18 CFR Ch.1, Sec 292.304. Qualifying Facilities are defined in Rule 25-17.080 FAC and consist of either Cogenerators or Small Power Producers. Cogenerators are facilities in which:

(a) The useful thermal energy output of a topping cycle cogeneration facility is not less than 5% of the facility's total energy output per year; and

(b) The useful power output plus half of the useful thermal energy output of a topping cycle cogeneration facility built after March 13, 1980, with any energy input of natural gas or oil is greater than 42.5% or 45% if the useful thermal energy output is less than 15% of the total energy output of the facility; and

(c) The useful power output of a bottoming cycle cogeneration facility built after March 13, 1980, with any energy input as supplementary firing of natural gas or oil is not less than 45% of the natural gas or oil input on an annual basis; and

(d) The cogeneration facility is not owned by a person primarily engaged in the generation or sale of electricity. This criterion is met if less than 50% of the equity interest in the facility is owned by a utility, utility holding company, or a subsidiary of them.

To qualify as a Small Power Producer:

(a) The small power producer does not exceed 80 MW; and

(b) The primary (at least 50%) energy source of the small power producer is biomass, waste, or another renewable resource; and

(c) The small power production facility is not owned by a person primarily engaged in the generation or sale of electricity. This criterion is met if less than 50% of the equity interest in the facility is owned by a utility, utility holding company, or a subsidiary of them.

In addition, small power producers and cogenerators which fail to meet the above criteria for achieving qualifying facility status but otherwise meet the objectives of economically reducing Florida's dependence on oil and the economic deferral of utility power plant expenditures may petition the Commission to be granted qualifying facility status.

[18] As-Available Energy is purchased at a unit cost, in cents per kilowatt-hour, based on the Company's actual hourly avoided energy costs, before the sale of interchange energy, which is calculated by the Company in accordance with FPSC Rule 25-17.0825.

[19] The avoided unit is the next avoidable fossil fueled generating unit of each technology type identified in the utility's Ten-Year Site Plan filed pursuant to Rule 25-22.071, FAC. Each IOU with no planned generating unit identified in its Ten-Year Site Plan shall use a planned purchase that can either be deferred or avoided for its standard offer.

[20] The energy payments are defined as the lower of (a) the avoided unit energy costs or (b) the marginal energy cost of the system for any given hour.

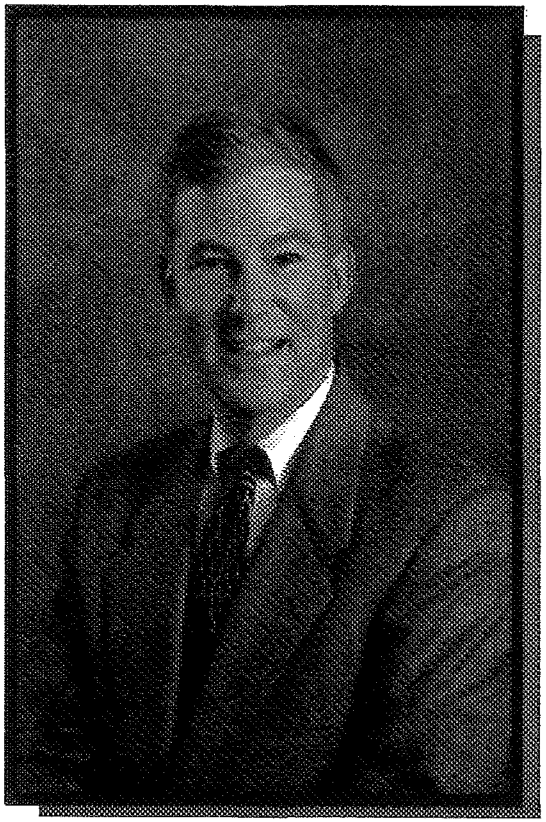
[21] FPL recently announced that it was suspending capital spending on its planned Turkey Point nuclear units 6 and 7, which were scheduled for operation in 2018 and 2019. This could result in accelerating a combined cycle gas unit from 2021 to 2018 (SNL Financial article dated January 14, 2010). PEF also announced significant delays in the completion of its planned Levy nuclear units 1 and 2 to beyond 2020 (SNL Financial articles dated May 1, 2009 and February 4, 2010). This could necessitate accelerating new combined cycle generation to 2016, which was the original in-service date of Levy 1.

[22] FPL considers both its DeSoto Solar and Space Coast Solar plants as non-firm resources until sufficient operating experience is obtained to determine that these facilities can reliably provide energy at FPL's system peak hours (see Florida Public Service Commission, *Review of 2009 Ten-Year Site Plans for Florida's Electric Utilities*, October 2009 at 16).

APPENDIX A

ABOUT THE AUTHOR

Biography of Jeffry Pollock



Jeffry Pollock is President of J.Pollock Incorporated. He has been an energy advisor since 1975. Mr. Pollock has a Bachelor of Science Degree in Electrical Engineering and a Masters in Business Administration from Washington University. At various times prior to graduation, he worked for the McDonnell Douglas Corporation in the Corporate Planning Department; Sachs Electric Company; and L.K. Comstock & Company.

Upon graduation, in June 1975, Mr. Pollock joined Drazen-Brubaker & Associates, Inc. (DBA). DBA was incorporated in 1972 assuming the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. From April 1995 to November 2004, he was a managing principal at Brubaker & Associates, Inc. (BAI).

J. POLLOCK
INCORPORATED

Biography of Jeffry Pollock

During his tenure at both DBA and BAI, Mr. Pollock engaged in a wide range of consulting assignments, including energy and regulatory matters in both the United States and several Canadian provinces. This encompassed preparing financial and economic studies of investor-owned, cooperative and municipal utilities on revenue requirements, cost of service and rate design, and conducting site evaluation. Recent engagements have included advising clients on electric restructuring issues, assisting clients in procurement and management of electricity in both competitive and regulated markets, developing and issuing request for proposals (RFPs), evaluating RFP responses and contract negotiation. Mr. Pollock spearheaded the development and presentation of seminars on electricity issues.

Mr. Pollock has worked on various projects in over 20 states and in two Canadian provinces. He has testified before the Federal Energy Regulatory Commission and state regulatory commissions of Alabama, Arizona, Colorado, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Louisiana, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, Ohio, Pennsylvania, Texas, Virginia, Washington, and Wyoming. He has also appeared before the City of Austin Electric Utility Commission, the Board of Public Utilities of Kansas City, Kansas, the Bonneville Power Administration, Travis County (Texas) District Court, and the U.S. Federal District Court.

J.Pollock, Incorporated assists clients to procure and manage energy in both regulated and competitive markets, and has offices in St. Louis, Missouri and Austin and Houston, Texas. Clients of J.Pollock include commercial, industrial, and institutional energy consumers. The J.Pollock team also advises clients on energy and regulatory issues. J.Pollock is also a registered aggregator in the State of Texas (Certificate No. 80051).

APPENDIX B

UTILITY PRODUCTION COSTS REFLECTED IN CURRENT BASE RATES

FLORIDA POWER & LIGHT COMPANY

Derivation of Production Cost Ratio

Line	Description	Biomass ($000)	Waste Heat[(A)] ($000)
		(1)	(2)
1	**Base Rate Production Costs**	$2,095,593	$1,406,662
	Cost Recovery Clauses		
2	Fuel	$4,314,838	$4,314,838
3	Energy Conservation	$355,819	$355,819
4	Capacity	$585,951	$585,951
5	Environmental	$166,416	$166,416
6	**Total Cost Recovery Clauses**	$5,423,024	$5,423,024
7	**Total Production Costs**	$7,518,617	$6,829,685
8	**Total Base Revenue Requirements**	$3,880,727	$3,880,727
9	**Total Revenue Requirements**	$9,303,750	$9,303,750
10	**Production Costs as a Percent of Total Revenue Requirements**	80.8%	73.4%
11	**Loss Adjusted Energy Sales (GWh)**	107,600.46	107,600.46
12	**Average Production Cost (¢/kWh)**	7.0	6.3

Source: Docket No. 080677-EI - FPL's Compliance Filing E-6a

(A) Reflects 50% of production demand-related costs

PROGRESS ENERGY FLORIDA

Derivation of Production Cost Ratio

Line	Description	Biomass ($000)	Waste Heat[A] ($000)
		(1)	(2)
1	**Base Rate Production Costs**	$857,361	$524,263
	Cost Recovery Clauses		
2	Fuel	$1,885,030	$1,885,030
3	Energy Conservation	$92,259	$92,259
4	Capacity	$645,247	$645,247
5	Environmental	$225,251	$225,251
6	**Total Cost Recovery Clauses**	$2,847,787	$2,847,787
7	**Total Production Costs**	$3,705,148	$3,372,050
8	**Total Base Revenue Requirements**	$1,580,567	$1,580,567
9	**Total Revenue Requirements**	$4,428,354	$4,428,354
10	**Production Costs as a Percent of Total Revenue Requirements**	83.7%	76.1%
11	**Loss Adjusted Energy Sales (GWh)**	41,281.68	41,281.68
12	**Average Production Cost (¢/kWh)**	8.98	8.17

Source: Docket No. 090079-EI - Schedule E-6a adjust for the approved Final Order Revenue Requirement

(A) Reflects 50% of production demand-related costs

TAMPA ELECTRIC COMPANY

Derivation of Production Cost Ratio

Line	Description	Biomass ($000)	Waste Heat[(A)] ($000)
		(1)	(2)
1	**Base Rate Production Costs**	$563,242	$421,918
	Cost Recovery Clauses		
2	Fuel	$898,448	$898,448
3	Energy Conservation	$51,441	$51,441
4	Capacity	$105,639	$105,639
5	Environmental	$65,851	$65,851
6	**Total Cost Recovery Clauses**	$1,121,378	$1,121,378
7	**Total Production Costs**	$1,684,620	$1,543,296
8	**Total Base Revenue Requirements**	$935,136	$935,136
9	**Total Revenue Requirements**	$2,056,514	$2,056,514
10	**Production Costs as a Percent of Total Revenue Requirements**	81.9%	75.0%
11	**Loss Adjusted Energy Sales (GWh)**	21,009.95	21,009.95
12	**Average Production Cost (¢/kWh)**	8.0	7.3

Source: Docket No. 080317-EI - Schedule E-6b, adjusted for approved rate increase

(A) Reflects 50% of production demand-related costs

APPENDIX C

SUMMARY OF UTILITY COST RECOVERY CLAUSE FACTORS

BILLING ADJUSTMENTS

The following charges are applied to the Monthly Rate of each rate schedule as indicated and are calculated in accordance with the formula specified by the Florida Public Service Commission.

RATE SCHEDULE	FUEL ¢/kWh	¢/kWh	¢/kWh	CONSERVATION ¢/kWh	CAPACITY ¢/kWh	$/kW	ENVIRONMENTAL ¢/kWh
	Levelized	On-Peak	Off-Peak				
RS-1, 1st 1,000 kWh	3.857			0.188	0. 621		0.179
RS-1, all addn kWH	4.857			0.188	0. 621		0.179
RST-1		4.674	3.958	0.188	0. 621		0.179
GS-1, WIES-1	4.181			0.186	0. 612		0.177
GST-1		4.674	3.958	0.186	0. 612		0.177
GSD-1	4.181			0.170		1.93	0.157
GSD-1 w/SDTR (June-Sept)		4.764	3.996	0.170		1.93	0.157
GSD-1 w/SDTR (Jan-May & Oct-Dec)	4.181			0.170		1.93	0.157
GSDT-1, HLFT-1		4.674	3.958	0.170		1.93	0.157
GSDT-1 w/SDTR (June-Sept)		4.764	3.996	0.170		1.93	0.157
GSDT-1 w/SDTR (Jan-May & Oct-Dec)		4.674	3.958	0.170		1.93	0.157
GSLD-1, CS-1	4.177			0.166		2.31	0.153
GSLD-1 w/SDTR (June-Sept)		4.760	3.993	0.166		2.31	0.153
GSLD-1 w/SDTR (Jan-May & Oct-Dec)	4.177			0.166		2.31	0.153
GSLDT-1, CST-1, HLFT-2		4.670	3.954	0.166		2.31	0.153
GSLDT-1 w/SDTR (June-Sept)		4.760	3.993	0.166		2.31	0.153
GSLDT-1 w/SDTR (Jan-May & Oct-Dec)		4.670	3.954	0.166		2.31	0.153
GSLD-2, CS-2	4.146			0.155		2.21	0.140
GSLD-2 w/SDTR (June-Sept)		4.733	3.970	0.155		2.21	0.140
GSLD-2 w/SDTR (Jan-May & Oct-Dec)	4.146			0.155		2.21	0.140
GSLDT-2, CST-2, HLFT-3		4.641	3.929	0.155		2.21	0.140
GSLDT-2 w/SDTR (June-Sept)		4.733	3.970	0.155		2.21	0.140
GSLDT-2 w/SDTR (Jan-May & Oct-Dec)		4.641	3.929	0.155		2.21	0.140

NOTE: The Billing Adjustments for additional Rate Schedules are found on Sheet No. 8.030.1

(Continued on Sheet No. 8.030.1)

(Continued from Sheet No. 8.030)

BILLING ADJUSTMENTS (Continued)

RATE SCHEDULE	FUEL ¢/kWh	¢/kWh	¢/kWh	CONSERVATION ¢/kWh	CAPACITY ¢/kWh	$/kW		ENVIRONMENTAL ¢/kWh
	Levelized	On-Peak	Off-Peak					
GSLD-3, CS-3	4.002			0.142		2.08		0.128
GSLDT-3, CST-3		4.474	3.788	0.142		2.08		0.128
OS-2	4.146			0.191	0. 642			0.188
MET	4.146			0.180		2.46		0.171
CILC-1(G)		4.674	3.958	0.152		2.37		0.136
CILC-1(D)		4.637	3.926	0.152		2.37		0.136
CILC-1(T)		4.474	3.788	0.141		2.25		0.125
SL-1,OL-1, PL-1	4.072			0.093	0. 149			0.070
SL-2, GSCU-1	4.181			0.146	0.414			0.130
						RDD	DDC	
SST-1(T)		4.474	3.788	0.130		0.28	0.13	0.115
SST-1(D1)		4.674	3.958	0.143		0.28	0.14	0.128
SST-1(D2)		4.670	3.954	0.143		0.28	0.14	0.128
SST-1(D3)		4.641	3.929	0.143		0.28	0.14	0.128
ISST-1(D)		4.637	3.926	0.143		0.28	0.14	0.128
ISST-1(T)		4.474	3.788	0.130		0.28	0.13	0.115

(Continued on Sheet No. 8.031)

RATE SCHEDULE BA-1
BILLING ADJUSTMENTS

Applicable:

To the Rate Per Month provision in each of the Company's filed rate schedules which reference the billing adjustments set forth below.

COST RECOVERY FACTORS
¢/ kWh

Rate Schedule/ Metering Level	Fuel Cost Recovery(1)			ECCR(2)	CCR(3)	ECRC(4)	
	Levelized	On-Peak	Off-Peak				
RS-1, RST-1, RSL-1, RSL-2, RSS-1 (Sec.)		7.069	3.889	0.270	2.041	0.593	
< 1000	4.611						
> 1000	5.611						
GS-1, GST-1							
Secondary	4.923	7.069	3.889	0.223	1.488	0.583	
Primary	4.874	6.999	3.850	0.221	1.473	0.577	
Transmission	4.825	6.929	3.812	0.219	1.458	0.571	
GS-2 (Sec.)	4.923	-	-	0.188	1.074	0.564	
GSD-1, GSDT-1, SS-1							
Secondary	4.923	7.069	3.889	0.210	1.326	0.571	
Primary	4.874	6.999	3.850	0.208	1.313	0.565	
Transmission	4.825	6.929	3.812	0.206	1.299	0.560	
CS-1, CST-1, CS-2, CS-3, CST-3, SS-3							
Secondary	4.923	7.069	3.889	0.194	1.170	0.571	
Primary	4.874	6.999	3.850	0.192	1.158	0.565	
Transmission	4.825	6.929	3.812	0.190	1.147	0.560	
IS-1, IST-1, IS-2, IST-2, SS-2							
Secondary	4.923	7.069	3.889	0.186	1.069	0.551	
Primary	4.874	6.999	3.850	0.184	1.058	0.545	
Transmission	4.825	6.929	3.812	0.182	1.048	0.540	
LS-1 (Sec.)	4.484	-	-	0.124	0.312	0.569	
GSLM-1, GSLM-2	See appropriate General Service rate schedule						

(1) Fuel Cost Recovery Factor:

The Fuel Cost Recovery Factors applicable to the Fuel Charge under the Company's various rate schedules are normally determined annually by the Florida Public Service Commission for the billing months of January through December. These factors are designed to recover the costs of fuel and purchased power (other than capacity payments) incurred by the Company to provide electric service to its customers and are adjusted to reflect changes in these costs from one period to the next. Revisions to the Fuel Cost Recovery Factors within the described period may be determined in the event of a significant change in costs.

(2) Energy Conservation Cost Recovery Factor:

The Energy Conservation Cost Recovery (ECCR) Factor applicable to the Energy Charge under the Company's various rate schedules is normally determined annually by the Florida Public Service Commission for twelve-month periods beginning with the billing month of January. This factor is designed to recover the costs incurred by the Company under its approved Energy Conservation Programs and is adjusted to reflect changes in these costs from one period to the next.

(Continued on Page No. 2)

TECO
TAMPA ELECTRIC

SIXTY-FIFTH REVISED SHEET NO. 6.020
CANCELS SIXTY-FOURTH REVISED SHEET NO. 6.020

ADDITIONAL BILLING CHARGES

TOTAL FUEL AND PURCHASED POWER COST RECOVERY CLAUSE: The total fuel and purchased power cost recovery factor shall be applied to each kilowatt-hour delivered, and shall be computed in accordance with the formula prescribed by the Florida Public Service Commission. The following fuel recovery factors by rate schedule have been approved by the Commission:

RECOVERY PERIOD
(January 2010 through December 2010)

Rate Schedules		Fuel ¢/kWh Standard	Fuel ¢/kWh Peak	Fuel ¢/kWh Off-Peak	¢/kWh Energy Conservation	¢/kWh Capacity	¢/kWh Environmental
RS (up to 1,000 kWh)		4.167	-	-	.254	0.539	0.486
RS (over 1,000 kWh)		5.167	-	-	.254	0.539	0.486
RSVP-1, GSVP-1	(P_1)	4.517	-	-	(0.573)	0.539	0.486
	(P_2)	4.517	-	-	(0.406)	0.539	0.486
	(P_3)	4.517	-	-	3.705	0.539	0.486
	(P_4)	4.517	-	-	29.254	0.539	0.486
GS, GST		4.517	5.407	4.173	0.249	0.526	0.486
TS		4.517	-	-	0.249	0.526	0.486
LS-1		4.383	-	-	0.113	0.158	0.484
GSD Optional							
Secondary		4.517	-	-	0.179	0.419	0.485
Primary		4.472	-	-	0.177	0.414	0.480
Subtransmission		4.427	-	-	0.175	-	0.475

Rate Schedules	Fuel ¢/kWh Standard	Fuel ¢/kWh Peak	Fuel ¢/kWh Off-Peak	$/kW Energy Conservation	$/kW Capacity	¢/kWh Environmental
GSD, GSDT, SBF, SBFT						
Secondary	4.517	5.407	4.173	0.88	1.74	0.485
Primary	4.472	5.353	4.131	0.87	1.72	0.480
Subtransmission	4.427	5.299	4.090	0.86	1.71	0.475
IS, IST, SBI						
Primary	4.472	5.353	4.131	0.78	1.55	0.474
Subtransmission	4.427	5.299	4.090	0.77	1.54	0.469

Continued to Sheet No. 6.021

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: December 30, 2009

APPENDIX D

EXCERPTS FROM THE
2009 TEN-YEAR SITE PLANS
FILED BY FPL, PEF, AND TECO

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		DeSoto Next Generation Solar Energy Center
(2)	**Capacity**		
	a. Summer	25 MW	
	b. Winter	25 MW	
(3)	**Technology Type:**	Photovoltaic	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2009	
	b. Commercial In-service date:	2010	
(5)	**Fuel**		
	a. Primary Fuel		Solar
	b. Alternate Fuel		N/A
(6)	**Air Pollution and Control Strategy:**		N/A
(7)	**Cooling Method:**		N/A
(8)	**Total Site Area:**	180	Acres
(9)	**Construction Status:**	U	(Under construction, less than 50% complete)
(10)	**Certification Status:**	Pemitted	(Individual Permits)
(11)	**Status with Federal Agencies:**	Permitted	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):		N/A
	Forced Outage Factor (FOF):		N/A
	Equivalent Availability Factor (EAF):		0.98
	Resulting Capacity Factor (%):		Approx. 25% (First Full Year of Operation)
	Average Net Operating Heat Rate (ANOHR):		N/A Btu/kWh
	Base Operation 75F,100%		
(13)	**Projected Unit Financial Data *,****		
	Book Life (Years):		25 years
	Total Installed Cost (2010 $/kW):		6,937
	Direct Construction Cost ($/kW):		-
	CWIP Amount ($/kW):		369
	Escalation ($/kW):		-
	Fixed O&M ($/kW -Yr.): (2010 $kW-Yr)		54
	Variable O&M ($/MWH): (2010 $/MWH)		0
	K Factor:		1.15

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes transmission interconnection.

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Space Coast Next Generation Energy Center

(2) **Capacity**
a. Summer 10 MW
b. Winter 10 MW

(3) **Technology Type:** Photovoltaic

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2009
b. Commercial In-service date: 2010

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel N/A

(6) **Air Pollution and Control Strategy:** N/A

(7) **Cooling Method:** N/A

(8) **Total Site Area:** 60 Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned- Individual Permits)

(11) **Status with Federal Agencies:** Permitted

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	N/A
Forced Outage Factor (FOF):	N/A
Equivalent Availability Factor (EAF):	0.98
Resulting Capacity Factor (%):	Approx. 21.3% (First Full Year of Operation)
Average Net Operating Heat Rate (ANOHR):	N/A Btu/kWh
Base Operation 75F,100%	

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25 years
Total Installed Cost (2010 $/kW):	7,890
Direct Construction Cost ($/kW):	-
CWIP Amount ($/kW):	427.7
Escalation ($/kW):	-
Fixed O&M ($/kW -Yr.): (2010 $kW-Yr)	54
Variable O&M ($/MWH): (2010 $/MWH)	0
K Factor:	1.2100

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes transmission interconnection.

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Cape Canaveral Next Generation Clean Energy Center

(2) **Capacity**
a. Summer 1,219 MW
b. Winter 1,343 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2011
b. Commercial In-service date: 2013

(5) **Fuel**
a. Primary Fuel — Natural Gas
b. Alternate Fuel — Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low No_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Once-through cooling water

(8) **Total Site Area:** 43 Acres

(9) **Construction Status:** T (Regulatory approval received, but not under construction)

(10) **Certification Status:** T (Regulatory approval received, but not under construction)

(11) **Status with Federal Agencies:** T (Regulatory approval received, but not under construction)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.1%
Forced Outage Factor (FOF):	1.1%
Equivalent Availability Factor (EAF):	96.8%
Resulting Capacity Factor (%):	Approx.90 % (First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,580 Btu/kWh
Base Operation 75F,100%	

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25 years
Total Installed Cost (2013 $/kW):	915
Direct Construction Cost ($/kW):	
AFUDC Amount ($/kW):	98
Escalation ($/kW):	
Fixed O&M ($/kW -Yr.): (2013 $kW-Yr)	14.81
Variable O&M ($/MWH): (2013 $/MWH)	0.15
K Factor:	1.494

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) Plant Name and Unit Number: Riviera Beach Next Generation Clean Energy Center

(2) Capacity
a. Summer 1,207 MW
b. Winter 1,310 MW

(3) Technology Type: Combined Cycle

(4) Anticipated Construction Timing
a. Field construction start-date: 2012
b. Commercial In-service date: 2014

(5) Fuel
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Ultra-low sulfur distillate

(6) Air Pollution and Control Strategy: Dry Low No_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) Cooling Method: Once-through cooling water

(8) Total Site Area: 33 Acres

(9) Construction Status: T (Regulatory approval received, but not under construction)

(10) Certification Status: T (Regulatory approval received, but not under construction)

(11) Status with Federal Agencies: T (Regulatory approval received, but not under construction)

(12) Projected Unit Performance Data:

Planned Outage Factor (POF):	2.1%
Forced Outage Factor (FOF):	1.1%
Equivalent Availability Factor (EAF):	96.8%
Resulting Capacity Factor (%):	Approx. 90% (First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,576 Btu/kWh
Base Operation 75F,100%	

(13) Projected Unit Financial Data *,**

Book Life (Years):	25 years
Total Installed Cost (2014 $/kW):	1,057
Direct Construction Cost ($/kW):	
AFUDC Amount ($/kW):	122
Escalation ($/kW):	
Fixed O&M ($/kW -Yr.): (2014 $kW-Yr)	15.32
Variable O&M ($/MWH): (2014 $/MWH)	0.12
K Factor:	1.494

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Turkey Point Unit 6 Nuclear Unit

(2) **Capacity**
a. Summer 1,100 MW
b. Winter 1,100 MW

(3) **Technology Type:** Nuclear

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2011
b. Commercial In-service date: 2018

(5) **Fuel**
a. Primary Fuel uranium dioxide
b. Alternate Fuel NA

(6) **Air Pollution and Control Strategy:** NA

(7) **Cooling Method:** Mechanical Draft Cooling Towers

(8) **Total Site Area:** 211 Acres

(9) **Construction Status:** T (Regulatory approval received, but not under construction)

(10) **Certification Status:** T (Regulatory approval received, but not under construction)

(11) **Status with Federal Agencies:** T (Regulatory approval received, but not under construction)

(12) **Projected Unit Performance Data:**
Planned Outage Factor (POF): TBD
Forced Outage Factor (FOF): TBD
Equivalent Availability Factor (EAF): TBD
Resulting Capacity Factor (%): Approx. 90% (First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR): TBD Btu/kWh
Base Operation 75F,100%

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

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2009

(1)	**Plant Name and Unit Number:**	**Suwannee P4**
(2)	**Capacity**	
	a. Summer:	**178**
	b. Winter:	**205**
(3)	**Technology Type:**	**COMBUSTION TURBINE**
(4)	**Anticipated Construction Timing**	
	a. Field construction start date:	**1/2012**
	b. Commercial in-service date:	**6/2014 (EXPECTED)**
(5)	**Fuel**	
	a. Primary fuel:	**NATURAL GAS**
	b. Alternate fuel:	**DISTILLATE FUEL OIL**
(6)	**Air Pollution Control Strategy:**	**UNKNOWN**
(7)	**Cooling Method:**	**UNKNOWN**
(8)	**Total Site Area:**	**596 ACRES**
(9)	**Construction Status:**	**PLANNED**
(10)	**Certification Status:**	**PLANNED**
(11)	**Status with Federal Agencies:**	**PLANNED**
(12)	**Projected Unit Performance Data**	
	a. Planned Outage Factor (POF):	**4.0 %**
	b. Forced Outage Factor (FOF):	**2.1 %**
	c. Equivalent Availability Factor (EAF):	**94.1 %**
	d. Resulting Capacity Factor (%):	**7.6 %**
	e. Average Net Operating Heat Rate (ANOHR):	**10,760 BTU/kWh**
(13)	**Projected Unit Financial Data**	
	a. Book Life (Years):	**25**
	b. Total Installed Cost (In-service year $/kW):	**976.34**
	c. Direct Construction Cost ($/kW):	**745.95**
	d. AFUDC Amount ($/kW):	**94.73**
	e. Escalation ($/kW):	**135.66**
	f. Fixed O&M ($/kW-yr):	**8.45**
	g. Variable O&M ($/MWh):	**7.95**
	h. K Factor:	**NO CALCULATION**

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2009

(1)	Plant Name and Unit Number:	Suwannee P5
(2)	Capacity	
	a. Summer:	178
	b. Winter:	205
(3)	Technology Type:	COMBUSTION TURBINE
(4)	Anticipated Construction Timing	
	a. Field construction start date:	1/2013
	b. Commercial in-service date:	6/2015 (EXPECTED)
(5)	Fuel	
	a. Primary fuel:	NATURAL GAS
	b. Alternate fuel:	DISTILLATE FUEL OIL
(6)	Air Pollution Control Strategy:	UNKNOWN
(7)	Cooling Method:	UNKNOWN
(8)	Total Site Area:	596 ACRES
(9)	Construction Status:	PLANNED
(10)	Certification Status:	PLANNED
(11)	Status with Federal Agencies:	PLANNED
(12)	Projected Unit Performance Data	
	a. Planned Outage Factor (POF):	4.0 %
	b. Forced Outage Factor (FOF):	2.1 %
	c. Equivalent Availability Factor (EAF):	94.1 %
	d. Resulting Capacity Factor (%):	8.0 %
	e. Average Net Operating Heat Rate (ANOHR):	10,830 BTU/kWh
(13)	Projected Unit Financial Data	
	a. Book Life (Years):	25
	b. Total Installed Cost (In-service year $/kW):	627.12
	c. Direct Construction Cost ($/kW):	460.71
	d. AFUDC Amount ($/kW):	60.84
	e. Escalation ($/kW):	105.57
	f. Fixed O&M ($/kW-yr):	3.22
	g. Variable O&M ($/MWh):	7.95
	h. K Factor:	NO CALCULATION

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2009

(1)	Plant Name and Unit Number:	Levy County Unit No. 1
(2)	Capacity	
	a. Summer:	1,092
	b. Winter:	1,120
(3)	Technology Type:	ADVANCED LIGHT WATER NUCLEAR
(4)	Anticipated Construction Timing	
	a. Field construction start date:	1/2010
	b. Commercial in-service date:	6/2016 (EXPECTED)
(5)	Fuel	
	a. Primary fuel:	URANIUM
	b. Alternate fuel:	--
(6)	Air Pollution Control Strategy:	N/A
(7)	Cooling Method:	COOLING TOWER
(8)	Total Site Area:	3,100 ACRES
(9)	Construction Status:	PLANNED
(10)	Certification Status:	PLANNED
(11)	Status with Federal Agencies:	PLANNED
(12)	Projected Unit Performance Data	
	a. Planned Outage Factor (POF):	5.1 %
	b. Forced Outage Factor (FOF):	3.0 %
	c. Equivalent Availability Factor (EAF):	92.0 %
	d. Resulting Capacity Factor (%):	91 %
	e. Average Net Operating Heat Rate (ANOHR):	9,710 BTU/kWh
(13)	Projected Unit Financial Data	
	a. Book Life (Years):	40
	b. Total Installed Cost (In-service year $/kW):	7425.01
	c. Direct Construction Cost ($/kW):	5165.91
	d. AFUDC Amount ($/kW):	1620.30
	e. Escalation ($/kW):	638.80
	f. Fixed O&M ($/kW-yr):	53.08
	g. Variable O&M ($/MWh):	2.87
	h. K Factor:	NO CALCULATION

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2009

(1)	Plant Name and Unit Number:	Levy County Unit No. 2
(2)	Capacity	
	a. Summer:	1,092
	b. Winter:	1,120
(3)	Technology Type:	ADVANCED LIGHT WATER NUCLEAR
(4)	Anticipated Construction Timing	
	a. Field construction start date:	1/2011
	b. Commercial in-service date:	6/2017 (EXPECTED)
(5)	Fuel	
	a. Primary fuel:	URANIUM
	b. Alternate fuel:	--
(6)	Air Pollution Control Strategy:	N/A
(7)	Cooling Method:	COOLING TOWER
(8)	Total Site Area:	3,100 ACRES
(9)	Construction Status:	PLANNED
(10)	Certification Status:	PLANNED
(11)	Status with Federal Agencies:	PLANNED
(12)	Projected Unit Performance Data	
	a. Planned Outage Factor (POF):	5.1 %
	b. Forced Outage Factor (FOF):	3.0 %
	c. Equivalent Availability Factor (EAF):	92.0 %
	d. Resulting Capacity Factor (%):	91 %
	e. Average Net Operating Heat Rate (ANOHR):	9,710 BTU/kWh
(13)	Projected Unit Financial Data	
	a. Book Life (Years):	40
	b. Total Installed Cost (In-service year $/kW):	5155.09
	c. Direct Construction Cost ($/kW):	3390.06
	d. AFUDC Amount ($/kW):	1278.60
	e. Escalation ($/kW):	486.43
	f. Fixed O&M ($/kW-yr):	37.16
	g. Variable O&M ($/MWh):	2.87
	h. K Factor:	NO CALCULATION

SCHEDULE 9

(Page 6 of 12)

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 1, 2 & 3
(2)	CAPACITY	
	A. SUMMER	56
	B. WINTER	61
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	SEP 2011
	B. COMMERCIAL IN-SERVICE DATE	MAY 2012
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	WET LOW EMISSION
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	2.6
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.4
	RESULTING CAPACITY FACTOR (2012)	4.2%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	10,603 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	623.95
	DIRECT CONSTRUCTION COST ($/kW)	559.67
	AFUDC AMOUNT ($/kW)	45.67
	ESCALATION ($/kW)	18.61
	FIXED O&M ($/kW – Yr)	21.35
	VARIABLE O&M ($/MWH)	3.97
	K FACTOR	1.5984

[1] BASED ON IN-SERVICE YEAR.

SCHEDULE 9

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 4
(2)	CAPACITY	
	A. SUMMER	149
	B. WINTER	177
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	MAY 2012
	B. COMMERCIAL IN-SERVICE DATE	JAN 2013
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	WET LOW EMISSION
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	2.6
	FORCED OUTAGE RATE (FOR)	2.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	94.4
	RESULTING CAPACITY FACTOR (2013)	6.3%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	12,579 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	742.27
	DIRECT CONSTRUCTION COST ($/kW)	651.47
	AFUDC AMOUNT ($/kW)	54.33
	ESCALATION ($/kW)	36.46
	FIXED O&M ($/kW – Yr)	8.09
	VARIABLE O&M ($/MWH)	17.79
	K FACTOR	1.5984

[1] BASED ON IN-SERVICE YEAR.

SCHEDULE 9

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 5 & 6
(2)	CAPACITY	
	A. SUMMER	149
	B. WINTER	177
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	SEP 2012
	B. COMMERCIAL IN-SERVICE DATE	MAY 2013
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	WET LOW EMISSION
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	2.6
	FORCED OUTAGE RATE (FOR)	2.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	94.4
	RESULTING CAPACITY FACTOR (2013)	4.5%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	12,928 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	742.27
	DIRECT CONSTRUCTION COST ($/kW)	651.47
	AFUDC AMOUNT ($/kW)	54.33
	ESCALATION ($/kW)	36.46
	FIXED O&M ($/kW – Yr)	8.09
	VARIABLE O&M ($/MWH)	17.79
	K FACTOR	1.5984

[1] BASED ON IN-SERVICE YEAR.

SCHEDULE 9

(Page 9 of 12)

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 7
(2)	CAPACITY	
	A. SUMMER	56
	B. WINTER	61
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	SEP 2013
	B. COMMERCIAL IN-SERVICE DATE	MAY 2014
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	WET LOW EMISSION
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	2.6
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.4
	RESULTING CAPACITY FACTOR (2014)	5.6%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	10,658 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	651.70
	DIRECT CONSTRUCTION COST ($/kW)	559.67
	AFUDC AMOUNT ($/kW)	47.70
	ESCALATION ($/kW)	44.33
	FIXED O&M ($/kW – Yr)	22.30
	VARIABLE O&M ($/MWH)	4.15
	K FACTOR	1.5984

[1] BASED ON IN-SERVICE YEAR.

SCHEDULE 9

(Page 10 of 12)

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 8 & 9
(2)	CAPACITY	
	A. SUMMER	56
	B. WINTER	61
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	SEP 2014
	B. COMMERCIAL IN-SERVICE DATE	MAY 2015
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	WET LOW EMISSION
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	2.6
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.4
	RESULTING CAPACITY FACTOR (2015)	6.6%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	10,649 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	666.05
	DIRECT CONSTRUCTION COST ($/kW)	559.67
	AFUDC AMOUNT ($/kW)	48.75
	ESCALATION ($/kW)	57.62
	FIXED O&M ($/kW – Yr)	22.79
	VARIABLE O&M ($/MWH)	4.24
	K FACTOR	1.5984

[1] BASED ON IN-SERVICE YEAR.

SCHEDULE 9

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 10 & 11
(2)	CAPACITY	
	A. SUMMER	56
	B. WINTER	61
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	SEP 2015
	B. COMMERCIAL IN-SERVICE DATE	MAY 2016
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	WET LOW EMISSION
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	2.6
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.4
	RESULTING CAPACITY FACTOR (2016)	7.7%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	10,621 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	680.69
	DIRECT CONSTRUCTION COST ($/kW)	559.67
	AFUDC AMOUNT ($/kW)	49.82
	ESCALATION ($/kW)	71.20
	FIXED O&M ($/kW – Yr)	23.29
	VARIABLE O&M ($/MWH)	4.34
	K FACTOR	1.5984

[1] BASED ON IN-SERVICE YEAR.

SCHEDULE 9

(Page 12 of 12)

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CC 1
(2)	CAPACITY	
	A. SUMMER	555
	B. WINTER	607
(3)	TECHNOLOGY TYPE	COMBINED CYCLE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2014
	B. COMMERCIAL IN-SERVICE DATE	MAY 2018
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	SCR, DLN BURNERS
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	3.8
	FORCED OUTAGE RATE (FOR)	3.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	93.2
	RESULTING CAPACITY FACTOR (2018)	88.4%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	6,837 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	1,528.71
	DIRECT CONSTRUCTION COST ($/kW)	1,158.85
	AFUDC AMOUNT ($/kW)	184.86
	ESCALATION ($/kW)	185.00
	FIXED O&M ($/kW – Yr)	6.70
	VARIABLE O&M ($/MWH)	4.66
	K FACTOR	1.6508

[1] BASED ON IN-SERVICE YEAR.

Susan F. Clark
Radey Thomas Yon & Clark

Presentation on Pricing for Qualifying Facilities and Renewable Resources

Presented by Susan F. Clark
Radey Thomas Yon & Clark, P.A.
March 11, 2010

Federal Legislation/State Implementation

- Public Utility Regulatory Policies Act (PURPA) passed in 1978
- Requires Utilities to Purchase from Qualifying Facilities (QFs)
- States Required to Adopt Rules to Implement PURPA
- Florida Adopted Rules in 1983, rules include terms and conditions of Standard Offer Contracts and Calculation of Avoided Costs

General Requirements

- Utilities must purchase power from QFs (small power producers, cogenerators, renewable energy producers)
- States cannot require utilities to pay more than "Full Avoided Cost "

Full Avoided Costs

- The cost the utility would have incurred by generating the power itself or purchasing from another supplier (366.51, F.S.)
- Includes capacity payments based on the value of deferring capacity the utility would otherwise have to build or acquire.
- Rates are no higher than if power otherwise generated by utility
- Alternative generators must perform like the plant that they are avoiding

Existing Law on Renewable Energy Contracts

- Section 366.91, Florida Statutes
  - Investor-owned utilities, JEA and OUC must continuously offer a contract to purchase renewable energy
  - Contract payment based upon “full avoided cost”
  - Contract term of at least ten years

FPSC Rules for Standard Renewable Contract

- Renewable generator selects contract length
  - minimum - 10 years
  - maximum - life of unit
- A variety of fossil units can be selected as units to contract against
- Standard contract available continuously
- No subscription limit on amount of capacity that can be contracted for
- Additional payment options would be available to facilitate funding from investors
- Re-opener clause if full avoided costs change as a result of new environmental requirements
- Expedited dispute resolution process
- Tradable renewable energy credits (T-RECs) and tax credits remain the property of the renewable generator

Federal Limitation

- Under PURPA states cannot mandate payments to QF that exceed the utilities avoided cost