BIOMASS CO-FIRING WITH COAL AT LAKELAND UTILITIES

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Mr. Phillip C. Badger, Contract Manager
Southeastern Regional Biomass Program
POB 1010
Mail Stop CEB 3A
Muscle Shoals, AL 35662-1010

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by

S. A. Segrest
The Common Purpose Institute,
Temple Terrace, FL, 33617,

D. L. Rockwood
School of Forest Resources and Conservation,
University of Florida,
Gainesville, FL 32611-0410,

J. A. Stricker
Polk County Cooperative Extension Service,
University of Florida,
Bartow, FL 33831-9005,

and A. E. S. Green
Clean Combustion Technology Laboratory,
University of Florida,
Gainesville, FL 32611-2050

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ABSTRACT

This project evaluates the major agricultural, power plant engineering, and business development issues associated with energy-crop biomass (i.e., "closed loop") cofiring with coal at Lakeland Utilities' McIntosh-3 unit in Polk County in central Florida. McIntosh-3 (a Babcock and Wilcox pulverized coal (PC), wall fired boiler design) is a large power plant (365 MW) operating as a base load facility (i.e., a historical availability/capacity factor of 80+%). Recognizing the MW size and capacity factor of McIntosh-3, achieving a biomass co-firing ratio in the 5 to 6 % range (based on generation) would represent a sizable renewable energy source of ~20 MWs.

Land for biomass cropping is readily available in the Lakeland vicinity. Some 22% of the land is presently timberland, much of which is in need of planting or other improvement. Cropland and pastureland constitute nearly 50% of the land base, and the pastureland has a very low opportunity cost. Within Polk County alone, 185,000 acres of pastureland occur within 15 miles of McIntosh-3.

These marginal and reclaimed lands are suitable for biomass cropping of sugarcane, elephantgrass, leucaena, Eucalyptus, and slash pine. Biomass yields vary with species, soil type, and cultural intensity, ranging from as low as 10 green tons/acre/year (tay) for E. grandis with minimal intensity on sandy soils, 17.5 tay for elephantgrass on overburden sites, 35 tay for leucaena on phosphatic clays, to as much as 55 tay for E. grandis when managed intensively on clay lands. Because these yields were estimated from relatively small experimental plots, commercial-size plantations, ~ 200/300 acres in size, of the promising energy crops are recommended to confirm yields.

For Lakeland Utilities, a target price for "Green Energy" based on delivered coal costs plus a 10% premium, is in the 2¢ per Kwh range, or $2 per MMBTU (using McIntosh's heat rate of about 10,000). Based on estimated yields, costs of establishment, harvesting, and transportation, high yielding crops grown on reclaimed clay settling areas, E. grandis and leucaena, meet the target price goal.

Expected Case MM BTU Production Costs for Four Energy Crops[1]

	Eucalyptus	Leucaena	Elephantgrass	Presscake
Establishment	$0.19	$0.25	$0.70	$0.43
Harvesting	$1.16	$0.86	$1.36	$1.15
Transportation	$0.41	$0.44	$0.57	$0.61
Total Production Cost	$1.76	$1.55	$2.63	$2.19

[1]Assumed yields of 55, 35, 20, and 31.5 tay, respectively

However, even with competitive production fuel costs for eucalyptus and leucaena energy crops, the economics to support capital investment of a closed loop biomass project are still severely limited. Under current Lakeland Electric economic assumptions of pricing green energy only at a small premium above avoided coal costs (i.e., no capacity component), direct injection co-firing represents probably the only realistic option. After subtracting estimated energy crop fuel costs from project revenues of ~2¢ per Kwh, very little income would be left to finance capital requirements needed to co-fire via external gasification. However, this perspective could change by (1) pricing Green Energy to customers at a premium over total electricity costs (instead of only the fuel cost component); and (2) applying federal incentive payments (i.e., the Renewable Energy Production Incentive, the Section 45 Tax Credit) to the Project.

Generally co-utilization of biomass with coal in a pre-existing PC boiler steam turbine facility can proceed by 1) direct injection co-firing or by 2) indirect co-firing using another thermal processing system and feeding its gaseous, liquid or solid products into the boiler. Prior direct co-firing studies are listed, including a similar wall fired burner arrangement for co-firing biomass. Currently, there are significant fuel processing related limitations at McIntosh-3 to increasing biomass direct co-firing.

Since McIntosh-3's limit of 2% RDF co-firing impedes effective direct co-firing of biomass or RDF-biomass combined, five ways of overcoming this limitation are identified. The mechanical processing necessary to feed the biomass through the RDF channel is also considered. For indirect co-firing technologies, lists of six external and two internal gasifier vendors are given along with comments on performance. A brief discussion of advanced gasifiers for directly firing combustion turbines is given. The Appendix contains an extended biomass gasifier vendor contact list and three tables summarizing a prior detailed evaluation of municipal solid waste or RDF thermal processors that might also be adapted for biomass.

Reviews of potential economic and market incentives for biomass cofiring were performed. Currently, every major Electricity Deregulation Bill in Congress includes a provision for a Renewable Energy Portfolio Standard (REPS). With a REPS, every electric utility would be required to generate minimum percentages of the electricity sold from Renewable Energy Sources such as wind, solar, or biomass. While proposed legislation varies, typical minimum levels are 2% of Mwh generation by the year 2000, increasing to 10% by 2010. Also, as electricity markets move toward deregulation, marketing research is consistently showing that a “Green Energy Option” is a significant factor in determining “Customer Choice Decisions.” In Pilot Deregulation Programs throughout the U.S., when customers are given an option to choose their electricity provider, a significant market share is showing a willingness to pay a premium of about 10% for “Green” sources of generation. Thus, when deregulation occurs, even if a REPS is not enacted, an Electricity Provider that can not offer renewable energy options to customers may find itself locked out of a significant market segment – even if it is the lowest cost provider.

The coming deregulation of electricity markets, coupled with current and future federal tax credits, pollution allowances, etc., suggests a significant business opportunity. However, without any incentive payments (e. g., the 1.5 cent/Kwh Renewable Energy Production Incentive (REPI) available to non-taxable electric utilities), only eucalyptus and leucaena have any “expected case” potential of meeting a target production cost of $2.00 per MM BTU for energy crops to be competitive with coal on fuel cost. Although the REPI Credit is legislated to be available for the first 10 years of a project’s operation, there is no guarantee by Congress to fund the REPI Program in years to come. This creates significant risk in the long term financing of a project at McIntosh-3, where uncertainty would exist as to whether the REPI Credit would be available to cover debt payments over the full term of any financing agreement.

One strategy to mitigate the risk of the REPI Credit would be for Lakeland Electric to sell some small amount of capacity (i.e., through a Unity Power Sale Agreement) of the McIntosh Unit (i.e., that generated "Green Energy" through co-firing) to an Investor Owned Electric Utility (i.e., TECO, Florida Power Corp., Florida Power & Light, Gulf Power/Southern Co.). Under this strategy, the Investor Owned Utility would take advantage of the Section 45 Tax Credit (not available to Lakeland Electric as a municipal electric utility), which is not subject to yearly Congressional Appropriations. TECO Energy may be an especially good candidate for this type of Unit Power Sale, as TECO has invested previously in tax oriented energy projects (Section 29 of the Internal Revenue Code).

INTRODUCTION

This report is one of only a few utility-sponsored feasibility studies of biomass cofiring with coal in Florida. Its definition of the most promising biomass production alternatives for central Florida is based on considerable research conducted by the University of Florida.

An agreement between the University of Florida's Institute of Food and Agricultural Sciences and the Gas Research Institute in the 1970's stimulated a 10-year research effort to identify and test energy crops for the manufacture of methane gas. The tall-growing perennial bunchgrasses had the most potential as short rotation biomass crops. These grasses are indigenous to the tropics, utilize the C_4 pathway of carbon fixation, and produce long hardened stems (37). Examples included elephantgrass (*Pennisetum purpureum* L., often referred to as napiergrass), sugarcane (*Saccharum* sp.), and Erianthus [*Erianthus arundinaceum* (Retz)]. Leucaena [*Leucaena leucocephala* (Lam.)], a tropical shrub/tree, also has desirable traits for biomass production.

In addition to manufacture of methane, these same crops may also be used for other biomass energy technologies such as the manufacture of ethanol from sugarcane. A biomass to ethanol system in central Florida using a dedicated feedstock supply system based on sugarcane, energycane, elephantgrass, leucaena, Eucalyptus, and slash pine was feasible (50, 51). The ethanol production plant would primarily utilize sugarcane, and a coupled lignocellulose conversion facility would convert the residues and other feedstocks.

The environmental impact of a dedicated feedstock supply system for energy production in central Florida is generally viewed as positive by the environmental community (50). Biomass crops improve water quality because few if any chemicals are needed, soil disturbance is kept to a minimum because crops are harvested over a number of years without replanting, and supplemental fertilization is minimal, especially on phosphatic clay (30). Wildlife impacts can be minimized by not disturbing established habitats on field margins or along drainage ways. Wildlife will also benefit if large areas of monoculture are avoided and harvests are staggered. There is no indication that biomass production would aggravate critical habitat for threatened and endangered species on lands targeted for biomass crop production (30). While research has shown (20, 21, 31, 52) that reclaimed phosphate land has higher levels of radionuclides, especially ^{226}Ra, than undisturbed lands in central Florida, plants grown on soils with relatively high radionuclide concentrations have been found to be safe, even for direct human consumption. No problem is expected with biomass crops, and burning biomass crops will not result in problems with airborne radionuclides.

Interest in the use of biomass grown in central Florida has recently expanded to include direct combustion to generate electricity at Lakeland's 365 MW McIntosh Station Unit Number 3. Senior Management for the City of Lakeland indicated that the key driver in their deciding to evaluate biomass co-firing was Electricity Deregulation. When McIntosh-3 went into commercial operation in September 1982, it was one of the first generating units in the U.S. specifically designed to accommodate suspension firing of refuse derived fuel (RDF) while burning pulverized coal (PC). McIntosh-3 (a Babcock and Wilcox PC, wall fired boiler design) is one of the largest power plants in Florida and operates as a base load facility (i. e., a historical availability/capacity factor of 80+%). McIntosh-3 also includes an Atlas Bin, pneumatic RDF fuel lines to boiler entry ports, and a relatively large boiler bottom. Currently, approximately 30,000 tons of municipal solid wastes (i. e., primarily organic waste streams) are processed and co-fired each year.

This study defines the most promising biomass production alternatives and currently available engineering approaches and develops overall economics and potential business structures for biomass cofiring at McIntosh-3.

MATERIALS AND METHODS

Land Base

We evaluated land availability and biomass cropping alternatives by updating previous work in the phosphate mining area south of Lakeland (50, 51). The updating included summarization of detailed soil maps of Polk County for soil types occurring within 15, 20, 25, and 30 mile radii of McIntosh-3. We also extended consideration of biomass resources to other lands, primarily timberlands, within a 50 mile radius of Lakeland by accessing data recently compiled by the Southern Research Station of the USDA Forest Service (6).

Biomass Crops

Costs for planting, maintaining and harvesting the biomass crops reported here were estimated with the aid of the AGSYS budget generator program. This program was developed by the Food and Resource Economics Dept. at the University of Florida (46). The AGSYS program is designed to estimate the cost of producing a specific crop through simulation of production decisions and activities over a period of time. Material and machinery databases are developed and used to calculate costs for all necessary production inputs.

The material and machinery databases are used by AGSYS to create budgets. The material database contains cost information for inputs including seed, fertilizer, pesticides, and labor. The machinery database has all the technical information needed to generate both fixed and variable costs for individual items of farm equipment used to grow the crop. When building a budget, AGSYS pulls information from both material and machinery databases and stores it as a budget file.

Crop production budgets bring together information from the material and machinery databases into operational records which serve to simulate a crop production plan. Each operation has a name, date performed, and a list of production input items. An example is: applying fertilizer on 3/30/96 with a 100 hp tractor, broadcast fertilizer spreader, traveling at 5 mph, and applying 350 lbs of ammonium nitrate fertilizer per acre. Budgets are a collection of one or more of these operational records. In addition to operation records, a budget includes a set of economic parameters that are used to calculate costs such as depreciation, interest expense, labor costs and overhead costs.

Three separate budgets were developed to estimate cost for each crop reported here. Budgets for land preparation and planting, a budget for annual crop maintenance including fertilization, where needed, and a budget for harvest operations. Costs for land preparation and planting were amortized over the expected life of the stand and combined with costs for crop maintenance to estimate a yearly cost to cover both establishment and maintenance.

Production alternatives and costs for woody biomass crops were developed from studies in peninsular Florida. For *E. grandis*, a growth and yield model was based on productivities observed on sites covering the spectrum of lands in central and southern Florida. Costs for plantation establishment and management were derived from commercial plantation activity in southern Florida. Harvesting costs were obtained from ongoing energywood harvests in southern Alabama. Slash pine data developed by the previously described ethanol study were applicable to this study.

Cofiring

We conducted engineering evaluations of the most promising cofiring techniques for McIntosh-3: 1) direct co-firing of biomass in the boiler furnace, 2) indirect co-firing by thermally processing the biomass into a gas, an oil or a charcoal, or a combination of the above, and 3) processing biomass into a higher quality gas or liquid fuel. Commercially available biomass co-firing technological approaches for direct injection, internal and external gasification were reviewed. For direct injection and external gasification, detailed 'test-burn" information was obtained. We addressed the McIntosh-3 specific issues of bottom grate fouling and biomass lofting.

Financial/Legal Analyses

As part of the feasibility assessment of biomass co-firing at Lakeland Utilities, a review of potential economic and market incentives was performed. We then performed financial and legal analyses to determine the most feasible cropping and cofiring options for implementation.

RESULTS AND DISCUSSION

Land Base

The use of marginal and reclaimed land within 50 miles of Lakeland, Florida, is favorable for biomass energy crops. Rangeland and cropland constitute about 50% of the land base (Table 1), but cattle production is marginally profitable, making some 3.5 million acres of pasture potentially available for biomass cropping. Timberlands compose some 22% of the lands.

Table 1. Classification of land use in counties within 50 miles of Lakeland.

	Timberland	Cropland	Pasture	Other NonForest	Total
Acres	2,123,434	1,264,488	3,509,605	2,757,148	9,850,551
Percent	22	13	36	28	

Timberlands in this 11 county region are largely composed of relatively inexpensive hardwood, and most lands are privately owned (Appendix 1). Approximately one million acres of hardwoods exist, and over one million acres of the lands are owned by individuals, farmers, or corporations.
Woody biomass on these timberlands is plentiful, although growth of the native timber is not rapid. Central Florida timberlands contain more than 153 million tons of biomass, mostly in trees less than 5" DBH (Appendix 2). Productivity on nearly 1.4 million acres is less than 85 cubic feet (about 2.5 green tons) per acre per year (Appendix 1).

Theoretically, woody biomass on timberlands within 50 miles of Lakeland could be available for cofiring. Over the broad central Florida region, some 150,000 acres need to be salvaged, harvested, or thinned, and most of these lands are privately held (Appendix 3). The almost 900,000 acres of timberland in need of regeneration, also mainly in private hands, constitute a considerable prospective land base for woody biomass production if awareness and incentives are sufficient.

The other large land base for biomass cropping is rangeland, which varies considerably in potential biomass productivity mainly due to soils. Three soil types are available in the immediate vicinity of Lakeland Utilities: reclaimed phosphatic clay, reclaimed overburden, and native sandy soils (Table 2). Phosphatic clay is a by-product of phosphate mining. Clay is separated from phosphate ore at a beneficiation plant, suspended with water and pumped to settling areas. Settling areas are often a square mile or more in size and 40 to 60 ft. deep. The clay settles out, and the water is decanted off and reused. Once the settling area is full, it is drained and reclaimed.

Phosphatic clay as a soil is unique in Florida where natural soils are typically sandy or organic in nature. Phosphatic clay has many desirable characteristics including high water holding capacity which greatly reduces the need for supplemental irrigation. Phosphatic clay is also naturally fertile with high levels of phosphorus, calcium, and magnesium. Adequate amounts of potassium and minor elements are also present. Soil pH varies from 7 to 8 which is slightly higher than optimum for most crops. The nature of clay soil can limit field access during wet periods and limit maintenance and harvest operations during critical periods for some crops (45, 49). Fortunately biomass crops permit a great deal of flexibility in time of field operations and as a result should work well on phosphatic clay soils.

Table 2. Acres by broad soil classification of Polk County soils used mainly for pasture within 15, 20, 25, and 30 miles of McIntosh-3.

Classification[1]	Radius from McIntosh-3			
	15	20	25	30
Fine Sands	126,045	175,635	205,134	262,135
Sands	14,744	33,322	60,887	63,897
Tailings	8,461	14,754	20,913	23,769
Clay Settling Areas (CSA)	14,744	33,322	60,887	63,897
CSA+Overburden	1,045	2,034	3,094	3,114
Overburden	20,014	22,387	26,625	28,974
	185,053	281,454	377,540	445,786

[1]See Appendix 4 for detailed soil types and numbers

Often, after reclamation, portions of clay settling areas are poorly drained. For high yield crop production on these areas additional drainage work is required. Bedding with beds approximately 200 ft wide and with a 2% slope gives excellent drainage (22). The estimated cost for building these beds is in the range of $800 to $1,200 per acre. The cost for this land improvement would be capitalized into the value of the land and not charged as a direct cost to crop production. Higher rental rates for well drained land would be justified. Because of the unstable nature of phosphatic clay soils, they are not suitable for building construction and are not likely to be developed. There is almost 15,000 acres of phosphatic clay soil within a 15 mile radius of McIntosh-3.

Overburden soil, also a by-product of phosphate mining, is the material removed from the top of the ore body and piled to the side. It is reclaimed by either re-contouring, creating a land and lakes land form, or by filling the mine cuts with sand tailings and then capping the tailings with overburden. Overburden is made up of quartz sand and clay lenses (kaolinite and montmorillonite) and the primary phosphate mineral apatite. Kaolinite, the principle clay in overburden, is rich in oxides of iron (Fe_2O_3), magnesium (MgO), and potassium (K_2O) (14). Depth of soil material varies from 0.5 to 6 m (1.5 to 20 ft). Soil color varies from white and light gray to dark brown and black. Soil texture ranges from sand, fine sand, loamy sand, sandy loam, sandy clay, and clay. There is no orderly sequence of horizons. Available water holding capacity, while generally low, increases with clay content. Internal drainage is also variable and is inversely related to clay content (15). Overburden, after being allowed to settle for a number of years, may support building construction. As a result, some of this land close to urban areas and with road access will eventually be developed. More than 21,000 acres of overburden soil are located within 15 miles of McIntosh-3.

Native sandy soil is made up of a number of soil types. Most soils are described as flat and poorly drained. Typical land uses would include cattle grazing, woodlands and wildlife habitat. Approximately 144,000 acres of this land are within a 15 mile radius of McIntosh-3. In general, these soils have a pH in the range of 3.6-6.5 and are relatively infertile with low water holding capacity.

Land with potential for growing biomass crops is now either being reclaimed, idle or is used for pastureland. The opportunity cost of the land, the value of the land in its next best use, is low. Presently there is little or no alternative large-scale agricultural use for this land other than for grazing cattle. For a biomass crop industry to become established in the area it would have to compete with grazing animals for use of the land. In 1991 a pasture rent survey was conducted in Polk County (49). Average rental for grazing land in the Lakeland area was $9.41 per acre with a range in rental rates of $0.31 to $30.00 per acre per year.

A survey of landowners in southwest Polk County conducted in 1996 found that most did not know about biomass as a possible new crop for Polk County (40). When asked what information they would need to make a decision about growing biomass crops the top response was information about potential net returns from the crop, followed by production and marketing risk, and then production costs. If landowners could receive a net return of $40 per acre per year they would be willing to grow 3,300 acres of biomass. With a net return of $50 per acre they would grow 7,300 acres, and at $60 per acre 12,000 acres would be grown. Using results developed later in this report, these rates of returns required by landowners to grow energy crops, stated on a production cost basis, yield the following costs per MM BTU:

Energy Crop	MM BTUs Per Acre Year	Cost/MM BTU @		
		$40/Acre Year	$50/Acre Year	$60/Acre Year

Eucalyptus[1]	398.21	$0.10	$0.13	$0.15
Leucaena	158.30	$0.25	$0.32	$0.38
Elephantgrass	217.64	$0.18	$0.23	$0.28
Presscake	171.68	$0.23	$0.29	$0.35

[1]Eucalyptus Energywood Improved Case

Biomass Crops

Central Florida lands have considerable potential to grow leucaena, elephantgrass, sugarcane, Eucalyptus, and slash pine (Tables 3-6, Appendices 5-10). Leucaena is propagated from seed and does not need nitrogen fertilization, which reduces costs. Once established, leucaena does not have to be replanted for 10 years or more. However, Leucaena is a slow starter and takes a few years to reach its maximum yield potential. Costs for establishment were amortized over a 10 year period and added to annual maintenance costs to arrive at an annual cost (Table 3). The most efficient harvest system is believed to be a high capacity forage harvester such as a Claas Jaguar harvester equipped with a willow head. The machine cuts the plants close to the ground, chops them into small pieces, and blows the material into a wagon following the harvester. In Europe, harvesting systems for short rotation woody crops include the Claas model 695 forage harvester. With half the knives removed (12 knives rather then 24), chips are 28mm (1.09") long. Willow chips produced by the Claas harvester were consistent in size with 87% in the 15-35mm (0.58" to 1.36") range. This exceeds what is desirable at Lakeland Utilities but it appears that adding more knives could further reduce chip size. While highly efficient, this system does not allow field drying.

Elephantgrass can be planted in January and first harvested in November or December of the same year. Annual harvests will follow through the life of the stand. Elephantgrass' small stem can be harvested by mowing and allowed to remain on the field. Once dry, the crop can be baled into large round bales. If placed in a well-drained area, the bales could be stored for several months with minimum dry-matter loss. The bales would have to be shredded or ground to prepare the elephantgrass for burning. The material would be relatively light and fluffy which would facilitate its being blown into a boiler. The bulky nature of large round bales increases transportation costs (Table 4). Establishment costs are amortized over a six year period. Higher costs for elephantgrass are partially offset by its higher BTU values from being field dried at harvest.

Sugarcane like elephantgrass is a short rotation crop, but whole-plant sugarcane is <u>not</u> a suitable biomass material for direct combustion because of its thick stalk and moisture content of 80-85%. It may be planted and harvested within the same calendar year. Higher establishment and maintenance costs for sugarcane on sand and overburden soils are a function of an anticipated shorter stand life (four vs. six years) (Table 3). The billet harvester chops the stalk into 12" to 18" lengths. The billets are transported, ground, and pressed to extract the juice. After pressing, the remaining material, called presscake, has a moisture content of around 60%.

There are a number of ethanol plants in Polk County that make beverage ethanol and could provide

Table 3. Annual yields and initial establishment costs ($/acre) for leucaena, elephantgrass, and presscake (sugarcane) on sand, overburden, and phosphatic clay land types.

		Sand	Overburden	Clay
MM BTU/Acre/Year:	Leucaena[1]	158.3	205.7	221.6
	Elephantgrass[2]	217.7	217.7	248.8
	Presscake[3]	171.6	171.6	206.3
Establishment:	Leucaena[4]	246	257	256
	Elephantgrass[5]	583	512	573
	Presscake[6]	273	285	294

[1] Moisture level of 60% at harvest (dry BTU/lb = 7915); 6.33 MM BTU/green ton; 25, 32.5, and 35 green tons/acre/year, respectively

[2] Moisture level of 20% at harvest (dry BTU/lb = 7773); 12.44 MM BTU/green ton; 17.5, 17.5, and 20 green tons/acre/year, respectively

[3] Moisture level of 60% after pressing (dry BTU/lb = 8191); 6.55 MM BTU/green ton; 26.2, 26.2, and 31.5 green tons/acre/year, respectively

[4] Once per 10 years or more

[5] Once per 6 years

[4] Half charged to presscake - once per 4-6 years

presscake as a biomass feedstock. Since ethanol (rum) would be a higher value product, half of the production costs were charged to sugarcane juice and half to the presscake (Table 3).

Yields for Eucalyptus and slash pine vary with soil type, culture, and drying. Of the several Eucalyptus species that may be grown in central Florida (42), E. grandis, especially particular clones, is now showing the greatest potential for the mined lands (Table 5). It would be harvested initially after four years on fertile clay sites and could continue to be harvested for perhaps three more four-year cycles. Its yield (Y) in dry tons per hectare can be estimated from age (A) in months, site index (S) in m at five years, and number of trees (N) in hundreds of trees per hectare by the function:

$$Y = e^{**}(7.5436 - 36.6913(1/A) - 0.066434S - 29.4517(1/S) + 0.18352(N/A))$$

Yields of E.grandis are least on infertile sandy soils with minimal culture and highest on clays with intensive culture (Table 5). With the minimal culture (burning/chopping of existing vegetation, application of ground rock phosphate, bedding, and planting 600 trees/acre) now used to grow mulchwood (tree stems chipped for ground cover) on sandy soils common to southern Florida, yields of even superior planting stock are only 10 green tons/acre/year of stem biomass. Prorating that growth over the 40 green tons produced in a four-year rotation results in an establishment cost of $1.36/MM BTU (Table 6). Applying a $13/green ton cost for current harvesting systems and a $2.80/green ton charge for transportation, the total cost is $3.65/MM BTU. After subtracting the REPI credit, the $2.15 net cost of mulchwood grown E. grandis is above the desired $2/MM BTU.

Table 4. Delivered fuel cost estimates[1] per ton and per MM BTU for leucaena[2], elephantgrass[2], and presscake[2] (sugarcane) on sand, overburden, and phosphatic clay land types.

Item		Cost Per Green Ton			Cost Per MM BTU		
		Sand	Over.	Clay	Sand	Over.	Clay
Estab. & Maint:	Leucaena	$3.49	$2.58	$1.58	$0.55	$0.41	$0.25
	Elephantgrass	$11.92	$11.58	$8.72	$0.96	$0.93	$0.70
	Presscake	$4.68	$4.64	$2.81	$0.71	$0.71	$0.43
Harvesting:	Leucaena	$5.87	$5.59	$5.45	$0.93	$0.88	$0.86
	Elephantgrass	$19.33	$19.33	$16.91	$1.55	$1.55	$1.36
	Presscake	$7.35	$7.35	$7.51	$1.12	$1.12	$1.15
Transportation:	Leucaena[3]	$2.80	$2.80	$2.80	$0.44	$0.44	$0.44
	Elephantgrass[3]	$7.14	$7.14	$7.14	$0.57	$0.57	$0.57
	Presscake[3]	$4.00	$4.00	$4.00	$0.61	$0.61	$0.61
Total Cost:	Leucaena	$12.16	$10.97	$9.83	$1.92	$1.73	$1.55
	Elephantgrass	$38.39	$38.05	$32.77	$3.08	$3.05	$2.63
	Presscake	$16.03	$15.99	$14.32	$2.44	$2.44	$2.19
REPI Credit (Federal subsidy paid to municipal utilities)					$1.50	$1.50	$1.50
Net Cost: Leucaena					**$0.42 (0.37-0.48)**	**$0.23 (0.19-0.27)**	**$0.05 (0.03-0.07)**
Elephantgrass					**$1.58 (1.49-1.68)**	**$1.55 (1.47-1.65)**	**$1.13 (1.07-1.21)**
Presscake					**$0.94 (0.88-1.02)**	**$0.94 (0.87-1.02)**	**$0.69 (0.65-0.74)**

[1]Cost estimate does not provide for profit for producer or harvester.

[2]Establishment costs amortized over 10, 6, 6, and 4 years, respectively, for leucaena, elephantgrass, presscake on clay, and presscake on sand and overburden; initial harvest 18 and 10-12 mos after establishment, respectively, for leucaena and elephantgrass and presscake; then annual harvests

[3]50,000 lbs per load at $70 and $100 per round trip, respectively, for leucaena and presscake; 24,000 lbs per load for elephantgrass

Table 5. Annual yield and establishment cost for Eucalyptus grandis stemwood[1] for central Florida under various management scenarios.

	Mulchwood	Energywood	
		Current	Improved
Green Tons/Acre/Year	10[1]	32[1]	55[1]
MM BTU/Acre/Year[2]	69	221	380
Establishment[3]: $ / Acre	375	325	290

[1]Add 20% to include branch and foliage biomass; coppice growth can be up to 25% greater
[2]Assumes moisture content of 60% on a wet weight basis
[3]Mulchwood includes chopping, bedding, fertilization, planting 600 trees/acre;
Current includes bedding, fertilization, mulching, planting 900 trees/acre;
Improved includes bedding, mulching, planting 1,000 trees/acre

Table 6. Delivered fuel cost estimates per ton and per MM BTU for E grandis in the first rotation.

Item	Cost Per Green Ton			Cost Per MM BTU		
	Mulchwood	Energywood		Mulchwood	Energywood	
		Current	Improved		Current	Improved
Establish.[1]	$9.38	$2.54	$1.32	$1.36	$0.37	$0.19
Harvesting	$13.00	$13.00	$8.00	$1.88	$1.88	$1.16
Transport.[2]	$2.80	$2.80	$2.80	$0.41	$0.41	$0.41
Total Cost	$25.18	$18.34	$12.12	$3.65	$2.66	$1.76
			REPI Credit	$1.50	$1.50	$1.50
			Net Cost	**$2.15**	**$1.16**	**$0.26**

[1]Once per 16 years
[2]Assumes moisture content of 60% on a wet basis

Current energywood (tree stems processed for cofiring) culture increases productivity and reduces cost (Tables 5 and 6). This more intensive culture on sandy soils, e. g., the addition of amendments such as composts, sludge, stormwater, and sewage effluent and higher planting density, or with less than maximal culture on overburden or clays, may yield 32 green tons/acre/year. The associated 221 MM BTU/acre/year grown over a four-year period combined with current harvesting and transportation systems results in a total cost of $2.66/MM BTU. Application of the REPI credit, reduces the net E. grandis cost to $1.16/MM BTU and within the range of annually harvested crops.

Improved energywood culture (bedding plus mulching) on reclaimed clays and overburden and lower harvesting costs reduce the cost of E. grandis energywood to less than $2.00/MM BTU without REPI credits. Improved culture could increase yields to 55 green tons/acre/year. Of the several options for decreasing harvesting costs for woody crops, the current $8-10 per green ton operative for energywood harvest of trees up to 5" in southern Alabama needs validation in central Florida, but a cost of $8/green ton lowers harvesting cost to $1.16/MM BTU. If a forage chopper suffices for small diameter trees up to 4" and further lowers harvesting cost, rotations may have to be shorter than the four years assumed in our calculations. Harvesting with any system may need to be restricted to winter months to insure coppice regeneration of E. grandis.

Field drying can substantially increase the energy content of E. grandis biomass. In as little as three summer months, stemwood moisture content can be reduced by 50% by stacking harvested trees on site. However, this option for improving biomass quality has not been included in our estimates.

Slash pine is projected to yield 20.1 dry metric tons/hectare/year (20.6 green tons/acre/year) with intensive culture over an eight year rotation on sand or overburden sites at a delivered cost of $31.34 per dry metric ton ($12.39/green ton) (50; after harvest, the plantation must be replanted). Slash pine, which may be harvested at any time, may serve to maintain biomass fuel levels throughout the year.

All biomass crops are subject to risk from weather events. However, biomass crops are not as vulnerable as agricultural crops since there is no specific time when harvest must take place such as with a fruits, vegetables or even grain crops. Total yield of biomass crops could be impacted by events such as a freeze or drought. Appendix 8 presents the effect on the net cost per million BTU for a 10% increase in yield or a 10% decrease in yield of leucaena, elephantgrass, and presscake. Slash pine yields can be increased by use of improved planting stock and intensive culture, which are also important factors in productivity of E. grandis. Winter freeze damage is a risk for E. grandis.

Co-Firing

McIntosh-3's steam generating system and air pollution control equipment were designed to fire a range of eastern bituminous coals, No. 6 oil and up to 10% RDF (7). The incoming municipal solid waste (MSW) is mechanically processed and aerodynamically sorted to reject ferrous and aluminum metals and glass. The remaining RDF, mostly light paper and plastics, are pneumatically lofted and injected at a high point into the coal fireball. The RDF is mostly burned in suspension but the larger particles that do not completely burn fall to a bottom grate where combustion is usually completed.

The general technical forms of co-utilization of biomass with coal in a pre-existing PC boiler steam turbine facility are (I) Direct co-firing of biomass in the boiler furnace, (II) Indirect co-firing by thermally processing the biomass into a) a gas, b) an oil or c) a charcoal or d) a combination of the above and feeding the products through the natural gas, oil and coal feeding systems available in most PC boiler steam turbine electrical generating facilities, and (III) Processing biomass into a higher quality gas or liquid fuel suitable for driving a combustion turbine usually available at a large utility and, in effect, blending the electrical output with the output of the coal facility (19).

Direct biomass co-firing experience (Option I) described in the literature has shown that a number of technical problems can arise. These include grinding and feeding problems; enhanced slagging, fouling, corrosion and deposition problems particularly with herbaceous species because of their high alkali and (in some cases) chlorine content; emission problems and degradation of market value of fly ash. Option II, first thermally processing the biomass into a gas, oil or charcoal can remove some or all of these problems. Figure 1 illustrates a conceptual form of Option II with the help of a fast pyrolysis preprocessor that first converts the biomass into a combination of gas, a liquid (bio-oil) and a char-ash.

The gas is directly injected into a natural gas channel or used for reburn to lower NOx emissions. The oil is fired through a Bunker C channel. The char-ash could be discarded if it has too much alkalis, chlorine or toxic metals. In the case of clean woody species that yield a good charcoal the solid product could be cooled and sent through the coal channel.

Option III potentially has even greater environmental and economic benefits since combustion turbine electrical generation (Brayton cycle) usually can achieve higher efficiencies than coal-steam turbine (Rankine cycle) systems. This option would however require a cutting edge type biomass gasifier.

<u>Direct Co-firing of Coal and Biomass in McIntosh 3 (Option I)</u>. In view of the unique RDF cofiring design of McIntosh-3, direct co-firing of chipped or shredded biomass using the RDF channel would theoretically require the smallest amount of modification . The simple alternative of blending the biomass with coal and feeding the blend into the existing coal pulverizers was also considered. However, test burns performed at Shawville, Pennsylvania (38) demonstrated significant boiler capacity limitations when co-firing 3% fuel blends of biomass and coal via the coal feeding route. The tests indicated problems with feeding biomass through the pulverizers and resulted in loss of capacity by 5-8%. It was reported that the 3% blends essentially behaved like wet coal. Pelletized biomass, dried during processing to a low moisture content, can successfully be processed through coal mills, but this route would be prohibitively expensive. Thus either loading the biomass to the input of the RDF system or if sufficiently preprocessed directly to the existing atlas for pneumatic transport through the RDF transport tubes are the primary direct co-firing options considered.

Successful co-firing test burns that have been accomplished at several other PC facilities may offer useful insights. Table 7 summarizes some information on documented co-firing test burns, where in all but one scenario, separate fuel preparation systems and fuel burners were used for the biomass.

A number of other examples have been found in the literature of co-firing biomass and coal in cyclone, fluidized bed, or stoker-type boilers. Since these configurations are dissimilar to the McIntosh-3 wall-fired boiler, they are not listed here. Unfortunately, the literature seems to indicate that of all coal boilers, the pulverized coal types are more difficult to co-fire with, and of the pulverized coal variety, the wall fired boilers are most difficult due to smaller residence times in the fireball. Of the four USA plants (16, 53, 54, 55) listed in Table 7 which performed biomass co-firing test burns, only the Madison Gas and Electric unit was wall-fired, the rest being tangentially fired. Thus, its test burn might be especially helpful for McIntosh-3. Their ability to co-fire at the 14% level by mass, ~7% by heat input is encouraging.

In a recent tour of major biomass to energy RD&D centers in Netherlands, Germany, Denmark and Sweden (17), information on co-firing, not widely available in the USA, was acquired (1, 8, 9, 10, 12, 25, 26, 28, 41,47). Extensive full-scale test programs carried out with straw in Denmark have clearly shown the limitations of direct co-combustion methods. These have been confirmed with

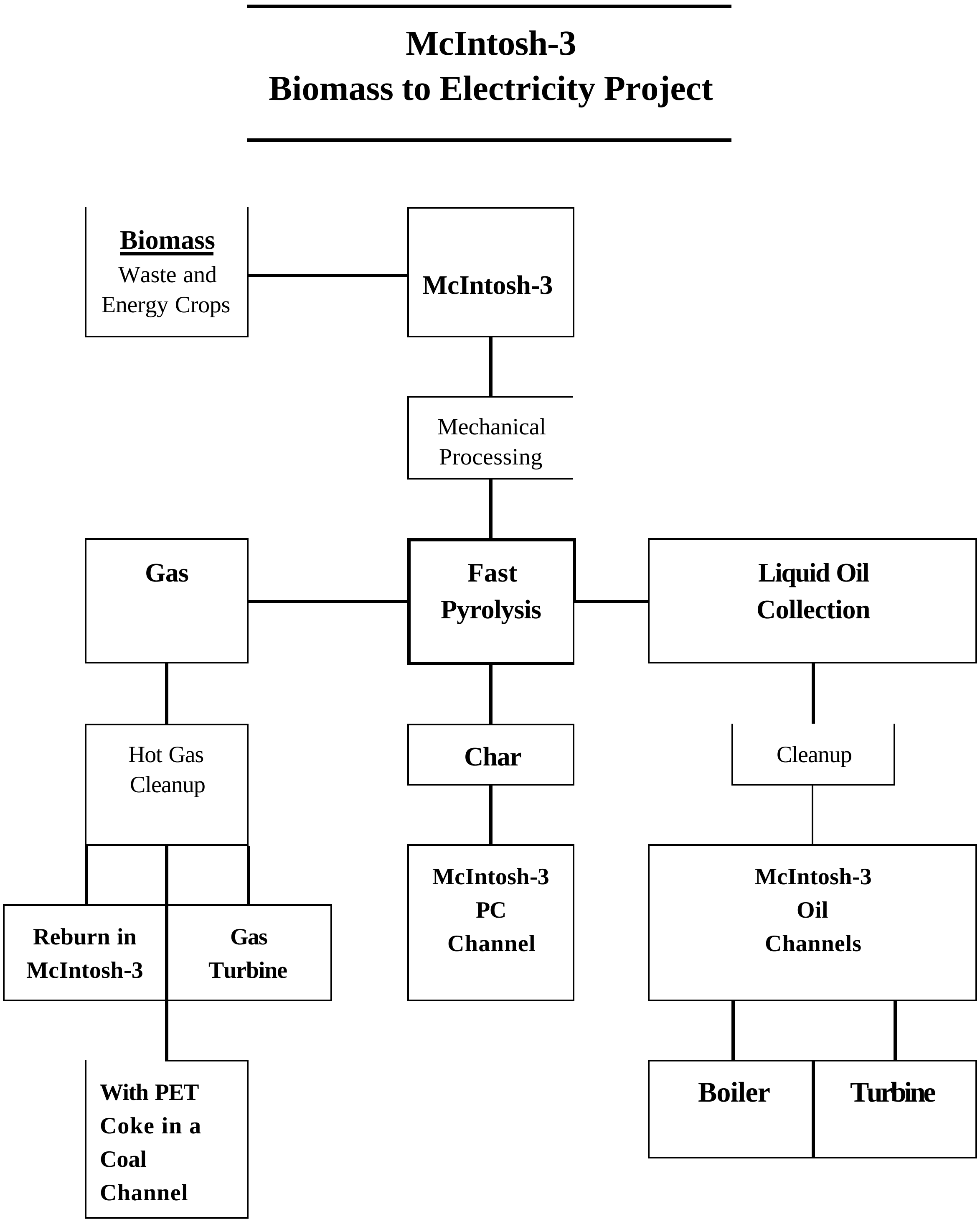

Figure 1. Schematic diagram illustrating possible uses of gas, liquid, and solid fuels from fast pyrolysis of biomass.

various agrobiofuels in USA (28). Experience with woody residues as well as other high quality woody feedstocks indicates that biofuels can be co-combusted together with coal without major problems in existing fluidized-bed boilers or even in pulverized combustors (4, 26).

Table 7. Documented co-firing test burns.

Utility	Boiler		Biomass	Feedstock	Corrosion/
	Capacity	Configuration	Load		Slagging
Madison Gas & Elec.	50 MW	Wall Fired	14% mass	Switchgrass	N
Flue gas temperature rose 20°C, indicating little deposition. No sparks were observed. (54)					
NY State Elec. & Gas	108 MW	Tangential	9 MW	Sawdust, 10% H_2O	N
			4-5 MW	Green Sawdust	N
No negative impacts on boiler efficiencies were observed. Installation of separate boiler entry ports was recommended. (55)					
Kingston, TN	~430 MW	Tangential	15% heat	Wood	N
Boiler efficiency loss was less than 1.5%. The flame temperature decreased by about 100°F, which had little impact on boiler operations. 'Significant reduction' in SO_2 and NOx. (16)					
Savannah Elec.& Power	54 MW	Tangential	≤40% heat	¼ Shred. Pallets	N
Significant reductions in NOx and opacity. Efficiency losses ~ 1.5-5.0%. No accumulations of unburned wood in the air heater, however, some unburned wood in the economizer hopper (53)					
SK Power Co. (Amager)	590 MW	Tangential	11-22% heat	Straw Pellets	-
Feedstock conveyed directly from coal yard through the coal mills and into boiler. Significant NOx reductions. (26)					
SK Power Co. (Kyndby)	60 MW	Tangential	45 MWe	Straw Pellets	-
100% biomass fired in PC boiler. ~50% NOx reduction. Not economically feasible due to cost of feedstock. (26)					
ELSAM/Vestkraft (Ger.)	130 MWe	Tangential	10-25% heat	Straw	See Below
Emissions: Increase in HCl, no increase in dioxins. Increased, but tolerable, corrosion. Slagging formed only on the furnace walls in the burner areas, without impairing the operation procedure (41)					

Co-Firing Issues Specific to McIntosh-3. The fact that McIntosh-3 now only has an RDF capability of 2% by heat, (~ 5% by weight) is a problem that must be addressed if a continuous biomass co-firing program can be initiated. The original design objective was 10%. Thus improving the performance of the RDF fired system was viewed as an essential step by the Clean Combustion Technology Laboratory (CCTL) if a significant quantity of biomass is to be burned (33).

1. Grate fouling. This limitation could be due to the fouling of the bottom grates with coal ash or RDF ash that accumulates and eventually clogging underfire air passageways. With the underfire air passageways clogged, the RDF material that does not burn in suspension might not burn on the grate for lack of oxygen. To correct this problem one might a) process the input to smaller particle sizes to facilitate better suspension burning, b) inject it tangentially or in an upward direction to extend the time in suspension, c) restore the openings in the grate more frequently than between McIntosh-3 outages, d) modify the overfire

system to compensate for some of the problem created by the plugged underfire air system, e) install natural gas burners directed towards the grate to burnout the larger particles.

The CCTL's initial suggestion for c) was to install spikes or a drop plate with spikes to unplug the holes in the grate (33). This was modified after crawling into the bottom of the boiler to obtain a more realistic picture of the grate structure (32). The grate appeared as an array of vertical (when grates are down) T shaped beams of about 1/2 inch thick steel with about 1/2 inch gaps between adjacent beams. In view of this, the third solution might be accomplished by installing an array of fixed blades aligned with the slots in the grates, which would systematically clean the passageways each time the grates are dropped. This would maintain an underfire air supply and allow for the continuous burning of material on the grates. If there is a practical support system for these blades this modification is strongly recommended to improve the capacity for RDF co-firing as well as biomass cofiring.

With the coal used at 11.9 MBtu/lb, depending upon the size distribution it is expected that biomass (~6-7 MBtu/lb) will behave somewhat like the RDF (~4.5 MBtu/lb) when directly injected and that some material will end up on the grate. Maintaining the grates underfire air passageways open should enhance this percentage cofiring capability of RDF or biomass or when they are both injected. While a test burn with the present status might produce some useful information it is important that the system be brought closer to the original co-firing design specification of 10% on heat input basis. Then McIntosh-3 would be capable of handling additional alternative solid fuels, RDF, biomass and possibly even dried sewage sludge.

In the event the slot clearing approach is impractical some compensation for the lack of bottom air might be accomplished by opening the outlets of the overfire air system and directing the flow to provide improved combustion on the ash bed. Assuming the detailed structure is similar to the insert in Figure 17 of B&W pg 27-10 (2) increasing the overfire air openings might be helpful. The final possibility under consideration is to get B&W suggestions as to how to bring their RDF system to its original specifications. Indirect information indicates that they have proposed adding gas burners directly at the grate to burnout the particles that reached it.

<u>2. Biomass lofting</u>. The air velocity required for a given particle of biomass to be pneumatically conveyed vertically depends on its geometry and density. Thus, biomass species, chipping method, moisture content, etc., all influence the lofting characteristics of the bio-fuel (24). A plot of particle size vs. lifting velocity for "irregularly shaped" wood particles (with specific gravity 0.64) shows that 0.4 inch particles require velocities of about 3000 feet per minute (50 feet per second) and 0.2 inch particles require velocities of about 1500 fpm (25 fps) for lofting. One might roughly extrapolate to larger sizes with the equation

$V = 150\ S^{1.2}$ where V is in feet/sec and S is in inches

The CCTL acquired, through surplus property channels and loans, equipment for exploratory studies on the lofting requirements for green wood chips and can test various feedstocks at air flow rates which are adjustable up to a maximum of about 35 fps. A 4" diameter glass tube that stands vertically about 6 ' is fed air by a 1 hp electric yard blower, and a bottom valve is used to adjust the flow rate. A static pressure tap and a stagnation pressure tap is used to determine the air velocity. This apparatus could be used to identify a green wood chip grind size that would be acceptable for the existing McIntosh-3 pneumatic transport tubes. It is necessary, however, to know (approximately) the air velocities in the Lakeland Utility air classifier and transport tubes.

The CCTL conducted preliminary tests with green wood chips from a Vermeer chipper, most of which easily blew out the top of our tube using the maximum air velocity of ~ 35 fps. However some larger chips (~3" +) were retained even at the maximum velocity (34). Of course, the allowable chip size for McIntosh-3 depends on the air velocity in the transport tubes. Our pre-(pre-trial test) tests could provide an idea of what to expect or what should be avoided during the proposed pre-trial test.

Although the direct injection approach is likely to require the least amount of physical change to the boiler and the surrounding facilities, a less problematic approach may be to preprocess the biomass and RDF to a form or forms that can be fed more easily (see Figure 1)

Option II, Low BTU Gasifier. Many potential biomass feedstocks, such as straw, have problematic ash melting behavior, which will cause sintering and fouling problems in combustors. Straw and many fast growing energy crops as well as industrial and municipal waste fuels often contain high amounts of chlorine and alkali metals, which have a tendency to cause severe corrosion problems in coal-fired boilers. This problem can be more severe in the modern plants where super-critical steam values are utilized. Some reductions of these problems have been achieved with fluidized bed combustion by pretreatment (washing) of the straw (23). However, no PC data have been found. In the USA a number of experts suggest that the most critical factor controlling the possibilities for direct co-firing of biofuels in large PC boilers is the usability of coal fly ash by the cement industry.

Figure 1 illustrates a conceptual alternate to direct co-firing that converts the biomass externally into bio-gas and/or bio-oil for injection into the boiler. The char ash might also be used for woody species but probably not for herbaceous species. Most of the available examples of the indirect approach use a conventional sub-stoichometric-type gasifier, and inject the hot, low BTU bio-gas into the boiler. These transform the solid feedstocks into a hot, low BTU gas mixture, comprised mostly of CO, CO_2, H^2, H_2O vapor, and usually N^2 (if the oxidizer is air). These conventional, low BTU gasifiers are generally simpler and less expensive than the more advanced gasifiers which generate higher BTU gaseous fuels, developed primarily for use with gas turbines or reciprocating engines. With the low BTU gasifiers, although the fuel value of the gas is low, much of the loss in fuel value can be recovered in the form of sensible heat energy if the hot, gaseous fuel is conveyed directly into the boiler. Using an external gasifier eliminates problems with pneumatic transport, grate burning, and ash contamination while still exploiting most of the fuel's energy content. Potential problems with corrosion and slagging can be reduced with the use of an external gasifier depending upon the use or disposal of the char-ash. Studies in Denmark using straw as a feedstock with fluidized bed gasifiers indicate that most of the direct co-firing problems can be mitigated by this route.

External processing of the biomass may not only allow for higher percentages of co-firing, but also reduce NOx emissions by using the gaseous fuel for reburning (5). Also, it is expected that slagging problems encountered in direct co-firing would be greatly reduced since the contaminants are, to a large extent, contained in the ash as long as the solids do not reach excessively high temperatures. Table 8 summarizes a select group of substoichiometric gasifier manufacturers whose products might be suitable for use at McIntosh-3 facility. Further information is contained in company brochures. Contact information for these options and other gasifier manufacturers/operators are given by Niessen et al.(35) and Bain (3) (Appendix 13).

Table 8. Select group of gasifier manufacturers.

Company	Gas	Approximate Cost

		Capital	O&M
PRM	Low Btu	11,000 $/t/d	3 $/t
2 tph stirred bed; many commercial units in Asia, pilot unit in Tulsa			
EPI	Low Btu	50,000 $/t/d	17 $/t
11 tph; designed, built 3 wood waste fired fluid bed gasifiers			
Thermogenics	Low Btu	N/A	N/A
3 t/h			
Brightstar Synfuels Co.	Medium Btu	N/A	N/A
1 tph externally heated (w/NG) steam reforming of biomass; could be coupled with a gas turbine (10)			
Environmental Incineration Systems	Low Btu	N/A	N/A
auger combustor, starved air incinerator			
Heuristic Engineering	-	N/A	N/A
80 MMBTU/hr EnviroCycler A-grate combustor; could be converted to gasifier, many units in field			

An alternative to gasifying the biomass externally in a separate gasifier unit is to do the gasification internally by modifying the bottom of the boiler to house the necessary gasification hardware. This option requires extensive modification to the boiler but does not require any additional real estate for the gasifier unit, or any ductwork to transport the hot gas. Successful installation of an internal gasifier would allow for the complete utilization of the biomass and RDF feedstocks, although the resulting ash mixture may not be a marketable by-product. Table 9 summarizes the two vendors and systems identified for the internal gasification option.

Table 9. Internal gasifier vendors.

McBurney
Underfire air is cut back to avoid complete combustion, then secondary air is injected into the lower furnace area to complete combustion. Capital costs ~$7,500,000 annual O/M costs ~$1,178,000
Imatran Voima Oy (IVO)
IVO has successfully integrated a fluidized bed combustor at a 90 MWe peat and coal fired power plant, implemented in 1993. The cost of repowering was ~$120/kWe.

Option III, Advanced Gasifier/Liquifiers. A third major co-utilization option would be to develop a more advanced form of gasifier or liquifier to convert biomass into a gas or liquid good enough to run a combustion turbine (17, 26, 29). Systems are in the demonstration phase in Sweden at Värnamo (47) and Nykoping (4). Both of these systems produce a low BTU gas so that special turbines are used or have been adapted. However there are efforts underway in the EU and the USA to develop gasifiers that make a medium BTU fuel to be use with standard combustion turbines with little modification. The most advanced efforts consider blending coal and biomass, coal and MSW and coal and dried sewage sludge with the objective of carrying out double or multiple community service (19). This would be helpful when the economics for generating electricity alone is not favorable. Then blending feedstocks in the gasifier or liquifier has a number of potential economic and environmental advantages (11, 13, 18, 27, 36, 48). Co-gasification is mostly in the RD&D stage and is probably 3 years or so from commercialization. While this work is outside the scope of the Lakeland-SERBEP co-firing project it might be useful if a new turbine system is contemplated.

Direct Injection Co-firing Option: As discussed previously, one co-firing option available to McIntosh-3 is to use the Unit's existing pneumatically fed RDF lines, to directly blow biomass into the boiler (7, Figure 2). These existing RDF lines have entry ports into the boiler almost parallel to the Unit's coal ports. To assist in evaluating a direct injection co-firing option, the McBurney Corporation provided proprietary information (45) on "test-burn" results that they conducted on a 54 MW Combustion Engineering pulverized coal, tangentially-fired boiler with 1,000^{o} F superheat and 1,000^{o} F reheat.

In this co-firing application, the technological approach is a direct injection of finely shredded wood fiber materials, where the wood is dried to less than 20% moisture, shredded to one-fourth inch minus, and blown into the furnace through existing burners or new injection ports. Coal and wood handling and processing are separate. This process has the advantage of not being limited by existing pulverizer equipment in the amount of wood which can be co-fired.

The Combustion Engineering PC Unit has two levels of coal nozzles, each level served by one pulverizer. The wood was injected into the furnace through the upper level of coal nozzles. The mill for those nozzles was disabled and disconnected from the exhauster fan inlet. The inlet of the exhauster fan was then connected to a 24" pipe which extended into the yard. Wood was unloaded from moving-bottom trailers into a small hopper/auger system. The outfall from the auger flopped into an opening in the 24" pipe and was vacuumed into the unit. Once through the exhauster fan, the wood traveled through the coal distribution piping and entered the furnace through the coal nozzles.

In these tests, co-firing levels of up to 40% by heating value were achieved at reduced load and zero natural gas. Full load was achieved with 36% wood co-firing by heat input and about 17% natural gas input. Maximum wood consumption rates with the test system was about 14 tons/hour.

With gas co-firing, the use of wood did not appear to cause opacity degradation. At zero gas co-firing, however, opacity appeared higher than with gas co-firing, but all opacity measurements were within legal limits. NOx levels were low during all tests with natural gas co-firing. There were indications that NOx levels may be considerably lower with wood co-firing than with coal alone.

Old Ports	Test Ports
Air	Air
Oil/Gas	Gas
Coal	Biomass
Oil/Gas	Gas
Coal	Coal
Air	Air

Figure 2. Cofiring port use in McIntosh-3.

Internal Furnace Gasification Option: Another biomass co-firing option is to use aspects of a pulverized coal boiler bottom re-design with hydro-grates or air cooled grates (Figure 3), developed by the McBurney Corporation. In a biomass co-firing design that created approximately 33 MWs of coal displacement (a co-firing ratio in the 20% range), a gasification chamber was created in the boiler itself. Basically, the design would open up the boiler throat, where the pulverized coal ash drops out, to approximately 5 or 6' convert this opening between the double arches to become the wood gas burner throat.

To facilitate wood gasification in the bottom quarter of the boiler furnace, the furnace water walls, just below the existing coal burners, would be reconfigured to provide a large venturi throat through which gas could rise from the furnace bottom. Below the new venturi section the water walls would flare out to form a wood gasification chamber in the bottom of the furnace. Two vibrating grates for receiving 1" wood chips would provide a fuel bed platform for wood gasification to take place. Wood ash would be removed with bottom ash in a manner similar to the ash removal process currently used.

The technological approach used is a variance of systems being used in wood-fired boilers operating at paper mills in the southeastern U.S. The difference between burning wood and gasifying wood with this technology is that undergrate airflow is cut back to prevent complete combustion. The wood gas generated off the fuel bed rises up through the venturi section above the lower furnace chamber and into a combustion zone where secondary air is injected into the wood as stream to complete the combustion process. Careful regulation of the gas-rich mixture and the admission of primary and secondary air must be maintained to control the rate of combustion.

Figure 3. Venturi throat design with hydrograte.

External Furnace Gasification Option: A final commercially available biomass co-firing option reviewed was the PRM System (39). In this System, solid fuel is introduced into the gasifier by a water-cooled screw conveyor that discharges into the drying and heating zone of the gasifier. The gasification process is controlled by the proportioned application of substoichiometric combustion air in a manner that supports efficient gasification. The residence time of the solids in the gasifier is varied by a residence time control system that is adjusted to achieve the desired carbon content and quality of the ash discharged from the gasifier. The combined use of mechanical bed agitation, precise gasification air control and zoning produces a clean, calorific biogas. The biogas exits the gasifier at temperatures ranging from 1200 to 1500^{o} F and is ducted to an existing boiler, which for McIntosh-3, would be located approximately 150 feet away.

In the final oxidative step, the biogas is ducted through a specially designed biogas burner for final oxidation. The biogas burner delivers the final combustion air to the biogas, providing flame stability over a large range of flows and heat input rates while promoting mixing to maximize combustion efficiency. The burner fires into the furnace section of an existing boiler where final oxidation of combustible compounds occurs.

In our review, the PRM gasifier has some very attractive features and cost advantages over other co-firing options such as conventional fluid bed gasifiers. The PRM System would be relatively simple to construct and install, compared to modifying the bottom of the McIntosh boiler to include water or air cooled grates (which would require a significant outage). The System appears easy to operate and control, has a minimum of moving parts -- where replacement parts could be fabricated in a local shop, and auxiliary fans are small and cheap.

One concern of the PRM gasifier is the required duct distance to the McIntosh boiler. PRM gasifiers require very large gas ducts as a result of the high temperatures and low delivery pressure of the bio-gas. Another potential concern is that PRM gasifers are designed to operate with a negative internal pressure. This may require a new design for fuel feed and ash discharge systems for pressurized operation. Also, the design of all vessel penetrations and gas seals would have to be reviewed to ensure that there will be no leakage of gas out of the gasifier when operated in a pressurized mode.

Due to its unique RDF co-firing capability, primary consideration has been given to the introduction of biomass via this channel after some technical improvements are completed. A test firing of more than 100 tons of Eucalyptus is scheduled. Secondary consideration is being given to preprocessing systems that convert the biomass into a low BTU gas that is delivered along with its sensible heat into the coal flame. A number of technical variations of Options 1 and 2 are now under consideration. Preliminary characterization of Eucalyptus and other crops for direct combustion is summarized in Table 10.

Table 10. Moisture content (MC, % on a green weight basis), heat value (HV, j/g on a dry weight basis), and ash content (% on a dry weight basis) for some biomass crops

Biomass Crop	MC	HV	Ash
Elephantgrass (air dry)	21.9	3476	4.95
Leucaena	60.0	3540	2.98
Eucalyptus	49.0	3712	1.97

Financial/Legal Analyses

Incentives for biomass co-firing. **Deregulation Legislation**: Currently, every major Electricity Deregulation Bill in Congress includes a provision for a Renewable Energy Portfolio Standard (REPS). With a REPS, every electric utility would be required to generate minimum percentages of the electricity sold from Renewable Energy Sources such as wind, solar, or biomass. While proposed legislation varies, typical levels are about 2% of Mwh generation by the year 2000, increasing to 10% by 2010:

Representative Shaefer (H.R. 655): All generators of electricity selling power are required to have Renewable Energy Credits equal to 2% of their generation in 2001 (increasing to 4% by the year 2010). H.R. 655 does not include hydro as one of the "protected" renewables. The list includes: Organic Wastes Biomass, Dedicated Energy Crops, Landfill Gas, Geothermal, Solar or Wind Resources.
Representative Markey (H.R. 1960): All generators of electricity selling power are required to have Renewable Energy Credits equal to 3% of their generation by 1999 (increasing to 10% by 2010).

Senator Bumpers (S. 237): In 2003, each retail electric energy supplier will have to get 5% of its power from renewables, increasing to 9% in 2008 and to 12% in 2013. S237 allows:

Renewable Categories:	Credit Per Unit Of Energy Generated:
Large Hydro > 80 MWs	One-Half Credit
Small Hydro < 80 MWs	One Credit

All Other Renewables	Two Credits

Senator Jeffords (S. 687): All generators of electricity selling power are required to have Renewable Energy Credits equal to 2.5% of their generation in 2000 (increasing to 20% by the year 2020).

To satisfy a REPS, Utilities could either generate electricity from their own facilities using Renewable Energy Sources, or purchase "Green Energy" from a Utility that has over-complied with the Minimum REPS Requirements. Thus, biomass co-firing in Florida's Base Load Units may not only afford a cost-effective mechanism to comply with any REPS requirements, but an opportunity to make off-system power sales (if an over-compliance of minimum REPS could be achieved). An illustration of this point is the recent Green Energy RFP Solicitation by TVA.

Renewable Energy Options: Florida's capacity situation is typical of most electric utilities today, where most of Florida's Utilities do not need additional base-load capacity (Mw). In meeting a possible REPS, biomass co-firing (i.e., partial fuel switching) may be the lowest production cost alternative, since wind natural resources do not exist in central Florida, and the current capital cost of solar energy is exceedingly high.

Customer Demand For Green Energy: As electricity markets move toward deregulation, marketing research is consistently showing that a "Green Energy Option" is a significant factor in determining "Customer Choice Decisions". In Pilot Deregulation Programs throughout the U.S., when customers are given an option to choose their electricity provider, a significant market share is showing a willingness to pay a premium of about 10% for "Green" sources of generation.

For example, in a Massachusetts Pilot Program where customers were given options to choose their Electricity Supplier, approximately one-third chose environmentally friendly sources of generation, over the lowest price option. In California, a recent survey showed that 30% of residents said they would be ``very willing'' to pay 10% more for energy from clean sources other than nuclear or coal. In polling surveys conducted by Central & Southwest (Texas), 16% of Residential Customers indicated that they were willing to pay an additional $5.60 a month on average for renewable energy.

Utility Green Marketing Programs: Thus, when deregulation occurs, even if a REPS is not enacted, an Electricity Provider that can not offer any renewable energy options to customers may find itself locked out of a significant market segment – even if it is the lowest cost provider. Because of this customer preference, a sizable number of utilities are now creating Green Energy Choice Programs before deregulation occurs, in order to establish a "Green Market" presence, and customer loyalty.

Federal Incentives For "Green Energy" Municipally Owned Utility Projects: As part of the 1992 Energy Policy Act, Congress created two incentives for Electric Utilities to develop renewable energy resources: The Section 45 Tax Credit (available to taxable investor owned electric utilities such as Tampa Electric, FP&L, Florida Power, Gulf Power), and the Renewable Energy Production Incentive (available to non-taxable utilities such as Lakeland Utilities, Orlando Utilities, Gainesville Utilities, Seminole Electric Co-operative, Jacksonville Electric Authority). Since 1992, the Renewable Energy Production Incentive (REPI) Credit has been utilized primarily for landfill methane projects for Municipal Electric Utilities, such as the Sacramento Municipal Utility District.

REPI is administered by the U.S. Department of Energy, and provides a direct cash payment valued at approximately 1.50¢ per Kwh for electricity generation produced from wind, solar, and biomass. As with most federal government programs, funding for REPI is subject to yearly budget appropriations by Congress, which presents a most definite concern in any long-term project development decision, which will be illustrated in the following discussion.

In administrating REPI, the U.S. Department of Energy has promulgated rules creating a two level hierarchy of Qualified Projects. Level 1 Projects are defined as wind, solar, and energy crop biomass. Energy Crop Biomass is defined as crops grown exclusively as a fuel feed-stock to produce electricity, and can not have a duel commercial use . For example, harvesting a whole tree for a duel use (i.e., pulpwood for paper, with the waste bark used for fuel) would not qualify as a Level 1 Project. However, forestry practices such a periodic thinnings of forests, where 100% of the thinnings would be used as a fuel feed-stock are believed to qualify as a Level 1 Project. Also, any forest management practice of overplanting trees on an acre of land (again, as long as the overplanted trees are exclusively used as a fuel feed-stock), would also qualify as a Level 1 Project.

Level 2 Projects are defined as projects using biomass wastes, such as landfill methane or organic waste materials (i.e., paper, cardboard, forest product wastes, etc.). In addition, REPI's promulgated rules state that MSW does not qualify.

The significance of the Level 1 or Level 2 hierarchy is only applicable to the distribution of funds appropriated to the REPI Program by Congress, in which Level 1 Projects have priority. Under circumstances where Congress has appropriated enough funds to make **all** payments of Utility requests for REPI payments, there is no impact to either Level 1 or Level 2 Projects. However, under circumstances where total Utility requests for REPI payments exceed the amount appropriated by Congress, wind, solar, and energy crop projects would be funded first, with remaining funds allocated on a pro-rata basis to Level 2 Projects.

From 1993 through 1997, Congressional appropriations were sufficient to fund all Level 1 and Level 2 requests. However, in 1998, Utility requests for payments exceeded Congressional funding for REPI, resulting in Level 1 Projects funded at 100%, and Level 2 Projects only funded at approximately 90%.

For Lakeland Utilities, qualifying a biomass co-firing project under REPI, and the availability of annual funding of the REPI Program is a critical determinant in any project development decision. Assuming a Power Plant Heat Rate of 10,000 (which approximates the McIntosh Unit's efficiency), the REPI Credit has an equivalent value of $1.50 per MM BTU. For example, with a biomass fuel value of 4,500 BTUs per pound, the fuel cost equivalent benefit of the REPI Credit would be $13.50 per ton (9 MM BTUs per green ton times $1.50).

Income Tax Incentives For Biomass Energy Crop Co-Firing: While not applicable to Lakeland Utilities, under Section 45 of the Federal Tax Code, a tax credit valued at 1.5 cents per Kwh (or $1.50 per MM Btu using a heat rate of 10,000) is available for the production of electricity placed on the grid using energy crop biomass from a Qualified Facility. One thing to recognize about Section 45, is that since it is a direct tax credit (rather than just a deduction to taxable income), the production cost (i.e., revenue requirement) value would be approximately $2.35 per MM Btu; calculated by taking the tax credit and dividing it by the product of (1 minus the federal income tax rate).

Air Compliance And Climate Change Incentives: Given the current and projected price of SO_2 emission allowances, the engineering uncertainly of the impact on NOx with co-firing, and current levels of voluntary CO_2 reduction values (i.e., between $3 and $10 per ton of carbon), any direct production cost benefits arising from achieving environmental initiatives through co-firing (Table 11) are believed to be negligible, or at least unclear at present.

This is not to say that biomass co-firing has no potential economic or significant environmental benefits. For example, co-firing bio-gas high in the boiler (i.e., re-burn) may be a very cost effective approach to reducing NOx.. Also, according to the Union of Concerned Scientists, the annual CO_2 emissions of a mid-size car is approximately 5 to 6 tons per year. Thus, each 1% biomass co-firing level at McIntosh would be the equivalent of removing over 1,500 cars each year from the highway.

Energy crop fuel requirements and costs. In evaluating the feasibility of co-firing energy crops in an existing Utility power plant boiler, significant effort must be spent to build effective communications between engineering and agriculture functions. While many issues are relatively simple to resolve, failure to do so can significantly effect work product and increase evaluation time.

Table 11. Examples of production cost credits from voluntary CO_2 reductions for each 1% co-firing at McIntosh-3.

	Value At		
	$3 A Ton	$5 A Ton	$10 A Ton
CO_2 Multiplier To Coal	3.67	3.67	3.67
MM BTUs Displaced	255,792	255,792	255,792
BTU/Lb. Value Of Coal	12,000	12,000	12,000
MM BTUs Coal/Ton	24	24	24
Coal Tons Displaced	10,658	10,658	10,658
Carbon Content Of Coal	22.80%	22.80%	22.80%
Tons Of CO_2 Reduced	8,918	8,918	8,918
CO_2 Credit/Carbon Ton	$3.00	$5.00	$10.00
CO_2 Credit/Coal Ton	$0.69	$1.14	$2.28
CO_2 Credit Value/MM BTU	$0.03	$0.06	$0.10

An important first step in effective communication is to clearly define what co-firing means – between a measurement basis of electricity generation (kwh) or fuel weight (tons). In the following evaluation, biomass co-firing levels are defined as a power plant's generation output. One simple approach to bridge communication barrier between co-firing levels based on electricity generation or fuel weight is to take the BTU/lb. for coal and divide by the BTU/lb. of the biomass fuel.

For example, with a 12,000 BTU/lb. value of coal, a biomass co-firing level of 1% by electricity generation, would mean a 3% co-firing level by fuel weight for green biomass (at 4,000 BTU/lb.) or a 2% co-firing level for drier biomass (at 6,000 BTU/lb.).

In determining the biomass fuel requirements needed for any level of co-firing, the Power Plant's Heat Rate was used (a measure of efficiency), which is the number of BTUs required to produce 1 kilowatt hour of electricity. For the McIntosh Unit, the Heat Rate is approximately 10,000. For the 365,000 KW (365 MW) McIntosh Unit, operating at full capacity for 1 hour, 3,650 MM BTUs (i.e., million BTUs) would be required to produce 365,000 Kwh. With a co-firing level at 1% at McIntosh, biomass fuel requirements would be 36.5 MM BTUs per hour.

The amount of biomass fuel needed for co-firing can be determined by simply taking the MM BTU fuel requirement, and dividing by the MM BTU value per ton of biomass (Table 12). For example, using a green biomass fuel feedstock of 4,500 BTU/Lb., the fuel value would by 9 MM BTU per ton (i.e., 4,500 BTU times 2,000 pounds, divided by 1 million). Thus, a one hour Test Burn at McIntosh with a co-firing level of 1% (with the Unit operating at full load), would require 4.055 tons of biomass fuel (36.5 MM BTUs divided by 9 MM BTUs).

Table 12. Examples of biomass fuel requirements to perform co-firing tests at McIntosh-3.

Co-Firing Level Of Test Burn	Duration Of Test Burn (Hours)	Biomass BTU Value/Lb.	Biomass MMBTU Value/Ton	Biomass Fuel Required (Tons)
1%	2	4,500	9	8.11
2%	2	4,500	9	16.22
3%	2	4,500	9	24.33
4%	2	4,500	9	32.44
5%	2	4,500	9	40.55
6%	2	4,500	9	48.66
			Total Requirements	170.31

In determining annualized fuel requirements for various co-firing levels, the above methodology is modified to reflect the Unit's Capacity or Load Factor, since Power Plants incur scheduled (i.e., maintenance) and unscheduled (operating problems) outages. For McIntosh-3, the historical Capacity Factor is approximately 80%. Thus, for each co-firing increment of 1% at McIntosh, annual biomass fuel requirements would be 255,792 MM BTUs (i.e., 36.5 MM BTUs per hour times 365 days times 24 hours times 80% availability).

Annual Co-Firing Level	Biomass MMBTU Value/Ton	Green Fuel Required (Tons)	Biomass MMBTU Value/Ton	Field Dried Fuel Required (Tons)
1%	9	28,421	12	21,316
2%	9	56,842	12	42,632
3%	9	85,263	12	63,948
4%	9	113,684	12	85,264
5%	9	142,105	12	106,580
6%	9	170,526	12	127,896

The McBurney Corporation believes the preceding fuel requirement estimates, based on the Unit's current heat rate, may result in a significant **under-estimate** of the actual amounts biomass fuel needed for co-firing. McBurney is of the opinion, that with a wood/biomass fuel of 45 to 50% moisture content on an as fired basis, the boiler efficiency (on the wood firing component only) will be measurably lower than with pulverized coal firing. McBurney's rough estimate of boiler efficiency on the wood firing component is in the 70% range. Adjusting the above estimates (i.e., biomass fuel requirements of 4.055 tons per hour for each 1% co-firing level based on a heat rate of 10,000), would result in fuel requirement estimates of 5.79 tons per hour.

McBurney raises a valid point, which needs to be addressed. However, since co-firing operating performance data does not yet exist for biomass fuels at various mesh size, moisture content, and co-firing levels, it is difficult to determine the adjustment needed to the Units Heat Rate (for the wood firing component only). Results of co-firing test-burns, that are scheduled for the McIntosh Unit, should provide the basis of any needed adjustment to the methodology to determine fuel requirements based on the Unit's Heat Rate..

Acreage planting requirements for eucalyptus, leucaena, elephantgrass, and presscake energy crops to support various **sustainable** co-firing levels at McIntosh-3 (Tables 13 and 14) are based on yield estimates provided.

Table 13. Estimates of Eucalyptus yields

	Producton Scenario		
	Mulchwood	Energywood Current	Energywood Improved
Dry Tons/Acre Year	4.3	14.0	24.0
BTUs/Lb. (Dry)	8,296	8,296	8,296
Fuel Moisture Level (Green)	49%	49%	49%
Conversion Dry To Green [1]	1.96	1.96	1.96
Green Tons/Acre Year	8.43	27.45	47.06
BTUs/Lb. (Green)	4,231	4,231	4,231
MMBTUs Per Ton	8.462	8.462	8.462
MMBTUs/Acre Year (Dry)	71.35	232.29	398.21
MMBTUs/Acre Year (Green)	71.35	232.29	398.21

Table 14. Estimates of short rotation crop yields (sand soil)

	Crop Scenario		
	Leucaena	Elephantgrass	Presscake
Dry Tons/Acre Year	10.0	14.0	10.48
BTUs/Lb. (Dry)	7,915	7,773	8,191
Fuel Moisture Level (Green)	60%	20%	60%
Conversion Dry To Green [1]	2.5	1.25	2.50
Green Tons/Acre Year	25.0	17.50	26.20
BTUs/Lb. (Green)	3,166	6,218	3,276
MMBTUs Per Ton	6.332	12.437	6.553
MMBTUs/Acre Year (Dry)	158.30	217.64	171.68
MMBTUs/Acre Year (Green)	158.30	217.64	171.68

[1] The conversion factor from dry to green tons is (1/(1 minus the moisture rate)).

In order to achieve good communications between a broad range of parties with very different technical backgrounds (engineering, agronomy, forestry, harvesting, transportation, etc.), yield values should always be presented on both a dry and green (specifying the moisture content) basis.

The use of a yield measurement basis of MM BTUs per ton, or acre year, is an excellent way for bridging potential communication barriers, and to insure the validity of work product. The reason for this is that the total BTUs available from an acre of energy crops would be the same, whether or not the crop is eventually used as green fuel or would be field dried; however, the net BTUs per acre decrease as moisture content increases. Green fuel from a planted acre would have more weight with lower BTUs per pound, and field dried energy crops would have more BTUs per pound but less weight. However, the total amount of available BTUs from an acre (whether green or field dried) is the same.

Based on the above crop yield assumptions, the following acreage planting requirements are necessary to provide fuel requirements for each 1% increment of co-firing at McIntosh-3 (i.e., for 2% co-firing the below values would be doubled, at 3% co-firing, values would be tripled, etc.).

The values for the “Total Planted Acres Needed” represent the total acres that are needed to sustain a yearly co-firing level at 1% – and is simply the yearly acreage requirements (based on yearly MM BTU fuel requirements needed for co-firing) times the assumed number of years between harvests (Tables 15 and 16). The Total Planted Acres Needed” would not have to be planted all in one year, but could be staggered in yearly increments based on the expected harvest cycle.

In the above “Energywood Current” Scenario (Table 15), a stand of 275 acres of eucalyptus trees planted each year over an initial four year period (a total plantation of 1,101 acres) would sustain a 1% co-firing level at the McIntosh Unit for 23 years – assuming that each stand could be harvested five times (i.e., coppice) and yield results per acre were identical between harvests.

Table 15. Yearly Eucalyptus crop acre planting requirements for 1% co-firing.

	Production Scenario		
	Mulchwood	Energywood Current	Energywood Improved
Yearly MM BTUs Needed	255,792	255,792	255,792
MM BTUs/Acre Year	71.35	232.29	398.21
Years Between Harvests	4	4	4
MM BTUs/Acre At Harvest	285	929	1,593
Needed Acres Per Year	896	275	161
Total Planted Acres Needed	3,585	1,101	642

Table 16. Yearly short rotation crop acre planting requirements for 1% co-firing.

	Crop Scenario		
	Leucaena	Elephantgrass	Presscake
Yearly MM BTUs Needed	255,792	255,792	255,792
MMBTUs/Acre Year	158.30	217.64	171.68
Years Between Harvests	1	1	1
MM BTUs/Acre At Harvest	158.30	217.64	171.68
Needed Acres Per Year	1,616	1,175	1,490
Total Planted Acres Needed	1,616	1,175	1,490

Like eucalyptus trees, short rotation energy crops also coppice after each harvest. The expected plot-stand life is 10 years for leucaena, 6 years for elephantgrass, and 4 years for energycane planted on clay soils. Using the establishment cost estimates, capital cost estimates for establishing energy crop plantations, by biomass fuel type, are in Tables 17, 18, and 19.

Financing Project Development. The primary cost benefit of co-firing energy crops in an existing electric utility boiler is the avoidance of capital costs associated with building a new stand-alone power plant (i.e., utilization of the existing boiler, turbine-generator, etc.). However, it must be understood that capital costs incurred with co-firing can still be significant, regardless of the co-firing technology (i.e., external gasification, hydro or air cooled grates) or fuel delivery system used (i.e., installation of a wood-yard, or modification of the existing McIntosh RDF processing system).

In developing estimated total production costs of co-firing energy crops (i.e., cost of delivered fuel, fuel handling O&M, financing cost of capital additions), it must be remembered that co-firing is simply a fuel switching strategy, adding no new KW capacity, and may even result in a slight de-rating of the Unit (depending on the moisture level of the biomass fuel).

Senior Management at Lakeland Utilities have communicated that for electricity generated from energy crops, Lakeland may be willing to pay a "green premium" of up to 10% above the production cost of coal. According to personnel at Lakeland Utilities, the current range of delivered coal cost is between $1.75 and $2.00 per MM BTU (i.e., firm fuel contracts, transportation). It should be noted that the transportation component of delivered coal cost is extremely high for Florida's Utilities, compared to other parts of the U.S., and will be a significant contributing factor if energy crop biomass can be cost competitive with coal.

Table 17. Eucalyptus plantation establishment capital cost for 1% co-firing

	Production Scenario		
	Mulchwood	Energywood Current	Energywood Improved
Establishment Cost/HA	927	803	717
HA To Acre Conversion	.40	.40	.40
Establishment Cost/Acre	375	325	290
Initial Acres Needed	896	275	161
Initial Year Capital Outlay	$336,000	$89,375	$46,690
Total Acres Needed	3,585	1,101	642
Total Capital Outlay	$1,344,375	$357,825	$186,180

Table 18. Short rotation crop plantation establishment capital cost for 1% co-firing.

	Crop Scenario		
	Leucaena	Elephantgrass	Presscake
Establishment Cost/Ha	608	1,441	675
Ha To Acre Conversion	.40	.40	.40
Establishment Cost/Acre	246	583	273
Initial Acres Needed	1,616	1,175	1,490
Initial Year Capital Outlay	$397,536	$685,025	$406,770

Table 19. Summary of planted acres needed and establishment cost ($'s In 000's).

Co-Firing Level	Eucalyptus[1]		Leucaena		Elephantgrass		Presscake	
	Acres	Cost	Acres	Cost	Acres	Cost	Acres	Cost
1%	642	$186	1,616	$398	1,175	$685	1,490	$407
2%	1,284	$372	3,232	$796	2,350	$1,370	2,980	$814
3%	1,926	$558	4,848	$1,194	3,525	$2,055	4,470	$1,221
4%	2,568	$744	6,464	$1,592	4,700	$2,740	5,960	$1,628
5%	3,210	$930	8,080	$1,990	5,875	$3,425	7,450	$2,035
6%	3,852	$1,116	9,696	$2,388	7,050	$4,110	8,940	$2,442

[1] Eucalyptus estimates based on Energywood Improved scenario.

At the time of this writing, coal fuel handling operation and maintenance expenses at McIntosh- 3 are unknown. When this information becomes available, the current estimate of coal production cost (i.e. $1.75 to $2.00 per MM BTU) will be adjusted upward. Because of this lack of information on coal fuel handling costs, the following financial evaluation excludes fuel handling operation and maintenance expenses for biomass fuels, although our experience indicates that the cost of operating a wood-yard is in the range of $0.35 to $0.50 per MM BTU (excluding the capital financing cost of equipment). In determining the "effective" fuel handling costs for biomass, the following methodology should be used:

1. Biomass Energy Crop Fuel Handling Expenses (i.e., wood-yard processing)
2. Less, Variable Cost Coal Fuel Handling Expenses (i.e., for coal displaced)
3. Equals, The "Effective or Net" Fuel Handling Expenses For Biomass Fuels

Using a target production cost of $2.00 per MM BTU for energy crops and "expected case cost scenarios" (Table 20), only eucalyptus and leucaena have any "expected case" potential of meeting this target, without any additional incentive payments (i.e., the 1.5 cent/Kwh Renewable Energy Production Incentive available to non-taxable electric utilities):

Table 20. "Expected Case" MM BTU production cost by energy crop.

	Eucalyptus	Leucaena[1]	Elephantgrass[1]	Presscake[1]
Establishment	$0.19	$0.25	$0.70	$0.43
Harvesting	$1.16	$0.86	$1.36	$1.15
Transportation	$0.41	$0.44	$0.57	$0.61
Landowner Return[2]	$0.13	$0.32	$0.23	$0.29
Sub-Total	$1.89	$1.87	$2.86	$2.48
Max. Financing Cost	**$0.11**	**$0.13**	-	-
Total Cost	$2.00	$2.00	$2.86	$2.48

[1] Planted on clay soil.
[2] Landowner Return at $50 per acre year.

CONCLUSIONS

This project evaluated the major agricultural, power plant engineering, and business development issues associated with potential energy-crop biomass (i.e., "closed loop") co-firing with coal at Lakeland Utilities' McIntosh-3 Unit in central Florida.

Marginal and reclaimed lands readily available in the Lakeland vicinity are suitable for sugarcane, elephantgrass, leucaena, Eucalyptus, and slash pine. Estimates of biomass yields vary with species, soil type and cultural intensity, ranging from as low as 10 green tons/acre/year (tay) for E. grandis with minimal intensity on sandy soils, 17.5 tay for elephantgrass on overburden sites, 35 tay for leucaena established on phosphatic clays, to as much as 55 tay for E. grandis managed intensively on clay lands. These yields from relatively small experimental plots should be confirmed in commercial size demonstration plantings of 40 to 200 acres.

Two energy crops meet Lakeland Utilities' 2¢ per Kwh, or $2 per MM BTU, target price for "Green Energy." The highest yielding Leucaena and Eucalyptus growth strategies had estimated production costs of $1.87 and $1.89 per MM BTU, respectively.

However, even with these favorable aspects, the economics of energy crop (closed loop) biomass will only support modest capital investment (and certainly not of the scale of a stand-alone power plant) at McIntosh-3. If closed loop biomass is going to be developed, co-firing is probably the only realistic option. After subtracting estimated energy crop fuel costs of ~1.9¢ per Kwh from project revenues of ~2¢ per Kwh (i.e., based on a 10% premium above the cost of Lakeland's coal generation), very little income would be left to finance capital requirements needed to co-fire (i.e., woodyard, external gasifier, etc.). With the MW and capacity of McIntosh-3, 5 to 6% biomass co-firing (based on generation) would represent a sizable renewable energy source of ~20 MWs.

Currently, there are significant limitations at McIntosh-3 to increasing co-firing. These are all fuel processing related, ranging from operational problems of fuel handling to inadequate RDF combustion (due to moisture, mesh size, and grate slit closure), resulting in significant bottom ash build-up. Potential direct and indirect co-firing options of overcoming these limitations are identified.

The coming deregulation of electricity markets, coupled with current and future federal tax credits, pollution allowances, etc., suggests a significant business opportunity. However, without the 1.5 cent/Kwh REPI, only eucalyptus and leucaena have any "expected case" potential of meeting a target production cost of $2.00 per MM BTU for energy crops. A broadening of the "closed loop" requirement to include "opportunity biomass" (i. e., yard waste, land clearing waste, etc.) that commands a tipping fee would be advantageous. Uncertainty about continued Congressional funding of the REPI Program creates significant risk in the long term financing of a project at McIntosh-3.

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APPENDICES

Appendix 1. Selected land characterizations (emphasizing timberlands) in counties within a 50-mile radius of Lakeland (adapted from 6).

County	All Land (acres)	Timberland (acres)	Timberland Ownership (acres): Nat For	Misc Fed.	State	County & City	Farmer	Corpor.	Individ.	Forest Type (acres): Pine	Pine-Hdwd	Hdwd	Site Class (cu. ft./acre/year): >164	120-164	85-119	50-84	20-49
Hardee	407,910	79,530			727	80	25,048	28,627	25,048	17,892	3,579	58,059			10,735	36,511	32,284
Hernando	306,112	155,853		707	55,344	1,630		34,493	63,679	48,563	20,540	86,750		5,169	13,266	100,685	36,733
Highlands	658,227	78,759		22,500	460	90	14,660	32,253	8,796	18,796	14,228	45,735				45,212	33,547
Hillsboro.	672,653	96,466			14,369	3,480	5,241	44,550	28,826	18,344	10,483	67,639			8,557	73,414	14,495
Lake	609,990	248,490	69,407	280	20,081	750	14,582	48,607	94,783	99,221	27,088	122,181	2,431	9,357	35,964	136,825	63,913
Manatee	474,368	40,003			2,870	6,321		18,487	12,325	15,353	2,054	22,596				23,570	16,433
Orange	580,883	149,304		268	22,422	7,870	5,937	65,309	47,498	47,021	11,874	90,409			2,969	94,144	52,191
Osceola	846,093	181,508		380	31,458	830	18,943	67,655	62,242	30,638	18,024	132,846			8,118	120,275	53,115
Pasco	476,794	159,125		20	59,319	5,885	7,413	32,124	54,364	40,321	16,129	102,675			9,366	103,327	46,432
Polk	1,199,955	243,155		15,198	17,832	1,968	39,381	84,388	84,388	68,042	18,777	156,336				656	168,251
Sumter	349,235	149,891			78,216	10	8,431	16,862	46,372	56,594	8,126	80,955	4,216	1,955	12,039	105,043	26,638
Total	6,582,220	1,582,084	69,407	39,353	303,098	28,914	139,636	473,355	528,321	460,785	150,902	966,181	6,647	16,481	101,014	839,662	544,032

Appendix 2. Timber quantities on central Florida timberlands by timber class (adapted from 6).

Timber Type	Timber Class (1000 cu. ft. in DBHs >4.9"): Growing Stock	Rough Trees	Rotten Trees	Dead Trees	Total	Green Wt. (100,000 lbs.): >4.9" DBH	<5" DBH	Ann. Mortality (1000 cu. ft.)
Softwood	1,500,361	10,974	2,333	1,812	1,515,480	1,309,820	98,300	10,482
Hardwood	1,134,560	399,118	29,369	0	1,563,047	1,499,101	170,596	23,049
	2,634,921	410,092	31,702	1,812	3,078,527	2,808,921	268,896	33,531

Appendix 3. Central Florida timberland treatment opportunities by forest type and ownership (adapted from 6).

Treatment	Forest Type (acres)			Ownership (acres)	
	Pine	Pine-Hdwd	Hdwd	Public	Private
Salvage	4,960		10,956	5,638	10,278
Harvest	7,339	11,768	92,783	36,483	75,407
Thinning	11,041		9,914	10,882	10,073
Other	14,246	11,378	39,237	22,005	42,856
Conversion			2,430		2,430
Regeneration	208,624	118,489	562,264	185,514	703,863
OK	376,522	74,339	347,306	216,682	581,485
Adverse		5,243	214,595	48,583	171,255
	622,732	221,217	1,279,485	525,787	1,597,647

Appendix 4. Summary by soil classification (number and name) of number of parcels and acres of Polk County soils used mainly for pasture within 15, 20, 25, and 30 miles of McIntosh-3.

Soil No.	Soil Name	Parcels within				Acres within			
		15	20	25	30	15	20	25	30
5	EauGallie	42	65	67	75	4,382	6,502	6,620	8,127
7	Pomona	362	552	644	733	63,843	75,364	79,710	88,047
10	Malabar	29	41	43	62	1,434	1,744	1,764	3,422
17	Smyrna/Myakka	450	712	977	1,171	24,041	35,275	50,333	81,991
22	Pomello	132	192	262	337	3,185	4,692	5,651	6,806
23	Ona	156	221	286	399	2,994	4,079	5,326	8,650
26	Lochloosa	124	192	210	226	1,586	2,298	2,515	2,735
27	Kendrick	108	152	160	163	2,530	3,194	3,238	3,278
30	Pompano	54	83	155	212	674	1,839	4,464	6,370
38	Electra	9	28	42	45	83	303	471	482
40	Wauchula	156	284	310	336	8,529	13,803	14,673	15,525
42	Felda	84	145	169	211	2,275	4,281	4,845	6,518
43	Oldsmar	26	36	45	51	323	434	747	1,104
44	Paisley	41	55	55	56	2,531	3,158	3,158	3,161
62	Wabasso	50	93	93	103	2,747	4,623	4,623	5,014
67	Bradenton	19	58	70	75	558	3,952	4,431	4,586
70	Duette	11	27	55	113	291	584	1,341	2,580
76	Millhopper	90	186	230	243	2,584	5,104	5,995	6,269
78	Paisley	10	39	41	53	464	2,013	2,042	2,399
87	Basinger	35	66	96	135	991	2,393	3,187	5,071
9	Lynne	58	70	70	73	4,435	4,834	4,834	4,852
21	Immokalee	180	289	441	564	4,045	7,305	11,199	16,445
41	St. Johns	16	17	19	28	125	145	222	726
74	Narcoossee	9	29	80	139	172	573	1,767	3,182
75	Valkarea	7	10	18	23	199	222	448	551
12	Tailings	91	143	205	252	8,461	14,754	20,913	23,769
8&57	Clay Settling Areas	161	227	289	309	14,744	33,322	60,887	63,897
39	CSA+Overburden	20	34	44	45	1,045	2,034	3,094	3,114
68	Overburden	81	133	169	182	20,014	22,387	26,625	28,974
		2,611	4,179	5,345	6,414	179,285	261,211	335,123	407,645

Appendix 5a. Leucaena estimated yield, BTU content and establishment costs.

	Sand Land	Overburden	Phosphatic Clay
Dry Tons[1] / Acre / Year	10	13	14
Green Tons [2] / Acre / Year	25	32.5	35
BTU per Green Pound[3]	3164	3164	3164
MM BTU per Green Ton	6.33	6.33	6.33
Establishment[4]: $ / Acre	$246.00	$257.00	$256.00

[1] Oven dried until no further weight loss.
[2] Assumes moisture level of 60% at harvest.
[3] Assumes moisture level of 60% at harvest (dry BTU/lb = 7915).
[4] Cost for initial establishment - One establishment is expected to last for 10 years or more.

Appendix 5b. Delivered fuel cost estimates[1] for Leucaena with establishment costs amortized over 10 year life of stand (initial harvest 18 months after establishment then annual harvests)

Item	Cost Per Green Ton			Cost Per MM BTU		
	Sand	Overburden	Clay	Sand	Overburden	Clay
Establish.	$3.49	$2.58	$1.58	$0.55	$0.41	$0.25
Harvesting	$5.87	$5.59	$5.45	$0.93	$0.88	$0.86
Transportation[2]	$2.80	$2.80	$2.80	$0.44	$0.44	$0.44
Total Cost	$12.16	$10.97	$9.83	$1.92	$1.73	$1.55
REPI Credit[3]				$1.50	$1.50	$1.50
Net Cost				**$0.42**	**$0.23**	**$0.05**

[1] Cost estimate does not provide for profit for producer or harvester.
[2] 50,000 lb per load at a cost of $70.00 per round trip.
[3] Federal subsidy paid to municipal utilities for burning biomass materials.

Appendix 6a. Elephantgrass - estimated yield, BTU content and establishment costs

	Sand Land	Overburden	Phosphatic Clay
Dry Tons[1] / Acre / Year	14	14	16
Green Tons [2] / Acre / Year	17.5	17.5	20
BTU per Green Pound[3]	6220	6220	6220
MM BTU per Green Ton	12.44	12.44	12.44
Establishment[4]: $ / Acre	$583.05	$611.84	$573.16

[1] Oven dried until no further weight loss.
[2] Assumes crop is cut, field dried to 20% moisture and baled into large round bales.
[3] Assumes moisture level of 20% at harvest (dry BTU/lb = 7773).
[4] Cost for initial establishment - One establishment is expected to last for 6 years.

Appendix 6b. Delivered fuel cost estimates[1] for elephantgrass with establishment costs amortized over 6 year life of stand (initial harvest 10 to 12 months after establishment then annual harvests).

Item	Annual Cost Per Green Ton			Cost Per MM BTU		
	Sand	Overburden	Clay	Sand	Overburden	Clay
Establish.	$11.92	$11.58	$8.72	$0.96	$0.93	$0.70
Harvesting	$19.33	$19.33	$16.91	$1.55	$1.55	$1.36
Transportation[2]	$7.14	$7.14	$7.14	$0.57	$0.57	$0.57
Total Cost	$38.39	$38.05	$32.77	$3.08	$3.05	$2.63
			REPI Credit[3]	$1.50	$1.50	$1.50
			Net Cost	**$1.58**	**$1.55**	**$1.13**

[1] Cost estimate does not provide for profit for producer or harvester.
[2] Load limited to 24,000 lbs because of the shape and bulk of large round bales.
[3] Federal subsidy paid to municipal utilities for burning biomass.

Appendix 7a. Sugarcane presscake (bagasse) 70% of dry-matter crop production is in presscake (30% recovered as sugar)

	Sand Land	Overburden	Phosphatic Clay
Dry Tons[1] / Acre / Year	10.5	10.5	12.6
Green Tons[2]/ Acre / Year	26.2	26.2	31.5
BTU per Green Pound[3]	3274	3274	3274
MM BTU per Green Ton	6.55	6.55	6.55
½ Establishment[4]: $ / Acre	$273.00	$285.00	$294.00

[1] Oven dried until no further weight loss.
[2] Assumes moisture level of 60% after pressing.
[3] Assumes moisture level of 60% after pressing (dry BTU/lb = 8191).
[4] Cost for initial establishment - Once established a stand is expected to last for 4 to 6 year. One half of cost charged to presscake.

Appendix 7b. Delivered fuel cost estimates[1] for sugarcane presscake with establishment costs amortized over the life of the stand[2] (initial harvest 10 - 12 months after establishment then annual harvests)

Item	Cost Per Green Ton			Cost Per MM BTU		
	Sand	Overburden	Clay	Sand	Overburden	Clay
Establish.	$4.68	$4.64	$2.81	$0.71	$0.71	$0.43
Harvesting	$7.35	$7.35	$7.51	$1.12	$1.12	$1.15
Transportation[3]	$4.00	$4.00	$4.00	$0.61	$0.61	$0.61
Total Cost	$16.03	$15.99	$14.32	$2.44	$2.44	$2.19
REPI Credit[4]				$1.50	$1.50	$1.50
Net Cost				**$0.94**	**$0.94**	**$0.69**

[1] Cost estimate does not provide for profit for producer or harvester.
[2] Stand life is estimated to be 6 years for phosphatic clay and 4 years for other soils.
[3] 50,000 lb per load at a cost of $100.00 per round trip.
[4] Federal subsidy paid to municipal utilities for burning biomass.

Appendix 8. Risk of freeze or drought effects on net cost per MM BTU of a 10% increase or decrease in yield (green tons per acre) of leucaena, elephantgrass, and presscake.

Crop	Sand Land		Overburden		Phos. Clay	
	Yield	Net Cost	Yield	Net Cost	Yield	Net Cost
Leucaena (60% H_2O)	25.00	$0.42	32.50	$0.23	35.00	$0.05
10% yield increase	27.50	0.37	35.75	0.19	38.50	0.03
10% yield decrease	22.50	0.48	29.25	0.27	31.50	0.07
Elephantgrass (20%)	17.50	1.58	17.50	1.55	20.00	1.13
10% yield increase	19.25	1.49	19.25	1.47	22.00	1.07
10% yield decrease	15.75	1.68	15.75	1.65	18.00	1.21
Presscake (60%)	26.20	0.94	26.20	0.94	31.50	0.69
10% yield increase	23.58	0.88	23.58	0.87	34.65	0.65
10% yield decrease	28.82	1.02	28.82	1.02	28.35	0.74

Appendix 9. Eucalyptus grandis stem wood and bark energywood assumptions for central and south Florida.

	Mulchwood	Energywood	
		Current	Improved
Dry Tons / Acre / Year	3.85[1]	12.31[1]	21.15[1]
Green Tons / Acre / Year	10[1]	32[1]	55[1]
BTU / Green Pound[2]	3455	3455	3455
MM BTU / Green Ton	6.9	6.9	6.9
Establishment[3]: $ / Acre	375	325	290

[1]Add 20% to include branch and foliage biomass

[2]Assumes 60% moisture content on a wet weight basis

[3]Mulchwood includes: chopping, bedding, fertilization, planting 600 trees/acre;
Current Energywood includes: bedding, fertilization, planting 900 trees/acre;
Improved Energywood includes: bedding, planting 1,000 trees/acre.

Appendix 10. Coppice rotation[1] delivered fuel cost estimates for Eucalyptus grandis (based on three coppice harvests every four years after first harvest at four years after planting).

Item	Cost Per Green Ton			Cost Per MM BTU		
	Mulchwood	Energywood		Mulchwood	Energywood	
		Current	Improved		Current	Improved
Establishment	$2.35	$0.64	$0.33	$0.34	$0.09	$0.05
Harvesting	$13.00	$13.00	$8.00	$1.88	$1.88	$1.16
Transportation[2]	$2.80	$2.80	$2.80	$0.41	$0.41	$0.41
Total Cost	$18.15	$16.44	$11.13	$2.63	$2.38	$1.62
REPI Credit				$1.50	$1.50	$1.50
Net Cost				**$1.13**	**$0.88**	**$0.12**

[1]25% more growth in four year coppice rotations

[2]Assumes 60% moisture content on a wet basis

Appendix 11. Estimated acreage requirement for 2% cofiring of McIntosh-3 with Eucalyptus grandis grown at the low productivity level.

MW Capacity of McIntosh	365
KW Capacity of McIntosh	365,000
2% Co-Firing at Nameplate (KW)	7,300
Assumed Capacity Factor	80%
Co-Firing KWH Generation:	
Nameplate KW	365,000
Hours Per Day	24
Days Per Year	365
Operating Factor	80%
Total Kwh	2,557,920,000
Kwh at 2% Co-firing	51,158,400
Heat Rate of BTUs/Kwh	10,000
BTUs Requried For 2% Co-fire	511,584,000,000
MM BTUs Required	511,584
BTU Value Of Biomass Per Green Lb.	3,455
BTU Value Of Biomass Per Ton	6,910,000
MM BTU Per Ton	6.91
Green Ton Yield Per Acre	40
BTUs Per Acre	276,400,000
MM BTUs Per Acre	276.4
Assumed Harvest Cycle -- Years	4
MM BTUs Per Acre At Harvest	1,106
Annual Acres Needed At 2% Co-fire	462.72
Total Acres Needed To Be Planted To Co-fire On A Sustainable Basis	**1,851**

Appendix 12. Estimated acreage needed to supply 2%, 4%, and 6% co-firing at McIntosh-3 with Eucalyptus furnishing 50%, leucaeua 30%, and elephantgrass 20% of fuel.

	Eucalyptus[1]	Leucaena	Elephantgrass	Total Acreage
Percent of fuel	50%	30%	20%	
MM BTU/Ton	8.5	6.33	12.44	
Yield/Yr	32	32.5	17.5	
MM BTU/A/Yr	272	205.7	217.7	
MM BTU for 2% Co-fire	255792	153476	102316	
Acres Harvested yr 2000		746	470	1216
Acres Harvested yr 2001		746	470	
Acres Harvested yr 2002		746	470	
Acres Harvested yr 2003	940	746	470	
Acres Harvested yr 2004	940	746	470	
Acres Harvested yr 2005	940	746	470	
Acres Harvested yr 2006	940	746	470	4976
MM BTU for 4% Co-fire	511584	306952	204632	
Acres Harvested yr 2000		1492	940	2432
Acres Harvested yr 2001		1492	940	
Acres Harvested yr 2002		1492	940	
Acres Harv. yr ‘03 to ‘06	1880	1492	940	9952
MM BTU for 6% Co-fire	767376	460428	306948	
Acres Harvested yr 2000		2238	1410	3648
Acres Harvested yr 2001		2238	1410	
Acres Harvested yr 2002		2238	1410	
Acres Harv. yr ‘03 to ‘06	2820	2238	1410	14928
[1] An acreage of Eucalyptus to supply 50% of MM BTUs planted each of first four (4) years to set up four (4) year harvest rotation.				

Appendix 13. Biomass Gasifier Contact List.

Appendix 14. Evaluation of Gasification and Novel Thermal Processes for the Treatment of Municipal Solid Waste.

Appendix 15. Heuristic Envirocycler Waste Disposal with Energy Recovery.