FINANCIAL ANALYSIS OF A PROPOSED LARGE-SCALE ETHANOL COGENERATION PROJECT

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Abstract

Financial analysis of an ethanol/electricity cogeneration plant indicates a rapid payback of investment and a high internal rate of return. This is primarily because cogeneration of steam for generation of electricity and biomass conversion to ethanol results in increased engineering efficiency compared to alternative ethanol alone production processes. Economic sensitivity testing included alternative price levels, interest rates, capacities, costs, and a "stand alone" case with no federal government excise tax subsidies. Supply and price analyses suggest the procurement of locally produced feedstock in Alabama and surrounding states is feasible. The robustness of the economic analysis provides support for consideration of ethanol cogeneration as a currently feasible strategy to utilize excess agricultural production capacity.

Key words: ethanol, cogeneration, financial analysis, biomass conversion, excise tax.

A large electrical power utility serving South Alabama and the Western Panhandle of Florida was faced in the early 1980's with continuing low plant capacity utilization at a "peaking" plant used primarily during summer months of high electricity demand. Disturbed with plant inefficiency, management surveyed options to improve profitability and decided to critically examine the hypothesis that ethanol cogeneration offered the prospect of providing significant efficiency gains in joint production of ethanol and electricity. With financial support from the State of Alabama, several engineering and economic studies were undertaken to systematically analyze key technical and price factors of the project to determine cogeneration feasibility.

The primary objective of this study is to present financial analyses of this unique project. Two secondary objectives are to: (1) briefly identify engineering efficiencies associated with ethanol cogeneration processes (that account in large part for the strength of the financial results) and (2) raise the issue of gasohol policy reevaluation, based on analysis of several current economic trends. These trends include the apparent excess capacity of U.S. agriculture, the continuing decline in the real prices of agricultural commodities, and the improvement of ethanol production technology. The confluence of these trends may warrant a critical reexamination of ethanol as an agriculturally based fuel that, unlike petroleum, does not become more expensive to discover and produce as it is used (Commoner).

REVIEW OF CURRENT ETHANOL/ COGENERATION ISSUES

During the 5 years 1979-83, ethanol production in the United States generally doubled in each succeeding year increasing from approximately 20 to 385 million gallons. The roughly 83 percent increase in 1983 (*Alcohol Outlook;* March, 1984) occurred during what would appear to be the worst scenario possible for the ethanol industry: falling petroleum prices and increasing commodity prices (the latter due to a large reduction in planted acreage associated with the Payment-In-Kind program, and the most severe drought experienced in the last half century). It appears that approximately 500 million gallons of ethanol were produced in 1984 indicating slower but continuing substantial growth (*Alcohol Outlook;* December, 1984). While the expanding volume of

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ethanol production signals its apparent profitability, future prospects appear even better based on anticipated crop surpluses for the remainder of the decade, the continuation of a longrun trend of declining real commodity prices (Edwards and Harrington), improvements in market distribution facilities (*Alcohol Outlook;* March, 1984), the increasing acceptance of ethanol as an octane enhancer (in addition to fuel extender, Tyner and Bottum), and the Environmental Protection Agency's recent ruling requiring a lead phasedown in gasoline. Currently, the cost of octane enhancement with ethanol is competitive with toluene and tertiary butyl alcohol. This situation combined with adoption of the Environmental Protection Agency lead phasedown proposal is projected to substantially enhance the competitive position of ethanol (Gill). Development of pharmaceutical, cosmetic, and industrial uses of ethanol are also occurring (Harmon Engineering and Testing, 1982).

A recent study by Christensen et al. suggests a large ethanol program could be accommodated without increasing soil erosion if farmers would adopt conservation tillage practices currently viewed to be needed by both agronomists and economists. Commoner has reported mathematical programming results showing ethanol derived from agricultural crops could provide 20 percent of automobile fuel needs without decreasing the current level of livestock production. However, this result would require major shifts in cropping patterns such as decreased soybean and increased corn production.

The prospect for continuing significant improvement in ethanol processing technology has been frequently noted (e.g., Hertzmark et al., 1980; Sama). Hertzmark et al. (1980), is one of the few agricultural economic studies found to discuss cogeneration energy savings. The authors report that cogeneration ethanol facilities have been proposed utilizing waste steam from oil refineries (the largest industrial gas user) and low-grade steam from geothermal reservoirs (p. 966). Stone and Webster Engineering Corporation provides another cogeneration feasibility study. Furthermore, there have been a number of instances reported in the press of cogeneration of steam and electricity at forest products and fertilizer plants. Teixerira points out that cogeneration in the food industry has been concentrated in processing of beet and cane sugars and in wet milling processes. He suggests that cogeneration technology may soon be adopted in other agricultural subsectors such as the malt beverage industries.

The principal advantages of cogeneration have been identified as follows. First, environmental standards require that steam be condensed, which is usually accomplished with expensive water recycling systems (Sama). The cogeneration ethanol facility achieves this standard, replacing a significant component of machinery investment normally required in steam powered electrical generation. Second, engineering studies have shown that cogeneration of ethanol at electrical utility plants results in process energy savings of 27-28 percent (Browning and Briggs; Sama). Third, use of only one coal unloading, storage, and conveying system for both the power generation and ethanol plant components further enhances efficiency. Fourth, combination of an ethanol processing facility with an electric utility plant creates a large, stable (year-round) customer for additional sales of electricity by the utility (this factor was of particular importance for the electrical power plant examined in this study). Finally, the economics literature has evidenced considerable, "healthy" skepticism with respect to the economic feasibility of processing agricultural commodities into ethanol (e.g., Brown; Litterman et al.; Sanderson). The discussion that follows will suggest this outlook may be less justified in the case of ethanol cogeneration.

FINANCIAL ANALYSIS

The potential profitability of ethanol cogeneration was first explored with an order-of-magnitude cost and economic feasibility study (Harmon Engineering and Testing; June and July, 1981). These initial analyses suggested the appropriateness of conducting feedstock (see Appendix) and product market surveys. A final technical feasibility study was completed the following year (Harmon Engineering and Testing, 1982). These studies resulted in the following specific financial and engineering projections.

Total investment for construction materials, labor, architectural, engineering, and site preparation costs were estimated at approximately $63 million. Inclusion of construction and finance costs raised this estimate to nearly $78 million. This estimate was particularly comprehensive, accounting for the retrofitting and expansion costs associated with cogeneration modifications of the electricity generation plant as well.

The ethanol plant would represent a new customer for 6,500 KW hours annually of electrical power at a stable level and 100 thousand pounds per hour of fixed steam flow. The added demand of the ethanol plant would require the addition of a new 4,000 KW generator (for peak period loads) adding substantial economies of size to electrical power generation.[1] On line boiler capacity was determined to be adequate with the additional installation of a back-pressure turbogenerator system. Steam would be supplied to the ethanol plant from the electric power company at a price less than the cost of steam generated from coal (reflecting the fact that steam is a by-product of electricity generation). It was projected that the cogeneration steam price would be competitive with the cost of burning by-products such as wood waste or peanut shells.[2]

The ethanol plant is projected to have an annual capacity of 36.3 million gallons of fuel grade (99.8%) ethanol. Corn grains (or grain sorghum) is dry milled followed by vacuum beer stillage. Centrifugation, evaporation, and drying transform distillers wet grain into distillers dried grains and solids (DDG/S). Process energy is supplied by steam used to drive the added turbogenerator in the electric plant. The entire process is designed for high energy efficiency. In addition to ethanol and DDG/S, carbon dioxide (CO_2) is captured as a by-product of the conversion process. Annual production and sales estimates are indicated in Table 1.[3] Product prices were estimated with market analysis reported by Harmon Engineering and Testing (1982). Estimated biomass acreage requirements to furnish corn, wheat, grain sorghum, sweet sorghum, or sweet potatoes for the ethanol plant are provided in Table 2.

TABLE 1. PRODUCTS, BASE PRICES, PRODUCTION LEVELS, AND ANNUAL SALES, PROPOSED LARGE-SCALE ETHANOL COGENERATION PROJECT, ALABAMA, 1984

Product	Selling price	Annual production	Annual sales
	Dol. per unit		Dol.
Fuel grade ethanol ..	1.70/gal.	36,300,000 gal.	61,710,000
Dried distillers grains with solubles (DDG/S)	150/ton	122,000 tons	18,300,000
Liquid carbon dioxide (CO_2)	40/ton	104,000 tons	5,600,000
Fusel oils and water (combined with ethanol)	1.70/gal.	600,000 gal.	1,020,000
Unleaded gasoline (combined with ethanol)	1.15/gal.	700,000 gal.	805,000
Total sales			87,435,000

The above engineering and price projections were incorporated in a computerized deterministic simulation model that generated cash flow, capital recovery, balance sheet, and financial ratio measures. The key relationships in the model are presented in equations (1) and (2). Equation (2) corresponds to the bottom line of Table 3.

TABLE 2. FEEDSTOCK CONVERSION ASSUMPTIONS AND ACREAGE REQUIREMENTS TO SUPPORT THE PROPOSED LARGE-SCALE ETHANOL COGENERATION PLANT, ALABAMA, 1984

Crop	Crop yield/ac.	Alcohol yield	Quantity of crop required	Acreage required
			Mil.	Thou.
Corn	55 bu.	2.5 gal./bu.	14.0	255
Wheat	36.7 bu.	2.5 gal./bu.	14.0 bu.	381
Grain sorghum	70 bu.	2.5 gal./bu.	14.0 bu.	200
Sweet sorghum	19.5 tons	17 gal./ton	2.1 ton	108
Sweet potatoes	65 bu.	.94 gal./bu.	37.2 bu.	572

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[1] Currently, the electric power plant operates three generators at less than 20 percent average annual capacity. Variable demand loads on the plant and the cost of coal versus hydro-powered generation available to the parent electric company have resulted in a very unstable operation level.

[2] The cost-savings associated with each of the mentioned factors was not indicated individually in the technical reports of the engineering consulting firms. Their objective was to provide an efficient comprehensive final design that would not present unforeseen technical difficulties. While more detail would be of general interest, the economic and engineering studies of ethanol manufacture from agricultural feedstocks seldom supply technical data of this nature.

[3] Several of the largest agricultural grain merchandising and processing firms expressed interest in purchasing the DDG/S by-product which, for example, could provide a high-protein feed ingredient for the large local poultry industry. While beverage grain carbon dioxide typically commands a price in the \$60-\$200 per ton range, a more conservative price of \$40 per ton was assumed in this analysis because of the strong relation between market value and the availability of local markets. The unleaded gasoline sales indicated in Table 1 refer to reclamation of relatively small amounts of a refining input rather than blending to make gasohol (which does not occur at the plant).

$$(1)\ CASHFLOW_n = CASHREV_n - CASHEXP_n - TAXES_n - LOANPRIN_n,$$

and

$$(2)\ NPVCF \sum_{n=1}^{15} = CASHFLOW_n\,(1 + r)^{-n},$$

where:

$CASHFLOW_n$ = after tax cashflow in year n,

$CASHREV_n$ = summation of sale of fuel grade ethanol, DDG/S, liquid carbon dioxide (CO_2), fusel oils and water (combined with ethanol), residual unleaded processing gasoline (combined with ethanol) less accounts receivable plus interest on excess cashflow in year n;

$CASHEXP_n$ = summation of feedstock purchases, labor expenses, chemical purchases, process energy expenses, other variable operating expenses, and interest expenses paid less accounts payable in year n;

$TAXES_n$ = summation of federal income tax, state income tax, and minimum tax less investment credit in year n;

$LOANPRIN_n$ = loan principal payments in year n;

NPVCF = net present value of cashflow over the investment time horizon; and

r = discount rate, equal to interest rate on borrowed capital.

Ethanol sales were projected to begin after a 2-year construction phase. The interest rate for the project during the period of construction was 17 percent; this rate was reduced to 15 percent (the base case interest rate) upon commencement of ethanol production. Interest costs were compounded forward from the time of the initial borrowing (for start-up construction costs), and cashflow available for debt service was automatically applied toward debt principal reduction. Excess cashflow was projected to earn 8 percent after tax bond interest.[4]

The most likely economic performance of the ethanol plant estimated, the base case, includes several restrictive assumptions that reflect a conservative bias. For example, plant capacity is 5 percent less than engineering consultants indicated was to be expected, and first year capacity was further restricted to reflect start-up performance.

In order to limit assumptions about local biomass production availability, it was assumed that corn grain is imported from other regions to provide a reliable feedstock. Base case nominal prices (shown in Table 1) were projected to inflate by the following rates during the 15-year assumed plant life: ethanol, 7 percent; carbon dioxide, 7 percent; DDG/S, 3.5 percent; corn, 3.5 percent; and other raw materials, utilities, and operating expenses, 7 percent. Thus, corn and dried distillers' grain were assumed to inflate at one-half the rate of the basically non-agricultural inputs and outputs. The faster rate of increase in ethanol as compared to corn prices reflects the view that energy production will increase more slowly, relative to its demand, than the increase in food production.[5] The base price of corn in 1981 dollars was $3/bu. (Note: the 3.5-7 percent range corresponds closely to the 3-10 percent inflation range frequently used in projections in the literature (Meekhof et al.; Tyner and Bottum)).

BASE CASE RESULTS

Base case financial performance estimates are presented in Table 3, which indicates gross receipts, expenses, interest, depreciation, taxes, capital recovery, and net capital position. Features that are prominent in Table 3 include repayment of construction debt

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[4] Financial theory suggests cash-throw-offs command a rate equal to the cost of capital (15 percent). The very conservative "markdown" to an 8 percent after-tax rate reflects concerns of the electric utility cooperative regarding limitations of future investment possibilities.

[5] The U.S. cost of discovering and developing natural gas and oil deposits (in energy equivalent barrels of oil) increased at five and one half times the rate of inflation during 1968-81. According to Commoner (p. 124), *"Thus, rising production costs create an underlying upward trend in the price of United States oil, quite apart from anything OPEC does."* As other studies concerned with estimating the direction of petroleum price trends have noted, this issue is extremely complex and there remains a wide divergence of views (e.g., Kiker and Bauman, p. 129).

TABLE 3. PROJECTED CAPITAL RECOVERY AND AFTER-TAX CAPITAL ACCUMULATION, PROPOSED LARGE-SCALE ETHANOL COGENERATION PLANT, ALABAMA, 1984

Item	Year 1	2	3	4	5	6	12[a]
	1,000 dollars						
Gross receipts	63,674.	101,522.	107,931.	114,763.	122,048.	129,818.	188,606.
Production expenses	44,249.	63,045.	65,887.	68,873.	72,011.	75,310.	99,037.
Cost of capital	8,977.	5,713.	534.	0.	0.	0.	0.
Depreciation	7,200.	6,360.	5,618.	4,963.	4,384.	3,872.	3,237.
N. O. L. carryover[b]	0.	0.	0.	0.	0.	0.	0.
Taxable income	3,248.	26,404.	35,892.	40,927.	45,653.	50,635.	86,331.
Federal income tax:							
Regular tax	139.	1,156.	15,213.	18,288.	20,400.	22,628.	38,594.
Minimum tax	653.	1,900.	319.	126.	39.	0.	0.
State income tax	123.	1,167.	598.	1,126.	1,261.	1,400.	2,387.
Total income tax	915.	4,224.	16,530.	19,540.	21,700.	24,028.	40,981.
Add to working capital	531.	560.	589.	621.	654.	689.	942.
Capital recovery	9,002.	27,980.	23,590.	25,729.	27,683.	29,791.	47,646.
Capital position	53,328.	–25,348.	–1,358.	24,372.	54,005.	88,116.	424,077.
Net present value of capital	–46,372.	–19,166.	–893.	13,935.	26,850.	38,095.	79,263.

[a] Years 7-11 were not shown in the interest of brevity.

[b] No net operating losses (N.O.L) occurred.

during year 4 as shown in the "cost of capital" entry (inclusion of the net buildup in inventories results in payback occurring in 2.8 years), the absence of net operating losses (indicating positive profits beginning in year 1), and a capital position consisting of bond investments that climb dramatically beginning in the fourth year. The net present value of capital at the end of year 12 is $79.3 million, and by the end of year 15 (not shown) is $82.7 million. Cost of capital in Table 3 is based on 20 percent initial equity (this assumption applies only to this table). This equity level was analyzed by request of the electric cooperative involved in the study. All results that follow will be based on zero equity and 100 percent debt financing.

The rapid rate of capital recovery indicates the projected financial performance of the ethanol plant is very favorable. This is further evidenced by an internal rate of return (IRR) of 31 percent, where the IRR is the discount rate that yields a net present value of zero over the project life. As indicated above, the IRR is based upon 100 percent debt financing. Finally, "Add to Working Capital" in Table 3 indicates increasing working capital requirements due to price inflation. The negative "capital position" in years 1-3 indicates the amount of long-term debt outstanding.

SENSITIVITY ANALYSIS

The robustness (i.e., consistency under varying assumptions) of project profitability was explored with excursions (sensitivity tests) 1-15 in Table 4. Types of excursions considered were: price, interest rate, plant capacity utilization, and increased plant construction costs. Note that "B" indicates a base value and "E" indicates an excursion value in Table 4. Price movements were generally coordinated to maintain consistency. For example, in the low price scenario (excursion 2), not only the corn price of $2.65 was low, but also the alcohol, DDG/S, and CO_2 product prices were the lowest considered (respectively, $1.55, $130, and $25). As indicated in the far right-hand column for this excursion, low commodity and ethanol prices increased the payback period from 2.8 to 3.3 years. High corn prices (excursion 4) on the other hand, increased the payback period from the base case by only 2 years (this lengthening of the payback period is due to a relatively greater projected increase in the corn price as compared to the ethanol price).

Other results illustrated by relative changes in the payback period in the far right-hand column were that changes in interest rates (excursions 6-9), and contingency plant costs (excursions 14-15) do not greatly alter plant profitability.[6] The lowest plant utilization (excursion 13) did result in a significantly longer capital payback period of 5.2 years (vs. the base case of 2.8 years). Recent years have been characterized by wide commodity and fuel price fluctuations. For example, the price of corn fluctuated between $2.25 and $4.25 in South Alabama during 1982-83, and currently is somewhat below the $3.00 estimated base level. On the other hand, recent DDG/S prices ranging between $180-$220 (*Alcohol Outlook;* March, 1984) are considerably higher than the base study price of $150 per ton. While the price of gasoline is currently substantially below this study's base market price assumption, current ethanol prices averaging approximately $1.60-$1.70 per gallon (*Alcohol Outlook;* December, 1984) are only slightly below the $1.70 base estimate. Input and output prices in this study are to be viewed as suggestive of long-range trends rather than precise short-range estimates.[7]

The Federal government excise tax subsidy to gasohol of $.04/gal. (raised to $.05/gal. in 1983 and $.06/gal. in January 1985) is included in the ethanol price (estimated payback occurs before the currently scheduled end to this subsidy in 1992). In order to provide an excursion with no carbon dioxide sales or federal excise tax subsidies, assumptions were modified as follows: no by-product sales of CO_2, the price of ethanol was reduced to $1.30 per gal. reflecting exclusion of the federal excise tax subsidy, 7 percent inflation was assumed for prices of all inputs and outputs, and 100 percent of expected plant capacity was utilized. These changes affected plant profitability significantly. For example,

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[6] Estimating an appropriate finance rate for a nascent technology, especially when cooperative ownership is involved, is difficult. In this regard, it is useful to note that an increase in the financing rate to 19 percent (in excursion 6) increased payback by only one tenth of a year.

[7] For the level of ethanol production envisioned in this study, judicious use of commodity futures markets would be imperative to reduce price risk variability.

TABLE 4. ALTERNATE ECONOMIC SCENARIOS CONSIDERED IN THE FINANCIAL ANALYSIS OF PROPOSED LARGE-SCALE ETHANOL COGENERATION PLANT, ALABAMA, 1984

	Base assumptions and excursions																									
	Prices												Interest rate					Capacity utilization					Plant cost			
	Corn			Alcohol			DDG/S			CO2																Years payback
Candidate scenarios	3.00	2.65	4.16	1.70	1.55	1.90	150	130	180	40	25	60	15	19	17	13	11	95	100	85	65	50	100	110	120	
		$/bu.			$/gal.			$/ton			$/ton				percent					percent				percent		years
1. Base situation	B			B			B			B			B					B					B			2.8
Price excursions:																										
2. Low prices		E			E			E			E		B					B					B			3.3
3. High prices			E			E	B		E			E	B					B					B			3.0
4. High corn prices			E	B			B			B			B					B					B			4.8
5. Low alcohol prices	B				E					B			B					B					B			3.3
Interest excursion:																										
6. 19% interest rate	B			B			B			B				E				B					B			2.9
7. 17% interest rate	B			B			B			B					E			B					B			2.9
8. 13% interest rate	B			B			B			B						E		B					B			2.7
9. 11% interest rate	B			B			B			B							E	B					B			2.7
Capacity excursions:																										
10. 100% capacity	B			B			B			B			B						E				B			2.7
11. 85% capacity	B			B			B			B			B							E			B			3.1
12. 65% capacity	B			B			B			B			B								E		B			3.9
13. 50% capacity	B			B			B			B			B									E	B			5.2
Plant cost excursions:																										
14. 110% contingency	B			B			B			B			B					B						E		2.8
15. 120% contingency	B			B			B			B			B					B							E	2.9

Note: "B" denotes base case value and "E" denotes an excursion value. For example, in excursion (3) prices higher than those assumed for the base case (1) are present for corn, alcohol, DDG/S, and CO2. Excursion refers to a sensitivy test of the model given the assumptions indicated.

the payback period increased to 11.1 years (assuming zero salvage value for the plant) and the net present value of the investment declined to $10 million. Attractiveness of the investment in this case was greatly diminished, illustrating the importance of federal government excise tax subsidies and sales of the CO_2 by-product. Also, note that the $1.30 ethanol price is higher than the present ethanol price with no federal or state subsidies ($.80-$1.00). Present feedstock prices are also less than the level included in this excursion ($3.00 per bu. of corn).

RELIABILITY OF RESULTS

The financial analysis presented provides one of the first practical examples (available in the literature) of a large commercial ethanol plant projected to operate profitably.[8] Requirements for cogeneration include land adjacent to the electrical generation plant (12 acres in this case), good access by rail and road systems, access to markets for ethanol and its by-products, and access to biomass feedstocks. From an engineering standpoint, excess electrical capacity makes an ethanol plant a more attractive investment. However, the engineering technology appears less critical than the mentioned economic and market factors.[9]

The power plant in this study provided only 0.38 percent of 1976 conventional steam electricity generation capacity in Alabama (Chaffin). Also, about 41 percent of U.S. electrical generation was powered by coal in 1980 (U.S. Department of Energy). Coal is a widely available fuel with massive reserves in Alabama, parts of the East, Midwest, and West. This suggests that cogeneration based on conventional steam powered electricity generation (as was the case in this study) could eventually support a large gasohol program. From this perspective, it should be noted that 25-30 ethanol cogeneration facilities comparable to the one depicted in this study would annually supply approximately 1 billion gallons of ethanol (and consequently blending for 10 billion gallons of gasohol), thus comprising a significant contribution towards U.S. automobile energy needs (70-80 billion gallons of fuel annually). It is acknowledged that the effects upon input costs of an additional billion gallons of ethanol production may critically depend upon the continued presence of large agricultural surpluses in the United States. Finally, the improving economic efficiency of ethanol cogeneration may provide a stronger rationale for serious consideration of ethanol production as a method to partially utilize current excess agricultural supplies. In this regard, the 1985 increase to $.06 per gallon in the Federal Excise Tax subsidy indicates continuing interest in ethanol on the part of policymakers.

CONCLUSION

This study presents financial and economic analyses of a proposed ethanol cogeneration plant. The rapid payback of the investment and high internal rate of return indicate apparent feasibility of the project. The efficiencies of cogeneration are in no small part responsible for this outcome, and provide further evidence of continuing improvements in ethanol technology. Recognition of the increasing prospect of current excess capacity in U.S. agriculture provides an additional reason for agricultural economists to reconsider the potential of ethanol production as a strategy to improve farm incomes and lower agricultural surpluses.

There are very major long-term risks associated with investing in a nascent technology, in this case; competing in a product market dominated by a few multi-billion dollar domestic firms and a powerful foreign cartel, and competing in an input market characterized by dramatic price fluctuations (Commoner; Harmon, 1982). Thus, while a comprehensive sensitivity analysis was conducted and the conclusions of the financial analyses were favorable, the magnitude of investment risk in the proposed ethanol cogeneration plant has thus far proven to be sufficient to preclude undertaking the ethanol

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[8] Technological advances have resulted in several recent studies that suggest even small scale gasohol plants are borderline profitable (e.g. Leiner and Braden; Arnette et al.).

[9] Engineers involved in the study have indicated their belief that there is no technological reason that efficient ethanol cogeneration could not be achieved at non-peaking utility plants as well. In fact, the cooperative and other firms currently involved in the investment analysis have also considered implementation of an additional cogeneration ethanol unit at a "non-peaking" power plant site with improved barge transportation access. The receptiveness of management to the increased complexity of cogeneration technology may also be a critical factor.

cogeneration project. Because of the financial and business risks, the electric cooperative has recently considered a scaled-back ethanol facility with flexibility to rapidly expand production as economic and risk conditions warrant.

The potential for ethanol cogeneration in Alabama and the Southeast is currently unknown, but appears to be large. The ethanol cogeneration engineering questions appear to have been basically resolved (Browning and Briggs), and economic and finance issues remain the major difficulties clouding future prospects. In view of continuing impressive improvements in ethanol technology and large increases in ethanol production levels, it is important that ethanol production should not be excluded as a variable in farm policy analysis (especially during continuing periods of large crop surpluses and/or large idled agricultural capacity). In this respect, agricultural economists may have a major educational role to play.

APPENDIX

Potential Supply of Feedstock for Ethanol Plant

There are several advantages to local production of feedstocks for the proposed ethanol plant. From the plant owner's perspective, these involve a strong base of local support for the plant and potential savings on transportation costs. For the region's farmers, the main advantage is the presence of a large, stable local market for grains (or other feedstock crops) produced.

In order to explore the issue of local supply, an area linear programming supply model was developed delineating 14 crop production regions in Alabama, Florida, and Georgia. To provide uniformity of distance to the plant, the 14 regions were subdivided into 21 regions. Cost and return budgets for corn, wheat, and grain sorghum were developed primarily based on "average management" practices from the USDA Farm Enterprises Data System. Model assumptions include: (1) crop production greater than current levels takes place only at full cost, (2) additional irrigated corn acreage was available at full cost, and (3) imported corn was available from the Midwest at a premium price.

Regional corn price differences were estimated with multiple linear regression techniques. Analysis of Alabama (a feedstock deficit area), Illinois (a feedstock surplus area), and U.S. corn price movements indicated that price movements were not time dependent. However, all prices increased significantly in 1973 due to increased export demand; also Alabama corn prices exceeded Illinois prices by 30-40 cents in 1980, reflecting transportation costs. Based on this analysis, a price premium of $.35 per bushel (above the Illinois price) was incorporated in the study. Also, grain storage, shrinkage, and transshipment costs were modeled.

When all feedstock possibilities were considered, the model solution included 25 percent wheat and 75 percent grain sorghum, which was locally produced. An "acid test" for the model assumed that current crop production was fixed and unavailable for the ethanol plant. The effect of this restriction on the feedstock supply model was that the basic wheat/grain sorghum mix was unchanged but was produced in a wider area than in the initial solution. Conclusions from the supply model are: (1) feedstock requirements of the plant can be produced within a 100-mile radius of the plant in the indicated states and (2) current cropping practices suggest that single cropped grain sorghum and wheat are likely biomass input candidates. It should be noted that in the long run, the relatively favorable potential for increased irrigation (including stream and river sources) may shift optimal biomass supply to irrigated corn. On the other hand, as can be inferred from differences in acreage requirements in Table 2, changes in production practices could partially shift the long-run supply solution to sweet sorghum.

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