I. Introduction, Purpose, and Study Layout

Thornwood Gas, Inc. (TGI) proposes to build a 34 mile pipeline from six natural gas wells in West Virginia to a distribution pipeline. Approximately 70 percent of the pipeline would be located in the Monongahela National Forest (MNF) in Pendleton, Pocahontas, and Randolph Counties of West Virginia or in the George Washington National Forest (GWNF) in Highland County, Virginia, with the remainder of the pipeline to be located on private land.

The proposed federal action is to authorize the installation of gas production equipment and to issue to TGI a renewable special use permit for a natural gas pipeline across the MNF and GWNF. The likely expected duration of the pipeline operation would be 20-50 years. This pipeline would produce natural gas from six existing natural gas wells in the Thornwood Gas Field that were drilled in the early- to mid-1960s in the MNF, near Thornwood, Pocahontas County, West Virginia. The pipeline route would run from the six wells, through the states of West Virginia and Virginia, to a terminus at an existing natural gas pipeline near Whitmer, Randolph County, West Virginia.

TGI owns or controls approximately 95,000 acres of oil and gas leases along and in the vicinity of the proposed pipeline. The six wells contained in the TGI pipeline proposal are located on about 5,600 acres of the 95,000 acres of leases. TGI reportedly does not plan on developing any other gas wells or fields along the pipeline in excess of the six proposed wells at this time (MNF and GWNF, 1995). However, some residents in the vicinity of the proposed project are concerned that the six wells may be the first stage of a more extensive gas development scenario that could have cumulative impacts on the private and public lands of the region. Of particular concern to some residents is the potential fate of the Laurel Fork Special Management Area in Highland County, Virginia, bordering the proposed pipeline route, parts of which are within the 95,000 acres of TGI leases.

This study examines the expected financial viability of the pipeline project as proposed by TGI to evaluate (1) whether the revenues obtained from selling the gas from the six wells would offset the costs of building and operating the pipeline, and (2) if significant excess capacity would exist in the proposed pipeline, over and above the amount needed for the expected output from the six gas wells. Analysis of the financial characteristics of the proposed pipeline project, presented in this study, will provide evidence to support whether or not the six wells in the current application could pay for the costs of building and operating the pipeline, or if revenues from other properties in the vicinity of the pipeline would likely be needed to make the project a profitable one.

The next sections of this report examine relevant characteristics of the proposed project's natural gas wells and details about the proposed pipeline. Subsequent sections discuss the financial model inputs used in this study, model results, pipeline capacity projections, conclusions, references, and an appendix with an example of a financial model run.

II. TGI Natural Gas Well Characteristics

Table 1 shows some of the physical characteristics of the six wells that would supply the proposed natural gas pipeline. The wells are all located in the Thornwood Gas Field in the northeastern corner of Pocahontas County, West Virginia. The primary producing reservoir within the six-well Thornwood Gas Field is the Oriskany Sandstone, with subsidiary contributions from the Huntersville Chert and Helderberg Group. The structural section within the wells shows a duplication in the section due to thrust faulting, creating a thickening of the reservoir (Cardwell, 1982, p. 46). Interpretations of the reservoir porosity from the original well logs led at least one reviewer to conclude that the porosity present in the reservoir is one of fracture porosity (Bartlett, 1995). The most viable method to project gas reserves in rocks with fracture porosity and limited data is through evaluation of stabilized gas flow tests.

Table 1 - Selected Characteristics of the Six TGI Natural Gas Wells

Characteristic	*GW-1393 USA "P"-1 47-075-0022*	*GW-1469 USA "S"-1 47-075-0024*	*GW-1355 USA "M"-1 47-075-0019*	*GW-1468 USA "R"-1 47-075-0023*	*GW-1329 USA "L"-1 47-075-0018*	*GW-1382 USA "O"-1 47-075-0020*	*Total*
Drilling Completion	Feb 16, 1963	Jul 12, 1964	Mar 15, 1962	May 8, 1964	Jun 16, 1961	Jun 2, 1962	NA
Elevation (ft.)	3,100	3,850	3,200	3,370	3,780	3,551	NA
Oriskany Thickness (ft.)	153	231	120	839	161	155	NA
Total Depth (ft).	5,880	5,951	5,730	5,165	10,823	6,113	NA
Acres	893	600	2,467	440	856	350	5,606
Specific Gravity	0.566	NA	0.563	0.564	0.565	NA	NA
Rock Pressure (PSI)	1,620	1,640	1,725	1,685	1,575	1,626	NA
Initial Open Flow (MCFD)	4,712	73	2,579	1,347	1,020 (salt H_20)	103	9,834
Stabilized Flow 1 (MCFD) (year) (time period)	602 (1984) (2.75 hours)	NA	1,270 (1983) (3.5 hours)	606 (1984) (1.75 hours)	606 (1984) (2.5 hours)	327 (1983) (4 hours)	3,411
Stabilized Flow 2 (MCFD) (year) (time period)	NA	NA	604 (1984) (3 hours)	NA	NA	NA	604
Latest Stabilized Flow (MCFY)	219,881	26,663	220,611	221,342	221,342	119,437	1,029,276

NA-Not Applicable or Not Available
Source: State of West Virginia, Department of Mines, Oil and Gas Division, Well Records, and Results of One-Point Flow Tests.

A scrutiny of Table 1 shows that all six of the wells had drilling completed on them between 1961 and 1964. The wells range in elevation from about 3,100 to 3,850 feet, and intersect the main natural gas reservoir, the Oriskany Sandstone, for between about 150 and 840 feet of their total depth. The total area of the leases in which the six wells are drilled is about 5,600 acres, a small portion of the more than 95,000 acres that Thornwood has currently under lease. Note that the rock pressures and specific gravity measures of the six wells all fall within a relatively narrow range--possibly indicating a single subsurface reservoir that is being tapped by all six wells.

Open flow levels represent a measurement of the volume of gas that was reported immediately after the well was drilled and fractured to increase production. As such, open flow measurements are not considered an accurate or reliable figure representing the long-term, sustainable flow that might be expected from the wells. Immediately after the drill bit has initially punctured the reservoir rock containing the gas under pressure, activity occurs that can be compared with the uncapping of a carbonated beverage bottle--pressure is immediately and explosively released at volumes that cannot be maintained. This initial release is followed by a diminution of the gas flow that usually stabilizes at a lower flow rate. It is this lower, stabilized flow volume that gas operators look at in order to estimate the initial gas flow that is likely to be produced from the well.

Once the gas flow has stabilized, the well typically shows a continual flow of gas that decreases as the contents of the natural gas reservoir diminish over time. This geological process is called reservoir depletion and is analogous to an uncapped carbonated beverage slowly losing pressure to the atmosphere, until it ultimately loses virtually all of the carbon dioxide that was in solution. Thus, the initial open flow rates reported for the wells above likely overstate the long-term gas production that might be expected from a well. The stabilized flow rate represents a better starting point to construct an estimate of the total amount of recoverable natural gas from a well, but even this value has a tendency to decline over time in wells that are not in production and have not been capped to retain reservoir pressure. Stabilized flow measurements taken on the same well in consecutive years can have widely different values because of the ongoing geological changes and the small time period during which the tests are conducted.

The aggregate initial open flow value of all six wells, as measured soon after drilling in the 1960s, amounted to about 9,834 thousand cubic feet of gas per day (MCFD). If this output were sustainable over a year, the wells could produce about 3.6 billion cubic feet of gas. Using the stabilized flow readings derived from tests conducted in 1983 and 1984, the aggregate gas output measured about 3,411 MCFD, or about 1.2 billion cubic feet in a year. Well USA "M"-1 had stabilized flow measurements taken in both 1983 and 1984, with the latter measurement recording a gas volume less than half of the one taken in the previous year. This large variation illustrates the disparity that can be encountered by using stabilized flow measurements taken over small time intervals (3.5 and 3 hours for the two tests).

The most recent stabilized flow measurements obtained by the author for the six wells are shown in the bottom row of Table 1--producing an aggregate of about 1.0 billion cubic year of natural gas production in the first year. In fact, this value probably also overstates the likely first year of gas output because the stabilized flow measurements are (1) more than ten years old and unplugged reservoir pressure tends to decline over time, and (2) the stabilized gas flow is not measured as it enters a gas pipeline under pressure but is gaged under atmospheric pressure. The actual volume of gas that would enter the pressurized pipeline will be smaller than the amount measured under atmospheric pressure.

III. TGI Pipeline Requirements

Table 2 presents data showing some of the pipeline diameters and mileage as proposed for TGI's project.

Table 2- Pipeline Requirements for Alternative 1-Proposed Action							
Pipeline Type	***GW-1393 USA "P"-1 47-075-0022 (miles)***	***GW-1469 USA "S"-1 47-075-0024 (miles)***	***GW-1355 USA "M"-1 47-075-0019 (miles)***	***GW-1468 USA "R"-1 47-075-0023 (miles)***	***GW-1329 USA "L"-1 47-075-0018 (miles)***	***GW-1382 USA "O"-1 47-075-0020 (miles)***	***Total (miles)***
3-inch pipeline	0.22	0.03	0.4	0.03	1.17	1.72	3.57
4-inch pipeline							2.12
8-inch pipeline							27.85
Total pipeline length							33.54

Sources: MSES Consultants, Inc, 1993, p. 7-4, and MNF and GWNF, 1995, p. 2.

Almost 75 percent of the pipeline would be constructed of the 8-inch nominal diameter main pipeline, with the remainder of the proposed project requiring either a 3- or 4-inch pipeline. The Draft Environmental Assessment further describe some other projected characteristics of the pipeline (Table 3).

Table 3- Pipeline Characteristics						
Steel Grade	***Outside Diameter (inches)***	***Wall Thickness (inches)***	***Minimum internal yield strength (psig)***	***Test Pressure Safety Factor***	***Test Pressure (psig)***	***Maximum operating pressure (psig)***
X-42	8-5/8	0.188	1,844	1.5	1,650	1,100
X-42	8-5/8	0.219	2,144	1.5	1,650	1,100
X-42	4-1/2	0.188	3,524	1.5	1,650	1,100
X-42	3-1/2	0.188	4,524	1.5	1,650	1,100

Source: MNF and GWNF, 1995, p. 44.

In addition to the pipeline requirements and characteristics, TGI proposes to construct gas well production facilities at each of the six existing wells described above. These facilities would consist of: a combination heater-separator unit, a positive shut-off drip, a meter, and a liquid collection tank surrounded by an earthen containment dike (MNF and GWNF, 1995, p. 11).

IV. Thornwood Gas Financial Model Inputs

The financial evaluation of the proposed gas pipeline project presented in this study uses three different model runs;

(1) *Replication of Environmental Assessment Model Run;*

(2) *Current Natural Gas Price and Pipeline Cost Model Run*; and

(3) *Actual Well Data Model Run.*

Financial model inputs typically span a range of defensible values. Where practical, the Thornwood Gas Financial Model use the model inputs that would yield the most profitable project.

The first model run extracts the scanty financial and cost information presented in the Environmental Assessment and Special Use Application and Report to replicate as closely as possible some of the critical project assumptions that were likely used by Thornwood Gas and federal assessors to evaluate the proposed project. The second model run duplicates the assumptions used in the first model run but updates natural gas prices and pipeline costs, to reflect more current data. Finally, the last model run uses the more current gas price and pipeline cost data, but replaces the gas production assumptions used in the first two model runs with the most recent available gas flow test data on the six wells.

To achieve an accurate estimate of the expected financial viability of the proposed natural gas pipeline, one needs at least three critical model inputs: (1) an estimate of the expected natural gas output over time of the six wells, (2) construction, operating and maintenance cost estimates for the pipeline, and (3) estimates of the revenue that the operator could expect to receive for sales of the natural gas. Subsequent sections examine these three types of model inputs for each of the model runs.

Mr. Chris Hanson of the Bureau of Land Management (BLM), in a letter to Ms. Linda Tracy of the Monongahela National Forest dated October 3, 1994, stated that his office conducted a financial assessment of the proposed Thornwood Gas Project. He stated that the office had received material from Thornwood on September 13, 1994 and by October 3, 1994 he was able to say

> "1. Thornwood has performed adequate well testing and utilized accepted reservoir engineering practices to generate reserve estimates and production projections. Our independent calculation of reserves suggests Thornwood's estimates are reasonable.
>
> 2. Using realistic estimates of gas prices and operating expenses, Thornwood has utilized standard economic evaluation techniques of project revenues and rate of return. Our independent economic calculation support Thornwood's assertion that their six wells will cover all expenses of the proposed pipeline project and provide for a reasonable rate of return. (Hanson, 1994)."

The letter further states that the data used to form the above opinions was being kept confidential under the appropriate provisions of the Freedom of Information Act (FOIA). This decision by the BLM to keep relevant economic and geologic data on proposed activities on public lands from public scrutiny has forced the author to spent a considerable amount of time and energy to accumulate alternative data sources.

A. Natural Gas Production Estimates

1. *Environmental Assessment Replication and Current Natural Gas Price and Pipeline Cost Model Run*s

The Environmental Assessment for the Thornwood Project describes the six wells' projected output "[t]hese natural gas wells are expected to yield 1 billion (1,000,000) cubic feet of natural gas over their producing life, typically 10-20 years (1991 MNF O&G EA, Appendix E, page E1 and Appendix C, page C-9), or a total of 6 billion cubic feet over about 15 years. ...Using a gas sale price of $2.45 per 1,000 cubic feet (from Appalachian Natural Gas Index), under Alternatives I, III, IV, and V these gas wells are expected to have generated about $1,378,000 undiscounted, $975,000 discounted back to 1995 dollars using a 10% discount rate to the U.S. Treasury over 15 years, and about $459,000 undiscounted or $325,000 discounted at

10% to West Virginia and Virginia Counties containing National Forest System Land over the same period. (MNF and GWNF, 1995, p. 116)." This average well production figure is based on hypothetical (representative?) wells, presumably derived from an examination of gas wells in the region, for Monongahela National Forest Oil and Gas Leasing and Development Environmental Assessment evaluation purposes.

Combining the above information with the assumption that the gas wells are expected to yield about 1 billion cubic feet of gas over a 15 year lifetime allows the author to replicate crucial assumptions apparently used by Thornwood Gas for this project. Assuming a 1 year interval from the granting of permits for pipeline laying until construction is finished, each of the six wells would produce an average of 234,654,000 cubic feet of gas in the first year, and the wells would show a constant annual decline of 23 percent in production to yield the revenue and output figures reported above. Under this scenario, each well would produce 1 billion cubic feet of gas over 15 years, and the undiscounted revenues to the U.S. Treasury would amount to $1,378,125 with discounted payments (at a 10% discount rate) totaling $975,293. Likewise, the expected royalty payments to West Virginia and Virginia are calculated at $459,375 and $325,098, undiscounted and discounted, respectively.

2. *Actual Well Data Model Runs*

The final model run uses the latest stabilized flow measurements from the six wells to estimate the first year's gas production in lieu of the hypothetical values used in the first two model runs. The determination of the actual well outputs is described in Section II of this paper. Analogous to the previous two model runs, after the initial year gas production is calculated, an annual production decline rate of 23 percent is assumed for all subsequent gas production. One very important difference between the Actual Well Data Model Run and the first two model runs is that the author has used an assumed production lifetime of 30 years, instead of the 15 years reported in the Environmental Assessment. This lengthened gas field lifetime should have the effect of making the project more profitable than if natural gas output ceased after only 15 years.

B. Capital, Operating, and Maintenance Cost Estimates

1. *Environmental Assessment Replication Model Run*

Only one estimate of the costs of constructing this project was found by the author in the Special Use Application and Report submitted by Thornwood Gas, Inc. The construction costs for the proposed action have been estimated at $4,000,000.00. The operation and maintenance costs are placed at approximately $25,000.00 for the yearly operation charges and $25,000.00 for the yearly maintenance charges (MSES Consultants, Inc., 1993, p. 11-1). These estimates were updated to 1995 dollars and used in the Environmental Assessment Replication Model Run.

2. *Current Natural Gas Price and Pipeline Cost and Actual Well Data Model Runs*

No source other than the Special Use Application and Report was found for operating and maintenance costs. The author examined annual pipeline construction cost surveys for 1993 and 1994 shown in the *Oil and Gas Journal* to assess the pipeline construction costs presented in the Special Use Application and Report. The *Oil and Gas Journal* data are presented in Tables 4 and 5 below.

Table 4 - Reported Pipeline Construction Costs in 1993				
Reference Number	*Pipeline Diameter (inches)*	*State*	*Length (miles)*	*Dollars/mile*
1	3	Virginia	0.38	$1,278,947
	Average 3-inch			$1,278,947
2	4	California	0.20	$1,664,999
3	4	California	0.40	$754,999
4	4	California	2.20	$296,818
5	4	California	5.00	$340,200
6	4	California	15.40	$232,792
	Average 4-inch without Reference #2			$406,202
	Average 4-inch without Reference # 1 & 2			$289,937
	Average 4-inch			$657,962
7	6	Colorado	0.57	$431,371
8	6	Florida	1.77	$536,723
9	6	Florida	1.90	$247,368
10	6	California	2.30	$462,608
11	6	California	4.70	$358,936
12	6	California	5.80	$348,620
13	6	California	5.80	$348,793
14	6	Florida	5.90	$316,515
15	6	California	8.20	$339,756
16	6	California	11.20	$340,803
17	6	California	17.60	$291,363
18	6	California	17.60	$291,477
	Average 6-inch			$359,528
19	8	Colorado	0.53	$208,345
20	8	Florida	2.20	$268,181
21	8	Florida	2.30	$252,173
22	8	Tennessee	12.20	$263,114

Table 4 - Reported Pipeline Construction Costs in 1993				
Reference Number	*Pipeline Diameter (inches)*	*State*	*Length (miles)*	*Dollars/mile*
23	8	California	26.40	$234,469
24	8	California	31.30	$291,341
	Average 8-inch			$252,937

Source: *Oil and Gas Journal*, November 22, 1993, p. 50.

Table 5 - Reported Pipeline Construction Costs in 1994				
Reference Number	*Pipeline Diameter (inches)*	*State*	*Length (miles)*	*Dollars/mile*
25	4	California	0.20	$1,670,000
26	4	California	1.90	$292,632
27	4	California	2.20	$298,182
28	4	California	3.40	$392,647
29	4	California	5.00	$258,800
30	4	California	5.30	$475,501
31	4	California	5.50	$480,030
32	4	California	6.20	$224,355
33	4	California	15.40	$233,831
	Average 4-inch without Reference Number 1			$331,998
	Average 4-inch			$480,665
34	6	California	1.50	$442,667
35	6	California	2.00	$331,000
36	6	California	4.70	$360,426
37	6	California	10.70	$482,273
38	6	California	11.90	$335,462
	Average 6-inch			$390,366
39	8	California	9.30	$259,355
	Average 8-inch			$259,355

Source: *Oil and Gas Journal*, November 21, 1994, p. 46.

The same article that contains the data in Table 5, the Oil and Gas Journal gives 10-year land construction costs trends. The average cost, in dollars per mile for an 8-inch pipeline has risen from a value of $94,884 per mile in 1984, to $259,355 in 1994 (*Oil and Gas Journal*, November 21, 1994, p. 57).

Pipeline construction costs encountered by Thornwood Gas, Inc. would likely be higher than the nationwide average, because the pipeline would not be crossing flat or open country. The proposed pipeline route would traverse relatively mountainous terrain, and in some case, forested regions. Excavation, pipeline bending, and other cost factors would presumably be at the higher end of cost ranges. Nevertheless, in keeping with this study's intent to find the maximum defensible project profit, the author uses average pipeline construction costs in this financial analysis.

Multiplying the average pipeline costs per mile from Table 5 by the pipeline requirements presented in Table 2 and adjusting for inflation yields total pipeline construction costs. The 3.57 miles of 3 inch pipeline is costed at the 4-inch pipeline rate due to the lack of information on 3-inch pipeline costs. Thus, 3.57 miles x $331,998 dollars per mile (discarding the most expensive outlier of 4-inch pipeline in Table 5) x 4 percent inflation from 1994 to 1995 dollars, results in a capital cost for the 3-inch pipeline of $1,232,641. Similarly, the 2.12 miles of 4-inch pipeline construction costs amount to $731,989, and the remaining 27.85 miles of 8-inch pipeline could be constructed for $7,528,786. Summing across all pipeline sizes, the total costs for constructing the proposed Thornwood Gas pipeline, using average 1994 costs, is $9,493,416. The average cost per mile for the 33.54 miles of composite pipeline (all three sizes) is $283,048.

C. Natural Gas Price Estimates

1. *Environmental Assessment Replication Model Run*

The sole reference to the assumed future natural gas price in either the Environmental Assessment or the Special Use Application and Report states that the Appalachian Natural Gas Index of $2.45 per thousand cubic feet is used (MNF and GWNF, 1995, p. 116).

2. *Current Natural Gas Price and Pipeline Cost and Actual Well Data Model Runs*

On October 10, 1995, the Appalachian Natural Gas Index was $1.78 per thousand cubic feet (personal communication, October 10, 1995). This is the price used for the latter two model runs of the Thornwood Gas Financial Model.

D. Summary of Thornwood Gas Financial Model Inputs

Table 6, shown below, presents a summary of important model inputs for the financial evaluation of the proposed pipeline project:

Table 6 - Selected Thornwood Financial Model Inputs

Variable	*Environmental Assessment Replication Model Run*	*Current Natural Gas Price and Pipeline Cost Model Run*	*Actual Well Data Model Run*
Natural Gas Price (1995 Dollars)	$2.45	$1.78	$1.78
Pipeline Construction Cost			

Table 6 - Selected Thornwood Financial Model Inputs			
Variable	***Environmental Assessment Replication Model Run***	***Current Natural Gas Price and Pipeline Cost Model Run***	***Actual Well Data Model Run***
(1995 Dollars)	$4,326,000	$9,493,000	$9,493,000
Annual Operations Cost (1995 Dollars)	$27,000	$27,000	$27,000
Annual Maintenance Cost (1995 Dollars)	$27,000	$27,000	$27,000
First Year Well Production (MCF)	1,408,000	1,408,000	1,029,000
Annual Production Decline (Percent)	23	23	23
Real Discount Rate (Percent)	10	10	10
Inflation Rate (Percent)	4	4	4
Combined West Virginia and Federal Income Tax Rate (Percent)	34	34	34
Depreciation Method	7 year MACRS	7 year MACRS	7 year MACRS
Depletion Allowance (Percent)	15	15	15
Federal Royalty (Percent)	12.5	12.5	12.5
Federal Share of Federal Royalty (Percent)	75	75	75
States' Share of Federal Royalty (Percent)	25	25	25
Pocahontas County Share of Federal Royalty (Percent)	8.25	8.25	8.25
West Virginia Severance Tax (Above $5,000) (Percent)	8.63	8.63	8.63

MACRS-Modified Accelerated Cost Recovery System
Source: Thornwood Gas Financial Model (this study).

V. Thornwood Gas Financial Model Results

A. Environmental Assessment Replication Model Run

The author assumes a $4,000,000 pipeline construction cost, and $50,000 annual operations and maintenance costs disclosed in the Special Use Application and Report (adjusted for two years of inflation at 4 percent per year) and uses these as inputs to the Environmental Assessment Replication Model Run of the financial model. A copy of this model run is presented in Appendix A. The rounded results of the financial model case are shown below:

Lifetime Gas Well Output (cubic feet)	6 billion
Construction Cost (discounted 1995$)	$4,326,000

Gas Price (1995$/mcf)	$2.45
Federal Royalty (discounted 1995$)	$975,000
States' Share of Royalty (discounted 1995$)	$325,000
Total Costs (discounted 1995$)	$8,117,000
Total Revenues (discounted 1995$)	$10,403,000
Above-Normal Profit (discounted 1995$)	$2,286,000
Return on Equity	28 percent

In the author's experience, a conventional oil or gas project usually requires a return on equity at least equal to 15 percent, to be considered economically feasible. Some project operators use a minimum return on equity of 10 percent, as is apparently the case for Thornwood Gas, Inc. A return on equity of 10 percent is not usually acceptable for these types of project, but the 10 percent rate is used in the Thornwood Gas Financial Model to maintain conformity with the Environmental Assessment analysis.

The Environmental Assessment Replication Model Run renders a discussion of the relative merits of a 10 or 15 percent minimum return on equity moot--the return on equity for this project is 28 percent, well above either of those hurdle rates. Thus, an above-normal profit of $2,286,000 is expected from the project (for purposes of economic evaluation a normal profit in this case is defined as a profit exactly equal to the discount rate--10 percent).

However, the author re-estimates three key assumptions given in the Environmental Assessment and Special Use Application and Report to generate inputs for subsequent model runs; (1) cost of constructing the pipeline, (2) future price likely to be received for natural gas, and (3) output of the six natural gas wells.

B. Current Natural Gas Price and Pipeline Cost Model Run

The Appalachian Natural Gas Index Price for October 10, 1995 was approximately $1.78 per thousand cubic feet of gas, considerably less than the $2.45 quoted in the Environmental Assessment (personal communication, October 10, 1995). Additionally, as discussed in a previous section of this report, *Oil and Gas Journal* reports average construction costs for similar pipelines far in excess of the $128,992 per mile ($4,326,400/33.54 miles) implied by the Environmental Assessment and Special Use Application and Report.

The Current Natural Gas Price and Pipeline Model Run of the financial model reported in this study assumes that future gas sales will receive $1.78 per thousand cubic feet and the construction costs will reflect the 1994 average pipeline construction cost of $9,493,416, in 1995 dollars ($283,048 per mile). Plugging these input figures into the financial model results in the following;

Lifetime Gas Well Output (cubic feet)	6 billion
Construction Cost (discounted 1995$)	$9,493,000
Gas Price (1995$/mcf)	$1.78
Federal Royalty (discounted 1995$)	$709,000
States' Share of Royalty (discounted 1995$)	$236,000
Total Costs (discounted 1995$)	$11,595,000
Total Revenues (discounted 1995$)	$7,558,000
Above-Normal Profit (discounted 1995$)	($4,037,000)
Return on Equity	(6 percent)

Using the updated price and pipeline cost figures instead of the outdated ones shown in the Environmental Assessment produces a profound change in the bottom line. Instead of a return of positive 28 percent on equity, this project actually has a return of negative 6 percent. Receipts from the sales of natural gas from the project do not even cover costs, much less show a profit. Of the $11.6 million invested in the project by Thornwood Gas only $7.6 million would be recouped by the end of the project, leaving a deficit of more than $4 million. Clearly, using these more current price and cost numbers, the proposed Thornwood Gas project does not come close to breaking even.

C. Actual Well Production Model Run

One final financial model run done by the author uses the latest available stabilized open flow measurements from the actual wells, instead of the hypothetical production figures reported on in the Environmental Assessment. Results from the Actual Well Production Case are reported below;

Lifetime Gas Well Output (cubic feet)	4.5 billion
Construction Cost (discounted 1995$)	$9,493,000
Gas Price (1995$/mcf)	$1.78
Federal Royalty (discounted 1995$)	$520,00
States' Share of Royalty (discounted 1995$)	$173,00
Total Costs (discounted 1995$)	$11,184,000
Total Revenues (discounted 1995$)	$5,552,000
Above-Normal Profit (discounted 1995$)	($5,632,000)
Return on Equity	(? percent)

This model run assumes a lifetime production of about 4.5 billion cubic feet, rather than the 6 billion cubic feet in the previous two model runs. This production reduction results in the Actual Well Production Model Run showing greater project losses than the Current Natural Gas Price and Pipeline Cost Model Run. Project revenues expected in this scenario would cover less than one-half of project costs. Because of the large negative return, the actual return on equity could not be calculated.

D. Summary of Thornwood Gas Financial Model Runs

Table 7 gives a summary of relevant Thornwood Gas Financial Model inputs and results. Financial model results are given in 1995 dollar amounts (end-of-year).

Table 7 - Selected Thornwood Financial Model Inputs and Results

Variable	***Environmental Assessment Replication Model Run***	***Current Natural Gas Price and Pipeline Cost Model Run***	***Actual Well Data Model Run***
Natural Gas Price (1995 Dollars)	$2.45	$1.78	$1.78
Pipeline Construction Cost (1995 Dollars)	$4,326,000	$9,493,000	$9,493,000
First Year Well Production (MCF)	1,408,000	1,408,000	1,029,000
Gas Field Lifetime (Years)	15	15	30
Lifetime Well Production (MCF)	6,000,000	6,000,000	4,473,000
Construction Cost (Discounted 1995 Dollars)	$4,326,000	$9,493,000	$9,493,000
Operating Cost (Discounted 1995 Dollars)	$206,000	$206,000	$253,000
Maintenance Cost (Discounted 1995 Dollars)	$206,000	$206,000	$253,000
Federal Royalty (Discounted 1995 Dollars)	$1,300,000	$945,000	$694,000
Federal Portion of Federal Royalty (Discounted 1995 Dollars)	$975,000	$709,000	$520,000
States' Portion of Federal Royalty (Discounted 1995 Dollars)	$325,000	$236,000	$173,000
Pocahontas County, WV Portion of Federal Roylaty (Discounted 1995 Dollars)	$107,000	$78,000	$57,000
West Virginia and Federal Income Taxes (Discounted 1995 Dollars)	$1,183,000	$95,000	$13,000
West Virginia Severance Tax (Discounted 1995 Dollars)	$895,000	$650,000	$476,000
Total Cost (Discounted 1995 Dollars)	$8,117,000	$11,595,000	$11,184,000
Total Revenues (Discounted 1995 Dollars)	$10,403,000	$7,558,000	$5,552,000
Above-Normal Profits (Discounted 1995 Dollars)	$2,286,000	($4,037,000)	($5,632,000)

Table 7 - Selected Thornwood Financial Model Inputs and Results			
Variable	***Environmental Assessment Replication Model Run***	***Current Natural Gas Price and Pipeline Cost Model Run***	***Actual Well Data Model Run***
Return on Equity (Percent)	28	(6)	(?)
Profitability	Profitable	Unprofitable	Unprofitable

Source: Thornwood Gas Financial Model (this study).

VI. Pipeline Capacity

A preliminary estimate of the capacity of the main 8-inch pipeline was conducted using the Institute of Gas Technology (IGT) Flow Equations with the following parameters:

Internal Pipeline Diameter	8.25 inches
Maximum Pressure	1,100 psi
Terminus Pressure	500 psi
8-inch Pipeline Length	28.2 miles
External Pressure	14.73 psi (sea level)
Capacity	1.3 million cubic feet/hour (11.4 billion cubic feet/year)

The highest annual estimate of natural gas shipment through the proposed pipeline is 1.4 billion cubic feet in the first year (Environmental Assessment Replication Model Run). The calculated capacity of the proposed 8-inch pipeline is greater than an order of magnitude larger than this maximum annual gas flow amount. In fact, the entire 6 billion cubic feet of the 15-year lifetime production from the six wells could be shipped through the proposed pipeline in slightly more than six months. Based on the analysis presented above, it is clear that the proposed main pipeline contains significant excess capacity capable of carrying large additional quantities of natural gas.

VII. Conclusions

The purpose of this study is analyze the financial viability of the proposed Thornwood Gas Pipeline Project to determine (1) whether the revenues obtained from selling the gas from the six wells would offset the costs of building and operating the pipeline, and (2) if significant excess capacity would exist in the proposed pipeline, over and above the amount needed for the expected output from the six gas wells. Analysis of the financial characteristics of the proposed pipeline project provides evidence that suggests that the six wells in the current application could not pay for the costs of building and operating the proposed pipeline. The author's analysis further implies that revenues from gas production on other properties in the vicinity of the pipeline would likely be needed to make the project a profitable one.

The only model run that describes a profitable project uses the following inputs; (1) hypothetical values of well production instead of values based on actual well test data, (2) pipeline construction costs more than 50 percent lower than the national average for similar-sized pipelines, and (3) future natural gas prices almost 40 percent higher than current prices. Substituting more current values for the values described above results in projects that no financial analyst would consider viable. In addition, estimates show that the entire 15-year production from the largest project could be transported in proposed pipeline in slightly more than six months.

Bringing the project into apparent conformity with current price, cost, and output information clearly shows that the project as proposed is likely unprofitable and that large amounts of excess capacity are built into the pipeline. One interpretation of the preceding analysis could be that Thornwood Gas, Inc. may indeed be using this minimal project to build the proposed pipeline without disclosing the large amount of excess capacity in the pipeline. Extensive additional production would likely be needed to fully cover the costs of building the pipeline to ensure even a minimal profit. One undisputable fact is that, if the pipeline were already in place, the costs of shipping any gas that might be found among the remainder of the 95,000 acres of oil and gas leases would be considerably less than if a pipeline were not yet built.

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in
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Appendix A