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AVAILABLE TECHNOLOGY FOR INDIRECT CONVERSION OF COAL TO METHANOL AND GASOLINE: A TECHNOLOGY AND ECONOMICS ASSESSMENT

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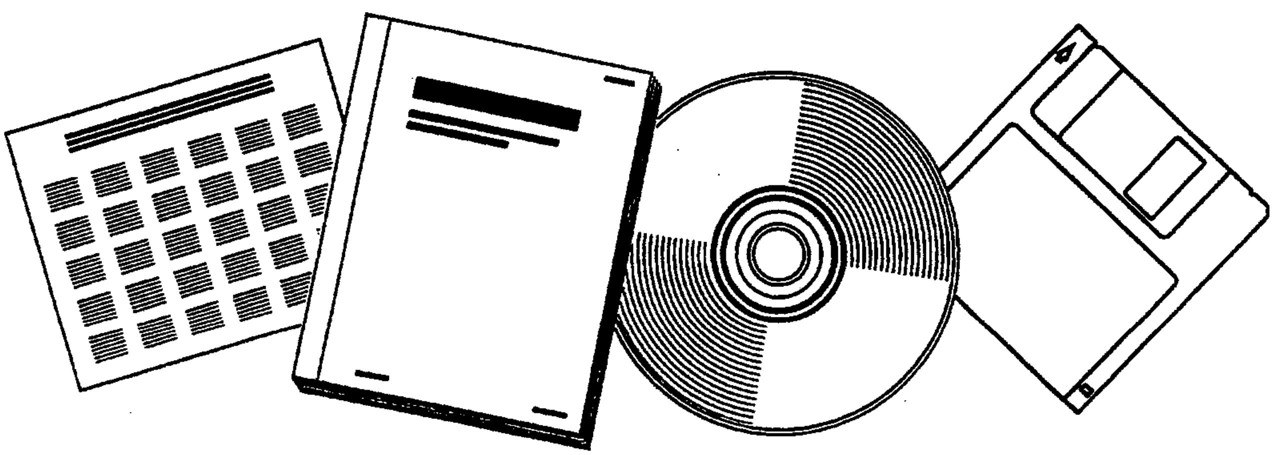

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AVAILABLE TECHNOLOGY FOR INDIRECT CONVERSION OF COAL TO METHANOL AND GASOLINE: A TECHNOLOGY AND ECONOMICS ASSESSMENT*

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**Oak Ridge National Laboratory

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AVAILABLE TECHNOLOGY FOR INDIRECT CONVERSIN OF COAL TO METHANOL AND GASOLINE A TECHNOLOGY

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ABSTRACT

The objective of the work was to review and assess the present state of the art of indirect liquid fuels synthesis, with particular emphasis to be placed upon those processes which produce methanol suitable for use as fuel.

Following this review, four conceptual designs for indirect conversion of a Western subbituminous coal to methanol and gasoline were prepared. Capital and operating costs for each of the four cases were then estimated. This information was used to calculate the required product selling prices under a "base case" set of financial ground rules. Results of the methanol production technology assessment and economic assessments of four coal conversion plants are presented.

1.0 INTRODUCTION

To properly direct its limited resources, DOE requires a limited assessment of the present state of the art of different coal conversion routes. Such assessments permit better understanding of the relative technical and economic potential of these processes and form an important part of the basis for future programmatic decisions. The objective of the work described here was to review and assess the present state of the art of indirect liquid fuels synthesis, with particular emphasis to be placed upon those processes which produce methanol. Potential uses for this product include combustion in peaking-type turbines or liquid-fueled boilers and conversion to premium-grade fuels through the use of upgrading processes such as the Mobil methanol to gasoline (MTG) process. The fuel-grade methanol product from many synthesis processes is likely to be contaminated by other light hydrocarbons since few such processes are highly selective; however, when the principal product consisted of storable, fuel-grade liquids, such processes were considered and evaluated.

Following this review and assessment of fuel-grade methanol synthesis technologies, Fluor Engineers and Constructors, Houston Division, prepared four conceptual process designs for indirect conversion of a Western subbituminous coal to either methanol or gasoline and estimated capital and operating costs for each of the four cases. This information was used by the Oak Ridge National Laboratory (ORNL) to determine the required product selling prices under a "base case" set of financial ground rules. The sensitivity of process economics to changes in a variety of these financial parameters was also investigated by performing numerous additional parallel cost determinations for each case.

The four designs examined in this study inclded indirect conversion of a generic Western coal located in northeast Wyoming to give the following products:

- methanol production for turbine-grade fuel, case B-2
- methanol production for gasoline blending, case B-1
- gasoline production with coproduction of synthetic natural gas (SNG), case C-2
- gasoline production maximized (via partial oxidation of methane), case C-1.

The total as received coal feed rate of each of the plants is ~30,000 tons per stream day. Lurgi-dry ash gasifiers, ICI methanol synthesis, and the Mobil (TPSD) methanol-to-gasoline (MTG) process are used.

2.0 ASSESSMENT OF METHANOL PRODUCTION TECHNOLOGY

The principal objective of this assessment was to review and assess the present state of the art of liquid fuels synthesis from coal by the indirect route, with particular emphasis on processes that produce methanol as the primary product. Results and conclusions of this assessment are given in ref. 2 and appear below:

Almost all the methanol produced today is made from natural gas or from petroleum-derived naphtha. One commercial plant in South Africa produces methanol from coal. Essentially all the methanol produced today is of high purity and is used as a chemical intermediate. The growing world shortage of liquid fuels from petroleum has caused increased interest in the potential of methanol as a fuel. The development of the Mobil MTG process, which converts methanol to high-octane gasoline, has sharpened this interest.

This review and assessment of fuel-grade methanol synthesis and related technologies covers the following general areas:

1. commercial methanol synthesis processes;
2. promising developments in fuel-grade methanol-type synthesis, including;
    - catalyst advances,
    - reactor configurations,
    - product upgrading,
    - syngas feed limitations;
3. industrial interest in this technology (as indicated, for example, by a patent search).

In addition, obsolete or unused methanol synthesis processes are reevaluated from the standpoint of liquid fuels production.

Based on a review of available information, a judgmental assessment of relative technical and economic potential of all processes identified was made without preparing detailed cost estimates.

This was accomplished by reviewing the literature and patents on methanol synthesis and had discussions with Davy Powergas, Haldor Topsoe, Lurgi, Mobil Research and Development, Chem Systems, and Wentworth Brothers (successors to Vulcan-Cincinnati). The investigation covered current processes, obsolete processes, economics, optimization of the synthesis loop, and possible variations from current technology that might occur as a result of large-scale use of fuel-grade methanol.

If unconventional processes are to be considered for fuel-grade methanol production, the base process against which they will have to compete is conventional methanol synthesis as typified by the Imperial Chemical Industries, Ltd. (ICI), Lurgi, Mitsubishi, Haldor Topsoe, or Wentworth Brothers technologies. We therefore felt it appropriate to examine these conventional technologies to determine the economic or technological breakthroughs that would have to be achieved by a new, unconventional process to make it more attractive than those now available.

A brief summary of the conclusions is given below.

1. We did not find any discarded or obsolete methanol synthesis processes that appear to offer any advantage over current commercial processes for the production of fuel-grade methanol. Thus, if the study is restricted to the production of fuels consisting essentially of methanol with minor amounts (up to 20%) of other fuel-type compounds as impurities, our conclusion is that no process is available that appears to be better than current methanol synthesis technology. However, if th scope of the study is expanded to include the production of other synthesis products (e.g., Fischer-Trosch-type products, olefins, etc.) and the possible conversion of such products to other fuels (such as gasoline or diesel fuel), the possibilities for new process development are enormously increased. This appears to us to be a very fruitful field for process and catalyst research and development.

2. It appears that for the production of industrial methanol, the low-pressure process (50 to 100 atm) has a clear economic advantage over the older, high-pressure process (200 to 300 atm)

3. The industrial preference for the low-pressure process since its introduction in about 1966 is not based on greater product purity or improved selectivity, but on better overall process economics. It appears probable

to us that, even if the product purity specifications are relaxed to permit the production of fuel-grade methanol, the low-pressure process will still have the economic advantage. However, it should be noted that the proponents of the high-pressure process do not agree with this, especially in regard to large coal-based plants. Resolution of this controversial question would require detailed designs and cost estimates with a high degree of provability. This would be a difficult task because (1) it would probably involve the use of high-pressure second-generation gasifiers that have not yet been fully demonstrated, and (2) it would require the use of catalyst data for which only limited proprietary evidence is available.

4. The capital cost of the final product purification section is negligible in comparison to the costs of other parts of the plant. Operating costs for the final distillation towers are also negligible since the heat can be supplied by low-pressure steam, which will generally be available in excess quantities in a coal-to-methanol plant. Thus elimination of product purification in a fuel-grade methanol plant reduces costs by only a very minor amount.

5. Development of a synthesis catalyst of greater activity could substantially reduce the cost of methanol production. There is no indication at present that such a catalyst is close to discovery; however, the possibility of such a development in the future should not be ruled out.

6. The Mobil MTG (methanol-to-gasoline) process has shown the potentialities of upgrading the initial synthesis products to high-octane gasoline. If similar upgrading processes could be developed for a wider range of initial synthesis products (e.g., Fischer-Trospch products), the possibilities for economic combinations of synthesis conditions, catalysts, and products are greatly increased. Industrial research in this area appears to be active

7. In a coal-to-gasoline plant using the methanol-Mobil-MTG route, the capital investment in the methanol synthesis loop is only about 10% of the total facility cost. The largest part of the total investment is in the coal handling, gasification, oxygen plant, gas purification, and utilities (steam, power, and water) systems.

8. New catalyst developments, which could occur at any time, might result in more economical processes for the production of methanol-related fuels from synthesis gas. This possibility is especially believable if the acceptable product spectrum is expanded to include higher alcohols, aliphatics, aromatics, ethers, and other compounds which might be useful as automotive or turbine fuels. Also, new developments in methanol synthesis catalysts could increase the optimal operating pressure for large-scale fuel-grade methanol plants and could increase the maximum methanol throughput per train, thus improving the economics. All these possibilities appear to be under active investigation by industry.

Cost savings would be expected to occur in the following areas: coal preparation and storage, reduced coal consumption in boilers and optimization of storage capacity/equipment design; oxygen production, use of three-3200 TPSD trains instead of four-2400 TPSD trains (for case C-1); gasification, 24 gasifiers instead of 28; compressor and makeup compressors on the same shaft; methanol conversion, less catalyst volume required due to reduction of trains.

The direct field costs were separated into major process areas and are shown in Figures 1-3. These figures depict the discribution of direct field costs for each design and illustrate the variations in distribution beteen designs. In general, offsites and power/steam generation account for ~50% of the total direct field costs. Oxygen production, syngas purification, gasification, and methanol synthesis each account for 6-11% of the total direct field costs. Methanol conversion to gasoline accounts for 5-6% in cases C-1 and C-2. Shift conversion is a small part of the total direct field costs, accounting for 1% in all cases. Case C-1 shows noticable increases in oxygen plant costs and stream/power generation costs over case C-2 due to the extra oxygen and steam required to reform the methane.

3.3 Economic Analysis

Economic analyses were performed by ORNL using the ORNL-developed economic analysis computer program PRP.[4] PRP calculates the required selling price of the main product from a processing plant for a given set of economic input values the discounted cahs flow (DCF) method. The calculated product price is the selling price of the product at the plant gate that will meet all the cost obiligations of the plant under a given set of financial parameters. The selling price does not include any additional tax levies on the product, or transportation and marketing charges. The base case economic parameters used in the analysis of each of the four conceptual plants are summarized in Table 7. The price per unit heating value for coproducts (SNG, C_3 LPG, C_4 LPG, crude diesel fuel, and naphtha) were ratioed to the price per unit heating value of the principal liquid product (methanol or gasoline). The prices used to determine the price ratios are based on a 1990 scenario for fuel prices given by DOE.[3] The price ratios are shown in Table 8.

Unit prices for ammonia and phenols were not ratioed to the main product price; however, they were credited to the plants at \$120/ton and \$0.125/lb, respectively. Excess power was given a credit of \$0.03/kWh in case C-1 where a slight excess of 14.3 MW was produced.

Sensitivity studies, were performed to determine the impact on the main product price of step changes in several economic parameters. In performing the sensitivity studies, the step change was introduced in one parameter at a time, keeping the remaining parameters at their base case values.

3.4 Results

Calculated product prices for the base conditions are shown in Table 10. The price of methanol for turbine-grade fuel is \$8.81/10^6Btu or \$0.56/gal. It should be noted that this is the required selling price at the plant gate. The price of methanol for gasoline blending is \$8.81/10^6Btu or \$0.57/gal. The difference in price per gallon of the two grades of methanol is a result of the difference in allowable water content.

When facilities for conversion of the methanol to gasoline are included, the price of gasoline is \$10.88/10^6Btu or \$1.25/gal. If the co-product SNG is steam reformed to produce more syngas for methanol synthesis/conversion, the price of gasoline increases to \$13.87/10^6Btu or \$1.59/gal.

3.0 Economic Assessment of Methanol and Gasoline Production from Coal

After the assessment of methanol production technology was completed, four conceptual designs for methanol and gasoline production from coal were prepared by Fluor Engineers and Constructors, Houston Division. The conceptual designs are based on use of consistent technology for the core of the plant (gasification through methanol synthesis) with additional processing as necessary for production of different liquid products of interest. A summary of the bases for design is given in Table 1. The case designations are as follows:

- Methanol production for turbine-grade fuel - case B-2
- Methanol production for gasoline blending - case B-1
- Gasoline production with coproduction of SNG - case C-2
- Gasoline production maximized - case C-1

Turbine-grade methanol may contain up to 2% water, whereas gasoline blending-grade methanol may contain no more than 0.1%.

Table 1. Bases for process design

Feed coal type	Wyodak
Feed coal quantity to gasifier, TPSD, MAF	16,000
Gasifier type	Mark IV Lurgi dry ash
Plant location	N. E. Wyoming
Power/char produced for sale	none
Preferred cooling medium	air
Environmental constraints	Zero wastewater discharge; solid waste disposal consistent with proposed RCRA guidelines; conformity with proposed NSPS air standards

Capital and operating cost information was also prepared for each design. A capital and cost summary is given in Table 2.

Table 2. Capacity and cost summary
(in mid-1979 dollars)

	Methanol production for turbine-grade fuel (case B-2)	Methanol production for gasoline blending (case B-1)	Gasoline production with coproduction of SNG (case C-2)	Gasoline production maximized (case C-1)
Coal feed rate (TPSD of MAF coal):				
Coal to gasifiers	16,000	16,000	16,000	16,000
Coal to power plant	4,210	4,210	4,321	5,702
Total coal feed	20,210	20,210	20,321	21,702
Products:				
Methanol (BPSD)	53,500	52,770	---	---
Gasoline (BPSD)	---	---	24,16[illegible]	42,580
SNG (10^6SCFD)	153	153	155	19
Propane LPG (BPSD)	---	---	1,240	2,165
Butanes LPG (BPSD)	---	---	2,200	3,460
Naphtha (BPSD)	1,380	1,380	-----	-----
Crude diesel (BPSD)	3,900	3,900	3,900	3,900
Crude phenols (10^3lb/SD)	384	384	384	384
Ammonia (TPSD)	110	110	110	110
Power, MW	0	0	0	0
Overall thermal efficiency	64.8	64.8	61.[illegible]	50.4
Total capital cost (10^6\$)[a]	2,135	2,137	2,318	2.792
Annual operating cost (10^6\$)[b]	331.1	331.2	340.[illegible]	375.8
Product prices for base case[c]				
Methanol (\$/gal--\$/10^6Btu)	0.56--8.81	0.57--8.81	-----	-----
Gasoline (\$/gal--\$$10^6$Btu)	-----	-----	1.25--10.88	1.59--13.87
SNG (\$/10^6Btu)	8.02	8.02	8.70	11.10

[a]This includes a 20% estimating allowance, working capital, and startup costs.

[b]Based on a stream factor of 95% for cases B-1 and B-2, 93% for case C-2, and 90% for case C-1.

[c]Base case assumed: 100% equity financing; 12% annual after-tax rate of return on equity; 1990 price scenario given in ref. 3; 25-year operating life; 5-year construction; 48% federal income tax; 3% state income tax; 2.75% local property [illegible] for 16 years; $1/10^6$ Btu coal; no salvage value.

ORNL utilized information developed by Fluor[2] the required product selling prices (hereafter referred to as product prices) under the base economic conditions indicated in Table 3. In the economic analysis, it was assumed that the price per unit heating value of most of the hydrocarbon co-products maintains a predetermined ratio with the principal liquid product price (methanol or gasoline) as given in ref. 3. The sensitivity of process economics to changes in a variety of financial parameters was also investigated by performing additional parallel cost determinations for each case.

Table 3. Economic base conditions

Percentage of equity financing	100
Annual after-tax rate of return on equity, %	12
Operating life, yrs	25
Construction period, yrs	5
Federal income tax rate, %	48
State income tax rate, %	3
Local property tax and insurance cost,[a] %	2.75
Estimating allowance, %	20
Depreciation method	Sum of years digits over 16 years
Coal cost, $\$/10^6$ Btu	1
Dollar value base	mid-1979

[a]Taken as a percentage of total depreciable capital.

3.1 Discussion of Processes

The total quantity of coal used in each case was ~30,000 tons per stream day (TPSD) of as-received coal. This varied slightly between cases, depending on the amount required to produce steam/power in the coal-fired boilers; however, in each case, 16,000 TPSD of moisture- and ash-free (MAF) coal, or 23,946 TPSD of as-received coal, is gasified. Twenty-eight Lurgi Mark IV dry-ash gasifiers, divided into two trains and followed by four trains of low-pressure methanol synthesis equipment, are used in the preparation of methanol. The technology used for the onsite units and offsite units is commercial or near-commercial technology.

The production of substitute natural gas (SNG), which occurs in all four cases, is a result of using Lurgi gasifiers. Lurgi gasifiers produce a synthesis gas containing a significant fraction of methane. This methane is inert in the methanol synthesis unit and has to be purged continuously from the reaction loop. In cases B-1, B-2, and C-2, the purge gas is methanated, dried and sold as SNG. In case C-1, the methanol unit purge gas is reformed to make more methanol synthesis gas ($CO + H_2$), resulting in a higher methanol yield and, subsequently, a higher gasoline yield. A small purge for removal of nitrogen, argon, and other inerts is still required in case C-1, producing a small quantity of SNG.

Environmental protection is based on conformity with proposed NSPS air standards, solid waste disposal consistent with proposed RCRA guidelines, and zero wastewater discharge. In using the proposed NSPS air stanards, it was assumed that atmospheric emissions apply to the plant as a whole rather than to individual process units (i.e., the bubble concept). Use of the bubble concept provided freedom in choosing a method to dispose of sulfur. Specifically, acid gas from a nonselective acid gas removal unit is incinerated in the boilers, and the resulting sulfur dioxide is removed in a flue gas desulfurization unit.

The following sections describe each case in more detail.

Methanol Production For Turbine-grade Fuel:
Case B-2

The major processing steps for production of turbine-grade methanol are coal preparation, coal gasification, raw gas shift, acid-gas removal, methanol synthesis, and methanol purification by fractionation. Other steps, such as air separation, hydrogen recovery, naphtha hydrotreating, phenol recovery, ammonia recovery, and methanation, are required to treat side streams and to prepare oxygen and hydrogen feed streams.

A significant feature of this case is the large amount of nonmethanol substances produced; less than half the total product heating value is represented by the methanol product. Other products are SNG, crude phenols, crude diesel fuel (light oil product), naphtha, and ammonia. Tar is also produced but is uded as supplemental fuel in a coal-fired boiler. The quantity and diversity of the nonmethanol products are attributable to the use of the Lurgi dry-ash gasifier, which normally produces a number of materials other than synthesis gas.

Methanol Production For Gasoline Blending:
Case B-1

The production of methanol for gasoline blending requires the same processing steps as does the production of turbine-grade methanol. Through more effective fractional distillation of the methanol, the water content of the product in this case is reduced $\leq$0.1%.

Gasoline Production With Coproduction Of SNG:
Case C-2

The production of gasoline is accomplished in case C-2 via catalytic conversion of crude methanol to gasoline-range hydrocarbons in a Mobil MTG fixed-bed unit. Fractionation and alkylation of the Mobil MTG product yield stabilized gasoline, propane, mixed butanes, and alkylate. The stabilized gasoline, alkylate, and hydrotreated naphtha are combined and pressured with butanes to yield a finished 10 RVP unleaded gasoline. Propane and excess butanes are sold as LPG.

Gasoline Production Maximized:
Case C-1

The process design in case C-1 differs from that in case C-2 the Lurgi oxygen-blown catalytic partial oxidation process to reform the methane in the gas purged from the methanol synthesis unit into synthesis gas. This process arrangement results in a 92% reduction in SNG production but a 76% increase in gasoline production.

3.2 Capital and Operating Costs

Cost estimates for each of the four plants were provided by Fluor and Constructors according to the guidelines presented in Table 4. Capital cost estimates for all four cases are summarized in Table 5. The total plant installed cost has been broken down into three major groups: onsited, offsites, and administrative/miscellaneous units. Fluor estimates the accuracy of the capital co e ± 30%. Operating costs for all four cases have been summarized in Table 6. Fluor estimates the accuracy of the operating costs to be ± 20%. Upon the recommendation of Fluor, an estimating allowance amounting to 20% of the total plant installed cost was added by ORNL as an estimate of cost increases which may result from a detailed design rather than a conceptual design. Start-up costs were not given by Fluor and were estimated by ORNL to be 6% of the total plant installed cost as given in Table 5.

The cost estimates presented in Tables are based on a first-of-its kind plant design. It was estimated that capital cost savings of 10-20% and operating cost savings of ~10% could be realized in an Nth plant design

Table 4. Fluor's basis for capital cost estimates

- Costs are represented in constant mid-1979 dollars. No escalation was applied beyond that date.
- Costs associated with the purchase of land and the costs of obtaining permits, government approvals, and lease rights are not included.
- Process licensor fees and royalties are not included.
- State and local sales taxes are not included.
- Limited site preparation is assumed to be required. Blasting, extensive timber removal, and structural piling are assumed to be unnecessary.
- SNG pipelines beyond the battery limits are excluded.
- Access roads to the plant site are excluded.
- Coal is supplied by unit train. Costs of railcars and railroad track outside of the plant battery limits are excluded.
- The plant is self-sufficient in utilities. Electrical power is neither purchased nor sold, except for the case of maximum gasoline production (case C-1) where an excess of 14.3 MW is sold.
- Water is obtained from water wells drilled on the plant site.
- The plant is assumed to be located in the northeastern part of Wyoming.
- Cost estimates for several of the units in the facility were provided by vendors. Where vendor estimates were not available, unit costs were estimated using Fluor's factored estimate methods to arrive at a Gulf Coast direct field cost (DFC). Corrections were then made to the Gulf Coast DFC to allow for wage differentials, productivity, etc., in the area where the unit is to be built.

Table 5. Capital investment summary
(all estimates are in millions of mid-1979 dollars)

	Methanol production for turbine-grade fuel (case B-2)	Methanol production for gasoline blending (case B-1)	Gasoline production with coproduction of SNG (case C-2)	Gasoline production maximized (case C-1)
ect field costs:				
rocess units	614.0	614.9	660.9	802.6
ffsite units	449.4	449.4	497.3	599.4
dministrative/miscellaneous units	409.4	40.9	41.0	42.2
Total direct field costs	1104.3	1105.2	1199.2	1444.2
irect field costs } at 45%				
ineering costs } of DFC	496.9	497.3	539.6	649.9
Total plant installed cost	1601.2	1602.5	1738.8	2094.1
imating allowance[a]	320.2	320.4	347.8	418.8
Total depreciable capital	1921.5	1922.8	2086.6	2512.9
irect capital:				
atalysts and chemicals	18.2	18.2	19.7	27.1
Start-up[b]	96.1	96.1	104.4	125.8
orking capital[c]	99.2	99.9	107.3	126.2
Total indirect capital	213.5	214.2	231.4	278.4
Total capital investment	2135.0	2137.0	2138.6	2792.0

timating allowance taken at 20% of total plant installed cost.

artup taken as 6% of total plant installed cost.

rking capital is taken as the sum of the following: 60-day supply of coal, 22-day oduct value, 30-day payroll and payroll burden, 30-day operating supplies and chemicals; ear supply of catalysts; and spare parts and other warehouse stock.

Table 6. Annual operating costs
(all costs are in millions of mid-1979 dollars per year)

	Methanol production for turbine-grade fuel (case B-2)	Methanol production for gasoline blending (case B-1)	Gasoline production with coproduction of SNG (case C-2)	Gasoline production maximized (case C-1)
Raw material (coal)[a]	178.0[b]	178.0[b]	175.4[c]	180.9[d]
Operating labor[e]	4.9	4.9	5.5	6.3
Maintenance labor[f]	5.4	5.4	5.4	5.4
Administrative and support labor	6.8	6.8	6.8	6.8
Labor burden[g]	6.5	6.5	6.7	7.0
Catalysts and chemicals	11.1	11.1	12.3	14.6
Maintenance materials[h]	33.0	33.0	35.7	43.1
General and administrative expenses[i]	32.0	32.0	34.8	41.9
Solids disposal[j]	0.6	0.6	0.6	0.6
Local taxes and insurance[k]	52.8	52.9	57.4	69.1
Total operating costs	331.1	331.2	340.6	375.7

[a]Coal at $\$1/10^6$ Btu.
[b]30,200 TPSD as received coal; 95% stream factor.
[c]30,400 TPSD as received coal; 93% stream factor.
[d]30,400 TPSD as received coal; 90% stream factor.
[e]Operators at $8.60/hr.
[f]General labor at $7.43/hr.
[g]38% of operating, maintenance, administrative and support labor cost.
[h]2.7%/yr of onsite plus 1.25%/yr of offsite plant installed investment.
[i]2%/yr of total plant installed cost.
[j]$0.40/ton includes labor and materials to truck ash and other solids from plant to disposal site.
[k]2.75% per year of total depreciable capital, added by ORNL.

ORNL DWG 80-1113

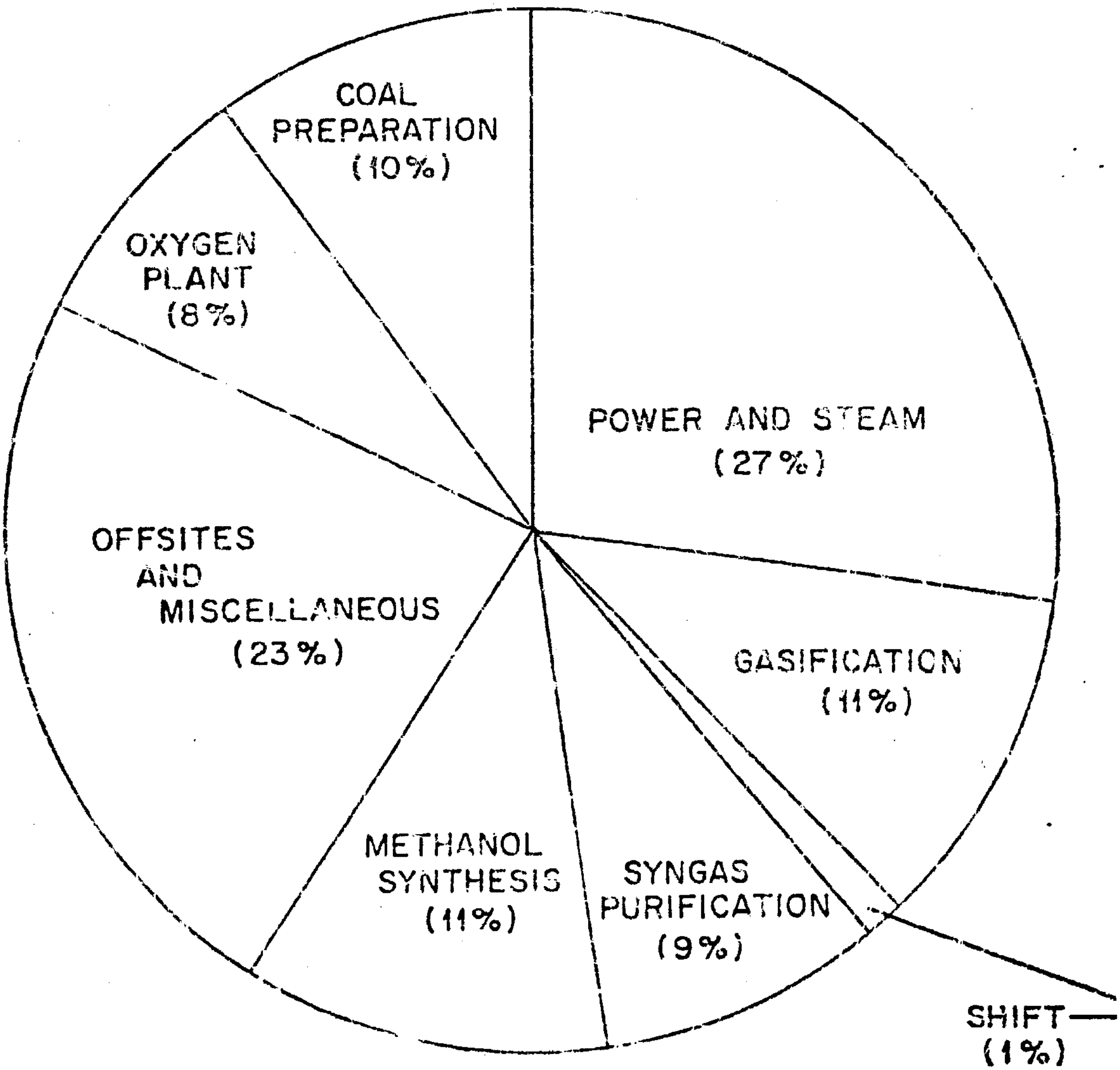

Fig. 1. Distribution of direct field costs estimate for Methanol production (cases B-1 and B-2)

ORNL DWG 80--111

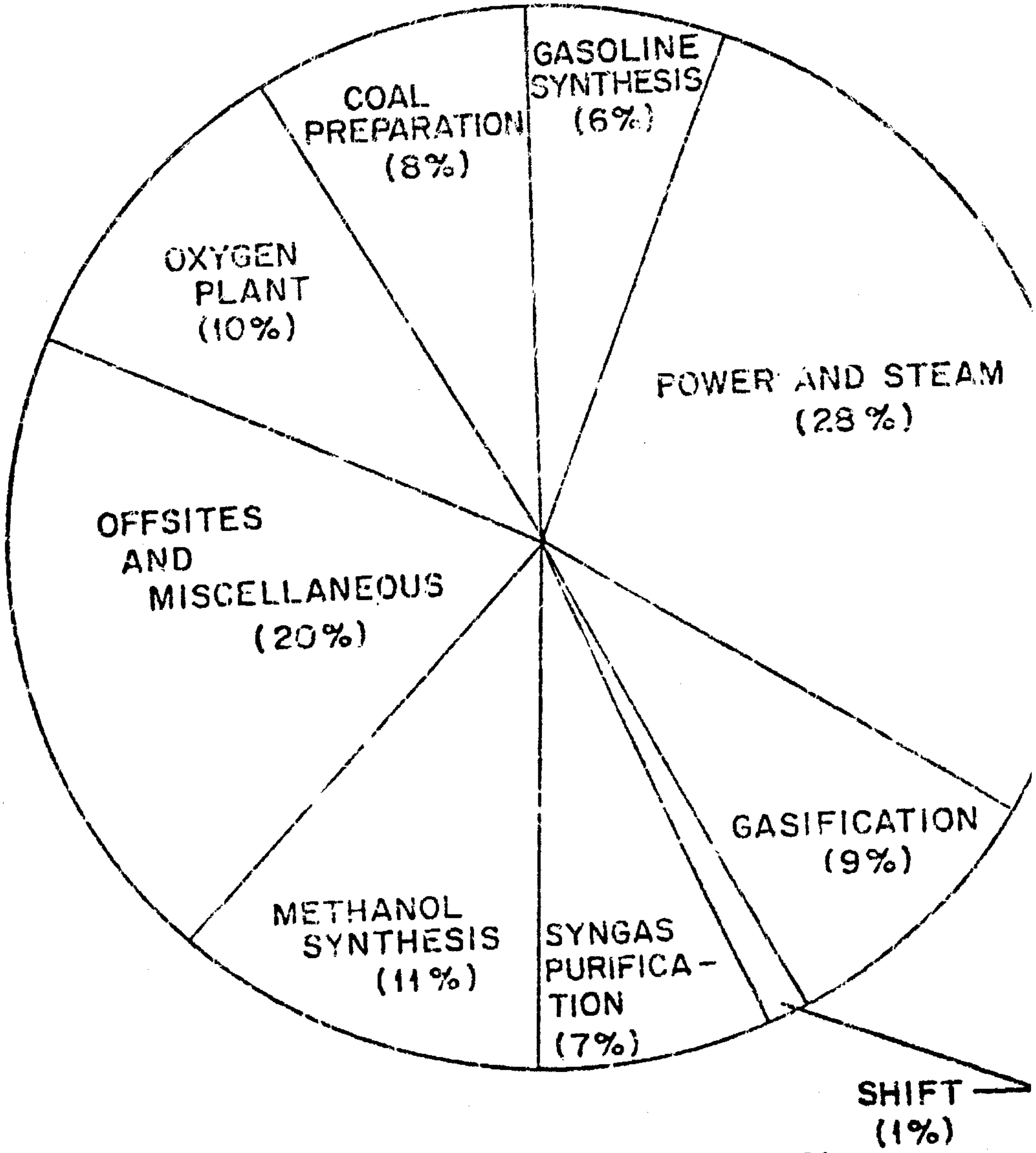

Fig. 2. Distribution of direct field costs for maximum gasoline production

ORNL DWG 80-1112

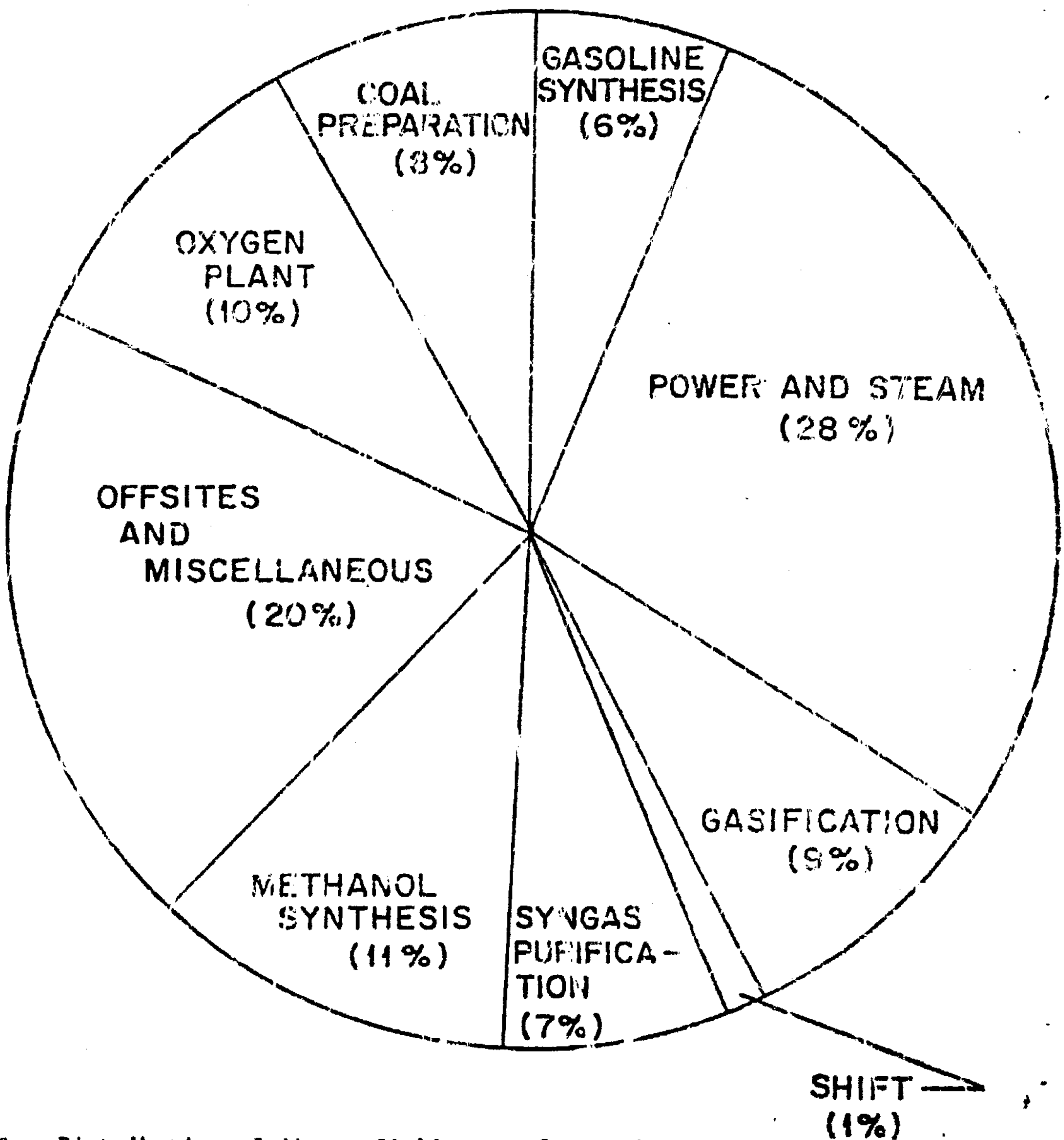

Fig. 3. Distribution of direct field costs for maximum gasoline production

Table 7. Base case economic parameters used in the economic analysis of the four conceptual plants

- 100% equity financing
- 12% annual after-tax rate of return (AARR) on equity
- Constant mid-1979 dollars
- No escalation of costs or prices beyond 1979
- Coal price: $1.0/10^6$ Btu
- Product price ratios for 1990 (See Table 6.2 for details)
- Plant life: 25 years
- 5 year construction period with the following investment schedule:

Year	% Investment
1	9.2
2	24.2
3	42.0
4	22.3
5	2.3
Total	100.0

• Federal income tax:	48%
• State income tax:	3%
• Local property tax and insurance cost:	2.75%
• Investment tax credit:	10%
• Estimating allowance	20%
• Project and process contingencies:	0%
• Annual plant service factors:	

	Methanol production for turbine-grade fuel (case B-2)	Methanol production for gasoline blending (case B-1)	Gasoline production with coproduction of SNG (case C-2)	Gasoline production maximized (case C-[illegible]
1st yr	50%	50%	50%	50%
2nd yr	75%	75%	75%	75%
3-25 yrs	95%	95%	93%	90%

- Zero salvage value
- Land costs and process royalties omitted
- Solids waste disposal cost: $0.40/ton

Table 8. Product price ratios[a] and by-product credits used in this study

	Price ratios based on unleaded gasoline	
	1979	1990
Methanol	0.84	0.88
Substitute natural gas (SNG)	0.59	0.8
C_3 LPG	0.69	0.85
C_4 LPG	0.76	0.87
Naphtha	0.88	0.93
Unleaded gasoline	1.00	1.00
No. 2 fuel oil	0.84	0.88
No. 6 fuel oil	0.62	0.73
Crude diesel fuel[b]	0.59	0.62
By-product credits[c]		
Phenols[d] $0.125/lb		
Ammonia[e] $120/short ton		
Power[e] $0.03/kW-hr		

[a]Product prices were provided by DOE (ref. 2) except as noted; price ratios are based on the ratio of the price per unit heating value of the coproducts to the price per unit heating value of unleaded gasoline and were determined by ORNL.

[b]Product price ratio based on the product price assumed by Fluor for this study.

[c]These values were not ratioed to other products.

[d]This product price was estimated by Fluor for this study.

[e]Assumed by ORNL for this study.

Table 10. Base case results

Case designation	Principal liquid product	Principal liquid product ($/gal - $/10⁶Btu
Methanol production for turbine-grade fuel (B-2)	methanol	0.56 - 8.81
Methanol production for gasoline blending, (B-1)	methanol	0.57 - 8.81
Gasoline production with coproduction of SNG, (C-2)	gasoline	1.25 - 10.88
Gasoline production maximized (C-1)	gasoline	1.59 - 13.87

In all cases, the response of product price to the various sensitivities were similar and are given below in Table 11.

Table 11. Effect of variation of capital and operating cost related parameters on product price

Test No.		Approximate percentage change of product price
1	15% annual after-tax rate of return on investment (vs 12% for base condition)	+27
2	Plant capitalization at 75% debt with 25% equity (vs. 100% equity for base condition)	-36
3	25% increase in depreciable capital	+17
4	$0.5/10^6$Btu increase in coal cost	+10
5	20% increase in annual operating costs (exclusive of coal)	+2

Variation of capital-related parameters have a large influence on product price. A large part of the product price is for capital recovery and, hence, the product price is very sensitive to changes involving the capital recovery charges. For example, an increae in total depreciable capital of 25% causes a 17% increase in product price (case 3). A graphical illustration of the marked effect of changes in total depreciable capital on the price of gasoline for case C-2 is given in Figure 4. For comparison, the relative insensitivity of gasoline price to changes in feed coal cost and operating costs are also shown. An increase in annual after tax rate of return on equity from 12% to 15% yields an increase of ~27% in product price (case 2).

When the method of financing is varied from 100% equity to 75% debt with 25% equity, product price drops ~36%, as expected, due to the large reduction in equity capital (case 3).

Substancial variations in parameters related to operating costs or coal costs caused small to negligible changes in product price. Increasing the annual operating costs (exclusive of coal costs) by 20% for example, caused a product price increase of less than 2% (case 5).

Process Economic Implications Derivable From This Study

Some of the major economic implications that can be derived from this study are:

1. *Effect of product methanol water content:* The effect of reducing the water content of the product methanol from 2% (turbine-grade methanol) to 0.1% (gasoline blending-grade methanol) has a negligible effect on the plant capital cost and practically no effect on the plant operating cost. The calculated price of the gasoline blending-grade methanol is 1¢/gal (~1.8%) more than the turbine-grade methanol. This reflects the difference in heating value rather than capital investment.

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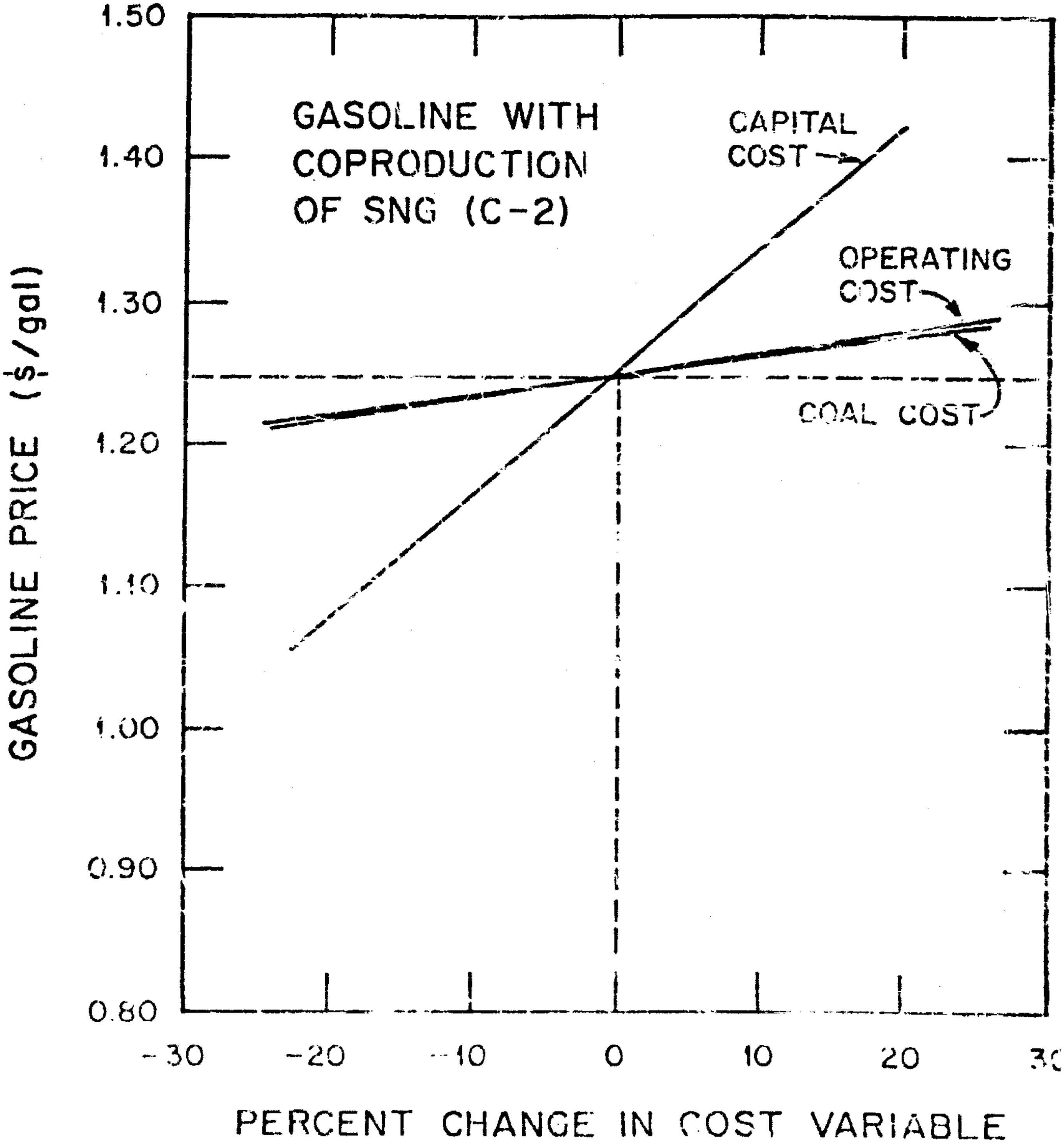

Fig. 4. Dependence of product price on various cost variables.

2. *Conversion of methanol to gasoline:* Including methanol conversion facilities (case C-2) in the basic design of a methanol production facility (case B-2) resulted in an increase of \$181 million in the total capital investment and an increase in annual operating costs of \$9.4 million. The overall thermal efficiency decreased from 64.8% to 61.6%. The calculated price of gasoline from this facility is \$1.25/gal when the product price ratios given in Table 7 are used. When constant-value product prices determined for case B-2 were used in calculating the price of gasoline for case C-2 (instead of price ratios), the resulting price of gasoline was \$1.38/gal. This compares with a price of \$0.56/gal for turbine-grade methanol, or \$0.556/gal for crude (unfractionated) methanol. This is in good agreement with the price relationship between crude (unfractionated) methanol and Mobil-MTG gasoline suggested by Mobil[5] and given below:

$$\left\{\begin{array}{l}\text{Mobil MTG}\\ \text{gasoline price}\\ (\$/\text{gal})\end{array}\right\} = 2.4 \times \left\{\begin{array}{l}\text{Crude}\\ \text{methanol price}\\ (\$/\text{gal})\end{array}\right\} + \$0.05/\text{gal}.$$

3. *Effect of reforming methanol synthesis unit purge gas to maximize gasoline production:* The Lurgi gasifier which was selected for coal gasification, produces a significant volume of methane which must be purged from th methanol synthesis loop. Two opetions for handling the purge gas when designing the plant have been studied. The purge gas can either be methanated and sold as a coproduct, or it can be reformed to yield additional syngas which can be further converted to increase gasoline production. The decision to reform the purge gas depends on the estimated selling price of SNG during the life of the plant. As an example, one of the results of this study indicated that, if the SNG price is below $\$5.35/10^6$Btu, it is more economical to coproduce SNG as a plant product

6. *Effect of capital related parameters on product price:* Capital related parameters have large effects on product price as evidenced by the sensitivity tests. Various methods of debt financing or other methods which reduce the total amount of capital investment will be a very effective methods which reduce the total amount of capital investment will be a very effective method of reducing product price.

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