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Underground Coal Gasification: Status and Proposed Program

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Summary

Background

Underground coal gasification (UCG) is similar to other coal gasification processes except that the coal is gasified in place by injecting steam and oxygen into the coal bed. Injection and production wells are connected by underground channels to facilitate adequate gas flow. The product gas, which has a medium heating value, can be converted into a number of products, including synthetic natural gas (SNG), methanol, gasoline, and electricity.

The technical feasibility of underground coal gasification (UCG) has been well established in 21 field tests, 16 of which were funded by the federal government. The UCG process has been shown to be site-specific. Sites with strong, dry, overburden rock and thick or moderately thick coal beds are most suitable. Sites with thin coal seams or with weak, wet, overburden rock are less suited to UCG.

Cost estimates for methanol and SNG using the data from the better field tests compare favorably with the costs of the same products from conventional sources in the 1990 time frame. Methanol is estimated to cost \$0.52/gal without tax, and SNG is estimated to cost \$5.19/10^6 Btu in 1982 dollars.

Successful implementation of UCG would permit the use of a huge, as yet incompletely assessed, coal resource that is otherwise unusable. Such a resource could provide clean energy for hundreds of years. Principal environmental concerns relate to subsidence and water quality. Subsidence can be handled with proper engineering design. Surface disruption should be comparable to or less than conventional mining.

Underground Coal Gasification introduces some inorganic and organic contaminants into the coal aquifer. Contamination of aquifers above or below the coal appears to be absent or minor. The concentrations of most organic and inorganic pollutants appear to decrease with time, apparently as a result of sorption, dilution, dispersion, and bacterial action. However, larger scale tests in varying hydrological regimes are needed to fully evaluate long-term effects on aquifers and water quality.

The prospects for using UCG to produce methanol for the transportation end-use sector are particularly attractive. The Bank of America's recently released report on the use of methanol as an automotive fuel concluded that methanol fuel costs are competitive with gasoline at today's prices. In addition, methanol is a superior automotive fuel to gasoline.

Proposed Program

Technical uncertainties remaining in the UCG technology include specific criteria for site selection, large-scale burn interactions, details of process control, multiple well operation, overall system reliability, subsidence, and water quality effects. Considerable effort has been expended on understanding and controlling the process, on predicting and mitigating subsidence, and on maintaining water quality. Some data are available on site acceptability, but as yet information from large-scale field tests are not in the public domain. Commercialization of UCG will not be possible until such data become available.

A program plan to commercialize UCG in an orderly, paced manner has been developed. The program would cost \$200 million over seven years, some of which could be cost-shared with industry. The proposed program includes development of a more detailed program plan.

The laboratory component of the program, although only a small fraction of the budget, is crucial. It contains environmental research, modeling, experimental studies, economic and system studies, instrumentation development, and materials studies.

The field component includes UCG of both flat and steeply dipping coal beds as well as of less tractable bituminous coal. The field projects involve development of criteria for site selection

and characterization, "large block tests" in bituminous coal,* simple, small-scale field tests, subsequent more complex and longer-running tests, and finally large scale, or pilot tests. Steam-oxygen gasification would probably be used.

The program is designed to commercialize UCG technology in bituminous, flat-lying, and steeply dipping subbituminous coal beds in a reasonable length of time, while minimizing total program costs. The program can be stretched out in time by decreasing the annual budgets but concomitantly increasing the total program cost. An accelerated program would decrease the commercialization time with attendant increased risk and total cost. The program proposed should produce enough information to assess the technical, environmental, and economic feasibility of UCG. If the program is successful, commercial UCG operation could begin in 10 years.

Benefits and Risks

Underground coal gasification is a high-risk technology because of site variability and uncertain knowledge of the underground environment. The laboratory research and small-scale field testing carried out to date indicate that the economics are favorable, but this will not be proved until results from larger scale experiments are known. Commercialization decisions cannot be made without such information; thus, the program, costing an estimated $200 million, has no guarantee of success.

The reward resulting from a successful UCG R&D program would be commercialization of methanol and SNG from coal at prices competitive with existing fuel sources. The deep coal resource made available would be sufficient to last for hundreds of years production. Conceivably the U.S. could develop an export market in transportation fuels. The first year of commercial operation alone would reduce the bill for imported oil and natural gas by an amount equal to the cost of the entire R&D budget.

A task force convened by the American Institute of Chemical Engineers examined UCG and concluded that the technology meets the requirements of long-term and high risk established by the administration as criteria for desirable energy research programs within the federal government. The task force recommended that the UCG program continue to receive federal monies at a level that would support a coherent multi-well program. The Gas Research Institute has provided funding and support for UCG over the past few years and also recommends continued federal support, including multi-well tests.

Conclusion

As a result of the repeated demonstrations of technical feasibility of the underground coal gasification process, it is becoming recognized as one of the most promising methods for producing clean fuels from coal that is unattractive or inaccessible for mining. Products such as synthetic natural gas or transportation fuels, which are vital to our nation's economy, could be produced by UCG at costs estimated to be competitive with the costs of such products from conventional sources. The UCG process appears to be environmentally benign. The proposed program plan outlines the process by which UCG can be commercialized within 10 years with a very reasonable ($200 million) budget. With the continued joint efforts of industry and government, UCG should make a significant addition to the U.S. energy economy.

U.S. Energy Overview

A common view held by energy analysts is that the sum total of the world's fossil fuels will not be depleted for about 100 years.[1,2] Although this may seem to justify the current complacency in the U.S. toward future energy shortages, it says little about the adequacy of U.S. supplies. Further, a 100-year supply does not guarantee timely development of the resources so as to minimize crises and ensure either a healthy world or U.S. economy. The 1973 and 1979 world energy crises have emphasized the importance of availability and distribution of a particular fossil fuel, crude oil.

The inconveniences, shortages, and oil price increases have had a profound effect on U.S. consumption patterns. They precipitated a recession and set in motion conservation patterns that may

* These tests are very small field tests that can be investigated by excavation after the burn.

prove to be irreversible. Examples of change designed to conserve energy include new fleets of fuel-efficient cars, modified building codes, and cogeneration plants. Forecasts have changed as well.

Before the 1973 embargo, forecasting U.S. energy use was considered to be straightforward. A clear relation between consumption and the gross national product (GNP) was demonstrable. The GNP and energy use had been steadily increasing for decades. The fact that oil and gas prices had been subject to artificial constraints of several sorts was largely overlooked. The price of electricity was thus influenced by low oil and gas fuel costs, although coal, whose price was subject to conventional market pressures, already accounted for 44% of net power generation by 1974.[3]

The wrenching crude-oil price increases of the 70s eroded the credibility of many energy modelers and trend extrapolators. Forecasting in the 1980s has been more cautious as well as thoughtful, and has always been qualified so as to protect the analyst from criticism in case of uncontrollable and unexpected events. Nonetheless, projections of future overall U.S. energy use continue to be modified annually—usually downward—by most forecasters.

There is a widespread feeling, however, that:

- Energy consumption will increase slightly in the future, but energy use per capita will continue to decline (Fig. 1). Conservation related to better efficiencies is anticipated to more than balance anticipated population increases.
- Use of oil, domestic and imported, will continue to fall off to the year 2000. Oil shale will make a small contribution to the total.
- Natural gas use will remain constant until the turn of the century, thanks primarily to increased imports, since domestic production peaked in 1973; a reversal in the downward production trend is not expected.
- Coal is expected to be the switch fuel whose use will steadily increase as domestic gas prices are decontrolled and the world's other industrial nations bid up the price of ever-increasing shorter supplies of light crude oils.
- The role nuclear energy will play is fairly certain in the 2000 time frame since any additions

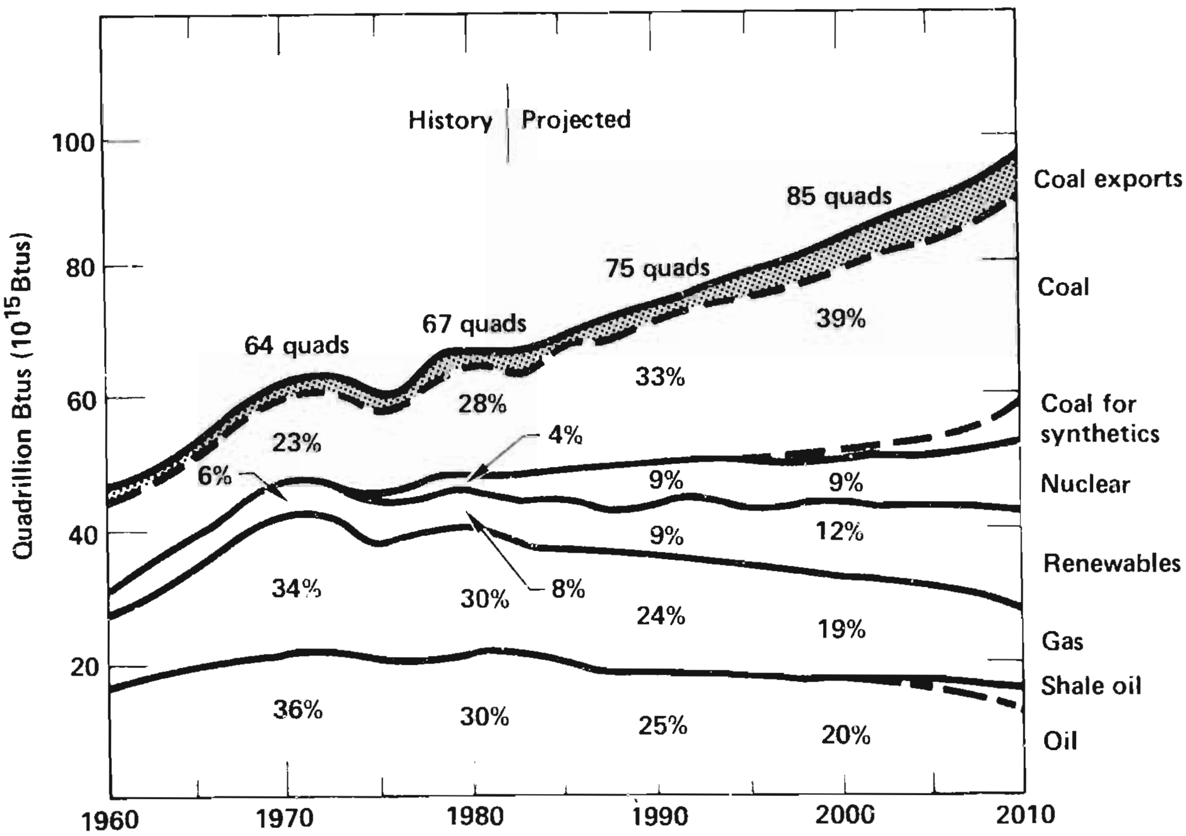

Figure 1. U.S. energy production (scenario B).[4]

to or replacement of existing generating capacity already have permits.

What then are the main uncertainties? To name a few:

- If coal is going to play a progressively larger role in the U.S. energy picture, are the environmental problems associated with conventional use (acid rain and general pollution) surmountable, both technically and, more importantly, economically?
- Can we forecast electricity requirements? Most past predictions have proved to be poor since they forecast steady growth (Fig. 2). The historical rate of 7%/yr (between 1960 and 1970) faltered in 1973 and averaged 2.5 to 3%/yr until 1984, when it increased again.
- Will the critical supply-demand relations in the market place stay in balance worldwide? In other words, with respect to premium (liquid) fuels, will there be "have" and "have-not" nations? This question presupposes any judgment of world stability.
- Will transportation fuels continue to be a point of vulnerability in the U.S.?

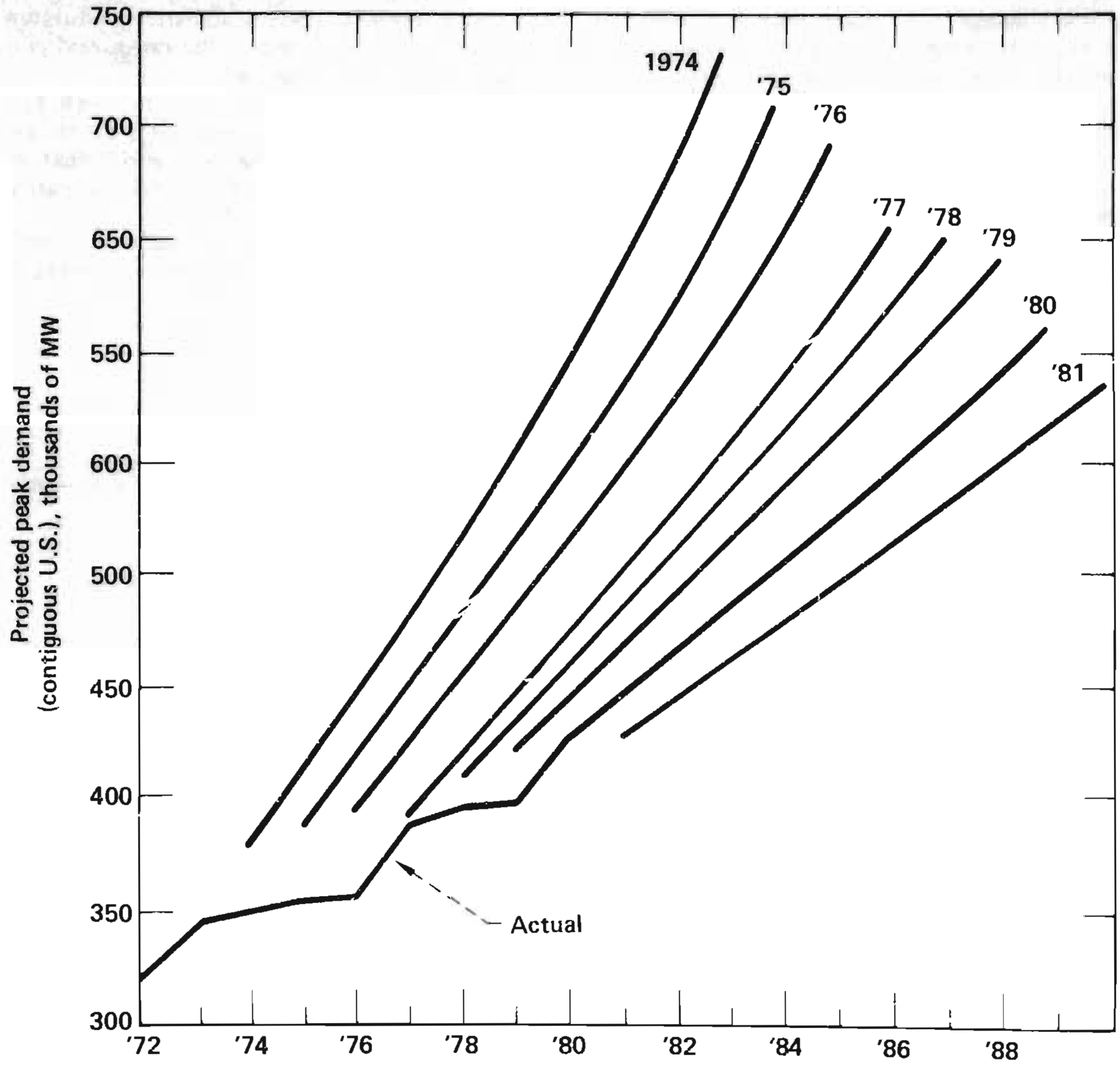

Figure 2. Forecasts of electric demand by the National Electric Reliability Council (1974-1981). 1974 forecast predicated on a 7.6% growth rate, 1981 on 3.4%.[5]

In the years from 1973 to 1982, transportation consumed 50 to 60% of all oil used in the U.S. Although in absolute terms gasoline use changed from a peak of 7.5 million barrels (mb)/day in 1978 to 6.8 mb/day in 1983, and industry predicts[6] a further drop to 4.8 to 5.5 mb/day by 2000, the demand for transportation fuel is anticipated to remain a large fraction of total U.S. oil demand. As much as 39% of the drop between 1978 and 1981 has been attributed to increased use of smaller cars.[7] Over the next 20 years additional factors are expected to impact the transportation sector. The most important of these are demographic changes: an aging population and a drop in growth of the "over 18" group as the "baby boom" of the 1950s ceases to impact car sales. The predicted decline in motor gasoline demand assumes, however, that vehicle miles traveled per year will remain close to current levels, 9000–10,000 miles/year. Even with these downward changes in demand, the need for transportation fuels—conventional as well as unconventional—promises to persist at a high level well into the foreseeable future.

The Coal Resource

All analysts are predicting greater reliance on coal in the U.S. This reflects the size of the U.S. coal resource. Proved recoverable reserves* of 125 billion tonnes of bituminous or higher grade coal, 100 billion tonnes of subbituminous coal, and 32 billion tonnes of lignite are the largest in the world.[8] In total they represent 27% of the world's proved recoverable reserve and comprise 60% of the amount of coal proved to be in place in the U.S. The proved coal reserves represent 87% of remaining fossil fuel reserves in the U.S.[9]

One of the most attractive features of UCG is its potential for utilizing an additional, huge, and otherwise unusable energy resource. The U.S. contains abundant, but largely unassessed, coal deposits in deep, thick beds. Conventional mining of these coal beds is difficult if not impossible: at best, less than 20 ft of the coal in a 50- to 100-ft-deep bed is extractable by underground mining. Underground coal gasification could make use of these otherwise only partly usable or unusable resources; it could probably triple the U.S. reserve.

The suitability of a coal deposit for UCG depends on a number of factors, including market potential, ownership, institutional factors, and environmental/socioeconomic aspects.[10] Only the coal type, depth, thickness, and geology/hydrology are considered here.

For UCG, low-rank coals such as subbituminous and lignite are preferred over bituminous coals because the former shrink upon heating, whereas bituminous coals swell and typically occur in thinner seams. The Soviet, British, and early U.S. experiments in UCG encountered severe problems when attempting to gasify coal seams 2 m thick or less.[11] Heat losses are considerable in such thin seams, leading to low thermal efficiency and poor product-gas quality.

It is estimated that minimum depths of 60 m for a seam 2 m thick and 90–120 m for a seam 6–9 m thick are required to avoid surface subsidence during gasification. The maximum depth is determined by the cost of drilling.

A coal seam overlain by a strong, dry roof rock with a tendency to plastic failure seems desirable to minimize heat losses and escape of gas to the overburden. The coal seam should not be a major aquifer, nor should major aquifers occur above the coal for at least twice the stable cavity height associated with the burn. This is to minimize excessive water influx into the gasifier, whether from the coal itself or from aquifers above it. Collapse of the intervening strata after a gasification cavity has been formed can potentially produce a pathway for any overlying water into the reaction zone.

* The World Energy Conference data quoted here are not specific with respect to depth limits or seam widths. In the U.S. the maximum depth for high rank coals is generally 1000 ft, and 200 ft for lignite. Minimum thicknesses are respectively 28 in. and 5 ft (including subbituminous) ranks.[9]

Underground Coal Gasification Process

The name underground coal gasification describes the process well. Coal is gasified in the underground seam by burning in place. If the underground burn geometry is properly arranged, the combustible gases that are produced escape without burning and are collected to form the product gas. The process is illustrated schematically in Fig. 3. The most useful product gas is formed by injecting oxygen and steam instead of air to burn the coal so that nitrogen is not introduced as a diluent. The steam provides the hydrogen necessary to complete the reactions and also provides a means of lowering the reaction temperature. The main constituents of the product gas are H_2, CO_2, CO, CH_4, and steam. The proportions of these gases vary both with the type of coal and the efficiency of the gasification process, but these major gases are always present. The product gas can either be burned directly to provide process heat or generate electric power, or it can serve as the feedstock for a chemical plant to make a variety of products such as synthetic natural gas, methanol, ammonia, etc.

In its natural state in the seam, coal is usually a material with low permeability. It is formed in layers under great pressure, and only by supplying oxygen at high pressure can sufficient flow be forced through the natural cracks or "cleats" and pores to sustain combustion. Gasification under these conditions is difficult, if not impossible, and certainly uneconomical.

Several processes have been used at various times to increase coal's permeability between the steam and oxygen injection and gas production points to a high enough level for effective gas flows rates. These methods include hydraulic fracture, electro-linking, reverse combustion, and directional drilling. Of these, only the latter two methods have proved practical.

The reverse combustion process involves injecting air into the seam through one well at a high enough pressure to produce a small air flow

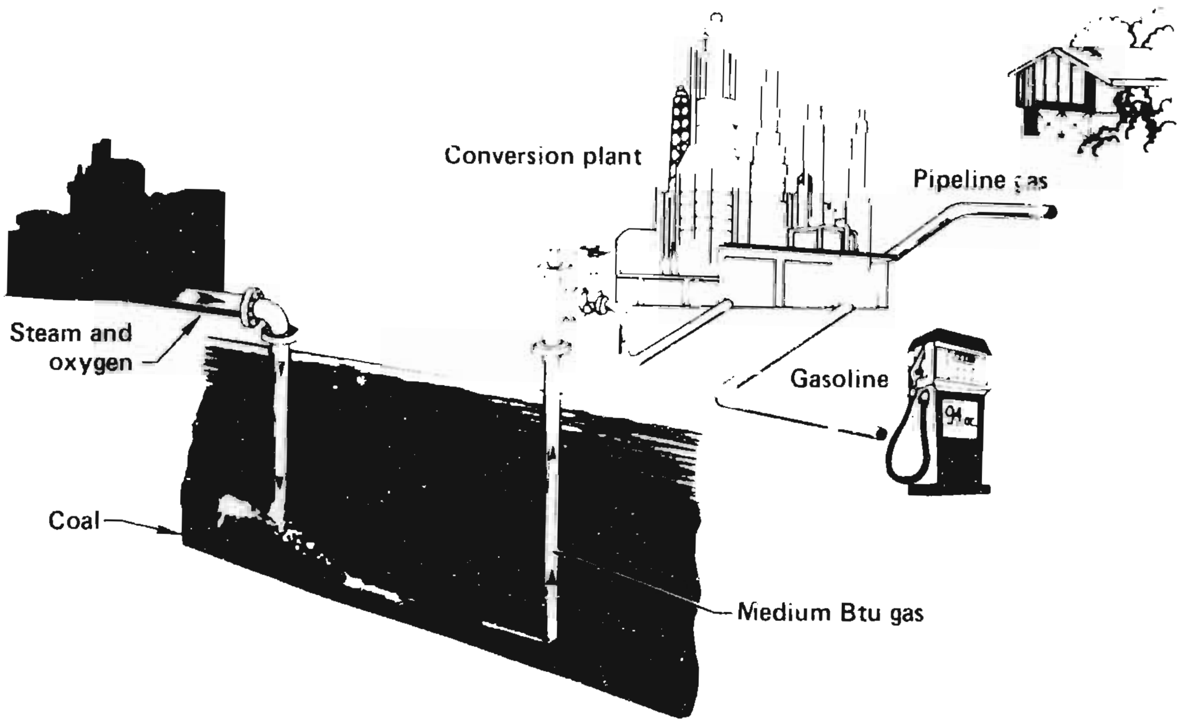

Figure 3. Cartoon showing underground coal gasification and its potential end uses.

through the seam to another well, and igniting the coal at the base of this second well. The burn front moves back against the flow by conduction, following the path of maximum air flow. This process produces channels about a meter in diameter filled with loose coal char and rubble. Reverse combustion has been used to link wells up to 20 m apart and, at medium depths, has always produced a link. However, there are some drawbacks to the method. At substantial depths (more than 300 m), the pressures required are so high that the coal near the injection well can ignite spontaneously, which makes the link impossible to complete. Even at moderate depths, there is no control over the path taken by the link and undesirable gasification geometries may result.

Directional drilling has been used successfully to physically link wells up to several hundred meters apart (Fig. 4). The drill, controlled from the surface, can be made to follow a predetermined path through the coal. Special rotary drilling techniques that use variable stabilizer placement and bit pressure to control the cutting direction have been used as well as down-hole hydraulic mud motors that can be tilted to change hole direction. Several gasification tests have been done using directionally drilled links but not without some difficulty. Although there is no fundamental reason why directional drilling cannot become a reliable and economical linking method, the directional control requirements are at the present state-of-the-art and current costs are high.

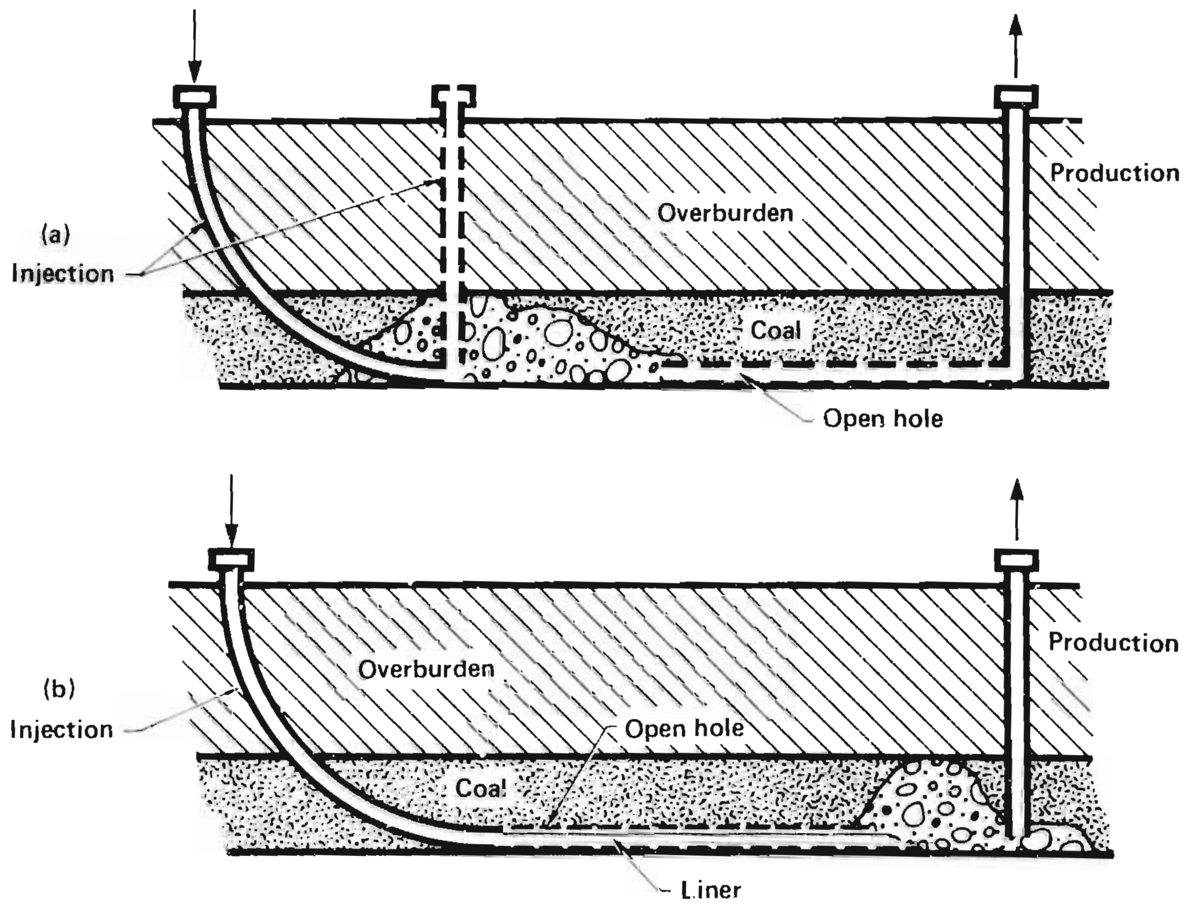

Figure 4. Underground coal gasification using directional drilling: (a) fixed air/oxygen injection point, (b) controlled retracting injection point.

Since directional drilling offers the possibility of greater control of the process geometry and also allows greater flexibility in choice of method, it is the linking method of choice under most circumstances.

After the wells are connected by directional drilling, the coal at the bottom of the injection well is ignited and gasification is started by injecting oxygen and steam into the coal seam. The coal burns around the base of the injection well and the fire slowly moves upward and outward, creating a pear-shaped cavity with the long axis proceeding toward the production well. As the cavity grows, the coal on the walls and roof of the cavity collapses as it is weakened by the heat, forming a rubble pile around the injection point. The product gas composition is best at this stage of the process because the burn zone is small and compact and because the only true heat loss is to the water in the coal that exits as steam. Eventually the cavity reaches the roof of the seam and the falling coal is replaced with falling roof rock. The burn zone then begins to move away from the injection point toward the unburned cavity walls. As the cavity gets larger, the burn zone tends to move to the top of the seam because ash and fallen roof rock impede the flow of oxygen to the lower part of the cavity. Oxygen-bypassing can occur, with the flow going through the inert rubble and with the burning of downstream product gas. The hot gases formed lose heat to the inert rock in the roof and to the water in both the coal and the roof rock. Thus, the heating value of the product gas begins to decline because of the lower efficiency of the process. This continues as the burn cavity gets larger and larger and more and more inert material is available for heat loss. Eventually the burn zone reaches the production well or the heating value drops to an unacceptable value. In either case a transition is then made to the next well pair to continue the process.

The degree of decline in heating value is a function of the water content of the coal, the roof material, and the strata above the roof, all of which are affected by the collapse as the cavity grows. Strong, dry materials are less of a problem than weak, wet rock; low permeability coals with little or no free water are preferred. Also, the thicker the coal seam, the smaller the fractional heat loss to the roof for the same size cavity.

With fixed injection and production points, little can be done to control the heat loss except to shorten the distance between wells to keep the cavities small enough to have acceptable losses. However, well drilling and surface piping can be major expense items, and the process quickly becomes uneconomical if the well spacings are too close. The Controlled Retracting Injection Point, or CRIP,[12] method was developed to minimize the effect of the heat losses and to add another control parameter to the process. The concept requires a drilled hole for linkage, as shown in Fig. 4b. A steel liner, inserted through the casing of the injection well until its tip reaches a position near the intersection point with the production well, carries the injectant, either air or oxygen/steam. Without the use of a liner, the burn cavity grows larger until it eventually intersects the roof of the seam and roof collapse begins. At some point the heat lost to the roof material begins to significantly degrade the gas quality. When this happens, the injection point is retracted in the upstream direction by burning off a section of the injection liner with the igniter. The coal opposite the burned zone ignites and a new cavity starts to grow. Because the high temperature zone is once again entirely within the coal, the heating value of the product gas will rise to its original value. The CRIP concept involves a repetition of this process and thus draws the burn step by step, in a controlled manner, upstream from the original injection point.

It is important to locate the connecting channel between the injection and production wells near the bottom of the seam. Low rank coals such as subbituminous and lignite shrink and fall apart on heating, so the coal immediately above the gasification zone falls to the bottom, creating an underground, packed bed of coal. Thus, the burn consumes the bottom as well as the top of the coal bed, using almost all the coal.

With the CRIP process, the maximum burn width becomes a function of the minimum acceptable product gas heating value for the designated end use. Almost all of the coal along the long injection channel can be used, but to get the highest possible heating value the parallel modules would have to be separated by about one seam width to access all of the coal. This still involves much less drilling and surface piping than a corresponding vertical well array.

If the gas heating value is of no concern, then the only limitation on the ultimate burn width per channel occurs when the level of oxygen transported to the walls drops so low that the heat generated by the reactions per unit wall area is equal to the heat loss. At this point the fire goes out and that oxygen is then available further downstream.

Thus, for burns in extremely wet coal such as Hoe Creek coal, the cavity was long and narrow and eventually burned out the production well.

A commercial UCG operation using CRIP would employ a large number (up to 100) of simultaneously operating injection–production well pairs like the pairs in Figs. 3 and 4. Each well pair would consume about 100 tons of coal per day, producing some 5 million standard cubic feet (scf) per day of medium-heating-value gas (250–300 Btu/scf).

Uncontrolled burns can be prevented by using only those coal seams that lie below the natural water table. In this instance, stopping the injection allows water to invade the reaction zone and extinguish the fire. A certain amount of underground water is desirable for the steam–char reaction; however, most UCG sites contain so much water that control of the influx is a problem.

Although Figs. 3 and 4 show gasification of flat-lying coal beds, similar principles apply to steeply dipping beds, which are difficult to mine by conventional techniques but appear to be accessible by the UCG process.

Status of Underground Coal Gasification Technology

The Soviet Program

The potential advantages of UCG were recognized long ago. The concept was first suggested by Siemens in 1868 and was outlined technically by Mendelev in 1888; Lenin read accounts of British field testing and proposed applying the technology in Russia in 1913.[13] A major field program was initiated in the Soviet Union in 1931, and after World War II there were field programs in several western nations, including the U.S. The Soviets published their early work quite freely during this time, and these reports have been translated and studied in the U.S.[11,13]

By the early 1950s the Soviets had developed a successful UCG system, which was applied in: (1) flat-lying beds in the coal fields at Tula and Schatska, near Moscow, and later at Angren near Tashkent; and (2) steeply dipping beds at Lisichansk in the Donets coal basin, and at Yuzhno–Abinsk in Siberia. The results at Tula, Lisichansk, and Yuzhno–Abinsk were sufficiently encouraging that plans were announced to increase UCG production from 0.7 billion m^3 in 1958 to more than 40 billion m^3/yr. These plans were not implemented, however; production peaked in 1966 at 2 billion m^3/yr and declined to 0.7 billion m^3/yr by 1977. (Production of 0.7 billion m^3 of low-heating-value gas—80–100 Btu/scf—is equivalent to 300,000 tons of coal consumed.) The Soviet production figures are plotted in Fig. 5, showing production of individual stations and estimated total production. No data are available past 1977.[15] Apparently the only stations presently in operation in the USSR are Angren and Yuzhno–Abinsk. The total decline in production may be due to very low heating values, closer wellbore spacings, and/or higher product-gas losses (e.g., at Angren) than had been expected. Such results would produce unfavorable economics in the U.S. The UCG technology in the USSR also faced stiff competition from increasing natural gas production and efficient open-pit coal mining.

It is unfortunate that the Soviets made little use of underground diagnostics and modeling, and apparently ignored several innovations that were suggested in their own literature. Some of these, such as linking by directional drilling, are now being used in the U.S. The U.S. program, sponsored by the Department of Energy (DOE), in contrast to the more mature Soviet program, emphasizes modeling and subsurface instrumentation in an attempt to understand, and hence to achieve, better control of the underground process. Perhaps because of the success of these attempts to understand the process, the U.S. results have been more encouraging.

The U.S. Program

Initial UCG tests were carried out by the U.S. Bureau of Mines in the 1950s near Gorgas, Alabama. The test results were not encouraging and the program was terminated. The U.S. government reviewed its support of UCG field testing in 1973. Since that time, 21 UCG tests have been carried out, 16 of which were funded by the federal government. Test results are summarized in

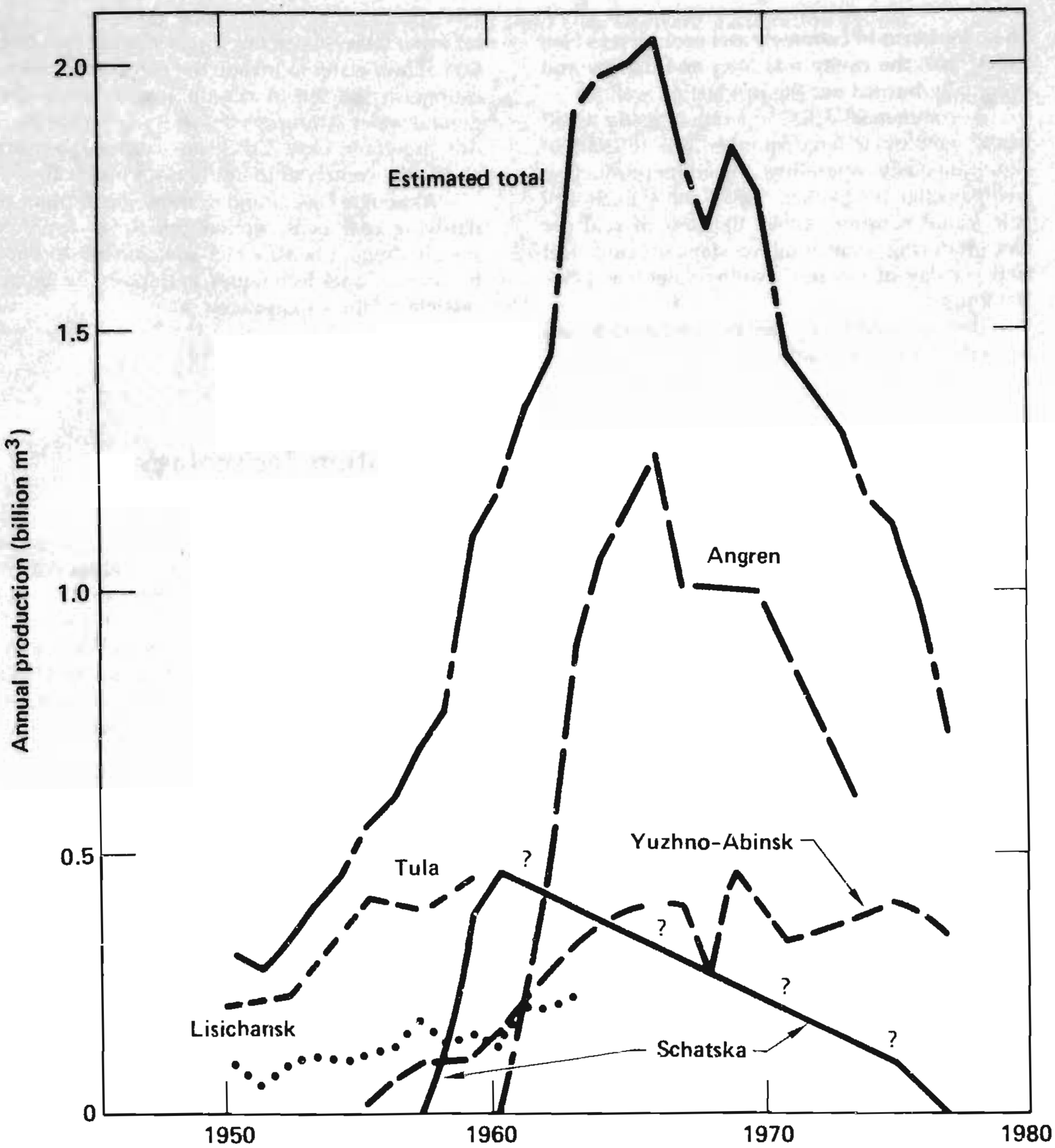

Figure 5. Annual Soviet UCG production, 1950-1977.[14]

Tables 1 and 2. Results from these tests are consistent. Sites with relatively dry, strong overburden and at least moderately thick coal produced the best results to date. Examples include the Hanna, Rawlins, and Centralia tests. Sites with thin coal or wet, weak overburden produce less favorable results, as the Hoe Creek or the Texas tests.

The encouraging technical successes of these tests and of related environmental, theoretical, and laboratory programs have led to increased interest in UCG in the private sector. Basic Resources, Inc., a subsidiary of Texas Utilities, purchased the rights of the extensive Soviet UCG technology in 1975 and, after conducting a number of tests in Texas lignite[16,17] (Table 2), is in the planning and permitting phases of an electrical generating demonstration plant (7-MWe capacity). Gulf Oil[18] (Table 1) concluded two successful tests

Table 1. Summary of U.S. DOE-sponsored UCG field tests (forward gasification phase).

Test	Year	Duration (days)	Coal consumed (tons)	Gas quality (Btu/scf)	Gas quality MJ/m[3]	Cold gas[a] thermal efficiency (%)
Laramie Energy Technology Center – Hanna, WY, site						
I	1973-1974	168	2720	126	4.7	77
II-1A	1975	37	962	137	5.1	85
II-1B	1975	38	780	143	5.3	86
II-II	1976	26	2201	168	6.3	92
II-III	1976	39	3414	132	4.9	77
III	1977	38	2663	138	5.1	77
IV-A(a)	1978	7	294	109	4.1	78
IV-A(b)	1978	48	3184	102	3.8	73
IV-B(a)	1979	7	468	149	5.5	95
IV-B(b)	1979	16	663	122	4.5	83
Lawrence Livermore National Laboratory – Hoe Creek, WY, site						
I	1976	11	123	101	3.8	82
II(air)	1977	13	286	108	4.0	80
II(O_2)	1977	2	47	263	9.8	88
II(air)	1977	43	1155	104	3.9	74
III(air)	1979	7	256	113	4.2	81
III(O_2)	1979	47	3251	212	7.9	73
Centralia, WA, site						
LBK(O_2)	1981-1982	20	140	262-284	9.8-10.6	80
(air)				140	5.2	
CRIP(O_2)	1983	28	1500	248	9.2	74
Morgantown Energy Technology Center – Pricetown, WV, site						
I	1979	17	234	149	5.5	97
Gulf Research and Development Co. – Rawlins, WY, site						
I(air)	1979	30	1207	151	5.6	91
I(O_2)	1979	5	125	250	9.3	74
II(O_2)	1981	66	8550	330	12.3	88

[a] Ratio of heating value of gas to heating value of the coal used in deriving the gas.

Table 2. Privately sponsored UCG field tests in the U.S.

Test	Year	Duration (days)	Gas quality (Btu/scf)	Gas quality MJ/m[3]	Coal gasified (tons)	Cold gas thermal efficiency (%)
Basic Resources, Inc.						
Fairfield, TX	1976	26	126	4.7	–	–
Tennessee Colony, TX:						
Air injection	1978-1979	197	81	3.0	4000-5000	–
Oxygen injection		10	230	8.6	212	–
ARCO Coal Co.						
Reno Junction, WY	1978	60	200	7.4	3600	94
Texas A&M University (with industrial consortium)						
College Station, TX	1977	1	35-114	1.3-4.2	2	–
Bastrop County, TX	1979	2	85	3.2	–	–
Bastrop County, TX	1980	<1	35-150	1.3-5.6	–	–

in a steeply dipping coal bed near Rawlins, Wyoming, and is presently considering plans for commercialization. World Energy, Inc., has developed plans for a 25-MWe generating facility near Rawlins, Wyoming. Application has been made to the U.S. Synthetic Fuels Corporation.

The Partial Seam CRIP Test

The Lawrence Livermore National Laboratory (LLNL), in cooperation with two U.S. utilities, the Washington Water Power Co. and Pacific Power & Light, has completed a two-phase field test using the CRIP method.[19,20] Called the Partial Seam CRIP test, it was the first full-scale test of the CRIP gasification method. It was conducted in the upper half of a nominal 40-ft-thick subbituminous coal seam near Centralia, Washington, in October, 1983. The basic design of the test is illustrated in Fig. 6. The injection well was drilled following the seam some 900 ft from the exposed coal face, where it was intersected by a vertical production well drilled from the surface. A second, slant-production well was drilled to cross over the injection well near the vertical well. This well was designed to test the effect of producing hot gas through a long open hole in coal as a possible economic alternative to vertical production wells. Oxygen and steam were the major injectants; air was used briefly during occasional outages.

A vertical production well was used for the largest part of the first burn; a switch was made to the slant production well for the rest of the experiment. Shortly after the production well change, the movable ignitor was used to burn off a section of the injection tubing in order to move the location of the main site of coal gasification. The maneuver was successful and a new burn cavity was started. The gas composition improved as predicted. The slant production well also proved successful and offers advantages especially for gasification of deep seams.

Due to time and budget restrictions, the first burn was ended before there was a substantial decline in the heating value of the gas. However, there was still a significant improvement in gas composition during the second burn after the CRIP maneuver (Fig. 7). The experiment was ended on schedule after 30 days. The heating value of the product gas is shown in Fig. 7. Interaction with the roof and subsequent heat loss can be seen during days 6 through 12 for the first cavity and during days 22 through 29 for the second. The CRIP maneuver occurred on day 14.

Approximately 670 tons of coal were gasified from the first cavity and 1330 tons from the second, for a total of 2000 tons. On-line thermal instrumentation was used to follow the progress of the burn. Major results for some typical periods are given in Table 3.

Major conclusions from the CRIP underground coal gasification test were:

1. The controlled retraction injection point method was successfully tested and resulted in improved efficiency of the UCG process.
2. Use of a slant production well proved advantageous for UCG.
3. The small-scale large-block tests conducted earlier at the same site produced results comparable to the much larger-scale partial seam test. Thus, large block experiments have predictive capability for UCG.
4. The Centralia site is favorable for underground coal gasification.

Key Features of the U.S. Program

The keys to the success of the U.S. program include careful site selection, steam-oxygen gasification, extensive instrumentation, and laboratory preburn modeling.

Because UCG is site-specific, the economics of a project clearly depend on the characteristics of the location. Careful selection and characterization are critical to a successful project.

Steam-oxygen gasification has been employed in seven of the U.S. field tests, primarily

Table 3. Partial seam CRIP test summary, giving average values during steam-oxygen gasification (October 16–November 14, 1983).

Dry product gas heating value	248 Btu/scf 9.2 MJ/m^3
Coal gasified	2000 tons
Dry gas composition (vol%)	
H_2	36.1
CH_4	5.4
CO	18.5
CO_2	36.1
C_nH_m	1.0
H_2S	1.6
N_2 & Ar	1.3
Product gas mol ratio	
H_2O/dry gas	1.3
Thermal efficiency %	74

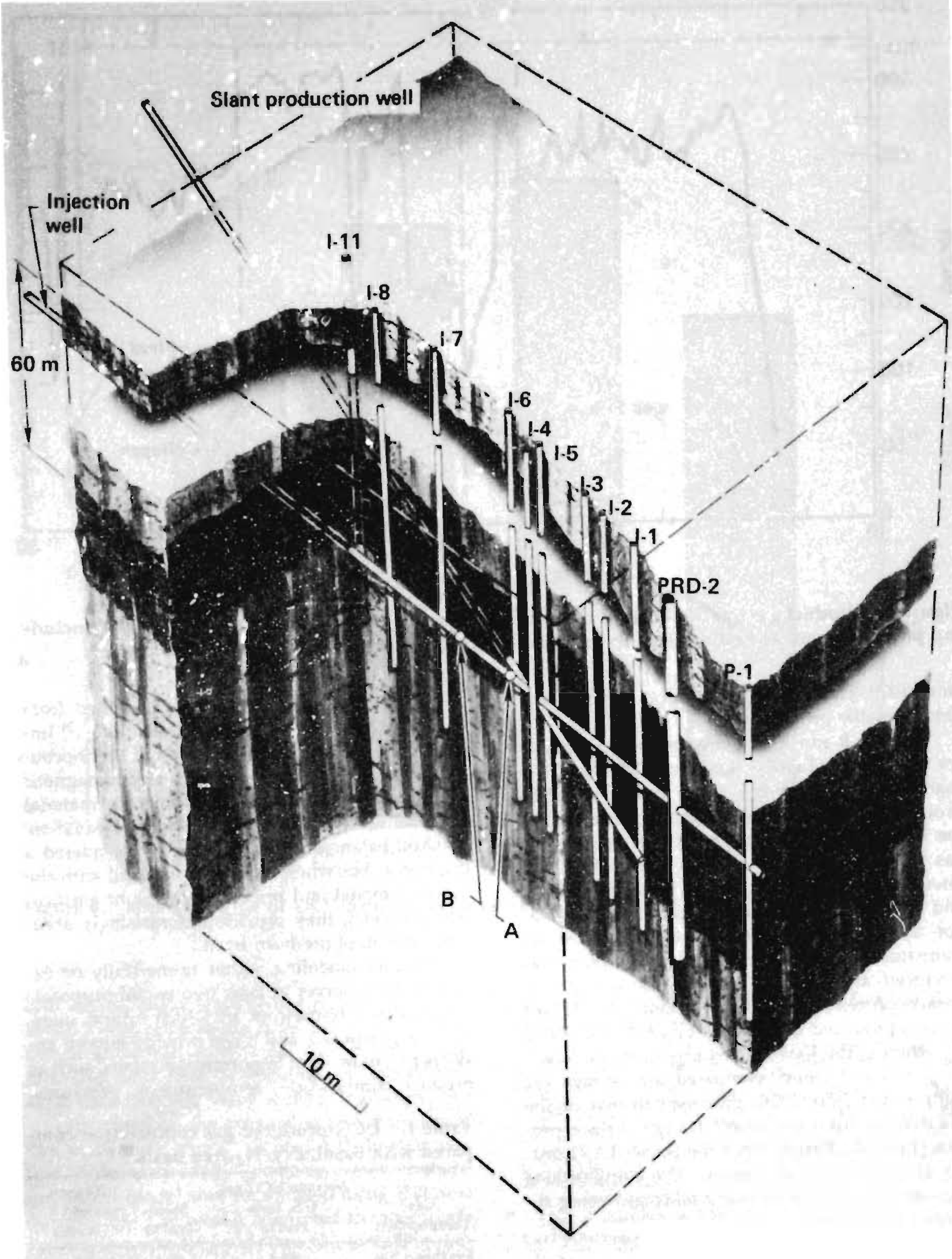

Figure 6. Layout of instrumentation, production, and injection wells for CRIP test at the WIDCO mine near Centralia, Washington. The burn was started at the point A and the gases were drawn off through vertical production well PRD-2 and later through the slant production well. About midway through the gasification the injection point was moved to point B, where a new burn was started.

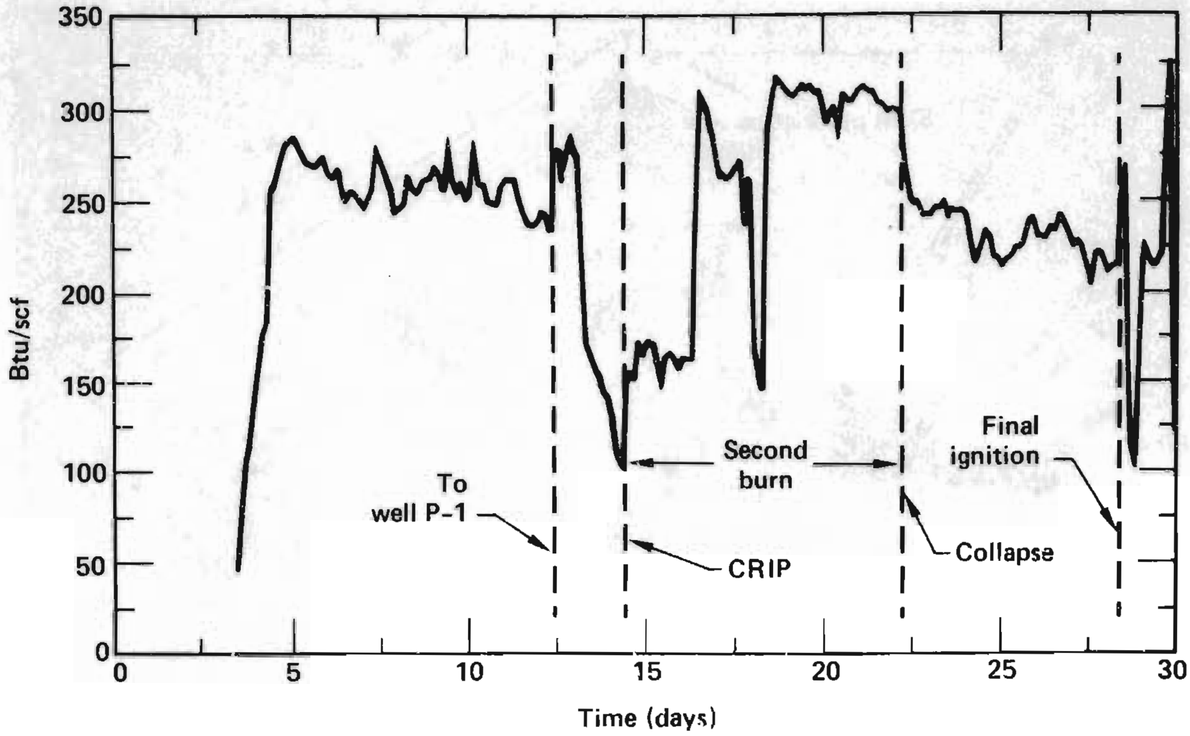

Figure 7. Product gas quality (heat of combustion) as a function of time for the entire test, including power outages and shutdowns for mechanical maintenance (plugged production line).

since 1979. This technique produces a more valuable, versatile product.

Figures 8 and 9 compare product gas quality for Rawlins II (Table 1) and the CRIP test with that from two leading surface coal gasification processes, the Lurgi[21] and Texaco[22] processes. As the figures show, the heat content of the product gas is similar in all four tests. The highest and lowest values in Fig. 8 are for UCG tests (CRIP and Rawlins II). The chemistry in these tests was not similar (Fig. 9), yet the heating values are comparable. The highest methane content was produced at Rawlins II, and the lowest in the Texaco process. On the other hand, the Texaco process produced the greatest amount of CO and H_2, whereas the Rawlins test produced the least.

Gash and Hunt[23] compared the average gas composition from UCG processes to that of the gas derived from the Sasol* (Lurgi) surface process (Table 4). Results from the Soviet UCG testing at Angren are also given. The compositions are similar, with the lowest quality gas being recorded at Angren.

* South African Synthetic Oil, Ltd.

The U.S. UCG program has benefited from the extensive use of *in-situ* instrumentation.[24] Important diagnostics include the use of thermocouples, downhole high-frequency electromagnetic measurements, borehole extensometers, material balances, and postburn coring and/or excavation. Material balances are not generally considered a diagnostic, but when they are combined with the use of a model and prior knowledge of gasification geometry, they provide a surprisingly accurate location of the burn front.

Process modeling, either numerically or experimentally, serves at least two useful purposes: it provides a framework in which critical questions can be posed, and it can provide interim answers to a number of important questions, such as product composition, temperatures, pressures,

Table 4. UCG-produced gas composition compared with Sasol, dry, N_2-free basis.[23]

Gas composition	Average UCG gas, U.S. tests (vol%)	Sasol (vol%)	Angren, Soviet UCG (vol%)
Synthesis gas (H_2 + CO)	60.4	60.8	59.5
CH_4	6.7	9.7	2.4
CO_2	32.9	29.3	38.1

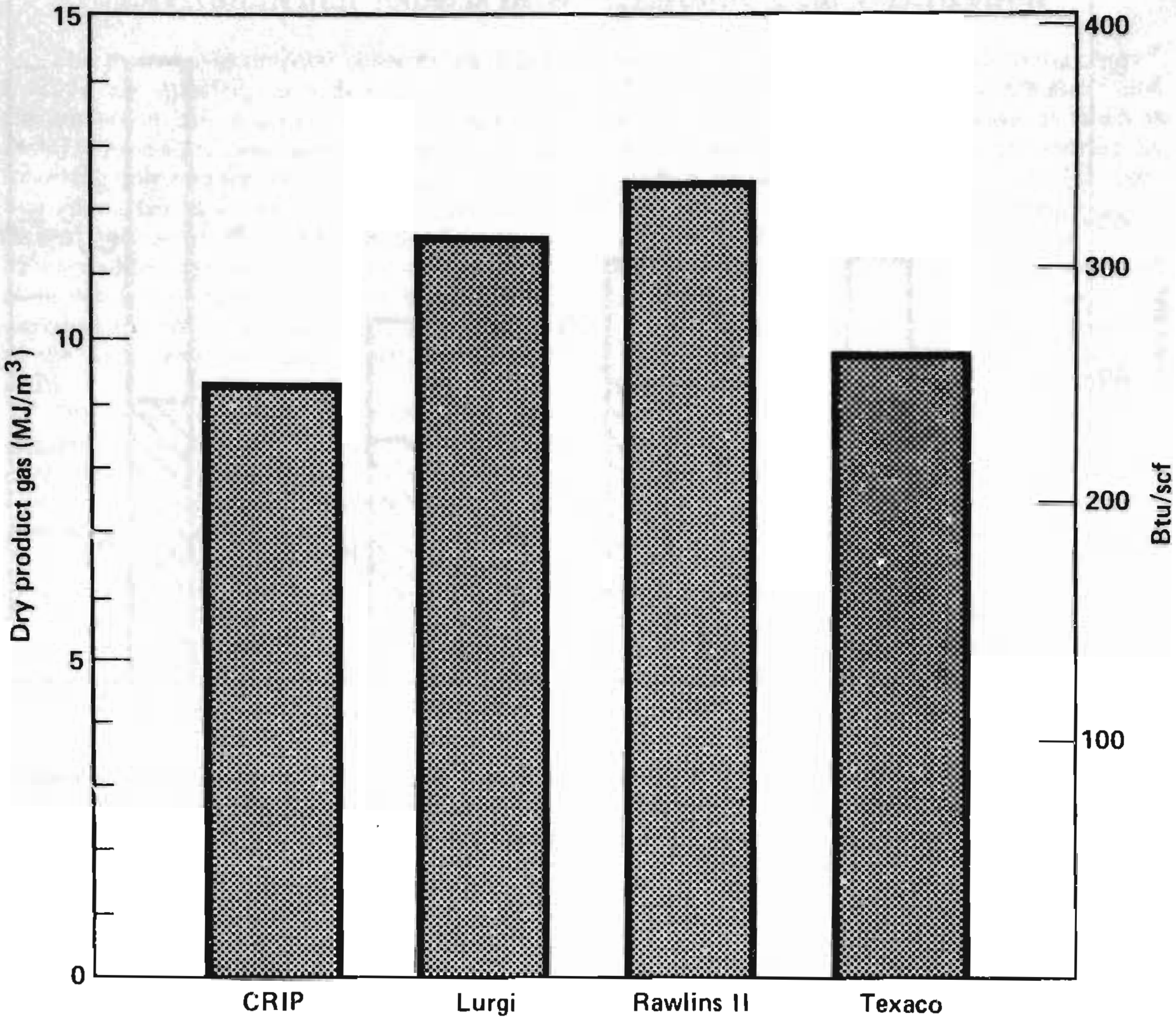

Figure 8. Heating value of UCG product as compared with products of surface gasification.

coal consumption and geometry, and roof collapse. These calculations have value only if they can be compared with actual field results. Thus, modeling and field diagnostics are interdependent; each has little value without the other.

For example, the excavation and mapping of five small-scale burns[25] yielded a fairly clear picture of the early cavity geometry. A new multidimensional model was constructed using this new information. The model attempted to incorporate the major controlling phenomena—including motion of solids—into a complete model process mode.[26] An early version of the model matched the details of the field test results, as shown in Table 5 and Fig. 10.

Table 5. Comparison of field gasification test (LBK-1) with modeling results.

Dry product gas (%)	LBK-1 test	Model
H_2	42	44
CH_4	3.5	2.6
CO	25	22
CO_2	28	30
Ratios to injected O_2		
Produced dry gas (mol/mol)	2.2	2.1
Heat of combustion (kJ/mol)	890	820
Cavity volumes (m^3)		
Void	8	7
Char rubble	19	21
Ash rubble	6	6
Total	33	33

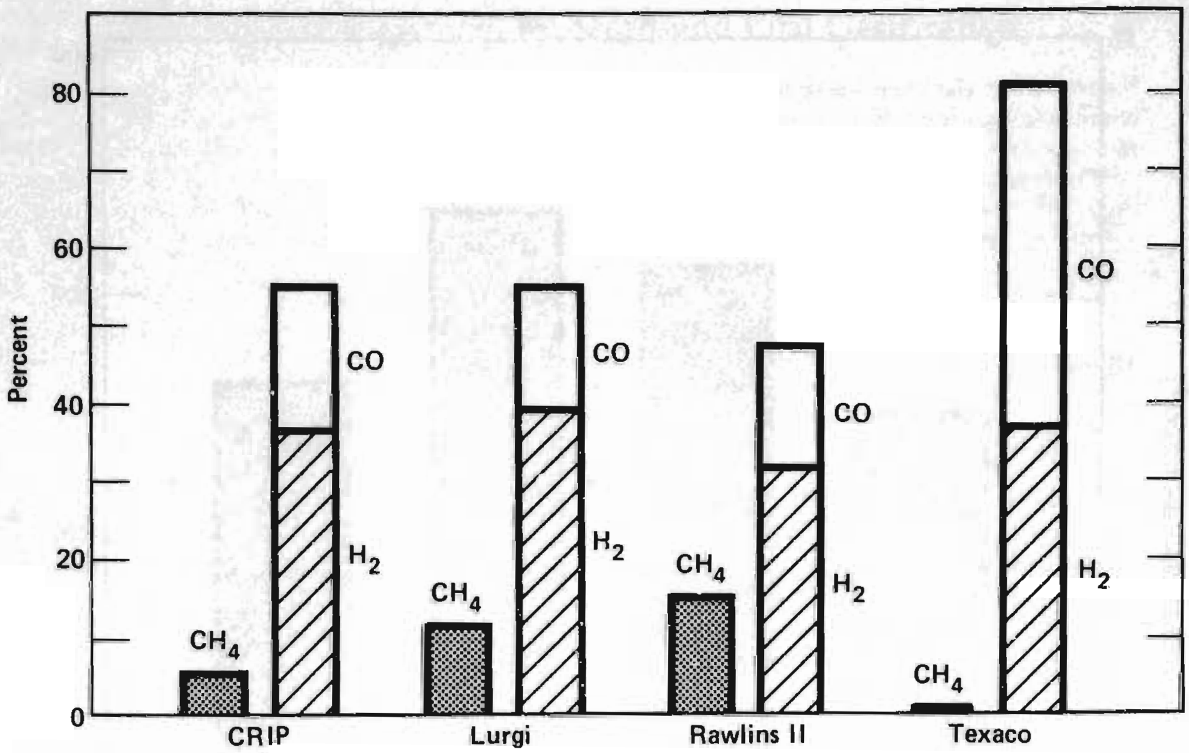

Figure 9. Variation in the proportions of the three principal combustible components in the product gas. Gas composition is strongly dependent on reaction temperature. Heating value is strongly influenced by the amount of hydrocarbons (e.g., methane) present.

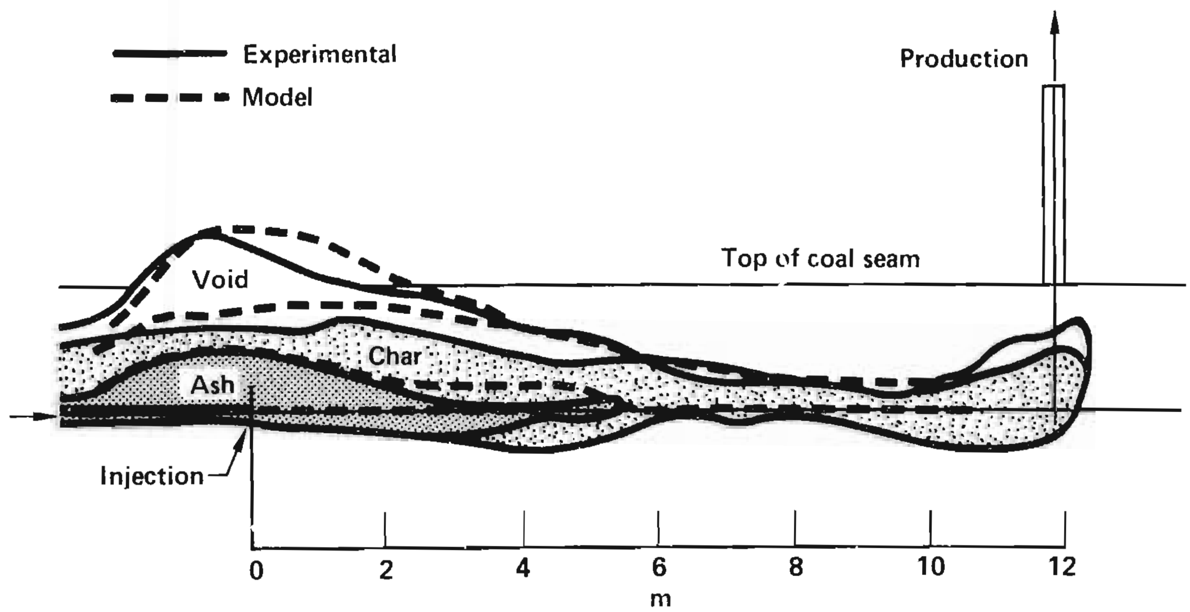

Figure 10. Comparison of actual LBK-1 cavity configuration with calculated model (elevation view).

Environmental Aspects of Underground Coal Gasification

The main environmental concerns for UCG include air quality, subsidence, and water contamination. Air quality generally is not believed to pose a problem. Subsidence has occurred following only one test, Hoe Creek No. 3,[27] which was conducted at a shallow depth of 160 ft. In general, the cavities formed by UCG collapse to a distance of less than two coal seam thicknesses.[28] However, the semicommercial Soviet UCG field experienced considerable subsidence[7] as a result of the large scale and close spacing of process wells.

There are two schools of thought in the U.S. concerning subsidence. One group advocates efficient resource extraction with or without concommitant subsidence and surface restoration. Another group suggests spacing rows of process wells so that surface collapse is minimized or even eliminated. Such a scheme, if it is practical, would limit eventual resource recovery. In either case, surface restoration should be at least as successful as in present comparable mining operations. Predictive models and some experience are presently available and should become validated with time.[29]

The UCG process introduces both inorganic and organic contaminants into the aquifer within the coal and possibly into aquifers above the coal.[30] In general, inorganics affect only the cavity water and are a relatively minor problem. They apparently derive in large part from residual coal ash and from overburden materials in the cavity.[30] Organics generated from pyrolysis are also found in the cavity water and, in one case, as much as 400 ft from the burn, probably transported by product gas escaping from the burn. The concentration of most organics and inorganics appears to decrease with time, apparently as a result of sorption, bacterial action, dilution, and dispersion.

So far, contamination of aquifers above the coal appears to be minor, although aquifers have become interconnected at Hanna III, Hoe Creek II and III (Table 1), and ARCO's Rocky Hill I test (Table 2).

Water contamination appears to be the most important environmental concern for UCG. Key problems include our current inability to predict contamination and the possible need for aquifer restoration. Restoration of the contaminated water within the cavity appears to be technically feasible but would be very difficult for water outside the burn zone.

The present evidence is ambiguous as to how long lived or far ranging the water pollution from an underground gasifier will be. More controlled tests are needed from several groups using different techniques to ensure reliability. The assurance of minimal environmental risk must be given before the technology can proceed to commercialization.

End Uses for Underground Coal Gasification Feedstock Gas

Methanol Vehicle Fuel

Methanol appears to be one of the most attractive products of UCG. The decline in the projected demand for vehicular fuels notwithstanding, methanol shows promise of becoming a substitute for gasoline and diesel in the 21st century. Methanol is currently finding increased use as an octane booster, in conjunction with cosolvents such as methyl tertiary butyl ether. However, this market is limited by the availability of cosolvents. Development of a "neat" (100%) methanol fuel and modified vehicles to use it face many obstacles, but the use of methanol can guarantee a healthy domestic transportation sector that is critical to the economy. In addition, the development of a methanol-based transportation industry has national energy security implications.

In keeping with methanol's lower price per unit volume, it contains approximately half as much energy* as gasoline. Therefore, the distance traveled per standard tank is appropriately lowered, which accounts for the over-sized fuel tanks in methanol-fueled cars. In addition, the use of methanol necessitates other engine modifications. Conversion costs including modified fuel tanks are currently estimated to be about $1000 per vehicle.[31]

* 56540 Btu/gal vs 115400 Btu/gal.

Production-built methanol cars cost about \$2000 more than their gasoline-fueled counterparts, based on experience in California.[32] The advantages of methanol use include potentially superior engine performance,[33] meaning higher efficiencies than obtained with conventional gasoline engines (Table 6) and lowered regulated emissions (NO_x hydrocarbons and CO). Aldehydes—which are suspected carcinogens—from methanol combustion are by-products that have yet to be assessed. The Environmental Protection Agency has not yet set emission standards for both aldehydes and uncombusted methanol. Thus, specific engine modifications or costs of abatement equipment, if needed, are unknown. Other environmental and practical concerns, e.g., handling, storage, or production, have not been examined, but difficulties do not appear insurmountable.

A greater uncertainty in the development of a methanol-based transportation sector is the production and availability of the fuel and availability of vehicles designed to use it. These two issues are interlinked and basically economic in nature. Collectively they are called[33,34] the "chicken or egg problem. Without available vehicles, no potential producer is likely to invest in a methanol plant and vice versa.

In an effort to promote the use of alternate fuels in California, the state has provided incentives for vehicle conversions. For example, it has allowed tax credits and levied fuel taxes on methanol, based on a Btu basis equivalent to gasoline rather than on a gallon basis. In addition, the state government plans to support its own 1000-car methanol fleet complete with the necessary refueling and maintenance infrastructure. As of mid-1984, the fleet consists of 540 Ford Escorts using 90% methanol and 10% unleaded gas. Other agencies in other states, e.g., the city of Baltimore and the Kentucky Energy Cabinet,[35] have made smaller but similar plans.

In the private sector, the Bank of America operates and tests a fleet of 266 "neat" methanol-fueled Ford and General Motors cars. After 7 million miles of fleet driving using methanol, the drivability "has been far superior to that of gasoline vehicles," according to the Bank of America drivers. The overall efficiency of General Motors' methanol-fueled cars has increased 30% over that using gasoline. Maintenance is essentially the same as for a gasoline vehicle. The Bank of America pays about 80¢/gal for methanol. After transportation, adding lubricants, corrosion inhibitors, and vapor pressure additives, the price is closer to \$1.00/gal (without state or federal tax).

Methanol derived from UCG is estimated to cost 50¢/gal, and adding 40¢/gal to cover additive costs and taxes (20¢/gal), one estimates a delivered fuel cost of 90¢/gal, which would make UCG-produced methanol competitive in today's transportation market.

In 1984 the House Energy and Commerce Committee passed H.R. 5048, which will set up a commission to consider the long term prospects for methanol, and will require DOE to acquire at least 1000 methanol-powered automobiles for federal use. Locations dispensing methanol to the federal fleet will also be allowed to sell the fuel to the public.[36]

However, the U.S. General Accounting Office believes that state and federal endorsements of

Table 6. Theoretical comparison of fuel costs and uses of methanol and gasoline vehicles.[33]

Parameter	Gasoline vehicle	Bank of America fleet, 1983[9] (GM-Citation)	Methanol vehicle with 85% technical efficiency improvement[a]
Fuel cost (incl. tax[b]) (\$/gal)	1.38	~1.20	0.85
Miles per gallon of fuel	25.0	14.5	20.8
Miles per million Btu[c]	216.6	238	367.8
Btu/mile	5950	4210	2720
Cost per 22-gal tank of fuel (\$)	30.36	26.40	18.70
Total annual fuel cost based on 10K miles/yr	552	828	408

[a] Assume 1.2 gal of methanol provides service equivalent to 1 gal of gasoline (based on Bank of America's reported efficiency improvements).

[b] Assume \$0.20/gal in state and federal tax on both gasoline and methanol (based on average tax on gasoline, 1983). Such volumetric taxes discriminate against methanol because of its lower energy content per gallon compared to gasoline.

[c] Based on 115,400 Btu/gal for gasoline and 61,000 Btu/gal methanol 88% fuel used by Bank of America.[31]

methanol by themselves are unlikely to provide a sufficient market to promote general availability of fuel or vehicles in the U.S.[33] Thus, the economic pressures anticipated with the declining availability of conventional fuels combined with the higher efficiencies of methanol-fueled cars may prove to be the driving forces in the next decades toward the development of alternate automotive fuels.

Methanol in Power Production

Among the many suggested uses for methanol, electrical generation is second to use as a vehicular fuel. Methanol's benign environmental impact is a clear advantage; however, its current cost for stationary energy use ($10/million Btu) is almost twice that of natural gas and fuel oil ($5/million Btu)[37] and it is, therefore, not cost competitive. These comparisons are based on using natural gas as a fuel and feedstock to produce methanol. Construction of methanol plants at sites of flared or otherwise unusable natural gas, e.g., at Punta Arenas, Chile, by Signal Oil Co. of California,[38] promises to lower the cost. However, except in remote locations, methanol produced from natural gas may not be the most cost effective fuel for power generation in the near term. Methanol from coal, in the long term, however, may prove to be cost competitive for power production or in special circumstances, for example, where pollution is a critical concern.

Other Uses

Cost estimates for UCG-derived gas are available for power, SNG, methanol, gasoline, and medium heating value gas. However, other products can be and are being made from coal gasification. In many parts of the world, including the U.S., ammonia is synthesized using coal as a feedstock. Recently, Tennessee Eastern Corp. constructed a currently operating chemical-from-coal complex near Kingsport, Tennessee.[39] The plant produces methanol and acetic anhydride, derived from low quality coal using the Texaco partial oxidation process. Therefore, production of chemicals from UCG is definitely possible, depending on markets and the cost of other feedstocks.

Cost Estimates for Underground Coal Gasification Products

Cost estimates (in 1982 dollars) for some products made using UCG as a feedstock include[40,41]:

• Medium heating value gas—250 - 300 Btu/MCF	$4.35/10^6 Btu
• Pipeline quality synthetic gas	$5.19/10^6 Btu
• Methanol	$0.52/gal or $9.19/10^6 Btu
• Gasoline	$1.39/gal or $10.20/10^6 Btu

Cost estimates for medium heating value gas, methanol, and gasoline assume a 30% equity and a 20% discounted cash flow profit.[40] The estimate for pipeline quality gas assumes a 35% equity and a levelized cost based on historical real returns as capital by the natural gas industry.[41] It also includes $0.45/10^6-Btu process development allowance. These estimates include the producer's profit but not transportation, excise taxes, or retail profit.

The estimates for medium heating value gas and methanol derived from UCG compare favorably with the costs of the same products from existing sources. The pipeline-quality gas estimate exceeds the present average wellhead price of natural gas in the U.S., but it is projected to be competitive with natural gas in the 1990–2009 time frame. The Gas Research Institute estimates that UCG-derived substitute natural gas at $5.19/10^6 Btu compares very favorably with equivalent estimates for production using the Lurgi ($5.96/10^6 Btu) or Westinghouse ($5.74/10^6 Btu) processes.[41]

The estimated gasoline price using UCG feedstock also exceeds the present market price of $1.18/gal without tax, or $10.20/10^6 Btu. However, the DOE's mid-range projection[42] shows crude oil at $57/bbl by 2000 (in 1982 dollars). Gasoline prices would then exceed the UCG-estimated price.

The cost estimate for UCG-derived electricity is about the same as that for a conventional coal-fired plant (5.0¢/kw·h)[43] Cost estimates for UCG-derived chemical products have not been published. Cost estimates for ammonia using the Texaco partial oxidation process have recently been quoted as $259 per tonne for a coal plant.[44]

Program Plan

A number of technical uncertainties impede the immediate commercialization of UCG, including criteria for site selection and the effects and predictability of large scale burns, especially on water quality. Although considerable effort is currently being expended on determining water quality effects and on the development of a predictive capability, and some data are available on site acceptability, to date only one large scale burn has been carried out in the U.S.: Tennessee Colony, a multiple well test, was executed by Basic Resources, Inc., in 1977–1978. Both small and large scale tests are needed to evaluate burn interaction, process control, multiple well operation, overall system reliability, criteria for site selection, subsidence, and water quality effects.

Figure 11 outlines a program plan to commercialize UCG in the U.S. The R&D program would last for seven years and cost about $200 million, some of which would be cost-shared with industry. The program includes both laboratory and field components.

Laboratory Experimental and Modeling Program

The goal of the laboratory experimental and modeling program is to develop enough understanding of the UCG process to extrapolate field data from one site to another. Complete understanding is not a practical goal for UCG. Desirable laboratory experiments vary from simple chemical and mechanical analyses and measurements of heat of combustion to large laboratory experiments in coal-like media 5 ft × 10 ft × 20 ft in

Projects and cost by fiscal year (million dollars)

Year	1	2	3	4	5	6	7
Environmental	3	3	3	3	3	3	3
Modeling	2	2	2	2	2	2	2
Lab experimental	2	2	2	2	2	2	2
Economics and system studies	1	1	1	1	1	1	1
Subbituminous (flat)	1 Site char.	6 Simple test	8 Test 2	10 Test 3	10 Pilot scale	15 test	
Steeply dipping	1 Site char.	10 Test 1	10 Pilot scale	15 test			
Bituminous	1 Site char.	3 Block expt.	6 Simple test	8 Test 2	10 Test 3	10 Pilot scale	15 test
Total costs, M$	11	27	32	41	28	33	23

Figure 11. Recommended underground coal gasification R&D schedule and funding.

dimension. The objective of the larger scale lab experiments is to enlarge the body of information concerning UCG chemistry and cavity development.

The modeling program is aimed toward the development of an adequate predictive capability for UCG. There are two general types of models: those incorporating detailed physics focused on specific aspects of UCG, and those containing general composite physics dealing with the overall UCG process. The large laboratory experiment and large block tests are particularly important to models of the second type, because the calculation of cavity shape can be directly compared with experiments.

Environmental Program

The goal of the environmental program is to obtain information concerning environmental hazards and their mitigation. Modeling, laboratory experiments, and field measurements will all be required. Experiments that attempt to understand and predict subsidence and water quality have been on-going for 12 years, yet much remains to be done. A predictive capability is nearly perfected for subsurface ground motion but is lacking for water quality. We have found that the environmental implications of UCG depend on the specific characteristics of the site and the details of the UCG process.

Economics, System Studies, Instrumentation, and Materials Research

A thorough program evaluation is necessary to provide a more comprehensive and detailed program plan than that presented here. Following this effort, cost estimates and system studies in support of commercialization plans will be developed to assist in R&D planning.

Included in the general heading of instrumentation research is the development of more durable thermocouples and tools to better delineate burn cavities and monitor rock response. A better definition of the instrumentation requirements of a commercial scale project is also needed.

Materials research to date has been *ad hoc*. A self-consistent materials program will save time and funds in the field program. Most of the materials testing can be done *in-situ* during the field tests, with subsequent characterization in the laboratory.

Field Program

The field program centers on the gasification of flat-lying as well as steeply dipping subbituminous and bituminous coal beds. The required field projects include site selection and characterization, simple gasification tests, more complex and longer running tests, and finally large scale, or pilot tests. Steam–oxygen gasification would probably be employed.

Goals for a project involving flat, subbituminous coal beds include site selection and characterization in the first year of the program, followed by a simple burn tests during the second year. The first test would consume about 2000–3000 tons of coal in a single module over a 30-day period.

Tests two and three would be more sophisticated single- or double-module tests over a longer duration, consuming more coal, and providing additional information on cavity growth chemistry and burn reliability. About 100 tons of coal would be consumed daily for periods of up to 100 days.

A pilot scale test during the fifth and sixth program years would be a multimodule, large-scale test to provide scaled-up data at the level of 300 tons of coal per day for periods of several months. Initial commercial development could follow these tests.

A project in steeply dipping subbituminous coal beds would follow a similar path as the program proposed for flat beds, except that fewer tests would be required. Underground coal gasification in steeply dipping beds is believed to be a more efficient process than in flat beds because of the added, beneficial effect of gravity in cavity development. We already have some experience in this type of situation. Site selection and characterization would be followed by a single sophisticated test using one or two modules at 100 tons per day for up to 100 days. A pilot scale test, similar in size to the flat subbituminous project, would follow. Again, commercial development could begin upon completion of the pilot scale test.

A proposed project sequence for UCG of bituminous coal is, as in previous types of coal, site selection and characterization during the first year. Bituminous coal poses unique problems. The coal swells upon heating and is generally found in thin beds. Both features are undesirable for UCG. Because of the uncertainties in cavity growth in bituminous coal, a sequence of large block experiments is proposed for the second year. Early cavity growth and product yield can be studied in 5 or 6 coal outcrop tests in which 20-40 tons of coal are consumed per test. Subsequently, the burns can be excavated and cavity growth examined in detail.

After the block experiments, the field experimental projects proposed are similar to those in the flat subbituminous program: a simple field test of 2000-3000 tons, followed by two more sophisticated single- or double-module tests, and finally a pilot scale test.

Commercialization

The program described in Fig. 11 should produce sufficient information to assess the technical, environmental, and economic feasibility of UCG. If the program is successful, commercial UCG operations could begin in 9 to 10 years.

The program is designed to commercialize the technology in three types of coal in a reasonable length of time, while minimizing total program costs. The projects can be stretched out in time, as is now being done, decreasing the yearly budget but correspondingly increasing the total program cost. An accelerated program could decrease the time required to reach commercialization with the attendant increased risk and program costs.

Many commercialization scenarios have been postulated over the past several years. For example, a conservative approach might call for pilot scale tests using 300 tons of coal per day. Then the first commercial plant could consume 1000 tons/day, or a modest scale-up factor of 3, producing either a medium heating value gas (50 million scfd at 270 Btu/scf) or electricity (about 50-60 MWe). Such a small-scale commercial plant could be built in three to four years and be profitable.

After gaining confidence in operations at this level, an operator could scale up to a level of 3000-10,000 tons of coal/day or even more. A wide range of products can be considered at this level, including 7000-23,000 bbl/day of methanol.

Scale up by factors of only 3, rather than the usual factors of 10 or more, offer lower risk to the commercial operator. These phases are not shown in Fig. 11, since DOE might not be directly involved. However, some sort of governmental assistance, such as a loan or price guarantees by the Synthetic Fuels Corp. or other agencies, would facilitate commercial development.

Risks vs Rewards

Although the technical feasibility of UCG has been established, the experiments have been relatively small in scale (consumption of 2000-8000 tons of coal per test, Table 1), and much larger scale tests are needed to establish commercial viability. As we have said, such a program is estimated to take about seven years and cost approximately $200 million with no guarantee of immediate commercialization. It is appropriate, then, to consider the potential risks and rewards from such a program.

The reward resulting from a successful R&D program in UCG would be commercialization of clean fuels from coal at prices competitive with existing energy sources. The deep coal resource, which would be converted into a reserve by this technology, would last for hundreds of years. Conceivably, the U.S., instead of being a net importer of oil, could develop an export market in transportation fuels. The first year of commercial operation alone would reduce the bill for imported oil and natural gas into the U.S. by an amount equal to the cost of the entire R&D budget.

The risk is that the R&D will prove unsuccessful, and the technology will prove uneconomic for either technical or environmental reasons.

The risks and rewards were described very differently in reviews of UCG during the past two years. In 1983, the Energy Research Advisory Board concluded that UCG research would not lead to any significant private sector effort.[45] They further concluded that the technology is site-specific, and that "the concept apparently does not lend itself to a once-and-for-all solution." These conclusions are consistent with an earlier Energy Research Advisory Board study, which stated that ". . . the *in-situ* coal gasification program has a low probability of a commercially viable success and can be phased out."[46] Generally, criticisms of the technology from other sources tend to emphasize the unproven nature of UCG, particularly the concern with the reliability of the underground process and possible problems with underground water quality.

These concerns have some basis. The private sector involvement is, in fact, small; however, the percentage of private sector cofunding is, in general, commensurate with government support of UCG, which is also small. Private sector cost-sharing of the last two field tests, for example, was 5% by Gulf Oil for their Rawlins II test. Cofunding of LLNL's recent CRIP test was 40% by the Gas Research Institute, the Washington Water Power Co., Pacific Power & Light, and the Electric Power Research Institute.

The UCG process is site-specific, and solutions must be tailored to match the site. UCG shares this feature with all *in-situ* processes, including mining, natural gas, and oil recovery. All of these enterprises can be either profitable or unprofitable, depending on a number of factors. UCG undoubtedly will not be economic for all coal resources that are slated for development. R&D is needed, in fact, to define the resources where UCG would be cost-effective.

Large scale testing of UCG has not been carried out in the U.S., with the exception of proprietary work by Basic Resources, Inc. (Table 2). Therefore, the concerns about the reliability and environmental effects of the underground process are still justified.

In 1982, the American Institute of Chemical Engineers convened a task force to review UCG. This group concluded[47]:

1. UCG as a technology is targeted to increase the nation's recoverable reserves fivefold.
2. The UCG program has made excellent progress in spite of low budgets.
3. Projections for the cost of UCG-produced fuel gases have been consistently attractive in comparison with the cost of the same products from surface gasification.
4. Despite the progress to date, UCG is not yet ready for commercialization and is still in a research stage.
5. Overall, UCG meets the requirement of long-term, high-risk technology established by the administration as criteria for supporting energy research programs.

The task force recommended unanimously that the UCG program continue to receive federal support at a level that would support a coherent multi-well test program.

Dr. Henry Linden, president of the Gas Research Institute, testified with regard to UCG[48]:

"Underground Coal Gasification (UCG) offers the largest potential for major reductions in capital investment of the different processes and methods for producing a medium-Btu gas or synthesis from coal. However, the high risks associated with the requisite oxygen-blown UCG technology currently preclude industry from developing the technology on its own."

In summary, UCG is a high-risk technology, and large scale tests are required to determine its environmental and economic acceptability. However, if successful, the technology could substantially restore the U.S. energy independence. The investment appears to be modest for such an enormous potential benefit.

Conclusions

As a result of the repeated demonstrations of the technical feasibility of UCG, it is becoming recognized as one of the most promising methods for producing clean fuels from coal that is unattractive for mining. Successful use of the technology could greatly increase proved U.S. reserves of coal. Products such as synthetic natural gas or transportation fuels, which are so vital to our nation's economy, could be produced by UCG at costs estimated to be competitive with the costs of such products derived from conventional sources. The UCG process appears to be environmentally benign, and could be commercialized within 10 years with a very modest budget. With the continued joint efforts of industry and government, UCG should make a significant addition to the U.S. energy economy.

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