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LFS, A Strategic Planning Capability for U.S. Liquid Fuels Supply

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LFS, A STRATEGIC PLANNING CAPABILITY FOR U.S. LIQUID FUELS SUPPLY

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ABSTRACT

Under the sponsorship of the Division of Policy and Strategic Planning (DOE/FE), Oak Ridge National Laboratory is conducting a research program in the modeling of liquid and gaseous fuel supplies. The strategic goal is to enable quantitative assessment of competitive supply technologies and thus contribute to the development of the knowledge base required for reducing the U.S. energy supply vulnerability to the economic and security implications of reliance upon scarce and increasingly expensive conventional petroleum resources. The specific objectives of the project are as follows:

1. Develop computerized models for U.S. liquid (LFS) and gaseous (GFS) fuels supply to enable quantitative assessment of competitive supply technologies, and provide DOE/FE with operational support in their use.
2. Develop an automated capability for LFS/GFS sensitivity and uncertainty analyses.
3. Develop a decision making methodology based on sensitivity theory to critically examine the potential benefits of various R&D programs.
4. Plan for contingencies in the event of supply interruptions (supply vulnerability analysis).
5. Provide DOE/FE with a "public sector home" for computer models and analyses.

Particular attention is being focused on representing mechanisms by which new technologies penetrate the oil market, and assuring reliable comparison of the relative economics of enhanced oil recovery, shale oil, synthetics, conventional onshore, and offshore production, in meeting United States needs for liquid fuels as functions of time.

The present document reports on the development of a comprehensive Liquid Fuels Supply (LFS) model. Particularly important features of this model include the disaggregation of the constituent liquid supply

technologies, the extensive review and documentation of the data associated with the model, and the capability to treat explicitly the dynamics of investment decisions and technological change.

The purpose of this paper is to call attention to the existence of this important new analytical tool, to provide a potential analyst with a reasonably complete description of its essential features, and to discuss the benchmarking completed and underway.

Detailed network diagrams, process equations, and sources of data are given. Twelve depletable resource processes are represented. These include *in situ* and surface retorting of western oil shale, tar sands, western and eastern conventional onshore production, three types of enhanced oil recovery, eastern and western offshore recovery, and Alaskan onshore and offshore production. Details of the LFS model equations used to determine the equilibrium prices and quantities of liquid fuels are included. The fundamental data parameters which provide the computational basis for each supply technology are calculated from technology specific relationships between marginal cost and supply. LFS results are compared to projections of the National Energy Policy Plan. It is found that the LFS results generally fall within stated NEPP uncertainty ranges. A comprehensive sensitivity analysis capability, developed in conjunction with the LFS formulation, has been indispensible in identifying the differences in calculated results.

Appendices provide additional details on the methodology used to project findings rates and on the computation of marginal costs.

The Liquid Fuels Supply model described herein is also being integrated into a World Oil Model sponsored by the DOE Division of Energy Security and is being considered for application by the Energy Information Administration. With such a potentially large and important user community, the need for documentation and review in the open literature, as well as public availability, is considered essential.

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I. INTRODUCTION

I.1. Purpose

The Division of Policy and Strategic Planning in the Office of Fossil Energy of the U.S. Department of Energy (DOE/FE) has sponsored the development of a model of liquid fuels supply to further the understanding of how explicit and implicit technological (e.g., size of the resource base, reservoir geophysical characteristics, efficiency of drilling, etc.), economic (e.g., taxation rates) and behavioral (e.g., allocation price elasticities) variables affect our capability to confidently develop options to deal with fundamental policy issues such as energy independence, which have long term consequences. Particularly important features of this model include the disaggregation of the constituent liquid supply technologies, the extensive review and documentation of the data associated with the model, and the capability to treat explicitly the dynamics of investment decisions and technological change.

The purpose of this paper is to call attention to the existence of this important new analytical tool, to provide a potential analyst with a reasonably complete description of its essential features, and to discuss the benchmarking completed and underway. The Liquid Fuels Supply (LFS) model described herein is also being integrated into a World Oil Model sponsored by the DOE Division of Energy Security and is being considered for application by the Energy Information Administration. With such a potentially large and important user community, the need for documentation and review in the open literature as well as public availability is considered essential.

I.2. Fundamental Policy Issues

Our nation is in an extremely vulnerable position, due at least in part to an undesirable dependence on foreign oil. This vulnerability is well recognized by members of the Organization of Petroleum Exporting Countries as well as the United States. Some of the potential consequences are:[1]

"A. World peace and stability are threatened because no major power, such as the United States, is likely to accede to the loss of a fraction of its oil supply.

B. The nation's freedom of action at home and abroad is threatened by the need to bend to the wishes of oil-controlling forces.

C. The health of our economy is threatened by potential oil cutoffs or large balance-of-trade deficits."

For example, with the recent oil price increases, the U.S. oil import bill rose from about $60 billion in 1979 to almost $80 billion in 1980 which significantly aggravated our balance of trade position.

There have been many excellent studies[2-7] addressing this problem, but few would deny that the complexity of analysis combined with uncertain inputs leave considerable room for a healthy skepticism. What then is the role of such analyses and projections?

I.3. The Role of Models

The role that energy-economy models can play in this arena is the vehicle by which complex, non-linear relationships can be made explicit, model assumptions subjected to scrutiny, and their input data precisely characterized, in order to allow for careful planning of difficult energy system changeovers requiring long lead times. In this manner, specific policy issues can be examined with a minimum of subjectivity; detailed data or equations can be the subject of contention rather than intuition. Similarly, the potential consequences of oil-related research and development decisions can be evaluated, and the sensitivity of important trends determined, particularly with respect to those factors which may have large uncertainties. For example, such analyses include alternatives to conventional liquids (such as EOR, shale oil, and coal liquids) and the time-dependent allocation of supply as a function of the time at which the technology is available, taxing structures, etc. Although the present authors subscribe to this view of the role of models, it is necessary to recall that models can easily be misused; their results can be misinterpreted, and in some cases, it is claimed, the model usage actually makes the problem worse![8] Much caution and careful documentation are necessary prerequisites to effective model usage.

The near term development of the liquid fuels supply model described herein is focused toward addressing specific questions such as:

- What is the best estimate for future world oil and gas prices?
- What is the most cost effective balance of financial resources: exploration and development, production, or conversion?
- Should we target toward oil, gas, or some other fuel form?
- What reserves need be secured and when should one commit to produce them?
- Which are the most promising new technologies: shale oil, coal conversion, tertiary oil, unconventional gas, etc.?
- How might new conversion technologies affect production strategies?
- How might government action (e.g., taxes, environmental or other regulations, incentives) shape private investment?
- How much capital is needed to build the required plants? What might this capital cost?

Other U.S. oil supply models, which have been used to address such issues, their structure and performance have been described in an earlier study of Sweeney.[9] In the framework of the present project, it was deemed essential to consider only such analytical tools that provide:

(1) A reasonable representation of the cost, performance, and reserve estimates (where appropriate) for existing and potential future technologies through the next 20-50 years.

(2) A full representation of relevant non technical variables (e.g., tax laws, economic growth, inflation rates) over the next 20-50 years.

(3) An energy market model which allocates various supplies to meet the required demand, in a form which is physically meaningful.

The energy-economy model and data base developed herein for analysis of liquid fuels related decisions meets the above three objectives. The analytical approach is applicable to government as well as private decisions.

I.4. An Overview of Potential Sources for Increased U.S. Oil Production

Livingston[1] presents five methods for potentially increasing U.S. oil production; these include oil from shale (5×10^{12} BBL in-place resources), coal liquefaction (4×10^{12} BBL, based on converting the recoverable

resource to oil at 60% efficiency), enhanced recovery (0.11×10^{12} BBL) and heavy crude (0.022×10^{12} BBL). The two methods with the largest resource bases are coal liquefaction and oil from shale, which are sufficient to supply our current oil demand for 500 years. Each of these potential supplies competes with accelerated conventional oil production (i.e., increased drilling and opening new acreage) and enhanced recovery, tempered by existing prices for imported oil, for increased market shares of the oil consumption as a function of time. The U.S. Liquid Fuels Supply (LFS) model described in this paper is a representation of this dynamic process.

II. DESIGN OF A LIQUID FUELS SUPPLY MODEL FOR U.S. POLICY ANALYSIS

In this section, we discuss the types of processes represented in the United States LFS model, the nomenclature employed, and the network diagram. LFS is an expanded version of the model discussed by Phillips,[10] which was designed by Decision Focus Incorporated in conjunction with the research discussed in this paper.

II.1. Nomenclature

A generalized equilibrium system[11] consists of a network of linked process models. Each process model represents an activity or market within the economy. The links represent the flow of energy-equivalents (in this particular case liquid fuels) and price information between these processes. Within each process model is a set of equations that describe the decisions made by the agent or agents represented by that specific activity. Each of the processes contained in the LFS model is described below; further clarification of the process equations is presented in Section III.

- Allocation Process (symbolized as a circle with a number of input and output links; see Fig.-1) - used to allocate demand for energy among competing generic classes of suppliers, and to set the average price of a combined energy flow.
- Depletable Resource Process (symbolized as a square with a single output link; see Fig.-1) - represents the economics of production of a resource, the availability of which is limited physically or economically in the sense that the costs increase as a function of cumulative production to the point that further extraction is no longer economic. The price of the resource consists of two terms. The first reflects the marginal cost of production of the resource. The second term is the so-called scarcity rent[12] that reflects the profit the resource owner is able to realize through his ability to choose the optimal time of sale.
- Conversion Process (symbolized by a box with several input links and one output link; see Fig.-1) - represents the economics and engineering of the transformation of several factor inputs into a single output commodity. Equations are based on the assumption that the owners of a facility make decisions that tend to maximize discounted cash flow, and represent the change in operating characteristics due to learning and aging, as well as the various time-dependent financial flows.

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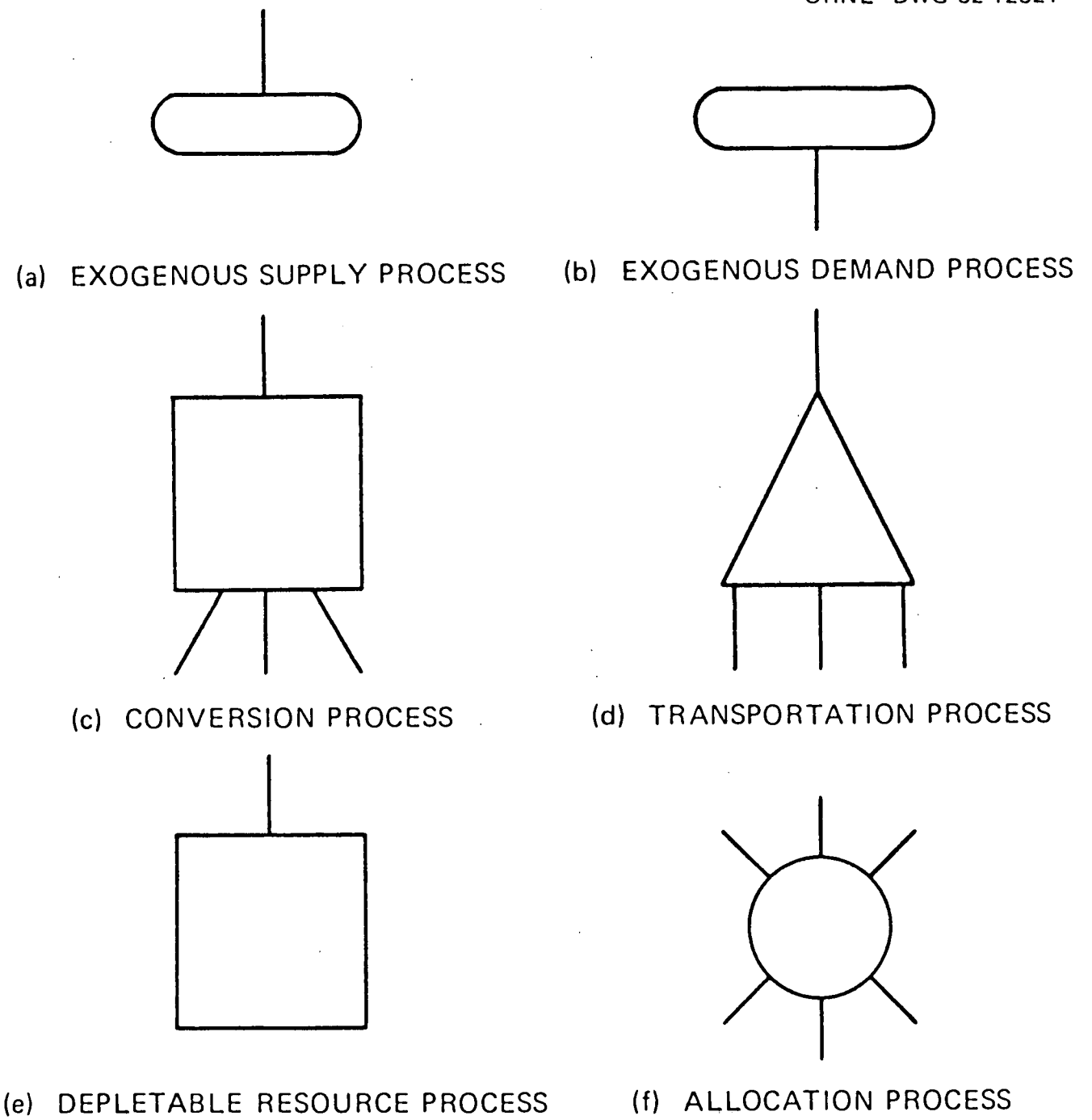

Fig. 1. Process Symbols Used in Network Construction

- Transportation Process (symbolized by a triangle in Fig.-1) - used to represent the economics of transporting energy between two locations. The only difference between the transportation process and the conversion process is that in the transportation process various data such as efficiency, variable operating cost, and specific capital cost vary as a function of distance.
- Exogenous Supply Process (symbolized by a flattened ellipse with a top-link; see Fig.-1) - represents a supply process where the time path of prices for an energy-equivalent flow is entered exogenously and is not a function of demand.
- Exogenous Demand Process (symbolized by a flattened ellipse with a bottom-link; see Fig.-1) - represents an exogenously entered time path of demands for an energy-equivalent flow that does not vary as a function of prices.

In general, exogenous processes are points at which a model is calibrated to the results of some larger model or to external projections of prices and quantities generated by some other means. Criteria used to determine those processes which were to be represented exogenously include: (1) where there is an explicit desire to calibrate aspects of a given model to common aspects of another; (2) where the mechanisms are so poorly understood that modeling is not feasible, i.e., testing the implications of alternative expert judgements; or (3) when one desires a convenient mechanism to test the implications of alternative price or demand strategies on the outcome of the model.

II.2. Liquid Fuels Supply Model

The LFS model is a model of the liquid fuels supply sector (refinery feedstock equivalent) of the United States economy. It models the competition between various sources of conventional and unconventional domestic liquid fuels, imported crude oil, and synthetic liquid fuels. It was built to determine the selling prices and quantities produced from these sources under different assumptions about the costs and availabilities of various liquid fuel supply technologies, and different assumptions about the future price of imported crude oil. Since the model was designed to address problems of crude oil supply, it does not contain a sophisticated treatment of the demand for liquid fuels. Moreover, it does not currently model the competition between various liquid fuels and

natural gas to satisfy end-use demands, nor does it address the competition between liquid fuels and other fuels for electricity generation.

A network diagram of the LFS model is shown in Fig.-2. Following the conventions established in Section II.1, squares are used to represent models of nonrenewable resource supply. The flattened ellipses represent exogenous inputs, the circles represent markets in which different sources of refinery feedstock compete, and the triangles denote energy transportation, e.g., the Alaskan pipeline. The network diagram is used to communicate the technology relationships considered in the LFS model. The figure also shows the level of aggregation of the liquid fuel technologies assumed in the current version of the model. The LFS network contains at present 12 depletable resource processes representing in-situ and surface retorting of western oil shale, tar sands, western and eastern conventional onshore production, three types of enhanced oil recovery, eastern and western offshore production and Alaskan onshore and offshore production.

Price tracks for eastern and western coal (Processes 19 and 11) must be entered exogenously. Coal production was modeled exogenously because the demand for coal to be liquefied will only be a small portion of the total demand for coal. However, to determine the future price of each type of coal, a depletable resource process needs to know the total demand. Hence, instead of adding a number of additional processes to model explicitly the future demand for eastern and western coal, the price of coal was repesented exogenously. The model also contains representations of coal liquefaction, both for western (Process 6) and eastern (Process 8) coal. Raw shale oil from both the in-situ and the surface retorting processes is upgraded in the shale oil upgrading process (Process 7). Liquids from all western and eastern sources, and from Alaska, must be transported by means of pipelines and tankers (Processes 4, 35, and 9). The price of imported oil is entered exogenously (Process 2), as are the total demand for liquid fuels (i.e., domestic demand, exports and Strategic Petroleum Reserve), and the natural gas plant liquids supply. The relative prices over time of labor, materials, debt

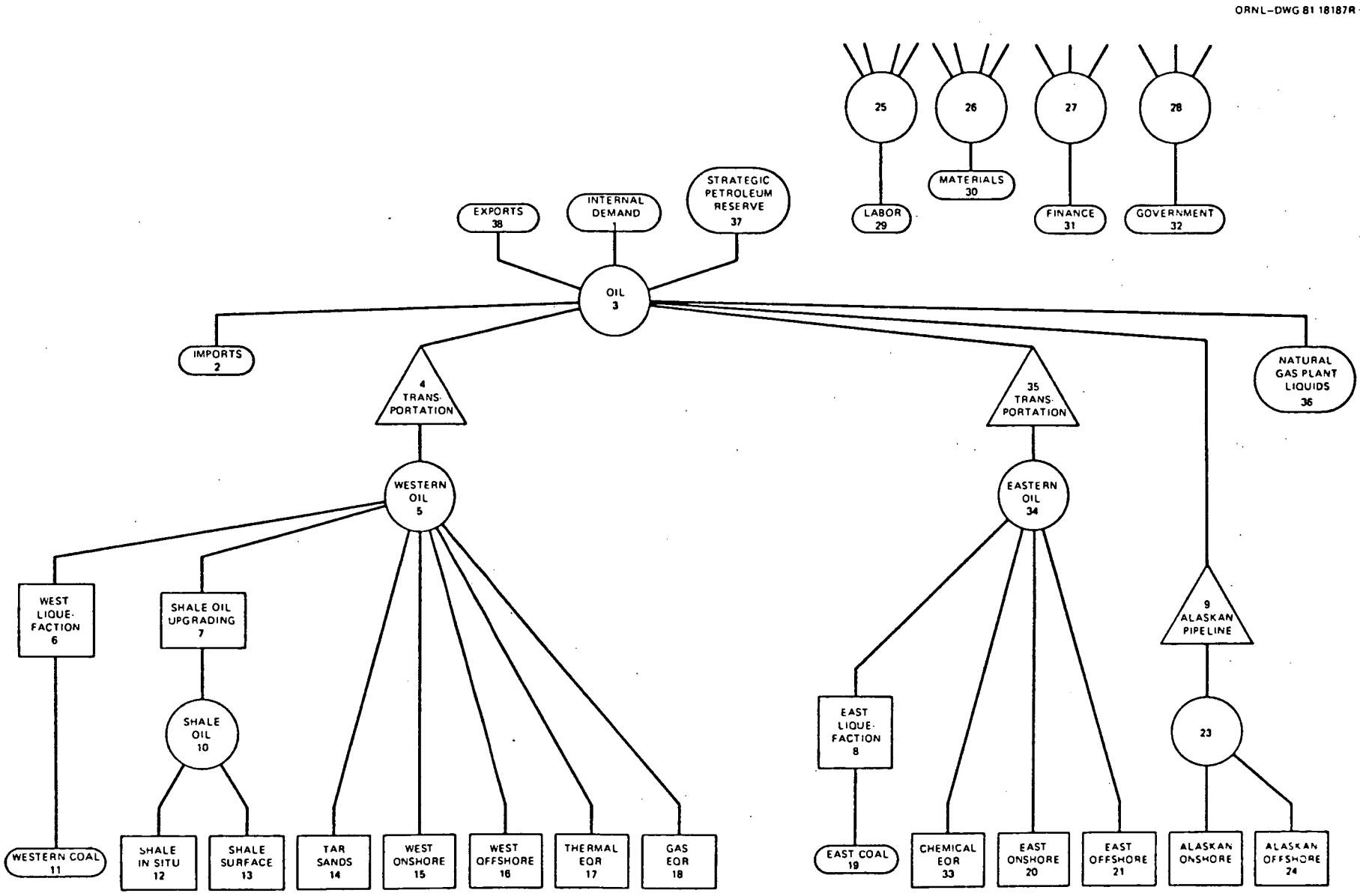

Fig. 2. United States Liquid Fuels Supply Model

and equity financing are also taken in exogenously (Process 29 through 31). The government process (Process 32) is currently not used.

Mathematically, the LFS model takes in price tracks over time for imported oil, western and eastern coal, and nonenergy factor inputs (labor, materials, debt and equity financing) along with a time path of inelastic demands and technology data for all processes and determines the equilibrium prices and quantities of liquid fuels from sixteen different sources. It can be used to determine the effect of changing demands, factor prices, or technology data on the equilibrium prices and quantities of liquid fuels from each source in the model. Details are given in the following section.

III. LFS MODEL EQUATIONS

Each of the processes described in Section II is represented by a set of equations that contain a variety of parameters. When the processes are combined to form a network (as in the LFS model, see Fig.-2), a coupled system of nonlinear time-dependent algebraic equations, that determine the "equilibrium" energy and dollar flows throughout the network, is obtained.[13,14] These equilibrium values are determined numerically, using a variety of iterative algorithms.[11,15,16]

The process equations used in the LFS model are thus of fundamental importance, and are discussed below.

III.1. Resource Process

The resource model is used in the LFS system to describe the process dynamics of depletable resources. A complete but succint presentation of the equations implemented in the LEAP-78 resource module can be found in Ref. 13, and an extensive discussion of the economics foundation of depletable resource processes as used in the Generalized Equilibrium Modeling System (GEMS) will be found in Ref. 11. The equations given in Ref. 11 and Ref. 13 differ in detail from each other and from the equations used in the LFS model.

The resource process receives as input the quantities of energy supply demanded at discrete time points and must calculate the prices necessary to bring forth these quantities. Consequently, there are two functions that a resource process must satisfy. First, it must compute the schedule according to which new reserves must be found and developed. Second, given this schedule of reserve commitments (i.e., capacity additions), the resource process must calculate the prices necessary to bring forth the quantities demanded over time without delay.

Since prices, quantities and capacity additions are calculated only at discrete time points in the LFS model, it is necessary to establish the time conventions before the equations can be written. Prices, quantities and capacity additions are calculated at N_T discrete time nodes beginning with 1980 and separated by intervals Δ of equal duration. The

interval Δ is currently set at 5 years. The above partition will be termed "global" time points. In addition, the resource model equations use N_t time points before the first global time point and after the last global time point to establish the conditions that exist before and after the model horizons. The number N_t is determined from the "characteristic life" of the well, which is an input parameter. In general then, there are $2N_t+N_T$ time nodes (called "local" time points) used in the equations. However, the output of the resource process consists of the prices and capacity additions at global time points only. Specifically, the variables of the resource process will be written as p^μ and N_w^μ where

p^μ = the price per unit energy output from the process at local time μ, with $N_t+1 \leq \mu \leq N_t+N_T$,

N_w^μ = capacity additions committed at local time μ, with $N_t+1 \leq \mu \leq N_t+N_T$.

In the following, unless otherwise specified, all times will be local times and the convention will be used that

λ = the commitment time of a well, i.e., beginning of production,

ν = the time the well became available,

μ = the current operating time,

implying $\mu \geq \lambda \geq \nu$.

III. 1.1. Equations for Prices

To establish the equations for determining the variables just defined let us begin by writing an expression for the before-income-tax profit Π_ν^λ measured at local time λ for a well of unit capacity first available at local time ν but delayed until λ. This profit may be written as

$$\Pi_\nu^\lambda = \sum_{\mu \geq \lambda} [p^\mu - K_\nu^{\lambda\mu}] Q_\nu^{\lambda\mu} D^{\lambda\mu} - C_\nu^\lambda \qquad \text{(III.1)}$$

where

$K_\nu^{\lambda\mu}$ = variable operating cost per unit energy,

$Q_\nu^{\lambda\mu}$ = production at μ from a well of unit capacity,

$D^{\lambda\mu}$ = discount factor (used in computing the present value at λ of the cash flow components at μ),

C_{ν}^{λ} = the present value at λ of the capital cost stream (before income taxes) generated by all fixed costs for a well first available at ν.

Equation (III.1) defines the before-tax profit as equal to the present value (before income taxes) of revenue minus the present value of operating and capital costs. Expressions for all of the various quantities defined in conjunction with Eq. (III.1) will be given in the following sections.

It is assumed that in order to induce an owner of mineral rights to lease a resource at λ, the producer will be willing to make a one-time capital cost expenditure L_{ν}^{λ} that exactly offsets the profit Π_{ν}^{λ} given all of the tax and financial considerations facing him. To understand the manner in which this one-time capital expenditure is approximated, consider the well that will be placed on the lease. If the capital expenditure for that well is $\overline{c}^{\lambda}$, and the present value of capital cost before taxes is c^{λ}, the ratio $c^{\lambda}/\overline{c}^{\lambda}$ can be regarded as defining the tax adjustment made to the capital expenditure resulting from tax depreciation, the investment tax credit, construction lead time, and so forth. It is assumed that the same tax adjustment must be made for the lease as is made for the well. That is

$$\frac{c^{\lambda}}{\overline{c}^{\lambda}} = \frac{\Pi_{\nu}^{\lambda}}{L_{\nu}^{\lambda}} \tag{III.2}$$

The lease owner has the option to delay the sale of the lease and would do so until his discounted profit is a maximum. Thus we may argue that

$$L_{M}^{\nu} = \underset{\lambda>\nu}{\text{Max}} \left[L_{\nu}^{\lambda} \left(\frac{1}{1+\rho_{o}} \right)^{(\lambda-\nu)\Delta} \right] \tag{III.3}$$

where

L_{M}^{ν} = the amount that the producer pays to the owner to acquire the lease

ρ_{o} = the owner's discount rate (input parameter).

Reversing the logic implicit in Eq. (III.2), the present value before tax of the actual lease payment is given by the relation

$$\pi_c^\nu = L_M^\nu \, c^\nu \, / \, \bar{c}^\nu \tag{III.4}$$

This base cost is added to the present value of capital cost of the well at time ν, C_ν^ν, to give the fundamental equation for the determination of prices in the resource process

$$- C_\nu^\nu - \pi_c^\nu + \sum_\mu [p^\mu - K_\nu^{\nu\mu}] \, Q_\nu^{\nu\mu} \, D^{\nu\mu} = 0 \tag{III.5}$$

$$\nu \leq \mu \leq 2N_t + N_T - 1, \quad N_t + \leq \nu \leq N_t + N_T$$

The quantity π_c^ν depends only on prices at times greater than ν, so Eq. (III.5) may be solved to give the price at ν in terms of future prices including prices beyond the model horizon (i.e., $\mu > N_t + N_T$). In the GEMS formalism these prices beyond the model horizon are calculated by means of a simplifying assumption. A discussion of the simplifying assumption will be found in Ref. 11.

III.1.2. Equations for New Capacities

In addition to the prices it is necessary to determine the capacity additions that are required to meet demand. It is assumed in the model that the rate of production from a well follows an exponentially declining profile. Thus, the average annual production during the initial period, assuming a capacity factor of unity, is simply

$$q_W = \frac{1 - e^{-\delta\Delta}}{\Delta} \tag{III.6}$$

where δ denotes the deposit decline rate. Values of δ used in the LFS model are calculated in accordance with the methodology presented in Section IV of this paper.

Given the demand q_D^μ at time μ, and the production from all wells still in activity at μ, the net amount of new reserves N_w^μ that must be proved at time μ is determined from the equation

$$N_w^\mu = \frac{q_D^\mu - \sum_{\lambda=1}^{\lambda=\mu-1} Q_\lambda^{\lambda\mu} N_w^\lambda}{\Gamma_\mu^{\mu\mu}\, q_w} \qquad \mu = N_t+2, \ldots N_t+N_T \tag{III.7}$$

where $\Gamma_\nu^{\lambda\mu}$ refers to the capacity factor of wells for which leases are first available at time ν, but are committed at time λ, and operated at time μ (see Section III.1.5.), and the other quantities have been defined previously. In Ref. 13 the quantity $\Gamma_\mu^{\mu\mu}$ in the denominator of Eq. (III.7) is approximated by unity. The numerator in Eq. (III.7) can, in principle, be negative meaning that the capacity in place at time μ actually exceeds demand and no additional drilling and development is needed. When this is the case production from wells in place is scaled down by redefining the capacity factor $\Gamma_\lambda^{\lambda\mu}$ as shown below:

$$\hat{\Gamma}_\lambda^{\lambda\mu} = \Gamma_\lambda^{\lambda\mu} \frac{q_D^\mu}{\sum_{\lambda'=1}^{\lambda'=\mu-1} Q_{\lambda'}^{\lambda'\mu} \; N_w^{\lambda'}} \qquad \lambda=1,\ldots,\mu-1 \tag{III.8}$$

This procedure is used in the model in place of a more sophisticated shutdown algorithm.

In Eqs. (III.7) and (III.8) capacity additions before the model horizon are needed. To obtain them, a linear assumption of capacity additions over one "characteristic well life" (input parameter) prior to the first global time point is considered, such that demand at $\mu = N_t+1$ is satisfied.

III.1.3. Equations for Capital and Operating Costs of Depletable Resources

In the model it is assumed that both capital cost and operating cost of new wells increase as the resource is depleted. The measure of the extent of depletion in the model is taken to be the cumulative resource

commitment to date; thus the capital cost and operating cost that would exist without depletion are multiplied by functions of the cumulative resource commitment. The equations used are

$$C_{\nu}^{\lambda} = c^{\lambda}[1+a_w(\chi_{\nu})^{b_w}] \tag{III.9}$$

$$K_{\nu}^{\lambda\mu} = K^{\lambda\mu}[1+a_w(\chi_{\nu})^{b_w}] \tag{III.10}$$

where

c^{λ} = the present value (before income tax) of capital costs without depletion effects (see Section III.1.4),

$K^{\lambda\mu}$ = the variable operating cost per unit energy without depletion effects (see Section III.1.7).

In the above expressions χ_{ν} denotes the cumulative resource commitments at time ν, and is defined as follows

$$\chi_{\nu} = \begin{cases} 0 & \nu \leq N_t+1 \\ \sum_{\mu} N_w^{\mu} & N_t+1<\nu\leq N_t+N_T \ , \ \mu\leq\nu-1 \end{cases} \tag{III.11}$$

Note that χ_{ν} is equal to the cumulative quantity of the resource base that has been committed at time ν, since a well of unit capacity produces a unit of energy (quantity) over its lifetime. The parameters a_w and b_w are determined from the assumption that the relationship between marginal cost (price) and cumulative production is the same as the relationship between capital cost and cumulative commitments, and between operating cost and cumulative commitments. The parameters a_w and b_w are thus given by

$$a_w = \frac{\overline{p}(1) - \overline{p}(o)}{\overline{p}(o)} \quad Q[\overline{p}(1)]^{-b_w} \tag{III.12}$$

$$b_w = \ln\{\frac{2\overline{p}(1) - \overline{p}(o)}{\overline{p}(1) - \overline{p}(o)}\} \Big/ \ln\{\frac{Q[2\overline{p}(1)]}{Q[\overline{p}(1)]}\} \tag{III.13}$$

where $\bar{p}^{(0)}$, $\bar{p}^{(1)}$, $Q[\bar{p}^{(1)}]$, $Q[2\bar{p}^{(1)}]$ are input parameters, referring respectively to initial resource price $\bar{p}^{(0)}$, reference resource price $\bar{p}^{(1)}$, and undiscovered recoverable resources at the reference price $Q[\bar{p}^{(1)}]$, and at twice the reference price $Q[2\bar{p}^{(1)}]$. The manner in which these input constants are determined for the various resource processes considered in the LFS model is addressed in detail in Section IV of this paper.

Equations (III.9) and (III.10) take into account the effects of the future proved reserves of the resource as a whole. In the GEMS formalism the variable operating cost of a well also increases with the age of the well, as a function of its specific depletion. A multiplier on the variable operating cost to capture this effect is included in the resource processes described in Refs. 11 and 13. This feature was, however, not used in the LFS model and therefore will not be discussed here.

III.1.4. Capital Cost

The producer's after-tax cash flow to equity $\Phi_\nu^{\lambda\mu}$ at μ for a well of unit capacity that was available at ν and began operation at λ is defined as follows

$$\Phi_\nu^{\lambda\mu} = [p^\mu - K_\nu^{\lambda\mu}]Q_\nu^{\lambda\mu} - \hat{C}^{\lambda\mu}[1+a_w(\chi_\nu)^{b_w}] \qquad \text{(III.14)}$$

In the above equation $\hat{C}^{\lambda\mu}$ denotes the depletion-free capital cost component of cash flow after income taxes. This capital cost is composed of several items; for the LFS model it may be written as

$$\hat{C}^{\lambda\mu} = C_D^{\lambda\mu} + C_E^{\lambda\mu} + C_I^{\lambda\mu} + C_{PT}^{\lambda\mu} + C_{IT}^{\lambda\mu} \qquad \text{(III.15)}$$

with

$C_D^{\lambda\mu}$ = repayment of debt principal at μ,

$C_E^{\lambda\mu}$ = capital investment from equity at μ,

$C_I^{\lambda\mu}$ = interest on debt at μ,

$C_{PT}^{\lambda\mu}$ = property taxes at μ,

$C_{IT}^{\lambda\mu}$ = income taxes at μ.

The income tax at μ can be calculated according to the expression

$$C_{IT}^{\lambda\mu} = \theta_{IT}[(p^{\mu}-K_{\nu}^{\lambda\mu})Q_{\nu}^{\lambda\mu} - C_{PT}^{\lambda\mu} - C_{TD}^{\lambda\mu} - C_I^{\lambda\mu}] - C_{ITC}^{\lambda\mu} \qquad \text{(III.16)}$$

where

θ_{IT} = income tax rate,

$C_{TD}^{\lambda\mu}$ = tax depreciation at μ,

$C_{ITC}^{\lambda\mu}$ = investment tax credit at μ,

If Eqs. (III.15) and (III.16) are substituted into Eq. (III.14) one obtains

$$\Phi_{\nu}^{\lambda\mu} = (1-\theta_{IT})[(p^{\mu}-K_{\nu}^{\lambda\mu})Q_{\nu}^{\lambda\mu}] - \Big\{ C_D^{\lambda\mu} + C_E^{\lambda\mu} + (1-\theta_{IT})C_I^{\lambda\mu} + (1-\theta_{IT})C_{PT}^{\lambda\mu} - \theta_{IT}C_{TD}^{\lambda\mu} - C_{ITC}^{\lambda\mu}\Big\} [1+a_w(\chi_{\nu})^{b_w}] \quad . \qquad \text{(III.17)}$$

The term in braces is called fixed cost after taxes. Dividing by $(1-\theta_{IT})$, one obtains the before-tax fixed cost of the well

$$C^{\lambda\mu} = \frac{1}{1-\theta_{IT}} [C_D^{\lambda\mu}+C_E^{\lambda\mu}-C_{ITC}^{\lambda\mu}] + C_I + C_{PT} - \frac{\theta_{IT}}{1-\theta_{IT}} C_{TD}^{\lambda\mu} \qquad \text{(III.18)}$$

The present value at λ of the capital cost stream $C^{\lambda\mu}$ is denoted by c^{λ}. Clearly, c^{λ} is the depletion-free present value of capital cost before income taxes that was introduced in Eq. (III.9). The actual computation of c^{λ} is rather lengthy and will not be addressed here. The corresponding formulae are given in Appendix A of Ref. 13 and their derivation is discussed in detail in Ref. 11.

III.1.5. Capacity Factor

The capacity factor used in the model is a function of operating cost and price and represents a behavioral operating rule that smoothly decreases the well production from maximum capacity to zero as the price goes from much greater than the operating cost to much less than the operating cost. The functional relationship currently implemented in the LFS resource process has the form

$$\Gamma_\nu^{\lambda\mu} = 1 \qquad 1 \leqslant \mu \leqslant N_t+1$$

$$= \frac{1}{1+\left[\frac{\alpha K_\nu^{\lambda\mu}}{p^\mu}\right]^{\gamma_r}} \qquad \begin{array}{l} N_t+1 \leqslant \mu \leqslant 2N_t+N_T-1 \\ \lambda \leqslant N_t+N_T \end{array} \tag{III.19}$$

where $K_\nu^{\lambda\mu}$ is the variable operating cost [see Eq. (III.10)] and p^μ is the price per unit energy as before. The quantities α and γ_r are input parameters that determine the behavior of the capacity factor as the ratio of variable operating cost to price varies. A comprehensive discussion of capacity factor models will be found elsewhere.[15,16]

III.1.6. Productive Age of Well and Production

A vintage-dependent time $T_\nu^{\lambda\mu}$, sometimes called the productive age of a well, is used in the calculations as a convenient means of keeping track of cumulative depletion from each vintage of wells. This "effective reservoir time" specifies how far out the exponential decline profile of each vintage of wells is depleted at each point in time. It is obtained recursively from the equations[11]

$$T_\nu^{\lambda\mu} = 0 \qquad \mu < \lambda\,,\ \lambda \geqslant \nu$$

$$T_\nu^{\lambda\mu} = T_\nu^{\lambda\mu-1} - \frac{1}{\delta}\ln[1-q_w\Delta\Gamma_\nu^{\lambda\mu}] \tag{III.20}$$

The recovery matrix $Q_\nu^{\lambda\mu}$ is defined as the product of the maximum possible average yearly production multiplied by the capacity factor. Thus

$$Q_\nu^{\lambda\mu} = q_w \, \Gamma_\nu^{\lambda\mu} e^{-\delta T_\nu^{\lambda,\mu-1}} \qquad \lambda < N_t + N_T \tag{III.21}$$

where all symbols on the right hand side of the equation have been defined previously.

III.1.7. Depletion Free Variable Operating Cost

The depletion free variable operating cost per unit energy introduced in Eq. (III.10) is the operating cost due to cost of labor and materials, and may be written as

$$K^{\lambda\mu} = \sum_\ell V_o f_\ell P_\ell^\mu \, \Lambda_{C\ell}^\lambda \Lambda_{O\ell}^\mu \Lambda_A^{\mu-\lambda} \tag{III.22}$$

where $\ell = 1$ for labor, $\ell = 2$ for materials, and

V_o = normalization constant calculated from input parameters,[11]

f_ℓ = fraction of the constant V_o due to labor or to materials costs (input parameters),

P_ℓ^μ = relative prices of labor or materials normalized to be unity in 1980 (input parameters),

$\Lambda_{C\ell}^\lambda$ = cost multiplier to account for changes in construction costs due to learning,

$\Lambda_{O\ell}^\mu$ = cost multiplier to account for changes in operating costs due to learning,

$\Lambda_{A\ell}^{\mu-\lambda}$ = cost multiplier to account for changes in operating costs due to aging.

Explicit expressions for the cost multipliers will be found in Refs. 11 and 13.

III.2. Conversion Process

The conversion process is used in the LFS model to describe the transformation of energy from one form to another, e.g., coal liquefaction

or shale upgrading. The detailed equations of the conversion process used in LEAP-78 are given in Ref. 13; further discussion of their theoretical foundations can be found in Refs. 11, 15 and 16. Some minor differences exist between the conversion process equations as given in Refs. 11 and 13 and those used in the LFS model. Since the equations for the conversion process are very similar to those presented in the previous section for the resource process, only the significant differences will be described here.

The variables in the conversion process are the output prices per unit energy from the process at the N_T global time points considered in the model, the capacity additions at the N_T time points, and the quantity of energy per year that must be input to the process to produce the required amount of output energy. If in the resource process formalism all depletion effects are neglected, then the equations for output prices and the equations for capacity additions in the conversion process are obtained. There is, however, one significant difference in input parameters to the conversion process and to the resource process. In the resource process, the specific capital cost per unit of capacity that is used to normalize the capital cost, and the constant V_O that is used in Eq. (III.22) to normalize the variable operating cost, are computed endogenously.[11] In the conversion process the specific capital cost per unit of capacity and V_O are input parameters. Furthermore, the thermal efficiency of the process is input to the code, and this thermal efficiency determines the amount of energy per year that must be input to the process to produce a required amount of output. The equations to compute this quantity at the N_T time points are Eq. (III.13) in Ref. 13.

III.3. Transportation Process

As the name implies, this process is used in the LFS model to describe transportation costs and any losses during transportation. The equations for the transportation process in the LFS model and in the Generalized Equilibrium Modeling System (GEMS)[11] are the same, and are those used in the conversion process. However, since many of the input

parameters to the conversion process are not relevant in the transportation process, the actual equations are considerably simpler than the equations used in the conversion process. These simplified equations are those given for the transportation process in Ref. 13.

III.4. Allocation Process

Allocation processes are used in the LFS model to represent markets where buyers and sellers trade for a commodity (i.e., liquid fuels) at a price. The allocation process is generally combined with the resource and conversion processes described in the previous sections, in order to extend the modeling capabilities from treatment of representative technologies to the analysis of decision-making processes.

In their simplest form, allocation processes are merely devices that either (1) channel a single supplier's commodity toward multiple demanders at an average transaction price or (2) allocate a single demander's purchases to the lowest-priced supplier. This simple picture is complicated by equal-price market-share parameters, price-responsiveness parameters, and behavioral lags. Algebraically, these concepts are related in a fairly straightforward manner. Consider that demand for liquid fuels has to be allocated among N_I competing suppliers. Assuming that the decision-maker could allocate the demand instantly (static allocation), the share of supplier i at time μ could be expressed as follows:

$$S_i^{\mu} = 1 \,/\, \{ 1 + \sum_{j \neq i}^{N_I} \frac{f_j}{f_i} \left[\frac{\Lambda_i^{\mu}}{\Lambda_j^{\mu}} \right]^{\gamma_a} \} \qquad \text{(III.23)}$$

Market shares at equal prices, f_i, need to be specified by the modeler and are used to encode any bias the decision maker may have with respect to the various suppliers. If no such bias exists, then

$$f_i = \frac{1}{N_I} \, . \qquad \text{(III.24)}$$

Market shares at equal prices are also required for situations in which the commodities flowing into the allocation process are not perfectly fungible (i.e., nonhomogeneous market).

The price responsiveness parameter γ_a models the sensitivity of the market shares to price. Specifically, increasing values of γ_a increase the sensitivity of the allocation process to price differentials. Very large γ_a values correspond to the simulation of perfectly competitive markets.

The shadow prices Λ_i^μ in Eq. (III.23) differ from the nominal transaction prices p_i^μ which represent the actual market price of the commodity, in the sense that they reflect the added cost of regulation and/or price premiums to the consumers of the commodity. In absence of regulation and/or premiums the shadow price will equal the transaction price.

Behavioral lag parameters reflect the degree to which the economic factions represented by the allocation processes will desire to change the flow of liquid fuels from one source to another in response to relative price changes. The desire to alter the flow of a commodity is one thing, but the ability to do so is something else. Sources of inertia may exist, such as investment in capital goods, long term contracts, or supplier loyalties. The behavioral lag model accomplishes the transition from static allocation illustrated by Eq. (III.23) to dynamic allocation in which market penetration curves serve as a vehicle for expressing the process dynamics between myopic allocation (i.e., constant market shares) and perfect foresight allocation (i.e., wizardy). Formally, the LFS behavioral lag treatment calculates the dynamic share allocation according to the relation:

$$\bar{S}_i^\mu = \beta\, \hat{S}_i^{\mu-1} + (1-\beta)\, S_i^\mu \qquad \text{(III.25)}$$

where β denotes the behavioral lag parameter ($0<\beta<1$). As emphasized in the introduction to Section III, the LFS system of nonlinear time-dependent algebraic equations is solved using an iterative approach. To accelerate the convergence to an equilibrium solution, one generally uses relaxation procedures. Specifically, the symbol $\hat{S}_i^{\mu-1}$ in Eq. (III.25) refers to the "relaxed" value of the market share $\bar{S}_i^\mu$ at time point $\mu-1$ and is obtained at iteration k from the relation

$$\hat{S}_{i,k}^{\mu-1} = \alpha\, \bar{S}_{i,k}^{\mu-1} + (1-\alpha)\, \hat{S}_{i,k-1}^{\mu-1} \qquad \text{(III.26)}$$

where the adaptive relaxation parameter $A_{i,k}^{\mu-1}$ was simply denoted by α, since no confusion is possible. With the shares $\overline{S}_i^{\mu}$ determined, the quantity of total demand q_D^{μ} allocated to the i-th supplier at time μ is given by

$$q_i^{\mu} = q_D^{\mu} \, \overline{S}_i^{\mu} \tag{III.27}$$

Notice that the market shares in the first model year are supplied externally (initial conditions). Further details can be found in Refs. 11 and 13.

IV. DATA BASE DEVELOPMENT

The LFS resource process requires over 150 input parameters for each technology represented in the network, assuming that the model's time span is partitioned into ten time intervals. Many of these parameters are problem generic, e.g., the federal income tax rate, the return on equity rate, etc... . The largest bulk of data refers to the time-dependent vectors containing initial guesses for prices (including eventually regulatory constraints components), quantities and new capacity additions, as well as labor, material and financial cost flows, consistent with the network link-interface.

The most involved input requirements are resource-specific. In particular, six fundamental data parameters provide the computational basis for each supply technology. They include: initial resource price, reference resource price, new resources at reference price, new resources at twice reference price, capital cost fraction and deposit decline rate. These parameters are calculated from the technology-specific relationships between marginal cost and supply. This section reports on the methodology used to derive these relationships for all depletable resource processes included in the current LFS model. Coal liquefaction and shale oil upgrading are treated in the LFS formalism using conversion processes. The obtention of the corresponding fundamental parameters is also briefly addressed. The detailed tabulations of the LFS data base are presented elsewhere.[17-19]

IV.1. Conventional (Primary and Secondary) Onshore Recovery

Three activity nodes are devoted in the LFS network to the modeling of conventional (primary and secondary) onshore recovery: Lower-48/West, Lower-48/East and Alaska, i.e., nodes 15, 20, 22 in Fig.-2. Relationships between marginal cost and supply were first derived for seven geographical areas, referred to hereafter as LFS onshore subregions. Regional aggregation was based on weights derived from the undiscovered recoverable resources as estimated by the United States Geological Survey.[20] The LFS onshore subregions include: (1) Alaska; (2) Pacific Coast; (3) Colorado Plateau, Basin and Range, Rocky Mountains and Northern Great Plains;

(4) West Texas and Eastern New Mexico (Permian Basin); (5) Gulf Coast; (6) Mid Continent; (7) Michigan Basin, Eastern Interior (Illinois), Appalachia and Atlantic Coast. These subregions are similar in scope to units employed in other major studies, i.e., the eleven onshore National Petroleum Council regions[21] and the twelve RAND subdivisions.[22] The LFS subregions were defined to maximize consistency with prior classifications and to facilitate a broad variety of analyses by approximating as well as possible geologic provinces and local political boundaries. For example, LFS subregion 7 combines NPC Regions 8, 9, 10 and 11, or equivalently RAND regions 11 and 12.

IV.1.1 Methodology Outline

In order to derive the marginal cost to supply relationships, from which the input parameters to the LFS model are obtained, it is necessary to first solve the equations which relate cumulative drilling efforts to incremental supply from the undiscovered resource base, and then estimate the marginal cost of new reserve additions. The calculations are performed on a subregional basis. The relationship between drilling effort and reserve additions is modeled by a logistic function. Complete identification of the function requires two data elements for each subregion:

- Contemporary Finding Rates: the most recent estimate of the quantity of reserves added per unit of drilling.
- Undiscovered Recoverable Resources: an estimate of the total resource which remains to be discovered through exploration.

Integration of the logistic function permits solving for the effort required to yield an increment of specific size from the undiscovered resource base. Details are given in Appendix-A.

The marginal cost of new reserves is estimated by engineering analysis of a "typical" well[23] in each subregion. Two types of data must be specified for the typical well: (1) productivity over time; and (2) investment and operating costs over time. The product of contemporary finding rate and average well depth yields the per-well ultimate recovery, which is translated to annual production using production

decline curves.[24] Engineering-based cost equations were developed to provide realistic estimates of:

- Drilling and completion costs
- Lease and well equipment costs
- Production equipment costs
- Injection and secondary recovery equipment costs
- Primary recovery operating costs
- Secondary recovery operating costs

The cost and production equations, combined with realistic assumptions about royalty, capital costs and taxation (including windfall profit tax) are solved to yield the initial resource price $\overline{p}(o)$. The initial resource price is, by definition, the minimum levelized price leading to a non-negative present value of cash flow for a unit resource facility, where a "unit facility" refers to a well whose maximum cumulative production over its lifetime is one unit. This levelized price would be required to build and operate the well without incurring a loss, where costs include normal return to capital, but exclude any resource rent. Further details are given in Appendix-B.

The use of the contemporary finding rate f_D to determine the per well ultimate recovery provides the analytic bridge between the effort-supply relationship and the cost analysis. In particular, if the total undiscovered recoverable resource QU is partitioned into $\Delta Q(k)$ components in order to calculate the finding rate's profile $f(k)$ (see Appendix A), the corresponding price levels $\overline{p}(k)$ are given by

$$\overline{p}(k) = \overline{p}(o)\ f_D\ /\ f(k) \qquad \text{(IV.1)}$$

and refer to the cumulative supply levels $Q(k)$ (with $Q(o) \equiv 0$):

$$Q(k) = Q(k-1) + \Delta Q(k) \qquad \sum_k \Delta Q(k) = QU \qquad \text{(IV.2)}$$

The "reference resource price," $\overline{p}(1)$, is then defined as the minimum price required to add the first increment of supply $\Delta Q(1)$. The latter is defined as the "undiscovered recoverable resource" at reference price. The

TABLE-1

Selected LFS Resource Process Parameters For Primary and Secondary Onshore Recovery

Region	$\bar{p}^{(o)}$	$\bar{p}^{(1)}$	$Q[\bar{p}^{(1)}]$	$Q[2\bar{p}^{(1)}]$	κ	δ^{e}
West Coast	8.78[a]	10.54	7.33 + 08[b]	2.49 + 09	.66	.20
Rocky Mountains and Plains	16.87	20.25	3.93 + 09	1.34 + 10	.86	.32
West Texas	13.67	16.41	9.00 + 08	3.06 + 09	.69	.22
Gulf Coast	13.02	15.63	1.18 + 09	4.02 + 09	.75	.21
Midcontinent	26.12	31.35	7.33 + 08	2.49 + 09	.75	.22
East Coast	27.04	32.45	4.83 + 08	1.64 + 09	.93	.90
Lower-48/East	3.29[c]	3.95	17.26	43.46[d]	.77	.31
Lower-48/West	2.28	2.74	12.86	93.96	.73	.25
Alaska	3.28[c]	3.94	6.67	22.68[d]	.99	.20

(a) Units for initial resource price $\bar{p}^{(o)}$ and reference resource price $\bar{p}^{(1)}$ are \$(1980)/BBL.
(b) Units for resource supply at reference price $Q[\bar{p}^{(1)}]$ and resource supply at twice reference price $Q[2\bar{p}^{(1)}]$ are BBL's.
(c) Units are \$(1980)/10^6 Btu, as input to the LFS code.
(d) Units are 10^{15} Btu's.
(e) Deposit decline rate, in percent/year.

"new resource at twice the reference price" is then calculated by interpolation in the above price-supply mapping. The capital cost fraction κ simply corresponds to the fraction of present value of total cost not attributable to operating cost. The resulting values are shown in Table-1.

IV.1.2. Alaska Onshore Recovery

In 1972 the API reserves committee made an exception to its standard procedures on reserve bookings for the Prudhoe Bay region. In particular, reserves beyond those actually proved by wells (i.e., estimated by engineering assumptions) were permitted to be entered.[25] This exception, added to exploration immaturity, makes the assumption of finding rate stability unreliable for the Alaska onshore recovery calculations.

Actually, a wide variation is observed, which requires the additional introduction of uncertainty with respect to finding rates in the analysis. Three values were chosen, i.e., 124, 58, and 23 BBL/ft to represent likelihoods of 0.05, 0.50 and 0.95, respectively in a triangular distribution. Thus, there is a ninefold structure of uncertainty for Onshore Alaska, resulting from three values for the finding rate and three for the undiscovered resource base. The two sources of uncertainty being independent, the likelihood of each of the nine points can be calculated directly.[17] The depletable resource process parameters for the Alaska subregion, as shown in Table-1, refer to a finding rate of 124 BBL/ft and an undiscovered recoverable resource estimate of 6.9 10^9BBL's.

IV.2. Offshore Recovery

Three activity nodes of the LFS network are devoted to the modeling of offshore recovery: Lower-48/West, Lower-48/East and Alaska, i.e., nodes 16, 21 and 24 in Fig.-2. The eastern offshore area includes both Atlantic and Gulf of Mexico activities. The principal determinants of cost in offshore recovery are based on aggregations of wells in discrete quanta (i.e., the production platform and transportation systems). Thus the unit of economic analysis for offshore resources must be the field and not the typical well.

In the following, the development of marginal-cost-to-supply relationships for all LFS/offshore activities is discussed.

IV.2.1. Offshore Gulf of Mexico

The Gulf of Mexico oil resource has two major subdivisions: (1) The Outer Continental Shelf, a gently sloping region extending approximately

200 miles from the surf line to water depths of 200 meters; (2) The Outer Continental Slope, a much smaller region in which water depth drops from 200 to 1000 meters in less than 75 miles. Of the two, the shelf has been the major focus of development activity. Drilling in the shallow coastal waters began during the 1940's. Many of the nation's largest fields are located in the Gulf of Mexico Outer Continental Shelf. Exploration and development of the slope have only recently begun, but have yielded at least one major field, i.e., "Cognac," at 350 meters depth.

The primary risks to development in the Gulf of Mexico are hurricanes and unstable bottom conditions. Field development costs are "moderate"; they are higher than the West Coast, but significantly less than those expected for Alaska.

There is abundant information about fields, costs and amount of resource in the gulf. The size of the undiscovered recoverable resource base was retained from the most recent USGS estimates.[20] In 1980 the USGS issued[26] Open-File Report 80-644 which estimates the form and parameters of the distribution of undiscovered oil fields by oil-in-place in both the shelf and slope; in this study distributions of recoverable resource were computed assuming[27] a recovery factor of 40%.

The standard USGS field size classification system was used to characterize 20 classes of fields in terms of recoverable resource.[24] The percentage of fields in each class for both shelf and slope was determined by transforming the log of class boundaries into uniform normal deviates, and using the t-distribution. The lognormal distribution describes the distribution of fields by size classes but does not describe the distribution of the actual resource. A general rule of thumb is that 80% of the resource lies in the largest 20% of the fields. There is no direct analytic method which can be used to determine either:

- The number of undiscovered fields
- The distribution of undiscovered resource as a function of field size

However, it is possible to use stochastic (Monte Carlo) simulation to approximate both quantities. Accordingly, a special computer program

was built to transform the overall estimate of undiscovered resource and the lognormal distribution of field sizes into the distribution of resource by field size. Each "Monte Carlo" trial consists of repetitively sampling (with replacement) fields from the lognormal distribution until the collective resource in the sample equals the estimate of undiscovered resource. The program keeps track of the total number of fields and the resource within each class. A total of 10,000 Monte Carlo trials were conducted for each of the three USGS estimates of undiscovered resource. The expected values and variance statistics for the number of fields (shelf and slope) are shown in Table-2. The detailed results of resource distribution by field size are given elsewhere.[18]

The methodology used to derive the marginal-cost-to-supply relationships is similar in scope to the one presented in Section IV.1.1. However, new cost categories appear and the unit of economic analysis is the field.

a. Production Curves - The Dallas Fields Office of the Department of Energy supplied[28] production curves[18] for typical wells in each of the various field sizes.

b. Exploration Costs - The development of offshore prospects imposes an unusual cost burden, because exploratory wells are generally not used for production. This occurs because such wells must be drilled from temporary platforms without facilities for processing or sales. Thus, exploratory wells are plugged and abandoned and expensed against the current tax liabilities of the operator. The cost of exploration is a component of the decision to bid; however, once exploration is completed, these costs are "sunk" and do not influence development plans. Exploration costs have two components:[28]

- The costs of geological and geophysical data collection.
- The costs of drilling both discovery wells and sufficient wells to determine the size of the field.

The actual costs of drilling are, in turn, a function of both water depth and the total drilled depth.[18]

c. Production Platform Costs - Because platforms are in reality steel towers, costs increase exponentially with water depth. To date, the

TABLE-2

Expected Number of Fields and Variance Statistics for the Offshore Gulf of Mexico

Region/ Probability Estimates		Undiscovered Recoverable Resource[a]	Expected Number of Fields	Standard Deviation (Fields)
Outer Continental Shelf[b]				
USGS Low	(F_{95})	1.10 + 09	25.0	8.4
USGS Medium	(F_{50})	4.00 + 09	92.1	14.6
USGS High	(F_{05})	9.50 + 09	210.4	25.9
Outer Continent Slope[c]				
USGS Low	(F_{95})	0.90 + 09	85.0	12.4
USGS Medium	(F_{50})	2.60 + 09	96.6	24.1
USGS High	(F_{05})	5.80 + 09	205.6	38.5

(a)Units are BBL's
(b)Water depths : 0 - 200 m.
(c)Water depths : 200 - 1000 m.

largest such platform is that built to develop the "Cognac" field in approximately 1,000 feet of water off the Louisiana coast. The major component of such costs is the requirement for steel. At a point between 300 and 500 feet water depth, the requirements for steel change significantly, due to a change in the "natural period" of the platform. This is the time within which a steel structure is deflected by a force (wind, wave, and/or current) and is restored to its original position. At depths between 300 and 500 feet, this period approximates 3 seconds; at this point, structures must meet additional design standards. This increase in design requirements has been documented extensively.[29,30]

Platform costs are a function of both the size of the platform (approximated by the number of "slots" for wells) and water depth. For this analysis, the number of wells was determined[18] by dividing the average field size within the range by the per-well ultimate recovery within each field size.

d. Drilling of Successful Development Wells - Developmental drilling is performed from a production platform. Directional drilling is used to reach into all areas of the field from the centrally located platform. The data for well costs were supplied[28] by the Dallas Field Office of DOE based on actual costs, including casing and equipment, reported from drillers; the data differ from those reported[31] in the API Joint Association Survey (JAS) in that the JAS data include the individual well's pro-rata share of platform costs.

e. Drilling of Developmental Dry Holes - A dry hole does not require casing or wellhead equipment. The cost of developmental dry holes is therefore primarily composed of the cost of drilling with a small amount allotted to costs of plugging and abandonment. Of importance to this analysis is the rate at which developmental dry holes are drilled. The statistics on developmental drilling in the Gulf of Mexico as reported[32] by the American Association of Petroleum Geologists, indicate that the developmental dry hole rate is in the range of 30%.

f. Production Equipment Costs - OCS development places severe demands on production equipment that are reflected in cost increases due to space and weight, special materials, modular design, and resistance to the hostile saltwater environment. Transportation also adds to the cost of equipment. Costs of equipment are proportional to the maximum flow rate of the fields and were supplied by the Dallas Field Office[28] based on previous studies and contact with manufacturers.

g. Pipeline Connection Costs - Each new production platform must be connected to a sales line by means of a subsea pipeline. The costs of these pipelines are a logarithmic function of length, water depth and pipe diameter. For this analysis, it was assumed that an average of ten miles of 15 inch diameter pipeline would be required to connect each newly constructed platform with a trunk sales line.[18]

h. Operating Costs - The Dallas Field Office of the DOE also supplied[28] information about yearly operating costs which include expenses for crew transportation, personnel necessary for operation of the platform, meals, workovers, maintenance, insurance, and overhead. It is assumed that lease oil (netted from production) is used as fuel, and thus, fuel costs are not included in the operating costs. Operating costs are a function of the number of wells (i.e., field size) and water depth which, in the Gulf, serves as a surrogate for distance to shore.

For the sake of brevity, the detailed tabulations of the various cost components have not been included in this article, but are listed elsewhere.[18] For the derivation of the marginal-cost-to-supply relationships, the shelf was represented by fields at 200 feet water depth and the slope was represented by fields at 1000 feet water depth. The resulting resource process parameters, aggregated over shelf and slope, and combined with Atlantic offshore estimates, are shown in Table-3 under the label Lower-48/East.

TABLE-3

Selected LFS Resource Process Parameters for Offshore Recovery

Region	$\overline{p}^{(o)}$	$\overline{p}^{(1)}$	$Q[\overline{p}^{(1)}]$	$Q[2\overline{p}^{(1)}]$	κ	δ [c]
Lower-48/East	5.17[a]	6.03	11.00[b]	28.00	.80	.16
Lower-48/West	5.17	7.40	16.50	21.80	.50	.16
Alaska	6.03	7.51	51.10	69.70	.80	.16

(a) Units for initial resource price $\overline{p}^{(o)}$ and reference resource price $\overline{p}^{(1)}$ are \$(1980)/10^6 Btu's

(b) Units for resource supply at reference price $Q[\overline{p}^{(1)}]$ and resource supply at twice reference price $Q[2\overline{p}^{(1)}]$ are 10^{15} Btu's

(c) Deposit decline rate, in percent/year

IV.2.2. Offshore Atlantic Coast

The Atlantic coast offshore region extends from Florida to Maine. The shelf averages from 75 to 100 miles wide along most of its 1250 miles of length. It is widest in New England where it extends from 250 to 300 miles; it is narrowest in South Florida, extending only 10 miles. The shelf extends to water depths of 400 feet while the slope drops rapidly to depths of 3300 feet. Sedimentary deposits (areas of potential hydrocarbon accumulation) average 7500 feet in thickness. They reach 16,000 feet off the New Jersey coast and may reach 30,000 feet off the coast of Georgia and North Florida.

There are two conflicting theories about the productive potential of the Atlantic offshore:[33]

- Pratt's Theory: The shelf acted as a "hinge" when the continent was uplifted; the shelf was downwarped with extensive sedimentation, resulting from inland erosion. Thus, the shelf should have excellent prospects for hydrocarbon reservoirs, while the coastal inland areas would have poor prospects.
- Weaver's Theory: The shoreline is not subject to movement; the shelf and coastal areas differ only in terms of erosive factors. Thus, the potential of the shelf should not differ from the adjacent inland areas.

It is known that the inland areas adjacent to the Atlantic coast have low productive potential. Thus, there is considerable uncertainty about the resource in place in the Atlantic coast offshore. Furthermore, the area has often been compared to the North Sea in terms of development risks which may include ice, major storms, limited drilling season, and hurricanes.

The potential of Atlantic offshore deposits has led to intense competition for leases; a number of exploratory wells have been drilled. To date, exploration has found a marginal amount of natural gas (not yet in commercial quantities) and no oil. There is little or no published data on actual fields. The Department of Energy has, however, chosen analogues[34] which may be used to generalize from known onshore areas to unknown Atlantic offshore areas. The present analysis determines the relationship between marginal cost and supply by using the DOE published

analogues to compute the number of undiscovered fields and the distribution of undiscovered resource as function of field size using stochastic simulation,[18] in conjunction with appropriate engineering based costs. The latter were obtained by transforming cost components in known areas (specifically the Gulf of Mexico) to costs in frontier areas using Kalter's drilling hostility multipliers.[35] The aggregated results shown in Table-3 under the label Lower-48/East refer to representative fields at an average depth of 200 feet for the shelf and 1000 feet for the slope.

IV.2.3. Offshore West Coast

The West Coast offshore region is composed of distinct locations along the Pacific Coast from Washington State to California. The areas are characterized by relatively benign environment and deposits close to shore. Earthquakes and Tsunami (tidal waves) are the principal risks of development. In the southern part of California, development of the resource had progressed significantly until curtailed for environmental reasons; three of the nation's 100 largest fields lie in the waters off Santa Barbara. However, apart from the developed portion of California, there is little data on the remainder of the West Coast offshore region. The collection of data through exploration has virtually ceased because lease sales in frontier West Coast Offshore regions are the subject of considerable current controversy. Because of this, it is difficult to speculate on the time at which this resource might become available for development.

The present analysis concentrates on the relationship between marginal cost and supply in this region by extrapolating from existing regions to the entire West Coast Offshore resource. The probabilistic estimates of undiscovered recoverable resource were again taken from the most recent USGS estimates.[20] The distribution of field sizes was computed applying Kaufman's procedure[36] to known field sizes;[37] the stochastic simulation methodology described in Section-IV.2.1 served as vehicle for determining the number of undiscovered fields, as well as the distribution

TABLE-4

Alaska 1980 Oil Production Used as Initial Conditions in LFS Resource Process (Activity Nodes 22 and 24)

Oil Field	1980 Production		
Onshore	Quads	10^6BBL	10^6BBL/day
Beaver Creek	0.0012	0.214	0.0006
Kuparak River	0.0	0.0	0.0
Prudhoe Bay	3.2290	555.394	1.5216
Swanson River	0.0217	3.728	0.0102
Subtotal	3.2519	559.336	1.5324
Offshore			
Granite Point	0.0255	4.394	0.0120
McArthur River	0.1215	20.895	0.0572
Middle Ground Shoal	0.0282	4.854	0.0133
Trading Bay	0.0126	2.167	0.0059
Subtotal	0.1878	32.310	0.0885
TOTALS	3.4397	591.646	1.6209

of undiscovered resources as function of field size. The costs of developing fields of various sizes were determined by engineering analysis, as specified in the 1977 study conducted by the Arthur D. Little Company.[38] These costs were updated to 1980 by means of inflation factors obtained from the Bureau of Labor Statistics, as summarized in a recent study[23] conducted by Lewin and Associates, and were further adjusted to take into account the effects of the windfall profits tax.[18] The corresponding LFS resource process parameters are shown in Table-3.

IV.2.4. Offshore Alaska

The offshore regions of Alaska are composed of four areas: (1) Gulf of Alaska and Kodiak Island; (2) Cook Inlet; (3) Bering Sea, including the Bristol Bay, St. George, Navarin and Norton Basins; (4) Chukchi and Beaufort Seas. These areas share the common characteristic of a hostile environment for the development of hydrocarbon resources. Field development costs are high due to the risk of ice, earthquakes, and severe weather. The only developed fields lie in Cook Inlet, which is relatively sheltered; these fields account for only 164 million barrels. The vast bulk of Alaska's potential lies in the Bering and Beaufort Seas, which have extremely hostile environmental conditions. Published information on offshore Alaska resources is scant;[20,39-42] the area is truly a frontier area in the sense that little is known and risks are high. The 1980 Alaskan oil production (an initial condition in the LFS model) is shown in Table-4.

The marginal cost-to-supply relationships for offshore Alaska were determined using the approach summarized in Section IV.2.3. The corresponding LFS resource process parameters (activity node 24) are given in Table-3.

IV.3. Enhanced Oil Recovery

The Lewin and Associates' Big Field data base[43] was used to develop the onshore, lower-48 EOR resource process parameters. This data base contains the reservoir characteristics for 609 onshore reservoirs that represent nearly 60% of the total oil resource in the nation's lower-48 onshore area, accounting for 230 billion of the 414 billion barrels of oil originally in-place.

Each reservoir in the data base is first screened for technical viability and then assigned one or more EOR technologies that could be applicable. The reservoirs having multiple technology assignments are further screened using detailed recovery and engineering costing models. Subsequently, each reservoir is allocated to the EOR technique that appears to provide the best oil potential and economic return, even though several EOR techniques might be technically applicable. The

TABLE-5

Allocation of the Lewin and Associates' Big Field Data Base to Alternative EOR Technologies and Base Case EOR Targets

EOR Technique	L&A Reservoirs	Original Oil In-Place For Sample (10^9BBL)	EOR Potential (10^9BBL) Price Level 35 $(1980)/BBL	EOR Potential (10^9BBL) Price Level 50 $(1980)/BBL
Steam Drive	45	51	11.8	15.9
In Situ Combustion	9	3	0.2	0.3
Carbon Dioxide Flooding	235	94	2.5	4.5
Surfactant/Polymer Flooding	51	19	0.1	1.5
Polymer Flooding	26	4	0.1	0.1
EOR not applicable	243	59		
Total	609	230	14.7	22.3

resulting distribution is shown in Table-5. The EOR potential of each geographical area is then derived by aggregating the individual reservoir data and extrapolating the results in the data base, based on the original oil-in-place.

Since the last comprehensive assessment,[44] published by DOE/Lewin and Associates, Inc. in 1978, major changes have occurred in EOR economics and status of technology: the economics of oil recovery have been influenced by changes in oil prices and tax legislation, and the technology is now better understood due to the results of laboratory and field research. The basic engineering costs, economics and oil recovery models used in the present analysis are discussed in detail in a recent DOE report,[23] and refer to mid-1980 conditions and levels of understanding. For the present study certain portions of the recovery models have been further updated based on ongoing comparisons with the results of field and pilot tests. A separate new report[19] includes the details of the assessment for EOR potential of the nationally representative reservoir data base. This assessment is based on the newly upgraded models and examines the impact of scientific advances and improved recovery technologies. The results reported herein refer to the "Base-Case" option only, i.e., in which we assume that existing EOR technology is applied to geologically favorable reservoirs.

IV.3.1. Steam Drive

The recovery model used for steam drive is based on Myhil and Stegemeier's modeling efforts.[45] This model determines oil recovery as a function of steam injection, steam zone growth, heat balance equations, and key reservoir characteristics. Although the model does not explicitly include the effects of reservoir heterogeneities on steam drive, it does include an empirical correction factor[23] based on a comparison with field tests.

The Base Case reservoirs for steam drive are heavy oil reservoirs with a depth of less than 2,500 feet. The majority of these reservoirs are located in California. The resource process parameters presented in Table-5 show that steam drive is the EOR technique with the greatest current recovery potential.

TABLE-6

Selected LFS Resource Process Parameters
for Unconventional Recovery Technologies

Technology	$\overline{p}^{(o)}$	$\overline{p}^{(1)}$	$Q[\overline{p}^{(1)}]$	$Q[2\overline{p}^{(1)}]$	κ	δ^c
EOR/Thermal	5.10[a]	6.03	69.6[b]	94.5	.50	.14
EOR/Gaseous	5.10	6.03	14.5	29.0	.50	.14
EOR/Chemical	5.30	6.03	1.2	10.4	.50	.14
Shale/In Situ	4.12	6.32	155.0	2018.0	.70	.05
Shale/Surface	4.12	6.32	311.0	4037.0	.70	.05
Tar Sands	4.75	6.00	15.0	30.0	.70	.05

(a) Units for initial resource price $\overline{p}^{(o)}$ and reference resource price $\overline{p}^{(1)}$ are \$(1980)/10^6 Btu.
(b) Units for resource supply at reference price $Q[\overline{p}^{(1)}]$ and resource supply at twice reference base price $Q[2\overline{p}^{(1)}]$ are 10^{15} Btu.
(c) Deposit decline rate, in percent/year.

IV.3.2. In-Situ Combustion

The in-situ combustion recovery model is based on engineering correlations derived from fourteen field projects.[46] The recovery equations are valid until the fireflood must be abandoned for technical reasons, such as the arrival of the burn front at the production wells or the severe breakthrough of air. The equations used signify that recovery increases as air injection continues, but that the efficiency (barrels of oil per Mcf of air) decreases exponentially, and that maximum ultimate recovery, before abandonment, is 31% of the original oil in-place.[19] This includes oil burned in the reservoir during the fireflood. The Base Case reservoirs for in-situ combustion constitute a fairly small target of relatively low gravity oil (19° to 30° API), generally with a depth greater than 5,000 feet. The corresponding resource process parameters are shown in Tables-5 and 6. In the latter in-situ combustion and steam drive are aggregated under the label "thermal" EOR.

IV.3.3. Carbon Dioxide Flooding

The recovery model for carbon dioxide flooding incorporates several reservoir properties, including heterogeneity, oil viscosity, and the API gravity of the crude oil. The recovery equations were derived[23] based on theoretical considerations and laboratory experiments and calibrated with field tests. In this model, the sweep of the carbon dioxide flood is calculated from the mobility ratio between CO_2 and the CO_2/oil mixture. For light oils, this will result in a CO_2 sweep that is less than that of a waterflood.

The Base Case reservoirs for carbon dioxide flooding are Southwest and Rocky Mountain carbonates. These are the reservoirs where the majority of the existing field tests are currently underway. The results presented in Table-5 show that at a base price of 35 $(1980)/BBL this EOR technique has the second largest recovery potential.

IV.3.4. Surfactant/Polymer Flooding

The recovery model used for surfactant/polymer flooding is based on an analysis of field and pilot tests.[23] The recovery equations assume that the surfactant/polymer bank will efficiently sweep approximately one-half fo the previous waterflood swept reservoir volume. This field correction factor has been derived from an average of pilot and field tests for which sufficient data is available for analysis.

The target reservoirs for Base Case surfactant/polymer flooding are shallow, homogenous sandstones, primarily in the Illinois Basin.

IV.3.5. Polymer Flooding

The polymer model used by Lewin and Associates was verified based on field results. The general equation for the polymer model assumes[23] that the residual oil saturation in the polymer swept zone was 98% of the residual oil saturation after waterflood. The equations express that the addition of polymer improves the recovery through two mechanisms. Not only does the residual in the waterflood swept zone decrease by a minor amount, but the sweep efficiency increases; the lower the waterflood sweep, the better the relative increase in the polymer flood sweep.

Generally, the recovery from the second component, improved sweep, far outweighs any additional oil recovery due to lowering of the residual oil in the already swept zone.

The Base Case reservoirs for polymer flooding constitute a relatively small target, consisting mainly of lower gravity reservoirs (20° to 35° API) with high permeability (more than 30 md). Again, the resource process parameters are shown in Tables-5 and 6.

IV.4. Shale and Tar Sands

The LFS model considers two generic technologies for extracting oil from shale; in-situ retorting (Process 12) and surface retorting (Process 13). In surface retorting, the oil-shale rock is mined and brought to a retorting facility on the surface where it is heated to about 900°F, so that the kerogen material it contains decomposes thermally to shale oil and gaseous products. It is currently a more commercial approach than in-situ retorting and several technologies, including the Bureau of Mines Gas Combustion, Paraho Union Oil, and Tosco-II, have been developed in the United States.[47]

In-situ retorting of oil shale is still at an early stage of development. Technologies considered for future commercialization (mid and long-term) are known as modified in-situ techniques. Basically, modified in-situ methods consist of extracting approximately 20 percent of the shale from an underground volume and rubblizing this volume by explosives; the rubblized shale is then retorted by establishing a flame front that burns the residual shale carbon, and then sweeping the rubblized retort volume with the front driving the shale oil product out prior to burning the carbon. Various in-situ retorting concepts are being developed. They include horizontal modified in-situ, hydrofracture, geokinetics, etc.[47]

The most important and economical shale oil deposits in the United States are located in the Green River formation of Colorado, Utah, and Wyoming. The oil potential of the Green River Formation deposit exceeds 2×10^{12} BBL of which at least 600 10^9 BBL is contained in high grade

shale, yielding 25 or more gallons of oil per ton of shale. It should be pointed out that the economic and practical problems of extracting this resource are still great. Beside engineering problems in both surface and in-situ retorting, there are significant environmental problems with extracting oil from shale rocks. The surface retorting process, which is currently the most economical, creates a very large amount of spent shale as waste. In addition, both processes, require a great deal of water, which is in short supply in the area surrounding the Green River formation.

One of the constraints for oil shale development is related to shale oil upgrading. Crude shale oil is not an acceptable feedstock for average petroleum refineries where severe hydrotreating facilities are not available. Current belief[47] is that even a one percent blend of shale oil with petroleum crude could cause severe problems in the operation of the desalters. Therefore, to avoid contamination, crude shale oil cannot be pipelined with petroleum crude oils. Consequently, crude shale oil upgrading to remove nitrogen, oxygen, sulfur, and arsenic needs to be performed prior to feeding the shale oil into a refinery or blending with petroleum crudes. This upgrading process is modelled explicitely in the LFS model using a conversion process (see activity node 7 in Fig.-2). The values of the corresponding key input parameters are given in Table-7; the resource process data for surface and in-situ retorting are shown in Table-6.

Tar sands are deposits of sand or rock containing viscous or solid hydrocarbons that cannot be recovered by conventional techniques. Although the most important tar sands deposit in North America is the Athabasca deposit in Northern Alberta, the United States has an estimated 23 to 33 billion barrels of oil in deposits of bitumen-bearing rocks with resources over 10^6 BBL per deposit.[48] Utah contains by far the most important tar sand resources with between 23 and 29 billion barrels of oil credited to 19 deposits. Four of these giant deposits, Asphalt Ridge, Hill Creek, P. R. Springs, and Sunnyside, are located in the Uinta basin; they contain a total of about 11 billion barrels of low sulfur

(less than 0.5 weight percent) oil, and are thus prime targets for initial consideration in developing production from the tar sands, using known surface mining and recovery techniques.[47] The United States tar sands recovery is represented in the LFS model by activity node 14; the corresponding process parameters are shown in Table-6.

TABLE-7

Selected LFS Conversion Process Parameters for Unconventional Technologies

Technology	SCC[a]	VOC[b]	EFF[c]	EQF[d]	PLT[e]
West Liquefaction	27.71	3.52	.70	.45	8
East Liquefaction	27.71	3.52	.70	.45	8
Shale Upgrade	9.51	1.48	.90	.45	6

(a) Specific Capital Cost in $(1980)/$10^6$ Btu/yr
(b) Variable Operating Cost in $(1980)/$10^6$ Btu
(c) Efficiency[59]
(d) Equity Financing Fraction[59]
(e) Planning Lead Time in years[59]

IV.5. Coal Liquefaction

The production of coal in the LFS model is represented by two exogenous processes, one representing western coal (activity node 11) and one representing eastern coal (activity node 19). For each of these two processes, the modeler must specify a future price track for coal. Coal production was modeled exogenously because the demand for coal to be liquefied will only be a portion of the total demand for coal. However, to determine the future price for each type of coal, a depletable resource process needs to know the total demand. Hence, instead of adding a number of additional processes to explicitly model the future demand for eastern and western coal, the price of coal was represented exogenously. The price tracks assumed for eastern and western coal are shown in Table-8. These price tracks were derived from a forecasting

TABLE-8

LFS Exogenous Price Tracks for Eastern and Western Coal Supply

Year	USA/East	USA/West	NEPP[a]
1980	1.31[b]	.74	1.11
1985	1.45	.82	1.28
1990	1.56	.88	1.35
1995	1.63	.95	NA
2000	1.68	1.00	1.55
2005	1.72[c]	1.06	NA
2010	1.75	1.12	NA
2015	1.77	1.18	NA
2020	1.79	1.22	NA
2025	1.80	1.26	NA

(a) The NEPP domestic average minemouth coal price is given for comparison purpose.
(b) Units are $(1980)/$10^6$ Btu.
(c) Prices adapted from ARC-80/LEAP data base[53]

model developed by DFI for the Gas Research Institute.[49] Coal liquefaction is modeled explicitely using the LFS conversion process. The impact of oil prices on synthetic fuel costs was incorporated in the derivation of the conversion process input parameter values, using the results of a recent SRC/SUNY study.[50] Data from three liquefaction processes, i.e., H-Coal, EDS and Fischer-Tropsch, were combined to obtain the parameter values shown in Table-7.

The water requirements of coal liquefaction processes are even greater than those of oil shale surface retorting. The Synyfuels Interagency Task Force in 1976 reported[51] that the Fischer-Tropsch liquefaction process requires over 13 barrels of water for each barrel of

oil produced. This can be compared with the estimate made by Crawford et al. in 1977 that about 3 barrels of water per barrel of oil will be required for surface retorting of shale oil.[52] Although water use will probably not be an important consideration in the East, it may very well constrain development of liquefaction in the West. As in the case of shale oil retorting, this restriction might be modeled using a mathematical constraint. Alternatively, water supply might be modeled using a depletable resource process, reflecting the fact that the cost of additional water will rise, the more water is consumed. Both approaches are currently under investigation for incorporation in future model enhancements.

V. COMPARISON OF LFS RESULTS TO NEPP PROJECTIONS

This section presents a comparison of petroleum supply projections, as prepared for the National Energy Policy Plan[53] (NEPP), with results from the LFS model. The intent is to document the type of benchmarking performed to date as part of a larger attempt to better understand energy-economy modeling techniques, as well as to further develop the accuracy of their projections.

V.1. Calibration of the LFS Model to NEPP

In order to provide a consistent comparison between NEPP and LFS projections for the supply of refinery feedstock-equivalent liquid fuels, all LFS exogeneous processes (i.e., total demand, imports, and natural gas liquids) were "calibrated" to NEPP. The corresponding NEPP data, used as LFS input parameters are shown in Table-9. As indicated by the table, imports are treated as a price constraint whereas natural gas liquids obey a quantity constraint. Data included in the table refer to NEPP's "mid-range" scenario, which assumes a three percent annual real increase in world oil prices, and a world oil market applying continual pressure on the industrial countries, particularly the United States, to decrease oil consumption. Even if current market conditions have resulted in world oil prices falling in real terms in 1981 and 1982, it is anticipated[53] that these falling prices, accompanied by a significant oil production cutback by OPEC are likely to restore higher levels of world oil demand. This, in the framework of the NEPP mid-range scenario should result in pressure on world oil prices over the longer term, i.e., by 1985 and beyond, as shown in Table-9.

The following sections provide information on the domestic liquid fuels supply outlook. The LFS projections for conventional (primary and secondary) onshore and offshore recovery are compared, in the aggregate, to the corresponding NEPP forecasts. Unconventional production results are compared by specific technology, i.e., enhanced oil recovery, shale oil and tar sands, and synthetic coal liquids. Given processes such as demand and imports, where variables with a most significant effect on the

TABLE-9

Calibration of LFS Model to NEPP Projections[a]

Year	Demand 10^{15} Btu	Imports $(1980)/10^6$ Btu	NGL[b] 10^{15} Btu
1980	33.69	5.80	2.17
1985	31.73	6.90	1.88
1990	28.69	8.16	1.59
1995	26.70	9.57	1.30
2000	24.72	10.98	1.01

[a]The current LFS Model has the capability of projecting supply through 2025. For the 2005-2025 period, demand was assumed constant at 24.72 quads and the price of imported crude was calibrated to ARC-80/LEAP.[58]
[b]Natural gas liquids

projections are largely of an uncertain nature (e.g., OPEC-dictated price of petroleum) it is of paramount importance to use sensitivity theory to assess the impact of uncertain imputs on the model results. Our current results in that area are briefly summarized in Section V.4.

V.2. Conventional (Primary and Secondary) Onshore and Offshore Recovery

The LFS and NEPP projections of conventional oil production from 1980 to 2000 are graphically displayed in Fig.-3a. In Figs.-3a to-3f, the uncertainty estimates for the NEPP results are those supplied as part of the NEPP studies. The projected quantities of petroleum in Fig.-3a include estimates from Alaska as well as from the Lower-48 onshore and offshore activities. NEPP projects a dramatic decline in the Lower-48 onshore production from 6 MMBD in 1980 to approximately 2.4 MMBD in the year 2000. The offshore production, which is currently concentrated almost exclusively in the Gulf of Mexico and in the shallow waters of Southern California is projected to increase from .3 MMBD in 1980 to 1.4 MMBD in the year 2000. The very large uncertainties reported by NEPP for

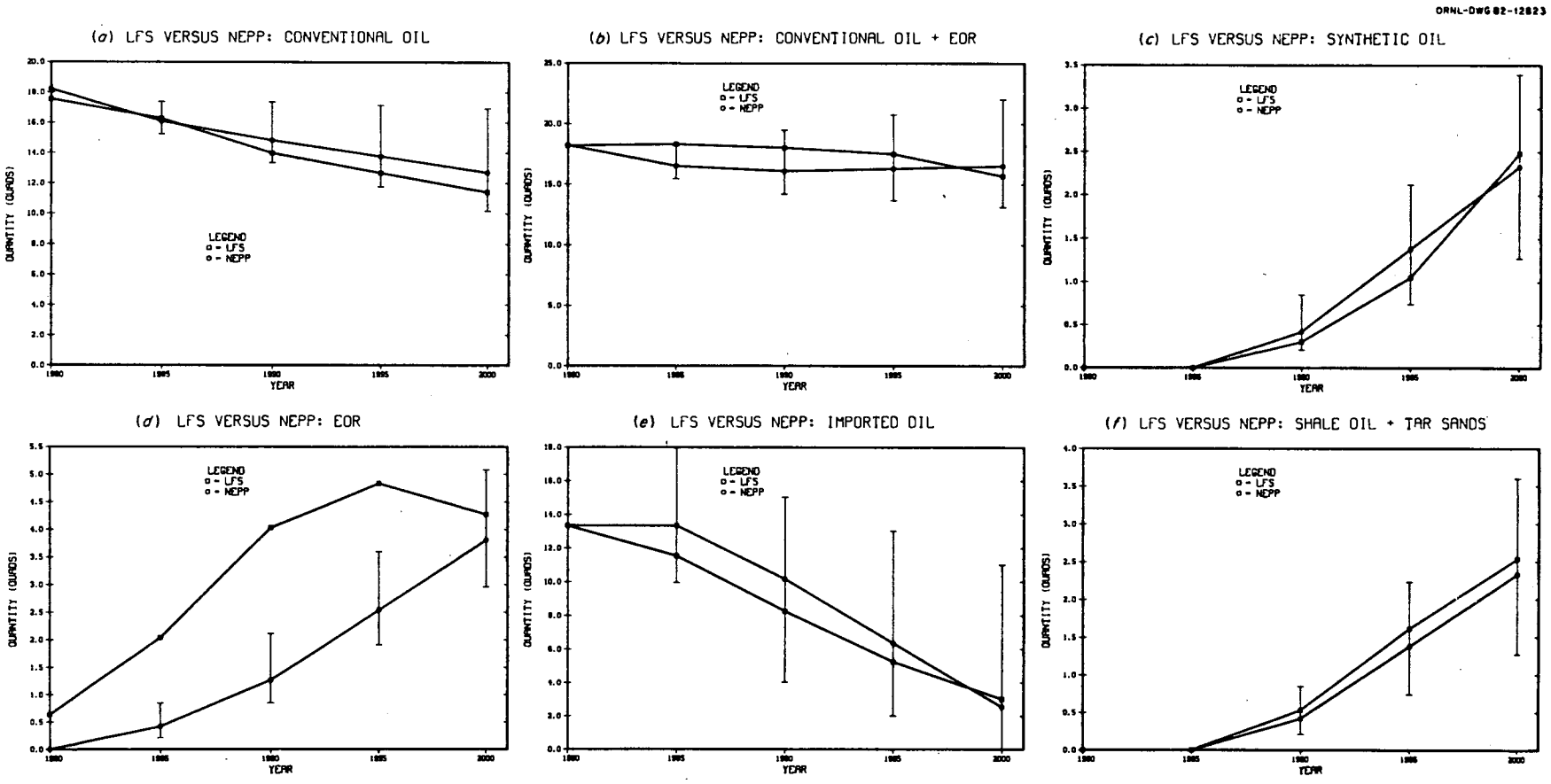

Fig. 3. Comparison of LFS Results to NEPP Projections

the east and west coast trace their origin, at least partly, to the limited exploration activities, as well as to the complexities involved in opening new offshore areas for development. Finally, production for Alaska is projected to increase moderately from 1.7 MMBD to 2.2 MMBD in the year 2000, assuming major new findings north of the Arctic Circle.

A similar trend can be observed for the LFS results in Fig.-3a, which generally fall within the NEPP uncertainty ranges. The variation in the estimated amounts of undiscovered recoverable resources,[17] which results in different discovery rates for LFS and NEPP, contributes significantly to the observed differences. Notice also that NEPP data for 1980 include heavy oil production from California under conventional recovery; in the LFS model heavy oils are included under the (thermal) EOR activities. Consistency between the two studies is reestablished in Fig.-3b where the sums of conventional plus EOR productions are compared for LFS and NEPP.

V.3. Unconventional Oil Production

The increasingly important role of unconventional oil production over the next 20 years is a striking feature of both NEPP and LFS projections. Clearly, the future production from each of the unconventional processes considered in these studies (i.e., EOR, shale, coal liquids) will depend not only on the prices and availability of conventional supplies, but also on the relative success in developing and commercializing new production technologies. In view of the proprietary nature of industries' actual expenditures and income data relative to such technologies, one must rely heavily on estimates by "knowledgeable" economic observers and analysts. Notwithstanding this limitation, and given the NEPP mid-range projection for world oil prices, both models show that all three types of production (Figs.-3c,-3d, and-3f) are expected to be economically viable after 1985, with EOR being the most competitive in terms of pure economic costs.

Both NEPP and LFS expect EOR to yield substantially more oil over the next 10-15 years than shale or synthetics. This is due to the fact that EOR techniques are at present relatively less risky and involve considerably less up-front investment than the other unconventional oil

technologies.[53] In the case of EOR, the LFS projections are somewhat larger than the NEPP projections, and are larger than the NEPP upper uncertainties in the years 1980 to 1995. Such differences find their origin in different estimates for EOR reserves, as well as in a different accounting for the California heavy oils. The latter discrepancy is resolved in Fig.-3b, where the total conventional plus EOR productions from LFS and NEPP are compared. Both models provide similar forecasts for the year 2000, showing that EOR production over time is expected to be constrained by the limited availability of resources, and the rapid rise of synthetic and shale supplies (see Figs.-3c and-3f).

Finally, a similar trend can be observed in the projections for imported crude. Notice, however, that while NEPP forecasts a constant import level during the 1980-1985 period, LFS shows a slight reduction in imports (see Fig.-3e). This is consistent with the faster rise in EOR production projected by LFS.

V.4. Sensitivity Analysis

The LFS model requires over 1000 input data parameters. In general, not all of these parameters will be of equal importance in producing a given calculated model result, and it is thus of interest to know which parameters are contributing appreciably. There has been available for some time a mathematical methodology, hereinafter referred to as adjoint sensitivity theory,[54-56] for determining the sensitivity of a calculated result to each of the data parameters that enter into the calculations. More precisely, if R is any result obtained by solving a large set of nonlinear equations, then adjoint sensitivity theory provides a means of calculating efficiently the derivative $dR/d\alpha$ for every data parameter, α, that enters into the calculation. The derivative $dR/d\alpha$ is taken with all parameters except α held fixed. After the sensitivity of R with respect to α, i.e., $dR/d\alpha$, is known for all α, it is straightforward to determine those parameters for which the sensitivity is large and perform an uncertainty analysis.[57]

Adjoint sensitivity theory has been used to determine the LFS sensitivities for two choices of R. The model used in obtaining the

sensitivities was an earlier and slightly different version of the one used to obtain the results presented elsewhere in this paper; however the conclusions regarding the most important parameters should be approximately correct for the final version of the model.

The results, R_1 and R_2, for which sensitivities have been obtained are (see Fig.-2)

$$R_1 = \frac{\text{Quantity of Fuel From East Coal Liquefaction in the Year 2000}}{\text{Quantity of Fuel Demanded in the Year 2000}}$$

and

$$R_2 = \frac{\text{Quantity of Fuel From Thermal EOR in the Year 2000}}{\text{Quantity of Fuel Demanded in the Year 2000}}$$

The five data parameters that have the largest sensitivities for these two results are shown in Table-10 and Table-11, respectively. In comparing sensitivities of different data parameters, it is usually more meaningful to consider the relative sensitivities defined by $\frac{\alpha}{R}\frac{dR}{d\alpha}$, where α and R are the base case values; this will be done in presenting the results here. In Tables-10 and-11 the first column gives the node number (see Fig. 2) in which the parameter occurs, the second column describes the data element being considered (see Ref. 59 for more details about the parameters), and the third column gives the relative sensitivity. The relative sensitivity is the percent change in the response for a 1% increase in the data element. The sign of the relative sensitivity is therefore negative when the response decreases with an increase in the data parameter. The parameters in Tables-10 and-11 are listed in the order of decreasing absolute value. It must be emphasized that while only the five largest sensitivities are shown, these are known to be the largest because the sensitivities with respect to all data parameters have been calculated.

The highest sensitivity in Table-10 is to the parameter describing the efficiency of the transport of western oil. It refers to the energy output of the process per unit energy input into the process. As shown in the table, the relative sensitivity to this parameter is negative because an increase in this efficiency decreases the quantity of fuel

TABLE-10

Sensitivity Results for Response R_1
(see text for definition of R_1)

Node[a]	Parameter	Relative Sensitivity $\frac{\alpha}{R_1}\frac{dR_1}{d\alpha}$
4	Efficiency (EFF[b]) in the Transportation of Western Oil	-3.5
8	Specific Capital Cost[b,c] of East Liquefaction Plant	-3.2
8	Availability (AVAIL[b]) of East Liquefaction Plant	3.2
8	Year in Which East Liquefaction Process Becomes Commercially Available (IYRAVL[b,d])	-1.9
9	Efficiency (EFF[b]) of Alaskan Pipeline	-1.7

[a]See Fig.-2.
[b]See Ref. 59 for details concerning these parameters.
[c]See Section IV for details concerning this parameter.
[d]The parameter α has been defined to be IYRAVL-1980.

that will be supplied by eastern liquefaction. The next highest sensitivities are to the specific capital cost and the availability of an east liquefaction plant. The specific capital cost increases the price and thus decreases the amount of fuel used from the plant, resulting in a negative sensitivity. An increase in the availability of east liquefaction decreases the price of fuel from the plant; thus more east liquefaction fuel will be used, resulting in a positive sensitivity. Similar reasoning may be used to understand the signs of the other parameter sensitivities in the table.

In Table-11 the four highest sensitivities are to the parameters that determine the resource supply curve from thermal EOR. These parameters are very basic to a resource process as discussed in Section IV of this

TABLE-11

Sensitivity Results for Response R_2
(see text for definition of R_2)

Node[a]	Parameter	Relative Sensitivity $\frac{\alpha}{R_2}\frac{dR_2}{d\alpha}$
17	Base Price[b] of Oil from Thermal EOR	-.86
17	Initial Resource Cost[b] of Oil from Thermal EOR	.82
17	New Resource at Twice the Base Price[b] of Oil from Thermal EOR	.69
17	Undiscovered Recoverable Resources[b] of Oil from Thermal EOR	.69
1	Price in 1985 (PRICIT[c]) of Imported Oil	-.66

[a]See Fig.-2.
[b]See Section IV for details concerning these parameters.
[c]See Ref. 59 for details concerning this parameter.

paper, and therefore it is to be expected that these parameters (e.g., for thermal EOR) would have significant sensitivities for the result being considered in Table-11. The fifth largest sensitivity in Table-11 is for the price of imported oil in 1985 and is negative, i.e., the quantity of thermal EOR in the year 2000 decreases when the price of imported oil in 1985 is increased. In this case what happens is that the price of imported oil in 1985 causes more oil from thermal EOR to be used in the earlier periods, 1985 and 1990, and less to be used in the year 2000. This is an example of a significant sensitivity that is not obvious, and thus emphasizes that only with the adjoint methodology, that provides sensitivities to all parameters, can one be assured that significant sensitivities will not be overlooked.

VI. CONCLUSIONS

The Liquid Fuel Supply (LFS) model represents the dynamic process by which oil (refinery feedstock equivalent) supply technologies such as shale, coal liquefaction, convention production, enhanced recovery, etc. compete for increased market shares of consumption as a function of time, as tempered by prices of imported oil. The model was built to determine the selling prices and quantities produced from these resources under different assumptions about the cost and availabilities of various technologies, and different assumptions about the future price of imported oil. This paper discusses the design, data and testing of the model. Supported by more detailed laboratory reports, it provides a reasonably complete documentation to "open" the model to public scrutiny and enable a potential analyst to determine whether LFS might be appropriate to his needs.

Since LFS was designed to address problems of supply, it does not contain a sophisticated treatment of the demand for liquid fuels. Moreover, it does not currently model the competition between various liquid fuels and natural gas to satisfy end use demand, nor does it address the competition between liquid fuels and other fuels for electricity generation.

Detailed network diagrams, process equations, and sources of data are given. Twelve depletable resource processes are represented. These include in-situ and surface retorting of western oil shale, tar sands, western and eastern conventional onshore production, three types of enhanced oil recovery, eastern and western offshore recovery, and Alaskan onshore and offshore production. Details of the LFS model equations used to determine the equilibrium prices and quantities of liquid fuels are given in Section III. Six fundamental data parameters (initial resource price, reference resource price, new resources at the reference and twice the reference price, capital cost fraction and deposit decline rate) provide the computational basis for each supply technology. These parameters are calculated from technology specific relationships between marginal cost and supply; elaboration is offered in Section IV.

LFS results are compared to projections of the National Energy Policy Plan in Section V. LFS results generally fall within stated NEPP uncertainty ranges. Specific deviations have been investigated and are now understood. A comprehensive sensitivity analysis capability, developed in conjunction with the LFS formulation, has been indispensible in identifying the differences in calculated results. We believe that the LFS model includes justifiable estimates for all input parameters, as of April 1982. Undoubtedly, these estimates will change as our knowledge of technological possibilities and sociological response are further developed.

We suggest that the LFS model offers a viable tool for systematic evaluation of various policy options toward attainment of our national energy independence. It is actively being used by the Division of Policy and Strategic Planning (DOE/FE), and is now being integrated into a World Oil Model under the sponsorship of the DOE Division of Energy Security. Current research is proceeding in application of this model to particular policy issues, in the development of a Gaseous Fuel Supply (GFS) model, and the LFS/GFS linkage.

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APPENDIX A

THE FINDING RATES MODEL

The basic assumption used for projecting finding rates is that the cumulative quantity of hydrocarbons discovered in a subregion n, Q_n, is related to the cumulative drilling effort E_n by a logistic function:

$$Q_n = Q_{n,\infty} \left[1-e^{-b_n E_n}\right] \tag{A.1}$$

The ultimate recovery estimate $Q_{n,\infty}$, is defined as follows:

$$Q_{n,\infty} = Q_{n,D} + Q_{n,U} \tag{A.2}$$

Since no confusion is possible, and in order to simplify the notation, the subregional indices will be omitted (i.e., $Q_{n,\infty}$, will be written Q_∞, etc.). For conventional (primary and secondary) onshore recovery for example, the quantity of hydrocarbons discovered to date, Q_D, is based on "known recovery" and "reserve growth" data, as given in Tables 5.1 to 5.12 of the RAND/Nehring report.[22] The quantity of hydrocarbons yet to be discovered, Q_U, is based on the most recent USGS estimates[20] of undiscovered recoverable resources. Aggregated values for Q_D and Q_U, corresponding to the seven LFS onshore subregions are shown in Table-A-1.

The finding rate is defined as the incremental quantity of hydrocarbons added for each unit of drilling effort:

$$f(E) = \frac{dQ}{dE} = (Q_D + Q_U)\ b\ e^{-bE} \tag{A.3}$$

The drilling effort E_D, required to add the known recoverable resource Q_D can not be obtained independently, since drilling statistics are generally available only from 1949 to 1980. Hence, using Eq. (A.1):

$$Q_D = (Q_D + Q_U)\ (1-e^{-bE_D}) \tag{A.4}$$

TABLE-A-1

Initial Conditions Used In Computing the LFS Resource Process Parameters for Primary and Secondary Onshore Recovery Regions

LFS Regions	Q_D*	Q_U†	f_D‡	ΔE_D**	$\langle N_E \rangle$††	δ‡‡
West Coast	2.95 + 10***	4.40 + 09	76.0	5.177 + 06	1781.8	.20
Rocky Mountains and Plains	1.21 + 10	2.36 + 10	16.9	1.265 + 07	2053.0	.32
West Texas	4.00 + 10	5.40 + 09	18.0	3.312 + 07	7841.3	.22
Gulf Coast	4.47 + 10	7.10 + 09	25.5	2.592 + 07	4533.7	.21
Midcontinent	2.49 + 10	4.40 + 09	9.0	2.888 + 07	7359.4	.22
East Coast Totals	1.05 + 10	2.90 + 09	4.5	1.132 + 07	4520.5	.90
Alaska	1.42 + 10	6.90 + 09	124.0	5.979 + 05	54.1	.20

*Quantity of hydrocarbons discovered to date[22] (BBL).
†Quantity of hydrocarbons yet to be discovered,[20] 50th fractile (BBL).
‡Initial condition finding rate; data refer to <74-79>[42] (BBL/Ft).
**Initial condition drilling footage[42]
††Net number of exploratory wells[42]
‡‡Deposit decline rate
***Reads as 2.95×10^{10} BBL

and denoting the 1980 drilling rate $f(E_D)$ by f_D we obtain by combining Eqs. (A.4) and (A.3):

$$b = f_D/Q_U \tag{A.5}$$

and

$$E_D = -\frac{Q_U}{f_D} \ln \left[1 - \frac{Q_D}{Q_D + Q_U}\right] \tag{A.6}$$

The incremental drilling effort ΔE required to add a quantity ΔQ to the discovered reserves is then computed as follows. By definition

$$\Delta Q = (Q_D + Q_U) \left[e^{-bE_D} - e^{-b(E_D + \Delta E)}\right] \tag{A.7}$$

Solving for ΔE, one obtains

$$\Delta E = -\frac{Q_U}{f_D} \ln \left[1 - \frac{\Delta Q}{Q_D + Q_U} e^{f_D E_D/Q_U}\right] \tag{A.8}$$

Practically, a "drilling-effort-to-oil-supply" mapping can be constructed by dividing the nominal estimate of undiscovered recoverable reserves into N_u (possibly equal) components $\Delta Q^{(k)}$. Then, the generalized form of Eq. (A.8) is

$$\Delta E^{(k)} = -\frac{Q_U}{f_D} \ln \left[1 - \frac{\Delta Q^{(k)}}{Q_D + Q_U} e^{f_D E^{(k-1)}/Q_U}\right] \tag{A.9}$$

where we have identified

$$E^{(o)} \equiv E_D$$

and

$$E^{(k)} \equiv E^{(k-1)} + \Delta E^{(k)} \tag{A.10}$$

Finally, the finding rate's profile is calculated by substituting the cumulative drilling effort levels $E^{(k)}$ into Eq. (A.3)

$$f^{(k)} \equiv f[E^{(k)}] = \frac{Q_D + Q_U}{Q_U} f_D e^{-f_D E^{(k)}/Q_U} \qquad (A.11)$$

This finding rate profile provides the analytic bridge between the "drilling-effort-versus-oil-supply" relationship, as expressed in Eq.(A.9), on one hand, and the cost analysis methodology developed in Appenidx-B, on the other.

APPENDIX-B

COMPUTATION OF MARGINAL COSTS

Marginal cost is defined as the minimum levelized price leading to a non-negative present value of cash flow for a unit of resource drawn from the undiscovered resource base. This levelized price would be required to build and operate a unit well (i.e., a well whose maximum cumulative production over its lifetime is one unit) without incurring a loss, where costs include normal return to capital, but exclude any resource rent. The finding rates analysis (see Appendix-A) provides a relationship between incremental effort (drilling) and reserve additions. Three additional components are needed to transform this relationship to a relationship between marginal cost and reserve additions.

- Actual engineering costs including drilling, equipment, and operating costs for primary and secondary recovery;
- Financial costs including royalty, severance tax, windfall profit tax and state and federal income taxes;
- Additional capital costs as summarized in a discount rate.

Note that the treatment of economic (scarcity) rents[12] is incorporated in the LFS model and is therefore not included in the analysis of marginal costs. The methodology is based on an engineering analysis of typical wells[23] defined for each LFS subregion in terms of average depth and production profile. In studying the Permian Basin the USGS has developed[24] exponential production decline rates that are applicable to a wide variety of onshore reservoirs. Expressed in terms of both well depth class and well size class (i.e., ultimate recovery), they were used to create the LFS onshore production profiles for typical wells. The average depth, $\overline{z}$, of a well in a given subregion is calculated once from the actual drilling effort, $\overline{\Delta E}$, and the net number of exploratory wells per year $\langle N_E \rangle$, for each subregion. Data refer to the most recent year for which drilling statistics are available, and are shown in Table A-1.

$$\overline{z} = \overline{\Delta E} \; / \; \langle N_E \rangle \qquad \text{(B.1)}$$

The chemcial nature of petroleum formation makes it reasonable to assume that oil wells will be found at this depth at all times in the future. However, future oil wells will be smaller and smaller as the finding rate decreases, since the maximum cumulative production q^{∞} from a typical well over its lifetime is defined using the average depth and the calculated finding rate at any point of the effort-supply mapping

$$q^{\infty}_{(k)} = \overline{z}\ f^{(k)} \tag{B.2}$$

This relationship incorporates increasing dry hole rate into the analysis. Since, well size class is a function of both depth and total recovery, the sub regional deposit decline rate δ can readily be found from published tables.[24] The rate of production as function of time from the well is then given by:

$$q^{(t)} = q^{\infty}\ \delta\ e^{-\delta t} \tag{B.3}$$

This assumes that the rate of production is proportional to the quantity remaining to be produced (for a well operating at full capacity). The production profile g^{μ}, defined as the fraction of total recovery produced in each time interval $[\mu-1, \mu]$ of unit duration, is calculated by first normalizing Eq. (B.3) to one unit of total resource availability, and then integrating from $t_{\mu-1}$ to t_{μ} to yield:

$$g^{\mu} = e^{-(\mu-1)\delta} - e^{-\mu\delta} \tag{B.4}$$

Let $\overline{p}^{(o)}$ denote the initial resource price,[11] i.e., the minimum levelized price leading to a non-negative present value of cash flow for a unit resource facility committed at time node $\mu=1$, where a "unit facility" refers to a well whose maximum cumulative production over its lifetime is one unit. This levelized price would be required to build and operate the well without incurring a loss, where costs include normal return to capital, but exclude any resource rent. Under this assumption, total revenue is calculated as the product of yearly production q^{μ} and levelized price $\overline{p}^{(o)}$, where:

$$q^{\mu} = q^{\infty}\ g^{\mu} \tag{B.5}$$

The net revenues, r^{μ}, are then given by:

$$r^{\mu} = q^{\mu}\ \overline{p}^{(o)}\ \theta_r \tag{B.6}$$

In the above expression, θ_r is defined as

$$\theta_r = (1-\theta_{roy})\ (1-\theta_{sev}) \tag{B.7}$$

with θ_{roy} and θ_{sev} denoting the royalty and severance tax rates, respectively. The Windfall Profit Tax (WPT), w^{μ}, is calculated on a per-barrel basis, as θ_w percent of the difference between the selling price p^{μ} and a legally established base price p_w:

$$w^{\mu} = q^{\mu}\ (p^{\mu} - p_w)\ \theta_r\ \theta_w \tag{B.8}$$

Depreciation is calculated according to the "unit-of-production rule": the yearly depreciation allowance ξ^{μ} is a percentage of the actual investment cost c_{π} determined by the ratio of yearly production to total production i.e.,

$$\xi^{\mu} = c_{\pi} q^{\mu}/q^{\infty} \tag{B.9}$$

In order to compute the actual investment cost c_{π}, it is necessary to estimate the development and production costs associated with conventional onshore recovery. The major source for such costs is the Joint Association Survey of Drilling Costs, conducted annually by the American Petroleum Institute and the American Gas Association. These costs are reported directly by operators and include costs for drilling and completing wells, installing surface equipment, and operating the wells. The costs are summarized in the form of equations, obtained from a recent study[23] of the economics of Enhanced Oil Recovery conducted by Lewin and Associates for the Department of Energy. In general costs are an exponential function of depth, having the form

$$c_{n,i} = a_{n,i}\ e^{\overline{z}\ b_{n,i}} \qquad i \in J_c \tag{B.10}$$

The set J_c of cost categories, includes the following elements i (cost components):

- Drilling and completion costs (i=1)
- Production equipment costs

- Lease and well equipment costs
- Injection equipment costs
- Annual primary recovery costs
- Annual waterflood costs (i=6).

The first three components are incurred before commercial production from the well is initiated. Injection equipment is installed in year μ_s (usually μ_s corresponds to the second year of operation). Primary recovery costs are incurred in each year of production. Waterflood (secondary recovery) costs are incurred in each year after μ_s. Again, for notational simplicity, the subregion index n will be omitted. Thus,

$$c_\pi = (1 - \theta_{ftc}) \; [c_1 + c_2 + c_3 + c_4 \; / \; (1 + \rho)^{\mu_s}] \qquad \text{(B.11)}$$

where ρ denotes the discount rate, and θ_{ftc} the federal investment tax credit rate. Operating costs ψ^μ are constant; in years one through μ_s they include only primary recovery costs; in all subsequent years they include both primary and secondary recovery costs:

$$\psi^\mu = c_5 + c_6 \; H(\mu - \mu_s) \qquad \text{(B.12)}$$

In Eq. (B.12) H denotes the Heaviside function. Taxable income is net revenue less costs of operations, depreciation, and windfall profits tax. The cash flow ϕ^μ in each year is calculated as the income after taxes plus the depreciation allowance

$$\phi^\mu = [\; r^\mu - \psi^\mu - \xi^\mu - w^\mu \;] \; \theta_x + \xi^\mu \qquad \text{(B.13)}$$

The tax coefficient θ_x is defined as

$$\theta_x = (1 - \theta_{sta})(1 - \theta_{fed}) \qquad \text{(B.14)}$$

where θ_{sta} and θ_{fed} refer to the state and federal income taxes respectively. To calculate the financial costs associated with conventional onshore recovery, which are paid from production revenues, the following rate values are assumed:

- Royalties, Severance and Other Taxes: royalties generally are 12.5% of revenues (although 20% royalty rates are becoming more frequent); state severance and ad valorem taxes range from negligible to 12.5%.

- Windfall Profit Tax: recent tax legislation has established a 30% excise tax on revenues from conventional recovery projects in excess of a variable adjusted base price, currently set at 18 dollars.
- State and Federal Income Taxes: a series of tax laws, depreciation rates, investment tax credits, depletion, etc., ultimately determine the state and federal income taxes due on a project; federal taxes are 46% and, in general, state taxes average 5% of net revenues.
- Return on Capital: a 20% after-tax return was assumed in the analysis using constant mid-1980 dollars.

Legislation provides that the Windfall Profits excise tax cannot exceed $\hat{\theta}_w$ percent of the taxable income, i.e.,

$$w^{\mu} \leq \hat{\theta}_w \, (r^{\mu} - \psi^{\mu} - \xi^{\mu}) \tag{B.15}$$

Currently, $\hat{\theta}_w$ is set at 90%. Hence, a generalized cash flow equation, accounting for the constraint formulated in Eq. (B.15), takes the form

$$\phi^{\mu} = r^{\mu} - \psi^{\mu} - \xi^{\mu} - \mathrm{Inf} \left[w^{\mu}, \theta_w(r^{\mu} - \psi^{\mu} - \xi^{\mu}) \right] \theta_x + \xi^{\mu} \tag{B.16}$$

The initial resource price $\overline{p}^{(o)}$ is determined by applying the present value operator Ω_t to the cash flow stream ϕ^{μ}, and setting the result equal to the actual investment cost c_{π}

$$\Omega_t \left[\phi^{\mu}\right] = c_{\pi} \tag{B.17}$$

Since the WPT is a function of the resource selling price, which in turn depends both directly (WPT constraint) and indirectly (possible inclusion of "resource rents") on the initial resource price, the situation is inherently dynamic and highly nonlinear, and requires an iterative algorithm. The actual implementation of Eq. (B.17) is a complicated problem whose discussion is presented elsewhere.[17] The above approach also assumes that markets are perfect. However, in reality, oil is selling at a price p_s (currently p_s is set at about 34 dollars per barrel). Thus, if $\overline{p}^{(o)}$ is less than p_s, there will be additional royalties, severance, windfall profits and income taxes on the quantity $p_s - \overline{p}^{(o)}$. These are calculated using the relationships described in this Appendix and are added to $\overline{p}^{(o)}$ as additional financial costs attributable to imperfect markets.

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