COMMENTS ON THE PROPOSED COMPONENT DESIGN OF THE NATIONAL ENERGY MODELING SYSTEM GAS AND OIL SUPPLY MODEL

by

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at

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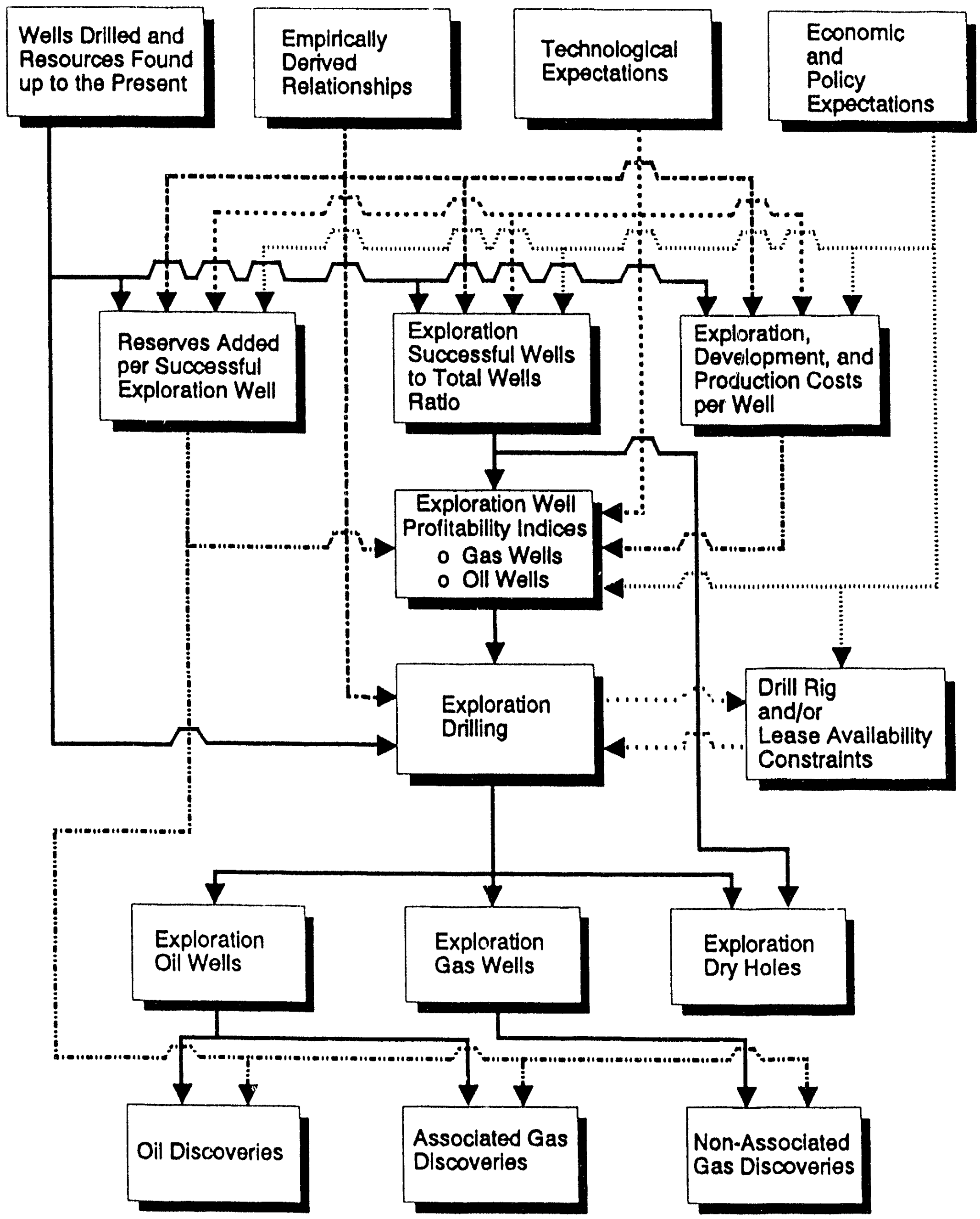
A.G.A.-TERA Drilling Model Overview



SOME OF THE FIRST TESTS A GAS AND OIL SUPPLY MODEL MUST PASS INCLUDE THE ABILITY TO SIMULATE AND PROJECT NOT ONLY ORDERLY FUTURES, BUT DISORDERLY ONES AS WELL:

- EXTENDED PERIODS OF RELATIVELY CONSTANT DRILLING ECONOMICS, CAUSING DRILLING LEVELS TO RISE OR FALL TOWARDS AN EQUILIBRIUM LEVEL;
- GRADUAL, EVOLUTIONARY IMPROVEMENT OR DETERIORATION IN DRILLING ECONOMICS, LEADING TO CONTINUOUS GROWTH OR DECLINE IN DRILLING;
- MASSIVE, SUDDEN ECONOMIC SHOCKS CAUSING PRECIPITOUS, THOUGH DELAYED, CHANGES IN DRILLING.

TO PASS THESE TESTS, A MODEL MUST EMULATE THE *SENSITIVITY* OF DRILLING LEVELS TO THE *INTERACTIONS* OF ANTICIPATED COSTS, FINDINGS, REVENUES, TIME-VALUES, AND OTHER FACTORS.

With the passage of time and the collection of data and the accumulation of experience, that is no longer generally true.

Let me point out to you very briefly the areas which seem to me in my experience to be major sources of uncertainty and major sources of concern to be aware of in building, fine tuning, testing, and in using drilling models.

One, of course, is the cost structure. Drilling cost, as we'll see, is a key uncertainty. Another is the findings per well, and this in my experience is the greatest source of uncertainty in drilling models, and where they indicate we're likely to be going as a nation. Finding rates tend to fluctuate. Success ratios, on the other hand, seem to be fairly stable. Let me show you.

On-shore exploration success has been in the 20-percent range. It went up, kissed the 30-percent range, and it's come back down to the 25-percent range. It's been quite stable at least to the first decimal place or two.

In the formulations that we're using -- and again I stress that our TERA supply models are rather simple -- we find that the key factors are the amounts of cumulative resource that have already been found as a result of previous drilling -- a kind of surrogate for resource depletion -- and wellhead prices. Wellhead prices tend to be positively related with success ratios, and as you'd expect, cumulative resources already found tend to be negatively associated. The time series, at least at an aggregate level, seems very stable and well behaved.

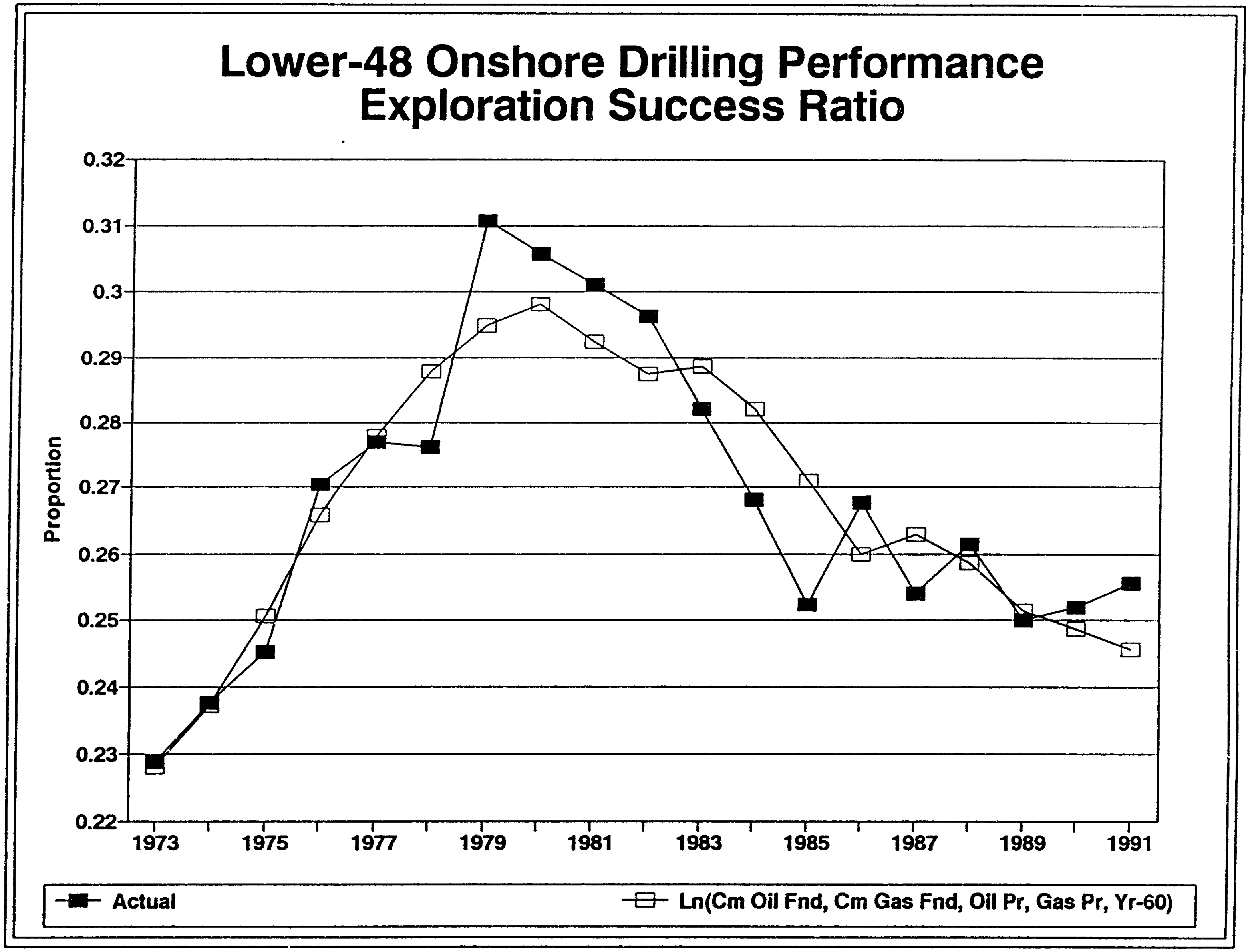
Development drilling has typical success ratios that are well above 70-percent, have been growing very slightly over time, and have been at or slightly above the 80-percent level in the last two or three years. The success ratios are very well behaved, very stable, with little variability, despite the fact that within the Lower 48 as a whole there have been radical shifts of drilling activity. Still at an aggregate level, the overall development success ratio remains very stable, growing slightly over time.

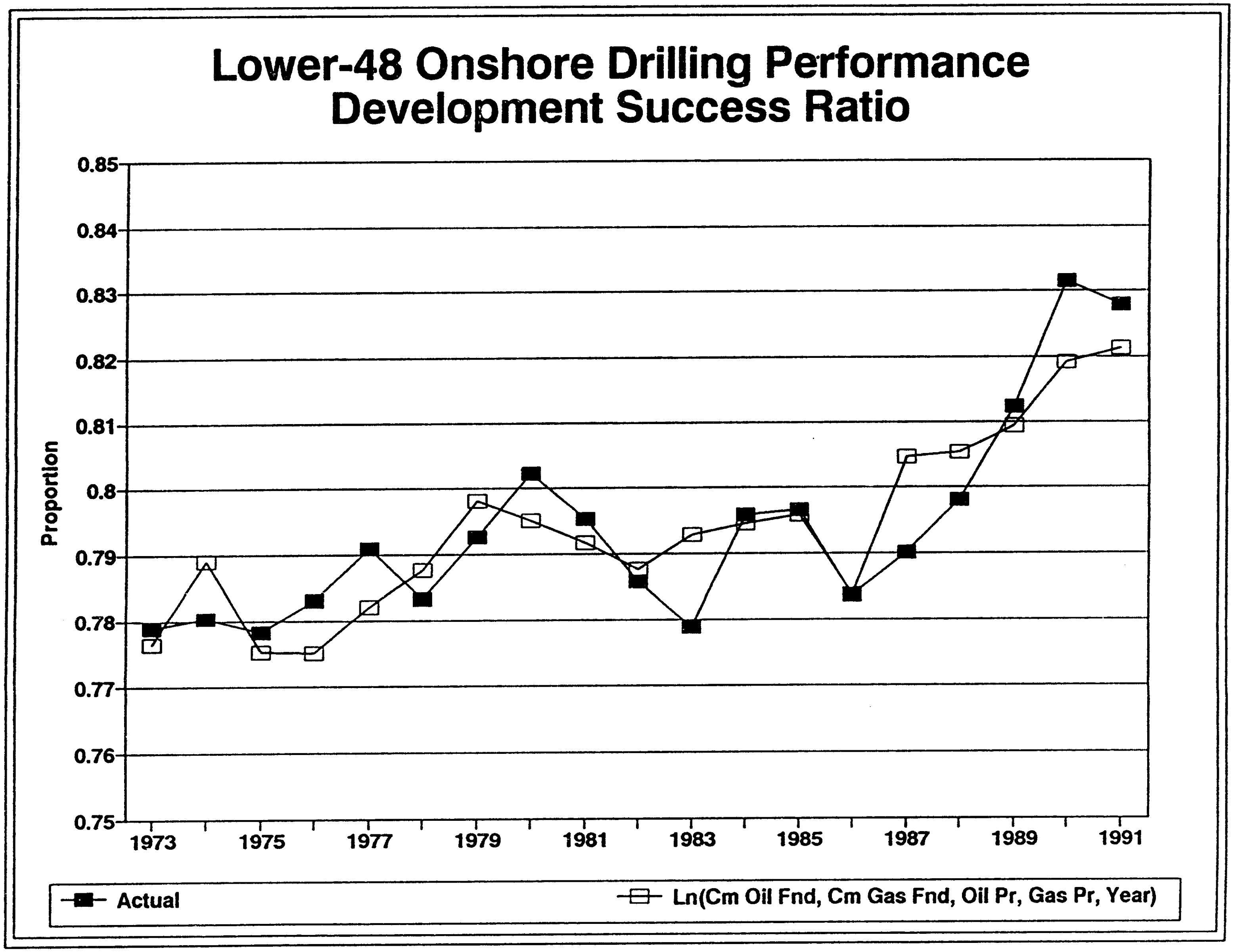
Statistically, resource depletion tends to have negative impacts on supply, as you'd expect. Time trends and implicitly, we think, technology trends beginning in the 1960's seem to be consistent with the kind of development well success growth that we've observed.

So if that is not an area of major uncertainty, then what is? Let's review data on finding rates.

Offshore, the nonassociated gas discoveries and extension per exploratory well -- and Bill and I use our words slightly differently, although in basic terms similarly -- has been growing and has been growing rather steadily. It took a huge bump upwards, up to over 50 to 55 billion cubic feet per well in 1990, back down to around 30 billion cubic feet per well in '91. There has been strong, overall average growth in offshore nonassociated gas findings per well, but a lot of variability there. That is a major source of uncertainty in our projections.

Where is that likely to be going down the road? I've shown it on an aggregate level, simply taking the offshore as a single, undifferentiated group. You break it down into several subgroups. Maybe you'll find more orderliness; maybe you won't. Maybe you'll find greater


Lower-48 Onshore Drilling Performance
Exploration Success Ratio
Proportion
0.32
0.31
0.3
0.29
0.28
0.27
0.26
0.25
0.24
0.23
0.22
1973
1975
1977
1979
1981
1983
1985
1987
1989
1991
Actual
Ln(Cm Oil Fnd, Cm Gas Fnd, Oil Pr, Gas Pr, Yr-60)



Lower-48 Onshore Drilling Performance
Development Success Ratio
Proportion
0.85
0.84
0.83
0.82
0.81
0.8
0.79
0.78
0.77
0.76
0.75
1973
1975
1977
1979
1981
1983
1985
1987
1989
1991
Actual
Ln(Cm Oil Fnd, Cm Gas Fnd, Oil Pr, Gas Pr, Year)

THE SUCCESS OF LOWER-48 ONSHORE DEVELOPMENT WELLS, ON AVERAGE, ROSE THROUGHOUT THE 1970S AND 1980S. ITS MOVEMENTS, TOO, APPEAR TO REFLECT A STRONG RELATIONSHIP WITH WELLHEAD PRICES, CUMULATIVE RESOURCES FOUND, AND TECHNOLOGICAL ADVANCE.

THE AMOUNT OF NON-ASSOCIATED NATURAL GAS FOUND PER LOWER-48 ONSHORE GAS WELL, ON AVERAGE, FELL THROUGH THE EARLY AND MIDDLE 1970S, AND ROSE GRADUALLY THROUGH THE 1980S. ITS MOVEMENTS APPEAR TO BE AFFECTED BY WELLHEAD PRICES, CUMULATIVE RESOURCES FOUND, AND TECHNOLOGY -- BUT THE LEVEL OF UNEXPLAINED VARIATION, ESPECIALLY SINCE 1985, SUGGESTS THAT ITS FUTURE DIRECTION IS VERY UNCERTAIN. SINCE FINDINGS-PER-WELL HAVE AN EXCEPTIONALLY STRONG EFFECT ON PROFITABILITY, AN IMPROVED UNDERSTANDING OF ITS FUTURE MOVEMENTS IS ESPECIALLY IMPORTANT.

disorder, but if your offshore findings per well are going to stay at 30 billion cubic feet per well, or maybe grow to 40 over time, then that gives you one kind of a future world. If they're going to turn around and start to come down over time, getting back down to 20 or 15 billion cubic feet per well, then you're facing a very different world.

That is a major source of uncertainty in our future and in, from a modeling standpoint, uncertainty on how we should be modeling it. Let me show the same slide for the on-shore Lower 48.

The on-shore Lower 48 nonassociated gas findings per exploratory well took a tremendous fall in the late '60s, early '70's, and stabilized down at around a half a billion cubic feet per well in the mid-'70's. It has been moving up since, but with a great degree of uncertainty, a fair amount of bounce that I at least have not explained successfully in my work. Because the last data point is a bounce downward, it gives you concern. I'm very eager to get another data point and hope that it's back up again.

If on-shore Lower 48 in aggregate is headed up towards or above one billion cubic feeet per well, then that gives us one kind of a future. If it's going to stabilize at around 0.7 billion cubic feet per well or turn around and come back down to 0.5, it gives us a very different future. From the modeling standpoint, my model reacts tremendously to the parameters that you feed in for the findings per well.

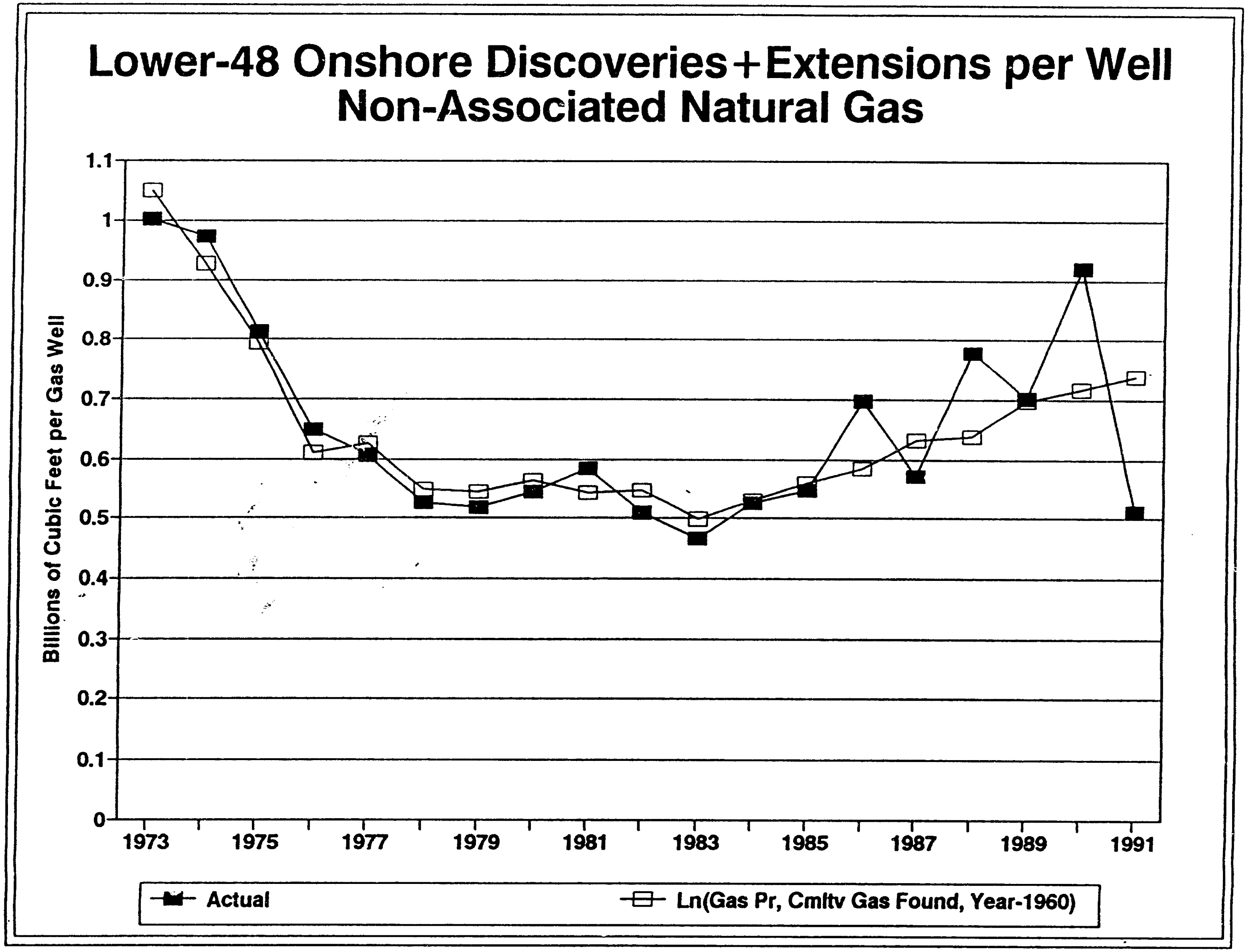
Andy mentioned sensitivity to the econometrically fitted parameters, and I can tell you at least in my drilling model that sensitivity to the fitting parameters for these findings per well is extremely high.

Turning to another major component of profitability and drilling simulation is the cost per well. As we can see over the last 15, 20 years, the drilling cost has been -- and that's the black bar -- a major component. It represents roughly 40 percent of the total. The other major component is equipment cost. The question for modelers is: how can you project and to what degree of certainty and comparability can you project future movements of those?

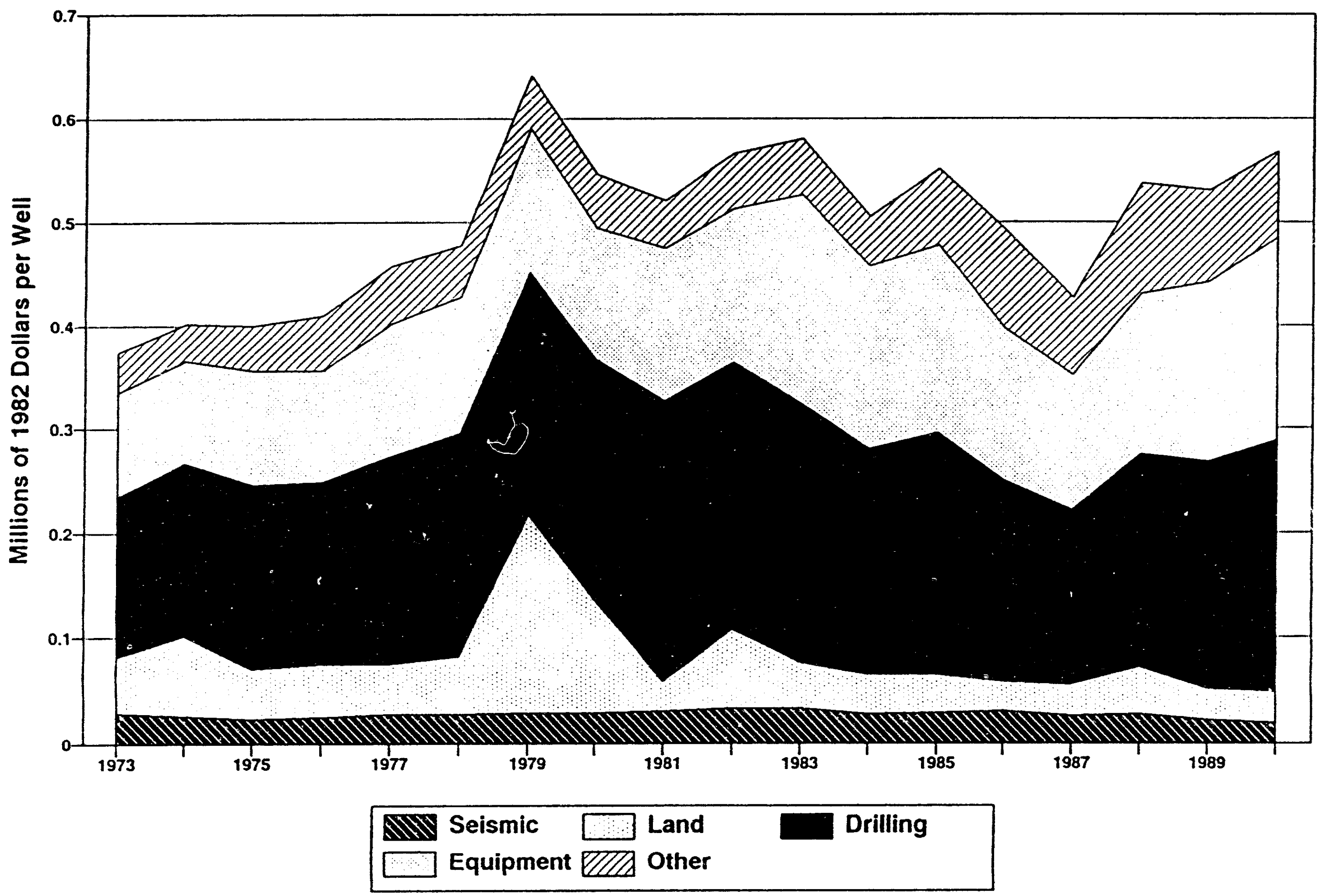
Let's just take a look at the drilling cost, since it is a big one. The drilling cost per well has moved up and down and recently has been moving back up again. We find that you can track its major movements. However, this is based on lower 48 as a single, undifferentiated; group, you might find somewhat different things looking at geologic subregions or geographic subregions.

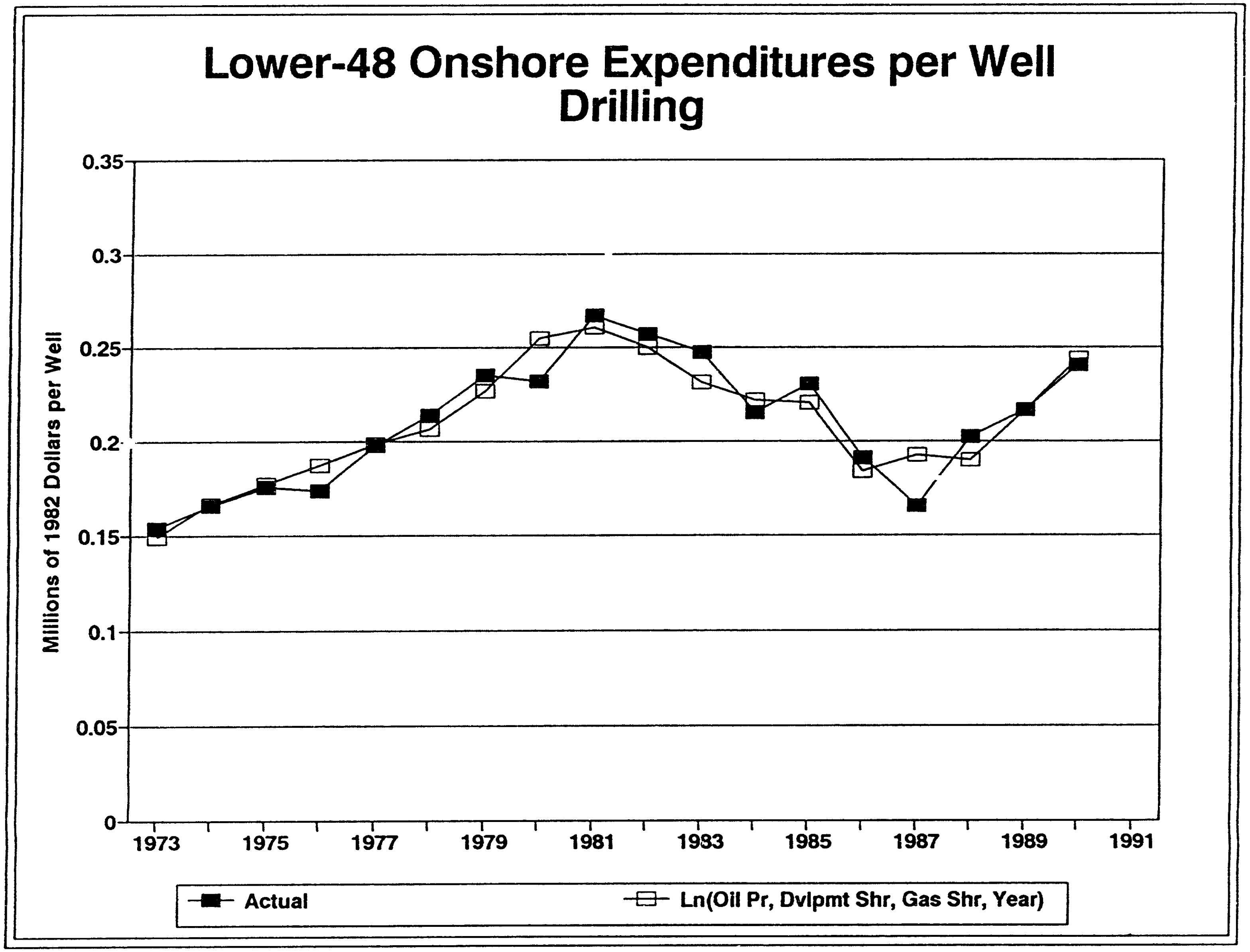
We find that wellhead price and some other variables allow you to track the major movements and turning points in drilling cost per well and give me, at least, some degree of confidence that I can project drilling costs with some degree of reliability. I can estimate and insert into my drilling model and capture in my drilling model the impact of drilling costs at least.

So where does that leave us? Again, I can only speak from the standpoint of my own modeling experience.


Lower-48 Onshore Discoveries+Extensions per Well
Non-Associated Natural Gas
Billions of Cubic Feet per Gas Well
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
1973
1975
1977
1979
1981
1983
1985
1987
1989
1991
Actual
Ln(Gas Pr, Cmltv Gas Found, Year-1960)

Lower-48 Onshore Expenditures per Well
Total




Lower-48 Onshore Expenditures per Well
Drilling
Millions of 1982 Dollars per Well
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
1973
1975
1977
1979
1981
1983
1985
1987
1989
1991
Actual
Ln(Oil Pr, Dvlpmt Shr, Gas Shr, Year)

DRILLING COST REPRESENTS, ON AVERAGE, THE LARGEST SINGLE COMPONENT OF CREATING A WELL. FOR THE LOWER-48 ONSHORE, DRILLING COST REPRESENTS ABOUT 40 PERCENT OF TOTAL WELL COST.

DRILLING COST, MEASURED IN INFLATION-FREE DOLLARS, INCREASED THROUGHOUT THE 1970S, DECLINED IN THE EARLY AND MIDDLE 1980S, AND HAS BEEN INCREASING SINCE 1986. OUR EXPERIENCE SUGGESTS THAT ITS MOVEMENTS REFLECT A STRONG RELATIONSHIP WITH WELLHEAD PRICES, THE BREAKOUTS BETWEEN EXPLORATION AND DEVELOPMENT AND BETWEEN OIL AND NATURAL GAS, AND TECHNOLOGICAL ADVANCE.

We find that you can put a drilling model such as ours into the context of a larger modeling system which includes simulation of energy demands and the various end use markets. We find that you do get an orderly representation and an extremely sensitive response to the external factors, be they rates of economic growth, crude oil price projections, or other things, such as taxes or policy variables. The results represent a balance -- a market clearing balance between drilling model behavior and demand model behavior. The results show you alternative futures that individually, unless you're extreme in your input assumptions, represent a somewhat believable, evolutionary change from the world that we have seen and the world that we're living in now.

So I think that there is reason to be hopeful that the NEMS drilling models will be very useful, and that they will deliver results that we'll feel comfortable with. I'm very eager to see your work as it goes on.

MR. KENDELL: Our second reviewer this morning is Dr. Emil Attanasi. He's been an economist with the U.S. Geological Survey for more than 20 years. His work has mainly focused on the application and development of oil and gas assessment methods, and includes frequent use of modeling techniques. We look forward to his insights this morning.

DR. ATTANASI: Good morning.

What we have here is pretty much an a priori specification of what modelers want to see in the oil and gas simulation model. There are a number of improvements that are represented by this, the NEMS model, including their common format and the regional price equilibrium. The unconventional gas is treated separately, and I'll speak more about that later. Domestic oil production finally affects world oil prices in the model. Our domestic oil and gas industry comprises one of the larger producers in the world, and in models it never seems to affect oil price.

We are concerned with a number of things. First of all, we want to talk about the structural characterization of the industry. When we deal with geologists, we like to give them a lot of data to do their appraisals. My colleague says that if you give them a lot of data, and show where the drilling is, they'll get a better idea of what might be undiscovered, and we call those training wheels.

This model needs some training wheels of its own. We don't find any way that you can constrain the amount of drilling in here both in terms of the overall investment and in terms of shifts across regions.

Now, Bill may be able to speak to that when we talk about the way he's going to estimate the shares of drilling that each region will receive.

There are also some incongruities. For example, in the EOR specification -- may I have the next slide -- it's pretty much onshore. However, you can see there are offshore oil fields that are being produced with EOR methods. We have the California fields that are hot water steam, and we also have some Gulf of Mexico and OCS, OCS and offshore Louisiana and Texas fields that are undergoing enhanced recovery methods.

A MODEL'S ABILITY TO CORRECTLY ANTICIPATE THE FUTURE WILL DEPEND ON THE LEVEL OF *INSIGHT* ACHIEVED IN EXPLAINING CERTAIN *KEY FACTORS*.

SOME OF THE CHALLENGES INVOLVED IN GAS AND OIL SUPPLY MODELING CAN BE ILLUSTRATED BY LOOKING AT A SET OF THREE *KEY FACTORS*:

- o DRILLING SUCCESS RATIO;
- o AVERAGE FINDINGS PER WELL;
- o DRILLING COSTS.

THE SUCCESS OF LOWER-48 ONSHORE EXPLORATION WELLS, ON AVERAGE, ROSE THROUGH THE 1970S, FELL THROUGH THE EARLY 1980S, AND HAS BEEN RELATIVELY STABLE SINCE 1985. OUR EXPERIENCE SUGGESTS THAT THIS IMPORTANT FACTOR'S MOVEMENTS REFLECT A STRONG RELATIONSHIP WITH WELLHEAD PRICES, CUMULATIVE RESOURCES FOUND, AND TECHNOLOGICAL ADVANCE.

THESE INTERACTIONS ARE NOT LINEAR. TO SUCCESSFULLY REPRODUCE REAL-WORLD *SENSITIVITY,* A MODEL MUST CORRECTLY REFLECT THEIR NON-LINEAR INTERRELATIONSHIPS.

A.G.A.'S EXPERIENCE WITH GAS AND OIL SUPPLY MODELING SUGGESTS THAT A PROPERLY IMPLEMENTED *PROFITABILITY CRITERION* PLAYS A KEY ROLE IN SUCCESSFULLY RECREATING *SENSITIVITY*.

THE A.G.A.-TERA DRILLING MODEL'S *PROFITABILITY INDEX* ILLUSTRATES THE CENTRAL ROLE OF PROFITABILITY IN GATHERING-TOGETHER MANY DIVERSE FACTORS AND DETERMINING THEIR COMBINED INFLUENCE ON DRILLING.

THE IMPORTANCE GIVEN TO THE *PROFITABILITY CRITERION* IN THE NEMS GAS AND OIL SUPPLY MODEL SUGGESTS THAT IT WILL PROBABLY BE ABLE TO PASS FIRST-ORDER TESTS OF SENSITIVITY.

I HAVE POINTED OUT A FEW KEY ISSUES THAT MUST BE SUCCESSFULLY ADDRESSED IN THE NEMS GAS AND OIL SUPPLY MODEL. THERE ARE MANY OTHERS: RECOMPLETIONS, INFILL DRILLING, REVISIONS, DISAGGREGATING THE RESOURCE BASE, ETC.

ULTIMATELY, THE SUCCESS OF THE NEMS GAS AND OIL SUPPLY MODEL, LIKE THAT OF A MUSICAL INSTRUMENT, LIES IN ITS TUNING. THE TUNING WILL COME ONLY WHEN THE MODEL IS OTHERWISE COMPLETE. ONLY THEN WILL ANYONE, INCLUDING THE NEMS MODELERS THEMSELVES, BEGIN TO KNOW HOW WELL THEY HAVE SUCCEEDED.

FOR NOW, I BELIEVE THAT THE OVERALL DESIGN IS ONE THAT IS CAPABLE OF PRODUCING A TRULY USEFUL MODEL OF DOMESTIC U.S. NATURAL GAS AND OIL SUPPLY, AND THAT THE MODELERS ARE ADDRESSING THE ISSUES THAT MUST BE FACED AT THIS STAGE IN THE MODEL'S DEVELOPMENT.

DISCUSSION POINTS

- MODEL PURPOSE AND STAGE OF DEVELOPMENT
- STRUCTURAL CHARACTERIZATION OF THE INDUSTRY
- RESOURCE CHARACTERIZATION
- MODEL APPLICATION AND VALIDATION

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So we have some incongruities. Let me encourage Bill to also work hard on getting those regions in the Gulf segregated because right now his drilling costs are only a function of drilling depth, but both exploration costs and development costs are, of course, functions of water depth. You have different rigs that can be used for drilling exploration wells, and of course, platforms are stressed for water depths.

There are some other problems that might be too detailed to express here, but we think one of them is the Northern Alaska characterization. The drilling costs, for example, on an exploratory well in the Point Barrow area, where all the commercial development is, are much less than if you have to build an air strip in the interior part of the North Slope to bring in equipment and so forth. So your assessment on undiscovered resources in Alaska should include some idea of geographic location.

There also is concern about the level of aggregation in the model. Again, the most glaring example is the way Southern Alaska is characterized. The next slide shows the fields that are offshore in Southern Alaska in the Cook Inlet area and those that are onshore. Clearly you have both types of production.

In fact, the offshore has two very different cost demarcations also. If you go outside the Upper Inlet and into the federal waters, the costs are much more than if you're in the balmy northern part of the inlet.

We're also concerned about the level of aggregation in the lower 48 model. I think this is more a question of testing the model to see whether aggregation makes any difference. We at USGS can provide at least drilling costs and undiscovered resource estimates on a basin level if you want to go down to a smaller region. We are working on a new assessment that should be done by the end of 1994 that will try to provide a more detailed characterization of the resources.

The next thing that I looked at very carefully was the resource characterization. Bill and I talked about the way the discovery or finding rate variable is specified, and we agreed that we needed some work on that. I won't go into that detail now.

There is one other part that I think needs to be mentioned, and that's the way inferred reserves enter the model. One should vintage those reserves. What I want to do is describe why it's very important to go the route that EIA has gone and make a very clear effort to separate unconventional gas resources from conventional resources.

David Root and I have been working for about a year and a half on the OGIFF database, which is a field database that the Department of Energy has constructed. Our idea was to get a handle on reserve growth: the inferred part of the reserve base that seems to be growing very fast.

Let me give you an explanation of what reserve growth is, or field growth as we call it. It's the periodic increase in ultimate recovery estimates as the field is developed and produced. The initial estimates are usually conservative, and as the field gets produced, estimated recovery grows. This occurs for a number of reasons. You have multiple completions of wells that exist.

EOR APPLICATIONS TO FIELDS EXTENDING OFFSHORE AND OFFSHORE FIELDS

HOT WATER/STEAM

BELMONT (OFFSHORE)	CALIFORNIA
HUNTINGTON BEACH	CALIFORNIA
WILMINGTON	CALIFORNIA

CO2/GAS INJECTION

BAY MARCHAND	LOUISIANA
SOUTH PASS BLOCK 61	OCS
SOUTH PASS BLOCK 89	TEXAS

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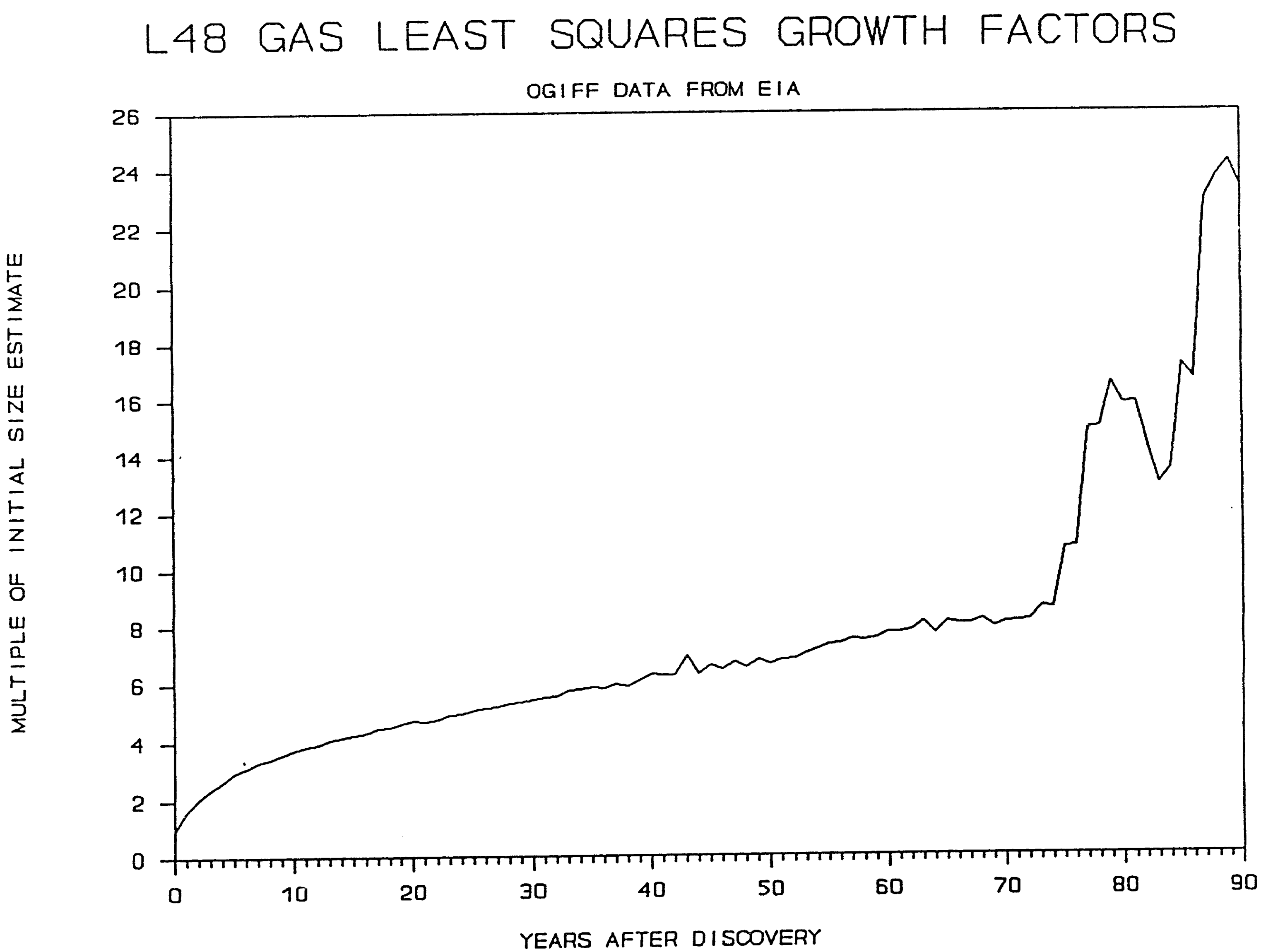

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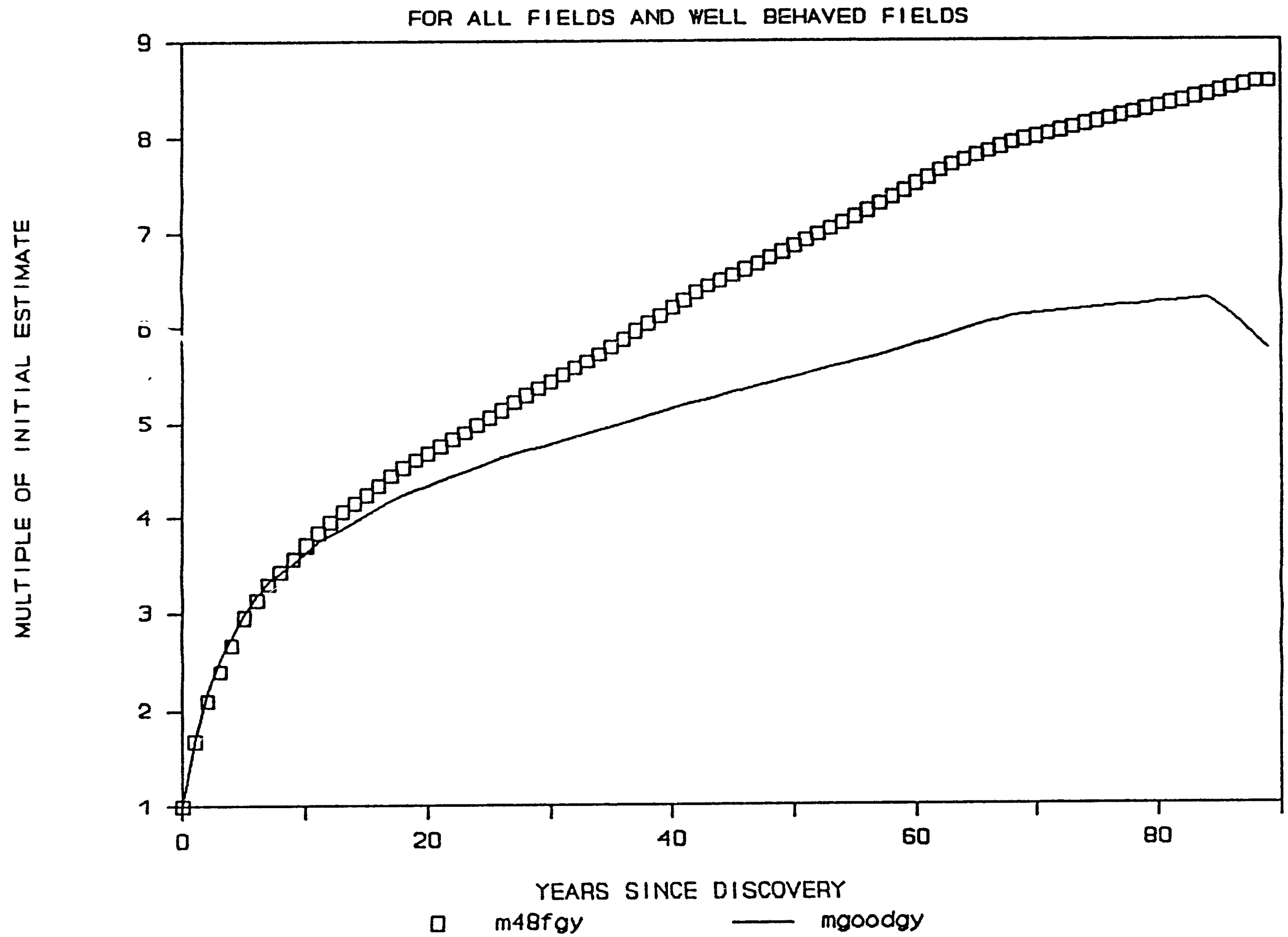
L48 NON-ASSOCIATED GAS GROWTH FACTORS



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You also have extension drillings and new reservoirs discovered within producing fields.

Field growth is usually characterized by a growth function, which relates expected field size as a multiple of the field's initial expected based on the number of years since the discovery.

There are only two data sources really for these reserves data. There's the old API series that runs from 1966 to 1979, and this new OGIFF data series which runs from 1977 to 1990. The OGIFF is a field database.

We looked at the OGIFF data for nonassociated gas. This slide shows the least squares growth function for nonassociated gas -- very strange looking. You would not expect that fields are growing for 80 years, 90 years. However, that's the trend in the data, and so that's the way the function is constructed.

The data need to be considered carefully. We rarely ever see reserve estimates for a field's initial discovery and annual estimates until it shuts down. What we have are small bits and pieces of fields, collections of fields that are 80 years old. Maybe some reserves are added and those bits and pieces go into estimating that growth function.

That growth function looks strange. If we were to posit that the growth should follow a monotonic function such that the percentage growth experience is a function of the age, growth should decline in those fields. In other words, as a field gets old, your percentage growth should decline. Then we would have a monotonic function; so we fit the data to a monotonic function. That's the upper curve on the next slide.

The interesting thing about that is if you put that into the normal way we estimate inferred reserves, the minimum you would get would be 350 tcf. You can get much more.

David and I looked at this very carefully, and we devised a statistical test for eliminating outlier fields. In other words, we processed our data set to identify data that deviate from our assumption of the way a field should be developed and finally produced.

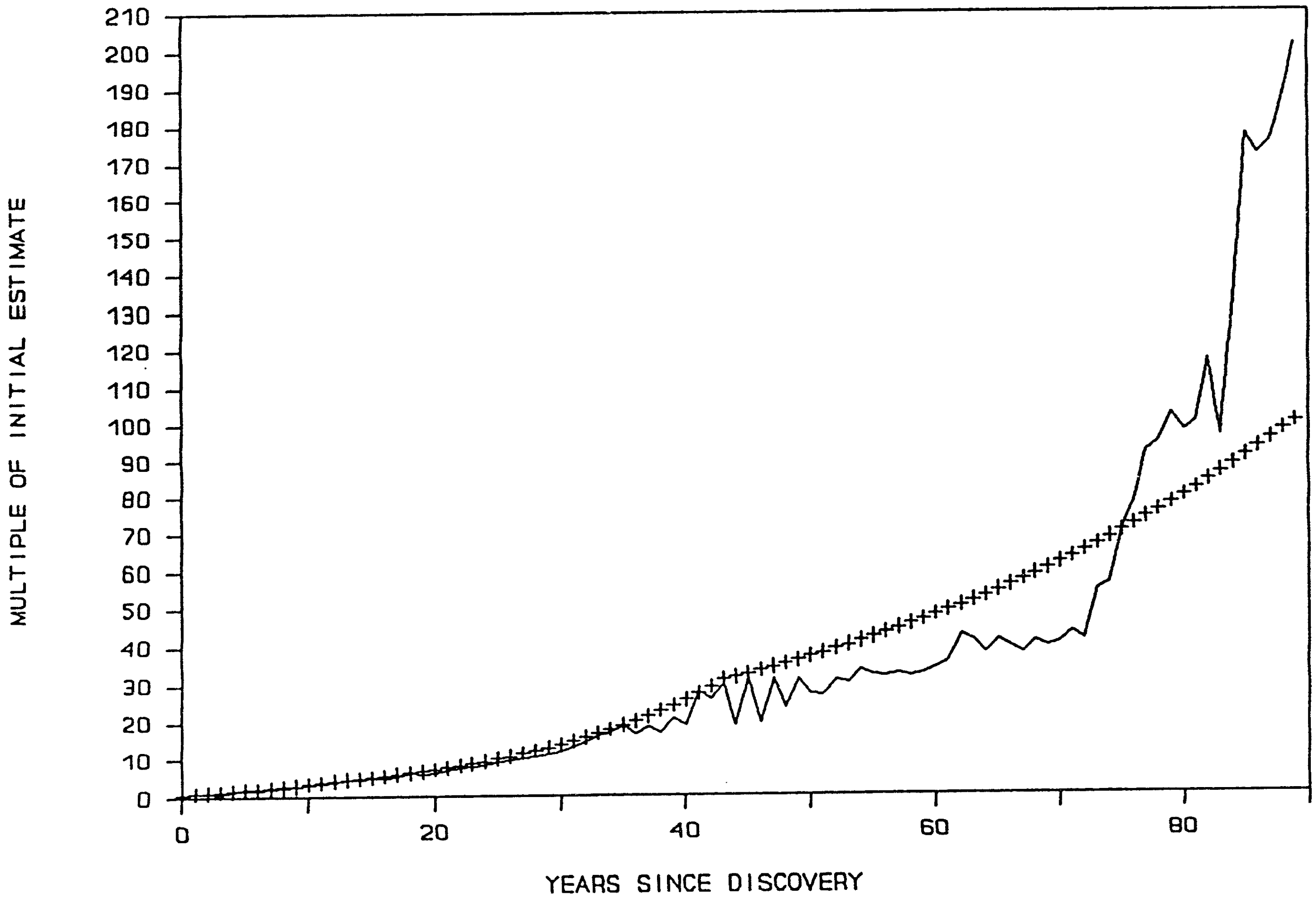
Our results, showed about 13 percent of the gas resources during the period from 1977 to 1990 grew 121 percent. For the oil 13 percent of the resources grew 68 percent. Normally the fields that were not in this outlier data set for gas grew only 17 percent over that 15, 14 year period, and 11 percent for the oil.

So the bottom curve represents what you would get if you deleted those outlier fields. When we looked at those fields, we realized that the older gas fields, many that were located in Appalachia, had very high RPs, characteristics of tight gas. They only got produced when the price went up to very large figures.

So the lesson here is twofold. Keep the conventional and unconventional separate in your inferred and if you can carry it separately, keep it separate in the producing field data. We would not have recognized this if we had not seen field data. By the way, the second curve gives us a conventional inferred reserves of about 190 tcf, which is very consistent with what

L48 NON-ASSOCIATED GAS OUTLIER FIELDS

MONOTONE AND LEAST SQ. GROWTH FACTORS



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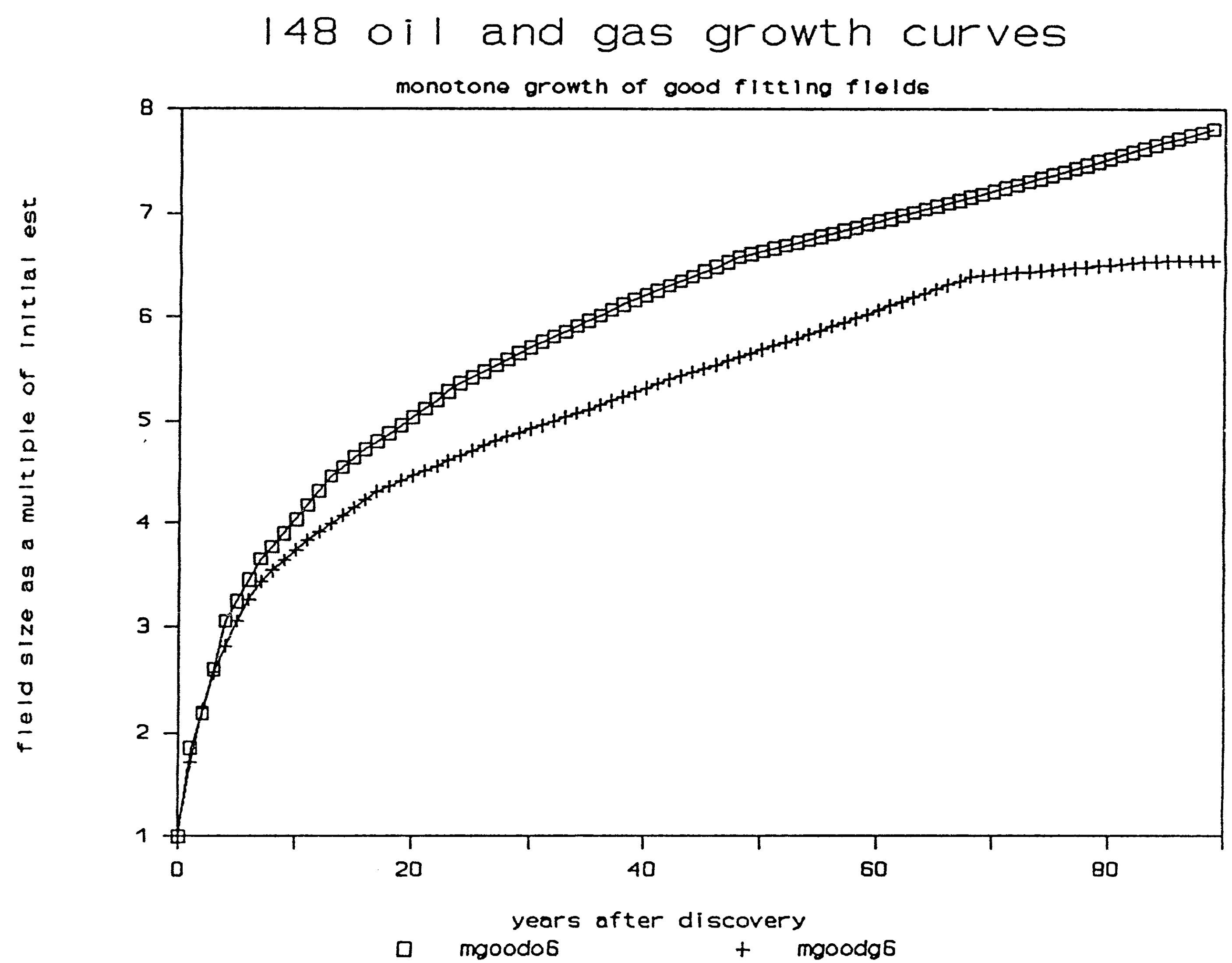

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N E M S

Oil and Gas Supply Models

Presentation by J. B. Corns

Director, Industry Analysis and Forecasts, North America

Amoco Corporation

February 1, 1993

the NPC just published.

The final point that I want to discuss is model validation and model uses. I think EIA should establish some very formal criteria for evaluating the NEMS model. What we see here is a part of a larger model. If that part is not making any significant impact, which I can't believe, then maybe one doesn't need sophisticated tools. I tend to think that the domestic oil and gas industry will be an important part of the NEMS process. They should also test the level of aggregation. Finally, since the industry has changed so much, I'm not sure that testing a model against history -- how well it reproduces history -- will be a very good measure of how it will do in predictive performance.

Thank you very much.

MR. KENDELL: Our final reviewer this morning is Joe Corns, the Director of Industry Analysis and Forecasts for Amoco Corporation, North America. As such, Joe's in charge of conducting oil and natural gas supply analyses. Like several of the other panelists this morning, he was a participant in the recent National Petroleum Council study on natural gas, and Joe is upholding the honor of the engineering profession this morning while the rest of us are simply economists. So we hope to hear some good insights from Joe.

MR. CORNS: Thank you, Jim.

I thought that I would approach this reviewing task by examining myself what I thought should be in a supply model and then comparing what NEMS has with my own personal views. I didn't try to do an exhaustive literature search to see what other people thought should be in models, but just introspected about it and came up with my own list.

My list starts with the resource. I say that the resource should be well defined with regional detail. Now, you always have a problem with the resource in that we're never going to know exactly what the resource is like until we've found it all and produced it all. We talk about undiscovered resource and people say, "Well, how do you know what the undiscovered resource is like if it hasn't been discovered yet?" And that's a good question.

Nevertheless, we do have ways. Geologists have ways of forecasting what the resource is going to be like. They have all of the statistical data on the resource that's been produced up to now.

Another factor is that industry behavior should be realistically simulated. People can say, "How do you simulate herd instinct?" That's an industry behavior that we've all seen. How do you simulate irrationality? That's another industry behavior we've all seen.

But the kinds of things that I'm talking about here are things like: what's the industry capacity to drill? And how much time does it take to change that? How much time does it take to build up or phase down that capacity? And what's the relative efficiency of drilling at high drilling rates versus low drilling rates?

If you want to talk about irrational behavior, it seems to me that one prime example is

Desirable Characteristics of Supply Models

- Resource Should be Well Defined, With Regional Detail
- Industry Behavior Should be Realistically Simulated
- Investment Rate Should be Constrained by Industry Cash Flow and Profitability of Unit Investments
- Logistics Should be Incorporated

Desirable Characteristics of Supply Models (Cont.)

- Supply and Demand Should Interact
- Technological and Regulatory Changes Should be Explored
- Seasonality Should be Included in Near-Term Forecasts
- Model Should Run Efficiently

100

Desirable Characteristics of Supply Models

- Capability to Explore

Uncertainties

what the industry did in 1979 and 1980 and 1981 when oil prices went up to $35 and $40 a barrel. The industry was running out to every available site that they could drill, and they were paying horrendous costs for rigs and horrendous cost for pipe. If you stand back and look at that behavior, it appears irrational.

Another factor is that the investment rate should be constrained by industry cash flow or industry revenues or something. Also, the model should look at the profitability of unit investments. It doesn't want to just keep drilling when the profitability or the projected profitability is very low.

Finally, some form of logistics should be incorporated. This is especially important for gas, since gas is so expensive to transport, but it's also important for oil because we have coastal refineries and inland refineries and all of those have their own logistics problems.

There are other desired characteristics. It should have some kind of supply and demand interaction. That doesn't have to be in the supply model, but there should be an interaction so that you don't always produce more oil and gas than the economy can use or, on the other hand, you don't produce enough to meet demand. As I say, this is something that doesn't have to be built into the supply model itself. It can be some kind of external interaction between modules.

Now, if we're looking at near term forecasts, very short-term modeling, we should look at seasonality because seasonality has a tremendous effect on, say, natural gas demand, and it also has some effect on oil demand, as well.

The model should run efficiently. It shouldn't cost a fortune to make a run, and the runs have to be able to be completed in a reasonable time.

You have to have a capability to explore uncertainties in the models. I know that this morning Dr. Kydes mentioned some points that made me think that maybe we're going to have some uncertainty capability built into NEMS, and that's great. In other words, you put in a parameter, and the model will give you a feeling for how much the supply, demand, or price will change with a change in that particular variable.

Chances are the model will have the wrong uncertainties built into it and that's just the way things are. Nevertheless, we have to be able to explore uncertainties if we're going to do modeling and expect to get very much out of it.

Here's a desirable characteristic of supply modelers: they have to be willing to explore uncertainties. This is a problem, particularly if you have to explore uncertainties by putting in a new set of parameters, because people often don't want to do it. It takes too much time and too much effort, and of course, it does take time and effort. There's no getting around it, but we have to be willing to look at these uncertainties to know where we're going with our models.

Some of the areas of greatest uncertainty now may not be the areas of greatest uncertainty in the future. We know that prices and price setting mechanisms are areas of great uncertainty. We, as industry forecasters, just don't do a very good job of forecasting prices.

Desirable Characteristic of Supply Modelers

- Willingness
  to Explore
  Uncertainties

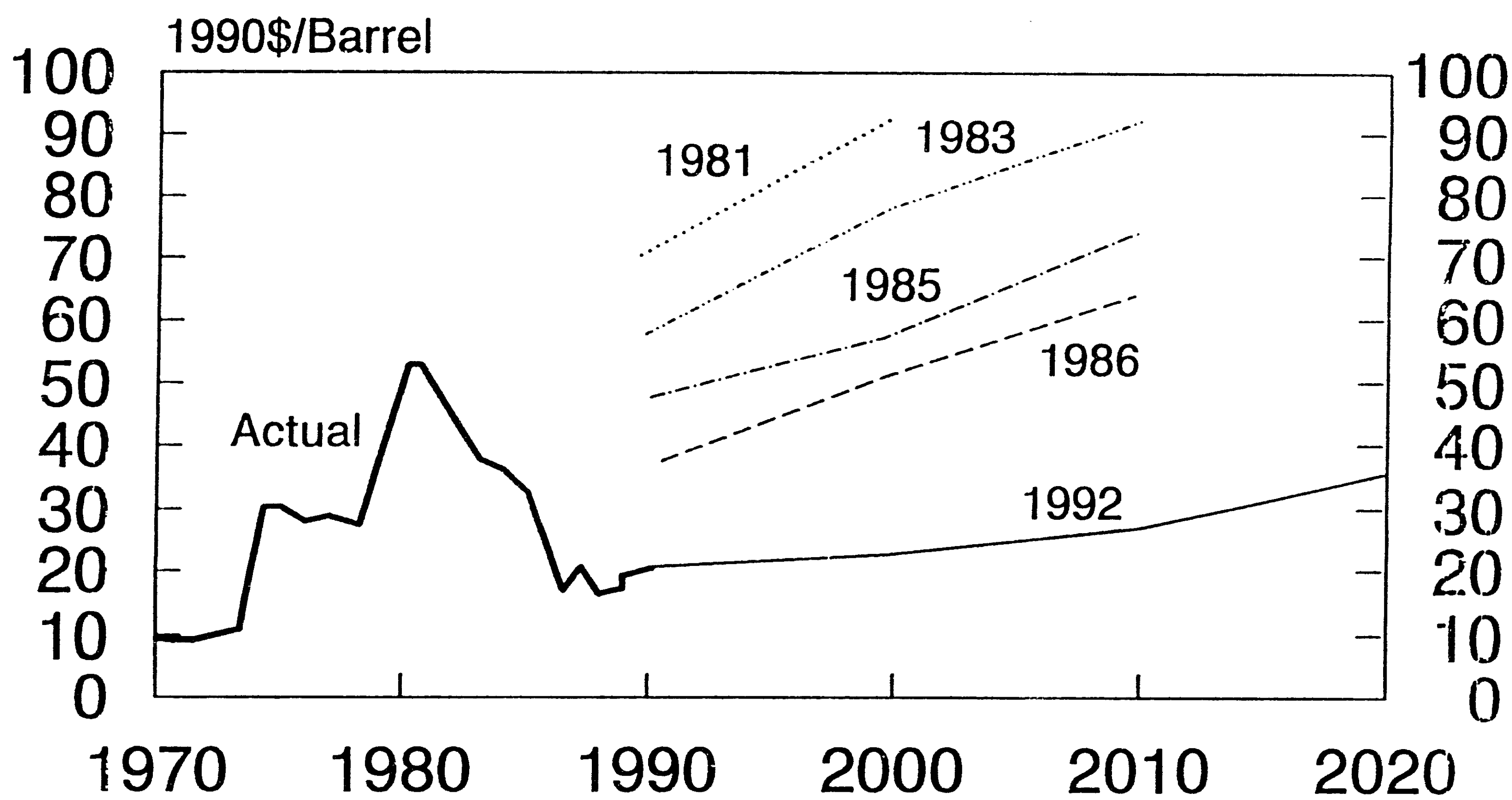
Areas of Greatest Uncertainty

- Prices and Price-Setting Mechanisms

- Size and Cost of Undiscovered Resource Base

- Political, Regulatory and Technological Developments

Crude Oil Prices
Actual and Successive IEW Polls



Another area is the size and the cost of the undiscovered resource base. We can draw supply curves, but just because we draw them doesn't mean they're right.

There are political, regulatory and technological developments. We have to look at those because they hold tremendous uncertainty. When I say "political," I'm including such things as disruptions in supply, like oil embargoes and other things which have a tremendous impact on short-term supply and price.

To illustrate the impact of some of the uncertainties, just look back at some international energy workshop polls on oil price. This is an example of trend forecasting. You go back to 1980 and 1981, and prices had gone up very rapidly for a few years prior to that. So the forecast said, well, it will keep going up from where it is now and it will go up forever.

So as a result of that, in 1981, we had a forecast that said you were going to be higher than $90 a barrel in 2000 -- and this is in 1990 dollars per barrel. Then if you look at the '83 forecast, prices were somewhat on the decline. So the forecast came down. In 1985 it came down some more; in 1986 still more. Of course, 1986 is when the prices really fell, and then if you look at other forecasts, other polls, there's a steady march down until you get to the 1992 poll, and it's pretty flat. This is going out to 2020.

Here's another example of a trend forecast. Anybody that remembers forecasts that were made at about 1970 or '71 or '72 can remember that everybody then was worried about where our oil would come from in the future. The reason for that was that oil demand had grown at about seven percent per year for 20 years, and we all said, "Well, it's going to continue to grow at seven percent per year. I mean after all it's done it for 20 years and longer." If you look at that forecast, it gets you up to about 180 million barrels per day of world oil demand by 1990 or so.

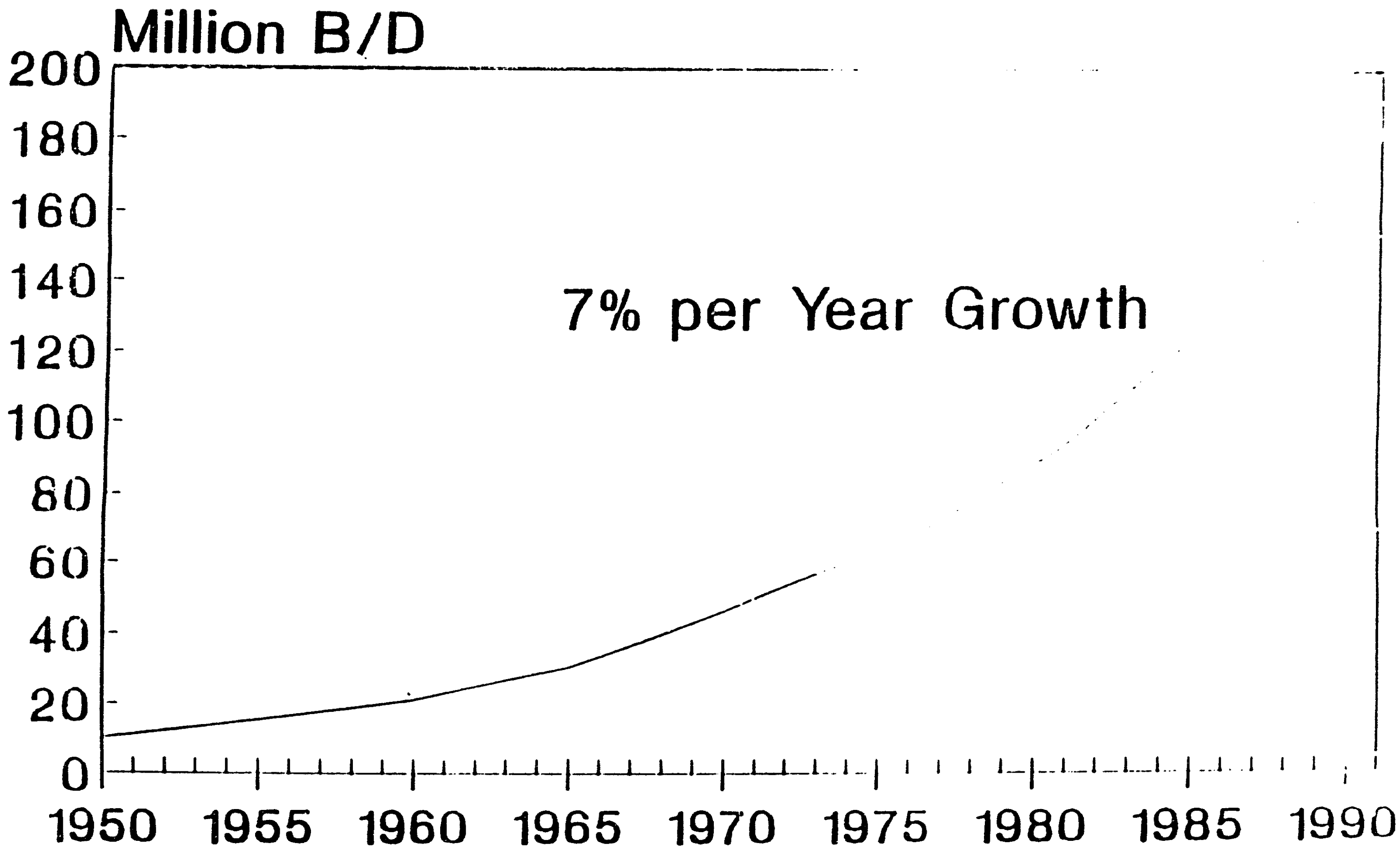
Here is what really happened. You can see that with the increase in oil prices that occurred about 1973 and the conservation that was encouraged from that, that we've had very little growth, maybe one or two percent growth for the 20-year period since 1973.

Well, now, I made that list of desirable characteristics. So how does NEMS measure up to that, to my list? Well, I said that I thought the regional resource should be well defined or the resource should be well defined with regional detail, and that there should be incorporation of logistics.

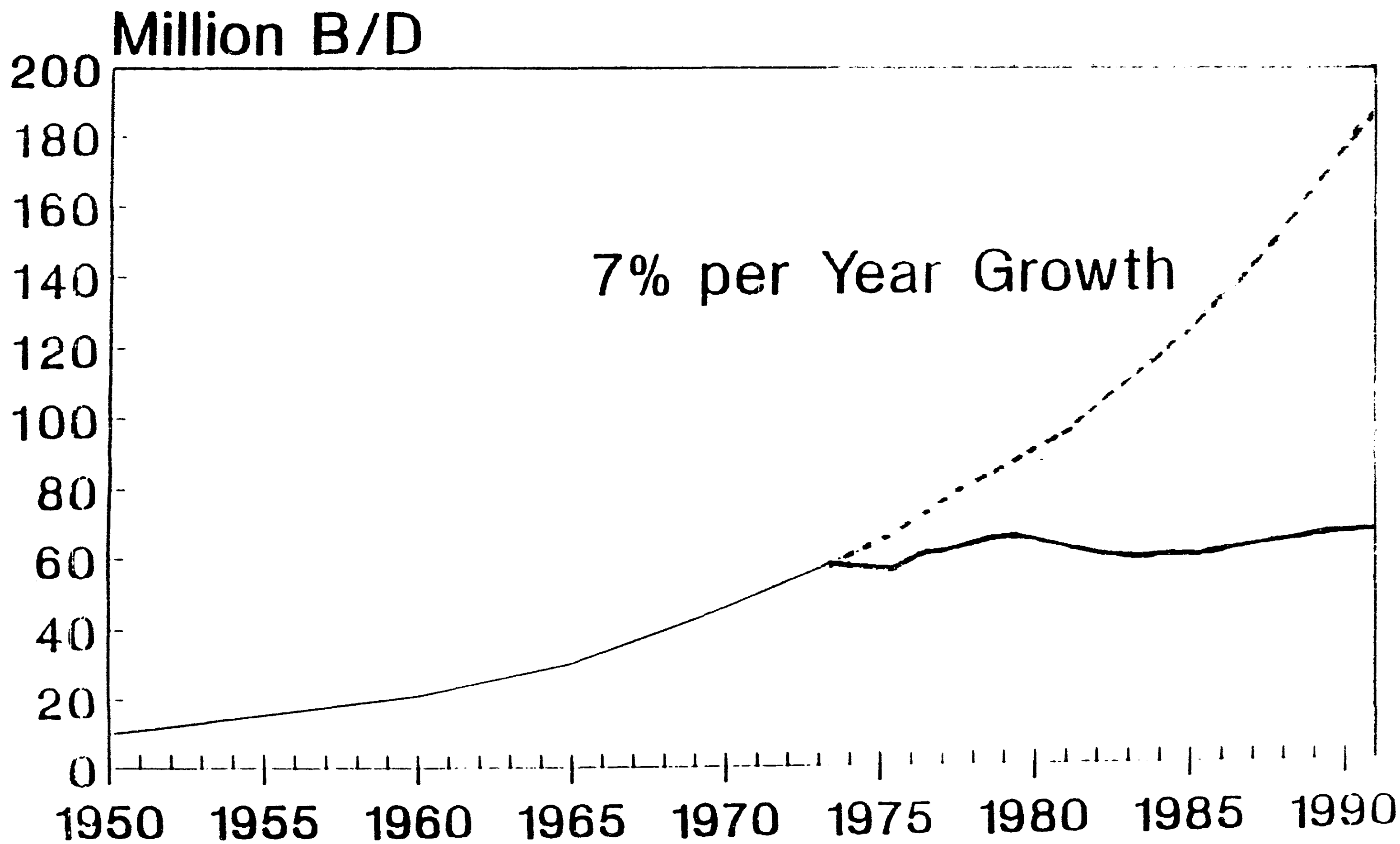
Well, Bill tells us that NEMS will allocate regional investment by regional profitability, which says that he meets the first criterion, and he's going to estimate regional market clearing prices in the model. Both of those things say logistics is going to be incorporated.

Now, if we look at the regionalization of the model, Bill has already showed you this map. I just wanted to show you that if we look at the National Petroleum Council study, it had a similar kind of regionalization with maybe a few more regions. The approach is that you divide up the resource and you look at it on a regional basis, and that way you can look at the logistics as well. How much does it cost to transport gas out of Rocky Mountain, say, to the Midwest and to the East Coast and so forth?

World Oil Consumption



World Oil Consumption



Another example of regionalization. This is Amoco's network for modeling natural gas logistics. We have the U.S. divided up into a number of supply hubs and market hubs. We don't try to estimate the cost of each individual pipeline. We just have a group of pipelines that we've put together and then estimate the cost of transport over those lines.

Another characteristic that I listed was that industry behavior should be realistically simulated. So Bill says that NEMS will simulate the activity of firms producing gas and oil or acquiring foreign gas or oil for resale. Now, we don't know exactly how he's going to do that, but at least he's looking at it, and I'm sure he'll do a good job.

Another thing that I listed was that the investment rate needed to be constrained by industry cash flow or revenues or something, and the profitability of unit investments had to be factored in. Well, NEMS, we are told, will base the level of investment on expected profitability, on the financial resources of the industry. It will also look at returns on foreign investment, so that it'll measure how much of the industry revenue and cash flow will be spent outside the United States. Of course, that in itself will limit the amount of money that will be available for spending inside.

Another characteristic, supply and demand should interact. NEMS will definitely allow this equilibration of supply and demand not in the supply model, but in module interactions. It will determine natural gas and crude oil prices. It will determine the quantities consumed and the quantities supplied.

Another thing that I had mentioned was that the model should run efficiently. NEMS has been designed so that this modular design, in and of itself, should promote efficiency. One of the things that was mentioned to us this morning in the discussion of the models was that there are going to be some mini-models or simplified models which can be used to shortcut the detail in some models where it isn't really needed.

In other words, in every model run you don't need to explore, say, the nonconventional gas production in detail. Maybe you could just take that as a given and look at some of the other things and save a lot of computer time.

The National Academy of Sciences or National Research Council did a study and published a book on what NEMS should include, and some of the things that they mentioned were that the primary outputs of NEMS should be the economic, environmental, and national security implications of alternative energy policies, meaning not alternative energy, but alternative policies.

It should incorporate behavioral and policy-driven aspects of decisions, whatever that means. I'm not sure.

It should analyze uncertainty explicitly, and it should be modular in structure, and I think you can see that NEMS is certainly following those recommendations.

I've still got a couple of minutes that I could run through a little bit of discussion on some of the modeling aspects from the recent National Petroleum Council study of natural gas.

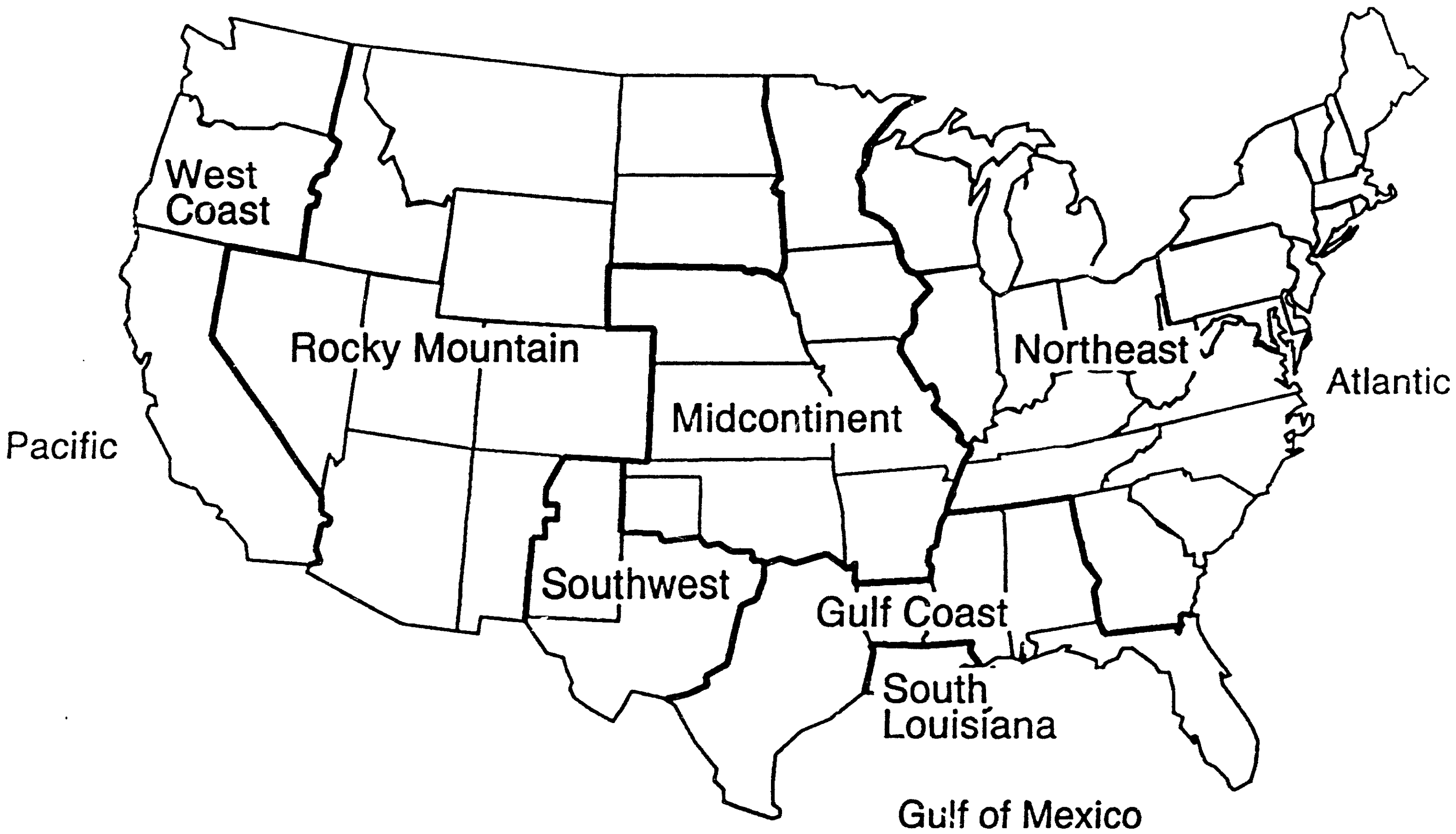
Desirable Characteristics

- Resource Should be Well Defined, With Regional Detail
- Logistics Should be Incorporated

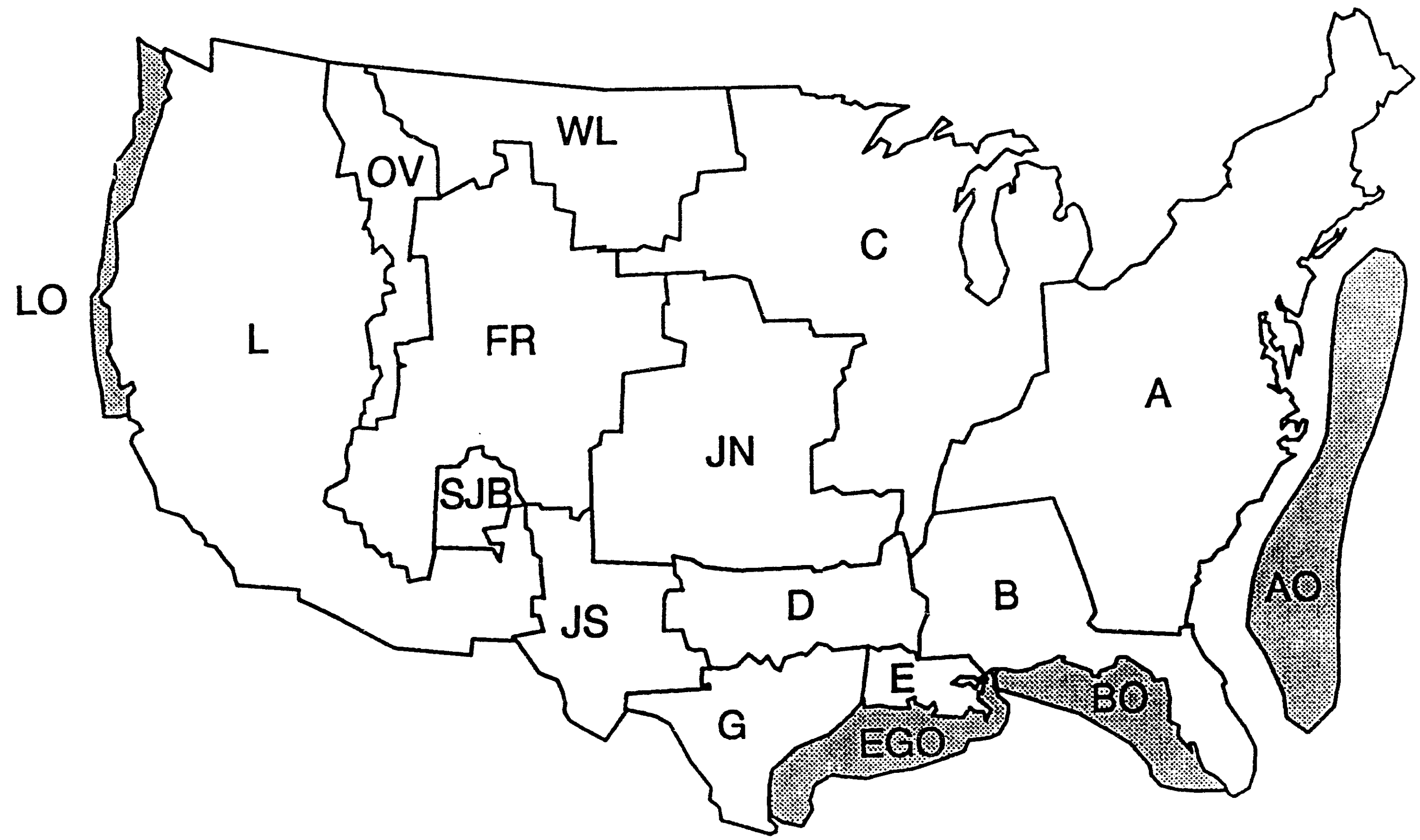
NEMS

- Allocates Regional Investment by Regional Profitability
- Will Estimate Regional Market Clearing Prices

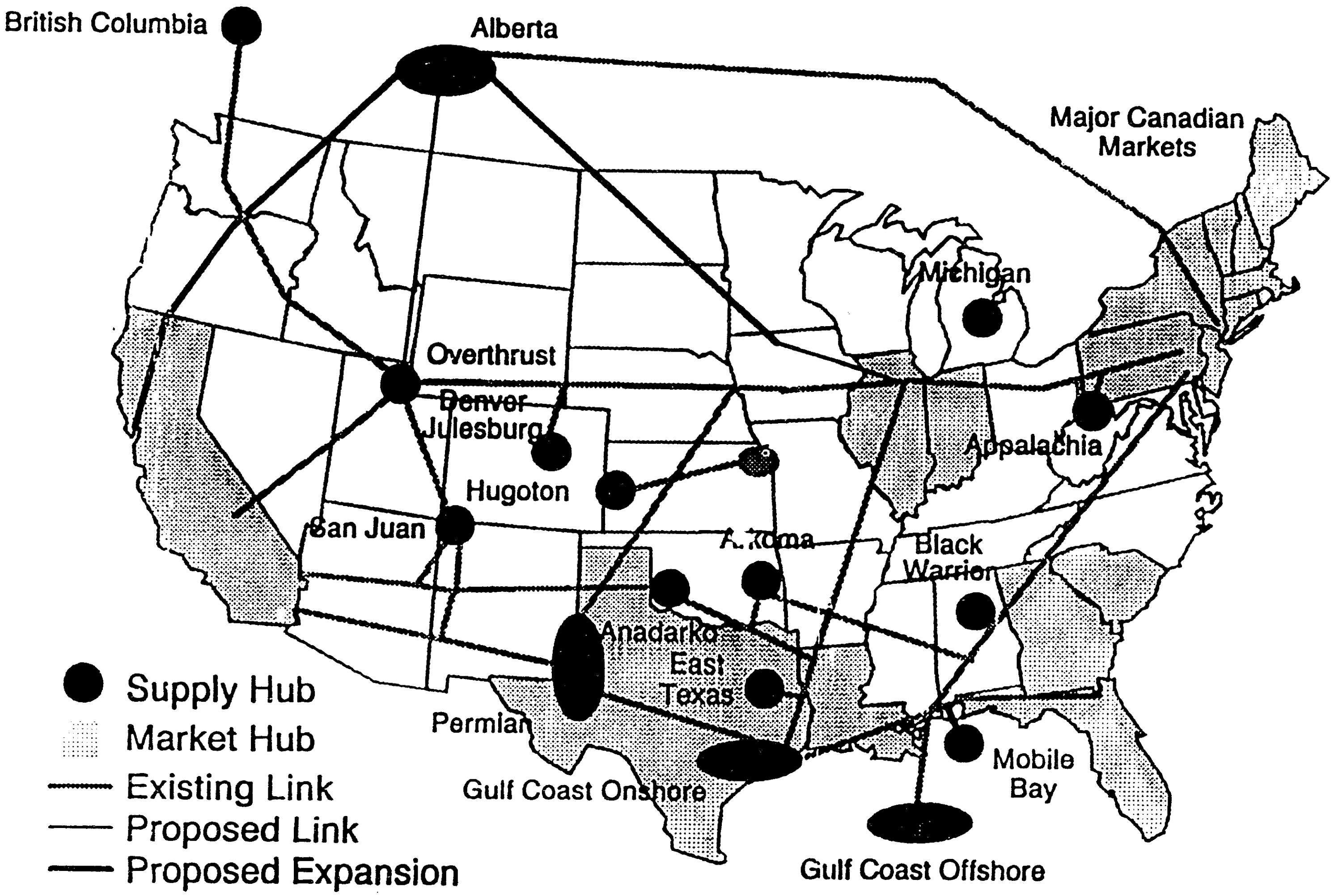
National Energy Modeling System Lower-48 Oil and Gas Supply Regions



National Petroleum Council Natural Gas Study
Lower-48 Hydrocarbon Model Regions



North American Natural Gas Supply Network



Desirable Characteristic

- Industry Behavior Should be Realistically Simulated

NEMS

- Will Simulate the Activity of Firms Producing Gas/Oil or Acquiring Foreign Gas/Oil for Resale

Desirable Characteristic

- Investment Rate Should be Constrained by Industry Cash Flow and Profitability of Unit Investments

NEMS

- Bases Level of Investment on Expected Profitability, Financial Resources of Industry, and Returns on Foreign Investment

Desirable Characteristic

- Supply and Demand Should Interact

NEMS

- Will Allow Supply and Demand to Equilibrate
- Will Determine Natural Gas and Crude Oil Prices, Quantities Consumed, and Quantities Supplied

Desirable Characteristic

- Model Should Run Efficiently

NEMS

- Modular Design Should Promote Efficiency

Recommendations of National Research Council Regarding NEMs Design

- Primary Outputs Should be the Economic, Environmental and National Security Implications of Alternative Energy Policies
- Should Incorporate Behavioral and Policy Driven Aspects of Decisions
- Should Analyze Uncertainty Explicitly
- Should be Modular in Structure

Here's an example of how the resource was divided up for the tight gas resource, with some examples of the volumes that were shown in various formations and basins, adding up to a total of about 230 trillion cubic feet of tight gas. This includes volumes in known locations and that volume in new places that are not yet drilled to any extent.

This is all based on current technology. There is also a similar set of numbers for advanced technology.

Location of the principal nonconventional gas basins included in the National Petroleum Council study. This, of course, captures coal bed methane, as well as tight gas, as well as Devonian shale.

The coal bed methane recoverable resource, again, here we're looking at current technology and advanced technology. A lot of coal bed methane resource is in the San Juan Basin, of course, and the Piceance Basin. A total of about 60 trillion cubic feet is recoverable with current technology, and then allowing for advances in technology, by 2010 there should be about 100 trillion cubic feet of recoverable resources.

Similar numbers for gas shales, but looking primarily at only the Appalachian Basin and the Michigan Basin as being the areas that will be developed in the next 20 years or so.

Speculative gas resources, gas hydrates, geopressured brines and deep gas. The NPC study acknowledges that there are huge resources in place, but we really don't know how to recover them. The costs are high, and we need knowledge and technology to know how to recover them. So none of those speculative resources were included in the NPC study.

Now, as a result of the modeling, we found that we saw some fairly substantial increases in nonconventional gas by 2010, and that included about four trillion cubic feet per year of tight gas production in 2010 and a couple of trillion cubic feet from other nonconventional, which would include the coal bed methane and the shales, gas shales.

The numbers that are shown here are just the Lower 48 states' supply. This is only one of the two cases that NPC looked at.

The NPC also did a run out to the year 2030 and looked at a number of price paths for this particular analysis. One of them was $1.50 wellhead prices, one of them was $4.50, and there were some other cases in between. Just looking at these extreme cases, we see that the analysis show that if prices stayed at only $1.50 per million Btu's in 1990 dollars, that total lower 48 gas production in 2030 would only be about four trillion cubic feet in the lower 48. Whereas, if gas prices were about $4.50 in 2030, that total production would be about 18 trillion cubic feet, including a lot of tight gas and other nonconventional gas. In fact, that's more than half of the total supply.

So that gives you some ideas of the scope of the NPC study and also gives you my analysis of where we stand on NEMS. We wish Bill and the other modelers all the best and look forward to receiving some output.

Tight Gas Recoverable Resource Base, TCF (Lower 48 States, Current Technology)

Region	Old Plays	New Plays	Total
Rockies	34	90	124
Cotton Valley	8	19	27
Anadarko	11	11	22
Permian	6	13	19
Others	25	15	40
Total	84	148	232

Source: NPC

Location of Principal Nonconventional Gas Basins

Coalbed Methane Recoverable Resources, TCF

Basin	Resources: Current Tech.	Resources: Advanced Tech.
San Juan	22	33
Black Warrior	7	10
Piceance	17	27
Misc. Rockies	8	12
No. Appalachian	9	15
Total	62	98

Source: NPC

Gas Shale Recoverable Resources, TCF

Basin	Resources: Current Tech.	Resources: Advanced Tech.
Appalachian	26.5	42
Michigan	10.5	15
Total	37.0	57

Source: NPC

Speculative Gas Resources

- Gas Hydrates, Geopressured Brines, Deep Gas
- Huge Resources in Place
- Costs High; Knowledge/Technology Needed

Estimated Lower-48 State Nonconventional Gas Production

	TCF/Year		
	1990	2000	2010
Tight Gas	1.7	2.0	3.7
Other Nonconventional Gas	0.4	1.6	1.9
Conventional	12.5	12.7	12.9
Assoc-Dissolved	2.7	2.0	2.0
Lower 48 States Supply	17.3	18.3	20.5

Source: NPC

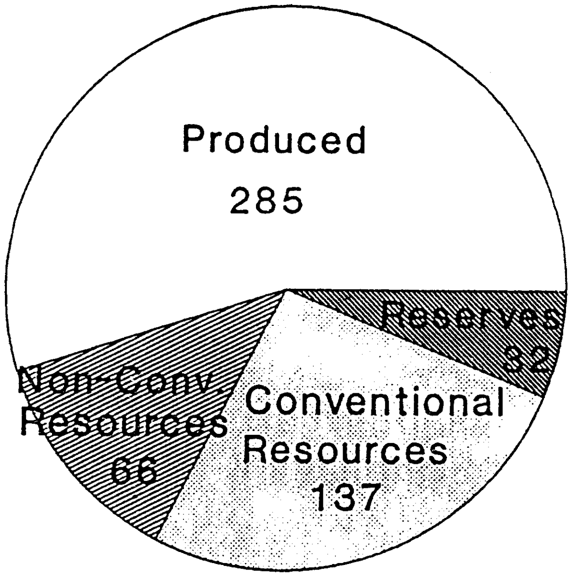
Estimated Lower-48 Gas Production, TCF

Price*	Actual 1990	2030
$1.50		
Tight Gas	1.7	1.7
Other Nonconv.	0.4	0.3
Total Gas	17.3	3.7
$4.50		
Tight Gas	1.7	9.4
Other Nonconv.	0.4	3.5
Total Gas	17.3	17.7

*Gulf Coast Wellhead, $1990/MMBTU

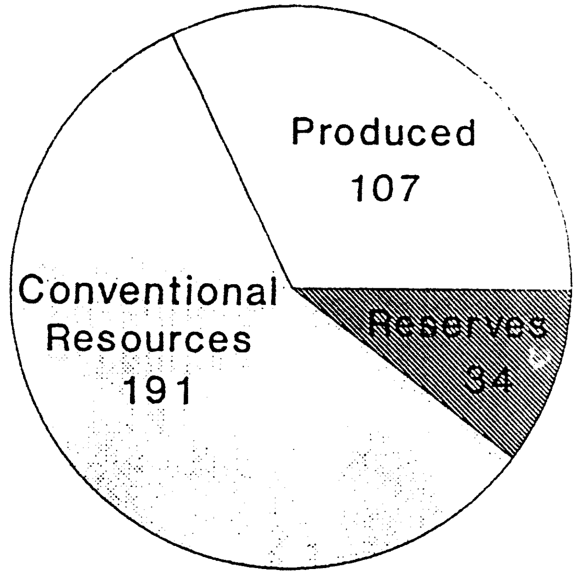
Source: NPC

Ultimate Natural Gas Resources by U.S. Supply Region



Gulf Onshore

520 TCF

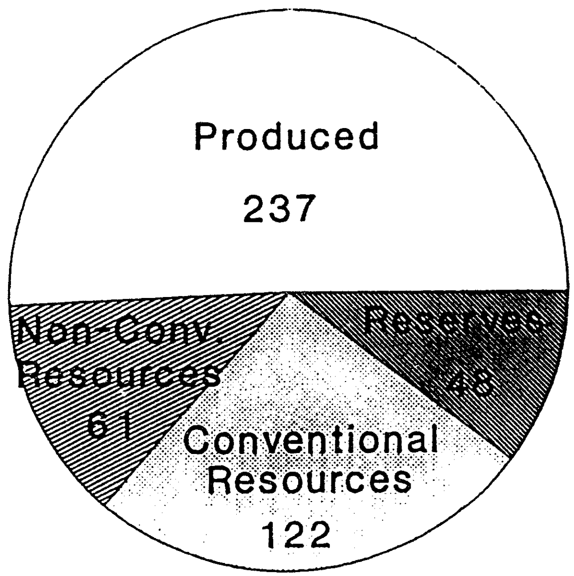


Gulf of Mexico

332 TCF

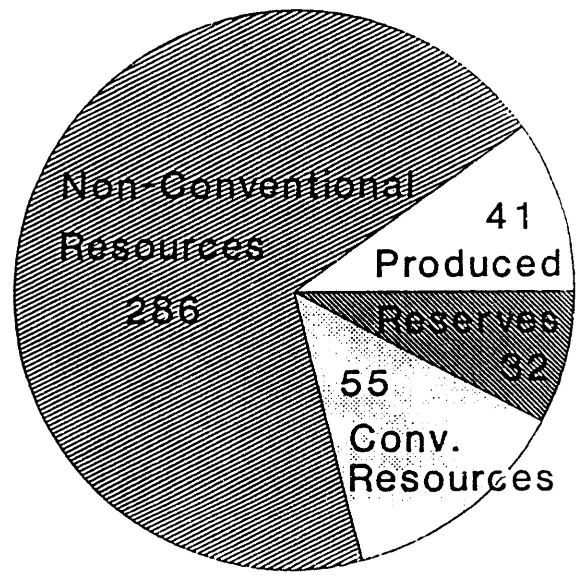
Source: NPC

Ultimate Natural Gas Resources by U.S. Supply Region



Mid-Continent

468 TCF

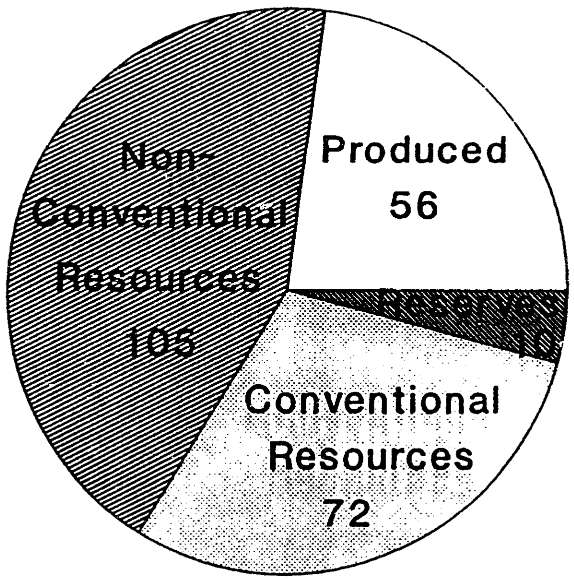


Rockies/San Juan

414 TCF

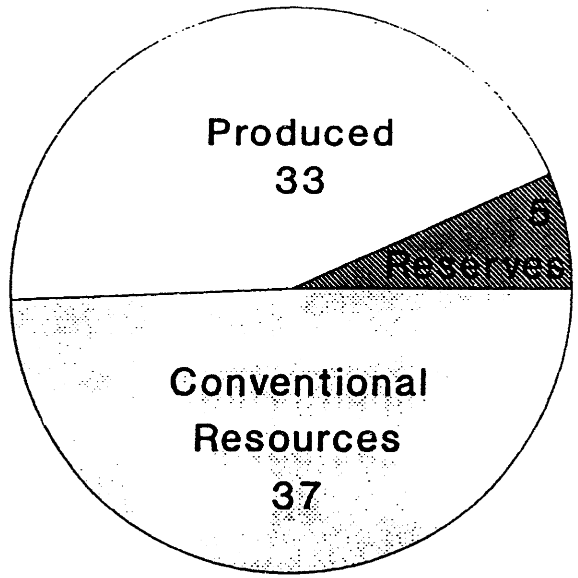
Source: NPC

Ultimate Natural Gas Resources by U.S. Supply Region



Eastern U.S.

244 TCF

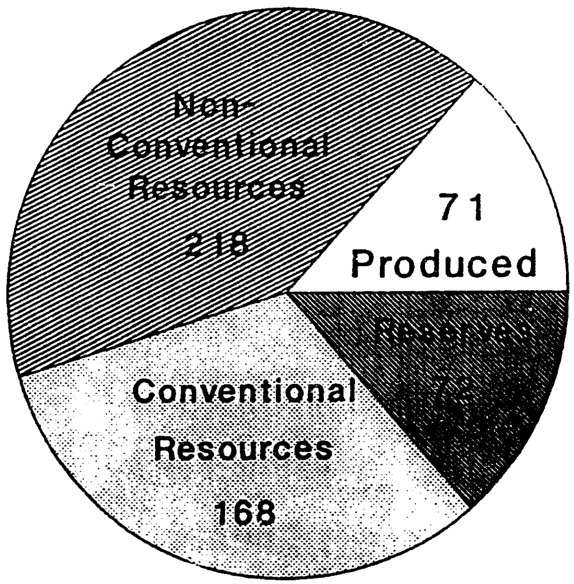


Pacific Coast

75 TCF

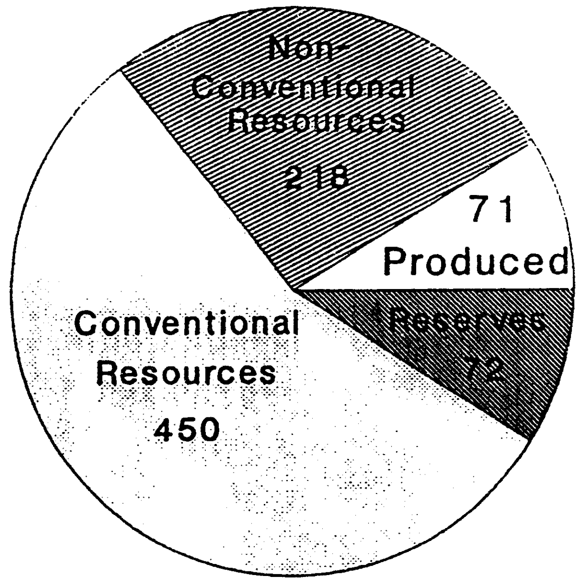
Source: NPC

Ultimate Natural Gas Resources - Canada



Western Canada

529 TCF



Total Canada

811 TCF

Source: NPC

Thank you.

MR. KENDELL: I'd like to sincerely thank the reviewers for their comments. I think we've learned a lot already. They've given us some insights that we'll be able to take back. We've had some really thorough reviews this morning, and I'm sure they've raised a lot of questions in your minds.

When we take questions we'd like you to identify yourselves by name and affiliation. However, we're first going to hear a rebuttal from Bill since he's up here and he's got something to say.

MR. TRAPMANN: If you knew me better, you'd know I always have something to say.

Rebuttal, I think, sounds perhaps too defensive. I certainly don't want to be defensive, but I'd like to provide a response that can shed some light on our thinking behind the decisions that we made.

I'd like to make one bit of clarification up front, because if it doesn't work out well, I wouldn't want my name so closely associated with this as it was this morning. Actually, the reason is more to be fair to the many people that contributed to this. In addition to the reviewers who you have here today, there are a lot of people that have taken time to review this -- in quite a number of cases their own time -- and I'd like to thank them even though a lot of them aren't here, but thanks anyway.

In particular, there are three people on my team that have made tremendous efforts and a lot of sacrifice. Since you've heard, "Bill, Bill, Bill," I'd like to mention by name Ned Dearborn, Ted McCallister and Dana Van Wagener as three people who have contributed greatly.

Thinking of a comment that, I believe, Joe made about the willingness to undertake certain things: unfortunately for Ned, Ted and Dana, they're more willing to undertake certain things, I think, at times, than I am. I rain on their parade and say, "Well, I don't think we can do that because we have a schedule." They appreciate the value of good work and want to do more than, at times, the resources and schedule would allow. But I certainly do want to note their sacrifices in supporting this effort.

Another comment I want to make is that beside everything that was said here today, there are other requirements that have been imposed on this whole process. There's a lot of detail that we're asked to generate, but we also have to stay within certain guidelines as to standards of execution. So the computational efficiency that we have tried to attain isn't just to do things better in some sort of purist sense, but also to do as much as we can within certain constraints.

This is, I think, relevant to a point that Emil stressed quite well in the beginning of his remarks: that there is an important distinction in attributes between categories of activities and the regions. The more we can subdivide that and recognize each one of these individual cells, the better the model would be. We certainly make no argument with that point.

We're hoping that we've properly balanced the tradeoff between disaggregation and the ability to get the show on the road come April 30th when it's supposed to be ready and operational.

What we're trying to do first is put up our holiday tree and then put the ornaments on. We're putting it up and putting some ornaments on right now. As we get used to what we're doing and recognize where we're spending a lot of time and resources, we can introduce further efficiencies and try to do more disaggregation.

I will concede the point that, ideally, on a more extensive schedule, we would build prototypes and be smarter right from the beginning to get the right level of aggregation. We just have not been able to do that.

As an example, I am sure both he and I agree on the extreme importance of the inferred reserves to the whole process of oil and gas supply modeling. The analysis that Emil showed in one or two slides takes a lot of data massaging -- a lot of cleaning up. I've also had discussion with people as to what on earth this phenomenon is.

We can see the outcome of the reserve appreciation. We have a measure. We have reserves, over time for any field -- there is a discussion as to what exactly the growth process is.

One thing that I did notice in his slides is that the explanatory variable on those slides is time. Emil and I have had a number of discussions on this, and I've had this discussion with other people. Ideally you want to tie that into some other activity. Drilling would be a nice one, but then as you go through the data, as you think about the industry and try to figure out what it is that you're dealing with, new drilling is only a part of the story.

There also is better geologic knowledge becoming available to the operators, so they file larger estimates of recoverable resources. Until we have a better handle on the mechanism behind all of this, it's hard to both clean up the data well and also build a model ourselves that would represent it.

There is one thing that you may recall in my remarks. This is a first step in trying to get inferred reserves into the model. It's certainly not a last step.

Any of us that have been doing modeling for a while anyway understand you're never done. It's just that at some point you have to freeze your snapshot of what the model is and use it for something. So we're going to do that, and as time goes along, the plan for NEMS is that the model will evolve. It will get better, I hope, instead of just different.

Other things did direct us into not vintaging the wells. There's the tremendous data problem, but also we got into some theoretical difficulties. If we had a phenomenon that occurs over, say, 100 years or 80 years, whatever his period was that cut off his analysis, we've got a set of reserves for a single region, perhaps even for a particular type conventional gas, which is only one of eight in that region, and we would have that split up 100 ways.

Now, the problem is how we estimate a total level of drilling activity and direct it into those reserves. Which ones get picked? Which ones get left out? Just to cut to the bottom line, we weren't sure that we would know how to pull that off. Yet we wanted to do something that would capture the dynamics of the process.

The model does have reserves coming from the inferred stock and entering the proved reserve base. We hope we're doing more than simply getting the right answer for the wrong reasons -- presuming we get the right answer -- but we did think long and hard about that one.

The only other thing I'll mention -- I realize this is your time to ask questions and I'm preempting that -- but Emil made a comment on the limits on spending that also Joe and Lee had discussed a bit in their own talks.

Cash flow generates money for the industry to reinvest, as we all know, but there is also the opportunity for the financial markets to make money available for these investment alternatives. We've got some econometric equations that include what we feel are the dominant variables, internal cash flow being one of them, the return on foreign investment being another. The return on foreign investment would actually be negatively related to the amount of expenditure in U.S. exploration or development. This is because if you can make more overseas, go. That's the way the system is supposed to work.

So we do have the cash flow in there. By using the econometric analysis, we like to think that it allows us to estimate, with reasonable reliability and precision, what the expenditures would be without having to go into some sort of explicit money market process, which I, for one, would have to do a heck of a lot more reading of my old graduate textbooks to know how to do.

Lastly, the sharing is an important thing. Once we have the national or aggregate levels of expenditure, we have to share them between activities. Right now, for those of you who have read the CDR, you know we have a very basic approach that takes the relatively profitability of the alternatives in a nonlinear function that will direct resources to the different types of activity.

The properties of the function are such that lesser profitability will not shut out endeavor in that area. In other words, some people continue doing something, even though no one else can make money doing it. They'll try it, make money on it, and keep doing it.

Or, someone may be expected to make more money if they did things differently or worked somewhere else, but they're comfortable in perhaps the Denver area, and they stay there, despite the fact that everyone else is leaving.

At times I feel I know very little about the whole industry, but you know, it's that sort of thing. They keep in there, working on things that on average aren't the best alternatives. Over time they will tend to be a smaller and smaller portion of the industry.

Last week we had the benefit of a session with Gordon Kaufman of MIT, yet another reviewer who has tried to improve our product, and he has offered us any number of ideas on how to adjust that equation both to provide some micro underpinnings with regard to risk and uncertainty and also make it estimable in its coefficients, which certainly was something that I thought was a nice attribute.

So with that I'll close and open the floor up to other questions.

MR. KENDELL: This is your time for questions.

MR. GELB: Bernard Gelb, Congressional Research Service.

Some would argue that at least so far as crude oil is concerned, U.S. producers are takers of a world price. I don't know if you agree with that or not, but to the extent you do, if you do, then you would have to reflect that somehow in the equilibration of supply and demand and prices here. I was wondering if you could talk a little bit about that.

MR. TRAPMANN: Okay. This actually goes somewhat outside our area, but what the heck? After a while domestic oil and gas starts getting somewhat limiting and boring. And it's always easier to talk about someone else's work. So I can talk a bit about the international model.

We have a petroleum market module that I referred to in my notes and on the slide. The refinery model has a set of domestic supply curves that are a given. On the other side I had made a reference to a box or two that did not appear on this slide. On that side you have both the petroleum product demand in the U.S., and also the international supply. The international module will provide supplies of crude oil by five broad classifications of type and the petroleum refined product supply.

In that configuration, we're saying on the domestic side that they are price takers. They're not going to drive the market tremendously. Their supplies, I think we can anticipate, are much more inelastic than the supply of international fuel to the U.S. for a number of reasons.

Now, to the extent that the international module provides very elastic supply curves -- in the extreme, perfectly elastic -- they will simply predetermine the price of any refined product or any type of crude.

At some point it remains to be seen as to what the relative elasticities in that model are. I think regarding the general nature of your question as to whether or not the domestic producers are price takers, they are. In the equilibration, the prices from the domestic refineries will probably be driven quite heavily by the availability of and the elasticity of the foreign supplies.

MR. KENDELL: Another question? Nobody has any questions. Well, there's one.

MR. RUDKEVICH: Thank you. I am Alex Rudkevich from Tellus Institute in Boston.

Before I ask my question, I think I need to provide some kind of a story. Otherwise it might be not understandable enough.

For several years before I joined Tellus Institute, I was working for the Energy Research Institute of the Soviet Academy of Science in Moscow, and I was developing the model which is named Octopus. Probably somebody's heard of it, and this model actually was doing the modeling of Soviet oil and gas production development.

When I found some kind of documentation of this model, I was really very pleased to see that not only is oil about the same on both parts of the world, but the way people model the production of it is also about the same.

At the same time some things concern me. First of all, there is not any analysis of these equations in terms of why they are written or the way they are written. So understand how some equations were produced. Some equations are surprising me. For example, if you consider the production of some resource and it seems that the same rate of extraction is applied both to old resources and to reserves additions, it looks a little bit strange.

The second thing is we analyzed the equations of about the same type and found the profitability criteria look different from what I can see here. Again, it would be very interesting to see any documentation on this.

So thank you.

MR. KENDELL: Okay. Bill.

MR. TRAPMANN: Well, you're the second person in less than seven days that has taken me to task on the form of the equations and why we did what we did.

The document initially was intended to provide the detail for someone to start implementing. I think within our organization we've had second thoughts about that, and we, I guess, glossed over some of the rationale. Well, let me not guess. We did gloss over some of the rationale for why we did what we did. I apologize for that to those of you who have spent a lot of time with it and wrestled with it perhaps without success.

I can say a few things about the equation forms. We drew from a lot of available material that we had both within EIA, the Energy Information Administration, and from other sources outside it. Perhaps at some point we did get a bit too close and the trees got in the way so we lost sight of the forest, but also we might have just relied too much on the inherent appeal that the forms had for us, but that was not universal.

We do have a methodology documentation coming out and a model developer's report. I was cautioned about schedule, but I think by the end of the year it should be available, and in that we will have a lot more of that kind of discussion.

On the rate of extraction for old versus new reserves, the equations -- and again, I apologize. Any of the errors and problems in presentation are mine. I introduced those deliberately just to see if anyone's reading the things.

If you recall, we had the three finding rates, the three equations. They have separate estimates for what is available to come out. They have separate levels of productivity. The initial finding rates sequentially get updated as we go through the periods, and so we recompute the deltas of which there also are three.

There are certainly different yields to the new field discoveries, to the exploration in known fields, and to the development in known fields. In fact, interestingly enough, when I looked at some of the early data for discoveries, I found that on an aggregate basis, the new field wildcat wells had a lower yield in terms of proved reserves than the other exploratory wells did. However, I can't say that this is seen in the more detailed data.

If that holds up -- and I should probably not say this with Emil here from USGS, but, at the risk of putting my foot in my mouth yet again -- it might just be that with the first well or two you're not quite sure what you have. You want to be somewhat conservative about the estimate, but then as you drill more in the field and get much more comfortable with what you're looking at on some of the indirect data -- the seismic and what have you -- you just tend to be more optimistic about what the field will yield.

MR. KENDELL: Do we have any questions for our reviewers this morning? Any more questions?

MR. KENDELL: Okay. I've got five minutes left. Maybe I'll let you go early. Would you like that or would you like me to ask another question?

I think you'd like to go early. Thanks to you all for coming. We appreciate it.