GAS TRANSMISSION AND DISTRIBUTION PANEL

February 1, 1993 - 1:00 pm

PANELISTS:

James M. Kendell, Moderator
Barbara Mariner-Volpe, Presenter
Thomas J. Woods, Reviewer
Joel Mumford, Reviewer
William A. Meroney, Reviewer

AUDIENCE PARTICIPANTS:

David DiAngelo

EIA

PROCEEDINGS

MR. KENDELL: I'd like to welcome you to the Gas Transmission and Distribution Panel this afternoon.

My name is Jim Kendell. I'm the Chief of the Oil and Gas Analysis Branch.

This afternoon we have Barbara Mariner-Volpe presenting the overview of the natural gas transmission and distribution system and we have three reviewers. I think we have a very good mix of reviewers this afternoon. We have a regulator. We have a capacity planner, as well as a full-time researcher.

Barbara Mariner-Volpe has been with EIA since 1981. She's the team leader of the Natural Gas Markets Team and, as such, is responsible for the development, design, and implementation of the models that she's going to be describing this afternoon. Barbara has been involved in a variety of natural gas-oriented studies. Most recently, she's been involved in modeling work related to the National Petroleum Council Study on gas availability.

I'd like to, once again, welcome you this afternoon and give you Barbara.

MS. MARINER-VOLPE: Thank you.

The Natural Gas Transmission and Distribution Model represents the activities of the transporters and marketers of natural gas. What I will be describing this afternoon is the mid-term model which is solved annually through the year 2015. The presentation is organized as follows. First I'll explain the role of the Natural Gas Transmission and Distribution Model in relation both to NEMS and to the other oil and gas models in the system. Then I will describe the methodologies incorporated in the NGTDM.

The next slide, if this little machine works -- success, just like NEMS! The purpose of the Natural Gas Transmission and Distribution Model is to provide a modeling framework to analyze the physical and economic interactions of the natural gas industry. It includes an explicit representation of the transmission system and thereby represents capacity limitations, inter-regional flows of natural gas, as well as expansion requirements, both location as well as cost. The model solves for the gas market equilibrium. It links the supply and demand for natural gas and solves for wellhead and end use prices of gas, as well as the inter-regional movement of gas.

This slide is a schematic of the three sets of modules in NEMS, the Oil and Gas Supply Module, otherwise known as OGSM, the Natural Gas Transmission and Distribution Model which henceforth I'm going to abbreviate with NGTDM, if that's all right with everyone, and then the Petroleum Market Module. The OGSM estimates the supply of both oil and gas. The NGTDM, as I stated, solves for the gas market equilibrium. And the Petroleum Market Module, the PMM, determines the petroleum market equilibrium.

The NGTDM links the supply and demand for natural gas in NEMS. As I said, it solves for the wellhead and end use prices of gas based on estimates from the supply model, OGSM,

Gas Transmission and Distribution
in the
National Energy Modeling System

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Barbara Mariner-Volpe
Energy Information Administration

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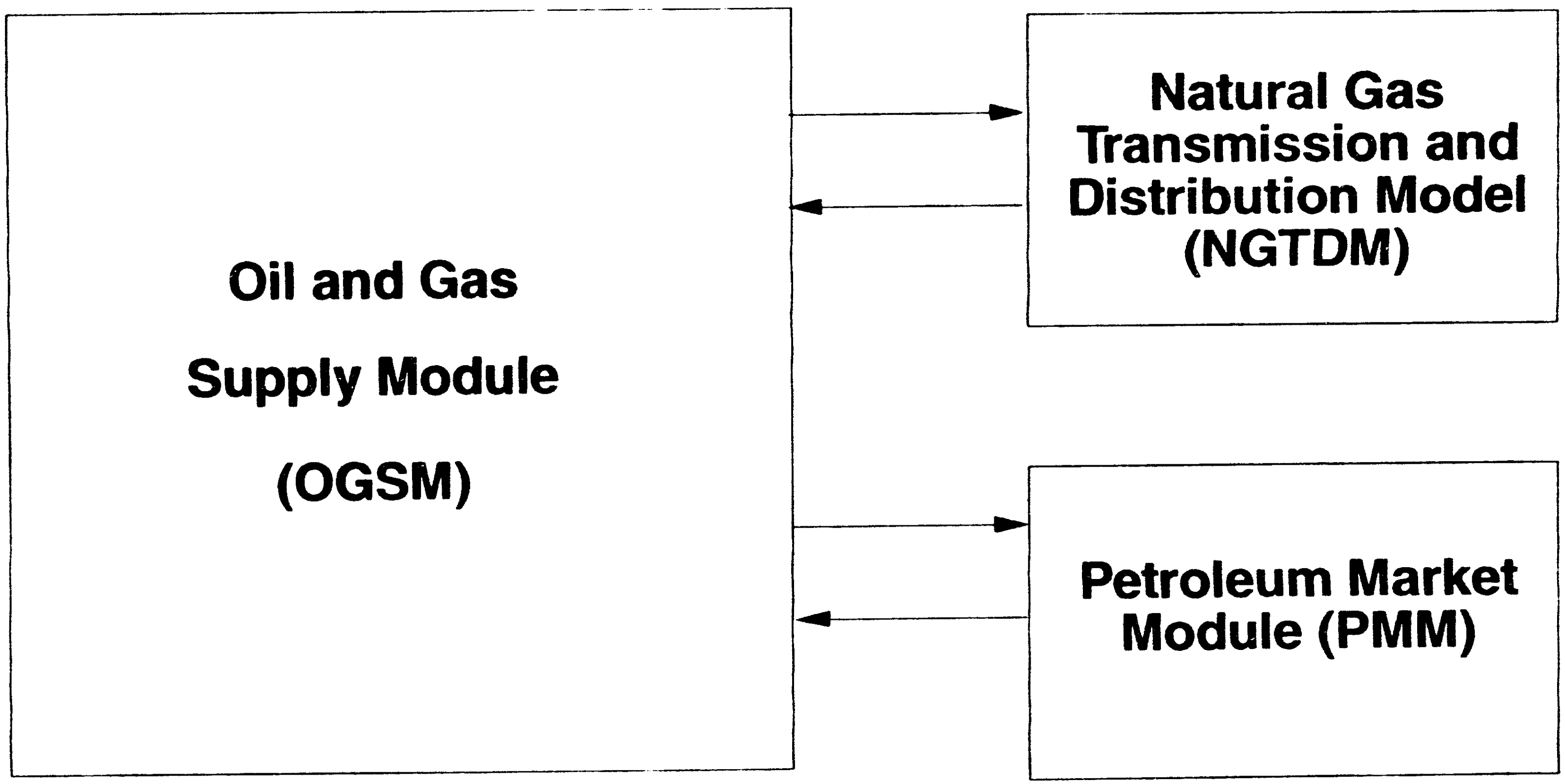
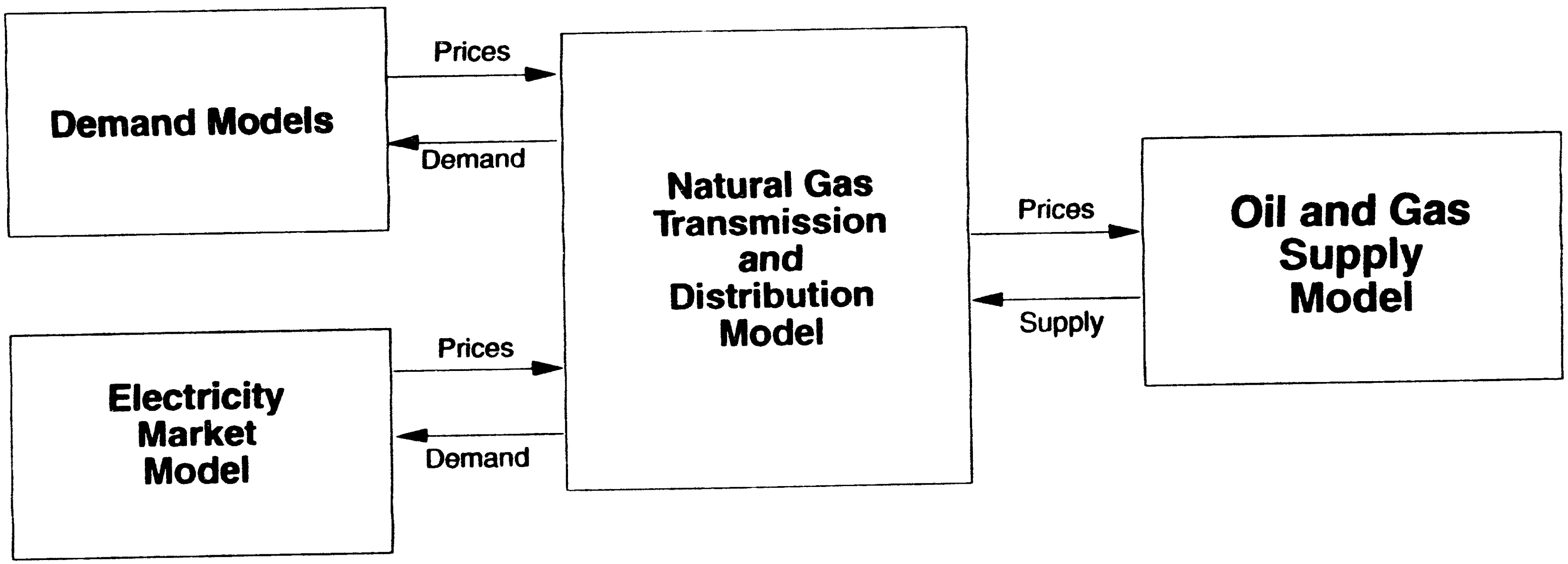
Purpose of the NGTDM

- Represent the physical transmission network
  - capacity
  - flow
  - expansion requirements
- Solve for the gas market equilibrium

OIL AND GAS MODULES



Primary Model Linkages for the NGTDM



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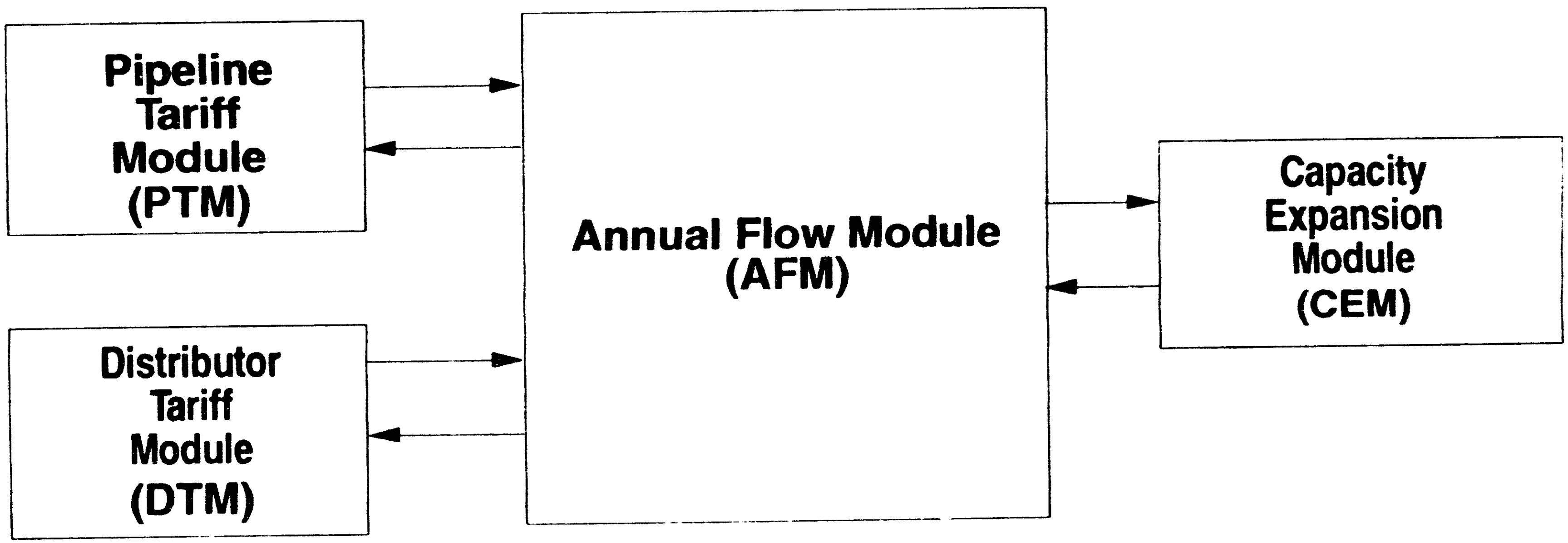
Natural Gas Transmission and Distribution Model Components



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as well as the other demand models in the NEMS system.

There are four modules in the NGTDM. The Annual Flow Module is the core component of the system. It determines the market balance based on inputs from not only outside of the NGTDM elsewhere in NEMS as well as from the other three peripheral modules within the NGTDM. The other three are the Pipeline Tariff Module, the Distributor Tariff Module, and the Capacity Expansion Module.

The PTM determines the components of rates for interstate pipelines. The Distributor Tariff Module estimates the rates covered by local or State regulatory bodies such as those that affect intrastate as well as local distribution companies.

The Capacity Expansion Module primarily determines the expansion requirements for both pipelines as well as storage facilities and, in addition, estimates the corresponding costs.

Now I'd like to describe the overall scope of the model that we have designed here. In establishing the transmission network, our idea was to keep the model as simple as possible and yet to capture the key aspects of the industry. With that in mind, we have defined 12 regions in the United States and I will show you a map on my next slide. There are nine Census divisions and then three separate regions, namely California, Florida, and then Arizona and New Mexico.

There is a simplified network of regional centers connected with arcs that represent the interregional pipeline capacity. The supply representation includes domestic on-shore and off-shore production, imports, both pipeline and LNG, ANGTS, as well as synthetic and supplemental supplies.

Regional demand is distinguished by sector and by market and we identify residential, commercial, industrial, electric generation, transportation, as well as exports. Each one of those categories can be further divided by type of service required, namely firm and interruptible for either the core or the non-core market.

This is the resulting map of the network. Within each of the 12 regions there is a trans-shipment node, and those are the little boxes noted on this figure. These are connected to neighboring regions by arcs which represent the pipeline capacity. What is not shown on this map are the arcs from the supply sources within a region as well as arcs to the individual demand sectors. These are the items that I have described on the immediately previous slide.

Network attributes that we are tracking include capacity, fuel use, emissions, tariffs, and flows. For the tariffs and flows, they're distinct by the type of service required, either firm or interruptible.

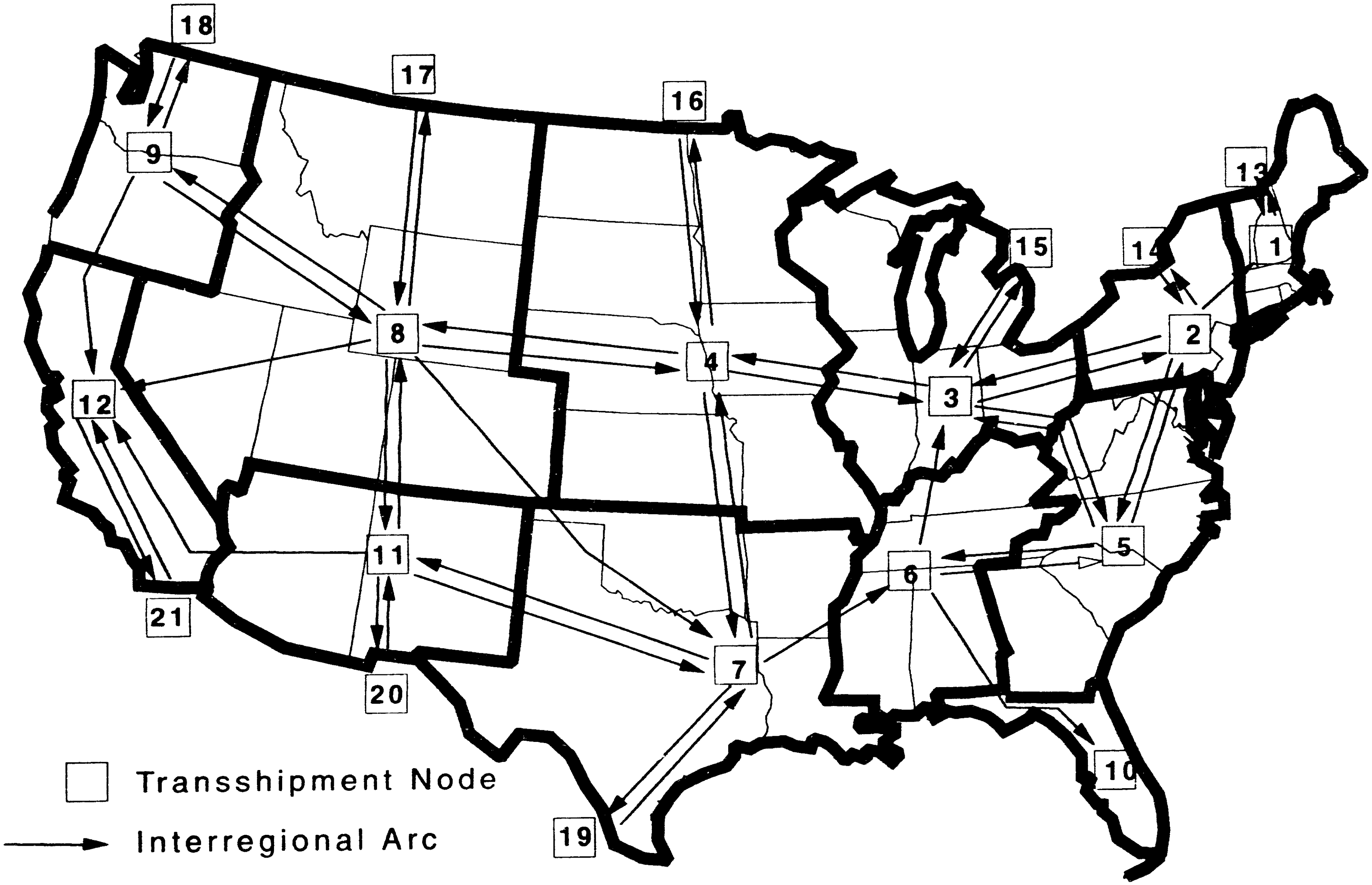
In solving for the network flows within the model, we have distinguished the firm and the non-firm service because of the key structural differences within the market. As the next series of slides will show, each market is solved for separately and then linked together.

I will start off by describing the methodology in the Annual Flow Module, the AFM, and I will then describe the methodologies in the remaining modules in turn. The fundamental

Classification Plan

- 12 regions
- Simplified transportation network
- Gas Supply
  - Domestic onshore and offshore production
  - Pipeline imports, LNG, and ANGTS
  - Synthetic gas and other supplemental supplies
- Demand Sectors
  - Residential, Commercial, Industrial, Electric Utilities, Transportation, Exports
  - Core and Noncore Markets

NGTDM Network



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assumption is that the firm service market will continue to be regulated. With that in mind therefore, the transportation for firm service will be based on cost of service tariffs that consist of both a fixed and a variable component. Customers requiring firm service, therefore, effectively pay an average charge for natural gas. The resulting treatment in the AFM is a heuristic methodology in which flows are based on historical patterns as well as future contracts. In designing the methodology for the firm service, it was felt that the capacity would not be a constraint to firm flows because in fact the interstate system is designed to satisfy that segment of the market.

Now I'd like to turn our attention to the treatment of non-firm or otherwise -- some folks call it "interruptible" service.

First of all, for non-firm service, it was felt that the market is more representative of a truly competitive market. Transportation rates are treated as market-based and the customer sees a marginal as opposed to an average price. Therefore, the tariff includes a variable component only. Capacity limitations may in fact affect the market solution because there are no guarantees of service in the non-firm market. The competitive nature of this segment of the industry led us to a linear programming formulation, an optimization in which costs are minimized.

I'd now like to describe how these two segments of the market are solved within the AFM, where they overlap. In fact, there are two areas of overlap between the approaches for the firm service and the non-firm service, both in terms of capacity as well as wellhead supplies.

Capacity limits imposed on the non-firm market are based on what's left over after satisfying the firm market. As I mentioned, there are no guarantees of service in the non-firm market. Both the firm and the non-firm market compete for the same competitively-priced wellhead supplies. The overlap is handled within the AFM by interactively solving for the two markets.

First, the firm market is solved via the heuristic approach that I described. The capacity utilization is determined and the unused capacity is identified and made available to the non-firm market. Then the non-firm market is solved via the LP methodology and the process continues until the two systems converge. That summarizes the AFM.

What I'd like to do now is describe the remaining three modules in the NGTDM, the first being the Pipeline Tariff Module.

The primary function of the Pipeline Tariff Module is to compute the cost of service rate for transportation and storage services of interstate pipelines. A secondary function is to generate tariff curves for additional capacity that relate incremental capacity to the corresponding tariffs. The tariff curves are then used in the capacity expansion module solution.

For fully regulated firm service, the rates determined by the PTM represent the actual price of transmission and storage service. But for loosely regulated service, for instance for the non-firm market, these rates represent bounds instead of the actual price. The upper bound is the firm service rate. The lower bound is the variable cost of moving the gas. These bounds are used within the Annual Flow Model and in fact the actual market clearing price is

AFM: Firm Service

- Noncompetitive market
- Fixed and variable tariff components
- Cost of service based transportation rates
- Non-binding capacity constraints
- Flows based on historical patterns and future contracts

AFM: Non-Firm Service

- Competitive market
- Variable tariff component
- Market based rates
- Capacity constraints affect the market
- Flows based on optimal decisions

Annual Flow Module:
Solution Methodology Steps

- Solve the firm market (Heuristic)
- Determine capacity utilization
- Solve the interruptible market (LP)
- Iterate until convergence is achieved

Pipeline Tariff Module (PTM)

- Cost-of-service based rates

- For fully regulated services:
  rates represent the price of transmission and storage service

- For loosely regulated services:
  - rates represent upper and lower bounds
  - actual "market clearing price" determined by the AFM

determined within the AFM.

The methodology consists of a six step accounting procedure, the first three of which are performed at a company level. The last three are performed at either an arc or a node level of the network.

The first step is to determine the total cost of service for the interstates, then to classify the costs as either fixed or variable. The costs are then allocated to rate components, in which reservation and usage fees are based on the rate design specified by the user. At that point, the costs are aggregated to the network and they are allocated to services, either firm or non-firm service, and the rates are computed by dividing the costs corresponding to each rate by the appropriate billing units.

The Capacity Expansion Module in the NGTDM is essentially a planning model. It determines the expansion of both pipeline and storage facilities necessary to satisfy expected firm requirements. The planning horizon as well as the type of foresight is a user parameter. The model is solved by segmenting the market into a peak and off-peak season. This is the only area within the NGTDM where we have some representation of seasonality. This segment of the model is formulated as an LP and the expansion design is based on both the location and relative cost of future supplies as well as the marginal rate to consumers and anticipated future market requirements.

The fourth module in the NGTDM is the Distributor Tariff Module. This module represents the tariffs or services by LDC's and intrastate pipelines. It includes a simplified econometric methodology that estimates the tariff based on the number of customers, total throughput, use per customer, and alternative fuel prices.

The model that I have described here is not static. What we have designed is, we hope, a reasonable modeling framework that will be configured and/or revised based on the analytic requirements.

What I'd like to do now is to review some of the capabilities of the model. I'm relying on the three panelists to highlight some of the limitations of the model.

The NGTDM can be used to analyze changes in regional consumption and supply patterns, shifts in seasonal patterns as well as types of services required -- firm or interruptible. It can also be used to analyze the regional impact of changes in expansion cost estimates, as well as the impact of different rate designs.

For those of you that are interested in additional details beyond what I've described here, we have a few copies of our component design reports in the back of the room. If anyone is interested, as was described this morning, there are sign-up sheets and if you simply fill out one of those forms or call someone in EIA we would be more than happy to send you a copy.

Lastly, I want to summarize the status of the NGTDM. Three of the four components are in the implementation phase. The last component for the Distributor Tariff Module is currently in the design phase and the component design report for that module will be available

Pipeline Tariff Module: Solution Methodology

- Determine total cost of service
- Classify line item costs as fixed and variable costs
- Allocate fixed and variable costs to rate components
- Aggregate costs to network
- Allocate costs to services
- Compute rates for services

Capacity Expansion Module (CEM): Basic Elements

- Determine the optimal pipeline and/or storage capacity expansion to satisfy peak period firm service

- Consider peak and off-peak seasons

- Consider future supplies and relative costs

- Account for expansion costs to consumers

Distributor Tariff Module (DTM)

- Represents the tariffs for services by local distribution companies and intrastate pipelines.

- Includes a simplified econometric methodology

- Tariffs are estimated as a function of number of customers, total throughput, and use per customer.

Analytic Capabilities

- Changes in natural gas consumption and supply availability.

- Shifts in seasonal patterns and types of services.

- Changes in expansion costs due to increased environmental restrictions or improved technology.

- Changes in rate designs (e.g., Modified Fixed Variable versus Straight Fixed Variable) later this month.

Thank you very much.

MR. KENDELL: What I plan to do this afternoon is ask you to hold your questions until after we've heard from our three reviewers and then you'll get an opportunity to ask questions of Barbara or any of the other panelists.

Our first reviewer this afternoon is Dr. Thomas J. Woods. Dr. Woods is an executive analyst at the Gas Research Institute. He has directed the development of the GRI Hydrocarbon Model and he is a nuclear physicist by training.

Dr. Woods?

DR. WOODS: Thank you.

I am a nuclear physicist by training and, in terms of using models, I am a complete Philistine. What I am really going to subtitle my talk, to a certain extent, is "A Philistine's View of Modeling Gas Transportation." As a result, what that means is I focus more on the use of the results than on how the results particularly were obtained.

My results, I feel, have to be related to transportation issues in the future, which is what a model is supposed to be able to do. But unfortunately, there is a down side of that. We have to be able to relate the results to what has happened in the past, because that is first of all what we use to drive the model and in addition it is what is necessary to use for credibility in the model results and its value to those who would use it. Because, for better or for worse, the people who will use this model will base their utilization and belief in the model on what they know to have happened in the past.

Now gas transportation has been generally seen as something of a poor relation in the modeling areas, almost as a second or Nth order effect in terms of talking about gas burner tip prices. And in the end, keep in mind that this is perhaps the fundamental thing that gas transportation modeling does. It generates a slate of burner tip prices to end use consumers. Everything else is a driving factor of that one big, major, ultimate result.

Treatment of gas transportation was generally static, had limited dynamics, and about the only dynamic was the fact that we took into account the fact that there was an increased cost to move the gas because the price of gas went up at the wellhead and, secondly, we looked at the fact that the volume related. If volume went up, we reduced the cost to move the gas. If it went down, we increased the cost.

Now this was not particularly unreasonable, given the fact that gas supply expectations in the past had been for declining gas supplies, which meant that you really didn't have to care about the pipes. We obviously would have more than adequate capacity and the only question was getting the supply in new areas to that existing capacity, and secondly the price of gas was going to grow very rapidly and what that meant was those transportation charges would become less and less important. This, however, has changed substantially.

We are now once again back to a situation where, on average, the burner tip price is dominated by the cost to move the gas from the point of acquisition to the point of consumption. In other words, we're back to what we had happen in the 1970s. As the expectations for gas prices continue to recede further into the future, there is an increasing role of gas transportation charges in setting burner tip prices and thus the competitors of gas become very important. So, what I'd like to do is talk a bit about these issues, to take a look at them.

I have two critical issues here: changes in industry operations and calibration of the model to the historical periods. Now gas transportation charges are no longer a cost plus. The market for better or worse has arrived, so in a sense you can almost tell the producers and the transporters and everybody, "Be careful of what you ask for. God sometimes gives it to you."

But the critical question is the changes and the issues that we are looking at today. Are they reflective of what the future is going to be or are they merely some sort of transient to be replaced by what has happened in the past or are they transitional to something which will be very different from what was in the past and what we are currently experiencing? And herein, I think, lies a very significant challenge to anybody who makes the model because the problem is we really don't know those answers.

I have no doubt that five years from now, if we were to have another similar meeting here, we might say, "Is that what we <u>really</u> put in the machine?" And the answer is yes. That's what we did, because it was based on what we knew.

Now the changes in the industry have been, first of all, the decline in the merchant function. Very little gas is now traditionally going through the traditional merchant function. But if, actually, you take a look at some of the data that INGAA has been presenting, transportation services appear to becoming some sort of an analogue for what was the traditional merchant function.

In gas-to-gas competition we have two questions here. Is it in supply or is it in transportation? I don't know how a model can deal with this problem and in going through the model descriptions I wasn't sure how it would.

My recommendation would be don't try. Make your own external judgments. Make an exogenous adjustment and look at it and see if it's rational. Sometimes it's going to be the supply which is going to take the major kick in terms of whether or not the discounts are going to show up on the producer. Sometimes they'll show up on the standpoint of the transporter. In some cases it will even show up for the consumer because the consumer will have to eat the increased cost himself. This will change depending on what the characteristics of the market are. I'm not terribly sure that you would want to make this model replicate those. So I think you want to put in some exogenous variable or lever that gives you the ability to sit down and analyze it and decide which way to go.

Secondly, we have to calibrate the model to a historical period because, if you can't, the problem is that nobody is going to believe you, because then they can't relate it to what they know. That's the good news. The bad news is none of the variables have any meaning today,

MODELLING GAS TRANSPORTATION

TRANSPORTATION MODEL ISSUES

- Changes in Industry Operations
  - Decline in Merchant Function
  - Gas-to-Gas Competition

- Calibration of Model to Historical Period
  - Projected Variables
  - Implied Variables

or at least they don't have the meanings that we had 5 years ago or even 2 years ago. And as we speak, the meanings change.

I used to think that I had figured with great, great work and effort and ability to make some sense out of it and take into account the shifting shares and how these samples had changed statistically over time, and I got kicked very hard in the ankles by one of the people who work for me, who pointed out that some of these prices have nothing to do with the market. So I think that's a problem, but for better or for worse those are the prices that people are going to use. And if we can't relate the results of the model to what people use, even if it's not right, then you're not going to be able to defend yourself because they'll just simply say, "How can I believe your model? The Natural Gas Monthly said this." So, that's what's happening.

Now the models have variables and they can be projected or implied and I'll give you an example. In the supply end, many people use reserve-to-production ratios as a driving factor of a projection. An R/P ratio is not a driving factor of anything or at least it hasn't been a driving factor of anything since FERC stopped demanding 20-year reserve-to-production ratios for building new pipelines.

R/P ratios are something that are implied by the model results, and so the critical question is to figure out which of these variables are driving the results as opposed to what are the results that are derived from it. And burner tip prices are a derivation of factors that drive them and among the factors that drive the transportation charges are the cost of capital, the volumes of gas that move, the breakdowns between variable, and capital costs.

Now, the existing structure of the gas transmission system in the lower 48 states is centered in the west south central regions. In other words, our gas transmission system was set up to take excess gas supply in the four west south central States and deliver it to various net importing regions. So, as a result, the transmission patterns reflect not just an end use demand, they reflect our expectations of what gas supply is going to look like.

Now, when we used to do our baseline projection, we used to think there was going to be a significant shift as more and more production of gas came from the Rocky Mountains and less and less production came from the west south central States. We have over the past 5 years begun to change that attitude and more and more we're able to maintain the production in the traditional producing areas so that in fact transmission patterns may not necessarily be on an interregional base is particularly important. It will also affect economic activity.

The second bullet here is transportation charges/revenues. In fact, it probably should be changed to revenue/charges because I think that when you look at the historical data, it will be very hard to figure out how we're going to allocate the charges of the future. No matter what you want to do, you still have to come up with the money. We're only arguing who's going to pay the check. So, the revenues may, in fact, be the constraint which is very easy to project and the critical question is to go back and look at the historical data and build up historical patterns based not on charges but based on revenue requirements because that has moved very little.

I would suggest if you go back and you look at the changes in who has recovered the revenues for transportation over the last 20 years, it's almost impossible to build any historical data if you look at the burner tip prices because the allocation of revenue recovery has just changed radically between whether it was residential or commercial or industrial or electric utility. The change that we're seeing in the last few years is not so much a radical change. It could be also explained in terms of the fact that the system is just going back to the way it looked around 1973. Now wouldn't that be a kick? We worked very, very hard. We have 636. We hire a lot of people and by 1996 the thing all settles out and guess what? It looks just like it did in 1969.

Finally, the last issue is seasonality. I think that that's important for utilization of investment, but more important also it's a question of upstream versus downstream. The seasonality as viewed by a distribution company is fundamentally different from the seasonality viewed by a pipeline. When a distribution company looks at it and says, "Gee, I've got all this unused capacity within my distribution system during the summer. So, if I sell a lot more gas during the summer, I'm going to be in great shape," the pipeline doesn't have that seasonality going to the producer.

So, if you can't match those two, that's the problem. When you do the seasonality, you can't look at the seasonality in aggregate. You have to break it between the seasonality at the city gate and the seasonality between the city gate and the burner tip.

What about transmission patterns? I've got five issues I want to raise here. The first one is interregional, which the model deals with. We used to focus on this quite a bit and we used to think it was the shift from the Gulf to the Rockies, but as we've gotten more optimistic about the Gulf Coast resource base, there's less and less of this shift occurring.

We are beginning to recognize that the intraregional, which the model is not currently set up to deal with, doesn't mean you can't build an off-line model to deal with it. At this point it might be better just to do that. That's generally when we come up with new ideas in our model. Rather than try to put it into the model for the first year or two, we do off-line calculations until we decide whether it was really worth the effort. You may find that some of these things tend to go away.

The good news is intraregional investments, intraregional flows reduce new investments. We have gone through them twice. Prior to 1980 we had a large amount of gas that was moving from the Hugoton field going west to Denver and going east to Chicago. When Colorado Interstate reversed its flow, production in the Hugoton field fell. Reserves are still there. It's just that there wasn't any capacity to move it out of the Hugoton field. So, in other words, reversal of flow can take up capacity. To give you an example right now, the critical issue is what's going to happen with gas moving from West Texas to California? Currently two billion cubic feet a day move west across the border of Texas into New Mexico, Arizona, and ultimately California. If that flow fully reversed, that would be the equivalent of stepping on four billion cubic feet a day of production in the western part of the Permian Basin. Now, you're going to have to find four billion cubic feet a day of pipe that isn't being used to move that gas somewhere.

The classical case is the San Juan Basin. I never could understand why the San Juan

TRANSPORTATION ISSUES

- Transmission Patterns
- Transportation Charges/Revenues
- Seasonality

Basin was capacity limited when it was only producing 300 to 400 billion cubic feet a year, when at the peak it was producing 600 billion cubic feet a year, until I went back and looked at the data. At its peak it was sending 100 billion cubic feet north and 500 billion cubic feet south. Today, 100 billion cubic feet comes in from the north and since it doesn't evaporate it eats up 100 billion cubic feet of capacity going south. So, when you have a reversal of flow, it double hits the capacity and it can have some very significant effects.

The other thing it does is reversals of flow allow you to deal with some very significant changes in regional gas demand without having to spend an awful lot of money. Sometimes it's just a question of putting in compression.

With new investments, they're very different depending upon how your capacity has changed. Is it new pipes or is it reversal of flow?

With net importing versus net exporting regions, that's very important to keep in mind because where the supply is will have a significant advantage. If more and more of the gas supply can occur downstream, then that's going to divert gas flow into different directions and there may, in fact, be capacity there to take care of it. But you have to distinguish between net importing and net exporting. Incidentally, this would be something else in terms of transmission lines if you're talking seasonality. You should also distinguish between seasonality of gas going into a net importing region versus seasonality of gas coming out of a net exporting region. They can be very different, too.

Finally, consider regional wellhead prices. Well, because of the reversal of flow, you better have a dynamic in treating regional wellhead prices. I assure you that if the gas suddenly starts moving east from the San Juan Basin, everybody who signed contracts for gas based on some marker of West Texas gas prices is going to find themselves paying some rather interesting prices relative to what prices are in California. So, we need to keep that in mind, that there's a dynamic there.

In terms of dealing with the revenues, transmission -- and again I'm talking transmission here to the city gate and I recognize that this is sort of an aggregate -- and finally distribution is from the city gate to the burner tip. The good news for transmission is we have pretty good data. Not only that, we have a countable number of pipelines and we also have pretty much the same kind of creature. They're all investor-owned. When you get the distribution companies you don't have good national data. The data is very episodic. Secondly, you have a lot more characters to deal with. And third, they're not all the same. So, it winds up that we start with the revenue and just work backwards. We accept fully that a large part of our treatment isn't very good.

For transmission charges and revenues, critical factors are these ones, I think, which are driving. The first is the cost of capital. This is critical in history. When we looked at the history of gas transmission charges per MCF, they increased substantially in the 1970s. About half of that increase had to do with the increased cost of capital. So, this can be tried with regard to the macroeconomic part of the NEMS system, but it should be locked and there should be a direct, close relationship between them.

TRANSMISSION PATTERNS

- Inter Regional
- Intra Regional
- New Investments
- Net Importing vs. Net Exporting Regions
- Regional Wellhead Prices

TRANSPORTATION CHARGES/REVENUES

- Transmission

- Distribution

The existing rate base is being amortized and then there are new investments. What we have found is that in looking at our own work that in fact in real dollars the rate base has historically tended to decline over time, except for those periods when we have these huge kicks of brand new investments, like big new pipelines.

Variable charges. Now, I've taken to breaking this into three components because I think that rather than have the variables broken out as a single one, they operate very differently. There is a piece that is customer-related. In other words, the number of customers that are there, and we can -- based on historical data -- relate it. There's a piece that's volume related. That's things like pipeline fuel. There's a fixed charge. In other words, there a general overhead or variables which are just going to be there, like a capital cost. If your volumes go up, your charges go down. If your volumes go down, charges per MCF go up.

Storage charges. They are acquisition price related, but they need a demand relationship. I'll talk a little bit later about that when I go to the question of seasonality. But I think that's a very important fact, that if you start wanting to put seasonality in, if you've got that capability in the machine, you might as well also tie it into the storage.

Also, incidentally, there's some technology in storage if horizontal drilling pans out the way some people think it will. We will take a large part of what we call base gas in our storage fields and turn it into working gas. That would have a very important reduction in storage charges.

New investments. I think we need to break new investments out into two pieces. First you've got to break it out in terms of what is the base historical rate at which the industry is investing to replace old, worn out equipment, make the little odds and ends to balance the system together. Then, there's the incremental investment necessary to add new large pipeline capacity.

A term which we put in is revenue credits. We don't handle it as well as we should, but the industry does get off of its investment some revenues which are used as a credit against the required revenues that they can then recover from their customers. That has to be in there and generally that will track with the price of gas or oil.

Allocation by customer class. My only comment here is good luck. It's revenues, it's judgmental, and I don't know what you're going to be able to do except put as much flexibility into the system as you can. Like I said, deep down I have a sneaking suspicion when this thing all settles down we'll find out the way they did it in the 1960s in substance, not form but in substance, may have been the best way.

Finally, Demand Side Management. One of the reasons I've broken this variable charge up into customer-related and volume-related is because the customer-related is something which is specific to the customers and it won't go away. So, in other words, if you reduce what this customer consumes, he's still got to pay that part of his variable cost. So, what you see is a good part of it -- part of it has to be flexible in terms of this.

Now, transmission companies look a lot like electric utilities where most of the charges

TRANSMISSION CHARGES/REVENUES

- Cost of Capital
- Rate Base
- Variable Charges
  - Customer-Related
  - Volume-Related
  - "Fixed"
- Storage Charges
- New Investments
- Revenue Credits
- Allocation by Customer Class
- Demand-Side Management

that are recovered from a customer are generic to the whole system. They are not customer specific, so they can be used elsewhere. But when we talk about LDC's, you'll see that isn't true and that can have some very interesting implications.

Rate base, I don't know what you can do with this. I mean in the end what we finally do is we just simply make some aggregate judgments and hope they pass a laugh test. Beyond that we just don't try to be any cleverer than that and make sure we have numbers that match. I think that's about all you're going to be able to do as well.

Variable charges. Again, the customer- related versus fixed. The fixed are the charges that can be picked up by any customer. The difference is that in the LDC's, most of the variable charges are customer-specific. They're not generic. So, what that means is that, if I skip ahead to this demand side management, if you cut the demand use by individual customers, all you're saving for them is the cost of the gas. You can't save a good part of the variable cost, unlike an electric utility or a transmission line. It's stuck on the back of the individual customer. That's a very important thing to keep in mind if you're going to model that. I get the feeling that you would like to ultimately. Then that breakdown has to be there.

In allocation by customer class, well, the historical data are just too darned erratic and I just think it's going to be a judgment. I think the best thing you can ever ask when you do that is that you pass a laugh test, or that it's credible. If somebody says he doesn't like it, the answer is that there are 10 different ways of looking at this. We're all going to be like blind men and women with our hands on different parts of the elephant. So, don't feel bad if you don't necessarily agree with everybody else.

Seasonality. Now, it has implications for utilization of transmission systems because the new investments are generally costed out on the basis that they're used around 90-percent. Now, the critical question is that generally when we've looked at seasonality we've looked at it on a sort of off-line basis to say, "Can we fit a 90-percent utilized new pipeline into an end-use pattern without distorting the relative shares of off-peak and peak demand?" If we can, then we don't care and we go on. In the end when you look at some of your seasonalities that may be what you'll have to do. Some of this, a lot of it, will be done off-line.

The important thing is that if that new investment comes in and it has to go at 90 percent, it's going to have some very interesting implications for the utilization of existing capacity. What we could find is some very, very brutal competition between new investments and old investments. If there's that brutal competition, my bet is, under those circumstances, the odds are the competition price is going to get pushed all the way down to the wellhead.

The second question is, if you want to look at this, rather than look at it on a monthly basis, I would suggest you look at peak quarters versus off-peak quarters. In some of the work that we've done, we were very shocked when we looked at the data. What we found is that the share of gas used in the peak quarters in the residential sector was the same, independent of the area in the country. In fact, the only thing that really seemed to dominate seasonality of peak versus off-peak quarters was the distribution of end-use sales.

Storage requirements, existing end uses by market. You're going to have to recognize

DISTRIBUTION CHARGES

- Rate Base

- Variable Charges
  - Customer-Related
  - "Fixed"

- Allocation by Customer Class

- Demand-Side Management

SEASONALITY

- Implications for Utilization of Transmission Capacity
  - New Investments
  - Existing Investments
- Peak Quarters versus Off-Peak Quarters
- Storage Requirements
- Effects on Transmission Charges

the fact that a large amount of new gas isn't going to have the same sort of seasonal patterns. You're going to have to break that out incrementally. Be very careful when you do that. For instance, don't put the total demand for residential. If you've got gas cooling in it, then it's going to have to be treated incrementally. Finally, effects on transportation charges. You've got to look at the storage costs.

I'll leave you with some final thoughts. The critical question is not just to have results. You've got to have some leading indicators. So, the model has to give the user some idea that if he or she buys off on it, they've got some leading indicators to check.

Finally, keep the model simple. I've given you a lot of ideas you might want to add into the model. Don't expand the model at this point unless it's absolutely necessary. Do all this off-line. When you finally cut your teeth on it, then you can start bringing some of it into the machine.

Thank you.

MR. KENDELL: I want to thank Tom for that wide-ranging review. I think we'll benefit from some of his experience there.

Our next reviewer is Joel Mumford. Joel is the manager of Southern California Gas' long-term capacity planning, including gas supply, interstate transportation, intrastate transportation, and underground storage capacity. He has 12 years experience with the company, including transmission and distribution system design, transmission operations and long-term capacity planning.

Mr. Mumford?

MR. MUMFORD: Thank you very much.

First of all, I'd like to thank the NEMS project team for the opportunity to offer comments on this project. I feel that defining the problem and the solution technique correctly, up front, is one of the most important steps in modeling. Obviously the second step will be putting the correct data into the model once you're finished. I think this type of ongoing review process is a very valuable tool in modeling.

I'm going to give a general overview of comments on NEMS and also on the natural gas transmission module. The areas I'll be going over include types of questions that can be answered by NEMS. I have a few comments on the Annual Flow Module and the Capacity Expansion Module and also have identified some potential areas that need to be considered in the future. Finally I'd like to just give a brief summary of how company planning needs may differ from the NEMS project.

Some of the types of questions that hopefully can be answered by NEMS are pretty basic and are mentioned in a lot of the material that's available; then also maybe a couple of them potentially could stretch the limits of NEMS. Obviously to forecast long-term prices and energy mix is a primary reason for the project. I agree that an integrated approach that looks at all

NEMS

NATURAL GAS

TRANSMISSION & DISTRIBUTION

MODEL

Joel D. Mumford
Southern California Gas Company

types of energy to determine the long-term prices and mix is necessary. By this I imply that the links between supply and demand must be considered. So, basically on those grounds, I agree that the NEMS project is headed in the right direction.

Some more specific questions in the news of today that hopefully NEMS could answer are the questions of the effects of energy tax on demand. There may be several objectives to coming up with some sort of energy tax, which could include deficit reduction, import levels, or job creation. This type of process could help determine which type of tax will meet or address most of the objectives.

One other type of question that hopefully will be able to be answered through this process would be: How do policy changes affect required infrastructure? An example of this could be if we have a policy decision that says we want to increase natural gas demand by 10 percent in the electric generation market, how is the transmission and storage infrastructure going to be affected? What types of capital investment are going to be required to meet that objective?

Finally on this slide, integrated resource planning has been a buzzword for the last year or so. I know internally at the gas company we are trying to look at a broad approach to different types of energy. Hopefully this project will help us in the future since it looks at the capabilities of all energy sectors from supply to end use. I think this is the type of process that we need to make the country more energy efficient and, therefore, more competitive in a world environment.

I'm going to talk a little more specifically now about the actual natural gas module itself. I have a few comments or additions that could potentially help the natural gas model. First of all, I'd like to mention again that there is going to be a difference between how an individual company looks at the detail they need to model versus something that's checking out country-wide policy. But I feel some areas would need more detail to capture intraregional competition. In California, for example, we now have some old existing interstate pipelines that move gas to California. That might only be 20 percent of the cost of gas. On the other side, we have new pipelines moving into the area with new investment and those might be 50 percent of the cost to move gas to California. We just feel there might be more detail to break down the arcs in the model.

One area also that certainly affects the market in California, although I'm not sure how it affects the rest of the country, is the seasonality versus annual average prices. The annual average prices that come out of the natural gas model would not be in enough detail to indicate least cost energy mixes to different types of end uses. Electric utility demand peaks in the summer time. Therefore, they would be looking for something that has a low cost in the summer. This may not get captured when you look at annual prices.

A type of deaveraging is being considered in the Capacity Expansion Module where you're looking at peak and off peak. I think this approach is a good step and necessary.

Certainly for our company needs, we would need a lot more detail than that. But I would suggest going to a four season approach, which Tom suggested. Show a winter season, spring, and fall, which we call shoulder months. You don't really know what's going to happen

TYPES OF QUESTIONS TO BE ANSWERED

ANNUAL FLOW MODULE

CAPACITY EXPANSION

OTHER AREAS THAT NEED TO BE CONSIDERED

COMPANY PLANNING NEEDS

WHAT TYPES OF QUESTIONS ARE TO BE ANSWERED

LONG-TERM PRICE FORECASTS & ENERGY MIX

EFFECT OF ENERGY TAX ON DEMAND

HOW CAN POLICY CHANGES AFFECT THE REQUIRED INFRASTRUCTURE

INTEGRATED RESOURCE PLANNING

ANNUAL FLOW MODULE

ANNUAL AVERAGES

INTRASTATE EFFECTS

EMISSIONS CALCULATION

STORAGE

there. A lot is determined by the weather. Then the summer peak month, which is high electric utility demand and injection into storage. But here the detail that you go into depends on the ultimate questions that you're trying to answer.

The intrastate effect. At the intrastate level there is significant competition. End use customers now have the ability to go to interstate pipelines directly or an intrastate LDC for service. Depending on what they use the natural gas for, the level of service they require is quite a bit different. Also, because of this new competition of intrastates coming in and providing direct service to customers, the LDC's, especially in California, are now looking at downsizing or rightsizing, as we call it, to shift costs away from this non-core market.

Another area of concern I had, based on the averaging effect again, is the emissions calculation. I'm not sure what the emissions calculation is going to be used for out of this model, but it appeared to me that some sort of average emission calculation was going to be done within the model. The reason I had concern there was because natural gas emissions are not a direct or linear function with throughput. There's going to be some sort of cutoff level where if you dropped to say, 50 percent of your utilization, you might not use any horsepower. There's also going to be some increment where if you dropped utilization by 20 percent you might actually cut the emissions or the horsepower required by 50 percent. The point I wanted to make was that it's not a linear function.

The way we view storage has several different uses. I think the one use that the model captures is the seasonal load-balancing function. However, due to unbundling of services, direct competition from interstate pipelines, daily balancing now has become a big requirement of large non-core customers. Also, supply protection or peak day protection has become very important. At least in Southern California, the price of storage is driven more by the last two, peak day protection and daily balancing, than it is driven by seasonal load balancing.

In the Capacity Expansion Module, I think going to an off-peak and on-peak season was a good step. Some areas that may need to be further addressed, that is, what's firm versus interruptible today or yesterday certainly is changing. We have seen interruptible customers that got very high levels of service for 5 or 10 years in the past, became accustomed to that, and expected it. Then once you try to invoke their interruptibility, they start pounding on your door.

Related to that, there are parts of the non-core market that will need firm service. That's been separated out in the model. Both core and non-core are separated into interruptible and firm service both.

I didn't quite agree with one area in the model that suggested that when you expand capacity, costs may go down, but the model is going to hold those costs flat instead of decreasing the costs of transportation. Certainly from some of the expansions that I've seen take place or that are proposed, it's getting the pipe in the ground that's the big cost. The expansions afterwards require considerably less investment. This drives the transportation cost down significantly. Driving that cost down can affect demand and should be included.

Just to relate that to what's happening in California: the non-core market that was interruptible got used to having very firm service for 5 or 6 years. Then when demand or

EXPANSION - WHAT TO CONSIDER

WHAT IS FIRM VS INTERRUPTIBLE

NONCORE MARKET NEEDS FIRM SERVICE

CALIFORNIA EXPERIENCE

UNBUNDLING OF INTRASTATE SERVICES

BENEFITS & COSTS OF EXCESS CAPACITY

supply became constrained and you tried to interrupt those customers, they became very upset. They expected to get firm service at an interruptible price. What this led to, because of the regulatory environment and the lead time for a regulated company to get approval for expansions, was outside competition coming into the market. This outside competition did have a negative impact initially on the LDC, but overall it had a very beneficial impact on non-core customers, as the competition has driven down the cost significantly.

Just as interstate services have been unbundled through 636, I see intrastate services also being unbundled. This, again, is due to the direct competition from interstate pipelines with LDC's -- the bypass issue that's right in the forefront of most LDC's eyes right now.

Another thing that gets driven by the regulations, mostly, is that it takes a long time for a regulated industry or an LDC to react to changes in the market. This sometimes leads to excess pipeline capacity being built by an outside party. This could lead to cost shifting between market sectors. Initially this could drive the costs down for the non-core market, but the core market or someone will have to pay for that.

A few other areas may need to be considered. I've seen in some of the documentation that technology is going to be included, although when reviewing the natural gas transmission modules I couldn't see specifically how technology was going to be addressed. Certainly technology is going to change production curves. Technology can reduce costs of transmission and technology advances can change shifts in the end use patterns. Technology can also reduce emissions.

Environmental issues could be driven by policy or public opinion. Somehow the model needs to be flexible enough to put these types of factors in, so it can address demand. And again, intraregional competition may affect end-use price. And end-use load patterns may shift from historical patterns. It seemed to me in reviewing one of the modules, that they were going to base utilization on historical patterns. I think that if natural gas is to become more widely used throughout different energy sectors, these end use patterns are going to change. So, you need to include that within the model.

I just wanted to put a partial list here of some of the things that the gas company or an LDC planner might look at. We usually put out 20-year plans that affect 5-year capital expenditures, so you're continually updating these plans. Some of the things that we include are regulatory and environmental policy and how that may affect supply and demand; technology advances and how that affects supply and demand. Certainly those two help lead into long-term supply and price forecasts. We also now have to do competitive analysis to make sure that the LDC can provide competitive services. After that, we try to forecast long-term demand. Once we have the demand and supply set, then we look at interstate transportation requirements. This may drive building of new capacity or just may drive the LDC into purchasing more existing capacity. Certainly this also drives intrastate transportation requirements and storage. This will lead to a short-term, 3- to 5-year capacity spending plan, which then leads to rates and cost allocation.

I think the NEMS project can certainly help lead to sound energy policy which would hopefully lead to more stable regulatory and environmental policy. That certainly would make

OTHER AREAS THAT NEED TO BE CONSIDERED

TECHNOLOGY ADVANCES

ENVIRONMENTAL ISSUES

INTRAREGIONAL COMPETITION

END USE LOAD PATTERNS

GAS COMPANY (LDC) PLANNING NEEDS

Regulatory & Environmental Policy

Technology Advances

Long-term Supply & Price Forecasts

Competitive Analysis

Long-term Demand Forecasts

Interstate Transportation Requirements

Intrastate Transportation Requirements

Storage Requirements

Capital Spending Plan

Rate Estimates

the long-term forecasts in my job much easier. Certainly, NEMS also is going to try to predict long-term supply and price forecasts. Even though more detail would be required for a specific company, I think this will be a help in planning for the LDC.

In closing, I would like to just add that, hopefully, the overall project will be structured so that regions and networks can be easily modified so local interests can study specific items.

Thank you.

MR. KENDELL: Thank you, Joel. That was quite a thorough review.

Our last reviewer today is William Meroney. Mr. Meroney is Director of the Data and Financial Staff in FERC's Office of Economic Policy. He's been directly involved in pipeline transmission issues as part of the analysis of the gas inventory charge, and before coming to FERC he was with the contracting firm that's been heavily involved in building this natural gas model.

MR. MERONEY: I'd like to add that my background by training is that of a mathematician and a philosopher and I've always found these two to be a very good combination for a modeler. The mathematics helps you to build the model and the philosophy helps you to rationalize what you've done.

I speak here today, however, primarily as someone who's been with the Commission for a few years, so I'm looking at the model primarily as a user or as a potential user of results. Now, the central tendency of the work that FERC does is really case work. So, it's very often highly detailed and would not typically have a need for the results of a model like this. However, there certainly are occasions in our part of the Commission where we're dealing with policy issues where the results from a model like this, and in some cases perhaps components or modules out of it, could be very useful in our work.

As I sit and look at what I put together in these slides, I realize that I've committed what I think is one of the sins of the Commission, or someone at the Commission when they go outside the Commission, and that is a tendency to talk about yourself in ways that no one else can understand. I'll do what I can to minimize that as I go through this and explain a term here or there if it's not obvious to everybody. Finally, I'll try to minimize it also by being as brief as is reasonable under the circumstances.

I'd like to say a couple of good things about the model in general, up front. I really think the modular approach is a very positive one. The ability potentially to get separate looks at the supply side and the demand side in the gas industry would have helped a lot a year or so ago when we were sitting down looking at the potential impact of Order 636. Along with that, the regional framework in general is a very positive one.

A couple of general concerns that may come up relate to the level of aggregation and disaggregation that's required, recognizing, of course, that everybody wants as much detail as possible. But I do have a specific concern about the fact that NEMS as a whole, and especially the natural gas transportation part as I look at it, has to interact with lots of other modules and the regions are often quite different. So, there are sharing mechanisms that transfer information or data from one model to another. It's part of the price that you pay by being modular and convenient in that way.

I also have a general concern with seasonality in the flow module. But perhaps like some others, the best way to deal with some of these concerns of detail, regional or temporal, is to try to deal with them outside the model without making more complex what is, obviously, already a complex system.

Let me go through a few issues that are sort of current at the FERC. There it is, the imperial FERC right away, the FERC. It's hard to miss these slips sometimes.

I think they are relevant for anyone who is thinking about the short to midterm features that play in a model like this. But the caution here is that a lot of these things haven't played out. They are not so much criticisms of the model as cautionary notes to keep an eye on as the actual gas transmission market evolves over the next few years.

I'll start out with rate design. Order 636 is the major FERC order that is engendering a restructuring of the natural gas industry in which services become unbundled into their component parts. Now, one of the things that is required under 636 is that pipeline rate designs follow a straight fixed variable format which means that no fixed charges go into the commodity charge that people pay. The pipeline tariff model appears to provide the user with a very wide and flexible menu of ways to deal with something like straight fixed variable. But now, of course, FERC being as connected as it sort of must be with the real world also requires that the effects of this change in rate design be mitigated in one way or another. The bottom line is the variations in what actual pipelines do make the use of most generic designs problematic. I think this is a pretty good case study in how the reality of regulatory mechanisms frustrates the attempt to analyze them generally. I've got other examples of that, bu in the interest of being brief I won't go into them right now.

Another issue coming in with the restructuring of the natural gas markets is that in secondary markets holders of capacity directly from the pipeline are permitted in one way or another to sell these rights to other people. Capacity brokering is something the Commission tried for awhile and then backed off on when it did Order 636 and put in place a releasing program that involves both the pipeline and a holder of the capacity such as an LDC. What this means is that holders of capacity can sell to third parties under a wide variety of arrangements. I think that this creates a whole range of services between the extremes of the old style core of firm service and the strictly interruptible service. I don't think it means a whole lot of change in the model right now, but this is one of those things that I think will change the face of the gas industry over the next few years.

An issue that is really just now starting to emerge as 636 goes into place is the whole issue of how transmission services are priced. The question of competition within the transmission network itself, which has always been heavily regulated as a natural monopoly, stays regulated after 636 as well. As part of 636, FERC instituted a task force to study the problem and think of ways in which competition could be used within the transportation network or within transportation services in the future. We're already seeing some proposals from pipelines for market-based interruptible or short-term transportation.

This seems to be one of those problems that, from the point of view of this model, is solved for us by being assumed away in that the whole non-firm market is treated on a purely competitive model. I think this has limitations as the world exists right now but might not be such a bad assumption down the line.

One thing that wasn't clear, at least to me, in the documentation, and this may be primarily a documentation problem, is exactly what was marginal about the marginal price when it was calculated that way? I'm not sure. It's at least not clear to me.

Another question was I realized that it's some kind of equilibrium, but I was unclear why the price wouldn't just go to the minimum anyway. If that's the case, then I don't think the market works that way.

Another pricing related question was just that, if I understood it correctly, the price of the gas itself was the same in firm and interruptible markets. I don't have any real reason right now to say that that's wrong, but it's at least questionable. Most people think there ought to be some kind of premium for holding long-term supplies or firm supplies of some sort.

Market centers are an issue that our office at FERC has had an interest in. Within the current restructuring the rules prevent or say the pipelines cannot put into place rate designs that inhibit the development of market centers. I think that it's just sort of assumed within the model that the kinds of things that we worry about when we worry about market centers at OEP will work themselves out. As far as I can see, the sort of intraregional trade within the model just seems to clear itself out without any problem of getting supplies from one corner to the other. Some of the other speakers mentioned or at least raised the question of how to deal with this. I don't suggest it go in the model, but I think off-line analysis might be helpful.

Lastly, new capacity is an issue that the Commission has yet to deal with, although there is an order that went out there and stopped. It hasn't done much for a while. It's going to need to be revisited within the Commission. That may have some effect on how new firm supplies come on line and how they're priced. I think the Capacity Expansion Module moves in the right direction, compared with earlier efforts, in terms of trying to represent the acquisition of new capacity in a two-period model, although I would second Joel's comment that that's only one way in which seasonal storage plays a role in pipeline operations.

My last point here is that it should represent rolled in and incremental pricing. Maybe it does; I'm not certain. But it's an undecided issue at the Commission. It's one of those issues that keeps coming back and can make a difference. Incremental pricing prices new capacity separately. If the cost of that new capacity was rolled in, all the capacity in a system rolls in and prices the capacity at an average.

Overall, I applaud the effort here. I think that it's in the general direction that can be more helpful to our work than some of the things that were in place a couple years ago.

MR. KENDELL: I'd like to thank the reviewers. I think we're going to benefit quite a bit from their insights, especially the benefit of their experience. We've brought to bear a wide variety of experience this afternoon.

What I'd like to do now before I take questions is to give Barbara a chance to respond to some of the questions that the reviewers raised.

When I do get on to taking questions, I'd like you to identify yourself and your affiliation for the record.

MS. MARINER-VOLPE: Thank you.

I have five and a half pages of comments here that I'd like to respond with. Only kidding.

Personally, I'd like to thank all of the reviewers. I think they did a great job and my rebuttal is: I agree.

As far as the issues raised with regard to seasonality and level of detail on the network, I think that our intention was to develop a framework that we know we will want to revise and expand depending on the type of analysis that we do. We would like to be all things to all people and to solve in a fraction of a second, but we knew going into this that we would not.

In addition, if we built the quintessential model, then perhaps that might be a static one and that would definitely increase the unemployment rate in town.

What I'd like to do now is skim through a few of my comments that I jotted down and provide a little bit more detail on our intentions over a period of time.

As far as the data problems that Tom was referring to, I agree and EIA is aware of data problems in specific areas. We hope that the data, in fact, will improve, and that our survey coverage will improve over time, but this is not instantaneous. Given the fact that we are developing the model now, we will have to make some heroic assumptions. We stand ready for that job. We are interested in whatever insights and work that GRI has done, as well as anyone else in the room for that matter.

As far as the capacity expansion module is concerned, the structure does include a look-ahead feature where we anticipate both shifts in supplies as well as shifts in demand over time. The supply information is provided by the supply modules in the oil and gas supply models in NEMS. Similarly, the demand is provided by the NEMS demand modules. The type of service required to satisfy those demands is also specified by the demand modules. Within the Capacity Expansion Module, however, I did describe the two seasons that we are considering. Currently, the seasonal profile will be based on parameters that the NGTDM develops and assumes in that structure.

As far as the issue of seasonality, this issue has impacts for the whole NEMS system. It is one that we have received numerous comments on and it's an area that we will be looking into in the future.

As far as the intraregional structure, it is correct that we have no intraregional capacity or physical flow representation in the model. This is largely due to the fact that there are significant data limitations in that area. It's an area that could possibly be expanded at some point in the future however.

As far as the different regions in the various models, the NGTDM has, as I described it, the 12 regions. Other modules similarly have defined their own regional structure and there are mapping algorithms and sharing functions to relate the two. As far as the supply regions, they are different and distinct from those 12 regions that I described earlier. So, I hope all of you attended this morning's presentation on the oil and gas supply modules in NEMS.

As far as the pipeline tariff component is concerned, the cost of service calculation, in fact, goes through a line item estimate. So, many of the line items that were listed, as well as many that were not, will in fact be estimated individually for the 35 or so interstate pipelines that we have included.

Jumping to the storage issue, storage is explicitly represented in the Capacity Expansion Module which includes a two-season representation. The results of the dynamics of storage, the withdrawals and injections are then provided to the Annual Flow Module. So, there is a structure in there right now. However, the Annual Flow Module, as we've mentioned, is an annual model and the market balance is done on an annual basis.

There were a number of comments about some of the parameters that we will require for the pipeline tariff module as far as allocating costs by rate class, et al. We have basically embraced Tom's recommendation and have included many, many levers, so we have a great deal of flexibility in that area.

As far as the issue of demand side management, we currently have no explicit structure within the model. However, this, similar to some of the other areas, is ripe for expansion in the future.

As far as issues relating to the impact of energy taxes on demand, for instance, and investment changes, the costs of investment for additional capacity are, in fact, estimated within the capacity expansion module and are provided to the other modules and the overall NEMS macroeconomic module. So, there are some feedbacks there. As far as the impacts of energy tax on demand, the model is designed to handle that particular structure.

I agree we are missing some competition in the area of the intrastates because of our regional definition. As far as the treatment of the profile of future market requirements between the firm and interruptible service, that is an input to the NGTDM and that is based on the different profile of demand. For instance, if for a particular scenario the treatment of electric utility use of combined cycle plants requires firm service, that then gets translated into the demands for firm service for natural gas and is passed along to the NGTDM and we in turn respond to that.

There was a comment about the possibility of excess pipeline capacity being built. That depends on a number of factors. As I described, the capacity expansion module is a planning module and it bases its decisions on expectations of future supplies as well as future demands. If one were to assume perfect foresight, then we would precisely anticipate the future market requirements and absolutely no pipeline capacity would be built. The extent of error, I guess, in these supply and demand estimates could result in some potential problems in that area.

As far as the issue of technology and the fact that there is not much discussion in the NGTDM area, I would refer participants today to some of the other components of the NEMS system, specifically on the supply side in which there is an explicit treatment of various technologies. As far as the NGTDM is concerned, however, there are some areas where there may be some technology improvements. They would largely enter the system in the way of costs. For instance, if there is a new technology for storage fields that resulted in a change in costs, that would be reflected in the cost curves for additional storage capacity.

As far as the ease of revising the network in the NGTDM, our goal was to make it as easy as possible. However, there will be some costs involved. There's no way around it. If you were to change the number of regions, for instance, in the network or the number of nodes, then that would require some changes to the inputs and some data work would be required. Depending on the analysis and the need, we anticipate that we will revise the networks as necessary to perform the analysis requested of us.

As far as the level of aggregation and the regional detail, we are concerned about the level of detail. However, we think that we've made a reasonable first cut here at balancing the tradeoff between too little detail versus too much detail.

As far as the Pipeline Tariff Module is concerned, the treatment of transition costs will be specified as an input to the PTM and will be accounted for in the development of pipeline tariffs.

As far as secondary markets for natural gas and capacity releasing programs, indirectly it is assumed in the model in that capacity that is not used to satisfy the firm market load is made available to the non-firm market.

I agree that the assumption that the non-firm market is completely competitive is a reasonable one over the long term and I also agree that there may be some short-term transition to that completely competitive market.

As far as the level of detail on the wellhead contracts, we currently have one price for natural gas within each of the regions. We do not have a distinction currently based on the type of contract, either long-term, spot market, or a short-term contract. That's another area that we may consider at some time in the future.

As far as the decision making in the capacity expansion module, the simplified assumption that we have structured in the model is that the decision to add capacity is based on an incremental price. But once that decision has been made, it is rolled into the rates. So, depending on how FERC comes out on pipeline capacity construction rules and things like that,

that may require some changes to the model. What we have designed here is a framework that we know we will be revising over time.

That concludes my comments. Thank you very much.

MR. KENDELL: Thank you, Barbara.

Now is your opportunity to ask questions. Do you have any questions for Barbara or the panelists? We've got a portable mike up here. As I said, I'd like you to identify yourself and your affiliation.

MR. DiANGELO: David DiAngelo, Pennsylvania Power and Light Company.

I have a question that relates to energy modeling and policy. Over the last 12 plus years, I think we've gone down the road to market pricing efficiency. FERC has been instrumental in that with regard to the gas sector. I'm wondering if anyone would hazard a guess with the new Administration that there may be some irony that the modeling we're getting, which I see a lagged attempt to get at incorporating market impacts and the phenomena we've been experiencing since the mid-1980s or the early 1980s, whether we might not revert for equity reasons back to a more managed competition where you see less efficiency and more of a concern with equity.

MR. KENDELL: Bill?

MR. MERONEY: Sure. The answer is I don't know and if I did, I wouldn't say.

It's hard to tell, but I think there's been a broad basis of support for something like this. There's a central tendency of what's been happening. You may see more concern for equity, especially ahead of time. Equity tends to sometimes force itself on you if you ignore it and I think the Commission saw that to some degree in 636. I would think that you might see more thinking about it ahead of time. But how much will actually change, it's hard to tell. I don't think that if you go on the campaign record that things are likely to change a whole lot, but stranger things have happened.

DR. WOODS: Let me give one clarification, Dave. I didn't say that we're going to go back to a fully regulated market. What I said what would happen is we might find the substance of how we did things. We might go back to a large part of our historical experience and use that.

I'll give you a classic example. When they were first starting to do some of the gas-to-gas competition and everything, a friend of mine was involved in a case and was sent down to get something out of the archives. He went back to the archives of his company and he grabbed the file. He didn't bother to look at the date. He just looked at what the letters said, and he said, "Ah, I guess I got it," and brought it back in. They opened it up and said, "What are you doing with a letter from 1948?" He says, "My goodness! They were talking about the same issues back in 1948."

What I'm saying is, don't throw away the historical experience. I think what's happened in this industry is that we've confused the form and we've thrown it away. So, no, I'm not saying you're going to go back to regulation. But what I am saying is we may find the substance of how you model something or how you structure it or how we choose to do things. We may find that some of those things, given the context of the new things, may in fact have been better ways to handle them.

That's all.

MR. MERONEY: Was my understanding correct that in terms of integrating framework NEMS does go back a little bit to some things that have been used before? Maybe that's going to happen in the industry too.

MR. KENDELL: Okay. Do we have any questions for Barbara? Questions about the model? No one has any questions about the model?

Well, I have some questions for the panelists, if you don't have any questions.

One thing Joel mentioned was integrated resource planning. I just wondered if either Joel or maybe Tom had some insights into how we might approach modeling the interaction of the electricity and gas industry as the electric utility industry goes to greater usage of natural gas for power generation, particularly as it regards pipeline capacity planning.

MR. MUMFORD: I first heard about that term through the electrical industry, through trade magazines. It seemed to me from being in the natural gas industry that integrated means you look at all energy sectors, not just how you can manage investment in electrical power plants the best. Certainly from the gas industry we see that. If you integrate all sources, where it's coal and nuclear or natural gas and you look into that in the conversion in the electrical power industry, you see that as a future strong market. I think a lot of the projected growth in natural gas supply and demand in the future is in the electrical generation market.

We've also looked at some off peak system uses. For example, gas air conditioning has been mentioned several times over the past few years. That not only increases throughput or utilization of gas pipelines, but it also reduces the electrical demand which would reduce capital investment required in generation.

DR. WOODS: The only thing I'll say is that you've got enough on your plate to get the model you've got running. What I've suggested to you, and I think what everybody else is telling you here is that people are going to ask you to be able to answer questions about a lot of issues. You better look at those to have that capability. As far as integrated resource planning goes, I don't know. I'm not even sure it's not just another one of these fads like least cost energy planning and then it gets more honored in the breach than in the observance.

It's like I've got a pipeline model. My contractor comes out to me and says, "Oh, we've got to model 636."

I say, "Fine. What is 636 going to do?"

He says, "Oh, we have a good idea."

I says, "Yeah, you do. But what happens when it gets through and it goes?"

"We don't know what it's going to do."

And I would say, "Don't get ahead of the curve. Just make sure you've got enough information. You're going to probably have as big a structure off-line dealing with these answers. Get the first one done."

I didn't see anything in your model that was going to blow it apart in your face. There may be things that will appear and you'll find things and say, "Gee, I really wish we didn't have that." Fix it when you see it. You won't know that until you run it. It may turn out that what we see as an error or, shall we say, a shortcoming, you manage to make three other shortcomings that we never caught and they offset it and nobody will ever know. So, don't worry about it. You try to fix that one, then you'll find the other three.

MR. KENDELL: Sounds like good advice to me.

Do you have anymore questions for Barbara? I've got one.

One of the things that Tom was concerned about is the reliance on historical data for a forecasting model in an industry that has changed so radically in the past 5 years or so. What I'd like to ask Barbara is what the process is that this model is going to be subjected to that will test its capability.

MS. MARINER-VOLPE: I think you've, in fact, asked me several questions there. I will answer the last question first. With regard to the testing and development procedures, we are in the process right now of implementing three of the four modules. They will be documented to EIA's excellent and very high standards and will include the full specifications of the resulting equations, as well as all of the relevant statistical and data transformations that were required.

As far as the testing of the model is concerned, before a model can be used as a tool within EIA, in addition to having documentation of the data and estimates, we must also generate a model developer's report, in which we provide background information as far as the approach, the reasons we've included the approach, as well as results for a number of sensitivities and scenarios. The idea there is to give a user some idea of the sensitivity of the model -- an idea of how it is performing. We have not as yet designed those specific tests and they will likely not be complete until the end of this year, but I am sure that there will be any number of cases examining the behavior of each one of the four submodules in the NGTDM.

With regard to what I heard as the first question as far as the data, as I said earlier, we know that there are some problems in coverage in some of the data because of the surveys and the way that they are structured and the changes that have taken place in the industry over the last few years. I'm not sure the extent that we would satisfy perhaps Tom's recommendation that we can incorporate some adjustments to the data to account for some of the coverage problems. We will, however, identify what the problems are and at least have some representation available for us to consider in the modeling.

Overall, we are bound by requirements of reasonableness. As I think Tom or someone said, if you don't match the Natural Gas Monthly, then there's a problem. We will be using some degree of judgment and I'm confident we will make the right decisions on that front.

MR. KENDELL: If I don't see anymore questions, I'd like to thank you for coming. Our next panel is at 3:15. I want to remind you of the refinery panel tomorrow morning at 8:30. Thanks for coming.

RENEWABLE FUELS PANEL

February 1, 1993 - 1:00 pm

PANELISTS:

Scott Sitzer, Moderator and Presenter
Tom Hoff, Reviewer
Walter Short, Reviewer

AUDIENCE PARTICIPANTS:

Bill O'Neill
Steve Bernow
John Molburg

EIA

PROCEEDINGS

MR. SITZER: Good afternoon, and welcome to the Renewable Fuels Session of this National Energy Modeling System Conference. I'm glad to see all of you.

My name is Scott Sitzer. I'm both the moderator and the presenter for this session. I have on the panel Walter Short, of the National Renewables Energy Laboratory, and Tom Hoff, an independent consultant, currently a graduate at Stanford University, who has also done work with Pacific Gas & Electric on solar photovoltaics, primarily. One of our reviewers has not arrived yet. If he does later then we will get the benefit of his review, otherwise we'll continue with the two reviewers that we have.

Since I'm both the moderator and a presenter I'll present myself. I'm with the Energy Supply and Conversion Division, and probably the most important characteristic of my background is that I've been in the Energy Information Administration since its inception back in 1977. I've worked in all areas of energy supply and demand, spent several years working on the Short-Term Energy Outlook, for those of you who are familiar with that; I worked on the first 34 of them. About five years ago, I became involved in coal analysis and forecasting. I'm relatively new to renewable fuels. For the past year, that's been one of my responsibilities, to help get the Renewable Fuels Module of NEMS going, and so I will make the presentation on that.

I'll give kind of a brief overview of what the NEMS Renewable Fuels Module is. There are a number of aspects to it that can't be covered completely in 20 minutes, but I will provide an overview, and we can get more into the details of it as you desire later.

I know there are a number of people out here actually who have worked on the model at one time or another and who are probably more familiar with some of the technologies than I am, and I'll be glad to listen to their ideas on expansion, and, perhaps, corrections as I go along.

So, I'd like to give you an overview of the Renewable Fuels Module of NEMS, and I guess one of the things I should mention is that, as was said this morning, renewables are one of the new areas that we are including in our mid-term and long-term energy models.

The treatment of renewables in the current forecasting system has been essentially exogenous. We have forecasted renewables as a decrement against conventional energy sources. For example, hydropower, geothermal, solar thermal and so on, have been essentially subtracted from the requirements for other energy sources, whose models then compete the remaining energy sources, such as coal, oil and gas, and nuclear. But, in this model we are going to attempt to integrate it and to let renewables compete economically and in other ways with other energy sources.

The Renewable Fuels Module has several major components. Its uses are in electricity generation -- hydropower, geothermal, solar, wind, biomass -- and non-electric uses, primarily solar, biomass and alcohol fuels for transportation. In 1990, the split between these two was relatively constant, approximately 3 quadrillion Btu for each.

Renewable Fuels
in the
National Energy Modeling System

Scott Sitzer

Energy Information Administration

February 1, 1993

OIAF 1/93

Renewable Fuels Module

- Major components:
  - Electricity Generation: Hydropower, geothermal, solar, wind, and biomass
  - Non-electric Uses: Solar, biomass, and alcohol fuels

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- Provide supply curves to the demand, electricity, petroleum modules for competition with conventional sources

- Integration of resource data with technological characteristics

The purpose of the renewable fuels module will be to provide supply curves to the demand, electricity, and petroleum modules, where there will be competition with conventional fuel sources. This isn't true completely across the board. Hydroelectricity will still be determined in an off-line manner. Municipal solid waste will be determined off-line, and both of those will be used as decrements against other energy sources.

But, in general, we do want to provide costs to those other models, where the competition between renewables and conventional sources will take place.

And a final purpose of the module is to integrate resource data with technological characteristics; the Renewable Fuels Module will be a repository for costs and fuel technology characteristics and resource supply curves.

There are a number of common characteristics of renewable fuels modeling that need to be taken into account in this process. One is market penetration. Renewable fuels are still a fairly small portion of today's energy supply, except for hydroelectricity; the future potential of renewables can be great depending upon the demand for energy and what happens with such other aspects of energy as world oil markets.

Renewable fuels tend to have negligible fuel costs, except for wood. In fact, for MSW, fuel costs are negative. So fuel costs are not an important issue with renewables, but they do compete with other energy sources in terms of their capital and operating costs.

Renewables can be used in both the electric and non-electric sectors, including cogeneration, and in electricity we expect to have penetration both in the utility and non-utility sectors, and to try to model that competition in both sectors.

There are special regional considerations for renewables. Geothermal is, basically, dominated by its Western sites. Only certain areas can show commercial feasibility for solar and wind. So, on top of the already complicated regional structure of NEMS, we have to look at each of these renewable technologies in terms of their own special regional considerations.

Currently, the residential and industrial sectors use wood, possibly there's increased use of solar for the residential sector in particular in the future.

Finally, the nature of renewables is that many of them are intermittent, particularly, solar and wind, and this affects strongly how they can be characterized in a model such as NEMS.

Let me move on to each of the technologies that we are attempting to model in Version I of NEMS, starting with hydropower; there are a number of issues dealing with hydropower. This is going to be one of the models where we will do basically off-line analysis.

In many ways, hydropower is the mature technology in the renewable fuels stable. We don't anticipate a lot of further growth because of many of the environmental and other costing factors involved, but we will continue to look at capacity factors, evaluation of any additional potential penetration, and especially of what utilities say they will be doing over the next 10 to 15 years.

Characteristics of Renewable Fuels Modeling

- Market Penetration - competition with conventional fuels

- Negligible Fuel Costs (except biomass)

- Uses in both electricity and non-electric sectors, including cogeneration

- In electricity, utility vs. non-utility penetration

Characterisics of Renewable Fuels Modeling
(Continued)

- Special regional considerations

- Residential and industrial sectors already use wood, possible increased use of solar in the future

- Intermittent availability for some technologies

Hydropower Issues

- Environmental Regulations
- Relicensing
- Additional planned capacity by electricity producers
- Capacity factors

Structure of Hydropower Submodule

- NERC Region Capacity and Capacity Factors

- Utility vs. Non-Utility

- Conventional vs. Pumped Storage

Outputs of Hydropower Submodule

- Existing and Incremental Capacity
- Capital and Operating Costs
- Capacity Factors
- All Outputs Provided to EMM by NERC Region, Ownership (Utility or Non-utility), Type (Conventional or Pumped Storage)

Environmental regulations are important for hydropower. There are considerable pressures for mitigation of the effects on fish and other wildlife, water availability, and water pollution; this is one of the aspects of hydropower that tends to reduce its penetration levels in the future.

Relicensing is important. It turns out that this year about 170 projects, which represent over 2 gigawatts of hydropower capacity, are expected to be up for relicensing. Once we have seen what happens with this, we'll have a better notion of what to do in the future on relicensing, in terms of the success rate.

Currently, we do expect successful relicensing for most applications, but we'll be looking over the next year or two as to what happens in terms of hydropower relicensing.

There's additional planned capacity by electricity producers. This is reported to EIA on its data forms, and these will be included in our modeling efforts.

With capacity factors, I want to look at the relationship between capacity and precipitation. We want to have both a base case and the potential for looking at drought scenarios, heavy precipitation scenarios and so on, so this is one of the areas that we hope to have some improvement on.

The structure of the Hydropower Submodule will include NERC region capacity and capacity factors, because NERC -- the North American Electric Reliability Council -- regions will be those which will be used in the electricity market module, and many of the renewables will be constrained to be modeled in terms of NERC region, so that we can transmit the information to the electricity market module.

We'll be looking at utility versus non-utility. Although most current capacity is utility owned, there is some non-utility and we'll continue to have those as separate entities within the model, and we'll also be looking at conventional versus pumped storage.

The output of the submodule will include: existing and incremental capacity, both that which is planned by utilities and that which we determine is important in terms of our off-line analysis; capital and operating costs, not so much for competition with other fuels, as for inclusion in the electricity financial model's determination of what overall electricity prices will be; capacity factors, both base and those for other scenarios, such as the drought scenario; and we will provide outputs to the EMM by NERC region, by ownership type, and by technology, i.e., conventional or pumped storage.

So, in general, hydropower will be stipulated similar to the current model that we have.

Looking at the Geothermal Submodule, this is one in which we hope to look more carefully at geothermal resource constraints, and what we'll be doing is trying to build supply curves of ascending steps of unit costs for new capacity.

The supply curves will be provided to the Electricity Market Module, so that it can determine the correct capacity planning and dispatch of geothermal within its planning and

Geothermal Submodule

- Geothermal resource constraints

  - Supply curve of ascending "steps" of unit costs

- Capital costs of capacity, including exploration

  - Flash steam
  - Binary fluid cycle

- Operating and maintenance costs

  - Fixed only

Structure of Geothermal Submodule

- 44 Geothermal Sites Available for Electricity Generation

- Separate Cost Functions for Binary Cycle and Dual Flash

- Available Capacities by NERC Region

dispatching algorithms.

Capital costs of capacity will include those both for exploration and for generation, for two primary technologies, flash steam and binary fluid cycle. This is, essentially, a hydrothermal model at this point. We won't be looking at hot dry rock right now, because of the lack of experience with that technology, and because it's our belief that the future -- the mid-term -- will basically be in the area of hydrothermal.

Operating and maintenance costs, primarily fixed, because of the assumption that geothermal plants need to run at full capacity in order to maintain the geothermal pressure.

The structure of the Geothermal Submodule: we've obtained data on 44 geothermal sites that are available for electricity generation. As I said before, these are all in the west, they are based on the U.S. Geological Survey's data, Bonneville Power Administration, information for northwestern sites, and other industry sources in a database which was jointly built by EIA and the DOE's Office of Conservation and Renewable Energy.

We intend to build separate cost functions for the binary cycle and dual flash technologies, using engineering cost estimates which were developed for IMGEO, a site-specific model being operated for the Office of Conservation and Renewables, and we'll also be looking at available capacities, again, by NERC region.

The outputs of the geothermal submodule will include supply curves for new geothermal electricity capacity, with capital and operating costs by NERC region, so that the Electricity Market Module can determine the optimal planning for geothermal as opposed to other sources of electricity, as well as for its price determination.

Maximum capacity factors, which we initially assume will be full capacity factors for geothermal, and emissions factors. There are six emissions that are being tracked by the National Energy Modeling System: carbon, carbon dioxide, carbon monoxide, sulphur dioxide, oxides of nitrogen and volatile organic compounds, such as ozone. For geothermal, the most important will be carbon dioxide, and we will track that.

Let me move on to the solar and wind submodules, which are similar in the sense that they are both intermittents. They cannot be used at full availability, and this is important in their modeling They are available in only certain geographic areas; solar is primarily an output of the southwest and California, wind is greatly dominated right now by its California sites, but there are considerable other resources available in the midwest and other areas of the country, and because of their intermittency there are limitations on what part of the load duration curve can be met by solar and wind.

The structure of the Solar Submodule -- both solar and wind are those for which we haven't yet released a component design report, we are still designing it, so this is still somewhat preliminary -- at this time we've identified 38 representative sites for solar resource evaluation, one for each of the NERC regions. In some cases, we've had to split those between solar thermal and solar PV, because different technologies require different resource levels.

Outputs of Geothermal Submodule

- Supply Curves for New Geothermal Electricity Capacity
- Capital and Operating Costs by NERC Region
- Maximum Capacity Factors
- Emissions Factors for CO2

Solar and Wind Submodules

- Intermittent nature of resources
- Only certain geographic areas
- Limitations on load duration curves

Structure of Solar Submodule

- 38 Representative Sites for Solar Resource Evaluation

- Separate Treatment of Solar Thermal and Solar Photovoltaic Technologies

- Output Data Provided by NERC Region

These are from a database which is available to us from the National Renewables Energy Laboratory, which is helping us to build this particular submodule.

We'll be handling solar thermal and solar photovoltaic technologies separately with different costing, different resource availability, and provide information to the electricity market module for both of those separately. And, as always, with the electricity renewables, we will provide data by NERC region.

The output of the Solar Submodule will include capital and operating costs by NERC region, again, for competition with other fuels in the electricity market module.

Resource availabilities by season and time of day, and by NERC region, will be outputs and this is one of the ways that we are trying to accommodate the intermittency of solar by splitting up the load duration curve into slices which correspond to different times of day and seasons for the electricity market module. We will provide separate outputs both for solar and PV technologies.

The Wind Submodule is somewhat similar, in terms of its being an intermittent. We'll be looking at state level data, which is used to characterize wind resource quantities and qualities, and these primarily relate to the regions of the country where the wind resource is available, and the speed which is proportional to the resource availability and how much electricity can be generated.

We'll be looking at a prototype technology for wind, known as the Horizontal Axis Wind Turbine. This is what we have costing data on and what we'll be using as a prototype for the model in terms of its passing of cost information to the electricity market module. And, we will characterize cost and performance characteristics by NERC region.

The outputs of the Wind Submodule will include supply curves for new capacity by NERC region, capital and operating costs, both for competition and for pricing, resource availabilities by the important slices of the load duration curve, and performance characteristics for wind-powered generating units, such as efficiencies and capacity factors.

Moving on to the Biomass Submodule; biomass is used both for electricity and non-electricity. For electricity, there is substantial market penetration of wood for independent and small power producers, and that's where we will be concentrating our efforts in terms of NEMS.

Municipal Solid Waste (MSW) electricity is, essentially, going to be modeled as a byproduct of the waste disposal process, so it will not compete with other sources of electricity, but will reduce the amount of electricity that needs to be met by the amount that MSW can generate.

Non-electric uses of biomass include, particularly, residential wood consumption, and that's a major portion of today's wood. About a third of wood energy consumption is consumed by the residential sector. Also, industrial consumption of wood and wood wastes. Over 90 percent of this is captive -- is a byproduct of the manufacturing process.

Outputs of Solar Submodule

- Capital and Operating Costs by NERC Region

- Resource Availabilities by Season and Time of Day (for dispatching) and NERC Region

- Separate Outputs for Solar and PV Technologies

Structure of Wind Submodule

- State-Level Data Used to Characterize Wind Resource Quantities and Qualities

- Prototype Technology (Horizontal Axis Wind Turbine)

- Costs and Performance Characteristics by NERC Region

Outputs of Wind Submodule

- Supply Curves for New Capacity by NERC Region
- Capital and Operating Costs by NERC Region
- Resource Availabilities by Season and Time of Day (for dispatching) and NERC Region
- Performance Characteristics for Wind-Powered Generating Units

Biomass Submodule

- Electricity Uses:
  - Market penetration of wood for independent and small power producers
  - MSW electricity as a byproduct of waste disposal process

- Non-electric uses:
  - Residential wood consumption
  - Industrial consumption of wood and wood wastes

To the extent that it's non-captive, i.e., that there are marketed wood supplies that are important, we will model it, but the primary consumption of industrial wood is as a byproduct of the manufacturing process.

The Wood Submodule will represent the residential, industrial and electricity sectors. The regionality is at a somewhat broader level than we would like, but we are going to be using data available from the U.S. Forest Service, which has also done some modeling of biomass. We'll be obtaining supply curve information for three broad regions, the Northeast/Midwest, the South and the West, and from these we'll compute delivered prices for the census divisions for residential and industrial consumption, and by NERC region for electricity consumption.

Finally, we'll be looking mostly at non-captive marketed wood. We are trying to determine fuel costs; those areas of consumption which have captive sources -- and that occurs both in the electricity and in the non-electric sectors -- will be modeled within those demand sectors.

The inputs of the Wood Submodule will be quantities of marketed wood demanded by sector, which would, in turn, be a function of the prices that we provide them; utility bond rates from the macroeconomic model, which will be used by the Electricity Finance Submodule, in terms of its determination of electricity costs, and also for competition with other fuels; distribution and preparation costs of wood, because these need to be added to the production costs. And, we're currently looking at the U.S. Forest Service and other industrial sources to determine what these costs might be and to trend them out over the future. And, conversion factors and efficiency rates by sector, and some of the sources for this include the Electric Power Research Institute, the U.S. Forest Service and other industrial sources.

The outputs from the Wood Submodule will include production of wood by Census division, delivered cost of wood, and, again, this will be used for competition with other renewables and conventional sources of energy, the cost of electricity generation from wood for capacity planning and dispatching and emissions, and, again, primarily this is CO_2 for wood.

Looking at municipal solid waste, like hydro, municipal solid waste will not be competed within the model. We are viewing municipal solid waste as a byproduct of the disposal process. In addition to recycling and landfilling, incineration is the third major way of getting rid of solid waste generated by firms and residential households, and rather than competing with other energy sources this is seen as a byproduct of that process.

The sectors represented will be both electricity and the industrial sector, where MSW is used for cogeneration and some is used directly for steam. Regionality, as with the other technologies, will be both the NERC regions for electricity sales to the grid, and Census divisions for industrial consumption.

The inputs to the MSW submodule, very similar to those for wood and other renewables involved in electricity, will be:

--Utility bond rates for electricity costs, and, again, these need to be rolled into all electricity costs in terms of the price of electricity coming out of the electricity model.

Structure of Biomass Wood Submodule

- Sectors Represented:
  - Residential
  - Industrial (mostly captive)
  - Electricity

- Regionality:
  - Supply Curves Available for Northeast/Midwest, South, and West Regions
  - Prices Computed for Census Divisions and NERC Regions

- Non-Captive (Marketed) Wood Only

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Inputs to Wood Submodule

- Quantities of Marketed Wood Demanded by Sector

- AA Utility Bond Rates (Macroeconomic Model) for Electricity Costs

- Distribution and Preparation Costs of Wood

- Conversion Factors and Efficiency Rates by Sector

Outputs From Wood Submodule

- Production of Wood by Census Division
- Delivered Costs of Wood by Sector and Region
- Costs of Electricity Generation from Wood for Capacity Planning and Dispatching
- Emissions from the Combustion of Wood

Structure of Biomass MSW Submodule

- Sectors Represented:
  - Electricity
  - Industrial (cogeneration and steam)

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- Regionality:
  - NERC Regions for Electricity Sales to the Grid
  - Census Divisions for Industrial Consumption

Inputs to MSW Submodule

- AA Utility Bond Rates (Macroeconomic Model) for Electricity Costs
- Gross Domestic Product (to Project Total MSW Stream)
- Shares of MSW Combusted by Region
- Heat Content by Year
- Tipping Fees
- Source Reduction Estimates

--Gross domestic product. Those of you who had a chance to read the CDR saw where we have an econometric equation where we have related the costs of the relationship between GDP historically and MSW, so that will be a second important input.

--Shares of MSW combusted for energy by region. Initially these are going to be stipulated. As we get more experience with these shares, we will look at ways of forecasting them.

--Btu and heat content by year. We'll be looking at data from the Environmental Protection Agency, how the waste stream changes its composition over time, and what changes in heat content might be.

--Tipping fees. This is the cost of disposal to incinerator operators, and represents a negative fuel cost for MSW.

--Finally, source reduction estimates. There are considerable pressures on households and firms to reduce their output of solid waste, so that a historical relationship may not be a good assumption in the future. Both recycling and alternative methods of packaging could reduce MSW in the future, so we'll be looking at ways of reducing the MSW input to our submodule.

The outputs from this submodule will include: electricity generation from MSW by NERC region, which will be decremented against total electricity generation requirements that the Electricity Market Module needs to meet; MSW-produced steam by Census division; the cost of MSW-generated electricity by NERC region, which will be rolled into the Electricity Market Module's price determination algorithm; and, finally, emissions from the combustion of MSW.

The final submodule I want to talk about is transportation, and our current methodology for transportation biofuels will be to look at the production of ethanol from corn and biomass crops. Dedicated energy crops will probably not be included in version one of NEMS, but will be added in later versions.

We will incorporate feedstock costs from the Agricultural Resource Interregional Modeling System at the University of Tennessee, and what we are doing here is trying to determine what the costs of corn will be at various levels of demand for alcohol fuels.

We'll include other costs of production and conversion, and for that we've looked at alternative reports from the U.S. Department of Agriculture, and we will add these costs to the costs of production to determine supply curves of delivered costs by PADD region, and transmit those to the petroleum market module, which will use those supply curves in its determination of the demand for ethanol, both as a neat fuel and as a blending component for gasoline.

The rather substantial subsidies that are involved in ethanol production will be included

Outputs From MSW Submodule

- Electricity Generation from MSW by NERC Region

- MSW-Produced Steam by Census Division

- Cost of MSW-Generated Electricity by NERC Region

- Emissions from the Combustion of MSW

Transportation (Biofuels) Submodule

- Production from corn and biomass crops
- Incorporation of feedstock costs from ARIMS Model
- Other costs of production and conversion
- Supply curves of delivered costs by PADD to the Petroleum Market Module

in the Petroleum Market Module, so that we'll have a handle on how those change over time, and what the impacts might be from an integrated modeling point of view.

That, basically, is an overview of the Renewable Fuels Module, and, again, I want to emphasize that the thing that's different about renewable fuels is that the technologies are very diverse, they are all new, market penetration is an important aspect of what's going to happen with renewable fuels in the future.

We have to be able to put them into this integrated modeling system known as NEMS, in such a way that we can keep the analysis to reasonable levels, and I think we are just basically learning how to include renewables in the modeling system. I think we'll learn a lot more over time. We are kind of picking and choosing what the important characteristics that we want to model in Version I are, and I will be glad to listen to further suggestions that you all may have on what we might do, either in this version or in future versions.

With that, let me turn it over to our first reviewer, who is Walter Short; Walter is the Manager of the Market Analysis Branch of the National Renewable Energy Laboratory. In this capacity, he oversees the activities of economists and engineers engaged in the analysis and modeling of renewable energy markets and policies. He also serves as leader of the NREL activities for the Department's Office of Planning and Assessment, within the Office of Conservation and Renewables. He's been with NREL and its predecessor organization, the Solar Energy Research Institute, for 12 years in various capacities ranging from the heat transfer analysis of active solar and solar thermal systems to his current position as Branch Manager.

Walter previously held the position of Senior Energy Modeler for Stanford Research Institute, which is now SRI International, where he worked extensively with the SRI Gulf Model of U.S. Energy Supply and Demand and the SRI World Energy Model.

He has a degree in Math from the University of Georgia and a degree in Operations Research from Stanford University.

So, Walter?

MR. SHORT: Thanks, Scott.

Good afternoon. I see Scott managed to keep you awake; I hope I can say the same when I am through. I only have seven vu-graphs, I may go through them pretty quickly, but I'll spend some time on each one individually.

Let me just say first of all, I was late getting my things in, and so you've got a separate little package of my vu-graphs. They are available in the back if you don't have one already.

I'd also like to say before I really get started, that NREL, as Scott mentioned, worked on photovoltaics and solar thermal, and has a subcontract which we let for the wind energy work for NEMS, and, therefore, I won't be commenting on those technologies, I'll leave it to Tom to say good things about at least one of those. I'm going to be commenting on the geothermal, hydro and biofuels submodules.