The original documents are located in Box 10, folder "Energy - Natural Gas Deregulation Report (3)" of the Ron Nessen Papers at the Gerald R. Ford Presidential Library.

To obtain production responses, the deregulation of natural gas brings forth reserve additions in 1980 and 1985 at different prices. The sensitivity of these aggregate reserve additions are displayed for 1980 and 1985 as a function of price. Only reserve additions for nonassociated gas are presented, since associated gas is a function of real petroleum prices.

Table 9 indicates the effects of changes in reserve additions as a function of price by region.

Table 9

Non-Associated Gas Reserve Additions (TCF)
for 1980 and 1985 by Region
(BAU)

	Well-head Price 1975 $	Regions**												
		2	2a	3	4	5	6	6a	7	8,9	10	11	11a	Total
1980	0.60	0.0	0.0	0.0	0.0	0.0	0.0	11.6*	0.0	0.0	0.0	0.0	0.0	11.6
	1.00	0.0	0.0	0.9	4.4	8.9	15.3	28.6	21.2	0.0	0.0	0.0	0.0	79.3
	2.00	0.6	0.0	2.3	6.1	14.0	19.7	28.6	17.2	0.2	1.4	0.0	0.0	70.1
	2.80	0.8	0.0	2.5	6.8	15.3	29.1	28.6	23.1	0.3	1.5	0.0	0.0	108.0
1985	0.60	0.0	0.0	0.0	0.0	0.0	0.0	11.6*	0.0	0.0	0.0	0.0	0.0	11.6
	1.00	0.0	0.0	1.0	4.4	8.9	17.3	51.1	22.6	0.0	0.0	0.0	0.0	105.3
	2.00	1.3	0.5	4.4	11.3	26.2	38.1	51.1	31.5	0.9	2.7	0.0	0.0	168.0
	2.80	2.3	0.9	4.9	13.3	33.8	57.3	51.1	40.5	1.4	3.4	0.0	0.0	208.9

* Drilling in region 6a commences for four years and then ceases.

**For names of regions see Table 8.

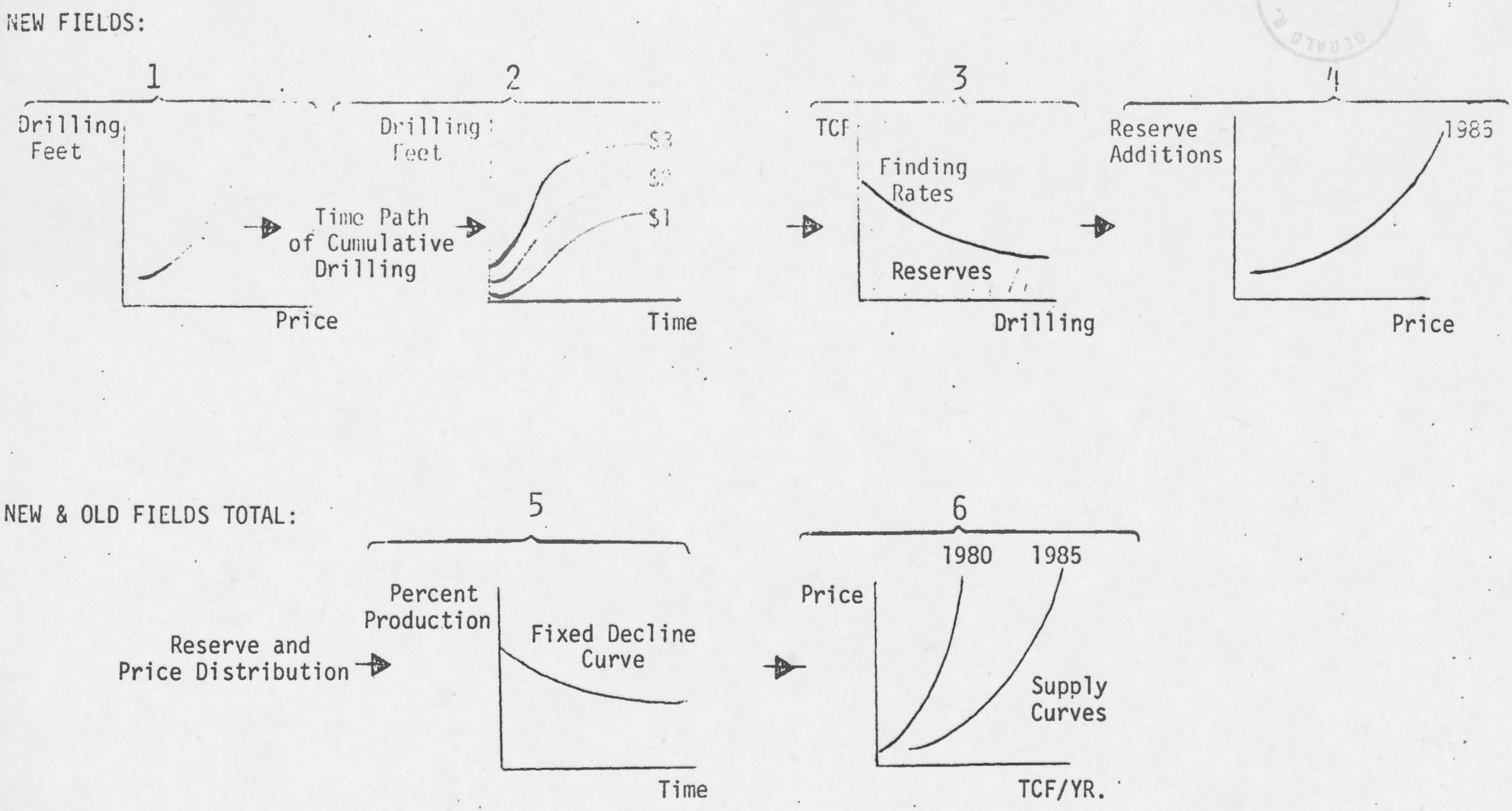
The annual average additions to reserves computed over six years from 1975 through 1980 are comparable to the reserve additions which occurred prior to 1970. In fact, at a $1.00 price, reserve additions average 13.2 TCF per year. Prior to FPC regulations constraining discoveries, the reserve additions including associated gas averaged above twenty TCF per year.

2.3 FEA Forecast Methodology

The estimation of possible natural gas production requires the systematic evaluation of factors such as total available reserves, drilling rates, finding rates, costs of exploration and development, rates of production from established reserves and the interaction of these factors with prices, tax policies, capacity development and leasing policies. The evaluation of particular natural gas policies and the integration of natural gas into the full energy system require an extensive capability to combine these elements and progressively improve the supply assessment.

The schematic of the FEA gas supply model is displayed in figure 2. The full detail of the system, combining associated, non-associated, special regions, and oil prices is not illustrated. In addition, the calculations described occur on a regional basis and actual production and consumption can be affected by demand and transportation differentials when combined in the full Project Independence Evaluation System. However, the general structure and the role of price assumptions are illustrated.

The first stage of the calculations ignores the important time phasing but applies the costing, reserves, and drilling information to estimate the total cumulative drilling that will take place eventually if the price is fixed at a given level. The result, a cumulative supply curve of drilling is input to stage 2. The cumulative supply of drilling at various prices is converted into a time profile of drilling, recognizing the need for gradual adjustment of drilling as increased facilities are developed and equipment is fully utilized over a reasonable life. The time path of cumulative drilling is applied, in stage 3, to a finding rate curve which portrays the total new reserves found as a function of cumulative drilling. This finding rate curve is established by initializing at the current experience, declining the curve exponentially after adjusting to ensure that the cumulative addition to reserves is equal to the U.S. Geological Survey Circular 725 estimate of total reserves. These total reserve estimates vary from the 95% confidence level of 766 TCF to the mean of 961 TCF to the 5% confidence level of 1156 TCF. The pessimistic and optimistic supply projections are taken, in part, from $\pm$ one standard deviation according to this distribution.



STRUCTURE OF FEA GAS SUPPLY MODEL

Figure 2

The combination of the drilling time path and finding curves produces, for each year, the approximate supply of reserve additions as a function of price shown in stage 4. For OCS development, the important impact of leasing schedules enters the system by limiting the reserves that can be added in a given year and thereby limiting the resulting production.

Existing reserves, arrayed by the marginal costs of production, are combined with the supply curve for reserve additions and applied to the production decline curve. This determines the rate at which production from reserves will occur over time and is the final step in calculating the supply for different years as a function of price. The FEA model establishes this decline curve to approximate historical rates. The decline curve does not vary with price in this model.

Once the schedule of annual reserve additions is combined with the decline curve, the additions of reserves at various prices are multiplied by the production rates to determine production and price combinations that would be forthcoming for each year of the analysis. The resulting supply curve is the representation of production possibilities, under the list of important assumptions, that can be combined with other estimates of fuel supply, demand and substitution to obtain an estimate of actual production and consumption.

The current FEA model employed is improved over that of the November 1974 Project Independence report in two ways. First, the reserve additions implied by the finding curves have been formally combined with the most recent estimates of total reserves published by the USGS. Previously, the finding rates were established judgmentally and drilling was curtailed when reserves additions approached total availability. This change improves the realism of the finding rate and associated cost estimates for large drilling changes. The second, and more significant change is the internal calculation of cumulative drilling as a function of price in stage 1. Previously, drilling was determined judgmentally and only one drilling curve was available for all prices. This curve was selected to approximate the drilling that would be forthcoming at wellhead prices of \$.97/MCF (\$.80 in 1973 dollars) in 1985. Table 8 indicates the estimates of production reported at that time and reflects this assumption, an assumption which defers production from higher priced reserves until later years. This simplification was used in the original study because the estimates at that time indicated that these prices and quantities would be sufficient to achieve equilibrium and the focus was on evaluating fuel substitution, not the evaluation supply increments at higher prices. Other improvements in FEA demand estimates have altered the equilibrium price calculations and motivated the more extensive treatment summarized here. It is indicated clearly that higher prices produce significantly higher supplies, and prices higher than today's regulated prices are needed if current consumption levels are to be maintained or forecasted demands are to be met from domestic sources.

2.4 Price Impacts on Demand

The impacts of prices on supply of natural gas are the major focus of this paper, but the corresponding effect on demand should not be overlooked. The revision of FEA estimates for total supply and demand illustrates that regulation can produce major supply deficits or regional imbalances. Due to the known existence of curtailments, an unregulated price may not affect consumption if only unsatisfied demand is being bid away. Conversely, a regulated price would not increase consumption, but would increase the quantity of unsatisfied natural gas demand.

TABLE 10

Original Project Independence Report Supply Estimates[1] (1985)

Price[2]	Non-Associated[3] Gas (TCF)	Associated[4] Gas (TCF)		Total Natural Gas[5] (TCF)	
		$8.48 Crude Price	$13.32 Crude Price	$8.48 Crude Price	$13.32 Crude Price
$0.48	9.48			15.30	16.11
0.73	16.66			22.48	23.29
.97	18.14	5.82	6.63	23.96	24.77
1.21	18.15			23.97	24.78
2.42	18.17			23.99	24.80

[1]Project Independence Report pp. 93 and 94, BAU case.

[2]1975 prices. In the PIR tables, all prices are given in 1973 dollars.

[3]Southern Alaska and tight gas. The non-responsiveness of supply above $1.20 is due to logistic and institutional constraints.

[4]Quantities of associated gas can be expected to vary with the natural gas price. This variation is not portrayed here. However, this variation with natural gas price is far less than the variation with crude oil price.

[5]This approximation is preliminary since the supply responsiveness with price is biased slightly upward as explained in Footnote 1 and is biased slightly downward as explained in Footnote 3. The overall effect of these offsetting biases, while small, is unclear.

2.5 Comparison of Alternative Supply Forecasts

In this section the FEA model supply forecasts are compared to five other forecasts of long term natural gas supply; the AGA-TERA Model of the American Gas Association, the MIT Model developed by MacAvoy and Pindyck, the SRI-GULF Model developed by Stanford Research Institute, the Federal Power Commission (FPC) and Energy Research and Development Administration (ERDA) natural gas projections. Four of these forecasts are based upon supply response to price (TERA, MIT, SRI-GULF, FPC). The ERDA forecast is a trend projection based upon assumed reserve availabilities.

Table 11

DOMESTIC NATURAL GAS PRODUCTION (TCF)

A Comparison of: FEA, TERA, MIT, SRI-GULF, FPC, and ERDA (1980 and 1985)

Year	Price $ '75 ($/MCF)	FEA at Current World Oil Prices	AGA-TERA	MIT	SRI-GULF (Nominal Case)	FPC*	ERDA**
1980	$1.75	20.63	19.6	40.7***	23.3	24.6	22.0
1985	2.00	22.67	21.7	N/A	25.7	26.4	24.5

* Forecast related to prices of $2.04 and $1.78 for 1980 and 1985 respectively.

** Forecast not related to price.

***The original MIT study limited prices to 90¢/MCF and corresponding production estimates of 32.6 TCF. This 40.7 TCF was attained by solution of the model at the $1.75 price which may be outside the range of reliability.

Strict comparison of the models is difficult due to differences in model construction, techniques, and basic assumptions underlying the forecast. The SRI-GULF Model, as does the FEA Model, solves for equilibrium supply, demand, and prices. The actual equilibrium prices from the SRI Model are $1.73 and $2.07. The TERA and MIT Models do not solve the equilibrium price; the wellhead price is exogenous to each model. The FEA equilibrium prices were input to these models to obtain the supply forecasts. The TERA forecast is about 1 TCF lower than the FEA forecast. In separate analysis, FEA has determined that this model tends to be pessimistic with respect to the drilling success ratios1/.

1/ A Comparison of Two Natural Gas Supply Models, by John A Neri, Federal Energy Administration Technical Report 75-15, June 10, 1975, Office of Quantitative Methods, Washington, D. C.

The MIT Model is much higher than all of the presented forecasts. The MIT supply forecasts are very optimistic with respect to discovery size and offshore gas. The SRI Model, while solving for essentially the same equilibrium prices, shows approximately 3 TCF more production than the FEA forecasts for 1980 and 1985. The FPC forecast is taken from the option three case - deregulation of new gas - as presented in "A Preliminary Evaluation of the Cost of Natural Gas Deregulation", January 1975. The forecasts for 1980 and 1985 are approximately 4 TCF above the FEA forecasts. The equilibrium prices from the FPC Model are very different from the FEA and SRI prices. These prices are $2.04/MCF and $1.78/MCF for 1980 and 1985 respectively. This reduction in the supply price is most likely due to the assumed threefold increase in the supply elasticity from .06 to .16 between 1980 and 1986.

The estimates are provided to indicate the range of estimates currently available and the relative position of the FEA forecasts.

Although all the models for which price data are available tend to confirm the FEA estimates about required future equilibrium prices, it is difficult to obtain an exact comparison of price sensitivity of the other systems. For the FEA, TERA, and MIT Models, approximate estimates of the aggregate price sensitivity are displayed in Table 12. As stated above, FEA analysis indicates that the TERA price sensitivity is pessimistic, and that of the MIT Model is optimistic. The FEA estimates, based on the best available data, methodology, and judgments is the most reliable representative of price impacts on supply. This model indicates that 5.3 TCF of additional product can be made available as gas prices increase from $1.00 to $2.00

Table 12

APPROXIMATE 1985 SUPPLY REDUCTIONS
DUE TO PRICE CHANGES (TCF)

Wellhead Price (1975 $)	FEA	TERA	MIT **
$2.00	20.8	21.7	40.7
1.00	15.8	18.9	32.6
CHANGE	5.0	2.8	8.1

** These figures are from the 1980 supply estimates for the MIT model with the $2.00 row evaluated at $1.75. Equilibrium solutions to the MIT model occur in 1980 at 90¢/Mcf. 1985 prices in the $2.00 range may be outside of the range of reliability.

3. Estimated Total Costs of Deregulation With S2310 in 1976

While the long-run impacts of natural gas deregulation are important, the short-run effects in 1976 are of interest. Section 4 of this paper examines the impacts of various deregulation proposals on the total fuel bill and the natural gas fuel bill of the residential user in 1985. In this section FEA's estimate of the impact of deregulation in 1976 are presented for the current version of S2310.*

The price of number 2 fuel oil in 1976 is translated into an equivalent retail price for natural gas. A number 2 fuel oil price of $15.50/bbl is comparable to a retail natural gas price of $2.66/MCF. To get the wellhead price, transportation and distribution costs are subtracted. In 1974 the average transportation cost plus distribution mark-up was 55¢/MCF. This yields a deregulated wellhead price of ($2.66 - $.55) = $2.11/MCF.** This estimate is a simplified method for estimating the short-run price change and does not assume any supply response. The deregulated price could be higher or lower if these responses develop.

Given the estimated wellhead prices of $2.11/MCF, the cost increases associated with various categories of natural gas are presented in Table 13.

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* S.2310 is know as the Natural Gas Emergency Act of 1975.

** The $15.50/bbl is the delivered price for oil at the burner tip. The $15.50/bbl distillate oil converts to $2.66/MCF gas. Subtracting the transportation cost and distribution mark-up of 55¢/MCF yields a wellhead price of ($2.66-$.55)= $2.11. This figure is consistent with the PIES estimated deregulation price of $2.13/MCF in 1985. The distillate price of $15.50 is in question, since the December 1975 price of distillate price used to convert to natural gas equivalent prices should be weighted average of both the industrial and residential price. From 1974 data it is derived that the industrial distillate fuel price is 96.4% of the residential price. Therefore using an average 1974 residential distillate fuel price of $15.82/bbl. The approximate industrial price would equal $15.26/bbl. From 1973 data it is found industrial distillate fuel, and the residential sector consumes the remaining 46 percent. Weighting the appropriate residential and industrial prices by these percentages yields an average distillate fuel price of $15.51/bbl. Since the average value of retail distillate is uncertain, a price of $15.50/bbl was chosen.

TABLE 13

FEA ESTIMATES OF 1976 COST INCREMENTS
DUE TO DEREGULATION OF NATURAL GAS UNDER S2310

Cost Element	Quantity*	Cost
1) Intrastate Gas	5	4.3
2) Non-Jurisdictional Interstate Sales	1	.86
3) OCS Gas	N/A	0.0
4) Onshore Gas	.3	.26
5) Additional Production	.5	0.0
6) Old Contracts	.3	.04 to .27
TOTAL	7.1	5.46-5.69

To the extent that increased natural gas production replaces higher priced imported oil, the above estimate is reduced.

* The quantities refer only to those increments of gas affected by S2310. Because of long-term contracts or lack of time response some qunatities are not affected (N/A).

4. Long-Term Impacts of Natural Gas Deregulation

FEA estimates of the long-run impact of natural gas deregulation on residential fuel bills are computed for several of the proposed legislative actions pending before Congress. The proposed legislative actions are outlined in an appendix.

This section reports estimates of the anticipated effects of several policy proposals for the field price of natural gas, which is currently regulated by the Federal Power Commission if it is sold for resale across state lines or if it is carried for resale by an interstate pipeline that has been certified by the Federal Power Commission. The results were derived from a parametric framework that uses supply and demand schedule information currently being used as inputs to the Project Independence Evaluation System (PIES). The supply curves are based upon the FEA production model, which uses a discounted cash flow technique to relate production levels with price. The consumer demand relationships are based upon the forecasts for the Federal Energy Administration's Econometric Regional Demand Model (ERDM), in which natural gas was one of several major fuels to be analyzed. This information is used to determine equilibrium prices, production, consumption, and associated economic impacts given certain price constraints on gas under existing interstate contracts and on new offshore gas.

4.1 Methodology

The analysis of the effects of deregulation of natural gas is conducted in the context of the Project Independence Evaluation Systems results for the 1985 $13.00 reference case, which represents the equilibrium solution when new gas is deregulated. For continued regulation, a regulated supply curve is constructed and allowed to equilibrate with a regulated demand curve to produce a new price and production level. A number of simplifying assumptions are made in order to approximate the solution.

The approach assumes a set of separated inter/intrastate markets in which the regulated demand curve is the demand in the region and the regulated supply curve is the supply in the region minus any volume under long-term contract to the interstate market. In the absence of price controls in the inter/intrastate markets, each of these markets will equilibrate

$$(1) \qquad D_i\ (P_i) = S_i\ (P_i) - ECS_i \text{ for all } i \varepsilon I_P$$

where D_i is the regional demand, S_i is the regional onshore supply, P_i is the unregulated price, and ECS is the volume supplied to the interstate market under existing contracts.

In addition, nonproducing states satisfy a portion of their demand for interstate gas in 1985 from existing gas contracts

$$(2) \qquad D_i(\bar{P}) = ECR_i + UD_i\ (\bar{P}) \text{ for all } i \varepsilon I_R,$$

where UD_i is the unsatisfied demand in the region and ECR_i is the interstate volume received under existing contracts.

A third class of states produce gas for intrastate use and also receive gas from existing interstate contracts

(3) $D_i\ (P_i, \bar{P}) = S_i\ (P_i) + ECR_i + UD_i\ (\bar{P})$ for all $i \epsilon I_{PR}$.

In principle, individual solutions for each state in class I_p can be derived. Further, given data on existing contracts supplied (ECS_i) and existing contracts received (ECR_i) and estimates of unsatisfied interstate demand ($UD(\bar{P})$), equilibrium intrastate prices can be derived for states in class I_p and I_{PR}. Total demand under interstate gas regulation is:

(4) $D_{US}^{R} = \sum_i D_i$, for all $i \epsilon (I_p \cup I_R \cup I_{PR})$.

An approximation to the above solution can be derived by concentrating on the major producing states (i.e., the WSC demand region) and determining regulated supply and demand for that region.

The following assumptions were made:

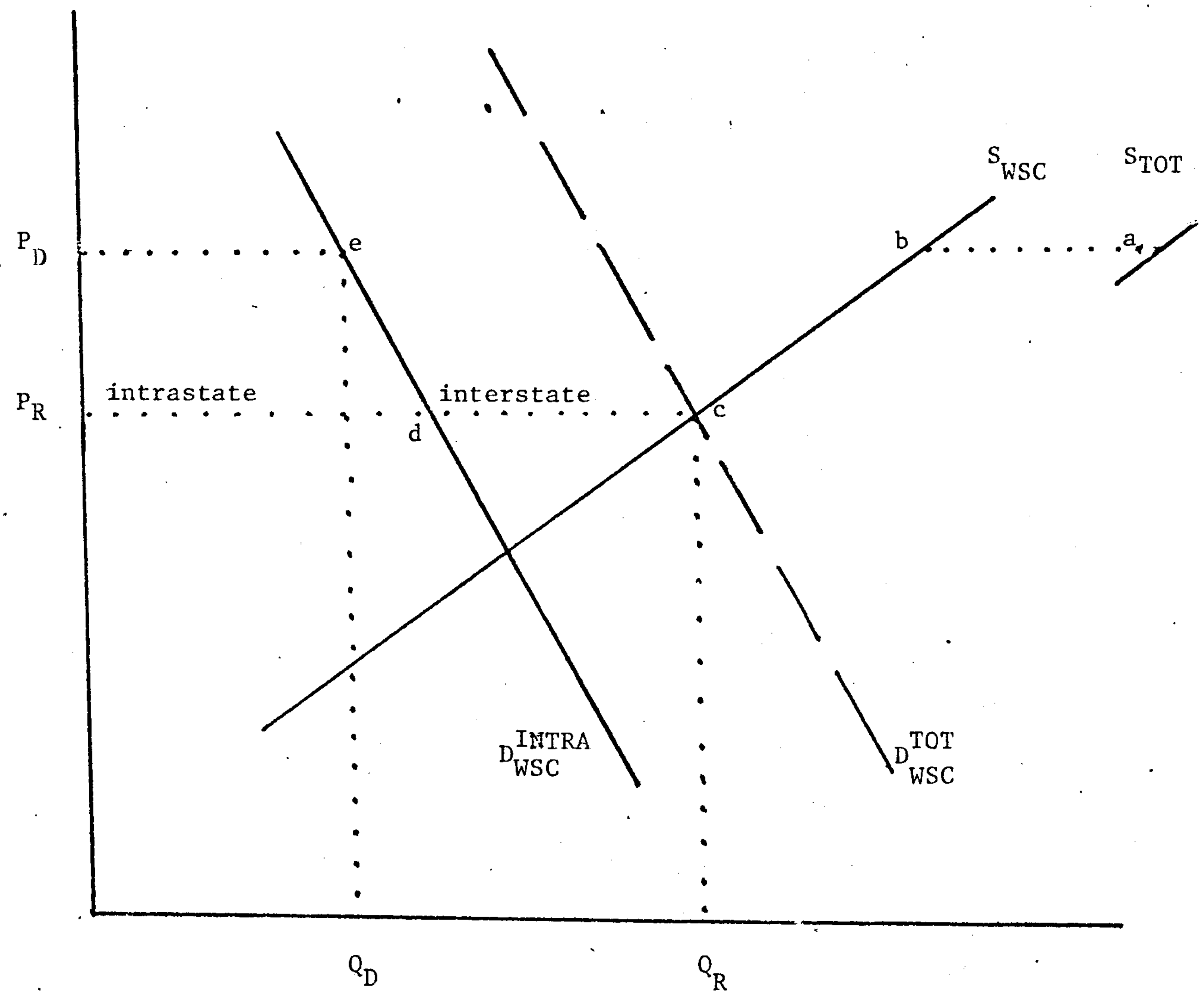
- All West South Central gas consumption is intrastate gas.
- The existing ratio of OCS to non-OCS contracts will be maintained under continued regulation.
- The WSC intrastate market is representative of all domestic intrastate markets.
- Quantities under existing interstate contracts decline at a rate of 7-8% per year.
- The ratio of non-WSC non-Alaskan production to WSC production continues at its present level.
- The intrastate demand curve for WSC is stable under deregulation, i.e., the regulated and deregulated intrastate equilibria are on the same demand curve.

The methodology is summarized in the accompanying graph. With continued regulations, the demand for onshore gas from the West South Central Region is D_{WSC}^{Intra} plus contracted interstate volume, or D_{WSC}^{TOT} which must be satisfied by the available supply, S_{WSC}. The market equilibrates at P_R and Q_R, of which d is intrastate and dc is interstate gas. When new gas is deregulated, interstate consumers bid for this onshore gas as well as for volumes from offshore and Alaska. The new contract price rises to P_d, which expands onshore production in this region to point b, and reduces intrastate consumption along demand curve, D_{WSC}^{Intra}, to point e. In addition, there is increased production in the offshore and Alaskan regions, gas from which must enter the interstate system.

4.2 Estimates of the Impact of Natural Gas Deregulation

Estimates of the effects of continuing present regulations as well as those

FIGURE 3
THE WEST SOUTH CENTRAL INTRASTATE
MARKET UNDER REGULATION AND DEREGULATION



LEGEND:

ab - non WSC supply from PIES
dc - estimated intrestate gas under continued regulation
e - deregulated intrastate equilibrium
a - deregulated total natural gas supply
bc - WSC supply expansion due to deregualtion
de - WSC intrastate demand contraction due to higher deregulated price
P_D - deregulated equilibrium price for WSC
P_R _ REGULATED EQUILIBRIUM PRICE FOR WSC intrastate gas

of several recently proposed legislative actions are derived from this methodology and appear in Table 14. The more important results are discussed below.

Present Regulations. With this option only the intrastate market will be in equilibrium. Gas from the onshore areas will be produced until demand in this market is satisfied at a new contract price of about $1.80/MCF. Offshore and Alaskan gas production, on the other hand, is restricted by an assumed FPC field price ceiling of $.60/MCF plus any cost-of-living adjustments. Total marketed production equals 17.9 TCF for the nation, although only 6.6 TCF of this would be allocated to the interstate market. Residential annual gas bills are a comparatively low $215 (the second last column) for those who maintain their gas service but the residential bills for all customers who would have gas under deregulation would be substantially larger at $280 per year, or even higher if synthetic natural gas is substituted. Finally, curtailed industrial users would be forced to purchase imported oil.

Krueger. The Krueger proposal defines new contracts as gas that is dedicated to the interstate market for the first time in addition to any volume under an expiring interstate contract. This option would stimulate more production than would the continued regulation case because: (1) the price of new onshore gas would rise above its $1.80/MCF level and (2) the price of new offshore and Alaskan gas would rise above its regulated level of $.60/MCF. The Krueger offshore provisions are particularly difficult to analyze because there is no a priori knowledge about how the Federal Power Commission will regulate this gas during the 1975-80 period, and current supply estimates make it impossible to forecast the producers' response to a phased deregulation that will end in 1981. The analysis assumes that under both Kruger and Pearson/Bertsen proposals, producers expect in 1976 a deregulated price for OCS gas by 1985. If there are uncertainties about the phasing out of these controls, production would be less and prices greater than indicated in the table. It should be noted that the FEA oil and gas production model, assumes flexible capital markets and does not incorporate any supply effects of an improvement in the gas producers' cash-flow. Thus, when expiring contracts are renegotiated at a market price rather than a regulated one, the improved cash-flow situation of the producers does not increase supply in the model.

Although gas expenditures will increase (as both price and production increase) oil expenditures in the interstate region will decrease. The net effect on total energy expenditures (column 4) is very small and therefore, the effects of natural gas deregulation on the costs of other goods and services (as a result of higher energy prices) is anticipated to be minimal - about $1 per person by 1985. Studies that relate increased gas costs to the general price level of the nation's goods and services are erroneous because they fail to account for the important substitution of gas for oil when natural gas is deregulated. In the interstate residential market, annual gas bills would increase to $304 to a group of consumers who would be paying $280 for both gas and oil under the continuance of the present regulations.

Pearson-Bentsen. The two main differences between this and the Krueger option are that: (1) gas under expiring contracts would continue to be regulated (at the assumed FPC ceiling of $.60/MCF plus any cost-of-living adjustments)

Table 14

1985: Comparison of the Effects of Proposed Natural Gas Legislation
(All Prices are in Constant 1975 Dollars)

Policy	Nation				Interstate				
	Marketed Gross (Tcf)	Production Net[a/] (Tcf)	Average Field Price[b/] ($/Mcf)	Net Energy Expenditures[c/] Per Capita ($/Yr)	Sales (Tcf)	Industrial Price ($/Mcf)	Residential Price ($/Mcf)	Residential Annual Gas Bill[d/] ($/Yr)	Residential Annual Fuel Bill[e/] ($/Yr)
1974	21.6	18.8	.30	-	11.6	.68	1.47	170	170
Present Regulations	17.9	15.9	1.24	160	6.6	1.08	1.85	215	280
Krueger	22.3	20.0	1.71	161	12.1	1.85	2.62	304	304
Pearson-Bentsen (Passed)	23.0	20.7	1.72	166	13.2	2.70	1.77	205	205
$1 National Ceiling Price	15.8	13.9	.80	130	9.1	1.20	1.97	229	260

a/ Gas consumed by end-users from domestic sources, excluding liquified natural gas, synthetic fuels and imported natural gas.

b/ Total gas revenues per mcf of net marketed production.

c/ Sum of revenues for gas and for required oil imports to satisfy the demand under deregulation, divided by a projected population of 244 million in 1985.

d/ Assumes that residential customer uses the same gas volume (116 mcf) as he did in 1974, even at higher prices.

e/ Represents the residential bill if the consumer replaces the gas available under deregulation with distillate oil, (using the residential price when crude oil is imported at $13/BBL). This calculation assumes that by 1985 residential users will be curtailed in proportion to their present share of the interstate market. Although curtailments in the past have predominately affected industrial users, many of the seriously curtailed pipelines have already lost much of their industrial load, leaving the residential customer served by these pipelines vulnerable. If interstate customers replace natural gas with synthetic fuels, the fuel bill under regulation and under the national ceiling price will be greater than that indicated above.

(2) the cheaper old gas would be allocated first to residential users. Both of these provisions place greater pressure on the bidding for new gas, causing the new contract price to be greater than in the Krueger option.

The provision that extends the regulated price to expiring contracts reduces the supply of gas that can be sold at the unregulated price. Paying an average price for all gas, consumers would bid the new contract prices higher than if a smaller volume of old gas was to be price-controlled.

The allocation of cheap gas to residential users does not encourage homeowners to conserve gas as much as they would under the Krueger option and, consequently, this reduces the volume that would be available to industries. To allocate this smaller supply of industrial gas among competing users, higher new contract prices would be negotiated, thereby eliminating industrial uses for which the value of gas is not equal to or above this higher price. As a result, the industrial price would be considerably larger than with the Krueger proposal, and this increase would be passed through to households when they purchase other products and services. Thus, the higher new gas and industrial prices would mean that all consumers who buy products and services would be asked to subsidize the homeowner who burns natural gas. (In addition, it is not clear that these price provisions will actually protect the residential customer from higher costs. A lower industrial load is likely to make it more costly for utilities to meet the highly seasonal demand for residential customers. The gas and fuel bills in the table do not account for any such increases in the residential distribution costs.

The higher new gas prices would stimulate some additional production above that in the Krueger option.[1/] Although interstate residential prices are lower, interstate industrial and intrastate prices are substantially larger, resulting in a small increase in average field price. Net energy expenditures per capita (column 4) is increased as a result of greater gas production (there are not additional oil expenditures as a result of excess demand in either case because natural gas demand is satisfied with either option). From an economic efficiency perspective, the additional domestic production of natural gas, which is made necessary by the greater subsidized residential demand, would not be warranted because domestic resources could be more productive if they were engaged elsewhere in the economy.

1/ The conclusion about greater production may not appear obvious from the discussion in the preceding paragraph because interstate residential consumption is increasing while interstate industrial and intrastate consumption is declining as compared to the results of the Krueger option. Increased production can be shown, however, by initially noting that in the Krueger case, total gas production is 22.3 TCF when the new contract prices reaches $2.10 per MCF. The Pearson-Bentsen pricing provision would augment this consumption level at that price by an amount equal to the difference between residential consumption at the lower Pearson-Bentsen price and that at the higher Krueger price. In short, subsidizing residential users increases the Bentsen residential level, resulting in higher new contract prices and more production.

$1 National Ceiling Price. There have been some proposals to extend price controls to the intrastate market. In Table 14 the results of a one dollar ceiling for all new gas are presented. This option would provide for some increments from offshore and Alaskan fields but would roll back substantially the equilibrium intrastate price under the continued regulated case (by 1985, from $1.80/MCF to $1/MCF). Total gas production would decline to 15.8 TCF with excess demand being created in both the intrastate and interstate markets.

4.3 The Interstate-Intrastate Distribution of Natural Gas Supply

The differences between deregulation and regulation are substantially more pronounced for interstate supply than for total national production. With the continuation of the present regulations at today's prices (in constant dollars), interstate supply would decline about 5.0 Tcf below its 1974 level of 11.6 Tcf - a reduction of 43 percent. If new gas is deregulated (as in the Krueger proposal), the higher gas prices would allow large volumes of gas to enter the interstate market, because not only will more offshore and Alaskan gas be produced but also some onshore gas will be bid away from the intrastate market. Under these conditions, the decline in interstate sales would be halted, resulting in slightly more sales than its present level by 1985. The Pearson-Bentsen proposal would increase interstate sales mainly through bidding gas from the intrastate market. It does this, however, at the expense of higher new gas prices and significantly higher industrial prices.

TABLE 15

PROJECTED INTERSTATE/INTRASTATE SALES UNDER
DIFFERENT POLICIES, 1985

Policy	Marketed Production: Gross	Marketed Production: Net*	Sales: Interstate*	Sales: Intrastate*
1974 Data	21.6	18.8	11.6	7.2
Present Regulations	17.9	15.9	6.6	9.3
Krueger	22.3	20.0	12.1	7.9
Pearson-Bentsen	23.0	20.7	13.2	7.5
$1 National Ceiling	15.8	13.9	9.1	4.8

* Gas consumed by end-users from domestic sources, excluding liquified natural gas, synthetic fuels and imported natural gas. Total gas consumption (including these other sources) would be greater.

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F.E.A. ANALYSIS OF THE CONGRESSIONAL
RESEARCH STUDY "ECONOMIC IMPACT OF S.2310'S PRICING PROVISIONS"

TECHNICAL REPORT 76-2

JANUARY 12, 1976

FEDERAL ENERGY ADMINISTRATION
OFFICE OF THE DEPUTY ASSISTANT ADMINISTRATION
FOR DATA AND ANALYSIS
OFFICE OF OIL AND GAS ANALYSIS

ACKNOWLEDGEMENTS

This paper was prepared by John A. Neri of the Office of Oil and Gas analysis.

EXCUTIVE SUMMARY

This technical report presents an analysis and critique of the Congressional Research Service study, "Economic Impact of S.2310'S Pricing Provisions" by Lawrence Kumins. The conclusion of the CRS study is that three additional TCF of natural gas would be made available yearly through deregulation of new gas but at an added cost of $20.2 billion to $22.3 billion in 1976.

The FEA analysis disputes this figure. Two fundamental objections to the CRS Study are raised:

- Estimated wellhead prices are too high. The CRS estimates a deregulation wellhead gas price of $2.50/MCF as a parity with the delivered, refined product price of distillate oil. This delivered price must be adjusted for transportation cost and distribution mark-up to arrive at the wellhead price. For 1974 the average transportation plus distribution cost was 55¢/MCF this yields a wellhead price of $1.95/MCF.*

- Large quantities of gas assumed to be affected will be unaffected due to existing long term contractual arrangements.

Correcting for these elements, a cost in the range of $4.4-$4.6 billion is calculated. To the extent that increased gas production replaces more expensive imported oil, this cost figure is reduced. The approach of this report is to critique each of the major assumption used by the CRS separately.

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*The CRS state the $2.50/MCF gas price is equivalent to $15.50/BBL distillate oil. Actually $15.50/BBL distillate oil converts to $2.66/MCF gas. Subracting the transportation cost and distribution mark-up of 55¢/MCF yields a wellhead price of ($2.66-$.55)= $2.11. This figure is consistent with the PIES estimated deregulation price of $2.13/MCF. The distillate price of $15.50 is in question, since the December 1975 price of distillate heating fuel was $16.84/BBL at retail. However, the heating fuel price in December 1975 may not be appropriate because the distillate price used to convert to natural gas equivalent prices should be a weighted average of both the industrial and residential price. From 1974 data it is derived that the industrial distillate fuel price is 96.4% of the residential price. Therefore using an average 1974 residential distillate fuel price of $15.82/BBL. The approximate industrial price would equal $15.26/BBL. From 1973 data it is found that industiral sector consumes 54 percent of total residential and industrial distillate fuel, and the residential sector consumes the remaining 46 percent. Weighting the appropriate residential and industrail prices by these precentages yields an average distillate fuel price of $15.52/BBL.

THE CONGRESSIONAL RESEARCH SERVICE STUDY

The cost estimate of the CRS Study is arrived at as follows:

1. The CRS argues the wellhead price of deregulated gas to be determined by the price of alternate fuels, namely #2 Fuel Oil. A distillate price of \$15.50/bbl is translated into a deregulated gas equivalent price of \$2.50/MCF.

2. With deregulation, intrastate gas will be allowed to cross state lines and the CRS argues the current \$1.25/MCF price will rise to the deregulated oil parity price of \$2.50/MCF. Assuming 5 TCF of interstate gas free to escalate, this yields and additional cost of: 5 TCF x (\$2.50-\$1.25) = \$6.3 billion per year.

3. The CRS next argues that 1 TCF of non-jurisdiction FPC gas will be sold at \$2.50/MCF with deregulation. This yields an additional cost of 1 TCF x (\$2.50-\$1.25) = \$1.3 billion.

4. Offshore gas under S.2310 will continue to be regulated but at a higher ceiling price. The CRS assumes the new ceiling price to be \$1.60/MCF (BTU equivalent OCS crude oil). With 1.9 TCF coming form the offshore, the additional cost is: 1.9 TCF x (\$1.60-\$.60) = \$1.9 billion.

5. Assuming past trends to continue, .76 TCF of new gas will be available each year. With deregulation of new gas at \$2.50/MCF, the additional cost will be: .76 TCF x (\$2.50 \$.60) = \$1.3 billion.

6. With deregulation, 3 additional TCF are assumed to go into production. The extra cost is : 3 TCF x \$2.50 = \$7.5 billion.

7. Next, the CRS <u>assumes</u> 1 TCF of old contracts of expire each year, yielding and additional cost of : 1 TCF x (\$2.50 - \$.60) = \$1.9 billion.

The sum of the cost elements is \$20.2 billion. In the following section it is argued that the assumed wellhead price of \$2.50/MCF is too high, and that significant quantities of gas assumed to be affected by S.2310 will be unaffected due to long term contractual arrangements.

FEA Critique of CRS Analysis

In this section each of above seven assumptions of the CRS Study are analyzed and critiqued:

1. Wellhead Price

   The $2.50/MCF deregulation wellhead price is arrived at by the CRS by converting the current distillate fuel oil price of $15.5/bbl into the gas equivalent price. The $15.50/bbl price is a delivered price for oil at the "Burner Tip". The $2.50/MCF price of gas, as calculated by the CRS, is thus the "Burner Tip" price of gas. To get the wellhead price, transportation cost and distribution mark-up must be subtracted from the $2.50. For 1974, the average transportation cost plus distributor mark-up was approximately 55¢/MCF. This yields a deregulated wellhead price of ($2.50-$.55) = $1.95/MCF.

2. Intrastate Gas:

   Allowing the 5 TCF of intrastate gas to rise to the deregulated wellhead price of $1.95/MCF we get an additional cost of $3.5 billion per year rather than $6.3 billion.

3. Non-Jurisdictional Gas:

   The CRS estimates 1 TCF of non-jurisdictional gas to exist in 1976 arguing this total volume to price escalate with deregulation. How much of this gas is committed under long term contract and not subject to S.2310 is unclear. For lack of better information we accept the CRS assumption that 1 TCF will escalate. This yields an incremental cost of 1 TCF X ($1.95 - $1.25) = $.7 billion.

4. Offshore Gas:

   The CRS Study addresses only old offshore gas. This gas would not be subject to price escalation under S.2310. Thus the incremental cost of new gas deregulation would be zero.

5. Onshore Gas:

   Without deregulation, the .76 TCF of onshore gas would go into the intrastate market. The cost of deregulation is the incremental cost over the intrastate price of $1.25/MCF rather than the regulation price of 60¢/MCF. At $1.95/MCF, this yields an additional cost of $.53 billion rather than $1.3 billion.

6. Additions to Reserves

The CRS assumes 3 TCF of additional gas to be available for production after deregulation arguing that this additional gas will be an added cost to users. An increase in production of 3 TCF (from 22 to 25 TCF) in 1976 is unrealistic even under deregulation. Even if the 3 TCF were to materialize, this can can not be considered as a "cost of deregulation" because if it does not occur, this energy demand must be made up by a substitute - imported oil. If gas and imported oil sell at parity, there is no change in the total energy bill. If gas sells at a price less than oil, there would be a net reduction in the total energy bill. Also, to the extent that increased volumes through the pipeline tramsmission system reduce the per unit cost of transportation, the cost to end-users is reduced.

7. Old Contract Gas:

The pricing provisions under S.2310 provide that the FPC will establish a new ceiling price for old gas as contracts expire. It is not clear from past FPC action what this price will be. The CRS assumed 1 TCF of old contracts to expire each year. Our analysis indicates expirations to be roughly .3 TCF per year. Using FPC prices of $.75, $1.00, and $1.50 we arrive at incremental cost of $.05 billion, $.12 billion, and $.27 billion respectively.

Summary

The following table lists the CRS and FEA 1976 costs of deregulation. Column (3) lists the cost using CRS prices and quantities, column (5) lists the cost using CRS quantities and FEA prices, and column (7) lists the cost using FEA prices and quantities.

Applying FEA price increments to the CRS quantity assumptions reduces the CRS cost increment by 75 percent from $20.2 billion to about $5 billion. The total 1976 cost increment based upon FEA price and quantity calculations is about $4.5 billion. To the extent that increased gas production replaces more expensive imported oil, the cost of deregulation is reduced even further.

COMPARISON OF CRS AND FEA 1976 COST INCREMENTS DUE TO THE DEREGULATION OF NEW NATURAL GAS UNDER S.2310

-st Element	(1) Quantity	(2) Increment	(3) CRS Cost (2)x(1)	(4) FEA Price Increment $1.95	(5) CRS at FEA Cost $1.95	(6) FEA Quantity	(7) FEA Cost (6)x(4) $1.95
.) Intrastate Gas	5	$1.25	6.3	$.70	3.5	5	3.5
.) Non-Jurisdictional Interstate Sales	1	1.25	1.3	.70	.7	1	.7
.) OCS Gas	1.9	1.00	1.9	N/A	0.0	N/A	0.0
. Onshore Gas	.76	1.90	1.3	.70	.53	.3	.21
.) Additional Production	3	2.50	7.5	N/A	0.0	.5	0.0
.) Old Contracts	1	1.90	1.9	.15, .40,90	.15, .40,.90	.3	.04, .12 .27
	12.66		20.2		4.88-5.63	7.1	4.45-4.68

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NATURAL GAS SHORTAGE EASES THIS WINTER, BUT ZARB SAYS LONG-RANGE PROBLEM REMAINS

Unseasonably warm weather in November and early December has taken some of the chill out of natural gas shortages predicted this winter, according to a Federal Energy Administration survey announced today.

"This survey shows natural gas shortages will be greater this winter than last, although not as great as previously forecast," FEA Administrator Frank Zarb said.

In October, the FEA reported projected distributor curtailments in 21 key States of 1.2 trillion cubic feet (Tcf) this winter. This would have been a 314 billion cubic foot (Bcf), or 37 percent, increase over last winter.

FEA's new survey of large gas distributors in the same 21 States shows total curtailments reduced to 1.0 Tcf this winter. This is a 140 Bcf, or 16 percent, increase over last winter.

Zarb said the warm weather reduced shortages by freeing up gas supplies which normally would have been used for heating in November and early December.

Shortages have been further eased through two Federal Power Commission (FPC) regulatory procedures for the redistribution of natural gas from surplus to shortage areas. These include:

--Allowing high-priority curtailed gas customers to buy the fuel directly from producers at free market rates and to arrange for its transportation through an interstate pipeline.

--Allowing local gas utilities and interstate pipelines to make 60-day emergency gas purchases at free market rates from available sources.

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The survey shows the warm weather has also reduced demand for propane and fuel oils, increasing the supplies available this winter to offset gas shortages.

"So far we can thank the weatherman for the improved outlook this winter," Zarb said, "but such good luck is not going to solve the Nation's longer-range natural gas problem."

According to Zarb, that long-range problem is one of declining natural gas production and shrinking natural gas reserves.

U.S. gas production is currently declining at a six percent annual rate. Current proved reserves, excluding Alaska, stand at 205 Tcf, the lowest level since 1952.

"Even a perennial summer won't save us from future shortages if we don't reverse these dangerous trends," Zarb said.

"Although conservation due to warm weather has helped in the short term, we must realize that the long-range answer to our growing natural gas shortage is to increase supply by encouraging production through higher natural gas prices," Zarb said.

Zarb also warned that the outlook this winter could again worsen in the event of severely cold weather.

Because residential use of natural gas is protected by government priority, Zarb said the increased gas supply this winter would only go to industry if heating demand for gas doesn't become too strong.

Severe weather resulting in increased industrial curtailment could also strain propane supplies in several States, including North Carolina, Ohio, South Carolina, Tennessee, and West Virginia.

Zarb said even with normal weather, the potential exists for industrial shutdowns this winter since the increased supply available is not enough to offset all previously projected curtailment to firm gas customers.

Firm customers are those who pay higher rates for assured natural gas delivery because they often do not have the capability of switching to alternative fuels.

Zarb cited North Carolina, Ohio, and Pennsylvania as States where the projected increased supply this winter cannot offset significant curtailment to firm customers.

On the positive side, he cited Maryland, Delaware, New Jersey, and Virginia as States where the gas supply and alternative fuel outlook have significantly improved.

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New Jersey and Virginia distributors now estimate that curtailments of customer gas requirements will be lower this winter than last winter.

Zarb concluded this winter's revised curtailment projection for the 21 States is no longer seriously above the level last winter, as long as the weather doesn't turn severely cold.

"Much of the curtailment," Zarb explained, "will fall upon industries and electric utilities which can readily switch to an alternative fuel." No curtailment is projected for residential or small commercial customers.

A table of State-by-State changes in curtailments, deliveries, and requirements is attached.

-FEA-

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E-75-418

COMPARISON OF OCTOBER REPORTED AND DECEMBER UPDATE FOR 21 STATES

(All Volumes in Bcf)

1974-1975 Heating Season (Actual)

	Deliveries	Curtail-ments	Require-ments*	% of Require-ments Curtailed
ARIZONA				
October Report	67.0	20.1	87.1	23
As corrected	67.6	20.4	88.0	23
CALIFORNIA				
October Report	753.4	283.9	1,037.3	27
As corrected	736.1	323.2	1,059.3	31
DELAWARE				
October Report	8.8	0.9	9.7	9
As corrected	8.9	1.1	10.0	11
FLORIDA				
October Report	60.6	38.3	98.9	39
As corrected	63.4	39.8	103.2	39
GEORGIA				
October Report	152.4	52.2	204.6	26
As corrected	158.9	51.9	210.8	25
INDIANA				
October Report	284.1	11.1	295.2	4
As corrected	278.6	11.7	290.3	4
IOWA				
October Report	158.4	32.1	190.5	17
As corrected	162.8	31.5	194.3	16
KANSAS				
October Report	223.4	54.6	278.0	20
As corrected	216.5	54.6	271.1	20
KENTUCKY				
October Report	110.6	7.1	117.7	6
As corrected	111.8	7.3	119.1	6
MARYLAND & D.C.				
October Report	100.1	12.5	112.6	11
As corrected	100.7	12.8	113.5	11
MISSOURI				
October Report	205.9	29.0	234.9	12
As corrected	208.5	29.7	238.2	12
NEVADA				
October Report	23.7	17.2	40.9	42
As corrected	24.6	18.0	42.6	42
NEW JERSEY				
October Report	144.1	31.1	175.2	18
As corrected	144.1	30.8	174.9	18
NEW YORK				
October Report	366.8	35.1	401.9	9
As corrected	366.8	35.1	401.9	9
NORTH CAROLINA				
October Report	52.7	38.0	90.7	42
As corrected	48.6	34.7	83.3	42

1975-1976 Heating Season (Projected)

	Deliveries	Curtail-ments	Require-ments*	% of Require-ments Curtailed
ARIZONA				
October Report	65.3	26.1	91.4	29
As corrected	65.3	26.2	91.5	29
December Update	69.3	22.2	91.5	24
CALIFORNIA				
October Report	755.3	402.3	1,157.6	35
As corrected	706.3	393.7	1,100.0	36
December Update	709.5	369.5	1,079.0	34
DELAWARE				
October Report	8.5	2.0	10.5	19
As corrected	8.5	2.2	10.7	21
December Update	9.4	1.3	10.7	12
FLORIDA				
October Report	51.5	47.5	99.0	48
As corrected	52.5	49.2	101.7	48
December Update	52.2	49.5	101.7	49
GEORGIA				
October Report	145.1	63.1	208.2	30
As corrected	152.4	62.9	215.3	29
December Update	152.4	62.9	215.3	29
INDIANA				
October Report	273.2	22.3	295.5	8
As corrected	272.5	23.1	295.6	8
December Update	278.5	17.1	295.6	6
IOWA				
October Report	168.1	35.8	203.9	18
As corrected	169.2	35.8	205.0	18
December Update	169.2	35.8	205.0	18
KANSAS				
October Report	213.1	59.9	273.0	22
As corrected	206.5	60.2	266.7	23
December Update	206.9	59.8	266.7	23
KENTUCKY				
October Report	109.9	17.5	127.4	14
As corrected	111.1	17.5	128.6	14
December Update	115.4	13.2	128.6	10
MARYLAND & D.C.				
October Report	97.1	21.7	118.8	18
As corrected	97.1	22.0	119.1	19
December Update	104.9	14.2	119.1	12
MISSOURI				
October Report	194.6	33.8	228.4	15
As corrected	197.1	35.1	232.2	15
December Update	197.1	35.1	232.2	15
NEVADA				
October Report	22.9	22.5	45.4	50
As corrected	23.5	24.2	47.7	51
December Update	23.5	24.2	47.7	51
NEW JERSEY				
October Report	154.1	33.4	187.5	18
As corrected	154.1	33.1	187.2	18
December Update	166.3	20.9	187.2	11
NEW YORK				
October Report	379.9	50.5	430.4	12
As corrected	381.1	45.0	426.1	11
December Update	385.3	40.8	426.1	10
NORTH CAROLINA				
October Report	45.4	49.8	95.2	52
As corrected	42.1	47.1	89.2	53
December Update	48.1	41.1	89.2	46

* Deliveries plus curtailments equal requirements.

COMPARISON OF OCTOBER REPORTED AND DECEMBER UPDATE FOR 21 STATES

(All Volumes in Bcf)

1974-1975 Heating Season (Actual)

	Deliveries	Curtailments	Requirements	% of Requirements Curtailed
OHIO				
October Report	580.6	63.9	644.5	10
As corrected	580.0	66.9	646.9	10
PENNSYLVANIA				
October Report	363.0	27.2	390.2	7
As corrected	377.8	27.6	405.4	7
SOUTH CAROLINA				
October Report	45.3	54.3	99.6	55
As corrected	48.9	55.3	104.2	53
TENNESSEE				
October Report	104.0	22.4	126.4	18
As corrected	111.4	22.7	134.1	17
VIRGINIA				
October Report	68.7	12.7	81.4	16
As corrected	69.5	12.8	82.3	16
WEST VIRGINIA				
October Report	55.7	8.4	64.1	13
As corrected	79.4	9.3	88.7	10
21 STATES TOTAL				
October Report	3,929.3	852.1	4,781.4	18
As corrected	3,964.9	897.2	4,862.1	19

1975-1976 Heating Season (Projected)

	Deliveries	Curtailments	Requirements	% of Requirements Curtailed
OHIO				
October Report	568.7	111.0	679.7	16
As corrected	568.3	109.0	677.3	16
December Update	599.5	77.8	677.3	12
PENNSYLVANIA				
October Report	370.1	49.4	419.5	[illegible]
As corrected	383.3	49.3	432.6	[illegible]
December Update	395.5	37.1	432.6	
SOUTH CAROLINA				
October Report	42.8	60.9	103.7	[illegible]
As corrected	46.4	62.0	108.4	57
December Update	49.3	59.1	108.4	[illegible]
TENNESSEE				
October Report	103.1	27.4	130.5	21
As corrected	111.9	31.3	143.2	22
December Update	111.9	31.3	143.2	22
VIRGINIA				
October Report	67.5	17.8	85.3	21
As corrected	65.5	18.1	83.6	22
December Update	72.0	11.6	83.6	[illegible]
WEST VIRGINIA				
October Report	52.2	11.9	64.1	[illegible]
As corrected	80.5	15.3	95.8	[illegible]
December Update	83.8	12.0	95.8	13
21 STATES TOTAL				
October Report	3,888.4	1,166.6	5,055.0	23
As corrected	3,895.2	1,162.3	5,057.5	23
December Update	4,000.0	1,036.5	5,036.5	

Note

This survey was taken by telephone with the five to seven largest distributors in each state. These account for 80 to 90 percent of total gas deliveries in the states. Major interstate pipelines were also contacted to assess changes in their deliveries.

Curtailment data obtained represents an update of data published in FEA's October report, Natural Gas Curtailments, 1975-76 Heating Season, which was based on a joint FEA/FPC survey of 1,700 pipeline companies and gas distributors.

As in the October report, curtailment data takes into account supplies of liquefied natural gas (LNG), synthetic natural gas (SNG), and gas storage which distributors can use to offset interstate pipeline curtailments.

October report data have been adjusted to account for erroneous projections previously submitted to FEA by distributors and other adjustments. These adjustments are shown in columns marked "as corrected."

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Possible questions and suggested answers:

1. Why are the curtailments numbers always changing?

Answer. There are two types of curtailments 1) from pipelines to distributors and 2) from distributors to end-users. This summer, according to papers filed with the FPC, interstate pipelines projected nationwide curtailments of 1.3 Tcf to their distributors. Instead of accepting those figures, FEA sent questionnaires to 1700 distributors (almost 100% coverage asking them what their end-users curtailments would be taking into account pipeline deliveries, storage, imports, synthetic gas, etc.

Based on those questionnaires, for 21 critical states (not nationwide), FEA projected 1.16 Tcf of curtailments. When the weather warmed up, FEA did a spot resurvey and reported an improved picture (shows our sincerity and veracity) of 1.03 Tcf.

Thus, there was no playing with numbers: 1.3 Tcf was a nationwide pipeline curtailments figure; 1.16 Tcf a 21-state projection; and 1.03 Tcf an updated 21-state projection.

2. Why aren't producers honoring the agreed-to delivery requirements of their contracts?

Answer. There are two basic types of contracts. The "warranty" contract is a commitment to deliver a certain amount regardless of what field it comes from, economic considerations, etc. These are rare contracts, 6 on file with the FPC out of thousands of contracts alltogether.

The overwhelming majority of contracts are "take-or-pay" type. The producer will make up to a certain amount of gas available and the pipeline has to buy all he makes available up to that amount. Delivery is generally tied to a specific reserve - if there was less gas than originally estimated or economic considerations are unfavorable, the producer is allowed to deliver less by the terms of the contract.

Thus, the so-called agreed-to amounts are not binding and usually failure to deliver that amount is not a breach of contract.

3. What about all this shut-in (or capped) reserves (wells)?

Answer. It is true there is gas not being produced. Most of it is so-called "behind the pipe gas." That is gas from different levels on wells already producing. It is economically and physically unfeasible to produce from many levels at the same time. When the presently producing levels are exhausted, these "behind the pipe" levels will be produced. Otherwise, you would jeopardize ultimate recovery.

Another reason is gas which is not close enough to pipelines and economically does not warrant the additional investment to build those pipelines at this time.

There are also wells which need work and are awaiting equipment, or where there is not enough gas left to economically warrant additional investments.

While there have been accusations of conspiratorial holding back, we (FEA) have challenged the accusers to give us the evidence. To date, none has been submitted.

4. Why do we need deregulation?

Answer.

a. Economic incentive to develop new gas supplies (OCS, Alaska, deeper onshore formations).

b. Encourages more efficient use of natural gas.

c. Eliminates price disparity between intrastate and interstate markets.

5. Won't deregulation cause gas bills to quadruple? (From 52¢/Mcf to $2.00 or $2.50)

Answer. Definitely not. Assume, for arguments sake, that the wellhead price of new gas quadrupled. (Don't forget, we're only talking about deregulation of new natural gas). The retail price would only rise slightly for the following reasons:

a. The wellhead price only makes up about 20% of final price (transportation, markup, etc.).

b. Since most interstate gas is under long-term (10-20 years) contracts, only about 7% a year would reach the deregulated price. Since old gas averages less than 40¢/Mcf, the average would only go up slightly each year (Theory of "rolled-in" gas price).

6. What is the Administration's position on:

a. Pearson-Bentsen (S. 2310)

b. Krueger

c. Brown

d. Dingell

e. Fraser

Answer.

a. While S. 2310 does deregulate it has a number of objectionable features, which we would hope to work out in conference.

b. Krueger comes the closest to workable legislation and, with minor modifications, would be acceptable.

c. Brown's 7-year bill has many fallbacks. While better than no deregulation, it falls far short of what we need. We understand that Brown himself is supporting Krueger.

d. Dingell is short-term only. Unless we deregulate, we'll continue to have emergencies (Band-aid approach). As a short-term bill, it has many problems.

e. Fraser's totally unacceptable and counterproductive.

7. Why does the government just accept industry reserve figures?

Answer. In October of 1975, FEA submitted an oil and gas reserve study to Congress. In its report concerning natural gas reserves, the FEA pointed out that in 16 states, operator estimates of reserves were higher than those of AGA, and in 9 states the converse was true. The FEA estimated that response to its operator survey for gas covered 95% of the universe based on 1973 production figures.

Because of questions relating to the validity of the reported reserves estimates, the FEA had independent field studies made on a number of the larger fields which were compared to the reserves and production values reported. These data indicate that the producers' estimates are sometimes higher and sometimes lower than those of the AGA's Committee on Natural Gas Reserves. A sample of operator responses was audited to confirm compliance with instructions and cast light on the validity of data submitted. This audit was separate from and in addition to the engineering studies which were made of a sample of 50 fields.