Appendix D

FERC Ratemaking Process

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The Natural Gas Act of 1938 (NGA) gave the Federal Energy Regulatory Commission (FERC) broad authority to regulate the interstate sales and transportation of natural gas. FERC ensures that rates are reasonable and nondiscriminatory by presiding over rate hearings. During a rate hearing, the pipeline company is required to justify its proposed rates by providing detailed information on its costs and proposed service levels (volume and demand requirements). Before deciding on the appropriate cost and service levels that will be used in determining pipeline company rates, the regulatory process provides all concerned parties the opportunity to present testimony to FERC.

The ratemaking process can be separated into five distinct steps:

- **Determine the overall costs that should be recovered in the rates.** FERC generally uses a historical cost approach to ratemaking in which actual costs for a recent 12-month period (base period) are adjusted for known and measurable changes expected to occur within nine months of the end of the base period. FERC sets up a "test period cost of service" that includes all pipeline company costs of providing service, including a fair return on investment. The individual components of the cost of service are discussed in greater detail below.

- **Separate the "test period cost of service" into pipeline functions such as gathering, transmission, and storage.**

- **Classify "functionalized" costs into demand and commodity components.** Variable costs, costs that vary with the volume of gas flowing through the pipeline, are classified as the commodity component. Depending on FERC's ratemaking goals, fixed, or nonvariable, costs are allocated to the demand and/or commodity component. Because the natural gas pipeline industry is very capital intensive, the majority of pipeline company costs are fixed.

- **Allocate demand and commodity components among pipeline company services.** Demand costs are traditionally allocated among services based on customer capacity requirements, while commodity costs are allocated on a volumetric basis. Part of the allocation process may also incorporate the distance gas travels to the customer.

- **Design unit rates.** Unit rates are developed by dividing the allocated demand and commodity costs by billing units for the respective services. Rates can be designed to incorporate a one-, two-, or three-part rate structure of billing. A one-part rate is designed to recover demand and commodity costs in a single volumetric charge—the customer is billed based on the number of gas units it consumes or transports. In a two- or three-part rate structure, reservation rates are designed to recover demand costs while volumetric rates recover commodity costs.

Rates are also designed to reflect the pipeline company's quality of service. For example, firm service rates recover more of the pipeline company demand costs than interruptible service rates. Firm customers have first call on capacity contracted for, while in cases of a shortage, interruptible customers may be bumped from the system. Hence, interruptible rates are usually one-part rates that are generally lower and include only a small portion of the demand cost.

While this description of the ratemaking process appears fairly straight forward, FERC can influence the ratemaking process to achieve policy goals that are pertinent to prevailing market conditions.[98] To achieve policy goals, FERC uses the cost classification aspect of the ratemaking process to classify fixed costs as either demand or commodity or some mixture of the two.

During the early 1980's FERC adopted the modified fixed-variable (MFV) method of cost classification. MFV classified all fixed costs as demand costs except for the return on equity and related income taxes (and sometimes fixed production and gathering costs) which were classified as commodity costs. This had the effect of lowering overall transportation rates. FERC adopted the MFV method to promote two goals: first, to reduce underutilization of the national natural gas pipeline system and second, to make natural gas more competitive with alternate fuels.

In addition to the MFV classification, FERC proposed to split demand costs between two demand components: the (D-1) component recovered demand costs through a peak-day charge, and the (D-2) component recovered demand costs through an annual demand charge. FERC proposed this change in rate

[98]FERC Docket Nos. RM91-11-000 and RM87-34-065, Order No. 636, p. 120.

design to mitigate the cost-shift impact on low-load-factor customers of the move to MFV rates.

In 1989 FERC once again reviewed its ratemaking policies in light of institutional changes that were affecting the pipeline industry, such as open-access transportation and the decontrol of natural gas wellhead prices. As part of this review, FERC released its *Policy Statement Providing Guidance with Respect to the Designing of Rates*, which evaluated the effectiveness of different aspects of ratemaking in meeting the goals of rationing transportation capacity and maximizing throughput. Specifically, FERC discussed seasonal rates, capacity adjustments, discounted transportation, maximum interruptible rates, and the classification of fixed and variable costs to demand and commodity charges. In its Policy Statement, FERC suggested that to meet the goals of rationing capacity in peak periods and maximizing throughput, the annual demand component associated with the MFV rate design should be eliminated and costs formerly recovered under the D-2 component be moved to the D-1 component. This essentially was a transition to the present practice of using straight fixed-variable (SFV) rate design prompted by Order 636.

While the changes in cost allocation and rate design initiated by FERC do not affect the total costs collected by the pipeline company, they do affect the overall unit cost of service charged to the customer. For example, the SFV rate design collects a larger share of fixed costs via the capacity reservation charges than does the MFV design. As discussed in the corridor rate study, the shift of costs to reservation charges increases the average unit cost of service to customers whose peak requirements are larger than their average annual requirements. Therefore, excluding any other changes in costs and services, the switch from MFV to SFV would increase the average unit cost of service to low-load-factor customers.

Components of the Pipeline's Cost of Service

The starting point for designing rates is to determine the total cost of service necessary for the pipeline company to provide service to its customers. The cost of service contains five base components.

- **Return on Rate Base.** The return is calculated by multiplying the allowed rate of return by the company's rate base. The rate base is generally calculated as net plant (gross gas plant in service plus construction work in progress less the accumulated depreciation, depletion and amortization) plus prepayments and inventory items (gas stored underground, materials and supplies, etc.) less accumulated deferred income taxes. The rate base is the foundation on which the natural gas pipeline company earns its profit (return on equity) and its financing costs (return on debt).

- **Operation and Maintenance (O&M) Expenses.** O&M expenses include the labor and materials expenses required for the pipeline company to perform its day-to-day service. These expenses are related to the production, distribution, transmission, and storage functions of the pipeline company and include the costs for customer services and administrative and general support.

- **Depreciation, Depletion and Amortization (DD&A) Expenses.** This represents a charge or credit to income taken against the decrease in value of an asset over a period of time. Some of the factors considered in determining DD&A are wear and tear, obsolescence, and salvage value.

- **Income Tax Allowance.** Income tax allowance provides the pipeline company a method to recover the booked cost of Federal and state income tax expenses from its rate payer. The income tax allowance is computed by multiplying the return on equity, as adjusted for tax purposes, by an income tax factor. The income tax factor is generally computed by dividing the tax rate by one minus the tax rate.

- **Other Operating Expenses.** These expense items include taxes other than income taxes, revenue credits, deferred income taxes, and other such miscellaneous expenses.

A number of factors have a natural tendency to influence rates over time. For example, depreciation of the natural gas plant facilities will tend to reduce rates over time. Depreciation reduces the return component of rates by reducing the rate base on which return is computed. If pipeline companies did not restore depreciated plants or invest in new plant facilities, rates would decline over time.

Increases in any one of the cost items identified above will place upward pressure on average unit rates, while decreases will tend to lower rates. However, the ability of a component to affect rates significantly is related to its share of the total cost of service. A large decrease in a component does not automatically lead to a large decrease in average unit rates. For example, between 1988 and 1994, other expenses almost doubled, however, they represent only a small portion of the total cost of service, and the increases did not dramatically increase average unit rates (Table D1). In fact, the rate base has increased by about $6 billion since 1988.

Unlike individual rate components, relative changes in deliveries to customers can and do have significant and inverse effects on average unit rates. For example, the 1994 sample average unit rate is $0.59 per thousand cubic feet. The unit rate calculated using 1988 volumes is $0.68 per thousand cubic feet. This indicates that the 16-percent increase in volumes from 1988 to 1994 results in a 12-percent decrease in average unit rates.

Table D1. Aggregate Cost of Service and Rate Components for Major Interstate Pipeline Companies, 1988-1994

	1988	1989	1990	1991	1992	1993	1994
Aggregate Cost of Service (nominal dollars, thousands)							
Return on Rate Base							
Total Rate Base	$20,219,700	$18,943,698	$23,177,756	$25,711,373	$26,307,394	$26,136,744	$25,617,891
Percent Return on Equity	6.43	6.39	6.64	6.62	6.37	6.63	5.74
Percent Return on Debt	5.05	5.30	4.79	4.77	4.27	4.84	4.42
Equity portion of Return	1,300,127	1,210,502	1,539,003	1,702,093	1,675,781	1,732,866	1,470,467
Debt portion of Return	1,021,095	1,004,016	1,110,215	1,226,432	1,123,326	1,265,018	1,132,311
O&M Expenses (excluding cost of gas)	6,965,146	8,035,884	5,514,858	8,411,606	7,162,898	6,794,636	5,419,034
Other Expenses							
Depreciation, Depletion, Amortization	1,550,952	1,343,755	1,348,979	1,301,518	1,118,227	1,528,583	1,307,123
Income Taxes	724,834	681,867	866,395	989,253	1,020,474	1,012,925	847,512
Other Expenses	508,255	733,191	677,666	15,130	739,712	721,141	916,759
Total Aggregate Cost of Service	$12,070,409	$13,009,215	$11,057,116	$13,646,032	$12,840,418	$13,055,171	$11,093,205
Natural Gas Delivered to Consumers (billion cubic feet)	16,320	17,102	16,820	17,305	17,786	18,488	18,851
Unit Rate Components (1994 dollars per thousand cubic feet)							
Total Return on Rate Base	$0.17	$0.15	$0.18	$0.18	$0.16	$0.17	$0.14
O&M Expenses (excluding cost of gas)	0.52	0.55	0.36	0.52	0.42	0.38	0.29
Other Expenses							
Depreciation, Depletion, Amortization	0.12	0.09	0.09	0.08	0.07	0.08	0.07
Income Taxes	0.05	0.05	0.06	0.06	0.06	0.06	0.04
Other Expenses	0.04	0.05	0.04	0.00	0.04	0.04	0.05
Total Unit Cost of Service	$0.90	$0.88	$0.73	$0.85	$0.75	$0.72	$0.59

O&M = Operating and maintenance expenses.

Sources: 1988-1989: Energy Information Administration, Statistics of Interstate Natural Gas Pipeline Companies 1991 (December 1992).
1990-1994: Federal Energy Regulatory Commission (FERC) Form 2, "Annual Report of Major Natural Gas Companies", Balance Sheet, O&M Expenses and Statement of Income files from FERC Gas Pipeline Data Bulletin Board System.
The Federal portion of the income tax expense is calculated by multiplying the equity portion of return by the Federal tax factor.