NATURAL GAS PIPELINE REGULATION IN THE UNITED STATES: PAST, PRESENT, AND FUTURE

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Abstract

This monograph provides a detailed overview of federal-level regulation of the U.S. interstate natural gas pipeline industry. To develop a more complete understanding of the current regulatory environment, we place contemporary rules and regulations into their proper historical context by first reviewing the evolution of gas pipeline regulation over the course of the 20th Century. We then discuss the market restructuring process that culminated in 1992 with FERC Order No. 636, review the economic and policy research that studied its effects on pipeline operations (and on the U.S. natural gas market writ large), and examine the current regulations and industry structure that have since emerged. Finally, we explore possibilities for the future of regulation in the gas pipeline industry, offering some predictions regarding the likely direction of regulatory changes, paying particular attention to the possibility of incentive-based regulation in natural gas transmission.

1. Introduction

"Natural gas is better distributed than any other fuel in the United States. It's down ever street and up every alley. There's a pipeline." – U.S. energy magnate, T. Boone Pickens

The North American "shale revolution" in natural gas (and oil) production has already impacted the U.S. economy and is poised to affect energy markets globally. Despite salient but tractable environmental concerns, the potential benefits of developing this resource – both in terms of direct market impacts and reduced carbon emissions – are immense (Mason et al 2015). This, coupled with the electricity sector transitioning away from coal toward gas-fired generation, leads many to expect that the U.S. natural gas industry will continue to grow enormously over the coming decades. The U.S. Energy Information Administration has projected that domestic natural gas production will increase from its mark of just over 25 trillion cubic feet (Tcf) in 2015 to more than 40 Tcf by 2040. Even absent a federal Clean Power Plan, gas will overtake coal as the dominant fuel in electric power generation by 2030 (EIA 2016).

A fundamental aspect of this critical energy market that is often overlooked, however, is that it is supported by the most extensive pipeline transmission network in the world. Along with over 1,400 compression stations and 400 underground storage facilities, the U.S. natural gas pipeline network consists of roughly 305,000 miles (491,000 km) of interconnected pipelines operated by more than 210 independent firms (see Figures 1 and 2).[1] Because over 70 percent of network transmission mileage is classified as *interstate* pipeline, most operators are subject to U.S. federal regulation. The main focus of this monograph is to provide a detailed economic overview of these

[1] Source: U.S. Energy Information Administration.

regulations; we review the relevant economic and policy literature that has tracked the evolution and regulation of the U.S. gas transmission market over the past century.[2]

[FIGURES 1 & 2]

The development of the interstate natural gas pipeline network, and its regulation, is indelibly etched in the U.S. natural gas industry. To understand the current regulatory framework, it is important to place contemporary rules and regulations into their proper historical context. As noted by Joskow (2013), the aforementioned benefits of the United States' new bounty in economically recoverable shale gas reserves "would not have been realized as quickly and efficiently absent deregulation of the wellhead price of natural gas, unbundling of gas supplies from pipeline transportation services, the associated development of efficient liquid markets for natural gas, and reforms to the licensing and regulation of prices gas pipelines charge to move gas from where it is produced to where it is consumed." In this spirit, Section 2 provides a detailed history of U.S. federal regulation of interstate gas pipelines, highlighting the most impactful regulatory changes and discussing both the immediate and lasting effects they had on the market. The history of gas pipeline regulation in the U.S. is a fascinating case study in both the benefits and unintended consequences of direct market intervention. Our goal in Section 2 is to show how specific regulatory measures were critical in helping the nascent (and integrated) natural gas extraction and transmission industry establish itself as a cornerstone of the U.S. energy portfolio, and how these same regulations, after the industry had grown, resulted in severe market distortions.

In response to these distortions and to increase market competition, the Federal Energy Regulatory Commission (FERC) issued Order 636 in 1992, mandating that the U.S. natural gas

[2] Our use of the term "regulation" throughout this monograph should be interpreted in the economic sense of *price regulation*, as opposed to the engineering concept of physical regulation of gas flows. For an up-to-date review of the engineering and operations research literature on gas pipeline network optimization, see Rios-Mercado and Borraz-Sánchez (2015).

industry be fully restructured into separate production, transportation, and distribution sectors. Twenty-five years later, FERC Order 636 remains the defining document in shaping the current regulatory framework faced by U.S. gas pipeline firms. A wealth of economic and policy literature has since analyzed the impacts of Order 636, both on the behavior of pipeline operators specifically, and on the U.S. natural gas market writ large. We provide a thorough review of this literature in the Section 3, and discuss the current industry structure that has emerged in response to arguably one of the most impactful regulatory regime shifts in U.S. history. Section 3 also includes a detailed explanation of FERC's current rate setting methodology for gas pipelines, a discussion of the "primary" and "secondary" markets for natural gas transmission and FERC's formal capacity release system, and a brief review of several important non-price regulations faced by pipeline operators.

Finally, in Section 4 we discuss the future of regulation in the gas pipeline industry, offering predictions and recommendations to policy makers and pipeline operators regarding the likely direction of regulatory changes. Despite the significant deregulatory push ushered in by Order 636, FERC maintains some key controls over the natural gas transmission market. Perhaps the most consequential is the use of price controls based on 'reasonable' rates-of-return on cost-of-service. A growing body of economic literature now praises the benefits of transitioning away from rate-of-return regulation in infrastructure-intensive industries, in favor of more flexible 'incentive-based' regulatory models. We discuss the likelihood and implications of a move toward incentive-based regulation in the U.S. gas pipeline industry.

2. History of Natural Gas Pipeline Regulation in the U.S.

We begin this section with a short discussion of the early natural gas market and the inception of the natural gas pipeline transmission industry. Then, we identify and discuss the crucial legislative and regulatory actions over the course of the 20th Century that helped shape the gas pipeline industry into its modern configuration. Because extensive historical accounts of the growth, evolution, and regulation of the gas industry are available elsewhere,[3] we avoid recounting the full market history here. Instead, our focus is narrower, highlighting what we believe to be the major regulatory events (and market forces) that affected the pipeline sector specifically. These are as follows. (1) The Natural Gas Act (NGA) of 1938 consigned regulatory oversight of the burgeoning *interstate* transmission market to the Federal Power Commission (FPC) and established rules and rates for 'bundled' pipeline transportation and sales services. (2) From 1942-1978 the FPC, bolstered by rulings of the U.S. Supreme Court, imposed and maintained 'wellhead' price controls on primary gas sales from producers to pipelines, under the pretense of protecting consumers from the alleged market power of producers. (3) The Natural Gas Policy Act (NGPA) of 1978 initiated a gradual phasing-out of wellhead price controls and finalized the transferal of regulatory authority over natural gas producers and interstate pipelines to a new body, the Federal Energy Regulatory Commission (FERC). (4) FERC ushered in the first wave of industry restructuring in 1985 with Order No. 436, which encouraged pipeline operators to discontinue bundled transportation and merchant services to become instead open access carriers of gas transacted directly between producers and consumers. Although the restructuring process would be completed seven years later in 1992, culminating with the issuance of FERC Order No. 636,

[3] See, in particular, Tussing and Tippee (1995) and MacAvoy (2000). Makholm (2012) provides a brief historical review of the regulation of both oil and gas pipelines, generally.

we save our discussion of Order 636 for the next section, as it bears enduring relevance to the current regulatory architecture.

2.1. The Early Natural Gas Market and the Birth of the Pipeline Industry

The gas industry began in the United States as early as the 1820's. Throughout the 19th Century, gas was used primarily as a source of light. Because no long-distance pipelines existed, it was technically infeasible to transport *natural* gas from the field to urban centers. Local 'gas-works' instead produced synthetic, *manufactured* gas from coal or oil, and in most cases also owned and operated the local distribution infrastructure. Apart from occasionally providing the pressure needed to pump oil from the ground, natural gas was considered a nuisance—a virtually useless by-product of oil production. Nearly all 'associated' gas was either flared or vented.[4] Even less useful, 'non-associated' gas was essentially worthless for lack of a market, and reservoirs were typically left undeveloped.

The first successful natural gas pipeline—two inches in diameter and just over five miles long—was built in 1872 to transport associated gas to the Titusville, PA town center from the nearby well at *Oil Creek*.[5] Despite progress in piping construction that made long-distance transmission technologically feasible, the industry developed slowly over the next 50 years. In that span, only a handful of long-distance transmission lines emerged—up to 200 miles in length and 20 inches in diameter—to connect supply basins with urban markets.[6]

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[4] Natural gas is classified as either 'associated' with oil production, or 'non-associated.' Associated gas is released from the oil reservoir during extraction, whereas non-associated gas is developed from reservoirs not containing oil (MIT Energy Initiative 2011).
[5] The Oil Creek field at Titusville is, of course, historically significant in its own right, as it was the site of the first modern oil well (Yergin 1991, Ch. 1).
[6] See Tussing and Tippee (1995, Ch. 3) for a detailed chronology of early pipeline projects.

Early technological improvement in pipeline transmission was spurred by the immense waste associated with gas flaring. *Rule of capture* laws exacerbated intense competition in oil extraction, while providing little incentive for producers to invest in the development of any associated gas resources.[7] Oil-producing states eventually responded to this profligacy by imposing restrictions on gas flaring designed to prevent both physical and economic waste of gas resources.

However, technological improvement and anti-flaring laws alone were not enough to spur widespread investment in long-distance transmission lines. Put simply, such ventures were still beset by near-intractable risk. Foremost was the risk that a specific gas field might be drained shortly after the pipeline was built; in those days geological surveying techniques of for estimating subterranean reserves were, at best, crude and highly inaccurate. A second source of risk, as explained by Petrash (2006), was that natural gas pipelines were 'transaction-specific' assets with little to no economic value beyond connecting production and consumption centers, leading to a potential 'hold-up' problem. The 'hold-up' problem, attributable to Goldberg (1976) and later formalized by Klein et al. (1978), is the idea that in complex transactions with incomplete contracts, a prior commitment made by one party may increase the rent-extraction capability of the other party at subsequent stages. In the early pipeline industry, absent regulatory oversight the success of a pipeline project depended on cooperation between producer, pipeline, and retail distributor. Once investment in the transaction-specific pipeline asset was sunk, investors faced the risk that a party occupying a different position on the value chain might engage in 'hold-up' style rent-seeking behavior. This created a significant barrier to investment absent contractual assurances from either upstream or downstream stakeholders (or both) regarding future revenue streams. Absent regulatory oversight, vertical integration prevailed as the dominant industrial

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[7] *Rule of capture* states that ownership of oil (and gas) is conferred upon whomever extracts it, regardless of the geographic distribution of underground reserves.

organization; upstream production and long-distance transmission assets were either owned by or affiliated with local distribution companies (LDC's).

Following further advances in pipe technology and the discovery of immense non-associated gas deposits in the Gulf Coast and Texas-Oklahoma Panhandle regions, a burst of construction totaling several thousand miles of new pipelines occurred in the late 1920's. Another key factor for industry growth after the turn of the century was the emerging dominance of natural gas as a heating fuel. The advent of electric light had rapidly supplanted natural gas as an illuminant, spurring LDC's to innovate by developing gas appliances designed to exploit the fuel's thermal capabilities—*e.g.*, ranges, ovens, water heaters, and space heaters. It would not be until the post-WWII era, however, that the pipeline infrastructure had expanded sufficiently for natural gas to capture a significant share of the U.S. energy market.

2.2. The Natural Gas Act of 1938

During the first quarter of the 20th Century, regulation of long-distance pipelines was the jurisdiction of the states. Such an arrangement was logical at the time; local utilities were understood to be natural monopolies owing to significant economies of scale, and pipeline regulation was an extension of public utility regulation.

Natural gas pipelines in this era operated as *merchant carriers*, offering bundled transmission and sales services—that is, they bought gas from producers, transported it, and then resold it downstream to retail distributors for a single price that encompassed both the transportation service and the commodity itself. To ensure pipelines' revenue streams and the availability of supply, producer-pipeline and pipeline-distributor relationships were solidified via long-term contracts with a standard duration of twenty years. With the emergence of long-distance transmission technology capable of transporting gas across state lines, states' attempts at regulating such transactions were routinely rejected by the federal courts, citing violation of the interstate commerce clause of the U.S. Constitution. In response to an apparently clear-cut case for federal-level regulation, Congress passed the Natural Gas Act (NGA) in 1938, instituting federal regulation of prices for interstate transmission and sales. Authority was granted to the Federal Power Commission (FPC), an agency created in 1920 to administer federal regulation of hydroelectric power. Perhaps most importantly, the NGA granted the FPC authority over interstate pipeline certification, making it the new gatekeeper in granting firms permission to build new facilities or expand existing systems.

The overarching goals of the NGA were straightforward. First, policymakers sought to systematize and nationally unify regulatory oversight of the rapidly expanding interstate natural gas market. This, it was hoped, would stabilize the nascent pipeline industry and reduce financial uncertainty with regard to the construction of new long-distance transmission facilities. Second, rate regulation protected consumers by preventing pipelines – already well understood to be local natural monopolies – from exercising market power. Tussing and Tippee (1995, p. 136) offer the following summary:

> *"The NGA, therefore, dealt mostly with the authorization of new pipeline services and construction, the financial organization and conduct of pipeline construction, …and the …reasonableness of the pipeline's transport rates and gas-sales prices. To this end, it straightened the previously confused line of demarcation between the regulatory jurisdiction of the states over the retail distribution of natural gas and manufactured gas, and federal jurisdiction over interstate transportation and sales of natural gas, which would henceforth be exercised by the Federal Power Commission."*

The NGA was, on balance, successful in its aims and scope. The interstate transmission market steadied and then expanded rapidly. Supply of natural gas was plentiful, and upon conclusion of WWII (when steel was no longer expropriated for the war effort), pipeline construction boomed. Market penetration of natural gas as a heating fuel continually reached new peaks, while prices remained low for consumers.

Many of the rules and procedures put in place for interstate pipelines by the FPC under the auspices of the NGA endure today (although now administered by FERC). For example, before a new pipeline can be constructed, the certification and licensing protocol still requires an application for a *certificate of public convenience and necessity*, approval of which hinges on the adequacy of demand to support the financing of the pipeline project. Regarding rate regulation, pipeline tariffs were (and still are) determined based on cost of service, allowing for a reasonable rate-of-return (a subject we discuss thoroughly later in this chapter), although the mechanics of rate calculation have evolved. For the economically inclined reader, Wellisz (1963)—aside from providing a remarkable amount of institutional detail on the FPC's regulation of interstate gas pipelines—presents a focused economic analysis of specific FPC rules and procedures. The analysis, which maintains considerable relevance to contemporary regulatory practices of FERC, pays particular attention to the FPC's framework for allocating overhead costs among rates charged to different classes of customer, in tandem with constraining profits based on a "fair return on investment."

For all its successes as a comprehensive regulatory mandate, the NGA resulted in its share of failures. The FPC's interpretation of some provisions of the NGA paved the way for specific market interventions, discussed next, that were ill-advised, caused severe distortions, and were rightfully abandoned (although perhaps not soon enough; many economists would argue they should never have been adopted to begin with). Even so, it is safe to say that despite these faults, and throughout the dramatic market growth and change that have occurred in the 80 years hence, the NGA has remained a seminal piece of legislation whose imprint on the interstate gas transmission industry is still relevant in the modern era.

2.3. Wellhead Price Controls (1942-1978)

With interstate pipelines subject to federal oversight under the NGA, a question remained about how the FPC might deal with those producers from whom the pipelines procured gas to be transported and resold across state lines. Absent any supervision of sales at the wellhead, vertical integration became even more alluring. Put simply, monopoly profits were still available via sales from producers to affiliated pipelines, in spite of regulation of downstream sales to LDC's. In 1942 the FPC implemented wellhead price controls on contract gas transacted between producer-pipeline affiliates.

At first, the FPC left sales from unaffiliated producers to pipelines to be subject only to the forces of the market, under the presumption that competition among such producers was sufficient to keep wellhead prices low. However, a landmark Supreme Court decision in 1954 required the FPC to regulate all wellhead prices for gas sold in interstate markets.[8] Petrash (2006) succinctly describes the resulting paradigm as one in which pipelines were "sandwiched between upstream and downstream long-term contracts, with federal price regulation at both ends."

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[8] The case, *Phillips Petroleum Co. v. Wisconsin* 347 U.S. 672 (1954), centered on an allegation by the Wisconsin Public Service Commission that Phillips had been charging excessive prices for natural gas sold to Michigan-Wisconsin Pipeline.

In hindsight, to say that the FPC's implementation of wellhead price controls was a failure would be an understatement. Its initial intent was to review and approve prices on a case-by-case basis. Burdened by the immense administrative cost, however, by the 1960's the commission attempted to simplify the process by adopting 'area-wide' prices, and finally in 1974 imposed a single, national wellhead price. There was simply no way that a single, one-size-fits-all wellhead price could be economically efficient in a production sector characterized by extraordinary variation in costs due to geographical, geological, operational, and financial heterogeneity.

A considerable body of economic and policy literature from the 1960's, 70's, and 80's (which we do not review here) lambasted federal wellhead price controls for the clear and costly market distortions they ultimately caused. As the decades progressed under the regime, the market ached to operate freely as the FPC continually tightened its cumbersome grip. Severe shortages ensued and became endemic.[9] Pipelines could no longer procure sufficient gas supplies to satisfy downstream demand. As a result, LDC's were eventually forced to curtail gas sales to end-use consumers. Over the period 1968-1977, the estimated net loss in the U.S. market resulting from the FPC's imposition of wellhead price controls was roughly $20 billion, measured at 1982 prices (MacAvoy 2000). The combined losses to producers forced to accept artificially low gas prices and to consumers suffering shortages far outweighed the gains to those consumers benefiting from such prices.

[9] One of the first things students learn in any introductory economics course is that price controls imposed in otherwise competitive markets lead to market distortions in the form of supply-demand imbalances. A 'price ceiling'—in which the government sets a maximum allowable price below the competitive equilibrium price—will result in a shortage, because the quantity demanded at the artificially low price will exceed the quantity supplied.

2.4. The Natural Gas Policy Act of 1978

By the late-1970's it was clear to most industry stakeholders that the FPC's wellhead price control regime was doing more harm than good. Still reeling from the sting of the economy-wide energy shortage that had accompanied the famous Arab Oil Embargo of 1973-74, Congress and the Carter Administration sought to ameliorate—if not eliminate—domestic natural gas shortages. Energy security loomed large, and wellhead price controls in natural gas markets only exacerbated the threat of another energy crisis. In 1977 Congress passed the Department of Energy Organization Act to establish the Department of Energy as a cabinet-level agency, abolish the defunct and discredited FPC, and relegate federal oversight of energy markets to a new agency: the Federal Energy Regulatory Commission (FERC).[10]

The Natural Gas Policy Act of 1978 (NGPA) followed shortly afterward to attend to the seemingly contradictory goals of clearing gas markets through (partial) deregulation of wellhead prices while at the same time preventing producers of gas already committed to long-term contracts with pipelines from benefitting from price increases. The NGPA, apart from putting the finishing touches on FERC's regulatory authority over the natural gas market, enacted a complex gradation of wellhead prices that depended not only on contract vintage,[11] but also on other considerations such as reservoir depth and onshore-versus-offshore production. As MacAvoy (2000) explains, the bill defined over thirty classifications of gas, of which only three were immediately eligible for fully deregulated prices at the wellhead.

[10] In addition to assuming the traditional regulatory jurisdiction of the FPC over hydroelectric power and natural gas markets, FERC would also be charged with oversight of oil pipelines, which had previously been administered by the Interstate Commerce Commission. See McGrew (2009) for a condensed but thorough guide to FERC's practices and procedures in regulating U.S. energy markets.

[11] The 'vintaging principle,' with which the FPC had already experimented, held that prices of gas committed on 'older' contracts should be kept lower than those on 'newer' contracts (Tussing and Tippee, 1995, p. 152).

Suddenly higher prices had an unanticipated (and ironic) effect. City gate prices on gas sales from pipeline to distributor shot upward to a level at which natural gas was no longer competitive with other fuels. But this was only part of the problem. The price shock, in conjunction with long-standing *take-or-pay* agreements between pipelines and producers, resulted in an untenable situation—pipelines found themselves contractually obligated to buy gas they could not resell. Generally speaking, *take-or-pay* agreements require that the buyer either purchase or pay for a specified minimum quantity, and are not unique to natural gas contracts. However, Masten and Crocker (1985) suggest that although take-or-pay requirements can be economically efficient in contract design, distortions arise when used in combination with regulated price ceilings—as in the pre-NGPA era—because sellers have incentive set take-or-pay obligations inefficiently high. The result, in tandem with the rapid rise in prices following the NGPA, was precisely the opposite type of market imbalance from the one the NGPA was intended to correct. By the early 1980's *excess* supply had built up at city gates that, according to Petrash (2006), persisted in storage inventories well into the late 1990's. An unregulated spot market soon emerged for unbundled gas to be sold at considerably lower prices than contract gas, as pipelines sought to unload this new surplus.

The partial decontrol of wellhead prices ushered in by the NGPA had other, less conspicuous, but equally impactful, effects on interstate pipeline firms. Sickles and Streitwieser (1992) studied a panel of major natural gas transmission companies over the period 1977-1985. Their findings indicate a clear pattern of declining technical efficiency[12] over the period, which the authors suggest is directly related to the phased, partial decontrol policy of the NGPA. In a follow-up study of a larger sample of pipeline firms over the same period, Sickles and Streitwieser (1998) again

[12] Technical efficiency is broadly defined in economics as obtaining the maximum possible output for a given quantity of inputs.

implicate the NGPA as contributing to negative productivity growth in the industry, largely the result of falling output against the backdrop of a fixed capital stock.

Regulation of wellhead prices was abandoned entirely in 1989 with passage of the Wellhead Price Decontrol Act, and although most of the NGPA of 1978 would ultimately be scrapped, the bill was an important first step in the direction of deregulation that marked a turning point for the market. The NGPA signified that the pendulum had begun to swing the other way; the forces of deregulation were gaining momentum. The newly empowered agency, FERC, would soon embark on a market restructuring effort that would fundamentally change the role of interstate natural gas pipelines within the U.S. natural gas market.

2.5. FERC Order No. 436: Unbundling Begins

By the early 1980's the excess supply problem created by contractual take-or-pay agreements required decisive action. FERC believed the answer—not just to solving take-or-pay problems, but to increasing competition and efficiency in the natural gas market generally—was for pipelines to abandon the *merchant carrier* model of bundled transportation and sales and instead become open-access *common carriers* of gas owned by others. Producers and consumers of gas would be best served if they were free to engage in transactions independently of mediation by regulated merchant pipelines. Decoupling gas transactions from gas transmission made practical sense from both economic and legal viewpoints. A number of other transport markets, including railroads, trucking, and (notably) oil pipelines, already operated under the obligation of common carriage (or *contract carriage*, a specific form of common carriage), and were not plagued by such maladies. Indeed, the idea of converting gas pipelines to common carriage was not new. Historically, various proponents in both the legislative and executive branches of the federal government had endeavored to bring about such a change, and the recently ensconced Reagan Administration was no exception.[13] None had yet succeeded.

FERC was in a unique position to guide the industry toward common carriage, but it had to be careful. According to Tussing and Tippee (1995, p. 204), the prevailing view was that the NGA's omission of any common carriage requirement for gas pipelines effectively prohibited FERC from *ordering* them to offer transportation-only service. Instead, the aim was to incentivize pipeline firms to unbundle transmission services of their own volition, but to allow them the freedom to continue bundled merchant services if they and their customers preferred. The incentive that FERC devised to achieve this goal proved effective, and was well within its powers to offer under the NGA.

In October of 1985 FERC issued Order No. 436, aptly titled *Regulation of Natural Gas Pipelines after Partial Wellhead Decontrol*.[14] With Order 436, FERC gave existing pipelines the option to apply for "blanket transportation certificates" to provide open-access transportation of gas owned by shippers, with transmission capacity allocated on a non-discriminatory, first-come-first-served basis (McGrew 2009, p. 119). The more tantalizing incentive, however, related to the certification process for new pipelines. FERC would offer *optional expedited certification* of a proposed pipeline project on the condition that the operating firm agreed to provide fully open-access, transportation-only services on the new infrastructure. This opportunity was all but irresistible, owing to FERC's notoriously slow certification protocol. Expedited certification, notes MacAvoy (2000, p. 78), promised to "take years off the approval process."

[13] See Mogel and Gregg (1983) for a thorough, contemporaneous review of the legal and regulatory precedent for the Reagan Administration's push to convert the natural gas transmission industry to common carriage.

[14] Order 436 was preceded by several smaller rulings meant to address a variety of emerging issues in the gas market attributable to the partial decontrol of wellhead prices. Griggs (1986) provides a review of these lesser-known antecedents, as well as a rich contextual legal exposition of Order 436 and FERC's execution of the early stages of gas market restructuring.

Order 436 also introduced changes to pipelines' transmission rates. Historically, pipelines designed rates as a *two-part tariff*, a method that has been widely applied in utility pricing (and elsewhere) since the early 20th Century.[15] Under a two-part tariff, customers paid a fixed (typically monthly) *capacity charge* for pipeline access, and a variable *commodity charge* per unit of gas purchased via bundled transportation and sales services. FERC effectively continued the two-part tariff system for unbundled, transportation-only service. Order 436 maintained the use of a commodity charge per unit shipped, and stipulated that in lieu of the capacity charge open-access pipelines adopt a *reservation charge* for "firm" transportation, reflecting the premium value of guaranteed transmission capacity.

Aside from these minor definitional changes, FERC sought to address a more important issue with its new pricing rules. Under the FPC's traditional cost-allocation scheme, the capacity/reservation charge recovered only a fraction of the pipeline's fixed costs, leaving the remainder to be recovered via the volumetric commodity charge. Order 436 therefore introduced two other mechanisms designed to incentivize open-access pipelines to maximize throughput (and therefore transportation revenues). The first was to allow pipelines to discount the commodity charge from the maximum rate down to variable cost. Second, any firm capacity not in use at a given point in time was required to be made available for *interruptible transmission* (IT) service. IT, by definition, would not carry a reservation charge, but the volumetric IT rate, would be set in relation to the firm reservation and commodity charges so as to recover all appropriable fixed and variable costs.

FERC's market restructuring experiment initiated in Order 436 was a near-immediate success. The natural gas market was eager to shed the burdensome merchant pipeline model in favor of an

[15] Utility infrastructure installations like pipelines typically incur large, up-front fixed costs. A two-part tariff is an economically efficient way of covering such costs (Coase 1946).

open-access regime that freed up buyers and sellers to engage in gas transactions while arranging separately for gas transportation along whichever pipeline was capable of providing it at the lowest cost. As asserted by Griggs (1986), Order 436 reflected FERC's "profound faith in the free market to achieve the objective of efficient resource allocation at reasonable cost to customers." But this was only the beginning. As we will see in the next section, it would not be long before the benefits of market restructuring would be undeniable, spurring FERC to mandate that all interstate natural gas pipelines provide fully open-access, unbundled transmission services—a regime that has endured a full quarter-century hence.

3. Current Regulation of U.S. Interstate Natural Gas Pipelines

On April 8, 1992, FERC issued Order No. 636 (referred to hereafter as Order 636, for brevity), which finalized the market restructuring effort set in motion by FERC Order No. 436 and later reinforced by the Wellhead Price Decontrol Act. Any discussion of current natural gas pipeline regulation in the U.S. begins with Order 636; twenty-five years later, it remains the defining document in shaping the regulatory framework faced by U.S. gas pipeline firms. We therefore start this section by reviewing the order's main provisions, followed by a thorough review of the economic and policy analyses that emerged as the market adapted to these new conditions.

Having thus reviewed all of the past century's landmark legislative and regulatory actions relevant to interstate gas transmission, we then offer a detailed explanation of FERC's standardized rate-setting methodology for interstate natural gas pipelines. This is followed by an overview of the 'primary' versus 'secondary' markets for interstate gas transmission services, which includes short discussions of FERC Orders 637 and 712, issued in 2000 and 2008, respectively. Finally, we close this section by highlighting some other key features of the current regulatory environment, particularly those pertaining to new project construction and to basic operational considerations.

3.1. FERC Order No. 636: Restructuring Finalized

According to the language of Order 636,[16] FERC sought "to improve the competitive structure of the natural gas industry and at the same time maintain an adequate and reliable service." The order's central objective emphasizes the central role played by the regulation of interstate pipelines (FERC 1992, pp. 6-7):

[16] For the complete text, follow URL: https://www.ferc.gov/legal/maj-ord-reg/land-docs/restruct.asp.

"The Commission must create a regulatory environment in which no gas seller has a competitive advantage over another gas seller. In particular, the Commission must regulate the pipeline transportation system and pipeline sales for resale in a manner that ensures that pipeline control of the transportation system – a natural monopoly – does not give a competitive advantage to pipelines over other sellers in the sale of natural gas. This will ensure that the benefits of decontrol redound to the consumers of natural gas to the maximum extent as envisioned by the NGPA and the Decontrol Act."

Order 636 sought to accomplish two "fundamental goals." The first goal was "to ensure that all shippers have meaningful access to the pipeline transportation grid so that willing buyers and sellers can meet in a competitive, national market to transact the most efficient deals possible," and the second was "to accomplish the first goal in a way that continues to ensure consumers access to an adequate supply of gas at a reasonable price." The following excerpt summarizes FERC's overarching motivation in adopting these goals (FERC 1992, pp. 8-10):

"The Commission believes that to accomplish those objectives it is vital to give all gas purchasers (LDCs and end users, such as industrials and gas-fired electric generators) the ability to make market-driven choices about the price of gas as a commodity and about the cost of delivering the gas. Simply put, efficiency in the now national gas market can be realized only when the purchasers of a commodity know, in a timely manner, the prices of the distinct elements associated with the full range of services needed to purchase and then deliver gas from the wellhead to the burner tip. Only then will gas purchasers be able to purchase, based upon their needs, the exact services they want with full recognition of the prices that they would have to pay. And only then will the Commission be assured that all gas is transported to the market place on fair terms. What best serves the interests of gas

purchasers – the ability to make informed choices – is also important for gas sellers. Non-pipeline sellers also need to know the prices of the distinct elements of pipeline services in order to price their product and to decide the exact pipeline services needed to bring their gas to market. This rule provides both gas purchasers and gas sellers with the ability to make the necessary informed choices.

"*The Commission is adopting the major elements of the proposed rule… In brief, this rule requires pipelines to unbundle (i.e., separate) their sales services from their transportation services at an upstream point near the production area and to provide all transportation services on a basis that is equal in quality for all gas supplies whether purchased from the pipeline or from any other gas supplier. This rule issues blanket sales certificates to pipelines so that they can offer unbundled firm and interruptible sales services at market-based rates. In addition, pipelines will be required to provide a variety of transportation services to their shippers… As stated above, this will permit gas purchasers and gas sellers to choose the exact transportation service that they want, including a combination of services that will ensure that the pipelines can deliver an adequate supply of gas to the city gate from various sources when that supply is needed.*"

With Order 636, FERC had finally achieved common carriage in the interstate gas transmission industry. The ruling immediately nullified existing bundled contracts, separating them into distinct sales and transportation contracts. Customers were even allowed, if they so desired, to terminate existing contracts to purchase pipeline gas. All points of first sale were henceforth to be specified at (or as close as possible to) the wellhead. Although pipeline firms are not prohibited from engaging in upstream gas resales, Order 636 requires all such sales to be transacted at market rates and to be completely unbundled from transportation services via strict segregation of a company's sales and transportation operations. Moreover, preferential treatment toward a pipeline's own sales division or affiliate is expressly forbidden—open-access rules require that all transmission services and information be made available to all shippers on an equal basis. As a result, most pipeline firms have since divested their sales divisions. Gas sales are now primarily the domain of independent brokerage firms, though some brokers maintain affiliations with pipelines (McGrew 2009, p. 120).

Two crucial provisions of Order 636 – namely, the standardization of pipeline tariffs using the *Straight Fixed-Variable* (SFV) method and the introduction of a secondary capacity-release market – we discuss in greater detail later in this section. Each of these has wide-reaching implications that warrant more thorough investigation. But first a few other aspects of Order 636 are worth noting.

For one, those pipelines previously offering *no-notice* bundled firm sales would be required to offer *no-notice* firm transportation. With *no-notice* transportation, firm customers "can receive delivery of gas on demand up to their firm entitlements on a daily basis" without prior notification to the pipeline, and without incurring daily balancing and scheduling penalties for failing to schedule the shipment beforehand. This service ensures subscribing firm customers can maintain the flexibility to satisfy sudden, unexpected peak-demand shocks (*e.g.*, from unexpected changes in temperature).

The definition of "transportation" was expanded to include natural gas storage; pipeline-operated storage facilities were thereby obligated to provide unbundled storage services on an open-access basis as well. In FERC's view (FERC 1992, pp. 101-103),

> *"…pipelines' superior rights with respect to access and control of storage provide them with several advantages over other gas merchants with no access to storage for their gas. First, the pipelines can use storage to implement seasonal supply management where they purchase gas during off-peak periods. This enables the pipelines to cut gas costs by buying gas when it is less costly during off-peak periods. Second, the pipeline can use storage as a supplement to transmission*

> *capacity. This occurs when mainline transmission capacity is less than the pipeline's firm obligations, with the difference delivered out of downstream storage close to the pipeline's market areas. Last, pipelines can use storage to maintain a constant flow of gas by taking supplies from, or diverting gas to, storage. This enables them to manage their system in response to rapidly changing customer demands for gas. The above-described uses of storage give the pipelines an unfair advantage over other gas sellers because non-pipeline shippers do not have the flexibility to provide fully a sales service which meets gas purchasers' peak needs."*

FERC believed all buyers and sellers – not just pipelines – should have equal opportunity to store gas for future use, whether for reasons related to reliability of supply or to take advantage of lower off-peak prices.[17] Open access to storage, it was argued, both upstream and downstream, would "enable all shippers to more effectively manage their gas supply and procurement programs."

Finally, Order 636 requires all interstate pipelines to maintain publicly accessible "electronic bulletin boards" to provide customers (current or potential) with timely information on operations. In the modern era of Internet accessibility, one can find on the website of every U.S. interstate gas pipeline a near-standardized *Informational Postings* directory. There, customers can access real-time, downloadable data on gas flows and available capacity, including firm capacity available for temporary release. Other important information made publicly available includes the pipeline's system map, tariff schedule, and an index of firm customers.

[17] In addition, several studies have shown that downstream storage capacity tempers fluctuations in the spot price of transmission capacity (*e.g.*, Nguyen 1976; Gravelle 1976; Crew and Kleindorfer 1979; Hollas 1990). Oliver et al. (2014) find evidence that upstream storage capacity allows shippers to mitigate the price effects of pipeline congestion through intertemporal substitution of transmission services.

3.2. Order 636: The Market Response

In the pantheon of U.S. regulatory history, one would be hard-pressed to find a more impactful document for the regulated industry – and for the U.S. domestic energy landscape in general – than FERC Order No. 636. In this section we review the economic and policy literature that analyzed the subsequent market response, both by the U.S. natural gas industry writ large and by interstate pipeline firms specifically. To summarize it succinctly, the response was, on balance, overwhelmingly positive.

In the years following Order 636 and FERC's restructuring of the U.S. natural gas industry, improved integration of gas prices was of paramount interest to economic and policy researchers. Empirical analyses of price movements found significant evidence of greater price integration across the geographically dispersed U.S. market. This was interpreted as a clear indication of increased economic efficiency, as it meant price signals were being transmitted more readily between network nodes, without significant interference or distortion from pipeline transportation costs.

Several studies found evidence of convergence in regional gas spot prices in the years following Order 636 (*e.g.*, De Vany and Walls 1993, 1994a, 1994b; Doane and Spulber 1994; Walls 1995; Serletis 1997; Dahl and Matson 1998; MacAvoy 2000; Arano and Velikova 2009, 2012). It was clear that local, regional, and national gas markets had evolved in response to increased arbitrage opportunities. MacAvoy (2000, p. 81) describes the effect as follows:

> "*Observations of prices for gas at sixty-three nodes… indicate that 82 percent of pairs of nodes in fact have gas prices that follow the law of one price. Even though the physical network does not have connections between all nodes, arbitrage unites*

> *them in one network, substituting nonexistent routes with existing parts of the network.*"

MacAvoy goes on to note that following Order 636, transportation costs passed on to gas buyers declined each year between major market hubs. MacAvoy et al (2007) estimate that over the period 1994-1997, annual consumer savings on final gas delivery costs totaled roughly 12 percent compared to 1990 levels. Increased competition in wholesale gas markets also led to a number of other consumer benefits including new product development and innovation, reduced costs, and broader choice sets, all of which enhanced the diffusion and integration of pricing information (Leitzinger and Collette 2002).

More than any other feature of Order 636, this convergence of spot prices across the network is attributable to the standardization of pipeline tariffs using the *Straight Fixed-Variable* (SFV) methodology. Prior to Order 636, rate structures had allowed pipelines to allocate a substantial portion of fixed costs to volumetric usage charges. This muddled the transmission of commodity price signals across the network, reducing efficiency and price integration. SFV, by contrast, requires a strict delineation in the apportionment of fixed and variable costs to the fixed (*reservation*) and variable (*usage*) rates charged to firm customers under the two-part tariff system. In theory, SFV pricing between any two nodes on the network implies that as long as the spot price differential exceeds the average variable cost of transmission—the latter being a few cents at most and in some cases as low as a fraction of a cent—spot price arbitrage will motivate gas transactions between those nodes until the price differential and usage charge are equalized or until the transmission capacity constraint binds. This mechanism allowed gas prices to converge across the network to an extent that had not previously been possible. As Tussing and Tippee (1995, p. 229) explain, "Under SFV, a customer's actual usage is reflected in its bill only to the extent of those pipeline costs that vary directly with throughput—principally compressor fuel in most instances." SFV pricing "remove[d] transport costs as the principal influence on geographic gas-price differentials and cause[d] market prices in… North America to converge and thereafter move… as an articulated whole."

Despite this, the U.S. natural gas market may still fall short of perfect integration. Several studies have found limitations in the ability of spot price arbitrage to integrate prices fully at the national level, due to regional bottlenecks in pipeline transmission capacity (MacAvoy et al 2007; Marmer et al 2007; Brown and Yücel 2008; Avalos et al 2016).[18] These price analyses suggest the U.S. gas pipeline network is largely concentrated around the three major regional markets of the Northeast, Midwest, and California.

Improved integration of natural gas spot prices – although arguably the most salient effect – was certainly not the only effect Order 636 had on the U.S. gas market. Pipeline operators' behavior naturally changed. The new industry structure heightened competition among interstate pipelines, forcing them to improve productive efficiency in order to remain competitive (Chermak 1998; Granderson 2000). Order 636 also induced changes in pipelines' operational and financial behavior. Pipeline firms became more homogeneous financially through a general reduction in expense preference behavior, but more heterogeneous operationally (Finnoff et al. 2004). The U.S. market became less 'balkanized'—in other words, the pipeline network operated more as an integrated whole, rather than as a disjointed network of geographically isolated supply-demand channels. Corporate ownership structures evolved as well; corporations heavily involved in

[18] Vickrey (1969) defines a bottleneck as "a situation in which a network segment has a fixed capacity substantially smaller relative to flow demand than that of preceding and succeeding segments." Bottlenecks can undermine efficiency in other ways. For one, mandatory unbundling of sales and transportation in the presence of bottlenecks may eliminate efficiencies of coordination. Network externalities arising from transmission bottlenecks – especially from the extraction of congestion rents – can be internalized through bundling. Thus, organizational efficiencies are likely gained through vertical integration (Lyon and Hackett 1993; Lyon 2000).

electric power generation made extensive acquisitions in the gas pipeline industry following Order 636, whereas corporations engaged in natural gas exploration and development made some of the largest divestitures of pipeline assets (Johnson et al 1999).

Given the envelopment of storage into FERC's revised definition of transportation, it was no surprise that storage operations also changed after Order 636. Interstate pipelines would be allowed to retain only enough storage capacity to operate their transmission systems smoothly and to provide no-notice services. Any remaining storage capacity would be subject to Order 636's open access rules. The responsibility of ensuring reliability of supply shifted primarily to end users. As a result, the importance of storage – both upstream and downstream – increased immensely under the new order, as it provided shippers the flexibility to react quickly to unforeseen supply and demand shocks (True 1994). This increased demand for a variety of storage services led to a burst of investment in salt cavern storage, due to its unmatched injection and withdrawal capabilities (Barron 1994). Other benefits were soon to follow. Just as a more efficient transmission system helped integrate spot prices across geographic locations, improved storage would help integrate spot prices across time; seasonal price differentials in an efficient gas market equal storage costs plus the prevailing market interest rate (Yoon 1995). MacAvoy et al (2007) provide empirical evidence that price differentials between winter and summer spot markets in consuming states did, in fact, decline following Order 636, indicating that storage costs generally decreased.

Finally, many researchers have explored the impacts of restructuring on residential consumers, LDCs, and other large industrial users. Early empirical evidence showed that prices charged to residential consumers rose slightly in response to Order 636 and its precursors, whereas industrial users enjoyed lower prices (Hollas 1994; 1999). A later study by Arano and Blair (2008) found significant increases in economic efficiency in the industrial sector. Increased competition along the gas supply chain also led to improved technical efficiency among LDCs (Hollas et al 2002). LDCs would now be forced to compete for supplies, transportation, and storage, leading to wholesale changes in overall operations management (Vineyard et al 1997).

3.3. Gas Pipeline Tariffs: Current Design and Structure

As mentioned earlier, Order 636 established a standardized SFV procedure for calculating interstate gas pipeline tariffs. This structure has remained solidly in place ever since. In this section we provide an overview the main features of FERC's SFV tariff design, using as our guide FERC's official tariff calculation manual (FERC 1999).[19]

To summarize, firm customers, who enjoy the security of guaranteed service up to their maximum contracted capacity entitlement, pay a uniform two-part tariff.[20] The first part is the fixed *reservation* charge per unit of firm capacity, typically listed as a monthly rate. The second part is the volumetric *usage* charge per unit of gas shipped (also commonly referred to as the *commodity* charge). Interruptible transmission (IT), as the name implies, may be interrupted at any time by a firm claim to capacity. IT customers, therefore, do not pay a capacity reservation charge *per se*. However, IT rates equal the sum of the usage rate and the daily firm reservation rate. The rates themselves are determined primarily by calculating a pipeline's *cost-of-service* (or 'revenue requirement'), which includes a specified rate of return on capital investment. Costs are then allocated among the pipeline's various classes of customers, such that each customer class is

[19] The 1999 FERC *Cost-of-Service Rates Manual* remains the industry standard used by all interstate pipelines to calculate the applicable tariffs for all classes of service. Full text of the manual is available at the following link: https://www.ferc.gov/industries/gas/gen-info/cost-of-service-manual.doc

[20] A great body of economic literature has explored the two-part tariff in considerable detail. While a full review is not warranted here, the interested reader may refer to, *e.g.*, Coase (1946), Oi (1971), Feldstein (1972), Ng and Weisser (1974), Schmalensee (1981), and Vogelsang (1989, 2001), among others.

designated to a specific portion of the total revenue requirement. Using this cost-sharing mechanism, unit rates are set for each class of service (McGrew 2009, pp.97-99).

FERC (1999) outlines five steps for calculating reasonable tariff rates for a gas pipeline based on cost-of-service, summarized in Table 1. These steps are as follows: (1) Computing the cost-of-service. (2) Computing a 'functionalized' cost-of-service. (3) Cost classification. (4) Cost allocation. (5) Rate design. We now discuss each of these steps in greater detail.

[TABLE 1]

Step 1: Computing the Cost-of-Service. FERC defines a pipeline's cost-of-service as "the amount of revenue a regulated gas pipeline must collect from rates charged to consumers to recover the cost of doing business." The basic cost-of-service formula is given by the following accounting identity:

$$\textit{Total Cost-of-Service} = \textit{Return} + \textit{Operation \& Maintenance Expenses}$$
$$+ \textit{Administrative \& General Expenses} + \textit{Depreciation Expense}$$
$$+ \textit{Non-income Taxes} + \textit{Income Taxes} - \textit{Revenue Credits}.$$

For the sake of brevity, we refer the interested reader to FERC's *Cost-of-Service Manual* for further details on how it defines of each of these components, with the exception of the first component, *Return*.

The *Return* allowance is found by multiplying the *Rate Base* by the *Overall Rate of Return*:

$$\textit{Return} = \textit{Rate Base} \times \textit{Overall Rate of Return}.$$

The *Rate Base* represents the pipeline firm's total capital investment, and is computed as

$$\textit{Rate Base} = \textit{Net Plant} - \textit{Accumulated Deferred Income Taxes} + \textit{Working Capital}$$

where

$$\textit{Net Plant} = \textit{Gross Plant} - \textit{Accumulated Depreciation}.$$

Gross Plant is defined as the original cost of the pipeline and other facilities, which includes the cost of land and land rights, rights of way, surveying costs, and construction costs.[21]

FERC calculates a pipeline's *Overall Rate of Return* as a weighted average of the cost of capital (WACC) based on three components: the pipeline's debt-equity capitalization ratio, the pipeline's cost of debt, and the allowed rate of return on equity. Denoting the *Overall Rate of Return* as r, we have $r = r_D\rho + r_E(1-\rho)$, where r_D is the cost of debt, r_E is the allowed return on equity, and ρ is the fraction of gross plant that is debt financed (which is directly related to the pipeline's debt-equity capitalization ratio).[22] As explained in the *Cost-of-Service Rates Manual* (FERC 1999, pp. 16-17), the pipeline's cost of debt refers to "the weighted average of all the debt issued and the cost at which the debt was issued." The allowed return on equity is the source of the pipeline's realized profit, and "is derived from a range of equity returns developed using a Discounted Cash Flow (DCF) analysis[23] of a proxy group of publicly held natural gas companies." The industry average *Overall Rate of Return* is roughly 12 percent (von Hirschhausen 2008).

Step 2: Computing a Functionalized Cost-of-Service. FERC describes the process of cost functionalization as follows (FERC 1999, pp. 23-24):

> *"Prior to Order No. 636, a pipeline's costs were traditionally functionalized into three broad categories;* Production, Storage, *and* Transmission, *which recognized the functions of the facilities owned by the pipeline. The* Production

[21] Construction costs typically include materials, labor, pipe coating, communications equipment, overheads, legal fees, and an *allowance for funds used during construction* (AFUDC). AFUDC encompasses financing costs on borrowed funds and equity return on the pipeline firm's own funds used during the construction period. Oliver (2015) has shown that pipeline capital costs display significant economies of scale and scope, as a pipeline's capacity or length can be increased for a less than proportional increase in total project cost.
[22] To illustrate, if the pipeline's capitalization ratio is 75% debt to 25% equity, the cost of debt is 10%, and the allowed ROR on equity 14%, then the overall ROR is $(0.75 \times 0.1) + (0.25 \times 0.14) = 0.11$, or 11%.
[23] FERC uses a two-stage DCF methodology, which "projects different rates of growth in projected dividend cash flows for each of the two stages, one stage reflecting short term growth estimates and the other long term growth estimates." For more details, see FERC's *Cost-of-Service Rates Manual* (p. 17).

> *function included the costs associated with a pipeline's own production as well as purchased gas costs and gathering costs. Today, as a result of Order No. 636, pipelines no longer act as gas merchants. This function has primarily been taken over by the pipeline's affiliated marketer. Additionally, many pipelines have sold or assigned their gathering facilities to non-jurisdictional entities. Thus, today a pipeline primarily has two functions,* Storage *and* Transmission.
>
> "*A functionalized cost-of-service is computed by directly assigning or allocating operation and maintenance expenses and other costs incurred by the company to the various functions, e.g.* Storage *function and/or* Transmission *function, of the particular pipeline company*."

Step 3: Cost Classification. This step begins by first classifying the functionalized costs that comprise the total cost-of-service for each function as either *fixed* or *variable*. FERC defines fixed costs as those that "remain constant regardless of the volume of throughput and are predominantly associated with capital investment in the pipeline system," and include such costs as maintenance, administrative expenses, and labor.[24] Variable costs, naturally, are those that vary with throughput, which consist mainly of the cost of compressor fuel, but also include certain non-labor operating expenses.

Fixed and variable costs are then classified as accruing to the *reservation* component of the two-part tariff or to the *usage* component. As noted already, the SFV method strictly requires all fixed costs to be classified under the *reservation* component and all variable costs to be classified under the *usage* component.

Step 4: Cost Allocation. Once costs have been functionalized and classified, they are allocated across geographical zones (for larger pipeline systems), and across 'jurisdictional' services (*e.g.*,

[24] That labor is classified as a fixed cost runs counter to most introductory economic teachings, but is logical for the operation of gas pipelines because the amount of labor employed is entirely independent of the level of output (referred to as 'throughput' in pipeline parlance).

firm and IT services). Cost allocation between jurisdictional services is based on *load factor*. The load factor for firm transportation service is the ratio of average daily use to contractual firm capacity entitlement. In other words, a firm transportation load factor of 90% means that on average, 90% of total firm capacity is utilized for shipping each day. Cost allocation to IT service is derived from a 100 percent firm transportation load factor. If a pipeline system is large enough to be divided into geographic zones, costs are allocated across zones based on dekatherm-miles.[25]

Step 5: Rate Design. The final step in FERC's rate-making protocol is to translate the costs allocated across jurisdictional services (and zones, when applicable) into unit rates.

Firm transportation rates are designed as a two-part tariff, consisting of a *reservation* charge and a *usage* charge. The reservation charge is a fixed charge per unit of contracted firm capacity, and is paid monthly in order to guarantee service up to the daily firm capacity entitlement. A firm customer must pay the reservation charge each month, even if it does not ship any gas at all. To compute the monthly reservation charge, first the annual sum of all fixed costs classified in Step 3 to the reservation component is divided by total annual firm capacity entitlements. This value is then divided by 12 to arrive at the monthly rate. In nearly all cases, 100 percent of a pipeline's capacity will be accounted for via firm contracts, which guarantees full recovery of all of fixed costs. To compute the firm usage rate, the sum of all projected annual variable costs classified in Step 3 to the usage component is divided by total projected firm and IT shipment volumes. A firm customer incurs the usage charge per unit of gas actually shipped.

[25] In transportation problems, output is often measured in unit-miles (or unit-kilometers)—that is, the shipment of one unit of the commodity one mile (km). An issue arises, however, because pipeline capacity is commonly measured volumetrically in terms of 1,000's of cubic feet (Mcf) per day, whereas natural gas prices are based on heat content. The heat content of gas is measured in British thermal units (Btu), where one dekatherm (Dth) is equivalent to one million Btu (MMBtu). The conversion factor for Mcf to Dth is 1.035—thus, 1 Mcf = 1.035 Dth.

IT rates are computed as a derivative of firm reservation and usage charges. That is to say, a pipeline's IT rate is precisely equal to the sum of its usage charge and its *daily* firm reservation charge, where the daily firm reservation charge is simply the monthly rate divided by 30.4 (the average number of days in a month). This design for IT rates is therefore equivalent to an imputed 100% firm capacity load factor, and ensures a level of fixed cost recovery that is proportional to the level of IT service provided.[26]

3.4. The Primary and Secondary Markets

FERC Order No. 636, by instituting a firm capacity release market, effectively organized the U.S. market for natural gas transmission into two distinct tiers, which we refer to as the 'primary' and 'secondary' markets. Figure 3 presents a schematic representation of the two-tiered market and its key characteristics. In practical terms, the primary market can be thought of as a market for firm transmission capacity, whereas the secondary market is effectively a market for gas transmission services.

[FIGURE 3]

In the primary market, entities wishing to have *guaranteed* access to transmission capacity – *e.g.*, local distribution companies (LDCs), gas traders,[27] or industrial users – purchase firm capacity contracts from pipelines. Order 636 requires open access in the primary market. In most cases, all primary market contracts for firm capacity are established prior to a pipeline's construction; thus in one sense firm customers can be viewed as investors in the infrastructure

[26] In fact, as Tussing and Tippee (1995, p. 207) point out, this design for IT rates allows pipelines to recover a portion of fixed costs twice, since the fixed costs of all capacity used for IT service will already have been recovered via the firm reservation charge.
[27] Secomandi and Wang (2012) provide a general overview of the standard operational activities of natural gas traders (referred to as 'merchants' in that paper).

asset. Moreover, before a new pipeline can be constructed, FERC requires the pipeline firm to demonstrate in its application that long-term (10 years or longer) firm capacity contracts are in place as evidence of market necessity and to underwrite the financing of the project (INGAA 2009; Black and Veatch LLC 2012).[28] As we have just discussed, FERC's regulation of the two-part tariff paid by firm customers is based on a reasonable rate of return on the pipeline's cost-of-service. Order 636 expressly considers interstate pipelines to be local monopolies.

After the pipeline has begun operation, an unregulated secondary market gives owners of firm contracts the opportunity to recover their capacity's instantaneous market value at any point in time. Shippers may, as a substitute for securing transmission via the secondary market, choose to purchase IT service directly from the pipeline. But IT service is, by definition, less reliable and is therefore often utilized only as a last resort. Shippers without firm capacity entitlements of their own typically prefer to utilize firm capacity released by others, as it confers the firm guarantee of service. LDCs and other regulated entities are required to release any unused capacity via FERC's formal capacity release system. Gas traders, by contrast, are unregulated and, therefore being more nimble than regulated utilities, have established themselves as influential players in the secondary market (Oliver et al 2014).

Gas traders with firm capacity entitlements act as a loose oligopoly over a given route, exercising localized market power in the secondary market. Once capacity is fully reserved via the primary market, the pipeline's limited capacity creates a natural barrier to entry, which generates rent extraction opportunities for firm capacity subscribers operating in the secondary market.

[28] Before contracts on any proposed new construction or expansion of capacity are allowed, FERC requires a pipeline to conduct two "open seasons." The first, known as a "turn-back open season," gives existing firm customers an opportunity to permanently relinquish their capacity, the firm rights to which are then transferred to new customers. Second, the pipeline must conduct an open season on its electronic bulletin board for any existing unsubscribed capacity and/or capacity under expiring contracts with no right of first refusal (Jost and Benson 2016).

Traders have the flexibility to engage in two types of transactions. For one, they can utilize capacity to conduct gas transactions in which the market value of transportation—including any congestion rent—is reflected in the commodity price spread between the geographical sales and receipt points (DeVany and Walls 1995). Alternatively, unused firm capacity may be released to other shippers at the secondary market rate, in which case the payment received from shippers for the utilization of that capacity is effectively a charge for transportation.[29]

Prior to Order 636, Alger and Toman (1990) presented experimental evidence that a market-based approach for such secondary market transactions could "outperform traditional rate-setting regulation" used in interstate pipeline transmission, with the caveat that short-term transportation charges could greatly exceed the regulated primary market rates during peak demand periods. Intuitively, shippers operating in the secondary market bid up these charges as unused transmission capacity becomes scarce. Because the primary market two-part tariff is regulated, this presents the opportunity for firm contract holders to extract congestion rents whenever the transportation charge exceeds the primary market two-part tariff. Oliver et al (2014) find empirical evidence for such an effect by examining spot price differentials between two major trading hubs connected by a pipeline route with a known bottleneck point. As pipeline congestion at the bottleneck increases, the scarcity value of transmission capacity rises, driving a wedge between spot prices, effectively inhibiting price integration. However, the opposite also applies; when transmission capacity available in the secondary market is plentiful, the transportation charge may fall short of the primary market two-part tariff, introducing the risk that the cost of the firm capacity contract is not fully recovered.

[29] Gabriel et al (2005) develop a large-scale simulation model of the U.S. natural gas market, demonstrating that rent extraction by third-party marketers can impede competition. By contrast, Doane et al (2008) suggest the secondary market may be more competitive than traditional market power statistics (*e.g.*, the Herfindal-Hirschman Index) indicate, because such measures do not account for IT service as a substitute for secondary market transportation.

Capacity release is crucial for maintaining an economically and operationally efficient gas transmission market. FERC's development of this secondary market, however, was not without difficulty. At first, Order 636 mandated that the regulated primary market rate apply to released capacity as well. But this restriction dampened firm subscribers' incentive to release unused capacity during peak periods, causing considerable concern about the resulting market efficiency implications of the rule. In February of 2000 FERC issued Order No. 637 to allow a two-year moratorium on price controls on short-term capacity releases of one year or less in duration (FERC 2000).[30] As FERC explained in Order 637, "Removal of the rate cap [on short-term capacity releases] will expand shippers' options, create a more efficient marketplace, increase market transparency, and better protect captive customers, without changing the current regulatory environment." The two-year period, FERC asserted, would be long enough to collect sufficient information on the results of the regulatory change, so as to fully assess whether such a change should be made permanent (and extended to include longer-term capacity releases).

Even before FERC's attempt at improving capacity release markets in Order 637, gas marketers had already turned to a more sophisticated method to evade FERC's control over capacity release rates. In privately negotiated "buy-sell" transactions, gas traders with firm capacity can operate as merchants, buying upstream supply from producers with intent to resell to buyers downstream.[31] In recent years, FERC has explicitly prohibited certain types of buy-sell transactions. For instance, a firm customer may not buy from a supplier with intent to resell to a *pre-specified* upstream buyer, as this is considered a violation of open access policy. FERC's 'shipper-must-have-title' rule now requires a shipper to own any gas transported on the pipeline (FERC 2012). Firm capacity holders seeking to exploit a constraint by making buy-sell

[30] Additionally, Order 637 allowed pipelines to file for differentiated peak and off-peak rate structures.
[31] See Tussing and Tippee (1995, p. 231) for further discussion.

transactions must buy the gas commodity from suppliers, ship, and then resell to *any* willing buyer at the upstream market price. Otherwise, capacity must be released directly to shippers at the secondary market rate.

In 2008 FERC approved Order No. 712, explicitly relaxing all restrictions on pricing in the formal capacity release market (FERC 2008; INGAA 2009; McGrew 2009, p. 123). The result has been a secondary market that effectively operates as a competitive spot market for transmission capacity.[32] All formal capacity release transactions are reported via pipelines' *Informational Postings* websites, providing secondary market participants timely information on capacity availability and market rates. Makholm (2015) describes this newly emerged capacity spot market as "Coasian" in the sense that all conditions for the Coase Theorem (Coase 1960) to hold are met (or are nearly met). That is, given well-defined property rights, zero transactions costs, perfect competition, complete information, and no other impediments to bargaining or resource allocation, resources will be allocated efficiently – including compensation for any and all externalities – regardless of ownership.

3.5. Other Important Regulations

We close this section with a short discussion of two other aspects of current pipeline regulation: (i) the *Application for Certificate of Public Convenience and Necessi*ty required to construct a new pipeline facility, and (ii) some key operational rules and regulations administered by agencies other than FERC.

[32] Secomandi (2010) examines a 'spread option' pricing approach to determining the appropriate trading value of pipeline transmission capacity. In equilibrium this value is equivalent both to the 'congestion' value (and opportunity cost) to pipelines of binding capacity constraints to the 'substitution' value and to producers and LDCs of being able to sell/procure supplies in remote markets.

Pursuant to the Natural Gas Act (NGA) and other federal regulations, before an interstate pipeline firm can begin construction of new facilities, it must file multifarious documents, most of which are publicly available, specifying a wide array of information regarding the proposed project. Figure 4 presents a general schematic flow for the development of a new (or expansion of an existing) pipeline.[33]

[FIGURE 4]

Once open season has been conducted and all proposed facilities have been designed, the initial (and arguably most important) document to be filed is the *Application for Certificate of Public Convenience and Necessity* (henceforth 'application', for brevity). In a typical application, the pipeline operator provides, *inter alia*, a background for and general description of the proposed project, a specific description of all proposed pipeline, compression, and other facilities to be constructed, evidence of market support, calculations of estimated cost-of-service and tariffs, as well as extensive environmental considerations. Each application contains a standard collection of 'exhibits,' in which the applicant submits such things as state authorizations, a list of company officials, a map of the proposed facilities, *etc*. Arguably, two of the most crucial are Exhibits G and K. Exhibit G contains the key engineering specifications of the project. A pipeline operator can submit Exhibit G separately and request that it be filed as 'Critical Energy Infrastructure Information' (CEII). The CEII classification restricts public access. Exhibit K is a detailed tabulation of estimated project costs. Within six months of project completion, the firm must also file a *Statement of Actual Costs*.[34] The *Statement of Actual Costs*, in addition to providing a detailed tabulation of actual project costs, provides side-by-side comparison to the Exhibit K estimates, and

[33] Source: EIA. https://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/develop.html

[34] Also referred to as a *Final Cost Comparison*, *Six-month Cost Report*, and a variety of other titles, depending on the operator.

provides explanations for any exceptionally large deviations between actual and estimated project costs.

FERC is not the only federal agency with regulatory jurisdiction over interstate natural gas pipelines, nor are the legislative and regulatory actions discussed so far the only laws and regulations affecting interstate pipelines (INGAA 2009, pp. 55-62). In particular, most aspects of federal oversight pertaining to pipeline operations, safety, and monitoring fall under the purview of the U.S. Department of Transportation (DOT). The Pipeline Safety Improvement Act of 2002 introduced important new requirements designed to promote pipeline safety and integrity. An interstate pipeline operator is required to prepare and implement an *Integrity Management Program* (IMP) to identify and analyze potential safety risks. IMPs are submitted to the Pipeline and Hazardous Materials Safety Administration of the DOT. Densely populated urban and suburban areas, in particular—referred to as 'High Consequence Areas'—require additional operating precautions. For example, regardless of a pipeline's wall thickness, the DOT sets a pipeline's *maximum allowable operating pressure* considerably lower in such areas. In addition to high safety standards imposed by the DOT, pipelines are subject to the jurisdiction of the U.S. Environmental Protection Agency (EPA) and other federal agencies under a number of environmental laws, including those pursuant to the National Environmental Policy Act of 1969, the Federal Water Pollution Control Act (also known as the 'Clean Water Act'), the Coastal Zone Management Act, the Endangered Species Act, and the Clean Air Act. The National Historic Preservation Act requires pipelines to consider potential impacts on any federally recognized historic sites or properties. Table 2 summarizes these laws, the relevant administering agencies, and how they affect interstate pipelines.

[TABLE 2]

Finally, in certain activities or circumstances pipelines may also rely on a number of other federal and state agencies, including the Occupational Safety and Health Administration, National Transportation Safety Board, Federal Highway Administration, the U.S. Coast Guard, the Federal Emergency Management Agency, state public utility commissions, or state and local fire departments (Folga 2007, pp. 14-16).

4. Possibilities for the Future of Gas Pipeline Regulation

What does the future hold for interstate gas pipeline regulation in the United States? In answering this question, our intent is not to speculate about specific rulings that FERC (or other agencies like the U.S. DOT) may be considering. Indeed, for the foreseeable future the regulatory machinery implemented by FERC Order No. 636 seems solidly in place. As with the relatively sparse – and relatively minor – adjustments FERC has made since Order 636, any future changes in federal regulation are likely to be incremental. If the twenty-five years hence have taught us anything, it is that the modern U.S. natural gas market is, for the most part, now operating efficiently and robustly under the deregulated system. FERC's restructuring effort was a resounding success, and we have no reason to expect any wholesale changes in the future.

With this in mind, we have reserved this section to speak more broadly about the likely direction of changes in pipeline tariff regulation. Despite the deregulatory push ushered in by Order 636, FERC maintains control – as we have already discussed – over the primary market two-part tariffs (and IT rates) charged by pipelines to firm customers, reflecting the Commission's continued assessment that most interstate pipelines enjoy a significant degree of local market power. These price controls are intended to rein in that market power by constraining a pipeline's profits. The mechanism is simply to set tariffs based on a pipeline's cost-of-service, which includes an allowance for a 'reasonable' rate-of-return on capital investment. This should come as a surprise to few; throughout most of the 20th Century, rate-of-return (henceforth ROR, for brevity) was the dominant paradigm in utilities regulation. But a growing body of economic literature now praises the benefits of transitioning away from ROR in infrastructure-intensive industries, in favor of more flexible ‘incentive-based’ regulatory models. In this light, we now discuss the likelihood and implications of a move toward incentive-based regulation in the U.S. gas pipeline industry.

4.1. The Changing Winds of Infrastructure Regulation

In 1962, economists Harvey Averch and Leland Johnson published one of the most influential papers of the 20th Century in regulatory economics. In it, they demonstrated that an ROR-regulated firm will (1) operate inefficiently by choosing a capital-labor mix that is not cost-minimizing, and (2) employ more capital than it would if unregulated because its cost of capital is effectively lower than the market cost (Averch and Johnson 1962). These results have come to be known among economists as the ‘A-J effect.’ In its wake a bewildering number of studies have explored extensions and provided empirical tests.[35] Ever since, it seems, regulatory economists have searched for viable alternatives to ROR for infrastructure-intensive natural monopolies; ROR is increasingly viewed as an inefficient and antiquated model.

Incentive-based models – so called because they are designed to increase firms’ incentives for cost reduction – seem most likely to supplant ROR as the dominant regulatory paradigm. Guthrie (2006) provides an excellent review of the mounting evidence in favor of incentive-based regulation over ROR. The key difference between the two is that incentive-based regulation decouples a firm’s pricing constraints from the measurement of its actual incurred costs, allowing substantially more flexibility in price setting. By contrast, Guthrie notes, ROR “allows the regulated firm the least flexibility in setting its prices.” Over the past several decades regulators in infrastructure industries characterized by rapid growth and technological progress have moved

[35] A full review is not warranted here. The interested reader may refer to, e.g., Klevorick (1966, 1971); Baumol and Klevorick (1970); Perrakis (1974); Spann (1974); Boyes (1976); Callen et al 1976; Das (1980); Sherman and Visscher (1982); Pescatrice and Trapani (1980).

toward eliminating barriers to entry in favor of greater competition. Competition is best served when firms minimize costs.

It seems reasonable, then, to ask why FERC maintains price controls based on ROR regulation for interstate pipelines, particularly when the restructuring effort of the 1990s was implemented expressly to increase competition in the U.S. natural gas market. Perhaps the cost of overcoming institutional inertia presents too formidable a barrier to change. This seems unlikely; FERC has already proven its willingness to engage in large-scale upheaval of the existing regulatory apparatus in its quest for improved efficiency. Perhaps it is because, as von Hirschhausen (2008) explains, "no over-arching consensus has been reached" regarding the effect of ROR regulation on infrastructure investment, and "case-specific assessments are still needed to derive concrete, applicable policy conclusions."

In the telecommunications and electricity generation industries, however, regulators in both the U.S. and Europe have already retired ROR in favor of incentive-based regulatory models. The move has been viewed as largely beneficial. Sappington and Weisman (2010) broadly review various benefits of a quarter-century of experience with incentive-based regulation in telecommunications, which include modernized infrastructure, lower prices, and increased productivity. After U.S. electricity markets were deregulated in the 1990s, nuclear power generators made the move toward earning returns based on market competition and away from the ROR model, spurring improved cost efficiency (Davis and Wolfram 2012) and safety performance (Hausman 2014). Another study found that European energy utilities subject to incentive-based regulation invested in new capital at a higher rate than those subject to ROR (Cambini and Rondi 2010). Such experiences in these infrastructure-intensive industries point to the benefits that may accrue in the natural gas transmission industry should FERC ever implement incentive-based regulation for intestate pipelines.

4.2. Rate-of-Return Regulation and Pipeline Investment

Providing further support for the argument against ROR for gas pipelines, some economists have asserted that under ROR the incentives for a pipeline to invest in greater transmission capacity are weakened, potentially resulting in market distortions related to congestion (Marmer *et al*. 2007; Brown and Yücel 2008). Such distortions occur in the form of wealth transfers from the pipeline to the owners of firm capacity contracts, which arise when constrained transport capacity enables a pipeline's firm customers to extract scarcity rents by shipping gas at transmission rates in excess of regulated two-part tariffs—a topic we have already discussed at length.

Oliver et al (2014) explain how this diversion of congestion rents from the pipeline to its firm customers might distort the economic signal for the pipeline to expand capacity when and where needed. In the two-tiered market, one could argue that purchasers of firm contracts are the real investors in expanded capacity. Thus, the true impetus to capacity expansion emerges in the congestion rents available to firm capacity subscribers operating in the secondary market, rather than to the pipeline firm itself, which operates only in the primary market. With no constraints on secondary market rate setting, firm customers can act as a loose oligopoly of sorts, in which high demand for transmission services would normally deliver the appropriate expansion incentives. A distortion arises when firm customers are unable to respond to increased rents by bidding up the two-part tariff paid to the pipeline, precisely because both parts are strictly controlled via FERC's rate-setting methodology. This misalignment of incentives inhibits the pipeline operator's response to increased transmission demand, and may ultimately lead to an inefficiently low level of capacity investment over time.

In other words, ROR regulation in the primary market in tandem with an unregulated secondary market effectively transfers market power (and the expansion decision) from the pipeline to its firm customers. Despite the prevention of monopoly (or oligopoly) pricing by the pipeline, the unintended effect of regulating primary market tariffs is thus a potential distortion of expansion signals. Any inefficiencies arising from these distorted signals should therefore be viewed as a cost of preventing the exercise of market power by the pipeline using ROR, although it is unclear whether such costs are properly taken into account by FERC in its exercise of regulatory authority in pipeline rate setting. If competition were increased such that pipelines' market power were sufficiently diminished, then the distorted signals and the resulting lack or delay of capacity expansion seem likely to have the more important welfare effect. In such cases a shift toward incentive-based regulation – the critical feature of which is to bolster competition through cost reduction – may prove highly beneficial. Indeed, in the Texas-Oklahoma and Gulf Coast regions of the U.S., where the interstate gas pipeline network is already highly interconnected (see Figure 1), competitive forces may already have begun to obviate the need to combat localized market power such that adherence to ROR regulation may be doing more harm than good. As the Marcellus shale region continues to emerge as the new preeminent supply center, a similar concern may become increasingly relevant in the Northeast as well.

FERC's cost-of-service pricing may inhibit pipeline expansion for a different reason, owing to overall cost diseconomies in pipeline construction. Oliver (2015) analyzes cost, capacity, mileage, and technical data for over 250 recent U.S. pipeline expansion projects. Empirical estimates indicate that although pipeline expansion projects exhibit cost economies at both the capacity margin and the distance (*i.e.*, mileage) margin in isolation, proportional increases in both capacity and mileage may be associated with greater-than-proportional increases in total project costs. Moreover, large-scale, long-distance pipelines requiring commensurate installations of compression horsepower display significant cost diseconomies, because the addition of compressor stations has a disproportionate effect on project costs. As these cost diseconomies are then passed on to firm customers via tariffs based on cost-of-service, FERC's rate-setting mechanism thus generates a disincentive for prospective customers in committing to long-term firm contracts for such high-capacity, long-distance expansion projects.

4.3. Incentive-Based Regulation in Interstate Gas Transmission

What changes might we expect if incentive-based regulation were implemented in the U.S. interstate gas pipeline industry? To get a sense of the possible implications, consider a possible move to *price-cap* regulation (PCAP, hereafter), a well-established class of incentive-based model. PCAP requires only that the price of a *basket* of the (multiproduct) monopoly/oligopoly firm's goods or services not exceed some specified constraint, allowing full pricing flexibility otherwise.[36] For a pipeline or other network operator using a two-part tariff structure for a single customer class, placing a price cap on the *sum* of the access (*i.e.*, reservation) and usage fees (Vogelsang 1990; 2001) implies a trade off between the marginal impacts of reductions in either rate in terms of customer demand for firm transmission capacity. Reallocating revenue streams away from access fees and toward usage fees may have the benefit of increasing demand for firm

[36] Here also, a full review is not feasible. See Brennan (1989), Isaac (1991), Cowan (2002), and Joskow (2008) for general theoretical treatment and discussion of some issues of implementation. Cabral and Riordan (1989) and Clemenz (1991) examine the cost-reduction incentives of price-cap regulation. Braeutigam and Panzar (1993) and Liston (1993) provide direct comparison with ROR regulation. Other key works include: Sappington and Sibley (1992); Armstrong et al. (1995); Cowan (1997); Lehman and Weisman (2000); Vogelsang (1990, 2001); and Dobbs (2004).

capacity, thus leading to greater capacity investment by pipelines. The flexibility of a price cap would allow the pipeline to develop a pricing structure in which firm customers pay more for utilized capacity and less for idle capacity—precisely the opposite of what occurs under ROR, particularly when coupled with FERC's strict adherence to its SFV methodology. Given the considerable uncertainty over demand for transmission services in the secondary market, such a scenario might prove quite attractive to both the pipeline and its firm customers.

FERC appears to acknowledge explicitly in its *Cost-of-Service Rates Manual* (FERC 1999, p. 33) that many pipelines would prefer such pricing flexibility:

> "…*the Commission has been faced with proponents that request a movement away from SFV. These proponents promote a move toward incorporating or shifting more fixed costs to the commodity (usage) component of rates arguing that this is necessary to encourage short-term markets, to market freed-up capacity and to keep costs low.*"

FERC goes on to state, "In select cases… the Commission has already approved deviations from the SFV rate design." To our knowledge, such approved deviations are extremely rare.

Industry-specific research on the practical implications of transitioning the interstate pipeline network from ROR to incentive-based regulation is, unfortunately, still sparse in the economic and policy literature. Oliver (2017) develops a series of stylized constrained optimization models a monopoly pipeline operating under alternative regulatory constraints, computing numerical solutions to compare the price structure and capacity that arise under each regime. Given the selected parameterization, model results indicate that the pipeline's capacity is roughly 50 percent greater under PCAP regulation than under ROR with SFV. Under PCAP, the optimal pricing structure is such that firm customers pay a single tariff per unit shipped that exceeds the pipeline's marginal shipping cost, allowing the pipeline to recover fixed costs via the volumetric usage charge.[37] An external benefit accrues because greater transmission capacity eliminates congestion rents, thereby reducing the spot price differential between the commodity markets connected by the pipeline. Overall economic efficiency is thus improved through an increase in total economic surplus in the spot gas market. These results suggest that implementing PCAP (or other incentive-based) regulation in the interstate natural gas transmission industry may result in substantial welfare gains in U.S. natural gas markets. In particular, if a more flexible tariff structure were to facilitate greater capacity expansion, the reduced commodity price distortions related to congestion and market fragmentation would likely benefit gas consumers and producers alike. As we have explained already, such issues are well known to have undermined complete and efficient market integration in the U.S. natural gas market following deregulation in the 1990's.

Economists, regulators, and other policy analysts must continue to research these issues with the ultimate goal of identifying and quantifying all relevant costs and benefits of potentially implementing incentive-based regulation in interstate gas transmission. Given the successes that other infrastructure-intensive industries have enjoyed since making the switch, it seems plausible that FERC would begin to take notice and start weighing the relevant regulatory options for pipelines as well.

[37] This result is similar to previous theoretical models of pricing for pipeline transmission, which indicate that the socially optimal pipeline tariff is, in fact, a single tariff that covers both the marginal cost of transmission and the value of capacity (Cremer and Laffont 2002; Cremer et al 2003).

5. Conclusion

The U.S. interstate natural gas pipeline network as it exists today is the product not only of decades of market growth and technological innovation, but also of extensive regulatory experimentation at the federal level. A primary goal of this monograph has been to illustrate the myriad ways in which the gas pipeline industry and the domestic commodity market it serves have changed over the past century, and the extent to which these changes have been driven by the evolution of federal regulation. We have reviewed in considerable detail the major events in the history of federal regulation of interstate gas pipelines, and how they laid the groundwork for the robust natural gas market we enjoy today. Indeed, one could reasonably argue that the gas industry has been at the center of some of the most impactful regulatory regime shifts ever undertaken in the United States. More changes may be yet to come, but for now the market is enjoying unprecedented stability and efficiency, thanks in large part to the major market restructuring effort of the 1990's.

Over the next quarter century and beyond, however, as shale gas expands its influence on energy markets both at home and abroad, the central role played by the gas pipeline industry in reaping the full benefit of this resource will become increasingly evident. The Interstate Natural Gas Association of America has estimated that between 45 and 58 billion cubic feet per day of natural gas pipeline capacity additions will be required over the period 2015-2035 to accommodate the expected growth in transportation demand, nearly all of which will be supported by the expansion of shale production (INGAA 2016). If investment in pipelines does not keep pace with the growing market, the likelihood is high that key transportation routes will become bottlenecks, in which case the availability of storage will be a primary determinant of the degree to which the congestion effects interfere with spot price integration (Oliver et al 2014). One change that we have argued may prove beneficial in this regard is a shift away from rate-of-return regulation in setting pipeline tariffs, in favor of more flexible incentive-based models. A primary rationale for such a change relates to infrastructure investment; the economic evidence thus far – while still limited – suggests the potential for a more efficient pace of capacity expansion relative to the growth of transportation demand under incentive-based regulation. It is therefore imperative that the Federal Energy Regulatory Commission and other agencies make informed and timely decisions in regulating this critical industry, in order to avoid any inefficiencies that may arise as a result of imposing outdated regulatory constraints on such a vigorous and dynamic energy market.

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Tables & Figures

Table 1. Summary of FERC's cost-of-service rate setting methodology for gas pipelines.

Step	**Description**
1. Computing the cost-of-service	Compute *rate base*; Allowed ROR is a *weighted average cost of capital*; Compute total cost-of-service as *return* plus operating and other expenses, net of depreciation, where *return* equals allowed ROR times *rate base*
2. Computing the 'functionalized' cost-of-service	Separate cost-of-service computations are required for distinct *Storage* and *Transmission* functions, where applicable.
3. Cost classification	Costs are classified as either *fixed* or *variable*.
4. Cost allocation	Costs are allocated across geographical zones and/or across 'jurisdictional' (firm, IT) services.
5. Rate design	Compute two-part tariff; SFV method requires all fixed costs to be apportioned to the *reservation* charge, all variable costs to the *usage* charge. IT rate is equal to the sum of usage charge and daily reservation charge.

Table 2. Other federal laws affecting natural gas pipelines (INGAA 2009).

Law	Agency	Relevance for Gas Pipelines
National Environmental Policy Act of 1969	EPA	Requires pipeline to prepare an *environmental impact statement* (EIS) for inclusion in application for certificate of public convenience and necessity; EIS provides a detailed description of any environmental impacts of a proposed project and of unavoidable adverse environmental effects.
Federal Water Pollution Control Act (Clean Water Act)	EPA; USACE	Pipeline must acquire permit from USACE for any discharge or disposal of material or effluent into navigable waters; permit application guidelines administered by EPA
Coastal Zone Management Act	NOAA	For pipeline projects that may impact coastal zone of a state (includes Great Lakes), applicant must demonstrate that proposed project complies with state's federally-approved coastal zone management program.
Endangered Species Act	FWS; NMFS	Before pipeline project's application for certificate of public convenience and necessity can be approved, FERC must check with FWS/NMFS to determine whether threatened or endangered species may be affected.
Clean Air Act	EPA	Pipeline may be required to obtain a variety of permits or authorizations related to emissions of hazardous air pollutants; particularly relevant for pipeline construction and for operation of compressor stations.
National Historic Preservation Act	ACHP	Before pipeline project's application for certificate of public convenience and necessity can be approved, FERC must consult state historical preservation office with guidance from ACHP, consider potential impacts on federally recognized historical sites.
Pipeline Safety Improvement Act of 2002	DOT; PHMSA	Pipeline must develop Integrity Management Program (IMP); conduct risk analysis of "high-consequence areas"; submit remediation plan to PHMSA (if necessary).
Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006	DOT; PHMSA	Reinforces Pipeline Safety Improvement Act of 2002; Multiple amendments to IMP requirements & monitoring activities of PHMSA
Abbreviations: EPA – U.S. Environmental Protection Agency; USACE – U.S. Army Corps of Engineers; NOAA – National Oceanic and Atmospheric Administration; FWS – U.S. Fish & Wildlife Service; NMFS – National Marine Fisheries Service; ACHP – Advisory Council on Historic Preservation; DOT – U.S. Dept. of Transportation; PHMSA – Pipeline and Hazardous Materials Safety Administration		

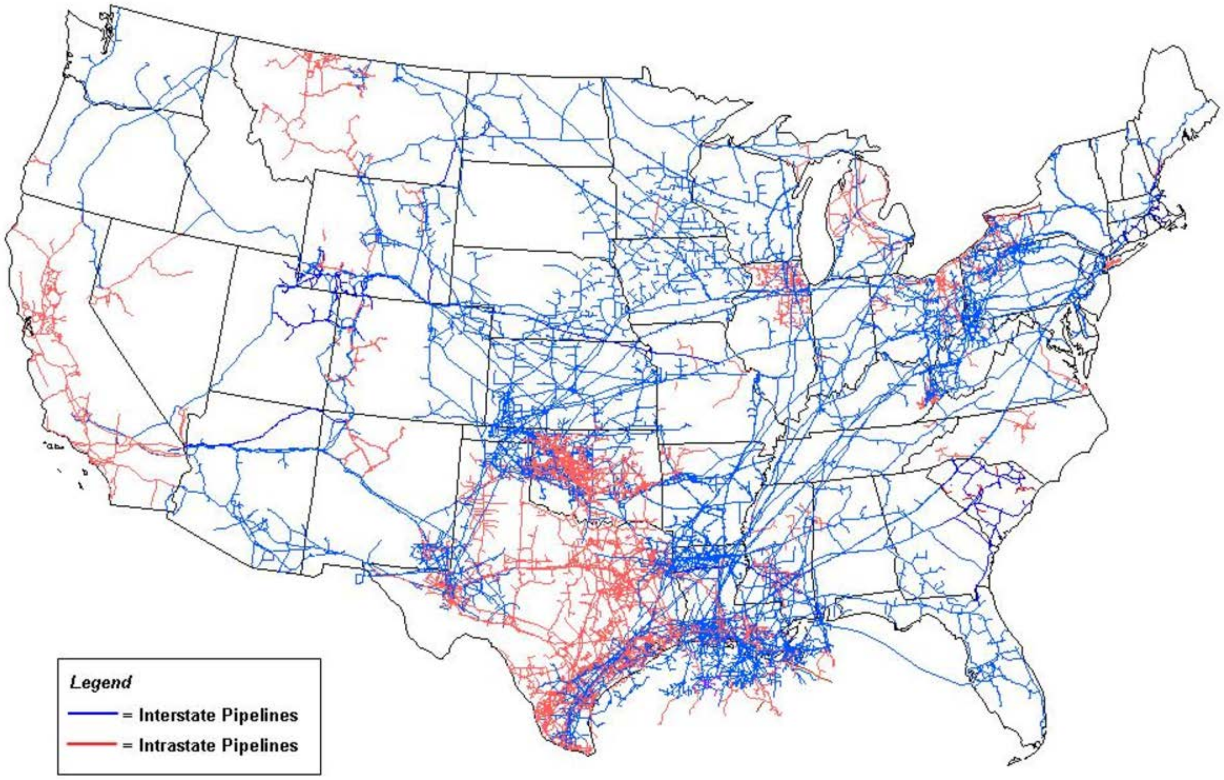

Figure 1. U.S. natural gas pipeline network (Source: EIA).

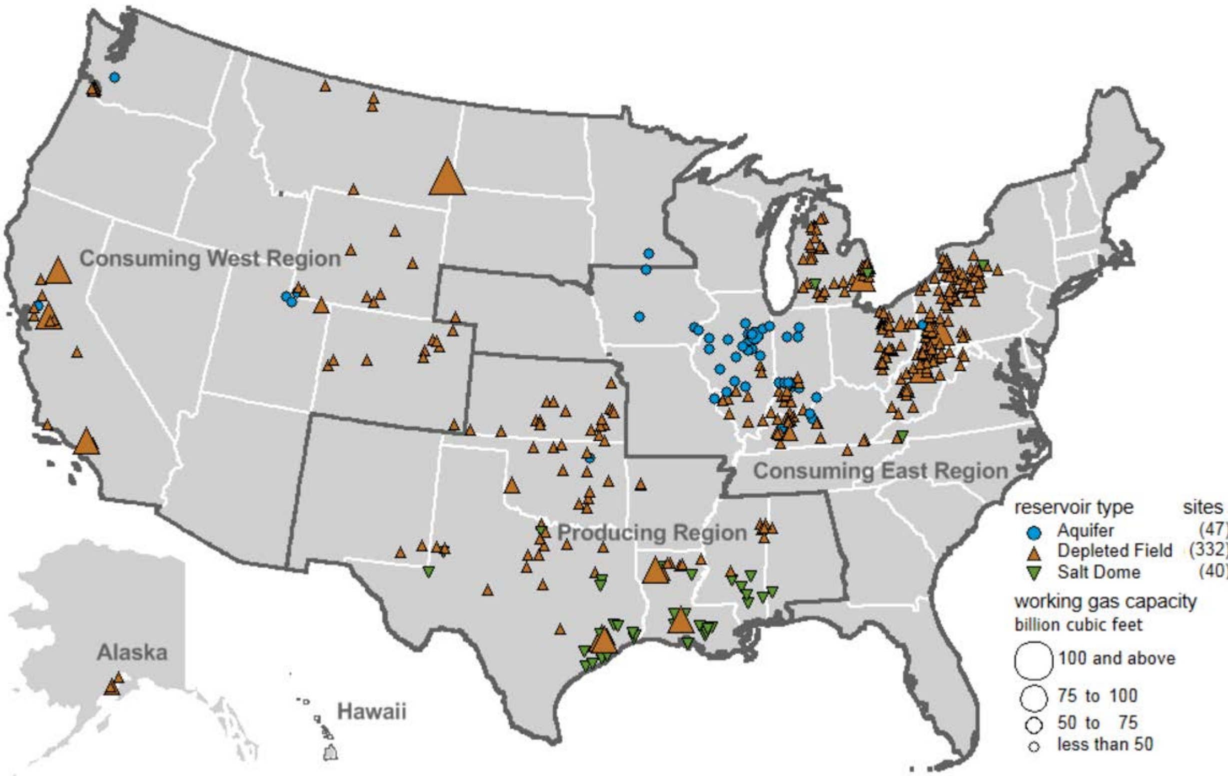

Figure 2. U.S. natural gas storage facilities (Source: EIA).

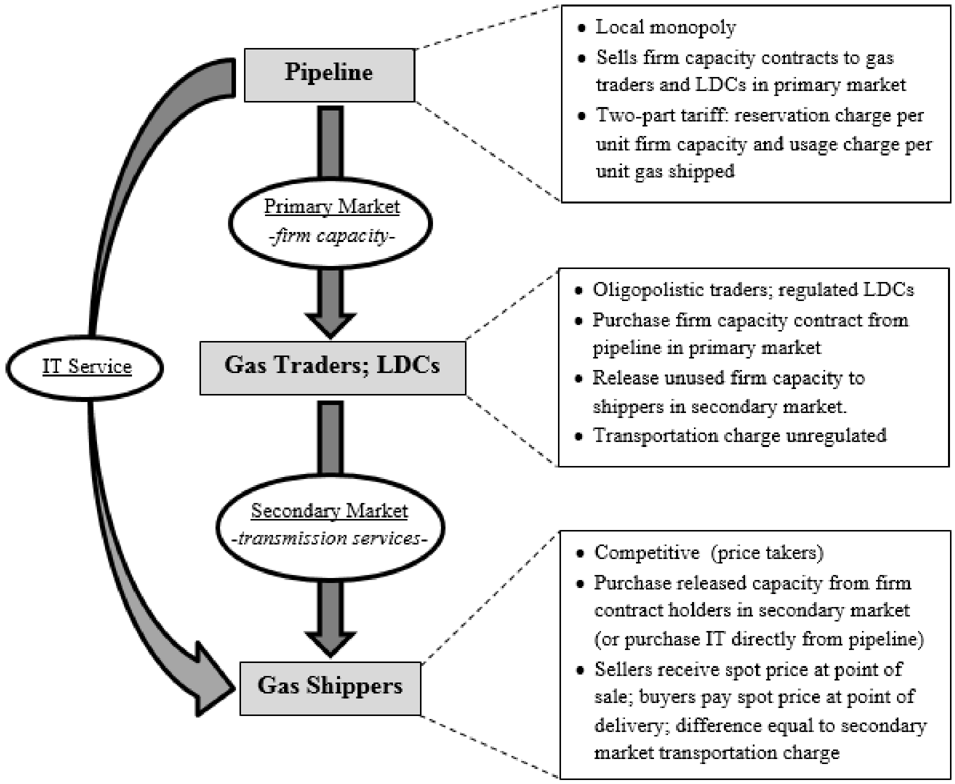

Figure 2. The two-tiered market.

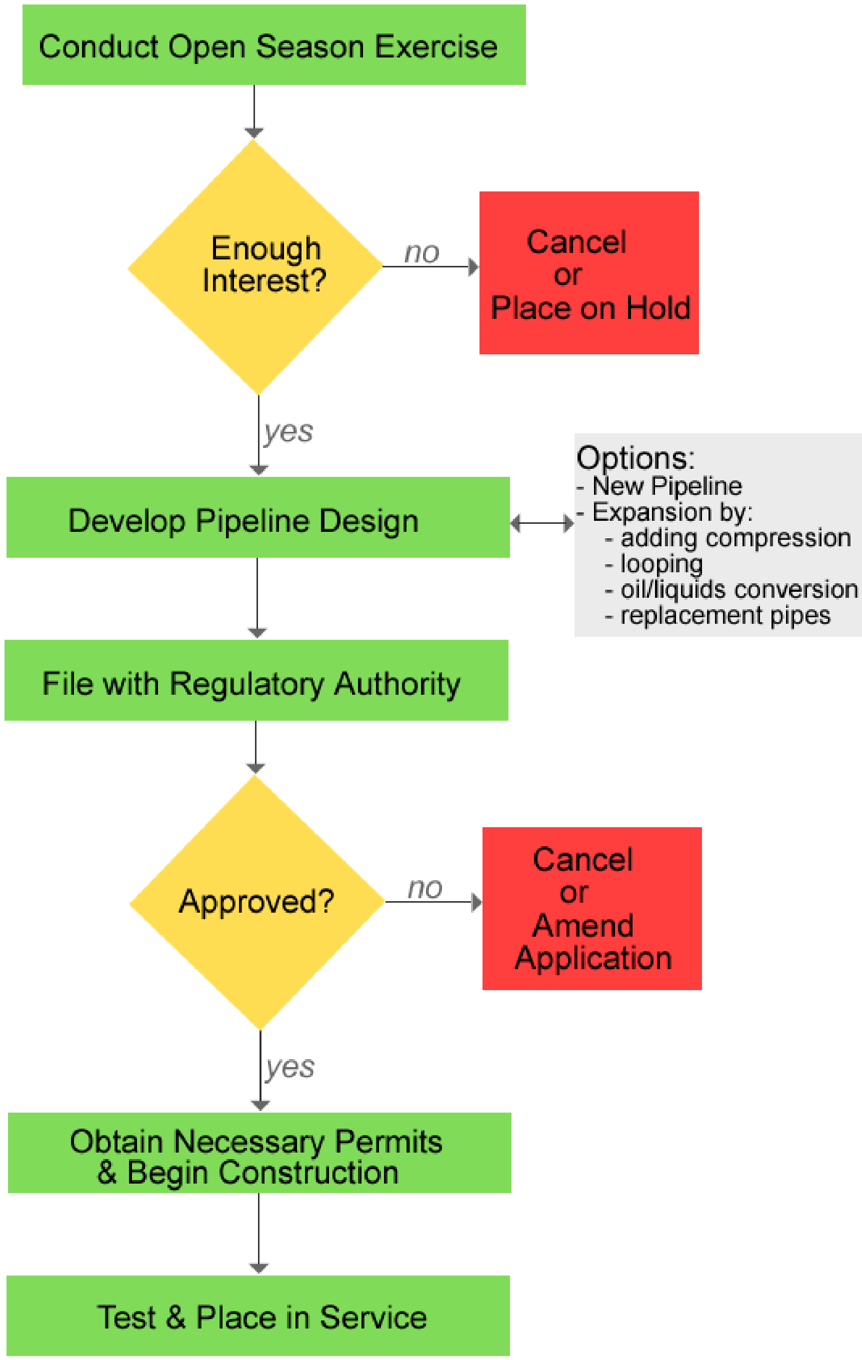

Figure 4. Schematic diagram of pipeline project planning and construction (Source: EIA)