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Pipelines play a critical role in matching the supply and demand of natural gas. The pricing of their capacity is an important problem in practice for pipeline companies and the users of this capacity, which include shippers such as natural gas merchants, producers, and local distribution companies. This paper conducts a normative analysis of how pipeline capacity should be priced by each of these players. Although the trading value of this capacity should be relevant to merchants and its substitution and congestion values to shippers and pipelines, respectively, this analysis shows that all of these are equivalent values. Thus pipeline capacity should be priced at its trading value, a prediction that can be empirically investigated. This paper also conducts an empirical analysis of this prediction based on transacted prices of transport contracts for the capacity of the Tennessee Gas Pipeline, a major interstate pipeline in the United States, and finds support for it. This analysis suggests that the uncertainty in the evolution of natural gas prices is an important driver of operational performance in the pricing of pipeline capacity. The results of this paper have potential relevance for the pricing of the capacity of other commodity conversion assets.

Key words: pricing and revenue management; operations management/finance interface; econometric analysis; petroleum/natural gas industries; real options
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1. Introduction

In the United States, the natural gas industry includes three main activities (Sturm 1997, Kaminski and Prevatt 2004): (1) exploration of gas reserves and production of gas, (2) transport of gas from supply to demand areas and storage of gas from periods of low to high demand, and (3) distribution of gas for local consumption. Figure 1 illustrates these activities. Producers and local distribution companies (LDCs) perform the first and third activities, respectively. Merchants, or trading/marketing companies, intermediate between them. Pipelines provide transportation services to shippers. A shipper is any player engaging a pipeline company to transport gas; that is, producers, merchants, and LDCs can all be shippers. Intrastate pipeline companies may also assume the role of a shipper, in addition to providing for the gas transportation. As a consequence of deregulation in 1978 and of subsequent orders by the Federal Energy Regulatory Commission (FERC), interstate pipelines cannot do that and act as common carriers.

Natural gas is physically traded at about 100 market hubs in North America. Trading of natural gas financial contracts, such as futures, swaps, and options, occurs on the New York Mercantile Exchange (NYMEX), the IntercontinentalExchange (ICE), and over-the-counter (OTC) markets. In addition to a vibrant futures market with a delivery location at Henry Hub, Louisiana, there exist about 40 financial locational basis swap contracts associated with the major natural gas market hubs in North America. (The price of a basis swap added to that of a NYMEX futures is effectively the price of a futures at the location associated with the basis swap.)

Pipelines play an important operational role in linking the trading of natural gas at market hubs, that is, in matching the supply and demand of natural gas across geographical locations. The pricing (valuation) of their capacity is an important problem in practice. The first objective of this paper is to conduct a normative analysis of how this capacity should be priced in theory.

Kaminski et al. (2004, pp. 73–77) and Eydeland and Wolyniec (2003, pp. 59–62) recognize that pipeline capacity contracts give merchants the option to ship natural gas contingent on the natural gas prices at the two ends of the pipeline and interpret these contracts

Figure 1   The Natural Gas Industry
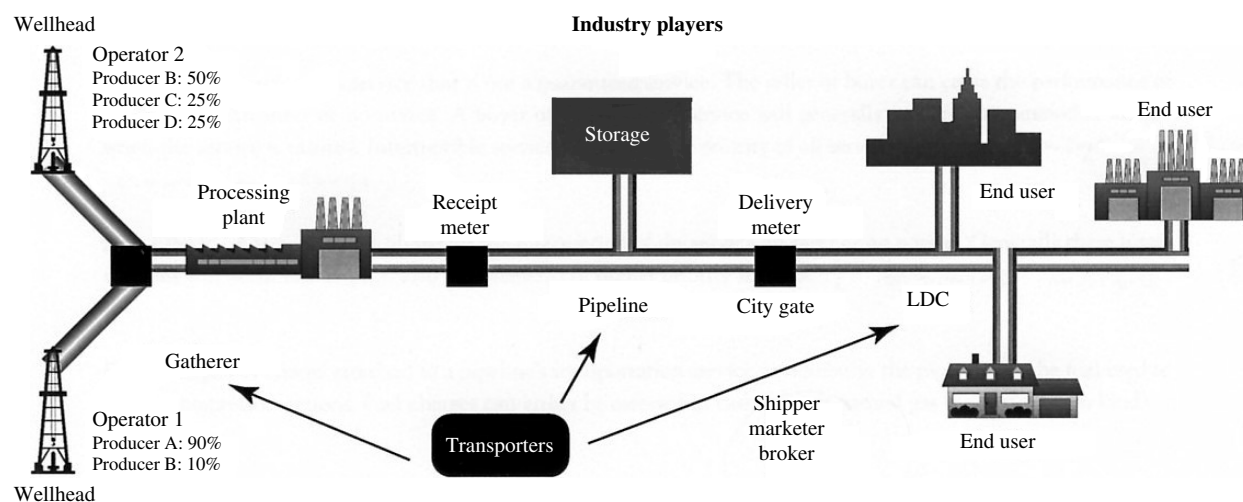
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as real options (Trigeorgis 1996) on the difference (spread) between the natural gas futures prices at these locations. Thus the *trading value* of this capacity can be interpreted as the value of a spread option on these prices.

Unlike merchants, producers and LDCs, respectively, can use pipeline capacity to sell and procure supply in remote markets rather than local markets. Thus their valuations of pipeline capacity should be related to the net value afforded to them by this operational market substitution rather than to the trading value of pipeline capacity. This paper shows that these *substitution values* are equal to the trading value of pipeline capacity.

Unlike shippers, interstate pipelines are engaged in the sale of transport capacity rather than spatial-trading, procurement, or selling of natural gas. The revenue management literature states that "[p]ipelines have to price their space [capacity] based on future demand forecasts as well as available capacity" (Talluri and van Ryzin 2004, p. 550)—that is, based on the *congestion value* of their capacity and the *opportunity cost* of committing it to satisfy a request for it (see also Secomandi et al. 2002). This paper leverages results available in the spatial and financial economics literature to show that the trading value of pipeline capacity is equal to its equilibrium congestion value—that is, the equilibrium value of binding

pipeline capacity constraint events—and to its opportunity cost.

This normative synthesis of different approaches to the pricing of natural gas pipeline capacity, based on differences in the operations of the various players involved in natural gas transportation, is significant because it provides a prediction that is amenable to empirical investigation: natural gas pipeline capacity should be priced at its trading value. The second objective of this paper is to conduct an empirical analysis of this prediction.

This paper uses a data set of transport contracts transacted on the Tennessee Gas Pipeline (TGP), a major interstate pipeline in the United States, to empirically investigate how the contracts' prices relate to their trading values. Here, it is useful to decompose the trading value of pipeline capacity into the sum of its intrinsic and extrinsic values: the former can be attributed to the current prices of forward contracts associated with the locations connected by a pipeline; the latter, to the uncertainty in the future evolution of these prices.

The intrinsic trading value of this capacity can be computed from prices that are directly observable in the marketplace. Although some spread options on locational natural gas price differences are traded on OTC markets, determining the extrinsic trading value of this capacity typically requires valuing a

spread option using real options models that capture the stochastic evolution of commodity prices. There are two basic types of real options models (Seppi 2002): reduced form (financial engineering) and equilibrium (financial economics). This paper uses a reduced-form model to *proxy* the extrinsic trading values of the stated TGP deals.

A regression analysis provides empirical evidence in support of the pricing of TGP capacity at its trading value, mainly at its extrinsic component. This finding is relevant because it suggests that shippers pay a significant amount of the total (intrinsic plus extrinsic) trading value of natural gas pipeline capacity to gain access to this capacity. In other words, this result suggests that uncertainty in future natural gas prices is an important driver of operational performance (Fisher 2007) in the pricing of interstate natural gas pipeline capacity in the United States. These results are not immediate. For example, Sturm (1997, pp. 142–146, 162–170), in a book widely read by natural gas traders, explains how to price pipeline capacity at its intrinsic trading value; however, Eydeland and Wolyniec (2003) and Kaminski et al. (2004) discuss reduced-form spread option models to compute the total trading value of this capacity from the merchant standpoint.

Although this paper deals with a specific setting, natural gas pipelines are examples of commodity conversion assets. From this perspective, its findings have potential relevance for the pricing of the capacity of other commodity conversion assets in domains such as the shipping of energy sources, including oil, coal, and electricity, and the refining of input commodities, including oil, corn, and soybean, into output commodities, including diesel/gasoline/jet-fuel, ethanol, and soyoil, respectively (Geman 2005). These examples feature substantive capacity valuation issues and fall within the area of research that deals with business-to-business commerce and contracting in capital intensive industries (Kleindorfer and Wu 2003).

The remainder of this paper is organized as follows. Section 2 discusses the novelty of its contributions relative to the existing literature. Section 3 introduces the spread option pricing approach to determine the trading value of pipeline capacity. Sections 4 and 5 establish the equivalence of the substitution and congestion

values of this capacity to its trading value. Section 6 conducts the stated empirical analysis. Section 7 concludes and discusses limitations of this paper and further research avenues.

2. Literature Review

The study of capacity plays a central role in the operations management literature (Van Mieghem 2003). An increasing number of authors has started to investigate the relevance of financial markets and hedging for capacity investment and inventory/production management choices (Huchzermeier and Cohen 1996, Birge 2000, Van Mieghem 2003, Gaur and Seshadri 2005, Caldentey and Haugh 2006, Ding et al. 2007, among others). However, this literature does not seem to have analyzed the real options pricing of the capacity of a commodity conversion asset such as a natural gas pipeline.

In recent years, empirical research has received increased attention within the operations management community, both in terms of theory building and testing (see, e.g., Fisher 2007, Roth 2007, Schroeder 2008). From this perspective, this paper combines theory building and empirical testing in an application domain that is novel to the operations management literature.

Part of the theory developed in this paper relies on the competitive spatial equilibrium formulas that relate the prices of a commodity at geographically connected markets. These go back to Samuelson (1952) and Takayama and Judge (1971) (see Nagurney 1999, Chapter 3, for a more recent account). They have been used by Cremer et al. (2003), Caldentey and Mondschein (2003), and Mudrageda and Murphy (2008), among others, in natural gas pipeline, copper production, and marine shipping contexts, respectively. The typical focus of this literature is modeling the equilibrium quantities and prices at the industry level. This is also the goal of those papers, such as those of Corbett and Karmarkar (2001) and Karmarkar and Rajaram (2008), that deal with market structure in supply chains. In contrast, this paper uses spatial equilibrium conditions to show the equivalence between the trading and congestion values of pipeline capacity.

The pricing of natural gas pipeline capacity as a real option is related to a stream of work that deals with the valuation of commodity and energy assets

(Brennan and Schwartz 1985; Smith and McCardle 1999; Deng et al. 2001; Kamat and Oren 2002; Eydeland and Wolyniec 2003, pp. 59–62; Jaillet et al. 2004; Kaminski et al. 2004, pp. 73–77; Geman 2005). However, this literature has not studied the valuation of natural gas pipeline capacity from the perspective of different players involved in natural gas transportation, nor has it conducted an empirical analysis of this problem.

3. Spread Option Model

After briefly discussing the basic institutions through which pipeline companies sell capacity to shippers, this section introduces the spread option model for the valuation of pipeline capacity at its trading value based on a simple representation of the natural gas pipeline industry.

Pipelines sell their services to shippers through transport capacity contracts. There are two main types of contracts: firm contracts, which give shippers the right to transport up to a given quantity of gas between specified locations during a given time period (that is, firm shippers are entitled to receive guaranteed services), and interruptible contracts, which allow shippers to receive best-effort services. The commodity rate is the unit price shippers pay on the shipped quantity when they use a contract. The demand rate is the unit price firm, but not interruptible, shippers pay on the entire booked quantity irrespective of utilization.

In the United States, FERC regulates the minimum/maximum commodity and demand rates that interstate pipelines can charge. It also requires them to sell their capacity in a nondiscriminatory manner to all interested shippers, usually through auctions run on their websites during time periods called open seasons (FERC 1992, 1999). In an open season, a pipeline company makes parcels of its capacity available for sale to all interested shippers through a sealed-bid auction; shippers submit binding bids. The pipeline company can specify a minimum acceptable demand rate for its capacity, which must be within the minimum and maximum FERC regulated rates. Moreover, through the "negotiated rate" practice, FERC allows interstate pipelines not believed to be in a monopolistic position to charge market based rates (see FERC 1996).

Negotiated rates are not subject to the maximum rate regulatory constraint.

Shippers buy firm contracts to reserve transport capacity in advance of its usage. By federal regulation, in the United States pipeline companies cannot overbook their capacity, and have the obligation to operationally satisfy their firm contracts, which are written with liquidated damages clauses, unless a force majeure event occurs.

This paper uses a simple representation of the natural gas industry. Natural gas and its related financial contracts are traded at two market hubs, a and b. An interstate pipeline connects them. Production occurs at both locations, in the sense that producers are located at production points connected to a market hub by dedicated pipes. Local distribution also occurs at both locations, in the sense that LDCs procure natural gas from a market hub and transport it via dedicated pipes to distribution points where they satisfy the demand of end users. Merchants are intermediaries operating at the market hubs.

The pipeline has bidirectional flow capabilities, as is typically the case in practice; that is, it can flow gas from a to b or from b to a. For simplicity of exposition, this paper focuses on the pricing of the transport capacity from a to b sold on a firm basis. A contract for a parcel of this capacity has the following attributes.

1. The receipt and delivery hubs a and b, where the pipeline company receives gas from the shipper and injects it into its system and withdraws it from its system and delivers it to the shipper, respectively. Because these operations occur simultaneously, from a financial standpoint, transport occurs instantaneously (clearly, the gas injected and withdrawn at the receipt and delivery points is not the same).

2. A period of time specifying the term of the contract with monthly time units.

3. The maximum quantity that can be shipped during each month in the contract term. Because there is no linkage across months, attention can be restricted to contracts with single-period terms without loss of generality.

4. The commodity rate (K) and the demand rate.

5. The fuel retention factor ϕ: to withdraw one unit of gas an amount $1/(1-\phi)$ must be injected because an amount $\phi/(1-\phi)$ is used as fuel in this process; that is, $1 \equiv 1/(1-\phi) - \phi/(1-\phi)$. This factor

can be time dependent, but for simplicity this is not expressed in the notation.

An *a-b* firm transport contract gives shippers the right to transport an amount of natural gas up to the maximum contract quantity from hub *a* to hub *b* during the contract term.

Consider future time period $T > 0$; assume that its length is one month. Suppose that at time 0, the open season time, the pipeline company puts Q units of its time period T, *a-b* transport capacity up for sale in the form of a firm transport contract with commodity rate K. Focus on time T, the beginning of time period T. Let $p_i(T)$ denote the time T spot price of natural gas at location $i \in \{a, b\}$. Eydeland and Wolyniec (2003, pp. 59–62) argue that at this time a merchant uses this contract if and only if the revenue from selling Q units of gas at b exceeds the sum of the costs of purchasing an amount $Q/(1 - \phi)$ of gas at a, inclusive of fuel, and delivering Q units of gas to b at cost KQ. (This assumes that the payoff from this trade occurs at time T.) Thus defining $\{\cdot\}^+ := \max\{\cdot, 0\}$, the time T per unit payoff of this trade is

$$\left\{ p_b(T) - \frac{p_a(T)}{1 - \phi} - K \right\}^+. \quad (1)$$

The problem at stake reduces to the valuation of payoff (1) as of time 0. Financial economics has developed a simple and powerful approach to value financial assets, that is, financial instruments that can be bought and sold (Luenberger 1998, p. 137). This is the so-called no-arbitrage valuation approach (see, e.g., Luenberger 1998, Chapters 8–9; Duffie 2001, Chapters 2 and 6). This approach can be applied to the valuation of real assets (see, e.g., Trigeorgis 1996; Luenberger 1998, pp. 337–343; Geman 2005)—in particular, when they involve the conversion of commodities for which futures contracts are traded (see Luenberger 1998, pp. 264–265 and 273–277, for definitions and illustrations of the relevant terminology). Pipeline capacity can be interpreted as an asset that can convert natural gas at one location into natural gas at a different location. This approach applies to the valuation of payoff (1) in North America, where natural gas futures are traded at several market hubs.

Let $F_i(t, T)$ denote the time $t \in [0, T]$ price of a natural gas futures contract with maturity T associated with location $i \in \{a, b\}$. Because the spot and futures prices are identical at a futures contract maturity, that is, $p_i(T) \equiv F_i(T, T), \forall i \in \{a, b\}$, payoff (1) satisfies the following identity:

$$\left\{ p_b(T) - \frac{p_a(T)}{1 - \phi} - K \right\}^+$$
$$\equiv \left\{ F_b(T, T) - \frac{F_a(T, T)}{1 - \phi} - K \right\}^+. \quad (2)$$

As seen from time 0, the spot price at time T and location $i \in \{a, b\}$ is a random variable, denoted by $\tilde{p}_i(T) \equiv \tilde{F}_i(T, T)$. Methodologically, the no-arbitrage valuation process is greatly simplified by a mathematical finance result, which states that when the relevant futures markets are arbitrage free and complete, the time 0 value of payoff (2) is equal to the following discounted expectation:

$$V_{ab}^{SO}(0, T) := \delta(0, T)\mathbb{E}_0^* \left\{ \tilde{F}_b(T, T) - \frac{\tilde{F}_a(T, T)}{1 - \phi} - K \right\}^+; \quad (3)$$

here, $\delta(0, T)$ is the risk-free discount factor from time T back to time 0 (assumed to be deterministic), and $\mathbb{E}_0^*$ denotes conditional expectation with respect to the *risk-neutral* distribution of random vector $(\tilde{F}_a(T, T), \tilde{F}_b(T, T))$, given the information set at time 0, e.g., the time 0 futures prices $F_b(0, T)$ and $F_a(0, T)$ (see, e.g., Duffie 2001, Chapter 6). This pricing technique is called risk-neutral valuation.

The quantity $V_{ab}^{SO}(0, T)$ is the trading value of one unit of time period T, *a-b* pipeline capacity. This quantity is also the value of a *spread* option because its defining payoff (2) is the spread between two prices (one adjusted for fuel) net of the commodity rate.

4. Producers and LDCs

Section 3 has focused on the case when the capacity holder is a merchant. However, pipeline shippers also include producers and LDCs (they may also include industrial customers, which can be considered LDCs

Table 1 The Logistical Flexibility of Transport Contracts for Different Shippers

Merchant	Producer	LDC
Option to intermediate between different locations	Option to shift location of production marketing	Option to shift location of supply procurement

for the purposes of this paper). Table 1 describes how transport contracts give these shippers logistical flexibility to support their operations and compares their usage to that of merchants.

A producer (respectively, an LDC) can use such a contract to sell its production (respectively, procure supply to meet its demand) in a remote hub rather than local hub. In contrast, a merchant uses a transport contract to intermediate availability of natural gas between two markets. Thus from an operational perspective, it may not be immediately evident why the valuation of pipeline capacity based on differences between natural gas prices at different geographical locations—specifically, payoff (1)—should be relevant to producers and LDCs. The remaining part of this section explains why this is the case.

Consider the case of a producer located at a and an LDC located at b. At first glance, it would appear that their valuations of time period T, a-b capacity should depend on their own production and procurement quantities because by using it they would be transporting the same production and procuring the same supply to and from a different market, respectively. In other words, the producer would be selling its production at b rather than at a, and the LDC would be procuring supply at a rather than at b. However, the producer and the LDC retain the ability to sell and buy natural gas on their local markets. Thus their capacity valuations must be based on the *relative* benefits (substitution values) that they accrue by optimally exercising the option to *substitute* operating on their local markets with operating on remote markets. Proposition 1 establishes that these substitution values are equal to the trading value of pipeline capacity.

PROPOSITION 1 (PRODUCERS AND LDCS). *The trading value of time period T, a-b pipeline capacity is equal to its substitution values for a producer located at a and an LDC located at b.*

PROOF. Consider time T, but for expositional simplicity suppress this time suffix from the relevant quantities. Consider a producer located at a whose production at time T is Q_a. (The production quantity is deterministic at this time but could be a random variable as of an earlier time.) Assume, without loss of generality, that the producer's operating cost is zero. Without the contract, the producer's payoff is

$\pi_a^P := p_a Q_a$. With the contract, the producer can choose whether to sell its production at a or b. If $Q_a \in [0, Q/(1-\phi)]$, this producer can ship to b an amount $(1-\phi)Q_a$ of its production Q_a by using ϕQ_a units of Q_a as fuel and can utilize the remaining $Q - (1-\phi)Q_a$ units of shipping capacity by trading on the a and b markets. If $Q_a > Q/(1-\phi)$ this producer can ship Q units of its production to b and sell the remaining $Q_a - Q/(1-\phi)$ units of Q_a at a. Thus its payoff is (here, $\cdot \vee \cdot := \max\{\cdot, \cdot\}$ and $\cdot \wedge \cdot := \min\{\cdot, \cdot\}$)

$$\pi_{ab}^P = [(p_b - K)(1-\phi) \vee p_a]\left(\frac{Q}{1-\phi} \wedge Q_a\right)$$
$$+ p_a\left(Q_a - \frac{Q}{1-\phi}\right)^+ + \left\{p_b - \frac{p_a}{1-\phi} - K\right\}^+$$
$$\cdot [Q - (1-\phi)Q_a]^+. \qquad (4)$$

The term $(p_b - K)(1-\phi)$ can be written as

$$[p_b - K - \phi p_a/(1-\phi)] - [p_b - K - p_a/(1-\phi)]\phi.$$

By further adding and subtracting $p_a[Q/(1-\phi) \wedge Q_a]$ to (4), rearranging, and noting that $Q_a \equiv [Q/(1-\phi) \wedge Q_a] + [Q_a - Q/(1-\phi)]^+$, (4) can be expressed as

$$\pi_{ab}^P = p_a Q_a + \left\{p_b - \frac{p_a}{1-\phi} - K\right\}^+ \left[Q \wedge (1-\phi)Q_a\right]$$
$$+ \left\{p_b - \frac{p_a}{1-\phi} - K\right\}^+ [Q - (1-\phi)Q_a]^+.$$

Thus the benefit of owning the transport contract to the producer is

$$\pi_{ab}^P - \pi_a^P = \left\{p_b - \frac{p_a}{1-\phi} - K\right\}^+$$
$$\cdot \{[Q \wedge (1-\phi)Q_a] + [Q - (1-\phi)Q_a]^+\}. \qquad (5)$$

Assume, without loss of generality, that the LDC's operating revenue is zero. The LDC's payoff without the contract is $\pi_b^{LDC} = -p_b Q_b$, where Q_b is the LDC's demand at time T. One can easily check that the payoff of the LDC with the contract is

$$\pi_{ab}^{LDC} = -p_b Q_b + \left\{p_b - \frac{p_a}{1-\phi} - K\right\}^+ (Q \wedge Q_b)$$
$$+ \left\{p_b - \frac{p_a}{1-\phi} - K\right\}^+ (Q - Q_b)^+,$$

so that the benefit to the LDC of owning the transport contract is

$$\pi_{ab}^{\text{LDC}} - \pi_b^{\text{LDC}} = \left\{ p_b - \frac{p_a}{1-\phi} - K \right\}^+$$
$$\cdot [(Q \wedge Q_b) + (Q - Q_b)^+]. \quad (6)$$

The claimed statement follows by using the identities

$$Q \equiv [Q \wedge (1-\phi)Q_a] + [Q - (1-\phi)Q_a]^+$$
$$\equiv (Q \wedge Q_b) + (Q - Q_b)^+$$

in (5) and (6) and comparing the resulting expressions with (1). □

5. Pipelines

As argued in §1, the relevant values of capacity for pipeline companies should be its congestion value and opportunity cost. This section shows that in a competitive spatial equilibrium setting the trading value of this capacity coincides with both its congestion value and opportunity cost. The ensuing analysis is based on the work of Cremer et al. (2003), who use the basic competitive model of Samuelson (1952) that is extensively discussed by Takayama and Judge (1971, pp. 107–108; De Vany and Walls 1995 provide empirical evidence that natural gas markets in North America behave competitively). As in Cremer et al. (2003), storage is not considered, which is consistent with the focus of this paper on transport (see Williams and Wright 1991, Chapter 9, for an equilibrium model that combines transport and storage).

Denote by x_i and y_i the quantities of natural gas produced and consumed at each market hub $i \in \{a, b\}$ during a given time period (month). The supply and demand functions at each market hub i during time period T depend, respectively, on parameter vectors θ_i and ψ_i that take values in sets $\Theta_i(T)$ and $\Psi_i(T)$. Denote these functions by $S_i(x_i; \theta_i)$ and $D_i(y_i; \psi_i)$, where their dependence on T is implicit through the inclusion of parameters θ_i and ψ_i in sets $\Theta_i(T)$ and $\Psi_i(T)$, respectively. Assume that at each location i the supply function is a continuous, differentiable, and monotonically increasing function of the production quantity x_i on an appropriate domain and that the demand function is a continuous, differentiable, and

monotonically decreasing function of the consumption quantity y_i on an appropriate domain. These assumptions are standard in the spatial economics literature (Takayama and Judge 1971, pp. 107–108).

At time T, the supply and demand functions for time period T are known. However, as seen from any prior time they are stochastic. Denote by $S_i(x_i; \tilde{\theta}_i(T))$ and $D_i(y_i; \tilde{\psi}_i(T))$ the random variables supply and demand during time period T at market hub $i \in \{a, b\}$, which depend on random variables $\tilde{\theta}_i(T)$ and $\tilde{\psi}_i(T)$ with possible realizations $\theta_i \in \Theta_i(T)$ and $\psi_i \in \Psi_i(T)$, respectively. Given such realizations, define the welfare function at location i as follows:

$$W_i(x_i, y_i; \theta_i, \psi_i) := \int_0^{y_i} D_i(y_i'; \psi_i)\, dy_i' - \int_0^{x_i} S_i(x_i'; \theta_i)\, dx_i'.$$

This function is the sum of the consumer surplus and the producer surplus at location i. By the assumptions on the supply and demand functions, the welfare function is jointly strictly concave in the quantities x_i and y_i (Takayama and Judge 1971, p. 108).

Given supply and demand amounts x_i and y_i, realizations θ_i and ψ_i, $\forall i \in \{a, b\}$, and natural gas flows z_{ab} and z_{ba} from a/b to b/a, the welfare function net of transportation costs is $W_a(x_a, y_a; \theta_a, \psi_a) + W_b(x_b, y_b; \theta_b, \psi_b) - K(z_{ab} + z_{ba})$. This expression does not explicitly include the revenue collected by the pipeline operator for transporting the shippers' natural gas and the amount shippers pay to receive these services because these quantities cancel each other out. Thus the following analysis also holds when the pipeline rates are capped. (However, different pipeline rates do affect how the pipeline company and the shippers share the relevant shipping margins.)

The equilibrium supply and demand quantities at each location and the equilibrium flows between them can be found by optimally solving the following math program, which features a strictly concave objective function and linear constraints:

$$\max \sum_{i \in \{a, b\}} W_i(x_i, y_i; \theta_i, \psi_i) - \sum_{i \in \{a, b\}} \sum_{j \in \{a, b\}, i \neq j} K z_{ij} \quad (7)$$

$$\text{s.t.} \quad y_i + \sum_{j \in \{a, b\}, i \neq j} \frac{z_{ij}}{1-\phi} \leq x_i + \sum_{j \in \{a, b\}, i \neq j} z_{ji}$$
$$\forall i \in \{a, b\}; \quad (\eta_i); \quad (8)$$

$$z_{ij} \leq C \quad \forall i, j \in \{a, b\},\ i \neq j;\ (\nu_{ij}); \quad (9)$$

$$x_i \geq 0 \quad \forall i \in \{a, b\}; \;\; (\gamma_i); \tag{10}$$

$$y_i \geq 0 \quad \forall i \in \{a, b\}; \;\; (\iota_i); \tag{11}$$

$$z_{ij} \geq 0 \quad \forall i, j \in \{a, b\}, \;\; i \neq j; \;\; (\lambda_{ij}). \tag{12}$$

The rightmost quantities in parenthesis in the constraints are Lagrange multipliers. Below, superscript "◇" denotes optimality in (7)–(12).

Recall that at any time before T, the time period T supply and demand functions are random variables. Thus denote by $\tilde{z}_{ab}^\diamond(T)$, $\tilde{\nu}_{ab}^\diamond(T)$, and $\tilde{\eta}_i^\diamond(T)$ the time period T random variables flow from a to b, dual of (9), and dual of (8) for location $i \in \{a, b\}$ in equilibrium, respectively. The quantities $\eta_a^\diamond(T)$ and $\eta_b^\diamond(T)$ are the time period T spot prices at market hubs a and b, respectively. As in §3, complete and arbitrage free futures markets with delivery during time period T exist both at a and b by assumption. Thus the random vector $(\tilde{F}_a(T, T), \tilde{F}_b(T, T))$ has a unique risk-neutral distribution conditional on the information set available at time 0, and it holds that $F_a(T, T) \equiv \eta_a^\diamond(T)$ and $F_b(T, T) \equiv \eta_b^\diamond(T)$. Proposition 2 characterizes the time 0 value of the a to b equilibrium congestion value of transport capacity during time period T.

PROPOSITION 2 (TRADING AND EQUILIBRIUM CONGESTION VALUES OF CAPACITY). *It holds that*

$$\delta(0, T) \mathbb{E}_0^* [\tilde{\nu}_{ab}^\diamond(T)]$$
$$= \delta(0, T) \mathbb{E}_0^* \left\{ \tilde{F}_b(T, T) - \frac{\tilde{F}_a(T, T)}{1 - \phi} - K \right\}^+ \tag{13}$$
$$= \delta(0, T) \mathbb{E}_0^* \left\{ \left[\tilde{F}_b(T, T) - \frac{\tilde{F}_a(T, T)}{1 - \phi} - K \right] \right.$$
$$\left. \cdot 1\{\tilde{z}_{ab}^\diamond(T) = C\} \right\}. \tag{14}$$

PROOF. Given a realization of the relevant random variables at time T, the Lagrangian function of math program (7)–(12) is

$$L(x, y, z, \eta, \nu, \gamma, \iota, \lambda)$$
$$:= \sum_{i \in \{a, b\}} W_i(x_i, y_i; \theta_i, \psi_i) - \sum_{i \in \{a, b\}} \sum_{j \in \{a, b\}, i \neq j} K z_{ij}$$
$$- \sum_{i \in \{a, b\}} \eta_i \left(y_i + \sum_{j \in \{a, b\}, i \neq j} \frac{z_{ij}}{1 - \phi} - x_i - \sum_{j \in \{a, b\}, i \neq j} z_{ji} \right)$$
$$- \sum_{i \in \{a, b\}} \sum_{j \in \{a, b\}, i \neq j} \nu_{ij}(z_{ij} - C) + \sum_{i \in \{a, b\}} \gamma_i x_i + \sum_{i \in \{a, b\}} y_i \iota_i$$

$$+ \sum_{i \in \{a, b\}} \sum_{j \in \{a, b\}, i \neq j} \lambda_{ij} z_{ij}.$$

The strict concavity of (7) and linearity of (8)–(12) imply that the following Karush-Kuhn-Tucker conditions (Bazaraa et al. 2006, Chapter 4) are sufficient and necessary for the optimality of a feasible solution to this math program:

$$-S_i(x_i; \theta_i) + \eta_i + \gamma_i = 0 \quad \forall i \in \{a, b\};$$

$$D_i(y_i; \psi_i) - \eta_i + \iota_i = 0 \quad \forall i \in \{a, b\};$$

$$-K - \frac{\eta_i}{1 - \phi} + \eta_j - \nu_{ij} + \lambda_{ij} = 0 \quad \forall i, j \in \{a, b\}, \; i \neq j; \tag{15}$$

$$\eta_i \left(-y_i - \sum_{j \in \{a, b\}, i \neq j} \frac{z_{ij}}{1 - \phi} + x_i + \sum_{j \in \{a, b\}, i \neq j} z_{ji} \right)$$
$$= 0 \quad \forall i \in \{a, b\};$$

$$\nu_{ij}(-z_{ij} + C) = 0 \quad \forall i, j \in \{a, b\}, \; i \neq j; \tag{16}$$

$$\gamma_i x_i = 0 \quad \forall i \in \{a, b\};$$

$$\iota_i y_i = 0 \quad \forall i \in \{a, b\};$$

$$\lambda_{ij} z_{ij} = 0 \quad \forall i, j \in \{a, b\}, \; i \neq j; \tag{17}$$

$$\eta_i, \gamma_i, \iota_i \geq 0 \quad \forall i \in \{a, b\};$$

$$\nu_{ij}, \lambda_{ij} \geq 0 \quad \forall i, j \in \{a, b\}, \; i \neq j. \tag{18}$$

Expression (15) implies that

$$\nu_{ab}^\diamond = \eta_b^\diamond - \left(\frac{\eta_a^\diamond}{1 - \phi} + K \right) + \lambda_{ab}^\diamond. \tag{19}$$

If $\eta_b^\diamond - \eta_a^\diamond/(1 - \phi) - K > 0$, then (19) implies that $\nu_{ab}^\diamond - \lambda_{ab}^\diamond > 0$, and this and (18) imply that $\nu_{ab}^\diamond > 0$. If $\nu_{ab}^\diamond > 0$, (16) implies that $z_{ab}^\diamond = C$, (17) implies that $\lambda_{ab}^\diamond = 0$, and (18) and (19) yield $\eta_b^\diamond - \eta_a^\diamond/(1 - \phi) - K = \nu_{ab}^\diamond \geq 0$; however, $\nu_{ab}^\diamond$ is positive by assumption so that $\eta_b^\diamond - \eta_a^\diamond/(1 - \phi) - K > 0$. Thus it holds that $\nu_{ab}^\diamond > 0$ if and only if $\eta_b^\diamond - \eta_a^\diamond/(1 - \phi) - K > 0$, or, equivalently,

$$\nu_{ab}^\diamond = \left\{ \eta_b^\diamond - \frac{\eta_a^\diamond}{1 - \phi} - K \right\}^+. \tag{20}$$

If $z_{ab}^\diamond \in [0, C)$, then (16) implies that $\nu_{ab}^\diamond = 0$. If $z_{ab}^\diamond = C$, similar to what shown above, then $\nu_{ab}^\diamond = \eta_b^\diamond - \eta_a^\diamond/(1 - \phi) - K$. Thus it holds that

$$\nu_{ab}^\diamond = \nu_{ab}^\diamond 1\{z_{ab}^\diamond \in [0, C)\} + \nu_{ab}^\diamond 1\{z_{ab}^\diamond = C\}$$
$$= \left[\eta_b^\diamond - \frac{\eta_a^\diamond}{1 - \phi} - K \right] 1\{z_{ab}^\diamond = C\}. \tag{21}$$

Expressions (13) and (14) follow from the identities $F_a(T, T) \equiv \eta_a^\diamond(T)$ and $F_b(T, T) \equiv \eta_b^\diamond(T)$ and the application of risk-neutral valuation to (20) and (21). □

Proposition 2 shows that the time 0 value of the equilibrium congestion value of time period T, a-b pipeline capacity is equal to its time 0 marginal trading value $V_{ab}^{SO}(0, T)$ and that $V_{ab}^{SO}(0, T)$ can be interpreted as the time 0 value of the time period T shipping margin when a binding capacity constraint event occurs during this time period in equilibrium.

This proposition helps to explain why expression (3), which defines $V_{ab}^{SO}(0, T)$, does not feature what would appear to be key operational details of natural gas shipping—the pipeline available capacity and the demand for its transport services. By focusing on the positive part of the shipping margin, this expression implicitly captures the value of binding capacity constraint events in equilibrium. The probability distribution under which the expectation in (3) is taken plays a key role in this respect, for it "weighs" the positive part of the shipping margin. In particular, if this distribution is not obtained from an equilibrium model, as is the case when one uses a reduced-form model of the evolution of natural gas prices, then this distribution does not depend directly on the pipeline capacity constraint and demand for transport. However, if the parameters of a reduced-form model are calibrated on market prices, such as the prices of futures contracts for delivery at markets a and b during time period T, which contain information about the pipeline capacity being fully utilized in the a-b direction during this time period, then the stated "weighing" of the positive part of the shipping margin reflects this information.

To establish that the trading value of capacity is also the pipeline opportunity cost of committing it to a request in advance of its usage, it is easy to show that the discounted trading value of this capacity is a martingale under the relevant risk-neutral distribution: $\delta(t, \tau)\mathbb{E}_t^*[\tilde{V}_{ab}(\tau, T)] = V_{ab}^{SO}(t, T)$, $\forall t, \tau \in [0, T]$, with $t \leq \tau$. This means that from a value perspective, there is no advantage for pipeline managers to "time" the sale of their capacity, that is, reject a known request for capacity now in the hope of receiving a more valuable request in the future. Thus, the opportunity cost of a parcel of this capacity at any time $t \in [0, T]$ is its size multiplied by $V_{ab}^{SO}(t, T)$. This also

means that pipeline companies should be indifferent between collecting the congestion value of their time period T, a-b capacity at time T, when this value is known with certainty, or at any earlier time $t \in [0, T]$, when this value is a random variable whose time t value is $V_{ab}^{SO}(t, T)$.

6. Empirical Analysis

This section empirically investigates whether transacted demand rates for TGP capacity contracts are consistent with their trading values and which of their components. Recall from §1 that a trading value can be decomposed into the sum of its intrinsic and extrinsic components. This is shown below. Define the time 0 intrinsic trading value of one unit of time period T, a-b pipeline capacity as

$$V_{ab}^{I}(0, T) := \delta(0, T)\left\{F_b(0, T) - \frac{F_a(0, T)}{1 - \phi} - K\right\}^+. \quad (22)$$

The trading value of this capacity is no smaller than its intrinsic trading value because the convexity of $\{\cdot\}^+$, Jensen's inequality, and the martingale property of futures prices under the risk-neutral measure imply that

$$V_{ab}^{SO}(0, T) = \delta(0, T)\mathbb{E}_0^*\left\{\tilde{F}_b(T, T) - \frac{\tilde{F}_a(T, T)}{1 - \phi} - K\right\}^+$$

$$\geq \delta(0, T)\left\{\mathbb{E}_0^*[\tilde{F}_b(T, T)] - \mathbb{E}_0^*\left[\frac{\tilde{F}_a(T, T)}{1 - \phi}\right] - K\right\}^+$$

$$= \delta(0, T)\left\{F_b(0, T) - \frac{F_a(0, T)}{1 - \phi} - K\right\}^+.$$

The extrinsic trading value of one unit of this capacity is $V_{ab}^{SO}(0, T) - V_{ab}^{I}(0, T)$. As discussed later in this section, the intrinsic, extrinsic, and total (intrinsic plus extrinsic) trading values of pipeline capacity are useful to estimate the intrinsic, extrinsic, and total demand rates of a pipeline contract.

6.1. Data

The ensuing analysis is based on a data set that contains 24 winning bids (deals) for firm transport capacity submitted to TGP by shippers during seven open seasons conducted between August 26, 2005 and January 27, 2007. Each bid specifies a maximum daily quantity (volume), a receipt and a delivery point, the

Table 2   ID, Pipeline Path, and Markets for Each Deal

Deal ID	Path (zone to zone)	Market	
		Receipt	Delivery
A	1 to 4	Chicago[1]	Dominion
B	1 to 2	Tennessee 500 Leg	Columbia Gas
C	1 to 2	Chicago[1]	Columbia Gas
D	1 to 1	Chicago[1]	Average of Tennessee 500 Leg and Tennessee 800 Leg
E	5 to 4	Niagara	Dominion
F	6 to 6	Dracut	Tennessee Zone 6
G	6 to 6	Dracut	Tennessee Zone 6
H	1 to 4	Tennessee 500 Leg	Dominion
I	0 to 4	Houston Ship Channel	Dominion
J	6 to 6	Dracut	Tennessee Zone 6
K	5 to 6	Iroquois Zone 2	Tennessee Zone 6
L	1 to 5	Tennessee 800 Leg	Iroquois Zone 2
M	6 to 6	Dracut	Tennessee Zone 6
N	6 to 6	Dracut	Tennessee Zone 6
O	1 to 2	Tennessee 500 Leg	Columbia Gas
P	6 to 6	Dracut	Tennessee Zone 6
Q	6 to 6	Dracut	Tennessee Zone 6
R	6 to 6	Dracut	Tennessee Zone 6
S	1 to 1	Tennessee 800 Leg	Texas Eastern
T	6 to 4	Dracut	Dominion
U	6 to 6	Dracut	Tennessee Zone 6
V	0 to 1	Tennessee Zone 0	Tennessee 800 Leg
W	0 to 1	Tennessee Zone 0	Tennessee 500 Leg
X	0 to 1	Tennessee Zone 0	Tennessee 500 Leg

[1]Adjusted for fuel (0.01) and transport ($0.07/Dekatherm (Dth)).

start date and length of service, a commodity rate, and a demand rate. Once accepted, a bid becomes a firm contract.

From an engineering perspective, a pipeline consists of meters, the pipes connecting them, and compressor stations; however, from a commercial and regulatory perspective, zones, which include sections of the pipeline in a given geographical area, play an important role. A zone contains several meters and may contain more than one market. A bid includes both the receipt and delivery zones as well as more detailed information on the meters that identify their associated markets. Table 2 displays the zone-to-zone paths and the receipt and delivery markets associated with each bid. (TGP uses eight zones labeled 0–6 and L; visit the TGP website, http://www.tennesseeadvantage.com/default.asp, for detailed system maps.)

The relevant markets for valuation purposes are those associated with natural gas futures and basis swaps. The NYMEX natural gas futures contract, whose delivery is at Henry Hub, Louisiana, is a vibrant contract with maturities currently extending 144 months into the future. A locational basis, or simply a basis, is the difference between the futures prices at Henry Hub and at a different location. A basis swap is a contract on this difference. NYMEX and ICE trade about 40 basis swap contracts, with maturities currently extending 72 months into the future. Basis swaps are settled financially and do not entail physical delivery. They "cover" the major natural gas production and consumption regions in North America.

Not all physical markets feature a basis swap, in which case a market incompleteness may arise for valuation purposes. Often this incompleteness can be easily resolved. Market research firms provide basis estimates at locations that do not feature a NYMEX or ICE basis swap; e.g., Kiodex provides basis estimates for Tennessee 800 Leg that is not a NYMEX or ICE basis swap. Basis quotes may also be available from brokers that operate in OTC markets. For example, Amerex provides basis quotes for Waddington, New York. Alternatively, the price at a given location can be statistically characterized as a function of the prices at other locations; e.g., according to practitioners, the price at the delivery location of deal D can be described as the average of the prices of the Tennessee 500 and 800 Legs.

Moreover, practitioners commonly use a simple rule to associate a futures market to a pipeline location that does not feature a basis swap. To illustrate, consider deals A, C, and D, which entail shipping natural gas out of Portland, Tennessee, where there is no market. This location is connected to the Joliet/Chicago hub through the Midwestern Gas Transmission (MGT) pipeline. One way to have gas available in Portland is to purchase it at the Joliet/Chicago hub and ship it to Portland along the MGT pipeline. This entails paying the maximum demand and commodity rates on this pipeline, for a transport cost of $0.07/Dth for the period of time under study and incurring a 0.01 fuel-related charge (Dth abbreviates Dekatherm). Thus the futures price in Portland is the Chicago futures price scaled by 1/0.99 and increased by $0.07/Dth.

It is possible that none of these alternatives can be used for basis discovery. For example, Dracut, Massachusetts, features an active spot market but not

Table 3   Volume, Bid Date, Term, Commodity Rate, and Transacted Demand Rate for Each Deal

Deal ID	Volume (Dth)	Bid date	Term Begin	Term End	K ($/Dth)	Observed demand rate ($\frac{\$}{\text{Month} \cdot \text{Dth}}$)
A	16,500	10/26/2005	11/1/2005	3/31/2006	0.1014	10.77
B	3,000	10/26/2005	11/1/2005	3/31/2006	0.0776	7.62
C	4,000	10/26/2005	11/1/2005	3/31/2006	0.0776	7.62
D	3,924	10/26/2005	11/1/2005	11/30/2005	0.0572	4.92
E	19,700	10/26/2005	4/1/2006	3/31/2012	0.0459	3.38
F	20,000	10/26/2005	11/1/2005	3/31/2006	0.0642	3.16
G	5,000	10/26/2005	12/1/2005	2/28/2006	0.0642	3.16
H	300	10/26/2005	11/1/2005	3/31/2006	0.1014	10.77
I	2,000	8/26/2005	9/1/2005	10/31/2018	0.0326	12.22
J	5,000	8/26/2005	11/1/2005	4/30/2006	0.0642	3.16
K	19,000	10/26/2006	4/1/2007	3/31/2013	0.0765	4.93
L	6,200	10/26/2006	11/1/2006	10/31/2007	0.1126	12.64
M	20,000	10/26/2006	11/1/2006	3/31/2007	0.0642	3.16
N	5,000	10/26/2006	12/1/2006	2/28/2007	0.0642	3.16
O	500	9/26/2006	11/1/2006	10/31/2007	0.0776	5.19[1]
P	425	8/23/2006	12/1/2006	11/30/2007	0.0658	3.16
Q	13,000	8/23/2006	11/1/2006	3/31/2007	0.0642	1.59[1]
R	5,000	8/23/2006	11/1/2006	3/31/2007	0.0642	1.59[1]
S	50,000	7/26/2006	8/1/2006	8/31/2006	0.0572	4.92
T	5,000	7/26/2006	11/1/2006	4/30/2007	0.0834	5.89
U	5,000	7/26/2006	11/1/2006	4/30/2007	0.0642	3.16
V	8,400	1/26/2007	4/1/2007	3/31/2012	0.0669	6.45
W	7,500	1/26/2007	4/1/2007	3/31/2013	0.0669	6.45
X	10,000	1/26/2007	4/1/2007	3/31/2017	0.0669	6.45

[1]Discount off the maximum demand rate.

a basis market. Linking Dracut to other basis swap locations does not seem straightforward. Thus in this paper each relevant futures price associated with a Dracut-related deal is proxied using averages of realized spot prices during each corresponding month.

Table 3 reports the additional features of the received bids. Table 4 shows the TGP minimum and maximum demand and commodity rates that were effective during the considered open seasons. The transacted demand rates are maximum demand rates for 21 out of 24 deals (the exceptions are deals O, Q, and R). Thus even if it were true that the transacted demand rates include both the intrinsic and extrinsic components of their trading values, 21 of these rates may not fully reflect the sum of these values. The transacted commodity rates of 23 out of 24 deals are discounts off their maximum values (deal P being the exception).

Table 5 displays the TGP zone-to-zone fuel factors that were in effect when the considered open seasons were held. These factors are seasonal; in particular, they are higher during the heating season

Table 4   Minimum and Maximum Demand and Commodity Rates for Firm Transport Capacity on the TGP System for the Period of Time Under Study

Receipt zone	Delivery zone 0	L	1	2	3	4	5	6
	Maximum demand rates ($/(Month·Dth))							
0	3.10		6.45	9.06	10.53	12.22	14.09	16.59
L		2.71						
1	6.66		4.92	7.62	9.08	10.77	12.64	15.15
2	9.06		7.62	2.86	4.32	6.32	7.89	10.39
3	10.53		9.08	4.32	2.05	6.08	7.64	10.14
4	12.53		11.08	6.32	6.08	2.71	3.38	5.89
5	14.09		12.64	7.89	7.64	3.38	2.85	4.93
6	16.59		15.15	10.39	10.14	5.89	4.93	3.16
	The minimum demand rate is always $0/(Month·Dth)							
	Minimum commodity rates ($/Dth)							
0	0.0026		0.0096	0.0161	0.0191	0.0233	0.0268	0.0326
L		0.0034						
1	0.0096		0.0067	0.0129	0.0159	0.0202	0.0236	0.0294
2	0.0161		0.0129	0.0024	0.0054	0.0100	0.0131	0.0189
3	0.0191		0.0159	0.0054	0.0004	0.0095	0.0126	0.0184
4	0.0237		0.0205	0.0100	0.0095	0.0015	0.0032	0.0090
5	0.0268		0.0236	0.0131	0.0126	0.0032	0.0022	0.0069
6	0.0326		0.0294	0.0189	0.0184	0.0090	0.0069	0.0031
	Maximum commodity rates ($/Dth)							
0	0.0455		0.0685	0.0896	0.0994	0.1134	0.1247	0.1624
L		0.0302						
1	0.0685		0.0588	0.0792	0.0890	0.1030	0.1142	0.1519
2	0.0896		0.0792	0.0449	0.0546	0.0697	0.0799	0.1175
3	0.0994		0.0890	0.0546	0.0382	0.0679	0.0781	0.1158
4	0.1145		0.1041	0.0697	0.0679	0.0417	0.0475	0.0850
5	0.1247		0.1142	0.0799	0.0781	0.0475	0.0443	0.0781
6	0.1624		0.1519	0.1175	0.1158	0.0850	0.0781	0.0658

Source. TGP website.

(November–March) than the rest of the year (April–October).

6.2. Computed Demand Rates
To determine the intrinsic trading value of a deal, that is, according to (22), denote by $\mathcal{M}$ the set that includes the months in the deal's term and compute the quantity $\sum_{m \in \mathcal{M}} V_{ab}^{\mathrm{I}}(0, T_m)$ (recall that the fuel factors are seasonal and (22) should be applied accordingly). The intrinsic demand rate of a deal is the ratio

$$\frac{\sum_{m \in \mathcal{M}} V_{ab}^{\mathrm{I}}(0, T_m)}{\sum_{m \in \mathcal{M}} \delta(0, T_m)}.$$

This is essentially the valuation method discussed by Sturm (1997, pp. 142–146, 162–170) mentioned in §1. The data required in this calculation consist of the relevant forward curves for each market pair, the risk-free rate as of each bid date, and the relevant commodity rate and fuel factors. With the exception

Table 5 Fuel and Loss Retention Percent Factors for the TGP System for the Period of Time Under Study

Receipt zone	Delivery zone							
	0	L	1	2	3	4	5	6
			November–March					
0	0.89		2.79	5.16	5.88	6.79	7.88	8.71
L		1.01						
1	1.74		1.91	4.28	4.99	5.90	6.99	7.82
2	4.59		2.13	1.43	2.15	3.05	4.15	4.98
3	6.06		3.60	1.23	0.69	2.64	3.69	4.52
4	7.43		4.97	2.68	3.07	1.09	1.33	2.17
5	7.51		5.05	2.76	3.14	1.16	1.28	2.09
6	8.93		6.47	4.18	4.56	2.50	1.40	0.89
			April–October					
0	0.84		2.44	4.43	5.04	5.80	6.72	7.42
L		0.95						
1	1.56		1.70	3.69	4.29	5.06	5.97	6.67
2	3.95		1.88	1.30	1.90	2.66	3.58	4.28
3	5.19		3.12	1.13	0.67	2.32	3.19	3.90
4	6.34		4.28	2.35	2.67	1.01	1.21	1.92
5	6.41		4.34	2.41	2.74	1.07	1.17	1.86
6	7.61		5.53	3.61	3.93	2.20	1.27	0.85

Source. TGP website.

of Dracut, the forward curves used in this paper are NYMEX futures prices added to closing NYMEX or ICE basis swap prices reported by Kiodex or estimates thereof made available to the author by TGP. The risk-free rate is that observed on each open season bid date.

The transacted demand rates exceed the intrinsic demand rates in all but two cases, deals D and K. The observed demand rates of deals D and K are both maximum rates. Thus the maximum demand rates constrain the intrinsic trading values of these two deals. The result for deal D is likely to be related to Hurricane Katrina in August 2005, which caused a drastic reduction in supply in the southwest U.S. production regions, a consequent surge in prices in this region, and a reversal of the flow of natural gas into, as opposed to out of, this production region. The result for deal K does not have a natural explanation.

To determine the deals' total demand rates, one needs to compute spread option values. This requires modeling the stochastic evolution of the natural gas prices at the locations of interest. As mentioned in §1, one could take the financial engineering approach of specifying a reduced-form model of the evolution of these prices; alternatively, one could take the

financial economics approach of specifying models of the evolution of the supply and demand processes at the relevant locations and endogenously derive their associated equilibrium prices, also considering the relevant operational constraints such as the pipeline capacity (such a model would correspond to a multiperiod version of the model discussed in §5). Schwartz (1997) and Routledge et al. (2000) discuss reduced-form and equilibrium models of commodity price evolution, respectively. Carmona and Durrleman (2003), Eydeland and Wolyniec (2003), and Kaminski et al. (2004) discuss reduced-form models to value spread options, with the latter two focusing on energy applications. The approach of Routledge et al. (2001) could be used to value spread options on commodity prices.

The equilibrium approach is theoretically more appealing than the reduced form approach, but it is also more difficult to apply. This paper proceeds by taking a reduced-form approach and assumes that the natural logarithms of the spot prices at markets a and b evolve as correlated mean reverting processes, which is consistent with Schwartz (1997) and Smith and McCardle (1999). Then the risk-neutral dynamics of the futures prices at the receipt and delivery markets, a and b, are described by the following model:

$$dF_i(t, T) = F_i(t, T)\sigma_i e^{-\kappa_i(T-t)}dZ_i(t) \quad \forall i \in \{a, b\}, \quad (23)$$

$$dZ_a(t)dZ_b(t) = \rho_{ab}dt. \quad (24)$$

This is a basic reduced-form model of futures price evolution (Clewlow and Strickland 2000, Chapter 8), where σ_i and κ_i, respectively, are the volatility and speed of mean reversion of the natural logarithm of the spot price at i, $\forall i \in \{a, b\}$, and ρ_{ab} is the instantaneous correlation coefficient between $dZ_a(t)$ and $dZ_b(t)$, which are increments to standard Brownian motions. A limitation of this model is the constant instantaneous correlation coefficient ρ_{ab}, which in practice may instead exhibit a time-dependent structure. The investigation of the possible mispricing effects associated with this feature of the model is a topic for additional investigation.

Under model (23)–(24) there is no exact closed-form formula for the value of a spread option on futures prices with a positive strike price (K) and hence expression (3), but such a formula exists when

the strike price is zero (see Margrabe 1978 and Hull 2000, p. 516). Kirk (1995) leverages this result to derive a fairly accurate (Carmona and Durrleman 2003) closed-form approximation that is frequently used in energy applications (Eydeland and Wolyniec 2003, pp. 342–249). Applied to the current setting, Kirk's logic yields the following approximation, which is exact when $K = 0$:

$$V_{ab}^{SO,K}(0,T) = \delta(0,T)\left\{F_b(0,T)\Phi(E_1)\right.$$
$$\left. - \left[\frac{F_a(0,T)}{1-\phi} + K\right]\Phi(E_2)\right\},$$

$$s_{ab}^2 := \frac{\sigma_b^2}{2\kappa_b}(1-e^{-2\kappa_b T}) - 2\frac{\rho_{ab}\sigma_a\sigma_b}{\kappa_a+\kappa_b}[1-e^{-(\kappa_a+\kappa_b)T}]G_a(0,T)$$
$$+ \frac{\sigma_a^2}{2\kappa_a}(1-e^{-2\kappa_a T})[G_a(0,T)]^2,$$

$$G_a(0,T) := \frac{F_a(0,T)/(1-\phi)}{F_a(0,T)/(1-\phi)+K},$$

$$E_1 := \frac{\ln\{F_b(0,T)/[F_a(0,T)/(1-\phi)+K]\}+s_{ab}^2/2}{s_{ab}},$$

$$E_2 := E_1 - s_{ab},$$

where $\Phi(\cdot)$ is the standard normal cumulative distribution function.

The total demand rate of each deal is *proxied* as follows. The parameters σ_i, κ_i, $\forall i \in \{a,b\}$, and ρ_{ab} of model (23)–(24) are estimated using the relevant historical spot price data up to each deal's bid date using the standard methods discussed by Clewlow and Strickland (2000, §3.2.2). The total demand rate of each deal is computed as the ratio

$$\frac{\sum_{m\in\mathcal{M}} V_{ab}^{SO,K}(0,T_m)}{\sum_{m\in\mathcal{M}} \delta(0,T_m)}.$$

The computed total demand rates exceed the transacted demand rates in 23 out of 24 cases. The exception is deal S. The bid date of this deal essentially coincides with the starting date of the deal's term and this deal has zero computed intrinsic demand rate. Thus it is highly unlikely that the transacted demand rate of deal S could be attributed to the extrinsic trading value of this deal.

The intrinsic and total demand rates computed as explained above ignore the maximum demand

rate rule imposed by federal regulation. Analogous demand rates that account for this rule are also computed; that is, these new intrinsic and total demand rates are computed as the minimum of the TGP maximum demand rate for each deal and their respective demand rates previously computed. These demand rates are refereed to as the constrained demand rates. The constrained intrinsic demand rates exceed the transacted demand rates in all but two cases, deals D and K. The constrained total demand rates are equal to the transacted demand rates in 20 out of 24 cases and exceed the transacted demand rates in 3 cases (deals O, Q, and R); the transacted demand rate of deal S exceeds its constrained demand rate, which is equal to its total demand rate.

6.3. Results

Four simple linear regression models are analyzed, models 1–4. The transacted demand rate is the dependent variable in each of these models. The independent variable is the intrinsic demand rate in model 1, the total demand rate in model 2, the constrained intrinsic demand rate in model 3, and the constrained total demand rate in model 4. These models are estimated using the ordinary least squares method. Table 6 reports the results of this estimation. The *p*-values shown in this table and discussed below pertain to statistical tests whose null hypotheses are that a regression coefficient (intercept or slope) is equal to zero.

Consider models 1 and 2. The estimate of the intercept is positive both in models 1 and 2 (but it is smaller in model 2 than in model 1). In both cases, the estimate of the intercept is different from zero at reasonable significance levels (the *p*-values are 0.0000 and 0.0131 in models 1 and 2, respectively). The estimate of the slope in model 1 is positive but not different from zero at any reasonable significance level

Table 6   **Model Estimation Results**

	Model 1	Model 2	Model 3	Model 4
Intercept	5.2185 (0.0000)	2.4887 (0.0131)	4.5920 (0.0000)	0.4892 (0.3316)
Slope	0.1873 (0.2352)	0.1672 (0.0005)	0.6850 (0.0094)	0.9079 (0.0000)
R^2	0.0634	0.4326	0.2693	0.8682
Adjusted R^2	0.0208	0.4068	0.2361	0.8622

Note. The values in parentheses are the *p*-values for the statistical tests whose null hypotheses are that a regression coefficient (intercept or slope) is equal to zero.

(the p-value is 0.2352). The estimate of the slope in model 2 is positive and different from zero at reasonable significance levels (the p-value is 0.0005). The R^2 and adjusted R^2 of model 1 are 0.0634 and 0.0208, respectively. Those of model 2 are 0.4326 and 0.4068, respectively. Moreover, a model that uses the extrinsic demand rate, the difference between each deal's total and intrinsic demand rates, as the independent variable provides results very similar to those obtained with model 2. For brevity, these results are not reported here.

These findings provide some evidence against the pricing of the TGP deals at their intrinsic demand rates and in favor of their pricing at their total demand rates, mainly at their extrinsic demand rates. However, that the estimates of the intercepts of both models are different from zero at reasonable significance levels suggests that these estimates might be a by-product of ignoring the FERC maximum demand rate rule in computing the relevant demand rates. That is, because 21 transacted demand rates are equal to their maximum demand rates, even if these deals were valued at their intrinsic or total trading values, this could not have been reflected in the observed data. Thus if it is true that these deals were valued at their intrinsic demand rates, the estimate of the intercept of model 3 should no longer be different from zero at reasonable significant levels. Failure to observe this result would provide evidence against the pricing of these deals at their intrinsic demand rates. Analogous statements hold for the pricing of these deals at their total demand rates and model 4.

Thus, consider models 3 and 4. Compared to models 1 and 2, the fit of these models improves: the R^2 and adjusted R^2 of model 3 are 0.2693 and 0.2361, respectively; those of model 4 are 0.8682 and 0.8622, respectively. The estimates of the slopes are positive and different from zero at reasonable significance levels both in models 3 and 4 (the p-values are 0.0094 and 0.0000, respectively). However, the estimate of the intercept of model 3 is positive and different from zero at reasonable significance levels (the p-value is 0.0000). In contrast, the estimate of the intercept of model 4 is positive but not different from 0 at any reasonable significance level (the p-value is 0.3316). Thus these results provide more evidence

against the pricing of the TGP deals at their intrinsic demand rates and in favor of their pricing at their total demand rates. (Similar to model 2, estimating a model that only considers the constrained extrinsic demand rates yields very similar results to those obtained for model 4.)

There are limitations in this analysis, including the small data set used and how the extrinsic demand rates were proxied. Notwithstanding these limitations, it seems fair to conclude that the results discussed in this section provide empirical evidence in support of the pricing of TGP transportation capacity at its trading value, mainly at its extrinsic component.

7. Conclusions

This paper studies the pricing of natural gas pipeline capacity both from a normative and an empirical standpoint. Its normative analysis establishes that this capacity should be priced at its trading value, which can be interpreted as the value of a spread option on natural gas prices at two ends of a pipeline, by every player involved in natural gas transport. Its empirical analysis provides support for this prediction and offers insights on the role played by the intrinsic and extrinsic components of the trading value of natural gas pipeline capacity in practice. These findings suggest that uncertainty in future natural gas prices is an important driver of operational performance in the pricing of this capacity.

There are limitations in the study reported in this paper. Its empirical analysis uses a small data set in which the prices of several deals are maximum demand rates. It would be of interest to extend the analysis of this paper to a larger set of bids, possibly including deals transacted on different pipelines. It would also be valuable to collect deals transacted through the negotiated rate practice, which is not subject to the maximum rate rule. Moreover, the (extrinsic) trading values computed in the empirical analysis are proxied using a reduced-form model of the evolution of natural gas prices. It would be interesting to perform this analysis by modeling this evolution using an equilibrium approach (see, e.g., Williams and Wright 1991, Chapter 9; Routledge et al. 2001). These limitations could be addressed by further research.

The results of this paper have potential relevance for the pricing of the capacity of other commodity conversion assets in different business-to-business settings, such as those discussed by Kleindorfer and Wu (2003). The natural gas markets in North America are fairly competitive (De Vany and Walls 1995), but other settings may exhibit markets with oligopolistic features. Additional research could address the valuation of the capacity of a commodity conversion asset in such markets. A pertinent example is the very recent work by Martínez-de-Albéniz and Vendrell Simón (2009), who extend the spread option model analyzed in this paper to the case of a "large" commodity merchant, that is, a merchant whose trades influence the commodity prices.

The development of equilibrium models for decision support in the pricing of the capacity of commodity conversion assets and other real options is also an interesting area for additional research (see Dixit and Pindyck 1994, Routledge et al. 2001, Smit and Trigeorgis 2004 for relevant work).

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