Energiewirtschaftliches Institut
an der Universität zu Köln

Energiewirtschaftliches Institut an der Universität zu Köln
Albertus-Magnus-Platz
50923 Köln

EWI Working Paper, No. 09.02

Nodal prices, capacity valuation and investments in natural gas markets - Overview and Analytical Framework

by

Stefan Lochner

December 2009

The authors are solely responsible for the contents which do not necessarily represent the opinion of the EWI

Nodal prices, capacity valuation and investments in natural gas markets - Overview and Analytical Framework

Stefan Lochner*

December 2009

Abstract

Especially in the short-term, prices in natural gas markets are not exclusively determined by overall supply and demand, but also by the availability of the transport infrastructure. If transportation capacity is scarce, prices may form in (local) residual markets and can differ regionally. If available, storages provide intertemporal arbitrage possibilities which also impact prices. Temporal and regional price differences, in turn, determine the value of storage and transport capacity if either one is scarce. This paper applies an analytical framework for a simple pipeline grid with a storage over two periods to illustrate the interdependencies between prices, scarce capacity and capacity value. The theoretically optimal transportation and storage tariffs are described analytically. The optimal pipeline investment size is shown to be related to marginal storage investment and a function of the discounted and aggregated cost of congestion over the lifetime's asset.

JEL: Q41, D41, L50, P42

Keywords: Natural gas, prices, transport capacity, storage, investment

ISSN 1862-3808

*EWI - Institute of Energy Economics at the University of Cologne, Vogelsanger Str. 321, 50827 Cologne, Germany. Tel. +49-221-27729-303, Internet: http://www.ewi.uni-koeln.de, Email: Stefan.Lochner@uni-koeln.de

1 Introduction

Competitive price formation in natural gas markets is just a recent phenomenon in many continental European countries. In many non-OECD countries, it does not yet exist.

The United States and the UK, which witnessed the liberalization of their gas markets earlier than continental Europe, have competitive markets. Nevertheless, the literature on price formation, the economic valuation of transport and storage capacity, and the value of system bottlenecks - which regards those factors simultaneously - is limited. While there are sophisticated investigations of each issue on its own[1], an encompassing microeconomic perspective is missing. A comprehensive and inclusive understanding of the dynamics between commodity and capacity prices is, however, of outmost importance for regulators, policy makers and practitioners. Due to Europe's pipeline grid being much more integrated and cross-linked than the North American one and significantly larger than the British one - with only one TSO and one price zone - this may be more relevant in Europe than in the other liberalized markets.

The application of the broader economic literature of the aforementioned issues delivers only partial insights. Natural gas being a network-bound industry, prices in the short-term are to a certain extent not determined by total supply and demand but by residual supply and demand in regionally confined markets. Hence, prices for the homogeneous good might differ regionally, not only due to transport costs but also due to transport restrictions. Transportation itself is in most of the literature considered a natural monopoly with prices set by regulators. Furthermore, compared to other grid-bound commodities, most notably electricity, natural gas can economically be stored over time in large quantities. Therefore, other than in the literature on electricity markets, an intertemporal view is required to understand prices and the value of capacities.

The contribution of this paper is to consolidate the explanation of prices and the value of storage and transportation by deriving an analytical framework which allows us to do so in an encompassing manner. Therefore, an existing microeconomic model with perfect foresight by Cremer et al. (2003) is extended to include storages and intertemporality in a pipeline transmission system. The framework will allow analyses of the impact of constraints in the infrastructure system on gas prices in downstream markets, the valuation of transmission and storage capacity, and optimal investment in both storage and pipeline capacity from a theoretical point of view.

The microeconomic model is presented in Section 3; its implications for optimal transport and storage tariffs and investments are discussed Sections 4 and 5. Section 2 gives an introduction to price formation in gas markets and its relevance for capacity

[1] See for example Chaton et al. (2008) on natural gas storage, Cremer and Laffont (2002) and Cremer et al. (2003) on regional prices and pipeline capacity valuation.

valuation; Section 6 offers a summary and some concluding remarks.[2]

2 Price determinants in gas markets

Generally, prices in natural gas markets respond to the same dynamics as prices in all other markets and are therefore a function of supply and demand - with the exception that the specific characteristics of network-bound commodities, the supply infrastructure and its availability, have to be taken into account.

This is thereby especially relevant in the short-term: infrastructure capacities are set and cannot be changed quickly and demand and supply are much less elastic than in the long-run. Hence, while infrastructure bottlenecks can be eliminated in the long-term and are therefore less relevant for price formation than the overall supply and demand situation[3], this is not true in the short-term. When the infrastructure is fixed, prices in a competitive market might differ regionally as the scarce transport infrastructure can constitute a physical impediment which limits trade.[4] Hence, due to the costly and limited infrastructure (pipeline grid), supply and demand might differ between geographically separated locations. In the theoretic modeling framework, these locations, which are connected by potentially scarce infrastructure, will be referred to as nodes. For illustrative purposes, we think of them as regionally separated upstream and downstream markets in this section.

In such a separated downstream market, supply encompasses all available gas volumes in the respective market including local production, supply from past time periods (presuming there are downstream storages and gas was previously stocked there) and potential transports to the market from all other natural gas sources on all available routes. Accordingly, the demand curve in the market is made up by present consumption (with the marginal willingness to pay differing between consumers), future consumption (for which gas can be injected into local storages) and potential demand from other markets (for example due to higher prices there) provided there is transport capacity available to get the gas to the alternative market.

If transport infrastructure availability (at any given moment in time) is not an issue, all gas sources can supply all downstream markets and all consumers can obtain gas from all sources. Hence, arbitrage should cause prices to equalize regionally apart from differences in transport costs. Scarcity of capacity, on the other hand, may cause the residual supply and demand functions in the separate markets to differ resulting in different prices. The difference between prices is the price of congestion and the economic value of transmission assets between the respective markets.

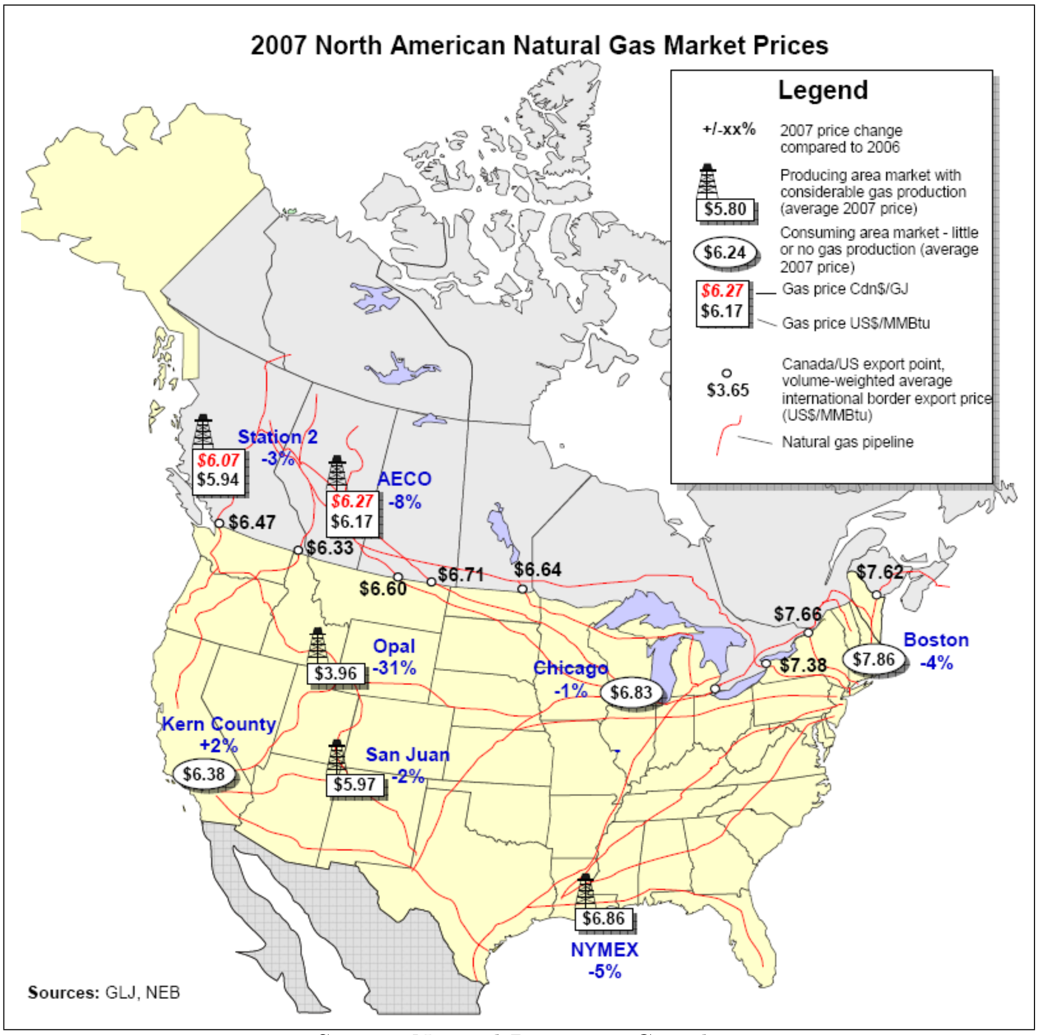
[2]Appendix A briefly introduces the TIGER Natural Gas Markt Model (by EWI) which can be applied to simulate locational marginal costs in the European downstream market. Furthermore, the implications of the conclusions from this paper for practitioners are outlined.

[3]See Stern (2007).

[4]See Stoft (2002), Chapter 5, for a similar elaboration on electricity markets.

Similarly, storage capacity (in a local market) can be thought of as transport capacity between temporally separated markets. The same logic applies: If storage capacity is unlimited, arbitrage over time is possible and price differences should not exceed variable storage costs.[5] Without storages, price formation between time periods is independent from each other.

Figure 1: Regional North American natural gas prices in 2007



Source: Natural Resources Canada

The North American gas market provides an illustrative example of differing prices between different regional markets (see Figure 1 which shows average 2007 market prices for six regions in the US and Canadian border prices)[6]. Generally, it can be observed that gas prices are lower in and closer to the production regions in Canada, the Gulf and the Western states of New Mexico, Wyoming and Idaho (with the latter seeing the overall lowest prices). The overall highest price is observed in New England (Boston) which is the downstream market furthest away from any source of production.

[5] In a microeconomic analytical framework with perfect foresight, such as the one presented in this paper.
[6] Source: Natural Resources Canada (http://www.nrcan-rncan.gc.ca/eneene//////pdf/revrev-eng.pdf).

Both findings may result from transport costs and are not surprising themselves.

Furthermore, Figure 1 also reveals the importance of infrastructure availability on prices and the impact of prices on the value of infrastructure. Similar average prices between Louisiana (Henry Hub NYMEX) and Chicago indicate that, on average, additional infrastructure between the two markets is not of great economic value. Between Chicago and Wyoming (Opal field), on the other hand, prices differ by almost 3 \$/MMBtu or three times estimated transport costs[7]. Hence, additional capacity between those two markets would allow additional trade. Whether such additional capacity is efficient is, however, not clear as that largely depends on whether or not the welfare gains from trade offset the capacity costs of the additional pipeline infrastructure over its lifetime (and the associated variable transport costs).

Hence, while infrastructure restrictions can cause prices to differ regionally in competitive gas markets, this is not necessarily inefficient (see also Section 5).[8]

3 Analytical Framework

This section develops a simple gas flow network and storage model. The model consists of two upstream and one downstream markets represented by three nodes (number 1, 2 and 3). Hence, two nodes are sources of gas with supply q_i ($i \forall 1, 2$) and one is a gas sink with demand d_3. Three pipelines connect the three nodes as illustrated in Figure 2. Pipelines from 2 to 1 (#21) and 1 to 3 (#13) have no capacity restriction, the maximum capacity of the line from 2 to 3 (#23) is K. This network is, hence similar, to Cremer et al. (2003). Other than Cremer et al. (2003), we explicitly consider storage. Therefore, we introduce a second time period and a downstream storage.

The costs of pipeline transmission for one unit of gas along one unit of length is c_{ij} for a flow from i to j. At nodes 1 and 2, gas is produced by independent (vertically from the transmission system unbundled) producers at costs of $C_i(q_i^t)$ for nodes $i = 1, 2$ and time $t = 0, 1$. Demand is inelastic at d_3^t for $t = 0, 1$. These assumptions may represent an accurate framework for short-term considerations in competitive gas markets. Even in Europe, where upstream competition is limited due to the small number of regionally separated suppliers, a large majority of supply contracts at the well-head (or the border where the gas enters the European Union) have their prices indexed to commodities other than natural gas (e.g. crude oil, fuel oil, coal, ...). Hence, the supply price is somewhat fixed and may deter suppliers from Cournot behaviour in the short-term[9], which is a sufficient precondition for our model.

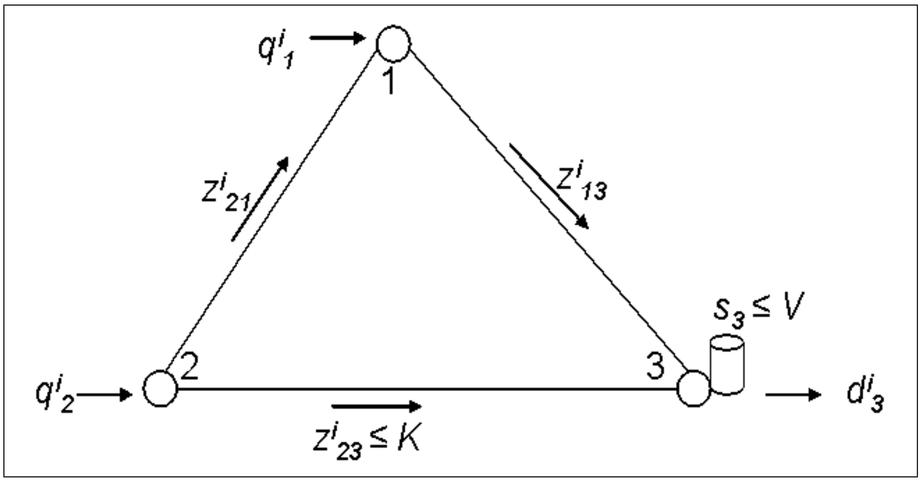
On the storage side, we regard only one gas storage in the downstream market which

[7]Based on OME (2001), we estimate transport costs over such a distance to be roughly 1.05 \$/MMBtu.

[8]In the aforementioned example, the market decided that it may be efficient (and profitable) to invest in additional infrastructure. The Rockies Express Pipeline from Colorado and Wyoming to Illinois and Ohio was completed in 2009 (http://www.rexpipeline.com). Early observations indicate a significantly decreasing price spread between the markets.

[9]A discussion on price indexation in this context can be obtained in Breton and Kharbach (2009).

Figure 2: Extended gasflow network



is presumed to be used in a welfare-maximizing way. We denote the per-unit variable costs of the storage (which incur in the period when gas is injected into the storage) with $c_{storage}$ and a working gas volume constraint of V. The variable for the amount of gas injected into the storage is denoted as s_3. For simplicity, we assume that period $t = 0$ is the off-peak period (summer) and 1 is the peak period (winter). The duration of each period can be incorporated with a proportion factor along the line of Gravelle (1976) with ω and $(1 - \omega)$ being the durations of the off-peak and peak periods respectively. However, to keep the model discrete, we simplify to $\omega = (1 - \omega) = 0.5$ which allows us to subtract from period duration altogether. We will introduce a duration factor in a simplified form in Section 5 as period duration becomes important with respect to investment costs.

Firstly, we study the first-best dispatch of natural gas, as done by a benevolent social planner, taken pipeline and storage capacity as given. The planer maximizes total social welfare. Thus, the social welfare function is given as:

$$\begin{aligned} SW \quad &= \sum_{t=0}^{1} \frac{1}{(1+i)^t} \Big[\qquad (1) \\ &+ \big(S(d_3^t) - p_3(d_3^t)d_3^t\big) \\ &+ \big(p_3(d_3^t)d_3^t - p_1(q_1^t)q_1^t - p_2(q_2^t)q_2^t - c_{13}(z_{13}^t)l_{13} - c_{21}(z_{21}^t)l_{21} - c_{23}(z_{23}^t)l_{23}\big) \\ &+ \big(p_1(q_1^t)q_1^t - C_1(q_1^t) + p_2(q_2^t)q_2^t - C_2(q_2^t)\big)\Big] \\ &- c_{storage}(s_3) - G - H \end{aligned}$$

with G and H representing the (annualized) capital costs for pipelines and storages respectively. $S(d_3^t)$ represents gross consumer surplus at node 3 and $C_i(q_i^t)$ the production function (technology) at node i.[10]

[10]Notation is, hence, analogue to Cremer et al. (2003) apart from introduced time indices and the storage variables.

As the in- and outflows of each node have to be balanced in each period, we can replace the produced and consumed quantities at the nodes as follows (with z_{ij} being the variable for volumes flows on the pipeline from i to j with $i, j \in [1, 2, 3]$):

$$
\begin{aligned}
q_2^t &= z_{21}^t + z_{23}^t \quad \forall \quad t = 0, 1 \\
q_1^t &= z_{13}^t - z_{21}^t \quad \forall \quad t = 0, 1 \\
d_3^0 &= z_{13}^0 + z_{23}^0 - s_3 \\
d_3^1 &= z_{13}^1 + z_{23}^1 + s_3
\end{aligned}
$$

This allows us to optimize over the dispatch variables $z_{ij}^t \; \forall \; ij = 21, 23, 13, \; t = 0, 1$ and s_3. The Lagrangian is as follows:

$$
\begin{aligned}
\max_{z_{13}^0, z_{21}^0, z_{23}^0, z_{13}^1, z_{21}^1, z_{23}^1, s_3} \quad L = & \\
S(z_{13}^0 + z_{23}^0 - s_3) - C_1(z_{13}^0 - z_{21}^0) - C_2(z_{21}^0 + z_{23}^0) & \\
-c_{13}(z_{13}^0)l_{13} - c_{21}(z_{21}^0)l_{21} - c_{23}(z_{23}^0)l_{23} & \\
-c_{storage}s_3 - S - H & \\
+\frac{1}{1+i}\left[S(z_{13}^1 + z_{23}^1 + s_3) - C_1(z_{13}^1 - z_{21}^1) - C_2(z_{21}^1 + z_{23}^1)\right. & \\
\left. -c_{13}(z_{13}^1)l_{13} - c_{21}(z_{21}^1)l_{21} - c_{23}(z_{23}^1)l_{23}\right] & \\
+\eta^0(K - z_{23}^0) + \eta^1(K - z_{23}^1) + \lambda(V - s_3) &
\end{aligned} \tag{2}
$$

where η^t is the Lagrange multiplier for the transmission capacity constraint in periods $t = 0, 1$ and λ is the Lagrange multiplier for the storage capacity constraint.

As we assume perfect competition in the upstream (firms supply at marginal cost) and downstream market (price equals marginal gross consumer surplus), we can rewrite the derivatives of the production functions and the gross consumer surplus with the respective inverse supply and demand functions: $p_1^t = C_1'^t$, $p_2^t = C_2'^t$, $S'^t(d_3) = p_3^t(d_3)$ for $t = 0, 1$. Hence, we obtain the following simplified first order conditions:

$$p_3^0 - p_2^0 - c_{23}' l_{23} - \eta^0 = 0 \tag{3}$$

$$p_3^0 - p_1^0 - c_{13}' l_{13} = 0 \tag{4}$$

$$p_1^0 - p_2^0 - c_{21}' l_{21} = 0 \tag{5}$$

$$\frac{1}{1+i}\left(p_3^1 - p_2^1 - c_{23}' l_{23}\right) - \eta^1 = 0 \tag{6}$$

$$\frac{1}{1+i}\left(p_3^1 - p_1^1 - c_{13}' l_{13}\right) = 0 \tag{7}$$

$$
\begin{aligned}
\frac{1}{1+i}\left(p_1^1 - p_2^1 - c_{21}' l_{21}\right) &= 0 & (8)\\
-p_3^0 - c_{storage}' + \frac{1}{1+i} p_3^1 - \lambda &= 0 & (9)\\
K - z_{23}^0 &= 0 & (10)\\
K - z_{23}^1 &= 0 & (11)\\
V - s_3 &= 0 & (12)
\end{aligned}
$$

Regionally differtiated prices, as discussed previously, can easily be established by looking at period $t = 0$. Rearranging equation (3) yields

$$
p_3^0 = p_2^0 + c_{23}' l_{23} + \eta^0 \tag{13}
$$

i.e. the price at the downstream node exceeds the price at the upstream node by variable transport costs $c_{23}' l_{23}$ if the pipeline is not congested ($\eta^0 = 0$). If congestion exists, the price at node 3 will increase by the shadow cost of the constraint η^0. In our framework (see next section), $\eta^0 = c_{13}' l_{13} + c_{21}' l_{21} - c_{23}' l_{23}$ (equation 19). Hence, in the case of congestion on pipeline #23, the price p_3^0 will increase to the supply cost of the next marginal unit, which would be transported over pipelines # 21 and #13. I.e.

$$
p_3^0 = p_2^0 + c_{13}' l_{13} + c_{21}' l_{21} \tag{14}
$$

As the competitive producer price p_2^0 is assumed to remain constant, the price increase at node 3 will cause the price difference to node 1 to rise, presuming that $c_{13}' l_{13} + c_{21}' l_{21} > c_{23}' l_{23}$.

Generally, such increasing regional price differences (in excess of marginal costs transport costs), hence, imply some form of transport infrastructure bottleneck, in this case on pipeline #23. It is, however, important to stress that an infrastructure bottleneck is not necessarily inefficient (see further discussion in Section 5 on optimal investment).

Temporal price relationships are similarly evident from equation (9). If the storage capacity restriction is not binding,

$$
p_3^1 = (1+i)\left(p_3^0 + c_{storage}'\right) \tag{15}
$$

i.e. the price in $t = 1$ equals the price in $t = 0$ plus the storage and interest costs. Similarly to regional price differences, a binding storage constraint impacts the temporal price relationship (see next section).

4 First-best transport and storage tariffs

Based on the first order conditions in equations (3) to (3), which are consistent with fixed upstream prices, a competitive downstream market and a regulated transportation infrastructure, we can also derive the optimal transport and storage charges, which imply the economic value of the marginal capacity unit of the transmission and storage asset respectively.

Optimal transmission tariff

The value of providing the service of transporting a good from A to B is represented by the difference in the value of the good between B and A. In an efficient market without trade restrictions and transport costs, arbitrage would lead prices to equalize in all markets. With transport cost and trade restrictions, this is not necessarily the case and prices may differ (see Section 2). Hence, transporting the good from B to A adds $p(B) - p(A)$ to its value. Theoretically, the transport service should, hence, be optimally priced at its value which equals the price difference.

This can easily be derived from our simple model. As shown by Cremer et al. (2003), rearranging the first order conditions for the off-peak period transport variables (equations 3 to 9) for the price difference between nodes yields that these are a function of variable costs, plus potentially the shadow costs of the pipeline capacity constraint in case of congestion:

$$p_3^0 - p_2^0 = c'_{23} l_{23} + \eta^0 \tag{16}$$

$$p_3^0 - p_1^0 = c'_{13} l_{13} \tag{17}$$

$$p_1^0 - p_2^0 = c'_{21} l_{21} \tag{18}$$

(Results are symmetrically for the second period.)

The shadow cost of the capacity restriction can be obtained by subtracting equation (4) from (3) and substituting into (5).

$$\eta^0 = c'_{13} l_{13} + c'_{21} l_{21} - c'_{23} l_{23} \tag{19}$$

Hence, the shadow costs for the capacity constrained of pipeline #23 are the extra costs incurred by using the dearer, unconstrained route via pipelines #21 and #13. More generally, as long as physical transport capacity between two locations is available, the dearest used route determines the price difference and, thus, the value of transportation on all routes. Introducing temporality and storage complicates this picture and exceeds the work by Cremer et al. (2003).

Optimal storage tariff

In order to assess the shadow cost of the storage constraint, storage needs to have a positive value as it would not be used otherwise.[11] Generally, such a positive value can for example be the result of higher marginal production costs (for higher production volumes) or a higher willingness to pay in the peak period. The same effects can, however, be shown by including the simple assumption that the pipeline constraint is binding in the peak-period. In the European gas market, this can be thought of as the consequence of higher winter demand which, despite possibly constant import prices, drives up prices as congestion on pipelines increases.

Therefore, suppose the pipeline capacity constraint is binding in period 1 but not in period 0 ($\eta^0 = 0$). η^1 is obtained similar to equation (19):

$$\eta^1 = \frac{1}{1+i}\left(c'_{13}l_{13} + c'_{21}l_{21} - c'_{23}l_{23}\right) \tag{20}$$

From first order conditions (3) and (6), we know the prices at node 3 in periods 0 and 1[12].

$$\begin{aligned} p_3^0 &= p_2^0 + c'_{23}l_{23} && (21) \\ p_3^1 &= p_2^1 + c'_{23}l_{23} + \eta^1(1+i) && (22) \end{aligned}$$

Substituting into (9) and replacing from (20):

$$\begin{aligned} \lambda &= \frac{1}{1+i}(p_2^1 + c'_{23}l_{23}) + \eta^1 - (p_2^0 + c'_{23}l_{23}) - c'_{storage} \\ \lambda &= \frac{1}{1+i}(p_2^1 + c'_{23}l_{23} + c'_{13}l_{13} + c'_{21}l_{21} - c'_{23}l_{23}) - (p_2^0 + c'_{23}l_{23}) - c'_{storage} \end{aligned}$$

Assuming competitive market structures p_2^t (for $t = 0, 1$) will equal marginal costs at node 2. Further assuming constant marginal costs and the absence of a production capacity constraint and constant returns to scale production functions, $p_2^1 = p_2^0 = p_2$ will hold true, simplifying the equation for λ to:

$$\lambda = \frac{1}{1+i}(c'_{13}l_{13} + c'_{21}l_{21}) - c'_{23}l_{23} - c'_{storage} - \frac{i}{1+i}p_2 \tag{23}$$

Thus, the shadow cost of the storage constraint equals the increase in transport costs for using the more expansive unconstrained route in period 1 minus the cost of using the less expensive route in the earlier period, the subsequent storing of the gas and the foregone interest associated with the earlier purchasing of the gas.

[11] In this case, storage can be thought of a transportation asset to supply gas from one time period to another. Without scarcity and storage costs, intertemporal arbitrage would, theoretically, lead to identical prices in both periods.

[12] $p_3^t \forall t = 0, 1$ could also be expressed in other terms in our framework. We analyse this case as it more interesting since it will combine the storage and pipeline capacity shadow costs.

The optimal storage tariff can then be expressed as the difference between prices at node 3 between periods 0 and 1, which is the value of the storage. From (9):

$$\frac{1}{1+i}p_3^1 - p_3^0 = \lambda + c'_{storage} \tag{24}$$

Trivially, we find that the equilibrium storage charge equals the marginal cost of storing gas if the storage volume constraint is not binding ($\lambda = 0$).

If $\lambda > 0$, we find from substituting from equation (23) that the storage charge is optimally set at:

$$\frac{1}{1+i}p_3^1 - p_3^0 = \frac{1}{1+i}(c'_{13}l_{13} + c'_{21}l_{21}) - c'_{23}l_{23} - \frac{i}{1+i}p_2 \tag{25}$$

I.e. the storage charge equals the cost increase in period 1 arising from using the more expansive transmission lines due to constrained storage and congested transmission line #23 in that period.

Substituting η^1 from (20), the shadow cost of the storage constraint λ from equation (23) can be rewritten as:

$$\lambda = \eta^1 - c'_{storage} - \frac{i}{1+i}(p_2 + c'_{23}l_{23}) \tag{26}$$

Thus, the shadow cost of storage capacity can also be expressed as the difference of the shadow cost of the transmission capacity constraint in period 1 (in period 0 terms) less the marginal storage costs less the foregone interest credit as a results of incurring the purchasing and transport costs in period 0 instead of in period 1 (when storing the gas).

Substituting into the optimal storage charge we find that it should equal the shadow cost of the pipeline constraint minus the foregone interest credit in optimum:

$$\frac{1}{1+i}p_3^1 - p_3^0 = \eta^1 - \frac{i}{1+i}(p_2 + c'_{23}l_{23}) \tag{27}$$

Optimal transmission tariff in the presence of storage

We now again turn to the optimal transmission tariff to investigate how it is influenced by storage capacity. As discussed before, the optimal transmission charges f can be expressed as the differences in prices between the respective nodes. From equations (3) to (5) (and (6) to (8) respectively), we find that for $t = 0, 1$:

$$\begin{aligned} f_{23}^t &= p_3^t - p_2^t = c'_{23}l_{23} + \eta^t(1+i)^t && (28) \\ f_{13}^t &= p_3^t - p_1^t = c'_{13}l_{13} && (29) \\ f_{21}^t &= p_1^t - p_2^t = c'_{21}l_{21} && (30) \end{aligned}$$

Due to pipelines #21 and #13 being unconstrained, their optimal tariff is given by the respective marginal costs. The constrained pipeline's (#23) optimal charge depends on the shadow cost of the congestion. To look at the impact of storage capacity, we again assume the constraint to be only binding in the peak period, i.e. $\eta^0 = 0$. To obtain η^1 we rearrange (26):

$$\eta^1 = \lambda + c'_{storage} + \frac{i}{1+i}(p_2 + c'_{23} l_{23}) \tag{31}$$

Substituting into the optimal transmission tariff (in period 1 terms) in equation (28) yields:

$$\begin{aligned} f^1_{23} &= p^1_3 - p^1_2 = c'_{23} l_{23} + (1+i)\lambda + (1+i)c'_{storage} + i(p_2 + c'_{23} l_{23}) \\ f^1_{23} &= (1+i)\left(c'_{23} l_{23} + \lambda + c'_{storage}\right) + ip_2 \end{aligned} \tag{32}$$

If the storage is not constrained ($\lambda = 0$), in optimum transmission on #23 should be charged at the marginal cost of storing plus the transport costs on the less expensive route in the off-peak period and plus the foregone interest by purchasing the gas in the earlier period (all in period 1 terms). Hence, the presence of (unconstrained) storage and an unconstrained transport route in an earlier period put an upper bound on the tariff for the congested pipeline in the peak period.

If $\lambda > 0$, then substituting from (23) yields the intuitive result that the transmission tariff for #23 in period 1 also has to equal the costs of the alternative unconstrained transport route (because using that route is always an alternative to storage and can therefore not be cheaper in order for storage to be viable):

$$\begin{aligned} f^1_{23} &= (1+i)\left(c'_{23} l_{23} + \frac{1}{1+i}(c'_{13} l_{13} + c'_{21} l_{21}) - c'_{23} l_{23} - c'_{storage} - \frac{i}{1+i} p_2 + c'_{storage}\right) \\ &\quad + ip_2 \\ f^1_{23} &= c'_{13} l_{13} + c'_{21} l_{21} \end{aligned} \tag{33}$$

Hence, vice versa to the previous observation, the costs of the alternative transport route constitute an upper limit on storage costs. As the next section demonstrates, in equilibrium the marginal costs of the alternatives (storage or using the dearer transport route) will be identical.

5 Optimal storage and pipeline capacity investment

We now introduce capacity investments into the social welfare optimization problem (equation 1). Therefore, the pipeline fixed costs H are replaced by $CP(K)/N$ and storage fixed costs G by $CS(V)/N$ where N denotes the number of off-peak periods the capacity can be used for (economic lifetime)[13]. Thus, $CP(K)/N$ and $CS(V)/N$ can be interpreted as the per-peak-and-off-peak-period (annualized) costs for pipeline and storage capacity respectively. For better understanding, they shall simply be referred to as annual capacity costs subsequently.

Furthermore, we introduce period duration within the year w^t for periods $t = 0, 1$. For simplicity, we denote the duration of the off-peak period with w; $(1 - w)$ is the duration of the peak period.

This will change the FOCs for s_3 (equation 9), η^0 (equation 10), η^1 (equation 11) and λ (equation 12) and produce two new FOCs:

$$\frac{\partial L}{\partial s_3} = -wp_3^0 - wc'_{storage} + (1-w)\frac{1}{1+i}p_3^1 - w\lambda = 0 \tag{34}$$

$$\frac{\partial L}{\partial \eta^0} = CP(K)/N - wz_{23}^0 = 0 \tag{35}$$

$$\frac{\partial L}{\partial \eta^1} = CP(K)/N - (1-w)z_{23}^1 = 0 \tag{36}$$

$$\frac{\partial L}{\partial \lambda} = CS(V)/N - ws_3 = 0 \tag{37}$$

$$\frac{\partial L}{\partial K} = w\eta^0 + (1-w)\eta^1 - \frac{CP'(K)}{N} = 0 \tag{38}$$

$$\frac{\partial L}{\partial V} = w\lambda - \frac{CS'(V)}{N} = 0 \tag{39}$$

Storage vs. Pipeline Investment

With the no-pipeline-congestion assumption for the off-peak period holding, i.e. $\eta^0 = 0$, we substitute $\frac{\partial L}{\partial K}$ and $\frac{\partial L}{\partial V}$ into equation (26):

$$\frac{CS'(V)}{N} + wc'_{storage} + w\frac{i}{1+i}(p_2^0 + c'_{23}l_{23}) = \frac{CP'(K)}{N} \tag{40}$$

Thus, in optimum, the per-period marginal capacity cost for pipeline equals the per-period marginal capacity cost for storage plus the extra costs incurred for storage (which are the marginal cost of storing one unit plus the foregone interest credit by purchasing and transporting this one unit of gas in the earlier off-peak period).

Hence, marginal annual pipeline and storage capacity costs are not equal in equilibrium but the former exceeds the latter by the extra cost incurred due to storing natural

[13] Please note from equation (2) that capital costs incur only once every two periods, i.e. only once for peak and off-peak period. Thinking of $t = 0, 1$ as summer and winter, N would thus be a year.

gas.[14]

Optimal investment level

For the optimal tariff on the congested pipeline (in period 1 terms), that would mean it is set at its long-run marginal cost[15]:

$$f_{23}^1 = p_3^1 - p_2^1 = c_{23}' l_{23} + \frac{1}{1-w} \frac{CP'(K)}{N}(1+i) \tag{41}$$

Hence, as the pipeline is only congested in the peak period, the marginal capital costs are only borne by peak usage through an increase in the tariff by $1/(1-w)$ accounting for the duration of the period. (The tariff, thus, decreases with a longer peak period $1-w$).

The absolute levels of pipeline investment on the congested route are determined by equation 38. Substituting from the shadow costs of the pipeline constraints in periods 0 and 1 (equations 19 (assuming $\eta^0 > 0$) and 20) yields:

$$\begin{aligned} \frac{CP'(K)}{N} &= w\left(c_{13}' l_{13} + c_{21}' l_{21} - c_{23}' l_{23}\right) \\ &\quad + (1-w)\frac{1}{1+i}\left(c_{13}' l_{13} + c_{21}' l_{21} - c_{23}' l_{23}\right) \end{aligned}$$

If $\eta^0 = 0$, as assumed earlier, the marginal capacity cost of the pipeline would in equilibrium equal the shadow cost of the constraint in the peak period (only).

Thus, we formulate more generally:

$$CP'(K) = \sum_t \left(w^t * \frac{1}{(1+i)^t} \eta^t \right) \tag{42}$$

with $\sum_t w^t = 1$ and $t = 0, 1, ..., N$ and N being the lifetime of the investment.

I.e. in a world with continuous (non-discrete) investment decisions, the marginal capital cost of the investment has to equal the discounted congestion costs over the lifetime of the asset.

6 Summary and Conclusions

The simplified gas flow model in this paper was based on a theoretical framework with perfect competition and perfect foresight. While regulators may be able to ensure workable competition in downstream markets, the latter is only present in economic theory.

Nevertheless, the findings bear some implications for prices, capacity valuation and investments in gas markets.

[14] These extra costs are weighted with w. The terms for $CP'(V)/N$ and $CP'(K)/N$ are weighted with the intra-year duration as the relative benefits of both incur in the same period within the year.

[15] Marginal capacity cost is multiplied by $(1+i)$ as it is incurred in period 0.

The model demonstrated that natural gas prices are in the short term significantly impacted by the availability of the transmission and storage infrastructure. Apart from commodity costs, location-specific supply costs are also affected by variable transport and storage costs. Consequently, the marginal cost of supply might be different for each point in the system (node), which could lead to different prices at each node. In a physically fully integrated market, the price difference between two points would not exceed the variable transport cost between these two points (for storages: the temporal price difference would not exceed variable storage costs).

However, if either transport or storage capacity is scarce, the regional or temporal price difference might exceed variable transport or storage costs.

The economic value of transmission or storage, thereby, equals the respective regional or temporal price difference - and tariffs in a theoretical optimum should reflect this value.

With respect to absolute investment sizes, the expected result, that the marginal capacity cost should equal the shadow cost of the capacity constraint, is also obtained in a simple network. Hence, a price difference in excess of variable costs, and therefore some form of bottleneck, is actually efficient if the marginal cost of additional capacity would exceed the aggregated discounted shadow cost of the constraint over the lifetime of the asset.

As storage and pipeline capacity impact prices and, thus, the shadow costs of the constraints, optimal investments in both are inextricably related to each other. Marginal capacity costs for storage and transmission are, thereby, not equal in equilibrium as gas storage bears additional costs which reduce its marginal capacity cost in the equilibrium condition relative to marginal pipeline capacity cost.

These findings with respect to absolute and relative investment have important implications for policymakers and regulators: Firstly, while a bottleneck may hamper competition and limit physical market integration, it is not necessarily efficient from an economic point of view to eliminate each bottleneck as the costs of the required investments might exceed the cost of the restriction. Secondly, a seasonal bottleneck in transportation might not be most efficiently removed by investment in transport capacity; it might be more efficient to invest in storage instead. The same can be true the other way around.

References

Breton, M. and Kharbach, M. (2009). Who benefits from price indexation? *Economics Bulletin*, 24(4):2705–2710.

Chaton, C., Creti, A., and Villeneuve, B. (2008). Some economics of seasonal gas storage. *Energy Policy*, 36(11):4235–4246.

Cremer, H., Gasmi, F., and Laffont, J.-J. (2003). Access to pipelines in competitive gas markets. *Journal of Regulatory Economics*, 24(1):5–33.

Cremer, H. and Laffont, J.-J. (2002). Competition in gas markets. *European Economic Review*, 46(4-5):928–935.

Gravelle, H. S. E. (1976). The peak load problem with feasible storage. *Economic Journal*, 86(342):256–277.

OME (2001). Assesment of Internal and External Gas Supply Options for the EU, Evaluation of the Supply Costs of New Natural Gas Supply Projects to the EU and an Investigation of Related Financial Requirements and Tools. Chapter 3 - Assessment of Future Supply Costs to Europe. Observatoire Méditerranéen de l'Énergie (OME), June 2001. [Online] Available: ¡http://www.ome.org/ PDF/ Etudes/gas_study/documents/chapter_3.pdf¿ (accessed on January 22, 2008).

Stern, J. (2007). *Is There A Rationale for the Continuing Link to Oil Product Prices in Continental European Long Term Gas Contracts?* Oxford Institute for Energy Studies.

Stoft, S. (2002). *Power System Economics: Designing Markets for Electricity.* IEEE / Wiley.

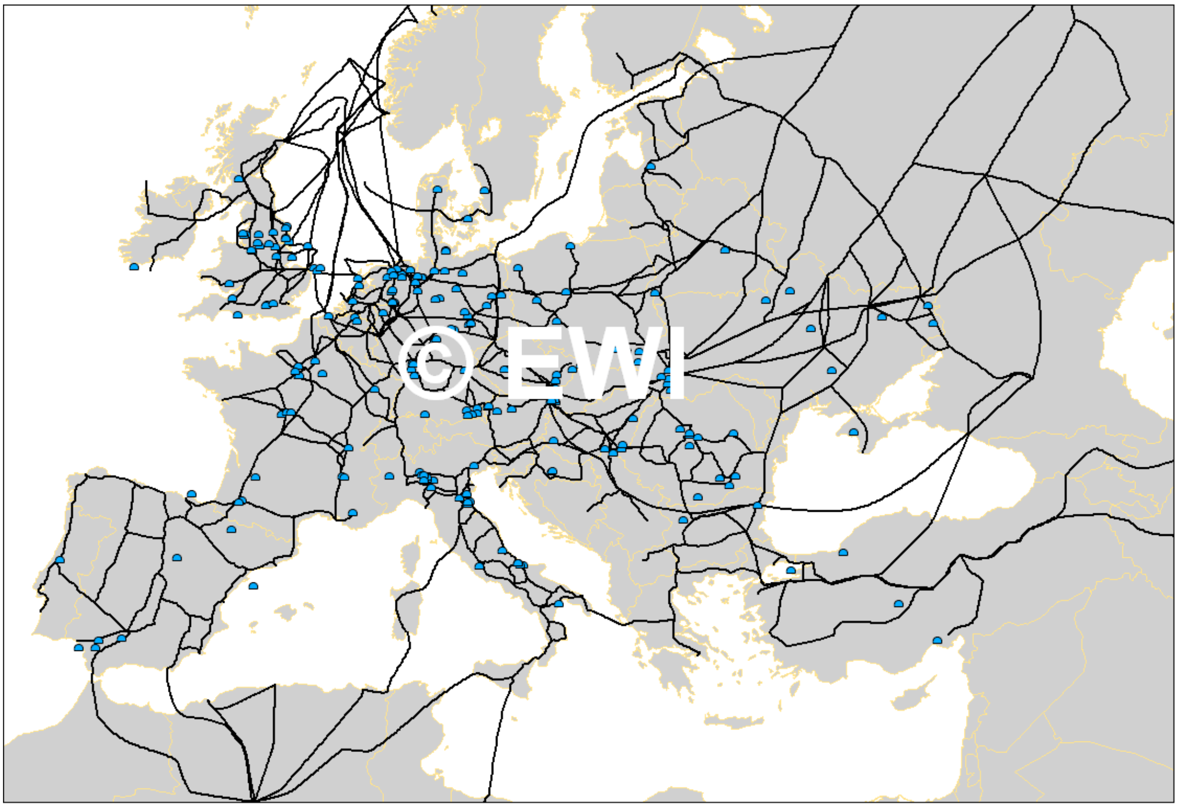
Appendix

A Nodal Prices in the EWI TIGER Infrastructure Model of the European Gas Market

Recognizing the importance of interdependencies within the European natural gas infrastructure with respect to the evaluation of new investment projects, physical market integration, and security of supply, the Institute for Energy Economics at the University of Cologne (EWI) developed the TIGER natural gas infrastructure model, which is linked to a database of the European gas market infrastructure containing all high-pressure long-distance transmission pipelines and all natural gas storages.

Apart from taking into account other gas-market characteristics, which were omitted in the theoretical considerations in this paper (LNG imports as a source of gas, production capacities and flexibilities), TIGER is, hence, a larger and sophisticated version of a gas flow model as shown in Figure 2 on page 5.[16] An illustration of the TIGER gas flow model including all pipelines and storages is depicted in Figure 3.[17]

Figure 3: EWI TIGER Gas Flow Model



Source: EWI, illustration including selected pipeline and storage projects

[16] A detailed description of the model and the database can be obtained in form of a model description on EWI's webpage (www.ewi.uni-koeln.de) or by request from the author of this paper.

[17] Nodes are omitted in the map for illustrative purposes but are located at each interception of pipelines and at locations of supply, demand and storages.

As the TIGER model can be applied with respect to the identification and economic valuation of bottlenecks and the determination of location-specific marginal costs, Appendix A.2 discusses the estimation of nodal prices with the model and the application of the conclusions from the theoretical part of this paper. Section A.1 presents the model mathematically.

A.1 Model Formulation

The model is a linear optimization model minimizing the total cost of gas supply in the European gas market taking into account the relevant technical constraints of the infrastructure and assuming an efficient utilization of infrastructure assets (i.e. effective regulation of the natural monopoly pipeline infrastructure and either a competitive storage market or its effective regulation[18]).

On the upstream side, it is assumed that gas is sold at price-inelastic commodity costs which is compatible with the assumptions of the theoretical model.[19] With respect to demand, the model does not incorporate a price elasticity in the short-term apart from an infinitely high threshold price above which consumers are assumed to reduce consumption.[20]

Hence, the objective function minimizes full commodity plus all variable costs incurred in the supply process:

$$
\begin{aligned}
\min \ TC \quad = \quad & \sum_{t,i} \text{CommodityCost}_i * \text{Supply}_{t,i} \\
& + \sum_{t,i,j} \text{TransportCost}_{i,j} * \text{Flow}_{t,i,j} \\
& + \sum_{t,i} \text{StorageCost}_i * \text{StorageLevel}_{t,i} \\
& + \sum_{t,i} \text{RegasificationTariff}_i * \text{LNGImports}_{t,i} \\
& + \sum_{t,i} \text{ThresholdPrice} * \text{DemandReduction}_{t,i}
\end{aligned}
$$

for all nodes i, all pipelines from nodes i to j, the respective storages and LNG terminals located at nodes i and all time periods t. Time periods t can, thereby, differ in length depending on the configuration of the model but are usually either one day or one month.

The optimization of this objective function is subject to a number of technical restrictions arising from production, transport pipelines, storages and LNG terminals.

[18]Depending on whether storage is regulated or not. The same holds true for LNG import facilities.

[19]Prices for short-term LNG cargos are presumed to form in the global market with Europe being a price-taker; commodity prices in long-term import contracts are supposed to be fixed by price-indexation to substitutes and therefore not a function of gas market supply and demand.

[20]This price is chosen to be so high that it only becomes relevant when supply costs rise to infinity, which is the case only when demand can no longer be met due to restrictions on the upstream or infrastructure side.

Production is aggregated to production regions but assigned for individual nodes. Both have to adhere to the following constraints (only depicted for nodes for simplicity):

$$\begin{aligned} \text{Supply}_{t,i} &\leq \text{PeakSupplyCapacity}_{t,i} \\ \sum_{t \in year} \text{Supply}_{t,i} &\leq \text{AnnualSupplyCapacity}_{year,i} \end{aligned}$$

The only restriction for transport pipelines is its capacity (which depends on t as it may change over time):

$$\text{Flow}_{t,i,j} \leq \text{PipelineCapacity}_{t,i,j}$$

For all combinations of nodes i, j where there is no pipeline, $PipelineCapacity_{i,j}$ is zero implying that the flow on the pipeline has to be zero, too. Pipeline directionality is taken into account by differentiating between capacities between i and j and between j and i.

Storages are constrained by a working gas volume (WGV) and maximum injection and withdrawal rates which are a function of the current storage level (as they change with the pressure inside the storage). Furthermore, storages need to adhere to a balance constraint ensuring that injections and withdrawals (and the resulting storage level) are in equilibrium over time:

$$\begin{aligned} \text{StorageLevel}_{t,i} &= \text{StorageLevel}_{t-1,i} \\ &\quad + \text{StorageInjections}_{t,i} - \text{StorageWithdrawals}_{t,i} \\ \text{StorageLevel}_{t,i} &\leq \text{WGV}_{t,i} \\ \text{StInjections}_{t,i} &\leq f(\text{MaxInjection}_{t,i}, \text{StorageLevel}_{t,i}) \\ \text{StWithdrawals}_{t,i} &\leq f(\text{MaxWithdrawal}_{t,i}, \text{StorageLevel}_{t,i}) \end{aligned}$$

Similar to production facilities, LNG import terminals are subject to maximum output rates and annual nominal import capacities (LNG storages are included in the same fashion as regular natural gas storages):

$$\begin{aligned} \text{LNGImports}_{t,i} &\leq \text{PeakRegasificationCapacity}_{t,i} \\ \sum_{t \in year} \text{LNGImports}_{t,i} &\leq \text{AnnualImportCapacity}_{year,i} \end{aligned}$$

In addition to all those technical constraints, an energy balance constraint ensures that the market clears. For all nodes n and time periods t it needs to be true that the sum of gas volumes *entering* a node are equal to those *leaving* it:

$$\begin{aligned} &\text{Supply}_{t,i} + \sum_j \text{Flow}_{t,j,i} + \text{StorageWithdrawals}_{t,i} + \text{LNGImports}_{t,i} \\ = \; &\sum_j \text{Flow}_{t,i,j} + \text{StorageInjections}_{t,i} + \text{DEMAND}_{t,i} - \text{DemandReduction}_{t,i} \end{aligned}$$

As this condition needs to be true for all nodes i and all time periods t, it also ensures that the system as a whole is in equilibrium in each time period and over time.

Formulating the Lagrangian of the optimization problem and solving the problem would not only provide results for all optimization variables $Supply_{t,i}$, $Flow_{t,j,i}$, $LNGImports_{t,i}$, $StorageLevel_{t,i}$, $DemandReduction_{t,i}$, $StorageInjections_{t,i}$ and $StorageWithdrawals_{t,i}$, but also allows an interpretation of the shadow costs (Lagrange multipliers) of the restrictions.

The shadow cost of the energy balance constraint, thereby, indicate the total system cost of supplying one additional unit of gas at the respective node and the respective time. These can, hence, be interpreted as location- and time specific marginal costs, which constitute nodal prices in a competitive market.

A.2 Modeled Locational Marginal Costs and their Implications

These nodal prices are notionally equivalent to the market prices at the different nodes which were derived in Section 3 of this paper.

The energy balance constraint of the model highlights the importance of infrastructure for short-term price formation in a regionally confined market (or at a node) as, apart from local supply and storage withdrawals, supply is largely made up by import (inflows) on pipelines. The same holds true for demand which can come in the form of demand for exports (outflows). As discussed before, if the pipeline infrastructure is scarce, demand and supply may differ regionally and limit arbitrage opportunities. Hence, prices may differ in excess of variable costs implying a bottleneck on a pipeline route. (See equation (13), page 7, with $\eta^0 > 0$.)[21]

However, as shown theoretically, a bottleneck is not necessarily inefficient. As demonstrated in Section 5 (equation (42)), if the marginal cost of the congestion does not exceed the marginal capacity cost, having price differences and, hence, an infrastructure bottleneck is efficient. With discrete investment decisions (as in the reality of a gas market: building a pipeline with a non-infinitesimal capacity or not), the marginal units cannot be considered and volumes have to be further taken into account. In theory, if the investment costs of a pipeline (expansion) exceed the discounted, volume-weighted shadow-costs of the capacity restriction, the investment is not efficient.

With respect to an analysis of bottlenecks in the gas market and implications for investment requirements, the following issues shall be noted:

1. As the TIGER Gas Flow Model does not include investments (and investment costs), it cannot compute optimal investment decisions. The model can, however, assist in evaluating potential investment projects. Differences in location-specific

[21] This section focuses on the discussion of pipeline bottlenecks. Similarly, storage bottlenecks can be identified by investigating temporal price differences and variable storage costs.

marginal costs can be used to determine the economic costs of the constraint and the economic value of the inframarginal additional capacity unit. Comparing these (over time aggregated and discounted) shadow costs with the capital costs of pre-defined investment projects will allow a conclusion on whether or not it is economically efficient to eliminate or reduce the bottleneck with the respective project. This project may be either a storage or a pipeline.

2. Furthermore, this paper demonstrated that pipeline investments are impacted by storage investments and vice versa. The same holds true with respect to interdependencies between one pipeline asset and another. Hence, if several investments are found to be economically viable, the simultaneous elimination of several bottlenecks may not be efficient as one is not unlikely to have an impact on the other. (One new investment might resolve more than one bottleneck.) Hence, by including the most beneficial investment project from an economic point of view, the model can not only be applied to calculate the potential reduction of the price differential and the decline in total systems costs as the consequence of the new project. In a second step, it may also be used to investigate the impact on other bottlenecks. The evaluation and identification of any second most beneficial investment project would only start there.

3. Finally, with respect to a practical implementation, it shall further be noted that the shadow cost computation of a constraint is associated with uncertainty regarding future demand and supply developments and potentially competing infrastructure(s). Hence, it is advisable to calculate expected shadow costs instead by including variations of the uncertain parameters in a scenario analysis. In the Tiger Model framework, each scenario would then be calculated separately. The derived scenario shadow costs, weighted with the probability of the scenario, would add up to the expected shadow costs of the constraint.