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Local Consequences of Global Uncertainty: Capacity Development and LNG Trade under Shale Gas and Demand Uncertainty and Disruption Risk

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Local Consequences of Global Uncertainty:

Capacity Development and LNG Trade under Shale Gas and

Demand Uncertainty and Disruption Risk

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Abstract

Recent supply security concerns in Europe have revived interest into the natural gas market. Here, we investigate investment behavior and trade in an imperfect market structure under uncertainty in both supply and demand. We focus on three uncertain events: i) transit of Russian gas via Ukraine that may be disrupted from 2020 on; ii) natural gas intensity of electricity generation in OECD countries that may lead to higher or lower natural gas demand after 2025; and iii) availability of shale gas around the globe after 2030. We illustrate how timing of investments is affected by inter-temporal hedging behavior of market agents, such as when LNG capacity provides *ex-ante* flexibility (e.g., in Ukraine to hedge for a possible Russian supply disruption) or an *ex-post* fallback option if domestic or nearby pipeline supply sources are low (e.g., uncertain shale gas resources in China). Moreover, we find that investment in LNG capacities is more determined by demand side pull (due to higher needs in electric power generation) than by supply side push (higher shale gas supplies needing an outlet).

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1 Introduction

Natural gas markets have regained the attention of policy makers and the public in recent years in the wake of the shale boom in North America and the Russian-Ukrainian war. Both developments have proven that natural gas plays an important role in today's energy systems where it covers about 20% of the global energy production (IEA, 2015). Natural gas is not only used directly in final consumption, but it is also an important feedstock and combustion fuel for industrial processes and it is used as fuel for the power sector.

The natural gas sector relies on sector-specific infrastructure in the form of pipelines and liquefied natural gas (LNG) export and import terminals. Hence, there is strong path-dependency once a capacity investment is realized. Today's decisions on capacity development are shaped by expectations of future demand and competitor behavior. Here, we aim to analyze how uncertainty in the future influences investment decisions and in turn natural gas flows, particularly in LNG. We previously suggested that LNG will play a major role in natural gas market dynamics in the coming decades due to the maturation of traditional pipeline markets (Holz et al., 2015).

Our analysis of uncertainty relies on a scenario tree that is structured around three impact factors that have proven to be influential in the global natural gas market. These impact factors were selected from the supply and demand side of natural gas markets. The three factors listed below each have several possible realizations.

a. Ukrainian transit: Transit of Russian natural gas exports to Europe via Ukraine may be permanently disrupted from 2020 on, reflecting the threat by Gazprom not to continue transit after expiration of the current transit contract in 2019. Alternatively, gas suppliers decide on a cost basis for their transits.

b. Natural gas demand: natural gas use in the electricity sector may increase in a post-Fukushima energy transition scenario. We assume higher demand for natural gas compared to the base case due to stronger use of natural gas in electricity generation, replacing nuclear generation (such as in Japan) and possibly coal (such as in North America) and providing fossil back-up for renewables. Alternatively, the German low-gas *Energiewende* could also occur in which renewables displace natural gas while low carbon prices favor coal.

c. Unconventional gas production: we assume high or low production capacity due to more or less favorable political and technical conditions to unconventional gas

production. The "boom" scenario follows the *Golden Age of Gas* case designed by the IEA (2012a). In contrast, the "gloomy unconventional" scenario limits the availability of unconventionals to the few countries that already have such production (USA, Canada, Australia, and China) with approximately their 2015 capacities.

In the next section, we discuss the literature of stochastic energy market modeling. Thereafter, we present the storylines underlying the eight scenarios included in the stochastic scenario tree and other input data assumptions and calibration. In Section 4, we briefly present the model and in Section 5, we discuss results. In the last section, we provide conclusions and directions for future research.

2   A Stochastic Model of Natural Gas Networks and Markets

2.1   Literature

In recent years, an increasing number of models explicitly addressing uncertainty in energy markets have been developed. Not every type of model is suitable for modeling energy markets. The imperfect competition situation that often occurs disqualifies optimization models for analyzing energy markets with multiple actors. In contrast, real option approaches may consider a game setting, but rather take the perspective of a single actor facing one or a few decisions under uncertainty (e.g., Murto et al. 2004). Stochastic equilibrium models can address both imperfect competition and uncertainty, and provide suitable tools for analyzing (imperfect) energy markets.

One common way to represent uncertainty is by limiting the number of possible future outcomes to a finite set of outcomes represented by scenarios. Extensive stochastic problem formulations include these scenarios and their probabilities explicitly. A stochastic problem contains at least two stages where some model actors' decisions, the *here-and-now* decisions, must be made at an earlier stage, prior to when uncertain events are known. Two-stage problems provide the simplest information structure. Typical first or early stage decisions concern long-term contracts and investments. In later stages, uncertain parameters, such as demand or price levels, become known and so-called *recourse* (or *wait-and-see*) decisions, for instance spot market trades, can be made.

Early two-stage stochastic complementarity problems for natural gas markets include a study by Haurie et al. (1990) who analyzed long-term contracting decisions in the European natural gas market under oil price uncertainty and studies by Zhuang (2005)

and Zhuang and Gabriel (2008) who looked into long-term contracting under gas spot price uncertainty. Abada (2012) presented a two-stage stochastic model for the European gas market (GAMMES) for infrastructure investments under gas demand uncertainty.

In contrast to the two-stage problems mentioned above, in multi-stage problems there are several moments in time where actors make decisions facing uncertainty; however, at later stages some of the uncertainty has been revealed. Genc et al. (2007) studied investment decisions in multi-period oligopoly problems with uncertainty and applied their model to the electricity market in Ontario. Egging (2010, 2013) developed a stochastic mixed complementarity problem for application to an aggregate regional representation of the global natural gas market. A similar model, S-GASTALE, for the European market is presented by Bornaee (2012).

In the above paragraph, we focused on extensive-form stochastic mixed complementarity models presented in the literature. Readers interested in solution methods to address scalability challenges of such models can refer to Fuller and Chung (2005, 2008), Gabriel and Fuller (2010), and Egging (2010, 2013) who developed and applied decomposition methods; Gabriel et al. (2009) who implemented scenario reduction; and Lise and Hobbs (2008) and Devine et al. (2015) who implemented rolling horizon approaches.

2.2   Data

The **base case** data ranges from years 2010 to 2035. The model is based on yearly averages in five-year steps. The database is similar to that used by Richter and Holz (2015) and contains 171 country/regions and LNG nodes in 79 countries.
[1]

The Base Case is calibrated to match the European Commission's "Reference Scenario 2013" (EC, 2013) for the European nodes and the IEA's "World Energy Outlook 2013" *New Policies Scenario* (NPS) for all other world regions (IEA, 2013).[2] It contains a number of quite optimistic unconventional assumptions such as continuous growth in North American unconventionals, strong coal bed methane (CBM) development in China

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[1] Several large countries are split into separate nodes and liquefaction and regasification terminals are represented as separate nodes. The dataset contains 11 consumption-only nodes, 88 nodes with consumption and production, 29 liquefaction, and 43 regasification nodes.

[2] In fact, before implementing the stochastic scenario tree, the *deterministic* GGM has been calibrated to reflect country specific consumption and production in 2010 and future years within a few percentage points for global totals, the continents, and most individual countries (as far as country-specific values were provided by EC and IEA projections). For some countries with rather small production and consumption, somewhat larger deviations still exist. Since we allow exertion of market power by traders, the calibration of this equilibrium model is not straight forward. Egging et al. (2010) described in detail the kind of adjustments made to calibrate various cost and market power parameters in the calibration process.

and Australia, but also in Russia, and significant shale gas production capacity in Mexico, Argentina, and other parts of South America. It also includes more than 50 billion cubic meter (bcm) unconventionals in Europe by 2035, mainly in Eastern Europe (Poland, Ukraine).

2.3 Scenario tree

Given the knowledge of events that we currently have until 2015, we set uncertainty to begin from 2020 onwards. In 2020, two scenarios can happen with equal probability (50% each), namely the Base Case or complete disruption of Russian gas transit via Ukraine. In each of the following periods, the scenario tree again splits into two branches of equal probability at each node (see Figure 1). Hence, at the end of the model horizon, the scenario tree consists of eight branches with equal probability to realize (12.5%) and 32 nodes in total (Table 1). In the following text, assumptions of the scenarios are described in detail.
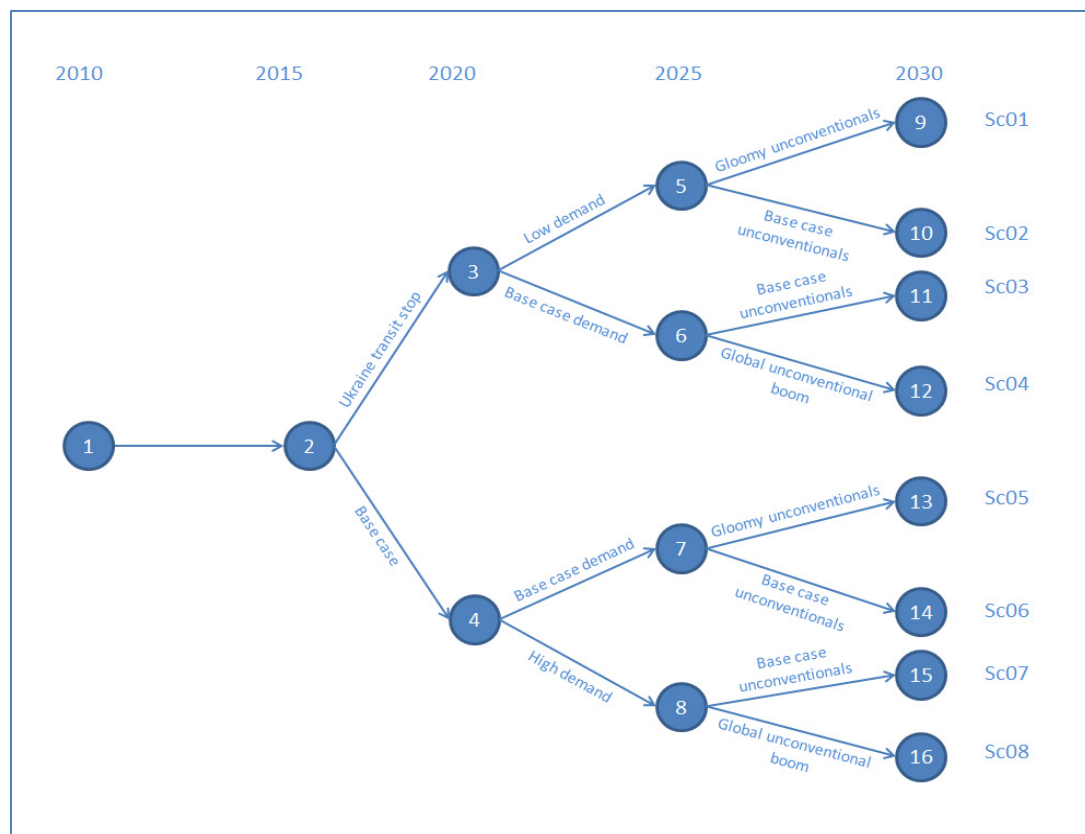

Figure 1: Scenario tree for the S-GGM application

Table 1: Scenario names and abbreviations

Year	Scenario node	Scenario abbreviation	Year Branch	Branch	Scenario	Branch
2010	01		2010			Scen-1-8
2015	02		2015			Scen-1-8
2020	03	UD	UD	UD	Ukraine disrupted	Scen-1-4
	04	UT	UT	UT	Ukraine transit	Scen-5-8
2025	05	UDLD	UD|LD	LD	Low demand	Scen-1-2
	06[a]	UDBD	UD|BD	BD	Base demand	Scen-3-4
	07	UTBD	UT|BD			Scen-5-6
	08	UTHD	UT|HD	HD	High demand	Scen-7-8
2030	09	UDLDLS	UD|LD|LS	LS	Low shale	Scen-1
	10	UDLDBS	UD|LD|BS	BS	Base shale	Scen-2
	11	UDBDBS	UD|BD|BS			Scen-3
	12	UDBDHS	UD|BD|HS	HS	High shale	Scen-4
	13	UTBDLS	UT|BD|LS	LS	Low shale	Scen-5
	14	UTBDBS	UT|BD|BS	BS	Base shale	Scen-6
	15	UTHDBS	UT|HD|BS			Scen-7
	16	UTHDHS	UT|HD|HS	HS	High shale	Scen-8

[a] Scenario 6/UTBDBS is based on Base Case assumptions only.

2.3.1 Scenario variation of Ukrainian transit

We assume that there is a 50% chance that Russian gas transit via Ukraine ends in 2019 and will not resume until the end of the model horizon. Indeed, in late 2014, Gazprom cancelled its South Stream project across the Black Sea to Bulgaria and announced that it would not renew the transit contract through Ukraine that expires in 2019.[3] Hence, Russian gas would have difficulties finding its way to traditional importers in Eastern and South Eastern Europe, such as Hungary, Bulgaria, and Romania, but also Slovakia. In principal, this effect should be negated by reverse flow capacities to be installed on all cross-border pipelines until December 2013 as mandated by the European Commission. However, there is not yet a complete bi-directional pipeline network achieved, particularly between many East European countries.[4]

In Richter and Holz (2015), we investigated the impact of a temporary transit disruption through Ukraine and found that the current network setting is not sufficient to protect the East European countries from strong consumption reductions and price increases. In this

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[3] Gazprom's announcement included the refusal to sell its gas beyond the EU border. Hence, if the newly planned "Turkish Stream" pipeline is accomplished, Russian gas would be delivered up to the Turkish-Greek border. All further pipeline transportation must be organized by the Europeans. Source: http://www.gazprom.com/press/news/2015/february/article218460/, Accessed on 18.03.2015.
[4] According to EC (2014), out of the EU's 53 cross-border interconnection points, only 21 (about 40%) are bi-directional. Reverse flows are still missing at some major interconnection points such as in Obergailbach (France-Germany), Waidhaus (Czech Republic-Germany), and on the BBL pipeline (Netherlands-UK).

paper, we analyze whether, in the long run, willingness to pay in this region is high enough to warrant additional pipeline investments to bring North European or LNG supplies to these markets.

2.3.2   Scenario variation of demand

Long-run demand for natural gas can vary in both directions in the largest consumption regions: North America, (Western) Europe, and Asia. The main uncertainty in natural gas demand lies in its consumption by the power sector. Consumption by industry (for petrochemicals or process heat) and households is likely to be more stable in the long run. Hence, we vary the demand by the power sector in this set of scenarios: we decrease (increase) the power sector's demand by 25% compared to the Base Case in 2025 and by 50% in 2030 and thereafter. We assume that demand decreases (increases) in the following countries and regions: USA, European Union members (EU-28), Switzerland and Norway, Ukraine, Japan, and China.

In Holz et al. (2015), we discussed the main drivers of demand uncertainty and investigated the impact on world markets of a Climate scenario with lower demand than the Base Case across the world but with different regional specificities. Given uncertainty on the use of natural gas by the power sector, both the high and the low demand scenarios are assumed to realize with the same probability. A lower demand for natural gas will, for example, happen in a power system where a strong increase in renewable capacity leads to replacement of natural gas by renewable generation. This is what happened in Germany in the last few years when the *Energiewende* was accompanied by low CO_2 prices that gave coal a competitive advantage against natural gas. In contrast, it is also possible that natural gas will replace coal and nuclear generation due to its favorable characteristics, including low GHG emissions and flexible electricity generation that can complement volatile renewable generation. In this case, demand for natural gas would be higher than in the Base Case.

2.3.3   Scenario variation of unconventional gas production

As mentioned in Holz et al. (2015), there is also uncertainty on the supply side of the natural gas market. One of the major uncertainties concerns the availability of unconventional gas as the last decade has shown that shale gas in the USA unexpectedly and very quickly became a major supply source. We focus our analysis on shale gas and

coal bed (and coal seam) methane.[5] Unconventionals may increase the availability of natural gas in many regions that are not endowed with conventional resources but are consumers of natural gas. Hence, the world trade patterns will be strongly affected by variation in the availability of unconventional gas.

It is noteworthy that our Base Case, which follows the *New Policies Scenario* in the IEA (2013) *World Energy Outlook*, implicitly contains very optimistic assumptions on unconventionals: by 2035 more than 1000 bcm of the world production of almost 5000 bcm is assumed to be unconventional gas. Compared to the IEA (2012b) low and high unconventional cases, our Base Case is considerably closer to the high unconventional case than to the low case (see Figure 2).[6]
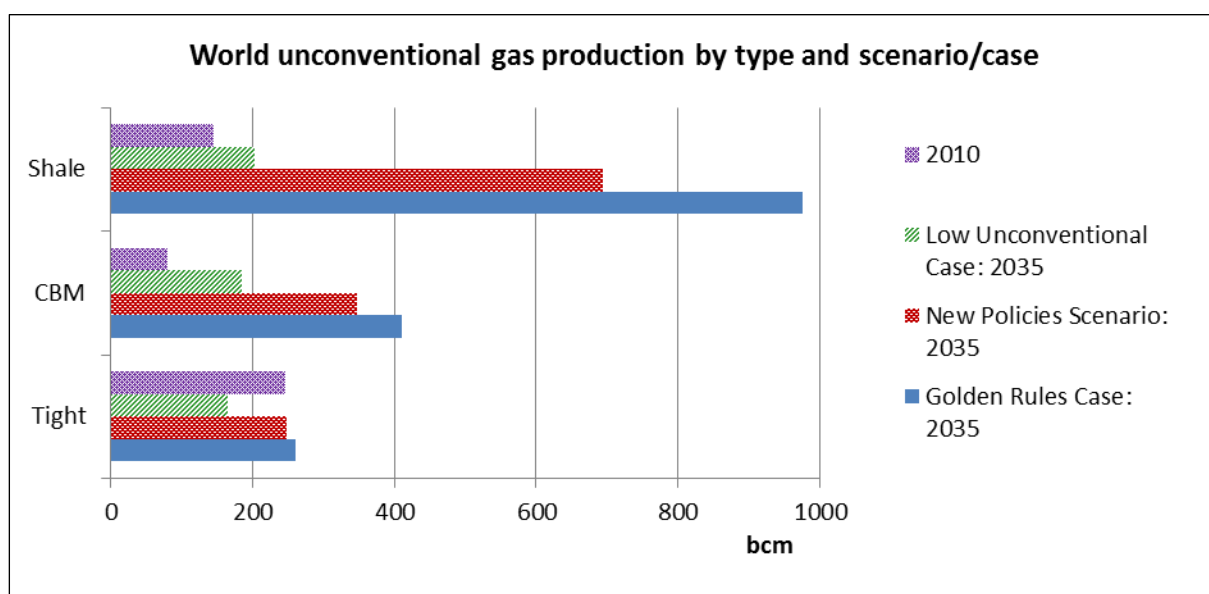
Figure 2: Comparison of unconventional gas production assumptions in different IEA scenarios[a]
[a] Source: IEA (2012b, p. 145)

In our gloomy unconventional scenario, we maintain the 2015 levels of unconventional production in 2030 and thereafter. This means that most countries are assumed to have no unconventional production (any more) in 2030 or thereafter, while unconventional production in the USA, Canada, China, and Australia returns to 2015 levels. Since the GGM dataset does not distinguish between conventional and unconventional production,

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[5] We consider tight gas, particularly in Europe and Russia, to be conventional gas, even though it is sometimes classified as unconventional gas source, particularly in North America.
[6] Note that the *New Policies Scenario* in IEA (2012) and IEA (2013) are very similar.

we adjust the total natural gas production capacity accordingly (see Table 4 in the Appendix).

In the unconventional boom scenario, we assume that the very optimistic forecasts of the case "Golden Age of Gas" (IEA, 2012a) materialize. This translates to a moderate increase in production capacities in the global total compared to our Base Case and some sizeable additions in a few regions (see Table 2 in the Appendix). For example, we assume 70 bcm higher production capacities in Europe in 2035 (mostly shale gas), an additional 280 bcm in China in 2035 (shale gas and CBM), and 10 bcm more in Japan (methane hydrates). The 2035 numbers from IEA (2012b) were already reached by the North American shale gas production of the last years, so we assume production capacities in 2035 to be larger by 200 bcm than the Base Case in the USA and 10 bcm larger in Canada. Given the logarithmic cost function used in S-GGM, larger production capacities will have the effect of keeping the cost curve in the lower section for a larger capacity.

2.4 Model

The analysis of future natural gas production, consumption, and trade patterns performed in this paper is carried out using the stochastic global gas model (S-GGM) presented in Egging (2010, 2013). However, rather than using the twenty-region dataset used by Egging (2010, 2013), we employ an up-to-date disaggregated dataset consisting of 79 countries and regions used in deterministic studies presented by Richter and Holz (2015). To allow the model to scale up to this regional detail, we reduce the level of detail of the representation of demand seasonality and storage. In other words, we consider yearly average volumes, without inter-seasonal storage.

The S-GGM distinguishes producers, traders, gas transportation infrastructure operators, and final demand sectors. The (upstream) trader is the central agent in the model's perspective. Figure 3 shows how gas traders buy gas from one or more producers, whereas producers can only deliver to one trader. Traders can sell gas domestically or use the pipeline transmission system and liquefied natural gas infrastructure to export gas to final-demand sectors in other countries. The consumption data reflect three final demand sectors: residential/commercial, power generation, and industrial consumption.
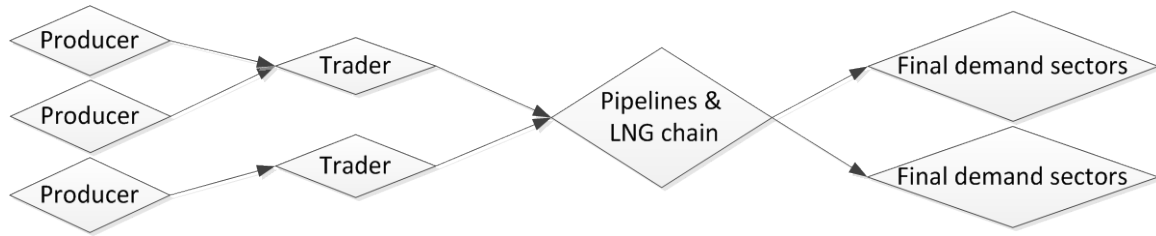
Figure 3: Supply chain illustration in the Global Gas Model

Producers maximize expected discounted profits of all periods facing production capacity constraints. Traders maximize expected discounted profits consisting of revenues from selling natural gas minus costs for purchasing natural gas and costs for using pipelines, liquefaction, and regasification capacities. Traders can be parameterized to exert market power. This is implemented through a conjectured variation approach, which allows for values between 0, no market power exertion, to 1, market power exertion à la Cournot. The Transmission System Operator (TSO) maximizes expected discounted congestion rents from renting out potentially scarce transportation capacities, minus investment cost for extending pipeline, liquefaction and regasification capacities. Final demand is represented by linear inverse demand curves, which are included in the trader's objective functions. For details and a full mathematical description (including the storage sector) refer to Sections 6.6-6.7 in Egging (2010) or Egging (2013).

In the following results discussion, volumes are typically presented in bcm/year (or bcm per annum, bcma) and prices in \$/kcm (USD/1000 m^3). Model results are discussed for the period until 2030, i.e., just after the last uncertainty has been revealed, although the model horizon runs to 2040 to allow for a sufficient payback period for capacity expansions coming online in 2030. We have rounded bcm values in the discussion to the nearest integer, unless it affects interpretation.[7]

3 Results and Discussion

Although reference demand assumptions for the LD and HD are symmetric, global market and price effects and infrastructure bottlenecks cause asymmetric results.

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[7] A discussion of stochastic modeling results is not complete without considering the Value of Stochastic Solution (VSS, Birge and Louveaux 1997). The VSS is a concept that measures the added value of addressing uncertainty in a model formulation. To calculate the VSS of the players in our model, we must take the capacity expansions for an *Expected Value* deterministic model run and freeze the values at all stages of the stochastic model run. We have tried several times in different ways to do this for the model and dataset used in this paper, but unfortunately the solver was not able to find a solution for these instances. Considering results reported previously for the aggregate Global Gas Model dataset (Egging (2010, 2013)), we speculate that the VSS is modest as a percentage value of total profits.

3.1 Disrupted Ukraine

For many decades, the Ukrainian gas network has been the backbone of Russian exports to Europe. Until the early 2000s, almost all Russian exports had to transit via Ukraine.[8] In the past, Russian dependency on Ukrainian transit ensured Ukrainian import of Russian gas; however, this situation changed with the Russian-Ukrainian crisis in late 2013. In the face of Russian threats to cease natural gas delivery to Ukraine, a number of reverse flow capacities from EU countries to Ukraine were put in place during 2014. During 2014 and the winter of 2014/2015, some of the provisional facilities became permanent supply routes and construction work is under way to keep these capacities in place beyond short-term crisis management. In line with ENTSO-G (2014), the dataset includes current pipeline capacity into Ukraine from Hungary (annual capacity of 6 bcm), Poland (1.5 bcm), and Slovakia (9.7 bcm). In our model runs, we found that no investment in additional pipelines into Ukraine takes place during 2015. In other words, the existing reverse flow capacity seems to be sufficient to balance a possible disruption of the Russian exports to Ukraine.
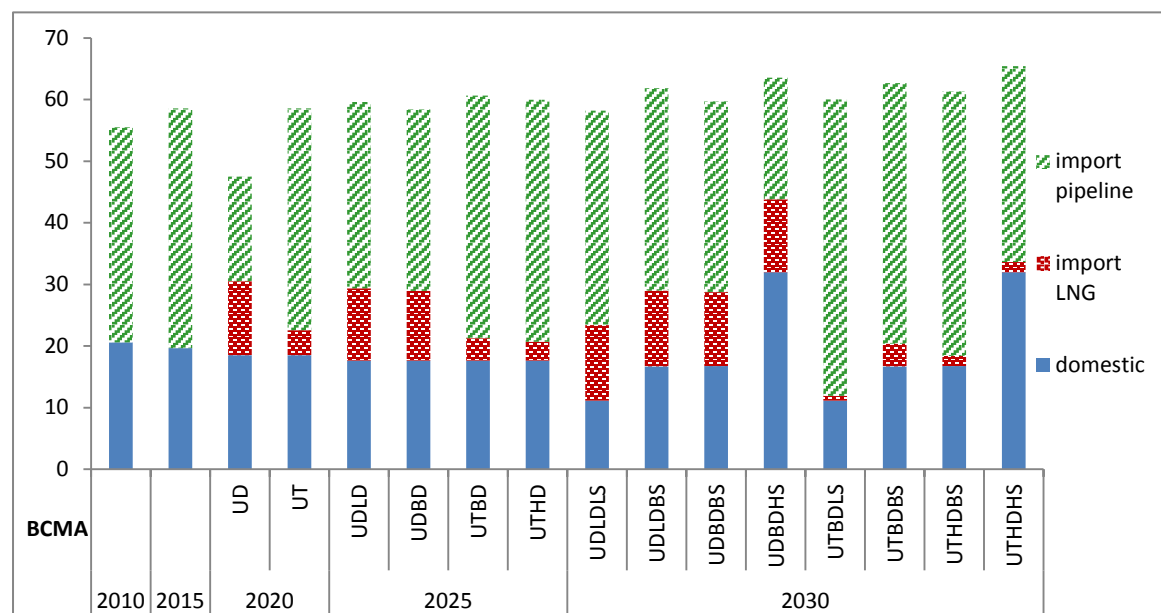

Figure 4: Ukrainian natural gas supply sources in all scenarios and years

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[8] With the exception of the – small – exports to Finland and the Baltics. In the early 2000s, the Yamal Europe pipeline to Poland and the Blue Stream pipeline to Turkey via the Black Sea reduced the importance of Ukrainian transit. Since 2011, the Nordstream pipeline to Germany via the Baltic Sea has allowed for shipping of very large volumes directly to West European customers, thereby avoiding Ukrainian transit.

To hedge for the 50% chance of disrupted supplies, Ukraine constructs a 12 bcm LNG import terminal in 2015 to ensure supply security (size is restricted by the expansion limit to reflect limited access to financial markets). Indeed, in all disruption scenarios, Ukraine imports between 11 and 12 bcm per year of LNG from 2020 onward, 19-25% of its consumption. In the other scenarios with imports from Russia, the LNG imports amount to at most 4 bcm (see Figure 4). In the disruption scenario in 2020, Ukraine suffers from a severe supply gap. From 2025 onward, increased pipeline imports and large transit from North-West Europe through Poland are able to compensate for most of the disrupted Russian supplies.

Because Ukrainian power generation is mostly coal-fired and hardly gas-fired, the demand assumptions vary little between Low Demand (LD) and High Demand (HD) scenarios. In contrast, due to Ukraine's large shale potential, in the high shale scenarios, domestic production can meet 50% of consumption. In low shale scenarios, domestic conventional supply would meet 19% of consumption – similar to today's situation. Depending on the disruption scenario, 60% or 80% of consumption would be met by pipeline imports.

3.2   Poland: The new hub in Northeastern Europe?

Poland, in recent years, has been merely a (small) import and transit country of the Yamal Europe pipeline. However, with the reverse flow requirements of 994/2010/EU and the Ukraine crisis, Poland has started to become a transit hub in Northeastern Europe and has the potential to further develop a hub role due to its coastline that can host LNG terminal(s) and receive offshore pipelines from North West European suppliers such as Denmark and because it still has expansion potential in cross-border pipelines. Indeed, there are no pipelines yet on the Polish borders Slovakia and with the current "gas island" Baltic countries. Depending on the scenario, we find more or less pronounced development in the direction of a hub.

One of the most influential factors on Poland's domestic consumption, however, is the assumption of unconventional production, mostly shale gas. Poland is one of the few European countries to embrace a positive attitude towards unconventional production, and – following the IEA expectations - we assume shale gas to be a large part of domestic production in the Base Case (8 bcm/year in 2035). Hence, in the "gloomy unconventional" scenarios (UDLDLS and UTBDLS), domestic production is strongly reduced (by 40% compared to the Base Case in 2035, Figure 5). Conversely, domestic

production is more than doubled in the "unconventional boom" scenarios (UDBDHS and UTHDHS). LNG imports hardly balance the missing domestic production in the "gloomy unconventional" scenarios and, hence, domestic consumption is directly affected by the reduced domestic production.

LNG imports vary little across scenarios and the initial capacity of the LNG terminal opened in 2015 is not fully used in any of the scenarios. LNG costs are generally higher than the cost of importing by pipeline and pipeline supplies are plentiful in Poland. In addition, in scenarios of Ukrainian transit disruption (UD), Poland can increase its imports from Russia via pipeline from Belarus. A relatively large share of the imports is re-exported (between 46% in the case with regular Ukrainian transit and 98% in the case with booming unconventionals) mostly to Ukraine and Germany.

Only special circumstances would allow Poland to expand its hub position. These expansions include building new pipeline connections (see Table 3 in the Appendix for details): a pipeline from Denmark to Poland (potentially also transiting Norwegian gas) if Ukrainian transit is disrupted (in 2015); and pipelines to the Baltics and Slovakia in 2020 in all scenarios, which are expanded in 2025 if demand in Poland is low enough to allow for additional re-exports (scenarios UDLD and UTBD). These investments do not take place until 2025 showing that it is beneficial to wait for the realization of scenarios that determine the quantities available for re-export. This is particularly true for the pipeline from Poland to Slovakia, which is of smaller size in the deterministic (EVS) runs.

Poland remains predominantly a transit country in the traditional East-West direction and requires domestic shale gas production to significantly expand the domestic consumption of natural gas. Its newly built LNG terminal will hardly have an influence on the supply mix and re-exports; rather, it can be viewed as insurance against disruption of traditional supplies to Poland, e.g., from Russia (e.g. Richter and Holz, 2015). Transits in the Eastern or Southern direction will to some extent rely on Norwegian supplies. It remains to be seen whether the Norwegian projection of 110 bcm production per year until 2040 can be sustained.
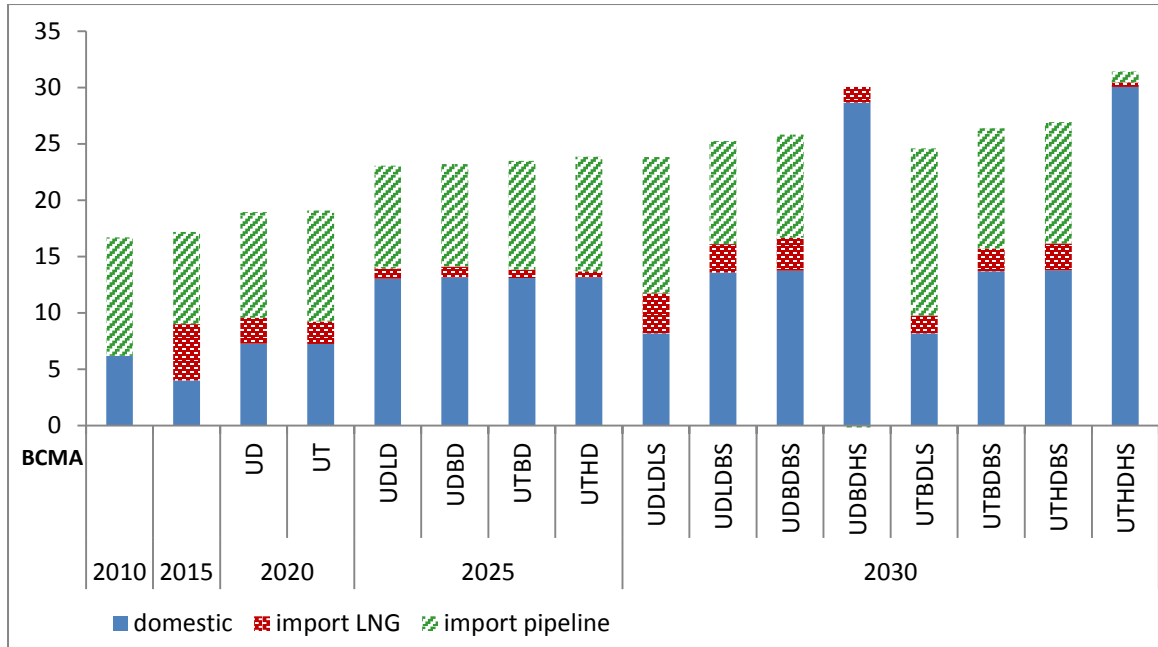
Figure 5: Poland's supply mix across scenarios and over time, in bcm/year

3.3 Dynamic China

China is a particularly interesting country to study because it has one of the most dynamic natural gas markets. In recent years, there has been a large increase in domestic demand and production, an increasing import dependency, and a tremendous expansion of LNG import capacities. The country also has a large unused reserve potential, for both conventional and unconventional resources.

China was able to accommodate domestic natural gas consumption by domestic production until 2007 (BP 2014a). In recent years, demand has grown at a much higher pace than production. In 2013, China imported almost 50 bcm of natural gas (BP 2014a), making it the fifth largest natural gas importer globally (IEA 2014). LNG imports come from the Pacific Basin (Australia, Indonesia, and Malaysia) and the Middle East (Qatar).

Since 2010, China has imported gas by pipeline from Turkmenistan (BP 2011a). Recently, other central Asian countries and Myanmar have started supplying natural gas by pipeline to China (EIA 2014), although Turkmenistan supplies the most (about 90%, BP 2014a). Today, slightly less than half of total imports arrive via LNG terminals, slightly more than half by pipeline. Production and demand forecasts indicate that domestic production will grow significantly; however, to meet the large domestic demand, it is likely that imports will continue to outpace domestic production growth.
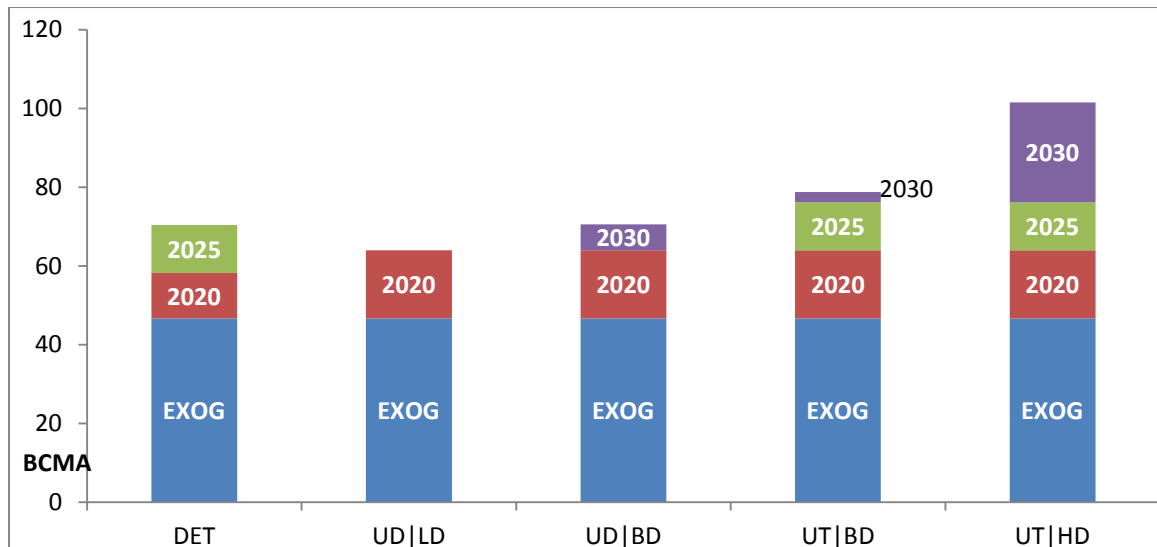
Figure 6: China regasification capacity development (by year available)

The Chinese regasification capacity in 2015 (exogenously available) amounts to 47 bcm (Figure 6)[9], of which 33 bcm are used in 2015. In the stochastic model results (see the four right most bars in Figure 6), the expansion of 17.3 bcm in 2015 (coming online in 2020) is 50% higher than the 11.5-bcm expansion in a deterministic case (left most bar).

Similarly, available pipeline import capacity in 2015 amounts to 54.2 bcm (42 bcm from Central Asia and 12 bcm from Myanmar, see Figure 7), of which 37 bcm are used in 2015. The model allows for pipeline construction in 2015 from the East of Russia to China, of this only 1.6 bcm are constructed and become available in 2020 (this small addition is visible but not labeled in the four right-hand-side bars in Figure 7).

The disruption of Ukrainian transit (UD) has a minor, albeit noticeable, effect on the Chinese gas supply situation in 2020 (Figure 8). In this case, Europe attracts more LNG, which raises market prices. As a consequence, Chinese LNG imports in 2020 are 9 bcm lower than in the case without transit disruption (UT) (namely 70 bcm rather than 79 bcm). The balance in Chinese supplies is mostly made up by higher pipeline imports (44 bcm vs. 36 bcm). Domestic production in China in 2020 hardly differs, and ultimately, the consumption in the disruption situation is only 1 bcm lower (-0.3%), at a level of 298 bcm. Hence, the immediate effect on Chinese consumers of Russia punishing Ukraine and

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[9] Indeed, the actual import volume of 50 bcm reported by BP (2014a) is larger than the import capacity. This is mostly due to unit of measurement conventions and how significant losses in the LNG chain are accounted for. Note that in model results, the LNG capacity is *not* restrictive in 2015. If we had accounted for seasons, possibly in winter a larger part of the LNG import capacity would have been used.

Europe is limited.[10] In later periods, the pipeline and regasification terminal expansions vary with the different supply-demand situations in scenario branch.
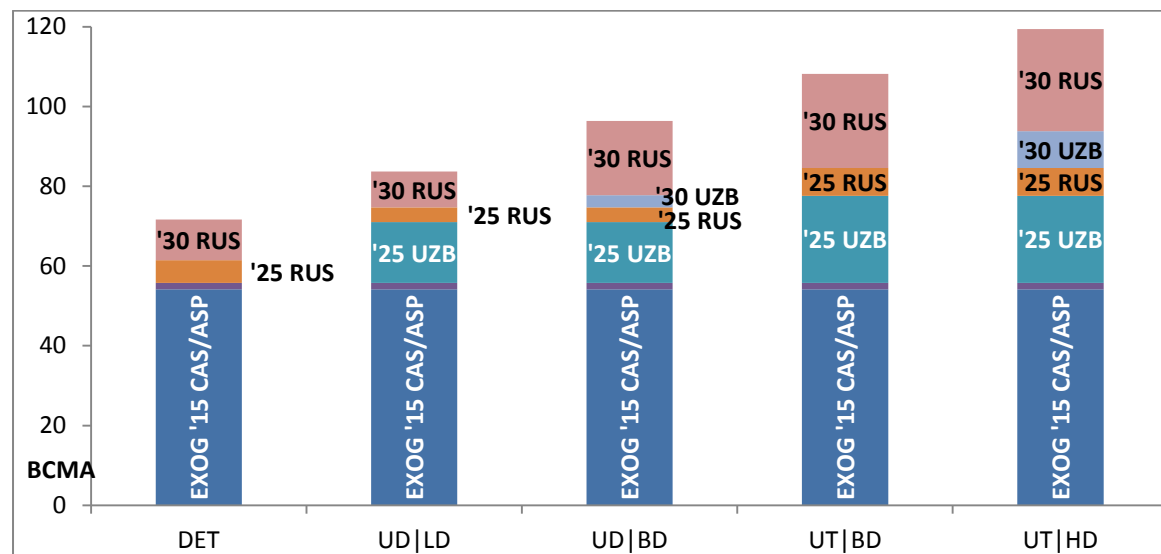

Figure 7: China import pipeline capacity development (by exporting country and year available)
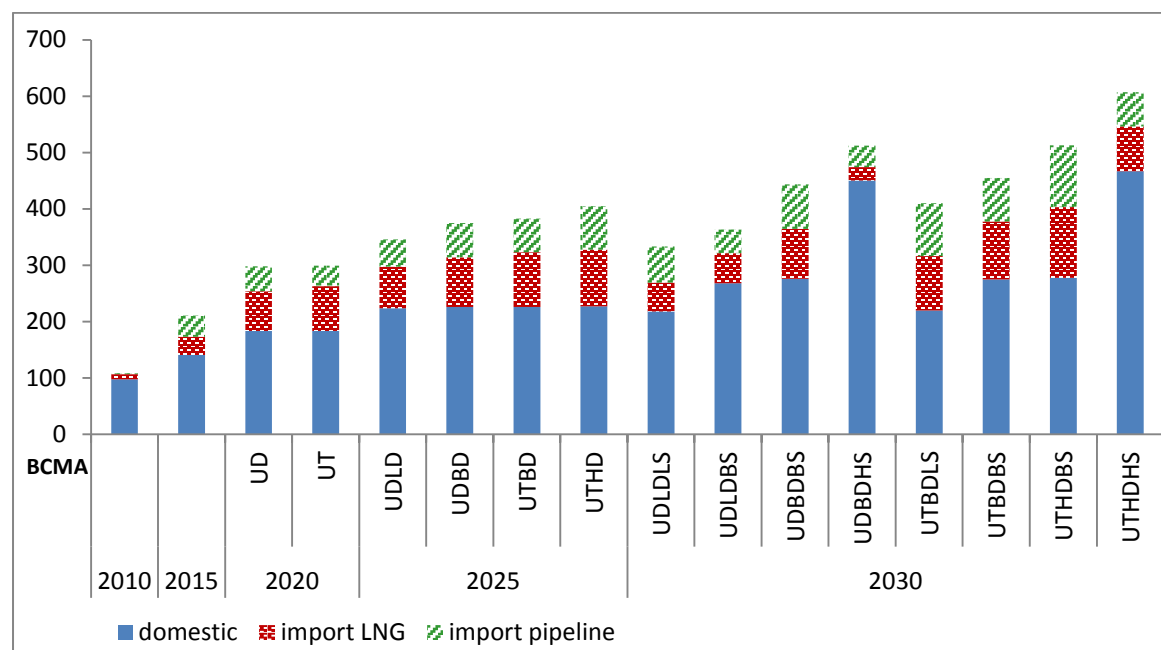

Figure 8: Supply Breakdown China

By 2025, anticipating demand developments in China (growth in all scenarios), all scenarios suggest significant capacity expansions from Uzbekistan to Western China (between 15 bcm and 22 bcm additional capacity, see Figure 7). Total Chinese

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[10] By ignoring seasonality, the yearly average values may blur an actual lack of available pipeline import capacities into China in the winter season.

consumption in 2025 ranges from 346 bcm to 405 bcm (aggregate bars in Figure 8). The Ukrainian transit disruption is also felt in 2025 via higher LNG prices and, hence, lower LNG imports. Comparing the two scenario branches with base case demand assumptions, LNG imports are almost 10 bcm higher (98 bcm in total) in the UT scenario. Since pipeline imports hardly vary (1 bcm higher in UD compared to UT), China can hardly benefit from Russian supplies to Europe being diverted. This is due to a lack of pipeline capacities and new projects must compete with pipeline supplies from Central Asia which is closer to the Chinese market.

In 2030, when the third uncertain event – regarding shale gas potentials – occurs, a great variation of outcomes on the Chinese market is possible (see Figure 8). Consumption can be as low as 333 bcm (Ukraine disruption scenario) and up to more than 600 bcm (High Shale scenario). Domestic production varies strongly with unconventional gas availability, but always satisfies at least 50% of Chinese demand. In scenario UDBD*H*S, we observe the highest level of Chinese self-sufficiency with 88% of the 512 bcm domestic consumption met by domestic supply, and only 5% by LNG and 7% by pipeline supplies. In contrast, the low shale variant of that scenario (UTBD*L*S) shows the lowest level of self-sufficiency, a mere 54% (of a demand level of 410 bcm). LNG and pipeline imports would amount to 97 and 94 bcm, respectively.

The large variation in total imports by 2030 (between 62 bcm and 235 bcm) and large additions to both pipeline and LNG regasification capacities in all years and in most scenarios illustrates how dynamics in the Chinese market will be a major determinant in the development of global gas markets in the coming decades. The higher the Chinese demand, the higher the import requirements. The scenario with the highest absolute import level is UTHDBS, with 126 bcm LNG imports and 109 bcm pipeline imports, adding up to 46% of 513 bcm.

While projections by EIA (2014) and BP (2014b) point to a dominance of pipeline imports, we find in six of the eight scenarios that LNG imports are higher than pipeline imports. However, over all eight scenarios, LNG imports are on average only 10% higher (78 bcm LNG vs. 70 bcm pipeline imports). This result may be due to not representing long-term contracts as well as market power assumptions in the model. We assume that Russia exerts significant market power in the Chinese market (0.5 in 2010 and 0.75 over the rest of the time horizon).

3.4 The USA – Becoming a global LNG supplier?

The major question for development of the US natural gas sector is whether it will become a net LNG exporter and, if so, how much LNG will be exported. While most US observers expect very large LNG exports, global modeling exercises find only moderate US exports (Holz et al., 2015, Richter, 2015). In Richter and Holz (2015), it was shown that LNG imports can help to compensate for disrupted Russian supplies to Europe. However, US exports would rarely be shipped to Europe, where Middle East and (North) African LNG is available at lower costs.

Figure 9 shows that in the next decades the US natural gas sector continues to primarily be a domestically focused market with strong self-sufficiency. The Ukrainian transit disruption, as a European issue, hardly affects the US market. However, the two other scenario variations – natural gas demand and availability of unconventionals – have a strong impact on the US sector.

Figure 9: US supply mix across scenarios and over time, in bcm/year

In particular, the availability of unconventional gas is decisive for the size of the US natural gas sector. Assuming about 35% lower production capacity for natural gas in 2030, in scenarios where unconventionals are limited to their 2015 levels, US consumption is considerably lower than in all other cases (Figure 9).[11] Consumption in

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[11] See Table 4 in the Appendix for production, consumption and trade details.

2030 is about 15% to 25% lower than the reference demand in the cases UDLD*L*S and UTBD*L*S, respectively, and consumption is 20% to 25% lower than in the comparable scenarios, UDLD*B*S and UTBD*B*S, respectively, which start from the same scenario branch. In other words, even though the US becomes a net importer of LNG again, these imports cannot fully compensate for missing unconventionals in a sector that is set on strong dependency on shale gas production. Net LNG imports in the "gloomy unconventionals" scenarios reach levels of up to 48 bcm (scenario UTBDLS, Figure 10). Conversely, we find small LNG net exports of, at most, 12 bcm when world supplies are reduced by the Russian disruption of Ukrainian transit (scenarios UTLDBS and UTBDHS).

Demand scenarios also have a significant effect, albeit smaller than the variation of unconventional supplies (Figure 9). In 2030, demand is 10% lower and 5% higher when comparing scenarios that are otherwise equal (i.e., comparing UD*L*DBS to UD*B*DBS and UT*B*DBS to UT*H*DBS, respectively). Higher consumption quantities of natural gas cannot be reached with Base Case production capacities, but require additional domestic production capacity such as in the "unconventional boom" scenario. Again, international trade hardly changes the domestic supply mix in the USA.
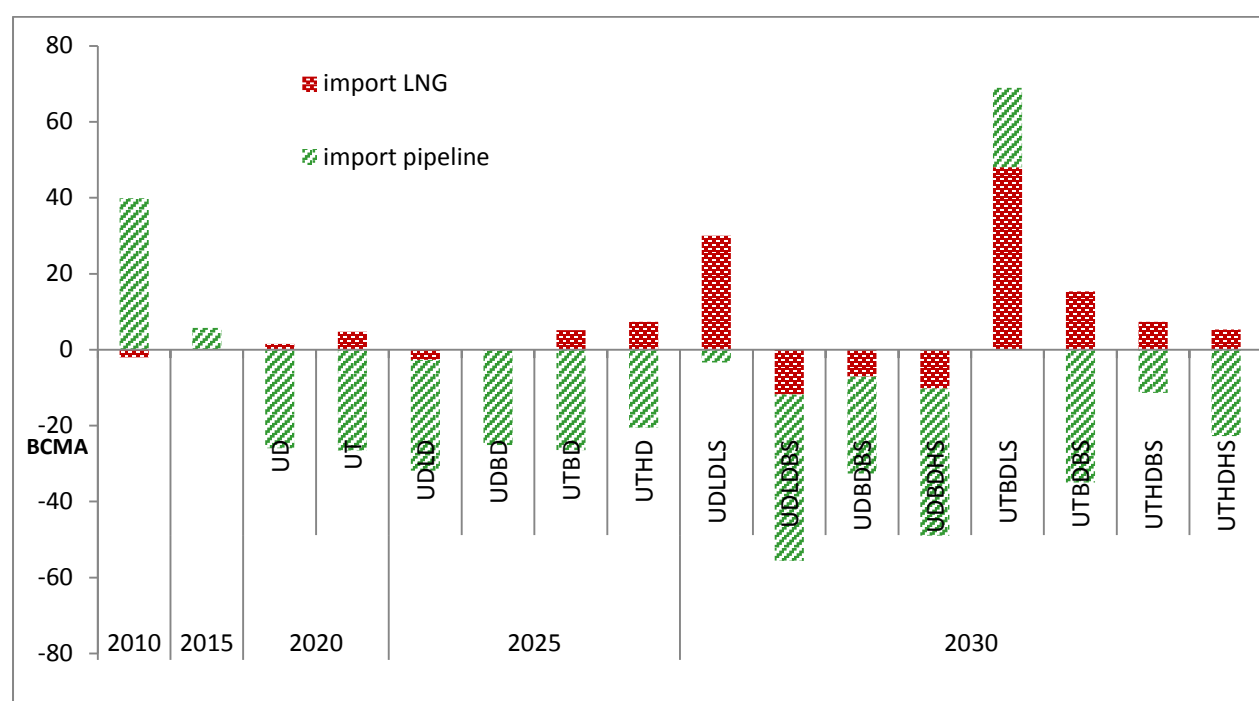
Figure 10: Trade balance[a] of the USA across scenarios and over time, distinguishing pipeline[b] and LNG trade, in bcm/year

[a] The negative values are exports.
[b] For pipeline imports the negative values are mostly pipeline losses.

International markets contribute only very small quantities to raise US demand, despite the existing (LNG) import infrastructure in North America and due to higher prices on international markets. Conversely, we find that consumption in our low-demand scenarios is higher than assumed when constructing the demand function. This is because domestic supplies are plentiful in the Base Case settings and are hardly shipped to the international market, due to high investment costs in LNG export infrastructure.

3.5   Large infrastructure projects in Europe

Europe has traditionally been a pipeline market that receives the majority of its imports via large-scale pipelines. LNG plays a complementary role because most European regions can be more or less easily reached by pipeline from large gas-supplying regions. Hence, growing import dependency due to strongly decreasing domestic production (Holz et al., 2015) is likely to be covered with additional pipeline gas. In this section, we analyze whether, and when, there are economic grounds for construction of additional large-scale pipelines to Europe.

In fact, in an environment of stable (if not decreasing) natural gas demand, Europe is currently over-supplied with import pipeline capacity, particularly since Russia added large capacities with the Nordstream pipeline in 2011. Hence, from an EU-wide perspective, it was unsurprising that Russia cancelled the Southstream project at the end of 2014 because it faced the threat of under-utilization.

There is also a regional component to each large pipeline project. Southstream, for example, had the objective of supplying the – small, but still growing – natural gas markets in South East European (Bulgaria, Romania, Serbia, Croatia, Hungary) that are today exclusively dependent on Russian supplies from the Ukrainian transit system. Hence, the Southstream pipeline would have a) increased import capacity in these countries and b) diversified their supply routes.

In the scenarios of a Ukrainian transit disruption, South East Europe must find new sources of gas from 2020 on. While Southstream cannot be assumed to be constructed (exogenously), we still allow for the investment decision in a Black Sea pipeline to Bulgaria; alternatively, transit capacities via Turkey along the Southern Corridor could also be built. We find the latter option to be pursued with gas coming from Iraq and the Caspian region (Azerbaijan) to Turkey and then on to South East Europe. There is economic rationale to invest in this "Nabucco-style" pipeline already in 2015 (before any

disruption) and then to expand it in all base case demand or high demand scenarios, with or without Ukrainian disruption. This pipeline reaches up to 27 bcm capacity (UDBD).

In addition, a very small "Southstream-style" pipeline between Russia and Bulgaria is invested in, with 6-bcm capacity decided in 2015. In all scenarios, the Southern Corridor is extended to Italy with a pipeline of 10 bcm at most by 2025 in the spirit of the Trans-Adriatic Pipeline (TAP).

The import pipeline capacities found in our model runs are considerably smaller than what were discussed for these large infrastructure projects. Nabucco and Southstream were both planned to carry between 50 and 60 bcm per year. One important reason for smaller capacity requirements on import pipelines is the considerable improvement of interconnectedness in East Europe by means of reverse flow capacities. Since the European Commission mandated reverse flows on all cross-border connections in 2010 (Regulation EU 994/2010) and since the start of the Russian-Ukrainian war, large reverse flow capacities have been installed going to Ukraine (see Section 2.3.1). We, therefore, do not find any rationale for additional reverse flows to Ukraine from Slovakia, but there is rationale for flows from Poland in case of transit disruption (14 bcm). Poland may develop a hub position in Northeastern Europe, as discussed in Section 3.2, and also establish southbound capacities to Slovakia – which would be much larger in the case of a Ukrainian transit disruption (20 bcm compared to 5 bcm).

3.6   Unconventionals and LNG

Figure 11 shows that at every stage in any stochastic scenario the total capacity expansions are higher than in the deterministic case. This illustrates two ways in which uncertainty is an incentive for investments in capacity expansions: 1. due to hedging decisions in anticipation of uncertain events and 2. due to recourse decisions after realization of uncertain events.

When we compare Figure 12 and Figure 11 below, we notice much larger relative variation in LNG capacity additions than aggregate (LNG and pipeline) additions. In general, the two investment incentives from uncertainty count even stronger for LNG capacity. Hedging decisions *in anticipation* of uncertain events favor LNG export/import capacity over pipeline capacity, because LNG routes are more flexible and construction of two import pipelines, one of which may not be used, is likely to be expensive. Whether *recourse decisions* after realization of uncertain events favor LNG or pipeline depend on

how the event affects the regional supply (or demand) situation and whether imports and exporters can focus on local or more distant market opportunities.
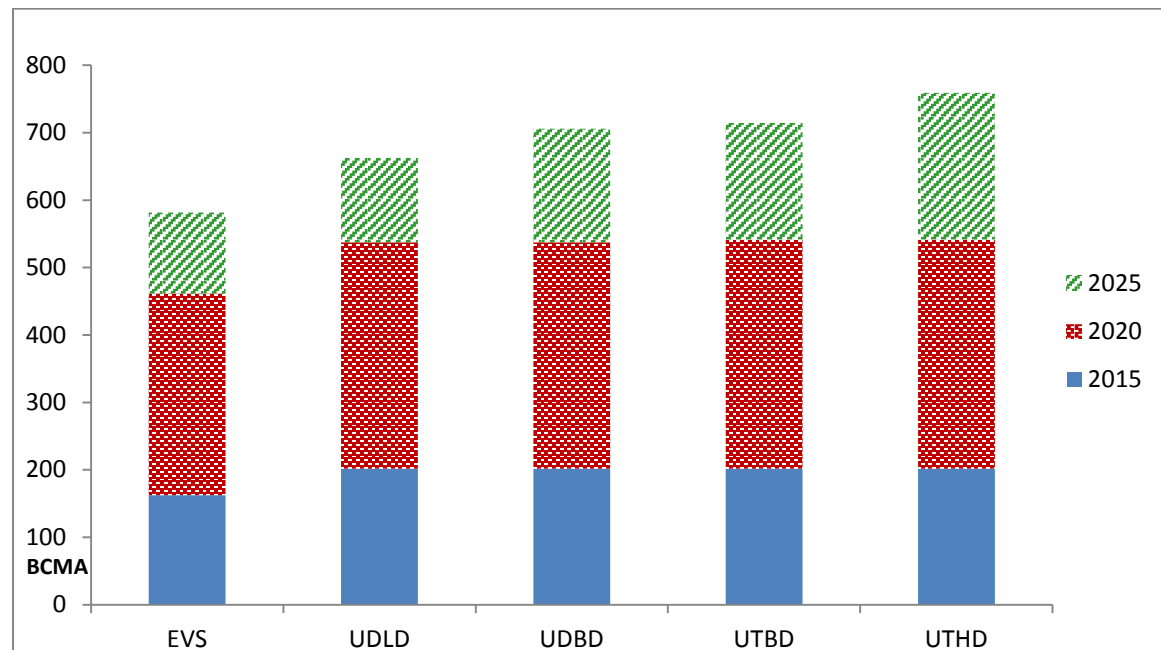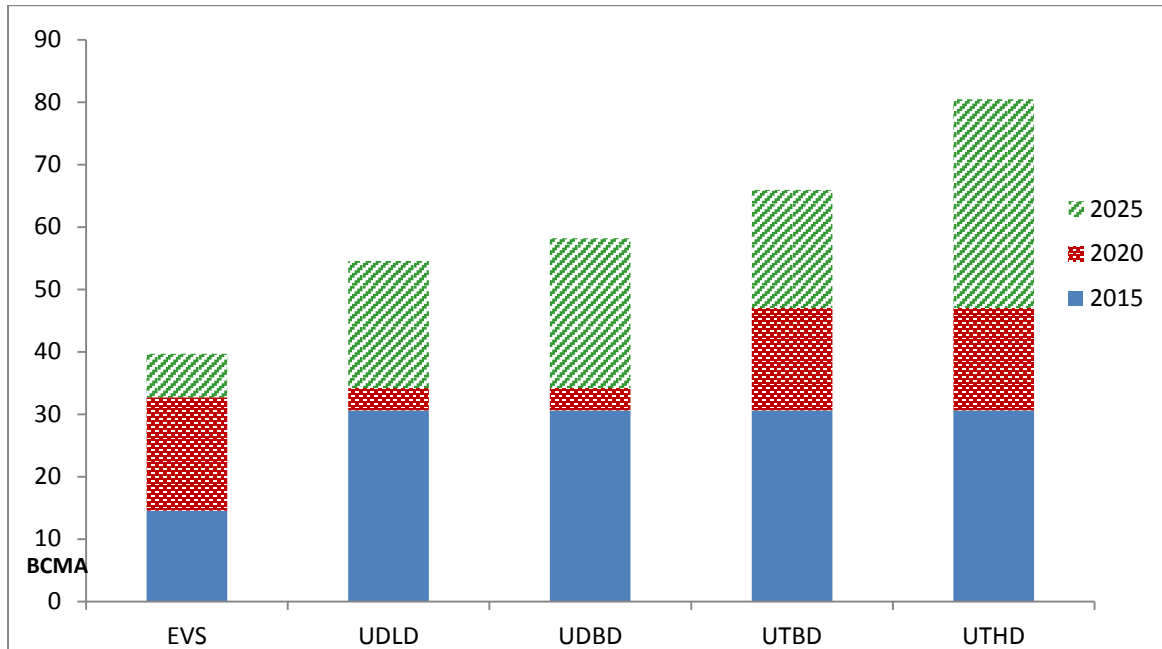

Figure 11: Aggregate total capacity expansions by period across scenarios, in bcm/year

It is interesting to note the liquefaction expansions in 2025 (in Figure 12). In the scenario Ukraine Transit Base Demand (UTBD), there is 50-50 chance of low or base case shale supply in the next period, while in Ukraine Transits High Demand (UTHD) there is 50-50 chance at base vs. high shale supply. It seems plausible *ex ante* that a chance on high shale is an incentive to *increase* export capacities. However, liquefaction capacity is increased *less* in the scenario with higher shale production. In contrast, we observe *higher* expansion of regasification capacities when higher shale gas production is expected (see Figure 13). As such, it appears that the demand side of the market is pulling investment in LNG chain capacity, rather than the supply side pushing investment.
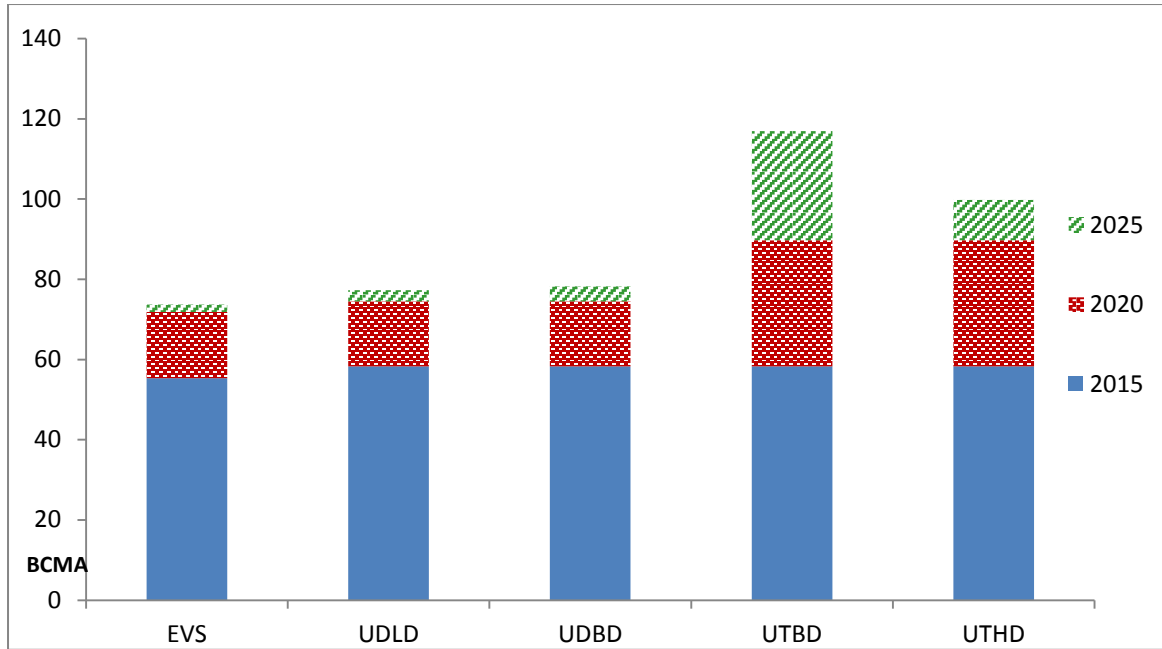
Figure 12: Aggregate liquefaction capacity expansions across scenarios and by period, in bcm/year

Figure 13: Aggregate regasification capacity expansions across scenarios and by year, in bcm/year

4 Conclusions

In this paper, we investigated the impact of uncertainty on the European, North American, and Asian gas markets. We developed a scenario tree encompassing uncertainty of three major aspects under scrutiny by policy makers and experts: Russian exports, gas demand, and unconventional gas.

Our results show the robustness of Chinese demand and import growth to all uncertainty. If Europe needs to import more LNG because of Russian withholding, China can rely on pipeline imports. If domestic shale gas reserves allow for a strong increase in Chinese indigenous production, Chinese consumption increases even more than in the other scenarios, but China remains a strong importer. In particular Chinese LNG imports are very flexible to adjust depending on the supply situation in domestic production and pipeline imports.

Given the possibility of a major disruption of Russian supplies, Ukraine would construct a major LNG terminal, even before a disruption materializes, and use reverse flows from Central Europe (Poland). Our results show that – in any case – there is economic rationale for additional reverse flow investments, particularly from Poland. Poland would become a transit hub in Northeastern Europe to bring Western gas to the rest of (South) East Europe, if the traditional East-West transit is disrupted.

We illustrate how the timing of investments is affected by inter-temporal hedging behavior of market agents. For example, this occurs when LNG capacity provides *ex-ante* flexibility (e.g., in Ukraine to hedge for a possible Russian supply disruption) or an *ex-post* fallback option if domestic or nearby pipeline supply sources turn out low (e.g., uncertain shale gas resources in China). Moreover, in the interplay of shale gas supply and demand uncertainty we find that investment in LNG capacities is more affected by demand side pull (due to higher needs in electric power generation) than by supply side push (higher shale gas supplies needing an outlet).

For the US energy policy, our modeling results confirm that there is little ground for worries of large LNG exports which would reduce domestic natural gas supplies. Our results also support EC policy initiatives where local demand and supply uncertainty warrant both additional LNG import capacities and the enforcement of bi-directional (reverse flow) capacities in the pipeline network, particularly in Eastern Europe. In this sense, our results provide input to the concretization of the European Energy Union announced in February 2015.

Among other initiatives, the European Commission wants to prepare a LNG Strategy which should take into account that European LNG imports will have to compete with the strong demand in Asia and that capacity investments are therefore likely to require subsidization. In addition, we confirm the importance of the Southern Corridor pipeline project(s) for South-East Europe as well as of the interconnection of Poland with all its neighbors. This has also been recognized by the European Commission in its list of

Projects of Common Interest.[12] Moreover, our modeling framework assumes the efficient use of the pipeline network; to that effect, the effective implementation of the European internal energy market must be pursued.

Future work on the S-GGM will be performed to enhance demand sector detail, allow endogenous production capacity expansion, and incorporate natural gas reserves and endogenous expansion. A broader line of research concerns the development of stochastic versions of the multi-fuel energy system model MultiMod (Huppmann and Egging 2014) and decomposition algorithms to solve large-scale instances of this stochastic model.

Acknowledgements

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[12] See http://ec.europa.eu/energy/en/topics/infrastructure/projects-common-interest (accessed on June 28, 2015).

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Appendix

Table 2: Assumptions of variation in natural gas production capacity in the unconventional boom and the gloomy unconventional scenario (adopted from IEA 2012a).

Region / Node	Node abbreviation	Additional capacity per year (bcm) in the Unconventional boom scenario		Reduction of production capacity in bcm/y. in the Gloomy unconventional scenario	
		2025	**2035**	**2025**	**2035**
Europe and Eurasia					
Poland	POL	15	25	3	8
France	FRA	10	15	-	-
Sweden	SWE	5	10	-	-
UK	GBR	5	10	0	3
Germany	DEU	5	10	-	-
Romania	ROM	-	-	0	1
Ukraine		10	20	-	-
Russia West	RUS_W	15	10	15	45
Asia					
China (total of all nodes)		100	280	10	100
India (total of all nodes)		16	30	10	60
Indonesia	IDN	5	40	0	20
Pakistan	PAK	10	30	-	-
Japan	JPN	0.5	10	-	-
Australia	AUS	40	20	10	93
South America					
Argentina	ARG	10	5	4.77	50
Brazil	BRA	10	30	-	-
North America					
Mexico	MEX	10	10	6.24	30
Canada West	CAN_W	20	10	30	70
USA (total of all nodes)		100	200	240	352
Africa					
Algeria	DZA	-	-	0	15

Note: The values for 2030 are linearly interpolated; the values for 2040 are equal to 2035 capacities.

Table 3: Pipeline capacity expansions – into Poland (bcma)

Year →	2015		2020			2025		
Case→	EVS	stoch	EVS	stochastic		stochastic		
From	DET	02	DET	03 / UD	04 / UT	UDLD	UDBD	UTBD
BALT			2.0	2.8	0.7	0.6		1.2
DEU								0.2
DNK	3.1	3.4						
SVK			0.8	1.4	1.5	0.7		1.2
BLR				1.1			0.3	
Total	3.1	3.4	2.7	5.4	2.3	1.3	0.3	2.7

Note: There are no Polish expansions in scenario node 08, and no LNG expansions at all.

Table 4: US mass balance in 2030 (bcma)

Scenario	production		consumption		LNG		pipeline	
	out	ref	out	ref	imp	exp	imp	exp
UD|LD|LS	526.0	509.9	552.6	649.8	30.4	-0.5	371.9	-375.3
UD|LD|BS	756.8	805.9	701.2			-11.9	571.1	-614.9
UD|BD|BS	810.4		777.7			-7.1	621.3	-646.9
UD|BD|HS	894.3	955.9	845.3	780.9		-10.3	673.4	-712.1
UT|BD|LS	527.3	509.9	596.2	780.9	48.0		381.2	-360.2
UT|BD|BS	806.1	805.9	786.5		15.4		596.9	-631.9
UT|HD|BS	828.1		824.0	911.9	7.3		653.6	-664.9
UT|HD|HS	946.2	955.9	928.7		5.3		724.7	-747.4

Note: "out" refers model outcome, "ref" is the reference value, "imp" are imports, and "exp" are exports.