Stochastic Modeling of Natural Gas Infrastructure Development in Europe under Demand Uncertainty

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ABSTRACT

We present an analysis of the optimal development of natural gas infrastructure in Europe based on the scenario studies of Holz and von Hirschhausen (2013). We use a stochastic mixed integer quadratic model to analyze the impact of uncertainty about future natural gas consumption in Europe on optimal investments in pipelines. Our data is based on results from the PRIMES model of natural gas demand and technology scenarios discussed in Knopf et al. (2013). We present a comparison between the results from the stochastic model and the expected value model, as well as an analysis of the individual scenarios. We also performed sensitivity analyses on the probabilities of the future scenarios. Comparison of the results from the stochastic model to those of a deterministic expected value model reveals a negligible Value of the Stochastic Solution. We do, however, find structurally different infrastructure solutions in the stochastic and the deterministic models. Regarding infrastructure expansions, we find that 1) the largest pipeline investments will be towards Asia, 2) there is a trend towards a larger gas supply from Africa to Europe, and 3) within Europe, eastward connections will be strengthened. Our main finding using the stochastic approach is that there is limited *option value* in delaying investments in natural gas infrastructure, until more information is available regarding policy and technology in 2020, due to the low costs of overcapacity.

Keywords: Natural gas, Infrastructure, Mixed integer quadratic programming, Stochastic modeling

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1. INTRODUCTION

The Energy Union strategy of the European Union consists of five dimensions: supply security, a fully integrated internal energy market, energy efficiency, emission reduction, and research and innovation. The ambition to create a fully integrated internal energy market shall be achieved by strengthening interconnectors to allow energy to flow freely across the EU. In addition to capacity extensions, technical and regulatory barriers must be overcome. For natural gas, the steps towards a fully integrated market have been set out in three gas directives (98/30/EC, 2003/55/EC, 2009/73/EC).[1]

1. See https://ec.europa.eu/energy/en/topics/markets-and-consumers/market-legislation (accessed May 6, 2016), http://ec.europa.eu/competition/sectors/energy/overview_en.html (accessed May 6, 2016).

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The directives establish rules for natural gas transmission, distribution, supply, and storage. This includes rules for market access, authorizations for transmission, distribution, supply and storage of natural gas, and the operation of systems. The motivation for the directives is a full opening up of national gas markets (including LNG) to achieve higher service quality, universal service levels, consumer protection, security of supply, as well as climate change mitigation (see, e.g., EC, 2010, 2016). The objective is to increase competition in national markets and integrate them into regional, and eventually, a single EU-wide market for natural gas. In order to achieve a fully integrated market, it is necessary to strengthen the cross-border gas transportation network in Europe. Cost-effective capacity expansion should consider uncertainty in future developments, specifically considering natural gas production and consumption trends.

In this paper, we present an analysis of the optimal development of the natural gas infrastructure in Europe based on the natural gas demand and technology scenario studies presented in Knopf et al. (2013). We use a stochastic model to analyze the impact of policy and technology uncertainty on optimal investments in pipelines. The policy dimension varies in terms of the greenhouse gas (GHG) emission reduction targets and the emission trading regimes within the EU. Except for a no policy baseline with a 0% GHG reduction target (BASE), all other scenarios assume either 40% or 80% reduction. The technology dimension varies the availability and technological progress of carbon capture and sequestration (CCS), nuclear power generation, energy efficiency, and renewable energy in five main storylines: default (DEF), default without CCS (noCCS), pessimistic (PESS), efficient (EFF), and green (GREEN). The policy and technology dimensions are combined into eight scenarios: 'BASE', '40%DEF', '40%EFF', '80%DEF', '80%noCCS', '80%PESS', '80%EFF', and '80%GREEN'. The uncertainty considered in this paper is in demand development. In the European Union, reference prices and quantities on which future inverse demand curves are based vary by scenario. In the (aggregated) other regions in the rest of the world, only reference prices are adjusted when calculating the future demand curves for the different scenarios.

The oil and gas industry is capital intensive and rich in complex operational and strategic planning problems. As such, it has a relatively long history of using computerized decision support for making investment decisions (e.g., Dougherty and Thurnau, 1969). The earliest applications focused on operational planning. Charnes et al. (1954) developed deterministic linear programming models, wherein uncertainty in input parameters is addressed using sensitivity analysis. Dynamic programming was applied to support both transient and steady-state analysis in a natural gas transportation network (Wong and Larson, 1968). Dougherty and Thurnau (1969) presented a computer system for optimal investments in oil wells and pipelines, also based on linear programming.

Over time, the computational power of computers has increased substantially and off-the-shelf optimization software allows for representation of decision problems in great detail, including the use of integer variables to represent the discontinuous nature of many capacity investment and expansion problems (e.g., Nygreen et al., 1998 and André et al., 2009). Gas trade has historically been dominated by long-term contracts. Such a setting more or less warrants a focus on cost minimization, and also reduces the uncertainties faced by the parties involved. Operations and investment models have tended to focus on deterministic cost minimization, finding the cheapest way to fulfill contractual obligations. The opportunities and risks encountered in an increasingly, but not perfectly, competitive and liberalized market are not well-addressed by cost minimization approaches where stochastic profit maximization is more suitable.

Quantitative energy market models addressing game-theoretic behavioral aspects started to arise in the 1980s (e.g., Haurie et al., 1987 and Mathiesen et al., 1987). Since then, gradually more natural gas market models have been developed with finer time granularity, a broadening geographical coverage, and a more detailed representation of the actors in the market. Examples of such models are GASTALE (Boots et al., 2004; Egging and Gabriel, 2006, Lise et al., 2008), GASMOD (Holz et al., 2008), EGM/WGM (Egging et al., 2008, Gabriel et al., 2012), GGM (Holz et al., this issue), Columbus (Hecking and Panke, 2012), and MultiMOD (Egging and Huppmann, 2012; Huppmann and Egging, 2014). These models share the equilibrium modeling approach that allows for representation of imperfect competition and explicit inclusion of a transportation network so that the interplay of market power and infrastructure bottlenecks and their impact on optimal capacity expansion can be analyzed.

Uncertainty is not commonly addressed in these models. The first representation of uncertainty (oil price) in an oligopolistic European natural gas market setting was proposed and solved by Haurie et al. (1987). Zhuang and Gabriel (2008) present a stochastic mixed complementarity problem (MCP) with a stylized application inspired by the North American market. Egging (2010, 2013) and Egging and Holz (2016) present and apply a multi-period stochastic version of the GGM with endogenous capacity expansions. Zheng and Pardalos (2010) address demand and local production uncertainty in a stochastic mixed integer program for minimizing expected costs of future gas transport and investments in the pipeline network and regasification terminals. Their model contains integer variables in the second stage and the authors implement an advanced Benders decomposition scheme to solve data instances that consider modest networks but large scenario trees. Goel and Grossmann (2004) look at decision dependent scenario trees for investments in natural gas production under uncertainty of the size of and maximum production rate from gas reserves. An interesting aspect, highly complicating the numerical tractability, is that they implement a decision dependent scenario tree wherein uncertainty about reserves is only resolved if the decision to explore them is actually made.

Two aspects ignored by most natural gas market literature are the nonlinear relationships between capacities and pressures and gas quality. In Midthun et al. (2009), the system effects of natural gas transportation networks and their impact on economic analyses are discussed. However, for onshore pipelines, additional compressors can be installed to increase gas pressure, and thereby, capacity at any point in a network. Li et al. (2011) address various aspects of gas quality in their two-stage stochastic mixed integer program, by designing an optimal gas transportation network for maximizing expected profits under uncertainty of needed throughput capacities at various points in the network.[2] The resulting model bears elements of non-convex pooling problems. The authors implement an advanced decomposition algorithm to solve two cases. A commonality among Zheng and Pardalos (2010), Goel and Grossmann (2004), and Li et al. (2011) is that the presence of integer variables in a multi-stage stochastic setting requires an advanced Benders-type decomposition approach to solve the model for data instances containing relatively modest networks. This makes these models not suitable for data instances representing the European gas market in a global context over a long time horizon. Bi-level models explicitly address the sequential and closed-loop nature of agent decisions in markets. The resulting models are very hard to solve and need advanced, customized solution approaches (e.g., Siddiqui and Gabriel, 2013). In a more general perspective, stochastic transportation network planning approaches can apply to natural gas networks. The characteristics of traffic demand uncertainty and network degradability in Siu and Lo (2008) can translate to demand uncertainty and pipeline disruptions in a natural gas network. Patil and Ukkusuri (2007, 2008) and Ukkusuri and Patil (2009) propose bi-level optimization approaches for transportation

2. The inclusion of uncertainty is stated on a general level so that it can represent different aspects, such as demand and supply uncertainty, or uncertainty in needed gas quality levels.

network design under demand uncertainty. Patil and Ukkusuri (2007) develop a two-stage mathematical program with equilibrium constraints, and they implement the model on a small test network. Ukkusuri and Patil (2009) extend this work to a multi-period network design formulation. Patil and Ukkusuri (2008) develop two-stage stochastic programs balancing network expansion costs with congestion reduction. Although interesting and insightful, the models presented in these papers do not scale up to a detailed enough representation of the European natural gas market.

The remainder of this paper is organized as follows. In Section 2, we present the Ramona model, which we used for our analysis, and the corresponding input data. In Section 3, we discuss the impact of uncertainty in demand on investment decisions. We also present detailed results from analysis of the different scenarios. In Section 4, we conclude and present thoughts and ideas related to future work and shortcomings of the current models. In the Appendix we present a mathematical model description, as well as input data and selected results.

2. THE RAMONA MODEL

The Ramona model is a multi-stage stochastic optimization model for natural gas infrastructure analysis. The model allows for endogenous infrastructure expansions in consecutive time stages, with uncertain developments such as future production capacities or consumers' willingness to pay. These are considered using a number of scenarios that may occur with a known probability. Ramona was originally developed for detailed infrastructure analysis on the Norwegian continental shelf and a detailed description of this model is provided in Hellemo et al. (2013). A deterministic version of the model with emphasis on modeling aspects that apply to the natural gas transportation network is presented in Hellemo et al. (2012).

Ramona has a flexible setup, allowing problem specific objective functions such as (expected discounted) cost minimization and maximization of (expected) profit or social welfare. In general, the model handles infrastructure decisions such as development of new fields, construction, and redesign of infrastructure (pipelines, compressors, processing plants), which can all be considered strategic decisions. On the operational level, the model can handle the relationship between pressure and flow, gas quality, processing, and security-of-supply restrictions.

2.1 Study Setup

For the study presented here, we used maximization of discounted social welfare in the time horizon from 2010 to 2050 with a 5-year resolution. The investment decisions are semi-continuous, which makes the model a mixed-integer quadratic problem. In our data sets, we used a country aggregation level for most of Europe, and a region aggregation for the rest of the world (North America, South America, Africa, Russia, Middle East, and Asia) resulting in a total of 40 nodes.[3] A detailed model description for the functionality included in this study is given in Appendix A.

3. With the rather high aggregation level used in this analysis, the technical representation of the natural gas flows becomes meaningless. In order to fully analyze such aspects, we would have needed a full representation of all pipelines and related infrastructure within the different countries and regions and a much denser time resolution, which would have resulted in a model size that could not have been solved within reasonable time limits.

We also focused on pipeline infrastructure without modeling of pressure dynamics.[4] The network of existing pipelines with capacities is based on data from ENTSO-G.[5] Pipeline investments represent generalized transportation capacity expansions, covering both pipeline and compressor expansions. Investment options are defined for the opposite direction of any existing pipeline and for neighboring countries. Existing and possible new pipelines are listed in Appendix B. The investment costs for expansion and new pipelines are estimated based on publicly available cost figures from finished pipeline projects, with a fixed cost term and a variable cost term depending on length (distinguishing between onshore and offshore) and capacity. A variable cost value of $71 per kcm per 1000 km is used for onshore segments, while, for offshore segments, this value is doubled. Investments are possible every 5th year with a time lag of 5 years from the decision to construction or expansion of a pipeline to the pipeline being available for operation. To test the importance of this time lag, we also used a 10 year lag in some of the model runs. Transportation losses and costs are based on pipeline lengths multiplied by 2%/1000 km and $15/kcm/1000 km.[6] Transportation costs and losses are summarized in Appendix B.

We included LNG liquefaction and regasification capacity for the nodes listed in Appendix B. Liquefaction and regasification capacity with expansions are exogenously given for all model periods, while the capacity for LNG trade routes is unlimited. Variable costs and losses are harmonized with Holz et al. (2016), specifically, for liquefaction the values are $35 /kcm and 12%, for regasification $12 /kcm and 1.5%, and for transportation $7 /kcm/1000 sea miles and 0.3% per 1000 sea miles, respectively.

Supply functions (production costs) are modeled as quadratic cost functions. The cost functions distinguish between low cost, medium cost, and high cost producers. Production costs range from $10/kcm for the first unit in Russia and $55/kcm for the first unit in the Netherlands, to about $110 per unit for production close to the capacity limit in Russia and about $200/kcm per unit close to capacity in the Netherlands and Norway. The parameters in the marginal cost function as well as production capacity limits are estimated and are aligned with the input used in Holz et al. (2016). Production costs and capacities are listed in Appendix B. Linear inverse demand functions are estimated based on elasticities given in Holz et al. (2016) and equilibrium levels (price and volume intersection).[7] The aggregate demand for EU27 is given by BP (2011), while the prices and country shares in total consumption are given by results from the PRIMES model (Knopf et al., 2013). Data for countries outside of the EU27 are based on BP (2011), the International Energy Agency's World Energy Outlook (IEA, 2009) and EuroStat Statistics from 2010.

2.2 Stochastic Consumption

We model three sectors: industry, power generation, and residential / commercial with separate inverse demand functions. For European demand, we include eight consumption scenarios

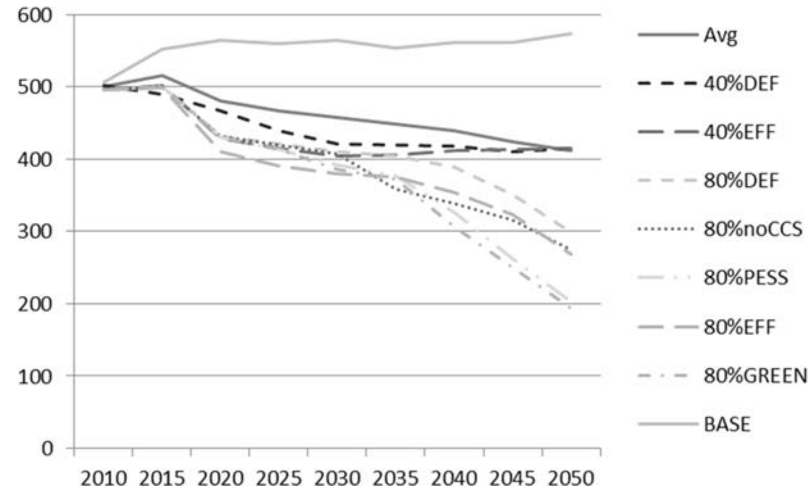
4. We also include LNG in our analysis, but we did not consider investments in LNG infrastructure. We included the existing regasification and liquefaction capacity in the different regions, as well as some exogenous capacity expansions in the years 2015 and 2020.

5. The European Network of Transmission System Operators for Gas, http://www.entsog.eu/maps/transmission-capacity-map (Accessed May 6, 2016).

6. The values for costs and losses vary depending on the state of the technology and specific circumstances of infrastructural facilities and shipping vessels. All values used are within value ranges that can be found in the literature and company reports.

7. The demand curves are based on the same assumptions as in Holz et al. (2016). The elasticities used for deriving the curves are -0.25, -0.4, and -0.75, respectively, for the residential, industry, and power generation sector.

Figure 1: Predictions for Natural Gas Demand in the EU27 by the PRIMES Model, Including an Average Path Over All Paths from PRIMES [bcm/y]



computed by PRIMES based on different policy and technology assumptions as specified in Holz and von Hirschhausen (2013) and Knopf et al. (2013).[8] Figure 1 illustrates the consumption development in Europe (EU27) computed by PRIMES in the different scenarios. Global demand projections were not available from PRIMES and were therefore taken from other public data sources (c.f., Holz et al., 2016). All scenarios show a falling demand in Europe (except for the BASE scenario where no policy or technology development is assumed). Global demand increases however, by 65% until 2050. The figure shows that, with the exemption of BASE, the different scenarios are quite similar in terms of natural gas consumption until 2035. In both 40% GHG reduction scenarios (40%DEF and 40%EFF), gas demand stabilizes after 2035, whereas in the 80% GHG reduction scenarios (80%DEF), demand continues to decrease until 2050. The BASE scenario shows, as expected, significantly higher natural gas consumption in Europe. Almost the entire increase would happen in the first decade of the model horizon.

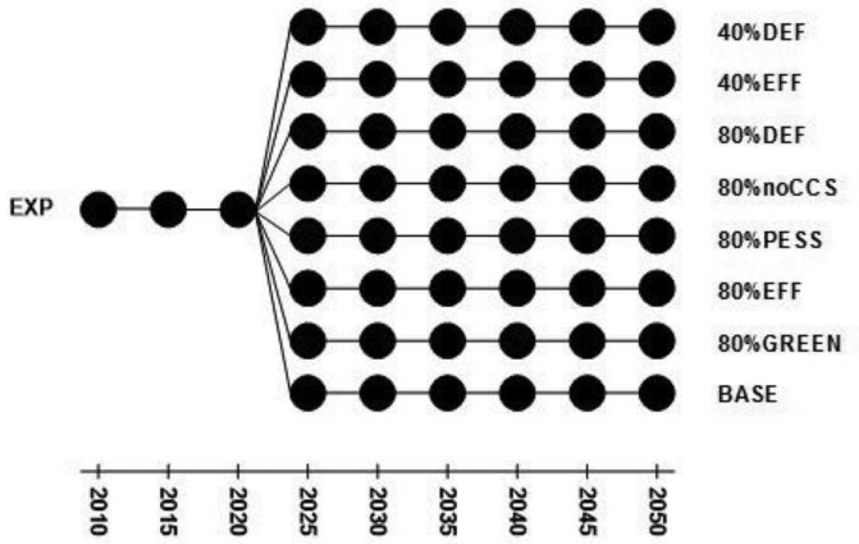
Figure 2 shows the scenario tree that we used for our analysis. We use expected demand for all scenarios for the first stage decisions (2010, 2015, and 2020) and the demand is scenario dependent from 2025 onwards. This gives us a two-stage stochastic program with eight scenarios. We assume equal probabilities between the scenarios in our base case. As we use expected demand until 2020 and then branch into the different scenarios, we see a significant change in consumption from 2020 to 2025 in some of the scenarios. This is particularly true for the BASE scenario.[9]

The resulting scenario tree consists of 51 nodes. The main motivation for using a scenario tree approach is to analyze the impact of uncertainty on optimal investment decisions in the first stage (the period between 2010 and 2020). In the second stage (from 2025 on), the original scenario values for future consumption are used in the scenario tree. Since the model must decide upon one

8. The term EFF stands for an energy efficiency scenario, DEF stands for the default technology assumptions, PESS stands for a scenario without CCS and nuclear, and GREEN refers to a high renewables scenario.

9. Assuming equal probabilities can be criticized since the different scenarios are probably not equally likely. Since we do not have any neutral way of estimating these probabilities, rather than assuming arbitrary other values, we have chosen to start with equal probabilities and we conducted sensitivity studies with varying probabilities.

Figure 2: The Scenario Tree Used in Our Analysis



investment strategy between 2010 and 2020, the model will prefer solutions that are robust in the sense that they perform well in all of the second stage scenario nodes. Another key aspect in this regard is flexibility. By investing in flexibility in the first stage, the model will be able to make good recourse decisions. The main results from our model are pipeline investments, production and consumption values, and flow patterns.

3. RESULTS AND DISCUSSION

In the following, we present results from the stochastic problem, denoted SP. In order to contrast the solutions from the SP approach, we will also solve the expected value problem, denoted EVP.[10] First, we look into the knowledge gained from using a stochastic programming approach rather than the more traditional deterministic programming approach. Further, we present decisions on capacity expansions, both aggregated and with details on particular connections, before we complete the picture with results on LNG flows. All results on expansions and flows are given in annual billion cubic meters (bcm).[11]

3.1 The Impact of Uncertainty

Input parameter uncertainty is a main driver of the quality of results of optimization models. Even though scenario-tree based optimization approaches have existed for several decades and

10. EVP is a deterministic problem wherein the uncertain parameters are replaced by their expected values.

11. Ramona is a mixed integer quadratic program. The optimality gap, the difference between the best solution found and the lower bound for the still possible best solution of the stochastic problem is 0.008%, achieved after 5.5 days of computations on a computer with 12 x 2.34 GHz CPU and 23.55 GB RAM running Xpress version 7.4. Although this is a small value, it corresponds to 7% of the total investment costs in the best solution found. This means that we must be careful when interpreting detailed results, especially when differences observed are small.

can be solved for significant problem sizes, the majority of optimization models remain deterministic (Keisler et al., 2014). Although the scenarios in our analysis are policy and technology driven, we ignore the original drivers. This suggests that the analysis may imply conclusions towards other exogenous scenarios with similar consequences for demand development over time. To test the impact of demand uncertainty on investment decisions, we have calculated the value of the stochastic solution (VSS) and compared the results on network development from an expected value problem and the stochastic problem. We have also looked at the expected value of perfect information (EVPI, cf., Birge and Louveaux, 1997) or Gollier, 2004)), which is the difference resulting from the use of a stochastic model for planning, and an approach that uses perfect information to allow for perfect adaptation of infrastructure development to each individual scenario (corresponding to a scenario analysis).

Consider a two-stage stochastic model with uncertain outcomes υ, the objective function to be maximized: $a^T x + z(y(x,\upsilon))$ and decision variables in the first stage denoted by x and in the second stage by y . The stochastic (or *recourse*) problem is defined in Eq. (3.1.1) and its solution is the stochastic solution (SS). The problem with expected values for uncertain outcomes $\bar{\upsilon} = \mathrm{E}_\upsilon \upsilon$ is the expected value problem (EVP) with solution value EV (cf., Eq. (3.1.2)).

$$\text{SP:} \quad ESS = \max_{x,y} \mathrm{E}_\upsilon(a^T x + z(y(x,\upsilon))) \tag{3.1.1}$$

$$\text{EVP:} \quad EV = \max_{x,y}(a^T x + z(y(x,\bar{\upsilon}))) \tag{3.1.2}$$

Generally, the EV is overly optimistic, since it ignores uncertainty when making decisions. Calculating the objective value of the first stage decisions of EV in the stochastic setting gives the expected value of the EV solution (EEV). Since the SP solution is optimal for the considered uncertainty, the ESS will be at least as much—and often higher—than the EV. Formally, the value of the stochastic solution (VSS) is defined as (Birge and Louveaux, 1997):

$$VSS = ESS - EEV = \max_{x,y} \mathrm{E}_\upsilon(a^T x + z(y(x,))) - \mathrm{E}_\upsilon \max_{x,y}(a^T x + z(y(x,\bar{\upsilon}))) \geq 0 \tag{3.1.3}$$

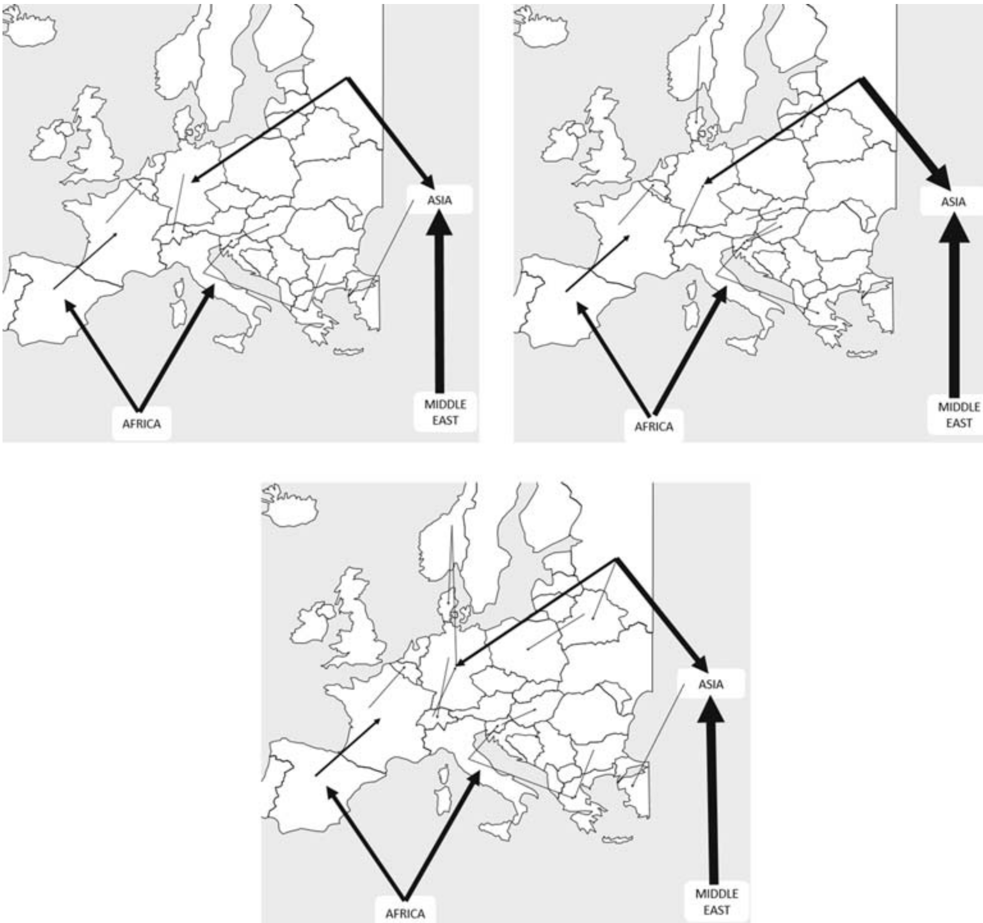
A wait-and-see (WS) problem gives optimal decisions for a single scenario, corresponding to having perfect information. EPI is the expected profit under perfect information for each separate scenario solved as a WS problem, weighted by scenario probabilities p_υ. The expected value of perfect information (EVPI) represents the added value of information about the future, i.e., knowing in advance which scenario will play out, which is the difference between EPI and ESS. Eq. (3.1.4) provides the EVPI for discrete probability distributions.

$$EVPI = EPI - ESS = \sum_\upsilon p_\upsilon \max_{x,y}(a^T x + z(y(x,\upsilon))) - \max_{x,y} \mathrm{E}_\upsilon(a^T x + z(y(x,\upsilon))) \tag{3.1.4}$$

For solving very large stochastic optimization problems, some of the VSS may be sacrificed in order to maintain computational tractability. Devine et al. (2008) implement a rolling horizon approach to solve a stylized stochastic gas market equilibrium problem and coin the term *value of the rolling horizon* to represent solution quality of the rolling horizon approach. In our analysis, we found system-wide VSS and EVPI values concerning global social welfare close to 0.0%.[12] This

12. The VSS must be nonnegative. We find, however, VSS −0.0097% (and EVPI 0.0121%). The optimization stopping criterion used for the computations was 0.01%. If solutions all have an optimality gap of 0.01%, the total gap of VSS and EVPI may be +/-0.02%. |-0.0097%| < 0.02% and EVPI = 0.0121% < 0.02%.

Figure 3: Capacity Expansion 2010–2020 for EVP (upper left), SP (upper right) and the Maximum Expansion on Each Connection in any WS Run (lower)



indicates that the value of using the stochastic model is very small and that the value of having perfect information regarding consumption development is very limited. These results are robust for sensitivity studies with regards to investment delay (we have used 5 and 10 year delays from investment decisions until operation of the pipelines) as well as changes in the probabilities of the individual scenarios (sensitivity cases presented in Section 3.2). Bearing in mind the consumption development in Europe shown in Figure 1, the result is not unexpected. The variation in gas consumption until 2020 is very low for 7 of the 8 scenarios (with only BASE deviating substantially from the expected value). In addition, the consumption in the rest of the world is not changed in these scenarios such that the total variation in gas consumption between the scenarios is small. This indicates that the scenario solutions will be quite similar. Despite the very small value of the VSS, we can still draw some conclusions regarding timing of infrastructure development in Europe. More specifically, we can conclude that the option value of postponing decisions on pipeline development in Europe until 2020 is very limited given the analyzed scenarios.

Figure 3 shows the capacity expansions in the first stage, available in 2025, in EVP, SP, and the union of WS runs for all scenarios. We generally expect fewer expansions in EVP, since it does not have to hedge against multiple futures. Also, because there is no hedging, each WS by itself should have fewer expansions than SP, although some may be of larger magnitude. Figure 3 shows only small variations in the investment decisions, which corresponds well to the small values for VSS and EVPI. Even though the differences are small, having fewer and smaller expansions in EVP relative to SP and the union of WSs are reasonable. The results for WS represent all expansions for multiple model runs, which, naturally, make the total expansion larger than the single EVP run. Contrary to the other models, the stochastic model (SP) needs to build flexibility into the network to hedge for uncertainty. This can be done in two ways, building larger pipelines or more pipelines, and both strategies can be seen in the results. The total expansion is larger for SP than WS and EVP, which indicates that some slack capacity is optimal to be flexible. There are also examples where the stochastic model builds pipelines in both directions between countries to gain flexibility, most obviously between Hungary and Slovenia. Such an investment, unless at very different points in time, cannot be optimal in any single scenario. This shows how a stochastic model can give structurally different solutions than deterministic models, due to the uncertainty.

There are, however, several aspects that could influence our conclusions regarding the impact of uncertainty on investment decisions. One of the main concerns is the source of data used in our analysis and the resulting consistency between European countries and the rest of the world. Since our source for demand data is the results from the PRIMES model, we do not have results for development in the rest of the world in the different scenarios. This means that we must rely on other data sources, and that the variance in the rest of the world's demand in the different scenarios is ignored. This, combined with the fact that the main developments in gas demand are outside of Europe, puts a limit to the value of the stochastic analysis (since a large part of the total demand in our model is deterministic). However, the fact that the rest of the world is not modeled at the same level of detail as the EU27 also introduces bias into the EVP cases.

Investment costs are very low compared to the cash flow from operating infrastructure. In fact, the cost of overcapacity is very low. This means that there is little value in waiting before investing, and that the main concern in designing the natural gas infrastructure is to ensure sufficient capacity. The low investment cost also means that the scenario differences in investments will lead to very small differences in objective function values.

3.2 Capacity Expansion—Aggregated Results

If we look in more detail at the difference in investments between the expected value problem (EVP, where the demand is represented by the expected demand over all scenarios) and the stochastic problem (SP) for the years 2010 to 2020, we do find significant differences for Europe. The additionally installed capacity for Europe is 11% higher in SP than in EVP (361 bcm versus 325 bcm). Considering the exogenously added expansions of 204 bcm, the difference in endogenously added capacity is more pronounced, at 29%: 157 bcm in SP versus 121 bcm in EVP.

If we compare the difference in infrastructure among European countries and the import capacity from outside Europe, we find the largest difference in internal infrastructure. Internally, no exogenous expansions are assumed. SP installs 99 bcm of new capacity, 42% more than the 70 bcm that EVP installs.

For import capacity to Europe, the difference is much smaller, approximately 6 bcm. SP adds 58 bcm in the first three periods, additional to the 204 bcm exogenously added in the first period. EVP gives 52 bcm of expansions, on top of the exogenously added capacities. The difference in investment levels between the two modeling approaches can be seen in Figure 4.

Figure 4: First-stage Pipeline Investments Within and Into Europe (in bcm)

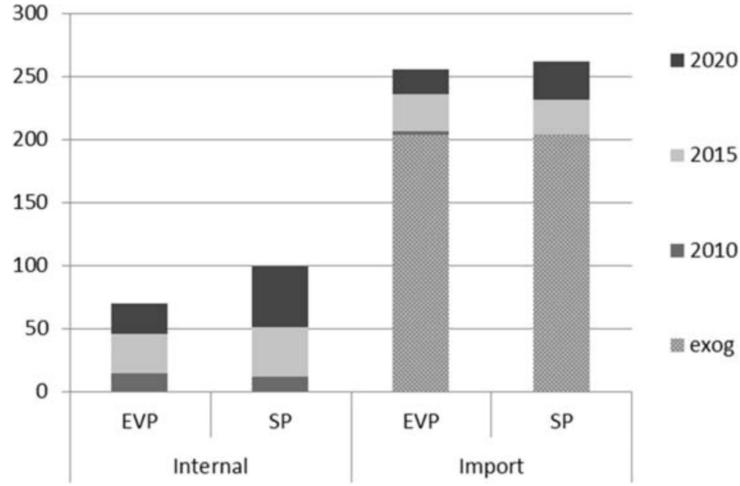
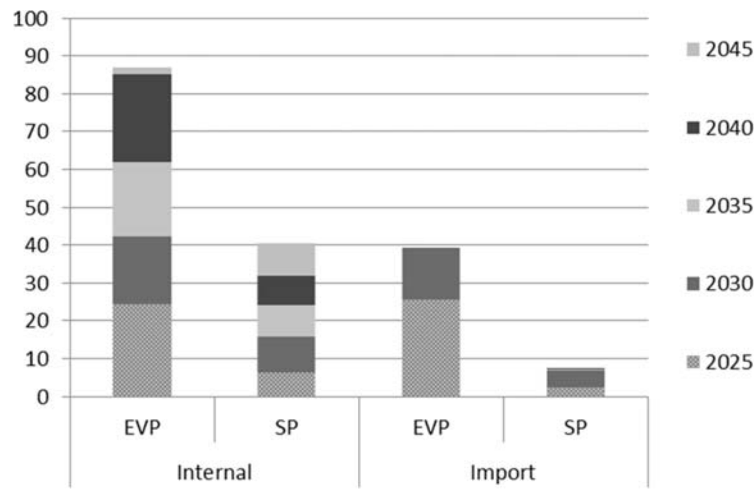


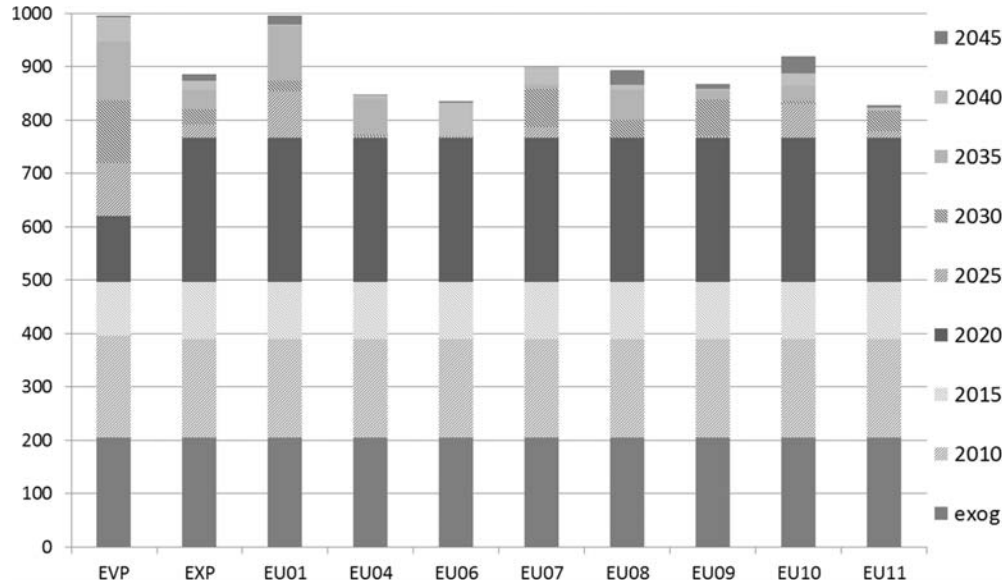
Figure 5: Second-stage Pipeline Investments in EVP and SP (average) (in bcm)



It is interesting to see that the expected second stage expansions by SP are lower than the expansions in EVP, as shown in Figure 5. Within Europe, SP adds 40 bcm in the second stage in expectation, versus the 87 bcm added by EVP. This more than outweighs the opposite relation in the first stage. Over the whole time horizon, the expected internal expansions are 140 bcm in SP, 11% lower than the 157 bcm of EVP. Towards Europe the same picture is seen in the second stage, with endogenous expansions of 7 and 39 bcm, respectively, for SP and EVP. With approximately the same level of expansions for the two approaches in the first stage, this gives total endogenous expansions of 65 and 91 bcm towards Europe.

The development of the expansions is depicted in Figure 6. Globally, the model data includes 1353 bcm of pipeline transport capacity in 2010. In 2025, after taking into account all capacity expansions in the first stage of 766 bcm, the total capacity is 2119 bcm in SP. In the second

Figure 6: Aggregate Pipeline Capacity Expansions by Scenario (bcm). AVG is the Expected Expansion in the Stochastic Model.



stage, in expectation, not much capacity is added. The total capacity by 2050 amounts to 2239 bcm, varying from 2181 in BASE to 2349 in 40%DEF. In contrast, the results from EVP show lower expansions in the first stage periods (620 bcm versus 766 bcm) and much higher in the second stage (374 bcm versus 119 bcm), eventually resulting in an aggregate capacity of 2348 bcm, which is higher than in all of the scenarios in SP except the 2349 in 40%DEF.

3.3 Sensitivity on Scenario Probabilities

To evaluate the results' sensitivity to our assumption of equiprobability between the eight scenarios, we have constructed two alternative cases: "EquiPol" and "NoBASE". "EquiPol" refers to a case where the policy targets, 0% (BASE), 40% (40%DEF and 40%EFF), and 80% (80%DEF, 80%NOCCS, 80%PESS, 80%EFF, and 80%GREEN) GHG reduction, are given equal probability. Each policy target level identifies a scenario group. "NoBASE" also has equal probability for the two GHG reduction scenario groups, and leaves out the group containing only BASE, as shown in Table 1. The original case is denoted "EquiScen". Changing the probabilities of the individual scenarios both shifts the weight between the different scenarios in the second stage of the scenario tree and changes the expected values for consumption in the first stage and in the EVP.

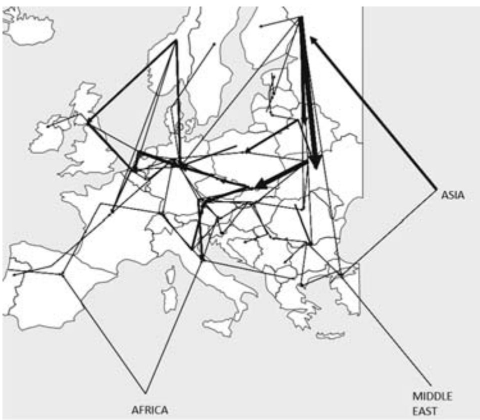
In the EVP, the pipeline capacity expansions in EquiPol are 19 bcm lower than in the EquiScen: 6 bcm lower in the first stage and 13 bcm in the second stage. The expansions are higher in two years, 2010 and 2030, and lower in all other years. In contrast, in the SP 9 bcm more is added in the EquiPol case compared to the EquiScen over the whole time horizon. In the first stage, the expansion is 24 bcm less, but this is outweighed by 33 bcm additional expansions in the second stage. In the NoBASE, EVP adds 6 bcm more over the whole time horizon in EquiPol than in EquiScen, and SP adds 18 bcm. Again, the SP expands relatively less in the first stage, but relatively

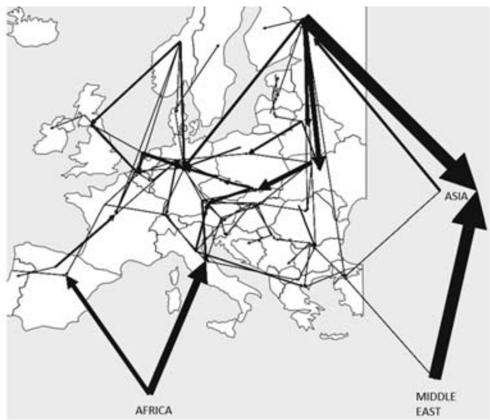
Table 1: Test Cases Used for Sensitivity Analysis on Scenario Probabilities

Scenario description	Name	40%DEF	40%EFF	80%DEF	80%NOCCS	80%PESS	80%EFF	80%GREEN	BASE
Equal probability for all scenarios	EquiScen	0.125	0.125	0.125	0.125	0.125	0.125	0.125	0.125
Equal probability for the three policy scenario groups	EquiPol	0.167	0.167	0.067	0.067	0.067	0.067	0.067	0.333
Equal probability for the two scenario groups, leaving out BASE	NoBASE	0.250	0.250	0.100	0.100	0.100	0.100	0.100	0

Note: Each scenario group contains scenarios with the same GHG reduction target for the EU.

Figure 7: Current Transportation Infrastructure in 2010 (left) and Expected Value Problem (EVP) Results for 2050 (right)





more in the second. We will use these three cases in the following section where we discuss the capacity extensions with more geographical detail.

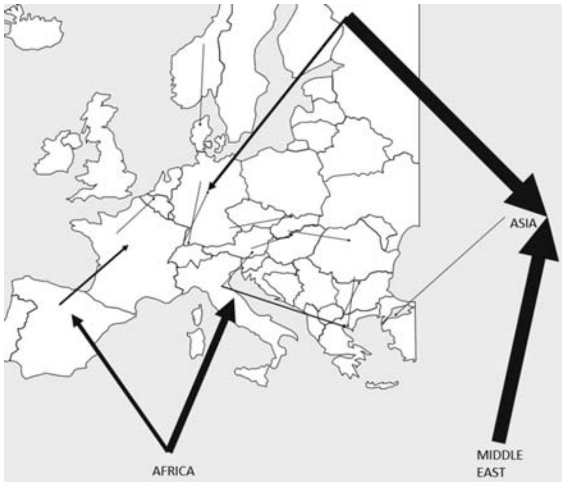
3.4 Capacity Expansion—Geographical Details

We now present detailed results for the capacity expansions. Figure 7 shows the resulting capacities from the EVP; the width of the arrows indicates the installed capacity. In addition to countries in Europe, Russia, Asia, the Middle East, and Africa are included in the figures. An illustration of the expansions in EVP over the whole model horizon, leaving initial capacities out, is given in Figure 8. The main conclusions from these figures are that 1) there is a trend of larger gas supply from Africa to Europe, 2) the eastward connections within Europe are expanded, and 3) the largest pipeline investments will be toward Asia.

Gas supply from Africa to Europe

There are two pipelines going from North Africa towards Europe in 2010: one to Spain and one to Italy. The pipeline from Africa to Italy is expanded from 10 to 99 bcm in 2015. In EVP and SP, and in all the sensitivity cases, pipeline capacity is increased. The timing, as well as the

Figure 8: Aggregate Infrastructure Expansions until 2050 in the Expected Value Problem (EVP) for the Case EquiScen



chosen capacity, varies between the cases and the model types. In EquiScen, the pipeline capacity is increased to 162 bcm by 2050 in EVP. The capacity of the pipeline is 122 bcm in 2020, and it is then expanded stepwise. In SP however, pipeline capacity is increased to 133 bcm by 2020, and it stays at that level in four of the eight scenarios. The highest value, 141 bcm, is attained in 80%NOCCS. In EquiPol, pipeline capacity is 118 bcm by 2020 and 159 bcm by 2050 in EVP. In SP, pipeline capacity is 126 bcm by 2020, while the capacity varies between 126 and 129 bcm in 2050. In NoBASE, the resulting capacities in EVP are similar to the capacities given by EquiScen. This is however not the case for SP, where the exclusion of BASE has a much more pronounced impact. The first stage expansions lead to a pipeline capacity of 128 bcm, which is further expanded to 152 and 151 bcm in the scenarios 40%DEF and 40%EFF, respectively. Pipeline capacity stays at 128 bcm in the other scenarios.

The capacity in the pipeline to Spain is increased from 11 to 71 bcm in 2015. In EquiScen, the capacity is increased further to 95 bcm in 2020 in SP, while it is increased to 97 bcm in EVP. For two of the scenarios in SP, capacity is even further increased to 105 bcm in 40%DEF and 123 bcm in BASE. EVP however, keeps the capacity at 97 bcm. In EquiPol, the expansions are roughly 10 bcm higher than in EquiScen in almost all scenarios (including EVP). The additional capacity investments are in place by 2020. In BASE, a capacity of 147 bcm is reached in 2035. The NoBASE scenario shows only small differences in capacity investments from EquiScen.

In summary, sensitivity results show that investments in pipeline capacity from Africa to Spain appear to be robust. There are only small deviations between the scenarios and between EVP and SP. The investments in the pipeline to Italy do however vary between the scenarios and between the different cases. These results may be explained by the fact that Italy has larger capacity in the transportation infrastructure to the rest of Europe than Spain, which facilitates gas flows through Italy to other European countries. This is further discussed in the following subsection.

Gas supply eastwards within Europe

To facilitate EU energy market integration, the EC has listed 248 projects that can qualify for accelerated licensing procedures, improved regulatory conditions, and access to financial support between 2014 and 2020 (EC, 2014). Several of these projects of common interest (PCIs) are aimed at strengthening West-East connections within Europe. In the following, we discuss the investment results for pipelines in Europe, first focusing on those where the gas supply goes from east to west. A complete overview of first stage expansions within the EU for both EVP and SP is given in Appendix C.

The increased export of natural gas from Africa to Italy and Spain leads to investments in capacity eastwards from these two countries. The pipeline capacity between Spain and France is increased stepwise in all six model runs from 1.8 bcm to between 35.0 and 41.7 bcm. The export capacity from Italy is strengthened by pipelines to both Greece and Slovenia. The pipeline to Greece is constructed in all six model runs stepwise to a value of between 8.2 and 9.9 bcm by the start of the second stage. EC (2014) lists two Greek LNG import terminals, but since our model does not allow construction of additional LNG capacity, and considering that other supply security considerations are not reflected in the model, the added pipeline capacity into Greece can be interpreted as support for this listing. The pipeline to Slovenia is expanded from 0.9 bcm to between 8.8 and 11.7 bcm in all but EVP EquiPol. From Slovenia, there is a further strengthening of the eastward capacity with a pipeline to Hungary. This pipeline is constructed in all runs but the EVP. The size of the pipeline is between 7.8 and 10 bcm. EC (2014) lists a pipeline from Hungary to Slovenia, which is in the opposite direction to what we find in our results.

The pipeline capacity from Austria to Slovakia is increased in EquiScen and NoBASE in the year 2025 (from 5.7 to 11.3 and 13.3 bcm) in SP, but not at all in EquiPol or in EVP. EC (2014) lists Austria to Czech Republic, but not Austria to Slovakia. However, given the abundant capacity from Slovakia to Czech Republic, this model result may reflect a cost-minimal strengthening of potential supply routes into the Czech Republic, again not considering other factors. Moreover, the pipeline capacity from Bulgaria to Greece is increased in both EVP and SP in EquiPol from 3.5 to 5.6 bcm. It is also increased with 5.1 bcm in EVP in EquiScen.

The model does not construct / extend several of the European Commission's PCIs, and some of the model results are not reflected in the EC priority list (EC, 2014), specifically, connections from Poland to Lithuania, Czech Republic and Slovakia, Turkey to Bulgaria, and Estonia to Finland. The reason that these pipelines are not developed by the model may be due to assumptions concerning yearly average volumes, the perfectly competitive market structure, and assumption of availability of Russian supplies through Ukraine after 2020, not considering disruption risk or other (uncertain) factors for which the model does not account. In contrast, expansions chosen by the model that are not in the list can be due to specific uncertainties considered in the scenarios. However, this can be interpreted as support for strengthening of West-East connections from a cost-minimizing perspective, even when not yet considering disruption risk and other external factors.

Other gas supply routes within Europe

The potential pipeline from France to Belgium is constructed by 2025 in all EVP and SP runs, except in SP NoBASE. However, in EquiPol and EquiScen, the capacity is 13.4 and 11.3 bcm, much higher than the 1.6 to 2.5 bcm in EVP for the three cases.

A pipeline from Norway to Denmark is constructed in EquiProb, but not in EVP. In 2025, at the start of the second stage, 5.5 bcm has been constructed. In some scenarios this is increased further to 8.5 bcm in later periods. The capacity in other pipelines originating from Norway is unchanged.

Generally, we see that in Europe, more and larger internal connections are constructed in SP than EVP. This is an indication that hedging for future uncertainty results in investments in flexibility.

Pipeline investments towards Asia

Due to aggregation, the model data set does not include many liquefaction facilities. To facilitate the increased import needs of Asia, pipelines are constructed from both Russia and the Middle East to export gas to Asia. Increased capacity of pipelines in all EVP runs is significantly lower than that of their counterparts for SP in the first stage. However, in all three cases, the expansions in EVP continue after 2020. By 2050, the total capacity is between 266 and 278 bcm, while in SP it ranges from 280 to 284 bcm. Also for the pipeline from the Middle East, capacity increases until 2020 are higher in SP than EVP for all sensitivity cases. The highest capacity investments of all cases by 2050 occur in 40%DEF (between 295 and 303 bcm), while 40%EFF ranks second (277 to 284 bcm). The EVP result by 2050 in EquiScen is 269 bcm, hence lower than 40%DEF and 40%EFF, but higher than in all other scenarios. In EquiPol and NoBASE, only 40%DEF and 40%EFF show any expansions in the second stage in SP.

The potential pipeline from Turkey to Asia is not constructed in most scenarios. It is, however, included in the last period in 80%GREEN in EquiScen and EquiPol, and the last period in 80%NOCCS in NoBASE. The scenario with the largest decline in EU consumption levels is 80%GREEN. So much so that it becomes economical to have an outlet from Europe towards Asia. If the model had allowed for endogenous liquefaction and regasification capacity expansion, the gas flows from Africa to Asia would most likely have been LNG flows. Indeed, when constructed, the pipeline is used to bring African gas towards Asia (via Italy and Greece).

3.5 LNG Trade Detailed Results

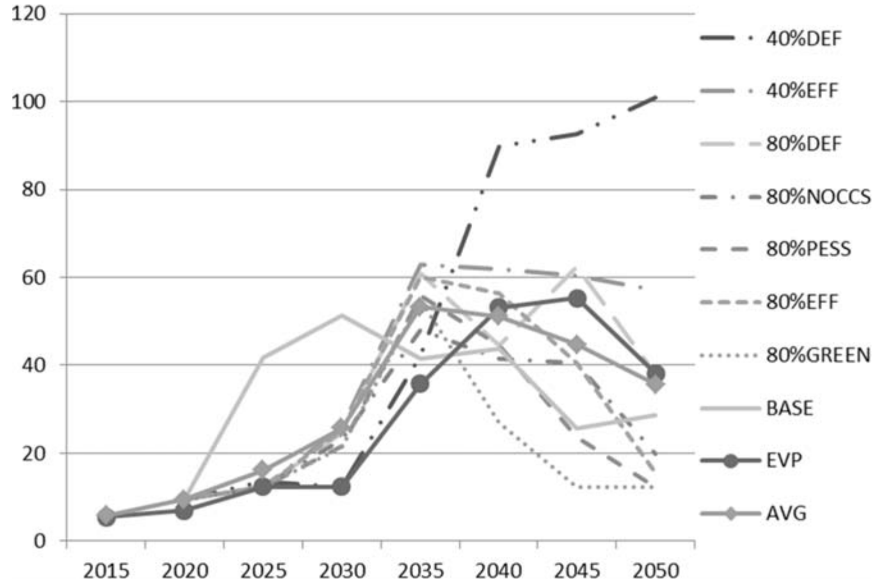
The aggregate LNG trade is equal in EVP and SP in the first period for all scenarios, and just slightly different between EVP and SP in the rest of the first stage. Naturally, the differences are larger in the second stage. Similar to the observations made in Holz et al. (this issue), there is a drop in LNG trade after 2010 due to modeling assumptions; however, some insight can be gained from LNG trade developments after the first period (see Figure 9).

In 2015, France and Greece are the only countries importing LNG in any of the scenarios. Due to the low pipeline investment costs, it is often cheaper to construct new pipelines—especially along shorter routes, such as from North Africa to Southern Europe—and use these for transporting gas, rather than continuing to use existing LNG capacities. Factors that support larger LNG usage, such as contractual trades, seasonal variations, gas quality, and security of supply are not considered in our analysis. In this regard, the quantitative results should not be taken at face value, but rather as indicative for how different developments over time and decisions related to uncertainty affect the nature of trade patterns. For instance, in 2025, just after the uncertainty is resolved, the global LNG trade is higher in two scenarios (40%DEF and BASE) versus all others. BASE is the only scenario where the EU demand in 2025 is higher than in 2020 (compare BASE vs. AVG vs. Figure 1). In the other scenarios, demand in 40%DEF decreases the least. In BASE, the destination of these LNG flows is the EU, originating from North and South America.[13] In 40%DEF, the flows are mostly from Africa to North America and some to Europe; the largest share is to Turkey and a modest amount to France.

In the years after 2025, the LNG trade results vary to a larger extent. By 2030, the investments in pipeline capacity in scenario BASE become available and, from that year on, the LNG

13. For a detailed discussion of LNG exports from a North American perspective see, e.g., Moryadee et al. (2014).

Figure 9: European LNG Import (bcm) Over Time by Scenario (Case EquiScen)



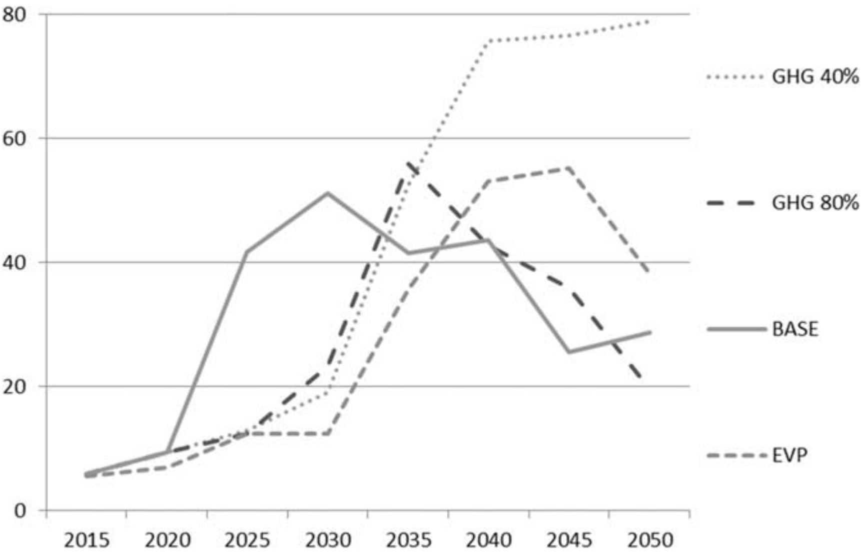
trade in this scenario decreases gradually, until becoming the lowest among all scenarios from 2035 onward. In all other scenarios, the aggregate global LNG trade increases significantly from 2025 onward.

By 2050, the global LNG trade (detailed results not shown in this paper) in the 80% reduction scenarios is on average 97 bcm, slightly lower than the 99 bcm average in the 40% reduction scenarios. However, because EU consumption stabilizes in the second stage concomitant with declining production in the 40% scenarios, Europe attracts a larger share of LNG flow. In the 80% reduction scenarios, EU gas consumption continues to decline in the second stage, resulting in lower import needs in Europe and a higher availability of LNG for Asia. In the 40% reduction scenarios, 79 bcm is oriented towards Europe (see Figure 10), and 20 bcm to Asia. In contrast, in the 80% reduction scenarios, on average, 77 bcm is exported to Asia and only 20 bcm is oriented towards Europe. Notably, the scenarios with the largest decrease in EU consumption, 80%PESS and 80%GREEN, are the scenarios with the highest global LNG trade in 2050.

In the first stage, the EU LNG imports are the same for SP and EVP. From 2025 on, the picture becomes more interesting. In BASE, LNG imports are used to meet the additional consumption needs. In the period 2035–2045, the EU LNG imports pick up in all 40% reduction scenarios, whereas they decline in BASE as well as the 80% reduction scenarios with the largest demand reduction in 80%PESS and 80%GREEN.

Africa is responsible for the majority of (often all) LNG exports in most years and scenarios, in all of the cases. Unlike Russia or the Middle East, Africa cannot directly export to Asia via pipelines. This results in growth of global LNG flows, particularly in scenarios where gas consumption in the EU decreases harshly towards the end of the time horizon. North and South American LNG supplies diminish after the first two periods and revive only in the scenario BASE in the period 2025–2035 and in the last two periods, to varying degrees, in the 80% reduction scenarios. Since the LNG capacity cannot be expanded in the model, it limits South America's potential to play a larger role in the BASE scenario in the periods 2025–2035.

Figure 10: European LNG Trade Over Time—Average by Scenario Group (bcm) (Case EquiScen)



The differences in LNG trade between SP and EVP in the first periods are small. In the first period, significant LNG trade can be observed, but in other periods, in the first stage, the LNG trade all but diminishes. Additional pipeline capacity is relatively cheap and pushes out existing LNG trade. In the second stage, LNG trade flows show a more diverse picture. Naturally, the different consumption levels in all scenarios in the EU require different imported amounts, and LNG is the marginal but flexible supply option that is used when pipeline supplies are scarce. Asia is the main destination for LNG not absorbed by the EU, with North America absorbing some supplies in some of the scenarios. Africa, with pipeline connections to Spain and Italy only, is the main LNG exporter by far in all future periods.

4. CONCLUSIONS AND FUTURE RESEARCH

We have presented an analysis of natural gas infrastructure development in Europe based on eight predefined technology and policy scenarios. We used input from PRIMES as a starting point for the demand functions in the different regions in the model, and supplemented with additional data where available. In our analysis, we considered individual scenarios and a two-stage approach to find the potential value of options in the system. Our main finding is that the option value of delaying investments in natural gas infrastructure, until more information is available regarding policy and technology in 2020, is very limited due to the low costs of overcapacity. We do, however, find structurally different infrastructure solutions in the stochastic and the deterministic models. In general, the stochastic model tends to invest in more capacity until 2020. We have also made some observations from the analysis in terms of infrastructure trends: 1) the largest pipeline investments will be towards Asia, 2) there is a trend toward a larger gas supply from Africa to Europe, and 3) expansion occurs eastward for connections within Europe.

One of the main research tasks relevant to our analysis is the inclusion of seasonal to short-term dynamics, such as the energy mix in the different countries and the resulting need for balancing services and flexible energy sources. An infrastructure designed for offering balancing services may be substantially different from an infrastructure designed for delivering a base load with some seasonal variations. This may influence both the need for higher capacity to the different landing points and flexibility in flow patterns. The Ramona model is well suited for these kinds of analysis, but the main challenge lies in gathering the necessary data. Scenarios for production and demand variability must be estimated, and these estimates will again depend on the scenarios, since the energy mix varies between the scenarios. Currently, these data are not available for analysis. Ideally, the representation of the network should also be more detailed with finer resolution in order to accurately perform these analyses.

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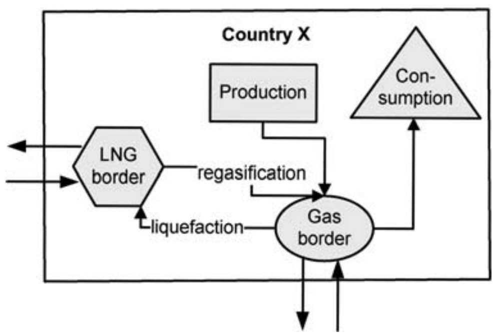
APPENDIX A—MODEL DESCRIPTION

The model consists of a network of nodes and directed connections. A country is represented by up to four interconnected nodes, as illustrated in Figure 11, production, consumption, and two intermediate nodes accounting for imports and exports of natural gas and LNG. Between countries, there are connections between all LNG border nodes, while the pipeline connections through the gas border nodes are limited to those listed in Table 7 and Table 8.

Figure 11: Generic Country Structure in Model



A.1 Declarations

Table 2: Sets

I	Nodes in the network
$I^P \subset I$	Production nodes
$I^C \subset I$	Consumption nodes
$I(i) \subset I$	Nodes connected to node $i \in I$ through pipeline or LNG transportation capacity directed into i
$O(i) \subset I$	Nodes connected to node $i \in I$ through pipeline or LNG transportation capacity directed out of i
K	Consumption sectors {Industry; Residential, commercial & transport; Power generation}
S	Scenarios
T	Time periods
$T^1 \subset T$	Time periods in the first decision stage

Table 3: Decision Variables

f_{ijst}	Flow from $i \in I$ to $j \in O(i)$ in scenario s in period t. Continuous
f_{ist}	Production from $i \in I^P$ in scenario s in period t. Continuous
f_{ikst}	Consumption in sector k in $i \in I^C$ in scenario s in period t. Continuous
x_{ijst}	Investment in transportation capacity from $i \in I$ to $j \in O(i)$ in scenario s in period t. Binary
y_{ijst}	Transportation capacity expansion from $i \in I$ to $j \in O(i)$ in scenario s in period t. Continuous

Table 4: Parameters

ρ_s	Probability of scenario s.
γ_t	Discount factor for time period t.
$C^A_{it},\ C^B_{it}$	Intercept (A) and slope (B) of production cost function for node $i \in I^P$ in period t.
$P^A_{ikst},\ P^B_{ikst}$	Intercept (A) and slope (B) of demand function for node $i \in I^C$ sector k in scenario s in period t.
$D^A_{ij},\ D^B_{ij}$	Fixed (A) and capacity dependent (B) transportation investment cost from $i \in I$ to $j \in O(i)$.
L_{ij}	Loss from $i \in I$ to $j \in O(i)$.
D	Delay from investment decision to available capacity
Q^P_{it}	Production capacity in node $i \in I^P$ in period t.
Q^0_{ijt}	Existing capacity from $i \in I$ to $j \in O(i)$ in period t.
$\underline{Q},\ \overline{Q}$	Lower and upper limit on capacity expansions.

A.2 Algebraic model definition

$$\max_{f,y,x} \sum_{s\in S}\sum_{t\in T}\sum_{i\in I^C}\sum_{k\in K}\rho_s\gamma_t[(P^A_{ikst}-0.5P^B_{ikst}f_{ikst})f_{ikst}] \tag{A.1}$$

$$-\sum_{s\in S}\sum_{t\in T}\sum_{i\in I^P}\rho_s\gamma_t[(C^A_{it}+C^B_{it}f_{ist})f_{ist}] \tag{A.2}$$

$$-\sum_{s\in S}\sum_{t\in T}\sum_{i\in I}\sum_{j\in O(i)}\rho_s\gamma_t[E_{ij}f_{ijst}] \tag{A.3}$$

$$-\sum_{s\in S}\sum_{t\in T}\sum_{i\in I}\sum_{j\in O(i)}\rho_s\gamma_t[D^A_{ij}x_{ijst}+D^B_{ij}y_{ijst}] \tag{A.4}$$

s.t.

$$f_{ist}=\sum_{j\in O(I)} f_{ijst} \quad i\in I^P,\ s\in S,\ t\in T \tag{A.5}$$

$$\sum_{j\in I(i)}(1-L_{ij})f_{jist}=\sum_{j\in O(i)} f_{ijst} \quad i\in I\backslash I^P, s\in S, t\in T \tag{A.6}$$

$$\sum_{j\in I(i)} f_{jist}=\sum_{k\in K} f_{ikst} \quad i\in I^C, s\in S, t\in T \tag{A.7}$$

$$f_{ist}\le Q^P_{it} \quad i\in I^P,\ s\in S,\ t\in T \tag{A.8}$$

$$f_{ijst}\le Q^0_{ijt}+\sum_{\tau\in T|\tau+D\le t} y_{ijs\tau} \quad i\in I, j\in O(i), s\in S, t\in T \tag{A.9}$$

$$\underline{Q}x_{ijst}\le y_{ijst}\le \overline{Q}x_{ijst} \quad i\in I, j\in O(i), s\in S, t\in T \tag{A.10}$$

$$y_{ijst}=y_{ijrt} \quad i\in I, j\in O(i), s\in S, r\in S, t\in T^1 \tag{A.11}$$

$$x_{ijst}\in\{0,1\}, f_{ist}\ge 0, f_{ijst}\ge 0, f_{ikst}\ge 0, y_{ijst}\ge 0 \tag{A.12}$$

The objective function consists of five parts: consumer surplus and sales revenues (both in A.1), the production cost (A.2), the operating cost for LNG liquefaction and regasification and pipeline transportation (A.3), and the semi-continuous investment cost (A.4). All objective function parts are weighted by the scenario probabilities and discount factors to maximize the expected discounted social welfare. Equations (A.5), (A.6), and (A.7) are mass balances for production, intermediate, and consumption nodes, respectively. Production capacity limitations are given in (A.8). Equation (A.9) represents transport capacity limitations on connections between nodes. This represents both pipeline capacities and LNG liquefaction and regasification capacities. For LNG, the capacities are given exogenously, while for pipelines, capacity expansions decided by the model are also included in the constraint. The semi-continuous property of capacity expansions, forcing positive investment decisions to give expansions above a minimum level, is represented in (A.10). (A.11) are non-anticipativity constraints to ensure a common solution for all scenarios in the first stage of the model. (A.12) are binary and non-negativity constraints for the variables.

APPENDIX B—INPUT DATA

Table 5: Transportation Investment and Operating Costs and Losses

Parameter	Value
Discount rate	5%
Fixed pipe investment cost	$77 mill.
Minimum capacity expansion	1.5 bcm /y
Maximum capacity expansion (dummy)	9999 bcm /y
Variable onshore pipe investment cost	$ 71 /kcm/1000 km
Variable offshore pipe investment cost	$ 142 /kcm/1000 km
Investment time lag	5 years[a]
Pipe transportation loss	2 % /1000 km
Pipe transportation cost	$15 /kcm/1000 km
LNG liquefaction loss	12 %
LNG liquefaction cost	$35 /kcm
LNG regasification loss	1.5 %
LNG regasification cost	$12 /kcm
LNG transportation loss	0.3% /1000 sea miles
LNG transportation cost	$7 /kcm/1000 sea miles

[a] In one of the sensitivity analyses we used a value of 10 years.

The production cost function has the shape $\left(I + 0.5\frac{I}{L}q\right)q$, where q is the production quantity and I and L are parameters representing the constant of the cost function and the production capacity. The parameter values are given in Table 6. Countries without capacity are not included in the table.

Table 6: Production Costs and Limits

Region	Node	Constant [mill. $/bcm]	Production capacity [bcm] 2010	2015	2020	2025	2030	2035	2040	2045	2050
EU27	Austria	50	1.63	1.56	1.48	1.32	1.18	0.93	0.73	0.63	0.55
EU27	Bulgaria	50	0.07	0.08	0.09	0.09	0.10	0.08	0.06	0.05	0.04
EU27	Czech Republic	50	0.19	0.18	0.17	0.16	0.15	0.11	0.08	0.05	0.03
EU27	Denmark	50	8.11	7.10	6.22	5.92	5.64	4.02	2.87	2.27	1.79
EU27	France	50	0.67	0.62	0.56	0.49	0.43	0.35	0.29	0.23	0.18
EU27	Germany	55	10.63	9.87	9.17	8.15	7.24	6.00	4.97	3.60	2.60
EU27	Hungary	50	2.15	1.99	1.83	1.66	1.51	1.13	0.85	0.54	0.34
EU27	Ireland	50	0.36	0.36	0.36	0.34	0.33	0.25	0.19	0.16	0.14
EU27	Italy	50	7.55	7.56	7.57	7.25	6.94	5.75	4.75	3.56	2.67
EU27	Netherlands	55	67.68	62.23	57.23	51.96	47.17	37.48	29.77	25.13	21.21
EU27	Poland	50	4.10	3.84	3.60	3.43	3.27	2.47	1.86	1.47	1.16
EU27	Romania	50	10.04	9.29	8.60	7.81	7.10	5.58	4.39	2.86	1.86
EU27	Slovakia	50	0.10	0.10	0.10	0.09	0.09	0.07	0.06	0.05	0.04
EU27	Spain	50	0.05	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.04
EU27	UK	50	57.07	50.80	45.23	41.37	37.83	30.98	25.37	20.23	16.12
ROEU	Belarus	50	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
ROEU	Croatia	50	2.31	2.22	2.13	2.04	1.96	1.87	1.79	1.74	1.69
ROEU	Norway	40	102.11	98.23	94.50	90.49	86.64	82.86	79.24	77.05	74.92
ROEU	Serbia	50	0.28	0.27	0.26	0.25	0.24	0.23	0.22	0.21	0.21
ROEU	Turkey	50	0.62	0.59	0.57	0.55	0.52	0.50	0.48	0.47	0.45
ROEU	Ukraine	30	18.55	17.85	17.17	16.44	15.74	15.05	14.40	14.00	13.61
AFR	Africa	10	209.02	277.27	341.26	384.98	425.50	471.36	504.45	513.42	522.55
ASP	Asia	30	643.32	840.59	1005.36	1106.29	1215.70	1321.64	1382.23	1398.66	1415.31
MEA	Middle East	10	460.70	589.30	648.56	686.58	783.87	864.38	931.16	949.14	967.48
NAM	North America	40	826.11	844.79	871.77	897.72	939.23	967.25	983.06	987.19	991.33
RUS	Russia	10	588.95	699.12	712.50	802.08	846.35	883.42	921.84	932.02	942.31
SAM	South America	20	161.23	201.53	241.84	252.45	268.36	285.33	309.37	315.84	322.45

Table 7: Existing Pipelines with Capacities in 2010

Reg –	Node –	Reg +	Node +	bcm/y
EU27	Austria	EU27	Germany	8.2
EU27	Austria	EU27	Hungary	4.2
EU27	Austria	EU27	Italy	37.1
EU27	Austria	EU27	Slovakia	5.7
EU27	Austria	EU27	Slovenia	2.5
EU27	Belgium	EU27	France	27.2
EU27	Belgium	EU27	Germany	9.3
EU27	Belgium	EU27	Lux	1.6
EU27	Belgium	EU27	Netherlands	10.2
EU27	Belgium	EU27	UK	25.4
EU27	Bulgaria	EU27	Greece	3.5
EU27	Czech	EU27	Germany	53.0
EU27	Czech	EU27	Slovakia	5.1
EU27	Denmark	EU27	Germany	1.0
EU27	Denmark	EU27	Sweden	3.2
EU27	Estonia	EU27	Latvia	2.6
EU27	France	EU27	Spain	3.4
EU27	Germany	EU27	Austria	3.5
EU27	Germany	EU27	Belgium	14.8
EU27	Germany	EU27	Czech	12.9
EU27	Germany	EU27	France	20.0
EU27	Germany	EU27	Lux	0.9

(continued)

Table 7: Existing Pipelines with Capacities in 2010 *(continued)*

Reg –	Node –	Reg +	Node +	bcm/y
EU27	Germany	EU27	Netherlands	13.4
EU27	Germany	EU27	Poland	1.1
EU27	Hungary	EU27	Romania	1.7
EU27	Italy	EU27	Austria	37.1
EU27	Italy	EU27	Slovenia	0.9
EU27	Latvia	EU27	Estonia	2.6
EU27	Latvia	EU27	Lithuania	0.7
EU27	Lithuania	EU27	Latvia	1.8
EU27	Netherlands	EU27	Belgium	42.7
EU27	Netherlands	EU27	Germany	63.9
EU27	Netherlands	EU27	UK	12.5
EU27	Poland	EU27	Germany	30.3
EU27	Portugal	EU27	Spain	3.5
EU27	Romania	EU27	Bulgaria	26.5
EU27	Slovakia	EU27	Austria	52.5
EU27	Slovakia	EU27	Czech	41.6
EU27	Slovenia	EU27	Italy	0.9
EU27	Spain	EU27	France	1.8
EU27	Spain	EU27	Portugal	5.9
EU27	UK	EU27	Belgium	19.9
EU27	UK	EU27	Ireland	10.1
EU27	Bulgaria	ROEU	Macedonia	0.8
EU27	Bulgaria	ROEU	Turkey	15.4
EU27	France	ROEU	Switzerland	7.1
EU27	Germany	ROEU	Switzerland	17.4
EU27	Hungary	ROEU	Croatia	6.6
EU27	Hungary	ROEU	Serbia	4.6
EU27	Italy	ROEU	Switzerland	20.2
EU27	Slovenia	ROEU	Croatia	1.7
ROEU	Belarus	EU27	Lithuania	6.4
ROEU	Belarus	EU27	Poland	36.4
ROEU	Norway	EU27	Belgium	14.2
ROEU	Norway	EU27	France	18.3
ROEU	Norway	EU27	Germany	42.4
ROEU	Norway	EU27	UK	46.3
ROEU	Switzerland	EU27	Italy	20.2
ROEU	Turkey	EU27	Greece	1.0
ROEU	Ukraine	EU27	Hungary	20.4
ROEU	Ukraine	EU27	Poland	5.7
ROEU	Ukraine	EU27	Romania	13.1
ROEU	Ukraine	EU27	Slovakia	101.7
ROEU	Belarus	ROEU	Ukraine	25.0
ROEU	Serbia	ROEU	Bosnia Herc	0.8
AFR	Africa	EU27	Italy	10.1
AFR	Africa	EU27	Spain	11.1[a]
ASP	Asia	ROEU	Turkey	8.8
ASP	Asia	RUS	Russia	60.0
RUS	Russia	EU27	Finland	8.2
RUS	Russia	EU27	Germany	0.0[b]
RUS	Russia	EU27	Latvia	5.4
RUS	Russia	ROEU	Belarus	55.9
RUS	Russia	ROEU	Turkey	16.0
RUS	Russia	ROEU	Ukraine	112.0
MEA	Middle East	ROEU	Turkey	13.1

[a] Exogenous expansion 11.1 to 19.1 in 2015
[b] Exogenous expansion 55 in 2015 (Nord Stream)

Table 8: Possible New Pipelines

Reg –	Node –	Reg +	Node +
EU27	Bulgaria	EU27	Romania
EU27	France	EU27	Belgium
EU27	France	EU27	Germany
EU27	Germany	EU27	Denmark
EU27	Greece	EU27	Bulgaria
EU27	Greece	EU27	Italy
EU27	Hungary	EU27	Austria
EU27	Hungary	EU27	Slovenia
EU27	Ireland	EU27	UK
EU27	Italy	EU27	Greece
EU27	Luxembourg	EU27	Belgium
EU27	Luxembourg	EU27	Germany
EU27	Romania	EU27	Hungary
EU27	Slovenia	EU27	Austria
EU27	Slovenia	EU27	Hungary
EU27	Sweden	EU27	Denmark
EU27	UK	EU27	Netherlands
EU27	Bulgaria	ROEU	Serbia
EU27	France	ROEU	Norway
EU27	Germany	ROEU	Norway
EU27	Greece	ROEU	Turkey
EU27	Hungary	ROEU	Ukraine
EU27	Lithuania	ROEU	Belarus
EU27	Poland	ROEU	Belarus
EU27	Poland	ROEU	Ukraine
EU27	Romania	ROEU	Ukraine
EU27	Slovakia	ROEU	Ukraine
EU27	UK	ROEU	Norway
ROEU	Croatia	EU27	Hungary
ROEU	Croatia	EU27	Slovenia
ROEU	Macedonia	EU27	Bulgaria
ROEU	Norway	EU27	Denmark
ROEU	Serbia	EU27	Bulgaria
ROEU	Serbia	EU27	Hungary
ROEU	Switzerland	EU27	France
ROEU	Switzerland	EU27	Germany
ROEU	Turkey	EU27	Bulgaria
ROEU	Bosnia Herc	ROEU	Serbia
ROEU	Ukraine	ROEU	Belarus
EU27	Italy	AFR	Africa
EU27	Spain	AFR	Africa
EU27	Bulgaria	RUS	Russia
EU27	Finland	RUS	Russia
EU27	Germany	RUS	Russia
EU27	Latvia	RUS	Russia
EU27	Romania	RUS	Russia
RUS	Russia	EU27	Bulgaria
RUS	Russia	EU27	Germany
RUS	Russia	EU27	Romania
ROEU	Turkey	ASP	Asia
ROEU	Turkey	MEA	Middle East
ROEU	Belarus	RUS	Russia
ROEU	Turkey	RUS	Russia
ROEU	Ukraine	RUS	Russia
ASP	Asia	MEA	Middle East
MEA	Middle East	ASP	Asia
RUS	Russia	ASP	Asia

Table 9: Countries with LNG Terminal, Including Capacities. Capacities Remain the Same from 2020 (bcm/y).

Region	Node	2010	2015	2020
Liquefaction				
ROEU	Norway	6.0	6.0	6.0
RUS	Russia	13.4	13.4	13.4
AFR	Africa	81.8	87.4	106.3
MEA	Middle East	129.1	129.1	129.1
ASP	Asia	118.0	124.0	190.5
NAM	North America	1.9	5.4	20.0
SAM	South America	27.4	27.4	27.4
Regasification				
EU27	Belgium	9.0	9.0	9.0
EU27	France	23.8	23.8	33.8
EU27	Greece	5.0	5.0	5.0
EU27	Italy	11.3	16.0	16.0
EU27	Netherlands	0.0	12.0	16.0
EU27	Poland	0.0	5.0	7.0
EU27	Portugal	5.2	7.2	7.2
EU27	Spain	60.1	60.1	60.1
EU27	UK	51.1	51.1	51.1
ROEU	Croatia	0.0	1.8	1.8
ROEU	Turkey	12.2	12.2	12.2
ASP	Asia	417.6	468.6	498.1
NAM	North America	183.8	194.8	194.8
SAM	South America	16.2	28.1	28.1

APPENDIX C—RESULTS

Table 10: First Stage Capacities (including expansions) within the EU (bcm/y)

From	To	Year	Case	EVP	SP
Austria	Slovakia	2010	EquiScen	5.7	5.7
Austria	Slovakia	2025	EquiScen	5.7	11.3
Austria	Slovakia	2010	NoBASE	5.7	5.7
Austria	Slovakia	2025	NoBASE	5.7	13.3
Belgium	Luxemb	2010	EquiPol	1.6	1.6
Belgium	Luxemb	2020	EquiPol	1.6	3.1
Belgium	Luxemb	2025	EquiPol	1.6	3.1
Belgium	Luxemb	2010	EquiScen	1.6	1.6
Belgium	Luxemb	2020	EquiScen	1.6	3.1
Belgium	Luxemb	2010	NoBASE	1.6	1.6
Belgium	Luxemb	2020	NoBASE	1.6	3.1
Belgium	Luxemb	2025	NoBASE	1.6	4.6
Bulgaria	Greece	2010	EquiPol	3.5	3.5
Bulgaria	Greece	2015	EquiPol	5.6	5.6
Bulgaria	Greece	2020	EquiPol	5.6	5.6
Bulgaria	Greece	2025	EquiPol	5.6	5.6
Bulgaria	Greece	2010	EquiScen	3.5	3.5
Bulgaria	Greece	2015	EquiScen	5.1	3.5
France	Belgium	2010	EquiPol	0.0	0.0
France	Belgium	2025	EquiPol	2.5	13.4
France	Belgium	2010	EquiScen	0.0	0.0
France	Belgium	2025	EquiScen	1.6	11.3
France	Belgium	2010	NoBASE	0.0	0.0
France	Belgium	2025	NoBASE	2.2	0.0
Hungary	Slovenia	2010	EquiPol	0.0	0.0

(continued)

Table 10: First Stage Capacities (including expansions) Within the EU (bcm/y) *(continued)*

From	To	Year	Case	EVP	SP
Hungary	Slovenia	2015	EquiPol	0.0	1.5
Hungary	Slovenia	2020	EquiPol	0.0	1.5
Hungary	Slovenia	2025	EquiPol	0.0	1.5
Hungary	Slovenia	2010	EquiScen	0.0	0.0
Hungary	Slovenia	2015	EquiScen	0.0	1.5
Hungary	Slovenia	2020	EquiScen	0.0	1.5
Hungary	Slovenia	2025	EquiScen	0.0	1.5
Hungary	Slovenia	2010	NoBASE	0.0	0.0
Hungary	Slovenia	2015	NoBASE	0.0	1.5
Hungary	Slovenia	2020	NoBASE	0.0	1.5
Hungary	Slovenia	2025	NoBASE	0.0	1.5
Italy	Greece	2010	EquiPol	0.0	0.0
Italy	Greece	2020	EquiPol	6.8	6.7
Italy	Greece	2025	EquiPol	9.7	8.2
Italy	Greece	2010	EquiScen	0.0	0.0
Italy	Greece	2020	EquiScen	6.6	4.0
Italy	Greece	2025	EquiScen	8.9	9.9
Italy	Greece	2010	NoBASE	0.0	0.0
Italy	Greece	2015	NoBASE	0.0	1.5
Italy	Greece	2020	NoBASE	6.2	6.2
Italy	Greece	2025	NoBASE	8.4	8.4
Italy	Slovenia	2010	EquiPol	0.9	0.9
Italy	Slovenia	2025	EquiPol	0.9	8.8
Italy	Slovenia	2010	EquiScen	0.9	0.9
Italy	Slovenia	2025	EquiScen	11.7	11.3
Italy	Slovenia	2010	NoBASE	0.9	0.9
Italy	Slovenia	2020	NoBASE	0.9	2.4
Italy	Slovenia	2025	NoBASE	11.5	10.8
Latvia	Lithuania	2010	EquiPol	0.7	0.7
Latvia	Lithuania	2015	EquiPol	0.7	2.2
Latvia	Lithuania	2020	EquiPol	0.7	2.2
Latvia	Lithuania	2025	EquiPol	0.7	3.7
Latvia	Lithuania	2010	EquiScen	0.7	0.7
Latvia	Lithuania	2020	EquiScen	0.7	2.2
Latvia	Lithuania	2025	EquiScen	0.7	3.7
Latvia	Lithuania	2010	NoBASE	0.7	0.7
Latvia	Lithuania	2015	NoBASE	0.7	2.2
Latvia	Lithuania	2020	NoBASE	0.7	2.2
Latvia	Lithuania	2025	NoBASE	0.7	2.2
Slovenia	Hungary	2010	EquiPol	0.0	0.0
Slovenia	Hungary	2025	EquiPol	0.0	7.8
Slovenia	Hungary	2010	EquiScen	0.0	0.0
Slovenia	Hungary	2020	EquiScen	0.0	9.8
Slovenia	Hungary	2025	EquiScen	10.0	9.8
Slovenia	Hungary	2010	NoBASE	0.0	0.0
Slovenia	Hungary	2015	NoBASE	0.0	1.5
Slovenia	Hungary	2020	NoBASE	0.0	1.5
Slovenia	Hungary	2025	NoBASE	9.7	9.2
Spain	France	2010	EquiPol	1.8	1.8
Spain	France	2015	EquiPol	15.2	15.0
Spain	France	2020	EquiPol	39.0	41.7
Spain	France	2025	EquiPol	39.0	41.7
Spain	France	2010	EquiScen	1.8	1.8
Spain	France	2015	EquiScen	11.3	12.0
Spain	France	2020	EquiScen	35.5	34.1
Spain	France	2025	EquiScen	35.5	41.4
Spain	France	2010	NoBASE	1.8	1.8
Spain	France	2015	NoBASE	12.0	10.0
Spain	France	2020	NoBASE	35.1	35.0
Spain	France	2025	NoBASE	35.1	35.0