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Evaluating the impacts of the external supply risk in a natural gas supply chain: the case of the Italian market

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Mid-streamers are assumed to be exposed to the external supply risk, which is estimated with indicators that we develop starting from those already existing in the literature. In addition, we investigate different degrees of mid-streamers' flexibility by comparing a situation where mid-streamers fully satisfy the LTC volume clause (``No FLEX'' assumption) to a case where the fulfillment of this volume clause is not compulsory (``FLEX'' assumption).

Our analysis shows that, in the ``No FLEX'' case, mid-streamers do not significantly change their supplying choices even when the external supply risk is considered. Under this assumption, they face significant profit losses that, instead, disappear in the ``FLEX'' case when mid-streamers are more flexible and can modify their supply mix.

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in the "FLEX" case when mid-streamers are more flexible and can modify their supply mix. However, the "FLEX" strategy limits the gas availability in the supply chain leading to a curtailment of the social welfare.

Keywords Equilibrium conditions · complementarity problem · natural gas market · supply chain network · external supply risk · mid-streamers' flexibility.

1 Introduction

Natural gas covers a significant quota of the energy mix of many of the European countries with a share of 24% in the Total Primary Energy Supply (see Holz et al., 2014). Many of the European natural gas imports originate from unstable regions and suppliers exposed to the risk of supply failure due to political and economical instability. The political instabilities of Northern Mediterranean area and the disturbances between the European-Russian relationship in the last years have increased the concerns on security of supply in the European natural gas market. Italy is one of the three largest gas consumers in Europe after Germany and the United Kingdom,[1] but it mainly relies on natural gas imports to cover its internal demand since its national production is very low. In particular, the 90.6% of the Italian gas demand in 2015 was satisfied with imports from Russia, Algeria, Libya, the Netherlands, Qatar, and Norway (see AEEGSI, 2016).

Considering this framework, in this paper we aim at analyzing the security of the external natural gas and Liquefied Natural Gas (LNG) supply (imports) of the Italian gas market. For this reason, we develop an optimization model that describes the equilibrium state of the natural gas supply chain where natural gas producers (suppliers), mid-streamers, and consumers can sell and buy both natural gas and LNG through long-term contracts (LTCs) or/and on spot market. Mid-streamers take on the role of intermediates in this supply chain network: on one side they exchange natural gas and LNG with supplying countries; on the other side they sell gas to final consumers. Since they are in charge of selecting the origin of natural gas and LNG imports, we assume that mid-streamers are the agent group exposed to the external supply risk associated with the imports from foreign countries. In other words, mid-streamers define the amount of gas and LNG to be imported not only on the basis of the relative production and transportation costs, but also taking into account the external supply risk related to the countries from which the gas originates. This risk is evaluated through indicators that we develop starting from those already existing in the literature (see Section 3.2 for a literature review on these indicators). These risk indicators are then inserted in the optimization problem as a weight assigned to the Italian natural gas and LNG imports operated by mid-streamers.

Several papers in the literature studies different aspects of the natural gas market. For instance, Egging and Gabriel (2006) develop a mixed complementarity model for the European natural gas market where producers can behave either in a perfectly competitive or in a Cournot strategic way, while the other players in storage and

[1] See Eurostat at `http://ec.europa.eu/eurostat/statistics-explained/index.php/Natural_gas_consumption_statistics`

transmission services operate in perfect competition only. This model investigates the impacts of producers' market power and the importance of pipeline and storage capacity. Egging et al. (2008) propose a detailed complementarity model for defining the equilibrium of the European natural gas market under a set of scenarios, including the disruption of Ukrainian pipelines, the disruption of Algerian supplies, and the increased transportation costs. Market players are represented by producers, pipeline and storage operators, marketers, liquefiers and regasifiers, LNG tankers, and final consumers. Egging et al. (2010) present an extensive model of the global natural gas market that allows for the description of the flows and endogenous investment decisions in infrastructures and the evaluation of the market power in the pipeline and LNG markets. Holz et al. (2016) analyze the infrastructure needs of the European natural gas market to adequate it to the decarbonization targets of the European energy system. Their results show that the current import infrastructures and intra-European transit capacity are sufficient to accommodate future import needs under the scenarios of increasing and decreasing consumption. The authors conclude that the supply security would benefit from relaxing the political and technical constraints on investments. Egging and Holz (2016) develop a stochastic global gas market model to study the infrastructure investments and the trade in an imperfect market structure taking into account the possible disruption of the Russian gas transit via Ukraine from 2020; the variation of the electricity intensity generation in the OECD countries after 2025; the availability of the US shale gas after 2030.

All these papers analyze the possible supply disruption with a set of scenarios, operating a sensitivity analysis. In our paper, we depart from this approach and we study the risk of external supply by directly integrating new risk indicators in our model. Our goal is to detect whether this risk affects the import choices of mid-streamers that can change not only their supplying country mix but also the type of gas purchased (i.e. they can favor gas to LNG or viceversa) and the payment method (i.e. LTCs vs. spot). To the best of our knowledge, it is the first time that such an approach is considered and this represents one of the contributions of our paper.

A second contribution of this is paper is represented by the investigation of two different degrees of mid-streamers' flexibility. In particular, we compare a situation where the mid-streamers fully accomplish the LTC volume requirements with a case where the mid-streamers behave in a more flexible way and they are not obliged to purchase all the quantity of gas and LNG contracted with LTCs. We assume that this flexibility regards both the gas and the LNG bought through LTCs, with and without external supply risk. This analysis aims at describing the current configuration of the European gas market where the co-existence of LTCs and hub-pricing systems implies that the natural gas is traded at two different prices on the same market. Depending on the conditions, spot price can be higher or lower than long-term contractual gas, implying possibly difficult situations for companies loaded with high price TOP gas against the low spot prices. This is what happened in the last years, where an excess of gas availability on the market has been reflected into prices at the European hubs lower than those fixed in the LTCs. As a reaction, mid-streamers have asked for an increase of the LTCs flexibility (see Sections 2 and 5 for more details).

For our analysis, we consider a single optimization problem that is then transformed in complementarity form through the corresponding Karush-Kuhn-Tucker conditions (see Facchinei and Pang, 2003; Gabriel et al., 2013; Nagurney, 1999). Complementarity-based models facilitate the formulation of equilibrium problems that describe the interactions of several agents whose choices are subject to technical and economic constraints, as it happens in our model.

The remainder of the paper is organized as follows. Section 2 illustrates the natural gas supply chain that we consider in our analysis and we provide some insights related to mid-streamers' behaviour in the European gas market. Section 3 describes the new external supply risk indicators that we construct and the optimization models that we develop. The case study is presented in Section 4, while Section 5 presents the results of our analysis. Section 6 concludes with the final remarks. Finally, Appendices A and B provide the complementarity formulations of the developed models and Appendix C illustrates some additional results.

2 The natural gas market

In this paper, we aim at analyzing the interactions of the main players of a natural gas supply chain taking into account the external supply risk. The considered players are N supplying countries (producers), M mid-streamers, and S consumers. The latest two agents' groups are both located in the destination country that, in our case, is represented Italy (see Figure 1).

INSERT HERE FIGURE 1
CAPTION:Natural gas supply chain

We assume that gas can be sold/purchased either through long-term contracts (LTCs) or on spot markets (hub pricing). This assumption aims at representing the current situation of the European gas market where LTCs and the hub pricing systems co-exist, even though it is still dominated by long-term contracts. The LTCs have been traditionally concluded over long periods (typically 20 years or more) and are characterized by quantity and price clauses that have been historically introduced to allow for risk sharing between gas producers and mid-streamers that respectively face price and volume risks (Abada et al., 2017). The Take or Pay (TOP) quantity clause obligates the buyer to take a certain quantity of natural gas or to pay for it. The Price Indexation clause relates the price at which gas is bought to some index on the market that has been traditionally represented by the price of crude and oil-products. The hub pricing approach developed in the nineties in the US and UK and is now developing in Europe. In this system, natural gas is traded, every day, on a spot market that determines prices and volume on the short term. International natural gas market is organized in different ways depending on the considered areas. North America is essentially organized on the basis of Henry Hub spot market; Asia is mainly supplied through long-term contracts; Europe is still dominated by long-term contracts, even though spot markets are growing and are expected to develop further. The main exception in Europe is represented by the UK where gas is largely traded at the National Balancing Point (NBP) spot market. In continental Europe, Zeebrugge (ZEE) and the Title Transfer Facility (TTF), respectively located in Belgium and in the Netherlands, are the two dominant spot market places and many others are emerging such as the Punto di Scambio Virtuale (PSV) in Italy. (see Melling, 2010).

The co-existence of two pricing systems in Europe implies that the natural gas is traded at two different prices on the same market, causing possibly difficult situations for companies (mid-streamers) that are charged with high LTC prices against the low spot prices. This is what happened in the last years, where the combined effects of the increase of the US shale gas exports, the reduction of European gas demand due to the economic crisis, and the increased availability of uncommitted LNG from Qatar led to an excess of gas availability on the market that was reflected into low gas prices at the European hubs. On the other side, oil-indexed long-term gas contracts failed to promptly adjust their positions implying significant losses for European gas mid-streamers that were stuck with their LTCs and could only dump the excess of gas on the spot market. As a consequence of this short-term but dramatic issue, European mid-streamers have asked for a re-negotiation of their long-term gas contracts to make them more flexible and closer to spot gas prices. These re-negotiations have resulted into a decline of oil-indexation and hub-linked pricing has rapidly become the basis for an increasing number of transactions in the European gas market. In addition, with regard to newly signed contracts for pipeline sales to Europe, there is a clear trend towards shorter commitments (see Franza, 2014).

In addition to the external supply risk, this paper aims at analyzing this structural problem of the gas industry by focusing on the short term and considering different degrees of flexibility of mid-streamers' behaviour. In particular, we compare the following two cases:

- **No flexibility**: In this case, we assume that the mid-streamer has to comply with all the LTCs that it already has. This corresponds to the situation where the mid-streamer has to buy at least the amount of natural gas and LNG already contracted. Under this assumption, they are also allowed to conclude new LTCs.
- **Flexibility**: This case aims at representing the current situation of the European gas market where LTCs and the hub pricing systems co-exist. In particular, we assume that the mid-streamer has the possibility to decide whether or not buying gas or LNG via LTCs. In other words, the mid-streamers is allowed to not respect the TOP clause for a short period (as the time framework that we consider).

As depicted in Figure 1, in our model, we assume that supply countries produce gas and LNG that they directly sell to mid-streamer with LTCs or on the spot market. On the other side, mid-streamers can decide to buy gas and/or LNG from supplying countries through LTCs. They can also operate on the spot market by either buying and selling gas. On the other side, we assume that mid-streamers can only buy LNG on spot because according to GIIGNL (2016), Italy does not re-export the imported LNG. Mid-streamers are also in charge of managing the storage site in the destination country. Finally, we consider three groups of consumers represented by industry, power generation, and residential/commercial.

3 Modeling the gas supply chain with external supply risk

In this section, we develop the optimization model used to describe the gas supply chain with producing countries, mid-streamers operating, and consumers located in the destination country. We consider a time span of one year, sub-divided into two time segments corresponding to a low-demand and high-demand periods. We start from the notation used in the mathematical formulation, we then describe the external supply risk indicators, and finally we present the optimization model.

3.1 Notation

Indices

- N: number of countries producing and supplying natural gas (producers/supplying countries), $n = 1, ..., N$;
- M: number of mid-streamers located in the destination country, $m = 1, ..., M$. In our model, we assume one destination country;
- F: number of natural gas entry points located in the destination country, $f = 1, ..., F$;
- S: number of consumption sectors in the destination country (industry, power generation, and residential/commercial) $s = 1, ..., S$;
- T: number of time periods, $t = 1, ..., T$. More precisely, we consider $T = 2$, where $t = 1$ is low-demand period and $t = 2$ is high-demand period.

Parameters:

- θ_t: duration in days of time periods t;
- $\bar{X}_n$: gas production capacity of producer n;
- $\bar{GP}_n$: capacity of gas pipeline connecting producing country n with the destination market where mid-streamers are located;
- $\bar{L}_n$: liquefaction capacity of producer n;
- $\bar{R}_m$: regasification capacity of mid-streamer m;
- $\bar{I}_m$: injection limit of storage site managed by mid-streamer m;
- $\bar{W}_m$: withdrawal limit of storage site managed by mid-streamer m;
- WG_m: working gas volume available at storage site managed by mid-streamer m;
- α_n: rate of liquefaction loss faced by producer n;
- β_m: rate of regasification loss faced by mid-streamer m;
- stc_{nm}^{LNG}: transportation costs of LNG through ship from the producing country n to the destination market where mid-streamers m are located;
- ptc_{nm}^{G}: transportation costs of gas through pipelines from the producing country n to the destination market where mid-streamers m are located;
- ptc_{n}^{SpotG}: pipeline transportation costs of gas sold on spot faced by the producing country n;
- dc_{ms}: gas distribution costs through pipelines faced by mid-streamer m to supply consumer s;
- τ_{nm}: (minimum) annual amount of gas that producer n supplies to mid-streamer m through long-term contracts;

- ξ_{nm}: (minimum) annual amount of LNG that producer n supplies to mid-streamer m through long-term contracts;
- Υ_{ft}: limit of the pipeline entry point f in the destination country in time period t;
- Γ_{fn}: limit of the pipeline entry point f that receives gas from producing country n in time period t.

Variables

- X^{G}_{nt}: total amount of natural gas produced by supplying country n in one day of time period t (mcm/d).
- x^{G}_{nmt}: amount of natural gas supplied by producer n through long-term contracts (LTCs) to mid-streamer m in one day of time period t (mcm/d).
- X^{LNG}_{nt}: total amount of natural gas transformed in LNG by supplying country n in one day of time period t (mcm/d).
- x^{LNG}_{nmt}: amount of LNG supplied by producer n through long-term contracts (LTCs) to mid-streamer m in one day of time period t (mcm/d).
- x^{SpotG}_{nt}: amount of natural gas sold by producer n on spot market in one day of time period t (mcm/d).
- $x^{SpotLNG}_{nmt}$: amount of LNG sold by producer n to mid-streamer m on spot basis in one day of time period t (mcm/d).
- Y^{LNG}_{mt}: total amount of natural gas re-gasified by mid-streamer m in one day of time period t (mcm/d).
- y^{LNG}_{nmt}: amount of LNG purchased by mid-streamer m through LTC from producer n in one day of time period t (mcm/d).
- y^{SpotG}_{mt}: amount of natural gas purchased by mid-streamer m on spot market in one day of time period t (mcm/d).
- $y^{SpotLNG}_{nmt}$: amount of LNG purchased by mid-streamer m from producer n on spot basis in one day of time period t (mcm/d).
- q^{SpotG}_{mt}: amount of natural gas sold by mid-streamer m on spot market in one day of time period t (mcm/d).
- z_{mst}: nonnegative amount of natural gas that mid-streamer m sells to consumer sector s in one day of time period t in Bcm.
- i_{mt}: nonnegative amount of natural gas injected by mid-streamer m in the storage site in one day of time period $t = 1$ in Bcm.
- w_{mt}: nonnegative amount of natural gas withdrawn by mid-streamer m from the storage site in one day of time period $t = 2$ in Bcm.
- d_{st}: nonnegative amount of natural gas demanded by consumer s in one day of time period t in Bcm.
- $P_{st}(d_{st})$: Inverse demand function of consumer s in one day of time period t in Bcm. This function can be stated as $P_{st}(d_{st}) = a_{st} - b_{st} \cdot d_{st}$ where a_{st} is the intercept of consumers' (affine) demand functions in time period t (€/Bcm) and b_{st} is the slope of consumers' (affine) demand functions in time period t (€/Bcm^2).

All these variables are assumed to be nonnegative. As already indicated, we consider a time span of one year subdivided into low-demand and high-demand periods with a duration in days θ_t, respectively. For each of these two periods, we consider a representative day and, therefore, variables and parameters have to be weighted by the duration θ_t in order to get annual values. Finally, we do not list here the dual variables associated with the constraints appearing in our model formulation. These are directly indicated next to the constraints to which they refer.

3.2 External supply risk indicators

Energy security is defined as the availability of a regular supply of energy at an affordable price (IEA, 2001). Security of gas supply in energy systems has always been an important issue due to the high dependence on energy. This is particularly true for Europe where about one quarter of all the energy used is natural gas, and many European countries import nearly all their supplies, as it happens for Italy. Supply disruptions caused by infrastructure failure or political disputes are real phenomena. As an example, we recall the the severe shortfall of gas in Western Europe due to Russia's decision to suspend gas deliveries to Ukraine in January 2009. A way to deal with energy security is a process of managing the associated risk. For this reason, in our analysis, we concentrate on short-term indices to assess the risk associated with external energy supply and possible insecurity of supply. The Herfindahl-Hirschman Index (HHI), the Shannon-Wiener Index (SWI), and the variations of it, such as the Shannon-Wiener-Neumann indeces (SWNIs) are amongst the most commonly used aggregate indicators for energy security applied to evaluate the diversification of the market (see Neumann, 2004).

The HHI is adopted as a measure of market concentration, namely the total number of companies operating. In a similar way, the diversity of energy suppliers is given by the sum of the squares of each supplier market share q_n:

$$HHI = \sum_{n=1}^{N} q_n^2 \tag{1}$$

where q_n represents the share of imports from a particular country n into the country considered. Thus, the higher the value of the index, the more concentrated the market is; the maximum value of the index is achieved when there is only one supplier. Consequently, the HHI is only used to investigate markets with a lack of diversity of suppliers, or to give greater weight to the larger suppliers (see e.g. Blyth and Lefevre, 2004; Cohen et al, 2011; Grubb et al., 2005, Gupta, 2008; Kruyt et al., 2009; Frondel et al., 2008).

The Shannon-Wiener concentration Index is an alternative approach to measure the diversity of energy suppliers. This index is computed as follows:

$$SWI = -\sum_{n=1}^{N} q_n \ln q_n \tag{2}$$

where q_n is the supplier's market share as in the HHI. The higher the value of the index, the more diverse the market is. Moreover, differently from the HHI, it puts more weights on the impact of smaller suppliers (see Kruyt et al, 2009, footnote 13, for more details on the mathematical properties of the SWI).

However, the security of external energy supply may be affected by the political situation in the exporting country. Starting from the SWI, Neumann (2004) takes this into account by using a measure of the political stability of the supplier n that we denote with r_n. In particular, Neumann (2004) proposes two additional indicators SWNI_1 and SWNI_2 that are defined as follows:

$$SWNI_1 = -\sum_{n=1}^{N}(r_n q_n \ln q_n), \tag{3}$$

and:

$$SWNI_2 = -\sum_{n=1}^{N}(r_n q_n \ln q_n)(1+g_n), \tag{4}$$

where r_n identifies the political risk rating associated with the supplying country n and g_n in the SWNI_2 represents the indigenous production of the resource in the supplying country n.

On the other side, Marìn Quemada et al. (2012) propose the Geopolitical Energy Security (GES) indicator that is computed as:

$$GES = \sum_{f=1}^{F}\left[\left(\sum_{n=1}^{N} r_n q_{nf}^2\right)\cdot e^{\dfrac{1}{P_f}}\right]\cdot\frac{C_f}{TPES} \tag{5}$$

where the index f represents the fuel type, and the ratio $\frac{\mathrm{C}_f}{\mathrm{TPES}}$ denotes the share of total consumption of fuel f in the Total Primary Energy Supply (TPES). The GES indicator combines a country exposure measure of market concentration q_{nf}^2, similarly to the HHI, with the market liquidity, involving as a key role the exponential function e^{1/P_f} where P_f represents the ratio between the offer of the resource f and its consumption. The GES indicator is an expansion of the $\mathrm{ESI}_{\mathrm{price}}$ index that does not consider the market liquidity, i.e. the exponential function (see IEA, 2007).

Le Coq and Paltseva (2009) develops the Risky External Energy Supply (REES) for each destination country a that is defined as follows:

$$REES_a^f = \left[\sum_{n=1}^{N}\left(\frac{NPI_{na}^f}{NPI_a^f}\right)^2 F_{na}^f r_n d_{na}\right]\cdot NID_a^f \cdot SF_a^f \tag{6}$$

where NPI_{na}^f is the net positive imports of fuel f from supplying country n to the destination country a, NPI_a^f is the sum of the net positive imports over all suppliers of country a, F_{na}^f is the fungibility of fuels f imported from n to a, r_n is the political risk index of the supplier country, d_{na} is a measure of a distance between countries n and a, NID_a^f is the net import dependency of country a for fuel f and SF_a^f is a share of fuel f in country a (see Le Coq and Paltseva, 2009).[2] The REES is the most comprenhesive among the indicators here illustrated, since it accounts for the diversification of the energy sources f, the political risk r_n, the distance between

[2] Note that all the other indicators presented above are computed per each destination country even though not explicitly indicated.

supplying and destination country d_{na}, and the fungibility F^f_{na} of imported fuels, in addition to the diversification of suppliers and the energy dependence. Note that the distance d_{na} represents a proxy for the risk involved in the transportation phase. On the other side, the market liquidity is a feature of the GES indicator.

Our analysis aims at measuring the effects of the external supply risk on the natural gas and LNG exchanges between producing and supplying countries n and mid-streamers m all operating in same destination country. In this framework, we assume that mid-streamer selects the supply countries from which importing natural gas and LNG on the basis of external supply risk of these producing countries. Our idea is to consider the external supply risk as an additional cost that the mid-streamers face when buy both natural gas LNG from the different supplying countries. This cost is indeed proportional to the amount of gas bought and therefore, in our model formulation, we weight each exchange of natural gas and LNG between the producers and the mid-streamers by the associated external supply risk that varies according to the considered supplying country. We are therefore interested in evaluating a risk per each type of natural gas imported and per each supplying country. The indicators presented above aggregated all this information that we, instead, need in a disaggregated form.

For this reason, we consider the HHI, the SWNI$_2$, the GES, and the REES presented above and we modify them in order to make them suitable for our scope. In this way, we develop new indicators that are all denoted as "Π". For their construction, we account for two fuels, natural gas (G) and LNG ($f = G, LNG$ considering the GES and the REES indicators) and one destination country (this means that, using the REES notation, $a = 1$). This latter assumption implies that mid-streamers face an identical external supply risk when importing the same type of gas from the same country.

The new indicators that we introduce are:

1.
$$\Pi^{HHI,G}_{nm} = (q^G_{nm})^2 \quad \text{and} \quad \Pi^{HHI,LNG}_{nm} = (q^{LNG}_{nm})^2, \tag{7}$$

These are a transformation of the HHI where q^G_{nm} and q^{LNG}_{nm} represents the share of imports of mid-streamer m from a particular country n respectively for natural gas and LNG. For the reasons explained above, we do not consider the sum over all supplying countries.

2.
$$\Pi^{SWNI_2,G}_{nm} = -(r_n q^G_{nm} \ln q^G_{nm})(1 + g_n), \tag{8}$$

$$\Pi^{SWNI_2,LNG}_{nm} = -(r_n q^{LNG}_{nm} \ln q^{LNG}_{nm})(1 + g_n), \tag{9}$$

These are similar to the SWNI$_2$, but, as in the $\Pi^{HHI,\,G}_{nm}$ and $\Pi^{HHI,\,LNG}_{nm}$, are computed taking into account the share of natural gas and LNG that country n supplies to mid-streamer m, without considering the sum over all supplying countries. The other terms r_n and g_n are as in the $SWNI_2$ indicator.

3.

$$\Pi_{nm}^{GES,G} = \left[\left(r_n (q_{nm}^G)^2 \right) \cdot e^{\dfrac{1}{P_G}} \right] \cdot \frac{C_G}{TPES}, \tag{10}$$

$$\Pi_{nm}^{GES,LNG} = \left[\left(r_n (q_{nm}^{LNG})^2 \right) \cdot e^{\dfrac{1}{P_{LNG}}} \right] \cdot \frac{C_{LNG}}{TPES}, \tag{11}$$

These result from the modification of the GES indicator, where we consider the share of natural gas and LNG imported by the mid-streamer m from country n, without operating the sum overall supplying countries. In addition, we maintain separate the two fuels supplied. The other terms are as in the GES indicator.

4.

$$\Pi_{nm}^{REES,G} = \pi_{nm}^G \cdot r_n \cdot d_{nm} \cdot F_{nm}^G, \tag{12}$$

$$\Pi_{nm}^{REES,LNG} = \pi_{nm}^{LNG} \cdot r_n \cdot d_{nm} \cdot F_{nm}^{LNG} \tag{13}$$

where, as in the REES indicator, r_n is the measure of political risk, d_{nm} is a factor that accounts for the distance between the capitals of the producing country and the location of mid-streamers, F_{nm}^G and F_{nm}^{LNG} are the fungibility respectively of natural gas and LNG, and π_{nm}^G and π_{nm}^{LNG} are the shares of natural gas and LNG that mid-streamer m in the destination country imports from supplying country n. These shares are computed as indicated below:

$$\pi_{nm}^G = \left(\frac{\tilde{q}_{nm}^G}{\sum_{n=1}^N \tilde{q}_{nm}^G} \right)^2$$

$$\pi_{nm}^{LNG} = \left(\frac{\tilde{q}_{nm}^{LNG}}{\sum_{n=1}^N \tilde{q}_{nm}^{LNG}} \right)^2$$

where $\tilde{q}_{nm}^G$ and $\tilde{q}_{nm}^{LNG}$ are parameters defining the *net* gas and LNG imports of mid-streamer m from the supplying country n.

Table 1 summarizes the indicators already existing in the literature, which we have present above, and the new indicators that we introduce starting from them.

Finally, note that in Section 3.4, we generally refer to these new indicators with the symbols Π_{nm}^G and Π_{nm}^{LNG}. In Section 5, we show the effects of the application of all these indicators that we have constructed.

Table 1 Summary of the new indicators proposed

Indicators existing in the literature	New indicators proposed	
HHI	$\Pi_{nm}^{HHI,G}$	$\Pi_{nm}^{HHI,LNG}$
SWNI$_2$	$\Pi_{nm}^{SWNI_2,G}$	$\Pi_{nm}^{SWNI_2,LNG}$
GES	$\Pi_{nm}^{GES,G}$	$\Pi_{nm}^{GES,LNG}$
REES	$\Pi_{nm}^{REES,G}$	$\Pi_{nm}^{REES,LNG}$

3.3 Model assumptions

In this section, we illustrate the main assumptions that characterize our model formulation.

- **Producing/supplying countries**. In the considered gas supply chain, supplying countries produce natural gas and/or LNG and can decide to sell them directly to mid-streamers with LTCs or on the spot market. We assume that gas is extracted from sites directly owned by producers. The extraction process is supposed to be lossless. Therefore, the amount of gas extracted corresponds to the one produced. As indicated in the nomenclature, the variables x_{nmt}^{G} and x_{nmt}^{LNG} identify the amount of natural gas x_{nmt}^{G} and LNG x_{nmt}^{LNG} that the production country n sells to mid-streamer m in the low- and in the high-demand periods, respectively. We assume that these quantities as well as their relative prices depend on time to account for possible renegotiation or updates of the contract price in short term (see Franza, 2014). The quantity of natural gas sold on the spot market x_{nt}^{SpotG} depends on the production country n and on the time period t only. This assumption reflects the fact that the producer participates to the spot market by submitting bids but without knowing who will be the buyer. Finally, the quantity of LNG sold on spot basis $x_{nmt}^{SpotLNG}$ refers to uncommitted ships that are already arrived in the destination country and can be traded in the short term between the supplying country n and the mid-streamer m.
- **Destination country**. It is assumed that there is just one destination country that corresponds to Italy (see Section 4).
- **Mid-streamers**. We assume that all mid-streamers operate in the considered destination country and are located in one citygate. As already indicated, mid-streamers can decide to either enter in gas/LNG LTCs with supply countries or exchange gas/buy LNG on the corresponding spot markets. They select the supply countries from which importing natural gas and LNG on the basis of their external supply risks. As final step, they sell gas to the consumption sectors that we classify into power generation, industrial sector, and residential/commercial. In addition, we assume that mid-streamers operate the storage sites and can take advantage of seasonal arbitrage by buying and injecting gas into storage in the low-demand season (summer) and then selling it to consumers in the high-demand season (winter). Parallel to the modeling of the producers' variables, we assume that the variables y_{nmt}^{G} and y_{nmt}^{LNG} respectively identify the amount of natural gas y_{nmt}^{G} and LNG y_{nmt}^{LNG} that the mid-streamer m buy from producing country n with LTCs in the

two time periods. We further assume that mid-streamer can both buy and sell natural gas on the spot market. These mid-streamer's actions are identified by the variables y_{mt}^{SpotG} and q_{mt}^{SpotG}, respectively. Note that these variables depend on the mid-streamer m on the time period t only. This assumption reflects the fact that the mid-streamer participates with bids/offers to the spot market without knowing who will be the counterparts. Finally, the quantity of LNG purchased on spot basis $y_{nmt}^{SpotLNG}$ refers to uncommitted ships that can be traded in the short term between the n supplying and the m importing countries. As already explained, we do not model the mid-streamer's opportunity to re-sell the LNG acquired on the spot basis.

– **Consumers**. We assume that the gas demands of three consumer groups (industry, power generation, and residential/commercial) are endogenously determined through inverse demand functions. The variable d_{st} denotes the quantity of natural gas required by consumer s in time t.
– **Time framework and LTCs**. We consider a time framework of one year. Since LTCs have a duration of 20-25 years, we take a different approach to study the aforementioned "no flexibility" and the "flexibility" cases. In particular, in the case of "no flexibility", we assume that, in the considered year, mid-streamers have to respect all the LTCs that they have already stipulated, but they can also decide to sign new LTCs. On the contrary, in the "flexibility" case, mid-streamers can ask for a re-negotiation of the existing contracts and therefore are not obliged to buy all the quantity of gas or LNG defined by the existing contracts.
– **Gas/LNG volumes and prices and degrees of mid-streamers' flexibility**. All gas/LNG volumes and prices are endogenously determined in the model. The volumes are defined through the supplying countries and mid-streamers' variables indicated above, while the LTCs and the spot prices correspond to the values of the dual variables associated with the relative gas and LNG balance constraints. Note that we impose some limits on the gas and LNG volumes contracted with LTCs. These limits vary according to the flexibility assumptions considered for mid-streamers. More precisely, we take as reference the annual volumes of gas and LNG that mid-streamers have contracted with already existing LTCs (these annual volumes are input data) and in the "no flexibility" case we assume that these amounts establish lower bounds on the total quantities of gas and LNG that mid-streamers have to buy with LTCs in the year. This reflects the idea that mid-streamers have to respect all the LTCs that they have already stipulated, but they can also decide to sign new LTCs in the considered year. In contrast, to respect the re-negotiation assumption that characterizes the "flexibility" case, the amounts of already stipulated gas and LNG LTCs are used as upper bounds on the volumes of gas and LNG that mid-streamers can purchase.
– **Pipeline and tanker transportation limits**. For sake of simplicity, we assume that the tanker used to transfer LNG have no capacity limits. A similar assumption has been adopted for the gas pipelines. Pipeline gas and LNG transportation costs are included as exogenous charges in the model. Moreover, we assume that in the destination country there are some entry points for pipeline gas. Each of this entry point has a specific location in the destination country and collects the gas coming from a subset of supplying countries. We use the incidence matrix Γ_{fn} to

define the link between supplying country and entry point. These entry points are characterized by a limited capacity that we model though a constraint.

- **External supply risk**. The external supply risk is considered as an externality that we internalize in our optimization problem. In general, the insecurity of supply could intervene at the time the prices are negotiated. As explained above, LTCs and spot prices for both gas and LNG are endogenously determined in our model. However, we assume that only gas and LNG traded with LTCs are exposed to the external supply risk. This is due to the fact that spot LNG refers to gas that is already landed in the destination country and therefore it is not risky. Similarly, the spot gas is freely traded on a short notice at the hub and therefore we suppose the external supply risk does not apply to its exchange. The inclusion of the risk indicators in our model is conducted as follows: we first construct and compute the values of the indicators presented in Section 3.2 on the basis of the ex-ante structure external supply of the considered destination country (Italy). We then use these indicators to weight the quantities of gas y_{nmt}^{G} and LNG y_{nmt}^{LNG} that appear in the respective LTC balance constraints (see model formulation in Section 3.4). We introduce the external supply risk indicators in the balances of the gas and LNG LTCs because these constraints not only represent the agreement between supplying countries and mid-streamers on the exchanged volumes but also are those that affect the prices of these LTCs. In this way, we can evaluate whether the external supply risk can modify the gas/LNG contract prices and volumes.

3.4 Optimization model for a natural gas supply chain with external supply risk

Finding the equilibrium state of the described natural gas chain with endogenous final consumers' demand consists in solving a social welfare optimization problem subject to some technical constraints. We first describe the cost functions that are included in our model formulation.

Supplying countries gain from selling gas but they face some costs in the gas production process. Let C_{nt} denote the production costs incurred by producer n. This is a continuous and convex function that depends on the total quantity of natural gas X_{nt}^{G} that supplying country n extracts in time period t. In particular, one has:

$$C_{nt} = C_{nt}\left(X_{nt}^{G}\right) \quad \forall n,\ \forall t \tag{14}$$

It could happen that a part of the produced gas is then sold as LNG by some of the supplying countries n. These countries face additional liquefaction costs that are denoted with the function LC_{nt}. This function is assumed to be continuous and convex and depends on the total amount of LNG X_{nt}^{LNG} that country n supplies in time period t:

$$LC_{nt} = LC_{nt}\left(X_{nt}^{LNG}\right) \quad \forall n,\ \forall t \tag{15}$$

On the other side, mid-streamers who import LNG in the destination (importing) country face the related regasification costs. These costs are represented by a continuous and convex function, denoted as RC_{mt}, that depends on the total quantity of LNG Y_{mt}^{LNG} that mid-streamer m regasifies in time period t. In particular, one has:

$$RC_{mt} = RC_{mt}\left(Y_{mt}^{LNG}\right) \quad \forall m,\, \forall t \tag{16}$$

In our gas supply chain, we further assume that mid-streamers manage the storage systems. They withdraw gas in the high-demand period $t = 2$ at zero cost,[3] while the gas injection is operated in the low-demand period $t = 1$ with a cost that we denote with I_{m1}. This is assumed to be a continuous and convex function that depends on the quantity of natural gas i_{m1} that mid-streamer m injects in the storage site in $t = 1$. In particular, one has:

$$I_{m1} = I_{m1}\left(i_{m1}\right) \quad \forall m \tag{17}$$

In the following, we first describe the optimization model for the “no flexibility” case (Section 3.4.1) and we then illustrate the modifications that are introduced for modeling the “flexibility” assumption (Section 3.4.2).

3.4.1 “No flexibility” case

Finding the equilibrium state of the described natural gas chain with endogenous final consumers’ demand consists in solving the social welfare optimization problem (18)-(38) presented below. The objective function (18) corresponds to the (annual) social welfare that is given by the difference between the final consumers’ willingness to pay $\int_0^{d_{st}} P_{st}(\xi)d\xi$ and all the costs respectively faced by supplying countries and mid-streamers. In particular, supplying countries pay the production, the LNG liquefaction, the pipeline and the cargo transportation costs; on the other side mid-streamers bear the regasification, the storage injection, and the distribution charges. The objective function (18) is subject to several constraints as detailed in the following.

$$\begin{aligned}
&\mathbf{Max}\ \sum_{s=1}^{S}\sum_{t=1}^{T}\theta_t \int_0^{d_{st}} P_{st}(\xi)d\xi - \sum_{n=1}^{N}\sum_{t=1}^{T}\theta_t \cdot \left[C_{nt}\left(X_{nt}^{G}\right) + LC_{nt}\left(X_{nt}^{LNG}\right)\right] \\
&- \sum_{n=1}^{N}\sum_{t=1}^{T}\theta_t \cdot \left[\sum_{m=1}^{M} ptc_{nm}^{G} \cdot x_{nmt}^{G} + \sum_{m=1}^{M} stc_{nm}^{LNG} \cdot x_{nmt}^{LNG}\right] + \\
&- \sum_{n=1}^{N}\sum_{t=1}^{T}\theta_t \cdot \left[ptc_{n}^{SpotG} \cdot x_{nt}^{SpotG} + \sum_{m=1}^{M} stc_{nm}^{LNG} \cdot x_{nmt}^{SpotLNG}\right] + \\
&- \sum_{m=1}^{M}\sum_{t=1}^{T}\theta_t \cdot \left[RC_{mt}\left(Y_{mt}^{LNG}\right)\right] - \sum_{m=1}^{M}\theta_1 \cdot I_{m1}(i_{m1}) - \sum_{s=1}^{S}\sum_{t=1}^{T}\theta_t \cdot \left[dc_{ms} \cdot z_{mst}\right]
\end{aligned} \tag{18}$$

subject to

[3] This assumption is taken from Egging et al. (2008).

Gas production (extraction) capacity constraint (supplying countries)

$$\bar{X}_n - X_{nt}^G \geq 0 \quad \forall n, \forall t \qquad (\overline{\gamma}_{nt}) \tag{19}$$

Gas balance between the total amount of gas extracted by supplying countries and sold to mid-streamers

$$X_{nt}^G - \left(\sum_{m=1}^{M} x_{nmt}^G + x_{nt}^{SpotG} + X_{nt}^{LNG} \right) = 0 \quad \forall n, \forall t \qquad (\gamma_{nt}) \tag{20}$$

LNG balance between the total amount of LNG produced by supplying countries and sold to mid-streamers

$$(1 - \alpha_n) \cdot X_{nt}^{LNG} - \left(\sum_{m=1}^{M} x_{nmt}^{LNG} + \sum_{m=1}^{M} x_{nmt}^{SpotLNG} \right) = 0 \quad \forall n, \forall t \qquad (\delta_{nt}) \tag{21}$$

Gas liquefaction constraint (supplying countries)

$$\bar{L}_n - (1 - \alpha_n) \cdot X_{nt}^{LNG} \geq 0 \quad \forall n, \forall t \qquad (\overline{\delta}_{nt}) \tag{22}$$

LNG regasification constraint (mid-streamers)

$$\bar{R}_m - (1 - \beta_m) \cdot Y_{mt}^{LNG} \geq 0 \quad \forall m, \forall t \qquad (\overline{\eta}_{mt}) \tag{23}$$

Balance between the total amount of gas regasified by mid-streamers and the quantity of LNG that mid-streamer buy from suplyiing countries

$$(1 - \beta_m) \cdot Y_{mt}^{LNG} - \left(\sum_{n=1}^{N} y_{nmt}^{LNG} + \sum_{n=1}^{N} y_{nmt}^{SpotLNG} \right) = 0 \quad \forall m, \forall t \qquad (\eta_{mt}) \tag{24}$$

Equilibrium constraint between the amount of gas that mid-streamers buy and then sell to final consumers or on the spot market in a summer day (low-demand period)

$$\begin{aligned} &\sum_{n=1}^{N} y_{nmt}^G + \sum_{n=1}^{N} y_{nmt}^{LNG} + y_{mt}^{SpotG} + \sum_{n=1}^{N} y_{nmt}^{SpotLNG} + \\ &- i_{mt} \geq \sum_{s=1}^{S} z_{mst} + q_{mt}^{SpotG} \quad \forall m,\ t = 1 \quad (\lambda_{mt}) \end{aligned} \tag{25}$$

Equilibrium constraint between the amount of gas that mid-streamers buy and then sell to final consumers or on the spot market in a winter day (high-demand period)

$$\begin{aligned} &\sum_{n=1}^{N} y_{nmt}^G + \sum_{n=1}^{N} y_{nmt}^{LNG} + y_{mt}^{SpotG} + \sum_{n=1}^{N} y_{nmt}^{SpotLNG} + \\ &+ w_{mt} \geq \sum_{s=1}^{S} z_{mst} + q_{mt}^{SpotG} \quad \forall m,\ t = 2 \quad (\lambda_{mt}) \end{aligned} \tag{26}$$

Storage constraints (mid-streamers)

$$i_{m1} - w_{m2} \geq 0 \quad \forall m \qquad (\mu_m) \tag{27}$$

$$\bar{I}_m - i_{m1} \geq 0 \quad \forall m \qquad (\nu_m) \tag{28}$$

$$\bar{W}_m - w_{m2} \geq 0 \quad \forall m \qquad (\sigma_m) \tag{29}$$

$$WG_m - \theta_2 \cdot w_{m2} \geq 0 \quad \forall m \qquad (\phi_m) \tag{30}$$

Lower bound on the natural gas purchase through LTCs (mid-streamers)

$$\sum_t \theta_t \cdot y_{nmt}^G - \tau_{nm} \geq 0 \quad \forall n, \forall m \qquad (\psi_{mn}^G) \tag{31}$$

Lower bound on the LNG purchase through LTCs (mid-streamers)

$$\sum_t \theta_t \cdot y^{LNG}_{nmt} - \xi_{nm} \geq 0 \quad \forall n, \forall m \qquad (\psi^{LNG}_{mn}) \tag{32}$$

Entry point capacity limits in the destination country

$$\Upsilon_{ft} - \left(\sum_{n=1}^{N} \sum_{m=1}^{M} \Gamma_{fn} \cdot y^{G}_{nmt} + \sum_{n=1}^{N} \Gamma_{fn} \cdot x^{SpotG}_{nt} \right) \geq 0 \quad \forall f, \forall t \qquad (\kappa_{ft}) \tag{33}$$

Balance between the amounts of natural gas sold by supplying country and purchased by mid-streamers with LTC contracts

$$x^{G}_{nmt} - \Pi^{G}_{nm} \cdot y^{G}_{nmt} = 0 \quad \forall n, \forall m, \forall t \quad (p^{G}_{nmt}) \tag{34}$$

Balance between the amounts of LNG sold by supplying country and purchased by mid-streamers with LTC contracts

$$x^{LNG}_{mnt} - \Pi^{LNG}_{nm} \cdot y^{LNG}_{mnt} = 0 \quad \forall n, \forall m, \forall t \qquad (p^{LNG}_{mnt}) \tag{35}$$

Balance between the amounts of natural gas sold by supplying country and traded by mid-streamers on the spot market

$$\sum_{n=1}^{N} x^{SpotG}_{nt} + q^{SpotG}_{mt} - \sum_{m=1}^{M} y^{SpotG}_{mt} = 0 \quad \forall t \quad (p^{SpotG}_{t}) \tag{36}$$

Balance between the amounts of LNG sold by supplying country and purchased by mid-streamers on a spot basis

$$x^{SpotLNG}_{nmt} - y^{SpotLNG}_{nmt} = 0 \quad \forall n, \forall m, \forall t \quad (p^{SpotLNG}_{nmt}) \tag{37}$$

Balance between the total quantity of gas supplied by mid-streamers' supply and the amount demanded by final consumers

$$\sum_m z_{mst} - d_{st} = 0 \quad \forall s, \forall t \qquad (p_{st}) \tag{38}$$

Constraints (19)-(22) identify the supply countries' activities. In particular, constraint (19) imposes an upper bound on the total quantity of gas that producers can extract (X^{G}_{nt}). As stated by the constraint (20), the gas produced by supplying countries can can be left in the gaseous form, and then sold either with LTCs (see variable x^{G}_{nmt}) or on the spot market (see variable x^{SpotG}_{nt}), or can be transformed in LNG (see variable X^{LNG}_{nt}). The variable X^{LNG}_{nt} represents the total amount of LNG produced by the supply country n that is then sold either with LTCs (x^{LNG}_{nmt}) or on spot ($x^{SpotLNG}_{nmt}$), as indicated by constraint (21). On the other side, constraint (22) imposes capacity limits on the liquefaction process. Note that the variable X^{LNG}_{nt} in constraints (21) and (22) is multiplied by the factor $(1 - \alpha_n)$ to account for the gas loss α_n that accrues during the liquefaction phase.

Constraints (23)-(32) refer to mid-streamers. In particular, mid-streamers buy gas and LNG from supplying countries with LTCs, or buy/sell gas on the spot market, or buy spot LNG. Mid-streamers regasify the total amount of LNG purchased (Y^{LNG}_{mt}) taking into account the capacity of their technologies as indicated in constraint (23). On the other side, constraint (24) explains that Y^{LNG}_{mt} accounts for the LNG that mid-streamers purchase both with LTCs (y^{LNG}_{nmt}) and on spot ($y^{SpotLNG}_{nmt}$). Note that both in (23) and (24) the variable Y_{mt}^{LNG} is multiplied by the factor $(1-\beta_m)$ to consider the losses of the regasification process. Constraints (25) and (26) define the balances among the quantities of gas managed by mid-streamer in the low ($t = 1$) and in the high-demand ($t = 2$) periods, respectively. More precisely, constraint (25) enforces that the total amount of gas purchased by the mid-streamer minus the gas injected in the storage site has to be greater or equal to the amount of gas sold to final consumers (z_{mst}) and on the spot market. In contrast, constraint (26) imposes that total amount of gas purchased by the mid-streamer plus the gas withdrawn from the storage site has to be greater or equal to the quantity of gas sold to final consumers (z_{mst}) and on the spot market. Constraints (27)-(30) regulate the storage process. In particular, (27) enforces that amount of gas injected in the storage site has to greater than the quantity withdrawn. Constraints (28) and (29) respectively define the injection and the withdrawal capacity limits, and, finally, (30) imposes the working gas limit throughout all withdrawal periods. On the other side, constraints (31) and (32) are used to model the “no flexibility” assumption described above. In particular, they respectively impose that the yearly amounts of gas and LNG that mid-streamers have to buy through LTCs have to be greater or equal to the volumes established (for that year) in already existing contracts. Such a constraint formulation allows mid-streamers not only to accomplish the volume TOP clause of the LTCs into which they have already enter, but also to possible negotiate new contracts. We explain in Section 3.4.2 how these constraints are modified to model the mid-streamers’ flexible behaviour.

Constraint (33) enforces the capacity limit of the entry points located in the destination country, while constraints (34), (35), (36) and (37) are the balances for gas and LNG respectively traded with LTCs and exchanged on a spot basis. Note that, as mentioned above, constraints (34) and (35) also include the external supply risk indicator as a weight of the quantities of gas and LNG purchased by the mid-streamers. Constraint (38) imposes the balance between the total quantity of gas sold by mid-streamers (z_{mst}) and demanded by consumers (d_{st}).

Finally, In order to detect the behaviur of the different players involved in the natural gas supply chain we consider complementarity formulation of this optimization problem. The corresponding Karush-Kuhn-Tucker (KKT) conditions are reported in Appendix A.

3.4.2 “Flexibility” case

The formulation of the welfare optimization problem under the “flexibility" assumption is identical to that presented in Section 3.4.1 with the exception of the constraints regulating the volumes of gas and LNG volumes that mid-streamers have to buy with LTCs. In particular, this change change regards constraints (31) and (32) that from lower bounds on the gas and LNG volumes purchased with LTCs become upper bounds. These are expressed as follows:

Upper bound on the natural gas purchase through LTCs (mid-streamers)

$$\tau_{nm} - \sum_t \theta_t \cdot y_{nmt}^G \geq 0 \quad \forall n, \forall m \qquad (\psi_{mn}^G) \tag{39}$$

Upper bound on the LNG purchase through LTCs (mid-streamers)

$$\xi_{nm} - \sum_t \theta_t \cdot y^{LNG}_{nmt} \geq 0 \quad \forall n, \forall m \qquad (\psi^{LNG}_{mn}) \tag{40}$$

From a mathematical point of view, this constraint modification implies some small changes in the KKT formulation of the optimization problem (see Appendix B for the discussion on the corresponding complementarity formulation). From an economical point of this, the illustrated constraint modification allows us to describe a more flexible behaviur of the mid-streamers which, in this case, have the possibility to ask for a LTC re-negotiation or to avoid the respect of the contract TOP clause for a short period.

4 Case study

Our case study is based on the Italian gas market that we consider as the gas destination area where mid-streamers operate. We select this market for two reasons: first, it is one of the three largest gas markets in Europe together with the UK and Germany; second, it mainly relies on natural gas imports to cover its demand since the national production is very low. According to the annual report of the Italian Authority (see AEEGSI, 2016[4]) the 90.6% of the national gas demand in 2015 was satisfied with imports from Russia, Algeria, Libya, the Netherlands, Qatar, and Norway. The main companies (mid-streamers) operating in Italy are ENI, Edison, and Enel with a market share of respectively 53.8%, 21.2%, and 11.2% (see AEEGSI, 2016). In 2015, these companies bought natural gas from Russia, Algeria, Libya, the Netherlands, and Norway; while LNG was imported by Qatar and Algeria (see AEEGSI, 2016). In general, residential/commercial is the gas consumers' sector with the highest demand, followed by power generation, and industrial sector (see also AEEGSI, 2016). The Italian natural gas and LNG imports are mainly delivered via long-term contracts, even though gas can also be traded on the Italian spot market "Punto di Scambio Virtuale (PSV)" that was created in 2003 (see Honoré, 2013 for a description of the liberalization process of the Italian gas market and the establishment of the PSV).

Considering this framework, our analysis refers to 2015 data and it is based on the following assumptions:

- **Destination country**: Italy.
- **Supplying countries**: Russia (RU), Algeria (AL), Libya (LIB), the Netherlands (NL), Qatar (QT), and Norway (NW). Since in the last years the Italian gas production is progressively reducing (see AEEGSI, 2016), we do not account for Italy among the producing and supplying countries.
- **Natural gas origin**: Russia, Algeria, Libya, the Netherlands, and Norway. For modeling the mid-streamers' flexibility assumptions, we consider the LTCs that Italy has established with these countries in the last years and are still active in 2015.

[4] This annual report is in Italian and refer to 2015 data. An English version is available at `http://www.autorita.energia.it/allegati/relaz_ann/15/annual_report2015.pdf` but refers to 2014 data.

– **LNG origin**: Algeria and Qatar (see BP Statistical Review of World Energy, 2016; GIIGNL, 2016). Similarly to gas, we consider the LNG LTCs that Italy has established with these two countries in the last years and are still active in 2015 to model the mid-streamers' flexibility assumptions.
– **Mid-streamers**: We assume that there is just one mid-streamer, since we do not dispose of detailed data for all the companies operating in the Italian gas market. This representative mid-streamer can buy both natural gas and LNG through LTCs or can trade them on the respective spot markets.

As already explained, we account for a time span of one year subdivided into two time periods with different demand levels. The high-demand period is assumed to have a duration of 151 days and comprehends the months from November to March included; the low-demand period lasts 214 days and covers the remaining months. Since, in our analysis, we consider a representative day per each period, all quantities are expressed in mcm/day while prices and costs are in €/cm.

The production (extraction) capacity data of the aforementioned supplying countries are taken from Egging et al. (2008).[5] These data are not recent but considering that the gas reserve to production (R/P) ratio computed at worldwide level has been almost unchanged in the last twenty years,[6] we consider these capacity data as a reasonable proxy. The liquefaction capacity data related to the supplying countries are taken from GIIGNL (2016) and refer to 2015.

No capacity limits are imposed on the natural gas transports via pipelines between supplying countries and Italy or on the LNG cargos. However, we consider the capacity of the entry points located at the borders of the Italian network that enforces restrictions on the amount of natural gas imported via pipelines. Italy has five entry points for pipelines that are Mazara del Vallo, Gela, Tarvisio, Passo Gries, and Gorizia. In Mazara del Vallo, natural gas is imported from Algeria thanks to the connection with the pipeline Transmed/Enrico Mattei; the natural gas from Libya enters in Gela though the connection with the pipeline Greenstream; Gorizia and Tarvisio receive gas from Russia thought the TAG pipeline, and, finally, Pass Gries gets gas from the Netherlands and Norway respectively via the Trans-European pipeline and the Transitgas. Considering this information about the gas provenience at the different entry points, we are able to limits the imports between Italy and the supplying countries (see constraint (33) in our formulation). The 2015 capacity data of these entry points are provided by SNAM (2016). For what concerns LNG, the capacity of the regasification plants implicitly limits the Italian LNG imports. There are three regasification plants in Italy that are located in Rovigo, Livorno, and Panigaglia. In our case study, we consider just one regasification plant whose capacity is obtained by aggregating those of these two plants. The respective data are taken from GIIGNL (2016) and refer to 2015.

The natural gas production costs faced by supplying countries are defined as linear function of the following type:

[5] See Table 14 at page 2410 of Egging et al. (2008).

[6] See BP at `http://www.bp.com/en/global/corporate/energy-economics/statistical-review-of-world-energy/natural-gas/natural-gas-reserves.html`

$$C_{nt} = c_n^G \cdot X_{nt}^G \quad \forall n, \, \forall t$$

where the parameter c_n^g has been estimated taking as reference Egging et al. (2008). In particular, the value of c_n^g for the considered supplying countries is obtained by multiplying the marginal production costs reported in the column "Max mag" of Table 14 in Egging et al. (2008) by 1.9 that is the average for 2015 of the "Euro Area Gross Domestic Product Chained 2010 Prices YoY".[7]

The liquefaction costs incurred by supplying countries are determined by the following quadratic function:

$$LC_{nt} = lc1_n^{LNG} \cdot X_{nt}^{LNG} + lc2_n^{LNG} \cdot (X_{nt}^{LNG})^2 \quad \forall n, \, \forall t$$

where the terms $lc1_n^{LNG}$ and $lc2_n^{LNG}$, as for the production costs, have been estimated taking as reference the data and the approach proposed by Egging et al. (2008). More precisely, the values of $lc1_n^{LNG}$ and $lc2_n^{LNG}$ respectively correspond to the α and β parameters reported in Table 15 of in Egging et al. (2008) multiplied by 1.9. i.e. the 2015 GDP.

For the Italian mid-streamer's regasification costs, we consider the following quadratic function:

$$RC_t = rc1^{LNG} \left(\sum_{n=1}^{N} Y_{nt}^{LNG} \right) + rc2^{LNG} \left(\sum_{n=1}^{N} Y_{nt}^{LNG} \right)^2 \quad \forall t$$

where the terms $rc1_n^{LNG}$ and $rc2_n^{LNG}$ have been evaluated using the data available in Egging et al. (2008). More precisely, the values of $rc1_n^{LNG}$ and $rc2_n^{LNG}$ respectively correspond to the α and β parameters reported in Table 16 of in Egging et al. (2008) multiplied by 1.9. i.e. the 2015 GDP.

The mid-streamer also controls and manages the storage site. We suppose that there is just one storage site whose capacity and injection rate are obtained by aggregating the capacities and injection rates of all the storage sites available in Italy. As in Egging and Gabriel (2006), we impose that the injection rate is equal to the peak output rates, while the extraction capacity is assumed to be twice the injection capacity. The data related to working gas and storage rates refer to 2015 and are taken from IEA (2016) and from the Stogit website.[8] Injection costs are defined through the following linear function:

$$I_1 = ic \cdot i_1$$

where the parameter ic is the unitary injection cost whose value has been taken from AEEGSI (2016).

[7] Gross domestic product (GDP) measures the final market value of all goods and services produced within a country. It is the most frequently used indicator of economic activity. The GDP by expenditure approach measures total final expenditures (at purchasers' prices), including exports less imports. This concept is adjusted for inflation. For our simulation, we GDP data from Bloomberg (ticker: EUGDEMU). See `https://www.bloomberg.com/quote/EUGNEMUY:IND`

[8] See `http://www.stogit.it/en/about-us/where-you-can-find-us/storage-sites.html`

Supplying countries also face the natural gas and LNG transportation costs. The costs of transfer natural gas though pipelines are taken from NERA (2014). In particular, we have taken the 2018 data in Figure 77 at page 132 of Appendix A and we have adjusted them with the pipeline cost adders provided in Figure 87 at page 139 of Appendix A for 2018. We have finally transformed all cost data from \$/Mcf to €/cm. On the other side, for evaluating the LNG transportation costs we follow the same approach adopted for production, liquefaction, and regasification costs. We consider a cost of 0.005€/cm/1000 sea miles that we have taken from Egging et al. (2008) and we have then multiplied it by 1.9. The sea miles are deduced from GIIGNL (2016). On the other side, the distribution costs faced by the mid-streamer are taken from AEEGSI (2016).

The data needed for the computation of the external supply risk indicators refer to 2015 and are taken from BP Statistical Review of World Energy (2016), GIIGNL (2016), and AEEGSI (2016). As in Le Coq and Paltseva (2009), we consider the political risk rating for 2015 published by the PRS Group.[9] This political risk measure assigns countries a rate whose values are between 1 and 100 with the following reasoning: the highest the rate, the lowest the political risk associated. In all indicators that we construct, we consider the complementary of this PRS risk, namely r_n is set in the following way:

$$r_n = 100 - \mathrm{PRS}_{\mathrm{Risk}}$$

Recall that the indicators $\Pi_{nm}^{REES,G}$ and $\Pi_{nm}^{REES,LNG}$ also account for the distance (d_{nm}) between the supplying and the destination countries and the fungibility of natural gas (F_{nm}^{G}) and the LNG (F_{nm}^{LNG}). Following Le Coq and Paltseva (2009), we set $F_{nm}^{G} = 1$ and $F_{nm}^{LNG} = 2$, and the transport risk is identified by the following parameter d_{nm}:

$$d_{nm} = \begin{cases} 1, & \text{distance between capitals} \; < \; 1700 \text{ Km} \\ 2, & 1700 \text{ Km} \leq \text{distance between capitals} \; < \; 2500 \text{ Km} \\ 3, & 2500 \text{ Km} \leq \text{distance between capitals} \; < \; 3300 \text{ Km} \\ 4, & \text{distance between capitals} \; \geq 3300 \text{ Km} \end{cases} \tag{41}$$

The external risk indicators that we obtain from our computations are reported in Table 2.

Table 2 External supply risk indicators

	$\Pi_{nm}^{HHI,G}$	$\Pi_{nm}^{SWN2,G}$	$\Pi_{nm}^{GES,G}$	$\Pi_{nm}^{REES,G}$
NW	1.598	2.877	0.102	0.115
NL	1.174	3.974	0.113	0.126
RU	18.779	19.140	11.564	6.464
AL	1.508	8.784	0.300	0.335
LIB	1.377	15.494	0.495	0.553
	$\Pi_{nm}^{HHI,LNG}$	$\Pi_{nm}^{SWN2,LNG}$	$\Pi_{nm}^{GES,LNG}$	$\Pi_{nm}^{REES,LNG}$
AL	0.111	3.515	0.001	0.003
QT	93.444	0.360	0.973	0.799

[9] See `https://www.prsgroup.com/category/risk-index`

In order to model the different degrees of mid-streamer's flexibility, we need the data of the annual volumes of gas and LNG that have been regulated by LTCs in 2015. We recall that Italy has natural gas LTCs with Russia, Algeria, the Netherlands, Norway, and Libya; while LNG LTCs are with Algeria and Qatar. The considered annual data are reported in Table 3 and are taken from Cedigaz[10]

We consider the following inverse demand functions to model the final consumers' gas demand:

$$p_{st} = a_{st} - b_{st} \cdot d_{st} \quad \forall s, \forall t$$

Parameters a_{st} and b_{st} have been estimated using an elasticity value of -0.1 for all consumer groups, the amount of gas demanded by Italian industry, power sector, and residential/commercial and the average prices that they paid for purchasing gas in 2015. These data are taken from AEEGSI (2016).

Table 3 Volumes of gas and LNG regulated by LTCs between Italy and supplying countries in 2015 (annual value)

	Gas	**LNG**
NW	5,450	-
NL	9,200	-
RU	35,000	-
AL	27,380	1,840
LIB	5,610	-
QT	-	6,400
Tot	82,640	8,240

Finally, we recall that the solution of the optimization problems presented in Sections 3.4.1 and 3.4.2 is found by implementing their complementarity conditions reported in Appendices A and B, respectively. These KKT conditions are run in the GAMS modeling environment, using PATH as solver (see Dirkse and Ferris 1995).

5 Results

To analyze the impacts of external supply risk on the mid-streamer imports' choices and we consider the following assumptions

1. **Mid-streamer's behaviour:**
   – The mid-streamer has *at least* to buy an amount of gas and LNG as defined in already existing LTCs ("No FLEX" case in the following);
   – The mid-streamer has *at most* to buy an amount of gas and LNG as defined in already existing LTCs ("FLEX" case in the following).
2. **External supply risk:**
   – No external supply risk is considered in model ("NO Risk" case in the following);

[10] See `http://www.cedigaz.org/products/natural-gas-database.aspx`

– All external supply risk indicators that we constructed are considered in the model as explained in the previous sections ("Risk" case in the following).

In the following we first analyze the impacts of the application of different degrees of mid-streamers' flexibility by comparing the "No FLEX" and "FLEX" without considering any of the external supply risk indicators (see Section 5.1). The effects of gas/LNG volumes and prices with risk are then presented in Section 5.2. Note that in this section we consider the risk indicators imposed in both the "No FLEX" and the "FLEX" cases. Note that, in any of the simulations that we have implemented, the mid-streamer re-sells gas on the spot market. Finally, we assume that the risk regards both the supply of gas and LNG with LTCs at the same time.

5.1 No external supply risk

We first consider the effects of the mid-streamer's flexibility on the annual amount of gas purchased. Figure 2a illustrate the yearly volume of natural gas, both in gaseous and liquefied forms, that the mid-streamer exchanges in the "No FLEX" and the"FLEX") cases, assuming that the external supply risk is not considered ("NO Risk").

INSERT HERE FIGURE 2
CAPTION: Yearly volume of gas exchanged per type and yearly demand per consumer group (mcm/year)

The mid-streamer accomplishes all gas and LNG LTCs that it has with all the supplying countries (compare the values reported in Figure 2a with those reported in Table 3), while this does not happen under the "FLEX" assumption leading to a gas volume drop of 21%. In particular, the mid-streamer reduces by 20% the annual volume of gas purchased with LTCs and does no longer buy LNG with LTCs. Even though it increases respectively by 4% and 107% the amount of gas and LNG acquired on spot markets at yearly basis, these spot purchases do not suffice to compensate the reduction in the LTC volumes. This has a negative impact on final consumers that see their gas availability reduced in the "FLEX" case. In particular, the mid-streamer still guarantee almost the entire gas supply to the residential/commercial sector (the drop is "only" by 7%), but it decreases the supply to the power companies and industry respectively by 51% and 22% with respect to the "No FLEX" case (see Figure 2b).

Figures 3 and 4 provide more details on the daily amount of gas and LNG exchanged between supplying countries and mid-streamers in the low- and in the high-demand periods under the "No FLEX" and "FLEX" assumptions. In general, we observe that between the flexibility and not flexibility cases, there is no a drastic variation of the mix of supplying countries. What the mid-streamer significantly modifies is the amount of gas/LNG purchased in the two time periods (shift of volumes exchanged in low- and high-demand periods) and the selection of the physical status of the gas traded (shift between the quantities of gas and LNG purchased, especially for the supply from Algeria). The set of supplying countries from which the mid-streamer receives gas/LNG is not subject to many modifications. Considering LTCs (Figure 3), the main changes in the gas supply mix between the “No FLEX” and “FLEX” cases are as follows: under the flexibility assumption, Norway does no longer provide gas to Italy in any period; Libya still procures Italy with gas but only in the low-demand period; and, finally, the total amount of gas provided by Algeria reduces, especially in the low-demand period. Note that this unsold Algerian gas is then transformed in LNG and sold on the spot market (see Figure 4). For what concerns LNG, as already indicated above, the difference between the “No FLEX” and “FLEX” cases is that the volume TOP clause of the Algerian and Qatari LTCs is not respected under the flexibility assumption because the mid-streamer prefers to buy spot LNG. On the other side, both in the “No FLEX” and “FLEX” cases, Libya and the Netherlands supply spot gas to Italy, even though in different quantities. Moreover, in the high-demand period of the “FLEX” case Russia appears as an additional supplier.

INSERT HERE FIGURE 3
CAPTION: Natural gas and LNG bought through LTCs (mcm/day)

INSERT HERE FIGURE 4
CAPTION: Natural gas and LNG bought on the spot market (mcm/day)

Table 4 Supplying countries and mid-streamer’s profits, final consumers’ surplus, and social welfare under the “NO Risk” assumption (€/year)

€/cm		NO Risk No FLEX	NO Risk FLEX
Supplying countries	Revenues	51,021	38,342
	Production costs	14,745	11,171
	Transport costs	36,057	27,188
	Net profits	**218**	**-17**
Mid-streamer	Revenues	50,247	52,550
	Distribution costs	11,326	9,895
	Purchase costs	51,021	38,342
	Regasification costs	149	53
	Injection costs	161	150
	Net profits	**-12,410**	**4,110**
Final consumers	Industry’s surplus	21,820	13,962
	Power Sector ’s surplus	14,454	4,899
	Residenatial’s surplus	182,618	159,711
	Total surplus	**218,892**	**178,572**
Social welfare		**206,700**	**182,664**

The comparison of the “No FLEX” and “FLEX” results under the assumption of absence of external supply risk shows that the mid-streamer changes its supply choices when it has the possibility to do that. The profit analysis can help understanding this change of strategies in the mid-streamer’s behaviur. Table 4 reports supplying countries and the mid-streamer’s profits, the final gas consumers’ surplus, and the social welfare in the “No FLEX” and “FLEX” cases. In the “No FLEX” case, the mid-streamer is forced to satisfy the LTCs that it has already contracted. This guarantees the remuneration of the supplying countries which gain from their activities, but it causes a significant loss for the mid-streamer because its cost of purchasing gas and LNG (“Purchase costs”) is higher than the revenues it obtains from selling gas to final consumers (compare Tables 5, 6, and 7 that report the LTC prices, the spot prices, and the prices charged to final consumers, respectively).[11] The situation changes in the "FLEX" case where the mid-streamer is not obliged to fully satisfy all the contracts. The outcome is that the mid-streamer modifies its supply mix in such a way it avoids negative profits. However, the mid-streamer's strategy of reducing its purchase of gas and LNG with LTCs compared to the "No FLEX" case is not beneficial for the whole gas supply chain because it implies not only a reduction of gas availability for final consumers with a consequent decrease of their surplus, but also a drop of supplying countries' profits that become negative (see Table 4). The final result is a 12% reduction of the social welfare. We recall that the remuneration of supplying countries is important because these guarantee the maintenance of the existing infrastructures and the investments in new ones, whose costs are, in general, very high. Considering these results, we can say that LTCs are necessary to maintain the stability and to guarantee the security of supply, even though this may incur in losses for the mid-streamers.

We finally reports in Tables 5 and 6 the prices for natural gas and LNG respectively sold with LTCs and on the spot market obtained in the "No FLEX" and the "FLEX" cases. Note that the label "n.s." in Tables 5 and 6 stands for "not sold". We recall that the gas spot price is not differentiated per supplier because we assume that there is just one market where all participants submit their offers and bids. This market sets the price for spot gas on a daily basis. The prices of LTCs for gas and LNG are higher than those defined on the spot market both under the "No FLEX" and the "FLEX" assumptions. This reflects the differences between these two pricing systems and explains the reason why mid-streamers have asked for the re-negotiation of the LTCs. Indeed, higher LTCs prices guarantee returns to supplying countries, but also they may lead to possible losses for mid-streamers. Moreover, as expected, the spot prices in the low-demand period are lower than in those in high-demand period because of the different consumption levels in the two time frameworks.

Table 5 Prices of gas and LNG LTCs under the "NO Risk" assumption (€/cm)

		NW	NL	RU	AL	LIB	QT
Gas LTCs	**No FLEX**	0.54	0.38	0.51	0.54	0.41	
	FLEX	n.s.	0.38	0.51	0.55	0.41	
LNG LTCs	**No FLEX**				0.51		0.72
	FLEX				n.s.		n.s.

Looking at Table 5, one can see that the gas prices of the LTCs with the Netherlands, Russia, and Libya are identical in the "No FLEX" and "FLEX" cases. In fact, the quantities of gas LTCs exchanged between these countries and Italy are the same under the two flexibility assumptions. This explains the effects on the volume reshuffle between low- and high-demand periods to which we assist in the "FLEX" case, as explained above. The unique exception is Algeria where the LTCs price in

[11] Note that, in the "No FLEX" case, the weighted average gas and LNG prices computed over the involved supplying countries and paid by the mid-streamer are: 0.50 €/cm (gas LTCs), 0.66 €/cm (LNG LTCs), 0.32 €/cm (gas spot), and 0.50 €/cm (LNG spot). In contrast, the weighted average price that the mid-streamer applies to final consumers is 0.48 €/cm).

Table 6 Prices spot of gas and LNG under the “NO Risk” assumption (€/cm)

			Low	High
Gas Spot	**No FLEX**		0.31	0.33
	FLEX		0.25	0.32
LNG Spot	**No FLEX**	**AL**	0.49	0.50
		QT	n.s.	n.s.
	FLEX	**AL**	0.31	0.38
		QT	n.s.	n.s.

the “FLEX” case is higher than under the “No FLEX” assumption. This is the reason why, in the “FLEX” case, the mid-streamer decides to reduce the amount of gas purchased with LTCs from Algeria and buy this gas on the spot basis at lower prices (compare Algerian prices in Tables 5 and 6).

Considering Table 6, one can notice that the prices of the gas and LNG traded on the spot markets are lower in the “FLEX” case than in the “No FLEX” instance. This is the reason why the mid-streamer increase its purchases on spot.

Finally Table 7 reports the prices applied in the two time periods to final consumers in the “no FLEX” and the “FLEX” cases. Note that the prices that the mid-streamer is able to apply to final consumers under the “FLEX” assumption are higher than those imposed in the “no FLEX” case. This indeed allows mid-streamer to increase its revenues and compensate its costs in such a way it does not incur in a profit loss (see Table 4).

Table 7 Final consumers’ prices under the “NO Risk” assumption (€/cm)

	NO Risk No FLEX		NO Risk FLEX	
	Low	**High**	**Low**	**High**
Industry	0.39	0.48	0.57	0.60
Power sector	0.37	0.45	0.55	0.58
Residential/commercial	0.47	0.56	0.65	0.68

5.2 External supply risk

In this section, we analyze the effects of the application of the external supply risk in the “No FLEX” and “FLEX” cases. We recall that the risk is applied only on gas and LNG LTCs.

INSERT HERE FIGURE 5
CAPTION: Yearly volume of gas exchanged per type (mcm/year)

The main outcomes are as follows. The external supply risk does not affect the mid-streamer’s behaviur in the “No FLEX" case since the total volume of exchanged gas and LNG both via LTCs and on spot are as under the “NO Risk No FLEX" assumption (see Figure 5) with the consequence that the total quantity of gas offered to final consumers remains unchanged (see Figure 6). Moreover, no changes in the supplying country mix is encountered with respect to the not-flexible risk without risk. As in the “NO Risk No FLEX" case, the mid-streamer accomplishes the natural gas and LNG LTCs independently of the risk measure considered (see Figures 7 and 8 in Appendix C). This depends on the fact that the mid-streamer must satisfy the LTC volume clause and it has, at least, to buy the volumes of gas and LNG that it has already contracted. The risk does not either affect the spot supply, even though the mid-streamer does not have any constraints on the amount of gas and LNG that it has to buy on the spot markets (see Figures 9 and 10 in Appendix C). In other words, the external supply risk does not have significant impacts on the mid-streamer’s strategies when no flexibility is allowed. We register only some shifts between the quantities of the LTCs and spot gas purchased in the low- and in the high-demand period (see Figures 7 and 9, respectively). This implies that the gas and LNG prices as well as those paid by the final consumers in all “Risk No Flex” cases are identical to those reported in Tables (5)-(7) for the corresponding “NO Risk No Flex” case, independently of the considered external supply risk indicator. The same holds for the social welfare of the gas supply chain and the profits/surplus of its player groups.

The situation in the “Risk FLEX” cases remains in line with that described under the “NO Risk FLEX” assumption and, depending on the considered supply risk indicator, it is even more exacerbated. The mid-streamer’s actions in the “Risk FLEX” cases can be summarized with the following items (see Figure 5 and also Figures 11-13 in Appendix C):

1. The total amount of natural gas that is traded in the “Risk FLEX” cases is lower than under the “NO Risk FLEX” assumption. This is particular evident when the Π_{nm}^{HHI} and $\Pi_{nm}^{SWNI_2}$ indicators are applied. Globally, we register a significant drop of gas imports compared to the “No FLEX” cases;
2. In the “Risk FLEX” cases, the mid-streamer modifies the mix of supplying countries depending on the applied risk indicator;
3. The amount of gas that the mid-streamer exchanges with LTCs in the “Risk FLEX” cases is lower than the corresponding one in the “NO Risk FLEX” because the risk induces the mid-streamer to buy cheaper gas and LNG on the respective spot markets;
4. The volumes of gas and LNG that are exchanged on the spot markets increases under the “Risk FLEX” assumptions compared to the “NO Risk FLEX” (and also “NO Risk No FLEX”) cases, but this increase does not suffice to recover the amount of gas that is not bought with LTCs;
5. As in the “NO Risk FLEX” case, also under all “Risk FLEX” assumptions, the mid-streamer does not respect the volume TOP clause of the LNG LTCs; i.e. no LNG is exchanged with contracts.

Table 8 provides a summary of the supplying countries that exchanges the different types of gas with Italy under the risk and flexibility assumptions. These are compared to the results obtained in the “NO Risk FLEX” case. For each case analyzed, “Yes” in the table cells indicates that there is a trade and the subsequent percentage reported in brackets corresponds to the weight in terms of volumes that the considered country has in the Italian supply mix. The symbol “-” means that no exchanges of gas or LNG are allowed between Italy and the producer, while “-No” means that Italy does not import from the specific country even though it has the possibility to do it. The provenience of spot gas and LNG is not affected by risk since the relative indicators are applied only on LTCs. As we already observed, there is an increase of the total volume of spot gas and LNG that is imported both from Algeria and Qatar, but this increase is not enough to restore the gas volume availability guaranteed by the respect of LTCs. The inclusion of risk has a significant impact on the external supply of gas with LTCs because the mid-streamer changes the provenience and the proportion of gas imported depending on the indicator. The principle driving the mid-streamer's choice is considering not risky countries. For instance, under the Π_{nm}^{HHI}, the mid-streamer decides to fully respect the gas LTCs with the Netherlands and Libya because these are the two countries with the lowest risk level (see $\Pi_{nm}^{HHI,G}$ in Table 2). The same happens when applying the other risk indicators. Note that the gas contracts with Russia are not honured because this is the producer with the highest risk in all considered indicators and, moreover, the mid-streamer does not accomplish to any gas LTCs under the $\Pi_{nm}^{SWNI_2}$ since the risk values associated with the different countries in this indicator are extremely high, much higher than those of the other indicators (see Table 2). On the other side, the mid-streamers does not buy LNG with contracts but prefers to resort to its purchase on spot, as it happens in the "NO Risk FLEX" case. This drop of natural gas import with LTCs has been already observed in Section 5.1 when describing the effect of the "NO Risk FLEX" case. The combination of the flexibility with the risk assumption exacerbates the phenomenon, implying a significant reduction of the total gas offered to final consumers in the "Risk FLEX" cases (see Figure 6). Only the residential/commercial sector maintains a relative adequate supply level, even though lower than in the corresponding "Risk No FLEX" and "Risk FLEX" cases, whereas industries and power generators face a significant curtailment. These two sectors are not even supplied when the $\Pi_{nm}^{SWNI_2}$ risk applies.

INSERT HERE FIGURE 6
CAPTION: Yearly demand per consumer group (mcm/year)

The mid-streamer behaves in this way because it wants to limit its exposure to risk, but mostly because it desires to mitigate its possible profit losses. This issue has already been detected in Section 5.1 when discussing the "NO Risk FLEX" case.

Table 9 reports supplying countries and the mid-streamer's profits, the final gas consumers' surplus, and the social welfare in the "NO Risk FLEX" and in the "Risk FLEX" cases. In all "FLEX" cases, the mid-streamer's profits are positive thanks to the set of strategies that it adopts. Note that the significant curtailment of the expensive gas volumes traded with LTCs under the risk assumption allows the mid-streamer to increase its net profit compared to the "NO Risk FLEX" case. This is also due to the fact that the prices imposed to final consumers are higher than under the "NO Risk FLEX" assumption (see Table 11). This is particular evident when the $\Pi_{nm}^{SWNI_2}$ risk is implemented, since no gas/LNG is purchased with LTCs, but also when applying the Π_{nm}^{HHI} where the amount of gas/LNG bought on spot is proportionally higher than that imported with LTCs. This indeed has a negative impact on final consumers that see their surplus reducing with respect to the "NO Risk FLEX" assumption. In fact, the lowest consumers' surplus is registered when the $\Pi_{nm}^{SWNI_2}$ risk is applied.

Table 8 Supplying countries that exchange gas and LNG with Italy under the "Risk" and "FLEX" assumptions

		NW	NL	RU	AL	LIB	QT
Gas LTCs	**NO Risk**	**No**	Yes (14%)	Yes (54%)	Yes (25%)	Yes (8%)	-
	Risk Π_{nm}^{HHI}	**No**	Yes (62%)	**No**	**No**	Yes (38%)	-
	Risk $\Pi_{nm}^{SWNI_2}$	**No**	**No**	**No**	**No**	**No**	-
	Risk Π_{nm}^{GES}	Yes (15%)	Yes (24%)	**No**	Yes (50%)	Yes (11%)	-
	Risk Π_{nm}^{REES}	Yes (14%)	Yes (23%)	**No**	Yes (50%)	Yes (13%)	-
LNG LTCs	**NO Risk**	-	-	-	**No**	-	**No**
	Risk Π_{nm}^{HHI}	-	-	-	**No**	-	**No**
	Risk $\Pi_{nm}^{SWNI_2}$	-	-	-	**No**	-	**No**
	Risk Π_{nm}^{GES}	-	-	-	**No**	-	**No**
	Risk Π_{nm}^{REES}	-	-	-	**No**	-	**No**
Gas Spot	**NO Risk**	**No**	Yes (59%)	Yes (1%)	**No**	Yes (40%)	-
	Risk Π_{nm}^{HHI}	**No**	Yes (50%)	Yes (16%)	**No**	Yes (34%)	-
	Risk $\Pi_{nm}^{SWNI_2}$	**No**	Yes (84%)	**No**	**No**	Yes (16%)	-
	Risk Π_{nm}^{GES}	**No**	Yes (53%)	**No**	**No**	Yes (47%)	-
	Risk Π_{nm}^{REES}	**No**	Yes (54%)	Yes (5%)	**No**	Yes (41%)	-
LNG Spot	**NO Risk**	-	-	-	Yes (100%)	-	**No**
	Risk Π_{nm}^{HHI}	-	-	-	Yes (29%)	-	Yes (71%)
	Risk $\Pi_{nm}^{SWNI_2}$	-	-	-	Yes (29%)	-	Yes (71%)
	Risk Π_{nm}^{GES}	-	-	-	Yes (29%)	-	Yes (71%)
	Risk Π_{nm}^{REES}	-	-	-	Yes (29%)	-	Yes (71%)

The effects of the risk implementation on supplying countries' profits vary according to the risk indicator analyzed. In particular, supplying countries globally face losses when the risk indicators Π_{nm}^{GES} and Π_{nm}^{REES} are considered, while they gain with the Π_{nm}^{HHI} and $\Pi_{nm}^{SWNI_2}$ measures. Note that these losses are higher than in the "NO Risk FLEX" case. In this latest case, it is true that their revenues are lower, but also the associated production and transportation costs are limited. This allows supplying countries to gain from the situation.

Table 10 reports the LTC prices for gas under the "NO Risk FLEX" and "Risk FLEX" assumptions. One can note that the risk leads to the a slight increase of these prices.

In conclusion, the "FLEX" strategy is more protecting for the mid-streamers, but it does not result to be beneficial for the whole supply chain that registers a reduction

Table 9 Supplying countries and mid-streamer's profits, final consumers' surplus, and social welfare under the "NO Risk" assumption (€/year)

FLEX						
		No Risk	**Risk** Π_{nm}^{HHI}	**Risk** $\Pi_{nm}^{SWNI_2}$	**Risk** Π_{nm}^{GES}	**Risk** Π_{nm}^{REES}
Supplying countries	Revenues	38,342	23,346	21,272	30,178	30,692
	Production costs	11,171	6,986	5,232	10,139	10,285
	Transportation costs	27,188	11,880	8,214	20,166	20,630
	Net Profits	**-17**	**4,480**	**7,825**	**-128**	**-223**
Mid-streamer	Revenues	52,550	49,877	45,647	52,481	52,464
	Distribution costs	9,895	6,247	4,471	8,472	8,579
	Purchase costs	38,342	23,346	21,272	30,178	30,692
	Regasification costs	53	185	185	185	185
	Injection costs	150	133	79	160	161
	Net Profits	**4,110**	**19,966**	**19,640**	**13,486**	**12,846**
Final consumers	Industry's surplus	13,962	961	-	7,436	7,934
	Power Sector 's surplus	4,899	-	-	945	1,122
	Residenatial's surplus	159,711	86,322	47,453	133,285	135,427
	Total surplus	**178,572**	**87,283**	**47,453**	**141,666**	**144,483**
Social welfare		**182,664**	**111,728**	**74,918**	**155,024**	**157,107**

of the social welfare. This phenomenon becomes more extreme with the application of the external supply risk measures.

Table 10 Prices of gas LTCs under the "Risk FLEX" assumptions (€/cm)

FLEX						
	NW	**NL**	**RU**	**AL**	**LIB**	**QT**
NO Risk	n.s.	0.38	0.51	0.55	0.41	
Risk Π_{nm}^{HHI}	n.s.	0.39	n.s.	n.s.	0.43	
Risk $\Pi_{nm}^{SWNI_2}$	n.s.	n.s.	n.s.	n.s.	n.s.	
Risk Π_{nm}^{GES}	0.56	0.41	n.s.	0.56	0.43	
Risk Π_{nm}^{REES}	0.55	0.40	n.s.	0.56	0.42	

Table 11 Final consumers' prices under the "Risk FLEX" assumptions (€/cm)

FLEX										
	NO Risk FLEX		**Risk** Π_{nm}^{HHI}		**Risk** $\Pi_{nm}^{SWNI_2}$		**Risk** Π_{nm}^{GES}		**Risk** Π_{nm}^{REES}	
	Low	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**
Industry	0.57	0.60	1.05	1.13	n.s.	n.s.	0.74	0.77	0.73	0.76
Power Sector	0.55	0.58	n.s.	n.s.	n.s.	n.s.	0.65	0.75	0.65	0.73
Residenatial	0.65	0.68	1.18	1.21	1.56	1.59	0.82	0.86	0.81	0.84

6 Conclusions

In this paper, we analyze the security of the external supply of the Italian gas market that mainly relies on imports to satisfy its gas demand. In particular, we develop an optimization problem model that describes the equilibrium state of a natural gas supply chain where supplying countries, mid-streamers and consumers exchange natural gas and LNG both with LTCs and on the spot market.

Mid-streamers who buy natural gas and LNG are assumed to be the market player mainly exposed to the external supply risk associated with the imports from foreign countries. In other words, mid-streamers define the amount of gas and LNG to be imported not only on the basis of the relative production and transportation costs, but also on the external supply risk associated with the countries from which the gas originates. The external supply risk is measured through indicators that we construct starting from those already existing in the literature. These indicators are then inserted in the volume balance constraints of the gas and LNG LTCs.

In addition to the impact of the external supply risk, we analyze different degrees of mid-streamer's flexibility. In particular, we consider both a situation where the mid-streamer fully satisfies the LTCs quantity clause and a case where the mid-streamer behaves in a more flexible way and it is not obliged to fulfill the LTC volume requirements.

Our analysis shows that, if the mid-streamer have to comply with the LTCs quantity clause ("No FLEX" assumption), it does not significantly change its supplying choices even when the risk is considered. Under this assumption, the mid-streamer faces significant losses, while the supplying countries gain. In contrast, these mid-streamers' losses disappear when it is not obliged to fully satisfy the LTCs requirements ("FLEX" case) because it is able to modify its supply mix. In particular, compared to the "No FLEX" case, it reduces the amount of gas imported with LTCs because it is more expensive and increases the quantity of cheaper spot gas. In addition, it increases its imports from less risky countries when possible. However, this flexible mid-streamer's behaviur has several drawbacks compared to the "No FLEX" case: the suppliers can face losses because of the significant drop in their revenues; the total amount of gas and LNG purchased drops because the decrease of the quantity of gas imported via LTCs is not fully compensated by the increase of the spot gas or LNG. This also leads to a reduction of gas availability for final consumers. In particular, the mid-streamer still guarantee the gas supply to the residential/commercial sector, but it decreases the supply to the power companies and to industries with respect to the "No FLEX" case. Considering these results, it turns out that LTCs are necessary to maintain the stability and to guarantee the security of supply, even though this may incur in losses for the mid-streamers. The "FLEX" strategy is more protecting for the mid-streamers, but it does not result to be beneficial for the society. This phenomenon becomes more extreme with the application of the external supply risk measures.

7 Acknowledgments

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A Complementarity formulation of the welfare optimization problem under the "no flexibility" assumption

In this appendix, we report the complementarity formulation of the welfare optimization problem presented in Section 3.4.1.

$$0 \leq -\gamma_{nt} + \frac{\partial C_{nt}\left(X_{nt}^{G}\right)}{\partial X_{nt}^{G}} + \overline{\gamma}_{nt} \perp X_{nt}^{G} \geq 0 \quad \forall n, \forall t \tag{42}$$

$$0 \leq -(1-\alpha_n) \cdot \delta_{nt} + (1-\alpha_n) \cdot \overline{\delta}_{nt} + \gamma_{nt} + \frac{\partial LC_{nt}\left(X_{nt}^{LNG}\right)}{\partial X_{nt}^{LNG}} \perp X_{nt}^{LNG} \geq 0 \; \forall n, \forall t \tag{43}$$

$$0 \leq -p_{nmt}^{G} + ptc_{nm}^{G} + \gamma_{nt} \perp x_{nmt}^{G} \geq 0 \quad \forall n, \forall m, \forall t \tag{44}$$

$$0 \leq -p_{t}^{SpotG} + \gamma_{nt} + ptc_{n}^{SpotG} + \sum_{f=1}^{F} \mathit{\Gamma}_{fn} \cdot \kappa_{ft} \perp x_{nt}^{SpotG} \geq 0 \quad \forall n, \forall t \tag{45}$$

$$0 \leq -p_{nmt}^{LNG} + stc_{nm}^{LNG} + \delta_{nt} \perp x_{nmt}^{LNG} \geq 0 \quad \forall n, \forall m, \forall t \tag{46}$$

$$0 \leq -p_{nmt}^{SpotLNG} + stc_{nm}^{LNG} + \delta_{nt} \perp x_{nmt}^{SpotLNG} \geq 0 \quad \forall n, \forall m, \forall t \tag{47}$$

$$0 \leq -p_{st} + dc_{ms} + \lambda_{mt} \perp z_{mst} \geq 0 \quad \forall m, \forall s, \forall t \tag{48}$$

$$0 \leq -(1-\beta_m) \cdot \eta_{mt} + \frac{\partial RC_m\left(Y_{mt}^{LNG}\right)}{\partial Y_{mt}^{LNG}} + (1-\beta_m) \cdot \overline{\eta}_{mt} \perp Y_{mt}^{LNG} \geq 0 \quad \forall m, \forall t \tag{49}$$

$$0 \leq -\lambda_{mt} - \psi_{nm}^{G} + \mathit{\Pi}_{nm}^{G} \cdot p_{nmt}^{G} + \sum_{f=1}^{F} \mathit{\Gamma}_{fn} \cdot \kappa_{ft} \perp y_{nmt}^{G} \geq 0 \quad \forall n, \forall m, \forall t \tag{50}$$

$$0 \leq -\lambda_{mt} + p_{t}^{SpotG} \perp y_{mt}^{SpotG} \geq 0 \quad \forall m, \forall t \tag{51}$$

$$0 \leq -\lambda_{mt} - \psi_{nm}^{LNG} + \mathit{\Pi}_{nm}^{LNG} \cdot p_{nmt}^{LNG} + \eta_m \perp y_{nmt}^{LNG} \geq 0 \quad \forall n, \forall m, \forall t \tag{52}$$

$$0 \leq -\lambda_{mt} + p_{nmt}^{LNG} + \eta_m \perp y_{nmt}^{SpotLNG} \geq 0 \quad \forall m, \forall t \tag{53}$$

$$0 \leq -p_{t}^{SpotG} + \lambda_{mt} \perp q_{mt}^{SpotG} \geq 0 \quad \forall m, \forall t \tag{54}$$

$$0 \leq -\mu_m + \frac{\partial I_{m1}\left(i_{m1}\right)}{\partial i_{m1}} + \nu_m + \lambda_{m1} \perp i_{m1} \geq 0 \quad \forall m, t=1 \tag{55}$$

$$0 \leq -\lambda_{m2} + \mu_m + \sigma_m + \phi_m \perp w_{m2} \geq 0 \quad \forall m, \forall t=2 \tag{56}$$

$$0 \leq \bar{X}_n - X_{nt}^{G} \perp \overline{\gamma}_{nt} \geq 0 \quad \forall n, \forall t \tag{57}$$

$$0 \leq \bar{L}_n - (1-\alpha_n) \cdot X_{nt}^{LNG} \perp \overline{\delta}_{nt} \geq 0 \quad \forall n, \forall t \tag{58}$$

$$0 \leq \bar{R}_m - (1-\beta_m) \cdot Y_{mt}^{LNG} \perp \overline{\eta}_{mt} \geq 0 \quad \forall m, \forall t \tag{59}$$

$$\begin{aligned} 0 \leq & \sum_{n=1}^{N} y_{nmt}^{G} + \sum_{n=1}^{N} y_{nmt}^{LNG} + y_{mt}^{SpotG} + \sum_{n=1}^{N} y_{nmt}^{SpotLNG} + \\ & -i_{mt} - \sum_{s=1}^{S} z_{mst} - q_{mt}^{SpotG} \perp \lambda_{mt} \geq 0 \quad \forall m,\ t=1 \end{aligned} \tag{60}$$

$$\begin{aligned} 0 \leq & \sum_{n=1}^{N} y_{nmt}^{G} + \sum_{n=1}^{N} y_{nmt}^{LNG} + y_{mt}^{SpotG} + \sum_{n=1}^{N} y_{nmt}^{SpotLNG} + w_{mt} + \\ & - \sum_{s=1}^{S} z_{mst} - q_{mt}^{SpotG} \perp \lambda_{mt} \geq 0 \quad \forall m,\ t=2 \end{aligned} \tag{61}$$

$$0 \leq i_{m1} - w_{m2} \perp \mu_m \geq 0 \quad \forall m \tag{62}$$

$$0 \leq \bar{I}_m - i_{m1} \perp \nu_m \geq 0 \quad \forall m \tag{63}$$

$$0 \leq \bar{W}_m - w_{m2} \perp \sigma_m \geq 0 \quad \forall m \tag{64}$$

$$0 \leq WG_m - \theta_2 \cdot w_{m2} \perp \phi_m \geq 0 \quad \forall m \tag{65}$$

$$0 \leq \sum_t \theta_t \cdot y^G_{nmt} - \tau_{nm} \perp \psi^G_{mn} \geq 0 \quad \forall n, \forall m \tag{66}$$

$$0 \leq \sum_t \theta_t \cdot y^{LNG}_{nmt} - \xi_{nm} \perp \psi^{LNG}_{mn} \geq 0 \quad \forall n, \forall m \tag{67}$$

$$0 \leq \varUpsilon_{ft} - \left(\sum_{n=1}^{N} \sum_{m=1}^{M} \varGamma_{fn} \cdot y^G_{nmt} + \sum_{n=1}^{N} \varGamma_{fn} \cdot x^{SpotG}_{nt} \right) \perp \kappa_{ft} \geq 0 \quad \forall t \tag{68}$$

$$0 \leq p_{st} - a_{st} + b_{st} \cdot d_{st} \perp d_{st} \geq 0 \quad \forall s, \forall t \tag{69}$$

$$X^G_{nt} - \left(\sum_{m=1}^{M} x^G_{nmt} + x^{SpotG}_{nt} + X^{LNG}_{nt} \right) = 0 \quad \forall n, \forall t \qquad (\gamma_{nt} : \text{free}) \tag{70}$$

$$(1 - \alpha_n) \cdot X^{LNG}_{nt} - \left(\sum_{m=1}^{M} x^{LNG}_{nmt} + \sum_{m=1}^{M} x^{SpotLNG}_{nmt} \right) = 0 \quad \forall n, \forall t \qquad (\delta_{nt} : \text{free}) \tag{71}$$

$$(1 - \beta_m) \cdot Y^{LNG}_{mt} - \left(\sum_{n=1}^{N} y^{LNG}_{nmt} + \sum_{n=1}^{N} y^{SpotLNG}_{nmt} \right) = 0 \, \forall m, \forall t \, (\eta_{mt} : \text{free}) \tag{72}$$

$$x^G_{nmt} - \varPi^G_{nm} \cdot y^G_{nmt} = 0 \quad \forall n, \forall m, \forall t \, (p^G_{nmt} : \text{free}) \tag{73}$$

$$\sum_{n=1}^{N} x^{SpotG}_{nt} + q^{SpotG}_{mt} - \sum_{m=1}^{M} y^{SpotG}_{mt} = 0 \quad \forall t \quad (p^{SpotG}_t : \text{free}) \tag{74}$$

$$x^{LNG}_{mnt} - \varPi^{LNG}_{nm} \cdot y^{LNG}_{mnt} = 0 \quad \forall n, \forall m, \forall t \qquad (p^{LNG}_{mnt} : \text{free}) \tag{75}$$

$$x^{SpotLNG}_{nmt} - y^{SpotLNG}_{nmt} = 0 \quad \forall n, \forall m, \forall t \quad (p^{SpotLNG}_{nmt} : \text{free}) \tag{76}$$

$$\sum_m z_{mst} - d_{st} = 0 \quad \forall s, \forall t \qquad (p_{st} : \text{free}) \tag{77}$$

B Complementarity formulation of the welfare optimization problem under the "flexibility" assumption

To model the "flexibility" assumption we only replace constraints (31) and (32) in the welfare optimization problem described in Section 3.4.1 with the constraints (39) and (40) presented in Section 3.4.2. This modification leads to some changes in the KKT conditions presented in Appendix A. In particular, conditions (50), (52), (66), and (67) are respectively substituted with the following ones:

$$0 \leq -\lambda_{mt} + \psi^G_{nm} + \varPi^G_{nm} \cdot p^G_{nmt} + \sum_{f=1}^{F} \varGamma_{fn} \cdot \kappa_{ft} \perp y^G_{nmt} \geq 0 \quad \forall n, \forall m, \forall t \tag{78}$$

$$0 \leq -\lambda_{mt} + \psi^{LNG}_{nm} + \varPi^{LNG}_{nm} \cdot p^{LNG}_{nmt} + \eta_m \perp y^{LNG}_{nmt} \geq 0 \quad \forall n, \forall m, \forall t \tag{79}$$

$$0 \leq \tau_{nm} - \sum_t \theta_t \cdot y^G_{nmt} \perp \psi^G_{mn} \geq 0 \quad \forall n, \forall m \tag{80}$$

$$0 \leq \xi_{nm} - \sum_t \theta_t \cdot y^{LNG}_{nmt} \perp \psi^{LNG}_{mn} \geq 0 \quad \forall n, \forall m \tag{81}$$

More precisely, since constraints (39) and (40) impose upper bounds on the primal variables y^G_{nmt} and y^{LNG}_{nmt}, the associated dual variables ψ^G_{mn} and ψ^{LNG}_{mn} enter with a positive sign in the KKT conditions (78) and (79) of these primal variables. The reverse happens in the complementarity formulation of the optimization problem under the "no flexibility" assumption. Since constraints (31) and (32) define lower bounds on variables y^G_{nmt} and y^{LNG}_{nmt} the associated dual variables ψ^G_{mn} and ψ^{LNG}_{mn} enter with a negative sign in the KKT conditions (50) and (52) of these primal variables. Finally, all the other KKT conditions are as indicated in Appendix A.

C Additional results

INSERT HERE FIGURE 7
CAPTION: Volumes of gas exchanged via LTCs under the “Risk” and “No FLEX” assumptions (mcm/day)

INSERT HERE FIGURE 8
CAPTION: Volumes of LNG exchanged via LTCs under the “Risk” and “No FLEX” assumptions (mcm/day)

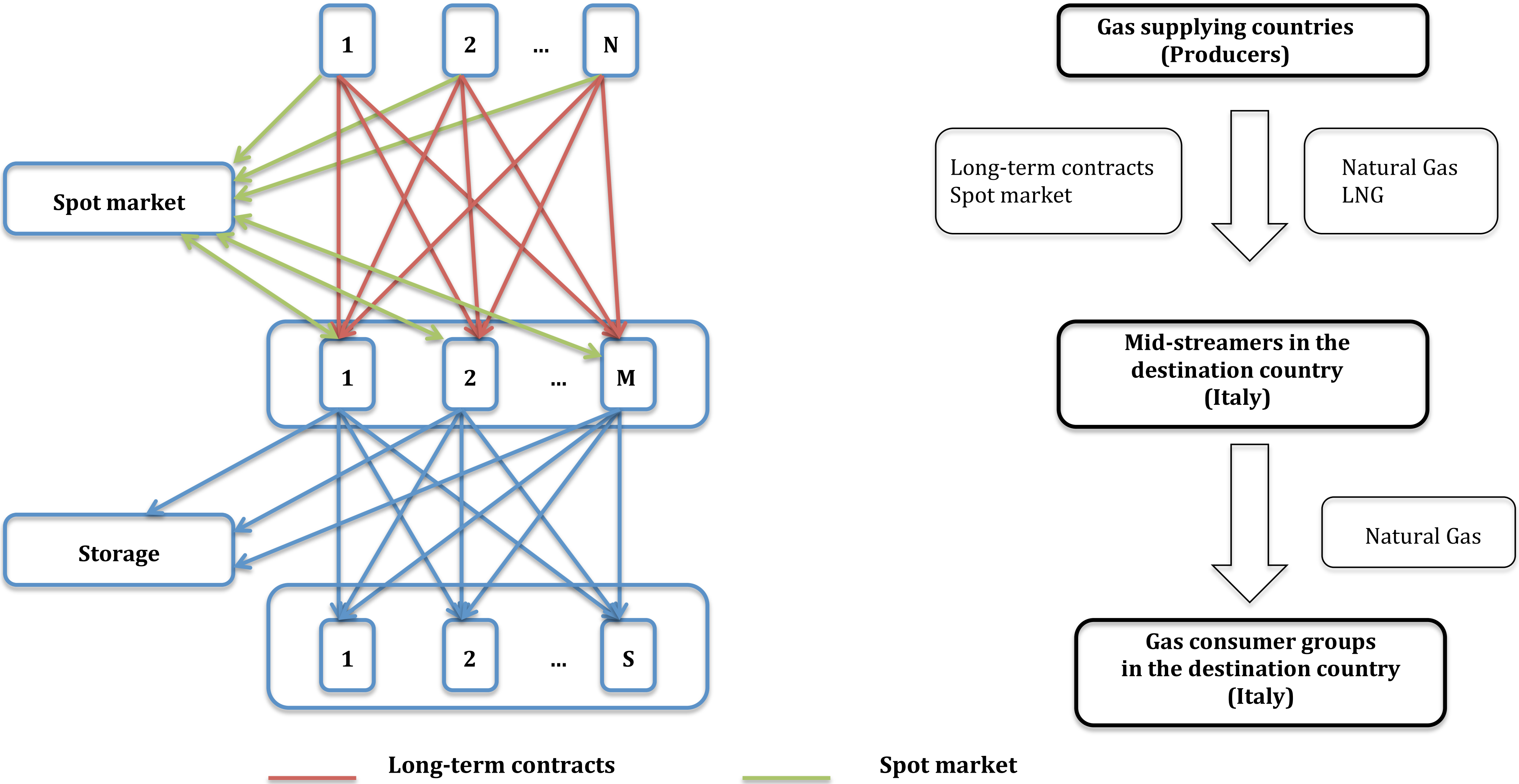
INSERT HERE FIGURE 9
CAPTION: Volumes of spot gas exchanged under the “Risk” and “No FLEX” assumptions (mcm/day)

INSERT HERE FIGURE 10
CAPTION: Volumes of spot LNG exchanged under the “Risk” and “No FLEX” assumptions (mcm/day)

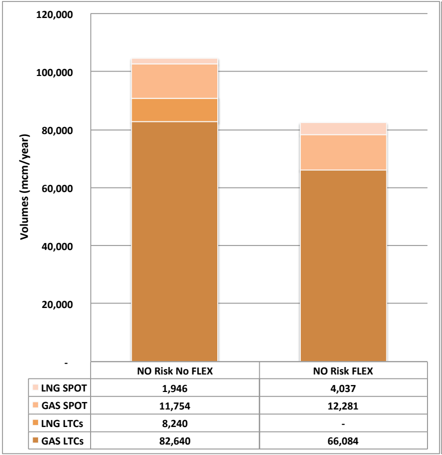
INSERT HERE FIGURE 11
CAPTION: Volumes of natural gas exchanged via LTCs under the “Risk” and “FLEX” assumptions (mcm/day)

INSERT HERE FIGURE 12
CAPTION: Volumes of spot gas exchanged under the “Risk” and “FLEX” assumptions (mcm/day)

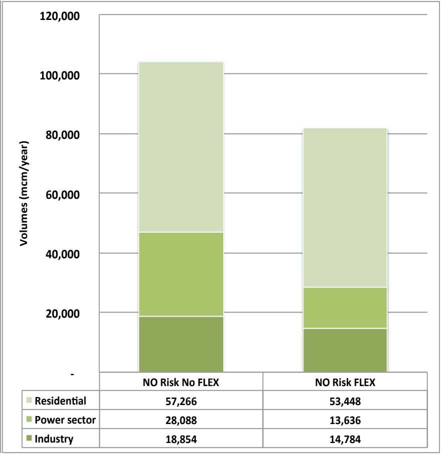
INSERT HERE FIGURE 13
CAPTION :Volumes of spot LNG exchanged under the “Risk” and “FLEX” assumptions (mcm/day))



1
2
...
N
Spot market
1
2
...
M
Storage
1
2
...
S
Gas supplying countries (Producers)
Long-term contracts
Spot market
Natural Gas
LNG
Mid-streamers in the destination country (Italy)
Natural Gas
Gas consumer groups in the destination country (Italy)
Long-term contracts
Spot market


120,000
100,000
80,000
60,000
40,000
20,000
-
Volumes (mcm/year)
NO Risk No FLEX
NO Risk FLEX
LNG SPOT
1,946
4,037
GAS SPOT
11,754
12,281
LNG LTCs
8,240
-
GAS LTCs
82,640
66,084

(a)


120,000
100,000
80,000
60,000
40,000
20,000
-
Volumes (mcm/year)
NO Risk No FLEX
NO Risk FLEX
Residential
57,266
53,448
Power sector
28,088
13,636
Industry
18,854
14,784

(b)

Figure 3 new

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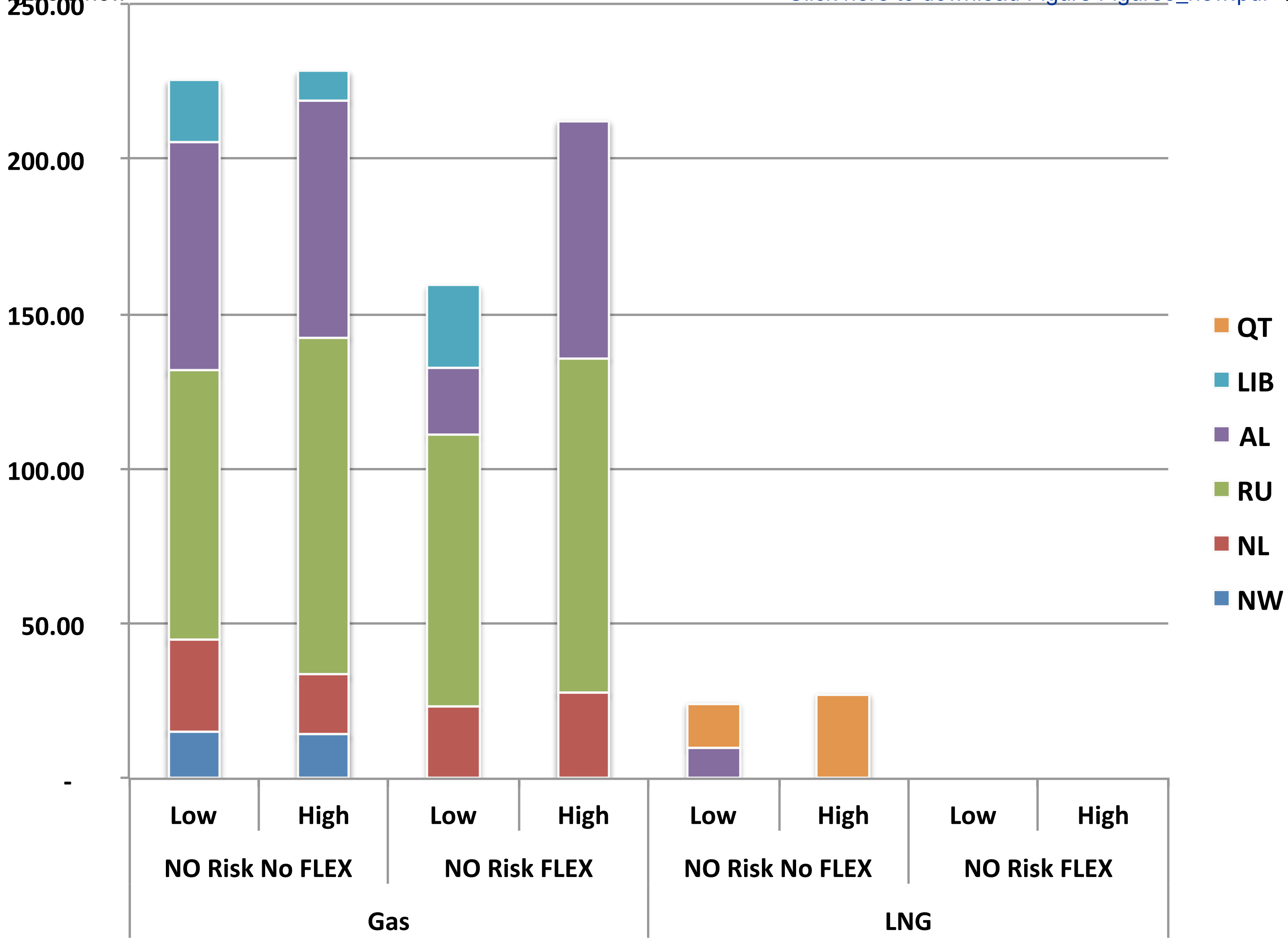

Figure 4 new
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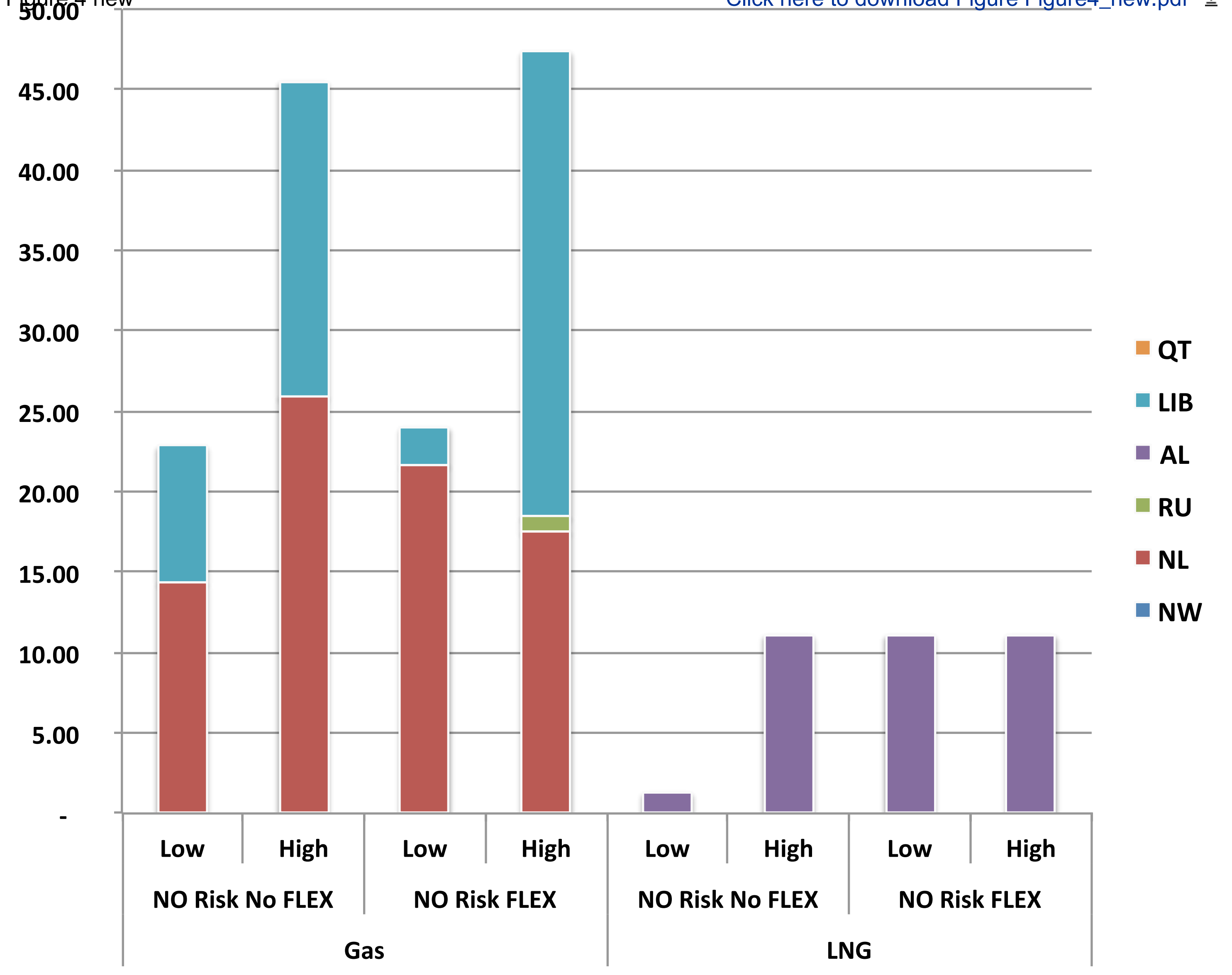

Figure 5 new

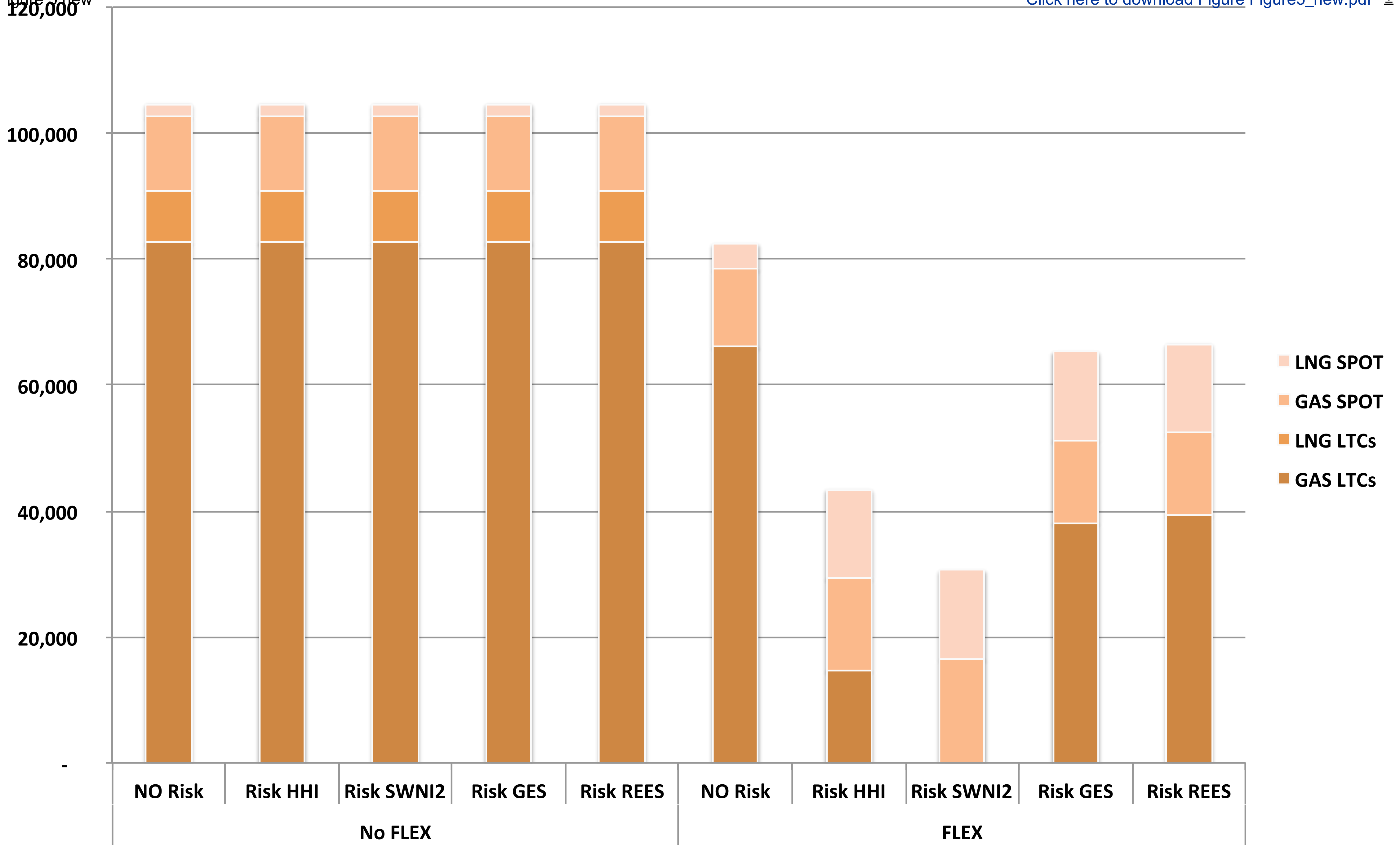
120,000
100,000
80,000
60,000
40,000
20,000
-
LNG SPOT
GAS SPOT
LNG LTCs
GAS LTCs
NO Risk
Risk HHI
Risk SWNI2
Risk GES
Risk REES
NO Risk
Risk HHI
Risk SWNI2
Risk GES
Risk REES
No FLEX
FLEX

Figure 6 new

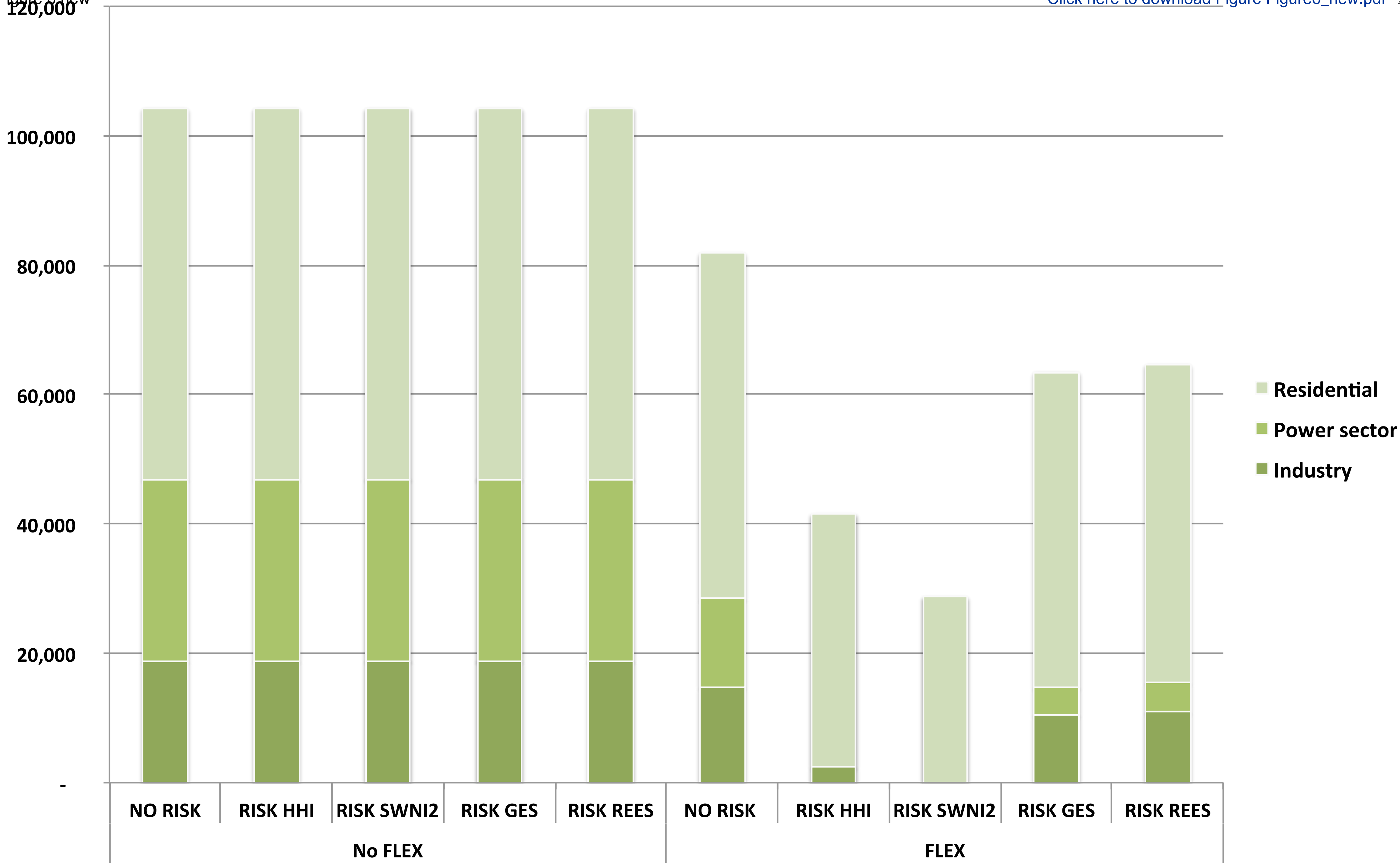
120,000
100,000
80,000
60,000
40,000
20,000
-
NO RISK
RISK HHI
RISK SWNI2
RISK GES
RISK REES
NO RISK
RISK HHI
RISK SWNI2
RISK GES
RISK REES
No FLEX
FLEX
Residential
Power sector
Industry

Figure 7 new

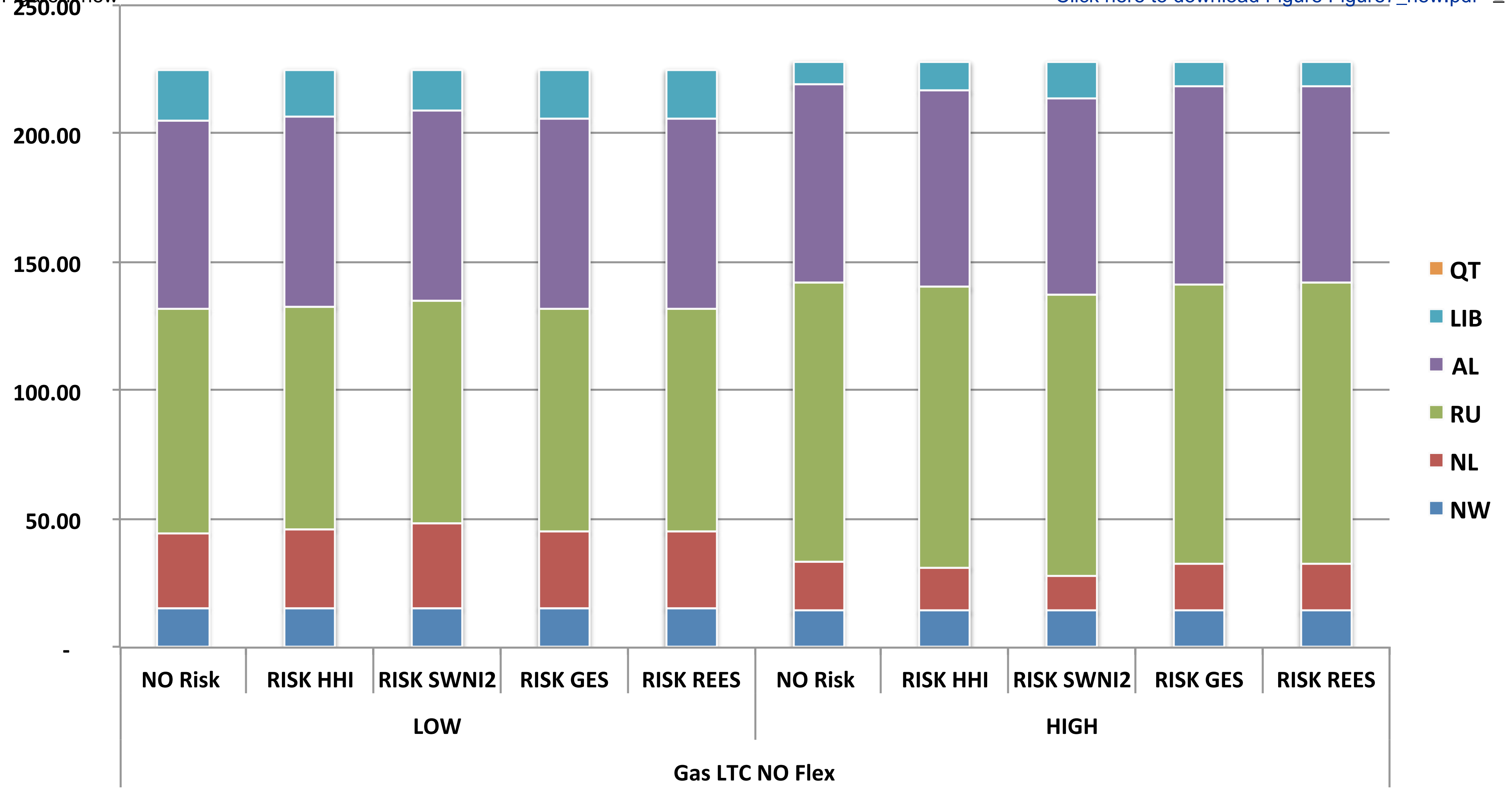
250.00
200.00
150.00
100.00
50.00
-
QT
LIB
AL
RU
NL
NW
NO Risk
RISK HHI
RISK SWNI2
RISK GES
RISK REES
NO Risk
RISK HHI
RISK SWNI2
RISK GES
RISK REES
LOW
HIGH
Gas LTC NO Flex

Figure 8 new

Click here to download Figure Figure8_new.pdf

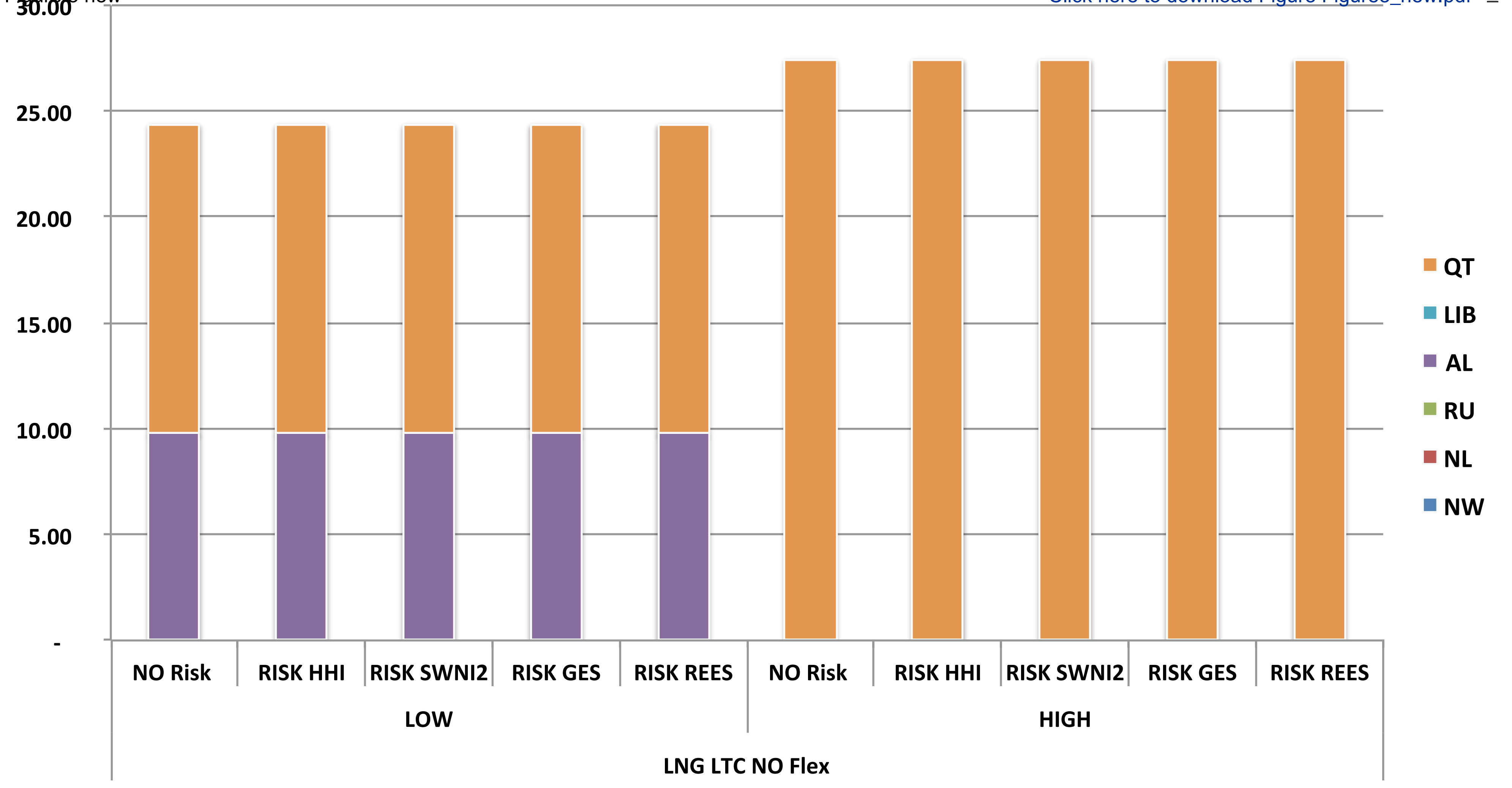

Figure 9 new

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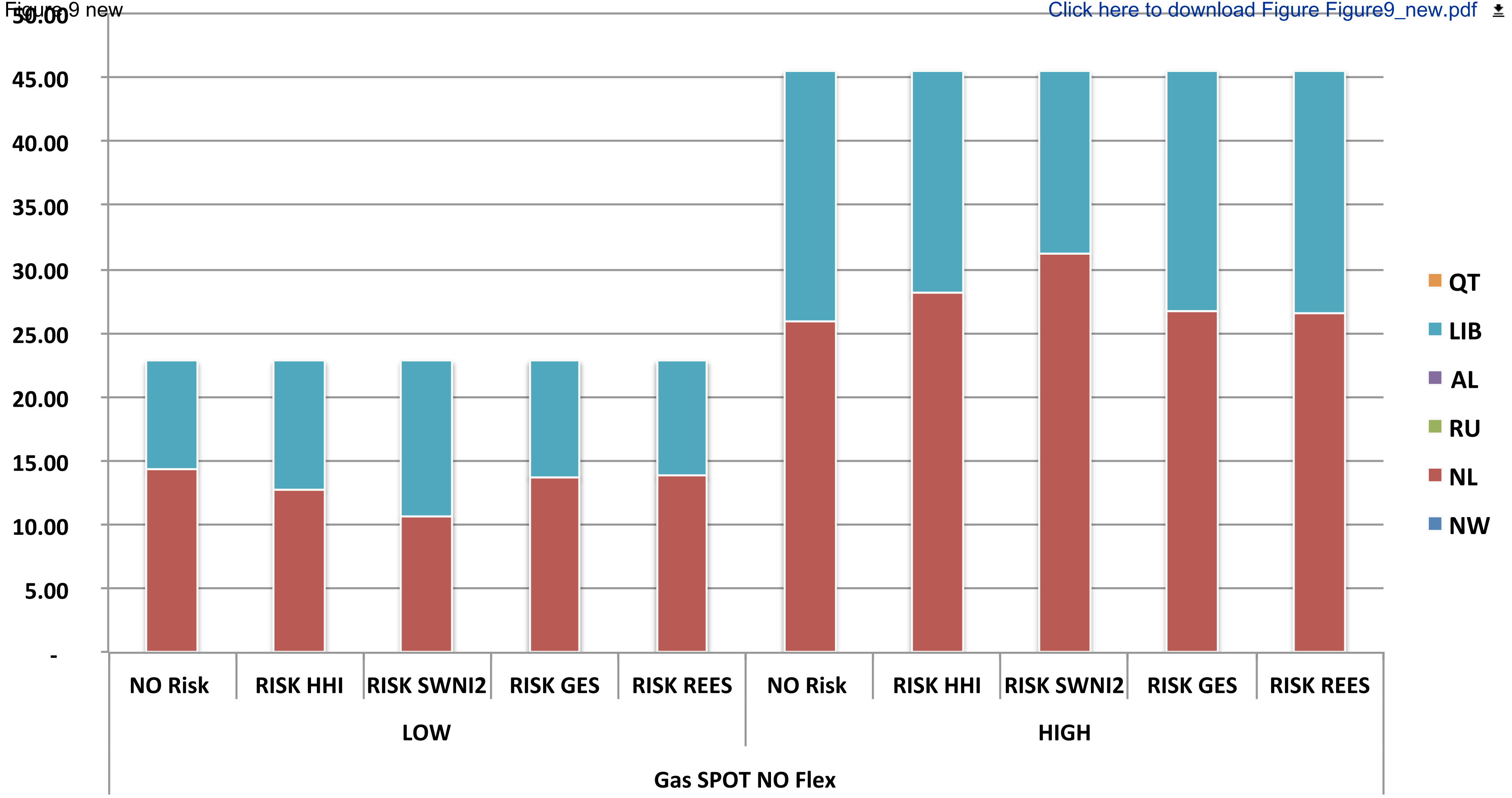


Figure 10 new

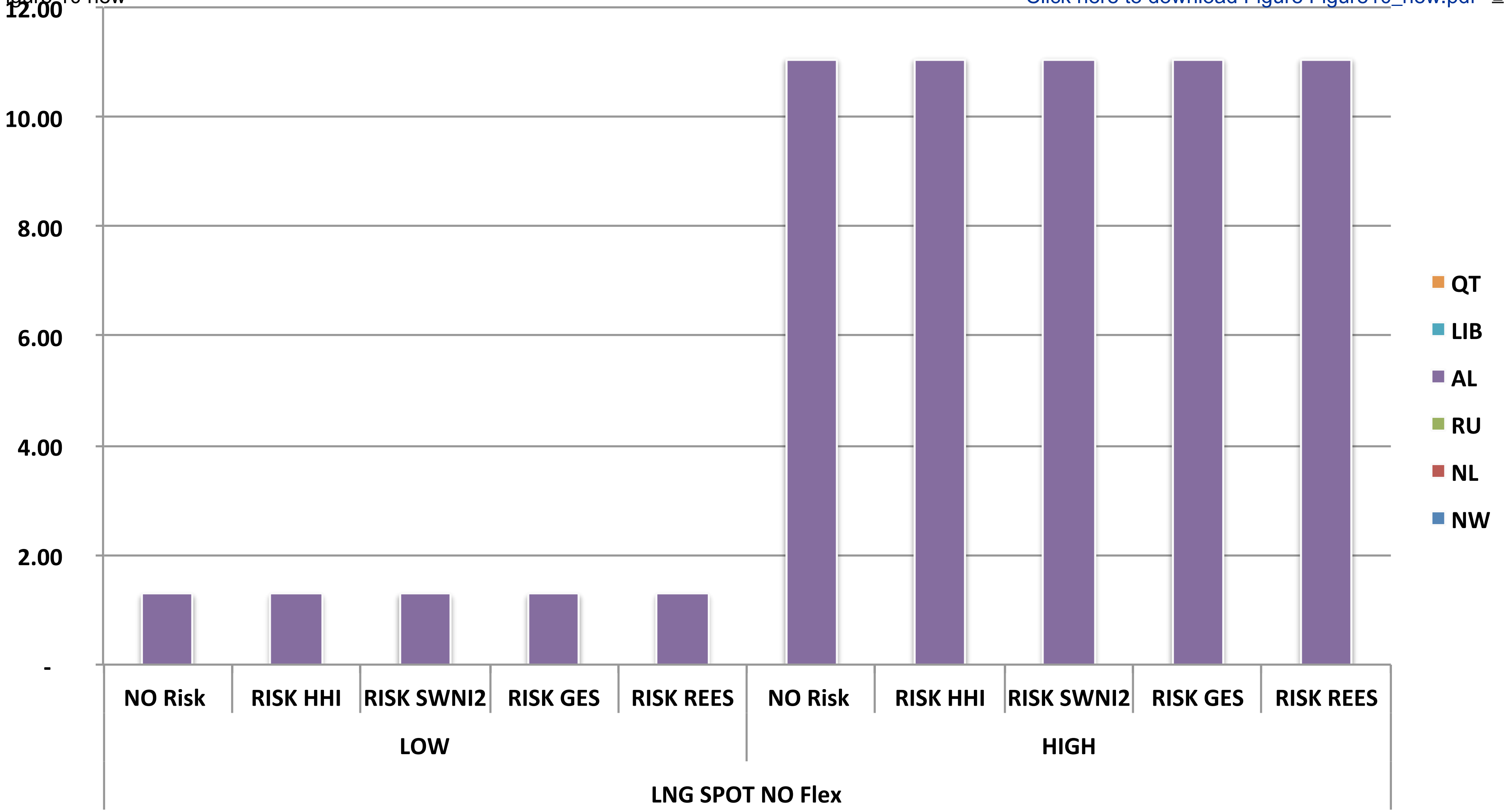


Figure 11 new

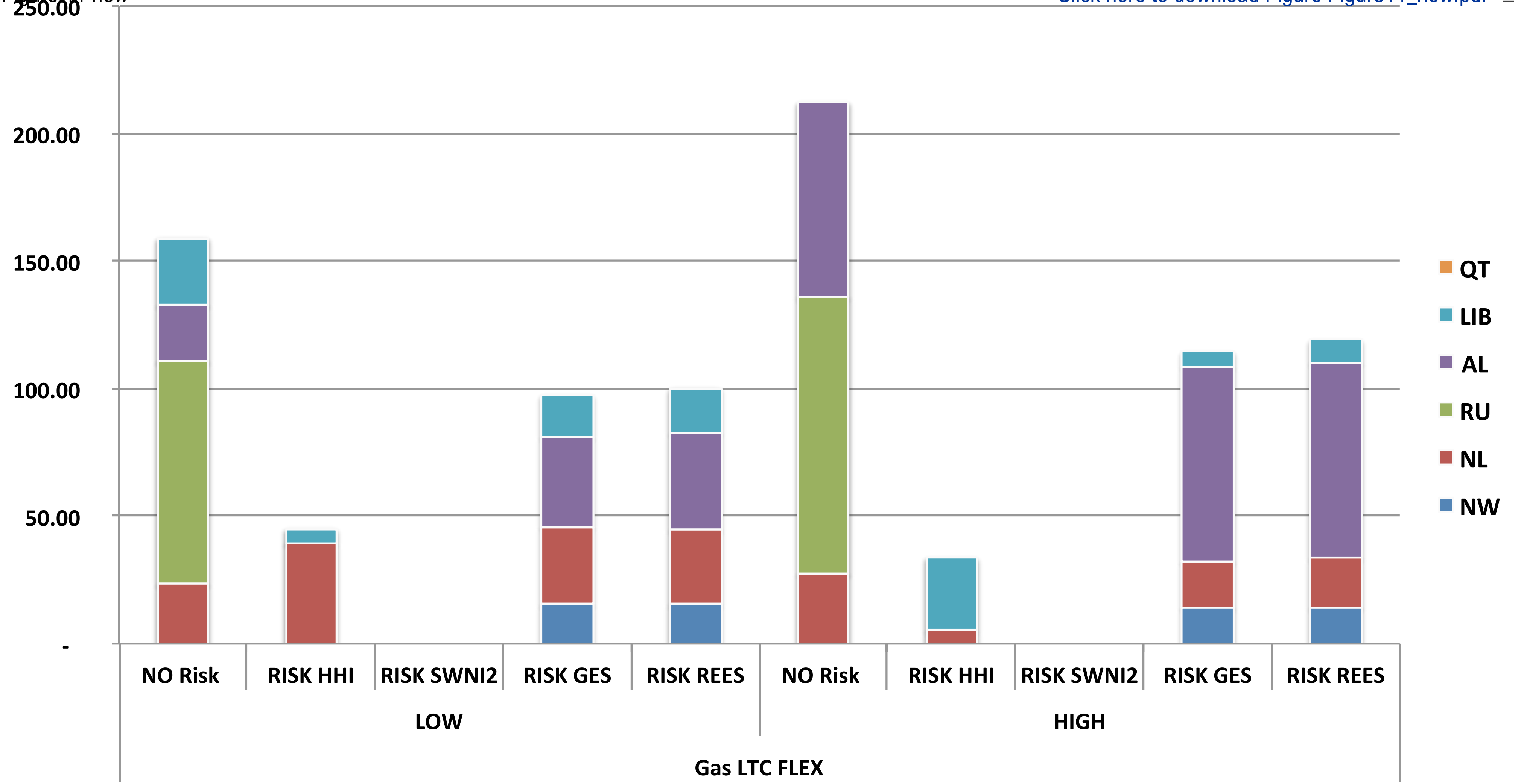
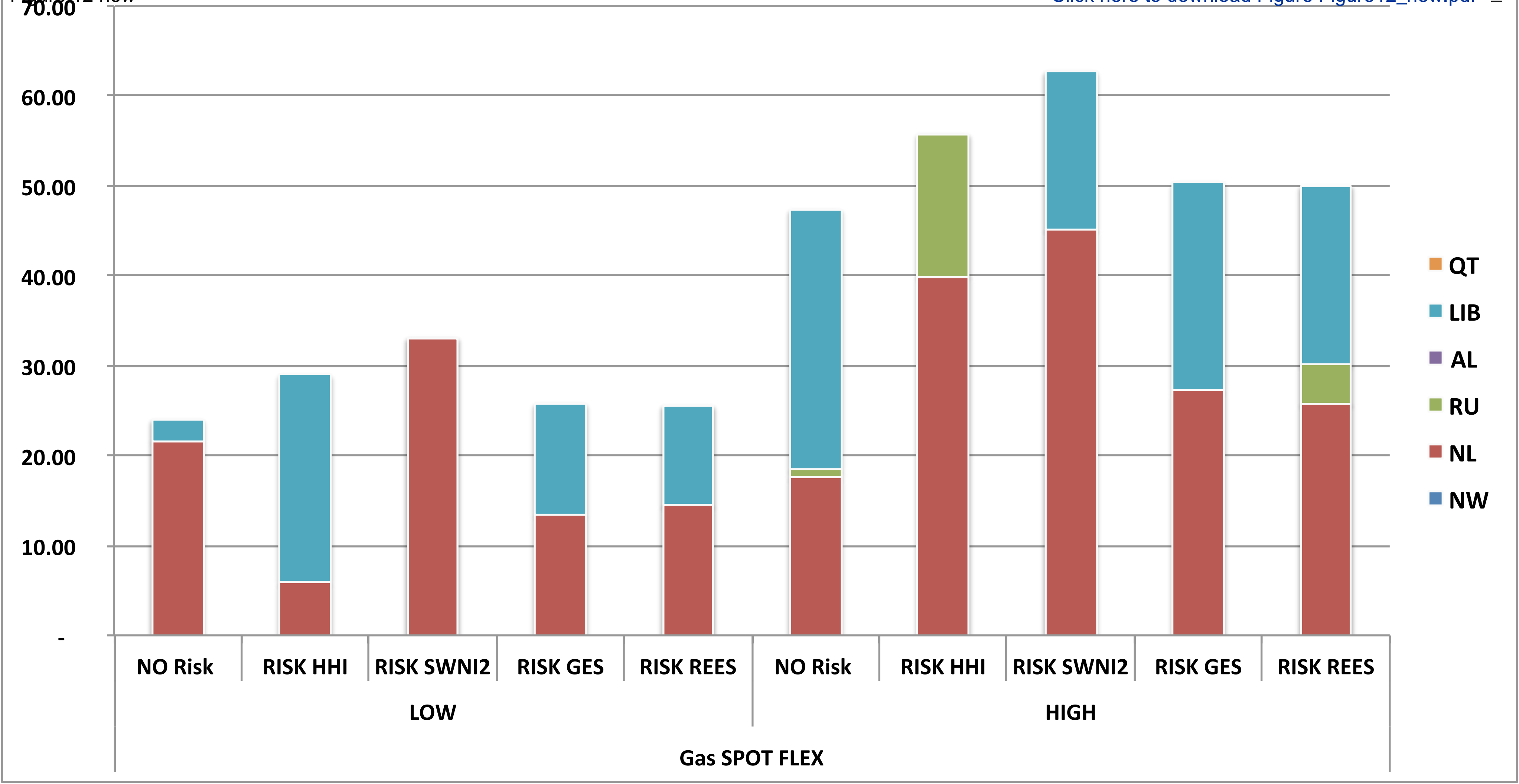
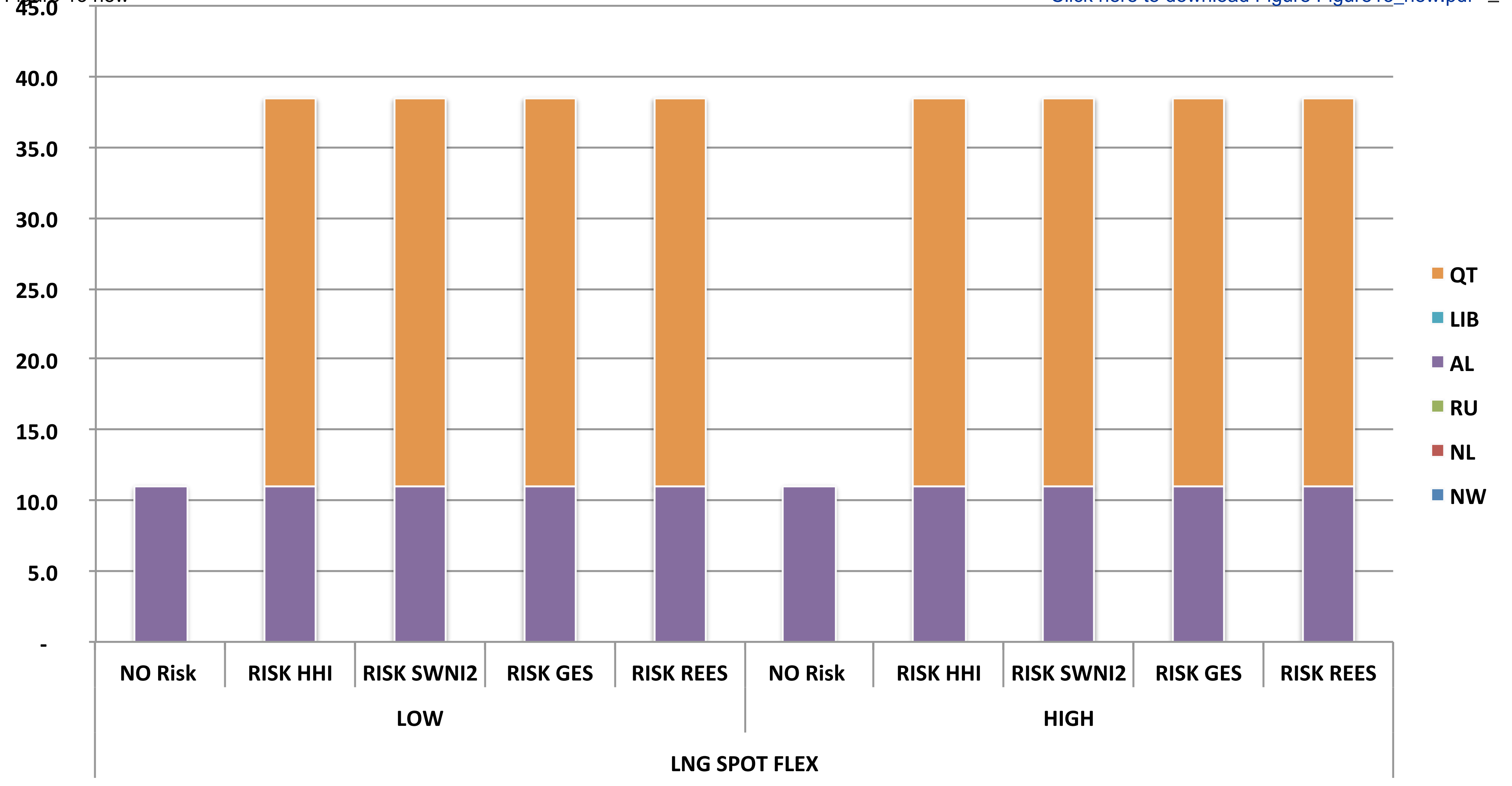


Figure 12 new

Click here to download Figure Figure12_new.pdf




45.0
40.0
35.0
30.0
25.0
20.0
15.0
10.0
5.0
-
NO Risk
RISK HHI
RISK SWNI2
RISK GES
RISK REES
NO Risk
RISK HHI
RISK SWNI2
RISK GES
RISK REES
LOW
HIGH
LNG SPOT FLEX
QT
LIB
AL
RU
NL
NW

Evaluating the impacts of the external supply risk in a natural gas supply chain: the case of the Italian market

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We thank **Reviewer #1** for the careful review and insightful comments. As required, we have modified our paper accordingly to this reviewer's comments. In the new version of the paper, we have highlighted in blue the additional or the changed parts. In the following, we provide answers and explanations to Reviewer #1's comments. Reviewer's requests are here reported in **bold**. Our answers are denoted as [**Authors**].

1 Revision (Reviewer #1)

I recommend the paper for publication in JOGO.

2 Authors' answers to minor comments

1) **The authors revised the paper according to reviewers' suggestions and comments. The authors are kindly required to provide an abstract of 150 to 250 words and check the text to avoid misprints.**

[**Authors**]. As required, we re-wrote the abstract by reducing its length from 292 to 247 words and we carefully checked the text to avoid misprints.