G1UNIVERSIDAD PONTIFICIA COMILLAS DE MADRID
ESCUELA TÉCNICA SUPERIOR DE INGENIERÍA (ICAI)
(Instituto de Investigación Tecnológica)

ANALYSIS OF THE OPERATION AND CONTRACT MANAGEMENT IN DOWNSTREAM NATURAL GAS MARKETS

Tesis para la obtención del grado de Doctor

Directores: Prof. Dr. Javier Reneses Guillén
Prof. Dr. Julián Barquín Gil

Autor: Ing. Pablo Dueñas Martínez

Madrid 2013

Acknowledgments

When I finished my Master thesis, I was not sure whether to take the challenge of doing a PhD. Although I love challenges, I hate working on the same subject for long. Three topics were on the table: continuing with the Master thesis, continuing working on the electric power sector, or starting a new voyage into the gas sector. The outcome is well known. I would therefore like to start by expressing my gratitude to both Javi and Julián because, without them, I would have not even taken the risk. From the beginning to the end, Javi has always known perfectly how to keep up my motivation and helped me out with excellent, realistic, and sensible solutions. Even though Julián moved to the industry side a few months ago, he did not quit research, but continued, as close as ever, providing splendid and inspiring ideas, which are spread all over this thesis. They were a great team from whom I have learnt so much; so, thank you again for allowing me to be part of this voyage.

This thesis has not only been developed in Spain, but also has a touch of MIT, where I spent three fantastic months. First of all, I am grateful to Melanie Kenderdine for being a wonderful host during that time and inviting me later to the MITEI Symposium, where I had the opportunity of presenting part of this work. I also appreciate the opportunity of working with Joe Hezir. Moreover, I especially would like to thank Ignacio for introducing me to the MIT community, and to Maite and Noel for their kindness and hospitality in the *tough* moments. Special thanks as well to Mort and his group of students, to the Electricity Student Research Group, to my MITEI colleagues, and to the professors I had the opportunity to talk to for their valuable comments. I would like to mention all of you, but it would require an additional chapter. In the future, I hope to be able to give back a little of what you gave me in Boston.

Back to Madrid, I would like to express my gratitude to the members of the IIT committee, Ignacio, Andrés and Javi GG, for their constructive comments, which have improved this document a lot. Besides, thank you to all my IIT colleagues during these years for your support in every moment. Again, I would need another chapter to mention all of you. Only the breakfast group would require one. Anyway, special thanks to all the members of VALORE and OMEGA, on both the IIT side and the Endesa side, with whom I have closely worked and without whom this thesis would lose its significance. In addition, I would like to show my indebtedness to Adelaida, for every coffee break in the basement; Álvaro, my travelling companion; María, because this thesis would have not been finished without you; and Sonja for whom no thank you can ever be enough.

Finally, many people have boarded and got off during this voyage that has lasted four years. I am sure that somehow a piece of each one has remained in this thesis. Moreover, I would like to thank every one of my friends, those who have not been already mentioned above, for being by my side all this time despite my absence. You can now check what I have been plotting during these last years (ñiiiiii). I would like to conclude by expressing my gratitude to my parents and my sister, who put up with me and my slides.

This thesis is also yours.

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e	Shippers, also known as marketers
f	Supply contracts
i	International markets, either seller or buyer
a	Market areas
b	LNG carriers
z	Balancing zones
r	Regasification terminals
w	Berths of regasification terminals
s	Underground storages
x	Cross-border pipelines
y	Years
m	Months
d	Days

Parameters

Q_b^{MET}	Capacity of LNG carrier b [GWh]
$\tilde{U}_b$	Flexibility in cargo of LNG carrier b [%]
Q_{rw}^{ULD}	Capacity of berth w of regasification terminal r [GWh]
T_b^{MET}	Mooring time of LNG carrier b [days]
Q_r^{REG}	Daily regasification capacity of regasification terminal r [GWh/day]
Q_r^{TNK}	Daily LNG road tankers loading capacity of regasification terminal r [GWh/day]
Q_r^{LNG}	LNG storage capacity of regasification terminal r [GWh]
Q_{xz}^{IMP}	Daily importing capacity by cross-border pipeline x to balancing zone z [GWh/day]
Q_{xz}^{EXP}	Daily exporting capacity by cross-border pipeline x to balancing zone z [GWh/day]
Q_s^{STO}	Storage capacity of underground storage s [GWh]
Q_s^{INJ}	Daily injection capacity of underground storage s [GWh/day]
E_s^{INJ}	Injection capacity decline of underground storage s [GWh/p.u.]
Q_s^{WTH}	Daily withdrawal capacity of underground storage s [GWh/day]
E_s^{WTH}	Withdrawal capacity decline of underground storage s [GWh/p.u.]
d_s^{INJ}	Injection days at underground storage s {0, 1}

d_s^{WTH} Withdrawal days at underground storage *s* {0, 1}

$Q_{zz'}^{ZON}$ Daily connection capacity between balancing zone *z* and balancing zone *z'* [GWh/day]

Q_z^{PCK} Daily line-pack capacity of balancing zone *z* [GWh]

C_r^{MET} Slot assignment tariff for unloading a LNG carrier at regasification terminal *r* [€/carrier]

$\hat{C}_r^{MET}$ Slot assignment tariff for loading a LNG carrier at regasification terminal *r* [€/carrier]

C_r^{ULD} Tariff for unloading LNG at regasification terminal *r* [€/GWh]

C_r^{RLD} Tariff for loading LNG at regasification terminal *r* [€/GWh]

CF_r^{REG} Fixed tariff for contracting regasification capacity in the long term at regasification terminal *r* [€/GWh]

CF_{rm}^{REG} Fixed tariff for contracting regasification capacity in the medium term at regasification terminal *r* the month *m* [€/GWh]

CF_{rd}^{REG} Fixed tariff for contracting regasification capacity in the short term at regasification terminal *r* the day *d* [€/GWh]

CX_r^{REG} Penalization for overrunning the contracted regasification capacity in at regasification terminal *r* the day *d* [€/GWh]

CV_r^{REG} Variable tariff for regasifying at regasification terminal *r* [€/GWh]

CV_r^{TNK} Variable tariff for loading LNG road tankers at regasification terminal *r* [€/GWh]

C_r^{LNG} Tariff for storing LNG at the end of the day at regasification terminal *r* [€/GWh]

CF_{xz}^{IMP} Fixed tariff for contracting import capacity in the long term at cross-border pipeline *x* to balancing zone *z* [€/GWh]

CF_{xzm}^{IMP} Fixed tariff for contracting import capacity in the medium term at cross-border pipeline *x* to balancing zone *z* the month *m* [€/GWh]

CF_{xzd}^{IMP} Fixed tariff for contracting import capacity in the short term at cross-border pipeline *x* to balancing zone *z* the day *d* [€/GWh]

CX_{xz}^{IMP} Penalization for overrunning the contracted import capacity in at cross-border pipeline *x* to balancing zone *z* the day *d* [€/GWh]

CV_{xz}^{IMP} Variable tariff for importing gas by cross-border pipeline *x* to balancing zone *z* [€/GWh]

CF_{xz}^{EXP} Fixed tariff for contracting export capacity in the long term at cross-border pipeline *x* to balancing zone *z* [€/GWh]

CF_{xzm}^{EXP} Fixed tariff for contracting export capacity in the medium term at cross-border pipeline *x* to balancing zone *z* the month *m* [€/GWh]

CF_{xzd}^{EXP} Fixed tariff for contracting export capacity in the short term at cross-border pipeline *x* to balancing zone *z* the day *d* [€/GWh]

CX_{xz}^{EXP} Penalization for overrunning the contracted export capacity in at cross-border pipeline *x* to balancing zone *z* the day *d* [€/GWh]

CV_{xz}^{EXP} Variable tariff for exporting gas by cross-border pipeline *x* to balancing zone *z* [€/GWh]

CF_s^{STO} Fixed tariff for contracting storage capacity in the long term at underground storage *s* [€/GWh]

CF_{sm}^{STO} Fixed tariff for contracting storage capacity in the medium term at underground storage *s* the month *m* [€/GWh]

CF_{sd}^{STO} Fixed tariff for contracting storage capacity in the short term at underground storage *s* the day *d* [€/GWh]

CX_s^{STO}	Penalization for overrunning the contracted storage capacity in at underground storage *s* the day *d* [€/GWh]
CV_s^{STO}	Variable tariff for storing gas at the end of the day at underground storage *s* [€/GWh]
C_s^{INJ}	Tariff for inject gas to underground storage *s* [€/GWh]
C_s^{WTH}	Tariff for withdrawing gas from underground storage *s* [€/GWh]
CF_z^{IN}	Fixed tariff for contracting entry capacity in the long term at balancing zone *z* [€/GWh]
CF_{zm}^{IN}	Fixed tariff for contracting entry capacity in the medium term at balancing zone *z* the month *m* [€/GWh]
CF_{zd}^{IN}	Fixed tariff for contracting entry capacity in the short term at balancing zone *z* the day *d* [€/GWh]
CX_z^{IN}	Penalization for overrunning the contracted entry capacity in at balancing zone *z* the day *d* [€/GWh]
CV_z^{IN}	Variable entry tariff to balancing zone *z* [€/GWh]
CF_z^{OUT}	Fixed tariff for contracting exit capacity in the long term at balancing zone *z* [€/GWh]
CF_{zm}^{OUT}	Fixed tariff for contracting exit capacity in the medium term at balancing zone *z* the month *m* [€/GWh]
CF_{zd}^{OUT}	Fixed tariff for contracting exit capacity in the short term at balancing zone *z* the day *d* [€/GWh]
CX_z^{OUT}	Penalization for overrunning the contracted exit capacity in at balancing zone *z* the day *d* [€/GWh]
CV_z^{OUT}	Variable exit tariff from balancing zone *z* [€/GWh]
K	Maximum long-term commitment threshold [%]
$\bar{V}_{fey}$	Maximum volume of supply contract *f* delivered to shipper *e* during year *y* [GWh]
$\underline{V}_{fey}$	Minimum volume, i.e., take-or-pay clause of supply contract *f* delivered to shipper *e* during year *y* [GWh]
$\bar{V}_{fem}$	Maximum volume of supply contract *f* delivered to shipper *e* during month *m* [GWh]
$\underline{V}_{fem}$	Minimum volume, i.e., take-or-pay clause of supply contract *f* delivered to shipper *e* during month *m* [GWh]
$\bar{V}_{fey}^{DIV}$	Maximum diverted volume of supply contract *f* delivered to shipper *e* during year *y* [GWh]
$\bar{V}_{fem}^{DIV}$	Maximum diverted volume of supply contract *f* delivered to shipper *e* during month *m* [GWh]
C_{fem}	Cost of supply contract *f* delivered to shipper *e* during month *m* [€/GWh]
ε_{fe}	Profit-sharing coefficient when diverting a volume of supply contract *f* delivered to shipper *e* [%]
P_{im}^{BID}	Selling price at international market *i* during month *m* [€/GWh]
P_{im}^{ASK}	Buying price at international market *i* during month *m* [€/GWh]
$\bar{Q}_{im}$	Maximum spot purchases at international market *i* during month *m* [GWh]
K_b^{MET}	World fleet share of LNG carrier *b* [%]

Variables

u_{birwed}^{MET}	Arrival of LNG carrier *b* for unloading pertaining to shipper *e* from international market *i* at berth *w* of regasification terminal *r* the day *d* {0, 1}
$\hat{u}_{birwed}^{MET}$	Arrival of LNG carrier *b* for loading pertaining to shipper *e* to international market *i* at berth *w* of regasification terminal *r* the day *d* {0, 1}
u_{birwed}^{ULD}	Percentage of unloaded LNG from carrier *b* pertaining to shipper *e* from international market *i* at berth *w* of regasification terminal *r* the day *d* [0, 1]
$\tilde{u}_{birwed}^{ULD}$	Flexibility of unloaded LNG from carrier *b* pertaining to shipper *e* from international market *i* at berth *w* of regasification terminal *r* the day *d* [0, 1]
q_{irwed}^{ULD}	Unloaded LNG by shipper *e* from international market *i* at berth *w* of regasification terminal *r* the day *d* [GWh]
q_{irwed}^{RLD}	Loaded LNG by shipper *e* to international market *i* at berth *w* of regasification terminal *r* the day *d* [GWh]
h_{re}^{REG}	Long-term regasification capacity contracted by shipper *e* at regasification terminal *r* [GWh]
h_{rem}^{REG}	Medium-term regasification capacity contracted by shipper *e* at regasification terminal *r* the month *m* [GWh]
h_{red}^{REG}	Short-term regasification capacity contracted by shipper *e* at regasification terminal *r* the day *d* [GWh]
$h_{red}^{\Delta REG}$	Regasification capacity contract acquisition by shipper *e* at regasification terminal *r* the day *d* [GWh]
$h_{red}^{\nabla REG}$	Regasification capacity contract release by shipper *e* at regasification terminal *r* the day *d* [GWh]
th_{red}^{REG}	Regasification capacity contract portfolio of shipper *e* at regasification terminal *r* the day *d* [GWh]
xh_{red}^{REG}	Regasification capacity overrun by shipper *e* at regasification terminal *r* the day *d* [GWh]
q_{red}^{REG}	Regasified volume at regasification terminal *r* by shipper *e* the day *d* [GWh]
q_{red}^{TNK}	Loaded volume into LNG road tankers at regasification terminal *r* by shipper *e* the day *d* [GWh]
q_{red}^{LNG}	Stored LNG at regasification terminal *r* by shipper *e* at the end of the day *d* [GWh]
$q_{red}^{\Delta LNG}$	LNG acquisition in physical swaps at regasification terminal *r* by shipper *e* the day *d* [GWh]
$q_{red}^{\nabla LNG}$	LNG release in physical swaps at regasification terminal *r* by shipper *e* the day *d* [GWh]
h_{xze}^{IMP}	Long-term import capacity contracted by shipper *e* at cross-border pipeline *x* to balancing zone *z* [GWh]
h_{xzem}^{IMP}	Medium-term import capacity contracted by shipper *e* at cross-border pipeline *x* to balancing zone *z* the month *m* [GWh]
h_{xzed}^{IMP}	Short-term import capacity contracted by shipper *e* at cross-border pipeline *x* to balancing zone *z* the day *d* [GWh]
$h_{xzed}^{\Delta IMP}$	Import capacity contract acquisition by shipper *e* at cross-border pipeline *x* to balancing zone *z* the day *d* [GWh]
$h_{xzed}^{\nabla IMP}$	Import capacity contract release by shipper *e* at cross-border pipeline *x* to balancing zone *z* the day *d* [GWh]
th_{xzed}^{IMP}	Import capacity contract portfolio of shipper *e* at cross-border pipeline *x* to balancing zone *z* the day *d* [GWh]

xh_{xzed}^{IMP}	Import capacity overrun by shipper *e* at cross-border pipeline *x* to balancing zone *z* the day *d* [GWh]
q_{xzed}^{IMP}	Imported volume by cross-border pipeline *x* to balancing zone *z* by shipper *e* the day *d* [GWh]
h_{xze}^{EXP}	Long-term export capacity contracted by shipper *e* at cross-border pipeline *x* to balancing zone *z* [GWh]
h_{xzem}^{EXP}	Medium-term export capacity contracted by shipper *e* at cross-border pipeline *x* to balancing zone *z* the month *m* [GWh]
h_{xzed}^{EXP}	Short-term export capacity contracted by shipper *e* at cross-border pipeline *x* to balancing zone *z* the day *d* [GWh]
$h_{xzed}^{\Delta EXP}$	Export capacity contract acquisition by shipper *e* at cross-border pipeline *x* to balancing zone *z* the day *d* [GWh]
$h_{xzed}^{\nabla EXP}$	Export capacity contract release by shipper *e* at cross-border pipeline *x* to balancing zone *z* the day *d* [GWh]
th_{xzed}^{EXP}	Export capacity contract portfolio of shipper *e* at cross-border pipeline *x* to balancing zone *z* the day *d* [GWh]
xh_{xzed}^{EXP}	Export capacity overrun by shipper *e* at cross-border pipeline *x* to balancing zone *z* the day *d* [GWh]
q_{xzed}^{EXP}	Exported volume by cross-border pipeline *x* to balancing zone *z* by shipper *e* the day *d* [GWh]
f_{xzd}^{CBP}	Net flow by cross-border pipeline *x* to balancing zone *z* the day *d* [GWh]
h_{se}^{STO}	Long-term storage capacity contracted by shipper *e* at underground storage *s* [GWh]
h_{sem}^{STO}	Medium-term storage capacity contracted by shipper *e* at underground storage *s* the month *m* [GWh]
h_{sed}^{STO}	Short-term storage capacity contracted by shipper *e* at underground storage *s* the day *d* [GWh]
$h_{sed}^{\Delta STO}$	Storage capacity contract acquisition by shipper *e* at underground storage *s* the day *d* [GWh]
$h_{sed}^{\nabla STO}$	Storage capacity contract release by shipper *e* at underground storage *s* the day *d* [GWh]
th_{sed}^{STO}	Storage capacity contract portfolio of shipper *e* at underground storage *s* the day *d* [GWh]
xh_{sed}^{STO}	Storage capacity overrun by shipper *e* at underground storage *s* the day *d* [GWh]
q_{sed}^{STO}	Stored gas volume at underground storage *s* by shipper *e* at the end of the day *d* [GWh]
$q_{sed}^{\Delta STO}$	Gas acquisition in physical swaps at underground storage *s* by shipper *e* the day *d* [GWh]
$q_{sed}^{\nabla STO}$	Gas release in physical swaps at underground storage *s* by shipper *e* the day *d* [GWh]
q_{sed}^{INJ}	Injected gas volume at underground storage *s* by shipper *e* the day *d* [GWh]
q_{sed}^{WTH}	Withdrawn gas volume at underground storage *s* by shipper *e* the day *d* [GWh]
f_{sd}^{STO}	Net flow at underground storage *s* the day *d* [GWh]
q_{zed}^{PCK}	Used line-pack capacity at balancing zone *z* by shipper *e* the day *d* [GWh]
$q_{zed}^{\Delta PCK}$	Gas acquisition in physical swaps at balancing zone *z* by shipper *e* the day *d* [GWh]
$q_{zed}^{\nabla PCK}$	Gas release in physical swaps at balancing zone *z* by shipper *e* the day *d* [GWh]

d_{zed}^{TOT}	Total demand in balancing zone *z* of shipper *e* the day *d* [GWh]
d_{zed}^{TNK}	LNG road tankers demand in balancing zone *z* of shipper *e* the day *d* [GWh]
$f_{zz'ed}^{ZON}$	Gas flow from balancing zone *z* to balancing zone *z'* of shipper *e* the day *d* [GWh]
$f_{zz'd}^{ZON}$	Net gas flow balancing zone *z* to balancing zone *z'* the day *d* [GWh]
h_{ze}^{IN}	Long-term entry capacity contracted by shipper *e* at balancing zone *z* [GWh]
h_{zem}^{IN}	Medium-term entry capacity contracted by shipper *e* at balancing zone *z* the month *m* [GWh]
h_{zed}^{IN}	Short-term entry capacity contracted by shipper *e* at balancing zone *z* the day *d* [GWh]
$h_{zed}^{\Delta IN}$	Entry capacity contract acquisition by shipper *e* at balancing zone *z* the day *d* [GWh]
$h_{zed}^{\nabla IN}$	Entry capacity contract release by shipper *e* at balancing zone *z* the day *d* [GWh]
th_{zed}^{IN}	Entry capacity contract portfolio of shipper *e* at balancing zone *z* the day *d* [GWh]
xh_{zed}^{IN}	Entry capacity overrun by shipper *e* at balancing zone *z* the day *d* [GWh]
h_{ze}^{OUT}	Long-term exit capacity contracted by shipper *e* at balancing zone *z* [GWh]
h_{zem}^{OUT}	Medium-term exit capacity contracted by shipper *e* at balancing zone *z* the month *m* [GWh]
h_{zed}^{OUT}	Short-term exit capacity contracted by shipper *e* at balancing zone *z* the day *d* [GWh]
$h_{zed}^{\Delta OUT}$	Exit capacity contract acquisition by shipper *e* at balancing zone *z* the day *d* [GWh]
$h_{zed}^{\nabla OUT}$	Exit capacity contract release by shipper *e* at balancing zone *z* the day *d* [GWh]
th_{zed}^{OUT}	Exit capacity contract portfolio of shipper *e* at balancing zone *z* the day *d* [GWh]
xh_{zed}^{OUT}	Exit capacity overrun by shipper *e* at balancing zone *z* the day *d* [GWh]
v_{irfed}^{MET}	Delivered LNG volume from international market *i* at regasification terminal *r* due to supply contract *f* of shipper *e* the day *d* [GWh]
v_{xzfed}^{IMP}	Imported volume by cross-border pipeline *x* to balancing zone *z* due to supply contract *f* of shipper *e* the day *d* [GWh]
v_{ifem}^{DIV}	Diverted volume to international market *i* due to supply contract *f* of shipper *e* during the month *m* [GWh]
$v_{ired}^{MET_{ST}}$	Spot LNG purchases from international market *i* to regasification terminal *r* by shipper *e* the day *d* [GWh]
$v_{xzed}^{IMP_{ST}}$	Imported volume by cross-border pipeline *x* to balancing zone *z* due to supply contract *f* of shipper *e* the day *d* [GWh]
$q_{zed}^{\Delta HUB}$	Gas purchases at hub of balancing zone *z* by shipper *e* the day *d* [GWh]
$q_{zed}^{\nabla HUB}$	Gas sales at hub of balancing zone *z* by shipper *e* the day *d* [GWh]

Gas-Electricity interaction model

Indices

e	Gas consumers
z	Balancing zones
j	Gas pipelines
g	Thermal power groups
m	Months
d	Days
l	States of the system
k	Wind scenarios

Parameters

α_0	Intercept of gas cost function [€/MWh-t]
α_1	Slope of gas cost function [(€/GWh-t)/GWh-t]
ω_k	Probability of wind scenario k [p.u.]
D_{zed}^{CNV}	Conventional demand at balancing zone z by consumer e the day d [GWh-t]
Q_j	Daily capacity of gas pipeline j [GWh-t/day]
T_{dlk}^{ST}	Duration of state of the system l during d for wind scenario k [hours]
$N_{mll'k}^{TRN}$	Transitions between state of the system l and state of the system l' during month m for wind scenario k
D_{mlk}^{PWR}	Power demand in state of the system l of month m for wind scenario k [MW-e]
Q_g^{MAX}	Maximum power of thermal group g [MW-e]
Q_g^{MIN}	Technical minimum of thermal group g [MW-e]
CV_g	Variable cost of thermal group g [€/MWh-e]
CF_g	Commitment cost of thermal group g [€/h]
C_g^{UP}	Start-up cost of thermal group g [€]
C_g^{DN}	Shut-down cost of thermal group g [€]
$F_g^{G\to P}$	Gas-to-power conversion factor of thermal group g [MWh-t/MW-e]

Variables

v_{zdk}	Gas purchases at virtual hub of balancing zone z the day d for wind scenario k [GWh-t]
d_{zedk}^{GFPP}	Gas-fired power plants demand located at balancing zone z belonging to gas consumer e the day d for wind scenario k [GWh-t]
h_{je}	Long-term capacity contracted by gas consumer e at pipeline j [GWh-t]
h_{jem}	Medium-term capacity contracted by gas consumer e at pipeline j the month m [GWh-t]

h_{jedk}	Short-term capacity contracted by gas consumer *e* at pipeline *j* the day *d* for wind scenario *k* [GWh-t]
Δh_{jedk}	Capacity contract acquisition by gas consumer *e* at pipeline *j* the day *d* for wind scenario *k* [GWh-t]
∇h_{jedk}	Capacity contract release by gas consumer *e* at pipeline *j* the day *d* for wind scenario *k* [GWh-t]
th_{jedk}	Capacity contract portfolio of gas consumer *e* at pipeline *j* the day *d* for wind scenario *k* [GWh-t]
q_{gmlk}	Production of thermal power group *g* in state of the system *l* of month *m* for wind scenario *k* [MW-e]
u_{gmlk}	Commitment decision of thermal group *g* in state of the system *l* at month *m* for wind scenario *k* {0, 1}
$u^{UP}_{gmll'k}$	Start-up decision of thermal group *g* from state of the system *l* to state of the system *l'* at month *m* for wind scenario *k* [0, 1]
$u^{DN}_{gmll'k}$	Shut-down decision of thermal group *g* from state of the system *l* to state of the system *l'* at month *m* for wind scenario *k* [0, 1]

Chapter 1

Analysis of Downstream Natural Gas Markets: Motivation and Objectives

1.1. Evolution of the natural gas industry

Natural gas is a mixture of gaseous hydrocarbons that can be found in underground natural rock formations, alone or together with petroleum or coal. It mainly consists of methane, 70%-90%, volatile hydrocarbons (ethane, propane, butane), up to 20%, and other components such as carbon dioxide, water, or hydrogen sulfide. Natural gas is a fossil fuel. It originates as a consequence of the accumulation of organic matter which is compressed under the earth, similar to the formation of petroleum and coal. For this reason, the three fossil fuels are often found together. However, natural gas also has a biogenic origin due to the anaerobic digestion of some microorganisms. This type of natural gas is also known as biogas or landfill gas because it is nowadays *artificially* produced from our own wastes, although the utilization of natural gas from rock formations still prevails.

The beginning of the gas industry is not linked to natural gas, but to manufactured coal gas as it was initially obtained from coal distillation. Coal gas composition differs from natural gas as it contains mainly hydrogen, (less) methane, and carbon monoxide, which results in a lower calorific value. Furthermore, coal gas can only be used for illumination or heating purposes due to its impurities; so it was gradually substituted by natural gas when the recovery and long-distance transportation technologies became economically competitive. In fact, before the mid of the 20th century, natural gas was released into the atmosphere or burnt off at oil fields because of its high exploitation costs.

The gradual substitution was possible as consumers were already connected to gas factories by gas pipelines when gas fields started to be exploited; that is, the product was not new and the infrastructure already existed. As a matter of fact, the regulatory framework did not change much. If a gas company used to be a vertically integrated monopoly, which owned a gas factory and a gas pipeline network to supply its consumers, after the advent of natural gas, the gas company maintained as a vertically integrated monopoly which did not produce gas, but was supplied by a gas producer which did not actually manufacture gas, but extract it from gas fields. This relationship between gas companies and gas producers was based on long-term agreements that remain nowadays.

As time passed by, first local, then national (or regional) gas markets enlarged and were recently opened to competition in different parts of the world such as in North America, Europe, Japan, Australia, or New Zealand. Market efficiency (lower prices, greater quality, etc.) has traditionally been expected to be gained as long as the competitive pressure increased in liberalized markets. But first, the market liberalization demanded the unbundling of the former vertically integrated monopoly into four main business activities: procurement, transmission, distribution and retail. Similar to the electricity system, procurement and retail activities can be subject to competition, whereas transmission and distribution activities may not. Distribution is a natural monopoly because it is economically inefficient to build several gas networks in parallel. In contrast, transmission facilities may compete under certain circumstances, but must be regulated in order to guarantee third party access (TPA). Two main TPA approaches have been implemented:

- Point-to-point access (e.g., in North America). Gas companies, which are commonly known as marketers, must contract for pipeline capacity from the supply point to the delivery point in each of the pipelines in which the gas flows. When pipeline capacity is not available, the marketers can come to an agreement and directly invest in new pipeline capacity in order to loop, or bypass, the congested pipeline. The pipeline operator is obliged to provide tap access, i.e., two connection points at each end of such pipeline.
- Entry-exit access (e.g., in Europe). Gas companies, which are commonly known as shippers, must contract for entry and exit capacity at the supply point and the delivery point disregarding the gas route. In short, the gas pipeline network is embedded in a so-called balancing zone, which is (or should be) defined according to network congestions. Price differences between two neighboring balancing zones provide location signals that should solve the congestion if investments in pipeline capacity do not take place.

This thesis is mainly focused on the entry-exit access systems that are being implemented in the EU in line with its Third Energy Package to constitute an internal gas and electricity market. Concerning the gas market, this legislative package defends the unbundling of business activities, the implementation of entry-exit access systems and the constitution of national or supra-national virtual hubs in order to enlarge the market, reduce the barriers to entry and encourage the degree of competition. Nevertheless, the conclusions and contributions of this thesis, with slight variations, are equally valid for point-to-point access systems.

Natural gas is advertised as a *clean* fossil fuel to cope with the climate change. This is one of the main reasons for the growing interest of the EU, and other countries (e.g., the U.S.), to gasify their economies. Besides, the development of shale gas extraction has reduced gas prices, which have also promoted this process. Gasifying the economies is possible, at least in the medium term, because natural gas has shown its potential as a reliable source of energy able to substitute other fossil fuels. Natural gas has traditionally been used for heating purposes; but, for example, new large-scale uses are being considered for road, air and sea transportation, which used to be an inaccessible territory for other fuels different from oil. Moreover, in the electric power sector, natural gas is becoming essential to support the integration of renewable, but intermittent, energy sources. However, although natural gas emits less carbon dioxide than coal or oil, it still does emit. As meeting the 2ºC target demands a zero carbon economy beyond 2050, as indicated by the International Panel on Climate Change, natural gas appears more as a bridge towards decarbonization than as a long-term solution.

Therefore, natural gas will play an increasingly important role in the future energy mix. At the present time, in the context of global relations and liberalized energy markets, well-working downstream natural gas markets are essential in order to allocate the resources adequately and to provide the proper economic signals to suppliers, investors, consumers, etc. This relevance increases even more when a consumption country lacks domestic production, as it occurs in most of the EU member states. Market inefficiencies lead to incoherent or incorrect market decisions that raise gas prices and may impoverish the country; hence, reducing the net social welfare.

In the next section, we describe both the natural gas chain and the business relations, which are studied in this thesis.

1.2. From wellhead to burner tip

The natural gas industry is habitually divided into three main segments: upstream, midstream, and downstream. The upstream segment is similar to the oil industry; in contrast, the midstream segment is not so important because the intermediate treatments of raw natural gas, such as sulfur removal or odorization, are insignificant in comparison to oil refinery. Finally, the downstream segment is comparable to the electric power system. Let us hereinafter incorporate the midstream segment into the upstream or the downstream segment and, hence, distinguish between upstream and downstream activities. The frontier between both segments is habitually established at the border of the consumption country (or region when a country both produces and consumes gas). In what follows, we describe the links in each segment of the natural gas chain, and introduce the main stakeholders and the business relations among them.

1.2.1. Upstream segment

The natural gas chain starts with the exploration and production activity. Gas reserves, that is, the amount that can be economically recoverable, are estimated during the prospecting stage, which is really capital intensive. However, as reserves depend not only on the technology, but also on the market price, gas reserves may vary. According to the BP Statistical Review of World Energy (BP 2013), the reserves-to-production ratio is 55.7

years; that is, the proved reserves (probability of recovery above 90%) can cover the current production during 55.7 years. Even though the classification may change from year to year, in 2012 Iran (18% of global proved reserves), Russia (17.6%), and Qatar (13.4%) were the top three countries in the classification of proved reserves.

On the other hand, production depends on whether the natural gas is found associated with oil, or alone. When natural gas is associated, it is first extracted to recover the petroleum. Nevertheless, when transporting gas by pipeline is expensive (e.g., because consumers are far away), it is burnt off or reinjected in order to maintain the internal pressure and, hence, improve the oil recovery. Furthermore, the reinjected gas can be recovered in the future. When natural gas is not associated, its extraction depends only on profitability considerations. The top three production countries in 2012 were the U.S. (20.4% of world production), Russia (17.6%), and Qatar (4.7%).

One major concern is that production areas are usually distant from consumption areas. For example, Europe imports gas from Siberia, the Persian Gulf or the North Sea. Moreover, natural gas transport is costly in comparison to oil transport. There are two ways to transport gas; by pipeline or by LNG carrier. Gas moves along pipelines, which can be hundreds of kilometers long (such as the Nord Stream that is 1,224 kilometers long and connects Siberia to Germany), due to the pressure differences at both ends. Compressor stations are normally installed at regular intervals to raise the pressure which is typically above 80 bar. In contrast, LNG carriers carry liquefied natural gas to overseas consumers. The process of transporting LNG comprises three stages: 1) LNG is obtained in a liquefaction facility which lowers the natural gas temperature to -160ºC and, therefore, reduces its volume and increases its energy density; 2) LNG is loaded into a LNG carrier that ships it to its destination; and 3) LNG is unloaded in a regasification terminal.

Depending on the distance, pipelines or LNG carriers are more cost-effective. Normally, the economics dictate that up to a few thousands of kilometers, gas pipeline transport is more cost-effective than LNG carriers. Either by gas pipeline or by LNG carrier, the natural gas enters the downstream segment.

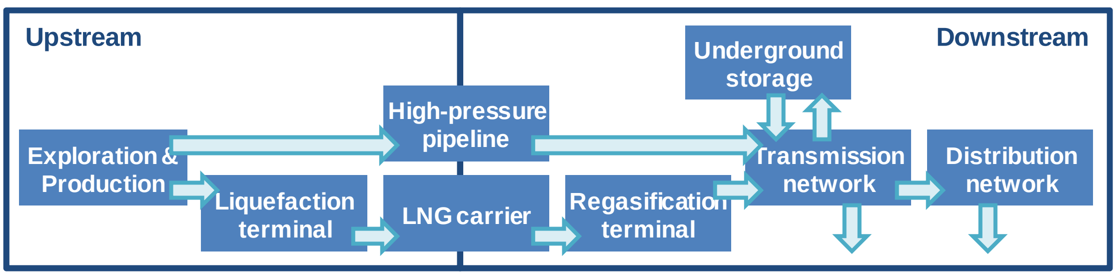

Figure 1-1 – Natural gas chain within upstream and downstream segments

1.2.2. Downstream segment

From the upstream segment description, we know that there are two entrances to downstream gas systems: gas pipelines from wellheads and LNG carriers. The gas pipelines connect directly to the downstream transmission pipeline network which is composed of high- (20 to 80 bar) to medium-pressure (4 to 20 bar) pipelines which carry gas along the country. The transmission network connects to the distribution network which carries gas to end consumers. Unlike transmission networks, distribution networks are composed of medium- (4 to 20 bar) to low-pressure (0.005 to 4 bar) pipelines to which gas consumers, such as industries and households, are connected. However, some large consumers (e.g., electric power plants) may be connected directly to transmission networks.

On the other hand, LNG carriers moor and unload their cargo which is stored in the LNG tanks of regasification terminals. These terminals vaporize the LNG and introduce it into the transmission network. Alternatively, the LNG can be loaded into LNG road tankers which carry it to the consumption point. Furthermore, the LNG can also be reloaded into another carrier and ship to other destination enabling the possibility of price arbitrage between non-directly connected (by pipeline) consumption countries.

Furthermore, we have previously remarked that electric power systems and downstream gas systems are similar. However, there is still a big difference between gas and electricity: the former energy vector can be stored at competitive costs, whereas the latter energy vector cannot. There are three cost-effective facilities which allow the storage of gas:

- Pipeline storage capacity, which is a consequence of maintaining a working pressure, is known as line-pack. Although the line-pack is a small quantity, it serves to respond to daily demand variations.
- We have already said that LNG can be stored in the LNG tanks of regasification terminals. The LNG tanks are useful for responding to weekly/monthly demand variations as their volume is larger than the line-pack capacity.
- Underground storages allow storing large amounts of natural gas. Depleted natural gas or oil fields, salt caverns, aquifers and mines can be used as underground storages. Commonly, they serve seasonal purposes as their equipment is commonly adapted to injection-withdrawal cycles: an injection period during warm months, a withdrawal period during cold months. Furthermore, strategic reserves are habitually maintained in underground storages.

Thanks to the possibility of storing natural gas, the dynamics in downstream gas systems are slower than in electric power systems. Gas allows for daily balances, while electricity requires instantaneous balances.

1.2.3. Business relations

Habitually, one type of company is specialized in each business activity. Gas producers, which typically have interests in the oil industry, can be either public, i.e., state-owned, or private companies. Nonetheless, when a private company is interested in exploiting the gas resources of a foreign country, it must usually come to an agreement with the local public authorities and, therefore, share the production profits via local taxes or royalties, or by constituting a semi-public company. State-owned, semi-public or private, this company is habitually in charge of the whole natural gas chain within the upstream segment, which includes the operation of the liquefaction terminal and a participation in the high-pressure pipeline project (sometimes[1]). On the other hand, LNG carrier services can be provided by the same gas producer, if it owns its own fleet of carriers, or by any transportation company.

Within the downstream segment and liberalized markets framework, we can distinguish three main types of companies. First of all, gas facility operators usually own, maintain, and operate regasification terminals, underground storages or pipelines; therefore, they are responsible for guaranteeing proper physical gas flows. Depending on the regulatory framework, an independent system operator in charge of coordinating the operation (e.g., daily balances or quality standards) is established. In the second place, local distribution companies maintain and operate the distribution network and purchase gas on behalf of the consumers. When retail competition is introduced, retailers take charge of the economic gas flow, i.e., of purchasing and selling gas to consumers. And, last but not least, marketers or shippers link the previously enumerated companies: producers, facility operators, and retailers or local distribution companies.

Let us now distinguish between the physics and the economics of gas flows. Physically speaking, gas moves from wellheads to consumers through different links. The coordination among the links can be centralized, by establishing an independent system operator, or decentralized, by allowing upward or downward communication between the two corresponding interconnected links (for example, a local distribution company specifies how much gas is needed at a certain delivery point to a transmission network operator). Economically speaking, gas moves because a consumer pays to a retailer which may (or may not) pay directly to a producer and to the corresponding facility operators. However, within liberalized markets, retailers commonly concentrate on their business activity, i.e., gas sale, and pays to a shipper (hereinafter, we only utilize this term) for the provided

[1] Holding a share of a high-pressure pipeline habitually implies holding a long-term supply contract. Consequently, the gas producer will be a shareholder only when it is interested in participating in the downstream gas system.

gas. As expected, the shipper has previously dealt with a producer and contracted for capacity at gas facilities.

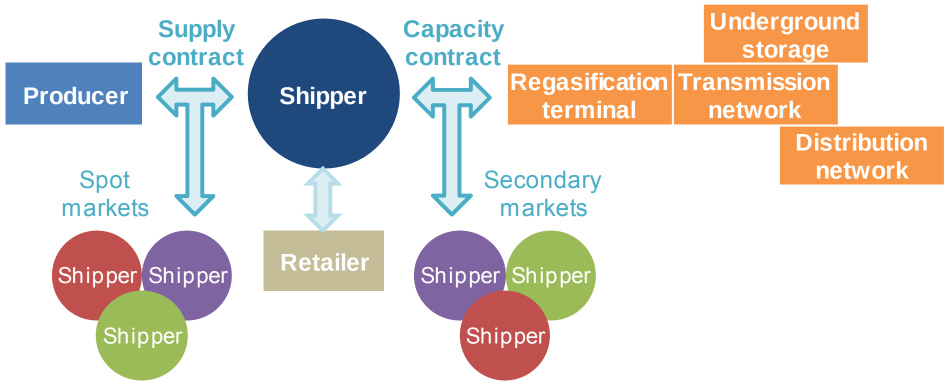

Figure 1-2 – Business relations in downstream gas systems

Shippers are, therefore, involved in every business relation in downstream gas systems (Figure 1-2):

- Shippers usually agree long-term supply contracts with producers. Their characteristics (quantities, prices, delivery points, etc.) condition the market results and in practice determine most of the final gas price; hence, the importance of analyzing their influence. Moreover, shippers interact among themselves in spot markets or balancing markets in entry-exit access systems. These transactions also deserve attention as they are the breeding ground to exercise market power.
- Shippers must contract for capacity in every facility by which their gas flows; except in entry-exit systems, in which shippers must only contract for entry and exit capacity. Capacity contracts range from several years to one day. Furthermore, in order to release unused capacity, secondary capacity markets, in which shippers also interact, are established. Both the capacity contract portfolios and the willingness to participate in these secondary markets have influence on market results and, therefore, are worth examining.

Shippers and retailers are also involved in business relations, but as a detailed description of the retail activity is out of the scope of this thesis, they are not considered explicitly. Nevertheless, shippers take on the role of retailers during this thesis as it actually occurs in several downstream gas systems.

1.3. Literature survey on gas market models

Although each chapter includes a specific review of the state of the art, we would like to highlight here the strengths of this thesis with respect to the existing literature. The core of this thesis is a new gas market model that has allowed us to conduct a thorough analysis of downstream gas systems. When we started with this work, about four years ago, one of the first papers we read was (Smeers 2008), which carefully examines the possibilities of existing (at that time) models as tools to support the EU decision-making process to constitute the internal gas market and fulfill its main three objectives: competition, security of supply and sustainability. We do not intend to repeat such complete work because, among other things, since then not-so-many models have been developed to our knowledge. Nevertheless, (Smeers 2008) was an inspiring paper which identifies several shortcomings. In a similar way, we have elaborated our own list of shortcomings, but not limiting ourselves to the objectives of the EU:

- A detailed representation of infrastructure operation, which was already identified by (Smeers 2008), but also incorporating both capacity contracting decisions and secondary capacity markets.
- The influence of long-term supply contracts on gas prices, which was also identified by (Smeers 2008). Moreover, long-term supply contracts may also affect operation and capacity contracting decisions.
- LNG carrier movements have gained relevance during the last years and, thereby, encouraging the gas market globalization, which also influences downstream gas systems.
- In the European framework, models cannot adequately capture market rigidities, in particular, the lack of liquidity. In general, establishing an organized market does not automatically guarantee a well-functioning market.

Another shortcoming that was previously identified by (Smeers 2008) is the consideration of anticompetitive behavior, which may occur in downstream gas systems, mainly: exercise of market power and market foreclosure. Market power has been traditionally represented through Cournot competition (Gabriel et al. 2005). However, the Cournot solution usually overestimates the market price. In order to overcome this drawback, conjectural variations, e.g. (Boots et al. 2004) or (Zwart et al. 2006), that allow calibrating the market power (i.e., the resulting market price) have been introduced. On the other hand, market foreclosure, in which a company restricts access to a good or service (e.g., entry capacity), was exclusively addressed a few years ago in order to examine the consequences of the (subsequently unsuccessful) acquisition of the main Spanish electricity company by the main Spanish gas company in (Vazquez and Barquín 2007); hence, further future research in this topic is required.

We have evaluated the five models which, in accordance with (Smeers 2008) and to our criteria, represent gas markets with detail (Boot et al. 2004), (Gabriel et al. 2005), (Zwart et al. 2006), (Holz et al. 2008)[2] and (Lise et al. 2008). In addition, we have included a recent publication about the Colombian gas market (Villada et al. 2013). Table 1-1 contains the results of the evaluation, in which a white circle points out that a shortcoming is not addressed at all and a black circle indicates that a shortcoming is fully addressed.

	Infrastructure operation	Long-term contracts	LNG movements	Market rigidities	Competition
Boots et al., 2004	◔	○	○	◑	◕
Gabriel et al., 2005	◑	◑	○	◑	◑
Zwart et al., 2006	◑	◔	◔	◑	◕
Holz et al., 2008	◑	◑	◔	◑	◑
Lise et al., 2008	◑	○	◔	◔	◑
Villada et al., 2013	◕	◑	○	◔	○
Our work	●	●	●	◕	◔

Table 1-1 – Main models comparative

We have detected a relevant and generalized gap regarding LNG carrier movements because LNG is, at most, included as an upper-bounded quantity disregarding the LNG chain logistics; and long-term supply contract considerations, which in the best case are represented as a quantity and a price. Both topics are significant strengths of our model. A complete representation of the infrastructure operation is achieved in (Villada et al., 2013), although it lacks some technical details in LNG terminals and underground storages which may affect the market operation. The other models do not represent every infrastructure and/or do not incorporate capacity contracts and secondary capacity markets. Market rigidities are sometimes contemplated by considering a partially contracted demand or arbitrageurs. We have incorporated both rigidities, but disregarded the price-demand elasticity, which is incorporated in almost every model. Anyhow, demand elasticity could be incorporated straightforwardly.

Another limitation of our model is that we do not capture anticompetitive behavior, which may actually occur in still imperfect gas markets. A conjectural variations approach could be easily integrated in the model by means of a quadratic term in the objective function as previously done in (Barquín et al. 2004) or (Centeno et al. 2007) for the electric power sector. However, due to our experience with conjectural variations (Dueñas et al. 2012), we know that this approach is strongly value-dependent. As liberalized markets are relatively young[3], we may not have enough information in order to estimate adequate values

[2] We have also considered its extensions, such as (Egging et al. 2008) and (Egging et al. 2010).

[3] As a matter of fact, sometimes even an organized market has not been implemented yet as in the Iberian peninsula.

for the conjectures. Furthermore, the anticompetitive behavior of incumbent agents in gas markets may be more linked to market foreclosure (e.g. capacity hoarding) than to strategic bidding (as in electric power markets). Hence, we believe that it would be worth developing an endogenous methodology able to capture both types of anticompetitive behavior: exercise of market power and capacity hoarding. Nevertheless, modeling both types of anticompetitive behavior is out of the scope of this thesis.

1.4. Thesis objectives

The general objective of this thesis is to conduct a thorough analysis of downstream gas markets, principally, within the European regulatory framework, i.e., subject to entry-exit access systems. This analysis that covers most of the business relations among the involved stakeholders (suppliers, shippers, gas facility operators) focuses on the perfectly competitive market outcome because this should be the goal of any regulatory authority that is concerned about an efficient resource allocation. In addition, we believe that business relations are better understood when they can be explained with a simple model. Furthermore, moving away from perfect competition can be straightforwardly achieved by doing *ceteris paribus* analyses, in which one condition is modified.

Consequently, our first specific objective is to develop a market model which must be able to capture accurately the performance of a real gas market that is based on an entry-exit access system; so it can provide us with reliable outcomes. Moreover, the model must not only fulfill our academic purposes, but also be useful for any stakeholder, such as a market participant, a regulatory authority or a facility operator. The achievement of this objective requires either developing a tractable model able to cope with real gas systems or proposing a new methodology in order to reduce the computational time, or both.

As we conduct a market performance analysis, the second specific objective consists of detecting the market flaws and proposing some regulatory measures to solve or, at least, alleviate the perverse effect. We intend to propose regulatory measures which not only favor the competitive environment, but also improve the market efficiency. In short, we will take the point of view of both companies and regulatory authorities.

Along the lines of the previous specific objective, the EU Third Energy Package includes the so-called Gas Target Model, which besides some legislative aspects defines a set of indicators to measure the degree of development of gas markets in diverse aspects: security of supply, size, liquidity, and competition. Our third specific objective is precisely to apply the Gas Target Model to a real system, which is composed by Spain and Portugal, because, coincidentally, they are currently addressing the establishment of a virtual hub, i.e., an organized market, in accordance with the Third Energy Package.

Last but not least, our fourth specific objective consists of establishing the foundations of a recent research guideline that is progressively gaining importance: the interaction between gas and electric power systems. In detail, we want to examine if the current operation rules for both systems are adequate to deal with the uncertainty that stems from the renewable energy sources intermittency without compromising the power system stability.

1.5. How to read the remainder of the document

Each chapter starts with a brief introductory section with the purpose of putting the reader into context. After a conceptual and motivational introduction of the topic that will be discussed in the corresponding chapter, its main analytical objective is clearly stated. All the analyses that have been conducted in this thesis have required the utilization of a single fundamental model, as we strongly believe that a fundamental model is able to capture the stakeholders' behavior and, therefore, to provide an improved representation of the market performance. Consequently, the model is developed throughout the thesis at the same time as the analyses are conducted. However, we have made an effort to write self-contained chapters, even though the reader is occasionally referred to the respective section in which the topic is thoroughly addressed for a better understanding of the text. Each chapter, in addition, contains a realistic (sometimes, real) case study that illustrates the analysis and allows us to draw applicable regulatory conclusions. Finally, a summary of contributions and future research guidelines conclude every chapter.

The remainder of the document is organized as follows:

- In Chapter 2, we study the shippers' behavior regarding the operation and contracting of gas facilities and the interaction among themselves in OTC balancing and secondary capacity markets within an entry-exit system framework. Chapter 2 also initiates the development of the entry-exit market model that will be used throughout this thesis; hence, it constitutes a basic chapter, particularly, for a reader who is not familiar with the topic, in order to observe the utilization patterns of gas facilities by shippers and understand how entry-exit access systems should perform within a perfectly competitive environment.
- In Chapter 3, we open the previously developed local entry-exit market model to the still globalizing gas market. In particular, we explain the international relations of shippers and producers, whose most visible consequence is usually a long-

term agreement, and introduce the key element that brings distant markets closer: the LNG carrier. This chapter allows the reader to be acquainted with and recognize the influence of the supply activity on the domestic gas market. Furthermore, as the execution time greatly increases with every model extension, we propose a new methodology in order to reduce the computational time.

- In Chapter 4, we go back to the local gas market, and incorporate an essential element that was initially omitted on purpose: an organized market. This chapter presents the market implications of applying a specific type of organized market, (a virtual hub) in accordance with the EU Third Energy Package. In addition, we compare different alternatives for establishing a virtual hub and examine the shippers' behavior and market performance. The reader will verify that organized markets and competitive markets are not synonyms; nevertheless, they do encourage the competition.
- In Chapter 5, we analyze the interaction of gas markets with electric power markets. The gas consumption upsurge, which has taken place worldwide recently, cannot be fully understood without considering a relevant gas consumer such as the gas-fired power plant. Moreover, gas-fired power plants are said to take on a predominant role in electric power systems during the upcoming years as a support to integrate renewable energy sources. Precisely, we examine how the uncertainty of the renewable power generation may affect long- and short-term decisions of gas-fired power plants in gas and electric power systems. The worth of liquid and competitive markets is again highlighted.

Finally, and following the classic structure of PhD thesis dissertations, we gather in a last chapter the main original contributions of this thesis and enumerate several future research developments in Chapter 6.

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Chapter 2

GASCOOP, a Model for Contracting and Operating in Entry-Exit Gas Systems

In 1817, David Ricardo formulated the law of comparative advantages in his book "On the principles of political economy and taxation", whose corollary is that countries, and companies, can gain by specializing in a good or service. In contrast, the gas industry has traditionally been founded on vertically integrated and regulated companies. However, the liberalization process has often resulted in the unbundling of former integrated companies in producers, operators of transportation assets, and retailers. In this context, a new company (named shipper, but also known as marketer) has found a business opportunity: to mend broken ties. In this chapter, we analyze the behavior of shippers that receive gas from producers, deliver gas directly to consumers or to retailers and, in particular, formalize different agreements with facility operators in a perfectly competitive environment.

2.1. The shipper as the main character

Natural gas activities can be classified into upstream, midstream and downstream segments. The oil industry clearly distinguishes the midstream segment from upstream and downstream segments, since refining is an important process. However, raw gas does not require numerous and difficult processes before being consumed (at most, sulfur removal and odorant adding). For this reason, we have distributed midstream activities[1] between upstream and downstream segments. The upstream segment involves three main activities: 1) exploration and production; 2) liquefaction to obtain LNG; and 3) long-distance high-pressure pipeline or LNG carrier transportation. Subsequently in the chain, the downstream segment, according to our classification, is made up of another three activities: 1) transmission, which groups LNG regasification terminal operation, storage services, and transportation through medium-distance medium-pressure pipelines; 2) distribution via short-distance low-pressure pipelines; and 3) retail.

From the previous classification, upstream activities are commonly settled in producing countries, while downstream activities can take place in any country where natural gas is consumed, independently of being a producing country. Consequently, the boundary between upstream and downstream segments frequently coincides with an international border of a country. When gas is transported by LNG carrier, the frontier can be established according to the carrier insurance terms, at the dock of the liquefaction terminal or of the LNG regasification terminal. In contrast, a delivery point in a pipeline network determines the frontier in producing countries where both upstream and downstream segments are present. Likewise in cross-border pipelines, which connect producing and non-producing countries, a delivery point is habitually agreed at the international border.

Different companies are specialized in the above mentioned activities (producers, carriers, shippers, operators, intermediaries, etc.). Among these types of companies, shippers play a central role because, in short, they are in charge of linking producers to consumers. Let us observe Figure 2-1, in which both upstream and downstream activities are illustrated. Shippers participate actively in supply[2] and retail activities, and make use of infrastructure to convey gas from wellheads to consumers. Furthermore, shippers take different roles in downstream markets: they participate as consumers in supply markets, as suppliers in retail markets, and as third parties when utilizing gas facilities; therefore, taking on an omnipresent role.

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[1] Midstream activities are indeed often included into the downstream segment.

[2] Upstream activities are put together in the supply activity, since an exhaustive analysis of the upstream segment is out of the scope of this thesis. The supply activity is addressed in Chapter 3.

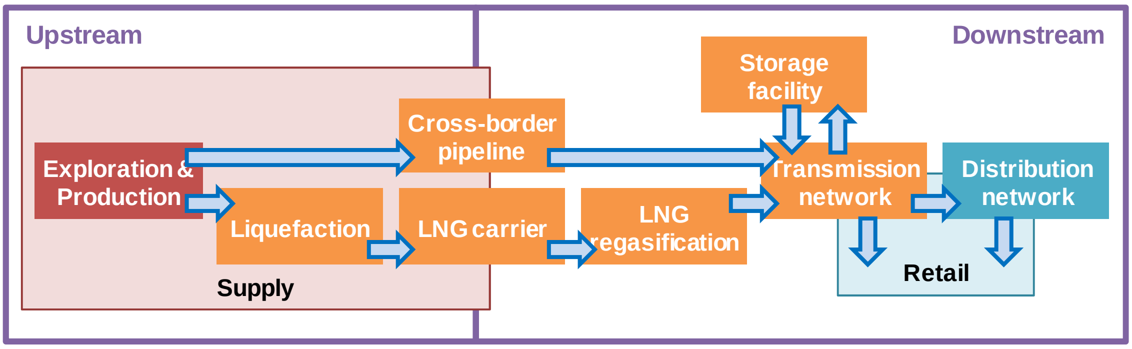

Figure 2-1 – Gas market upstream and downstream segments

Supply and retail are typically liberalized activities in which shippers compete among themselves. A shipper can either formalize an agreement and sign a long-term supply contract with a producer, or buy directly an amount of gas, for instance, one LNG carrier, in a spot market, such as the American Henry Hub or the British NBP. Shippers' participation in the supply activity is thoroughly treated in Chapter 3. At the other extreme of the chain, a shipper that participates in the retail activity offers specific products to industrial consumers or households with the objective of increasing its market share. A shipper can also deliver gas to a retailer, who will persuade consumers. In both supply and retail activities, earned profits and assumed risks depend mainly on shippers' decisions.

On the other hand, infrastructure access can be completely or partially regulated, or even fully liberalized. Capital-intensive gas facilities are habitually operated in a monopoly regime and, hence, subject to regulated third party access. However, negotiated third party access, not subject to regulated tariffs, is permitted to encourage private investments in some regulatory frameworks, like in the EU member states (EC 2009a). Exemption to regulated third party access can also be partial; that is, the exemption does not apply to total capacity. For example, there are one regulated and one partially regulated LNG terminals in Italy. From shippers' perspective, regulated or negotiated third party access regimes are indifferent as far as a shipper has right of access. The right of access requires formalizing capacity contracts between the infrastructure owner and the shipper. The type of contract may depend on the gas facility and state regulation (e.g., EC 2009a, 2009b). Once a shipper has contracted for capacity, a facility can be utilized.

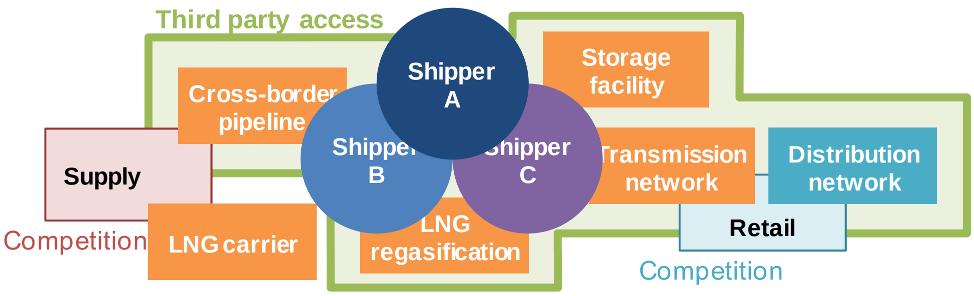

Figure 2-2 – Shippers' participation in downstream gas markets

In summary, shippers compete among themselves within downstream markets (Figure 2-2). First, they negotiate with producers in order to obtain favorable volume, price and fulfillment conditions in a competitive environment. Then, shippers formalize capacity contracts with infrastructure owners, so shippers can utilize gas facilities. Third party access is sometimes regulated, in which case shippers observe a regulatory framework; sometimes negotiated, in which case shippers come to an agreement with infrastructure owners[3]. Finally, shippers supply gas to a retailer, often formalizing a contract, or directly sell gas to a consumer, acting as a retailer (as assumed in this thesis).

2.2. Regulatory framework: entry-exit systems

The development of a proper downstream gas market requires, among other market rules, the definition of quality standards, as well as contracting and operating rules and a cost recovery framework for the regulated infrastructure[4] (LNG regasification terminals, cross-border pipelines, storage facilities, and transportation and distribution networks). Quality standards, typically a calorific value and certain composition properties, are essential for guaranteeing homogeneous characteristics of the energy product[5]. Moreover, these quality standards allow market participants to trade with a reliable product and, therefore, to obtain a unique market price. However, the homogeneity is only one of the conditions for a unique market price. Gas market prices may differ (and do differ) geographically. At a global level, transportation costs, e.g. LNG carrier freights, explain most of the difference. At a local level, price differences are not only caused by transportation costs, but also due to the regulatory framework.

On the one hand, point-to-point systems establish two prices at both pipeline extremes. The difference between both prices (must) reflect transportation costs and scarce capacity valuation when transportation constraints appear. On the other hand, entry-exit systems fragment the market by defining balancing zones and establishing entry and exit tariffs (Alonso et al. 2010). The fundamentals of a balancing zone lie in disregarding transportation and distribution network characteristics, except at entry and exit points. In short, the network is embedded into a uniform balancing zone. A zonal market price is

[3] It is not strange that a shipper participates in the infrastructure ownership, in which case it will face the operating costs, besides the corresponding capital costs.

[4] Negotiated third party access is not omitted on purpose as it is indeed an exception to regulated third party access. Instead of being imposed by regulatory authorities, the cost recovery framework will be decided by the infrastructure owner. Nevertheless, the owner is not totally free to set access rules, which are normally subject to regulatory authorities' approval.

[5] Natural gas composition (methane content, hydrogen sulfide presence, etc.) varies depending on its origin. Later in the chain, "different" gases mix in gas networks yielding a new gas, whose properties are strongly related to primary gases and, hence, the necessity of establishing quality standards.

determined from the balancing process, in which each shipper must observe a balance between inflows, outflows, inventory variations, and buy/sell transactions in the balancing zone, due to the possibility of storing a small amount of gas in pipelines that can be used during the day. Naturally, equal market prices should be expected during a day in neighboring balancing zones. However, even when transportation constraints do not appear, an entry and/or exit tariff does alter the gas price with respect to the neighboring balancing zone[6]. Consequently, in order to minimize market efficiency losses, the boundaries of the balancing zones should ideally coincide with in practice permanent network congestions providing location signals for a better operation.

Nevertheless, the balancing zones may be delimited by unintentional or intentional political intervention. Under unintentional political intervention, vested rights are typical cases. In detail, when the time comes to delimitate balancing zones, a system is divided and distributed to two (or more) companies, who also become independent system operators (ISOs). However, the division has nothing to do with any network congestion, but with the historical ownership of network assets. Under intentional political intervention, we introduce a new concept: the market area. A market area is not exactly equivalent to a balancing zone. Geographically speaking, market areas are over balancing zones. In other words, a market area comprises at least one balancing zone, but the market area may also comprise more than one balancing zone. Specifically, a market area delimitates a geographic region (commonly, a country), in which the same regulatory framework is enforced. For instance, despite the European Commission's efforts urging the common rules for the internal gas market (EC 2009a), the lack of a real harmonization[7] of the national regulatory frameworks establishes separate market areas within the EU borders. The market area is separately defined from balancing zones because when a shipper decides to participate in a market area, it must adapt its behavior to a different regulatory framework.

It is worth mentioning that entry-exit systems establish different frameworks to access to, and remunerate, the network. Other gas assets that are connected to the network do not follow necessarily an entry-exit system. As a matter of fact, those shippers interested in utilizing other assets, such as LNG terminals or storage facilities, pay for the offered services, which may be unrelated to third party access. Figure 2-3 summarizes the entry

[6] If gas flows from balancing zone A to balancing zone B, the resulting price in B, p_B, is the sum of the price in A, p_A, plus the exit tariff from A, $c_{A\rightarrow B}$, plus the entry tariff to B, $c_{B\rightarrow A}$, that is, $p_B = p_A + c_{A\rightarrow B} + c_{B\rightarrow A}$. Therefore, despite the lack of congestions, both prices are different unless entry and exit tariffs are equal to zero, or equal with opposite sign.

[7] An appropriate harmonization requires going beyond the mere application of universal access or unbundling rules. For example, tariff structures and their values should also be in accordance to provide coherent economic signals.

and exit flows in balancing zones. Entries correspond to regasified gas from LNG terminals, imports from cross-border pipelines, withdrawals from storage facilities, and inflows from neighboring balancing zones. Alternatively, exits correspond to exports by cross-border pipelines, injections to storage facilities, consumers' demands and outflows to neighboring balancing zones. Flows are a consequence of shippers' operation. Furthermore, shippers must contract for entry and/or exit capacity in some of the above network points depending on the regulatory framework.

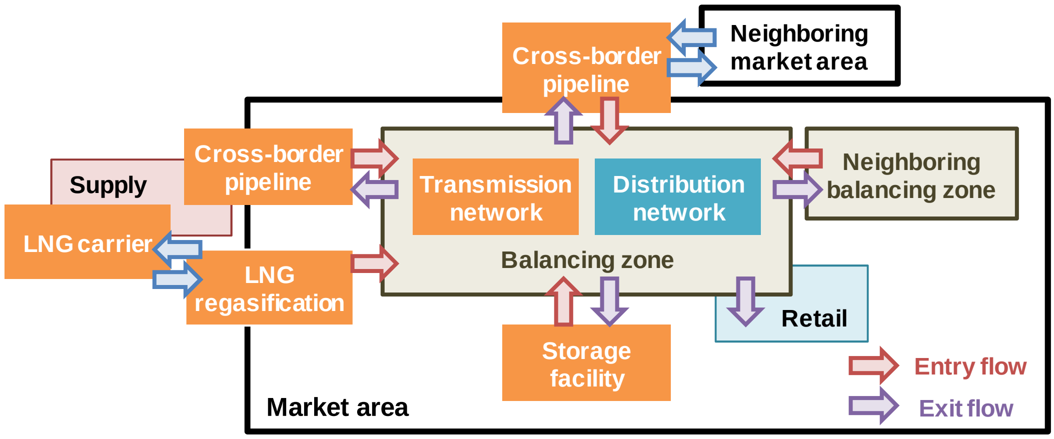

Figure 2-3 – Entry and exit flows

2.3. A shipper facing an entry-exit system

Our objective is to analyze the shippers' behavior when they participate in an entry-exit gas market. Other authors have addressed companies' behavior in regulated and deregulated downstream gas systems. (Avery et al. 1992) propose a linear programming (LP) model to optimize purchase, storage and transmission contracts of a gas utility; and (De Wolf and Smeers 2000) minimize supply and transmission costs of a vertically integrated gas utility. Both models optimize decisions of a gas utility under a regulated environment. In contrast, under a deregulated framework, (Gabriel et al. 2005) propose an equilibrium problem, in which decisions of different companies of the gas chain (producers, network and storage operators, and retailers) are optimized by solving a linear-complementarity problem (LCP). In a similar way, (Zwart et al. 2006) also add decisions on investments and arbitrage on behalf of traders between different markets. (Boots et al. 2004) introduce the concept of successive oligopoly, in which producers extract rent from shippers and shippers extract rent from consumers. At a national level, (Holz et al. 2008) study different market structures within the EU, including some capacity constraints between an incumbent shipper and its market that approximates network constraints among different countries, and (Lise et al. 2008) incorporate investments on transmission capacity in the EU corridors. Recently, (Villada et al. 2013) analyze security of supply in Colombia through a simulation model that incorporates the behavior of producers and wholesalers, as well as transmission capacity trading.

The model that is introduced below has tried to overcome some shortcomings of the previous approaches: entry-exit systems, capacity contracting, and different temporal horizons. In fact, besides introducing balancing zones and an entry-exit system, one of the main strengths of our model is the optimization of capacity contract portfolios (long- and medium-term decisions), and its influence on the short-term operation decisions. Moreover, the disaggregation level of the temporal horizon, the day, allows for a really detailed representation of the operation decisions. Let us go back to the evaluation of current gas market models (section 1.3, pp. 9–12). In consideration of the evaluation, we close a relevant gap in this chapter: a detailed representation of the infrastructure operation. Although we do not model gas pipelines, as we focus on entry-exit systems, we also include some technical details of LNG regasification terminals and underground storage facilities, which have been omitted in most models. Furthermore, we have incorporated a capacity contracting framework that is nowadays applied in gas markets (e.g., the EU or the U.S.) with slight variations and, to the author's knowledge, has not been addressed yet.

However, in contrast to some preceding models such as (Boots et al. 2004) or (Gabriel et al. 2005), and despite the typical concentration of gas markets, we model a perfectly competitive market. The incorporation of strategic behavior would require a complex model, which would be probably unable to represent the gas market in detail and, hence, unable to satisfy the interests of neither the academia nor the industry, which included a shipper that participates in a downstream market or a regulator that monitors the market's performance. Besides the market behavior, some simplifications, which are mentioned along the description, have been adopted to preserve not only a tractable, but an understandable model.

It is, therefore, assumed that the perfectly competitive outcome will minimize total costs borne by the involved parties, subject to demand and supply constraints. As gas procurement prices and demand volumes, and final consumer demand and prices are held constant, this statement implies that total regulated costs borne by shippers are going to be minimized. This is because, from the shippers' perspective, regulated costs are analogous to purely technical costs, such as transportation or other operation costs, as nobody can avoid or negotiate away these costs. The perfect competition assumption requires that a suitably large number of shippers have access to capacity contracts in all relevant infrastructures to exogenously regulated prices, and that they are able to trade these capacity rights among themselves.

Figure 2-4 contains a graphical representation of the overall model structure. Every balancing zone in each market area includes the required infrastructure to connect supply and demand, such as LNG terminals, storage facilities, and cross-border pipelines. Both LNG terminals and cross-border pipelines can be connected with the upstream sector. Market areas are also interconnected by cross-border pipelines as the regulatory frameworks are commonly enacted by each country. Balancing zones within a market area are connected by an equivalent pipeline that determines entry and exit capacities.

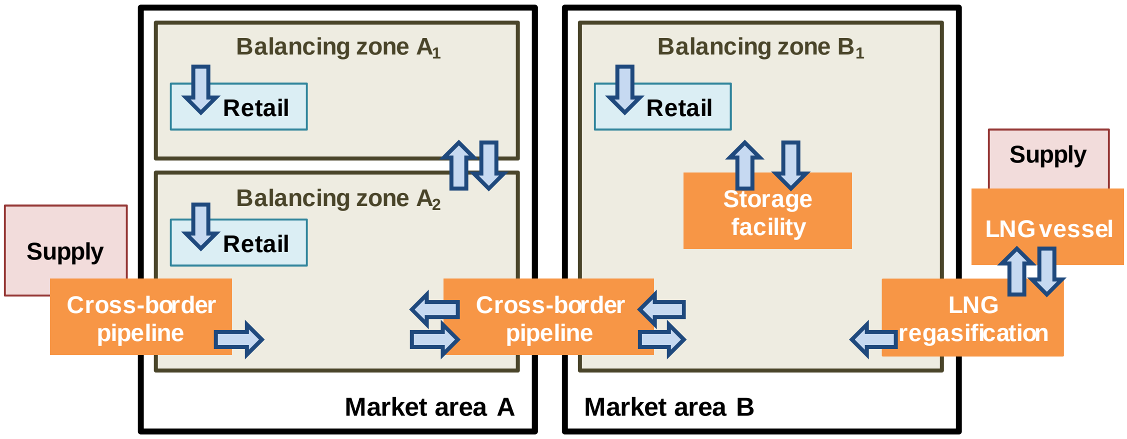

Figure 2-4 – Overall model structure graphical representation

In short, the model describes the following process. Each shipper, e=1,2,…,E, that participates in each market area, a=1,2,…,A, acquires an amount of gas in supply markets, i=1,2,…I, which is either delivered by LNG carrier or though a cross-border pipeline. This amount of gas is used for satisfying its own demand in each balancing zone, z=1,2,…,Z, by making use of diverse gas facilities, that is, LNG terminals, r=1,2,…,R; storage facilities, s=1,2,…,S; and cross-border pipelines, x=1,2,…,X; which require formalizing capacity contracts. Shippers' balances among entries, exits and stock variations in gas facilities and balancing zones are monitored each day, d=1,2,…,D, by an ISO; hence, the day is the model time step. (Another temporal index that is used is the month m=1,2,…M).

The market model is formulated as a combination of MIP and LP problems. For the sake of clarity, the model formulation is classified into an operation layer (section 2.4) and a contracting layer (section 2.5) according to shippers' decisions. In the former layer, decisions are related to physical gas flows; in the latter layer, decisions are related to infrastructure contracting in order to acquire the right to utilize them. Naturally, both types of decisions are not independent, but, on the contrary, interdependent, as shown in section 2.5. Afterward, two separate markets are introduced: over-the-counter (OTC) physical swapping markets (section 2.6.1) that allow shippers to balance their daily position; and secondary capacity markets in which the shippers can acquire released capacity (section 2.6.2). Finally, demand segmentation is briefly addressed in section 2.7.

During the model description, uppercase and Greek letters represent parameters, while lowercase letters represent decision variables. Moreover, decision variables are all continuous and positive, except when explicitly indicated otherwise. Furthermore, as the day is the time step, flow variables provide values during the day, while stock variables provide a value at the end of the day. For the sake of clarity, representative units of measurement are shown in brackets when parameters and variables are first introduced.

2.4. Optimizing operation decisions

Shippers' operation decision variables are related to infrastructure utilization and resulting physical gas flows. Let us go back to Figure 2-3 again. As a balancing zone is in a nutshell an equivalent of gas transmission and distribution networks, it gains relevance as a central platform by which (almost) every particle of gas flows. Therefore, the operation layer description starts with the entry points to the downstream gas market (LNG terminals and cross-border pipelines), continues with storage facilities and finishes with balancing zones. Additionally, the regulatory framework commonly defines at least two operation regimes: normal system operation and under emergency conditions. The model is intended for medium- to long-term simulations and, therefore, for a normal system operation regime. Nevertheless, an operation under emergency conditions could be simulated if some element, e.g., one LNG terminal, were considered to be unavailable when decisions have partially been taken.

2.4.1. LNG regasification terminals

LNG regasification terminals are one of the doorways to downstream gas markets (the other doorways are cross-border pipelines). This gas facility, which is located either onshore or off-shore, makes the following operations possible:

- Reception and unloading LNG carriers.
- Loading LNG carriers.
- Production of gas (regasification of LNG).
- Loading LNG road tankers.
- LNG storage in its tanks.

So far, regasification and LNG storage have been included in gas market models; while unloading has always been represented in a coarse way. We have gone a step further and explicitly modeled both carriers and road tankers in order to take account of every possible operation in detail. These operations include reception and unloading of carriers, production of gas, and storage of LNG in its tanks. With this simple structure (input, output, storage), which is reproduced throughout the paper in the different infrastructure, LNG terminals are useful facilities for diversifying supply sources and for responding to weekly demand variations. Additionally, LNG terminals offer other output services, such as loading LNG road tankers and LNG carriers. Loading road tankers is considered by the model in a straightforward manner since it is a residual activity compared to gas production. Loading carriers is an activity that allows shippers to arbitrage when international markets present relevant price differences. For instance, nowadays after the U.S. shale gas revolution and the Fukushima incident, differences in price among America, Europe and Asia are greater than transportation costs, so significant business opportunities arise. Nonetheless, loading carriers is associated to the supply activity and, hence, postponed to section 3.4 (pp. 85–88).

Because the LNG carrier world fleet is relatively standardized (and limited), carriers can be assigned to different categories, b=1,2,…B, according to their capacity Q_b^{MET} [GWh][8]. The number of LNG carriers that can be unloaded at the same time is restricted by the number of berths, w=1,2,…,W, of a LNG terminal. Each berth dimension Q_{rw}^{ULD} [GWh] limits the category of carriers that can moor. In addition, depending on the carrier capacity, the whole operation, including mooring, unloading and departure operations, may take up to two days.

LNG terminal owners may apply a tariff to each offered service: slot assignment C_r^{MET} [€/carrier], and unloading service C_r^{ULD} [€/GWh]. Shippers minimize costs associated with both services:

$$\min_{u_{birwed}^{MET},\, q_{irwed}^{ULD}} \sum_{i,r,w,e,d} \left(C_r^{MET} \cdot \sum\nolimits_b u_{birwed}^{MET} + C_r^{ULD} \cdot q_{irwed}^{ULD} \right) \qquad (2.1)$$

LNG carrier arrivals to a berth of a LNG terminal from a supply market are represented through binary variables u_{birwed}^{MET} {0, 1}, while continuous variables q_{irwed}^{ULD} [GWh] represent the unloaded cargo. The index, i, is here used to define a market of origin of the carrier. As the supply activity is not addressed in this chapter, so far, we define one market of origin I_1. Furthermore, daily arrivals to LNG terminal berths are considered as known, but distributed among shippers:

$$\sum\nolimits_e u_{birwed}^{MET} = U_{brwd}^{MET} \quad \forall b, i = I_1, r, w, d \qquad (2.2)$$

[8] Despite gas volumes can be measured in cubic meters or cubic feet, a way to compare different gas qualities is measuring the heat energy content, i.e. the calorific value, of a gas volume in British thermal units (Btu) or, as done in this thesis, in Giga-watts-hour (GWh).

Naturally, a carrier arrival is prevented when the carrier capacity is larger than the berth dimension:

$$Q_b^{MET} > Q_{rw}^{ULD} \quad \Rightarrow \quad u_{birwed}^{MET} = 0 \quad \forall b,i,r,w,e,d \tag{2.3}$$

As well as any other carrier arrival is not permitted when a carrier is already moored at the LNG terminal berth:

$$\sum_{d'>d-T_b^{MET}}^{d'=d} \sum\nolimits_{b,e} u_{birwed'}^{MET} \leq 1 \quad \forall r,i,w,d \tag{2.4}$$

Binary variables indicate LNG carrier arrivals; however, any carrier is moored during up to few days T_b^{MET} [day]. During this period of time the carrier unloads a percentage of its cargo, represented by the continuous variable u_{birwed}^{ULD} [0, 1], whose lower and upper limits are zero and one, respectively:

$$u_{birwed}^{ULD} = \sum_{d'>d-T_b^{MET}}^{d'=d} \frac{u_{birwed'}^{MET}}{T_b^{MET}} \quad \forall b,i,r,w,e,d \tag{2.5}$$

From (2.5), the whole cargo is unloaded during the arrival day when $T_b^{MET} = 1$; each half of the cargo is unloaded during the arrival day and the immediate next day when $T_b^{MET} = 2$; and so on and so forth (if applicable). The approximation is suitable since the minimum time step is the day and not the hour; hence, starting and finishing hours of the unloading process can be omitted.

A last equation converts daily unloaded percentages into energy terms:

$$q_{irwed}^{ULD} = \sum\nolimits_b Q_b^{MET} \cdot u_{birwed}^{ULD} \quad \forall i,r,w,e,d \tag{2.6}$$

The objective function (2.1) subject to constraints (2.2)–(2.6) constitutes a MIP problem that supports shippers' decision-making process regarding LNG carrier arrivals.

The main operation decision in LNG terminals lies in regasifying (i.e., evaporating) liquefied gas q_{red}^{REG} [GWh], and injecting it into the transmission network. Sometimes, stored LNG is loaded into a LNG road tanker q_{red}^{TNK} [GWh], and transported by road directly to consumers. In both cases, LNG terminals work similar to natural gas wellheads in producing countries. As in the previous case, LNG terminal owners may apply a tariff to regasification service CV_r^{REG} [€/GWh], and road tankers loading service CV_r^{TNK} [€/GWh]. Shippers minimize costs associated with both activities:

$$\min_{q_{red}^{REG}, q_{red}^{TNK}} \quad \sum_{r,e,d} \left(CV_r^{REG} \cdot q_{red}^{REG} + CV_r^{TNK} \cdot q_{red}^{TNK} \right) \tag{2.7}$$

Loading service can also be applied per road tanker. However, bearing in mind that road tankers tend to be a residual output of regasification terminals, the model does not incorporate (discrete variables for) road tankers that will complicate the model resolution with low added value.

Both regasification and road tankers loading present daily maximum limits Q_r^{REG} [GWh] and Q_r^{TNK} [GWh], respectively:

$$\sum_e q_{red}^{REG} \leq Q_r^{REG} \quad \forall r,d \tag{2.8}$$

$$\sum_e q_{red}^{TNK} \leq Q_r^{TNK} \quad \forall r,d \tag{2.9}$$

The objective function (2.7) subject to constraints (2.8)–(2.9) constitutes a LP problem that supports shippers' decision-making process regarding utilized regasification capacity and LNG road tankers loading.

Regasification terminals can store LNG q_{red}^{LNG} [GWh] in their tanks. In the same way as in the previous activities, LNG terminal owners may apply a tariff to storage utilization C_r^{LNG} [€/GWh] at the end of the day. Shippers minimize costs associated with storage service:

$$\min_{q_{red}^{LNG}} \sum_{r,e,d} C_r^{LNG} \cdot q_{red}^{LNG} \tag{2.10}$$

The total capacity of a LNG tank includes an immobilized volume (named base gas) that is necessary to keep tanks in operation. The base gas is normally acquired by the facility owner through a market mechanism, like an auction. Therefore, shippers cannot utilize base gas because it does not belong to them. In a few words, total LNG tank capacity is diminished by base gas. The difference between the total capacity and the base gas is named working capacity. LNG storage capacity Q_r^{LNG} [GWh] of a regasification terminal is equal to the sum of working capacities of its tanks. Shippers' decisions cannot violate the maximum LNG storage capacity:

$$\sum_e q_{red}^{LNG} \leq Q_r^{LNG} \quad \forall r,d \tag{2.11}$$

Once a carrier has unloaded its cargo, LNG is stored to be subsequently extracted when LNG is regasified or loaded into LNG road tankers. In order to monitor LNG inventories, and in accordance to most regulatory frameworks, every shipper should observe a daily balance among inputs (carriers unloading), outputs (road tankers loading and regasification), and inventory variations:

$$q_{red}^{LNG} - q_{re(d-1)}^{LNG} = \sum_{i=l_1,w} q_{irwed}^{ULD} - q_{red}^{REG} - q_{red}^{TNK} \quad \forall r,e,d \tag{2.12}$$

The objective function (2.10) subject to constraints (2.11)–(2.12) constitutes a LP problem that optimizes shippers' LNG inventories, which is as well linked to other shippers' decisions, such as the unloaded or regasified amount of LNG through (2.12).

Figure 2-5 illustrates the MIP problem that results from adding up objective functions (2.1), (2.7), (2.10) subject to constraints (2.2)–(2.6), (2.8)–(2.9) and (2.11)–(2.12). This MIP problem supports shippers' decision-making process by optimizing their operation decisions in LNG terminals (carrier arrivals, regasification, road tankers loading, and inventory variations).

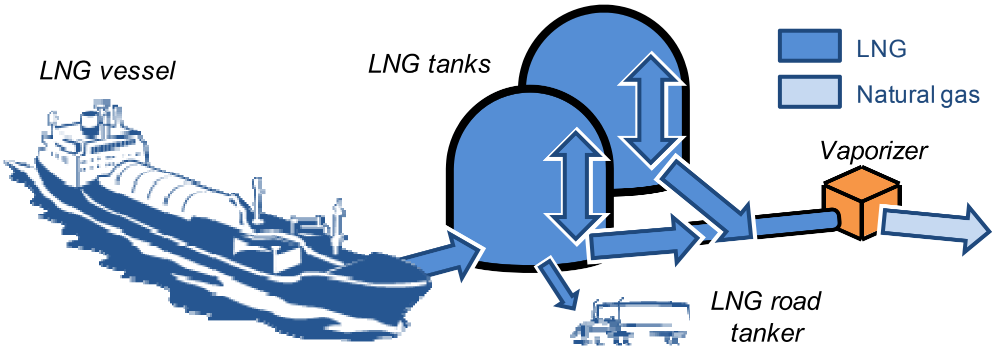

Figure 2-5 – Schematics of a LNG regasification terminal

$$
\min_{\substack{u_{birwed}^{MET}, q_{irwed}^{ULD} \\ q_{red}^{REG}, q_{red}^{TNK}, q_{red}^{LNG}}} \sum_{r,e,d} \left(\sum_{i=l_1,w} \left(C_r^{MET} \cdot \sum_b u_{birwed}^{MET} + C_r^{ULD} \cdot q_{irwed}^{ULD} \right) + CV_r^{REG} \cdot q_{red}^{REG} + CV_r^{TNK} \cdot q_{red}^{TNK} + C_r^{LNG} \cdot q_{red}^{LNG} \right)
$$

$$
\begin{aligned}
\text{s.t.} \quad & \textstyle\sum_e u_{birwed}^{MET} = U_{brwd}^{MET} \quad \forall b, i = l_1, r, w, d \\
& Q_b^{MET} > Q_{rw}^{ULD} \Rightarrow u_{birwed}^{MET} = 0 \quad \forall b, i = l_1, r, w, e, d \\
& \sum_{d' > d - T_b^{MET}}^{d' = d} \sum_{b,e} u_{birwed'}^{MET} \leq 1 \quad \forall r, i = l_1, w, d \\
& u_{birwed}^{ULD} = \sum_{d' > d - T_b^{MET}}^{d' = d} \frac{u_{birwed'}^{MET}}{T_b^{MET}} \quad \forall b, i = l_1, r, w, e, d \\
& q_{irwed}^{ULD} = \textstyle\sum_b Q_b^{MET} \cdot u_{birwed}^{ULD} \quad \forall i = l_1, r, w, e, d \\
& \textstyle\sum_e q_{red}^{REG} \leq Q_r^{REG} \quad \forall r, d \\
& \textstyle\sum_e q_{red}^{TNK} \leq Q_r^{TNK} \quad \forall r, d \\
& \textstyle\sum_e q_{red}^{LNG} \leq Q_r^{LNG} \quad \forall r, d \\
& q_{red}^{LNG} - q_{re(d-1)}^{LNG} = \textstyle\sum_{i=l_1,w} q_{irwed}^{ULD} - q_{red}^{REG} - q_{red}^{TNK} \quad \forall r, e, d
\end{aligned}
$$

2.4.2. Cross-border pipelines

Cross-border pipelines are the other doorway to downstream gas systems. As previously mentioned, when the upstream segment is also present in a consumption country, a delivery point in the transmission network usually establishes the frontier between the upstream and downstream segments. In other words, a delivery point acts as a fictitious "international border" connecting with the supply market. Alternatively, cross-border pipelines may also connect two separate market areas as a consequence of a regulatory fragmentation (section 2.2). Because in this latter case a cross-border pipeline connects two balancing zones, we define the importing or exporting flow direction for the following parameters and variables from the point of view of a specific balancing zone. Similar to other models, we make use of the flow conservation law in order to represent flows along the cross-border pipelines.

From a market area perspective, cross-border pipelines are used for importing q_{xzed}^{IMP} [GWh], or exporting q_{xzed}^{EXP} [GWh] gas. Cross-border pipeline owners may apply a tariff to imports CV_{xz}^{IMP} [€/GWh] and exports CV_{xz}^{EXP} [€/GWh]. Actually, these tariffs are entry-exit tariffs as those introduced in section 2.5.4. Shippers minimize import and export costs:

$$\min_{q_{xzed}^{IMP},q_{xzed}^{EXP}} \sum_{x,z,e,d} \left(CV_{xz}^{IMP} \cdot q_{xzed}^{IMP} + CV_{xz}^{EXP} \cdot q_{xzed}^{EXP} \right) \tag{2.13}$$

Gas flow through a pipeline depends on some technical parameters, like the diameter or the friction, and on the difference of pressures at both ends of the pipeline (Martin et al. 2006). Whereas technical parameters are predetermined, compressor stations allow the control of pressures at both ends and, hence, gas flow management, both in quantity and direction. Therefore, the gas flow through a cross-border pipeline f_{xzd}^{CBP} [GWh] can be explicitly optimized without losing much detail by overlooking pressures and avoiding non-linear constraints. The gas flow will be limited by (known in advance) maximum daily import Q_{xz}^{IMP} [GWh] and export capacities Q_{xz}^{EXP} [GWh], according to pipeline and compressor stations characteristics:

$$-Q_{xz}^{EXP} \le f_{xzd}^{CBP} \le Q_{xz}^{IMP} \quad \forall x,z,d \tag{2.14}$$

The gas flow through a cross-border pipeline f_{xzd}^{CBP} is a free variable that denotes the flow direction from/to a balancing zone. A positive flow is equivalent to a net gas import (inflow); a negative flow is equivalent to a net gas export (outflow). The net gas flow is then calculated as the difference between shippers' import and export decisions:

$$f_{xzd}^{CBP} = \sum\nolimits_e q_{xzed}^{IMP} - \sum\nolimits_e q_{xzed}^{EXP} \quad \forall x,z,d \tag{2.15}$$

Constraint (2.15) takes account of backhaul flows; that is, imports (exports) can exceed maximum import (export) capacity provided that the excess is compensated by exports (imports). In this way, the real physical flow never violates the constraint. Backhaul flows have typically to do with contractual commitments in which a shipper has a bilateral arrangement with, for instance, a retailer. Despite gas is probably flowing against nature, i.e., from a low price area to a high price area, bilateral arrangement terms together with backhaul possibility may improve shipper's operation.

A final consideration regarding cross-border pipelines is that when a cross-border pipeline *x'* is directly connected to a natural gas production field, exports are impossible and, hence, must be prevented:

$$q_{x'zed}^{EXP} = 0 \quad \forall x', z, e, d \tag{2.16}$$

The objective function (2.13) subject to constraints (2.14)–(2.16) constitutes a LP problem that optimizes shippers' operation decisions on cross-border pipelines (Figure 2-6).

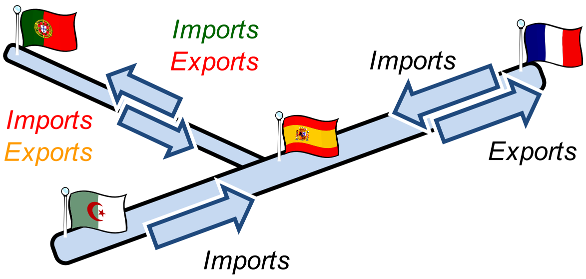

Figure 2-6 – Schematics of cross-border pipelines

$$\begin{array}{ll} \min\limits_{q_{xzed}^{IMP}, q_{xzed}^{EXP}} & \sum\limits_{x,z,e,d} \left(CV_{xz}^{IMP} \cdot q_{xzed}^{IMP} + CV_{xz}^{EXP} \cdot q_{xzed}^{EXP} \right) \\ s.t. & -Q_{xz}^{EXP} \le f_{xzd}^{CBP} \le Q_{xz}^{IMP} \quad \forall x, z, d \\ & f_{xzd}^{CBP} = \sum_e q_{xzed}^{IMP} - \sum_e q_{xzed}^{EXP} \quad \forall x, z, d \\ & q_{x'zed}^{EXP} = 0 \quad \forall x', z, e, d \end{array}$$

2.4.3. Storage facilities

Three different cost-effective facilities allow the storage of significant amounts of gas:

- The first facility is the LNG tank, which have been already addressed in section 2.4.1. LNG tanks are useful facilities for responding to weekly demand variations. However, they should not be used for storing strategic reserves because their working capacity permits typically the storage of about two large LNG carriers (less than 0.1% of the EU-27 consumption in 2011).
- The second facility is the network, i.e., the pipelines themselves, which are addressed in section 2.4.4. Pipeline storage capacity is known as line-pack. The line-pack is a small quantity that, nevertheless, is a valuable support to respond to daily demand variations.
- The third facility, mainly described in this section, is the underground storage.

Depleted natural gas or oil fields, salt caverns, aquifers and mines are adapted and used for storing huge gas volumes. Their significant capacity together with their reduced flexibility that (in general) do not allow them to respond to daily or weekly demand variations make these facilities an adequate place for maintaining strategic reserves[9]. Underground storages are commonly less flexible than LNG terminals because, first of all, withdrawal and injection rates may depend on the amount of stored gas and, secondly, the equipment is commonly adapted to injection-withdrawal cycles: an injection period during warm months, a withdrawal period during cold months. This characteristic utilization pattern is a consequence of the difference between gas supply, which is almost constant due to supply contracts characteristics (see section 3.2, pp. 78–82), and demand seasonality, even though two seasonal demand peaks have been observed lately: one peak during the cold season as a result of gas consumption for heating purposes, and another peak during the summer due to gas-fired power plants (GFPPs) consumption for electricity generation. However, the cold season peak is still higher than the warm season peak in most systems.

Underground storage owners may apply a tariff to each of the three main activities associated with its utilization: daily storage CV_s^{STO} [€/GWh], injection C_s^{INJ} [€/GWh] and withdrawal C_s^{WTH} [€/GWh]. Shippers minimize underground storage utilization costs, that is, stored gas q_{sed}^{STO} [GWh] at the end of the day in, injected gas to q_{sed}^{INJ} [GWh] and withdrawn gas from q_{sed}^{WTH} [GWh] underground storages:

$$\min_{q_{sed}^{STO}, q_{sed}^{WTH}, q_{sed}^{INJ}} \sum_{s,e,d} \left(CV_s^{STO} \cdot q_{sed}^{STO} + C_s^{INJ} \cdot q_{sed}^{INJ} + C_s^{WTH} \cdot q_{sed}^{WTH} \right) \qquad (2.17)$$

The underground storage capacity is divided into cushion gas capacity and working gas capacity. Similar to LNG tanks, cushion gas is necessary to maintain the pressure and keep the underground storage in operation. Although in case of emergency a part of the cushion gas can be mobilized (at higher costs), under the normal operation regime the working gas capacity Q_s^{STO} [GWh] is equal to the difference between maximum storage capacity and cushion gas. Shippers can only utilize working gas capacity to store gas:

$$\sum_e q_{sed}^{STO} \leq Q_s^{STO} \quad \forall s, d \qquad (2.18)$$

When representing the underground storage operation, models have commonly omitted backhaul flows, which (virtually) increase the injection and withdrawal capacities, and the variation of the injection and withdrawal capacities with the gas stock. Both characteris-

[9] Nonetheless, underground storage typology may improve its flexibility, as it occurs in salt caverns, which can alter their cycles quickly in short-time periods and are nowadays utilized to respond to peak demands.

tics have been considered in our model. Net injected or withdrawn gas flow f_{sd}^{STO} [GWh] is calculated as the difference between injection and withdrawal shippers' decisions:

$$f_{sd}^{STO} = \sum_e q_{sed}^{INJ} - \sum_e q_{sed}^{WTH} \quad \forall s,d \tag{2.19}$$

Similar to (2.15), the net flow f_{sd}^{STO} is a free variable that is positive when the resulting flow is equivalent to an injection and negative when equivalent to a withdrawal.

Injecting gas into an underground storage is a mechanical process that requires external power because the storage pressure is greater than the atmospheric pressure. Varied equipment, such as a compressor, is needed to inject gas. Therefore, injections can be maintained constant despite the interior pressure increment while the storage is being filled, as long as the compressor has enough power. Occasionally, however, the injection rate may depend on the amount of stored gas:

$$f_{sd}^{STO} \le Q_s^{INJ} - E_s^{INJ} \cdot \frac{\sum_e q_{sed}^{STO}}{Q_s^{STO}} \quad \forall s,d \tag{2.20}$$

To be precise, the upper bound of the net injected gas flow is characterized by an affine function[10], whose intercept is the maximum injection rate Q_s^{INJ} [GWh] when the underground storage is "technically" empty, i.e., at its cushion gas level or minimum working pressure; and whose slope E_s^{INJ} [GWh/p.u.] reflects the injection capacity decline when a storage is being filled, that is, when the working gas stock increases in percentage.

In contrast, withdrawing gas from an underground storage is a process that can take place naturally as the pressure outside is lower than the storage pressure. Consequently, except when other external processes are carried out (for instance, water pumping), the withdrawal rate depends on the amount of stored gas:

$$f_{sd}^{STO} \ge E_s^{WTH} \cdot \frac{Q_s^{STO} - \sum_e q_{sed}^{STO}}{Q_s^{STO}} - Q_s^{WTH} \quad \forall s,d \tag{2.21}$$

Likewise, the lower bound of the net withdrawn gas flow is characterized by an affine function, whose slope E_s^{WTH} [GWh/p.u.] reflects the withdrawal capacity decline when the storage is being emptied; and whose intercept is a negative value equal to the difference between the maximum withdrawal rate Q_s^{WTH} [GWh] when the storage is full and the decline slope. Figure 2-7 illustrates both bounds, in which it is remarkable the lower slope of the injection decline in comparison to the withdrawal decline.

[10] The upper (as well as the lower) bound is approximated by an affine function to avoid non-linear constraints. This approximation is habitually accurate enough.

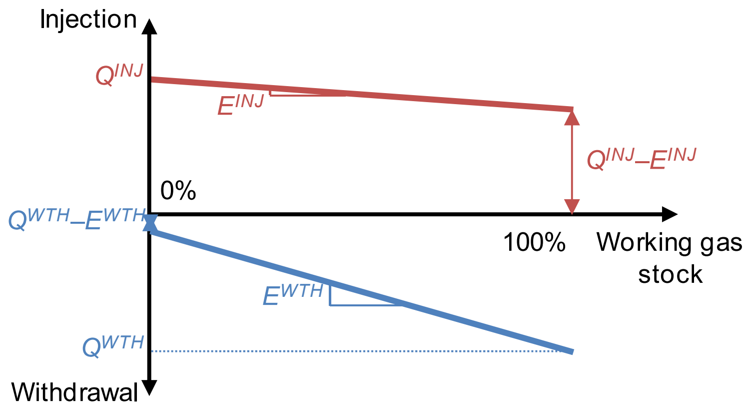

Figure 2-7 – Upper and lower bounds on net flows in underground storages

Two additional constraints are necessary when an underground storage is operated according to an annual cycle. The cycle is made up of injection days during the off-peak warm season d_s^{INJ}, and withdrawal days during the peak cold season d_s^{WTH}:

$$f_{sd}^{STO} \geq 0 \quad \forall s, d \in d_s^{INJ} \tag{2.22}$$

$$f_{sd}^{STO} \leq 0 \quad \forall s, d \in d_s^{WTH} \tag{2.23}$$

Backhaul flows, which facilitate an optimal operation, are still possible, but conditioned to obtain net flows that do not violate either (2.22) or (2.23).

According to most regulatory frameworks, shippers must also observe a daily balance among inventory variations, injections, and withdrawals:

$$q_{sed}^{STO} - q_{se(d-1)}^{STO} = q_{sed}^{INJ} - q_{sed}^{WTH} \quad \forall s, e, d \tag{2.24}$$

The objective function (2.17) subject to constraints (2.18)–(2.24) constitutes a LP problem that can be employed by shippers for optimizing their operation decisions (injections, withdrawals, and inventory levels) in underground storages.

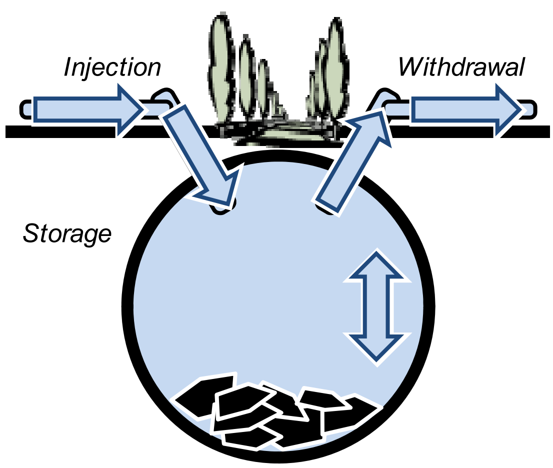

Figure 2-8 – Schematics of an underground storage

$$\min_{q_{sed}^{STO}, q_{sed}^{WTH}, q_{sed}^{INJ}} \quad \sum_{s,e,d} \left(CV_s^{STO} \cdot q_{sed}^{STO} + C_s^{INJ} \cdot q_{sed}^{INJ} + C_s^{WTH} \cdot q_{sed}^{WTH} \right)$$

$$\begin{aligned}
s.t. \quad & \textstyle\sum_e q_{sed}^{STO} \le Q_s^{STO} \quad \forall s,d \\
& f_{sd}^{STO} = \textstyle\sum_e q_{sed}^{INJ} - \sum_e q_{sed}^{WTH} \quad \forall s,d \\
& f_{sd}^{STO} \le Q_s^{INJ} - E_s^{INJ} \cdot \frac{\sum_e q_{sed}^{STO}}{Q_s^{STO}} \quad \forall s,d \\
& f_{sd}^{STO} \ge E_s^{WTH} \cdot \frac{Q_s^{STO} - \sum_e q_{sed}^{STO}}{Q_s^{STO}} - Q_s^{WTH} \quad \forall s,d \\
& f_{sd}^{STO} \ge 0 \quad \forall s, d \in d_s^{INJ} \\
& f_{sd}^{STO} \le 0 \quad \forall s, d \in d_s^{WTH} \\
& q_{sed}^{STO} - q_{se(d-1)}^{STO} = q_{sed}^{INJ} - q_{sed}^{WTH} \quad \forall s,e,d
\end{aligned}$$

2.4.4. Balancing zones

A balancing zone represents in a simplified manner[11] the gas transmission and distribution networks that connect an entry point to a downstream gas market with an exit point from a downstream gas market. Entry points include regasified gas from LNG terminals, withdrawals from underground storages, and imports from cross-border pipelines. Exit points include injections to underground storages, exports through cross-border pipelines, and consumers' demand instead. Balancing zones, which are indeed an equivalent of transmission and distribution networks, are modeled satisfying the flow conservation law as in models which represent balancing zones. Nevertheless, we do not only consider entries and exits, but also the storage capacity of pipelines.

According to entry-exit regulatory frameworks, gas transmission and/or distribution network owners may apply a tariff either to daily inflows CV_z^{IN} [€/GWh] to or to daily outflows CV_z^{OUT} [€/GWh] from a balancing zone. From aforesaid entry-exit points, imports and exports have already been addressed in section 2.4.2. Furthermore, injections to and withdrawals from underground storages are not commonly charged with an exit or entry tariff because gas is already flowing within the transmission and distribution networks and, injections and withdrawals would be double charged otherwise. Actually, injected or withdrawn gas has already been or will be charged with an entry tariff or exit tariff, respectively. Therefore, shippers minimize costs associated with entries from LNG terminals and exits due to consumers' demand:

[11] From the formulation point of view, balancing zones definition avoids the representation of the gas network and the complexity of calculating gas flows, which are defined by a non-linear equation (Martin et al. 2006). Although some authors have proposed linear approximations of the equation to calculate gas flows with optimization models (De Wolf, Smeers 2000; Muñoz et al. 2003; Martin et al. 2005; and Tomasgard et al. 2007), entry-exit systems do not require gas network modeling.

$$\min_{q_{red}^{REG}, d_{zed}^{TOT}} \sum_{z,e,d} \left(CV_z^{IN} \cdot \sum_{r \in z} q_{red}^{REG} + CV_z^{OUT} \cdot d_{zed}^{TOT} \right) \tag{2.25}$$

Consumers' demand d_{zed}^{TOT} [GWh] represents the aggregation of demand functions of, first, different customers, such as residential, commercial, and industrial customers, and GFPPs; and, second, different consumption points[12]. Although an exhaustive analysis of demand segmentation is out of the scope of this thesis, this topic is briefly treated in section 2.7.

Within a market area, there may be several balancing zones. The establishment of a balancing zone may depend on technical or non-technical factors, such as the existence of capacity constraints, the ownership of the transmission network, or the number of ISOs (see section 2.2). Whatever the case, the establishment of a balancing zone creates a new entry-exit point with another balancing zone. Inflows $f_{z'zed}^{ZON}$ [GWh] from balancing zone *z'* to balancing zone *z*, as well as outflows $f_{zz'ed}^{ZON}$ [GWh] from balancing *z* to balancing zone *z'*, may also be subject to entry-exit tariffs, whose associated costs are minimized by shippers:

$$\min_{f_{z'zed}^{ZON}, f_{zz'ed}^{ZON}} \sum_{z,z',e,d} \left(CV_z^{IN} \cdot f_{z'zed}^{ZON} + CV_z^{OUT} \cdot f_{zz'ed}^{ZON} \right) \tag{2.26}$$

Daily flows between balancing zones $f_{zz'd}^{ZON}$ [GWh] are defined as the sum of shippers' individual decisions taking account of backhaul capacity:

$$f_{zz'd}^{ZON} = \sum_e f_{zz'ed}^{ZON} - \sum_e f_{z'zed}^{ZON} \quad \forall z, z', d \tag{2.27}$$

Maximum daily flows in both directions $Q_{zz'}^{ZON}, Q_{z'z}^{ZON}$ [GWh] are established by technical parameters of the pipeline and compressor stations that connect both balancing zones:

$$-Q_{z'z}^{ZON} \le f_{zz'd}^{ZON} \le Q_{zz'}^{ZON} \quad \forall z, z', d \tag{2.28}$$

A minimum pressure is required within a pipeline to make it operative. The pressure is achieved by maintaining a quantity of gas inside it. Therefore, transmission and distribution networks can store a small quantity of gas, which is known as line-pack. Line-pack capacity can be modified by increasing the interior pressure, as long as the pressures at both ends are within the security range. The line-pack capacity of a balancing zone Q_z^{PCK} [GWh] can be used by shippers q_{zed}^{PCK} [GWh] for covering their demand in the (very) short term, that is, within the day:

[12] Actually, each customer is a consumption point. But with such a level of detail, the optimization problem would be computationally intractable.

$$\sum_{e} q_{zed}^{PCK} \leq Q_{z}^{PCK} \quad \forall z,d \tag{2.29}$$

A balancing zone not only represents the gas transmission and distribution networks in a simplified manner, but it also serves for monitoring daily shippers' balances among inflows, outflows, and inventory variations:

$$q_{zed}^{PCK} - q_{ze(d-1)}^{PCK} = \left\{ \begin{array}{l} \sum_{r \in z} q_{red}^{REG} + \sum_{s \in z} \left(q_{sed}^{WTH} - q_{sed}^{INJ} \right) + \\ \sum_{x} \left(q_{xzed}^{IMP} - q_{xzed}^{EXP} \right) - \sum_{z'} \left(f_{zz'ed}^{ZON} - f_{z'zed}^{ZON} \right) - d_{zed}^{TOT} \end{array} \right\} \quad \forall z,e,d \tag{2.30}$$

An ISO is commonly in charge of monitoring daily shippers' balances[13]. If the ISO observes a shortage or an excess on behalf of a shipper, the ISO will warn the shipper about the irregular situation. The shipper will have to put a remedy to the irregularity either purchasing or selling gas. Consequently, balancing zones are usually linked to balancing markets, in which the traded good is gas. Further details on balancing markets are shown in section 2.6.1 and Chapter 4.

The objective functions (2.25) and (2.26) subject to constraints (2.27)–(2.30) constitute a LP problem that optimizes shippers' decisions regarding inflows, outflows and inventory variations within balancing zones (Figure 2-9).

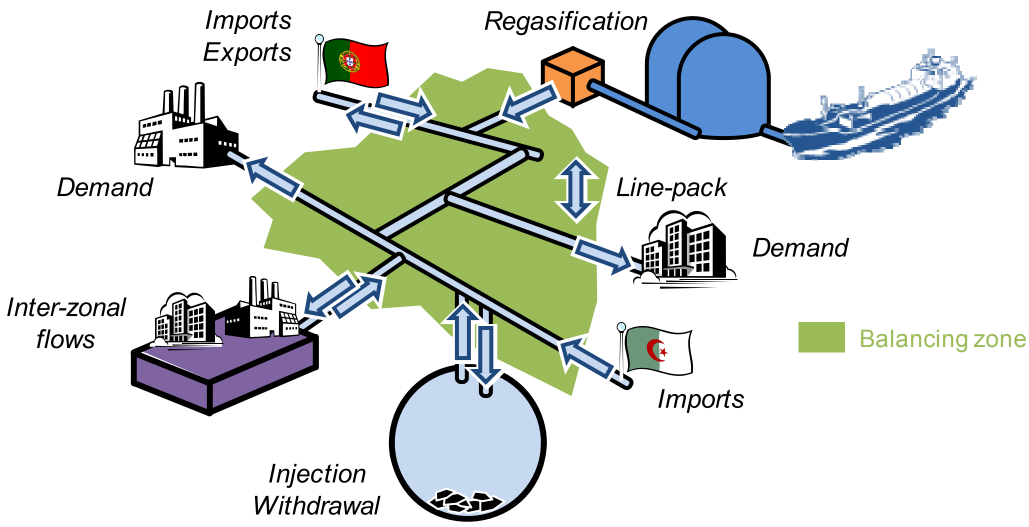

Figure 2-9 – Schematics of a balancing zone

Finally, LNG road tankers demand is represented straightforwardly, because it is much lower than consumers' demand through the transmission and distribution networks and, hence, a simplified representation does not change considerably the optimization pro-

[13] Daily balance monitoring is essential to assure a correct performance of the gas system and an accurate allocation of the inventories among shippers.

cess. Road tankers demand in a balancing zone d_{zed}^{TNK} is covered by the LNG terminal of the same balancing zone for geographical proximity reasons:

$$\sum_{r \in z} q_{red}^{TNK} = d_{zed}^{TNK} \quad \forall z,e,d \tag{2.31}$$

A detail description might require representing road tankers as integer variables, optimizing distances to consumption points from LNG terminals, or including storage capacities of isolated systems supplied by road tankers. In other words, developing a specific model with the objective of optimizing road tankers utilization would hold more interest than its influence on the whole market.

$$\begin{array}{ll}
\min\limits_{\substack{q_{red}^{REG}, d_{zed}^{TOT} \\ f_{z'zed}^{ZON}, f_{zz'ed}^{ZON}}} & \sum\limits_{z,e,d} \left(CV_z^{IN} \cdot \left(\sum\limits_{r \in z} q_{red}^{REG} + \sum\limits_{z'} f_{z'zed}^{ZON} \right) + CV_z^{OUT} \left(d_{zed}^{TOT} + \sum\limits_{z'} f_{zz'ed}^{ZON} \right) \right) \\
s.t. & f_{zz'd}^{ZON} = \sum_e \left(f_{zz'ed}^{ZON} - f_{z'zed}^{ZON} \right) \quad \forall z,z',d \\
 & -Q_{z'z}^{ZON} \le f_{zz'd}^{ZON} \le Q_{zz'}^{ZON} \quad \forall z,z',d \\
 & \sum_e q_{zed}^{PCK} \le Q_z^{PCK} \quad \forall z,d \\
 & q_{zed}^{PCK} - q_{ze(d-1)}^{PCK} = \left\{ \begin{array}{l} \sum\limits_{r \in z} q_{red}^{REG} + \sum\limits_{s \in z} \left(q_{sed}^{WTH} - q_{sed}^{INJ} \right) + \sum\limits_{x} \left(q_{xzed}^{IMP} - q_{xzed}^{EXP} \right) - \\ \sum\limits_{z'} \left(f_{zz'ed}^{ZON} - f_{z'zed}^{ZON} \right) - d_{zed}^{TOT} \end{array} \right\} \quad \forall z,e,d
\end{array}$$

2.5. Optimizing capacity contract portfolios

Contractual decision variables are related to shippers' capacity contracting decisions to make use of the infrastructure. Independent of the infrastructure, capacity contracts can be classified into different categories according to their duration:

- Long-term capacity contracts. Development of new, or extension of, usually capital-intensive facilities, such as LNG regasification terminals, underground storages, or transportation pipelines, requires huge investments. Gas facility owners need to assure a certain level of infrastructure utilization in order to recover their investments. For this reason, open season periods are commonly announced before starting the construction of gas facilities, so shippers can commit themselves to make future use of it. Open season periods are win-win games, in which the shippers reserve firm capacity to supply future consumers and the owners guarantee constant revenues to recover their investments. This commitment is formalized through long-term capacity contracts during, for instance, 5, 10, or 20 years, depending on the regulatory framework and the investment amount. The regulatory authorities, who are concerned about encouraging competition, may establish a threshold of maximum commitment, or long-term contracting, for new (or extended) facilities because long-term contracts commonly obstruct the entry of new shippers.

- Medium- and short-term capacity contracts. Residual capacity, which has not been contracted in the long term, can be contracted on a medium- or short-term basis. Medium- and short-term capacity contracts are usually standardized to encourage trading transactions in secondary capacity markets. Furthermore, capacity contracts sometimes include use-it-or-lose-it clauses, which oblige those shippers with spare contracted capacity to release it, favoring the entry of new shippers. Monthly (medium-term) and daily (short-term) capacity contracts are the most typical capacity contacts.

Long-term capacity allocation during open season periods normally goes along with a first-come first-served basis, although other mechanisms, such as pro-rata, can be used. Besides typical open season periods, capacity auctions are another possibility for capacity allocation. The main difference lies in resulting capacity prices: in the former option, regulatory frameworks usually establish (or approve) capacity prices that allow facility owners to recover their investments; in the latter option, capacity prices are determined by an auction. Free medium- or short-term capacity can be allocated on a first-come first-served basis accompanied again by explicit or implicit regulated prices. In addition, the regulated prices of medium- and short-term capacity contracts may vary monthly, or daily, to differentiate peak and off-peak periods within the year.

As a general rule, a shipper submits its daily operation decisions, commonly known as nominations, to an ISO. The ISO is in charge of verifying that a shipper holds enough contracted capacity and, after collecting other shippers' nominations, ensuring gas system stability. Exceptionally, and on condition that gas system stability is not compromised, the regulatory framework may allow a shipper to operate over its contracted capacity, i.e., overrunning its contracted capacity[14], although paying subsequent penalties. In order to avoid penalties, or when overruns are not permitted, a shipper can purchase capacity in secondary capacity markets (section 2.6.2), in which its competitors release and sell, voluntarily or forced, their unused contracted capacity. When secondary capacity markets are not competitive and liquid enough and regulatory authorities are unable to enforce use-it-or-lose-it clauses, shippers may have an incentive for capacity hoarding, even though capacity hoarding may imply paying an additional amount of money[15] over

[14] Some regulatory frameworks also allow infrastructure owners to offer capacity contracts that exceed the infrastructure nominal capacity. However, they also must include a priority access scheme as in the case of firm and interruptible capacity contracts.

[15] The difficulty of enforcing use-it-or-lose-it clauses conducts regulatory authorities to establish penalties to shippers that are underutilizing the infrastructure with respect to their contracted capacity.

regulated capacity prices. The consequences for the competitors may range from increasing costs due to overrun penalties to market closure. This sort of strategic behavior is not endogenously considered in this thesis, which represents a perfectly competitive market; however, their explicit introduction may be relevant to understand the market performance (Smeers 2008).

One relevant contribution of this thesis is the thorough formulation of capacity contracting decisions, which moreover condition the operation decisions mentioned above. Capacity contract formulations for regasification terminals, cross-border pipelines, underground storages, and balancing zones follow the same pattern, unlike operation decisions that depend on the infrastructure. For this reason, in the first place, we describe a general formulation and, then, indicate what capacities are subject to contracting in each infrastructure. In what follows, (×) is the placeholder for capacities: *REG*, *IMP*, *EXP*, *STO*, *IN*, *OUT*[16]; and (•) is the placeholder for indices: *r*, *x*, *s*, *z*.

Regarding capacity contracts temporal horizon, long-term capacity contracts $h^{\times}_{\bullet e}$ [GWh] span the whole simulation horizon (during several years), and medium- and short-term capacity contracts $h^{\times}_{\bullet em}, h^{\times}_{\bullet ed}$ [GWh] represent standardized monthly and daily capacity contracts, respectively. Regulated prices, which depend on the facility, are applied to long- $CF^{\times}_{\bullet}$ [€/GWh], medium- $CF^{\times}_{\bullet m}$ [€/GWh], and short-term $CF^{\times}_{\bullet d}$ [€/GWh] capacity contracts. Overruns $xh^{\times}_{\bullet ed}$ [GWh] are permitted, but penalized $CX^{\times}_{\bullet}$ [€/GWh].

Shippers minimize costs associated with contracting capacity decisions, that is, contract portfolios and overrunning costs:

$$\min_{\substack{h^{\times}_{\bullet e}, h^{\times}_{\bullet em} \\ h^{\times}_{\bullet ed}, xh^{\times}_{\bullet ed}}} \sum_{e} \left(CF^{\times}_{\bullet} \cdot h^{\times}_{\bullet e} + \sum_{m} \left(CF^{\times}_{\bullet m} \cdot h^{\times}_{\bullet em} \right) + \sum_{d} \left(CF^{\times}_{\bullet d} \cdot h^{\times}_{\bullet ed} + CX^{\times}_{\bullet} \cdot xh^{\times}_{\bullet ed} \right) \right) \tag{2.32}$$

Everyday each shipper holds a portfolio $th^{\times}_{\bullet ed}$ [GWh] of long-, medium-, and short-term capacity contracts[17]:

$$th^{\times}_{\bullet ed} = h^{\times}_{\bullet e} + h^{\times}_{\bullet em} + h^{\times}_{\bullet ed} \quad \forall e, m/d \in m, d \tag{2.33}$$

Shippers' total contract portfolios are constrained by infrastructure maximum capacities $Q^{\times}_{\bullet}$ [GWh]:

[16] Some of these abbreviations have been already employed, but some are new. As a reminder, *REG*, *IMP*, *EXP* and *STO* stands for regasification, import, export and storage capacities, respectively; while new *IN* corresponds to entry capacities from LNG terminals and neighboring balancing zones; and *OUT* to exit capacities to neighboring balancing zones and to consumers' demand, respectively.

[17] Observe that overruns do not "contribute to" contract portfolios, as they are not indeed a type of capacity contract.

$$\sum_{e} th^{\times}_{\bullet ed} \leq Q^{\times}_{\bullet} \quad \forall d \tag{2.34}$$

In addition, the regulatory authorities usually impose maximum commitment thresholds K [%] (habitually, the same to every facility), which oblige the owners to offer medium- and short-term capacity contracts to shippers with the final objective of encouraging competition:

$$\sum_{e} h^{\times}_{\bullet e} \leq K \cdot Q^{\times}_{\bullet} \tag{2.35}$$

As aforementioned, operation decisions are authorized by an ISO when a shipper has contracted enough capacity, or when overrunning its contracted capacity does not compromise the operational integrity of the system:

$$q^{\times}_{\bullet ed} \leq th^{\times}_{\bullet ed} + xh^{\times}_{\bullet ed} \quad \forall e,d \tag{2.36}$$

The resulting LP problem from aggregating the objective function (2.32) and constraints (2.33)–(2.36) optimizes shippers' capacity contracting decisions.

So far, we have defined the general formulation for optimal capacity contracting. However, each facility has its own peculiarities that, although, they do not modify the above formulation, they do determine the specific capacity to be contracted.

2.5.1. LNG regasification terminals

From previously described operational activities in LNG terminals, gas exits (i.e., regasification and road tankers loading) determines the facility dimension, because the number and dimension of berths and LNG tanks depend mainly on regasification capacity and, residually, on road tanker loading capacity. We consider, as it occurs in some regulatory frameworks, that LNG terminal owners offer capacity contracts for regasification capacity and may offer capacity contracts for road tanker loading capacity. Other activities, such as reception and unloading carriers, and LNG storage services, are subject to contracting regasification capacity. As road tanker loading is a small fraction of gas exits (typically, 3% to 7% in capacity terms), the formulation only includes regasification capacity contracts, which in turn entitle shippers to berth and unload carriers, to store LNG in the tanks, and to load road tankers.

Shippers optimize their long-, medium-, and short-term capacity contract portfolio:

$$\min_{\substack{h^{REG}_{re}, h^{REG}_{rem} \\ h^{REG}_{red}, xh^{REG}_{red}}} \sum_{r,e} \left(CF^{REG}_{r} \cdot h^{REG}_{re} + \sum_{m} \left(CF^{REG}_{rm} \cdot h^{REG}_{rem} \right) + \sum_{d} \left(CF^{REG}_{rd} \cdot h^{REG}_{red} + CX^{REG}_{r} \cdot xh^{REG}_{red} \right) \right) \tag{2.37}$$

$$th^{REG}_{red} = h^{REG}_{re} + h^{REG}_{rem} + h^{REG}_{red} \quad \forall r,e,m/d \in m,d \tag{2.38}$$

$$\sum\nolimits_{e} th_{red}^{REG} \leq Q_{r}^{REG} \quad \forall r,d \tag{2.39}$$

$$\sum\nolimits_{e} h_{re}^{REG} \leq K \cdot Q_{r}^{REG} \quad \forall r \tag{2.40}$$

$$q_{red}^{REG} \leq th_{red}^{REG} + xh_{red}^{REG} \quad \forall r,e,d \tag{2.41}$$

2.5.2. Cross-border pipelines

Both gas pipeline design and compressor station installation, which account for most of the investment amount, determine the import and/or export capacities. Correspondingly, cross-border pipeline owners offer import and/or export capacity contracts; and shippers optimize their long-, medium-, and short-term capacity contract portfolio:

$$\min_{\substack{h_{xze}^{IMP}, h_{xzem}^{IMP} \\ h_{xzed}^{IMP}, xh_{xzed}^{IMP}}} \sum_{x,z,e} \left(CF_{xz}^{IMP} \cdot h_{xze}^{IMP} + \sum\nolimits_{m} \left(CF_{xzm}^{IMP} \cdot h_{xzem}^{IMP} \right) + \sum\nolimits_{d} \left(CF_{xzd}^{IMP} \cdot h_{xzed}^{IMP} + CX_{xz}^{IMP} \cdot xh_{xzed}^{IMP} \right) \right) \tag{2.42}$$

$$th_{xzed}^{IMP} = h_{xze}^{IMP} + h_{xzem}^{IMP} + h_{xzed}^{IMP} \quad \forall x,z,e,m/d \in m,d \tag{2.43}$$

$$\sum\nolimits_{e} th_{xzed}^{IMP} \leq Q_{xz}^{IMP} \quad \forall x,z,d \tag{2.44}$$

$$\sum\nolimits_{e} h_{xze}^{IMP} \leq K \cdot Q_{xz}^{IMP} \quad \forall x,z \tag{2.45}$$

$$q_{xzed}^{IMP} \leq th_{xzed}^{IMP} + xh_{xzed}^{IMP} \quad \forall x,z,e,d \tag{2.46}$$

$$\min_{\substack{h_{xze}^{EXP}, h_{xzem}^{EXP} \\ h_{xzed}^{EXP}, xh_{xzed}^{EXP}}} \sum_{x,z,e} \left(CF_{xz}^{EXP} \cdot h_{xze}^{EXP} + \sum\nolimits_{m} \left(CF_{xzm}^{EXP} \cdot h_{xzem}^{EXP} \right) + \sum\nolimits_{d} \left(CF_{xzd}^{EXP} \cdot h_{xzed}^{EXP} + CX_{xz}^{EXP} \cdot xh_{xzed}^{EXP} \right) \right) \tag{2.47}$$

$$th_{xzed}^{EXP} = h_{xze}^{EXP} + h_{xzem}^{EXP} + h_{xzed}^{EXP} \quad \forall x,z,e,m/d \in m,d \tag{2.48}$$

$$\sum\nolimits_{e} th_{xzed}^{EXP} \leq Q_{xz}^{EXP} \quad \forall x,z,d \tag{2.49}$$

$$\sum\nolimits_{e} h_{xze}^{EXP} \leq K \cdot Q_{xz}^{EXP} \quad \forall x,z \tag{2.50}$$

$$q_{xzed}^{EXP} \leq th_{xzed}^{EXP} + xh_{xzed}^{EXP} \quad \forall x,z,e,d \tag{2.51}$$

In case of import or export capacity congestions, backhaul flows can partially alleviate the congestion only if overruns are permitted. If not, backhaul flows could not occur as additional capacity would not be available. Because backhaul flows are indeed good to improve market performance, habitually, overruns are weakly penalized (if anything).

2.5.3. Storage facilities

Within storage facilities, LNG tanks are necessary for a proper performance of regasification terminals, but LNG storage is not a reason to build LNG terminals. Line-pack capacity within pipelines is a residual result of gas transportation, but pipelines are not built to fulfill storage objectives. Therefore, underground storages are by far the most relevant facility for the seasonal storage of gas in the system. Underground storage owners offer storage capacity contracts, as storing capacity is the main parameter of these facilities. These capacity contracts habitually entitle the shippers to utilize injection and withdrawal services, whose capacities are often allocated in a first-come first-served basis.

Shippers optimize their long-, medium-, and short-term capacity contract portfolio:

$$\min_{\substack{h_{se}^{STO},h_{sem}^{STO}\\ h_{sed}^{STO},xh_{sed}^{STO}}} \sum_{s,e}\left(CF_s^{STO}\cdot h_{se}^{STO}+\sum\nolimits_m\left(CF_{sm}^{STO}\cdot h_{sem}^{STO}\right)+\sum\nolimits_d\left(CF_{sd}^{STO}\cdot h_{sed}^{STO}+CF_s^{STO}\cdot xh_{sed}^{STO}\right)\right) \quad (2.52)$$

$$th_{sed}^{STO}=h_{se}^{STO}+h_{sem}^{STO}+h_{sed}^{STO} \quad \forall s,e,m/d\in m,d \quad (2.53)$$

$$\sum\nolimits_e th_{sed}^{STO}\leq Q_s^{STO} \quad \forall s,d \quad (2.54)$$

$$\sum\nolimits_e h_{se}^{STO}\leq K\cdot Q_s^{STO} \quad \forall s \quad (2.55)$$

$$q_{sed}^{STO}\leq th_{sed}^{STO}+xh_{sed}^{STO} \quad \forall s,e,d \quad (2.56)$$

2.5.4. Balancing zones

Gas transmission and distribution networks are melted into balancing zones, except in entry and exit points where capacities are known and, therefore, offered to shippers as capacity contracts. Entry points include regasified LNG from regasification terminals and flows from neighboring balancing zones, whereas exit points include consumers' demands and flows to neighboring balancing zones[18]. Other entry-exit points, like cross-border pipelines and their corresponding import and export capacity contracts, have already been formulated. Moreover, entry-exit capacities of pipeline connections with underground storages are not subject to contract since their utilization depends on holding underground storage capacity contracts.

Although there may be different transportation and distribution pipeline ownerships, an ISO is normally in charge of offering entry and exit capacity, and of sharing the takings among the owners. As a matter of fact, regulated tariffs are usually calculated all together to recover total system costs irrespective of temporal or spatial considerations, which may distort the economic signals for a proper temporal consumption pattern or consumers' localization (Vazquez et al. 2012).

Shippers optimize their long-, medium-, and short-term capacity contract portfolio at entry points:

[18] In order to consider entry-exit points of neighboring balancing zones, these must be enclosed in the same market area, because otherwise these connections are cross-border pipelines

$$\min_{\substack{h^{IN}_{rze},h^{IN}_{rzem}\\h^{IN}_{rzed},xh^{IN}_{rzed}}} \sum_{r,z,e}\left(CF^{IN}_z\cdot h^{IN}_{rze}+\sum\nolimits_m\left(CF^{IN}_{zm}\cdot h^{IN}_{rzem}\right)+\sum\nolimits_d\left(CF^{IN}_{zd}\cdot h^{IN}_{rzed}+CX^{IN}_z\cdot xh^{IN}_{rzed}\right)\right) \quad (2.57)$$

$$th^{IN}_{rzed}=h^{IN}_{rze}+h^{IN}_{rzem}+h^{IN}_{rzed} \quad \forall r,z,e,m/d\in m,d \quad (2.58)$$

$$\sum\nolimits_e th^{IN}_{rzed}\le Q^{REG}_r \quad \forall r\in z,z,d \quad (2.59)$$

$$\sum\nolimits_e h^{IN}_{rze}\le K\cdot Q^{REG}_r \quad \forall r\in z,z,d \quad (2.60)$$

$$q^{REG}_{red}\le th^{IN}_{rzed}+xh^{IN}_{rzed} \quad \forall r\in z,z,e,d \quad (2.61)$$

$$\min_{\substack{h^{IN}_{z'ze},h^{IN}_{z'zem}\\h^{IN}_{z'zed},xh^{IN}_{z'zed}}} \sum_{z',z,e}\left(CF^{IN}_z\cdot h^{IN}_{z'ze}+\sum\nolimits_m\left(CF^{IN}_{zm}\cdot h^{IN}_{z'zem}\right)+\sum\nolimits_d\left(CF^{IN}_{zd}\cdot h^{IN}_{z'zed}+CX^{IN}_z\cdot xh^{IN}_{z'zed}\right)\right) \quad (2.62)$$

$$th^{IN}_{z'zed}=h^{IN}_{z'ze}+h^{IN}_{z'zem}+h^{IN}_{z'zed} \quad \forall z',z,e,m/d\in m,d \quad (2.63)$$

$$\sum\nolimits_e th^{IN}_{z'zed}\le Q^{ZON}_{z'z} \quad \forall z',z,d \quad (2.64)$$

$$\sum\nolimits_e h^{IN}_{z'ze}=K\cdot Q^{ZON}_{z'z} \quad \forall z',z,d \quad (2.65)$$

$$f^{ZON}_{z'zed}\le th^{IN}_{z'zed}+xh^{IN}_{z'zed} \quad \forall z',z,e,d \quad (2.66)$$

Maximum entry capacity from a LNG terminal is established by its regasification capacity (if we assume that the transportation pipeline has been correctly designed); while from a neighboring balancing zone is limited by the inter-zonal capacity.

Similarly, shippers optimize their long-, medium-, and short-term capacity contract portfolio at exit points:

$$\min_{\substack{h^{OUT}_{ze},h^{OUT}_{zem}\\h^{OUT}_{zed},xh^{OUT}_{zed}}} \sum_{z,e}\left(CF^{OUT}_z\cdot h^{OUT}_{ze}+\sum\nolimits_m\left(CF^{OUT}_{zm}\cdot h^{OUT}_{zem}\right)+\sum\nolimits_d\left(CF^{OUT}_{zd}\cdot h^{OUT}_{zed}+CX^{OUT}_z\cdot xh^{OUT}_{zed}\right)\right) \quad (2.67)$$

$$th^{OUT}_{zed}=h^{OUT}_{ze}+h^{OUT}_{zem}+h^{OUT}_{zed} \quad \forall z,e,m/d\in m,d \quad (2.68)$$

$$\sum\nolimits_e th^{OUT}_{zed}\le Q^{DEM}_z \quad \forall z,d \quad (2.69)$$

$$\sum\nolimits_e h^{OUT}_{ze}\le K\cdot Q^{DEM}_z \quad \forall z,d \quad (2.70)$$

$$d^{TOT}_{zed}\le th^{OUT}_{zed}+xh^{OUT}_{zed} \quad \forall z,e,d \quad (2.71)$$

$$\min_{\substack{h^{OUTz}_{zz'e},h^{OUTz}_{zz'em}\\h^{OUTz}_{zz'ed},xh^{OUTz}_{zz'ed}}} \sum_{z,z',e}\left(CF^{OUT}_z\cdot h^{OUT}_{zz'e}+\sum\nolimits_m\left(CF^{OUT}_{zm}\cdot h^{OUT}_{zz'em}\right)+\sum\nolimits_d\left(CF^{OUT}_{zd}\cdot h^{OUT}_{zz'ed}+CX^{OUT}_z\cdot xh^{OUT}_{zz'ed}\right)\right) \quad (2.72)$$

$$th^{OUT}_{zz'ed}=h^{OUT}_{zz'e}+h^{OUT}_{zz'em}+h^{OUT}_{zz'ed} \quad \forall z,z',e,m/d\in m,d \quad (2.73)$$

$$\sum\nolimits_e th^{OUT}_{zz'ed}\le Q^{ZON}_{zz'} \quad \forall z,z',d \quad (2.74)$$

$$\sum\nolimits_e h^{OUT}_{zz'e}=K\cdot Q^{ZON}_{zz'} \quad \forall z,z',d \quad (2.75)$$

$$f^{ZON}_{zz'ed}\le th^{OUT}_{zz'ed}+xh^{OUT}_{zz'ed} \quad \forall z,z',e,d \quad (2.76)$$

Total exit capacity Q_z^{DEM} represents the aggregated peak demand that can be provided to consumers. If the demand were segmented, the total exit capacity could be separated according to pressure levels and consumer types. Similar to the entry capacity case, the exit capacity to a neighboring balancing zone is limited by the inter-zonal capacity. Furthermore, in case of entry or exit inter-zonal congestions, backhaul flows may solve a congestion as long as overruns are allowed because, as with cross-border pipelines, additional capacity to be contracted would not be available.

2.6. Shippers' interaction in balancing and capacity markets

Gas markets have traditionally relied on long-term bilateral contracts for covering gas demand. Producers signed long-term supply contracts with shippers, usually in the context of a win-win game, in which producers guarantee the recovery of their huge investments in capital-intensive facilities and shippers guarantee a firm supply at prices well-known in advance. Besides, shippers signed long-term capacity contracts with infrastructure owners in the context of another win-win game already explained. Finally, consumers, like industries or local authorities on behalf of households, signed long-term contracts with shippers for similar reasons. Nowadays, because the traditional framework can be found in similar terms or with slight variations in many regions worldwide, producers, shippers and consumers still sign these long-term contracts. For instance, point-to-point systems do reproduce the traditional framework structure, but introducing competition among shippers and even among gas transmission network owners (Makholm, 2012). Alternatively, entry-exit systems that (seem to) suppose a rupture with the traditional framework, however, share some common elements with the traditional framework (especially, concerning long-term supply and capacity contracts). In both cases, the major change is the opening of the market to competition, whose main consequence is the interaction among shippers in downstream gas systems. This interaction is reflected in two sub-markets: balancing OTC markets and secondary capacity markets.

2.6.1. Balancing OTC markets

One fundamental difference between point-to-point systems and entry-exit systems is the possibility of tracking every "molecule" of gas flowing within the pipelines. Entry-exit systems, whose main characteristic is embedding transmission and distribution networks in balancing zones, automatically reject this possibility. Therefore, a way to monitor that each shipper covers its demand with its own gas is necessary. An ISO is commonly in charge of monitoring shippers' entries, exits, and inventory variations within a balancing zone. And not only the ISO, but the facility owners look after the shippers' balances in their facilities. The day is widely used as the time unit in entry-exit systems in order to monitor balances, although gas characteristics (particularly, the storage possibility) may allow considering other time units. In contrast, electric power systems require an instantaneous balance between supply and demand as electricity cannot be stored at competitive costs yet.

Shippers can control their entries to a market area through regasification terminals or cross-border pipelines, but their demand is habitually out of their control due to uncertainty. Although they can submit accurate forecasts in advance to the ISO or to facility owners, real-time operation decisions may differ from in advance forecasts. In addition, LNG carrier arrivals are discrete and temporarily distant. Consequently, any shipper may find itself (positively or negatively) unbalanced at the end of the day. However, a shipper can solve this situation and comply with daily balance requirements by trading with other shippers. In fact, some shippers will present an excess (positive unbalance), while other shippers will present a shortage (negative unbalance) of gas. Before the formation of organized platforms, such as the virtual and physical European hubs (British NBP, Dutch TTF, Belgian Zeebrugge, French PEG, Italian PSV, etc.), shippers traded (and still trade) in OTC markets. As most organized platforms have been constituted recently and are still immature, except NBP and probably TTF in Europe, only OTC bilateral operations are represented herein, leaving the introduction of an organized platform, a hub or spot market, to Chapter 4. In addition, since the major objective of these operations is balancing, we model those balancing markets in which shippers collaborate among themselves transferring gas today in exchange of a future return of gas (physical swaps). In other words, there are no money transfers like in spot markets. Naturally, these operations cannot be maintained open indefinitely because, otherwise, price spreads can become relevant. Therefore, positions should be closed in a short-time period in order to avoid large price disparities. To the author's knowledge, physical swaps have not been represented in current gas market models.

Within entry-exit gas systems, transfers and returns are possible where gas can be stored, that is, inside LNG tanks, storage facilities and pipelines:

$$\sum_e q_{red}^{\Delta LNG} = \sum_e q_{red}^{\nabla LNG} \quad \forall r,d \tag{2.77}$$

$$\sum_e q_{sed}^{\Delta STO} = \sum_e q_{sed}^{\nabla STO} \quad \forall s,d \tag{2.78}$$

$$\sum_e q_{zed}^{\Delta PCK} = \sum_e q_{zed}^{\nabla PCK} \quad \forall z,d \tag{2.79}$$

In short, transfers and returns are represented by an increase $q_{red}^{\Delta LNG}, q_{sed}^{\Delta STO}, q_{zed}^{\Delta PCK}$ or a decrease $q_{red}^{\nabla LNG}, q_{sed}^{\nabla STO}, q_{zed}^{\nabla PCK}$ in gas inventories within a LNG terminal, a storage facility and a pipeline (contained in a balancing zone) due to an OTC operation, respectively.

Shippers perform OTC bilateral operations in the search of balancing their entries, exits and inventory variations daily. Balancing equations (2.12), (2.24) and (2.30) are accordingly modified:

$$q_{red}^{LNG} - q_{re(d-1)}^{LNG} = \sum_{i,w} q_{irwed}^{ULD} - q_{red}^{REG} - q_{red}^{TNK} + q_{red}^{\Delta LNG} - q_{red}^{\nabla LNG} \quad \forall r, e, d \tag{2.80}$$

$$q_{sed}^{STO} - q_{se(d-1)}^{STO} = q_{sed}^{INJ} - q_{sed}^{WTH} + q_{sed}^{\Delta STO} - q_{sed}^{\nabla STO} \quad \forall s, e, d \tag{2.81}$$

$$q_{zed}^{PCK} - q_{ze(d-1)}^{PCK} = \begin{Bmatrix} \sum_{r \in z} q_{red}^{REG} + \sum_{s \in z} \left(q_{sed}^{WTH} - q_{sed}^{INJ} \right) + \sum_{x} \left(q_{xzed}^{IMP} - q_{xzed}^{EXP} \right) - \\ \sum_{z'} \left(f_{zz'ed}^{ZON} - f_{z'zed}^{ZON} \right) - d_{zed}^{TOT} + q_{zed}^{\Delta PCK} - q_{zed}^{\nabla PCK} \end{Bmatrix} \quad \forall z, e, d \tag{2.82}$$

Let us assume that every shipper closes all its positions during a moving week in the same type of infrastructure, and of the same market area. For instance, if shipper A transfers LNG to shipper B in terminal C, shipper B can return LNG to shipper A in terminal D, being both regasification terminals in the same market area. However, shipper B cannot return gas in storage facilities or as line-pack in pipelines in exchange for LNG because depending on the place where gas is stored, a shipper faces different tariffs[19]:

$$\sum_{r \in a, d'=d}^{d+7} \left(q_{red'}^{\Delta LNG} - q_{red'}^{\nabla LNG} \right) = 0 \quad \forall e, d \tag{2.83}$$

$$\sum_{s \in a, d'=d}^{d+7} \left(q_{sed'}^{\Delta STO} - q_{sed'}^{\nabla STO} \right) = 0 \quad \forall e, d \tag{2.84}$$

$$\sum_{z \in a, d'=d}^{d+7} \left(q_{zed'}^{\Delta PCK} - q_{zed'}^{\nabla PCK} \right) = 0 \quad \forall e, d \tag{2.85}$$

Constraints (2.83)–(2.85) characterize the final result of aggregating multiple individual physical swaps of different pairs of shippers closing their positions.

2.6.2. Secondary capacity markets

We have previously mentioned that infrastructure utilization requires contracting. At the same time, market mechanisms that allow a shipper to release its unused capacity and another shipper to acquire the unused released capacity favor the entry of new shippers and encourage competition. ISOs and facility owners commonly provide electronic platforms to reduce transaction costs and facilitate cession agreements, which regularly expire at the end of the day. Organized capacity markets are established where capacity contracts are offered (regasification terminals, cross-border pipelines, storage facilities,

[19] For instance, underground storage tariffs are typically cheaper than LNG storage tariffs because the former facilities maintain strategic reserves. In addition, a gas molecule in a LNG tank faces more tariffs than a gas molecule in a pipeline before being delivered to a consumer.

and balancing zones); although OTC markets at higher transaction costs may happen naturally if organized markets are not available. With the incorporation of secondary capacity markets, we complete the modeling of capacity contracting decisions, which is one of the main contributions of this thesis.

Daily acquisitions $h_{\bullet ed}^{\Delta\times}$ and releases $h_{\bullet ed}^{\nabla\times}$ of unused capacity[20] are possible in those facilities where capacity contracts are offered:

$$\sum_e h_{\bullet ed}^{\Delta\times} = \sum_e h_{\bullet ed}^{\nabla\times} \quad \forall d \tag{2.86}$$

These operations modify the daily portfolio of capacity contracts (2.33):

$$th_{\bullet ed}^{\times} = h_{\bullet e}^{\times} + h_{\bullet em}^{\times} + h_{\bullet ed}^{\times} + h_{\bullet ed}^{\Delta\times} - h_{\bullet ed}^{\nabla\times} \quad \forall e, m, d \in m \tag{2.87}$$

This general formulation is easily adapted to different facilities where capacity contracts are offered. Firstly, in LNG terminals, shippers can acquire and release unused regasification capacity contracts:

$$\sum_e h_{red}^{\Delta REG} = \sum_e h_{red}^{\nabla REG} \quad \forall r, d \tag{2.88}$$

$$th_{red}^{REG} = h_{re}^{REG} + h_{rem}^{REG} + h_{red}^{REG} + h_{red}^{\Delta REG} - h_{red}^{\nabla REG} \quad \forall r, e, m, d \in m \tag{2.89}$$

Secondly, in cross-border pipelines, unused import and export capacity contracts can be released and acquired by shippers:

$$\sum_e h_{xzed}^{\Delta IMP} = \sum_e h_{xzed}^{\nabla IMP} \quad \forall x, z, d \tag{2.90}$$

$$th_{xzed}^{IMP} = h_{xze}^{IMP} + h_{xzem}^{IMP} + h_{xzed}^{IMP} + h_{xzed}^{\Delta IMP} - h_{xzed}^{\nabla IMP} \quad \forall x, z, e, m, d \in m \tag{2.91}$$

$$\sum_e h_{xzed}^{\Delta EXP} = \sum_e h_{xzed}^{\nabla EXP} \quad \forall x, z, d \tag{2.92}$$

$$th_{xzed}^{EXP} = h_{xze}^{EXP} + h_{xzem}^{EXP} + h_{xzed}^{EXP} + h_{xzed}^{\Delta EXP} - h_{xzed}^{\nabla EXP} \quad \forall x, z, e, m, d \in m \tag{2.93}$$

Thirdly, in storage facilities, shippers can release unused storage capacity, as well as other shippers can acquire the released capacity:

$$\sum_e h_{sed}^{\Delta STO} = \sum_e h_{sed}^{\nabla STO} \quad \forall s, d \tag{2.94}$$

$$th_{sed}^{STO} = h_{se}^{STO} + h_{sem}^{STO} + h_{sed}^{STO} + h_{sed}^{\Delta STO} - h_{sed}^{\nabla STO} \quad \forall s, e, m, d \in m \tag{2.95}$$

Finally, in balancing zones, shippers can trade with (that is, acquire and release) unused entry capacity contracts:

[20] The placeholders (×) and (•) stand for the same capacities and indices as in section 2.5.

$$\sum_e h_{rzed}^{\Delta IN} = \sum_e h_{rzed}^{\nabla IN} \quad \forall r,z,d \tag{2.96}$$

$$th_{rzed}^{IN} = h_{rze}^{IN} + h_{rzem}^{IN} + h_{rzed}^{IN} + h_{rzed}^{\Delta IN} - h_{rzed}^{\nabla IN} \quad \forall r,z,e,m,d \in m \tag{2.97}$$

$$\sum_e h_{z'zed}^{\Delta IN} = \sum_e h_{z'zed}^{\nabla IN} \quad \forall z',z,d \tag{2.98}$$

$$th_{z'zed}^{IN} = h_{z'ze}^{IN} + h_{z'zem}^{IN} + h_{z'zed}^{IN} + h_{z'zed}^{\Delta IN} - h_{z'zed}^{\nabla IN} \quad \forall z',z,e,m,d \in m \tag{2.99}$$

And unused exit capacity contracts:

$$\sum_e h_{zed}^{\Delta OUT} = \sum_e h_{zed}^{\nabla OUT} \quad \forall z,d \tag{2.100}$$

$$th_{zed}^{OUT} = h_{ze}^{OUT} + h_{zem}^{OUT} + h_{zed}^{OUT} + h_{zed}^{\Delta OUT} - h_{zed}^{\nabla OUT} \quad \forall z,e,m,d \in m \tag{2.101}$$

$$\sum_e h_{zz'ed}^{\Delta OUT} = \sum_e h_{zz'ed}^{\nabla OUT} \quad \forall z,z',d \tag{2.102}$$

$$th_{zz'ed}^{OUT} = h_{zz'e}^{OUT} + h_{zz'em}^{OUT} + h_{zz'ed}^{OUT} + h_{zz'ed}^{\Delta OUT} - h_{zz'ed}^{\nabla OUT} \quad \forall z,z',e,m,d \in m \tag{2.103}$$

One of the main advantages that secondary capacity markets offer is facilitating a mechanism to reduce long-term contracts rigidity. In addition, it is worth mentioning, although out of the scope of this thesis, that secondary capacity markets may be a valuable support to tackle with capacity hoarding opportunities when dominant shippers are interested in establishing barriers to newcomers.

2.7. A few words about the demand

Two demand types have been defined in a balancing zone: consumers' demand d_{zed}^{TOT}, and LNG road tankers demand d_{zed}^{TNK} (section 2.4.4). Their main distinction is the different path that each type of demand follows from the supply point to the consumption point. Whereas consumers' demand in a balancing zone does make use of (transmission and distribution) pipelines embedded in a balancing zone, road tankers convey gas from LNG terminals to habitually small isolated systems by, not surprisingly, road.

Simultaneously, the former type of demand can be segmented into different categories according to its final use. One of the most usual segmentations distinguishes among demand for heating purposes (domestic, commercial), demand for electricity generation and demand for other purposes (for instance, manufacturing). It is not the objective of this thesis to explore the demand functions of different consumers and group them into different segments. Nevertheless, for its recent and growing importance to gas markets the demand is segmented in GFPP demand D_{zed}^{GFPP}, and conventional demand D_{zed}^{CNV} that includes demand for heating and other purposes. Chapter 5 highlights the GFPP demand relevance and its interaction with conventional demand.

Both demands are considered as inelastic because gas prices have not been included yet. Furthermore, both demands are known and exogenous. GFPP gas consumption can be forecasted with an electric power market model that has such an objective (Centeno et al. 2007). Another interesting topic is the analysis of the coordination and integration of both electric power and gas systems, which is addressed in Chapter 5. Regarding the conventional demand, although shippers are competing in gas markets to increase their market share, it is not the intention of this thesis to conduct a detailed analysis of retail markets, for instance, modeling the consumers' switching rate among companies. Consequently, each shipper covers a constant and known conventional demand. Different models, such as (Liu et al. 1991) and (Sánchez et al. 2007), can support shippers in forecasting their conventional demand.

2.8. Description of the Iberian natural gas market

Since 2008, Spain and Portugal have been working together with the objective of establishing a common gas market. This initiative has its framework in the European Commission recommendation for the constitution of regional markets in search of the final consecution of a single market. Furthermore, the structure of the Iberian gas market (hereinafter, MIBGAS) makes it a paradigm for the analysis of operation and contracting decisions in entry-exit gas markets. For this reason, the case study is inspired by MIBGAS, replicating its physical and market structure. In contrast, the Spanish and Portuguese regulatory frameworks are (slightly) adapted to the above exposed regulatory framework, which nonetheless does not suppose a great deal as both countries have transposed the EU energy directives. It is important to highlight that the constitution of MIBGAS has not finished yet and, therefore, there are still two differentiated market areas with their own regulatory frameworks: Spain and Portugal[21].

Despite the main intention of the case study is to show the performance of the model, for the sake of reality, an effort has been carried out to gather real technical and market data. In what follows, the set of data is public information corresponding to 2012 that can be found on the web pages of the Spanish and Portuguese gas ISOs and/or regulatory authorities and the electricity market operator[22]. If some information was not available and had to be estimated, this is clearly stated during the exposition.

[21] Even though both regulatory frameworks are substituted for a general regulatory framework, both separated market areas are maintained in the case study to replicate the tariff structure differences.

[22] Enagas is the Spanish gas ISO (www.enagas.es); REN is the Portuguese gas ISO (www.ren.pt). CNE is the Spanish regulatory authority (www.cne.es); ERSE is the Portuguese regulatory authority (www.erse.pt).

Figure 2-10 – MIBGAS picture

A general system picture (Figure 2-10) might be helpful to follow the whole description. The situation of MIBGAS at the end of 2012 is the following:

- Spain is divided into five balancing zones, named Levante, Catalunya, Ebro, Noroeste and Centro. Not every balancing zone is interconnected with each other. For instance, Noroeste is in practice isolated[23]. Portugal is constituted as one balancing zone.
- Each balancing zone has at least one LNG terminal: two in Levante (Cartagena and Sagunto); one in Catalunya (Barcelona); one in Ebro (Bilbao); one in Centro (Huelva); one in Noroeste (Mugardos); and one in Portugal (Sines).
- Each market area has at least one large storage facility. Two underground storages are located in Ebro (Gaviota and Serrablo); and another one is located in Portugal (Carriço).

Spain and Portugal have merged their electricity markets in a single market, known as MIBEL. Information on GFPP daily production is provided by the market operator at the Spanish side, OMIE (www.omie.es).

[23] Actually, Noroeste has reduced capacity interconnection with Centro, and only through backhaul flows (i.e., a shipper displaces gas from Noroeste to Centro when another shipper displaces gas in the other direction).

- The two market areas, Spain and Portugal, are interconnected by two cross-border pipelines, Badajoz (between Portugal and Centro) and Tuy (between Portugal and Noroeste).
- The geographic position of the Iberian Peninsula makes it a crossing point from the significant Algerian gas fields to Central European consumers. For this reason, Southern Spain is connected to the Algerian fields through two cross-border pipelines, one arriving to Tarifa in Centro, and another to Almeria in Levante. At the North, two cross-border pipelines, Larrau and Irún, are connecting Spain to France, both of them departing from Ebro.

The main objective of the case study is to examine the behavior of the shippers in a perfectly competitive context; i.e., how shippers would operate and contract for capacity when they minimize operation and contracting costs (or equivalently, maximize the net social welfare). Nevertheless, sensitivity analyses are carried out during the case study to evaluate situations that take place in imperfect markets, like real downstream gas markets.

Next subsection provides a full description of the physical system, including some essential numbers to track the case study. Afterward, the market structure is explained, in particular, focusing on demand characteristics (segmentation, number of shippers, market shares) and simplifications of supply activity, which is actually addressed in Chapter 3. At last, the main differences between the adopted regulatory framework and current (Spanish and Portuguese) regulatory frameworks are briefly exposed.

2.8.1. Technical details of the physical system

Both Spain and Portugal exhibit low gas penetration rates (below 30%) in comparison to the total number of electricity customers. A reason to traditional low gas utilization can be found in the quick depletion of the meager local gas fields. However, public authorities of both countries have been favoring investments in different facilities to encourage the development of a gas market. Gas facilities are described below, starting with gas assets that connect to gas producers, that is, LNG terminals and cross-border pipelines, continuing with underground storages, and finishing with balancing zones.

2.8.1.1. LNG regasification terminals

Certainly, one of the strongest points of MIBGAS is the numerous LNG terminals that allowed both Spain and Portugal to achieve a LNG import share in 2012 that was well above and about 50% (Spain 70% and Portugal 46%). Moreover, Spain, with six regasification terminals, enjoys a diversified portfolio of suppliers, in which the major supplier provides about 35% of imports and seven suppliers exceed 5% import share.

The main characteristics that define the dimension of LNG terminals appear in Table 2-1. The berth capacity establishes the LNG carrier size that can moor at the dock of the terminal. Carriers are categorized according to the current world fleet[24], the historical arrivals and the regulatory framework definition, in four categories: small (220 GWh), medium (485 GWh), large (900 GWh), and extra large (1500 GWh); therefore, every category cannot arrive to every terminal.

LNG regasification terminal	Berths (#)	Berth capacity (up to GWh)	Regasification capacity (GWh/day)	LNG working storage capacity (GWh)
Cartagena	2	220; 1,500	377	3,659
Sagunto	1	900	279	3,939
Barcelona	2	220; 1,500	544	5,236
Bilbao	1	1,500	223	1,870
Mugardos	1	900	115	1,932
Huelva	1	900	377	3,862
Sines	1	1,500	213	2,672

Table 2-1 – LNG regasification terminals characteristics[25]

Initial and final inventories (Table 2-2) as they occurred in 2012 are provided to the model in order to simulate the system as close to reality as possible. Due to the lack of public data, inventories are distributed among shippers by the model.

Regasification terminal	Initial inventory (GWh)	Final inventory (GWh)
Cartagena	1,657	847
Sagunto	2,070	1,068
Barcelona	1,446	2,468
Bilbao	480	1,171
Mugardos	1,557	652
Huelva	2,301	1,266
Sines	1,448	1,324

Table 2-2 – Initial and final inventories in LNG regasification terminals

[24] The fleet of LNG carriers can be consulted, for instance, on the web page www.shipbuildinghistory.com.

[25] For the sake of clarity, LNG road tankers loading capacity has been omitted as long as this type of demand is excluded from the case study (section 2.8.2).

2.8.1.2. Cross-border pipelines

Import capacity of the Iberian Peninsula is large (up to 726 GWh/day), in particular, when it is compared to its export capacity (up to 59 GWh/day). This is a consequence of two combined effects. First of all, the huge investments in connections to the Algerian fields, with the objective of supplying Central European consumers and reducing their dependence on the Russian gas. Second, however, the connection reinforcement to France has been delayed. As a matter of fact, both the projected reinforcement and new connections would multiply the capacity at least by four times by 2020. And not only is the connection capacity between the Iberian Peninsula and Europe far from the desired level to encourage market integration, but connections between Spain and Portugal are also insufficient. There are indeed neighboring balancing zones in Spain that exceed the connection capacity between Spain and Portugal (section 2.8.1.4).

Monthly import and export capacities of cross-border pipelines are shown in Table 2-3. Monthly variations respond to security margins and different technical operation procedures in cold and warm months[26]. Backhaul capacity is available when a cross-border pipeline does not connect to a production field.

Cross-border pipeline	Flow Direction[27]	Jan-Apr Nov-Dec (GWh/day)	May-Oct (GWh/day)	Backhaul capacity
Tarifa	DZ → ES	355	-	No
Almería	DZ → ES	266	-	No
Badajoz	ES → PT	134	134	Yes
	PT → ES	35	70	
Tuy	ES → PT	25	25	Yes
	PT → ES	30	40	
Larrau	ES → FR	30	50	Yes
	FR → ES	105	90	
Irún	ES → FR	5	9	Yes
	FR → ES	0	10	

Table 2-3 – Cross-border pipelines characteristics

2.8.1.3. Underground storages

Each country operates its underground storages in a different fashion due to the geologic origin of the storages. On the Spanish side, Gaviota and Serrablo are depleted gas fields whose equipment lacks flexibility. Consequently, both storages are operated according

[26] Gas systems are more demanded during cold than during warm months. As a result, compressor stations operate at higher pressures affecting the available pipeline capacity.

[27] Each country is represented by its ISO code: ES – Spain, PT – Portugal, FR – France, DZ – Algeria.

to annual injection-withdrawal cycles. The injection-withdrawal periods within the cycle may vary in a couple of months depending on the climatology. In any case, injection periods always coincide with warm months, while withdrawal periods coincide with cold months[28]. In contrast, Carriço, on the Portuguese side, is a salt cavern that allows multiple injection-withdrawal cycles and, hence, its operation is not seasonally constrained.

Current underground storages characteristics are shown in Table 2-4. Probably, the lack of storage capacity is one of the main flaws of MIBGAS (less than 8% of a low demand year like 2012)[29]. As mentioned in section 2.4.3, the injection rate normally depends on the equipment as injection requires external mechanical work. However, the withdrawal rate may be affected, depending on the equipment, by the storage pressure, i.e., by the inventory level. Carriço and Gaviota are paradigmatic examples of underground storages whose equipment allows them to maintain an almost constant withdrawal rate.

Underground storage	**Working gas capacity** (GWh)	**Injection rate** (GWh/day)	**Injection slope** (GWh/day / inventory in %)	**Withdrawal rate** (GWh/day)	**Withdrawal slope** (GWh/day / inventory in %)
Gaviota	18,340	53	-	68	2
Serrablo	9,730	52	-	79	62
Carriço	1,659	238	-	86	-

Table 2-4 – Underground storages characteristics

Initial and final inventories of underground storages in 2012 are also given to the model (Table 2-5). Again, due to the lack of public data, both inventories, disregarding cushion gas, are distributed among the shippers by the model.

Underground storage	**Initial inventory** (GWh)	**Final inventory** (GWh)
Gaviota	15,908	14,828
Serrablo	7,992	8,618
Carriço	820	874

Table 2-5 – Initial and final inventories in underground storages

2.8.1.4. Balancing zones

Balancing zones are as a matter of fact a gas network equivalent. Therefore, their main parameters coincide with those of pipelines: transportation and line-pack capacities.

[28] In 2012, the withdrawal period included January, February, March, October, November and December; while the injection period included April, May, June, July, August and September.

[29] The projected put into operation of three new underground storages (in Spain) in the upcoming years will improve the situation.

Within the European framework, they have been established to favor the creation of a single gas market. Although, a balancing zone should correspond with a market area, when transportation constraints appear, ISOs usually fragment the market area in different balancing zones (as in the case of Spain). Table 2-6 shows the connection capacities between those balancing zones in Spain that are indeed connected. Notice that the connection capacity is bidirectional, i.e., each connection distinguishes between inflow and outflow capacities. For instance, the outflow connection capacity of Noroeste is zero, but Noroeste may receive inflows from Centro.

	Levante	Catalunya	Ebro	Noroeste	Centro
Levante		365[a], 280[b], 260[c], 250[d] 230[e]			380[a,b,c,d,e]
Catalunya	280[a,e], 305[b], 300[c], 285[d]		280[a,e], 305[b] 300[c], 285[d]		
Ebro		110[a], 120[b], 20[c,d], 50[e]			255[a], 235[b,c,d,e]
Centro	285[a,b,c,d,e]		112[a], 125[b], 77c[,d], 83[e]	74[a], 31[b,d], 20[b], 24[e]	

[a] January, February, November, December
[b] March, April, October
[c] May, September
[d] June, July
[e] August

Table 2-6 – Connection capacity between balancing zones

Line-pack capacities of each balancing zone have been estimated, as these data are not explicitly available. Available public data are line-pack capacities of each market area, so line-pack capacities have been distributed among balancing zones according to their demand[30]. In addition, initial and final inventories, which are again distributed among the shippers by the model, are given to the model as they occurred during 2012 (Table 2-7) in order to simulate the system as close to reality as possible.

Balancing zone	Line-pack capacity (GWh)	Initial inventory (GWh)	Final inventory (GWh)
Levante	61	6	59
Catalunya	76	7	73
Ebro	65	6	62
Noroeste	29	3	28
Centro	130	12	124
Portugal	100	29	44

Table 2-7 – Line-pack capacity, and initial and final inventories in balancing zones

[30] The approximation is based on the fact that demand is usually correlated to the number of pipelines.

2.8.2. Market structure

Both Spain and Portugal are (relatively) immature gas markets, which not so many years ago were constituted as public vertically integrated monopolies and nowadays are at the edge of finishing the liberalization process. Despite of the fact that the process is still in progress, changes are noteworthy. Nevertheless, an incumbent company in each market still enjoys a dominant position (over 50% market share). Another important transformation that has had influence on the development of gas markets has been the gas utilization for electricity generation. Consequently, the main electricity utility in each market is also an important gas consumer (around 15%). For both reasons, five companies have been defined in the case study:

- ESP1 and POR1 correspond to the former incumbent gas companies in each market. These companies not only cover part of the conventional demand, but they also have GFPPs and may consume gas for electricity generation.
- ESP2 and POR2 represent the main electricity utilities in each market. The liberalization process has allowed both companies to participate in gas markets and compete against former incumbent companies to cover part of the conventional demand.
- OT aggregates other market participants. It consumes gas for electricity generation and covers partially the conventional demand.

The conventional demand (including the demand of LNG road tankers) is more predictable and about four times greater than demand for electricity generation (Figure 2-11). GFPP demand intermittency is indeed caused by renewable energy sources intermittency (section 5.2, pp. 125–128).

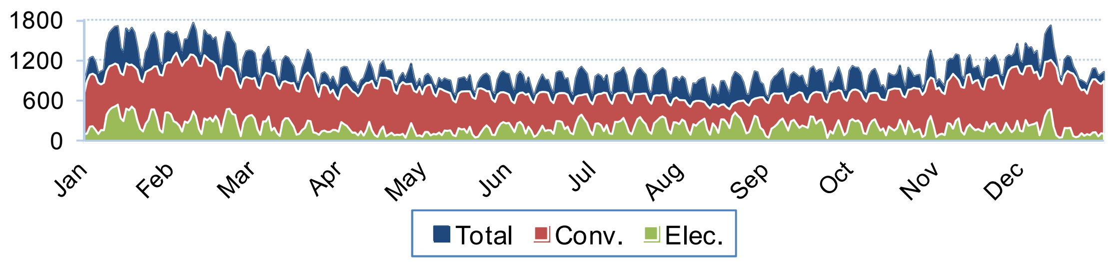

Figure 2-11 – MIBGAS daily conventional and GFPP demands in GWh

Quite the opposite, the conventional demand pattern responds usually to weather conditions and labor activity. Moreover, Spanish gas demand is about seven times greater than Portuguese gas demand (Figure 2-12). Just the Spanish GFPPs demand is habitually larger than total Portuguese gas demand. Indeed, Spanish consumers determine most of MIBGAS profile demand.

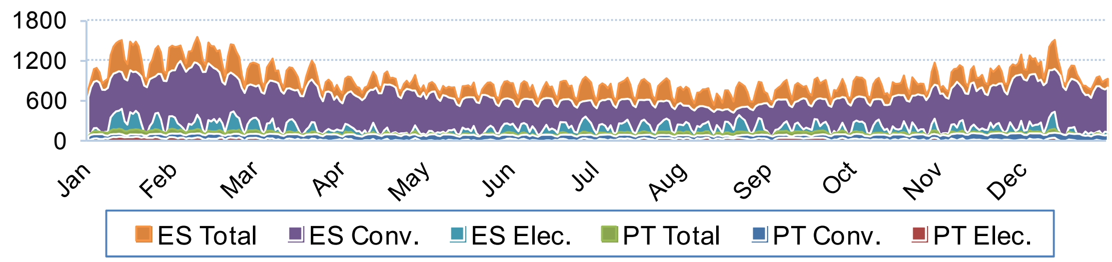

Figure 2-12 – Spanish and Portuguese daily conventional and GFPP demands in GWh

Within Spain, conventional demand shares in each balancing zone distribute in the following manner: Centro 36%; Catalunya 21%; Ebro 18%; Levante 17%; and Noroeste 8%. Conventional gas demand shares of each company in each balancing zone are shown in Figure 2-13.

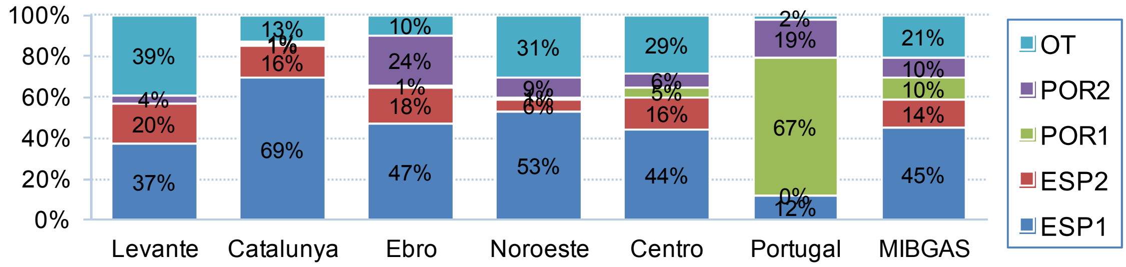

Figure 2-13 – Companies conventional demand shares

Regarding gas demand for electricity generation, each company owns some GFPPs, which are located in different balancing zones and operated according to the electricity market-clearing process. For instance, Figure 2-14 illustrates the intermittency of GFPP gas demand of ESP2 in Levante, Centro, Noroeste and Portugal.

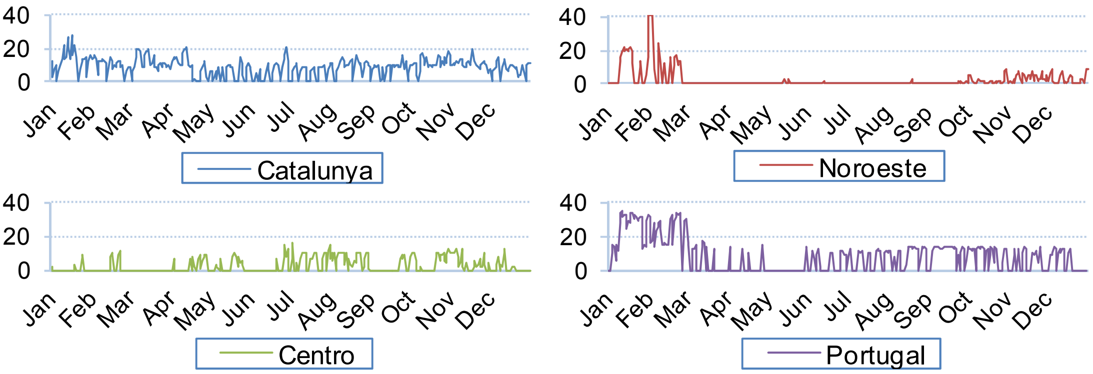

Figure 2-14 – GFPP demand of company ESP2 in GWh

Since local gas production is negligible, companies must import their gas necessities. There are two ways of importing gas: by LNG carrier or through a cross-border pipeline. As supply activity is addressed in detail in Chapter 3, in this case study imports are predetermined. On the one hand, actual daily arrivals of LNG carriers, classified by category, to regasification terminals are specific to the model that distributes them among the companies. As shown in Figure 2-15, in which daily arrivals have been aggregated into months, monthly arrivals vary between 19 in June and 30 in February, being 25 the number of average monthly arrivals. This is an indicative of the presence of take-or-pay clauses. Moreover, large LNG carriers predominate over any other category of LNG carrier.

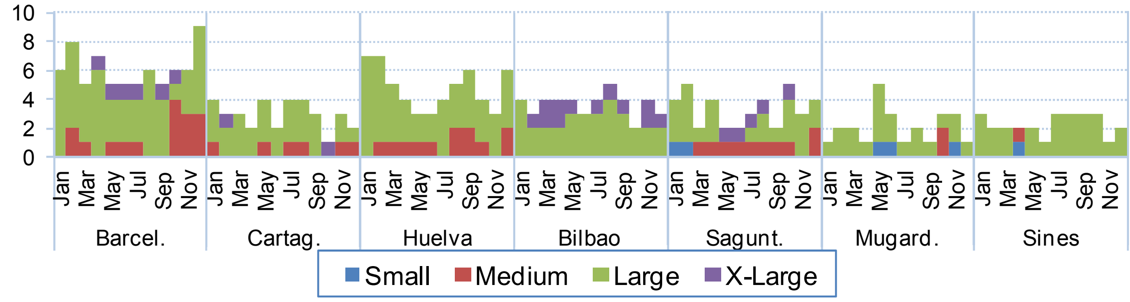

Figure 2-15 – Monthly carrier arrivals to LNG regasification terminals

On the other hand, Imports and exports through cross-border pipelines, except those connecting Spain and Portugal (Badajoz and Tuy), are controlled by establishing minimum and maximum limits. These limits are equivalent to (very simplified) supply contracts with take-or-pay clauses (further details on supply contracts are given in section 3.2, pp. 78–82). These limits have been estimated in line with the cross-border pipelines historical utilization during 2012, and then distributed among the companies according to different sources of information like pieces of news or annual reports. These simplified supply contracts can be observed in Table 2-8. An interesting observation is that net exports from MIBGAS to Europe amounted to zero.

Cross-border pipeline	ESP1	ESP2	POR1	POR2	OT
Tarifa DZ→ ES	170–250[a] 85–150[b] 40–100[c]		30–40[a,b,c]		
Almería DZ→ ES		12–18[a] 9–12[b] 7–10[c]			85–130[a] 70–90[b] 55–80[c]
Larrau FR → ES	30–33[a,b,c]	30–33[a,b,c]			30–33[a,b,c]
Irún FR → ES				4–6[d]	

[a] January, February, March, May, June, October, November, December
[b] April
[c] July, August, September
[d] April, May, June, July, August, September, October

Table 2-8 – Import and export limits on cross-border pipelines

2.8.3. Regulatory framework

The adopted regulatory framework is in line with a broad interpretation of the EU directives. A variable tariff is applied to daily gas facility operation, while a fixed tariff is applied to infrastructure capacity contracting. In addition, fixed tariffs are modified depending on contract durations (long-, medium-, or short-term contracts). At last, penalties are faced when a company operates over its contracted capacity.

The current Spanish regulatory framework is quite similar. A variable tariff is applied to daily operations, except for storing in underground storages, and, although not explicitly[31], a fixed tariff is applied to contracts depending on its duration, except again for underground storages. Penalties are also faced when a company operates over 105% of its contracted capacity. In contrast, the Portuguese regulatory framework is quite different regarding fixed tariffs (variable tariffs are applied in the same manner). A fixed tariff is monthly applied to the maximum daily utilization of a facility during the last moving year. In addition, there are two tariffs: one for long-term operation, another for short-term operation[32]. Consequently, punctual utilizations are strongly penalized, but this has little (if anything) to do with contracting. In the case study, the variable and fixed tariffs of each system are those corresponding to the beginning of 2012. The fixed tariffs are, in particular, equal to the costs of contracting long-term capacity.

Table 2-9 contains LNG terminal tariffs. Applied tariffs to road tankers are omitted as their demand has been added to the conventional demand.

LNG regasification terminal	**Slot assignment** (€/LNG carrier)	**Unloading service** (€/GWh)	**Regasification service -fixed tariff-** (€/(GWh/day))	**Regasification service -variable tariff-** (€/GWh)	**LNG storage service** (€/(GWh/day))
Cartagena Sagunto Huelva	31,319	63	18,077	107	30
Barcelona Bilbao Mugardos	15,659	32	18,077	107	30
Sines	-	192	7,484	177	29

Table 2-9 – Established tariffs in LNG regasification terminals

[31] Tariffs depend on the comparison between the maximum daily utilization during a month of a facility and the contracted capacity. When the ratio is below 85%, 85% of contracted capacity is charged. When it is between 85% and 105% the maximum daily utilization is charged. Therefore, this is (more or less) equivalent to apply a fixed tariff to the contracted capacity including a floor.

[32] While this thesis was in the publishing process, a new Portuguese regulatory framework in line with the EU directives and, hence, with the case study was being implemented.

Table 2-10 presents cross-border pipeline tariffs. The pancaking effect, that is, the sum of import-export tariffs when crossing different international borders from a gas field to a consumer, is still notable despite the efforts to reduce it. Among other efforts, variable tariffs have been eliminated in Spain. An illustrative example of the pancaking effect is how gas, from Algeria with destination to a Portuguese consumer, experiences an increase of its price due to export tariffs in Badajoz (on the Spanish side) and import tariffs in Badajoz (on the Portuguese side). The pancaking effect is an evident indicator of the still fragmented single European gas market.

Cross-border pipeline	Flow direction	Fixed tariff (€/(GWh/day))	Variable tariff (€/GWh)
Tarifa, Almería	DZ → ES	9,999	-
Badajoz, Tuy	ES → PT (ES)	18,491	-
	ES → PT (PT)	8,580	-
	PT → ES (PT)	10,556	250
	PT → ES (ES)	9,999	-
Larrau, Irún	ES → FR	18,491	-
	FR → ES	9,999	-

Table 2-10 – Established tariffs in cross-border pipelines

Regarding underground storages, tariffs are shown in Table 2-11. Storage service tariff is considered a fixed tariff since a company has contracted for gas storage capacity, independently of being used. Storage service variable tariff is therefore nil.

Underground storage	Storage -fixed tariff- (€/(GWh/day))	Injection service (€/GWh)	Withdrawal service (€/GWh)
Gaviota	14	244	131
Serrablo	14	244	131
Carriço	27	206	206

Table 2-11 – Established tariffs in underground storages

At last, entry-exit tariffs[33] can be observed in Table 2-12. Entry tariffs that are applied to imports as well as exit tariffs to exports have been already exposed. In both systems, the entry capacity tariff lacks of a variable term. Exit capacity tariffs for the two types of demand have been taken out from the tariff brochure. A typical industrial consumer has been selected to represent the equivalent payment of conventional demand. The tariffs here specified are normally paid by GFPPs.

[33] Inter-zonal flows among neighboring balancing zones are not subject to fixed or variable tariffs and, hence, contracting inter-zonal capacity is not required.

Balancing zone	Entry capacity (regasification)		Exit capacity (conv. demand)		Exit capacity (GFPP demand)	
	-fixed tariff- (€/(GWh/day))	-variable tariff- (€/GWh)	-fixed tariff- (€/(GWh/day))	-variable tariff- (€/GWh)	-fixed tariff- (€/(GWh/day))	-variable tariff- (€/GWh)
Levante Catalunya Ebro Noroeste Centro	9,999	-	37,895	1,033	26,415	567
Portugal	8,580	-	20,398	989	20,398	250

Table 2-12 – Established entry-exit tariffs in balancing zones

Those companies who sign long-term capacity contracts pay above fixed tariffs monthly, in accordance with the Spanish regulatory framework. However, long-term contracts are usually cheaper than medium- and short-term contracts. Being Spain the largest system in terms of demand and infrastructure development, prices of medium- and short-term capacity contracts are increased as it is done in the Spanish regulatory framework. In detail, different factors multiply the fixed tariff depending on the month, increasing prices of medium- (monthly) and short-term (daily) contracts more in cold, October to March, than in warm, April to September, months. This way, the Spanish regulatory framework favors those companies that properly foresee their capacity necessities and perform smooth infrastructure utilization. Table 2-13 contains these factors. Regarding medium-term contract factors, in warm months is irrelevant whether contracting in the long or the medium term. This is not so in cold months, in which medium-term contracting is twice penalized with respect to long-term contracting. On the other hand, short-term contracts are always penalized. For instance, if a company decides to contract a whole month through short-term contracts, it would pay 3 (in winter) or 1.8 (in summer) times more than with a long-term contract. Overrunning the contracted capacity is penalized daily twice as much as short-term contracts.

Month	Medium-term (Monthly)	Short-term (Daily)
Jan-Mar, Oct-Dec	2	0.10
Apr-Sep	1	0.06

Table 2-13 – Medium- and short-term contract extra-costs

Finally, a key parameter is the obligation that is imposed on facility owners to offer capacity as medium- and short-term contracts. The Spanish regulatory framework establishes this threshold in 25%, i.e., as much as 75% can be offered as long-term contracts.

2.9. Shippers' behavior in the Iberian natural gas market

The model has been formulated in GAMS and solved by using CPLEX 12 on an Intel® Core™ i7 64-bit at 3.40GHz with 16GB RAM. The computational time to solve the case study (474,329 variables, of which 1,237 integer variables, and 253,041 equations) was eleven hours and a half, using 6 threads and barrier algorithm[34]. From all the information provided by the model, we present the most interesting results. The first group of results is useful for validating the model, while the second group that includes different sensitivity analyses is useful for inferring some conclusions about market efficiency.

The model distributes LNG carrier arrivals among companies and determines imports that are subject to maximum and minimum limits. These entries to MIBGAS, LNG carrier arrivals and imports, together with inventory variations (LNG in tanks, gas in storage facilities and line-pack capacity), are used for covering shippers' demand and exports[35]. The balance in 2012 is shown in Figure 2-16. It also provides a good picture of the system. MIBGAS is practically dominated by one company (the former Spanish incumbent company) and imports all gas consumption because there is no local production. Moreover, imports are mainly done by LNG carriers.

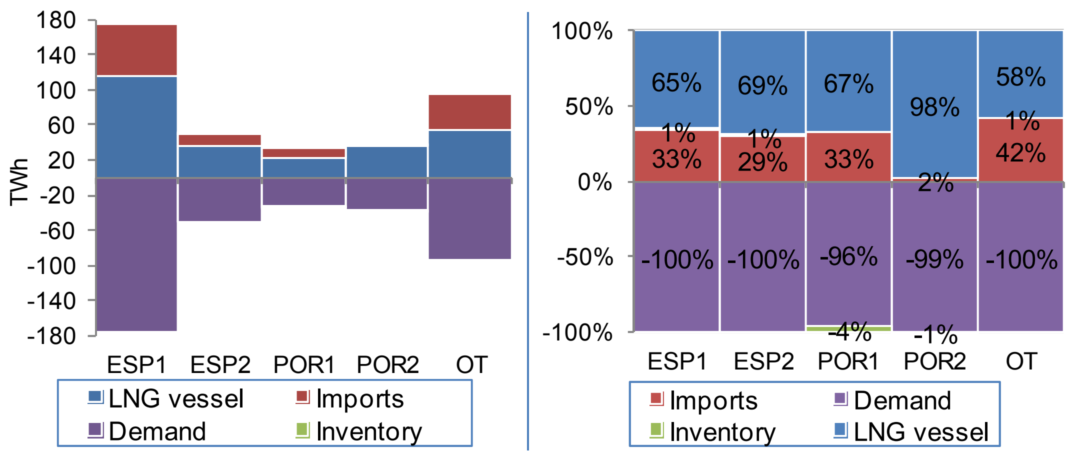

Figure 2-16 – Balance between entries to and exits from MIBGAS

Both gas supply rigidity, which we have been tried to reproduce in the case study (but it is explicitly discussed in Chapter 3), and demand seasonality establish an employment pattern of LNG terminals, underground storages and cross-border pipelines. The utilization pattern of the LNG terminal at Bilbao is shown in Figure 2-17. The plateaus are closely related to the optimal way of simultaneously operating and contracting for capaci-

[34] Different tactics have been employed (e.g. emphasizing feasibility over optimality or controlling the heuristics invocation) in order to reduce the computational time. Option *epgap* has been set to 5%.

[35] In this case study, and as a result of what occurred during 2012, there are no exports to Europe.

ty that flatten the regasification curve. Nevertheless, when more gas is required to fulfill the demand, regasification spikes can occur. With regard to the LNG inventory, it increases when a carrier arrives and decreases according to the regasification rate.

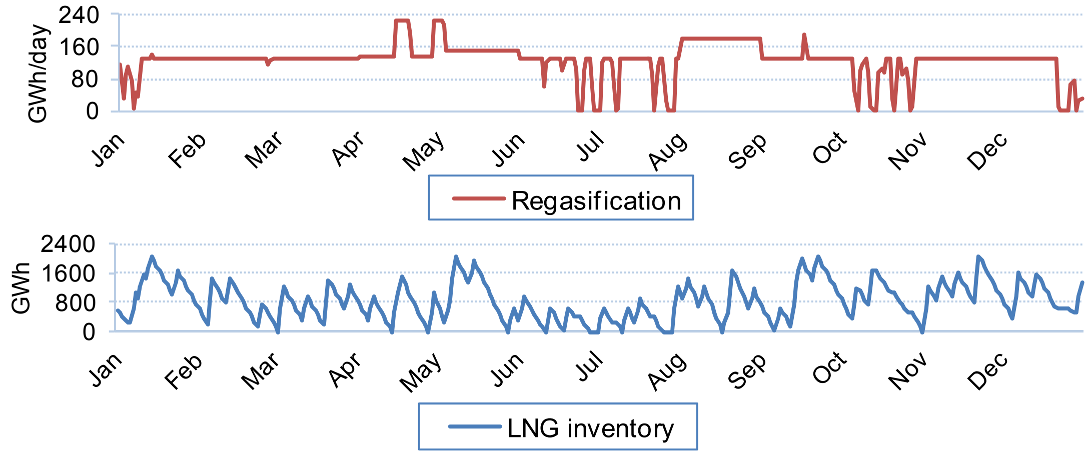

Figure 2-17 – LNG regasification terminals utilization pattern

The operation of an underground storage, such as Gaviota (Figure 2-18), is determined by the injection and withdrawal periods. Besides, shippers are usually comfortable with this way of proceeding because they can comply with their supply contract take-or-pay clauses (Chapter 3), which produce constant gas entries to MIBGAS, and satisfy, at the same time, the seasonal demand pattern (Figure 2-11). Observe that the storage filled up well before the end of the injection period, reproducing exactly 2012. A cause could be found in the consumption decrease due to the economic crisis and the impossibility of renegotiating take-or-pay clauses in the short term.

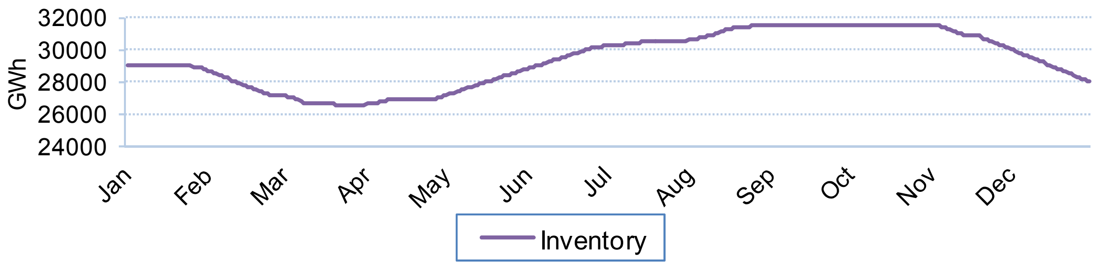

Figure 2-18 – Underground storages utilization pattern

On the other hand, cross-border pipeline operation is (so far) the model weakest point. Actually, imports and exports depend on prices at both sides of a cross-border pipeline, but prices are incorporated with the supply activity in Chapter 3. Despite the lack of supply prices, we illustrate the utilization of Badajoz in Figure 2-19. Badajoz, as well as Tuy, does not depend just on prices since its operation is related to shippers' decisions regarding carrier arrivals. Note the lack of imports from Spain via Portugal.

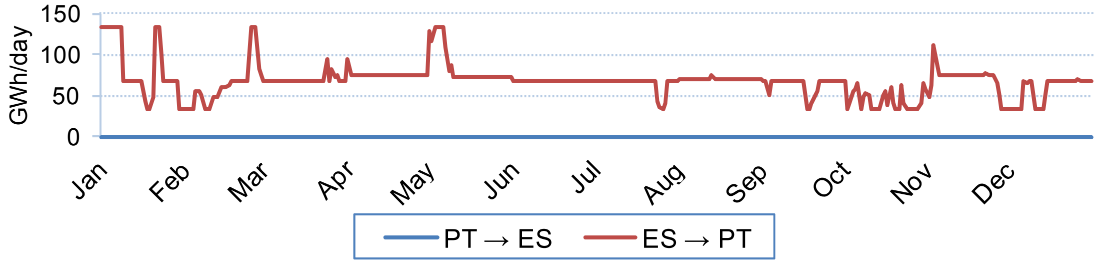

Figure 2-19 – Cross-border pipelines utilization pattern

These results prove the model accuracy when they are compared to reality and, in particular, to the utilization patterns. In any case, our intention was not to obtain precise numbers, but proper physical gas flows. Once the model has been verified, we can analyze different market aspects.

Balancing zones constitution within a market area, due to (supposedly) capacity constraints, may fragment the market, against market efficiency. For this reason, it is relevant to observe whether balancing zones respond to real capacity constraints. According to the obtained results, except the balancing zone Noroeste (63.9% average occupancy) and maybe Ebro (28.2%), the rest could be merged into one balancing zone. Ebro does present relatively high exit capacity utilization rates since two connections to France and two underground storages, besides one regasification terminal, are located in the balancing zone. Nevertheless, inter-zonal connections are in general far from being congested (Table 2-14), except Ebro-Catalunya and Centro-Noroeste, which are congested during 86 days and 137 days, respectively.

	Levante	Catalunya	Ebro	Noroeste	Centro
Levante		10.15%	-	-	23.90%
Catalunya	1.80%		11.15%	-	-
Ebro	-	39.70%		-	24.56%
Noroeste	-	-	-		-
Centro	4.41%	-	12.20%	63.88%	

Table 2-14 – Percentage utilization of inter-zonal connections

Another market flaw that has been already mentioned is the pancaking effect. This effect increases gas prices when gas flows through cross-border pipelines. In addition, it may result in a permanent market fragmentation due to a cross-border pipeline underutilization. The effect is observable in MIBGAS and its two market areas: Spain and Portugal. In the base case, gas flows from Spain to Portugal amounted to 26.7 TWh (46.0% utilization) and from Portugal to Spain were nil. If import-export tariffs in Badajoz and Tuy at both sides are eliminated, these gas flows significantly grow up to 51.6 TWh (88.8% utilization) and to 32.1 TWh (77.6% utilization), respectively. Even though shippers' entries to and exits from MIBGAS have been fixed in this sensitivity analysis and they have less flexibility to modify their decisions, the pancaking effect is still appreciable.

Shippers collaborate among themselves to achieve a daily balance in gas facilities and balancing zones. The way to collaborate is through physical swaps, that is, transfers and returns of gas. Market liquidity can be measured with the churn rate. In our case, the churn rate compares the traded gas quantity with the facility capacity where exchanges take place: LNG working gas capacity in regasification terminals, working gas capacity in underground storages, and line-pack capacity in balancing zones. Hence, the churn rate measures the number of times the numerator is included in the denominator. In the base case, the churn rate in Spain[36] amounted to 4.43 (90.1 TWh), 0.002 (0.07 TWh) and 6.9 (2.5 TWh), respectively (absolute terms in parentheses). This result confirms that line-pack capacity of pipelines, which are (geographically speaking) close to consumers, are especially used for achieving daily balances. Therefore, more transactions take place in comparison to its small volume. The case considers minor transaction costs, 0.0001 €/MWh. One of the main advantages of organized markets is their negligible transaction costs when compared to OTC markets. In Chapter 4, different types of organized markets, without transaction costs, are discussed and included into the downstream gas market.

Last, but not least, let us observe how shippers optimize their capacity contract portfolios. Some illustrative examples of a LNG terminal, an underground storage, an entry to a balancing zone (imports) and two exits from a balancing zone (conventional and GFPP demand) can be observed in Figure 2-20, Figure 2-21, Figure 2-22, Figure 2-23 and Figure 2-24, respectively. Each reveals a different contracting pattern that is, as already indicated, related to the distinctive operation in facilities and balancing zones.

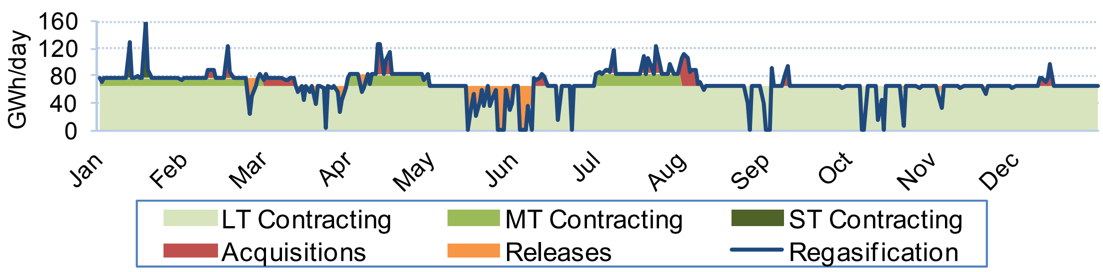

Figure 2-20 – Capacity contract portfolio of ESP1 in LNG regasification terminal at Barcelona

LNG terminal operation is sometimes volatile, and subject to daily sharp changes due to demand spikes. However, an almost constant utilization base simultaneously extends

[36] In Portugal, no gas exchanges took place. This could be a consequence of both the market size and the relative large market share of the former incumbent company.

during the time horizon, which coincides with the long-term contracting (Figure 2-20). Some months, the shippers contract for medium-term capacity. Moreover, shippers prefer secondary markets with respect to contract for capacity in the short term, except when every shipper needs capacity and released capacity is not available. The secondary capacity market totalizes 14.6 TWh of traded capacity, while the total short-term contracted capacity is 4.2 TWh, about 3.5 times lower.

Underground storages present predictable profiles due to their injection and withdrawal cycles. This operation pattern allows companies to hold a combination of long-, medium-, and short-term capacity contracts that approximately follow the curve (upper part of Figure 2-21). In contrast, trades in secondary capacity markets are nil because every shipper is willing to acquire and release capacity during the same period, that is, during the injection and withdrawal cycles, respectively.

In contrast, since Carriço is not subject to injection and withdrawal cycles, it is operated halfway from a regasification terminal to an underground storage (lower part of Figure 2-21). In detail, shippers hold a diversified portfolio of different time scope contracts, but secondary capacity markets are really active as well. Resulting short-term capacity contracts amount 7.9 TWh; while 54.1 TWh are traded in secondary capacity markets.

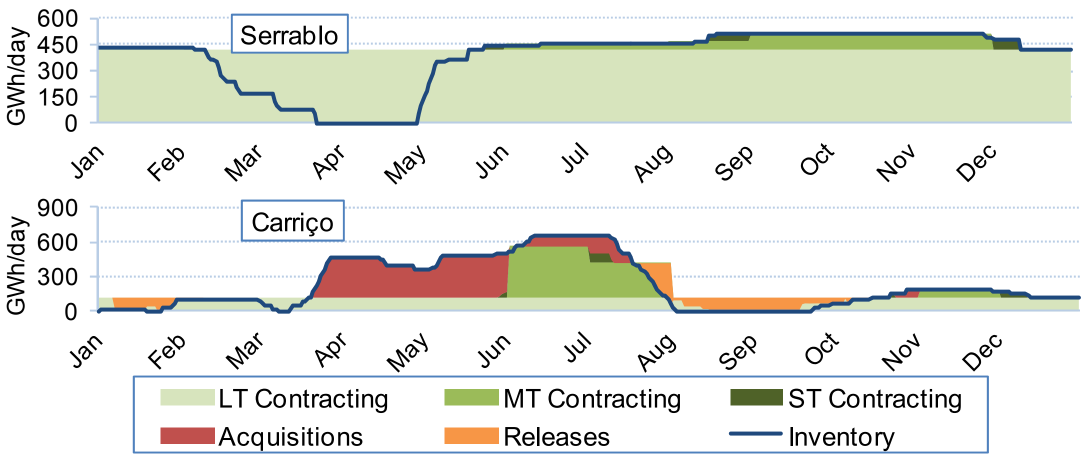

Figure 2-21 – Capacity contract portfolios of OT in underground storages Serrablo and Carriço

Similar to LNG terminals, cross-border pipeline utilization varies considerably in the short term. Consequently, shippers mainly hold long-term capacity contracts and then resort to trading in secondary capacity markets to fit their contract portfolio to the operation. For instance, if we observe Figure 2-22, the long-term capacity contract amounts to 5.81 GWh/day, while mean daily acquisitions and releases add up 5.55 GWh/day. Some utilization spikes are also covered through short-term capacity contracts.

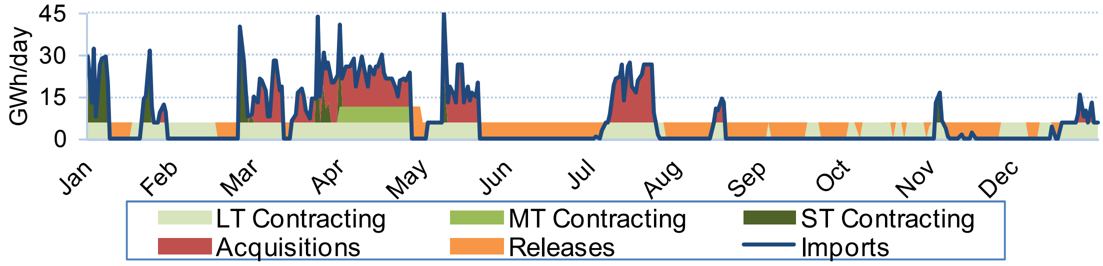

Figure 2-22 – Capacity contract portfolio of POR2 in Badajoz on the Portuguese side

Regarding the demand, each type of demand resembles to one of the above operation ways. On the one hand, shippers rely on a portfolio of long-, medium-, and short-term contracts to satisfy their foreseeable conventional demand (Figure 2-23), such as in underground storages subject to injection and withdrawal cycles.

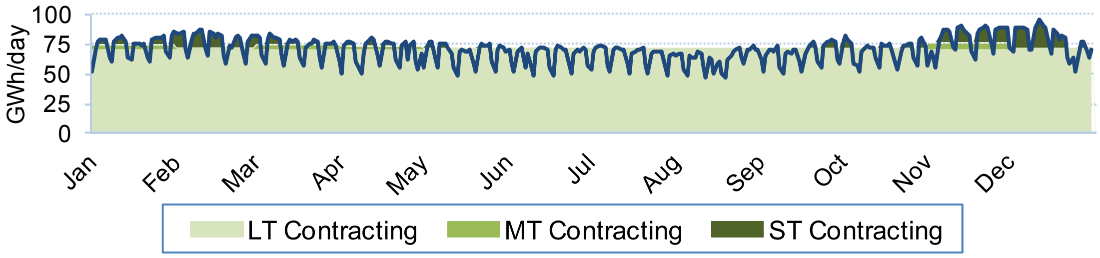

Figure 2-23 – Conventional demand capacity contract portfolio of POR1 in Portugal

On the other hand, shippers prefer secondary capacity markets, such as in LNG terminals, when covering the volatile GFPPs demand (Figure 2-24). Whereas total traded conventional demand capacity hardly reaches 14 GWh, up to 7.1 TWh of GFPP demand capacity contracts are negotiated in secondary markets.

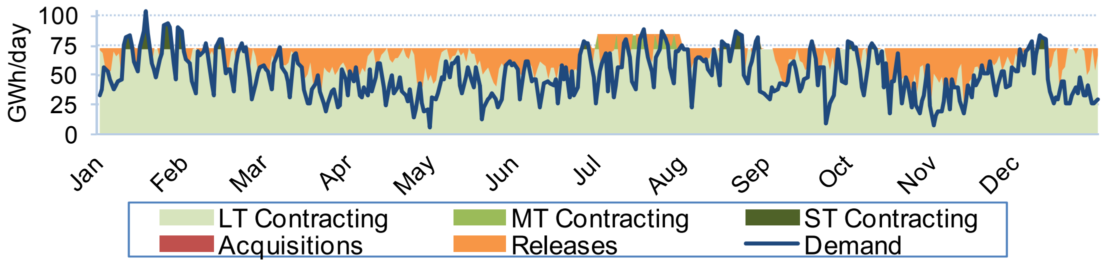

Figure 2-24 – GFPP demand capacity contract portfolio of ESP1 in Centro

So far, we have shown that shippers make use of secondary markets to fulfill their capacity contracting requirements. At this point, we can examine how would affect to the market's performance a closure of secondary capacity markets because electronic platforms have not been established yet and/or transaction costs are relevant. In this last sensibility analysis, we fix again LNG carrier arrivals and imports, and close secondary capacity markets. We reproduce capacity contracting costs in Table 2-15. We can observe that the former incumbent company in Spain, and dominant shipper with 44% market share, benefits from the market closure. An additional effect is the increase of contracting costs in MIBGAS.

	ESP1	ESP2	POR1	POR2	OT	MIBGAS
w/ secondary markets	416.93	122.24	64.62	85.63	203.97	893.39
w/o secondary markets	412.97 ↓ 0.95%	123.79 ↑ 1.26%	67.12 ↑ 3.88%	88.48 ↑ 3.34%	211.44 ↑ 3.66%	903.80 ↑ 1.17%
w/o ESP1 willingness	409.83 ↓ 1.70%	126.45 ↑ 3.44%	62.08 ↓ 3.92%	89.74 ↑ 4.80%	209.90 ↑ 2.91%	897.99 ↑ 0.52%
w/o ESP1, POR1 willingness	409.28 ↓ 1.84%	123.50 ↑ 1.03%	64.46 ↓ 0.25%	87.64 ↑ 2.35%	214.34 ↑ 5.09%	899.22 ↑ 0.65%

Table 2-15 – Expenditures in capacity contracting in million Euros

Consequently, it seems reasonable to think that the former incumbent company may not be willing to participate in secondary capacity markets to take advantage of its dominant position. This anticompetitive behavior would not only be favorable to the interest of ESP1, but also to the interest of POR1, former incumbent company in the other market area (Table 2-15). Supposedly, both companies may share a common objective of maintaining their dominant position in their respective market areas. In case of tacit collusion, that is, if none of the former incumbent companies participate in secondary capacity markets, we observe that both companies are again better off (Table 2-15). Regarding total contracting costs in MIBGAS, notice that the least costs are faced with open secondary markets, while closing markets is the most expensive solution. Former incumbent companies' willingness origins intermediate solutions, being more costly for the system when both companies tacitly collude than when one company takes the initiative.

Another relevant result has to do with demanded gas facilities. For instance, the underground storage in Portugal, Carriço, presents an average inventory level during the year equal to 84.8%. Despite the aggregated high utilization level, each shipper individually injects and withdraws considerable gas volumes. Actually, shippers inject 4.5 TWh and withdraw 4.4 TWh and, therefore, they need to fit their contract portfolio to their individual inventory level, which is almost daily modified by injections and withdrawals, by making use, in first place, of releases and acquisition and, secondly, of short-term capacity contracts. Nevertheless, if secondary capacity markets are closed, shippers cannot attain enough free short-term capacity[37]. The main consequence is that shippers overrun their contracted capacity up to 1.3 TWh with subsequent penalties that amount to 0.26 million Euros.

[37] Remind that we have established that at least 25% of total capacity must be offered as short-term capacity contracts, which as well means that not necessarily more than 25% is offered.

2.10. Brief summary of contributions

This chapter has introduced the core of the model that will be used along the thesis. We have formulated a broad entry-exit model that can be applied to any gas market based on this type of third party access system. The model is formulated as a MIP problem that assures a global and unique solution, with a relatively low computational effort compared to the level of detail and quantity of results that can be obtained. The model can be employed by three main stakeholders of downstream gas markets:

- Shippers can optimize their capacity contract portfolio, operate efficiently in different facilities, supply at a minimum cost their conventional and GFPP demand, or estimate the competitors' behavior.
- Independent system and facility operators can forecast the future use of gas facilities and prevent emergency conditions or anticipate future capacity expansions, or identify users' necessities and offer new services.
- Regulatory authorities can examine the market performance, and propose and implement new regulatory measures to promote competition, to improve security of supply, or to guarantee system sustainability.

Regarding entry-exit markets, we have analyzed their functioning and come to relevant conclusions that may promote market integration and increment market efficiency:

- Balancing zones must be examined and suppressed when they have not been established as a consequence of transportation constraints. Nevertheless, in case of transportation constraints, balancing zones should be maintained since they can proportionate locational signals until bottlenecks are solved.
- Additional tariffs must not be charged to gas transiting between market areas and, particularly, between balancing zones, eliminating the so-called pancaking effect. This effect that raises gas prices is not justified from the point of view of liberalized gas markets and discourages market integration.
- Balancing markets must be constituted because they allow shippers to balance their gas inventories at negligible transaction costs. Moreover, these balancing markets can provide transparency to and foster competition in the system.
- Secondary capacity markets must also be constituted. Shippers' collaboration in gas facilities through (unused) capacity contract releases and acquisitions lead to improvements on infrastructure utilization and a contracting costs decrease. Furthermore, former incumbent companies may be tempted to abuse of their dominant position by hoarding capacity since this anticompetitive behavior favors their position. Consequently, regulatory mechanisms should be applied to persuade dominant companies to participate in secondary capacity markets.

Although we are concerned that other measures may be implemented, we have herein proposed some measures, whose advantageous effects have been tested with a reliable model. These measures are markedly relevant for the fulfillment of the three objectives of the Single European Gas Market: sustainability, competition and security of supply.

2.11. Brief summary of future developments

In subsequent chapters, we introduce novelties such as the global market and a domestic spot market, which are obvious model developments. However, regarding the specific shippers' operation in entry-exit markets, four additional developments can be considered in future research:

- Capacity contracts normally include not only firm capacity, but also interruptible capacity. Shippers may be interested in contracting interruptible capacity since this type of capacity is normally cheaper than firm capacity. Although its incorporation would require risk-averse agents, some allusions to interruptible capacity, and its effects on operation decisions, are nonetheless mentioned in Chapter 5.
- Long-term capacity contracts are offered by facility owners to guarantee almost constant incomes and elevated rates of infrastructure utilization. But long-term capacity contracts can provide investment signals as well. In a few words, when a facility is fully contracted in the long term, shippers are indicating that they are willing to utilize additional capacity. Therefore, the relationship between long-term capacity contracting and investment decisions could be examined.
- Capacity hoarding is a main concern in tight gas systems. This anticompetitive behavior may hamper market operation and, above all, increase operation costs and reduce consumer surplus. Furthermore, new entrants may be prevented, resulting in even less competitive markets. Anticompetitive behavior should be analyzed with more detail.
- Demand has been represented in a rather simplified manner, i.e., constant, inelastic and aggregated. Future developments may involve both price- and cross-elasticity considerations, as well as a more detailed distinction among the consumption points. Furthermore, gas markets are not as rigid as we have modeled them. Both the consumers' possibility (and *laziness*) to switch between gas providers and new entrants should be included, therefore, modifying initial market shares.

At last, demand uncertainty may affect capacity contracting. A stochastic model could be useful for a better understanding of shippers' contracting decisions. An illustrative example of how uncertainty modifies contracting decisions is shown in Chapter 5.

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Chapter 3

Management of Traditional Supply Contracts within a Globalizing Gas Market

Since the beginning of the 19th century, oil and gas have been inseparable companions, probably because they have lived under the same roof for ages. However, as companions, not brothers, they present obvious physical differences, which characterize most of their respective industries. Dr. Fereidun Fesharaki provided a clear definition to distinguish both industries: "Oil is like dating; gas is like marriage." Oil is a viscous liquid that is relatively easily transported. In contrast, gas is either transported by pipeline or liquefied, to augment its energy density, so long-distance transportation is worth it. These operations require huge investments in infrastructure with just one purpose: conveying gas. Accordingly, producers demand long-term commitments of gas purchasers in order to recover their investments. Moreover, because oil and gas do share common end uses, and not only common origins, gas producers have traditionally prevented purchasers from switching to oil by linking gas and oil prices. Lately, however, gas prices have started to decouple from oil prices as a consequence of gas extraction technology developments, constituting an incipient global gas market. In this chapter, we explain how traditional oil-linked gas supply contracts affect shippers' decisions in entry-exit gas markets, as well as how shippers participate in a globalizing market.

3.1. An incipient global gas market

Natural gas can often be found in oil fields. In the early stages of the oil industry, natural gas was released into the atmosphere or burnt off since gas was considered a worthless by-product. However, gas was manufactured from coal distillation[1] at the time; i.e., gas was indeed a valuable product. Although at first sight contradictory, this behavior had its economic fundamentals. Gas pipeline investments and transmission costs from well-heads to consumers were huge in comparison to coal transportation from mines to gas factories, which besides were usually located close to towns.

Whereas manufactured gas established the foundations to constitute local gas distribution companies, natural gas exploitation established the foundations of traditional supply contracts. Both cases did respond to externalities. In the former case, economies of scale lead to the establishment of a vertically integrated company, which was habitually regulated or owned by public authorities, in charge of the whole gas chain. In the latter case, long-term agreements were necessary for hedging significant investment risks of producers, so they can guarantee constant incomes and a satisfactory rate of return.

During the 20th century, long-term agreements prevailed over the gas industry. Long gas pipelines were put into operation and an increasing number of natural gas fields were developed. By the end of the 20th century, natural gas acquired relevance as an energy source, in particular, for electricity generation (section 5.1, pp. 123–125). A liberalization process began in most countries and different gas markets appeared worldwide. Nevertheless, globalization which has also reached gas markets thanks to improvements on LNG technology (in particular, due to cost reductions in liquefaction and carrier construction) has brought distant markets closer. Although current prices diverge, gas prices are expected to converge in the near future.

At a global level, there are three relevant consumption geographic regions with their corresponding idiosyncrasies: North America, Japan and Europe. North America is living a golden age of gas. Shale gas extraction cost reductions have allowed the U.S. to become almost energy independent and Canada to consolidate its position as producing country. Moreover, wellhead gas prices have dropped significantly due to the combination of a production excess and a lack of exporting facilities like liquefaction terminals[2]. In

[1] Manufactured gas is a mixture of carbon monoxide, hydrogen, methane (some) and other reduced gases, quite different from natural gas (mostly methane).

[2] Both the U.S. and Canada do not share common frontiers with current or emergent gas consumption countries, such as the EU, Japan, or China. Consequently, they must export overseas by LNG carrier.

contrast, Japan has observed a dramatic increment of gas prices. After the Fukushima incident, Japan decided to shut down its nuclear power plants temporarily and substitute them with gas-fired power plants. Since Japan is an archipelago that is not connected to the continent by gas pipelines and whose domestic gas production is negligible, Japanese gas imports have relied on LNG carriers. North American and Japanese dissimilar conditions have been reflected in gas prices. In 2012, Henry Hub[3] average gas price was 2.8 $/MMBtu, while Japan LNG price amounted to 16.8 $/MMBtu (BP 2013). These price differences that are larger than the transportation costs from the U.S. to Japan (about 5 $/MMBtu) are an indicative of fragmented, not yet global, gas markets.

European gas prices are halfway between North American and Japanese prices, and not because of its geographic position. National Balancing Point[4] average gas price in 2012 was 9.5 $/MMBtu (BP 2013), but transportation costs from the U.S. to Europe are close to 2 $/MMBtu. In contrast, gas price differences between Europe and Japan better reflect the transportation costs, near 4 $/MMBtu. From these numbers we can draw some conclusions[5]: North American gas prices may be extremely low because supply exceeds demand and export capacity is reduced; Japanese gas prices may be equal to European gas prices plus transportation costs plus a (minor) premium due to low import capacity; and European gas prices, which are not currently limited by import or export capacities, may be, supposedly, determined by free market rules. However, European gas markets are still overcoming their own market rigidities.

3.2. The role of traditional supply contracts in Europe

The U.S. price is about 7 $/MMBtu lower than the European price. Although the U.S. lack export capacity[6] may account for most of the price difference, European gas market peculiarities may intensify the difference as well. We mentioned previously that long-term agreements prevailed over gas industry during the 20th century, but incipient gas spot

[3] The Henry Hub is a physical hub that interconnects nine interstate pipelines and is close to the producing area of the Gulf of Mexico. Due to its importance, it is considered a reference pricing point in the U.S.

[4] The National Balancing Point (NBP) is a virtual hub in which companies purchase and sell gas in order to achieve daily balances. It has acquired importance during last years and has become not only a reference pricing point in UK, but also in Europe.

[5] Different studies have analyzed the integration between international gas prices: (Silverstovs et al. 2005), (Brown, Yucel 2009) and (Neumann 2009). They conclude that gas markets were still segmented, but prices were converging. However, new studies would be required because structural market changes (shale gas revolution, Fukushima incident) have taken place lately.

[6] As gas production is larger than domestic consumption and gas storage is limited, gas prices are low. In addition, a reduced export capacity stresses this effect that will mitigate during the next years. For instance, the Department of Energy authorized a second facility to export LNG to countries that do not have a free-trade agreement (all except 20). Press release of Department of Energy, “Energy Department Authorizes Second Proposed Facility to Export Liquefied Natural Gas”, May 17, 2013.

markets have not had time to prevail over long-term agreements, which are still active in most European countries. Traditionally, gas supply contracts have satisfied equally the objectives of producers and vertically integrated companies. Thanks to long-term contracts, gas producers have guaranteed constant incomes to recover their huge investments and vertically integrated companies have assured certain prices to supply their consumers in a regulated environment, in which supply costs were simply recognized. To maintain the *status quo* and avoid unilateral contract rescissions, traditional supply contracts normally have exhibited the following characteristics:

- An agreed annual delivery volume that may present some flexibility (e.g., –10%). Since gas consumption has been typically season dependent[7], monthly or daily, in pipelines, deliveries could also vary (e.g., –20%) with respect to the monthly or daily agreed quantity. In any case, we observe that delivery floors are relevant in supply contracts. Known as take-or-pay (ToP) clauses, these floors strongly condition the management of supply contracts. In fact, the consequences of not complying with a ToP clause may go beyond "pay." The disappointed producer may not be happy with the unreliable shipper and take future reprisals such as raising contract prices or rescinding the contract.
  Nevertheless, contracts sometimes include flexibility clauses that alleviate the fulfillment of ToP clauses and maximum volumes. For example, if a ToP clause is not observed during a specific month or year, the shipper can receive the undelivered gas (known as make-up gas) the following month or year. On the other hand, if additional gas above the maximum volume is required during a specific month or year, the shipper can obtain more gas (known as carry-forward gas) at the expense of reducing future deliveries.
- A delivery price is also agreed on. Contract prices have been normally linked to oil price indices (or any oil distillate), although other energy products can be included as well. The economic fundamentals behind the indexation have been preventing consumers' switching to substitute products since oil and gas uses are rather similar. This way, producers, as well as shippers, secure consumers.
- Producers used to impose destination clauses to neutralize shippers' temptation, or necessity when domestic demand declined, to divert gas to other markets and, hence, to become their competitors. Nowadays, any sort of destination clause, even profit-sharing clauses, has been prohibited in the EU. However, the Interna-

[7] Traditionally, gas has been used as a heating fuel and in the manufacture of fertilizers and other products. Since industrial utilizations are almost constant during the year, gas consumption used to depend on temperatures (lower in warm months, higher in cold months). However, cooling systems have also incremented gas consumption lately during warm months since gas is increasingly used for electricity generation (Chapter 5).

tional Commercial terms, published by the International Chamber of Commerce[8] are utilized in overseas gas supply contracts. From all rules, free-on-board (FOB) and delivered-at-place[9] (DAP) rules are the most utilized. The main difference between both rules is the physical point in which the goods are passed from the seller to the buyer. In FOB rules, the delivery occurs after the shipment. In DAP rules, the delivery occurs at destination. Consequently, a negotiation between the seller and the buyer must take place in DAP contracts to modify the destination point. Both parts normally agree to share profits.

More details on gas supply contracts are provided in (Asche et al. 2002).

We, therefore, observe that traditional supply contracts introduce some market rigidities, especially, regarding gas prices. Gas contracts either will expire during the next decade, according to latest news[10], or are diminishing its duration (Neumann, von Hirschhausen 2008) providing opportunities to renegotiate prices. New supply contracts are indeed being linked to gas price indices. In any case, the rigidity of traditional contracts will influence gas spot prices during the next years. For example, while a decoupling between oil and gas prices in the U.S. may be already noticeable, European gas prices are still correlated to oil prices (Asche et al. 2013). However, European shippers can still take advantage of new business opportunities thanks to LNG carriers.

The main objective of this chapter is to analyze the shippers' behavior when they participate not only in downstream markets, but also in a globalizing market. In Chapter 2, we examined the shippers' behavior when they contract for capacity and operate in gas facilities and balancing zones, but constrained to predetermined LNG carrier arrivals and gas imports by pipeline. From now on, the shipper also manages its supply contracts and can take part, to a certain extent, in international trades either by diverting a carrier to another market, or by loading a carrier in a domestic LNG terminal and shipping it to another market (Figure 3-1). In contrast, cross-border pipelines physically prevent shippers from diverting gas because gas is delivered at a predetermined point of the network. Therefore, we can state that supply contracts by cross-border pipelines always include implicit destination clauses.

[8] The International Chamber of Commerce is an international organization whose main objective is strengthening commercial ties among nations. To this end, it has developed a large array of voluntary rules, guidelines, and codes, which facilitate cross-border transactions. An example is Incoterms rules, which are globally accepted in contracts for the international sale of goods (www.iccwbo.org).

[9] DAP rule has substituted delivered-ex-ship (DES) rule, which was of common use in gas supply contracts.

[10] For instance, "Most of Europe's gas supplies still linked to oil prices" in Reuters (February 22, 2013) or "Expiring Gas Contracts Offer Europe Chance to Renegotiate Prices" in Wall Street Journal (April 3, 2013).

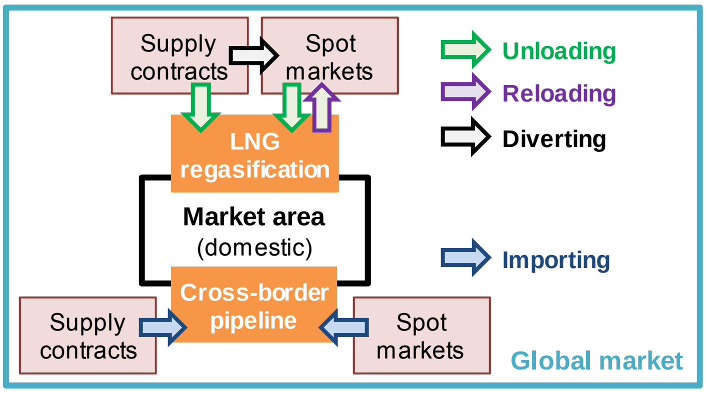

Figure 3-1 – A shipper within the global gas market

Since the U.S. gas market deregulation, the influence of long-term supply contracts and, particularly, ToP clauses formation on liberalized markets have been examined, such as in (Masten, Crocker 1985) or in (Hubbard, Weiner 1986). In our case, contract characteristics are provided in advance as we do not intend to study the economics of contract constitution, but the management of supply contracts within a competitive environment. Other authors have studied the integration of spot and contract gas prices in Europe, such as (Panagiotidis, Rutledge 2007) or (Asche et al. 2013), with econometric methods. Nonetheless, one of our major objectives is modeling spot markets (Chapter 4) and contract management through a fundamental model, which is one of the contributions of this thesis. From the point of view of fundamental models, different authors have optimized gas production, e.g., (Mantini, Beyer 1979) or (Murray, Edgar 1979); or spot purchases, e.g., (Boots et al. 2004) or (Gabriel et al. 2005), but a few have considered gas contracts characteristics. (Avery et al. 1992) and (Guldmann, Wang 1999) optimize contract portfolio supplies and spot purchases by pipeline by a local distribution company, but omit LNG carriers. Furthermore, the management of gas supply contracts has been also addressed from the perspective of electric utilities in (Chen, Baldick 2007), (Street et al. 2008) and (Dueñas et al. 2012); however, they do not represent gas systems in detail.

To our knowledge, no fundamental model that combines a detailed representation of the operation and contracting of gas facilities and the management of supply contracts has been published. Moreover, one advantage of our model is the consideration of the global business opportunities that arise from LNG transportation, which allows us to analyze the shippers' behavior within a global market. Therefore, we close a relevant gap (section 1.3, pp. 9–12), in this chapter, by contributing with a detailed model for examining the influence in downstream gas markets of both the traditional supply contracts and the global movement of LNG carriers. Next section 3.3 incorporates supply contracts into the operation model that has been already described in Chapter 2 (pp. 26–50). Subsequently, section 3.4 improves the representation of LNG transportation and includes the possibility of making decisions concerning loading carriers in regasification terminals, which allow shippers to profit from price opportunities beyond their domestic markets.

3.3. Management of gas supply contracts

Producers commonly tie their customers (in our case, shippers) through long-term supply contracts. Shippers that wish to acquire gas have to come to an agreement with either a state-owned company or a private company, which often have also signed an agreement with the producing country authorities. Whatever the case may be, large quantities of money have been or are invested in putting into operation the production facilities (including transportation pipelines and/or liquefaction terminals). Consequently, long-term supply contracts, f=1,2,…,F, are offered to shippers, e=1,2,…,E, by producers, which assure the investment recovery. The contractual terms typically include:

- A minimum and maximum delivery volume $\underline{V}_{fey}, \overline{V}_{fey}$ [GWh] during year y.
- A minimum and maximum delivery volume $\underline{V}_{fem}, \overline{V}_{fem}$ [GWh] during month m.
- A contract price C_{fem} [€/GWh] during month m. Prices are habitually updated when gas is delivered according to a prearranged formula, which commonly includes several-month, e.g., 3 months, moving averages (Asche et al. 2002) that smooth contract prices. Consequently, we have approximated resulting contract prices to an average monthly price that also incorporates freights and/or other fees.

Furthermore, there is an additional coefficient that stems from the producer's *threat*[11] to a future raise of prices. When a LNG supply contract is based on FOB rules, a shipper must not report its decisions, either if a carrier is unloaded in the domestic market or if it is diverted to another market. In contrast, a shipper that is willing to divert gas of a supply contract following DAP rules must agree upon a new destination with the producer, which will be in charge of redirecting the carrier. A profit-sharing coefficient ε_{fe} [%] will result from the negotiation process.

Independent of contract rules, total incomes are determined by gas prices P_{im}^{BID} [€/GWh] of market i, to which gas is diverted, during month m. For the sake of simplicity, freights and/or other fees are already discounted from market prices. Furthermore, because placing gas in other markets may not be an easy task if markets are not liquid enough, we establish an upper bound on maximum monthly and annual diverted volumes $\overline{V}_{fem}^{DIV}, \overline{V}_{fey}^{DIV}$ [GWh].

[11] Although natural gas fields are not concentrated in a few countries such as oil fields, gas producers maintain a dominant position that may have influence over shippers' decisions.

Shippers have flexibility to decide when and how much gas is delivered, but constrained by above contract terms and conditions. Shippers may take three different decisions depending on the type of contract (LNG carrier or pipeline delivery):

- Receiving a carrier v_{irfed}^{MET} [GWh] in regasification terminal *r*, the day *d*. We have included the market of origin *i* in order to track the carrier voyage.
- Receiving an import v_{xzfed}^{IMP} [GWh] by cross-border pipeline *x* connecting to balancing zone *z*, the day *d*.
- Diverting gas v_{ifem}^{DIV} [GWh] to other destination market *i* during the month *m*. To be precise, we should consider each rerouted carrier individually; but, for the sake of simplicity, we obtain the monthly aggregated volume.

Supply contracts are modeled in a rather similar way to (Dueñas et al. 2012). First of all, shippers minimize total costs when exercising their supply contracts:

$$\min_{\substack{v_{irfed}^{MET},v_{xzfed}^{IMP}\\ v_{ifem}^{DIV},v_{fem}^{ToP}}} \sum_{f,e,m} C_{fem}\cdot\left(\sum_{i,r,d\in m} v_{irfed}^{MET}+\sum_{x,z,d\in m} v_{xzfed}^{IMP}\right)+\sum_{i,f,e,m}\varepsilon_{ife}\cdot\left(C_{fem}-P_{im}^{BID}\right)\cdot v_{ifem}^{DIV} \quad (3.1)$$

The first summation represents delivery costs of gas entering the market area, whereas the second summation represents revenues and/or losses due to diverting gas. Diverted gas naturally does not enter the market area.

Supply contracts exercise is subject to minimum and maximum monthly and annual volume constraints:

$$\sum_{i,r,d\in m} v_{irfed}^{MET}+\sum_{x,z,d\in m} v_{xzfed}^{IMP}+\sum_{i} v_{ifem}^{DIV}\geq \underline{V}_{fem} \quad \forall f,e,m \quad (3.2)$$

$$\sum_{i,r,d\in m} v_{irfed}^{MET}+\sum_{x,z,d\in m} v_{xzfed}^{IMP}+\sum_{i} v_{ifem}^{DIV}\leq \overline{V}_{fem} \quad \forall f,e,m \quad (3.3)$$

$$\sum_{i,r,d\in y} v_{irfed}^{MET}+\sum_{x,z,d\in y} v_{xzfed}^{IMP}+\sum_{i,m\in y} v_{ifem}^{DIV}\geq \underline{V}_{fey} \quad \forall f,e,y \quad (3.4)$$

$$\sum_{i,r,d\in y} v_{irfed}^{MET}+\sum_{x,z,d\in y} v_{xzfed}^{IMP}+\sum_{i,m\in y} v_{ifem}^{DIV}\leq \overline{V}_{fey} \quad \forall f,e,y \quad (3.5)$$

As well as diverted volumes:

$$\sum_{i} v_{ifem}^{DIV}\leq \overline{V}_{fem}^{DIV} \quad \forall f,e,m \quad (3.6)$$

$$\sum_{i,m\in y} v_{ifem}^{DIV}\leq \overline{V}_{fey}^{DIV} \quad \forall f,e,y \quad (3.7)$$

Finally, gas deliveries must be linked to physical operation decisions. In detail, deliveries by the LNG carrier are unloaded in regasification terminals:

$$\sum_{w} q_{irwed}^{ULD}=\sum_{f} v_{irfed}^{MET} \quad \forall i,r,e,d \quad (3.8)$$

While deliveries through cross-border pipelines are equal to imports:

$$q^{IMP}_{xzed} = \sum\nolimits_f v^{IMP}_{xzfed} \quad \forall x, z, e, d \tag{3.9}$$

The objective function (3.1) subject to constraints (3.2)–(3.9) constitutes a linear programming (LP) problem that optimizes the shippers' exercise of gas supply contracts.

3.3.1. Exceeding maximum gas deliveries

We have previously mentioned that gas supply contracts may incorporate flexible clauses, such as make-up and/or carry-forward gas clauses. Despite we have decided not to model any flexible clause, a shipper has often the possibility of agreeing on a short-term gas supply contract with a producer[12], probably paying a higher price P^{ASK}_{im} [€/GWh] in comparison to a long-term contract. For the sake of clarity, freights and/or other fees are already included in market prices[13]. Therefore, we define two new variables, short-term purchases that can be either delivered by LNG carrier $v^{MET_{ST}}_{irem}$ [GWh] or by pipeline $v^{IMP_{ST}}_{xzem}$ [GWh].

Shippers minimize total costs from short-term purchases:

$$\min_{v^{MET_{ST}}_{ired},\, v^{IMP_{ST}}_{xzed}} \quad \sum_{i,m} P^{ASK}_{im} \cdot \left(\sum_{i,r,d \in m} v^{MET_{ST}}_{ired} + \sum_{x,z,d \in m} v^{IMP_{ST}}_{xzed} \right) \tag{3.10}$$

Constraints (3.8)–(3.9) are correspondingly adapted because gas can have either a long-term or a short-term contract origin:

$$\sum\nolimits_w q^{ULD}_{irwed} = \sum\nolimits_f v^{MET}_{irfed} + v^{MET_{ST}}_{ired} \quad \forall i, r, e, d \tag{3.11}$$

$$q^{IMP}_{xzed} = \sum\nolimits_f v^{IMP}_{xzfed} + v^{IMP_{ST}}_{xzed} \quad \forall x, z, e, d \tag{3.12}$$

Nevertheless, LNG markets may not be liquid and short-term purchases may be limited. In order to represent this market constraint, we have established a monthly maximum volume $\bar{Q}_{im}$ [GWh]:

$$\sum\nolimits_{r,e,d \in m} v^{MET}_{ired} \le \bar{Q}_{im} \quad \forall i, m \tag{3.13}$$

[12] As a matter of fact, most authors only consider this type of short-term purchases in their models.

[13] Hence, the ask price is higher than the bid price for the same market. Supposedly, the gas price is unique, but after adding to and discounting from the gas price the freights and/or other fees, both prices are naturally different: $P^{ASK}_{im} = P^{GAS}_{im} + F_{im} \ge P^{GAS}_{im} - F_{im} = P^{BID}_{im}$, where F_{im} represents the freights and/or other fees.

In general, a shipper will turn to short-term contracts when it finds itself on the verge of a gas shortage, i.e., unable to satisfy its demand. If it has foreseen adequately its gas necessities, exercising long-term contracts will be typically more economical than purchasing gas in a short-term basis.

3.4. LNG carriers connecting distant markets

Overcoming the technological barriers of overseas transportation thanks to the development of LNG facilities has eased, if not caused, the gas market globalization. Besides, it has provided access to relatively isolated, but currently large consumers, such as Japan and Spain[14]. Despite we explore downstream gas markets in this thesis, their functioning cannot be fully understood without putting them into the global context, i.e., incorporating LNG movements that may have influence on domestic prices.

The world fleet of LNG carriers is standardized and limited. Indeed, as indicated in Chapter 2, there is an online database (free of charge) that provides relevant information such as ship names, owners, and capacities. Another webpage[15] even shows the real position of every ship. Although representing the LNG global market with such level of detail is out of the scope of this thesis, we can take advantage of this knowledge and incorporate the global fleet in a simplified manner. First of all, we limit the arrivals u_{birwed}^{MET} of a specific carrier category b during month m[16]:

$$\sum_{i,w,e,d\in m} u_{birwed}^{MET} \leq K_b^{MET} \cdot \sum_{b',i,w,e,d\in m} u_{b'irwed}^{MET} \quad \forall b,r,m \tag{3.14}$$

The parameter K_b^{MET} is the maximum percentage of a carrier category that arrives during a month and is related to the fact that carriers of a certain capacity predominate over others. For instance, about 80% of the fleet can transport about 900 GWh, while only 5% of the fleet can ship 220 GWh. Accordingly, more arrivals of large than small carriers are expected.

Secondly, we have already assigned in Chapter 2 a particular capacity Q_b^{MET} to each carrier category. Nevertheless, different gas volumes q_{irwed}^{ULD} are actually unloaded depending

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[14] These countries are isolated because they are either islands or peninsulas poorly interconnected. In both cases, LNG carriers are like pipelines that connect producing countries, where a liquefaction facility is installed, with consuming countries, where a regasification terminal is installed.

[15] Both web pages are www.shipbuildinghistory.com and www.marinetraffic.com.

[16] Other reasonable periods could have been selected: fortnights, quarters, semesters, years, etc. However, the selected period should be neither too short nor too long, but fit to a time scope that presents almost uniform arrivals when they are classified by type. We opt for the month to be in accordance with supply contract constraints.

on gas characteristics, such as calorific values; carriers themselves that may present different levels of gas leakages; and distances to destination as gas is consumed during the voyage. We have tried to represent these variations by including in equation (2.6) a free variable $\tilde{u}^{ULD}_{birwed}$ [%] that may modify the daily unloaded cargo:

$$q^{ULD}_{irwed} = \sum_b Q^{MET}_b \cdot \left(u^{ULD}_{birwed} + \tilde{u}^{ULD}_{birwed} \right) \quad \forall i,r,w,e,d \tag{3.15}$$

The unloading tolerance is contained within a predetermined range $-\tilde{U}_b \leq \tilde{u}^{ULD}_{birwed} \leq \tilde{U}_b$ in order to avoid large alterations of the unloaded cargo. As a result, carrier capacities will be hereafter defined by two parameters: $Q^{MET}_b \pm \tilde{U}_b$ [GWh ±%]. In addition, we need to assure that tolerances and unloading decisions are tied; that is, a tolerance can be different from zero only if a carrier is unloading its cargo:

$$-u^{ULD}_{birwed} \leq \tilde{u}^{ULD}_{birwed} \leq u^{ULD}_{birwed} \quad \forall b,i,r,w,e,d \tag{3.16}$$

A final remark is that carriers tend to be small when they connect markets that are close and large when markets are distant. Therefore, every carrier category does not usually access every market. In fact, brand new large LNG carriers, Q-Flex and Q-Max, have their base of operation (i.e., market of origin) in Qatar. As our model can track the route of each carrier from a market of origin to a LNG terminal, we can take into account these transportation details by means of an incidence matrix (*b*, *i*) that establishes which carrier category has access to which market.

Constraints (3.14)–(3.16) plus the incidence matrix represent in a simplified manner, but accurate enough for our objectives, the world fleet of LNG carriers and its characteristics.

3.4.1. Loading LNG carriers

LNG is the only possibility to arbitrage between distant markets that are not connected by pipeline. Although LNG regasification terminals have been traditionally installed as entry points to gas systems that lack domestic natural gas production, during the last few years a gradually larger utilization as exit points have been observed. Regasification terminals normally also allow loading LNG carriers, which can be shipped to markets that exhibit higher prices in comparison to domestic prices. Since the Fukushima incident, significant high prices have been observed in Asia, so shippers have started to load carriers in order to arbitrage between markets and profit from price differences.

We have already described and modeled LNG regasification terminal operations and, in particular, the arrival and unloading of carriers (section 2.4.1, pp. 26–30). As expected, the arrival and loading can be addressed in a similar way. LNG terminal owners may apply a tariff to each offered service: slot assignment[17] $\hat{C}_r^{MET}$ [€/carrier], and loading procedure C_r^{RLD} [€/GWh]. Shippers minimize costs associated with both services, but maximize incomes from selling gas in another market:

$$\min_{\hat{u}_{birwed}^{MET}, q_{irwed}^{RLD}} \sum_{i,r,w,e,d} \left(\hat{C}_r^{MET} \cdot \sum_b \hat{u}_{birwed}^{MET} + C_r^{RLD} \cdot q_{irwed}^{RLD} \right) - \sum_{i,r,w,e,d \in m} P_{im}^{BID} \cdot q_{irwed}^{RLD} \tag{3.17}$$

LNG carrier arrivals to a berth w of a LNG terminal are represented through binary variables $\hat{u}_{birwed}^{MET}$ {0,1}, while continuous variables q_{irwed}^{RLD} [GWh] represent the daily loaded and shipped cargo. The index i is used to define a market of destination. Equivalent to (2.3), a carrier arrival for loading is prevented when the carrier capacity is larger than the berth dimension Q_{rw}:

$$Q_b^{MET} > Q_{rw} \quad \Rightarrow \quad \hat{u}_{birwed}^{MET} = 0 \quad \forall b,i,r,w,e,d \tag{3.18}$$

Furthermore, constraint (2.4) is extended because any other carrier arrival is henceforth not permitted when a carrier is already moored at the terminal berth, either unloading or loading its cargo:

$$\sum_{d'>d-T_b^{MET}}^{d'=d} \sum_{b,e} \left(u_{birwed'}^{MET} + \hat{u}_{birwed'}^{MET} \right) \leq 1 \quad \forall r,i,w,d \tag{3.19}$$

Binary variables represent carrier arrivals; however, any carrier may be moored during a few days T_b^{MET} because the loading process takes that time. During such period of time, a carrier loads a percentage of its cargo, represented by a continuous variable u_{birwed}^{RLD} [0,1]:

$$u_{birwed}^{RLD} = \sum_{d'>d-T_b^{MET}}^{d'=d} \frac{\hat{u}_{birwed'}^{MET}}{T_b^{MET}} \quad \forall b,i,r,w,e,d \tag{3.20}$$

Consequently, the cargo is loaded during the arrival day when $T_b^{MET} = 1$; the cargo is loaded during the arrival day and the immediate next day when $T_b^{MET} = 2$, and so on and so forth. To this point, we have represented the mooring of a carrier during some days. Evidently, the carrier is filled with gas during these same days:

$$q_{irwed}^{RLD} \leq \sum_b Q_b^{MET} \cdot u_{birwed}^{RLD} \quad \forall i,r,w,e,d \tag{3.21}$$

Observe that a carrier may not be full at the end of the process as it actually occurs. Finally, as well as LNG short-term purchases may be limited, markets, where carriers ship

[17] We differentiate the tariff that is applied to a carrier with the intention of unloading its cargo from the tariff that is applied to a carrier with the intention of loading. Habitually, the latter tariff is more expensive than the former tariff because LNG terminals are designed and installed as entry points.

gas to, may not be liquid enough to receive large gas volumes. Consequently, we must restrain, e.g., monthly sales to other markets:

$$\sum_{r,w,e,d\in m} q^{RLD}_{irwed} \leq \bar{Q}_{im} \quad \forall i,m \tag{3.22}$$

The objective function (3.17) subject to constraints (3.18)–(3.22) constitutes a MIP problem that supports shippers' decision making on loading LNG carriers and regarding their participation in other markets beyond their domestic market frontiers.

3.5. Speeding up resolution time: Shape, sand and polish

The case study of Chapter 2 took about eleven hours and a half to be solved by using CPLEX 12 on an Intel® Core™ 64-bit at 3.40GHz with 16GB RAM, although the options of CPLEX were chosen in such a way that we minimize this computational time. In addition, in that case study we specified carrier arrivals in the model and the model distributed them among shippers. Thanks to this shortcut, because our main objective was to examine shippers' operation and contracting behavior in downstream markets, we reduce the number of integer variables, from about 55,000 to 1,237 variables, and obtain a relatively tractable model in terms of resolution time. However, our current objective is to analyze the shippers' behavior within a global context; that is, each shipper can decide the arrival date of a LNG carrier either to be unloaded or loaded. As a result, the number of integer variables is considerably increased. In addition, the number of continuous variables also grows with the incorporation of both long-term contracts and short-term purchases. We, therefore, need to come up with an approach to reduce computational time without losing accuracy. We propose an approach by exploiting both capacity and supply contracting aspects of gas markets.

If we go back to results from section 2.9 (pp. 64–71), we can observe a distinctive operation pattern as long- and medium-term capacity contracts condition the operation of most facilities (especially, LNG terminals and cross-border pipelines) which present an almost constant monthly utilization pattern only altered by a few daily spikes, which are a consequence of daily demand variations. Moreover, the exercise of supply contracts also depends on the month because prices and volume constraints fluctuate on a monthly basis. Consequently, the analyzed temporal horizon can naturally be partitioned into months, thereby obtaining small sub-problems which are potentially easier to solve. Nonetheless, the partition must take into account constraints and decisions which span over several months, e.g., long-term capacity contracts, and must transfer the precise set of data for a coherent execution from month to month, e.g., the final inventories.

In consideration of both requirements, the proposed approach consists of the following three stages (Figure 3-2):

- We first broaden the model time step from days to months. To do so, we aggregate daily flow input parameters, such as regasification, injection-withdrawal and import-export capacities and demands, into months. Furthermore, balancing and secondary capacity markets are closed because these markets are based on daily transactions. From the monthly resolution, we save some key variables that are used in the next stage: LNG, underground storage and line-pack inventories at the end of each month; monthly arrivals by carrier category, distinguishing their purpose: unloading or loading; long-term contracted capacities; and monthly exercise of supply contracts.
- Subsequently, we solve each month individually in a daily basis after fixing final inventories, and indicating carrier arrivals (and their purpose), long-term capacity contracts and exercise of supply contracts. Moreover, balancing and secondary capacity markets are reopened. The only objective of these individual resolutions is obtaining the exact date of LNG carrier arrivals.
- At last, we obtain a solution for the whole temporal horizon in a daily basis maintaining daily carrier arrivals of the previous stage, but releasing other decisions related to final inventories or contracts.

In order to corroborate its accurateness, we have compared the solutions with and without applying the proposed approach. Whereas the resolution time reduces from eleven hours and a half to 12 minutes, the objective function value only worsens 1.10%[18]. Remark that, despite other considerations, the objective of the model is providing those decisions that maximize the social welfare; therefore, the importance of obtaining similar objective functions.

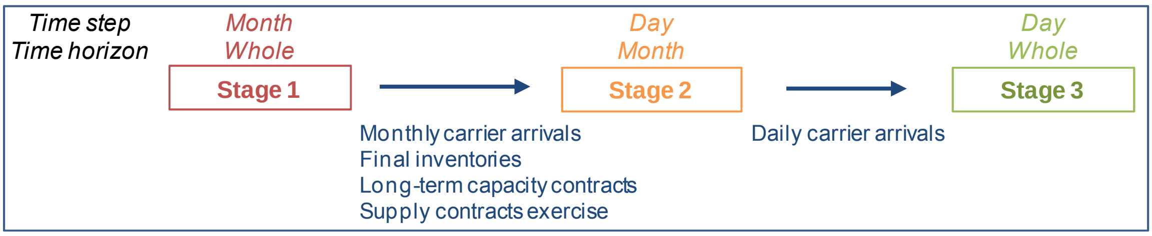

Figure 3-2 – Proposed resolution approach

[18] One percent might still represent a lot of money in reality. A possibility would consist in *buffing* the solution by allowing the LNG carriers to change their arrival date by one or two days. As a matter of fact, when a carrier informs of its arrival date to an operator, there is an implicit time frame around the expected date.

3.6. Application to the Iberian natural gas market

In Chapter 2 (pp. 51–64), we have already described the physical system, market structure and tariff brochure of MIBGAS in detail. In this case study, we alter one major aspect: supplies by LNG carriers and cross-border pipelines are no longer fixed, but dependent on the exercise of realistic gas supply contracts[19]. We continue reproducing the market conditions of 2012. In what follows, we describe global market parameters and supply contract characteristics.

Month	Europe		North America		Asia	
	Price	Capacity	Price	Capacity	Price	Capacity
January	22.37	-	7.65	1,000	44.21	3,000
February	27.41	-	6.36	1,000	41.45	3,000
March	24.12	-	5.82	1,000	42.25	3,000
April	24.99	-	4.89	1,000	43.57	3,000
May	24.62	-	5.17	1,000	45.65	3,000
June	23.81	-	6.94	1,000	46.96	3,000
July	24.60	-	7.19	1,000	50.25	3,000
August	24.37	-	7.87	1,000	48.83	3,000
September	25.82	-	7.17	1,000	44.53	3,000
October	26.85	-	7.95	1,000	40.17	3,000
November	27.25	-	8.93	1,000	40.00	3,000
December	27.36	-	8.73	1,000	40.15	3,000

Table 3-1 – Monthly prices[20] in €/MWh and capacities in GWh in spot markets

According to data provided by the Spanish and Portuguese regulatory authorities[21], imports by either LNG carriers or cross-border pipeline, to MIBGAS during 2012, had its market of origin mainly in Algeria (near 40% in each country), Nigeria (15% in Spain and about 60% in Portugal), Middle East (12% in Spain), and Europe (close to 15% in Spain). We have also included Asia, North America and South America to complete the global market. Within these markets, we must distinguish between markets based on long-term contracts and spot markets. Whereas deliveries from Algeria, Nigeria, Middle East and

[19] Unlike physical operation, which is almost public, supply contracts are of strategic importance for shippers and little information is public, in particular, regarding prices and volumes. Therefore, we would like to warn that contract characteristics here reproduced are realistic, but not real.

[20] North American prices are very low, so we are here indicating the ask price, that is, the price at which gas is purchased. In contrast, Asian prices are very high, so we are showing the bid price, that is, the price at which gas is sold. We assume that ask and bid European gas prices are almost equal.

[21] CNE is the Spanish regulatory authority (www.cne.es), and ERSE is the Portuguese regulatory authority (www.erse.pt).

South America habitually rely on long-term agreements; Europe[22], North America and Asia are commonly considered as spot markets in which short-term purchases, or sales, take place. As previously mentioned, these spot markets present two main parameters: price and capacity (Table 3-1). In detail, European gas prices have been extracted from Powernext, which provides the reference French price; North American gas prices corresponds to Henry Hub prices; and Asian gas prices are equivalent to the reference price Japan LNG. Furthermore, we have established that the number of large LNG carriers that can be either purchased or sold monthly in North America and Asia are about one and three, respectively.

As previously mentioned, supply contract characteristics are of strategic importance for shippers to compete in gas markets and, consequently, little information is publicly available. From all information that must be provided to the model, annual volumes and markets of origin can be roughly obtained from press notices and annual reports. With the available public information, we have constructed the contract portfolios of Table 3-2.

Shipper	By LNG carrier	By cross-border pipeline
ESP1	Algeria, Nigeria, Middle East	Algeria (Tarifa)
ESP2	Algeria	Algeria (Almería)
POR1	Nigeria	Algeria (Tarifa)
POR2	Nigeria	
OT	Algeria, S. America	Algeria (Almería)

Table 3-2 – Type and market of origin of contract portfolios

Annual volumes have been estimated in line with previous obtained results from Chapter 2. Imports from Algeria by cross-border pipelines amounted to around 48 TWh for ESP1, 4 TWh for ESP2, 11 TWh for POR1, and 28.5 TWh for OT. On the other hand, LNG deliveries were equal to about 115 TWh for ESP1, 35.5 TWh for ESP2, 22 TWh for POR1, 35.5 TWh for POR2, and 55 TWh for OT. LNG volumes have been increased by 10% because in Chapter 2 neither diverting nor loading carriers were contemplated. Then, the increase has been distributed among above supply contracts trying to maintain the real weight of each market of origin. Take-or-pay clauses oblige to exercise at least 90% of the total annual volume. Regarding monthly volumes, we have uniformly allocated annual volumes to each month and then increased them again by 10% because the summation of monthly volumes is not necessarily equal to the annual volume. In addition, take-or-pay clauses obligate to exercise at least 80% of monthly volumes (Table 3-3).

[22] This is only valid from the perspective of MIBGAS. For instance, German shippers have signed long-term contracts with Norway or Russia, that is, European producers also rely on long-term contracts.

Shipper	Contract by market of origin	Max. annual volume	Min. annual volume	Max. monthly volume	Min. monthly volume
ESP1	Algeria	70.0	63.0	6.42	5.13
	Nigeria	10.0	9.0	0.92	0.73
	Middle East	46.5	41.9	4.26	3.41
	Algeria (Tarifa)	48.0	43.2	4.40	3.52
ESP2	Algeria	39.0	35.1	3.58	2.86
	Algeria (Almería)	4.0	3.6	0.37	0.29
POR1	Nigeria	24.2	21.8	2.22	1.77
	Algeria (Tarifa)	11.0	9.9	1.01	0.81
POR2	Nigeria	39.0	35.1	3.58	2.86
OT	Algeria	25.5	23.0	2.34	1.87
	South America	35.0	31.5	3.21	2.57
	Algeria (Almería)	28.5	25.7	2.61	2.09

Table 3-3 – Supply contract characteristics (volumes in TWh)

Month	LNG carrier	Cross-border pipeline
January	26.38	27.68
February	25.35	28.11
March	26.60	27.81
April	25.55	27.89
May	26.77	28.51
June	26.58	28.86
July	28.17	29.11
August	25.97	29.88
September	27.06	29.62
October	26.27	29.44
November	23.11	28.62
December	26.12	28.29

Table 3-4 – Monthly supply prices according to customs declarations in €/MWh

Contract prices are especially challenging to be estimated. Fortunately, the Spanish regulatory authority publishes average supply prices according to shippers' customs declarations, which provide an idea of contract prices when deliveries are made either by LNG carrier or by cross-border pipeline (Table 3-4). As former incumbent companies may present more bargaining power than late entrants due to their size and experience[23], we suppose that the former incumbent companies, ESP1 and POR1, obtain a 5% discount,

[23] As long as we consider that every contract is still linked to oil indices as actual prices reveal, we can make the subsequent assumption. However, a new entrant that has recently signed a supply contract will for sure benefit from better prices because its new contracts will be linked to gas indices.

while, regarding the late entrants, ESP2 achieves the same price, and POR2 and OT observe a 5% and 10% increment, respectively. Furthermore, when a shipper has several LNG contracts, delivery prices for every contract are equal.

If prices are commonly not transparent, information concerning commercial rules, that is, FOB or DAP rules, or the possibility of diverting is absolutely unknown. Nevertheless, EU regulations forbid destination clauses, so LNG carriers can be diverted to other markets. We assume that almost 10% of total annual volume and 15% of total monthly volume can be diverted. In addition, we have decided that those contracts that were (most likely) signed before the EU banning are based on DAP rules, while recent contracts[24] rely on FOB rules (Table 3-5). In DAP contracts, shippers share 50% of total profits.

Shipper	Contract by market of origin	Max. diverted annual volume	Max. diverted monthly volume	Commercial rules
ESP1	Algeria	7.0	0.96	DAP
	Nigeria	1.0	0.14	FOB
	Middle East	4.7	0.64	FOB
ESP2	Algeria	3.9	0.54	DAP
POR1	Nigeria	2.4	0.33	DAP
POR2	Nigeria	3.9	0.54	FOB
OT	Algeria	2.6	0.35	DAP
	South America	3.5	0.48	FOB

Table 3-5 – Supply contract characteristics (diverted volumes in TWh)

	220 GWh	485 GWh	900 GWh	1500 GWh
Algeria	1	1	1	-
Nigeria	-	-	1	-
Middle East	-	-	1	1
South America	-	-	1	-
Europe	-	1	1	-
North America	-	-	1	-
Asia	-	-	1	-

Table 3-6 – Supply contract characteristics (diverted volumes)

We have redefined LNG carriers. In Chapter 2, we define four carrier categories according to their size: small (220 GWh), medium (485 GWh), large (900 GWh), and extra large (1500 GWh). We maintain four categories, but establish a variation range that depends on the category. In particular, the variation ranges are 220 GWh ±5%, 485 GWh ±10%, 900 GWh ±10%, and 1500 GWh ±5%. As previously mentioned, the world fleet of LNG

[24] However, these contracts are not-so-recent to be linked to a gas index.

carriers is limited. Consequently, we restrict the carrier arrivals depending on the carrier category. Specifically, at most 5%, 25%, 80%, and 15% of total arrivals are due to small, medium, large, and extra large carriers, respectively. Moreover, not every carrier category accesses every market. Table 3-6 contains the incidence matrix, i.e., the carrier category that can have access to each market. Finally, regulated tariffs for loading LNG carriers in regasification terminals amounted to 163,003 €/carrier and 1,441 €/GWh during 2012.

		Equations	Variables	Integer variables	Binary variables	Time
Stage 1	Year	12,239	19,384	1,812		0' 03''
Stage 2	Jan	39,324	61,050		450	4' 19''
	Feb	36,831	57,263		420	1' 47''
	Mar	39,276	60,913		420	3' 26''
	Apr	37,905	58,733		638	4' 19''
	May	39,080	60,460		420	3' 39''
	Jun	37,942	58,814		493	2' 37''
	Jul	39,182	60,379		420	1' 33''
	Aug	39,286	60,930		540	2' 04''
	Sep	37,987	58,954		406	2' 59''
	Oct	39,466	61,200		480	3' 14''
	Nov	38,095	59,184		464	3' 20''
	Dec	39,219	59,956		330	1' 51''
Stage 3	Year	463,179	703,753			1' 42''

Table 3-7 – Size and computational time of each model execution

3.7. Shippers' behavior within a global gas market

The model has been formulated in GAMS and solved by using CPLEX 12 on an Intel® Core™ 64-bit at 3.40GHz with 16GB RAM. The computational time to solve the case study was 37 minutes thanks to the new proposed approach to reduce it significantly. It would have taken several days otherwise. Table 3-7 presents the size and the computational time of each model execution, in which we can observe the methodological advantage when we examine stage three. A model execution without any binary variables, since they are already fixed in stage two, takes more than one minute and a half, which is approximately the same that it would take to solve each node during the branch and bound algorithm application time, as the heuristics may reduce the computational time. Furthermore, we have observed that the number of binary variables would be above 55,000. Both facts together would increase significantly the computational time, probably, to several days. The proposed methodology is another relevant contribution of this thesis as it allows us to obtain detailed solutions of a large time horizon for gas systems.

Optimizing the shippers' management of gas supply contracts is one of our main objectives. Annual volumes of every contract are exercised, and take-or-pay clauses are never breached. Let us now observe Figure 3-3, in which the monthly exercise by ESP1 of its supply contracts, grouped according to the way of delivery, is shown. We can notice the mirror-image symmetry between prices and delivered quantities. As expected, higher prices imply lower deliveries. In fact, during these high-price months, shippers are willing to pay for reducing the monthly take-or-pay clause as shippers would have an additional amount of gas to be delivered in low-price months. The dual variables of constraints (3.2) indicate that, for example, ESP1 is willing to pay 1.52 €/MWh in August in order to reduce the monthly take-or-pay clause of its supply contract by cross-border pipeline.

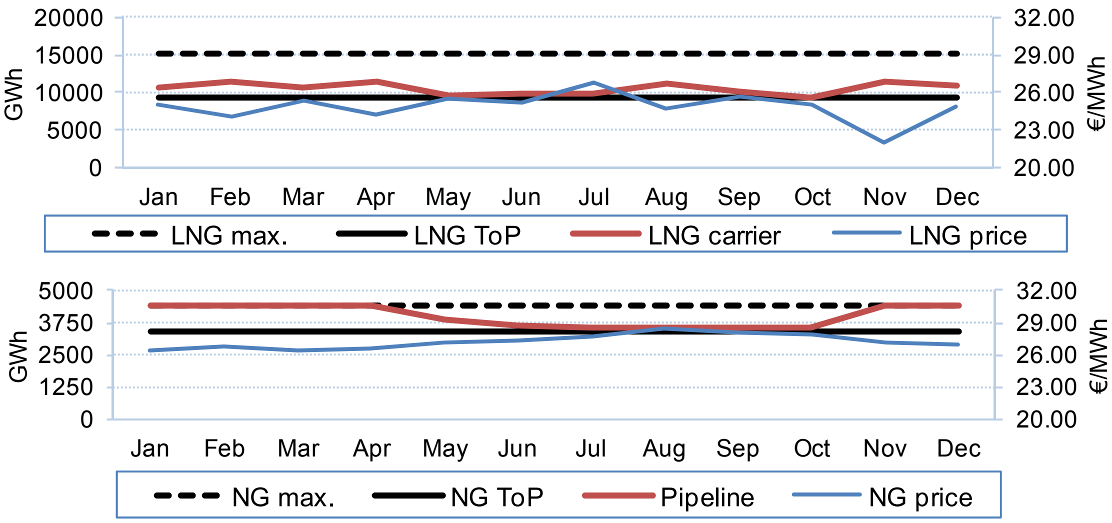

Figure 3-3 – Monthly exercise by ESP1 of its contract portfolio

One important aspect that is worth examining is the destination of the exercised LNG quantities. According to our input data, diverted volumes can amount to as much as 10% of annual volume and 15% of monthly volume. A priori, it could be expected that diverted volumes will be significant in those months that present a larger margin between both destination market and contract prices (August in Figure 3-4). Nevertheless, another relevant diverted volume coincides with the minimum margin (October in Figure 3-4). This behavior results from minimizing the costs of complying with the take-or-pay clause, in October, in order to be technically capable of exercising the monthly maximum volume during the cheapest month, in November. In short, POR2 is willing to lose some money in October in exchange for saving it in November. We can verify this statement by comparing the dual variables of constraints (3.3) in November and (3.2) in October: POR2 would save up to 2.70 €/MWh if the maximum volume were renegotiated upwards, while it would lose 0.44 €/MWh if the take-or-pay clause were increased as well. Therefore, the behavior that seems inconsistent is economically justified.

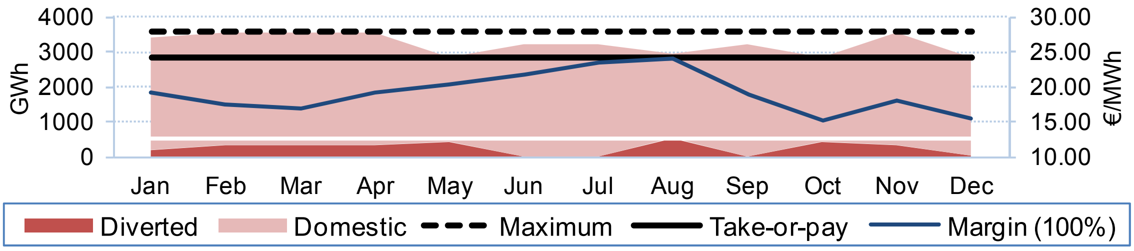

Figure 3-4 – Destination of LNG deliveries by POR2

Furthermore, an additional advantage of incorporating the supply activity is that we can now examine the gas chain value, i.e., how much do regulated entry-exit tariffs and supply costs of total gas costs represent. We observe in Table 3-8 that regulated third party access to Spain is about 1.45 €/MWh cheaper than to Portugal[25]. Consequently, the regulated costs represent above 23% of total Portuguese gas cost in contrast to 19% of total Spanish gas cost. Naturally, these cost differences have an influence in the cross-border pipeline utilization. Gas flows from Portugal to Spain only add up to 3.77 TWh, while gas flows from Spain to Portugal amount to 12.80 TWh (Figure 3-5), which is in line with actual Spanish imports 3.22 TWh and exports 8.33 TWh during 2012. Moreover, the model also captures quite accurately the real utilization of the cross-border pipelines between Spain and France, despite the fact that the model is only guided by exogenous prices because any supply contract has been assigned to the cross-border pipelines. Actual Spanish imports and exports during 2012 amounted to 35.3 TWh and 0.2 TWh, respectively; simulated Spanish imports amount to 38.3 TWh, simulated exports to zero. These results confirm that the utilized public sources of information are reliable, at least to some extent, and that the model performs properly.

	Regulated costs	Supply costs	Total costs
ESP1	6.07 (19%)	25.44 (81%)	31.51
ESP2	5.00 (16%)	26.16 (84%)	31.16
POR1	7.52 (23%)	25.52 (77%)	33.04
POR2	10.24 (27%)	27.12 (73%)	37.36
OT	3.92 (12%)	29.30 (88%)	33.22

Table 3-8 – Annual unitary gas costs in €/MWh

[25] The value has been calculated as the difference between the regulated tariffs of two comparable shippers, that is, the former incumbent companies ESP1 with POR1.

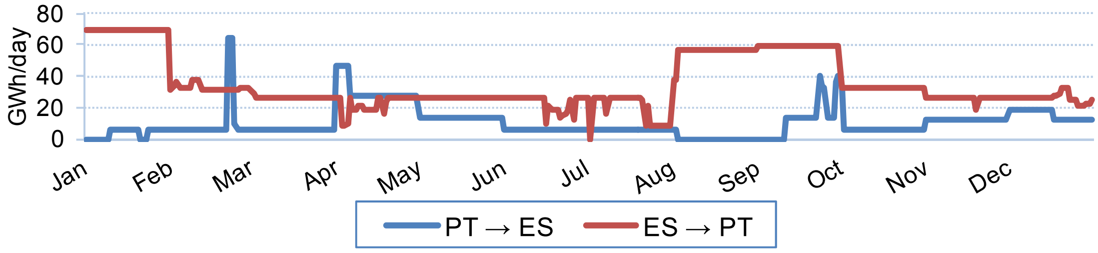

Figure 3-5 – Cross-border pipeline utilization between Spain and Portugal

Regarding LNG carrier movement throughout the world, MIBGAS receives 332 carriers, of which 60 are medium, 251 are large, and 21 are extra large carriers. In relative numbers, 18%, 75.6% and 6.4% of total arrivals correspond to medium, large and extra large carriers. Real arrivals during 2012 (section 2.8.2, page 58) were equal to 301, of which, in relative numbers, 2%, 15.6%, 74.1% and 8.3% were small, medium, large and extra large carriers, which are not-so-different from estimated arrivals. What the model is not able to capture accurately is the variation of monthly arrivals (Figure 3-6). The mean absolute error is 3 carriers, while the average real monthly arrival amounts to 25 carriers (i.e., 12% relative error). Moreover, the real standard deviation of monthly carrier arrivals was about 3 carriers during 2012. However, when the model is free to decide the carrier arrivals, the standard deviation reduces to 1.4 carriers. As the model is guided by supply contracts, we may have underestimated the supply contract flexibility regarding both take-or-pay and maximum volumes and/or the supply contract monthly price variability.

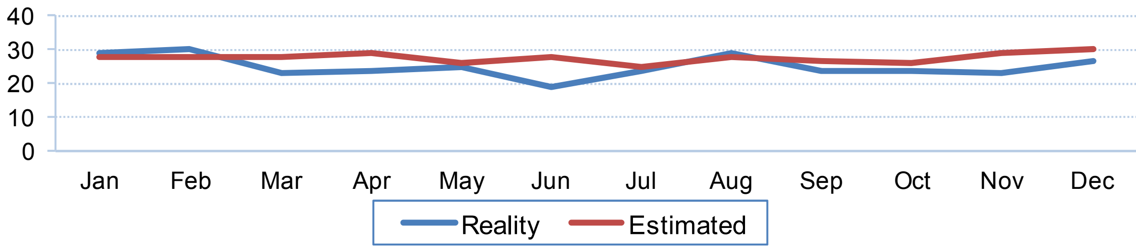

Figure 3-6 – Monthly carrier arrivals during 2012, reality vs. model

In any case, annual maximum volumes are wholly delivered, i.e., the shippers fully exercise their supply contracts. This behavior is logical as they find an extraordinary profitable business opportunity in exercising the contracts beyond the mere satisfaction of their domestic demand: Asian gas prices economically justify diverting or loading LNG carriers. Before going into details about carrier loadings at domestic LNG terminals, let us examine the dual variables of constraints (3.5) in order to appreciate the opportunity costs that represent the imposition of maximum annual volumes on gas deliveries. Every shipper is willing to pay for increasing the annual maximum volume, even of the contracts that are delivered by pipeline since if additional gas is available by pipeline, LNG deliveries can be released from satisfying the domestic market demand. Let us observe

Table 3-9, which shows the dual variable values and the average supply costs. We have included a supplementary column, which contains the sum of dual variable values and average annual supply costs. For LNG supply contracts, this column evaluates which contract is more advantageous beyond supply costs, which are equal for every contract belonging to the same shipper. The dual variables are actually internalizing the contract terms and conditions. In the case of pipeline supply contracts, this column implicitly provides the chain cost of loading LNG carriers. The shippers are willing to renegotiate the maximum annual volume clause until the supply cost equals about 38.66 €/MWh. The additional gas (by pipeline) releases LNG that can be now shipped to other markets. In the extreme, the supply cost plus the loading costs must equal the price at which gas is sold, i.e., the Asian gas price, which is around 44 €/MWh. Therefore, loading costs amount to about 5.34 €/MWh.

	LNG supply contracts			Pipeline supply contracts		
	Dual variables (€/MWh)	Supply costs (€/MWh)	Total (€/MWh)	Dual variables (€/MWh)	Supply costs (€/MWh)	Total (€/MWh)
ESP1	13.90 18.00 14.50	24.85	38.75 42.85 39.35	11.50	27.16	38.66
ESP2	12.40	26.18	38.58	10.10	28.59	38.69
POR1	9.00	25.02	34.02	11.50	27.16	38.66
POR2	13.00	27.43	40.43			
OT	8.80 9.20	28.73	37.53 37.93	7.20	31.44	38.64

Table 3-9 – Dual variables of annual maximum volume constraints and average supply costs

Shipper	Number of loadings	Loaded quantity (GWh)	Loading spread (€/MWh)	Diverted quantity (GWh)	Diverting spread (€/MWh)
ESP1	11	10,262	19.40	4,930	19.05
ESP2	3	2,814	14.92	347	11.00
POR1	3	2,531	14.08	440	10.70
POR2	4	2,655	17.07	2,955	16.53

Table 3-10 – Carrier loadings at LNG regasification terminals

Loading LNG carriers in regasification terminals and shipping them to other markets allows shippers to benefit from price opportunities beyond their domestic market. We have previously observed the big difference between European gas prices (also, those declared at Spanish customs) and Asian gas prices. In accordance with the model results, 21 loadings, which total 18.3 TWh, are shipped to Asia. As shown in Table 3-10, average annual loading spreads are higher than diverting spreads. Moreover, the spread differences widen when a shipper is obliged to share the profits from the diverted carrier, which results in 6 to 8 times larger loaded quantities than diverted quantities. In contrast, when profits from diverted quantities are not shared, the differences between loaded and diverted quantities diminish significantly.

3.8. Brief summary of contributions

In Chapter 2, we introduced an entry-exit gas market model able to capture the market performance regarding both operation and contracting decisions in gas facilities (regasification terminals, underground storages, pipelines, etc.). We have incorporated a simplified global gas market that allows us to complete the previous model and to consider how domestic decisions can be influenced by distant market conditions. Several stakeholders may profit from this innovative model. For example, shippers can optimize the management of their supply gas contracts and obtain useful information on the economic value of contract terms and conditions in order to renegotiate them. Furthermore, shippers can improve the coordination between their operation and capacity contracting decisions and their supplies, which may contribute to the efficient utilization of gas facilities. A second relevant novelty is the integration of a global gas market into the model with a basic, but accurate for our purposes, representation of the LNG carrier world fleet and the definition of different producing and/or consuming countries. Thanks to these developments, shippers can not only focus on competing in their domestic market, but also take advantage of price opportunities in distant markets either by diverting gas from their supply contracts or by loading LNG carriers at the regasification terminals and shipping them overseas.

After the model extension, the arising model size led to the implementation of a new developed methodology in order to maintain its computational tractability. Although the initial model was solvable numerically, it would most likely take several days before obtaining a satisfactory solution. Consequently, we present an approach, which reduces greatly the computational time (about 98%) without losing accuracy in practice. The success of this approach is based on making the most of gas market features, such as capacity and supply contract characteristics.

3.9. Brief summary of future developments

One last and relevant development to represent and understand downstream natural gas markets performance takes place in Chapter 4, in which a hub that facilitates the interaction of shippers when trading gas is incorporated and examined. In addition, concerning supply contracts and a simplified global gas market[26], four additional developments can be conducted:

- Daily maximum volumes, as well as take-or-pay clauses, are commonly imposed on gas supply deliveries by pipeline due to the physical characteristics of natural gas wells. Maintaining steady working pressures at the wells is essential in order to economically recover as much gas as possible from a gas field. Therefore, the production rate that depends on the working pressure should also be constant. Although this rigidity on deliveries does not modify in general terms gas facilities utilization, its introduction may give additional detail to, for instance, the daily utilization of underground storages.
  Furthermore, contract prices are updated according to an indexed formula, which would be interesting to include; although shippers may not *easily* provide this information as it is a key component of any contract.
- Despite the typical rigidity of supply contracts, flexible clauses do exist. We have already mentioned make-up and carry-forward clauses. Their incorporation would be undoubtedly of interest for shippers willing to obtain the best management of their gas supply contracts.
- We have obtained monthly diverted volumes; however, these volumes are actually diverted carriers. In order to obtain accurate numbers, we could represent each diverted carrier to better characterize these operations and their value chains (freights, earnings, etc.). Nevertheless, too much detail may produce an intractable model. Hence, another possibility would be grouping monthly diverted carriers to maintain a tractable model, but gaining accuracy with the explicit incorporation of carriers.
- The opening of natural gas markets to competition has brought out new opportunities to newcomers, including producers. In this new framework, former incumbent companies may become suppliers of newcomers through new supply contracts, and producers may also become competitors of former incumbent companies, i.e., their customers. In both cases, two parties that are tied by a long-term agreement, named bilateral supply contract, compete in the same market. Besides their management, the interest of modeling bilateral contracts lies in considering strategic behaviors that may occur in downstream gas markets, such as market power or market foreclosure.

Finally, cargo freights and/or other fees, which have not been included in the formulation for the sake of clarity, can be straightforwardly incorporated. In addition, it would provide

[26] A complete global gas market description would require deep developments

a final touch to the arrival decisions because freights may vary slightly depending on the market of origin and the regasification terminal of destination.

3.10. References

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Chapter 4

Economic consequences of including a virtual hub into an entry-exit system

Trading and human development have been closely related ever since humans started to spread around the world. The first great civilizations flourished next to large navigable rivers (Nile, Tigris and Euphrates, Yellow River, and Indus) because they not only provided fresh water and fertile lands, but also facilitated transport, reducing transaction costs. Later on, the improvements of sea navigation and the geographic position of the East-West alignment of the Mediterranean Sea favored the birth of relevant civilizations, whose development was based on commercial exchanges (Phoenicia, Greece, Carthage, and Rome). During the Middle Ages, fairs (i.e., organized markets) that connected Northern and Southern Europe established most of the current business laws. Overseas navigation opened new markets since the 15th century; while railways and road vehicles brought inland markets closer during the 19th and 20th centuries, respectively. Telecommunications have completely changed the commercial relations recently, as transactions can happen instantly. Every technological development in transport, standardization and communication has often caused a reduction in transaction costs. In this chapter, we analyze the incorporation of a virtual hub (i.e., an electronic platform) where instantaneous commercial transactions at negligible transaction costs can take place, which may result in improved market efficiency.

4.1. Organized markets after the gas market liberalization

Prior to the gas market liberalization that occurred in North America, Europe, Japan and Australia, among others, either state-owned or regulated vertically integrated monopolies were in charge of the whole gas value chain (i.e., supply, transmission and retail). Consequently, organized downstream gas markets neither existed nor were expected. After the liberalization, gas markets were opened to competition and new entrants appeared on the scene to compete with the former monopolies. According to the microeconomic theory, a possibility is that the new entrants gain market share by offering prices below those of the former incumbent company, which may maintain inflated prices (above marginal costs) to take advantage of its market power position. Nevertheless, if market power is exercised, it may not be maintained indefinitely as an increasing competitive pressure from new entrants over time may force the dominant company to reduce prices in order to stop the drain of market share. Only in this case, the final result would be a perfectly competitive market, as long as, among others, the free access rule holds. However, barriers to entry are particularly high in gas markets, sometimes hindering new entrant willingness and favoring the dominant company position. For this reason, the liberalization process may include the privatization and splitting of the former monopoly; but, this hypothesis has not been considered in this thesis.

When free market rules are being breached, the regulatory authorities must intervene. At the early stage of a liberalization process, the regulatory framework must provide stable and sound economic signals to foster competition. With the goal of promoting a competitive gas market, two completely different regulatory models that guarantee the free access of third parties have been enforced on both sides of the Atlantic. In the U.S., the third party access is based on point-to-point transportation, in which each shipper (normally known as marketer) arranges pipeline capacity contracts to convey its gas from a supply to a consumption point. In this way, a shipper has the freedom to access the market as long as free pipeline capacity is available. When the price difference between two points, i.e., the scarce capacity valuation, indicates that additional capacity is demanded by shippers, a pipeline investor will announce an open season period. During the period, one or several shippers ask for additional long-term capacity, committing themselves to the investment payment. This procedure leads to the so-called pipeline competition (Makholm 2012). In contrast, the EU has opted for a model that ignores pipelines: the entry-exit access model (CEER 2011). This model is based on the so-called balancing zones that embed the gas transmission and distribution networks, in which each shipper must observe periodical, commonly daily, balances between its entries, exits and stock variations (balancing zones have been described in Chapter 2, pp. 21–23, 36–39).

Opinions in favor and against of both approaches have been, are and will be expressed in forums about gas market regulation. From our point of view, the starting points of both gas markets, which were completely dissimilar, conditioned the later imposed regulatory framework. In the beginning, the U.S. counted on the presence of numerous local distribution companies. Quite the opposite happened as one company dominated the gas market in each EU member state. Therefore, whereas markets could appear naturally in the U.S. and, particularly, secondary capacity markets because the pipeline capacity was not monopolized, EU gas markets required an external boost. A recognized advantage of entry-exit systems is that they practically eliminate the barriers to entry thanks to the constitution of balancing markets, in which new entrants collaborate among themselves to obtain their daily balances. Even when the dominant company may not be willing to participate[1], the new entrants may create enough liquidity.

Two types of organized gas markets have emerged, each associated with each regulatory framework: physical hubs in the U.S. and virtual hubs in the EU[2]. Their main difference lies in the location of their trading platform. Physical hubs are linked to a specific existent gas facility; typically, a relevant intersection of the gas system. For example, the most important physical hub worldwide, i.e., the Henry Hub, is a distribution hub that interconnects the offshore gas wells in the Gulf of Mexico and nine interstate and four intrastate pipelines, and that also provides storage services. The shippers simply trade with gas at the physical hub determining a gas price at the location. On the other hand, virtual hubs are balancing electronic platforms. Therefore, virtual hubs are not linked to a specific gas facility, but to the gas facilities embedded in a balancing zone. As the entries to and exits from the balancing zones may be uncertain, shippers buy and sell gas to balance their position. The obtained prices from the trading transactions reflect the gas prices of the entire geographic zone as it disregards internal transportation costs.

Within the entry-exit paradigm, which has previously been explained in section 2.2 (pp. 21–23), the EU has envisioned the single European gas market as a combination of competitive virtual hubs (CEER 2011). Many national-level virtual hubs have already been constituted since the mid 90's: NBP in the UK (1996), TTF in the Netherlands (2003), PSV in Italy (2003), PEGs in France (2004), and Gaspool and NCG in Germany[3] (2009). Moreover, national-level physical hubs also exist inside the EU frontiers, such as

[1] Results along these lines for secondary capacity markets have already been obtained in section 2.9 (page 70). As a matter of fact, the European Commission has implemented use-it-or-lose-it clauses in capacity contracts with the aim of encouraging unused capacity releases (EC 2012).

[2] Physical hubs have also been established in the EU, such as the Zeebrugge area that interconnects the UK and continental Europe, the Norwegian gas fields, and also has one LNG terminal.

[3] Gaspool and NCG have actually evolved from other markets that were initially established in 2000 and 2006, respectively.

Zeebrugge in Belgium (since 2000) and CEGH in Austria (2005). Nevertheless, both Belgian and Austrian national authorities are planning the creation of virtual hubs in line with the EU Third Energy Package requirements. Virtual hubs may attract the desired liquidity as a natural approach to trade in entry-exit systems; therefore, virtual hubs are expected to prevail over physical hubs[4] (Figure 4-1). Further information on European hubs can be consulted in (Heather 2012).

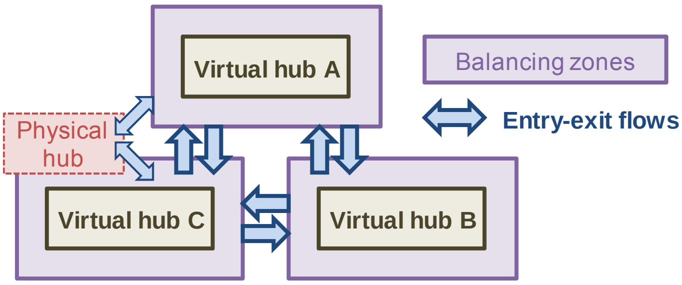

Figure 4-1 – Schematics of the single EU gas market

From all the major gas consuming countries or areas in Europe, the Iberian Peninsula, Spain and Portugal, still lacks a virtual hub. Currently, all the implied parties (regulatory authorities, shippers, consumers) are discussing how to implement a virtual hub as it is not straightforward. There are two separate market areas, each with a different regulatory framework, and up to six balancing zones. Consequently, besides the harmonization of the regulatory frameworks, an investment effort in pipeline capacity that eliminates the network congestions is necessary. In Chapter 2, we have already harmonized both regulatory frameworks. Moreover, we have also confirmed that some balancing zones can be merged. Hence, our objective is now to examine the consequences of introducing a virtual hub and, specifically, to compare the market performance before and after the virtual hub incorporation.

4.2. Measuring organized markets performance

An organized market presents a major advantage over an OTC market: reduced transaction costs because it eases four main aspects of commercial transactions. First of all, buyers and sellers are gathered in a common platform to negotiate, so organized markets avoid searching costs. Second, the access to organized markets is commonly restricted to reliable traders that have beforehand deposited an admission fee to guarantee their position; hence, organized markets significantly reduce information costs. In the third place, as tradable goods are commonly standardized, the bargaining costs are al-

[4] Unless the EU changes the access rules and adopts a point-to-point system.

most negligible. Finally, organized markets habitually have the support of clearinghouses to cover defaults and, therefore, organized markets eliminate enforcement costs.

However, organized markets are useless if involved parties do not participate. In the European framework, the Council of European Energy Regulators have proposed a set of indicators to measure the functioning of the organized gas markets, that is, of the virtual hubs (CEER 2011). In addition, CEER has also provided a reference value to each indicator. As we are evaluating the incorporation of a virtual hub in an entry-exit system *a la* EU, these indicators have also been utilized in this chapter. In detail, there are the following indicators:

- The churn rate is used for measuring the market liquidity. It is actually a ratio that compares the total traded gas volume to the total consumed gas volume. CEER recommends a value over 8.
- The Herfindahl-Hirschmann Index (HHI) is used for measuring market concentration. It is calculated as the sum of squared market shares σ_e of market participants e=1,2,…E. CEER suggests a value below 2000, i.e., $\text{HHI}=\sum_e \sigma_e^2 \leq 2{,}000$.
- The number of different sources, i.e., suppliers, is used for measuring the security of supply. This requirement is rather vague as CEER just indicates that three different sources must, at least, provide gas.
- The size of the entry-exit zone is measured through the total annual gas demand. CEER establishes a minimum threshold equal to 20 bcm, i.e., about 235 TWh.
- The Residual Supply Index (RSI) is as well used for measuring market concentration. It actually measures the capacity of other market participants different from the largest company to supply the demand. It is defined as a ratio, which is calculated as the market supply capacity minus the main supplier capacity compared to the total demand. CEER recommends a value of more than 110% for more than 95% of days each year.

Besides these five indicators, there are other relevant market results such as the system gas prices, or each shipper’s traded volumes, markets shares and profits, which provide information to examine not only the market performance, but also the shippers’ incentives to behave efficiently under a perfectly competitive framework.

4.3. Incorporation of a virtual hub in an entry-exit model

Organized gas markets have already been included by other authors in the main families of gas market models. In most cases, the organized markets are equivalent to virtual hubs because regions, instead of pipeline networks, are established to take into account transportation constraints, such as in (Boots et al. 2004), (Zwart, Mulder 2006), (Holz et al. 2008) and (Lise et al. 2008). On the other hand, (Gabriel et al. 2005) develop a point-to-point system model, in which physical hubs are represented.

In this section, we incorporate an organized market, as a virtual hub, into the previously described entry-exit market model; that is, we extend the model with a virtual hub and, simultaneously, maintain the supply and capacity contracting structure that none of the previous references include, at least, with such level of detail. In section 2.6.1 (pp. 46-48), we have already included three OTC balancing markets through equations (2.77)–(2.79) in LNG terminals, in underground storages, and in balancing zones (equivalent to pipeline networks), respectively. We have as well defined three constraints (2.83), (2.84), and (2.85), which represent the physical swaps that happen when markets are not developed enough and lack liquidity. When these three constraints are excluded from the model, that is, when shippers sell and buy gas in exchange for money, we are roughly[5] representing several physical hubs in an entry-exit framework. One physical hub in each gas infrastructure has little sense though, because the liquidity requirements for a proper hub performance would be clearly compromised. In any case, we have previously mentioned that in an entry-exit system, a virtual hub is the adequate type of organized market and, consequently, we do not include physical hubs.

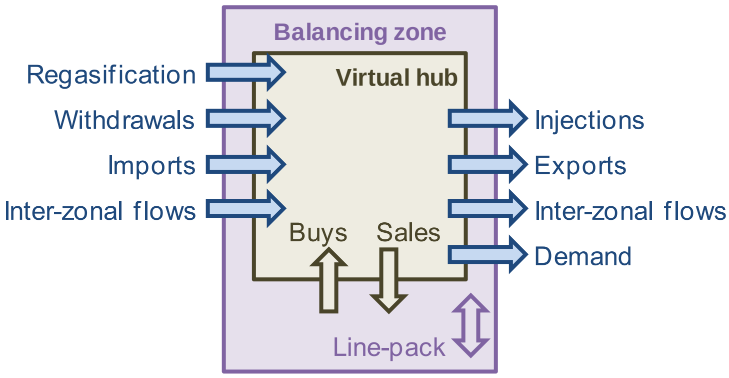

Figure 4-2 – Entry and exit flows, and balancing operations in a virtual hub

A virtual hub is an organized market that allows shippers to balance their positions within an entry-exit framework; i.e., a virtual hub is indeed a balancing market (Figure 4-2) that is linked to a balancing zone z, where shippers buy $q_{zed}^{\Delta HUB}$ and sell $q_{zed}^{\nabla HUB}$ gas during day d:

$$\sum_e q_{zed}^{\Delta HUB} = \sum_e q_{zed}^{\nabla HUB} \quad \forall z,d \tag{4.1}$$

These purchases and sales modify the daily entry-exit balance constraint (2.30):

[5] It is roughly in particular for gas pipelines as transactions do not only occur in the form of line-pack (as we are representing), but also as sold or purchased gas flows.

$$q_{zed}^{PCK} - q_{ze(d-1)}^{PCK} = \begin{Bmatrix} \sum_{r \in z} q_{red}^{REG} + \sum_{s \in z} \left(q_{sed}^{WTH} - q_{sed}^{INJ} \right) + \sum_{x} \left(q_{xzed}^{IMP} - q_{xzed}^{EXP} \right) - \\ \sum_{z'} \left(f_{zz'ed}^{ZON} - f_{z'zed}^{ZON} \right) - D_{zed}^{TOT} + q_{zed}^{\Delta HUB} - q_{zed}^{\nabla HUB} \end{Bmatrix} \quad \forall z,e,d \qquad (4.2)$$

Although the inelastic demand D_{zed}^{TOT} is a parameter that represents the total daily demand of each shipper in each balancing zone, the market transactions may modify the demand that is actually satisfied by each shipper. In a few words, the shippers compete in virtual hubs, despite the underlying, supposedly rigid, contract structure.

Both constraints (4.1) and (4.2) introduce a virtual hub for each balancing zone into the entry-exit model that we have been describing during Chapter 2 and Chapter 3.

4.4. Valuation of organized market alternatives

In Chapter 2 and Chapter 3, we have also described the case study; specifically, the gas system (section 2.8, pp. 51–64), which includes the technical details, the markets structure and the regulatory framework, and an accurate supply contract portfolio (section 3.6, pp. 90–94) of MIBGAS during 2012. In what follows, we compare four plausible cases regarding the incorporation of virtual hubs:

- No-market case (NM). We prevent any market transactions as no virtual hub exists. However, we allow physical swaps in LNG tanks, which are necessary in order to obtain a feasible solution[6]. The NM case represents a non-collaborative solution.
- Six-virtual-hub case (6VH). We include one virtual hub in each current balancing zone: Levante, Catalunya, Ebro, Noroeste, Centro and Portugal. We, in addition, maintain Spain and Portugal as separate market areas, i.e., we do not eliminate the so-called pancaking effect that increases gas prices without proper economic foundations as it does not provide correct economic signals. The 6VH case represents a situation in which investments in new infrastructure do not take place, and may be useful for future cost-benefit analyses which examine whether investment costs compensate net social benefits.
- Single-virtual-hub case (SVH). We consider that there are enough investments to increase the capacity connection between the existent balancing zones and between Spain and Portugal, in order to merge both market areas and all the balancing zones into one market area and one balancing zone. The SVH case foresees MIBGAS as it seems to be in the future.

[6] As a matter of fact, physical swaps occur in LNG tanks when organized markets do not exist because LNG carrier arrivals are temporarily distant. Imbalances in LNG stocks would be common otherwise.

- Single-virtual-hub plus physical-swap case (SVH+PS). As physical swaps in LNG terminals are relevant, we assume that OTC balancing markets, in which physical swaps happen, do not extinct after the incorporation of a virtual hub. Therefore, the SVH+PS case is a plausible extension of the SVH case.

The former two cases (NM and 6VH) correspond to the left-hand side, while the latter two cases (SVH and SVH+PS) to the right-hand side of Figure 4-3.

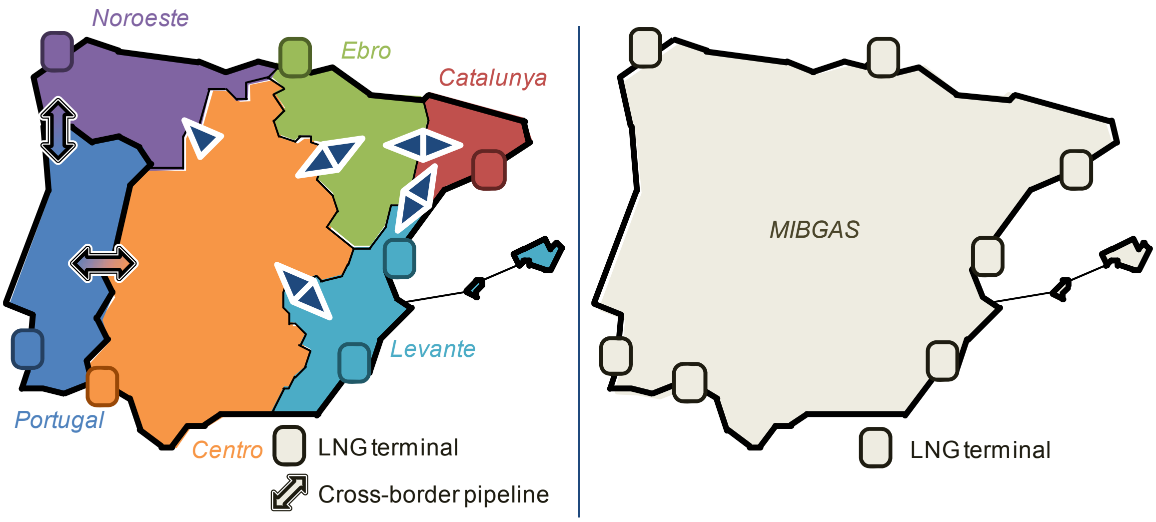

Figure 4-3 – Pre-investment and post-investment MIBGAS situation

4.4.1. Gas Target Model objectives

Let us start comparing the CEER indicators for the previous four cases. Regarding the market size, only the merging of both market areas and all the balancing zones, SVH and SVH+PS cases, achieves the minimum recommended demand of 235 TWh. Specifically, MIBGAS as a single market area presents an annual demand of 390 TWh, whereas the maximum zonal demand when MIBGAS is fragmented amounts to 117 TWh in the balancing zone Centro.

On the other hand, the number of supply sources is mostly predetermined by the supply contract portfolio for all the cases. According to the contract portfolios that we have estimated, Algeria supplies 55% of total gas, Nigeria around 17%, Middle East and Europe supply each about 10%, and 8% is supplied by South America.

Market liquidity is measured by the churn rate, which is defined as the ratio between the traded volume and the demand. For the sake of simplicity, we compare annual volumes, although other time scopes (day, month, quarter, etc.) can be used. Actually, fulfilling the churn rate objective is impossible as the model does not represent market makers. For this reason, we utilize the NM case as benchmark to observe the churn rate improvements when virtual hubs are incorporated. Table 4-1 shows the churn rate values for the four cases. The churn rate of NM case, in which only LNG physical swaps are permitted, is 0.16. The churn rate of MIBGAS increases to 0.50 when a virtual hub is established in each balancing zone (6VH case). However, the churn rate only slightly improves when there is one market area and balancing zone (SVH case) as it increases to 0.21 with respect to the NM case. The situation does not improve much when physical swaps are also permitted (SVH+PS case) as the obtained churn rate amounts to 0.32, of which half are physical swaps and half are virtual trades. According to (Heather 2012) calculations, if we exclude NBP and TTF, in which the churn rate amount to 21.35 and 14.25, respectively, thanks to market makers, the market liquidity is a major concern of European authorities because its lack is a common and chronic problem of European virtual hubs (e.g., 1.32 in Germany or 0.54 in France). In any case, as we do not represent market makers, we are actually estimating the proportion of the total demand that is supplied through an organized market. In the 6VH case, this proportion reaches up to 50%, which may be an adequate value (for example, similar to the Iberian electric power market). On the contrary, the SVH and SVH+PS cases clearly present inadequate liquidity levels.

NM	0.16
6VH	0.50
SVH	0.21
SVH+PS	0.32

Table 4-1 – Churn rate for each case

	Value	Evolution
NM	2,371	-
6VH	2,416	-1.90%
SVH	2,344	1.14%
SVH+PS	2,265	4.47%

Table 4-2 – HHI value and evolution

The last two indicators measure the market concentration. The HHI is clearly determined by the inelastic demand, which is an exogenous parameter. In fact, as we only have defined five shippers, the minimum HHI is 2000, which coincides with the suggested HHI value by CEER. For this reason, we calculate the HHI with the four main shippers assuming that OT is actually composed of shippers with a 1% market share. In any case, as a virtual hub allows shippers to sell and/or buy demand, we can compare the evolution of the HHI index with respect to the NM case. The gas market is in general more competitive as it is enlarged, although the HHI changes at most 4.47% (Table 4-2). As a matter of fact, constituting several virtual hubs results in additional market concentration. Therefore, the correct long-term policy in order to encourage competition is to constitute a single virtual hub as new entrants find a business opportunity to gain market share.

Nevertheless, we should examine, through the RSI value, if the system provides enough access capacity to new entrants. The supply capacity that is used for calculating the RSI cannot automatically be defined when the domestic production is negligible. The first possibility is considering gas supply contracts, but as little public information is available, RSI values would be extremely conditioned by our estimations. In order to overcome this drawback, we have defined a daily supply capacity equal to the immediately available supply capacity, which includes the part of regasification $\hat{q}_{rd}^{REG}$, withdrawal $\hat{q}_{sd}^{WTH}$, import $\hat{q}_{xzd}^{IMP}$ and inter-zonal connection $\hat{q}_{zz'd}^{ZON}$ capacities that are not utilized by the main supplier. However, as the utilization of LNG terminals and underground storages is subject to the availability of gas inventories, when the residual regasification or withdrawal capacities are larger than their respective stocks, these stocks determine the immediately available supply capacity. Moreover, inter-zonal connection capacity is conditioned by the immediately available supply capacity of the neighboring balancing zones. At last, we also include the line-pack storage in pipelines as immediately available capacity. In short, the daily RSI in each balancing zone is calculated as follows:

$$\begin{gathered}
\mathrm{RSI}_{zd} = \frac{\sum_{r\in z}\hat{q}_{rd}^{REG} + \sum_{s\in z}\hat{q}_{sd}^{WTH} + \sum_{x}\hat{q}_{xzd}^{IMP} + \sum_{z'}\hat{q}_{zz'd}^{ZON} + \sum_{e\neq \mathrm{ESP1}} q_{zed}^{PCK}}{\sum_{e} D_{zed}^{TOT}} \\
\left|\begin{array}{l}
\hat{q}_{rd}^{REG} = \min\left(Q_{r}^{REG} - q_{r[e=\mathrm{ESP1}]d}^{REG}; \sum_{e\neq \mathrm{ESP1}} q_{red}^{LNG}\right) \\
\hat{q}_{sd}^{WTH} = \min\left(Q_{s}^{WTH} - q_{s[e=\mathrm{ESP1}]d}^{WTH}; \sum_{e\neq \mathrm{ESP1}} q_{sed}^{STO}\right) \\
\hat{q}_{xzd}^{IMP} = Q_{xz}^{IMP} - q_{xz[e=\mathrm{ESP1}]d}^{IMP} \\
\hat{q}_{zz'd}^{ZON} = \min\left[Q_{zz'}^{ZON} - f_{zz'[e=\mathrm{ESP1}]d}^{ZON}; \max\left[\left(\sum_{r\in z'}\hat{q}_{rd}^{REG} + \sum_{s\in z'}\hat{q}_{sd}^{WTH} + \sum_{x}\hat{q}_{xz'd}^{IMP} - D_{z[e=\mathrm{ESP1}]d}^{TOT}\right); 0\right]\right]
\end{array}\right.
\end{gathered} \tag{4.3}$$

Constituting either several or a single virtual hub results in a counterintuitive conclusion, such as it may not favor the fulfillment of the RSI objective (Table 4-3). Although it may be a sign of capacity hoarding by the dominant company, we must keep in mind that we have utilized our own RSI definition, which may somehow differ from actual RSI values.

	Lev.	Cat.	Ebro	Nor.	Cent.	Port.	MIBGAS
NM	100.00%	96.99%	99.18%	95.08%	100.00%	99.45%	-
6VH	100.00%	97.27%	99.18%	75.68%	100.00%	92.90%	-
SVH	-	-	-	-	-	-	91.80%
SVH+PS	-	-	-	-	-	-	93.17%

Table 4-3 – Percentage of days of RSI above 110%

We compare the level of fulfillment of the CEER objectives by the four previous cases in Table 4-4. First of all, we notice that the lack of liquidity, which may as well be related to the market concentration as the HHI indicates, is a big issue in any case. Nevertheless, with an investment effort to eliminate the capacity congestions and, therefore, merge all the balancing zones into a single one, the foundations for a competitive market will be at least established as the RSI reveals. On the other hand, the minimum market size is only achieved when a single virtual hub is constituted. Therefore, we can conclude that the best solution to achieve a competitive gas market consists in merging all the balancing zones into a single one. However, both liquidity and market concentration will still represent major concerns for a proper market performance.

	Churn rate	HHI	Supply sources	Market size	RSI
NM	🔴	🔴	🟢	🔴	🟢
6VH	🟢	🔴	🟢	🔴	🔴
SVH	🔴	🟡	🟢	🟢	🟡
SVH+PS	🟡	🟡	🟢	🟢	🟢

Table 4-4 – Percentage of days of RSI above 110%

4.4.2. Shippers’ behavior in virtual hubs

Let us now focus on some specific market results. One of the most interesting results is the convergence of each shipper’s marginal costs. Within a perfectly competitive framework, these marginal costs coincide with the domestic gas price that is offered by each shipper to its consumers. As expected, when a single virtual hub is constituted, the marginal costs reach a unique value, which coincides with the gas price. In contrast, when a single virtual hub is not established, the marginal costs move in unison, but do not exactly overlap because each shipper has a different market share in each balancing zone (Figure 4-4). This result can also be observed in Figure 4-5, in which the average zonal marginal costs are shown. Noroeste, because it is virtually isolated, and Portugal, due to the pancaking effect, present different marginal costs, although Noroeste is closer to the four converging balancing zones. Moreover, we can observe that the average marginal costs of POR1 are a consequence of the Portuguese market, where it is the dominant company and, hence, covers a large part of the demand.

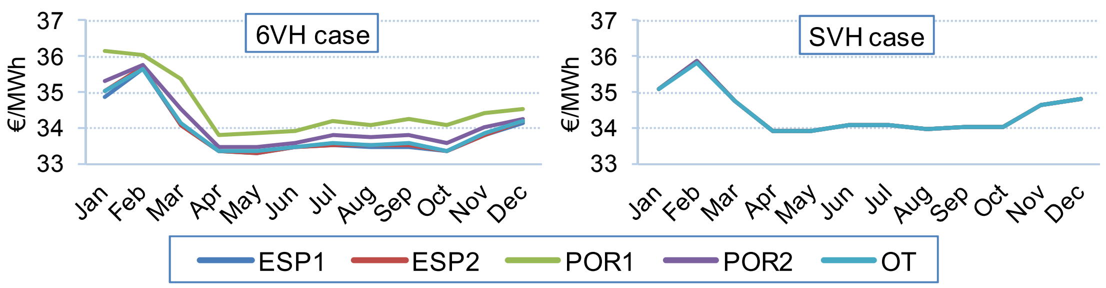

Figure 4-4 – Shippers’ marginal costs in 6VH and SVH cases

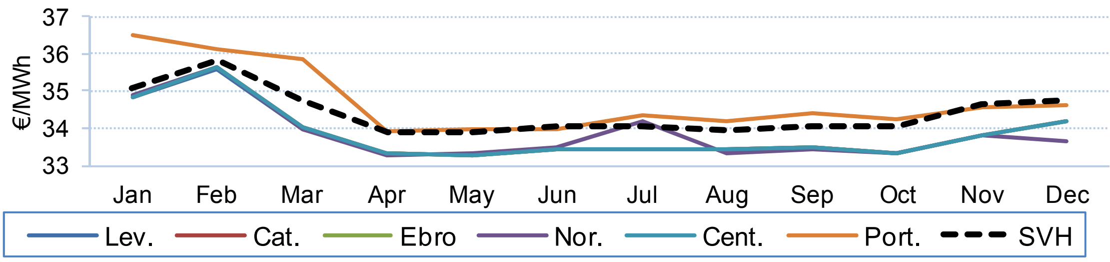

Figure 4-5 – Zonal marginal costs in 6VH and SVH cases

When comparing the shippers' traded quantities and market shares (Table 4-5 and Table 4-6) of each case, we can promptly notice that the dominant company, i.e., ESP1, does not participate in virtual hubs in accordance with its market share, even within a perfectly competitive framework. In addition, ESP1 incurs losses when it participates in the virtual hub (86.3 and 210.4 million Euros in the SVH and SVH+PS cases, respectively); and it earns 13.1 million Euros in the 6VH case, which coincides with its maximum participation in the virtual hubs. As strategic behavior cannot take place within a perfectly competitive framework[7], the market structure does determine that the dominant company is only willing to participate when it obtains profits. For this reason, a high participation of the dominant company may not be expected when the market is not indeed competitive. We reach the same conclusion as when we previously applied the Gas Target Model analysis: both the liquidity and the market concentration are major concerns for a proper market performance.

	ESP1	ESP2	POR1	POR2	OT
6VH	118.16 30%	71.11 18%	44.90 12%	55.90 14%	103.33 26%
SVH	44.05 29%	28.80 19%	21.02 14%	23.69 16%	35.09 22%
SVH+PS	31.21 27%	18.11 16%	19.91 17%	23.17 20%	24.43 20%

Table 4-5 – Shippers' traded quantities in virtual hubs in GWh

	ESP1	ESP2	POR1	POR2	OT
NM	45.28%	13.04%	8.09%	9.21%	24.36%
6VH	45.43%	10.77%	10.82%	10.95%	22.03%
SVH	44.66%	12.25%	10.74%	9.19%	23.16%
SVH+PS	43.69%	11.71%	9.84%	11.10%	23.66%

Table 4-6 – Shippers' market shares after virtual hub trading

[7] Price-taking behavior takes place in perfectly competitive markets in accordance with one of the perfect competition assumptions: a large number of sellers and buyers.

4.4.3. Price sensibility to supply variations

Organized markets bring price transparency to their market participants. Accordingly, a unique gas price is obtained for each supplied quantity; that is, a virtual hub provides a price-supply curve, which allows consumers to optimize their consumption decisions and determines, together with the price-demand curve, the market functioning. We have calculated the price-supply curve for the SVH case by varying the supplied quantity, i.e., the inelastic demand ±2%. The resulting curve is shown in Figure 4-6. We have initially obtained a linear function, which presents a positive slope and fits the data accurately (R^2=0.96):

$$c(q)=1.74\cdot q+328 \tag{4.4}$$

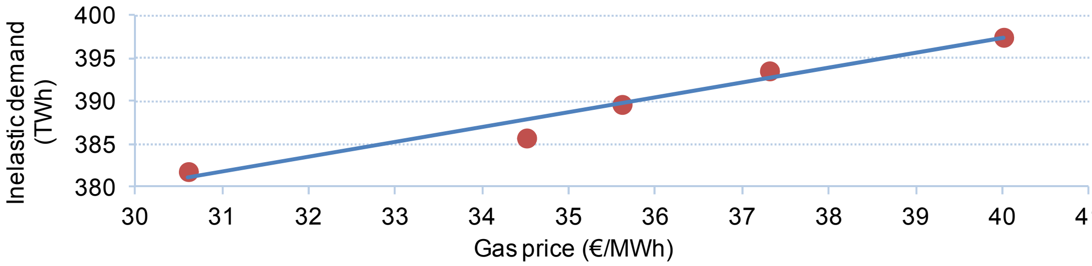

Figure 4-6 – Price-supply curve of the virtual hub (linear function)

The obtained linear function can be directly used in other optimization problems in which the specific gas market details can be simplified. For example, we employ an equivalent linear curve in section 5.3.1 (pp. 130–131). Despite the fact that a linear function maintains the (quasi) convexity and increasing monotonic properties and captures adequately the price-supply relationship, we have also defined a quadratic function (Figure 4-7) in order to show that its curvature is as well convex due to the law of diminishing marginal productivity that also applies to the gas industry. Naturally, the quadratic function also fits the data accurately (R^2=0.97):

$$c(q)=0.55\cdot q^2+1.77\cdot q+390 \tag{4.5}$$

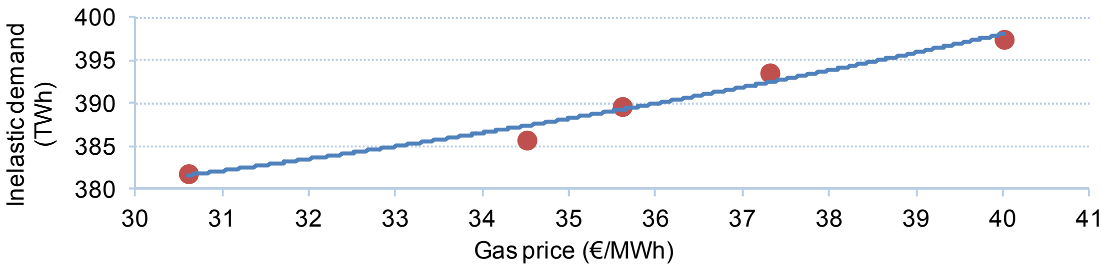

Figure 4-7 – Price-supply curve of the virtual hub (quadratic function)

4.5. Brief summary of contributions

The incorporation of a virtual hub into the entry-exit model that we have been developing along Chapter 2 and Chapter 3 is the main contribution of this chapter. In this way, we have finished the development of a complete entry-exit model, which has allowed us to examine several aspects of entry-exit gas markets. In previous chapters, we have highlighted how stakeholders, such as shippers, regulatory authorities, or system operators, can benefit from the model utilization. The last improvement, i.e., the virtual hub incorporation is as well worthwhile for the stakeholders and, in particular, shippers and regulatory authorities:

- Shippers can evaluate their degree of participation in a virtual hub; in order to not only maximize their profits through gas spot sales and purchases, but also to gain market share. Furthermore, a virtual hub provides transparent gas market prices that can be forecasted with the model, so shippers can also know when to participate. Both optimization processes should result in a reduction of gas prices.
- Regulatory authorities can monitor the market performance and prevent market power abuses by establishing the model solution as the gold standard. Moreover, when a market flaw is identified, the regulatory authorities can utilize the model to evaluate different policies to correct the flaw.

On the other hand, the model extension has allowed us to examine the incorporation of a virtual hub into a real system, the MIBGAS, which is planning to establish a virtual hub in the near future. After comparing the estimated results with the Gas Target Model requirements, we have concluded that establishing a virtual hub may affect positively the degree of competition in line with the EU objectives. However, a virtual hub is not the panacea for achieving competitive downstream gas markets, because the market structure may condition its performance. In particular, the market concentration that reduces the virtual hub liquidity hinders the entrance of new shippers; therefore, the degree of competition does not increase.

At last, and thanks to the price transparency that is provided by organized markets, we have obtained the price-supply curve of the downstream gas market. The functioning of any market is determined by both the supply and demand curve; hence, the relevance of obtaining this curve through a fundamental model, which considers all the technical and economic aspects of the gas market.

4.6. Brief summary of future research guidelines

With the virtual hub incorporation, we have finished the development of a very complete entry-exit market model. In the previous chapters, we have already addressed several relevant issues that may be worth being included in further model extensions. This chapter has also left two open questions to better represent virtual hub operation:

- Public market data indicate that gas markets are concentrated. Furthermore, we have observed that an elevated market concentration considerably conditions the virtual hub results. For a dominant company, exercising its market power position is a *temptation*, which should be considered in a model that is intended to examine the market performance. For example, (Boots et al. 2004) model market power through conjectural variations.
- Liquidity requires the intervention of market makers, which facilitate the finding of counterparties to close the transactions. As important participants of virtual hubs, they could be included in future model extensions.

Finally, we have concluded that the Gas Target Model is hardly achievable with the current market structure. However, different long-term policies or regulations to encourage the degree of competition could be evaluated, such as requiring the dominant company to transfer customers to the competition or merging neighboring gas markets (i.e., constituting the single EU gas market) to dilute the market concentration.

4.7. References

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Chapter 5

Intertwined Energy Markets under Uncertainty: Decision Making in Gas and Electricity Markets

One of the major revolutions in street lighting took place when gas, from coal distillation, was revealed as a commercial solution to illuminate the streets of cities, starting with London in 1817. Gone were the days of candles and lamplighters; and of gas lamps as well, because later in the same century, electric lamps appeared and displaced gas lamps that nowadays are maintained as past reminiscences in some urban areas of Berlin, London or Boston. Nevertheless, fashions some way or another come back. Since the early 2000s, natural gas has been increasing its share in the power generation mix and, hence, illuminating our streets again. In this chapter, we partially addressed a breaking concern: the interdependency of gas and electric power systems. In detail, we analyze the behavior of a generation company that purchases gas in a spot market, contracts for capacity of a shared pipeline, and competes in an electric power market, and making these decisions under an uncertain environment due to renewable energy sources intermittency.

5.1. A fashionable fuel for electricity generation

Over the last two decades, natural gas has played an increasingly larger role as an input fuel for electricity production. For instance, gas consumption in the U.S. electric power sector has increased 2.24 times from 1997 to 2012. The EU has not been a mere witness to the process and some of its members, like Spain, produce up to 30% of electricity with gas, when gas consumption was almost insignificant a decade ago. And not only developed countries, but also emerging countries, such as China, Brazil, or Russia, plan to utilize gas to fuel their growing economies. Furthermore, recent events in Fukushima, which has rekindled the nuclear debate, and technological improvements on shale gas extraction[1], and the subsequent cost reduction, have given a final boost to rely on gas for electricity generation. Beyond these facts and numbers, two main reasons explain the likelihood that gas will remain the preferred fossil fuel for electricity generation over other fossil fuels such as coal or oil. First, while gas prices may not necessarily remain lower than coal prices in terms of monetary units per unit of released thermal energy, gas-fired power plants (GFPPs) have higher conversion efficiencies than coal power plants. Typical GFPPs operate with thermal efficiencies near 60%, while coal plants operate with thermal efficiencies near 30%. Furthermore, in electric power systems with environmental regulations that limit or tax emissions such as CO_2, SO_2, and/or NO_x, gas technologies will habitually undercut other fossil fuel technologies. Second, the rate of return on investment for GFPPs is relatively large compared to other fossil fuel technologies because GFPPs have significantly lower investment costs relative to other types of thermal plants.

The increasing importance of GFPPs in electric power systems for both economic and environmental reasons justifies the joint analysis of gas and electricity systems. Although pipeline companies have made large investments to adapt their infrastructure in anticipation of greater gas demand, electricity generation companies can still face pipeline capacity scarcities that prevent them from participating in electricity markets. As previously mentioned in Chapter 2 in order to operate in gas facilities is required to contract for capacity. If several consumers (e.g., households, industries, and generation companies) share a common pipeline, and capacity on that pipeline becomes scarce, for instance, in the middle of winter due to increased gas consumption for heat, electricity generation companies may not have access to the pipeline capacity that they need to receive their fuel; therefore, contracting for pipeline capacity in advance, which is similar to make a

[1] Shale gas is the name given to gas that is trapped within shale formations. Mainly in the U.S., the technological improvements have caused considerably gas production increments and gas price drops.

hotel reservation in every sense[2], is a necessity for generation companies. Although future work will be still required to conduct a comprehensive study, in this chapter we introduce an initial approach to examine electric power and gas systems integration. To this point, our objective is to analyze pipeline capacity contracting by a generation company that shares a common gas pipeline with other consumers.

In addition to concerns about pipeline capacity contracting, electricity generation companies must purchase their gas through long-term contracts (Chapter 3) or in the domestic spot market, or hub (Chapter 4). In the spot market, prices tend to be directly proportional to demand, and these prices directly influence the behavior of gas generators in electricity markets. Consequently, we define an equivalent price-quantity curve of the zonal hub (Figure 5-1), such as it has been done in section 4.4.3 (page 116). In this manner, we can obtain a price-quantity curve that represents gas price increments when gas is progressively being demanded (i.e., gas is an ordinary good). Both gas consumers and generation companies purchase gas in the spot market altering prices. However, as long as generation companies compete in the electric power market with other producers and gas prices are not constant, the chapter objective extends to include not only pipeline capacity contracting decisions by a generation company that shares a common pipeline with other consumers, but also its concurrently participation in both a gas spot market and an electric power market.

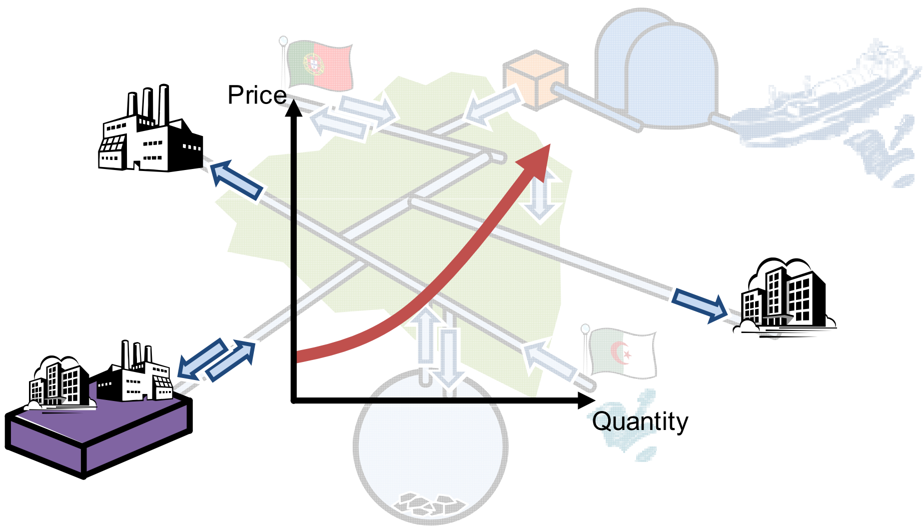

Figure 5-1 – Graphical representation of reducing the gas system to a gas spot market

[2] Hotel reservations and capacity contracts share common characteristics. For instance, hotels typically offer a discount if a guest stays during several days as well as a contract that spans in time is usually cheaper than a short duration contract. Even last minute offers and rush prices appear in both hotel reservations and capacity contracts. If a generation company waits until the very last moment, it can either purchase released capacity in secondary markets at a price that can be indeed lower than in primary markets, or contract available, i.e., non-allocated capacity at high prices.

GFPPs have also recently played a prominent role providing operational flexibility, specially, with respect to ramp rates and start-up/shut-down times compared to other thermal technologies, to electric power systems with intermittent renewable energy sources. Yet, to provide this flexibility, the owners of gas generators in power systems with liberalized markets must incorporate the uncertainty of renewable energy sources into their decision-making process, particularly, when they contract for pipeline capacity, well in advance of actually knowing their electricity commitments. Finally, our previous objective extends to analyze pipeline capacity contracting by a generation company that shares a common pipeline with other consumers when this generation company is participating in both a gas spot market and an electric power market subject to the uncertainty of renewable energy sources. Once the objective of this chapter has been clearly stated, we emphasize the GFPP increasing importance to support the integration of renewable energy sources and describe how the new operational context can affect the decision-making process of a generation company.

5.2. From gas wellheads to windmills

Climate change, energy independence, or fossil fuel depletion are different motivations that have led public authorities to encourage the development and deployment of renewable energy sources. For instance, according to Eurostat (the statistical office of the EU), the share of electric power generated from renewable energy sources in the EU-25 has increased from 12.45% in 2002 to 20.54% in 2011. Renewable energy sources include intermittent sources, such as wind and solar power[3], or dispatchable sources, such as hydro, biomass and geothermal power[4]. If we focus on the electric power system stability, dispatchable sources are preferable to intermittent sources. Nevertheless, the development and deployment have predominantly relied on intermittent sources because they present: 1) a relevant potential, any place where wind blows or sun shines; 2) a reduced impact on other economic activities, windmills in vacant lots or solar panels in building roofs; and 3) fast learning curves, wind and solar technologies costs have dropped dramatically during the last decade approaching to grid parity[5]. For example, according to Eurostat, in the EU-17, solar power increased from 5.8 GWh in 2002 to 65.8 GWh in 2011, while wind power increased from 29.5 GWh to 140.3 GWh; that is, intermittent

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[3] We cannot control when the wind blows or the sun shines. In fact, experienced meteorologists making use of really complex models sometimes fail to forecast tomorrow’s weather.

[4] Water and biomass can be stored in reservoirs or warehouses, while geothermal power (i.e., the Earth) is an “infinite” source of power.

[5] Grid parity is a concept that defines the cost at which a new technology equals the electricity market price, which normally coincides with the most expensive fuel cost, such as oil. At this point, subsidies or tax credits to encourage renewable energy sources may start to be reduced.

sources have risen from a meager 4.6% to a relevant 15.4% of total renewable energy used for electricity generation. Moreover, wind power, which is more intermittent than solar power, accounted for most of the increment in absolute terms.

As the deployment of intermittent renewable energy sources will continue, electric power systems are evolving to give an answer to the challenge of integrating a growing share of intermittent sources. The main concern about integrating such a large amount of intermittent sources is that it can lead to more system instability. This instability can be caused by sudden changes of renewable power generation and, in particular, by a drastic fall of generation if, for instance, the wind stops blowing. Independent system operators (ISOs) that are in charge of monitoring power system stability have different ways to respond to this intermittency. Briefly, in general, the possibilities are the following (COWI, 2012):

- Hydro power plants can start up in a few seconds when needed due to a sudden decrease of renewable power generation. In contrast, if renewable power generation increases, pump storage plants can come into operation in about a minute offering small energy losses (total efficiency around 70%). However, their main drawback, at least in developed countries, is that new hydro sites may be scarce, and the re-powering potential of old plants is limited.
- Nuclear and coal power plants are rather inflexible and unable (or able at high costs) to start up or alter their output as fast as renewable sources do. Oil power plants are flexible, but expensive, and they are often unavailable, or even in process of being dismantled[6], particularly, in developed countries.
- We can distinguish two types of GFPPs: combined-cycle gas turbines (CCGTs) and open-cycle gas turbines (OCGTs). A CCGT power plant is slower (start-up time in 8 minutes), but more efficient (up to 60%), than an OCGT power plant (3 minutes, up to 40%). In addition, OCGTs tolerate more start-ups and shut-downs than CCGTs during their lifetime, because the steam turbine lifetime[7] is reduced by start-ups and shut-downs quicker than gas turbines lifetime.
- Demand side resources such as interruptible demand contracts, with economic benefits for consumers, have been in place for a long time. Furthermore, several current research projects on improving demand-side management seek to design smarter power systems.
- Compressed-air and hydrogen power plants are still being developed. When they are finally cost-competitive, they will be installed next to wind farms and will serve

[6] Lately, huge investments in GFPPs have caused the expelling of expensive oil plants from the market and, hence, their put out of business.

[7] CCGTs differentiate from OCGTs in the steam turbine. The higher efficiency of CCGTs with respect to OCGTs is because the steam is produced with the residual heat of exhaust gas from gas turbines.

as clean energy storages[8]. Wind farms will compress air or produce hydrogen in periods of low electricity demand and high wind conditions, and utilize one of both products for electricity generation in periods of high electricity demand and low wind conditions. The operation will be similar to hydro pump power plants.

From the previous available possibilities, the best alternative to support the integration of renewable energy sources at the present time is utilizing GFPP flexibility. They offer flexibility at a reduced cost and, moreover, are ubiquitous in electric power systems, so they can collaborate to voltage control. However, generation companies manage their GFPPs in liberalized power systems, neither the ISOs, nor the regulators[9]. A generation company, whose objective is making profits, should be ready to replace, for example, windmills when wind stops blowing and electricity prices raise. Generating electricity with a GFPP is a short-term decision that is commonly taken the day before, or a couple of hours or minutes earlier, depending on what market (day-ahead, intraday, balancing, etc.) clears at each moment, on condition that gas is available in the gas pipeline network. Simultaneously, its availability depends on whether a generation company has acquired gas and contracted for the corresponding capacity to transport gas right to the GFPPs.

However, as already said, a generation company competes in an electricity market with more generation companies that may own gas, other thermal (nuclear, coal, oil), and hydro power plants. The market clearing that is influenced by renewable energy sources determines which company produces. Once the electricity market has been cleared, a generation company requires gas that can be purchased in a gas spot market where the generation company also faces competition, because industrial users, households and other generation companies participate in gas spot markets and may increase gas prices. In addition, the generation company shares a common pipeline with other consumers. When the capacity is scarce, those gas consumers that hold capacity contracts have right of access, while the rest of consumers are prevented from using the pipeline. Typically, pipeline operators offer two types of capacity contracts:

- Firm capacity contracts provide the highest priority to the holder. Consequently, a pipeline operator may not offer firm capacity above the available capacity, which coincides with the difference between the pipeline capacity and the firm capacity already contracted. Even though firm capacity is the most expensive one, its highest priority level makes it really interesting to pipeline users, which are willing

[8] Neither compressed air nor hydrogen produces CO_2 emissions when they are used for electricity generation.

[9] Needless to say, ISOs do not lose their authority to modify electricity market results (e.g., with another market) when system stability is not guaranteed, as well as regulators may intervene if they observe an anomaly in market performance.

to reserve capacity in advance. Pipeline operators, which offer long- to medium-term capacity contracts, benefit from a situation that guarantees stable incomes during the pipeline lifetime.

Besides, pipeline operators commonly constitute an electronic platform in which users can release their unused capacity and transfer the payment duty to other users that obtain firm capacity. In such a manner, pipeline operators also guarantee elevated pipeline utilizations, and subsequent incomes.

- Interruptible capacity contracts provide the lowest priority to the holder. These contracts can be offered with a discount or even for free. The sum of firm and interruptible capacity may exceed the available capacity; or may not, as some consumers may be interested in contracting cheaper interruptible capacity (in comparison to firm capacity) and when interrupted either resign themselves or switch to alternative fuels, like oil.

A generation company, who seeks to maximize profits in an electric power market, must not only consider market characteristics (intermittency of renewable sources among others), but also optimize both purchases at a gas spot market and capacity contracts portfolios. In a few words, a generation company turns to a spot market to supply its GFPPs and, in addition, contracts for the corresponding pipeline capacity because any gas flow would be impeded otherwise. In detail, a generation company faces various decisions with two different time scopes: 1) short-term gas purchases, which are directly related to electric power market results and, hence, subject to the uncertainty of renewable energy sources; and 2) long- to medium-term capacity contracting decisions, which are taken in a specific moment (well in advance to short-term operation) and should be robust despite short-term uncertainty. Robust decisions imply that risk-neutral agents take unique long- and medium-term contracting decisions for all scenarios, whereas short-term decisions, i.e., gas purchases and electric power generation, do depend on each scenario.

5.3. Gas purchases, capacity contracts and power markets

Our main objective is to simulate a generation company that owns a set of GFPPs, purchases gas in a spot market, and contracts for pipeline capacity. The problem has been in part addressed by other authors. In the very short term, different authors propose similar single-period models to jointly analyze electric power and gas systems, in which the gas network includes compressor stations[10]: (Muñoz et al. 2003) examine the reliability

[10] Compressor station modeling implies the incorporation of the gas flow equation (also known as Weymouth equation) to calculate gas flows according to pressures at both extremes of the pipeline. The models basically differ in the way of dealing with an optimization problem with a non-linear constraint introduced by the

of an electric power system by maximizing the GFPPs production; (An et al. 2003) and (Unsihuay et al. 2007a) obtain gas and electric optimal power flows that maximize social welfare or minimize total system costs; (Dias de Mello and Ohishi 2006) dispatch a power system without considering the network; and (Urbina and Li 2007) include supply contracts and minimize electricity costs. (Abrell and Weight 2010) examine a stylized representation, which omits the compressor stations, of the European gas and electricity networks with a static model. In the short term, (Shahidehpour et al. 2005) discuss the impact on an electric power system of different contingencies in a gas facility that cuts off the supply of GFPPs; (Li et al. 2008) solve an unit-commitment problem subject to gas network constraints with fuel switching possibility; (Chaudry et al. 2008) include line-pack capacity and gas storage facilities when minimizing gas supply, gas network operation and electric power generation costs; and (Liu et al. 2009) consider, besides gas storage, compressor stations to solve an unit-commitment problem.

In the medium and long term there is little literature to our knowledge. (Bezerra et al. 2006) propose a dynamic programming model in order to obtain the operation plan of hydrothermal and gas systems subject to stochasticity; and (Dueñas et al. 2012) seek to maximize the profits when managing gas supply contracts (including gas network congestions) in imperfect electric power markets. (Unsihuay et al. 2010) extend their single period model to capacity expansion of both systems.

The model here presented has tried to fill a gap that is of interest in current deregulated gas and electric power systems: how long- and medium-term decisions related to pipeline capacity contracting influence short-term decisions related to GFPP operation subject to renewable power generation uncertainty.

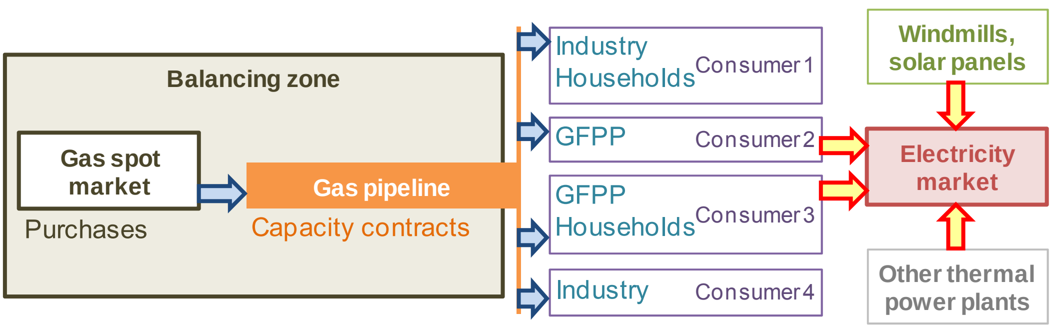


Figure 5-2 – Graphic representation of overall model structure

Figuratively, the gas spot market is connected with the electricity market through a gas pipeline (Figure 5-2). The purchased gas flows through the pipeline, as long as capacity

Weymouth equation $sign(f_{ii'}) \cdot f_{ii'}^2 = C_{ii'}^2 \cdot (p_i^2 - p_{i'}^2)$, where p_i is the pressure at node i, and $sign()$ defines the flow $f_{ii'}$ direction.

has been contracted, to either the electricity market or to other gas consumers such as industrial users or households. However, gas consumption in the electricity market also depends on a market-clearing process in which gas must compete with other fossil fuels (coal, oil, etc.). Let us assume a thermal system (that is, without hydro power plants), in which intermittent wind and solar are always dispatched[11].

In short, there is a zonal gas spot market, *z*. An exit gas pipeline[12], *j*, connects the market with gas consumers, *e*=1,2,…,*E*. A balance between inflows (market purchases) and outflows (demands) is monitored each day, *d*=1,2,…,*D*. Gas covers industrial users and households demand and feeds GFPPs. These GFPPs and other thermal power plants in this system constitute the group of power generators, *g*=1,2,…,*G*, that satisfy the residual thermal electricity demand after dispatching renewable generation. As long as renewable power generation is subject to uncertainty, residual electricity demand is defined for different scenarios, *k*=1,2,…,*K*.

The model, a mixed-integer quadratic programming (MIQP) problem, is formulated as a combination of a quadratic programming (QP), a linear programming (LP), and a mixed-integer programming (MIP) problem. We start with the description of the gas spot market model. Then we present the capacity contracting model, which is really similar to the one described in section 2.5 (pp. 39–46). Finally, we introduce the electricity market model and its link to the gas system. In this model description, uppercase letters represent parameters, while lowercase letters represent continuous and positive variables (except where explicitly indicated otherwise).

5.3.1. Purchasing at gas spot markets

Geographically speaking, a balancing zone is a regional fragmentation that embeds a set of transmission and distribution networks, in which network costs are shared among users and network congestions are negligible; therefore, there is a unique zonal gas price. Balancing zones include entry points, that is, pipelines from LNG regasification terminals, gas wellheads or neighboring balancing zones; and exit points, that is, pipelines to consumers and neighboring balancing zones. An underground storage is another entry-exit point embedded in balancing zones. For further details on balancing zones, the reader is referred to Chapter 2 (pp. 21–23, 36–39).

[11] For the sake of clarity, hydro power plants are omitted because our intention is to analyze the behavior of a generation company that owns GFPPs. More details on hydrothermal systems can be found in (Centeno et al. 2007).

[12] There may be other pipelines, but we focus on one specific pipeline.

A zonal gas price results from buying and selling transactions among the companies that participate in a gas market. The buying and selling transactions can take place over-the-counter or in organized markets, that is, physical or virtual hubs. Physical hubs are usually established in gas facilities. On the other hand, virtual hubs are not linked to a specific facility. In this chapter, we opt for a virtual hub, from which a relationship between gas prices and demands can be obtained (section 4.4.3, page 116). Let us consider that the functional form of the marginal cost curve of gas $c(v_{zdk})$ for daily purchases v_{zdk} can be represented by an affine function with cost intercept α_0, and cost slope α_1:

$$c\left(v_{zdk}\right)=\alpha_0+\alpha_1 \cdot v_{zdk} \tag{5.1}$$

Naturally, consumers would like to acquire gas at its minimum cost, or, concisely, consumers minimize expected acquisition costs:

$$\min_{v_{zdk}} \sum_{z,d,k} \omega_k \cdot c\left(v_{zdk}\right) \cdot v_{zdk} = \sum_{z,d,k} \omega_k \cdot \left(\alpha_0+\alpha_1 \cdot v_{zdk}\right) \cdot v_{zdk} \tag{5.2}$$

The new parameter ω_k represents the scenario occurrence probability. Their sum over k is equal to one.

Gas acquisitions are used for complying with a certain industry and households demand quantity D_{zed}^{CNV} while GFPPs demand a variable and uncertain quantity d_{zedk}^{GFPP}:

$$v_{zdk}=\sum\nolimits_e \left(d_{zedk}^{GFPP}+D_{zed}^{CNV}\right) \quad \forall z,e,d,k \tag{5.3}$$

Although the gas spot market is liquid and large, and purchases are not limited, total gas demand for consumers connected to pipeline j is constrained by pipeline capacity Q_j:

$$\sum\nolimits_e \left(d_{zedk}^{GFPP}+D_{zed}^{CNV}\right) \le Q_j \quad \forall z, j \in z,d,k \tag{5.4}$$

The objective function (5.2) subject to constraints (5.3)–(5.4) constitutes a QP problem, i.e., a quadratic objective function with linear constraints that minimizes expected gas acquisition costs considering the uncertainty of renewable energy sources.

5.3.2. Contracting pipeline capacity

Generally, the pipeline operator offers, either interruptible or firm, capacity contracts with different time scopes. Accordingly, consumers can contract for capacity in the long term h_{je} (i.e., during several years); in the medium term h_{jem} (i.e., during a month); and in the short term h_{jedk} (i.e., during a day). The correspondence between time scopes and periods follows a standard that commonly takes place in reality. Standardized long-term contracts expire several years later. Medium-term contracts usually expire the next month, and short-term capacity contracts the next day. In addition, we consider that long- and medium- term contracts represent firm capacity commitments, while short-term contracts represent non-firm capacity commitments because gas consumers are unaware that enough free capacity will be available when the contracting time comes[13]. The immediate consequence is that short-term contracting decisions are different for each scenario k and are subject to the uncertainty of renewable energy sources, while long- and medium-term contracting decisions are common for every scenario.

Capacity prices vary with the time scope. In addition, we assume that it is less expensive to contract for capacity in the long term CF_j, than in the medium term CF_{jm}, and that it is less expensive to contract for capacity in the medium term than in the short term CF_{jd}. This assumption aligns with the pipeline operator's anticipation of income and reduction of risk due to idle pipeline capacity. Furthermore, the pipeline operator may apply a variable tariff CV_j to gas flows.

Gas consumers (connected to the same pipeline) minimize resulting costs from contracting for firm and non-firm capacity:

$$\min_{\substack{h_{je},h_{jem}\\ h_{jedk},d^{GFPP}_{zedk}}} \sum_{j,e}\left[CF_j \cdot h_{je} + \sum\nolimits_m \left(CF_{jm}\cdot h_{jem}\right) + \sum\nolimits_{d,k}\omega_k \cdot \left[CF_{jd}\cdot h_{jedk} + CV_{jd}\cdot \sum\nolimits_{z\in j}\left(d^{GFPP}_{zedk} + D^{CNV}_{zed}\right)\right]\right] \quad (5.5)$$

Daily, each gas consumer holds a portfolio th_{jedk} of long-, medium-, and short-term capacity contracts:

$$th_{jedk} = h_{je} + h_{jem} + h_{jedk} + \Delta h_{jedk} - \nabla h_{jedk} \quad \forall j,e,m/d\in m,d,k \quad (5.6)$$

Contract portfolios include acquisitions Δh_{jedk} and releases ∇h_{jedk} that take place in secondary markets, in which unused capacity is negotiated:

$$\sum\nolimits_e \Delta h_{jedk} = \sum\nolimits_e \nabla h_{jedk} \quad \forall j,d,k \quad (5.7)$$

It seems reasonable to think that a gas consumer will not contract for short-term capacity to subsequently release it in secondary capacity markets. For this reason, we limit releases to the portion of contract portfolios that consists of long- and medium-term capacity contracts:

$$\nabla h_{jedk} \le h_{je} + h_{jem} \quad \forall j,e,m/d\in m,d,k \quad (5.8)$$

[13] We are assuming risk-neutral agents in perfectly competitive gas and electricity markets. Interruptible contracts would require at least including risk-averse uninformed agents.

Similar to gas demand that is constrained by pipeline capacity (5.4), total consumers' capacity portfolios are also restricted by maximum pipeline capacity Q_j:

$$\sum_e th_{jedk} \leq Q_j \quad \forall j,d,k \tag{5.9}$$

If a consumer has contracted for enough capacity, the operator will let gas flow through the pipeline:

$$d_{zedk}^{GFPP} + D_{zed}^{CNV} \leq th_{jedk} \quad \forall z, j \in z, e, d, k \tag{5.10}$$

The objective function (5.5) subject to constraints (5.6)–(5.10) constitutes a LP problem that allows gas consumers to optimize, by minimizing total costs, their capacity contract portfolio under uncertainty. It is noteworthy that there is one common long-term and medium-term contracting decision for all scenarios as firm capacity contracts may be formalized well before (up to several years before) the time of operating GFPPs that is, nonetheless, subject to the uncertainty of renewable energy sources.

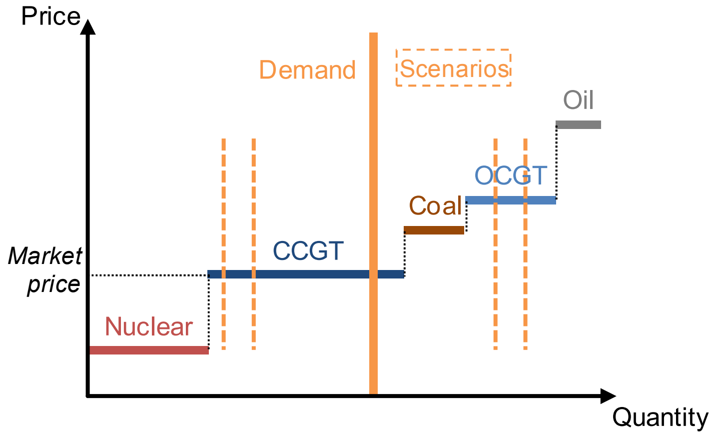


Figure 5-3 – Day-ahead electricity market with inelastic demand

5.3.3. Operating in electricity markets

Liberalized electricity markets commonly rely on day-ahead markets that determine for the most part the generation unit dispatch and the electricity price of the next 24 hours[14]. In the day-ahead market, the unit dispatch and the price are obtained after matching the generation unit offers and the consumers' bids. One of the main consequences of electric power system gasification is the dependence of electricity prices on gas costs because the price is equal to the offer of the last dispatched unit. The market clearing process for different scenarios is shown in Figure 5-3. Moreover, in high demand scenarios,

[14] There are other subsequent markets (intraday and balancing, mainly) that only refine the dispatch and the price as a lower number of transactions are normally traded in these markets.

if generation companies have not accurately predicted pipeline capacity requirements or gas purchases, the power system may face non-supplied energy situations. Examining how generation companies operate in gas systems is, therefore, economically and technically justified.

Before describing the electricity market model, let us focus on electricity demand. Demand and supply must be balanced instantaneously because electricity in most power systems cannot be stored at competitive costs. Modeling power systems with such a level of temporal detail would be intractable. For instance, system and/or market operators that utilize algorithms to determine the optimal dispatch “group these instants” into hours (Boiteux, 1960). But even modeling each hour in the long or medium term is troublesome. For this reason, traditionally, a load duration curve has been constructed and some load levels (e.g., peak and off-peak, working and non-working days) that were able to capture the behavior of hydrothermal systems with no penetration of renewable energy sources[15], in exchange for losing the chronology, have been established. Recently, to accommodate renewable energy deployment, a net load duration curve (demand minus renewable power generation) is sometimes used to define load levels. The main disadvantage of using this procedure to define load levels is that off-peak load levels will combine hours of high demand and high wind conditions with (significantly different) hours of low demand and low wind conditions[16]. Moreover, maintaining hourly chronology leads to a more realistic representation of demand because renewable energy intermittency can heavily influence the operation of power plants (in contrast to the *calm* operation of old times). For these reasons, we define load levels using “system states,” which is another contribution of this thesis.

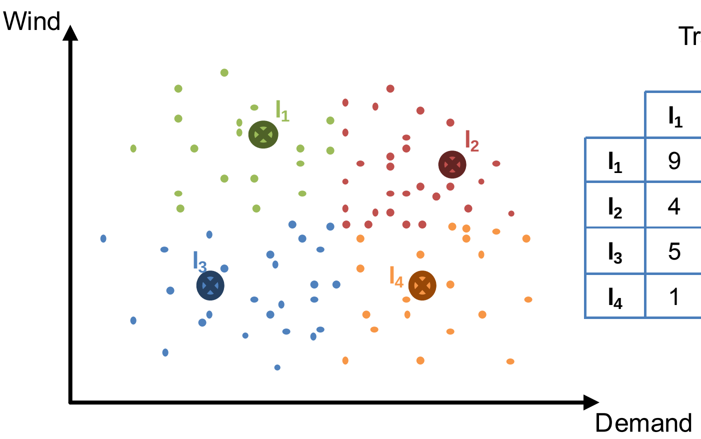
A system state is a predefined set of circumstances that occur simultaneously and frequently in a power system during an analyzed period of time (a week, a month, a year, etc.); hence, each hour is linked to a state with the advantage of maintaining the chronology because transitions between states, i.e., transitions between hours[17], are known. The methodology to define the states is explained with the next example. Let us consider a small isolated system with windmills, and one diesel fuel power plant. Weather conditions will undoubtedly set electricity prices. Let us define four states as a combination of

[15] Traditional power system operation was characterized by rigid structures: nuclear power plants were producing always; coal power plants shut down the weekends if demand was too low; hydro power plants shaved the peaks; and gas and/or oil power plants adapted to the residual demand due to their flexibility.

[16] In this example, spinning reserves are critical in high demand scenarios to answer to a sudden decrease of wind generation; not so, in low demand scenarios.

[17] Two consecutive hours (*a* and *b*) that belong respectively to two different states (l_a and l_b) increase in one unit the number of transitions between states l_a and l_b. At the end of the count, the number of consecutive hours that are allocated to different states is equal to the number of transitions between the states.

two events: high and low demand; high and low wind conditions. We now construct a scatter plot with the hourly demand in the X-axis and the hourly wind power generation in the Y-axis and then apply a clustering technique to obtain four representative points out of the whole sample (Figure 5-4). Each hour will be linked to a representative point, i.e., a state, which does not necessarily correspond to a real hour. Furthermore, the transitions between states will be equal to the number of transitions between hours; hence, the chronology is maintained thanks to the transition matrix. The four states are l_1 (low demand, high wind); l_2 (high demand, high wind); l_3 (low demand, low wind); and l_4 (high demand, low wind). When other parameters have also influence on electric power market results, new dimensions corresponding to each new parameter can be added to the scatter plot.



Transition matrix

	l_1	l_2	l_3	l_4
l_1	9	5	4	0
l_2	4	15	2	6
l_3	5	3	12	5
l_4	1	6	4	9

Figure 5-4 – Illustrative example of system states definition

Returning to the model description, we can define several system states, l=1,2,…,L. As a consequence, each day is made up of different states, and the duration of each state in hours within a day d is known T_{dlk}^{ST}. As previously mentioned, load levels are defined for a period of time (hereinafter, a month). The chronology is maintained because the number of transitions between two states l and l' within a month m is known $N_{mll'k}^{TRN}$.

We have defined the net electricity demand D_{mlk}^{PWR} in each load level within a month as the difference between the electricity demand and the renewable power generation. As a result, there is a net demand curve as well as different system state durations and transition matrices for each renewable power generation scenario. Generation companies that own thermal power plants produce electric power q_{gmlk} to cover the monthly net electricity demand:

$$D_{mlk}^{PWR} = \sum_g q_{gmlk} \quad \forall m,l,k \quad : \lambda_{mlk} \tag{5.11}$$

One advantage of using QP and LP problems is the possibility of obtaining dual variables of technical constraints whose economic interpretation is usually of interest. For example, the dual variable of (5.11) provides monthly electricity prices p_{mlk}^{PWR} in each load level after an easy calculation $p_{mlk}^{PWR} = \lambda_{mlk} \Big/ \sum_{d \in m} T_{dlk}^{ST}$.

The generated quantity is limited by a maximum power level Q_g^{MAX}, a technical minimum level Q_g^{MIN}, and a binary decision variable u_{gmlk} that reveals if the group is committed:

$$q_{gmlk} \le Q_g^{MAX} \cdot u_{gmlk} \quad \forall g, m, l, k \tag{5.12}$$

$$q_{gmlk} \ge Q_g^{MIN} \cdot u_{gmlk} \quad \forall g, m, l, k \tag{5.13}$$

Nonetheless, group commitments actually depend on start-up and shut-down decisions. If a group starts up between states *l* and *l'* (obviously, it was not committed in state *l*), it will be committed during state *l'*. In contrast, a group will not be committed if it was committed in state *l* and shuts down between states *l* and *l'*. Last, if a group does not start up or shut down between states *l* and *l'*, it remains in its current commitment mode during both states *l* and *l'*. Other combinations do not apply (Table 5-1).

Commitment *l*	Start-up *l* → *l'*	Shut-down *l* → *l'*	Commitment *l'*
0	1	0	1
1	0	1	0
0	0	0	0
1	0	0	1

Table 5-1 – Unit commitment, start-up and shut-down decisions

Constraint (5.14), which includes start-up $u_{gmll'k}^{UP}$ and shut-down decisions $u_{gmll'k}^{DN}$, describes these processes:

$$u_{gmlk} - u_{gml'k} = u_{gmll'k}^{UP} - u_{gmll'k}^{DN} \quad \forall g, m, l, l', k \tag{5.14}$$

Note that start-up and shut-down decision variables need not be binary, but only bounded between zero and one, because their value is automatically determined by the binary commitment decisions.

Generation companies within perfectly competitive markets minimize the operating costs of their thermal power plants. The main costs of thermal groups can be summarized in variable costs CV_g (related to generation), fixed costs CF_g (related to commitment), start-up costs C_g^{UP}, and shut-down costs C_g^{DN}:

$$\min_{\substack{q_{gmlk}, u_{gmlk} \\ u_{gmll'k}^{UP}, u_{gmll'k}^{DN}}} \sum_{g,m,l,k} \omega_k \cdot \left[\sum_{d \in m} T_{dlk}^{ST} \cdot \left(CV_g \cdot q_{gmlk} + CF_g \cdot u_{gmlk} \right) + \sum_{l'} N_{mll'k}^{TRN} \cdot \left(C_g^{UP} \cdot u_{gmll'k}^{UP} + C_g^{DN} \cdot u_{gmll'k}^{DN} \right) \right] \tag{5.15}$$

The objective function includes the weight of each scenario ω_k as it makes no sense to define a common decision for all scenarios, but for each scenario, because power plants operation is a short-term decision. In addition, observe that start-up and shut-down decisions are multiplied by the number of transitions between states to internalize properly these costs. GFPP variable costs connected to a zonal spot market are already considered in (5.2) and, hence, CV_g=0.

The objective function (5.15) subject to constraints (5.11)–(5.14) constitutes a MIP problem that allows generation companies to optimize their electric power generation decisions under the uncertainty of renewable energy sources.

5.3.4. Coupling gas and electricity markets

So far, we have broken down a model that optimizes gas purchases and gas pipeline capacity contracting by gas consumers, and power plants operation by generation companies under uncertainty. At this point, we gather the previous objective functions and constraints in the following unique model, in which we minimize costs of gas purchases, capacity contracts and electricity generation:

$$\begin{array}{lll} \min & (5.2)+(5.5)+(5.15) & \rightarrow \text{Gas purchases + Capacity contracts + Power production} \\ s.t. & \left| \begin{array}{l} (5.3)\ldots(5.4) \\ (5.6)\ldots(5.10) \\ (5.11)\ldots(5.14) \end{array} \right. & \begin{array}{l} \rightarrow \text{Gas spot market} \\ \rightarrow \text{Gas pipeline} \\ \rightarrow \text{Power market} \end{array} \end{array}$$

However, a constraint that links GFPP production to gas operation has not been established yet. In detail, GFPPs that are connected to the analyzed pipeline consume a daily quantity of gas which depends on their gas-to-power conversion factor $F_g^{G \rightarrow P}$. GFPP daily consumptions d_{zedk}^{GFPP}, which are connected to the same pipeline and belong to the same generation company, links electric power market decisions to gas system decisions:

$$d_{zedk}^{GFPP} = \sum\nolimits_{g \in (z,e),l} F_g^{G \rightarrow P} \cdot T_{dlk}^{ST} \cdot q_{gmlk} \quad \forall z,e,d,\left(m/d \in m\right),k \tag{5.16}$$

After incorporating this last constraint, we obtain the final MIQP model:

$$\begin{array}{ll} \min & (5.2)+(5.5)+(5.15) \\ s.t. & \left| \begin{array}{l} (5.3)\ldots(5.4) \\ (5.6)\ldots(5.9) \\ (5.11)\ldots(5.14) \\ (5.16) \end{array} \right. \end{array}$$

5.4. Description of a realistic system

Our objective is to analyze the behavior of a generation company that only owns GFPPs. Therefore, the generation company must coordinate its purchases in the gas spot market with its pipeline capacity contract portfolio. Simultaneously, this company must compete in the electricity market with other power producers. We do not intend to represent an actual system, but a system that reproduces actual operation conditions. Let us go back to Figure 5-2. Our system consists of a gas spot market, a shared gas pipeline and an electricity market. In the following, we describe the chain elements from gas acquisitions to electricity generation. Capacities, prices, etc. are inspired by real systems, but do not represent a specific system. The time scope is one year.

The gas spot market is characterized by a price-quantity curve. The minimum daily price is 12 €/MWh-t[18]. The slope of the price-quantity curve is 0.05 (€/MWh-t)/GWh-t. In addition, the gas spot market establishes gas system prices for GFPPs that are not connected to the shared pipeline. As a simplifying assumption, we consider neither the contracting nor the operation of other pipelines whose reference price is determined by the gas spot market.

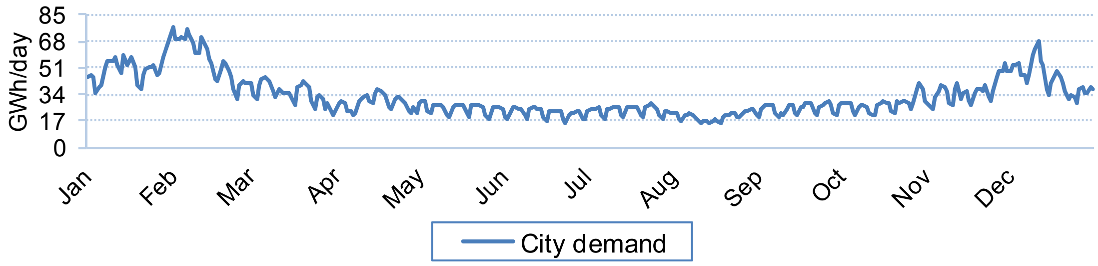


Figure 5-5 – Daily gas households demand

Gas pipeline capacity amounts to 85 GWh-t/day. The pipeline supplies a city. Of importance, during times of congestion, the city's gas demand takes priority over other demand[19]. The demand curve (Figure 5-5) reflects two relevant cold snaps that reduce free gas pipeline capacity up to 9.7% to other consumers, such as the GFPPs that are connected to the same gas pipeline. In fact, the generation company owns four GFPPs that are connected to this shared gas pipeline: CCGT1, CCGT2, OCGT1 and OCGT2 shown in Table 5-3 and Table 5-4. One of the basic concerns about gas-power systems that we have tried to represent with this system is how scarce capacity affects the con-

[18] '-t' indicates units of thermal energy. Later, '-e' is used for units of electric energy.

[19] Maybe placing the conventional demand at the highest position of the priority rank, even above any capacity contract, is simplistic; or maybe not, because households are often the last consumers to be interrupted in case of scarcity.

tracting and operation of a generation company. At most, free pipeline capacity after supplying the city allows the generation company to use its four GFPPs at full capacity during 184 days, or its two CCGTs during 325 days and its two OCGTs during 349 days (each at full capacity).

Months	Medium-term contract factor (Monthly)	Short-term contract factor (Daily)
Jan-Mar	2	0.20
Apr-Sep	1	0.05
Oct-Dec	2	0.20

Table 5-2 – Medium- and short-term contract extra-costs

Similar to Chapter 2, the long-term capacity contract price is 26,415 €/(GWh-t/day). The generation company pays monthly for the corresponding pipeline capacity during the years that the long-term contract is active, instead of paying for the capacity in all at once, in accordance with some regulatory frameworks. Medium- and short-term contract prices are obtained after multiplying long-term prices by a monthly factor (Table 5-2). As cold months are strongly penalized, the company has an incentive to contract properly during high demand months for gas facilities. For instance, the short-term capacity costs incurred over 10 days are enough to secure capacity for a cold month via a medium-term contract (the same is true for short-term capacity costs incurred over 20 days for a warm month). Last, a tariff is applied to gas flowing through the pipeline equal to 567 €/GWh-t.

Thermal groups	Maximum power (MW-e)	Technical minimum (MW-e)	Gas-to-power factor (MW-t / MW-e)
CCGT1–4	400	200	1.7
Coal1–2	600	300	-
OCGT1–4	200	0	2.5
Oil	600	100	-

Table 5-3 – Technical characteristic of the thermal groups

Thermal group	Variable cost (€ / MWh-e)	Commitment cost (€ / h)	Start-up cost (€)	Shut-down cost (€)
CCGT1–4	-	650	50,000	3,000
Coal1–2	35	900	100,000	7,000
OCGT1–4	-	1,000	10,000	1,000
Oil	70	1,200	30,000	2,000

Table 5-4 – Costs of the thermal power plants

The power system consists of gas (CCGT and OCGT), coal and oil power plants whose technical characteristics and operation costs are shown in Table 5-3 and Table 5-4, respectively. GFPP variable costs result from the gas spot market.

Thermal power plants and wind power generation satisfy the inelastic electricity demand (Figure 5-7). Mean electricity power demand is 2.7 GW-e, while mean wind power scenarios range from 0.2 to 0.8 GW-e (in detail, 9%, 18%, 20%, 23%, and 29% wind penetration). Each scenario probability is 0.05, 0.25, 0.4, 0.25 and 0.05, respectively. Given that we consider a wind profile that differs for each scenario, we have five net electricity demand curves with their corresponding state transition matrices and state durations. As an illustrative example, we reproduce a net electricity demand in Figure 5-6 and a transition matrix in Table 5-5. System states have been determined with the MATLAB® clustering function *k-means*. There is one remarkable fact: the matrix is not symmetric; therefore, transitions between consecutive load levels need not be transitions between consecutive hours. Notice that the number of transitions is equal to the number of hours[20].

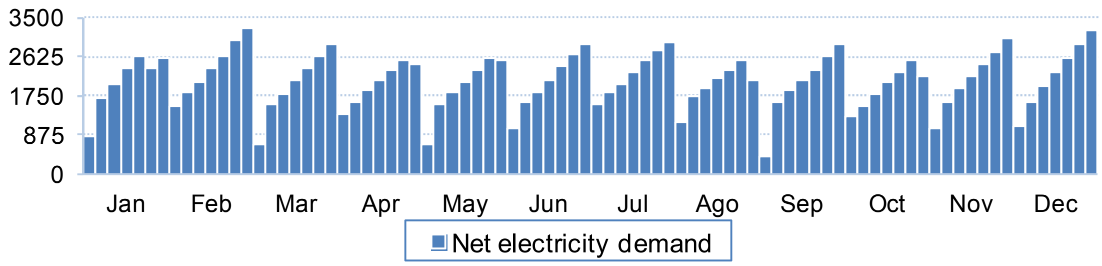


Figure 5-6 – Monthly net electricity demand by load level in MW-e

	State 1	State 2	State 3	State 4	State 5	State 6	State 7
State 1	56	14	-	-	-	-	-
State 2	14	72	19	3	-	-	-
State 3	-	22	88	28	3	-	-
State 4	-	-	34	66	33	-	-
State 5	-	-	-	35	63	20	-
State 6	-	-	-	1	19	69	17
State 7	-	-	-	-	-	17	51

Table 5-5 – System state transitions during a month (January, central scenario)

[20] Actually, it is equal to the number of hours minus one because there are *N*-1 transitions between *N* hours during a predetermined period of time.

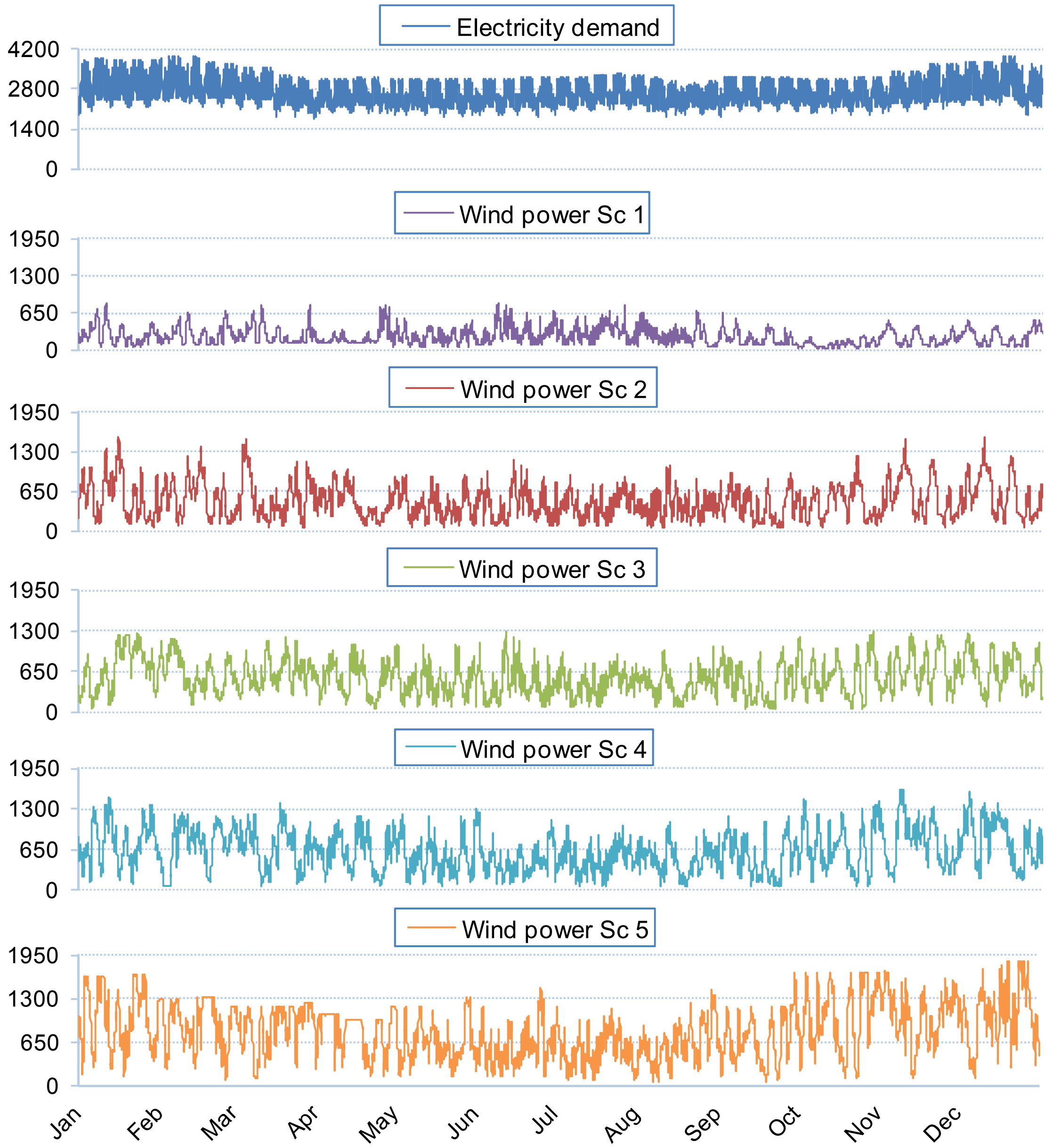


Figure 5-7 – Inelastic electricity demand and wind power generation scenarios in MW-e[21]

5.5. Market results after coordinated operation

The model has been formulated in GAMS and solved by using CPLEX 12 on an Intel® Core™ i7 at 3.40GHz with 16GB RAM. The computational time to solve the case study (47,842 variables, 5,040 integer variables, and 63,419 equations) was about 10 minutes, using 6 threads. One of the first results that can be observed from the stochastic solution is the strong relationship between expected gas and electricity prices (Figure 5-8). How-

[21] Figure 5-6 reproduces both demand and wind scenarios to illustrate its variability. Although, we do not intend to represent an actual system, we have utilized a real, although scaled, hourly demand curve (from Portugal during 2012) and five real hourly wind profiles (obtained between 2008-2012)

ever, the electricity price behavior is not only a consequence of gas price evolution; price spikes, which are particularly noticeable during both cold snaps, seem to be more related to the scarce pipeline capacity than to gas price increments.

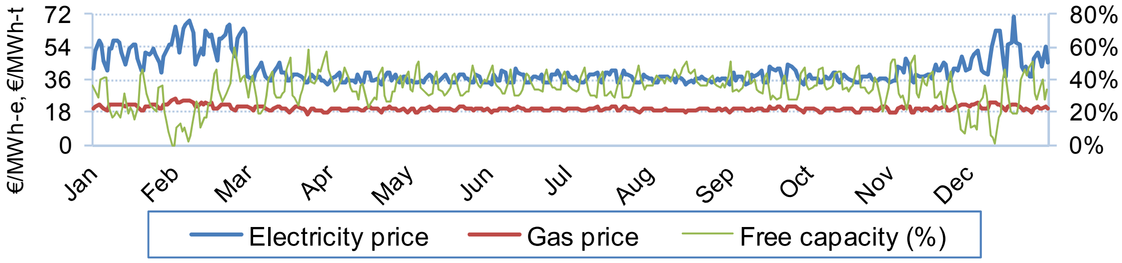


Figure 5-8 – Electricity and gas prices vs. free pipeline capacity

The generation mix also confirms the relevance of gas technologies to respond to wind variations (Figure 5-9). Coal power plants almost operate as baseload plants due to their reduced flexibility, which is reflected in higher start-up and shut-down costs with respect to other thermal power plants. In contrast, CCGTs deal with demand variations most of the analyzed period. For instance, CCGTs decrease their production from 29.9 GWh-e to 20.5 GWh-e at the beginning of May, while they increase their production from 16.8 GWh-e to 27.5 GWh-e in mid March, in one day. OCGTs and oil power plants are used for satisfying demand spikes due to their flexibility. The latter power plants are especially relevant when pipeline capacity is scarce and GFPPs cannot be supplied.

Regarding each technology share in the power generation mix, gas accounts for 54% of thermal generation, while coal accounts for 45%. In contrast, a meager 1% of thermal power generation corresponds to oil power plants, although they are essential to prevent non-supplied energy. The case study could be a mirror of an actual system that is transiting from a coal-based production to a gas-based production with renewable energy sources. Notice that hydro power plants, which often play a relevant role in power systems, have not been considered in this chapter. Moreover, wind power generation covers approximately 20% of demand. Actually, we present the residual demand in Figure 5-9; that is, the total demand net of renewable power generation.

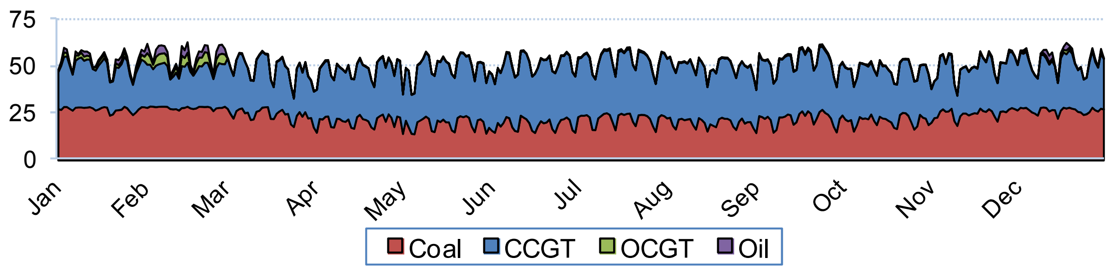


Figure 5-9 – Daily thermal generation mix in GWh-e

The main objective of this chapter is to analyze the pipeline capacity contracting behavior of a generation company under uncertainty and that shares the pipeline with other consumers. Let us observe Figure 5-10, where the contract portfolio is shown. At first sight, we can observe that the generation company contracts for capacity over expected gas flow (in white) as a consequence of wind power generation uncertainty. The mean margin between expected gas flow and contracted capacity is near 15%, being 250 days above 5%. Long-term capacity equals 26.14 GWh-t. Gas releases take place during cold months, when the city demand needs and obtains capacity because of its priority. In contrast, gas acquisitions take place during warm months, when the city does not require its gas pipeline capacity. Medium- and short-term capacity contracts are almost residual. The effect of uncertainty can be also observed in Figure 5-11, which contains the expected contract portfolio and the gas flows for each scenario.

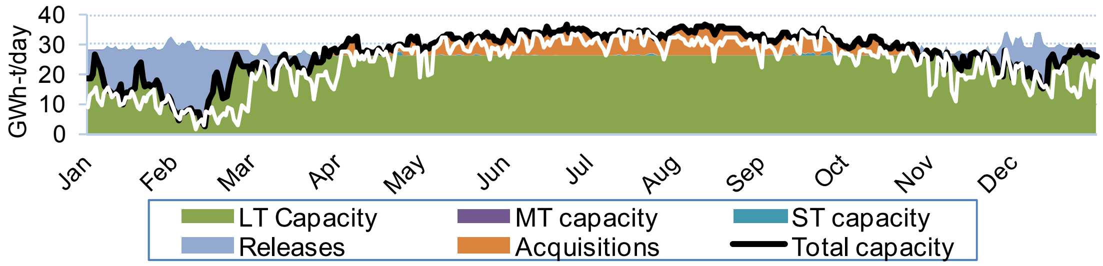


Figure 5-10 – Capacity contract portfolio of the generation company with secondary market

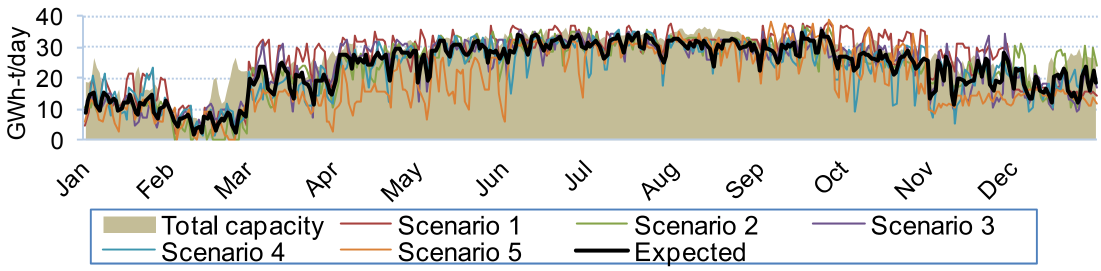


Figure 5-11 – Expected contract portfolio and gas flows

The second very relevant result is the amount of releases and acquisitions, which underlines the importance of secondary markets. In detail, the generation company and the city exchange 2.54 TWh-t, which means that 8.2% of pipeline capacity is traded daily. To examine the importance of secondary markets, we conduct a sensitivity analysis by closing the secondary market to impede acquisitions and releases of capacity. Results show that the generation company increases medium-term capacity contracts, which are twice as expensive as long-term contracts during cold months, in exchange for reducing long-term capacity contracts (Figure 5-12). Supposedly, the generation company should contract for more long-term capacity to compensate the additional costs of contracting for medium-term capacity; however, the lack of free capacity during February makes even more expensive the capacity contract portfolio since more long-term capacity is not available. The immediate consequence is a deterioration of the company's merit order position and a production decrease from 5.0 to 3.6 TWh-e. From the point of view of the system, total costs increase from 884.4 to 888.9 million euro. Furthermore, electricity system stability may be compromised because the margin between the expected gas flow and the contracted capacity is reduced to 8%. Additionally, closing the secondary market reduces the number of days that the margin exceeds 5% to 163 days.

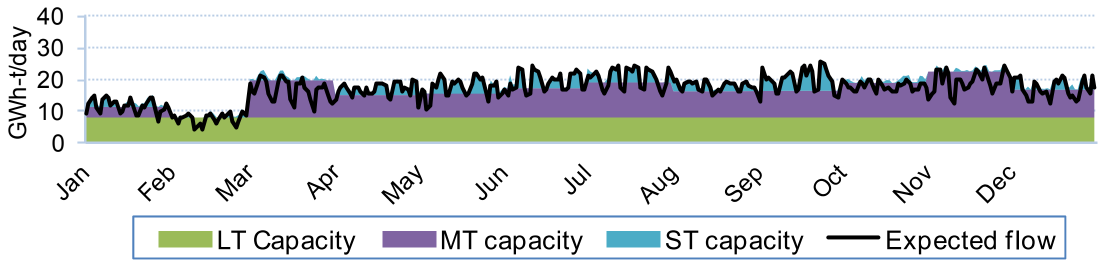


Figure 5-12 – Capacity contract portfolio of the generation company without secondary market

5.6. Brief summary of contributions

After a detailed discussion on the downstream natural gas market in previous chapters, we have addressed (partially) for the first time in this thesis an intertwined energy system consisting of two energy products: gas and electricity. The link between both systems is the GFPP that, in the context of liberalized markets, is operated by a generation company that is in charge of acquiring gas, contracting for pipeline capacity and submitting production offers to an electricity market under the uncertainty of renewable energy sources. With the objective of supporting and analyzing the decision-making process of such generation company, we have developed a novel model that optimizes simultaneously the following:

- The gas purchases in a zonal spot market under the uncertainty of renewable energy sources. Although the zonal hub provides a price-quantity function, the whole gas system model, as well as other types of hub, could be employed after a small adaptation. Therefore, we could also optimize the operation and contracting in gas systems and the management of supply contracts.
- The portfolio of pipeline capacity contracts subject to the uncertainty of renewable energy sources.
- The operation of thermal power plants in the electricity market framework under the uncertainty of renewable energy sources. In addition, we have established a different method to define load levels, named system states, which consider the intermittency of renewable energy sources and allows internalizing the real start-up and shut-down costs.

Furthermore, we have shown, as well as quantified, the importance of liquid and competitive secondary capacity markets, in which the consumers can release their unused capacity and other consumers can acquire and benefit from the released capacity; benefits that also have a positive effect on the whole system.

5.7. Brief summary of future developments

As a research guideline that begins during the early 2000s, there is still much work to do. Regarding what has been addressed in this chapter, we can give some indications for future developments in each one of the sub-models previously mentioned:

- The gas spot market is a strong simplification of the whole gas system that may cause the loss of relevant operation, contracting and supply details. One of the best options would be incorporating the gas-electricity model (section 5.3.4) into the complete gas system model (Chapter 2 and Chapter 3). However, this solution can result in an intractable model. Another option would be communicating both models precisely through the price-quantity curve of the zonal hub (Chapter 4).
- For the sake of clarity, we have only considered two gas consumers connected to the same pipeline; otherwise, we have not been able to draw the previous conclusions as results would have been indistinguishable. Nonetheless, several gas consumers are connected to gas pipelines, as well as several gas pipelines share the same price. Both the number of gas consumers and pipelines should be increased. Furthermore, gas consumers are risk-averse agents that may (or may not) contract for capacity in advance depending on how much costs involve being interrupted, which leads to another relevant topic: the priority access scheme. In short, more gas consumers, more pipelines, risk-averse agents and a priority access scheme are some future developments of interest for a better understanding of pipeline capacity contracting and its interaction with electricity markets.
- The representation of the electricity market does not include hydro and pumping power plants, which are also relevant facilities to support the integration of renewable energy sources. With respect to the market structure, the joint operation in gas and electricity systems is the breeding ground to achieve significant synergies, but also to the exercise of market power. For instance, a generation company can hoard pipeline capacity by not participating in secondary capacity markets, and expel another company from the electricity market. We do believe that modeling imperfectly competitive markets is of great interest as anticompetitive behaviors may condition the proper performance of gas-electricity systems.

At last, uncertainty is not only a consequence of renewable power production. Demand, fuel prices, hydro conditions, pollutant (CO_2, NO_X or SO_2) prices, or forced outage rates are also sources of uncertainty. Despite extending the number of stochastic variables is a possibility, large models may become extremely difficult to solve. Another possibility is implementing smart Monte Carlo simulation techniques (Dueñas et al. 2011).

5.8. References

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Chapter 6

Conclusions, Original Contributions and Future Research Guidelines

6.1. Thesis summary

Throughout the thesis, we have provided a comprehensive view of the downstream gas system and, in particular, of entry-exit systems, which are currently being implemented in Europe. However, its extension to the other widely utilized access system, i.e., the point-to-point system (e.g. in the U.S.), requires minor changes. In fact, it suffices to define a balancing zone which contains each continuous section (up to a diversion or compressor station) of a transmission pipeline (Figure 6-1), and, in addition, impose that both entry and exit contracted capacities are equal in each point-to-point balancing zone.

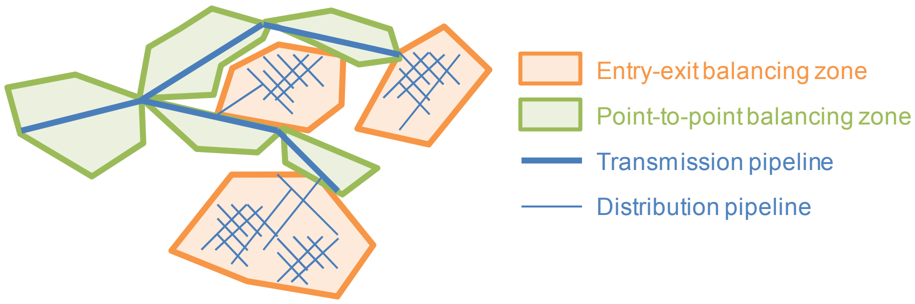

Figure 6-1 – Entry-exit model extension to point-to-point access system

In addition, we have focused on analyzing the behavior of a key player, which is involved in almost every business activity: the shipper, which simultaneously acts as a purchaser, a supplier and a third party in the context of liberalized gas markets. Moreover, the shipper also interacts with other shippers. All these business relations determine the market results. In order to capture the market performance properly, we have proposed a fundamental model and, in particular, a mixed-integer programming (MIP) model:

- In Chapter 2, we have characterized the shippers' behavior when they must contract for capacity to utilize the gas facilities: regasification terminals, underground storages, cross-border pipelines, and balancing zones (which actually embed the transmission and distribution networks). Capacity contracting possibilities include long- (some years), medium- (month to month) and short-term (day to day) contracts; therefore, we have developed a model that optimizes the contract portfolios subject to the operation decisions. Besides, we have incorporated secondary capacity markets in which the shippers can release their unused capacity, which is acquired by other shippers.

  Thanks to the developed model, we have observed the typical patterns of utilization and contracting of each infrastructure. Regasification terminals are contracted in the long term as they are typically utilized in a baseload mode. If a shipper requires daily peak capacity, this is covered with purchases at secondary capacity markets. When the underground storages are operated according to injection-withdrawal cycles, the shippers mainly contract for long-term capacity and modulate with medium- and short-term capacity, but do not use secondary markets as they all are willing to purchase or sell at the same time. In contrast, when the underground storages are not subject to injection-withdrawal cycles, the secondary capacity markets are really active. Furthermore, the pipeline capacity contract portfolios do not follow a predetermined pattern, except when the shippers supply the conventional demand due to its predictability.

Finally, we have also modeled OTC markets, in which a large number of transactions take place, especially, in line-pack capacity and LNG tanks.

- In Chapter 3, we have moved one step upwards in the natural gas chain in order to examine the influence of long-term gas supply contracts, which are agreed on between producers and shippers, on market prices. After describing the fundamentals of the supply contracts, the model has been extended with the aim of optimizing their management. As we are considering open gas markets within a globalizing market, international trade has also been included and, particularly, overseas trade which basically happens thanks to the development of LNG technology.

  With the incorporation of LNG carriers to the MIP model, we detected that the execution time dreadfully incremented. Therefore, we have proposed an approach, which reduces the execution time by 98% by taking advantage of the gas market characteristics.

  Regarding the results, we have observed how supply contracts should be managed, as well as the shippers' willingness to renegotiate some contract terms and conditions. Moreover, we have also appreciated the relevance of the LNG carrier movements, when they are either diverted or loaded at domestic LNG terminals.
- In Chapter 4, we have applied the previously developed model to a real system, the Iberian gas system, in order to examine the market performance after the incorporation of a virtual hub; i.e., of an organized market into an entry-exit system framework. We have evaluated, by using the proposed indicators of the European Gas Target Model which seeks the constitution of the internal gas market, different alternatives: from not establishing a hub, that is, the current situation, to establishing a single virtual hub. In addition, we have analyzed the shippers' behavior by exploring other specific market results, such as prices, market shares, or profits. Finally, the single virtual hub has allowed us to obtain a price-supply curve of a real system.

After this thorough analysis of the downstream gas system, we have shed light on a topic that is nowadays not only of interest, but also of concern to regulatory authorities: the integration between the gas and electric power systems. Recently, natural gas has been acquiring importance as input fuel for electricity generation due to the development of the combined-cycle gas turbine technology which has proven to be cleaner, in comparison to other fossil fuels (oil, coal, etc.), and as a flexible technology to support the integration of intermittent and uncertain renewable energy sources. As a matter of fact, we have examined the required coordination between long-term decisions, which usually occur in the gas system because capacity has to be contracted well in advance, and short-term decisions, which mainly take place in electric power systems as a consequence of renewable power generation uncertainty.

6.2. Original contributions

In this section, we now gather and highlight the original contributions of this dissertation. For the sake of clarity, we have classified them into two main groups: modeling contributions and regulatory recommendations.

6.2.1. Modeling contributions

The complete entry-exit market model is certainly one of the main original contributions of this thesis. We have extended the current literature in many aspects, as mentioned in section 1.3 (pp. 9–12). First of all, we have improved the representation of the infrastructure operation by providing a daily detail to the operation decisions. Moreover, we have included capacity contracting decisions with different time scopes, as it habitually occurs in actual downstream gas systems, and established secondary capacity markets where shippers can trade with unused capacity. In the second place, we have integrated long-term supply contracts (after explaining their main characteristics) into the model in order to better capture shippers' behavior in downstream gas systems because long-term supply contracts mostly determine the market results in several places. Third, LNG carriers have been modeled carefully as the recent developments on LNG technology are boosting overseas LNG commercial transactions, which allow shippers to profit from arbitrage opportunities between distant markets. At last, we have incorporated an organized market. As we have not altered the two main sources of rigidity (i.e., captive consumers and long-term supply contracts) the organized market internalizes them.

The developed model can equally be utilized by shippers, regulatory authorities and gas facility operators, that is, the main stakeholders of downstream gas systems:

- The model provides interesting information to shippers, which can simultaneously optimize their capacity contract portfolio and operate efficiently in different facilities. Furthermore, they can also optimize the management of their long-term supply gas contracts and obtain useful information on the economic value of contract conditions in order to renegotiate them, and thanks to the modeling of LNG carriers, shippers can profit from price opportunities in distant markets either by diverting gas from their supply contracts or loading LNG carriers at the domestic regasification terminals.

- The model allows regulatory authorities to monitor the market performance, e.g., evaluating the degree of competition of the domestic market by comparing prices at international markets; detect and/or prevent market power abuses; and, in the end, propose and implement new regulatory measures to promote competition, to improve security of supply, and to guarantee system sustainability.
- The model also supports operators by forecasting the utilizations of their gas facilities, in order to prevent emergency operation conditions. In addition, they can, at least, anticipate future capacity expansions.

Moreover, the incorporation of an organized market provides both shippers and regulatory authorities with a price-supply curve which can be used for defining market strategies (shippers) or coping with anticompetitive behavior (regulatory authorities).

The model is formulated as a mixed integer programming (MIP) problem, in which the integer variables represent the LNG carrier arrivals and departures. The model assures a global and unique solution with a relatively low computational effort compared to the level of detail and quantity of results that can be obtained. However, we believe that models should satisfy not only academic purposes, but also industry objectives. Hence, we have proposed a new methodology that speeds up the computational time (98% reduction of time) and maintains the accuracy of model results (about 1% error). The success of this approach is based on making the most of gas market features, such as capacity and supply contract characteristics.

The last modeling contribution is related to the interaction between gas and electric power systems. As the link between both systems is the gas-fired power plant, we have developed a new model which simultaneously optimizes the gas purchases, the pipeline capacity contracting portfolio and the submitted production offers of a gas-fired power plant in a competitive environment. In addition, we have introduced renewable energy sources, subject to uncertainty, and made use of a novel methodology to better capture the power plants operation under intermittent conditions: the so-called system states.

6.2.2. Regulatory studies

It has been shown that we have developed a model in this thesis, which can be used to address a number of questions of regulatory interest. Typically, regulatory decisions entail a balance among different effects. Therefore, a careful quantification of both the current ex-ante regulatory status and the likely ex-post status is often required. In this spirit, a number of regulatory reforms stemming from discussions regarding the fulfillment of the Single European Gas Market goals (sustainability, competition and security of supply) in the context of entry-exit access systems have been analyzed. Our results quantify and lend support to a number of recommendations, and specifically:

- When balancing zones are defined, they must respond to chronic bottlenecks in gas transmission networks in order to proportionate proper locational signals.
- The pancaking effect is not economically justified in liberalized gas markets, as it only increases gas prices without economic foundations. Besides, it discourages market integration.
- Liquid and competitive secondary capacity markets are essential for a correct performance of downstream gas systems because capacity transactions lead to efficient utilizations and a decrease of utilization costs. Moreover, the secondary capacity markets benefit other intertwined energy systems, such as the electric power system.
- A single virtual hub, which reduces the transaction costs and provides transparent prices, fosters the competition as it alleviates the barriers to entry.

However, we have also observed that capacity markets and virtual hubs themselves are not a solution in order to promote competitive downstream gas markets, as the market structure conditions their performance. Downstream gas markets, at least, in the European framework tend to be concentrated in one or two companies. Therefore, anticompetitive behavior, such as exercise of market power or capacity hoarding, may take place in any case. A meticulous market monitoring by regulatory authorities may work. Nevertheless, perfectly competitive markets require a set of assumptions: free concurrency, a large number of sellers and purchasers, and elastic demand; which cannot be attained by market monitoring.

6.3. Future research guidelines

As when one door shuts, another opens, this thesis has not only provided some remarkable conclusions, but also left interesting open questions that can be addressed in future work. Although we have enumerated future research guidelines at the end of each chapter, we now classify them into four main groups: market operation details, market behavior, long-term vs. short-term decisions, and gas-electricity interaction.

Market operation details involve two main topics:

- Demand representation. Although the demand for energy products is usually rather inelastic, it is not totally inelastic. In gas markets we could consider two types of demand elasticity: 1) price elasticity of demand, which measures the responsiveness of gas demand to a change in gas price; and 2) cross-price elasticity of demand, which measures the responsiveness of gas demand to a change in a substitute good price. We could also incorporate the effect of consumers' switching behavior, including switching barriers.
- Supply contracts. When a contract is delivered by pipeline, there is commonly a wellhead at the other end of the pipeline. Improved well performances are obtained when gas is extracted constantly. Therefore, daily maximum volumes and take-or-pay clauses are habitually imposed. Moreover, delivery prices are updated with indexed formulas, which could be included, as well as cargo freights and other fees. Another interesting aspect of supply contracts has to do with flexible clauses, which allow not complying with either maximum volumes (make-up gas) or take-or-pay clauses (carry-forward gas). Finally, diverted volumes are actually shipped by carriers, which could be modeled.

Anticompetitive market behavior has not been addressed in this thesis. In downstream gas systems, there are two main types of anticompetitive behavior: exercise of market power and market foreclosure. The former behavior could be represented through conjectural variations. However, market foreclosure defined as capacity hoarding by a dominant company, which restricts newcomers' third party access, is particularly difficult to model. Furthermore, market foreclosure may also involve restricting access to a good, in this case, gas. Bilateral contracts in which both parties, i.e., the supplier and the purchaser, participate in the market could be incorporated and used for modeling unequal power relationships. For example, the supplier might be tempted to hinder an optimal exercise of the contracts by the purchaser in order to gain market share. At last, our organized markets have shown illiquid because, among other things, we have not considered market makers, or arbitrageurs. We do not affirm that market makers automatically create liquidity, but they could at least be represented in order to observe whether both liquidity and market efficiency improves.

Concerning the time scope, we have developed a model that is able to cope with long-, medium- and short-term decisions. However, we could bring extra added value if we take into account the following topics:

- Investment signals. As a matter of fact, when shippers contract for capacity in the long term, but additional long-term capacity is not available, they are clearly providing an investment signal to the gas facility operator, which can invest in new capacity and simultaneously guarantee constant incomes in order to recover the investment costs. Therefore, investment decisions, which would be appreciated as well by the regulatory authorities to support their evaluation of different regulations of energy policies, could be incorporated.
- Uncertainty. Long- and short-term decisions are interrelated. For example, when a shipper has not contracted for capacity in advance, it may be prevented from operating if free or released capacity is unavailable. Short-term uncertainty due to gas demand or price variations may modify long-term decisions. A probabilistic or stochastic approach would allow us to include the uncertainty into the deterministic model.

The interrelation between long- and short-term decisions leads us to another relevant topic, such as risk aversion, which is also related to market behavior. Modeling risk-averse agents would in addition allow us to define a priority access scheme and other types of capacity contracts, such as interruptible contracts.

To conclude, our approach to examine the interaction between the gas and electric power systems has left some open questions:

- Both electricity and gas market models are typically huge models, which cannot be merged or integrated straightforwardly as the single model may be intractable. In fact, we have simplified both models in Chapter 5. For example, we have represented the gas market by its equivalent price-quantity curve and omitted hydro assets in the electricity market. Consequently, different methods for an efficient communication between both models could be studied, as it would be worthwhile for an energy company that holds interests in both gas and electric power markets and would like to achieve synergies from a joint operation.
- Operating in both markets is the breeding ground to exercise input foreclosure, in which, for example, a company that supplies gas to another company expels this latter company from the electricity market by limiting its access to gas or capacity. Therefore, besides anticompetitive intra-market behavior, the inter-market behavior could be examined as well.
- The importance of combined-cycle power plants to guarantee the power system stability, under certain circumstances, brings up another question which is related to the priority access scheme to obtain pipeline capacity. Households commonly hold the highest priority, even above firm capacity contracts. Consequently, com-

bined-cycle power plants may be subject to cut-offs in extreme cold weather conditions, despite their importance for the power system if, for example, wind stops blowing. Different priority access schemes, such as firm and interruptible capacity contracts, should be examined.

Furthermore, besides renewable power production, the uncertainty in electric power systems can be due to electric power demand, fuel prices, hydro condition, or pollutant prices, which could be incorporated to the model.