Cost-Benefit Analysis
Main Assumptions and Results

Spain & Portugal
Republic of Ireland, Northern Ireland and Great Britain
Romania & Hungary

DNV KEMA

July 19, 2013

Outline

- General Approach to Cost Analysis
- Spain & Portugal
  - Cost Analysis
  - Benefit Analysis
- Republic of Ireland, Northern Ireland & Great Britain
  - Cost Analysis
  - Benefit Analysis
- Hungary & Romania
  - Cost Analysis
  - Benefit Analysis

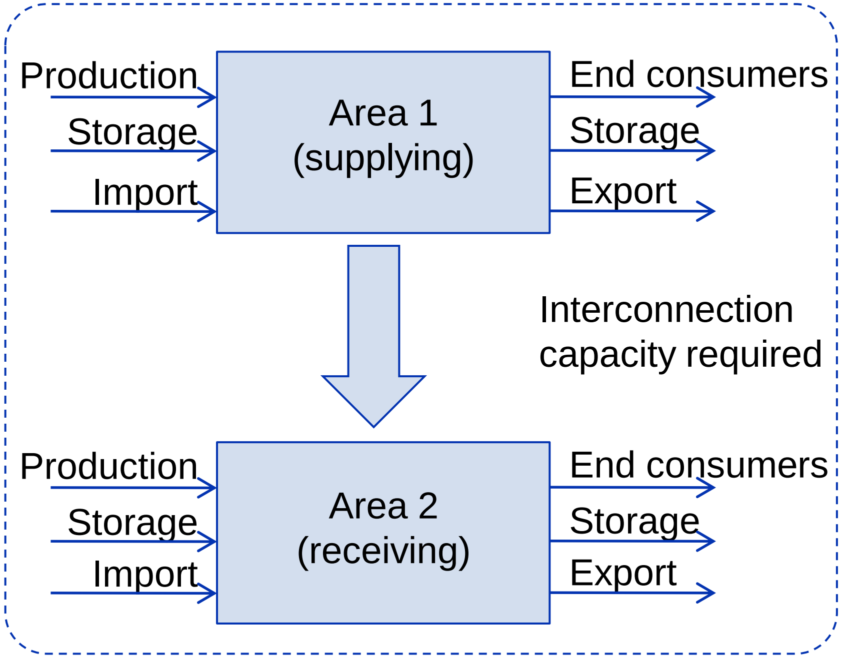
General Approach to Cost Analysis

General Approach

The approach consists out of two steps for assessing the required interconnection capacities and associated costs

- Deriving the interconnection capacity required between market areas
  - Use of scenario's based on values observed in 2012
  - Interconnection capacities required between market areas result from:
    - the differences between entry and exit capacities
    - available capacities at existing interconnection points
  - Does not explicitly take into account network topology
  - Provides estimate for interconnection capacity required

- Assessing the measures required and associated costs
  - In case additional interconnection capacity is required we calculate associated costs for realizing this additional interconnection capacity
  - We apply typical figures for increasing interconnection capacity



Scenarios to Derive Interconnection Capacity

Different cases are used to arrive at estimates for the required interconnection capacity

- In the worst case, the maximum interconnection capacity is determined by:
  - Maximum technical supply capacity in one area needs to meet all maximum technical demand capacity in the other area
  - Domestic demand in supplying area is equal to zero, while demand in receiving area is at maximum
  - Entry capacity used in receiving area is at absolute minimum, while entry capacity in the supplying area is maximally used
- Rather extreme and highly unrealistic case resulting in high and inefficient investments
- Need for cases that are more realistic, but not overly positive in order to avoid the risk of jeopardizing network integrity
- We apply both an conservative and optimistic approach

Assumptions on Expansion Costs

The investment costs associated with potential expansions of interconnection capacity is based on the following data

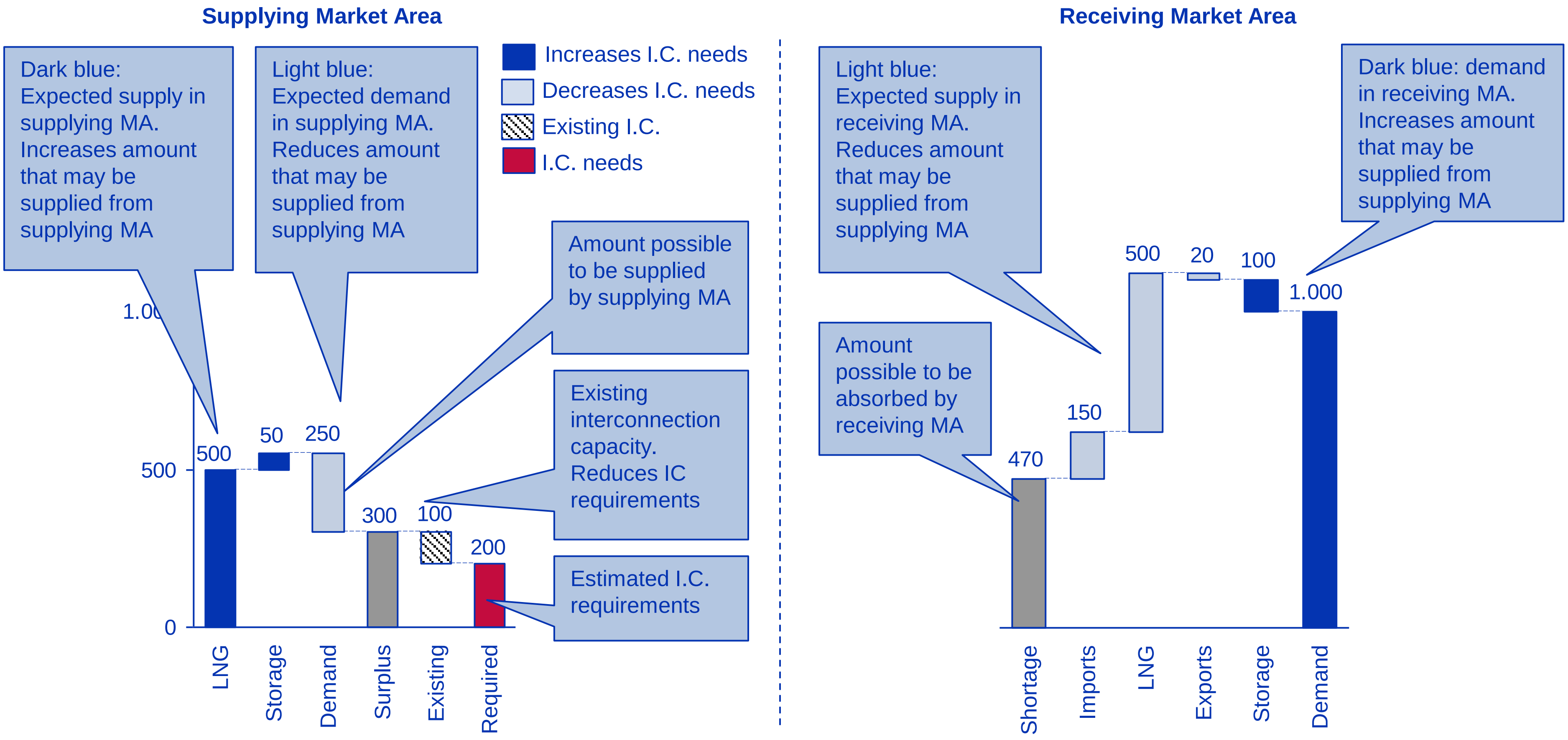
- Average investment costs in pipelines is based on an approximate value of 35 €/(m*inch)
- In Europe this ranges from 45 €/(m*inch) in densely populated West European countries, to 25 €/(m*inch) in South European countries
- Translated into average annual cost by annuitizing investment costs

Diameter	Inch	30	36	42	30	36	42
Pressure	Bar	60	60	60	80	80	80
Pipeline unit costs	M€/km	1,024	1,312	1,760	1,024	1,312	1,760
Cross-sectional area	m^2	0.44	0.64	0.87	0.44	0.64	0.87
Gas volume[(a)]	Mcm/km	26.51	38.17	51.95	35.34	50.89	69.27
Cost of capacity [(b)]	€/kW	44.71	39.78	39.21	33.53	29.84	29.41
Cost of capacity [(b)]	€/GWh/d	1,863	1,658	1,634	1,397	1,243	1,225

(a) – Ideal gas law approximation; (b) – for 250 km, incl. 10% premium for compressor stations
Calculations based on a design transport speed of 6 m/s
Source: COWI/DNV KEMA

Explanation of Results on the Following Slides

FICTITIOUS EXAMPLE



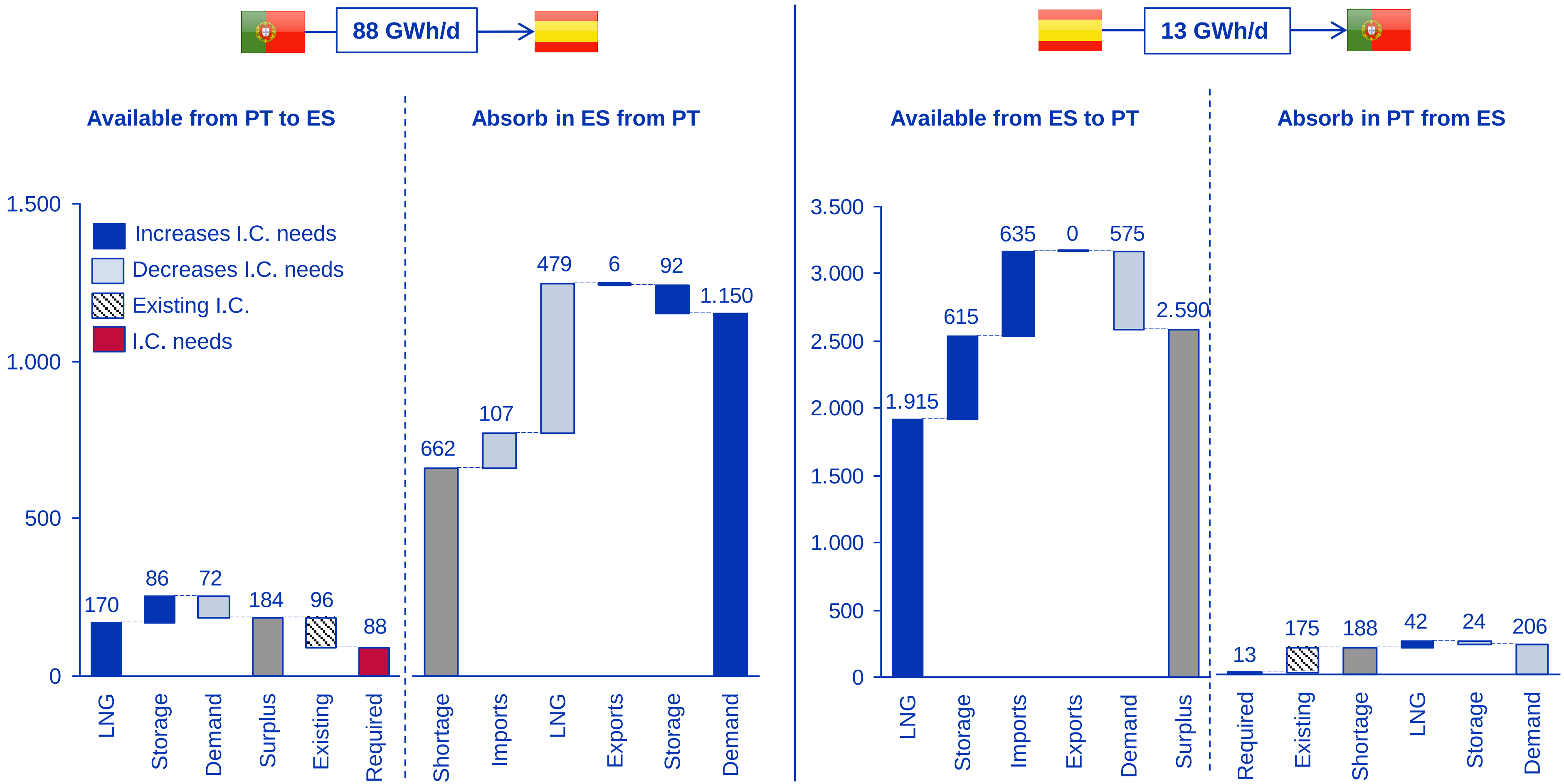
I.C. = Interconnection Capacity

Spain – Portugal Market Integration

Cost Analysis

Summary of Interconnection Capacity Requirements

For both directions, assumptions on the use of Portuguese gas infrastructure are determinant for interconnection capacity requirements

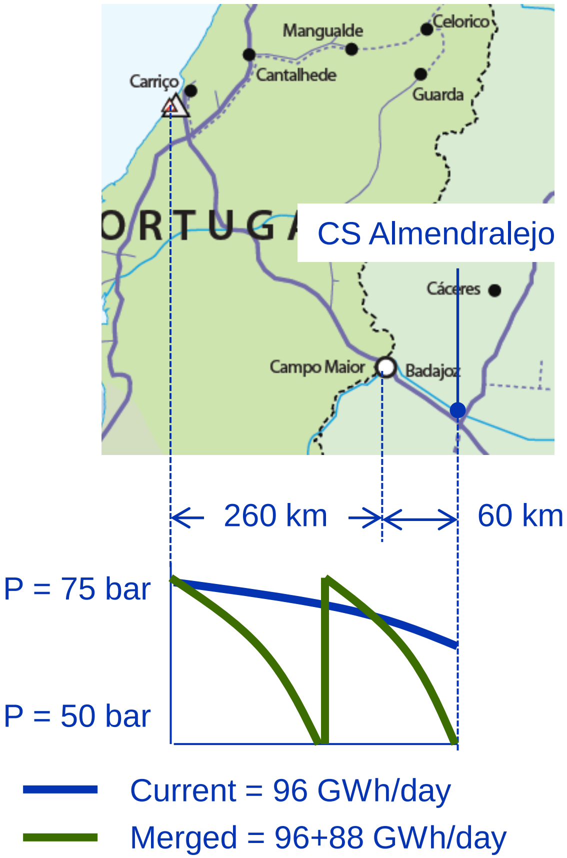


Associated Required Investments

If additional capacity would need to be created, a new compressor station on the pipeline between Carrico/Pombal and Campo Maior/Badajoz could be place

- Flows may increase to 644 dam^3/h (96 + 88 GWh/day) from 336 dam^3/h today
- Pressure drop over Carrico – Campo Maior section will be too high. Additional compression could resolve this problem by increasing pressure
- Compression would need to be located at around halfway between Carrico and Campo Maior
- Approximately 8.8 MW would be required (Q=644 dam^3/h, Δp = 25 bar). This would cost around 23 M€ (2+1)[1]
- Due to exceptional situation in which capacity would be required, <u>other non-investive measures would be more appropriate</u>

INDICATIVE

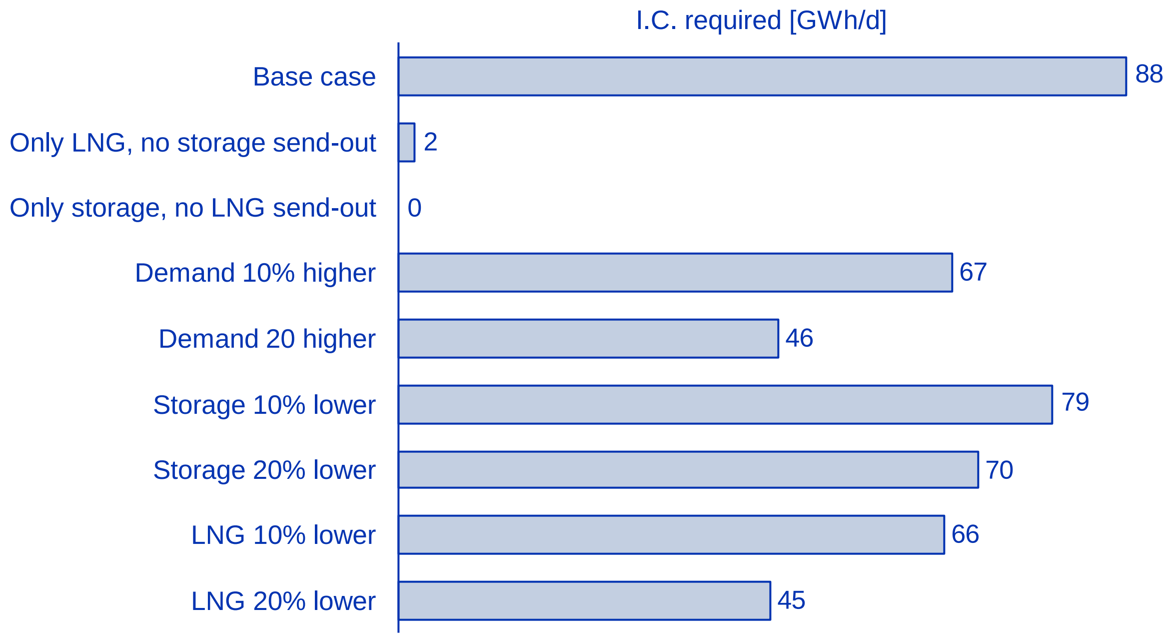


1. BOLETÍN OFICIAL DEL ESTADO, No. 314.

Sensitivity of Results

The outcome of the analysis depends on the assumptions taken. Therefore, a sensitivity analysis was conducted regarding the assumptions for Portugal

- Assumptions regarding the Portuguese market are of only importance and in the direction Portugal to Spain
- Due to exceptional situation in which capacity would be required, <u>other non-investive measures would be more appropriate</u>.



Scenarios – Portugal → Spain

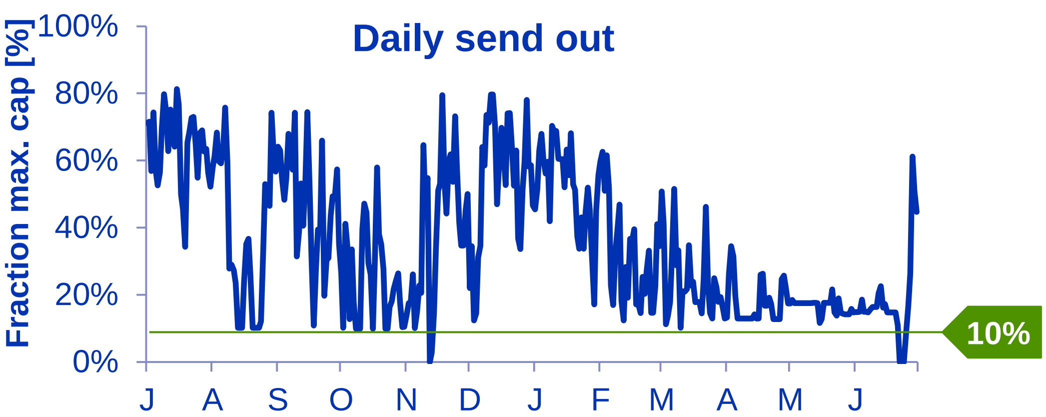
			Technical [GWh/d]	Low demand scenario	High demand scenario
Portugal	LNG send-out		212	80%	10%
	Storage	Withdrawal	86	100%	0%
		Injection	24	0%	100%
	Domestic demand		206	35%	100%
Spain	LNG send-out		1915	25%	100%
	Storage	Withdrawal	138	0%	100%
		Injection	91.6	100%	0%
	Imports	Algeria	266	15%	60%
		Morocco	444	15%	70%
		France	165	0%	100%
	Exports	France	165	10%	0%
	Domestic demand		1643	70%	50%
Existing interconnection capacity				96	96
Needed additional interconnection capacity				88	0

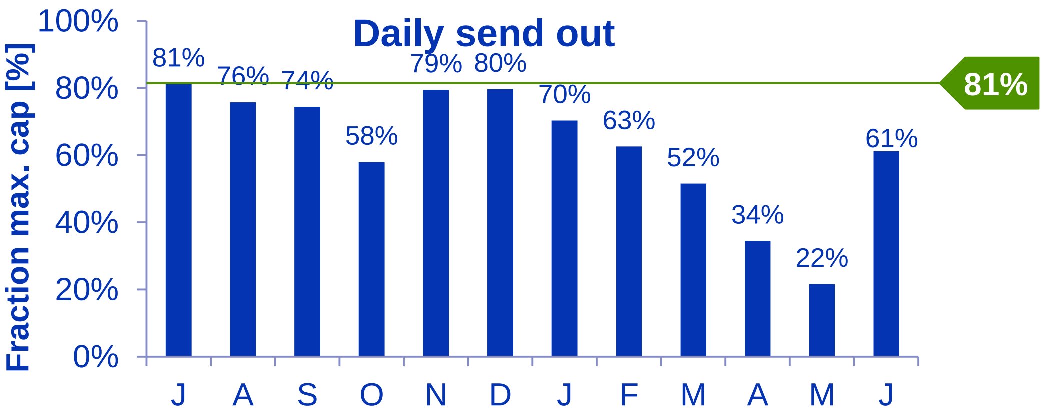
Scenarios – Spain → Portugal

			Technical [GWh/d]	Low demand scenario	High demand scenario
Spain	LNG send-out		1915	80%	25%
	Storage	Withdrawal	138	100%	0%
		Injection	91.6	0%	100%
	Imports	Algeria	266	60%	15%
		Morocco	444	70%	15%
		France	165	100%	0%
	Exports	France	165	0%	10%
	Domestic demand		1643	35%	100%
Portugal	LNG send-out		212	20%	100%
	Storage	Withdrawal	86	0%	100%
		Injection	24	100%	0%
	Domestic demand		206	100%	40%
Existing interconnection capacity				175	175
Needed additional interconnection capacity				13	0

Portugal - LNG

The Sines LNG terminal send out has no seasonal profile. During winter it peaked at 71% of maximum send out capacity and 81% in summer





- Sines LNG terminal, the only one in Portugal, is located on the southern Atlantic coast and is in operation since 2004, it had an increase in capacity in 2012
- Sines supplies approx. 47% of the Portuguese gas market
- Minimum send out from terminal usually around 10% of maximum send out capacity

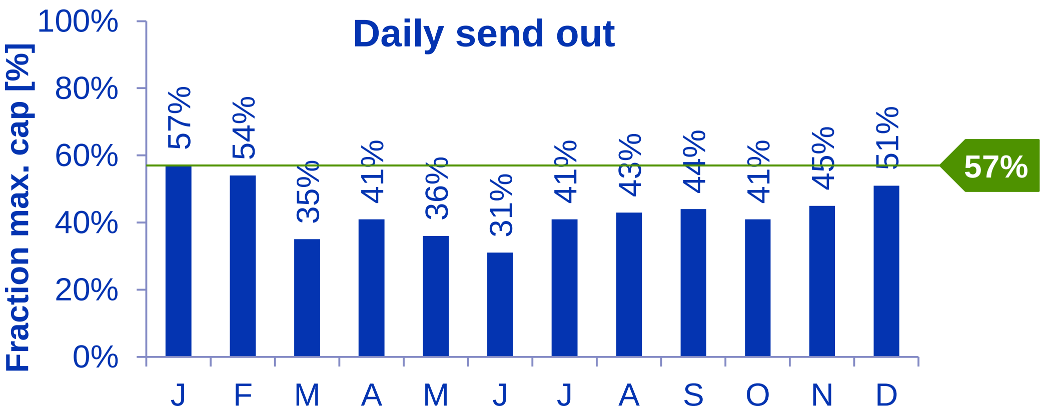
Sines LNG	Value
Storage capacity	2,737 GWh
Nominal send out	212 GWh/d
Min. send out	10 %

Sources: Ren Gasodutos

Spain - LNG

The send out of Spanish LNG terminals has no seasonal profile. During winter it peaked at 57% of maximum send out capacity and 73% in summer

- 72% of Spanish gas demand is supplied by LNG
- Historical maximum send out was (only) 57% in January (2012)
- Minimum send out from Spanish LNG terminals is 491 GWh/d or around 25% of maximum send out capacity



LNG terminal	# tanks	Send-out [GWh/d]
Barcelona	7	544
Cartagena	5	377
Huelva	5	377
Bilbao	2	223
Sagunto	3	279
Murgados	2	115

Total LNG Spain	Value
Storage capacity	46,693 GWh
Nominal send out	1915 GWh/d
Min. send out	491 GWh/d

Sources: Enagas

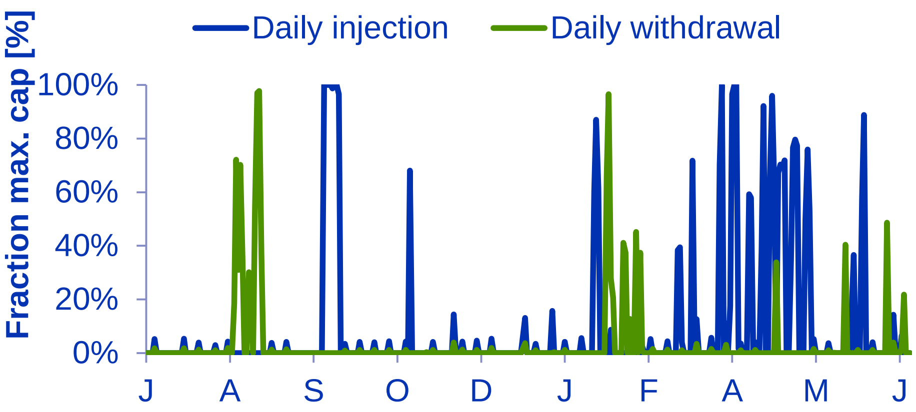
Assumptions about LNG Terminal Send Out

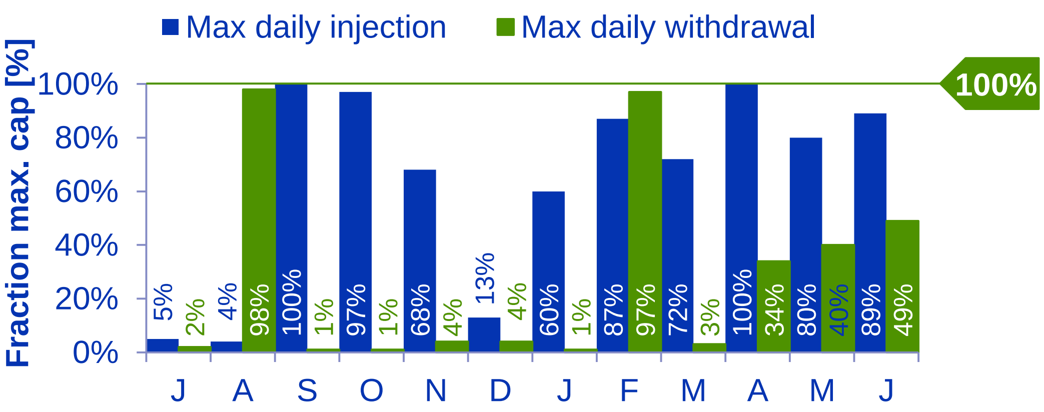
- Portugal:
  - LNG send out does not follow specific seasonality pattern
  - Peak output of 100% nominal send-out seems to be available whenever needed
  - Minimum output is assumed to be 10% of the nominal output

- Spain:
  - Also for Spain LNG output does not follow seasonality
  - Peak output is low throughout the year in reality, thus a maximum of 80% of nominal send-out is assumed to be available when needed
  - Minimum output is approximately 25% of the nominal output

Portugal - Storage

The Carriço storage has no clear seasonal profile. During winter it peaked at 97% of maximum send out capacity and the injection maxed in Autumn/Spring





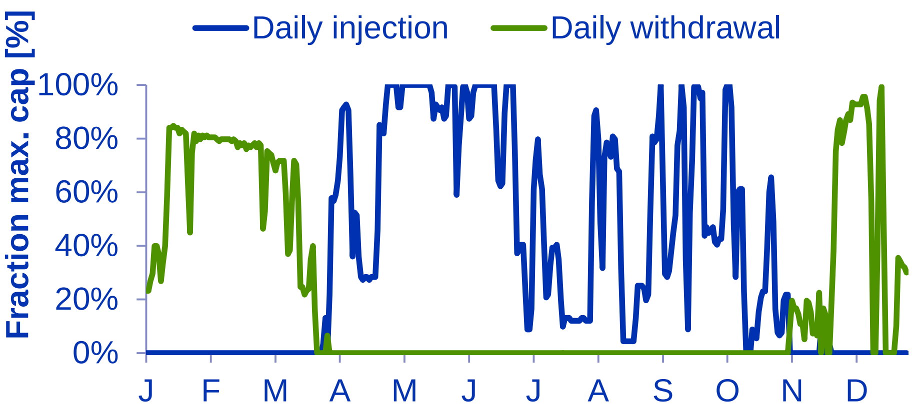
- Portugal has one underground natural gas storage facility, Carriço. It consists of four underground caverns
- Highest withdrawal loads:
  - During winter (February): 97% (83.4 GWh/d)
  - During summer (August): 98% (84.3 GWh/d)
- The highest injection loads in September & April of 100% (24 GWh/d)

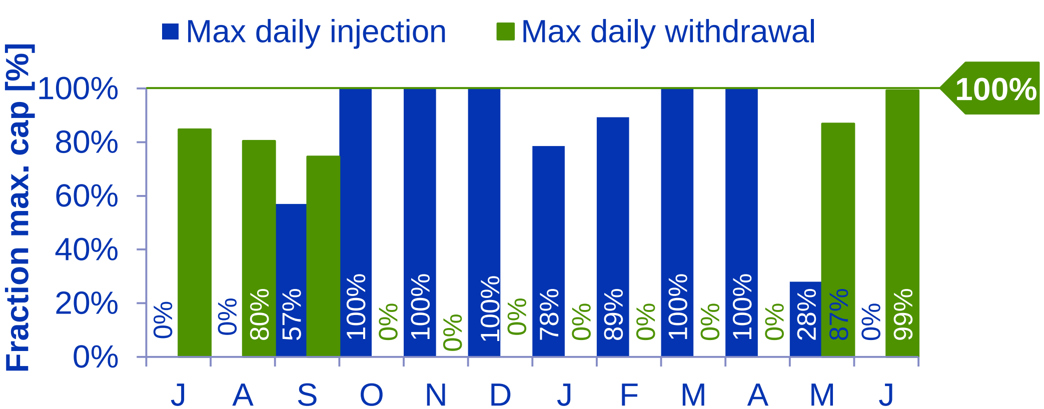
Carriço	Value
Storage capacity	2100 GWh
Maximum withdrawal	86 GWh/d
Maximum Injection	24 GWh/d

Sources: Ren Gasodutos

Spain - Storage

Storage in Spain follows seasonality by withdrawing during winter and injection in other periods. It has both used 100% injection and withdrawal capacity





- Underground storages in Spain meet 6% of domestic demand and have historically been a scarce resource with limited withdrawal capacity
- New capacity has been commissioned in 2012 and additional storage capacity will come online in 2013

Storage	WGV GWh	Inject GWh/d	Withdraw GWh/d
Serrablo	9,045	42	75
Gaviota	14,846	49.6	63
Yela ('12)	9,725	107	161
Marismas ('12)	735	38	47
Castor ('13)	2,135	86	269
Total		323	615

Sources: Enagas, energy-regulators.eu

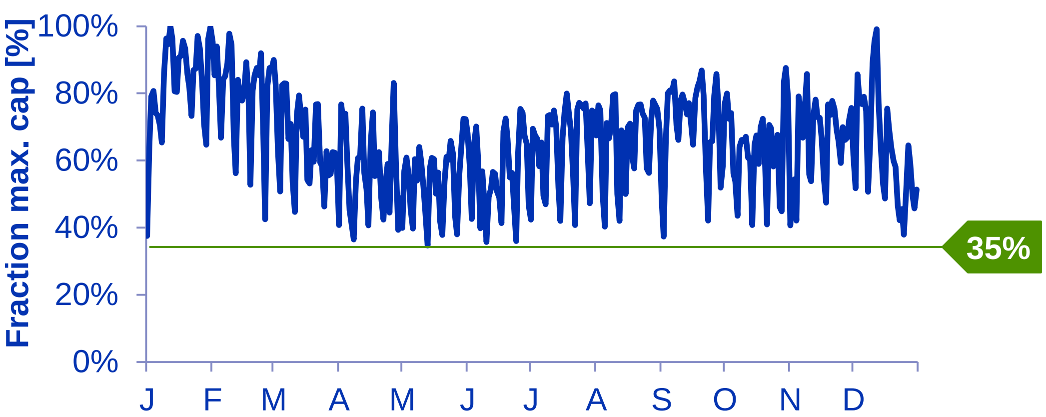
Assumptions about Storage Use

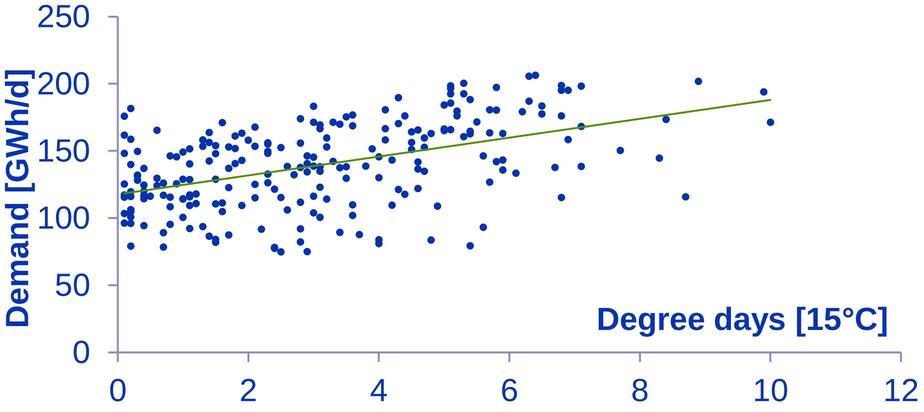
- Portugal:
  - Storage injection and withdrawal do not seem to follow seasonality
  - Both peak withdrawal and injection capacity are available when needed
  - Also, minimum usage of storage can take place at any time during the year

- Spain:
  - Storage injection and withdrawal seem to clearly follow a seasonal pattern
  - Withdrawal is not possible from April to November; however during this period, we assume it can be used at both maximum withdrawal rate or minimum
  - Injection only occurs during Spring and Summer (May up to and including October). Again, the assumption is that it can be used at 100% or 0% of maximum injection capacity

Portugal - Demand

Demand in Portugal follows seasonality with an increase during the coldest months and peaking in January at 100%, it is lowest in spring at 35%



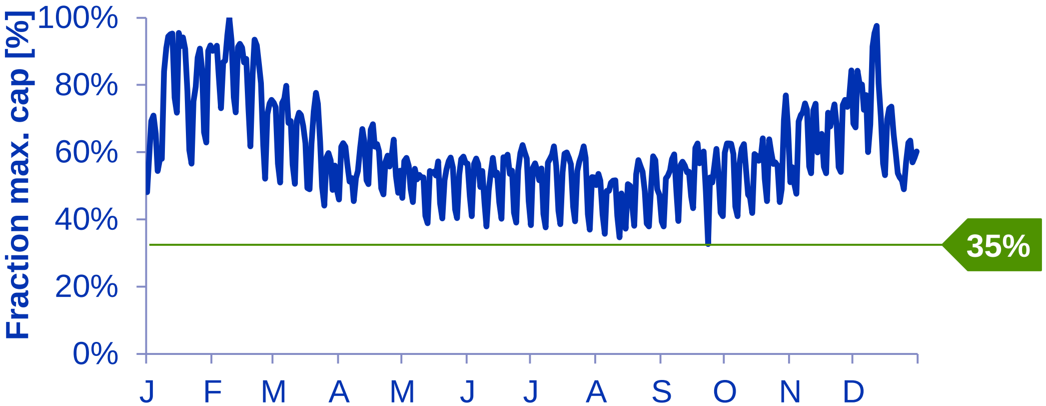


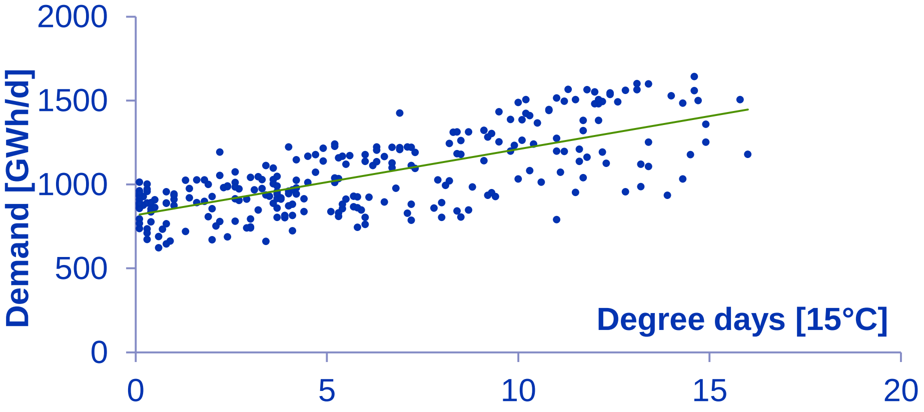
- In Portugal, 75% of natural gas is consumed by large customers, 15% is consumed by industries and 10% is consumed by residential customers
- For Portugal there are a peak demand of 206 GWh/d in winter and the lowest demand of 72 GWh/d in spring
- Demand shows direct correlation with degree days for heating, thus follows seasonality and is inversely correlated with temperature

Sources: Ren Gasodutos, energy-regulators.eu, degreedays.net

Spain - Demand

Demand in Spain is seasonal as well; the peak occurred in January at 100% as in Portugal





- Most of the demand is located in the area of Madrid and the Eastern part of Spain
- Energy consumption is divided as follows: 14% households/commercial, 55% Industrial, 30% energy generation, 1% other
- Spain had a peak demand of 1,643 GWh/d in winter and the lowest demand of 739 GWh/d occurred in autumn
- Demand shows high direct correlation with degree days for heating, thus follows seasonality and is inversely correlated with temperature

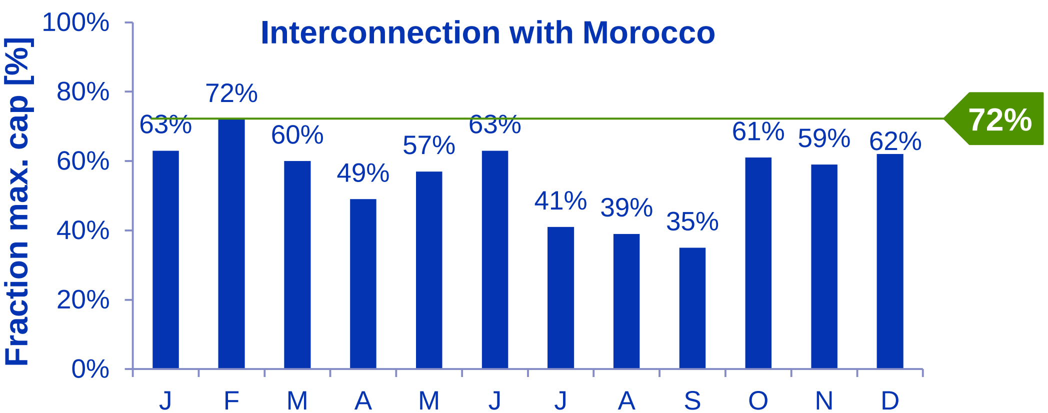
Sources: Enagas, energy-regulators.eu, degreedays.net

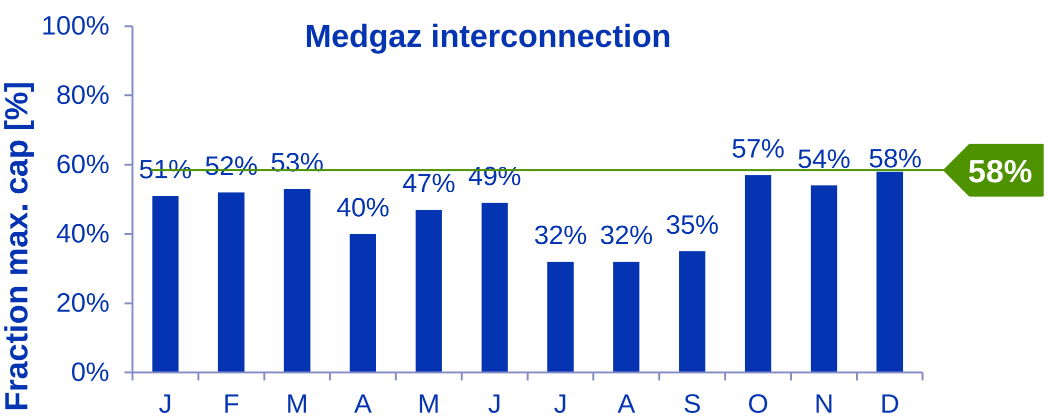
Assumptions about Domestic Demand

- Portugal: Portugal to Spain direction
  - Low demand scenario: 35% of maximum demand is taken
  - High demand scenario: 100% of maximum demand is taken
- Portugal: Spain to Portugal direction
  - Low demand scenario: 100% of maximum demand is taken as it requires high values of Portuguese exit points and in September, when Spain has the lowest domestic demand, Portugal has a high domestic demand of 90%
  - High demand scenario: highest demand in Spain is in winter. The lowest possible Portuguese exit flows are used in this analysis; therefore the winter demand in Portugal is taken for the analysis (40%)
- Spain: Portugal to Spain direction
  - Low demand scenario: lowest demand in Portugal occurred in spring. The highest possible Spanish exit flows are used; therefore the highest spring demand in Spain is taken for the analysis (70%)
  - High demand scenario: the highest demand in Portugal is in winter. The lowest possible Spanish exit flows are required for this analysis; thus the lowest winter demand in Spain is used (50%)
- Spain: Spain to Portugal direction
  - For the low demand scenario: 35% of maximum demand is taken, as it is the lowest daily demand observed
  - For the high demand scenario: 100% of maximum demand is taken

Spain – Imports from Algeria

Imports from Algeria show some seasonality. At Tarifa, loads ranging from 72% to 13% of firm capacity occur. For Medgaz, this is 58% to 15%





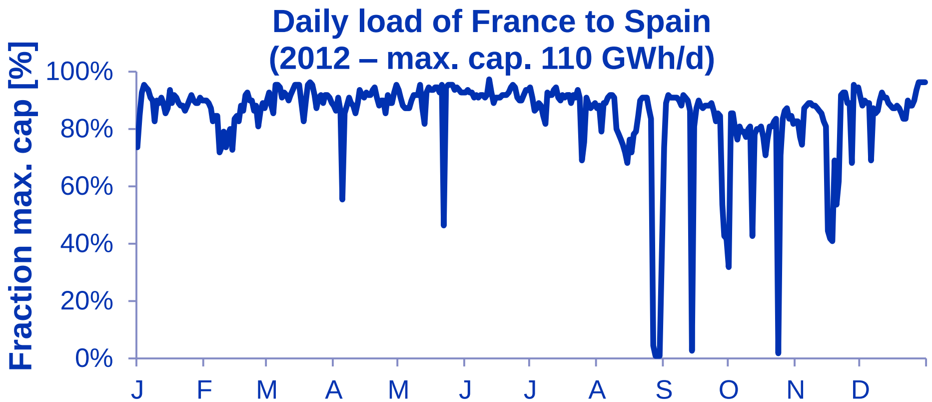
- Algeria is the largest gas supplier for Spain taking up 38% of the total gas supply
- The interconnection point at Tarifa which supplies 14% of gas brings it from Algeria by transiting it through Morocco
- The Almeria interconnection point supplies 10% of total gas in Spain via the Medgaz pipeline directly from Algeria

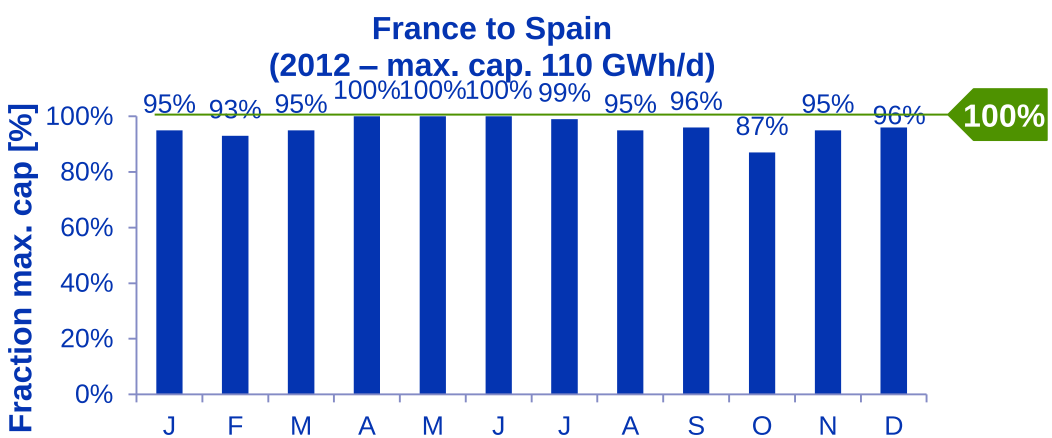
From Algeria	Capacity [GWh/d]
From Morocco	444
Medgaz	266

Sources: Enagas

Spain – Interconnection with France

Flows from France to Spain are volatile with no seasonal pattern, whereas flows from Spain to France have not been observed





- Four per cent of gas supplied to Spain comes from France
- Bidirectional flow is offered at both of the interconnections of 165 GWh/d (as of 2013)
- The load shows high volatility but monthly highs are quite stable in the France to Spain direction
- Despite possibility to flow gas in the Spain to France direction, no actual flow observed throughout the year

Point	France to Spain tech cap	Spain to France tech cap
Total	165 GWh/d	165 GWh/d

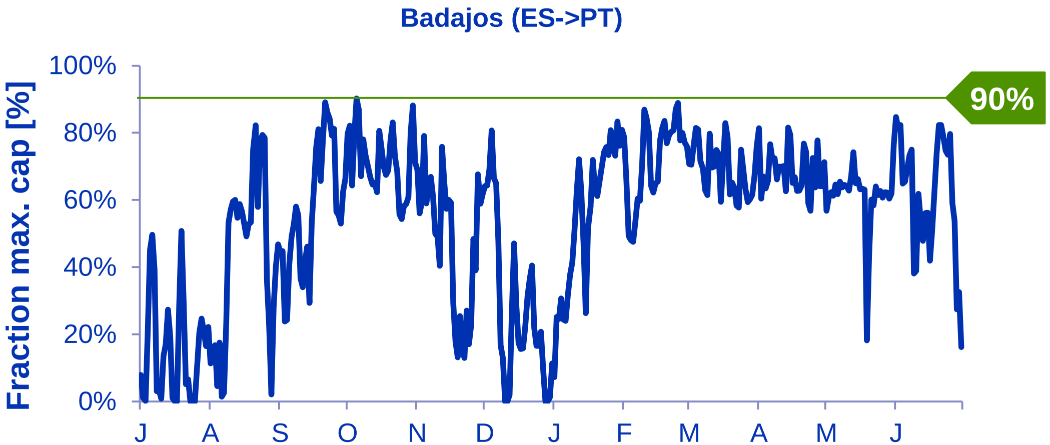
Sources: Enagas, energy-regulators.eu

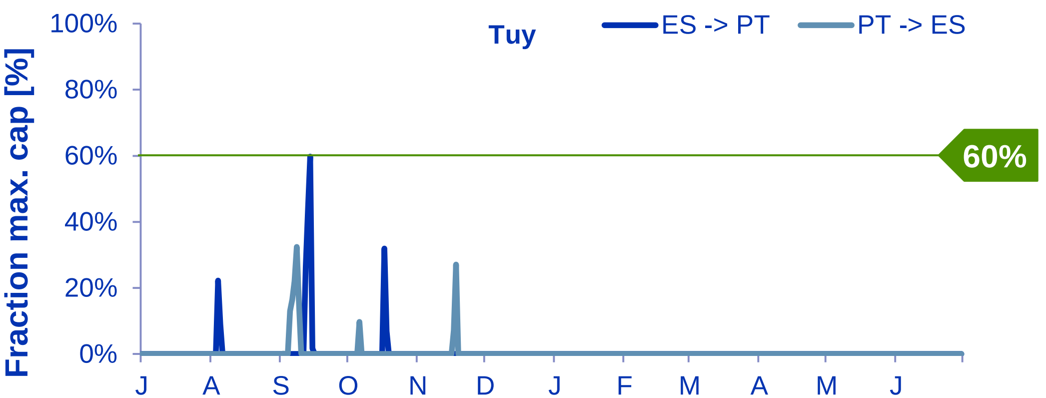
Assumptions about Interconnections with Algeria and France

- Spanish imports from Algeria:
  - Import flows do not seem to follow seasonality
  - A maximum of 60% technical capacity is available via the Medgaz pipeline and 70% of firm capacity is available via Morocco whenever it seems to be required
  - A minimum of 15% technical capacity is available via the Medgaz pipeline and 15% of firm capacity is available via Morocco when needed
- Spanish interconnection with France:
  - Import or export flows do clearly not follow a seasonal pattern
  - For the France to Spain direction, both maximum and minimum utilization may occur at any time during the year
  - For the Spain to France direction, based on the analysis above we assume an export flow of 10% the maximum capacity

Existing Interconnection between PT and ES

High loads during autumn and spring; however only significant flows from Spain to Portugal





- At Badajos highest load occurred during Autumn and Spring from Spain to Portugal. No flows from Portugal to Spain
- At Tuy, loads of up to 60% from Spain to Portugal and up to 30% in the other direction very rare occur

Point		Capacity [GWh/d]
Badajos	PT->ES	70
	ES->PT	134
Tuy	PT->ES	25
	ES->PT	41
Total	PT->ES	95
	ES->PT	175

Sources: National Grid, GasLink

Spain – Portugal Market Integration

Benefit assessment

Approach to Assessing Benefits

A. Benefits from Enhancement of Competition

- Starting from oligopolistic competition and assuming that additional price reduction is possible due to stronger competition
- Estimated benefits: negligible

B. Integration Benefits

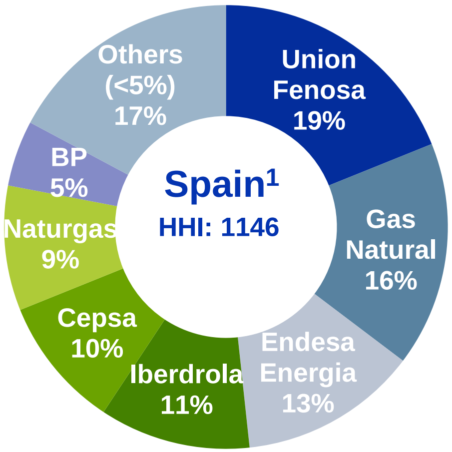
- Due to integrating two markets, access to other and potentially cheaper sources of supply is possible resulting in an overall reduction in price
- Estimated benefits: 5 M€/annum

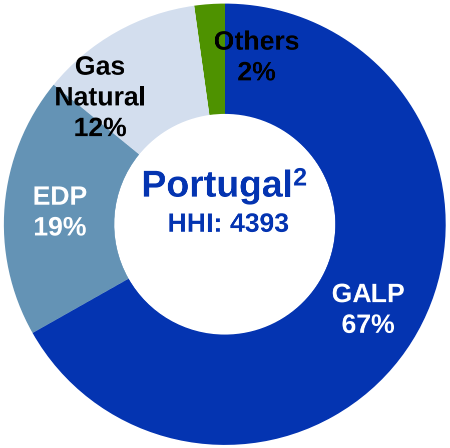
- Benefits are assessed from a consumers’ perspective

Benefits from Enhancement of Competition

Starting from oligopolistic competition and assuming that additional price reduction is possible due to stronger competition

- Spanish gas market has a relatively low HHI indicating workable competition (<2,000). Portuguese gas market is still concentrated and has two large players
- Benefits from increased competition after market area integration may be expected
- After merging, the market share of largest player in Portugal would drop from 67% to 8.3%
- Given Spain's low HHI and the size of its market, the HHI of integrated market would presumably drop as well





Sources: CNE, ERSE
1. Spain: market shares in OTC market 2011
2. Portugal: market shares of suppliers December 2011

Considerations of Cournot Approach

Several assumptions are required for applying in the Cournot model to the integration of Spain and Portugal

- Largest firm is regarded as price setter and marginal cost of this firm is determined by the most expensive supply including transmission cost and estimated retail margin
- ERSE mentioned that GALP and EDP are already heavily competing with each other
- Assumes single price for all industrial users, whereas currently this is bilaterally negotiated
- Only applied to Portugal and high pressure customers using industrial prices
- The approach takes a consumers' viewpoint and neglects the effects at the producers side
- Provided the relatively small Portuguese market, assuming Spanish prices may be just as justified
- As the approach is quite simplistic, the results are only indicative. The results should not be interpreted as an outcome of a fully-fledged competition analysis

Approach to Assessing Benefits from Enhancement of Competition

We use a Cournot competition model in order to assess the possible reduction in price due to increased competition after market integration

Inputs

- **Import prices PT**
- **Market shares ES-PT**
- **Industrial prices PT**
- **Monthly gas volumes**
- **Price elasticity of demand**

Calculate gas price after integration
- Based on new market shares
- Using price elasticity of demand
- Monthly basis

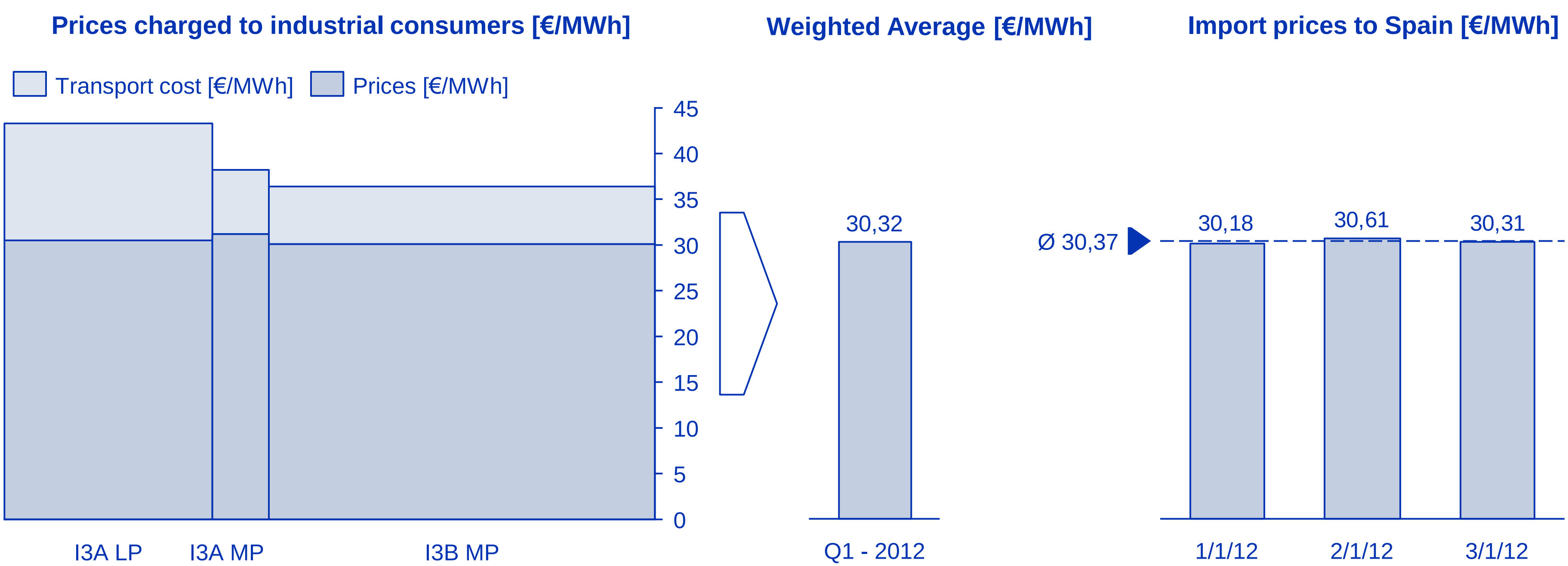
Calculate total benefits
- Calculate differences with current gas prices
- Multiply by volumes consumed in industrial market

- Main assumptions:
  - Under Cournot competition: two or more firms decide how much they want to produce in order to optimize profits
  - Increased competition (reduced market shares) should result in reduced prices
- Cournot model: $[P – MC_i] / P = s_i / \varepsilon$.
  - P = gas price
  - MC_i = marginal cost of firm i
  - s_i = market share of firm i
  - ε = price elasticity of demand
- Elasticity:
  - Boots et al. use elasticities between 1.4 (residential) – 2.2 (power generation). We assume 1.4 for Portuguese medium pressure industrial demand (10,000 GJ < demand > 100,000 GJ)

Price and Marginal Cost of Gas Supply

Benefits from a reduction in rents seem to be negligible as prices charged to consumers do not seem to be excessively high but rather low

- No conclusion concerning margins applied by the gas suppliers in the Portuguese markets may be drawn given the available data
- Prices charged to industrial consumers are inline with Spanish pipeline import prices



Sources: CNE, ERSE

Market Model for Assessing Benefits of Market Integration

Technical & Commercial inputs

LNG imports:
- Prices
- ACQ
- Pirce spreads

Pipe imports:
- Prices
- ACQ
- ToP penalties

Storage:
- Working gas volumes
- Injection / withdrawal capacity
- Tariffs

Infrastructure:
- I.C. capacity and price
- Import pipeline capacity
- LNG send-out

Demand:
- Daily gas demand

Gas Market Model

Cost minimization based on linear programming

Outputs

Supply of piped gas & LNG
- Volumes
- By source

Costs/prices
- Cost of supply
- Costs of storage use
- Opportunity costs

Storage utilization
- Daily injection and withdrawal volumes
- Storage inventory levels

Flows
- Import flows
- Interconnection flows
- LNG send out

Market Model for Assessing Benefits of Market Integration

A comparison is made between an “Status Quo” case and an “Integrated Market” case

- The model assumes perfect competition; no potential benefits from increased competition are thus assessed in the model (compare previous method)
- For a fair comparison, two situations are calculated: the current situation (“status quo”) and an integrated market. No comparison with historic or actual values is made
- Overall costs are minimized. The following are taken into account. Benefits may be found in these same areas:
  - Lower costs of supply
  - Reduced storage costs
  - Reduction in opportunity costs
- Potential reduction of I.C. costs not considered → full revenue recovery by regulated entities

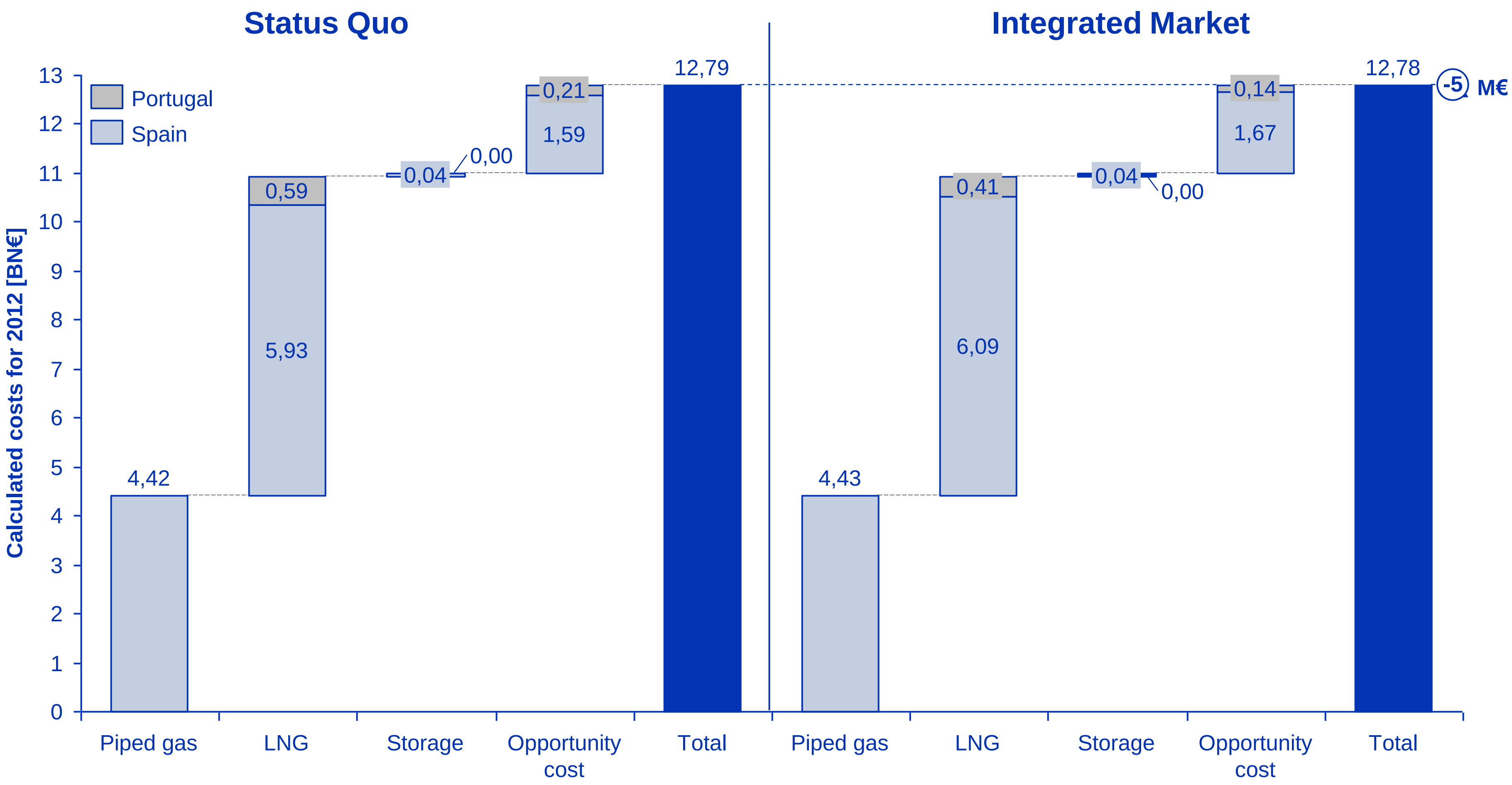
Cases Used for Assessing Benefits

A comparison is made between an "Status Quo" case and an "Integrated Market" case

Status Quo	Integrated Market
• Interconnection costs of 2.5 €/MWh between Spain and Portugal	• No interconnection costs
• 'Restricted' interconnection capacity	• No constraints on interconnection capacity
• Contracts between supplying countries should be adhered to	• Supply to Iberian Peninsula instead of Spain and Portugal particularly

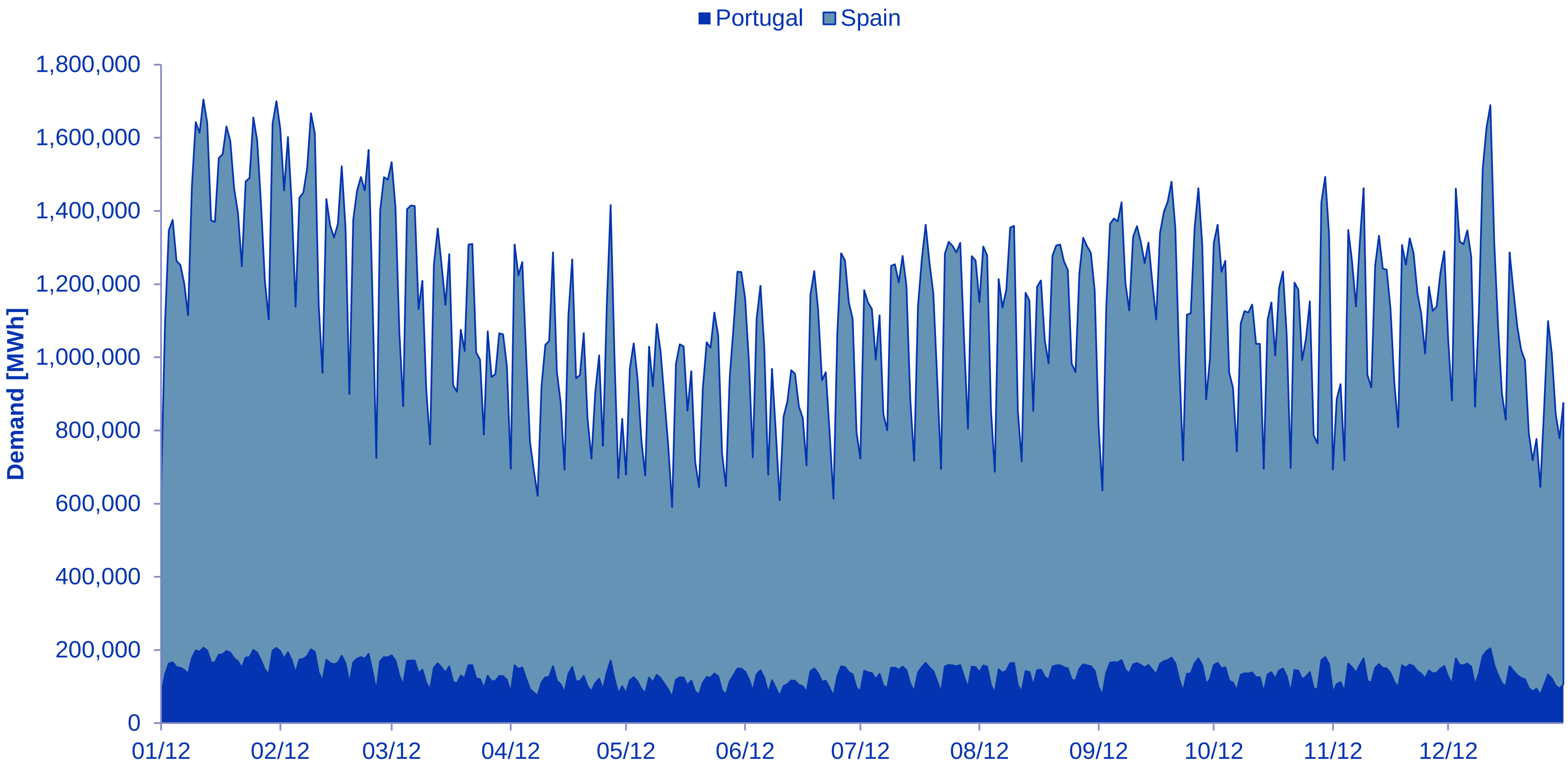
Main Results

The benefits of 5 M€/annum, as calculated by the model, are relatively small compared to the total size of the market



Daily Gas Demand in Spain and Portugal

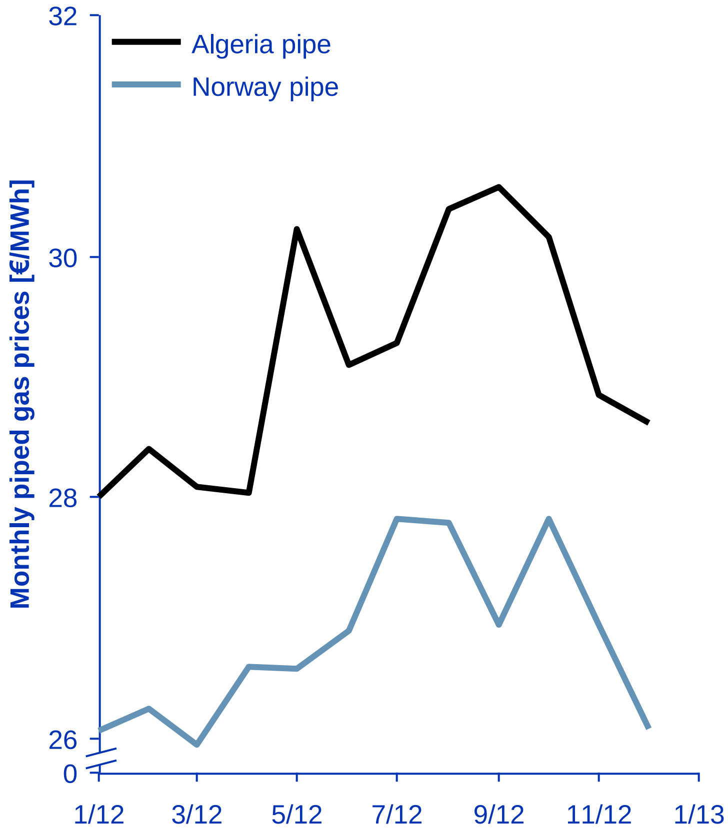
Historic daily demand for 2012 has been included in the model. The model will always supply as much as required by the consumers

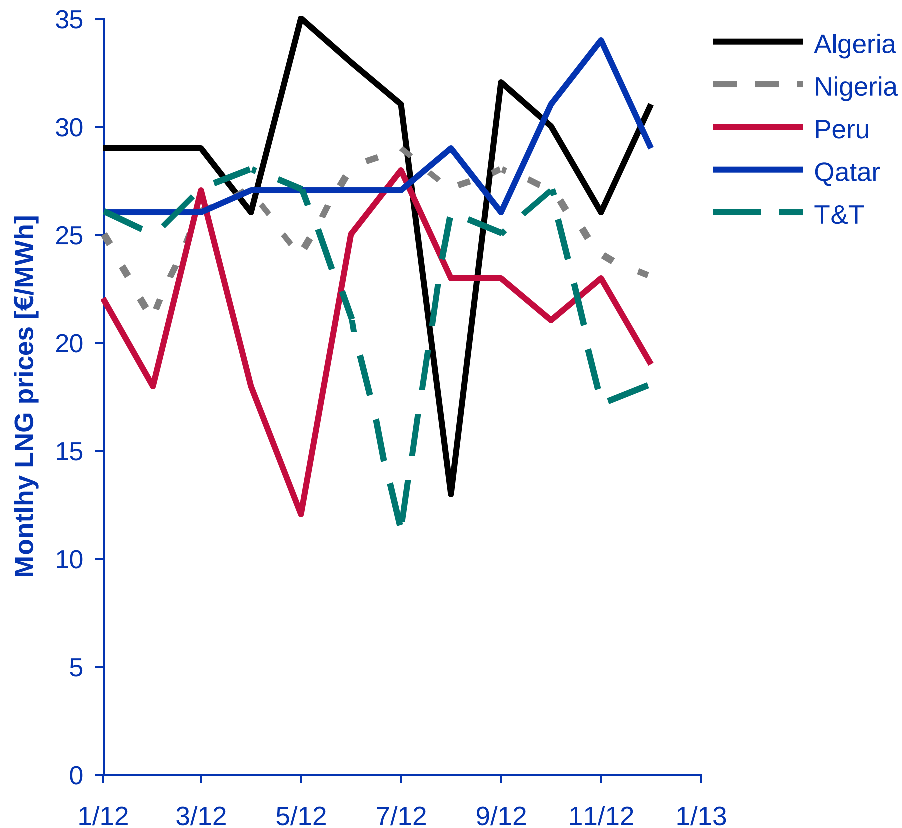


Sources: ENAGAS, REN

Import Prices to Spain

Import prices for piped gas to Spain and LNG to Portugal and Spain. The model endogenously calculates the flows from Spain to Portugal and vice versa

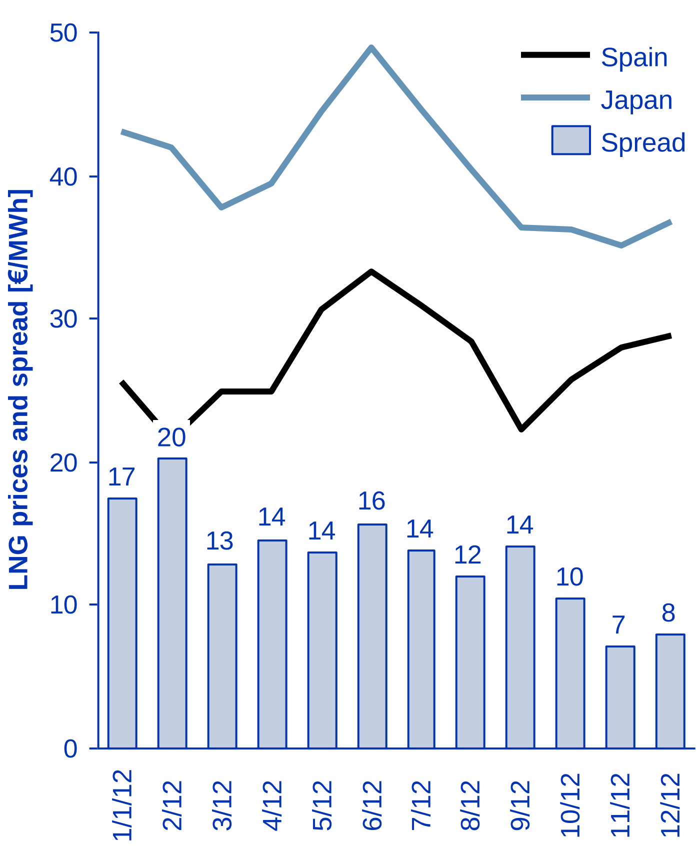


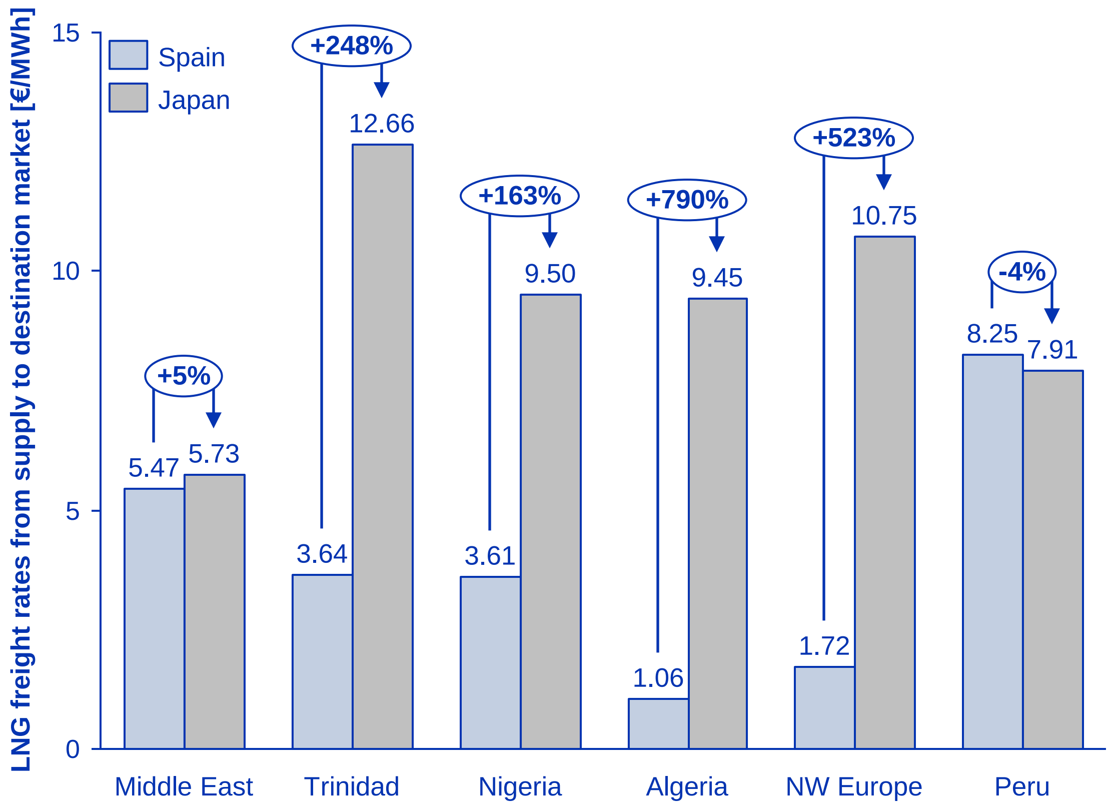


Sources: EUROSTAT COMEXT
Subset of actual LNG suppliers. Other supplier excluded for clarity

LNG Spreads and Freight Rates

LNG spreads with Japan and freight rates are included in order to take into account opportunity costs of LNG supplied to Spain or Portugal





Sources: FERC, Platts LNG Daily, CNE

Contracted Quantities and Limitations

Annual volumes from suppliers should be at least equal to the minimum ACQ. Maximum volumes are capped at 115% of the ACQ.

Type	Supplier	Importer	ACQ		Min. ACQ	Max. ACQ
LNG	Algeria	Spain	2.67	MT/year	50%	115%
	Egypt	Spain	4.3	MT/year	50%	115%
	Nigeria	Spain	3.46	MT/year	50%	115%
	Norway	Spain	1.13	MT/year	50%	115%
	T&T	Spain	1.83	MT/year	50%	115%
	Qatar	Spain	2.81	MT/year	50%	115%
	Nigeria	Portugal	2.48	MT/year	50%	115%
Pipe	Algeria	Spain	9	BCM	65%	115%
	Norway	Spain	1.8	BCM	65%	115%
	Algeria	Portugal	2.3	BCM	65%	115%

Minimum and maximum constraint. Supply needs to be between these thresholds

Sources: GIIGNL, ERSE, DNV KEMA estimations

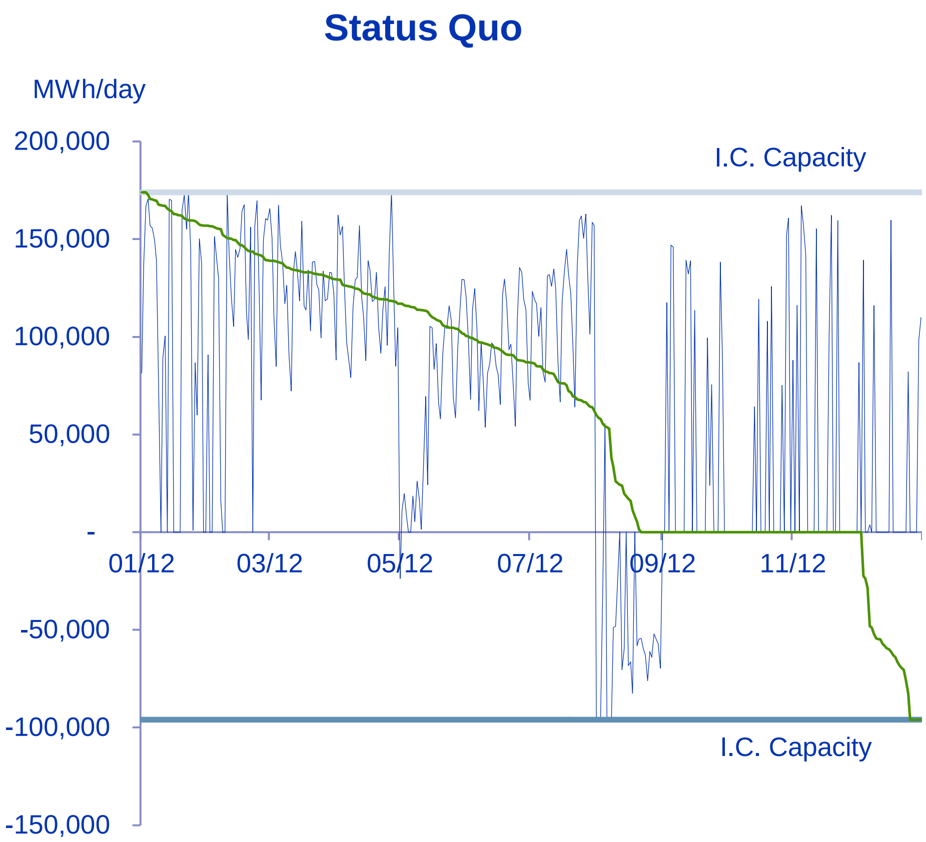
Storage

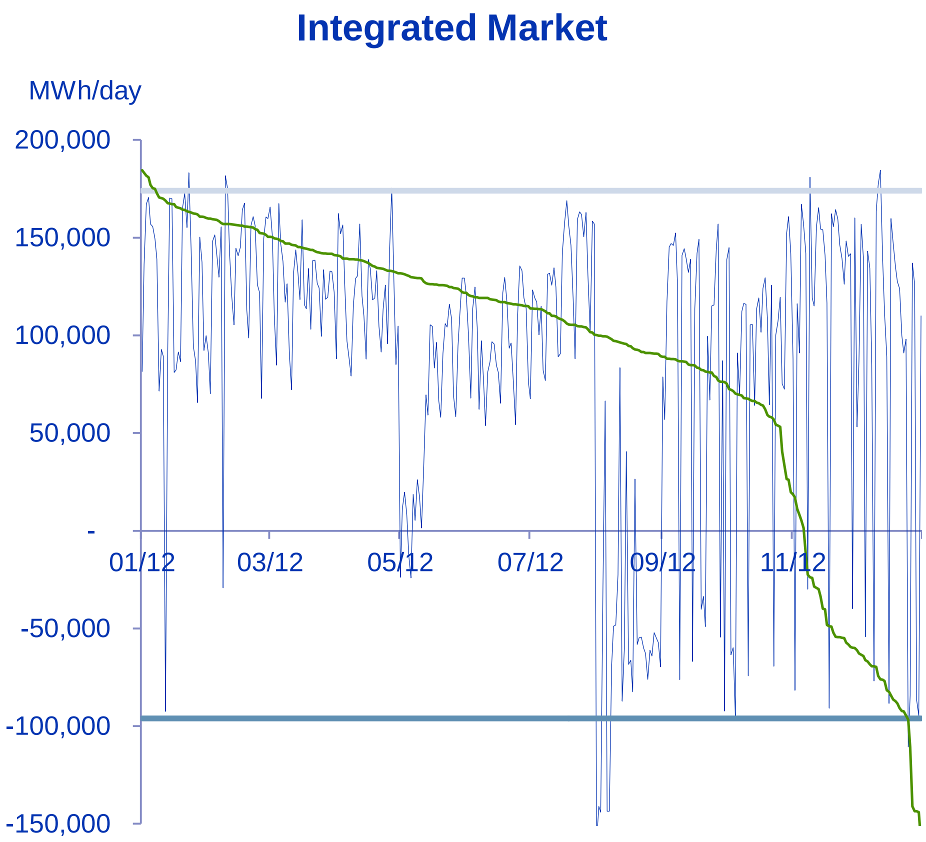
The model calculates the optimal (minimum total cost) storage injection and withdrawal strategies. Storage volume at start and end of year are half of WGV

	Technical constraints			Storage costs		
Country	**Volume**	**Withdrawal**	**Injection**	**Fixed**	**Injection**	**Withdrawal**
	MWh	MWh/day	MWh/day	€/MWh/day	€/MWh	€/MWh
Portugal	2,100,000	86,000	24,000	0.02899	0.20619	0.20619
Spain	23,891,000	138,000	91,600	0.01348	0.24400	0.13100

Sources: ENTSOG,ERSE, CNE

Interconnection Flows



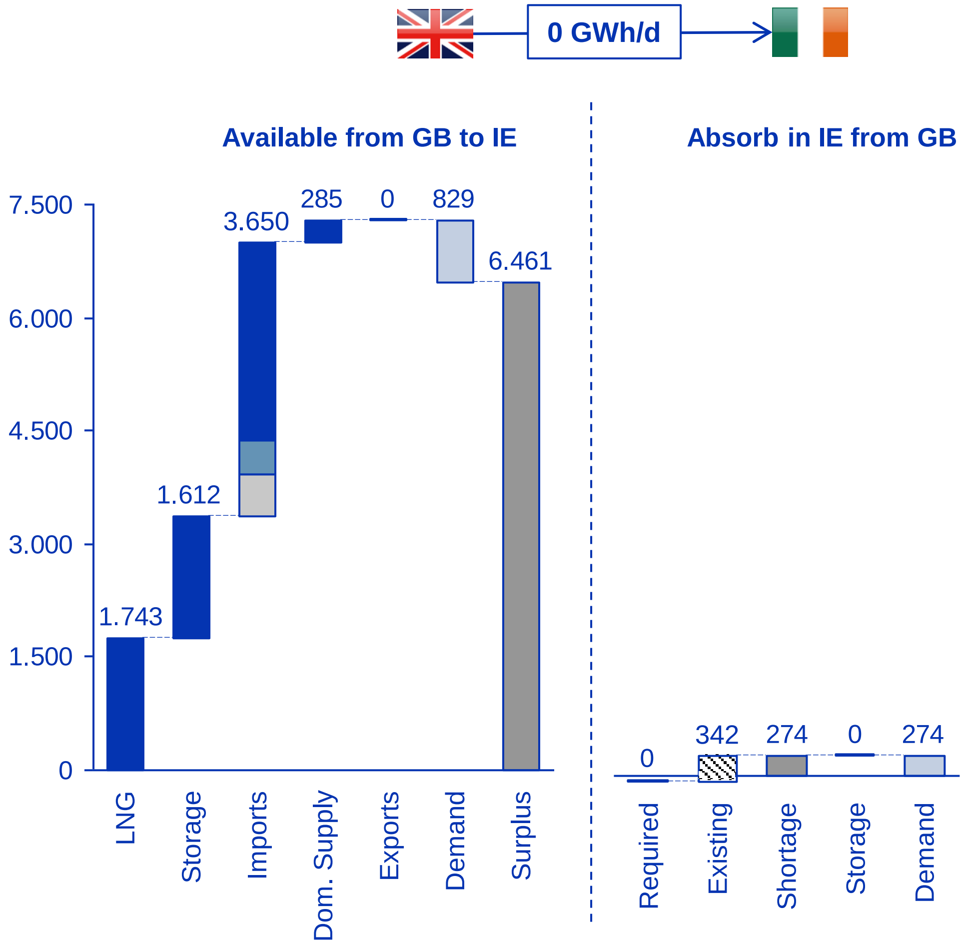


Republic of Ireland, Northern Ireland & GB – Market Integration

Cost Analysis

Summary of Interconnection Capacity Requirements

Only the assumptions with regard to the Irish gas markets and flows are of importance for the required interconnection capacity



- GB's market is much larger compared to the Irish market. Therefore, we assume that there is always sufficient gas available to flow to the Irish market
- Irish situation is therefore determinant for the interconnection capacity required
- Existing interconnection capacity is higher than the maximum observed demand in 2012 in the island of Ireland. Therefore no additional interconnection capacity required

Outlook into the Near Future

In 2017/18, supplies from RoI/NI to GB could be physically possible leading to potential investments of >200M€.

- Potential supply in RoI/NI in 2017/2018 could be 4.4 mscmd (48 GWh/day) larger than minimum demand, resulting in export possibilities from RoI/NI to GB
- Primary issues:
  - differences in odorization practices
  - physical reverse flow in interconnector system
- The table below gives a high level cost estimate in order to resolve these issues.

Project	Cost (M€)
Onshore compression on the island of Ireland	90
Install odorization in Ireland	25/21*
Deodorization plant at Moffat	50/51*
Reinforcement of pipelines transporting gas west to east in Ireland	45
Reconfiguration costs at Moffat AGI	17
Twynholm AGI bi-directional modifications	4
Total	231

* DNV KEMA estimate
Sources: National Grid, GasLink

Scenarios – GB → Ireland & Northern Ireland

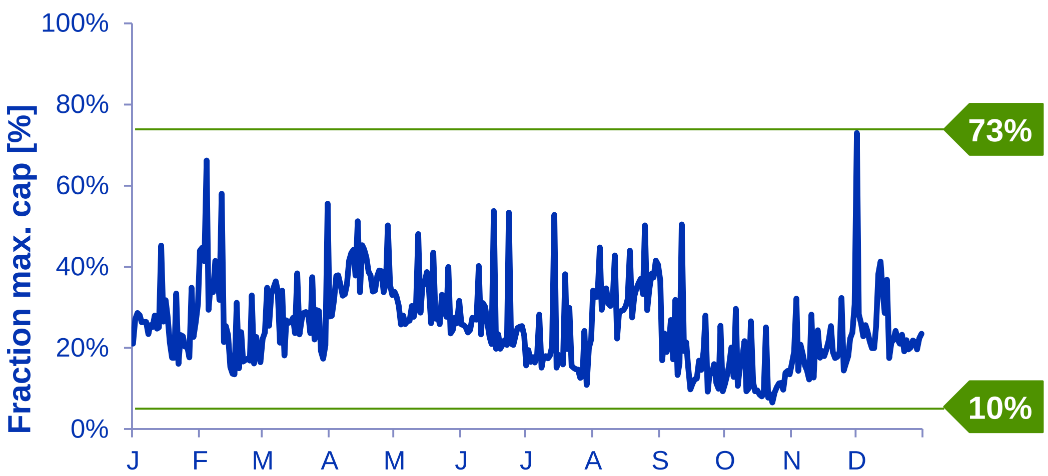
				Technical [GWh/d]	Low demand scenario	High demand scenario
GB	LNG send-out			2179	80%	10%
	Storage	Withdrawal		1612	100%	0%
		Injection		993	0%	100%
	Imports	Via St. Fergus		1375	80%	20%
		Via Easington		1084	90%	10%
		Bacton	Interconnector	805	70%	0%
			BBL	449	100%	0%
			Other	624	90%	20%
	Domestic supply			1427	20%	5%
	Exports	Bacton Interconnector		636	0%	90%
	Domestic demand			4154	20%	100%
Irelands	Domestic supply			63	0%	100%
	Domestic demand			274	100%	70%
Existing interconnection capacity					342	342
Needed additional interconnection capacity					0	0

UK (GB only) - LNG

The send out of GB's LNG terminals has no seasonal profile. During winter it peaked at 73% of maximum send out capacity

- 25% of GB's gas demand is supplied by LNG
- Historical maximum send out was 73% in February (2012)
- Minimum send out from GB's LNG terminals is 220 GWh/d or around 10% of maximum send out capacity

LNG terminal	# tanks	Send-out [GWh/d]
Isle of Grain	4	700
South Hook & Dragon	7	950
Teesside	1	529



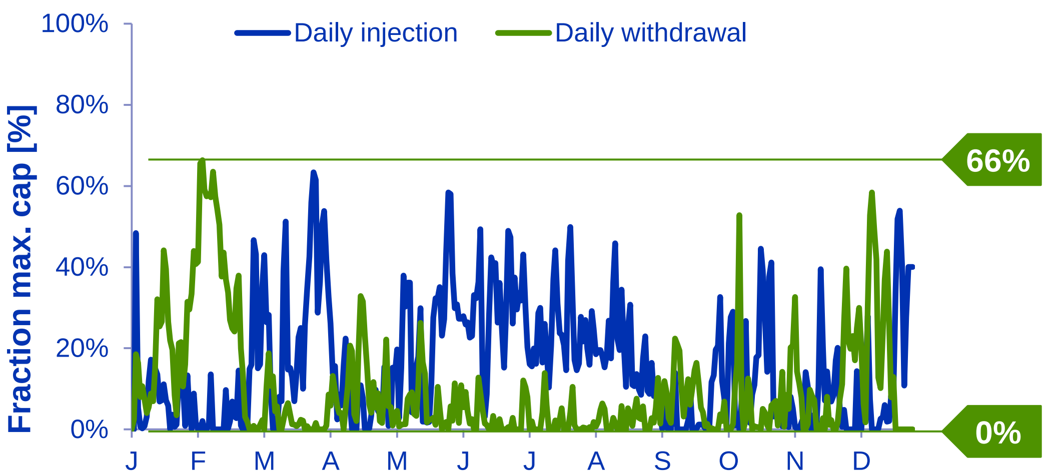
Total LNG UK	Capacity
Storage capacity	2.2 mln m³
Nominal send out	2,179 GWh/d
Min. send out	200 GWh/d

Sources: National Grid

UK (GB only) - Storage

Storage does not follow seasonality. During winter withdrawal peaked at 60% of maximum capacity; for each single storages ranges from 0% to 100%

- UGS's can meet 39% of domestic demand
- Storages are privately owned and do not follow seasonality, operation being based on commercial needs
- Although total loads are up to 60%, analyzing storages one by one shows loads from 0% to 100%



Storage	Volume	Inject-ion	With-drawal
Rough	35,580	279	485
Hornsea	3,666	27	203
Humbly Grove	3,158	83	107
Holford	1,804	248	248
Aldbrough	1,297	200	260
Hatfield Moor	1,276	31	26.5
Avonmouth	912	4.6	162
Hole House Farm	846	120	120
Total	48,539	992.6	1611.5

Sources: National Grid

Scenario assumptions about LNG terminals and storage

- GB LNG:
  - The LNG output does not follow seasonality
  - A maximum of 80% of nominal send-out is available when needed
  - Minimum output is 10% of the nominal output and is available when according to the scenario low GB entry point capacities are needed

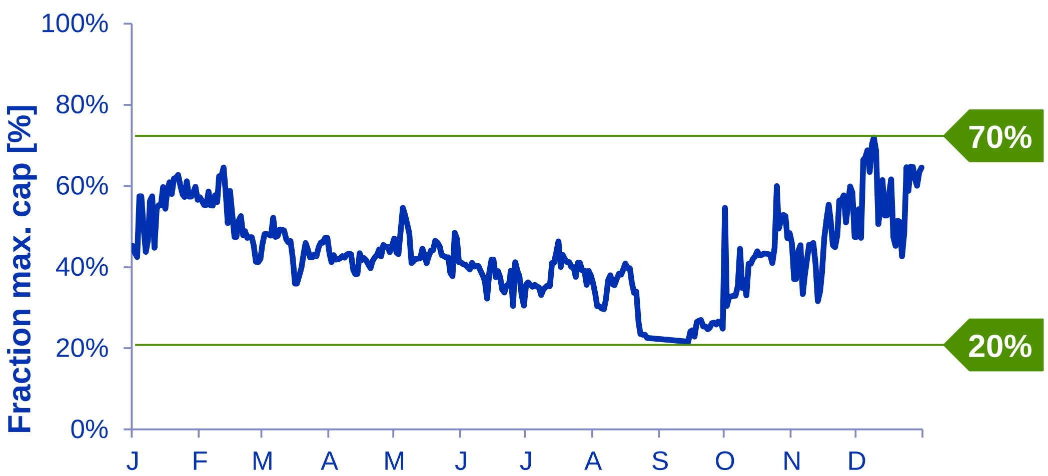
- GB Storage:
  - Storage injection and withdrawal do not follow seasonality and can be used upon need
  - As such, peak withdrawal may be used when needed and as no seasonality constraints are applied
  - Injection capacity is treated similar and may be used at any time if required

UK (GB only) – Imports at St. Fergus

The terminal has an inverse load correlation with temperature, peaking in winter. Maximum load was 70% in winter and minimum load of 20% in summer.

- Imports gas from Norway as well as over 20 North Sea gas fields
- There are 4 gas plants in operation
- The point provides for around 20% of GB's gas demands

- The gas flows from St. Fergus seem to be correlated to temperature, having highest loads in winter
- Highest load is 70% in winter
- Lowest load is 20% at the end of summer



St. Fergus	Capacity [GWh/d]
Nominal capacity	1375
Minimum capacity	275

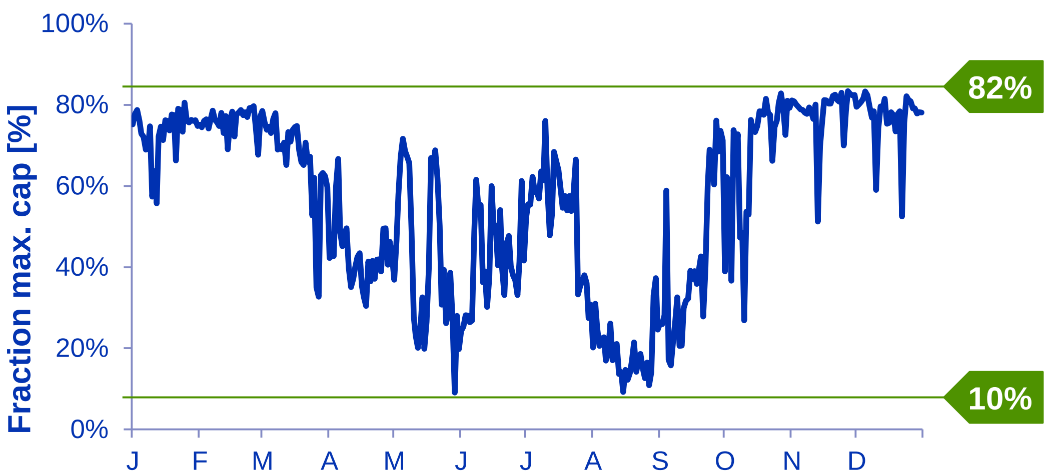
Sources: National Grid

UK (GB only) – Imports by Easington

The terminal does not show clear load correlation with temperature. The maximum load of 82% in winter and min load of 10% in summer.

- Imports gas from Norway as well as over 10 North Sea gas fields
- There are 4 gas plants in operation
- The point provides for around 15% of GB's gas demands

- The load correlation with temperature is unclear
- Highest load is 82% in winter
- lowest load is 10% in summer

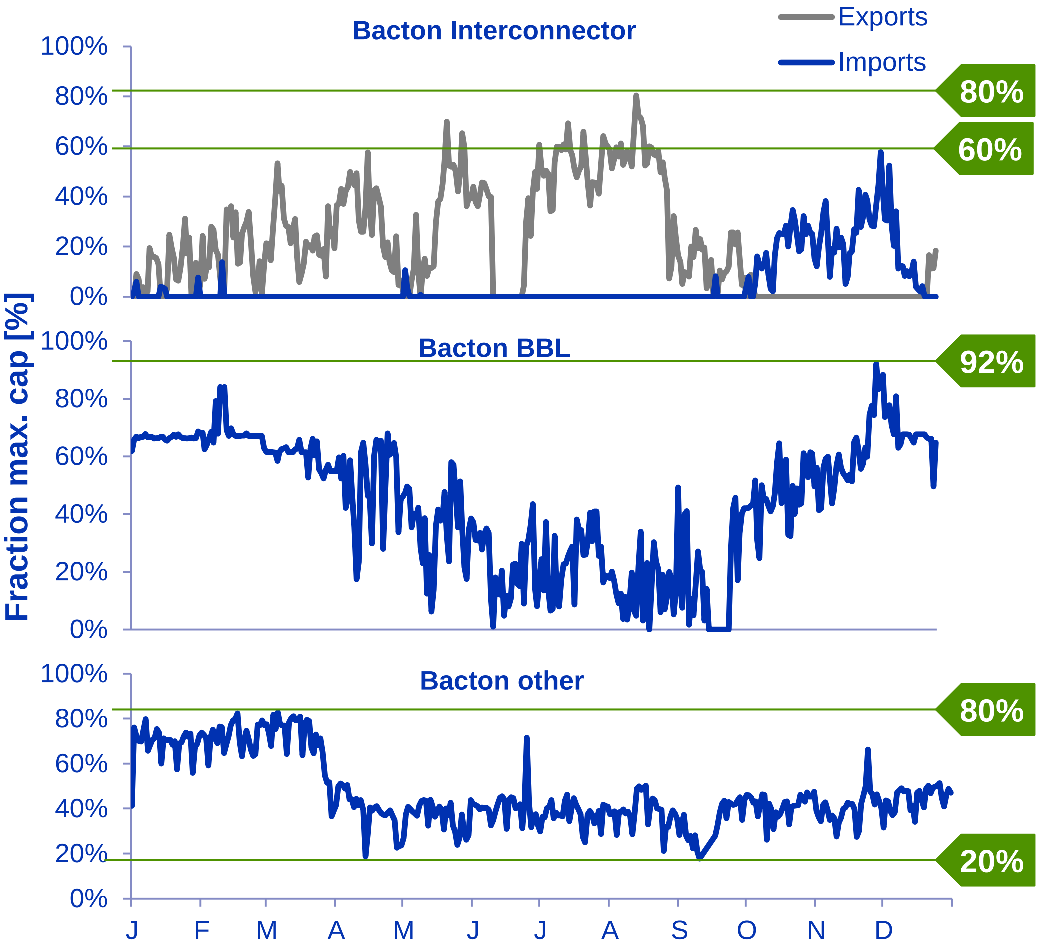


Easington	Capacity [GWh/d]
Nominal capacity	1084
Minimum capacity	108

Sources: National Grid

UK (GB only) – Interconnections at Bacton

BBL pipeline shows inverse load correlation with temperature, peaking in winter, other connections do not show seasonality. Loads range 0% to 92%.



- Bacton terminal can supply ~30% of gas demand in the UK
- IUK: Mostly used for export purposes in 2012, load ranging from 0% to 80%
- BBL: Solely used for physical imports, load ranges from 0 to 92%
- Gas from over 20 North Sea gas fields flows to this terminal as well, remaining terminal load ranging from 20% to 80%

Pipeline		Capacity [GWh/d]
IUK	Import	805.4
	Export	635.6
BBL		449
Other		623.6

Sources: National Grid

Assumptions of Major Beach Terminals

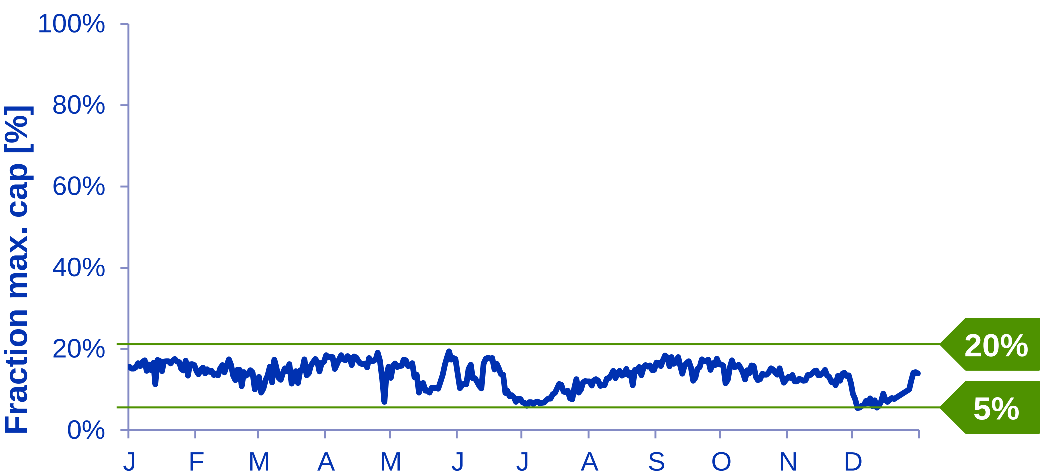
- GB imports by St. Fergus terminal:
  - Imports do not seem to a clear seasonal pattern
  - We assume a flow equal to 80% of technical capacity (70% was observed)
  - In addition, we assume a minimum of 20% technical capacity as observed during 2012
- GB imports at Easington terminal:
  - Also, at this terminal there seems to be no seasonality
  - Assumption: a maximum of 90% technical capacity (82% in 2012)
  - We assume that a minimum of 10% of technical capacity is always used.
- GB imports by Bacton BBL:
  - Again, imports do not have to follow seasonality
  - Flows can reach 100% of technical capacity (92% are observed in 2012)
  - However, flows may go down to a minimum of 0% technical capacity
- GB imports and exports by Bacton interconnector:
  - Both imports and exports do follow a specific pattern
  - Imports:
    - In 2012, a flow of 60% of capacity was observed. We assume that 70% of technical import capacity is available when needed
    - Minimum flows can be at 0% import capacity
  - Exports:
    - A maximum of 90% technical export capacity is available when needed (80% observed)
    - A minimum of 0% technical export capacity is available when needed
- GB imports by other Bacton connections:
  - We assume a maximum of 90% technical capacity is available (80% observed in 2012)
  - Also, a minimum flow of 20% technical capacity is always available.

UK (GB only) – Other Supply Points (Only Domestic)

The terminal shows an increase in load during spring and autumn. The maximum load is in spring at 20% and minimum load is in winter at 5%

- Gas from 6 fields flows to the Barrow supply point
- Gas from 20 fields flows to the Theddlethorpe gas terminal
- Gas from 4 fields flow to the Burton (Point of Ayr) terminal

- The points have highest loads during the first part of the year, reaching 20% load in spring and lowest loads in summer as well as winter at 5%



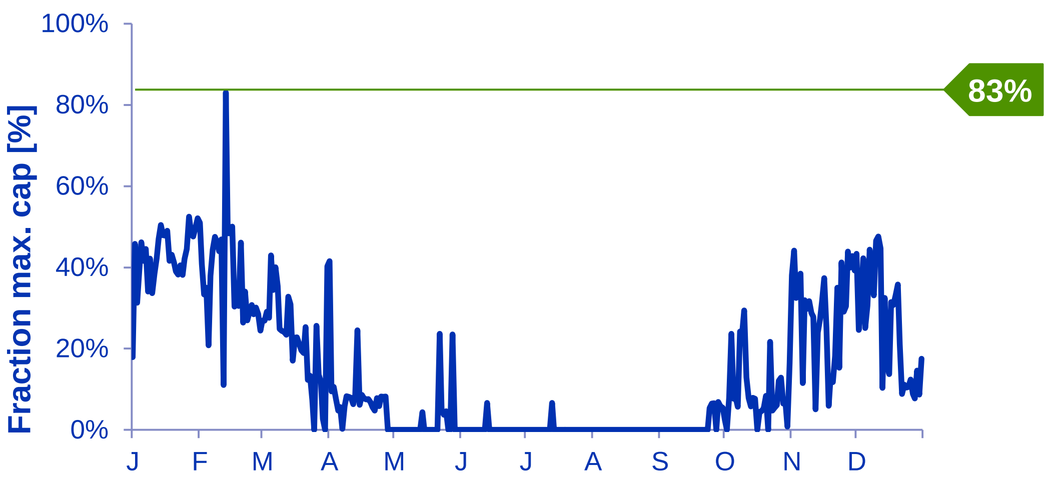
Point	Capacity [GWh/d]
Barrow	669
Theddlethorpe	498
Burton (Ayr)	260
Total	1427

Sources: National Grid

Ireland – Domestic Supply

The terminal shows an increase in load during winter. The maximum load is at 83% and minimum load is at 0%.

- Gas from the Kinsale Head gas field flows to this point
- The point has highest loads during the colder season, reaching 83% load in January and lowest loads in summer at 0%



Midleton (Inch)	Capacity [GWh/d]
Nominal capacity	63

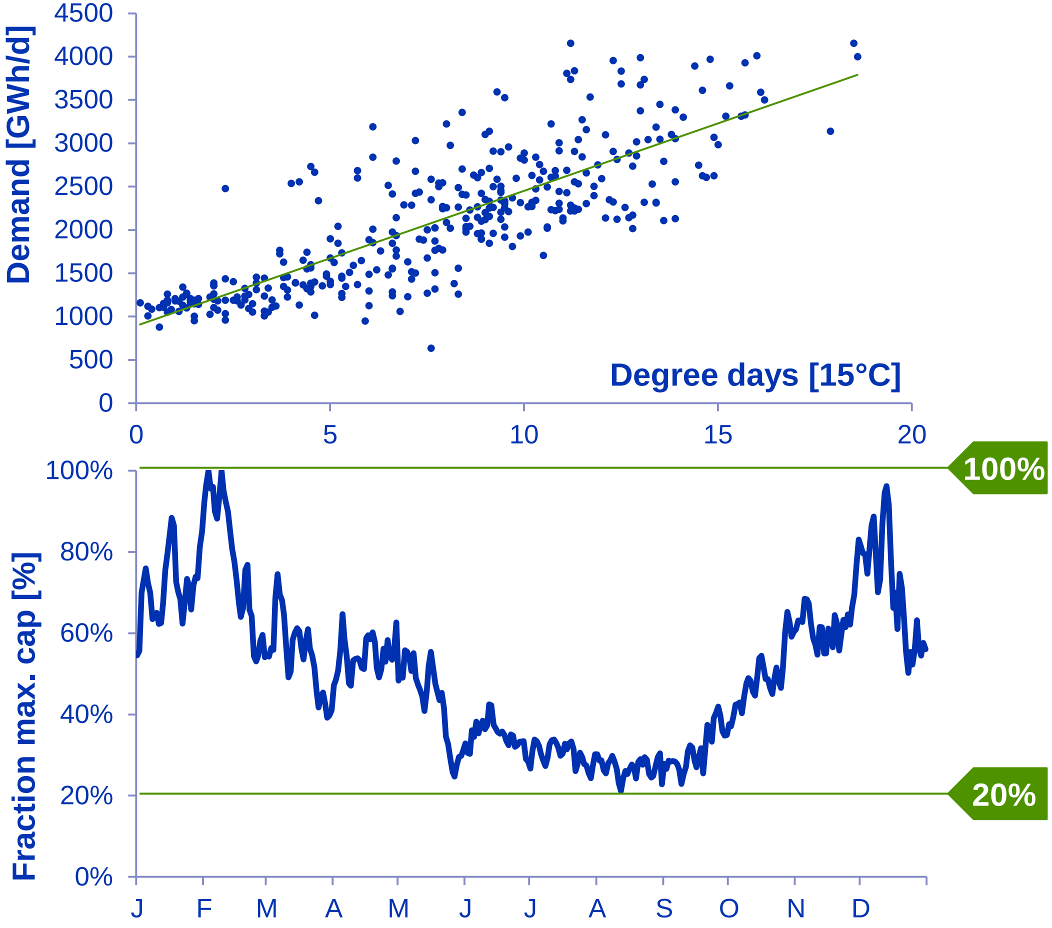
Sources: GasLink

Assumptions about Domestic Supply Points

- GB:
  - Supply from UKCS does not follow seasonality.
  - A maximum supply of 20% of technical capacity seems to be available when needed.
  - The minimum output is approximately equal to 5% of capacity.
- Ireland:
  - Similar to the GB, actual output does follow seasonality.
  - However, we assume that a maximum of 100% of supply is available when needed (83% observed in 2012).
  - A minimum flow of 0% of the nominal output.
  - Overall, the flow from the fields are relatively small compared to the interconnection with Great Britain.

UK (only GB) - Demand

Demand on GB follows seasonality with an increase during the coldest months and peaking in February at 100%, it is lowest in summer at 20%.

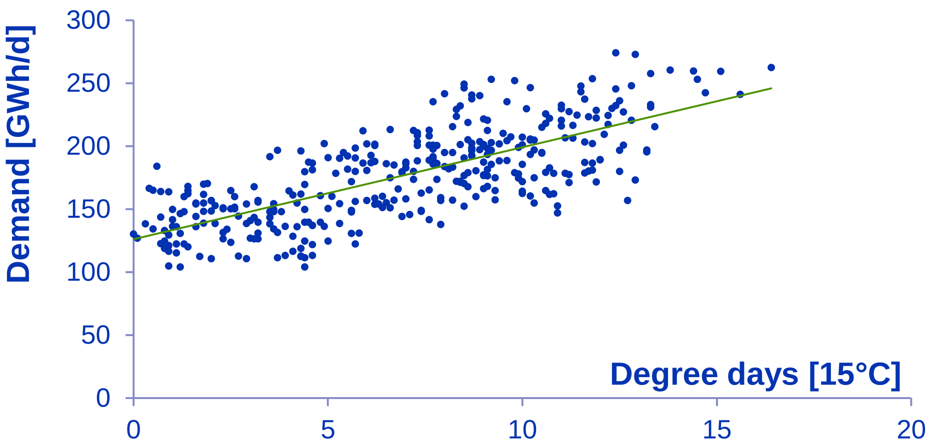


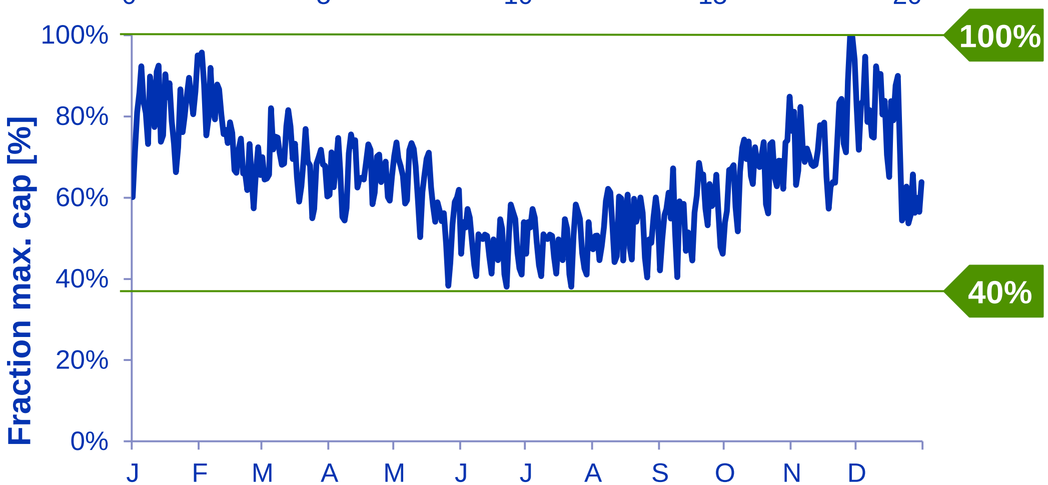
- GB has a peak demand of 4153.6 GWh/d in winter and the lowest demand of 831 GWh/d in summer
- Demand shows direct correlation with degree days for heating, thus follows seasonality and is inversely correlated with temperature

Sources: National Grid, degreedays.net

Ireland (incl. NI) - Demand

Demand on the Irish island follows seasonality with an increase during the coldest months and peaking in February at 100%, it is lowest in summer at 40%





- The gas market has a peak demand of 274.2 GWh/d in winter and the lowest demand of 109 GWh/d in summer
- Demand shows direct correlation with degree days for heating, thus follows seasonality and is inversely correlated with temperature

Sources: GasLink, degreedays.net

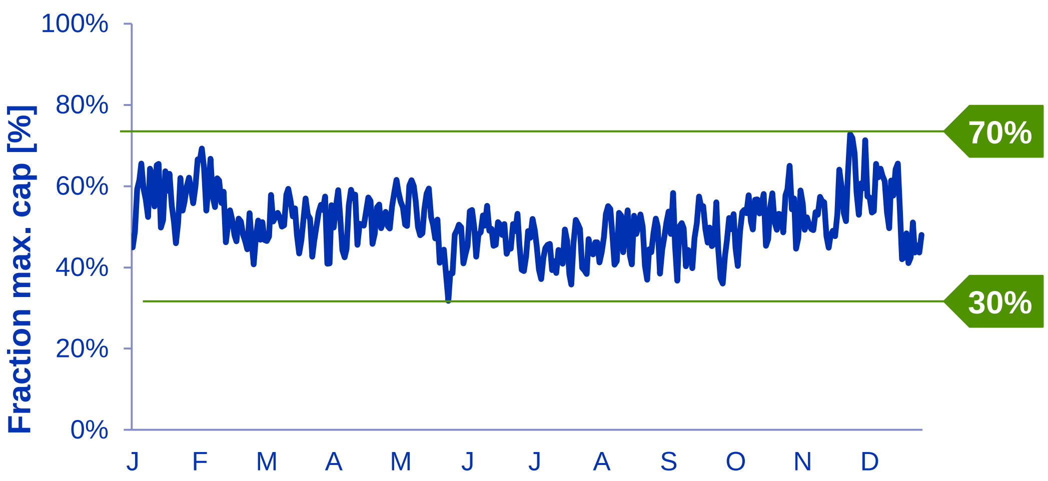
Assumptions about Domestic Demands

- Both countries follow seasonality according to the same pattern (inverse correlation with temperature).
- UK (GB only):
  - Assume that highest load is winter at 100% peak demand (2012).
  - We assume that the lowest load in summer at 20% peak demand (2012).
- Ireland (incl. NI):
  - For the conservative low demand summer scenario, when GB has the lowest demand, the highest summer demand in Ireland is taken (60% of peak 2012).
  - For the optimistic high demand winter scenario, when GB has the highest demand, the lowest winter demand in Ireland is taken (70% of peak 2012).

UK & Ireland Existing Interconnection Capacity

The terminal shows some seasonality with inverse correlation with temperature. The maximum load is in winter at 70% and minimum load is in summer at 30%.

- All the gas imports in Ireland come from the Moffat point in the GB
- The capacity is split between the SNIP pipeline in Northern Ireland, 2 interconnectors in Southern Ireland and a small amount flows to Isle of Man
- Flow is highest in winter with total load of 72% and it is lowest in summer at 30% load



Point	Capacity [GWh/d]
Twynholm (SNIP)	95.7
Interconnectors	241.8
Isle of Man	4.5
Total (Moffat)	342

Sources: National Grid, GasLink

Ireland, Northern Ireland & GB - Market Integration

Benefit Analysis

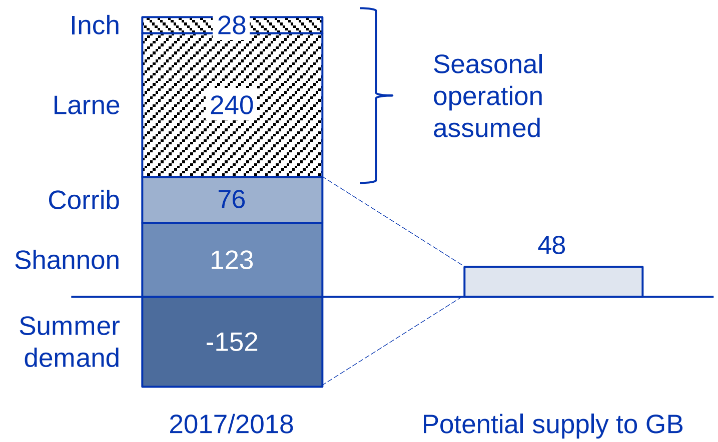
Irish Gas Market

- The Irish gas market can be divided into three distinct segments:
  1. **Large Daily Metered (LDM)**:
     - Power stations & large industrial consumers.
     - Approx. 16 consumers taking care of their own gas shipping activities by purchasing gas directly from the wholesale market.
     - The LDM segment is thus non-regulated.
  2. **Daily Metered (DM)**:
     - Approximately 240 industrial and large commercial consumers, but with a smaller annual consumption than LDM consumers.
     - As the LDM segment it is non-regulated.
  3. **Non Daily Metered (NDM)**:
     - Residential, commercial and small individual parties consuming less than 5.55 GWh annually
     - The so-called “domestic market” consisting of residential NDM consumers is the <u>only segment still subject to price regulation</u>.
- A large share of the Irish gas market has been deregulated as CER envisaged sufficient competition in these segments.
- Also, gas prices in Ireland are coupled to NBP prices; this basically implies that both markets are already integrated.

Potential Benefits from Changed Cost Allocation

- Although connected to NBP, prices in Ireland are increased by transportation costs incurred for use of the Interconnectors 1 & 2.
- Supply/demand situation in 2017/2018 could lead to higher unit transportation costs for the Interconnectors which may push up "… the wholesale price for gas in Ireland. This would be inefficient and damaging to both consumer interests and Ireland's energy competitiveness".[1]
- Increased competition may thus lead to an increase in prices as long as gas flows from Great Britain determine gas prices (due to higher specific costs).

Supply/demand situation summer's day 2017/2018 [GWh/day]



- A market merger leads to the elimination of the interconnectors as separate entry/exit points. And a reallocation of the revenue over the remaining entry and exit points would at least theoretically solve this issue.
- Other measures might be able to deal with this situation (cost allocation problem) as well.

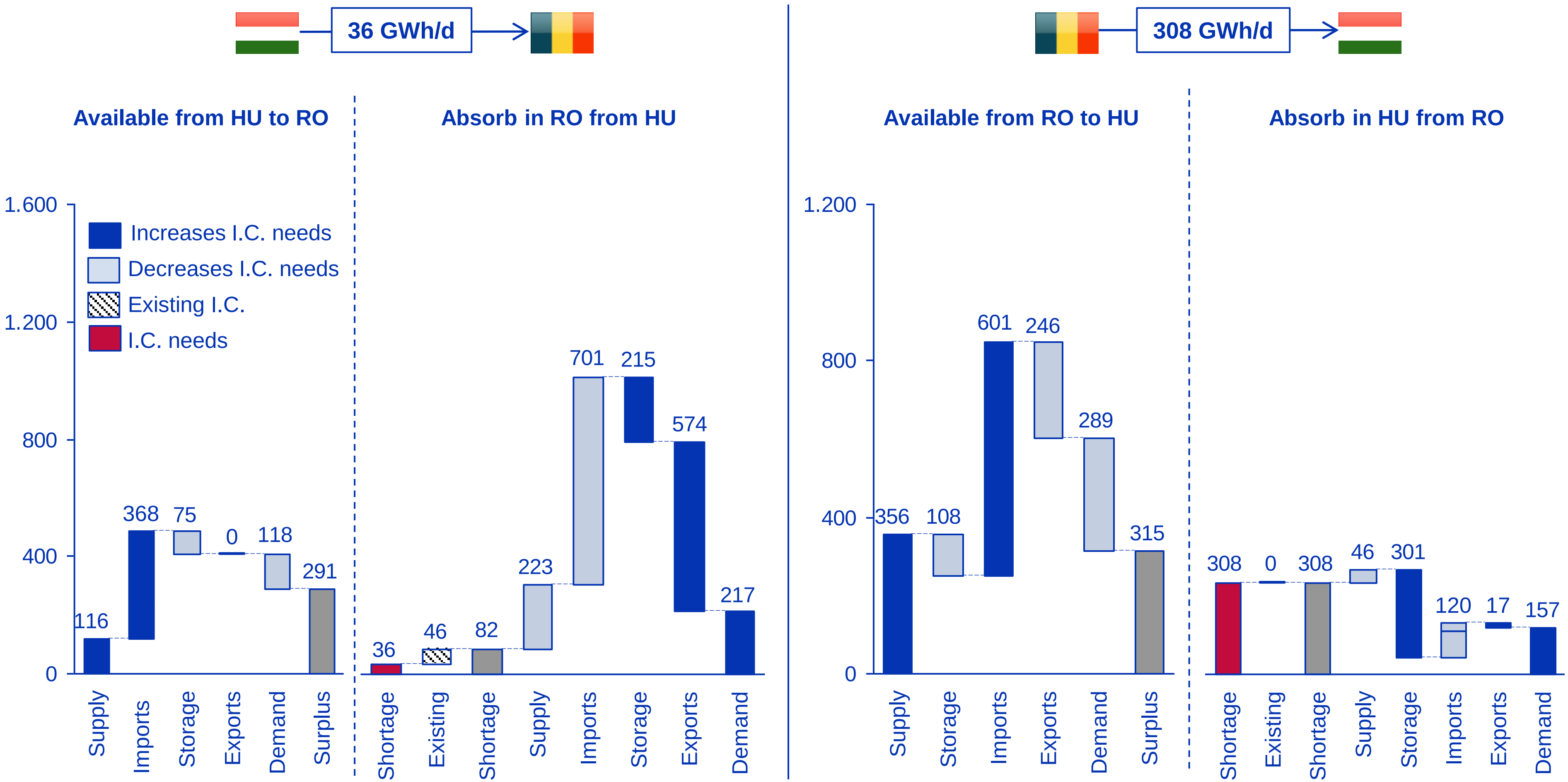
1 Commission for Energy Regulation (CER/12/087)

Romania - Hungary Market Integration

Cost Analysis

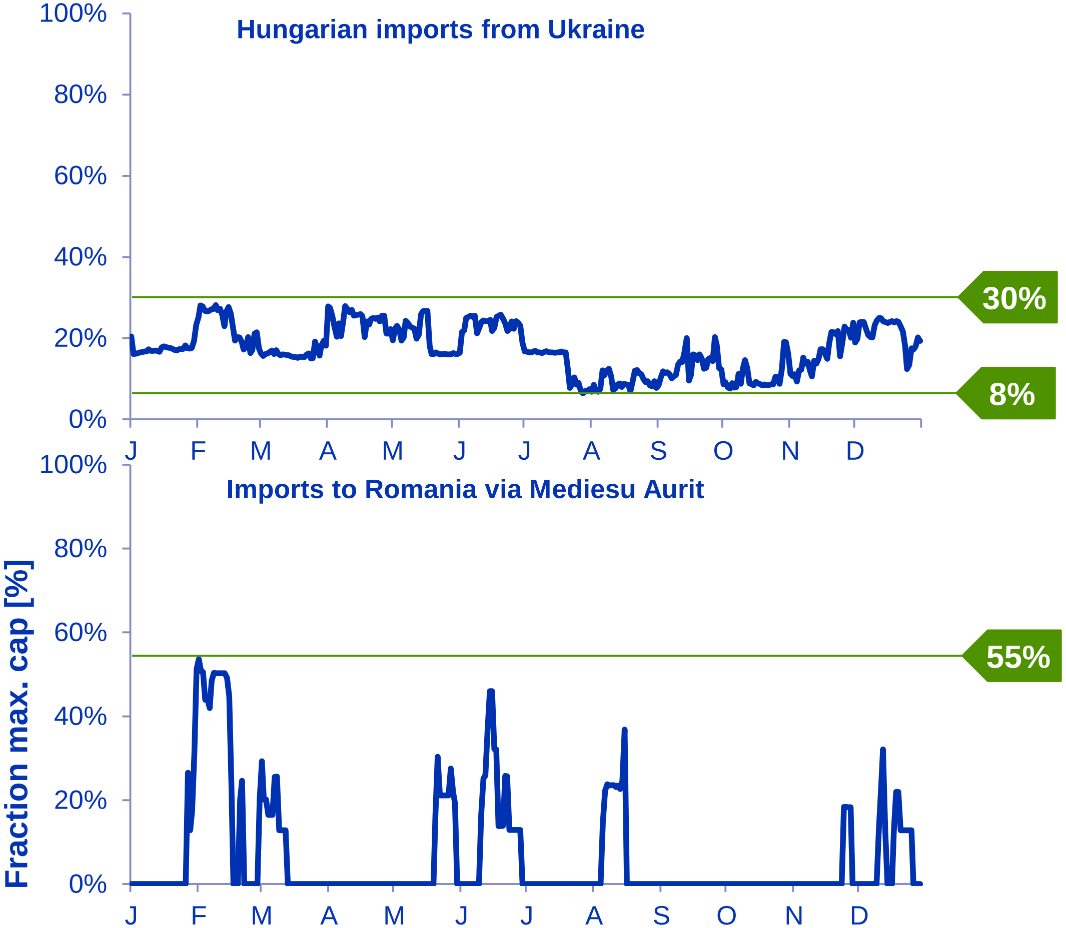
Summary of Interconnection Capacity Requirements

About 308 GWh/day (> 1.1 mln. m³/h) of capacity needs to be build between Romania and Hungary in order to enable a single entry-exit system.



Hungary & Romania- Swap Capacity via Ukraine

A possibility to swap capacities at the Beregdaroc and Mediesu Aurit imports from Ukraine would reduce the additional needed capacity to 245 GWh/day.



- Domestic imports from Ukraine have unused capacity throughout the year (60% for Hungary and 30% for Romania)
- Instead of building additional interconnection capacity between HU-RO, the gas flowing via the two pipelines can be swapped between countries
- “Conservative” scenario:
  - HU->RO capacity would be reduced to 0
  - RO->HU capacity would be reduced to 245

Csanadpalota	Capacity [GWh/d]	Avail-able	Possible for a swap
Beregdaroc (HU)	597	358 (60%)	Up to **63** from Romania
Mediesu Aurit (RO)	114	**35** (30%)	Up to **180** from Hungary

Sources: Fgsz, Transgaz

Associated Required Investments

Merging Hungarian and Romanian gas markets would require additional infrastructure to accommodate potential flows from Romania to Hungary

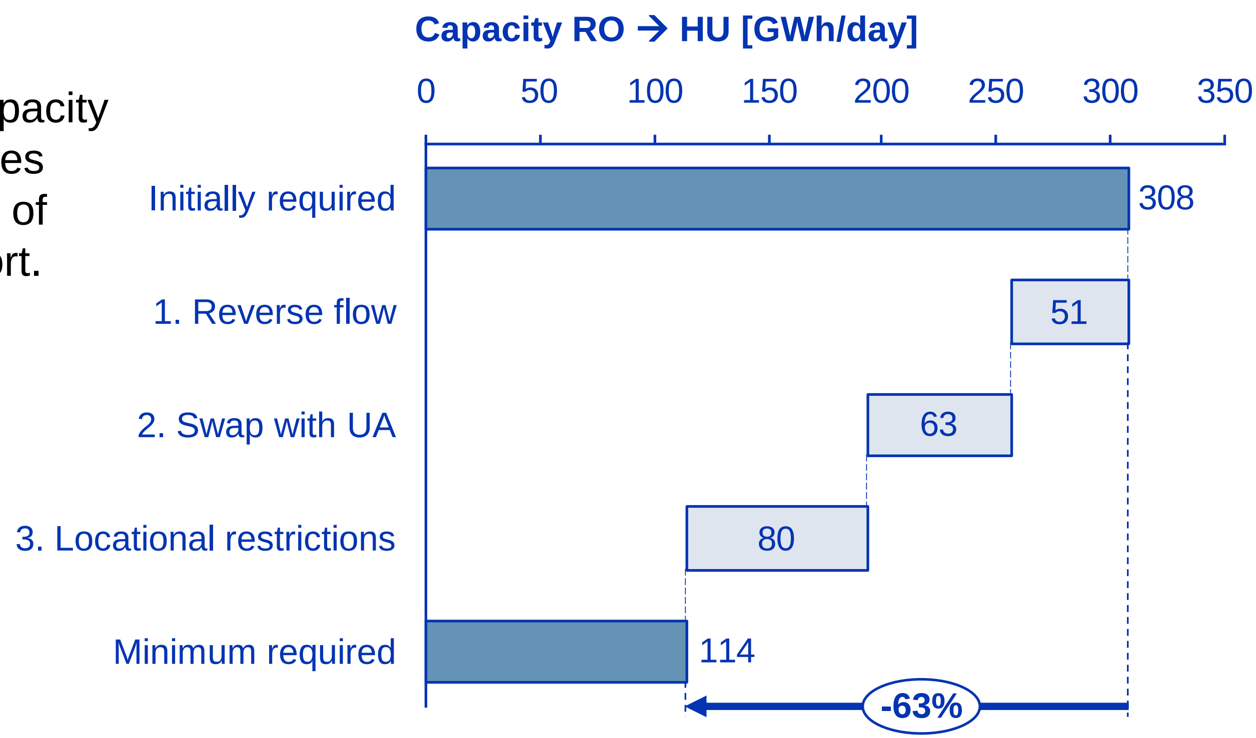
- Without swaps with Ukraine additional interconnection capacity from Romania to Hungary amounts to 308 GWh/day. With swaps, this would reduce to 245 GWh/day.

Item	Without swap UA	With swap UA
Capacity	308 GWh/day	245 GWh/day
Pipeline diameter	Ø = 36 inch	Ø = 32 inch
Pipeline length	109 km	109 km
Compressor station power	7.6 MW	5.5 MW
Capex pipeline	128 M€	111 M€
Capex compressor station	21 M€	17 M€
Opex	2.8 M€/yr	2.4 M€/yr
Total	15.5 M€/yr	13 M€/yr

Hungary & Romania - Locational Restrictions UA-BG

Applying locational restrictions between UA and BG border points in Romania could reduce necessary investments further

- Large share of gas transported through Romania could be characterised as transit between Ukraine and Bulgaria
- Applying locational restrictions, i.e. point-to-point obligations, could reduce required investment further.
- Required interconnection capacity largely determined by volumes Hungary can absorb instead of volumes Romania may export.



Scenarios – Hungary → Romania

			Technical [GWh/d]	Low demand scenario	High demand scenario
Hungary	Domestic supply		116	100%	40%
	Storage	Withdrawal	893	0%	0%
		Injection	501	15%	60%
	Imports	Ukraine	597	40%	5%
		Austria	129	100%	70%
	Exports	Croatia	203	0%	30%
		Serbia	140	0%	5%
	Domestic demand		786	15%	100%
Romania	Domestic supply		890	25%	70%
	Storage	Withdrawal	324	0%	80%
		Injection	215	100%	0%
	Imports	Ukraine	1002	70%	60%
	Exports	Bulgaria	820	70%	80%
	Domestic demand		723	30%	60%
Existing interconnection capacity				46	46
Needed additional interconnection [GWh/d]				36	0

Scenarios – Romania → Hungary

			Technical [GWh/d]	Low demand scenario	High demand scenario
Romania	Domestic supply		890	40%	25%
	Storage	Withdrawal	324	0%	0%
		Injection	215	50%	100%
	Imports	Ukraine	1002	60%	90%
	Exports	Bulgaria	820	30%	80%
	Domestic demand		723	20%	100%
Hungary	Domestic supply		116	40%	100%
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		Injection	501	60%	0%
	Imports	Ukraine	597	5%	40%
		Austria	129	70%	100%
	Exports	Croatia	203	5%	0%
		Serbia	140	5%	0%
	Domestic demand		786	20%	60%
Existing interconnection capacity				0	0
Needed additional interconnection [GWh/d]				308	0

Hungary – Domestic supply

Supply shows an increase in load during winter and a decrease in spring/summer. The maximum load is 90% and minimum load is around 40%

- There are 5 supply points in Hungary, MOL Nyrt KTD összevont betáplálási pontjai (2/H) being the major one
- Domestic supply shows seasonality, loads reaching 90% of technical capacity in winter and dropping to 41% load in summer

Point	Capacity [GWh/d]
Babócsa "REGIONALIS"	1.1
Kenderes II	5
MOL Nyrt KTD (2/H)	100.6
MOL Nyrt KTD (2/S)	6.4
Tiszavasvári II	3.44
Total	116.54

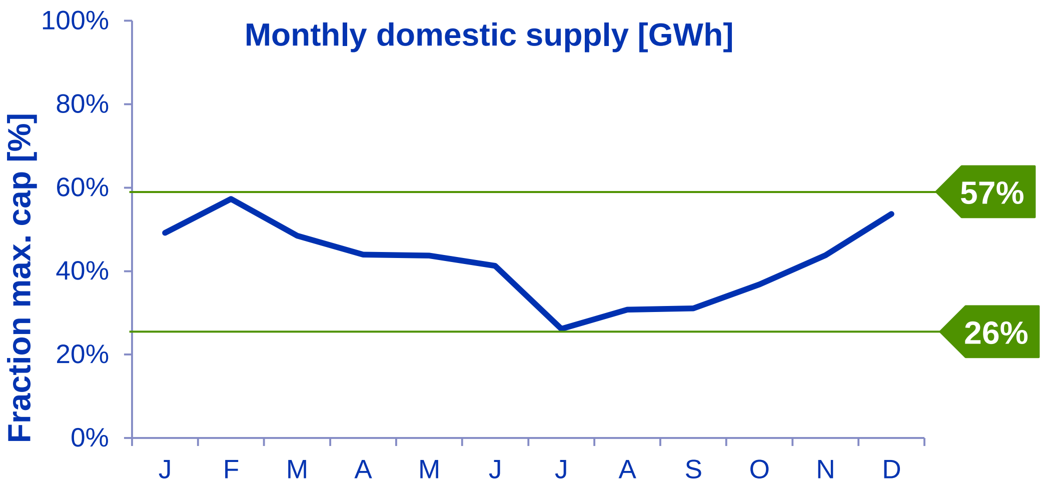
Sources: Fgsz

Romania – Domestic supply

Supply shows seasonality similarly as demand. The maximum load is in winter at around 60% and minimum load is in summer at around 25%

- Romania has the third largest gas reserves in the EU
- It supplies over 80% its own domestic demand

- Domestic supply shows seasonality same as domestic demand, loads reaching 60% of technical capacity in winter and dropping to 26% load in summer



	Capacity [GWh/d]
Domestic supply	890

Sources: Eurostat

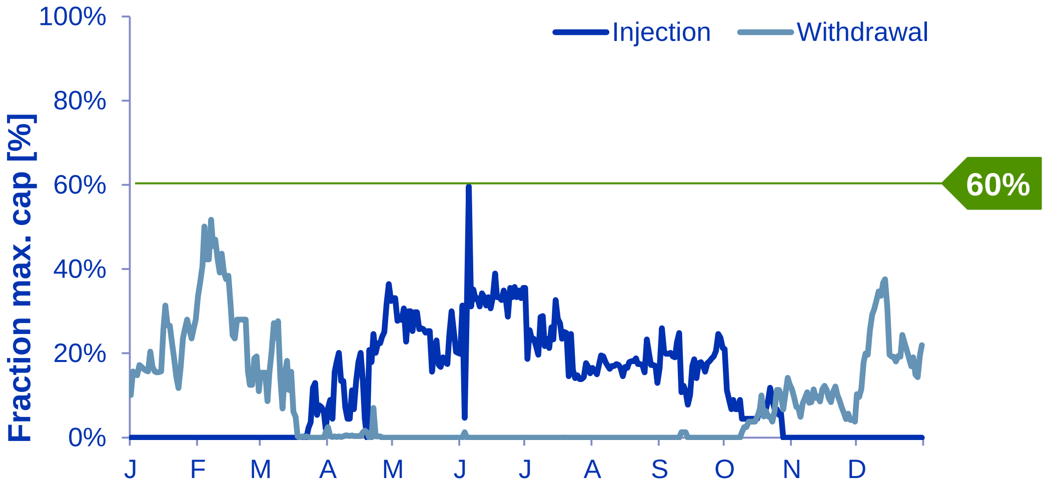
Assumptions about Domestic Supply Points

- Hungary:
  - Domestic supply seems to clearly follow a seasonal pattern
  - However we assume it can be used at 40% or 100% (90% actual maximum) load at any time
- Romania:
  - Domestic supply seems to clearly follow a seasonal pattern as in Hungary
  - However we assume it can be used at 25% or 70% (57% actual maximum) load at any time

Hungary - Storage

Storage follows seasonality. During winter withdrawal peaked at 50% of maximum capacity; Injection peaked at 60% in summer.

- UGS' can meet around 50% of domestic demand
- Storages strongly follow seasonality, injection increasing with increase in temperature and withdrawal increasing with decrease in temperature
- Withdrawal is up to 50% in winter and injection is up to 60% in summer, both having minimums of 0% of technical capacity
- Loads are up to 100% in separate storages, but commonly the loads are as stated before



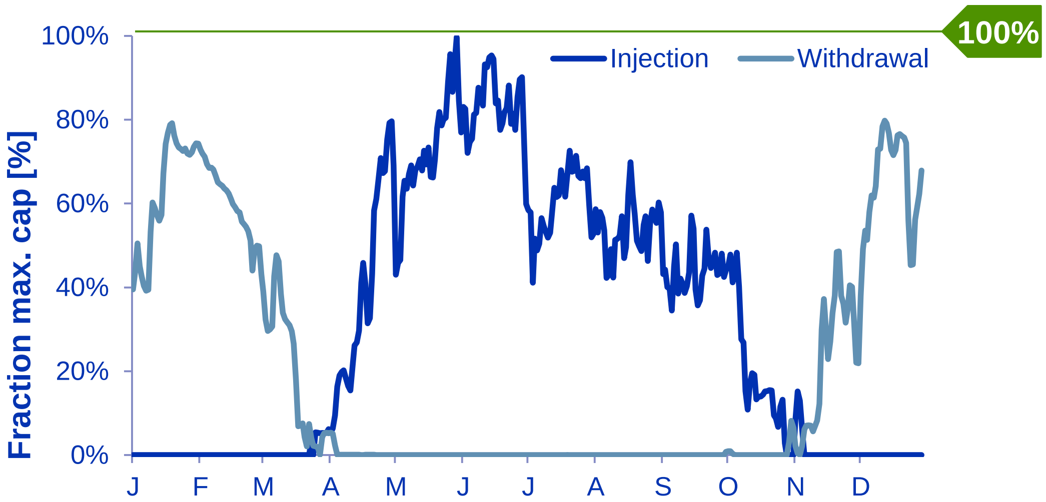
[GWh/d]	Volume	Injection	Withdrawal
Storage	68,350	500.6	893

Sources: Gie, E.On

Romania - Storage

Storage follows seasonality. During winter withdrawal peaked at 50% of maximum capacity; Injection peaked at 60% in summer.

- UGS' can meet around 30% of domestic demand
- Storages strongly follow seasonality, injection increasing with increase in temperature and withdrawal increasing with decrease in temperature
- Withdrawal is up to 80% in winter and injection is up to 100% in summer, both having minimums of 0% of technical capacity
- Injection and withdrawal loads are quite strongly correlated between sources



[GWh/d]	Volume	Injection	Withdrawal
Storage	36,059	215	324

Sources: Transgaz

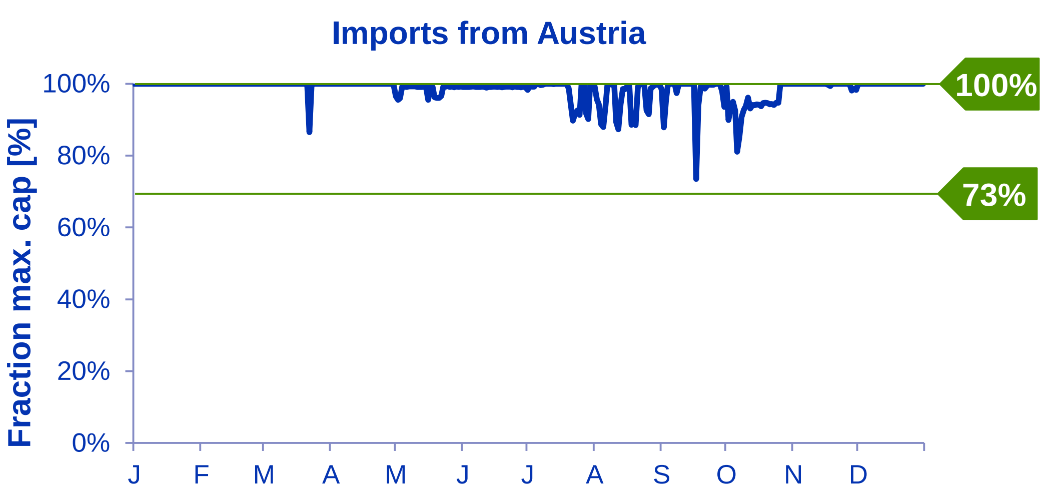
Assumptions about Storage Use

- Hungary:
  - Storage injection and withdrawal seem to clearly follow a seasonal pattern
  - Withdrawal is not possible from May to October
  - Injection does not occur during winter
- Romania:
  - Storage injection and withdrawal seem to clearly follow a seasonal pattern
  - Withdrawal is not possible from April to November
  - Injection may occur at each time aside from winter

Hungary – Imports from Austria

The terminal does not show correlation with temperature. The maximum load of 100% is seen throughout a large part of the year, minimum is 70% in Autumn

- Load at the Mosonmagya interconnection point with Austria is very high throughout the year
- The point provides for around 16% of Hungarian gas demand
- There is no seasonality in load
- Highest load is 100% and is observed throughout most part of the year
- Lowest load is 73% in Autumn



Mosonmagya point	Capacity [GWh/d]
Nominal capacity	128.5
Minimum capacity	90

Sources: Fgsz

Hungary – Imports from Ukraine

The terminal does not show clear correlation with temperature. The maximum load is 30%, minimum is around 10%

- Load at the Beregdaroc interconnection point with Ukraine is low throughout the year
- The point could provide for around 76% of Hungarian gas demand, but currently provides only about 23%
- There is a drop in load at the end of summer/ beginning of Autumn
- Highest load is 29% and is observed in winter and spring
- Lowest load is 8% in summer

Beregdaroc point	Capacity [GWh/d]
Nominal capacity	596.7
Minimum capacity	48

Sources: Fgsz

Romania – Imports from Ukraine

Imports from Ukraine show inverse correlation with temperature. The maximum load is around 90%, minimum is around 30%

- Load at the Interconnections with Ukraine are high throughout the year
- Isaccea point: Up to 246 GWh/d can be imported for domestic usage, the rest is transited straight to Bulgaria
- Load shows a seasonal pattern with an increase during the cold season
- Highest load is 86% and is observed in winter
- Lowest load is 30% in summer and autumn

Point	Capacity [GWh/d]
Isaccea	888
Mediesu Aurit	114
Total	1002
Minimum capacity	306

Sources: Transgaz, Bulgartransgaz

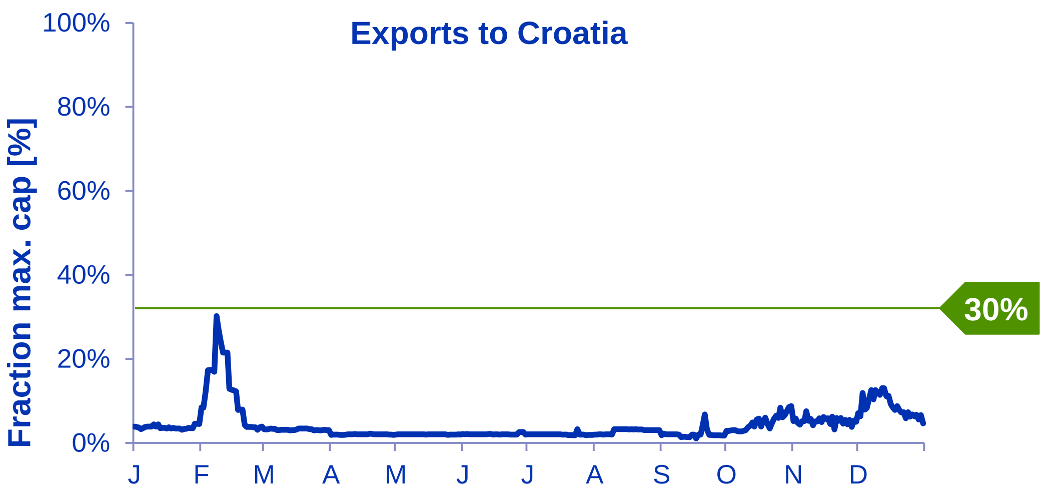
Assumptions about Imports

- Hungary:
  - Imports do not seem to follow a seasonal pattern
  - Imports from Austria are high throughout the year and can have a load between 100% and 70% at any time during the year
  - Imports from Ukraine have a low load which can be from 5% to 40% (30% actual maximum) at any time
- Romania:
  - Imports from Ukraine clearly follow a seasonal pattern
  - The load can be 90% or 60% in winter and is positively correlated with exports to Bulgaria
  - The load can be 70% or 30% in summer and is positively correlated with exports to Bulgaria

Hungary – Exports

The terminal shows a load increase in winter. The maximum load is 30%, minimum is around 1%

- Load at the Dravaszerdahely interconnection point with Croatia is low throughout the year
- There was no load observed at the Kiskundorozsma interconnection point with Serbia
- There was a short term increase in exports to Croatia in winter peaking at 30% load, otherwise the load is low with a minimum of 1%



	Capacity [GWh/d]	Minimum capacity
Export Croatia	203	0
Export Serbia	139.8	0

Sources: Fgsz

Romania – Exports to Bulgaria

Imports from Ukraine show inverse correlation with temperature. The maximum load is around 90%, minimum is around 30%

- Load at the Interconnections with Bulgaria are show variation in a wide range
- Almost all of the capacity is transit capacity from Ukraine via Isaccea
- Load shows a seasonal pattern with an increase during the cold season
- Highest load is 93% and is observed in winter
- Lowest load is 30% in summer and autumn

Point	Capacity [GWh/d]
Negru Voda I	210.3
Negru Voda II	610
Total	820.3
Minimum capacity	246

Sources: Transgaz, Bulgartransgaz

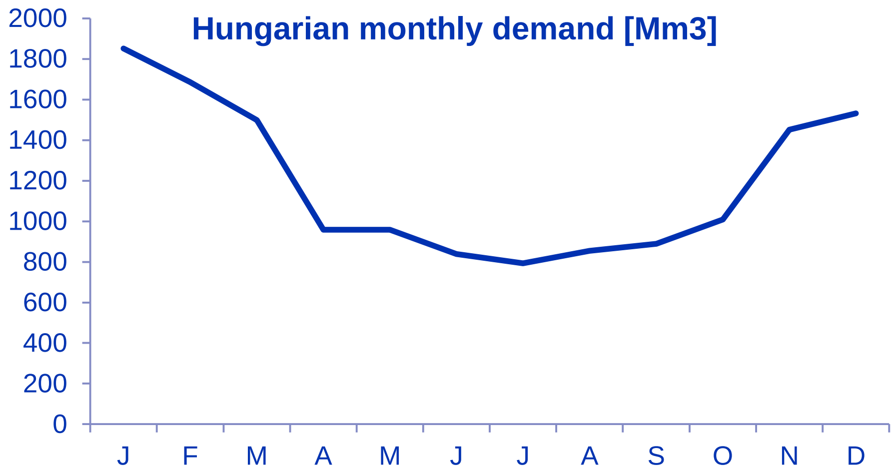
Assumptions about Exports

- Hungary:
  - There were no physical flows to Serbia observed, thus we assume a load of 10% or 0% at any time
  - Exports to Croatia are very low throughout the year and seem to follow a seasonal pattern
  - They increase in winter, but we assume a 30% or 0% load at that period
  - Exports to Croatia are low in summer, we assume a 5% or 0% load during that period
- Romania:
  - Exports to Bulgaria clearly follow a seasonal pattern
  - The load can be from 80% up to 95% of maximum capacity in winter
  - In summer, the load can be anywhere between 30% to 70%

Hungary - Demand

Demand in Hungary follows seasonality with an increase during the coldest months and peaking in February at 100%, it is lowest in summer at 13%

- Natural gas plays the most important role in Hungary's energy consumption
- It has a peak demand of 786 GWh/d in winter and the lowest demand of 107 GWh/d in summer
- Demand clearly follows seasonality and is inversely correlated with temperature



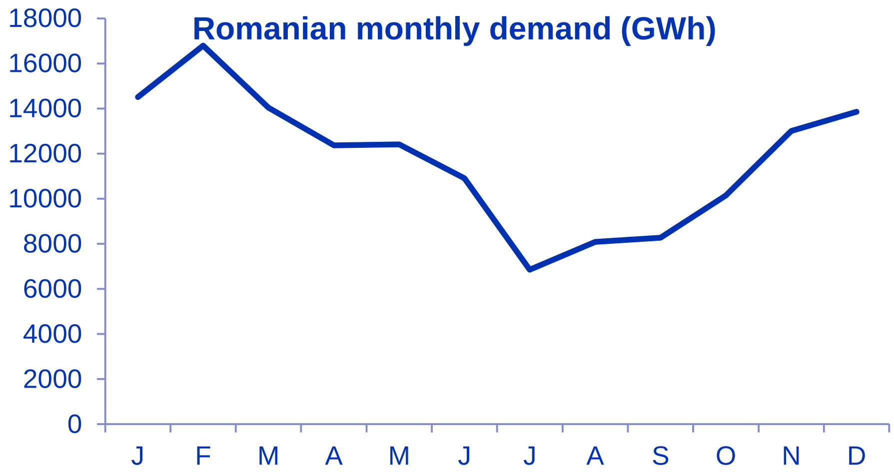
Demand [GWh/d]	High	Low
Summer	155 (20%)	107 (15%)
Winter	786	450 (60%)

Sources: Entsog

Romania - Demand

Demand in Hungary follows seasonality with an increase during the coldest months and peaking in February at 100%, it is lowest in summer at 20%.

- Natural gas plays the most important role in Romania's energy consumption
- It has a peak demand of 723 GWh/d in winter and the lowest demand of 147 GWh/d in summer
- Demand clearly follows seasonality and is inversely correlated with temperature



Demand [GWh/d]	High	Low
Summer	213 (30%)	147 (20%)
Winter	723	450 (60%)

Sources: Entsog, timetric

Assumptions about Domestic Demand

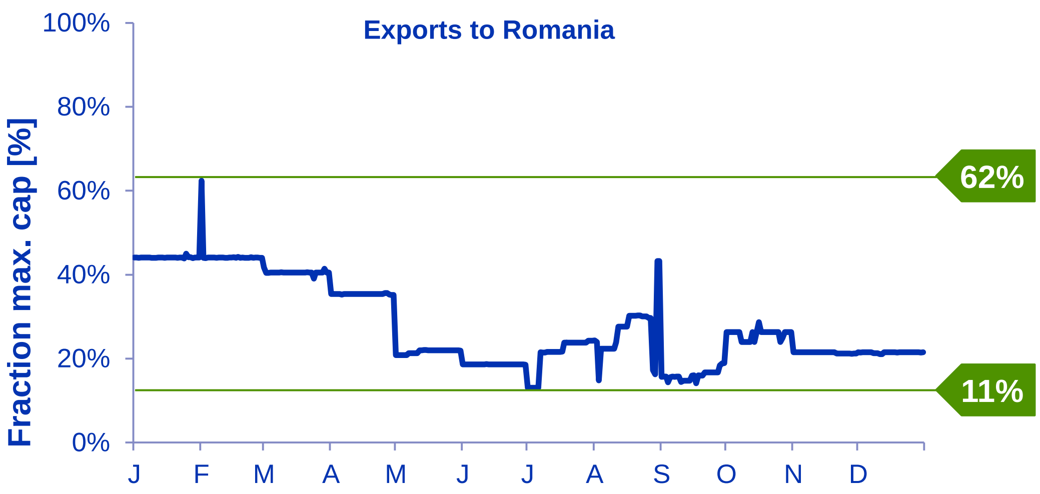
- Hungary: Hungary to Romania direction
  - Low demand scenario: 15% of maximum demand is taken
  - High demand scenario: 100% of maximum demand is taken
- Hungary: Romania to Hungary direction
  - Low demand scenario: lowest demand in Romania occurred in summer. The highest possible Hungarian exit flows are used; therefore the highest summer demand in Hungary is taken for the analysis (20%)
  - High demand scenario: highest demand in Romania is in winter. The lowest possible Hungarian exit flows are used in this analysis; therefore the lowest winter demand in Hungary is taken for the analysis (60%)
- Romania: Hungary to Romania direction
  - Low demand scenario: lowest demand in Hungary occurred in summer. The highest possible Romanian exit flows are used; therefore the highest summer demand in Romania is taken for the analysis (30%)
  - High demand scenario: the highest demand in Hungary is in winter. The lowest possible Romanian exit flows are required for this analysis; thus the lowest winter demand in Romania is used (60%)
- Romania: Romania to Hungary direction
  - For the low demand scenario: 20% of maximum demand is taken, as it is the lowest daily demand observed
  - For the high demand scenario: 100% of maximum demand is taken

Hungary & Romania- Existing Interconnection

The terminal shows a load increase in winter. The maximum load is 30%, minimum is around 1%.

- Load at the Csanadpalota interconnection point, at which gas flows from Hungary to Romania,varies within a wide range

- Exports to romania follow seasonality and are inversely correlated with temperature
- Loads are highest in winter peaking at 62%, lowest load is in summer with a minimum of 11%



Csanadpalota point	Capacity [GWh/d]
Nominal capacity	46
Minimum capacity	6

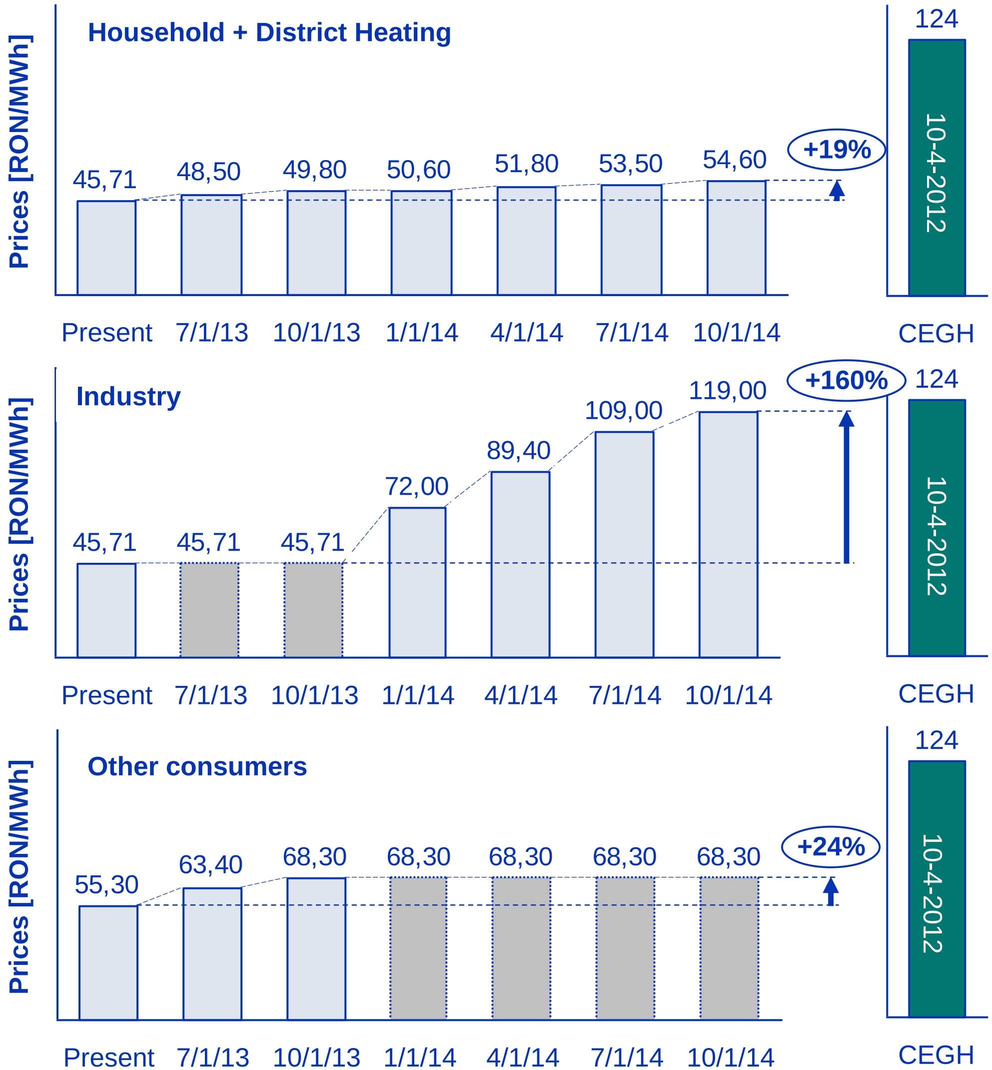
Sources: Fgsz, HEO

Romania - Hungary Market Integration

Benefit Analysis

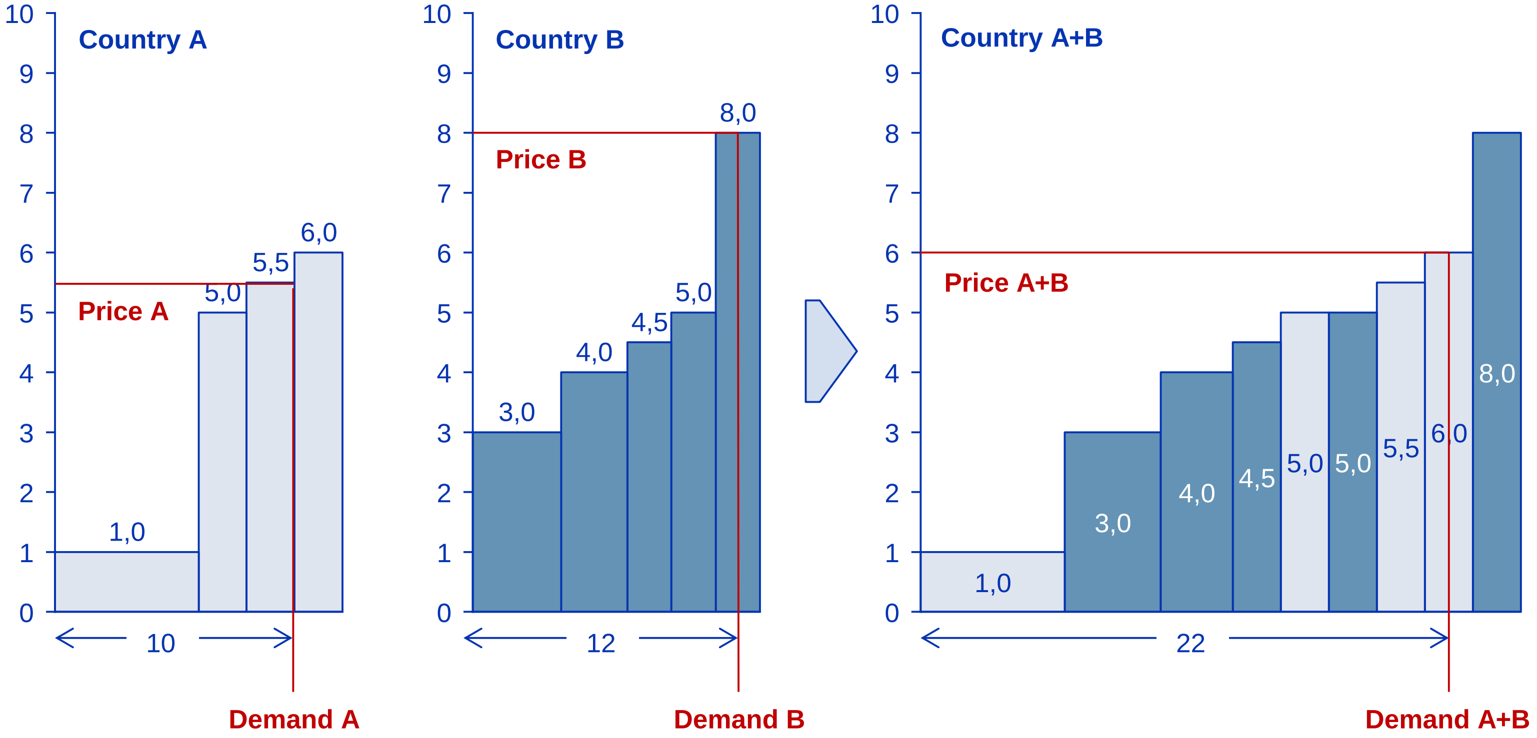
Most of Romania's Gas Market is Regulated

- Romania has committed to the World Bank, IMF and EC to deregulate its gas market. Gas prices will be deregulated for:
  - industrial users by 31-12-2014
  - household consumers 31-12-2018
- Currently, gas prices are set for a mix of domestically produced gas and the more expensive imported gas. The share of gas produced in Romania allocated to household consumers is greater than industrial consumers
- Imported gas is said to be three times more expensive than domestically produced gas
- Due to regulated prices and subsequent deregulation, it is impossible to quantify any potential benefits from a market merger



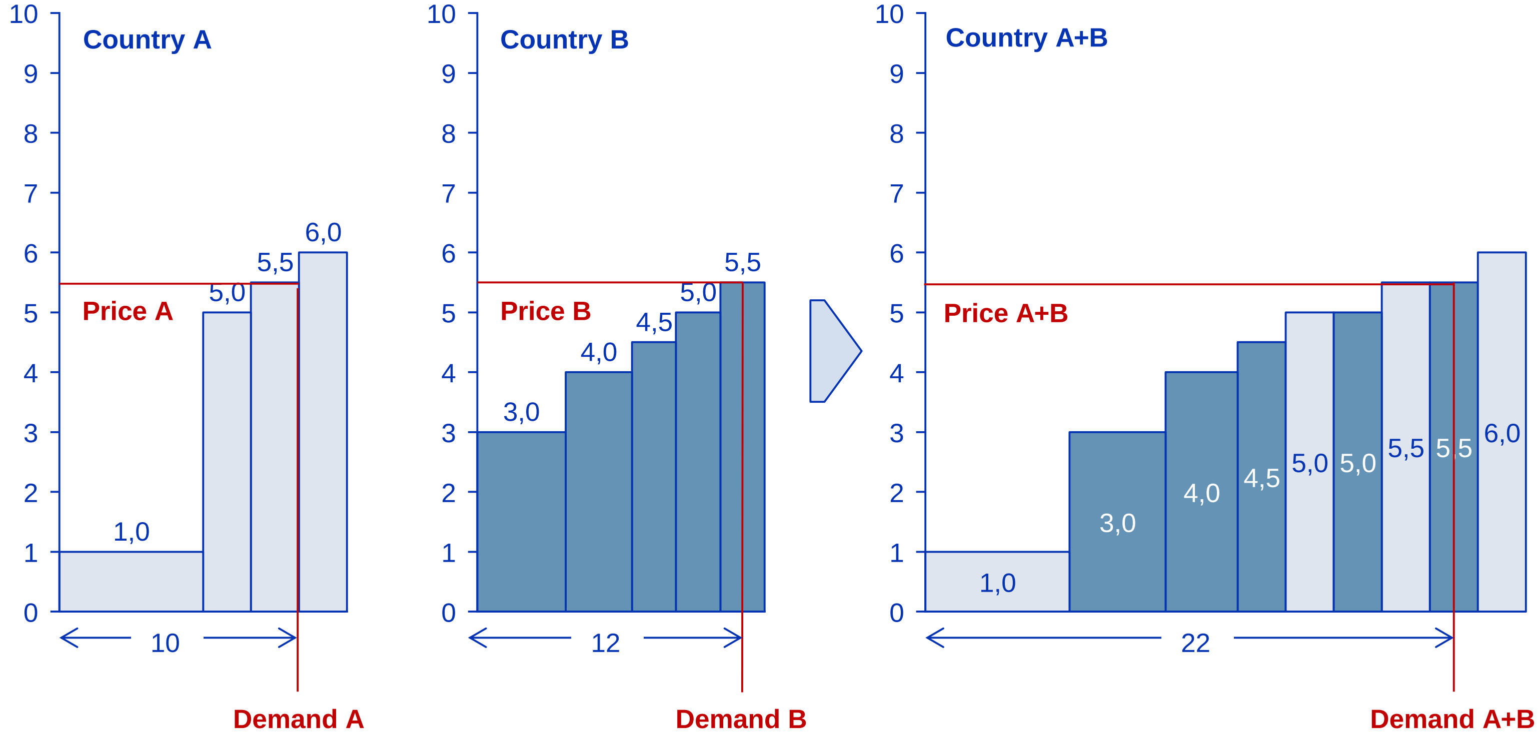
Theoretical Benefits of Market Merger

- Merger markets basically combined supply (and demand) curves of both markets
- Benefits can be attained if cheaper supplies in one market do not ‘make it’ to the more expensive market due to barriers, e.g. infrastructure bottlenecks



Theoretical Benefits of Market Merger

- However, in case marginal cost of supply are the same, these benefits are not present
- Prices of supply to Hungary and Romania are not publicly available, therefore making it difficult to judge which situation applies to this combination



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