Energy Community

Study on Recommendation for Funding Investments in the Energy Community Gas Ring

Gas

Energy Market Insights

December 2011

This report was financed by the Energy Community.

Recommendations for Funding Investments in the Energy Community Gas Ring

Final Report

31 December 2011

Contents

Executive Summary

Background to the Gas Ring study

1. This Study examines the framework which would be appropriate to attract the investments needed to complete two sections of the Gas Ring. The 'Northern Route' involves Croatia, Serbia and Bosnia and Herzegovina. The 'Southern Route' involves Albania, FYR of Macedonia and UNMIK. In addition feed-in lines to the Northern and Southern Route include: Bulgaria, Hungary, Italy, Greece and Romania.

Requirements for a sound investment climate

2. The large amounts of capital for investment in gas infrastructure must come largely from private sources. In order to attract private capital it is essential to ensuring that those providing this investment capital will get a reasonably secure return on their investment. There are two basic ways of achieving this outcome. The first of these is through the establishment of commercial contracts and the second through a regulatory agreement that the investor will receive income through regulated network tariffs.

3. It is possible to apply both the market based and regulated approaches to the capacity to be constructed within a single project. This hybrid of market based and regulated investments is commonly used where the infrastructure will serve different purposes.

4. As investors in gas infrastructure must have reasonable certainty that they will get a return on their investment in order to justify their investment decision, it is a critical part of their investment decision to undertake a full financial risk assessment for the project. The result of this analysis will determine what return the investor will require, and a higher return will be demanded for those projects where the risk is perceived to be higher. If the risk is very high then the investor may decide not to invest in that project at all. Regulators also need to understand these risks.

Assessing the risks faced by investors

5. The scope of the Risk Assessment Framework (RAF) is restricted to those risks which are outside of the direct control of the investor of the infrastructure project.

6. As each project has its own unique risk profile, a RAF must be tailored to fit each project. The process for establishing the RAF will have the following four sequential steps:

   i. The identification of the risks which investors in a particular project may be exposed to, and are outside of their direct control.
   ii. A quantified assessment of the severity of those risks in relation to the level of exposure of the investor (i.e. the risk that the investor will make a loss rather than a reasonable profit over the life of the project).
   iii. An assessment of whether any of the identified risks is sufficiently high to merit further treatment, or should be left with the potential investor;
   iv. Analysis of the risk and potential benefit to other parties if the risk were to be wholly or partly passed to them, based on the options in the risk management toolkit.

Designing solutions

7. Where risks have been identified which are likely to pose an obstacle to the investment proceeding, there are some steps which regulators, donors, governments and other actors can take which can reduce the risk faced by investors in gas infrastructure. Some of these measures are used commonly in gas markets internationally.

8. Risks to an investment may take a number of forms, but can be grouped into the following categories:

- Political risks
  These are risks which result from the legal and regulatory environment, matters which fall to governments to control, and geopolitical risks.

- Commercial risks
  These are risks which stem from the market and the commercial arrangements surrounding the project.

9. Critical risks where risk management measures involve actors other than the investor are volume and price risk, and legal and regulatory risks. Regulators, Governments and International Financial Institutions can play a central role in applying risk mitigation measures to address the identified risks.

Key Finding and Recommendations

i. Volume and price, and payment risks pose major obstacles to new investments. Regulatory risk poses a medium risk obstacle. In countries where there are few or no gas consumers there will be no private investment in new gas infrastructure unless there are government guarantees in place.

ii. A market test should be undertaken to identify potential investors in Tier B capacity and to identify specific candidate anchor loads.

iii. Some form of government guarantees or public private partnership arrangement is likely to be required to enable investments in Tier B capacity to proceed in relation to projects where Tier B capacity shares the infrastructure with tier A and/or Tier C capacity. These guarantees could take a number of forms, some of which are described above. Some regulatory risk management measures could also be applied including time limited exemption from third party access.

iv. Government guarantees are also likely to be required for investment in Tier A and C capacity to proceed.

v. A full risk assessment of the whole value chain of each anchor load project should be undertaken and potential risk management measure identified. This will require discussion between regulators and governments to develop a risk management strategy for specific projects based on the base case described above.

vi. The incremental development of the network to serve anchor loads should also be considered in order to provide Tier A and Tier C capacity to develop the gas market in this region. An analysis is required to determine the size and cost of this incremental capacity. TSOs in the region will need to play a major role in this work. This may need some time limited derogation from the requirements of the EU 3rd energy package.

Chapter 1

Introduction

1. This Study examines the framework which would be appropriate to attract the investments needed to complete two sections of the Gas Ring. The 'Northern Route' involves Croatia, Serbia and Bosnia and Herzegovina. The 'Southern Route' involves Albania, FYR of Macedonia and UNMIK. In addition feed-in lines to the Northern and Southern Route include: Bulgaria, Hungary, Italy, Greece and Romania.

2. This Report contains:
    a. an overall approach for developing an investment framework appropriate to the conditions existing in both of these routes
    b. options for the underlying business model
    c. a methodological approach based on risk assessment and risk management for the choice of business model and adjustments to it in order to manage (where necessary) investment risks
    d. options for the appropriate allocation of costs (including across borders) and for the recovery of costs
    e. base case business models for the Northern and Southern routes which are intended to provide an initial basis for further elaboration by regional experts.

CHAPTER 2

Possible business models for Gas Ring infrastructure development

Introduction

1. The large amounts of capital for investment in gas infrastructure must come from private sources. There are two basic ways of ensuring that those providing this investment capital will get a reasonably secure return on their investment. The first of these is through commercial contracts and the second through a regulatory agreement that the investor will receive income through regulated network tariffs. A combination of these two basic approaches can be employed on single infrastructure projects.

Market based investments

2. In this case, future users of the capacity contract with the investor and commit to pay, over a defined period of time, for the use of capacity. The form of such contracts varies. The typical approach is as follows:

- An open season is undertaken by the TSO. During the open season potential users of the capacity to be built bid for capacity.
- Successful buyers commit to purchase future capacity. This commitment will normally take the form of a commitment to pay the tariff on a defined amount of capacity for a defined period of time. The time period may last from 10-25 years. The longer the time period, the more confidence the TSO will have that the investment will achieve a return. The buyer may make a financial deposit with the TSO.
- When built, the tariff payable to the TSO for the capacity will be established through regulatory means.
- The buyer of the capacity will have the right to use the capacity. The regulator may impose conditions such as 'use it or lose it' or 'use it or sell it' on the capacity holder.
- The new EU Capacity Allocation and Congestion management framework Guidelines from ACER propose that TSOs may be able to buy back capacity, or that the capacity could be financially firm rather than physically firm. In both of these cases the consequence for capacity holders would be that in certain circumstances (some of) the capacity they hold could be transferred to another user, but they would be fully compensated for that financially. Consequently this innovation should have no effect on investment decisions.

3. The advantages of market-based investments are that:

- Risks fall to investors, not consumers
- Costs are properly allocated directly to users, even across borders

4. The disadvantages are:

- Long term contracts can inhibit the development of competition
- Risks are likely to be higher than that for regulated investments and consequently the cost of capital will be higher
- Infrastructure sized to meet market needs and to attract a commercial return may be undersized from a public policy perspective (e.g. it may have no allowance for security of supply requirements)

Regulated Investments

5. In this case the requirement for investments in gas infrastructure is calculated by the TSO and is subject to regulatory supervision. The cost of the resulting investment (and a regulated return on the investment) is recovered through network tariffs over a period of time. The time period normally relates to the expected life of the asset but in practice varies from 20-40 years. The typical approach is as follows:

- The TSO may undertake a 'market test'. This is similar in many ways to the 'open season' described above in that potential users of the capacity to be built are asked to indicate their future capacity requirements. However, no contractual commitment results from the process in this case.
- The TSO uses the information gathered through the market test, together with other information (such as network standards, past usage data, demand growth forecasts etc.) to determine the appropriate size of the infrastructure to be built.
- Subject to regulatory approval (the methods for which vary) the cost of the infrastructure is passed into the regulatory asset base of the TSO and the costs may then be recovered through tariffs.

6. The advantages of the regulated approach are that:

- The new capacity is entirely open to third parties and so provides a good basis for the development of competition.
- The risk is very low and so a low cost of capital can be achieved. This reduces the cost of the investment to the benefit of consumers.

- The TSO is required to take into account public policy goals (such as security of supply) when designing the infrastructure.

7. The disadvantages of this approach are:

- Risk is transferred to consumers
- There is no commercial incentive on network users to give correct information to the TSO during the market test.
- The method does not automatically allocate costs (and risks) correctly when investments have cross border effects.
- An established gas market is essential for the method to operate.

Hybrid Projects

8. It is possible to apply both the market based and regulated approaches to the capacity to be constructed within a single project. This hybrid of market based and regulated investments is commonly used where the infrastructure will serve different purposes.

9. The ECRB GWG has identified three categories of use for the capacity in the Gas Ring:

Tier A will be the part of the estimated capacity devoted to (or primarily meant for) satisfying national gas consumption in the country the section crosses. This demand, and the corresponding capacity, should, in principle, be accommodated and developed under a fully regulated TPA regime, following the provisions of the EU aquis since the capacity is designed to benefit all network users (i.e tariff payers). The development of Tier A capacity will be normally be the task of the relevant TSO, unless national legislation provides for other solutions (such as private or public/private shared ownership). The TSO will be fully remunerated, through tariffs, for the costs of the capacity. It should be noted that Tier A capacity could be part of the Ring formed by the system of one TSO whilst it is used to serve the needs of consumers in another TSO network (i.e. capacity used to transport gas to a TSO network to serve the national demand in that network). As mentioned above, such cross border effects give rise to cost allocation issues in the context of a fully regulated regime.

Tier B will be the part of the estimated capacity dedicated to large users (usually commercial users), who have reserved it for their own purpose (e.g. following an “exemption” procedure, or under a long term contract). In this case the cost of the investment is allocated to the large user who is the beneficiary. Typically Tier B capacity would be purchased by a large user such as a power station. Typically Tier B capacity will be purchased in the form of a contract which commits the buyer to pay the required tariff charges for a defined period of time. An initial payment from the buyer to the developer (usually the TSO) is also a normal feature. These commercial arrangements surrounding Tier B capacity also address cost and risk allocation issues directly. Market based investments are described in more detail above.

Tier C will be additional capacity, dedicated to the Ring, and in principle, open to all Ring-users. The capacity will not be allocated to any specific group of current users, but will anticipate future market development. Since this capacity is designed to benefit all network users in the future, it will be funded under a regulated TPA regime, preferably common for all national segments of the Ring.

10. In employing the market-based and regulated approaches in respect of the Gas ring, the disadvantages of each approach will need to be addressed.

Application of the business models to the Gas Ring

11. Different circumstances apply to the different sections of the Gas Ring. In the Northern Route gas markets are established (although in different stages of development), whilst in the Southern Route for some sections there is no established gas market. Their circumstances affect the applicability of the business models to each section:

	Market exists	**Immature market**	**No market**
Fully regulated	Possible	Depends on circumstances*	Not possible*
Fully market based	Possible	Possible	Possible
Hybrid	Possible	Possible	Not possible*

*Clearly, the regulated approach, which depends on the existence of tariff payers, cannot be employed where no market exists. A sufficient number of tariff payers is essential to underpin the funding of a project. Where no market exists risk management tools are likely to be necessary to encourage necessary investments.

12. This suggests that in the Northern Route all business models are open, whereas in some sections of the Southern Route the market based model may be the only option immediately available. However, incremental capacity may be developed on the assumption that future consumers will emerge as the market develops and that the tariffs they pay will fund the investment of the capacity used to serve them.

13. The long term goal on all sections should be the achievement of fully regulated third party access to all infrastructure capacity.

A practical approach to determining the appropriate business model

14. The application of the business models must be designed to meet the needs of each section of the Gas Ring and must take into full account the results of the risk assessment and the application of the risk management tool box.

Step 1: Assessment of capacity usage

15. The intended use of the capacity to be constructed will vary across the different sections of the Gas Ring and the assessment should determine what proportion falls into Tiers A,B and C. Such an assessment is made on a national basis during the normal network planning procedure of the national TSO. Typically, every one or two years the TSO will prepare a plan looking forward over a ten year period. The plan will based on a national network model and will take account of current information of current and forecast demand, and on current and future sources of supply (such as LNG in gas and generation projects in electricity). The methodology for the preparation of the national plans is, normally, approved by the national regulatory authority. The preparation of each national plan is dependent on developments in adjacent networks and so some interaction between TSOs is needed. Whilst it is possible to create a set of co-ordinated plans in this way (as happens in most countries currently), the sum of the plans will almost certainly result in a less efficient outcome than a top down plan based on a regional network model. The development of a regional network plan will require the TSOs in the region to collaborate at regional level and a new institution to enable that collaboration will be required. This arrangement could be similar to that established under the EU 3rd energy package where the TSOs collaborate within the framework of ENTSO-E and ENTSOG.

Step 2: Determination of the appropriate business model

16. The appropriate business model should result from a careful assessment of the applicability of the model to the circumstances of the project, as well as an analysis of the advantages and disadvantages of each model. The considerations are summarised in the following table:

	Tier A	Tier B	Tier C
Regulated	This should be the chosen model for established markets. Where there is no market, there will be no Tier A capacity. In immature markets the development of Tier A capacity is likely to require to application of risk	Where capacity is dedicated to long term users of the network the approach of choice would normally be the market based one. Some of the Tier B capacity may be put under a regulated arrangement if there are wider benefits to consumers	This should be the chosen model for Tier C capacity. The application of the regulated model means that cost allocation issues must be addressed.

	management tools	(such as security of supply or the potential benefit to the longer term development of the market) which emerge from the risk assessment.	
Market based	This model would not normally be applied to Tier A capacity unless risk management tools are applied. However, it may be applicable to feed in lines which supply users of Tier A capacity (e.g. for the supply of gas to a hub).	This should be the chosen model for long term users requiring dedicated capacity. Regulators should consider whether there could be foreclosure issues which result from the application of this model as part of the risk assessment.	A market based approach would not normally be applied to Tier C capacity unless risk management tools are applied.
Hybrid	A hybrid approach would not normally be applied to Tier A capacity.	A hybrid approach may be used where the risk assessment indicated that there are wider consumer benefits from a mixed market-based and regulated approach.	A hybrid approach would not normally be applied to Tier C capacity.

Step 3: Risk Assessment

17. This is described in Chapter3.

Step 4: Application of the Risk Management Tool Box

18. This is described in Chapter 4.

Step 5: Negotiation with investors (including TSOs)

19. It is inevitable that investors will have a different view from regulators on the level of risks and on who should bear them. The challenge is to reach a common understanding (but not necessarily agreement) on:

- The business model
- The risks to the investment posed by the project
- The public policy goals which need to be achieved
- The risk management tools which are available to address the risks

CHAPTER 3

Risk Assessment of new Investment in Major Gas Infrastructure Projects

The role of risk assessment

1. Investors in gas infrastructure must have reasonable certainty that they will get a return on their investment in order to justify their investment decision. It is therefore a critical part of their investment decision to undertake a full financial risk assessment for the project. The result of this analysis will determine what return the investor will require, and a higher return will be demanded for those projects where the risk is perceived to be higher. If the risk is very high then the investor may decide not to invest in that project at all.

2. There are some steps which regulators, donors, governments and other actors can take which, where appropriate, can reduce the risk faced by investors in gas infrastructure. These steps are described in the chapter on the 'risk management toolkit'. Some of these measures are used commonly in gas markets internationally. For example:

- New investments in gas networks are commonly paid for through network tariffs. The consequence is that the risk of individual investments is shared by all tariff payers rather than by the individual investor. This may result from the choice on business model (such as applying a regulated approach instead of a market based one) but could also result from specific choices made by regulators on the combination of market based and regulated arrangements in place in a specific project. 'Cross subsidies' of this kind have been justified on the basis of the wider benefits to consumers (tariff payers) resulting from the project in terms of (e.g.) security of supply or future market development. Regulators may choose to adopt a regulated approach because such investments are deemed to be essential and very low risk. By reducing the risk exposure of investors they can obtain a lower cost of capital and obtain a lower rate of return, thus reducing the overall cost of the network to tariff payers.

- New investments in gas interconnectors may be exempted from the European Union legal requirement to allow third party access to the capacity of the pipeline. This enables long term capacity contracts to be let which reduces the risk that the investment will not be fully utilised. Regulators have agreed to this exemption in those projects where, without such an exemption, the resulting risk would be deemed to be too great for the investment to be made.

3. The risks posed by each gas infrastructure project are different and each must be assessed based on its particular circumstances. Further, the discussion between potential investors,

regulators and other actors is inevitably a difficult one as in principle investors logically will wish to minimise their risks whilst maximising their potential returns, Regulators have a duty to keep the costs to network tariff payers (and hence to consumers) low which means that they must make difficult judgements about whether to allow risks to be passed away from investors and ultimately onto consumers.

4. Achieving a successful and balanced outcome of such negotiations is central to the achievement of efficient and essential gas infrastructure investments.

5. This chapter does not (and cannot) provide a roadmap for these negotiations between investors, regulators and other actors. Nor does it attempt to replace the risk assessment analysis which investors, regulators and other financially interested parties must undertake. However, it does offer a simple and easily understood common risk assessment framework for the discussion of risk which should facilitate the negotiation process. It aims to:

- Provide a common basis for the identification of sources of risk
- A common measure of the level of risk exposure
- A single set of tools for the management of risk
- A single process for the assessment of risk, and the assessment of the possible tolls to manage them

6. By this means the risk assessment framework will enable negotiations between investors, regulators and other actors to be undertaken on a common basis which should facilitate understanding between the parties. It will facilitate each of the parties communicating their own assessment of risks in with a common framework, and discussion of the options for managing those risks.

Risk Assessment Framework

7. The scope of the Risk Assessment Framework (RAF) is restricted to those risks which are outside of the direct control of the investor of the infrastructure project. Those risks which it is within the ability of the investor to control should not be transferred to another party, and the level of those risks will depend upon the capability of the investor itself to manage them. The physical operation of the infrastructure project, when built, is a prime example of this principle. The investor should not be compensated for risks resulting from poor operation of the asset when decisions on the physical operation are under the control of the investor (e.g. if the investor is not itself a TSO, then the investor should ensure that the appointed TSO is competent – this risk

should therefore be left with the investor).

8. As each project has its own unique risk profile, a RAF must be tailored to fit each project. The process for establishing the RAF will have the following four sequential steps:

    i. The identification of the risks which investors in a particular project may be exposed to, and are outside of their direct control.
    ii. A quantified assessment of the severity of those risks in relation to the level of exposure of the investor (i.e. the risk that the investor will make a loss rather than a reasonable profit over the life of the project).
    iii. An assessment of whether any of the identified risks is sufficiently high to merit further treatment, or should be left with the potential investor;
    iv. Analysis of the risk and potential benefit to other parties if the risk were to be wholly or partly passed to them, based on the options in the risk management toolkit.

Step (i): The identification of the risks which investors in a particular project may be exposed to, and are outside of their direct control.

9. Project risks can be divided into political risks and commercial risks.

10. The ECA report 'South east Europe: Regional Gasification Study' identified the following risks which should be assessed in relation to each project:

Political Risks	**Commercial Risks**
Expropriation	Planning
Security	Design
Breach of contract	Construction
Legal and regulatory	Volume (including price risk)
Currency transfer restriction	Supply
Dispute resolution	Payment
	Exchange rate
	Interest rate

11. Risk mitigation in relation to each of the above risks will be within the scope of different parties. For example:

- Volume risk and Price risk. The risk that the project will not be able to sell enough quantity (of capacity), and the risk that the investment will not be able to command in the market the price required (in the currency of the investment) to achieve a reasonable return on the investment can be mitigated through contractual means or through guarantees underwritten by governments.

- Legal and regulatory risk. The risk that the legislative of regulatory rules change in a way which undermines the commercial viability of the investment. This can be addressed through the implementation (by government) of an independent and predictable regulatory framework.

<u>Step (ii): A quantified assessment of the likelihood of each identified risk impacting on the investor (i.e. the risk that the investor will make a loss rather than a reasonable profit over the life of the project).</u>

12. Each of the risks identified in step 1 should be assessed and allocated a risk factor of between 1 and 5. Those items assessed to be very unlikely to materialise should be graded as 1 whilst those assessed to have a high likelihood of occurring should be assessed as 5.

13. There is no science in these assessments and the purpose is to facilitate discussion between the parties in order to understand and compare views on a common basis.

1	2	3	4	5
Very low prospect of occurring	Unlikely to occur	Some likelihood it will occur	Likely to occur	Very likely it will occur

<u>Step (iii): An assessment of the whether any of the identified risks is sufficiently high to merit further treatment by regulators, governments or donor organisations, or should be left for the potential investor to manage</u>

14. Each of the risks identified will have different potential impacts on the investment. These impacts must be assessed and quantified. Those with a low impact (i.e. where there would be a low impact on the value of the investment if the risk were to be realised) will be assessed as 1, those with a medium impact (i.e. where the anticipated profits generated by the investment would be significantly reduced if the risk materialised) as 2, and those with a high impact (i.e. where the investment would result in a loss if the risk were to materialise) as 3. The risk assessment for each item is the product of multiplying the risk factor by the impact assessment.

This will give the risk assessment for each risk item identified graded numerically between 1 and 15. Those items with a high impact and a high risk will be of most concern, whilst those with a high risk, but low impact may not be of concern.

1-5	6-9	10-11	12-15
Low	Medium to low	Medium to high	High

15. The resulting matrix can then be used to calculate an overall risk assessment for the project. The total of all the individual risk assessments should then be divided by the total number of items which will result in a risk assessment for the project in a range between 1and 5.

16. The calculation looks like this:

$$\text{Project risk factor} = \frac{\sum_{n1}^{nx} (\text{risk factor n})(\text{impact assessment n})}{\text{x}}$$

(where n is an identified risk item of a total list of x identified risk items)

17. Whilst the overall project risk assessment is of interest, it is likely that it will be the individual assessments of the risks items which will reveal the areas of the project which are of most concern to a potential investor and where appropriate measures may need to be taken to manage those risks specifically using the risk assessment toolbox.

Step (iv): The management and transfer of risk

18. Having understood the risks which an investor is exposed to it is necessary to analyse each one which is deemed to be significant as a result of the preceding analysis. All significant risks should be considered to determine whether:

- there is scope to reduce the absolute level of that risk (this may be the case with some political risks, for example)
- it should be best managed by the investor (some of the commercial risks fall into this category)
- It should be transferred or shared with another party. Preferably the party which is to bear the risk, or to share part of it, should also be a beneficiary from the investment either directly or indirectly. Volume and price risks are likely candidates for risk sharing or transfer.

19. This is discussed in more detail in Chapter 4 on the risk management toolbox.

CHAPTER 4

Risk Management Toolbox

Forms of project risk

1. Risks to an investment may take a number of forms, but can be grouped into the following categories:

- Political risks
  These are risks which result from the legal and regulatory environment, matters which fall to governments to control, and geopolitical risks.

- Commercial risks
  These are risks which stem from the market and the commercial arrangements surrounding the project.

Risk management tools and relevant actors

2. The ECA report 'South East Europe: Regional Gasification Study' identified the following areas of risk for each category. The following possible risk management measures could be possible:

Political Risks	**Possible risk management measures**	**Main relevant actor**
Expropriation	Government assurance Contractual commitment for Government compensation in case of expropriation	Government
Security	Policing of law and order Private security	Government Investor
Breach of contract	Well structured contract	Investor
Legal and regulatory	Sound legal environment Regulatory framework to allow any costs incurred as a result of change to be allowed for recovery	Government Regulator
Currency transfer restriction	Open financial system Hedging insurance	Government Investor
Dispute resolution	Independent judicial and regulatory regime (i.e. a national regulatory authority) in place with dispute resolution arrangements Contract specifies (binding) independent arbitrator	Government Investor Regulator

Commercial Risks	Possible risk management measures	Main relevant actor
Planning	Sound planning rules Good project management	Government Investor
Design	Good project management	Investor
Construction	Good project management	Investor
Volume (including price risk)	See discussion below	Investor Government Regulator Donors
Supply	Infrastructure maintenance	Investor
Payment	Advance payments Collateral security (e.g. letters of credit)	Investor Regulator (where theft is a problem)
Exchange rate	Index payments to common currency	Investor
Interest rate	Fixed interest loans Sound independent and predictable regulatory regime	Investor Government

3. It can be seen from the above analysis that the critical political risks rely on governments to provide a secure and legally reliable climate for investment to take place. Of the remaining identified risks the critical ones where risk management measures involve actors other than the investor are volume and price risk, and legal and regulatory risks.

Price risk

4. These measures can be used to address the risk that the investor may not achieve the price for the capacity that is expected. This risk arises mainly in relation to market based investment and the market based element of hybrid investments.

5. Any risks management arrangement to provide greater certainty to the investor will limit the potential for loss or lower returns. However, the solution should not simultaneously reduce the risk of loss, whilst also allow super-returns. Reducing the risk to the investor should also limit the level of return they can expect on their investment. The regulatory option for addressing price risk is to provide a 'cap and collar' arrangement under which the investor will have a lower limit on the returns it can make (thus limiting any loss) whilst also being required to surrender any profit beyond an upper limit. Whilst the risk of any losses will be underwritten by tariff payers, tariff payers in this arrangement also stand to benefit if there are higher returns. In the UK such arrangements are used in a number of ways. A cap and collar arrangement is used to provide an incentive to the TSO to minimise balancing costs below a target figure. A different

cap and collar arrangement is being developed to provide defined returns to new renewable generators and this is planned to operate by providing a feed in tariff when electricity prices fall below a predefined ‘collar’ level, and profit surrender when prices rise above a ‘cap’ level.

6. Other options for risk reduction, risk sharing and risk transfer exist but are outside of the scope of regulators functions. The key ones are:

- Risk sharing through a cap and collar arrangement where the risk sharing party is a bank or donor
- Risk reduction through the offering of a subsidy from a government or donor
- Risk transfer where the risk of loss is underwritten by a government or donor (in which case the rate of return allowed on the investment should reflect the investor’s lower exposure to risk)
- Partnership between Government and the private investor (a Public Private Partnership). These can take a number of forms but typically they could:
    - Provide a volume guarantee to the investor through an agreement whereby government commits to purchase a defined level of output
    - A shared equity arrangement where the risks and rewards of the project are shared (often called ‘Public Private Partnership’)

<u>Volume risk management</u>

7. This risk arises from the potential for the new capacity being utilised at a lower level than forecast.

8. The main risk management tools available to address this risk are:

- Allowing a time-limited exemption from third party access. This has the effect of reducing uncertainty over access to the capacity and thus to the market.
- The forward sales of capacity on long term take or pay contracts. The effect is similar to that above.
- Aggregation of gas demand across the region could enable the creation of a single entity which could contract from the total sum of gas required in the region. In this ‘single buyer’ model the risk of fluctuations in gas demand will be aggregated and this reduced, and the potentially poorer credit standing of smaller buyers overcome. The single entity could commit to purchase future capacity on new infrastructure investments. This model was put forward by the European commission at the 4th Joint ECRB and PHLG meeting on 14 October 2011. The single buyer approach was named the ‘Caspian development Corporation’ concept. Single buyer models are used in developing electricity markets, including many in the Middle East.

- Allowing the capacity to be built undersized. This has the affect of both reducing the capital costs to some extent, whilst also increasing the potential value of the capacity for any given level of demand (assuming that there is some congestion). The consequence is reduced public benefit from the investment which could have risks for the future realisation of the Gas Ring.

Potential risk sharing partners

9. There are a number of parties who could potentially be candidates for accepting risk in respect f individual projects:

- Tariff payers. Regulators can transfer risks where there is a demonstrable public benefit in the investment proceeding and where it would not if an element of the risk is not transferred.
- Donors. Donors may be prepared to accept some risk, or to provide funding which reduces the overall level of capital at risk, in order to achieve their objectives in relation to the development of the relevant market.
- Banks may be prepared to enter into risk sharing arrangements (or offer insurance against certain downside risks) where they consider the commercial prospects of the project to be good.
- Traders and speculators may purchase future capacity on the assessment that its future value will rise.
- Governments may be prepared to provide subsidies for individual projects (subject to state aid rules).

Sound Legal and Regulatory Framework

10. The fundamental basis for private capital being invested in gas infrastructure is the certainty of receiving future returns on that investment through regulated tariffs over a period of 20-40 years. The implementation of a robust regulatory framework with a regulator at arm's length from government and independent of commercial interests is central to the achievement of the predictable regulatory regime that is a good basis for investments. This is a central element of achieving a sound investment climate.

11. The basic elements of such a regime are included in the EU acquis, including in the 3rd energy liberalisation package. In particular, the 3rd package sets out the requirements for the terms of appointment for regulators and the bases on which they may be dismissed from their posts, the powers, objectives and duties of regulators. These requirements form a benchmark for all regulatory regimes.

12. The main instrument for implementation of the EU acquis in the Contracting Parties is the Treaty Establishing the Energy Community and legally binding decisions of the Energy

Community Ministerial Council, especially the Decision on implementation of the 3rd package in the Contracting Parties adopted on 6th October 2011 in Chisinau, Moldova. In order to effectively achieve a single regulatory space comprising the EU 27 and the Contracting Parties, it is important that the Treaty Establishing the Energy Community clearly and unambiguously establishes the obligation to implement the existing and envisaged cross- border mechanisms set by the acquis also on the borders between EU MS and Contracting Parties. Any gap between regulatory frameworks of EU and the Contracting Parties should be reduced to maximum extent in order to ensure that the regulatory risks are minimised.

13. A further important element is the separation of the network operator from the potentially competitive parts of the market. Consequently network operation should be unbundled from gas production, shipping and supply. This is a requirement of the EU 3rd energy package.

CHAPTER 5

Cost Allocation and Cost Recovery

Cost allocation

1. Those who benefit from the existence of infrastructure should pay for its cost. There are different types of 'benefit' that may accrue to network users:

- Gas transportation is the primary function of gas infrastructure and the cost of this service should be allocated directly to those consuming the gas. This could relate to Tier A and Tier B capacity.
- Security if supply requires some level of redundancy in the network (to deal with maintenance outages, reverse flow possibilities etc.) and this benefits all network users. The level of network security of a TSO's network may benefit from being interconnected to that of another. This may be the most efficient solution, but the other TSO may incur costs as a result. However, the benefit from a particular project may be limited to a particular region. In this case the cost should be allocated to those in that region where the benefit is delivered. This relates to Tier C capacity.
- Future enhancements to market functioning. This is a general benefit the costs of which should be smeared across all of those in the region where the benefit is likely to be delivered. This relates to Tier C capacity.

2. Within a country the normal method of cost allocation in relation to the cost of gas infrastructure is through the structuring of network tariffs. Normally the view is taken that all network users benefit from being connected to the gas transmission network and so all pay a share of the cost. How much each person pays may depend upon where they are connected. The further they are located from the sources of gas then the further the gas must be transported, and so the more of the network that user will use relative to other users located nearer the sources of gas. Consequently in many countries the network tariffs are structured so that they are higher further away from the sources of gas and lower nearer to them. Often there is an additional element to the tariff which is a flat charge (i.e. non-locational) which reflects the costs of the general benefits received by all uses – mainly in terms of network security. One of the major tasks of regulators is to ensure that network tariffs are cost reflective and fair.

3. In relation to the cost of infrastructure which is used for cross border purposes (i.e. capacity which is serving users outside of the TSO's area) costs should, in principle, be allocated to those persons who benefit from that capacity, and it should not be paid for by the tariff payers on that

TSO's network. To achieve fair cost allocation in the regulated tariff arrangements, co-operation between regulators is required. In many countries where the benefits of cross border capacity are considered to be fairly evenly spread, it is common for a simplified approach to be adopted and the costs of the new investment is shared 50:50 between the two TSOs and reflected in their RAB in that way. Where the benefits and costs are not evenly spread (which may often be the case) then the benefits will need to be assessed by the regulator. This is a complex topic, but in summary the assessment (of how consumers connected to a TSO's network) may benefit can be made in terms of:

- Enhancements to competitiveness. In this area the direct effect of the increase in network capacity on prices can be assessed, together with an assessment on the potential impact which may result in the future as a result of enhancements to competition.
- Enhancements to security of supply. An increase in the number of gas sources, or greater network resilience will reduce the prospect of supply interruptions. Such an assessment should be able to quantify the reduction in loss of load probability and the avoided loss in economic production.
- Enhancements to sustainability. Some investments may give benefits in terms of reduced carbon emissions. Quantifying this benefit may be done directly if there is a reliable price for carbon, or may be assessed in terms of avoided costs of achieving the same benefit using other technologies.

4. The EU is currently developing proposals on cost allocation as part of its work on the draft Infrastructure regulation.

5. In all of these cases some adjustment must be made to the allowed revenues of the TSOs in order to reflect those cross border costs which cannot be charged directly to energy users (to recover the costs associated with gas transportation). These costs relate to Tier C capacity. There are two options for making the necessary adjustments:

Central fund. Network modelling techniques can be used to determine the proportion of each TSO's network which is used for non-domestic purposes, and also what use each TSO makes of the networks of other TSOs. The cost of this can be calculated and the 'users' required to pay into a central fund. The fund can then be used to reimburse those TSOs whose network has been used by others.

This approach is similar to the Inter-TSO Compensation Scheme (ITC) used in the EU in relation to electricity networks. The advantage is that it addresses directly the cost allocation question. The disadvantages are that it needs centralised organisations (of TSOs, governments and regulators) to operate it and this implies additional costs, and (perhaps because the sums of money involved are large and are pooled into a central fund) the setting of the financial sums may be controversial. In the case of the inter-TSO compensation scheme operated in the EU the establishment of the total amount of the compensation fund and its allocation between members states was for many years a a difficult process, although the operation of the scheme was straightforward once these parameters had been decided. Another approach is described below which avoids the need for a pooled fund, but otherwise has similar features.

Line rental. Under this arrangement similar centralised network modelling would be required to determine the users of others TSO networks and the costs of that usage. In this approach TSOs would simply invoice users directly for the costs which have been identified. There would be no central fund.

The advantage of this scheme is that TSOs would invoice their costs directly, thus avoiding the need for a centrally administered fund. Those receiving an invoice would be able to recover the cost through their network tariff (and thus pass on the cost to the network users benefitting for the non-domestic infrastructure). The disadvantage is that central organisations would be needed (again, in the sense that it implies additional costs) in order to undertake the network modelling and to oversee the operation from a regulatory perspective.

A modification (and simplification) of this scheme could be made if the cost of existing infrastructure was considered to be sunk. However, such a decision could be considered unfair by some and would need close examination. In that case only the cost of new infrastructure would need to be allocated. This could be done on a case by case basis by determining the potential beneficiaries of the Tier C element of the capacity to be constructed. The necessary changes to the allowed revenues of the affected TSOs could then be made. No centralised organisation would be required in this case.

Cost recovery

6. There are a number of ways in which costs can be recovered across national borders:

<u>Market based arrangements</u>

7. Market based arrangements rely on a contractual commitments between the TSO and network users (see the description of market based arrangements above). In some cases the charges paid by the users are reflected in the contract as a result of negotiation. This negotiation reveals the market value of the capacity. The result is that under such contracts network users pay fees directly to the TSO. In reality these fees may be paid to a number of TSOs where the capacity

reaches across a number of TSO networks. In these cases the costs are allocated directly to the users independently of the differences of country and regulatory jurisdiction.

8. Arrangements such as these in the European Union must be consistent with EU Regulation (EC) No 715/2009 on gas which requires that all high pressure gas pipelines should be open to third party access. These contractual arrangements have application in interconnections that run beyond the EU's borders.

9. Normally contracts commit users to pay tariffs on a defined amount of capacity. This gives rise to the same cost allocation issues that exist in relation to regulated arrangements.

Regulated arrangements

10. Regulated arrangements are focussed on the regulation of a single TSO network by a national regulator. Consequently they do not automatically address costs which occur outside of the TSO's area, nor the benefit derived by the network users of that TSO from the interconnection to other TSO networks. Consequently different or complementary mechanisms are required to ensure proper cost allocation and recovery in relation to infrastructure used for cross border purposes. Co-ordination between national regulatory authorities (or those setting network tariffs in cases where it is not the regulator) is necessary to establish a common method of cost recovery. Co-ordination between regulators on tariff setting could be undertaken on a voluntary basis through existing structures. However, a voluntary arrangement would be less certain in its effect that the binding arrangements which are being implemented in the EU as a result of the development of tarification guidelines under the 3rd energy package.

11. There are a number of options:

Pay as you go. This is a commonly used method where users simply pay the network charges for capacity along the route that they wish to transport the gas. The problem with this approach is that commonly the detailed arrangements for buying and selling capacity either side of a border at an interconnection point are not harmonised which makes it difficult for shippers to easily purchase co-ordinated blocks of capacity either side of an IP.

A further issue is that unless the tariffs of each TSO are cost reflective there can be 'pancaking' of charges so that the shipper may overpay for the capacity along the chosen route. It is possible to arrange for the network tariffs to be cost reflective and co-ordinated. In the EU the basic system adopted is for each market to have one or more gas zones. Each zone has a gas hub. Users pay an entry charge to enter the zone and an exit charge to leave the zone or to supply demand within the zone. These entry-exit tariffs are normally calculated with reference to the gas hub and, on this basis, it is possible to make them cost reflective. Shippers wanting to ship gas across a number of zones have to pay the relevant entry and exit charges to cross each zone. The amount of revenue a TSO can recover will be determined by its regulator who will decide the allowed revenue of the TSO. The allowed revenue will, in turn, determine the level of the tariffs. The size of a zone should be consistent with the largest efficient balancing area and this will depend upon the topology of each network.

The advantage of this approach is that it is understandable by network users and allocates the costs directly to each user through tariffs. The disadvantage, as a result of the additional administration and cost, is that the calculation of the tariffs is complex and some co-ordination between regulators is necessary.

Bundled tariffs. A simplification of the pay as you go approach would be to bundle the entry-exit tariff at each IP so that network users pay one tariff charge to move from one zone to the next. To achieve this simplification the capacity products either side of the border at the IP would also need to be bundled. The bundled tariff would have to be unbundled subsequently so that the revenues can be shared between the two TSOs.

Train Ticket (or one stop shop). Under the arrangement users would pay an entry charge and there would be an exit charge at the point of consumption (or at the hub at the destination) regardless of how many zones had been crossed. In this case an agent would have to determine the charges to be paid by bundling the entry-exit charges along the route and then subsequently unbundling the revenues for allocation to the relevant TSOs.

12. The last two of the above approaches are developments of the pay as you go approach.

13. Whilst in theory it would be possible to develop the train ticket approach further – so that tariffs were set through a single methodology which applied to the whole region as if the region's networks were a single system and the resulting revenues subsequently allocated to the relevant TSOs – this is not proposed here as a possible solution. This partly because of the complexity (and it is not clear that the benefits derived would outweigh the costs of implementation and operation of such a scheme), but also because such a scheme would need a firm legal and regulatory basis, as well as the necessary institutional arrangements for its administration. The legal and institutional framework within the SEE region does not exist at present and would need to be developed. Tariff arrangements in the EU are currently under development but it is not envisaged that a pan-EU tariff scheme will be implemented in gas in the foreseeable future.

CHAPTER 6

Northern Route Base Case Business Model

Introduction

1. This chapter examines the key challenges which must be overcome in order to provide a sound climate for investment for each of the markets along the Northern Route. The approach used is to apply the risk assessment framework described in Chapter 3 to identify the key challenges. The regulatory toolkit has been applied to the identified key challenges in order to determine options for the management of the associated risks. The outcome is a 'base case business model' and as such it is intended to be a starting point for negotiations with potential investors and other relevant actors.

Features of the Northern Route

2. The 'Northern Route' involves Croatia, Serbia and Bosnia and Herzegovina. More precisely it includes the existing pipeline Gospodjinci (Serbia) - Loznica (Serbia) – Zvornik (BIH) Sarajevo (BIH) – Zenica (BIH) with two planned interconnectors of Slobodnica (Croatia) - Gospodjinci (Serbia) and Slobodnica (Croatia) – Zenica (BIH).

3. Croatia is a significant producer of gas (2.3 Bcm pa in 2010) relative to the size of its market, with the remainder of its current requirements (1.1 Bcm pa in 2010) being imported. It is projected that annual demand will rise from 3.1 Bcm in 2010 to 4.4 Bcm by 2020 according to the Republic of Croatia Energy Strategy. A LNG receiving terminal is proposed at Krk Island with a capacity of 10-15 Bcm/y. The Croatia Energy Regulatory Agency (HERA) is independent of government and commercial influence and is expected to gain powers to set tariffs. Significant gas transmission network developments are planned or underway, such as the newly opened interconnection with Hungary and the connection of the existing gas system to the southern part of the country (the regions of Lika and Dalmatia).

4. Bosnia and Herzegovina has no indigenous production of gas and imports all current gas supplies from Russia. At the policy level, the intention is to adopt the EU energy aquis. The constitution of Bosnia and Herzegovina is complex. In the Federation of Bosnia and Herzegovina the regulation of the gas market is currently undertaken by the government, whilst in the Republika Srpska gas market regulation is undertaken by the Regulatory Commission for Energy (RERS). The largest single customer on the Bosnia and Herzegovina system is the Birač aluminia plant. Other large customers include the Mittal steel plant in Zenica, a brick factory in Visoko and a cement factory

in Kakanj. Natural gas is the main source of energy for households in Sarajevo. Where results for Bosnia and Herzegovina differ for its entities (the Federation of Bosnia and Herzegovina and Republika Srpska), they are displayed separately in this report.

5. Serbia has been producing its own gas for half a century, but has always been a net importer of gas. Northern Serbia is fully gasified, Western and Central Serbia are only partly gasified while the southern region has hardly any gas. There is a National Action Plan for Gasification, with investment resources for gas projects channelled through the National Infrastructure Development Fund. The gas sector is regulated by the Energy Agency of the Republic of Serbia (AERS) which was established in 2005 and is functionally independent of any state body. A tender for a new CCGT power station on Novi Sad is currently open. Gas demand is forecast to grow modestly to 3.6 Bcm/y in 2025.

Risk assessment

6. The following initial assessment has been made in relation to the categories of risk identified in Chapter 3:

A) Political Risks

Expropriation

7. The risk of expropriation of the invested assets, or profits arising is assessed to be low in relation to all regions on the Northern Route. Were expropriation to happen, however, the impact on the investment would be high.

Country	Risk factor	Impact assessment	Risk assessment (Risk Factor multiplied by the Impact assessment)	
Croatia	1	3	3	
BiH	1	3	3	
Serbia	1	3	3	

8. No risk management tools are required in this area.

Security

9. The risk to the invested assets from lack of security in the market is assessed to be low in relation to all regions on the Northern Route. Were damage to the assets to occur as a lack of security, the impact on the investment would be medium. This assessment is made on the basis that any damage cause would be likely to be localised.

Country	Risk factor	Impact assessment	Risk assessment	
Croatia	1	2	2	
BiH	1	2	2	
Serbia	1	2	2	

10. No risk management tools are required in this area.

Breach of contract

11. This is a matter for the investor and so is not assessed here.

Legal and regulatory

12. The situation is different in each of the relevant markets. In Bosnia and Herzegovina there is currently no gas regulator other than in the Republika Srpska. As a result the regulation of the gas market in this country is undertaken by different authorities – in some regions it is the regulator whilst in others the function is undertaken directly by the Ministry. The lack of a regulator which is independent of government increases the regulatory risk to investors (since the regulatory regime is inevitably more exposed to political influence).

13. In Serbia and Croatia there is an energy legal and regulatory framework and the relevant institutions are in place. In both countries the energy regulatory authorities are independent of Government and commercial interests.

Country	Risk factor	Impact assessment	Risk assessment	
Croatia	1	3	3	
BiH	3	3	9	
Serbia	1	3	3	

Currency transfer restriction

14. There are no currency restrictions in place in the relevant markets

Country	Risk factor	Impact assessment	Risk assessment (Risk Factor multiplied by the Impact assessment)	
Croatia	1	2	2	
BiH	1	2	2	
Serbia	1	2	2	

15. No risk management tools are required in this area.

Dispute resolution

16. Dispute resolution arrangements must be reliable, inexpensive and timely in operation. Dispute resolution services are normally defined within the contract, but in cases where independent legally binding dispute resolution is needed which falls outside of that envisaged in the contract, then separate arrangements must be in place. This can be the case typically in relation to contracts between monopoly providers (such as network companies) and third parties (such as those connected to the network) where the monopoly nature of the activities of a TSO and the regulated framework within which they operate do not allow for an unfettered dispute resolution in all cases. Normally the arbiter of disputes in these circumstances is the independent energy regulator. The absence of an energy regulator will therefore result in a higher risk in this area. In cases where dispute resolution fails, then recourse to the courts should be available, but this should only be a last resort.

Country	Risk factor	Impact assessment	Risk assessment (Risk Factor multiplied by the Impact assessment)	
Croatia	1	2	2	
BiH	3	2	6	
Serbia	1	2	2	

Commercial Risks

Planning

17. The risk associated with obtaining approvals for the construction of new infrastructure depends upon the planning regime in place in each country. This is the responsibility of national governments. (note: the assessment here needs to be made by regional experts)

Country	Risk factor	Impact assessment	Risk assessment (Risk Factor multiplied by the Impact assessment)	
Croatia				
BiH				
Serbia				

Design

18. The design of the project is entirely in the hands of the developer and so is not assessed here.

Construction

19. The construction of the project is entirely in the hands of the developer and so is not assessed here.

Volume (including price risk)

20. Both Serbia and Croatia have (relatively) developed gas markets whilst the gas market in Bosnia and Herzegovina is small and developing.

21. The development of the gas market will benefit existing consumers in the region through enhancements to security of supply and enhancements to the operation of the market. It will also benefit future consumers through the provision of gas supplies. Consequently the proportion of the investment costs which provide these benefits could be allocated to current and future tariff payers on the basis of a regulated arrangement. The scope for the development of significant regulated capacity seems less in Bosnia and Herzegovina than in Croatia or Serbia because the gas market is smaller and relatively less developed.

22. Where industrial users of gas (including power producers) can be identified who will commit to purchase future capacity market based arrangements may be appropriate.

23. The risk to the investors will be higher in relation to that capacity where future users of the planned capacity have not been committed contractually in advance of the commencement of the infrastructure development project (such as future domestic consumers). This risk seems most significant in the case of Bosnia and Herzegovina .

Country	**Risk factor**	**Impact assessment**	**Risk assessment (Risk Factor multiplied by the Impact assessment)**	
Croatia	3	3	9	
BiH	4	3	12	
Serbia	3	3	9	

Supply

24. The capability of the infrastructure to continue to operate and supply transmission services to users is entirely in the hands of the developer and so is not assessed here.

Payment

25. Obtaining sufficient assurance that users will pay their bills normally depends upon the creditworthiness of the users. Major new users of future gas transmission capacity are not yet known. However, where capacity is based on regulated arrangements the risk will be low.

Country	**Risk factor**	**Impact assessment**	**Risk assessment (Risk Factor multiplied by the Impact assessment)**	
Croatia	3	3	9	
BiH	4	3	12	
Serbia	3	3	9	

Exchange rate

26. Hedging of exchange rate risks is a normal part of project financial risk management and hedging instruments are available, including through IFIs assist in this process. The management of exchange rate risks is the responsibility of the developer and so is not assessed further here.

Interest rate

27. Hedging of interest rate risks is a normal part of project financial risk management and hedging instruments are available, including through IFIs assist in this process. The management of interest rate risks is the responsibility of the developer and so is not assessed further here.

Applying the Risk Management Toolbox

28. Having identified the key risks to be addressed the task is to examine which risk management tools might be most appropriate to manage the relevant risk and to determine which body (or bodies) should be involved.

29. This section looks at the key risk factors identified and considers what risk management tools might be applied in each case.

Legal and regulatory

30. Serbia and Croatia have in place an independent regulator for gas and a legal framework which would support an appropriate regulatory regime for gas. The situation in Bosnia and Herzegovina, however, is mixed and putting the appropriate measures in place is a task for the government of Bosnia and Herzegovina. All countries have agreed to implement the EU 3rd energy package, although, as mentioned earlier, clarity in the interface between the SEE region and the EU is important. This framework of legislation contains all of the central features required for a good regulatory regime which would be conducive to new investments. A clear public commitment to do so, coupled with a defined timetable would substantially address the immediate concerns of investors.

Dispute resolution

31. This issue will be largely addressed in Bosnia and Herzegovina when an independent gas regular is appointed with authority to settle disputes.

Volume and price risk

32. In each of the markets there are risks to investors although they vary. The cost of new capacity which will benefit existing consumers (Tier A capacity) could be allocated to them and this will be low risk. Capacity funded through market based investments where the contracting user has a good credit rating will also be low risk (Tier B capacity). However, capacity which is intended to be incremental to serve demand which does not yet exist will be high risk (tier C capacity).

33. An analysis is required to identify the proportion of capacity that falls into each Tier and therefore to determine the business model which can be applied to each element. Ideally this analysis should be undertaken by TSOs in the region working in co-operation on a co-ordinated network plan for the region according to a methodology approved collectively by the regulators in the region. This would be consistent with the approach adopted in the EU. The final business model will be hybrid as will contain the sum of the business models applies to each capacity Tier.

34. In this section it is assumed that all three Tiers of capacity are required in each market area. The final business model could be determined through a combination of the following measures:

- Expand the system by attracting market-based investments. In order to achieve this, a market test will be required through an open season exercise or similar arrangement. An open season test would be managed by the TSOs acting in co-operation. Such a test could form part of the development of the regional network plan described above. Through this process new users (with a good credit rating) could be identified who would be prepared to commit contractually to pay for future capacity (i.e. market based investments). They could pay either directly (by placing a deposit) or commit only to pay future tariffs on a defined amount of capacity. Clearly any potential investor would need to understand the proposed tariff regime and so this step is first dependent on the implementation of a sound regulatory framework in the relevant region of Bosnia and Herzegovina. It is expected that this process will identify potential 'anchor loads'. Probably these will be new gas fired power generating stations or existing stations converted to burn gas. The economics of conversion to gas and the place of gas in the existing generation merit order need to be established. An examination of the consequent impact on the electricity market would be required to understand the risks which would arise in finding a secure market for the resulting electricity output. This may be much easier to address in the case of power plant conversion (if it is financially viable) as the market of such a plant will already be established. The conversion to gas would simply change the plants input costs. The position of a new power plant would be different as it would initially need to displace existing plant from the merit order in order to find a market. In such a case power purchase agreements would normally need to be in place to provide the necessary assurance to investors over the whole value chain (this is normal practice within the EU and elsewhere for many projects undertaken by investors who are not one of the established market participants) or some form of risk sharing or risk transfer arrangement will be required. This could take the form of a subsidy, a cap and collar arrangement, equity sharing by government, or sovereign guarantee. Transferring some of the risk of new network investments away from investors through the application of a cap and collar regulatory framework put in place by the regulator. In this arrangement the potential return expected by an investor would not go below a defined (low) level but also could not go above a defined upper level. Another body would need to stand ready to make up any shortfall in returns should they fall below the collar level, but would receive any profits above the collar level. Such a body needs to be identified. It is unlikely that existing tariff payers could bear such a risk and the most likely candidate is government. A similar effect could be applied though a joint venture between government and a commercial investor (i.e. a public private partnership arrangement).

- New incremental capacity to serve existing consumers (Tier B capacity) would enhance existing network capacity but is unlikely of itself to create new pipeline routes to complete the Northern Route of the Gas Ring. Normal network planning techniques used by TSOs (and overseen by regulators) is the usual method applied to determine the quantity and location of new Tier B capacity. The development of new Tier B capacity which spans borders (so that capacity in created in one country to serve (partly of wholly) consumers in another country required co-operation between TSOs but this too is a normal part of TSO operations. In the case of the Northern Route TSOs are well established in each country to undertake this function. Of most interest is the determination of Tier B capacity which would be required as part of the new elements of the Northern Route. The costs of this element of capacity could be recovered using regulated arrangements through tariffs. The costs would need to be allocated to those consumers that would benefit from the new Tier B capacity.

- New capacity for future market development (Tier C capacity) is a normal part of network planning within national networks and the costs and risks are borne by national tariff payers in these cases. However, interconnectors and other pipelines which are funded through market based arrangements do not normally have Tier C capacity. This is because the pipe is either built to supply a specific commercial load, or because the value of the investment is determined in part by the congestion rents it can command (in a market, over supply of capacity would reduce its value to zero with the result that there would be insufficient congestion revenues to fund the project). In some cases, where the commercial benefits of the project are positive, regulators can require investors to include an element of Tier C capacity which can be used in defined circumstances (typically it is made available only for short term needs so that there is limited interaction with the long term market for the remaining pipeline capacity). However, is not likely to be possible to persuade investors to create Tier C capacity where the commercial case for the pipeline is not clear cut. Consequently in the case of the Northern Route any Tier C capacity will need to be paid for by existing and future network tariff payers where, in principle, the costs should be allocated according to who is expected to benefit. To the extent this is not feasible (and this will depend upon the ability of the pool of identified tariff payers to bear the relevant costs and risks, then other risk management mechanisms will be needed. Given that the outcome of underutilised Tier C capacity will be a reduction in regulated tariff income compared to that anticipated, the most likely risk management mechanisms will be a government subsidy or government guarantee.

- Some risk reduction measures could be considered for some or all of Tier A and B capacity. Providing protection from competition for a defined period of time is a typical regulatory risk reduction measure (although this reduction in financial risk must be managed to ensure that it does not operate against the longer term interests of consumers). It could take a number of forms:
    - Exemption from third party access for the new network capacity by the regulator. TPA exemption will reduce the risk that a third party will undercut the initial purchaser of the capacity and thus reduce their expected investment return. Such a situation is more likely to occur as the gas market on the Northern Route develops and the risks which exist currently have reduced.
    - Providing monopoly access to a market for a defined period. An example could be the licensing (by government) of the supply of gas to a town or city to one (or just a few) suppliers for a period of time. This would not be consistent with the terms of the EU 3rd energy package which required third party access to distribution pipelines and so some form of derogation would be required in order to apply such an approach. This would need political agreement between the contracting parties of the ECT countries and the EU.
    - Purchasing the output of the 'anchor load'. This could take the form of a power purchase agreement for a power station for example. Such a contract would have to be supported financially by government. Similar arrangements have been used successfully in the Middle East in relation to combined generation and water desalination plants. A similar arrangement is in place in the UK to support investments in renewable generation. In this case it takes the form of an obligation on suppliers to buy power generated by such plants up to a pre determined price limit. This encourages suppliers to sign power purchase agreements with renewable generators. However, in the UK there is no significant volume risk and so government guarantees are not required to address this possibility.

Payment

35. The creditworthiness of future users is not known at this stage. In fact, even commitments from creditworthy companies could end up not being fulfilled if circumstances change after the commitment is given (although some form of financial redress would be expected). Some for m of government guarantee may be required to address this uncertainty. This would require Government to make up any shortfall in funding of the investment that should result from default by future users. In addition, commitments should be accepted only from creditworthy future users.

Recommendations

36. The key outcomes of the risk analysis are:

i. Volume, price and payments risks pose major obstacles to new investment. Regulatory risks need to be addressed in Bosnia and Herzegovina

ii. Further analysis is required to determine the size and location of Tier A and C capacity. This analysis should be undertaken by TSOs acting in co-operation to develop a regional network plan according to a methodology approved collectively by the regulators in the region.

iii. A market test should be undertaken (co-ordinated by TSOs working in co-operation) to identify commercial investors in new Tier B (market based) capacity. This is critical to address the risks identified. The market test should be used to confirm possible 'anchor loads'.

iv. A form of government guarantee (see the chapter on Regulatory Toolbox) is likely to be required for Tier A capacity, and possibly for Tier B capacity where it is part of a single project which also contains Tier A and/or Tier B capacity.

v. A government guarantee (possible forms of which are described above) or public private partnership arrangement may also be required for Tier B capacity. Another (possibly additional) option could be risk transfer measures implemented by national regulators.

vi. A full risk assessment should be undertaken on the full value chain of identified anchor load projects and risk management tools applied where appropriate to manage the identified risks.

vii. Close co-ordination between regulators, governments and TSOs is required, as well as with other potential investors.

CHAPTER 7

Southern Route Base Case Business Model

Introduction

1. This chapter examines the key challenges which must be overcome in order to provide a sound climate for investment for each of the markets along the Southern Route. The approach used is to apply the risk assessment framework described in Chapter 3 to identify the key challenges. The regulatory toolkit has been applied to the identified key challenges in order to determine options for the management of the associated risks. The outcome is a 'base case business model' and as such it is intended to be a starting point for negotiations with potential investors and other relevant actors.

Features of the Southern Route

2. The 'Southern Route' involves Albania, Former Yugoslav Republic of Macedonia and UNMIK (and more precisely the route Fier – Skopje – Pristina), together with possible feed-in lines (principally from Italy and Greece to Albania).

3. In the 1980s, Albania had a significant gas industry but domestic production has now dwindled to almost nothing. Most of the pipeline infrastructure has deteriorated beyond use. The Albanian Energy Strategy foresees a major role for gas from imports of piped natural gas or of LNG. A Gas law was approved in 2008 (now under amendment) which has expanded the authority of the existing electricity regulator to include the gas sector. Licensing procedures have been approved and a number of other acts are in draft form. There is a CCGT power generation project in Vlora. It is dual fuel (gas and diesel) but it is not currently running on gas because of a lack of piped gas supply. Large energy consumers exist in Elbasan, near Tirana and elsewhere. Households are increasingly using LPG for heating and other domestic purposes.

4. Former Yugoslav Republic of Macedonia has an Energy Market Law which covers both electricity and gas. The sector is regulated by the Energy Regulatory Commission, which in respect of gas has published a methodology for transmission, distribution and supply pricing. With no indigenous supplies, consumption of gas in Former Yugoslav Republic of Macedonia is met entirely from imports. Only about 10% of the annual capacity of the small 0.8 Bcm/y transmission pipeline from Bulgaria to Former Yugoslav Republic of Macedonia is utilised at present. Most (around 80%) of that gas is used for electricity generation in small plants. Other large customers are steel plants and district heating companies. It is government policy for gas transmission to be extended to all major towns where CHP facilities will replace non-gas district heating plants. With

power, industry and other end-uses also projected to grow, rapid expansion of demand for gas is possible.

5. Currently there is no gas market in the UN Mission in UNMIK. Industrial, district heating and household energy needs are met by electricity (from lignite) and heavy fuel oil. Besides electricity, fuel wood and LPG are used by households, mainly in the small towns and villages. Future energy plans do, however, include gas, with the replacement of heavy fuel oil by gas in district heating plants being a particular target. The law on natural gas was passed by Kosovo's Parliament in November 2009 extending the role of the Energy Regulatory Office to include gas. Demand in UNMIK is projected to grow to 0.9 bcm/y by 2025.

Risk assessment

6. The following initial assessment has been made in relation to the categories of risk identified in Chapter 3:

B) Political Risks

Expropriation

7. The risk of expropriation of the invested assets, or profits arising is assessed to be low in relation to all regions on the Southern Route. Were expropriation to happen, however, the impact on the investment would be high.

Country	Risk factor	Impact assessment	Risk assessment (Risk Factor multiplied by the Impact assessment)	
Albania	1	3	3	
FYR of Macedonia	1	3	3	
UNMIK	1	3	3	

8. No risk management tools are required in this area.

Security

9. The risk to the invested assets from lack of security in the market is assessed to be low in relation to all regions on the Southern Route. Were damage to the assets to occur as a lack of security,

the impact on the investment would be medium. This assessment is made on the basis that any damage cause would be likely to be localised.

Country	Risk factor	Impact assessment	Risk assessment	
Albania	1	2	2	
FYR of Macedonia	1	2	2	
UNMIK	1	2	2	

10. No risk management tools are required in this area.

Breach of contract

11. This is a matter for the investor and so is not assessed here.

Legal and regulatory

12. The situation is different in each of the relevant markets. In Albania there is a gas regulatory framework in place and a gas regulator, but there is no gas TSO and no detailed gas regulation on e.g. tariffs. The risk will depend upon the transparency of the remaining elements of the regulatory framework. The risk will also depend upon the satisfactory resolution of the institutional issues including the appointment of a regulator and TSO. This is addressed further in the section on risk management.

13. In Former Yugoslav Republic of Macedonia there is an energy legal and regulatory framework and the relevant institutions are in place. The Energy Regulatory Commission is independent of Government and commercial interests.

14. In UNMIK there is a gas regulator but the detailed gas regulatory framework in relation to e.g. tariffs is not yet complete. There is no gas TSO. The situation is similar to that of Albania in this regard.

Country	Risk factor	Impact assessment	Risk assessment	
Albania	3	3	9	
FYR of Macedonia	1	2	2	
UNMIK	3	3	9	

Currency transfer restriction

15. There are no currency restrictions in place in the relevant markets

Country	Risk factor	Impact assessment	Risk assessment (Risk Factor multiplied by the Impact assessment)	
Albania	1	2	2	
FYR of Macedonia	1	2	2	
UNMIK	1	2	2	

16. No risk management tools are required in this area.

Dispute resolution

17. Dispute resolution arrangements must be reliable, inexpensive and timely in operation. Dispute resolution services are normally defined within the contract, but in cases where independent legally binding dispute resolution is needed which falls outside of that envisaged in the contract, then separate arrangements must be in place. This can be the case typically in relation to contracts between monopoly providers (such as network companies) and third parties (such as those connected to the network) where the monopoly nature of the activities of a TSO and the regulated framework within which they operate do not allow for an unfettered dispute resolution in all cases. Normally the arbiter of disputes in these circumstances is the independent energy regulator. The existence of a properly constituted regulatory authority will therefore result in a low risk in this area. In cases where dispute resolution fails, then recourse to the courts should be available, but this should only be a last resort.

Country	Risk factor	Impact assessment	Risk assessment (Risk Factor multiplied by the Impact assessment)	
Albania	1	2	2	
FYR of Macedonia	1	2	2	
UNMIK	1	2	2	

Commercial Risks

Planning

18. The risk associated with obtaining approvals for the construction of new infrastructure depends upon the planning regime in place in each country. This is the responsibility of national governments. (note: the assessment here needs to be made by local experts.)

Country	**Risk factor**	**Impact assessment**	**Risk assessment (Risk Factor multiplied by the Impact assessment)**	
Albania				
FYR of Macedonia				
UNMIK				

Design

19. The design of the project is entirely in the hands of the developer and so is not assessed here.

Construction

20. The construction of the project is entirely in the hands of the developer and so is not assessed here.

Volume (including price risk)

21. In Albania and UNMIK there is no gas market of any significance and consequently there is no current means of obtaining a commitment that any volume of gas to be supplied in the future will be bought and consumed unless new users can be identified. Both volume and price risk is therefore high. As there are no tariff payers there is no scope to develop Tier A or Tier C capacity on the basis of current regulated arrangements. However, in the case of the 97MW CCGT plant at Vlora there is a demand for gas and consequently for Tier B capacity. Immediate gas demand is for 150 millions of Nm^3 per annum and for further supplies when plans to expand the plan to 400MW are fulfilled. Albania consumes also 100,000 tonnes of LPG per year. In the case of Former Yugoslav Republic of Macedonia there is a gas market which principally supplies existing industrial users and power generators. Such users are unlikely to be willing to fund new Tier A or Tier C capacity unless they benefit directly from it. However, capacity exists in the supply

infrastructure to supply further users should this additional demand appear. In this area there is very limited scope to expand the gas network into new areas on the basis of existing tariff payers (i.e. regulated investment).

Country	Risk factor	Impact assessment	Risk assessment (Risk Factor multiplied by the Impact assessment)	
Albania*	5	3	15	
FYR of Macedonia	4	3	12	
UNMIK	5	3	15	

* the risk profile of Tier B capacity to supply the Vlora plant will be lower, as would the case of any other established commercial sites with firm gas demand

Supply

22. The capability of the infrastructure to continue to operate and supply transmission services to users is entirely in the hands of the developer and so is not assessed here.

Payment

23. Obtaining sufficient assurance that users will pay their bills normally depends upon the creditworthiness of the users. New users of future gas transmission capacity are not yet known and it is unclear at this stage what their credit position will be, although selecting users with a good credit rating will reduce payment risk. The lack of a market with tariff payers means that new Tier A and Tier C capacity will relay on the market being developed in parallel with the development of new infrastructure so that future tariff payers exist to fund the development of these categories of capacity. This is relatively high risk.

Country	Risk factor	Impact assessment	Risk assessment (Risk Factor multiplied by the Impact assessment)	
Albania*	5	3	15	
FYR of Macedonia	5	3	15	
UNMIK	5	3	15	

* the risk profile of Tier B capacity to supply the Vlora plant will be lower, as would the case of

any other established commercial sites with firm gas demand

Exchange rate

24. Hedging of exchange rate risks is a normal part of project financial risk management and hedging instruments are available, including through IFIs assist in this process. The management of exchange rate risks is the responsibility of the developer and so is not assessed further here.

Interest rate

25. Hedging of interest rate risks is a normal part of project financial risk management and hedging instruments are available, including through IFIs assist in this process. The management of interest rate risks is the responsibility of the developer and so is not assessed further here.

Applying the Risk Management Toolbox

26. Having identified the key risks to be addressed the task is to examine which risk management tools might be most appropriate to manage the relevant risk and to determine which body (or bodies) should be involved.

27. This section looks at the key risk factors identified and considers what risk management tools might be applied in each case.

Legal and regulatory

28. All three countries have in place an independent regulator for gas and a gas legal framework. In the case of Albania and UNMIK further development of the gas regulatory framework is needed in key areas such as tariffs in order to provide a predictable investment climate.

Volume and price risk

29. In all three countries the lack of a developed gas market results in the risk that future income from new potential users anticipated at the time the investment is made will not materialise. This is a major obstacle to future investment. This can be addressed by a combination of the following measures:

- Expand the system based on the development of Tier B capacity by attracting market-based investments. New users (with a good credit rating) could be identified who would be prepared to commit contractually to pay for future capacity (i.e. market based investments). They could pay either directly (by placing a deposit) or commit only to pay future tariffs on a defined amount of capacity. Clearly any potential investor would need to understand the proposed tariff regime and so this step is first dependent on the implementation of a sound regulatory framework. Any new user will need a direct use for the gas to be supplied through the new capacity and in the case of all of the markets on the Southern Route this means creating a new market for the gas rather than the incremental expansion an existing one. A new market could be created by undertaking a market test to identify new users and related 'anchor loads'. Probably the anchor loads will be new gas fired power generating stations or existing stations converted to burn gas, although they could be new large industrial consumers of gas. As discussed in Chapter 6, the risk associated with the conversion of an existing power station may be less that the construction of a new one. In both cases a full risk assessment of the full value chain of each anchor load project should be undertaken. The economics of conversion to gas and the place of gas in the existing generation merit order need to be established.

- The development of Tier A and Tier C capacity incremental to anchor loads. Developing gas supplies to towns and cities close to new anchor loads so that domestic consumers and small enterprises have access to gas. The network element of this approach would be provided by a monopoly network company and in principle the cost should be funded through future tariff revenues paid by future gas consumers. In this case the investment could be based on regulated arrangements since new users will pay regulated tariffs through a gas supplier (assuming gas is economically preferable to other available fuels). Some form of <u>government</u> guarantee (or subsidy) would probably be needed to manage the risk that insufficient numbers of gas consumers are signed up.

30. Some risk management measures could be considered for all types of capacity:

- Transferring some of the risk of new network investments away from investors through the application of a cap and collar regulatory framework put in place by the <u>regulator</u>. In this arrangement the potential return expected by an investor would not go below a defined (low) level but also could not go above a defined upper level. Another body would need to stand ready to make up any shortfall in returns should they fall below the collar level, but would receive any profits above the collar level. Such a body needs to be identified. It is unlikely that existing tariff payers could bear such a risk and the most likely candidate is <u>government or IFIs</u>. A similar effect could be applied though a joint venture between <u>government</u> and a commercial investor (i.e. a public private partnership arrangement)

- A subsidy towards the new investment could be provided by government. This would reduce the financial risk to the investor but would allow very high profits if the investment were to prove successful. Furthermore, any subsidy would need to be substantial if it were to affect the overall risk of the project and it would need to be consistent with state aid rules. For these reasons subsidy is not recommended as a possible way forward at this stage.

- Providing protection from competition for a defined period of time. This reduction in financial risk must be managed to ensure that it does not operate against the longer term interests of consumers. It could take a number of forms:

    - Exemption from third party access for the new network capacity by the regulator. TPA exemption will reduce the risk that a third party will undercut the initial purchaser of the capacity and thus reduce their expected investment return. Such a situation is more likely to occur as the gas market on the Southern Route develops and the risks which exist currently have reduced.

    - Providing a monopoly market for a defined period of time. An example could be the granting (by government) of the supply of gas to a town or city to one (or just a few) suppliers for a period of time. This may not be consistent with the terms of the EU 3rd energy package which required third party access to distribution pipelines and so some form of derogation would be required in order to apply such an approach.

    - Purchasing the output of the 'anchor load'. This could take the form of a power purchase agreement for a power station for example. Such a contract would have to be supported financially by Government. Similar arrangements are common in the Middle East in relation to combined generation and water desalination plants.

Payment

31. The creditworthiness of future users is not known at this stage. In fact, even commitments from creditworthy companies could end up not being fulfilled if circumstances change after the commitment is given (although some form of financial redress would be expected). Some form of government guarantee may be required to address this uncertainty. This would require Government to make up any shortfall in funding of the investment that should result from default by future users. In addition, commitments should be accepted only from creditworthy future users.

Recommendations

32. The key outcomes of the risk analysis are:

i. Volume and price, and payment risks pose major obstacles to new investments. Regulatory risk poses a medium risk obstacle. In countries where there are few or no gas consumers there will be no private investment in new gas infrastructure unless there are government guarantees in place.

ii. The regulators of Albania and UNMIK should proceed to set out the remaining key elements of the regulatory framework (including the tariff regime).

iii. In the case of Albania and UNMIK the entities to act as gas TSOs must be identified.

iv. A market test should be undertaken, co-ordinated by TSOs in the region working in co-operation, to identify potential investors in Tier B capacity and to identify specific candidate anchor loads.

v. Some form of government guarantees or public private partnership arrangement is likely to be required to enable investments in Tier B capacity to proceed in relation to projects where Tier B capacity shares the infrastructure with tier A and/or Tier C capacity. These guarantees could take a number of forms, some of which are described above. Some regulatory risk management measures could also be applied including time limited exemption from third party access.

vi. Government guarantees are also likely to be required for investment in Tier A and C capacity to proceed.

vii. A full risk assessment of the whole value of each anchor load project should be undertaken and potential risk management measure identified. This will require discussion between regulators and governments to develop a risk management strategy for specific projects based on the base case described above.

viii. The incremental development of the network to serve anchor loads should also be considered in order to provide Tier A and Tier C capacity to develop the gas market in this region. An analysis is required to determine the size and cost of this incremental capacity. TSOs in the region will need to play a major role in this work. This may need some time limited derogation for the requirements of the EU 3rd energy package.

CHAPTER 8

Recommendations and next steps

Essential elements for a functioning gas market

1. A number of basic regulatory issues must be addressed to establish a functioning regional gas market which is consistent with the approach being adopted within the EU. These requirements are briefly summarised in this section.

2. Implementation of Entry-Exit system

- In all Member States as a first step an entry-exit systems with a trading hub shall be implemented. To enhance competition through liquid wholesale markets for gas, it is vital that gas can be traded independently of its location in the system. The only way to do this is to give network users the freedom to book entry and exit capacity independently, thereby creating gas transport through zones instead of along contractual paths.

3. Establishing an interconnected regional gas transmission network

- A network plan for the region (i.e. more than the sum of national plans) must be prepared. This implies that the TSOs must co-operate across borders and so some form of regional TSO group is needed to undertake this work. In the EU 3rd energy package the EU wide ten year network development plan (TYNDP) and the ENTSOs fulfil this function.

4. Establishing cross-border regulatory framework. The list here is the same as is included in the EU 3rd energy package. The list below identifies priority topics from that longer list:

- Comprehensive cross border regulatory framework. The topics are those in the EU list of Framework Guidelines. Key ones are:
  - Capacity allocation. This should not only define how capacity is allocated cross border (e.g. explicit auctions etc) but also requires uniform capacity products be used and define the firmness of those products.
  - Congestion management. This should define how and when TSOs may reallocate capacity and withdraw capacity from the market if there is insufficient to satisfy demand.

- Balancing. This defines TSO and user responsibilities when contracted flows do not match physical ones. The key thing is to make sure the rules applied are not discriminatory.
- Transparency. It is critical to ensure that there is a minimum (high) level of transparency so that all players understand what is going on in the market.
- Tariffs. Co-ordination of tariffs can assist the process of cost allocation across borders.
- Interoperability. This defines the data flows between TSOs to make sure the networks interact securely. It can also include gas quality standards where this is relevant.

- Ensure clarity in the definition of the interface between EU Member State and ECT Contracting party
  - Community Ministerial Council, especially the Decision on implementation of the 3rd package in the Contracting Parties adopted on 6th October 2011 in Chisinau, Moldova. In order to effectively achieve a single regulatory space comprising the EU 27 and the Contracting Parties, it is important that the Treaty Establishing the Energy Community clearly and unambiguously establishes the obligation to implement the existing and envisaged cross- border mechanisms set by the acquis also on the borders between EU MS and Contracting Parties. Any gap between regulatory frameworks of EU and the Contracting Parties should be reduced to maximum extent in order to ensure that the regulatory risks are minimised.

5. Monitoring

- Monitoring of the regional market as it develops is critical. This can be done by the regional regulatory body (see below) or through co-ordination between NRAs.

6. Governance issues

- Regional TSO body is needed
- Regional regulatory body is needed (ECRB)
- NRA duties should be extended so they are required to take account of regional interests when taking national decisions (and not just national)
- Government forum is needed (inevitably)
- Some level of unbundling of TSOs is highly desirable, not least because we need them to co-operate on regional issues, whereas in competition law terms we would not want them to collaborate if they are vertically integrated (i.e. collusion – which the companies would probably be equally concerned about)

Basic requirements

The above points are aimed at building a regional gas market. It assumes that national arrangements are in place. Basic elements include:

- National TSO
- National regulator
- Independent and predictable regulatory framework

Branch- specific recommendations

Northern Branch

7. The key outcomes of the risk analysis for the Northern Branch are:

i. Volume, price and payments risks pose major obstacles to new investment. Regulatory risks need to be addressed in Bosnia and Herzegovina

ii. Further analysis is required to determine the size and location of Tier A and C capacity. This analysis should be undertaken by TSOs acting in co-operation to develop a regional network plan according to a methodology approved collectively by the regulators in the region.

iii. A market test should be undertaken (co-ordinated by TSOs working in co-operation) to identify commercial investors in new Tier B (market based) capacity. This is critical to address the risks identified. The market test should be used to confirm possible 'anchor loads'.

iv. A form of government guarantee (see the chapter on Regulatory Toolbox) is likely to be required for Tier A capacity, and possibly for Tier B capacity where it is part of a single project which also contains Tier A and/or Tier B capacity.

v. A government guarantee (possible forms of which are described above) or public private partnership arrangement may also be required for Tier B capacity. Another (possibly additional) option could be risk transfer measures implemented by national regulators.

vi. A full risk assessment should be undertaken on the full value chain of identified anchor load projects and risk management tools applied where appropriate to manage the identified risks.

vii. Close co-ordination between regulators, governments and TSOs is required, as well as with other potential investors.

Southern Branch

8. The key outcomes of the risk analysis for the Southern Branch are:

   i. Volume and price, and payment risks pose major obstacles to new investments. Regulatory risk poses a medium risk obstacle. In countries where there are few or no gas consumers there will be no private investment in new gas infrastructure unless there are government guarantees in place.

   ii. The regulators of Albania and UNMIK should proceed to set out the remaining key elements of the regulatory framework (including the tariff regime).

   iii. In the case of Albania and UNMIK the entities to act as gas TSOs must be identified.

   iv. A market test should be undertaken, co-ordinated by TSOs in the region working in co-operation, to identify potential investors in Tier B capacity and to identify specific candidate anchor loads.

   v. Some form of government guarantees or public private partnership arrangement is likely to be required to enable investments in Tier B capacity to proceed in relation to projects where Tier B capacity shares the infrastructure with tier A and/or Tier C capacity. These guarantees could take a number of forms, some of which are described above. Some regulatory risk management measures could also be applied including time limited exemption from third party access.

   vi. Government guarantees are also likely to be required for investment in Tier A and C capacity to proceed.

   vii. A full risk assessment of the whole value chain of each anchor load project should be undertaken and potential risk management measure identified. This will require discussion between regulators and governments to develop a risk management strategy for specific projects based on the base case described above.

viii. The incremental development of the network to serve anchor loads should also be considered in order to provide Tier A and Tier C capacity to develop the gas market in this region. An analysis is required to determine the size and cost of this incremental capacity. TSOs in the region will need to play a major role in this work. There may need to be some time limited derogation from the requirements of the EU 3rd energy package.