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by

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Abbreviations and acronyms

ACER	Agency for the Cooperation of Energy Regulators
AL	Albania
BiH	Bosnia and Herzegovina
BVS	Block valves
CAPEX	Capital expenditure
CCGT	Combined Cycle Gas Turbines
CEGH	Central European Gas Hub in Austria
CHP	Combined Heat and Power
cm	Cubic metre
CTMS	Custody transfer metering stations
DSCR	Debt service coverage ratio
EBIT	Earnings before interest and tax
ECA	Economic Consulting Associates
EPC	Engineering, Procurement and Construction
EU	European Union
FEED	front end engineering design
FS	IAP Feasibility Study published in 2014
GoA	Government of Albania
GoC	Government of Croatia
HGA	Host Government Agreement
HR	Croatia
IAP	Ionian Adriatic Pipeline
IMF	International Monetary Fund
IRR	Internal Rate of Return
LNG	Liquefied natural gas
MAED	Model for Analysis of Energy Demand
ME	Montenegro
MoU	Memorandum of Understanding
OPEX	Operating expenditure
PCI	project of Common Interest
PECI	Project of Energy Community Interest
PMI	Project of Mutual Interest
PRMS	Pressure reduction / metering stations
PSV	Punto di Scambio Virtuale

PT	Pig traps
RoW	Right of Way
RS	Republika Srpska
TANAP	Trans Anatolian Pipeline
TAP	Trans Adriatic Pipeline
TPA	Third Party Access
TSO	Transmission System Operator
TYDP	Ten-Year Development Plan
UGS	underground gas storage
WACC	Weighted Average Cost of Capital
WBIF	West Balkan Investment Framework

Executive summary

The objective of this report is to review and update the commercial and financial analysis of the Feasibility Study (FS) of the Ionian Adriatic Pipeline (IAP) completed in April 2014 by COWI IPF. The focus is on reviewing and updating the parameters identified in the FS as critical for the financial viability of the proposed project including IAP throughput assumptions, business models and tariff calculations, economic feasibility analysis, and CAPEX estimations.

IAP: the project

IAP is a bi-directional international gas pipeline concept connecting the Croatian gas transmission system with the Trans Adriatic Pipeline (TAP) offtake point in Albania at Fier. Passing through Albania and Montenegro and potentially providing a feeder pipe to Bosnia-Herzegovina and Kosovo, the project stretches 520[1] km along the Ionian and Adriatic coast mainly onshore.

Its main objective is to enable gas supplies from the Caspian and Middle Eastern region[2] to reach the established Croatian gas market and help gasify Albania and Montenegro. Additionally it can help diversify supply sources in Bosnia Herzegovina and other West Balkan markets. The main findings of the authors of FS were that IAP is not commercially viable as tariffs for the pipeline would be too high to provide competitive supplies to offtakers in Croatia, Montenegro and Albania. The estimated transmission tariffs yielding a given Internal Rate of return (IRR) far exceeded a regional benchmark transmission tariff of €2.5c/cm

Since the completion of the FS however, some factors have changed that have the potential to improve the commercial viability of the project. These include low gas prices, a recovery in Croatian gas demand after a drop in the wake of the financial crisis, the development of TAP and its potential for expansion to 20 Bcm/y capacity, and the publication of Gas Masterplans in 2015 and 2016 for both Albania and Montenegro proposing ambitious gasification strategies.

Commercial drivers for IAP

IAP can play an important role in the gasification of the West Balkans (Montenegro, Albania, Bosnia Herzegovina and Kosovo) and crucially provide a north-south axis for the Southern Gas Corridor, ie supplying Caspian and Middle Eastern gas into the EU. We identify the main commercial drivers for IAP to be the following:

- **Croatia as key potential anchor market** - At initial stages of IAP development Albania, Montenegro and Bosnia and Herzegovina (BiH) are unlikely to provide large critical anchor loads for IAP to be commercially feasible. Croatia, as the only well-established and sizeable gas market connected to IAP will therefore

[1] The exact route is not yet finalised.
[2] flowing through TANAP (in Turkey) and TAP (in Greece and Albania)

play a crucial role as an anchor offtake markets over the first five to ten years of operation.

- **International transmission through Croatia –** As the offtake markets along the IAP route are likely to develop slowly and Croatia's import demand is facing gas-on-gas competition, international transmission for EU markets beyond Croatia – particularly at initial stages of development - will be of utmost importance for IAP's viability. If this cannot be ensured, pipeline tariffs will be too high for IAP to provide competitive gas supplies.

- **Competitiveness of IAP sourced gas -** Gas transported through IAP and delivered to Croatia, Albania and Montenegro will have the same source as gas delivered through TAP into Italy, ie originating from Azerbaijan or the Middle East. As Croatia and potential EU markets to the north of Croatia will be the key offtake markets at initial stages of development, IAP will have to provide gas at a more competitive price than existing sources or at least be more competitive than alternative routes of supply from Caspian and Middle Eastern gas (eg through the Italian transmission system). This sets the upper limit for IAP transmission tariffs. We estimate this limit at €1.9c/cm, which approximates the costs of transporting gas from southern Italy to the Slovenian border and through Slovenia to the Croatian border.

- **Gasification strategies of Montenegro, Albania and BiH -** The importance of gas in the three country's energy mix and the ability to provide anchor loads in these three countries will be a longer term driver. However, the scope for significant gas-to-power developments is limited and distributed gas demand (households, commercial and small industrial) is slow to develop.

- **Expansion of TAP and access to wider sources -** To deliver significant volumes (up to 5 Bcm/y) through IAP, associated gas pipelines need to expand their capacity. Initially TAP will transport up to 10 Bcm of which 8 Bcm are already contracted for the Italian market. While TAP's existing capacity and contractual arrangements are sufficient for short to medium term IAP flows, the expansion of TAP to 20 Bcm will be an important pre-condition for IAP to maximise south to north flows and become a competitive supply route.

Throughput volumes

On the basis of the new drivers for utilisation of IAP and latest gas demand developments we update the throughput projections made in the FS. In our base case scenario, we project throughput volumes to be 1 Bcm initially (2025), ramping up to 3 Bcm in 2035 and 4.2 Bcm in 2045 and reaching 5 Bcm by 2050. While the volumes we project are similar to those in the FS in the first 10 years of operation, our projections are considerably lower for the period thereafter. We perceive the gas demand development assumptions in the FS for Albania and Montenegro to be too optimistic. Consequently our split of throughput across different offtake regions is markedly different, which is important when making recommendations on identifying potential areas to improve the project commercially.

Our throughput analysis identifies international transmission to be the main driver for IAP's commercial viability (not considered in the FS) as well as Croatian offtake. Albania and Montenegro offtake from IAP will be relatively small. For Albania this is largely due to the location of planned gas fired power plants and industrial users, which are not located along the IAP route but near to the TAP route (also not considered in the FS). BiH gas demand will depend on the chosen gasification strategy in the country, which is uncertain at this stage.

The development of IAP as an integrated project with TAP and TANAP forming part of the Southern Gas Corridor to diversify EU supply sources is therefore key. International transmission will provide the necessary base throughput that is required – particularly at early stages of development – for cost recovery.

CAPEX and OPEX

The report also reviews the cost assumptions made in the FS. Overall, we agree with the technical design and route proposed in the FS. We do however note that some factors relating to pipeline routing such as river and road crossing have not been investigated in great detail. This could have some repercussions on the cost estimate.

We assess the pipeline investment costs in the FS to be generally underestimated for Albania and Montenegro. This is mainly due to an underestimation of the additional costs incurred by building pipelines over mountainous and hilly terrain. For Croatia, we rely on the latest detailed estimates made by the Croatian TSO, Plinacro. These are significantly lower than the estimates for Croatia in the FS and also lower than estimates based on European comparable data.

The total investment costs are estimated at €611 million, which is fractionally lower than in the FS. OPEX is estimated €10.5 million annually, which is similar to the OPEX levels in the FS. Overall, and in light of the early development stage of the project, we would expect a variation of ±20% of the investment costs calculated.

Business models

The report distinguishes between three business models and tests the impact of tariffs and risks for each. The business models are:

- **Business model ❶: IAP Company -** one IAP Company develops, owns and operates the pipeline on the back of long term take or pay gas purchase agreements and gas sales agreements with offtakers in each country. We would assume IAP would to be exempt from EU third party access arrangements and one cost recovery tariff applies for the whole pipeline on the basis of a regulated return[3].

- **Business model ❷: Regulated TSO -** IAP is treated as being split in three segments, which are each developed and financed by the national TSOs. Tariffs apply that are in line with national regulated transmission tariffs and are based on a cost recovery mechanism of the IAP investment and the wider national networks and national demand levels.

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[3] More advanced tariff structures such as distance related tariffs or entry and exit charges could also apply. However for comparison across business models and the FS, we opt for this simple tariff structure in this business model.

- **Business model ❸: IAP Company + Regulated TSO -** a combination of ❶ and ❷ where the Albania-Montenegro connection is treated as a standalone project and the Croatian segment is integrated into the Croatian asset base. One tariff would apply for the Montenegro-Albania section and a separate tariff – in line with the existing tariff regime in Croatia – would apply to the Croatian segment.

Transmission tariffs

The commercial viability of IAP ultimately depends on the tariffs that can be charged and this is the key measure we use to determine the degree of commercial viability of the project and the three business models. To provide complementarity to the FS approach, we adopt a different methodology: we calculate the tariffs on the basis of a regulated return on assets and not on the basis of an Internal Rate of Return (IRR). This is done because we simulate the integration of parts of the IAP pipeline into national gas transmission systems and therefore the regulated asset base in at least two of the three business models. In this approach IAP would form part of a regulated network of assets and therefore be subject to an allowed revenue or cost plus regulatory regime setting rates of return on assets.

Our analysis shows that tariffs for IAP – under almost all of the three business models and throughput scenarios – are in excess of our estimated threshold value (€1.9c/cm) that would ensure competitive gas supply. Our proposed Business model 3 – the integration of the Croatian IAP segment into the Croatian asset base and the treatment of the Montenegrin and Albanian section as an international pipeline - consistently shows the lowest tariffs across all sensitivity and throughput cases. It is also the only business model – in combination with high throughput assumptions – that provides a tariff below €1.9c/cm.

Hence, if project developers want to pursue the IAP project, we recommend splitting the assets into a Croatian segment and Albanian-Montenegrin connection for the purposes of tariff setting, as this is likely to result in the lowest transmission tariffs. This is in line with the results and recommendations made in the FS, albeit on the basis of very different analytical approaches and throughput assumptions. The tariff levels across four throughput scenarios and for our base case assumptions on CAPEX and OPEX and a regulated return of 8%[4] are shown in the table below.

Transmission tariffs in *€c/cm*				
Throughput scenarios> *Business models*	*Lowest throughput*	*Base throughput*	*Medium throughput*	*Highest throughput*
❶ IAP Company	5.00	3.23	2.56	2.15
❷[5] Regulated TSO	10.63	7.06	5.89	5.24
❸[6] IAP Company + Regulated TSO	3.69	2.64	2.20	1.88

[4] We test the sensitivity of the results to these parameters. 8% regulated rate of return has been chosen as our base case assumption to mirror the IRR assumption in the FS of 8%. The analysis in the report also tests the sensitivity of the IRR with changes in the regulated return.

[5] Sum of national gas transmission tariffs

[6] Sum of postage stamp tariff of AL-ME connection and entry, exit and commodity charge in Croatia with an asset base expanded with IAP investment costs and system strengthening costs in Croatia (€60 million) to ensure transit

The transmission tariffs are highly dependent on throughput volumes and could reach competitive tariffs under the most optimistic throughput assumptions. This can only be secured if the following throughput drivers are met:

- International transmission of gas plays a critical role and reaches volumes of between 0.8 and 1 Bcm/y or more. These flows are crucial to improve the viability of IAP as they can provide short term throughput that is vital to recover costs until Albania and Montenegro advance their gasification efforts. IAP should therefore be developed in conjunction with TAP as forming part of the Southern Corridor and opening up a new supply route to the EU.

- Croatia's import demand for gas is met by between 40% and 50% from IAP. This would mean very low utilisation of the planned LNG terminal for Croatian demand (less than 10%) and only 85% utilisation on the Slovenian interconnector and only 10% usage of Hungarian interconnector[7].

- Gasification efforts of distribution customers in Albania and Montenegro along the IAP route are expedited and in place within five years of IAP operation.

- Gas to power developments in Montenegro and Croatia to reach a minimum of additional capacity of 1,500 MW within five years of the operation of the pipeline.

- Including a BiH connection and ensure it forms the new main supply route into Bosnia Herzegovina. Depending on the gasification strategies in BiH this could improve IAP feasibility significantly. However only if the connection displaces the existing supply route, provides gas supply to newly developed power plants (eg Zenica 390 MW plant) and gasification efforts for distributed customers are stepped up will a BIH connection have a significant impact on IAP. If the connection to Zenica/Sarajevo is not pursued, the impact will be minimal.

- The Croatian transmission system is expanded and developed (where necessary) to accommodate maximum international transmission volumes to provide access to other established EU gas markets. Hungary, Slovenia and Austria are the most obvious markets to target.

Financial viability

Even, however, if the high throughput volumes can be secured, the project's IRR would be less than 5% to reach a competitive tariff. Any tariff that would ensure an IRR above 8% (as used in the FS) would far exceed the commercially viable threshold level in our analysis – even in the most optimistic throughput scenario. This is the same insight as that reached in the FS.

This means that the project, as simulated across the scenarios and business models, is not viable from the perspective of a private commercial investor. Some factors that would improve the project's financial viability - besides ensuring all necessary measures are taken

[7] Or a combination of utilisation across the interconnectors that would result in similar supply volumes as 85% (Slovenia) and 10% (Hungary).

to maximise throughput in the first five to ten years of operation as listed in the bullets above, are:

- **Grant funding of more than 50% of the IAP project**. The share of grant funding for IAP that would bring the tariffs to a competitive level in the base case scenario is 60% (€370 million) and 50% in the good case (€300 million). The grants have been assumed to be distributed evenly across the entire segment.

- **Setting tariffs for the Croatian segment separately from the Albania-Montenegrin section**. The Croatian segment would be subsumed into the Croatian regulatory asset base[8] and the Albanian-Montenegrin section would have its own separate tariff. While not a guarantee for project viability, this business model would result in the lowest possible total tariff for the project as a whole.

- **Involving Caspian and Middle Eastern gas suppliers in the project**, who may be able to sell gas at a more competitive price in return for ownership of midstream gas operation in the region – this would help to raise the critical threshold level for the transmission tariff. More details on this are described in the following section.

- **Provide the project with regulatory exemptions** as done for TAP. Although this will not solve the conflict between high tariffs (for financial viability) and low throughputs, it may limit the risks of the project and thereby attract investors.

- **Increase the equity portion of the investment**. This possibility will be closely related to the business model, risk appetite of investors and financing terms. Our estimates suggest that for every additional 10% equity provide into the financing of the project the IRR improves by around 0.5% with a regulated return on assets of 8%.

- **Attract investors that do not require a high return on this project alone**. Investors could be identified that would see IAP as forming part of their overall project portfolio. Hence, they would not rely exclusively on IAP as a major profit centre. Instead they may consider it a vehicle to access markets where higher returns can be made. SOCAR or other Caspian and Middle Eastern gas producers would be possible candidates. Additionally the project would form part of an upstream and midstream portfolio and therefore may not need to provide high returns on its own accord.

- **Provide concessionary loans** with low interest rates reducing the debt repayment obligations and improving cash flow. For each 1% interest rate reduction (from 5.5% in our base case), the IRR improves by around 0.2%.

Economic viability

Our approach for the economic viability assessment consists in quantifying the avoided costs from IAP by displacing incumbent fuels and reducing CO_2 emissions. The results of

[8] And exit, entry and commodity charges would be calculated as per the current regulations in Croatia

our base case throughput assumption suggest that the project is economically viable. The Economic NPV is positive at €1.13 billion and the economic rate of return (ERR) is 13.6% far above the social discount rate of 5.5%. This is broadly in line with the result from the FS, which estimated an economic NPV of €847 million and an ERR of 14.1%.

Our analysis shows that it is the supply of gas to the non-power sector that has the greatest impact on the economic feasibility of the IAP project. In particular the replacement of electricity and fuel oil in the heating sector with gas results in the largest benefits to the region. It is therefore important to combine the IAP project with an extensive gasification plan of residential and commercial customers if the project is to achieve economic feasibility. However, even if only targeted at the power sector, the project would be economically feasible.

These results remain robust across all throughput scenarios and key parameter sensitivities. Only under a scenario of very low electricity prices, would the economic NPV become negative. This is unlikely however, as electricity prices have been kept artificially low in Montenegro and Albania due to subsidies given to the electricity sector.

Risk assessment

The risk assessment confirms the results of the financial and commercial viability assessment in that Business model ❸ mitigates against the identified risks most. The business model has the advantage of (i) minimising offtake risk by not making the tariffs exclusively dependent on IAP throughput volumes, (ii) minimising regulatory risk, as the Croatian segment would be treated like the existing Croatian transmission system and no additional parallel regulatory measures would need to be in place in Croatia, (iii) mitigating financing risk as the Montenegrin-Albanian section would have the benefits of an international transit pipeline (Third Party Access exemption) with long term contract agreements and (iv) minimising institutional/political risk as no new (or parallel) TSO would need to be set up in Croatia.

Conclusion

This report has adopted a variant methodology in calculating transmission tariffs for IAP and has updated the key input parameters of CAPEX, OPEX and throughput volumes. Our results largely confirm the findings of the FS that IAP is only marginally commercially viable. According to our analysis the lowest tariffs are achieved by integrating the Croatian section into the Croatian regulatory asset base and a standalone tariff for the Montenegro-Albania section. This does not mean that the two segments should be developed independently, but for the purpose of tariff estimation a separate treatment of the assets is sensible. Our conclusions on the drivers for IAP and possible sources of offtake are different to the FS because we identify international transmission of gas to EU markets beyond Croatia as a crucial component in enabling the project's viability. Offtake in Albania, Montenegro and BiH is likely to be small – particularly at early stages of development - and therefore Croatian offtake and international transmission could provide the necessary throughput for a low transmission tariff.

1 Introduction

This report is the *Draft Final Report Task 2*, the third deliverable of the World Bank funded project *South East Europe Gas Power Consortium – Phase II*. The report presents the results of Task 2 of the project focusing on the commercial viability of the Ionian-Adriatic Pipeline. This report follows our first deliverable – the inception report – submitted in December 2016 and second deliverable – Task 1: Vlore feasibility report – submitted in April 2017.

Objective and scope

The objective of the report is to review the commercial and financial analysis of the Feasibility Study of the Ionian Adriatic Pipeline (FS) completed in April 2014 by COWI IPF. The Ionian Adriatic Pipeline (IAP) is an international pipeline project linking the Trans Adriatic Pipeline (TAP) offtake point in Albania with the Croatian transmission system traversing Albania and Montenegro and providing an interconnection to Bosnia and Herzegovina. The focus of this study is on reviewing those parameters identified in the FS as critical for the financial viability of the project. In particular, the study will focus on the following:

- *IAP throughput assumption* – the gas volumes transported through IAP are a key determinant for the commercial viability of the project. There is significant uncertainty on the throughput volumes as Albania and Montenegro have no gas markets yet and Croatia has a well-diversified gas supply mix. The assumptions made in the FS for gas demand and throughput are now slightly dated and importantly are not based on the latest detailed Gas Masterplans for Albania and Montenegro published in 2015 and 2016. One major aspect of our analysis is therefore an assessment of the assumptions underlying IAP's gas throughput volumes. This is closely related the potential importance of transit volumes, which have not been considered in the FS.

- *Business models and tariff calculations* – the business models for pipeline development, which includes ownership of pipelines and the regulatory treatment of costs, will influence the viability of IAP and the tariffs it needs to charge. The FS assess different business models; however it is not clear how the costs are treated in each of the business models and how the throughput volumes are apportioned to different segments. To build on the results of the FS, we set out three business models and develop separate tariff methodologies for each. They are

  - ❶ ***IAP Company*** – IAP as a standalone project, where one postage stamp tariff applies regardless of the entry and exit points of gas

  - ❷ ***Regulated TSO*** - IAP segments integrated into national transmission assets; for Croatia this means adjusting the regulatory asset base and other parameters in the current entry/exit/commodity charge methodology; for Albania and Montenegro we assume a postage stamp tariff that will apply to their respective transmission network developed as per their respective gas Masterplans.

  - ❸ ***IAP Company + Regulated TSO*** – IAP is developed as an international gas pipeline; however the tariff in the Croatian segment is treated differently to the combined segments in Albania and Montenegro. In Croatia, the IAP sections are integrated into the existing regulatory asset base providing an updated system wide transmission tariff. In Albania and Montenegro, the IAP sections however are treated separately from any future transmission developments with one postage stamp tariff.

- *IAP CAPEX assumptions* – the FS shows a high sensitivity of the results to changes in CAPEX assumptions. We therefore collaborate with a pipeline engineer to review the cost assumptions made in the FS and provide a high level 'sense-check' and update on the design and costs proposed in the FS. For the Croatian section we rely on CAPEX data received from Plinacro as a result of very recent and detailed routing studies for the Croatian IAP sections.

- *Risk analysis* – the different business models will result in different ownership structures and therefore have different risk profiles. These will be reviewed and updated from the FS.

The report will provide up to date conclusions on the financial feasibility of the project and identify the most suitable business model to take IAP forward. It will therefore build on the recommendations and assessments made in the FS.

Structure of the Report

The Report is structured as follows:

- Section 2 provides background to IAP describing the project and its recent developments, providing regional infrastructure context to show how IAP fits into the wider regional gasification strategy and gives a brief overview of the gas markets in Albania, Montenegro, Bosnia Herzegovina and Croatia

- Section 3 outlines our demand and IAP throughput assumptions. This will include a review of the assumptions made in the IAP FS and our alternative scenarios.

- Section 4 reviews the route and the design of the pipeline and provides up to date capital cost numbers as well as operating costs.

- Section 5 presents our financial analysis, which is focused on gas transmission tariff calculations for IAP under different business models as well as key financial indicators.

2 Ionian Adriatic Pipeline

This section provides a brief background to the Ionian-Adriatic Pipeline (IAP) project by firstly recapping the history and concept of the project, secondly giving regional context to the project and thirdly outlining the gas markets to be served by IAP in more detail. The section concludes by highlighting the main drivers of the IAP project and how these may have changed in recent years.

2.1 Concept, route and history

IAP is an international gas pipeline concept connecting the Croatian gas transmission system with the Trans Adriatic Pipeline (TAP) offtake point in Albania at Fier. Passing through Montenegro and providing a feeder pipe to Bosnia-Herzegovina, the project stretches around 520[9] km along the Ionian and Adriatic coast. Its main objective is to enable gas supplies from the Caspian and Middle Easter region[10] to reach the established Croatian gas market and help gasify Albania and Montenegro. The project is planned to be bi-directional also allowing for a north-south gas flow and thereby providing an export route for gas in Croatia. Croatia has well-diversified gas supply routes and is currently planning the development of an LNG terminal. A schematic of the different IAP routes considered is shown in Figure 1 together with existing transmission networks in the region.

2.1.1 Background

The IAP project was initiated in 2007 through a Ministerial declaration signed by the Ministries of Energy of Croatia, Albania and Montenegro and at a later stage Bosnia and Herzegovina. In 2010 and 2011 Memoranda of Understandings (MoUs) were signed between the Croatian gas transmission company Plinacro and Governments of Albania and Montenegro and TAP to set up the Joint Working Group of IAP/TAP. As the entity with most experience in gas transmission, Plinacro has taken the lead in implementing the project and in 2011 conducted a Gas Market Study on the feasibility of IAP and shortly after initiated a Feasibility Study (FS) of the entire project.

The FS was completed in 2014 and provides the key reference for this study. Since the completion of the FS in early 2014, the project seemed to stall; which was partly due to high gas prices, stagnating gas demand and uncertainty on gasification strategies of Montenegro and Albania. However the commitment for gasification of Montenegro and Albania – by publishing Gas Masterplans in 2015 and 2016 respectively, more favourable gas market conditions and the speedy development of TAP have reignited interest in the project. In August 2016, a new MoU was signed between the Governments and importantly also SOCAR, Azerbaijan's state owned gas company supply gas through TAP to Italy. As part of these agreements, the IAP Project Management Unit (PMU) was established which consists of representatives of the respective Governments (and existing transmission system operators), to which IAP would supply gas to as well as SOCAR.

[9] The exact route is not yet finalised.
[10] flowing through TANAP (in Turkey) and TAP (in Greece and Albania)

Figure 1 IAP route

Source: IAP Feasibility Study, 2014, COWI

The IAP project is backed by the Energy Community Ministerial Council in 2016, when it was considered a Project of Mutual Interest (PMI). The European Commission was also supporting the project through the West Balkan Investment Framework (WBIF); however it does not feature as a project of Common Interest (PCI) in the 2017 list

2.1.2 IAP financial viability

As per the FS, the pipeline would mainly run onshore and have an initial capacity of 5 Bcm/y. The total investment costs of the project were estimated at € 620 million. This breaks down as € 330 million for the Croatian segment, € 120 million for the Montenegrin segment and € 170 million for the Albanian segment. The FS examined a number of business models for implementing the project, tested against the economic/financial criteria of achieving an IRR of 8% with the aim of a transportation tariff of €c2.5/cm.

The study found large differences between the profitability of the Albania/Montenegro (IAP East) and Croatia (IAP West) sections which pointed towards a conclusion that these sections could be regarded as two separate projects with two separate business and development scenarios. For both sections however, the economic viability of the project was brought into question. The main objective of this assignment is to review the assumptions made in the FS and update the analysis with new numbers.

The FS examined the risks for the commercial feasibility of the project, of which the principal ones were found to be:

- Most of the gas which should be consumed within Albania is in the electricity production sector (60% of foreseen Albania consumption), while there is currently a lack of electricity production capacity in Albania
- The gas transmission tariff heavily depends on the anticipated volume of the Croatian market as the largest market out of four countries.
- Only Croatia has a well-developed distribution and gas market that can readily expand the consumption of the volume of supplied gas
- The institutional risk in Montenegro and Albania is very high and in Bosnia and Herzegovina moderate.
- The ability or willingness of TAP owners (gas producers and/or shippers in TAP) to enter into gas supply agreements with local energy players/buyers of gas to supply the IAP countries' gas markets.

As the project is still at early stages of development, it is not clear what business model and ownership structure will apply. The FS tested the feasibility against three alternate business models/financing structures; a Regulated TSO concept for each country (with a corporate finance structure), or two alternate project finance structures: a single shipper[11] (IAP company, with TPA exemption), or multiple shippers – one or more for each country. The study found that the single shipper / TPA exempt model would have the lowest project financing risk and be able to achieve the most competitive tariff at 3.4€c/cm. This compares highly with the benchmark tariff of 2.5€c/cm and even with the most optimistic input variations, the tariffs remained high. Although not explicitly mentioned in the FS, it seems that overall, the authors of the study came to the conclusion that the project was not financial viable unless a very high transmission tariff can be applied.

The remainder of our study will review the financial and commercial analysis in the FS and critically appraise the assessment and conclusions. One shortcoming of the FS that can already be flagged at this stage however is that IAP is only considered in isolation, ie as a standalone project. With the publication of the Gas Masterplans of Albania and Montenegro over the past two years, this study is able to simulate the impact on gas transmission tariff levels when considering the integration of IAP (or its segments) into the respective national gas transmission networks. Additionally, no efforts appeared to have been made in the FS to consider the ongoing Croatian transmission tariff regime and how the additional Croatian IAP segment could have impacted the entry, exit and commodity charge in Croatia. Importantly however, the FS does not consider the feasibility of IAP acting as a transit pipeline and the impact this may have on tariffs.

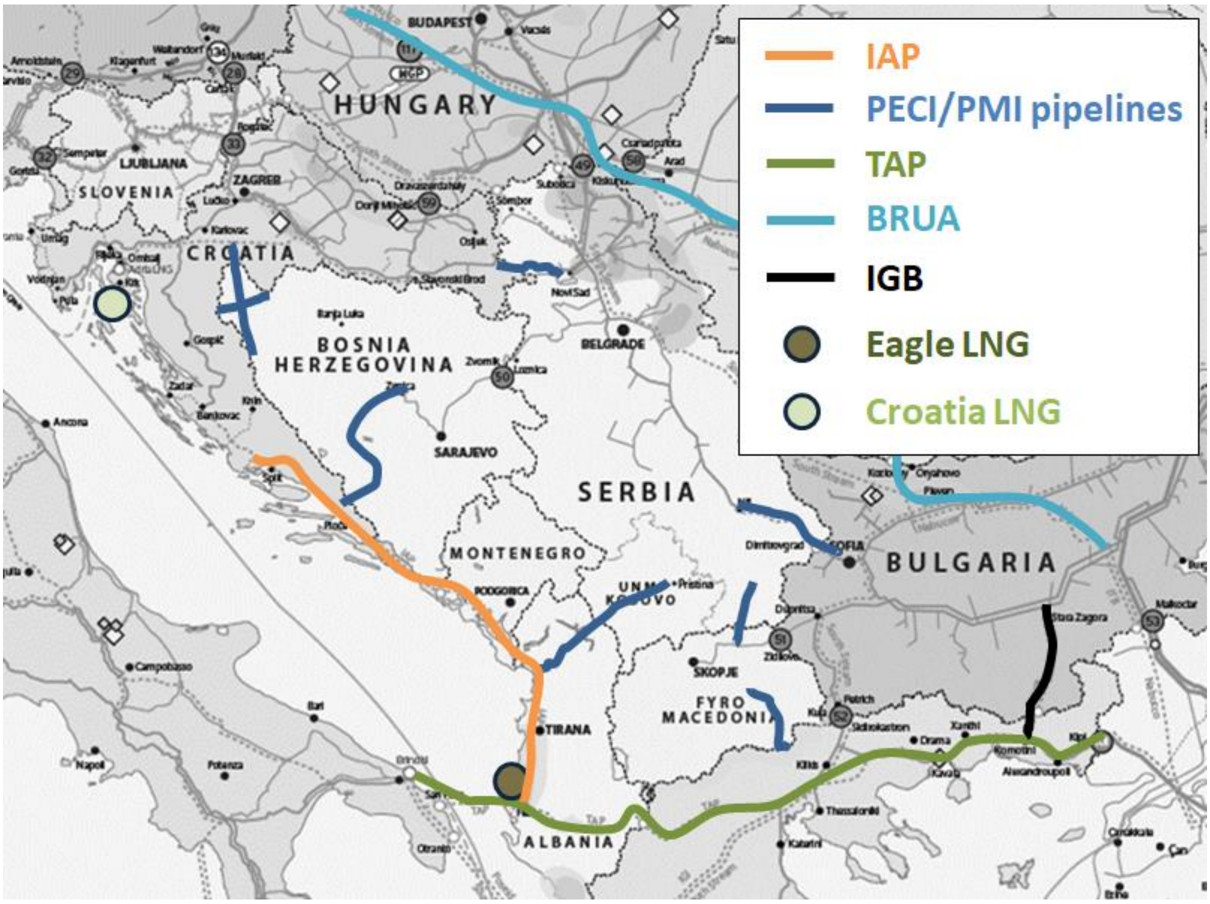
[11] The shipper refers to the company commercially responsible for bringing gas from the TAP tie in point to Split. Under the FS scenario this would be the same as the pipeline owner.

2.2 IAP in the region

The viability of IAP is closely linked to the development of other gas infrastructure in the countries that IAP plans to link as well as in the wider region. The two most important projects are TAP and the LNG terminal in Croatia. The former would enable gas flows from south to north, the latter would provide a new gas supply point for a north to south gas flow in IAP. Another gas pipeline project; however more removed that will also impact IAP is the Greece- Bulgaria-Romania-Hungary–Austria (BRUA) corridor, which could provide a competing route for Caspian and Middle Eastern gas flowing into Europe. So far however seems to be mainly used as supply route for Romanian gas northbound.

The full list of projects of relevance for IAP is shown in Figure 2. Brief presentations of each of the projects is provided in the following sections which includes a table of the PECI/PMI projects.

Figure 2 Major international gas supply project proposals



2.2.1 Trans-Adriatic Pipeline

TAP has emerged as the key gas pipeline project to supply Azeri gas from the Shah Deniz II project into the European Union. In June 2013, the Shah Deniz consortium selected the TAP consortium as its dedicated European export pipeline, following an open competition with alternate pipeline projects, especially Nabucco. The initial capacity of TAP will be 10 Bcm/y, which can gradually be increased to 20 Bcm (planned for the mid 2020's). Starting from the Greek-Turkish border at Kipoi and running through Greece and Albania, TAP ultimately connects with the southern Italian gas transmission grid after crossing the Adriatic Sea. The Italian market is expected to be the largest offtaker of gas flowing through TAP and commercial agreements between Shah Deniz and 9 parties in Italy, Greece and Bulgaria for just over 10 Bcm already exist. Of those, close to 9 Bcm are intended for the Italian market and 1 Bcm to the Greek and Bulgarian market, according to Shah Deniz II news reports[12]. This agreement followed the previously agreed sale of 6 Bcm of Shah Deniz II gas to Turkey's BOTAS.

TAP is expected to be completed in 2020. The front end engineering design (FEED) stage was completed in March 2013 and in September 2013 TAP began the land leasing and acquisition process. As of early 2017, the pipeline is in construction and parts are being laid in Greece and Albania. Although passing through Albania and close to FYR of Macedonia, no direct connections to the West Balkans are currently in process and no final commercial agreements are in place to secure parts of the gas flowing through TAP for the region. These connections are however technically feasible and expected by TAP and the host government agreements (HGA) between TAP and the Greek and Albanian governments include commitments to provide at least one offtake point in each country. Additionally, the national regulatory authorities have made a joint decision on exemption from some provisions from the 3rd Energy Package.

TAP is crucial for the viability of IAP if the pipeline is to act as a supplier for low cost gas into Albania, Montenegro, Croatia, Bosnia and Herzegovina and potentially beyond. With the majority of existing capacity of TAP earmarked for the Italian market, it is doubtful whether significant volumes of gas can be carried through IAP before the expansion of TAP to 20 Bcm/y is secured, which is unlikely to happen before 2022. The involvement of SOCAR in both IAP and TAP and the main original gas supply point (Shah Deniz II) is however promising, as any decision on developing IAP would be coordinated with greater flows through TAP and TANAP.

2.2.2 Croatian LNG terminal

The Croatian onshore ***Adria LNG*** project development was proposed several years ago by OMV, E.on/Ruhrgas and Total. With an initially planned annual regasification capacity of 10 to 15 Bcm the project would cover a substantial volume of the region's demand. A feasibility study was completed in 2008 and a location permit was issued in 2010. The project is currently on hold however due to low gas demand levels and a final investment decision was scheduled for 2013, which did not materialise.

In light of slow progress, the two Croatian state owned energy companies (HEP and Plinacro) have launched their own project *Hrvatska LNG* (*Croatia LNG*) in mid-2013 also located on the island of Krk. This project has examined floating regasification units and onshore facilities with capacities in the range 2 to 3.5 Bcm/y. Croatia LNG is currently at the stage of looking for secured offtakers to move the project development forwards. After a

[12] BP news, *Shah Deniz Major Sales Agreements with European Gas Purchasers Concluded*, September 2013

non-binding open season invitation to book capacity of the terminal in 2015, the project company called for equity investors in late 2015, which seems to be still ongoing. As of January 2017, the Energy Minister suggested that the project is going ahead and will be completed in 2019[13]. It is largely expected that the European Commission will provide at least 30% of the financing of the project with 102 million EUR already approved for the FSRU. Considered as one of the EU's PCI projects, the terminal would enable access to a well-diversified pool of gas suppliers. Plinacro has however made clear that additional transmission investments will be needed to connect the LNG terminal with the existing network.

Similarly to TAP, the LNG terminal project can act as a catalyst for developing IAP. This would be to provide a north to south flow and could result in a shortened version of IAP only connecting Croatia with Montenegro. LNG supplied through the terminal may not be as competitive as Azeri gas, but would provide access to a diversified supply source. However at 2 Bcm initially, this is a small volume and unlikely to be sufficient in supplying gas to the four potential offtake markets. Additionally, LNG supplies are typically used for seasonal variations in demand rather than baseload gas supplies. IAP could therefore be considered complementary to LNG Croatia.

If the terminal is used as a baseload supply option for either Croatian offtakers or onward consumers in Hungary, there could be a degree of competition between the projects. While this scenario is unlikely, the risk exists.

2.2.3 Albanian LNG terminal: the 'Eagle LNG project'

The ***Eagle LNG*** project located on the coast of Albania is a floating regasification terminal with a capacity indicated to be between 4 and 8 Bcm. The project was initiated in 2007 by Groupo Falcione, an Italian trader and distribution network consortium. The plans of the project foresee the majority (90%) of the gas to be delivered to Italy and include an offshore gas pipeline. The remaining gas volumes would be supplied to Albania. As per the project developers, the project has obtained all necessary licences and documentation from the Albanian Government to develop the terminal. The development of TAP however seems to have stalled the project as little progress has been made over the past years. Unlike the LNG terminal in Croatia, no open season calls for capacity have been made, the project implementation unit has little public exposure and the commercial viability of the project is brought into question by the development of TAP.

The project could provide an additional source of supply to feed into IAP if not sufficient gas volumes could be secured from TAP. However the slow development of the project, the ease of expanding TAP to 20 Bcm and the higher likelihood of development of the Croatian LNG terminal make this project only a fringe project of direct relevance for IAP.

2.2.4 BRUA gas pipeline

The selection of TAP and development of TANAP has meant that one of the European Union's priority projects, *Nabucco*, looked unviable. Nabucco and TANAP were scheduled to follow a similar route through Turkey. Beyond the Turkey-Bulgaria border, Nabucco was planned to pass through Bulgaria, Romania, and Hungary to deliver gas into the gas hub at

[13] *Croatia floating LNG terminal taking a year longer to finish*, Reuters, 25 January 2017

Baumgarten in Austria. To avoid duplication of pipeline routes in Turkey, the Nabucco consortium initially re-shifted its focus onto the *Nabucco West* component of the route, ie the part of the route running from Bulgaria to Austria. Partners in the Nabucco West project are European mid- and downstream market participants including RWE, OMV and the national transmission system owners in the respective countries involved. The capacity of Nabucco West is planned to be 10 to 23 Bcm. The project is, however, now discontinued and a successor project, BRUA, was initiated in 2014.

The BRUA project is significantly smaller than the initial plans for Nabucco West and largely consists of building a new pipe a new 478 km natural gas trunk pipeline on the Romanian territory and three compressor stations. The transmission systems in Romania and Bulgaria are understood to have sufficient capacity to allow for transit flows from TAP/TANAP all the way to Austria. The initial capacity of the pipeline is significantly smaller than the initially planned Nabucco West; only 1.75 Bcm per annum, which can be further increased in the future to 4.4 Bcm per annum. The project costs are estimated at close to 600 million EUR and the project is supported by the EU and national Transmission System Operators in Bulgaria, Romania and Hungary.

In fact the project features as an EU Project of Common Interest (PCI) and has already secured funding from the EU through the Connecting Europe Facility (CEF) of around 179 million EUR. Besides Caspian gas, the project can also deliver EU gas production in Bulgaria and Romania to other EU consumers.

However in July 2017, the Hungarian TSO, FGSZ, announced that it could not conduct an open season for the pipeline stretch connecting Romania, Hungary and Austria. It announced that only the Romania-Hungary interconnection would be 'economically viable'. This meant that the project was temporarily stalled. This decision was revised later in 2017 and a conditional open season auction was successfully conducted by Transgaz and FGSZ. Despite these positive developments, there remain legal challenges in Romania as it is not yet clear whether domestically produced gas can be exported.

The importance of BRUA (or any other parallel gas pipeline) for IAP is that it could be a competitor to act as a transit pipeline for Caspian and Middle Eastern gas. While the link is not immediately clear, as BRUA is earmarked for Romanian gas and not Caspian gas and the markets to be served are somewhat different, it is worth noting that a transit route through Bulgaria, Romania and Hungary could act as a competing project. As we will show in our analysis below, the feasibility of IAP will hinge on the ability to act as a transit pipeline to northern demand centres. If these volumes were not to materialise the IAP project may not be viable.

2.2.5 PECI/PMI gas pipeline projects

The gas pipeline Projects of Energy Community Interest (PECI) and Project of Mutual Interest (PMI) are a shortlist of priority projects which can qualify for European support. IAP is a PMI together with four other projects listed in the table below.

Together these projects will help to interconnect West Balkan Energy Community markets as well as neighbouring EU country gas markets. The PCI /PMI projects in combination with existing pipelines will form part of a concept developed by the Wold Bank in 2006: the Energy Community Gas Ring ('Gas Ring'). The Gas Ring will ensure security and diversity of supply in the region by connecting all markets. Additionally, the Gas Ring combines the relatively small individual country loads to form one regional demand load spreading regional gas transmission costs across large volumes and improving the economics of gas infrastructure.

Table 1 PECI/PMI projects

	Project description
PECI – Gas 009	Serbia (NIS) – Bulgaria Interconnector
PECI – Gas 011	Serbia (Vranje) – Macedonia FYR (Klechovce-Sopot)
PECI – Gas 013	Albania – Kosovo Interconnector (Fier –Lezha-Pristina)
PMI – Gas 02	Bosnia and Herzegovina (Trzac-Bosanska Krupa) – Croatia (Licka Jesenica) Interconnector
PMI – Gas 03	Bosnia and Herzegovina – Croatia Interconnector (Zagvozd – Posusje-Novi Travnik with a main branch to Mostar)
PMI – Gas 04b	Greece – Macedonia, FYR (Hamzali –Stojakovo) Interconnector
PMI – Gas 10	Servia (Futog) – Croatia Interconnector
PMI – Gas 16	Ionian Adriatic Pipeline (Fier, AL – Split, HR)

Source: Energy Community Secretariat

The projects are all at various stages of development with the Serbia-Bulgaria interconnector currently showing most traction and securing financial support from the EU together with PMI Gas 03. PMI Gas 04b – connection between Greece and FYROM – also has gained some momentum in recent months with the new Government of FYROM and the Greek TSO, DESFA, agreeing to collaborate closely on the project. So far however no financing for the project has been secured.

For IAP, the Kosovo and Bosnia interconnectors could be relevant. We include an assessment of both interconnectors as sensitivity assessments in our analysis (see section 5.4). The Kosovo-Albania interconnection is highly uncertain and at this stage looks very unlikely to be developed given the continued reliance on coal for power generation in Kosovo. Additionally, the recently completed electricity interconnector between Albania and Kosovo mean that the complementarity of electricity demand and supply between these countries can be utilised without requiring a gas pipeline.

2.2.6 Interconnector Greece-Bulgaria (IGB)

The Interconnector Greece-Bulgaria (IGB) project is an alternative route to IAP for Caspian gas to reach EU markets. However its supply reach focuses on Bulgaria and Romania and as such will provide alternative supplies to different markets than IAP (West Balkans, Slovenia, Austria, and Hungary). IGB plays a very important role for diversity and security of supply for the EU and is a crucial component of the Southern Gas Corridor of the EU. Connecting the Greek and Bulgarian transmission systems, the IGB is 182 km long with a capacity of 3 Bcm/y, which can be increased to 5 Bcm/y.

The project is developed by a joint venture company (ICGB AD) owned by the state owned Bulgarian energy company (50%) – BEH-, the Greek natural gas company (DEPA) (25%) and the Italian energy company Edison (25%). It was initiated in 2009 and has since secured funding from the EU (close to €45 million) and obtained long term debt financing from the EBRD. In 2013, the project secured all environmental approvals and in late 2016 completed its binding open season auction for capacity of the interconnector. The results yielded five binding offers amounting to 2.7 Bcm signalling strong interest among market participants to utilise the interconnector. In late 2017, the procurement for the Owner's Engineer was launched, but suspended in early 20187 due to appeals by participants. This may set back the timeline of the project beyond its initially scheduled start date of operation in 2020.

2.3 Gas markets served by IAP

Besides regional gas infrastructure, the viability of IAP will crucially depend on the development of gas demand and gas transmission in Croatia, Albania and Montenegro and to a lesser extent Bosnia Herzegovina. Demand and transmission strengthening in Croatia is of particular importance, as Croatia provides both a mature and well developed gas market that could provide gas offtake as soon as IAP is operational and it can provide transit for gas flowing through IAP into Slovenia and Hungary.

This section provide brief snapshots for each of these markets highlighting latest developments, sector overviews and infrastructure developments. A more detailed demand analysis and associated IAP throughput volumes are presented in section 3.

2.3.1 Albania

Albania currently has no gas demand. The TAP pipeline, which is expected to be completed in 2020 will provide first gas supplies, although no gas supply agreements are secured as of mid-2017. It is also not clear at this stage which entities would provide the necessary anchor load for any gas supply contract to materialise from TAP. Inevitably however, the main anchor consumers will be located close to TAP with offtake from TAP rather than IAP if it eventually materialises.

The Government of Albania (GoA) has shown strong interest in the gasification of Albania; however no significant projects (other than TAP) are currently ongoing. One immediate project that could be developed is the connection of TAP's offtake point at Fier with the dual fuel power plant at Vlore. However funding for this short pipeline is still uncertain.

GoA and the regulatory authority is also currently in the process of drafting the necessary regulatory and market framework documentation to enable the gas market to develop. So far, no details about a transmission tariff methodology, market design and market rules are available.

The most comprehensive and up to date document setting our Albania's gas sector development ambitions is the Gas Masterplan[14]. The plan contains details on supply/demand assessments and importantly a detailed gas transmission plan. According to the plan, the demand potential for gas in Albania is close to 1.5 Bcm in 2020 rising to nearly 3 Bcm in 2040 (see Figure 3) . This is a potentially very sizeable market. The plan

[14] *Gas Masterplan for Albania and Project identification Plan*, COWI, IPF June 2016

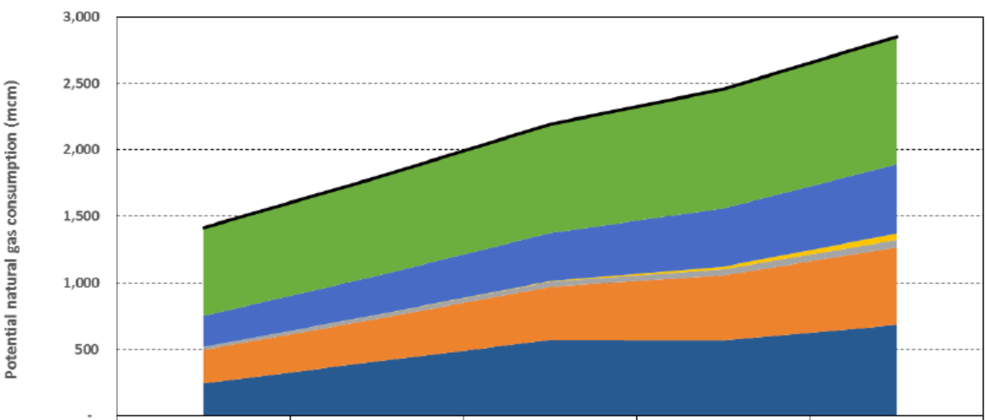
however notes that this potential demand is unlikely to materialise, which we fully agree with. The actual demand forecast for 2020 is 1.2 Bcm and for 2040 is 2.2 Bcm

Even these numbers are optimistic in our view. Despite being based on extensive MAED modelling framework, it would be unreasonable to expect a roll out of sufficiently extensive gas distribution or transmission networks until 2020 to accommodate 1.2 Bcm by 2020. Additionally or alternatively, one would expect that this sort of gas demand development would be carried by anchor consumers and the power sector. However anchor consumer would realistically make up only 0.3 Bcm/y and gas in the power sector generation mix has very limited viability. In the first task of this assignment, ECA modelled the viability of converting the 100 MW power plant at Vlore from fuel oil to gas. Even in the most optimistic scenario, load factors for this small scale plant would not have exceeded 40%. This suggests that gas to power has very limited potential in Albania. This is likely to be sustained for the foreseeable future with stagnating electricity demand and sufficient hydro resources and increased interconnection with neighbouring electricity markets.

It seems that the FS has taken an even more optimistic view of gas demand and in particular gas to power demand (2 Bcm in 2040) in Albania without substantiating their forecasts. A more detailed critique of the numbers used in the FS will be provided in section 3.

Albania has an existing onshore gas field at Delvina close to Durres with the domestic gas sold to the petrochemical industry in Albania. The precise production numbers are uncertain but public reports suggests that production is less than 10 mmcm of associated gas per year, which is minimal. Prospects for new gas finds exists; however so far no significant drilling has taken place and volume of production is uncertain. For this study, we therefore assume no new gas finds in Albania.

Figure 3 Potential gas consumption in Albania



	2020	2025	2030	2035	2040
Households	661	737	818	893	959
Services	234	292	361	438	520
Transport	0	2	5	20	48
Agriculture	22	30	38	47	55
Industry	253	320	400	489	584
Anchor consumers	244	410	571	568	684
TOTAL	1,413	1,791	2,193	2,454	2,851

Source: Gas Masterplan for Albania and Project identification Plan, COWI, IPF June 2016

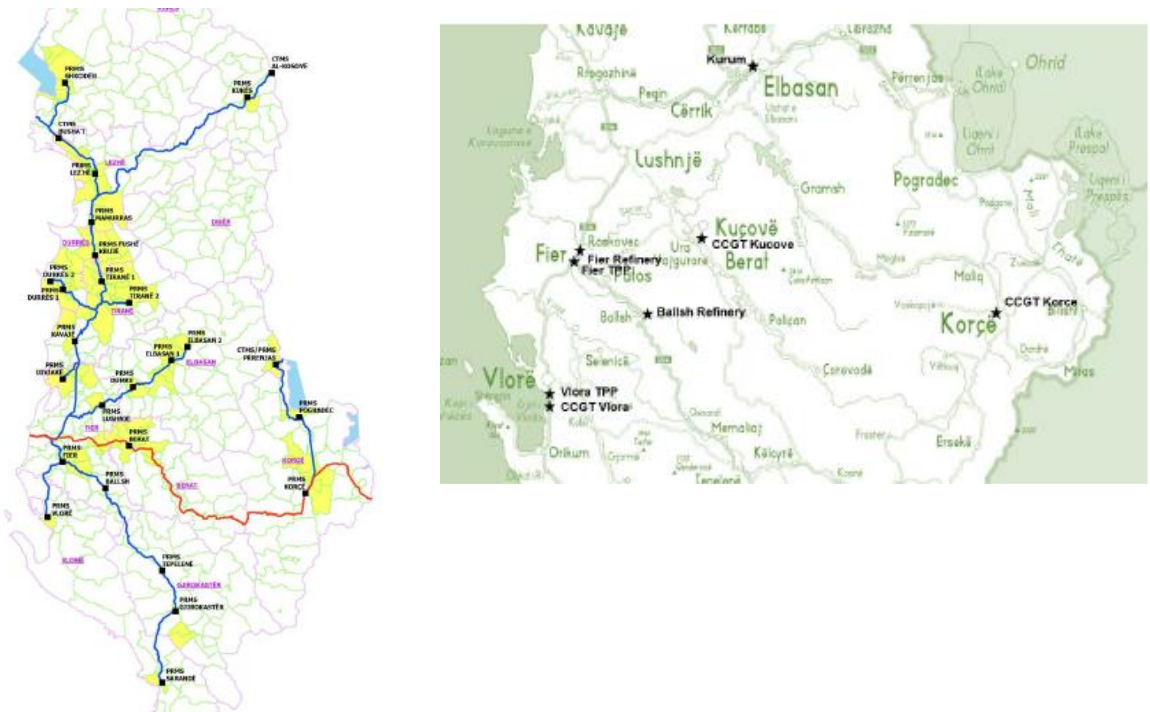
Albania is reported to have gas reserves; however little publicly available documentation is available. We understand that the most promising field is the onshore Delvina field located in far south of the country. Chevron evaluated the reserves of the field in 1993 at between 1.7 Bcm and 7.9 Bcm. In 2015 and as part of a transaction of the concession of the field from TransAtlantic Petroleum to Ionian Adriatic Partners, the reserves were estimated at 1.5 Bcm. Informally the current operator expects reserves of between 5 and 7 Bcm. This suggests that there is a high degree of uncertainty on Albania's reserves. Should these prove to be significant, it could open further possibilities for IAP, as gas could be competitively supplied to Croatia and beyond.

Infrastructure

The Gas Masterplan provides a very detailed and fully costed gas transmission and distribution investment plan. The plan is replicated in the Annex and shown in Figure 4. With a development phase of over 20 years the plan appears reasonable and we use the plan in our estimation of national gas transmission tariffs in Albania under the business model that IAP Albanian segment would be subsumed into the national regulatory asset base (see section 4). It is clear from the plan that IAP plays a crucial role in the gasification strategy of the country. It appears as the backbone trunk line for the system. This however also implies that gas demand in Albania along the IAP route will only materialise gradually after the completion of IAP unless GoA develops IAP and the national transmission and distribution system in parallel, which is not scheduled as per the investment plan.

Consequently, it is unlikely that Albania will provide large offtake volumes at early stages of IAP's development. Additionally and as shown in the right hand panel of Figure 4, the majority of anchor offtake points – industrial users and planned power plants – are located along the route of the currently developed TAP pipeline. This means that gas volumes flowing through IAP and destined to the Albania market will almost exclusively be for residential or small scale commercial consumption.

Figure 4 Transmission development plan and anchor offtake points - Albania



Source: Gas Masterplan for Albania and Project identification Plan, COWI, IPF June 2016

Importance for IAP

Albania is unlikely to provide significant offtake volumes for gas delivered through IAP in its early stages of development (first five to ten years, ie until 2035). The limited potential for gas to power in Albania, the location of anchor customers along TAP and the relatively slow roll out of gas distribution systems mean that only a small fraction of the potential gas demand estimated in the Masterplan is likely to materialise. One advantage for IAP is that it would cross the most densely populated areas of Albania; hence gas distribution demand potential may be high. True consumption figures would however only gradually increase as and when distribution grids are rolled out and gas becomes competitive.

A more detailed discussion on Albania's gas demand potential and IAP throughput is provided in section 3.

2.3.2 Montenegro

As for Albania, Montenegro currently has no gas market and no gas offtake. The Government of Montenegro's energy strategy recognises the potential for natural gas, but only estimates the potential for gas demand at less than 0.1 Bcm in its Energy Strategy 2030

A Gas Masterplan[15] published in 2015 provides more optimistic demand estimates and a detailed gas transmission and distribution plan. Total gas consumption is estimated in the Masterplan at close to 0.6 Bcm in 2040. This is split evenly between gas to power demand and the residential and commercial, and industrial sectors.

In Phase 1 of this assignment, we published 'Country Briefs' that aimed at summarising the gas sector potential in each of the West Balkan countries. For Montenegro's industrial sector we applied a netback analysis to establish growth rates for the main energy intensive and gas price-sensitive industrial sectors in the region, in which gas is more likely to replace incumbent fuels. We concluded that in the most optimistic case industrial demand could be 90 mmcm/year[16], but the likelihood of this materialising is very low. For the residential sector a maximum of 130 mmcm could be expected.

Montenegro's Energy Development Strategy until 2030 outlines the Governments power generation expansion plans, which include a 220-250 MW coal power plant and two

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[15] *Gas Masterplan for Montenegro and Project identification Plan*, COWI, IPF July 2015

[16] In Montenegro, industrial production is low and prospects of gas demand in industry is bleak. The major source for industrial gas demand could potentially come from the steel industry and the aluminium industry. The only steel mill in the country, located in the northern city of Niksic, is ***Zeljezara Niksic.*** The company was declared bankrupt and bought by a Turkish metals company in 2013. From ECA's estimation, at full production, the steel mill could consume as much as 30 mmcm/year. The only aluminium smelter in the country is based in Podgorica and was declared bankrupt and shut down in 2013. If production would restart again and the aluminium smelter of ***Kombinat Aluminijuma Podgorica (KAP)*** decides to invest in on-site gas fired power generation turbines, gas demand could be as high as 60 mmcm/year. This is however an unlikely scenario, as KAP only managed to remain in production due to low and subsidised electricity prices. With increasing global competition and falling global Aluminium prices, it is doubtful that gas can competitively be delivered to Montenegro to re-invigorate the Aluminium production.

additional hydropower plants with capacity of 238 MW and 168 MW respectively. Additionally increased renewable energy integration is expected to make up close to 700 MW by 2030. This would be sufficient to meet domestic demand and potentially export electricity as well. The strategy does not foresee significant gas fired power generation to be developed in the medium to long term.

Despite not being mentioned in the development strategy, there is a potential opportunity for gas to power demand in Montenegro through the planned electricity interconnector to Italy. Although the development of the 1,000 MW interconnector has been delayed and is now pushed back to the end of 2017, its development would provide a real opportunity for large scale power generation development in Montenegro. With higher electricity prices in Italy and expensive and depleting lignite reserves in Montenegro, gas to power generation could provide an alternative. However this crucially hinges on the construction of IAP and an offtake point in Montenegro.

The Montenegro Gas Masterplan suggests the development of a 100 MW and a 300 MW plant. These appear to be realistic and we use these power generation plans to vary Montenegro's demand scenarios for IAP throughputs.

Infrastructure

The Gas Masterplan also provides a gas transmission and distribution plan. While the timing of the plan is unrealistic – development for the entire country in three years and completed in 2020 – the costs and linkages to demand centres are based on a detailed analysis. The transmission plan is replicated in Figure 5. We adjust the transmission plan to take into account the ramp-up of demand expected from residential users. Details are provided in the Annex.

Figure 5 Montenegro transmission development plan

Source: COWI, Montenegro Gas Development Masterplan 2015

Importance for IAP

The main driver for gas demand in Montenegro will be the timing of the development of power generation plants. With the development a subsea electricity interconnector to Italy, Montenegro could export electricity to the higher priced Italian market. Additionally, domestic lignite based power plants are ageing and are in need of replacement. These power plants could provide some anchor load for IAP.

Non-power demand will remain small and only provide limited offtake volumes for IAP. Unlike Albania and Croatia, all gas demand in Montenegro would be served by IAP. IAP is therefore the vital component of Montenegro's gasification strategy.

2.3.3 Croatia

At just under 2.9 Bcm per annum, Croatia is by far the largest of the four gas markets IAP would supply gas into. It has a well-established gas sector and an interconnected gas transmission system with connections to Slovenia (capacity: 1.8 Bcm/y) and Hungary (2.6 Bcm/y). Croatia also produces natural gas domestically from 16 on-shore and 9 off-shore fields. The current production of gas of close to 1.2 Bcm/y covers almost 40% of demand; however this is expected to decline rapidly over the next ten years to 0.5 Bcm/y by 2026[17].

All demand not covered by domestic production is imported through mainly the interconnectors. There have been stark variations in the utilisation of the interconnectors with the Slovenian interconnection seeing far higher utilisation in 2015, operating at 56% of capacity, compared to 2% of the Hungarian interconnection. More recent this has reversed however.

Until very recently, Croatia elected to buy on open spot market and did not renew its long term contract from Gazprom when it expired in 2011. However in 2017, a new ten year contract was signed with Gazprom for 1 Bcm/y.

Gas demand in Croatia is dominated by the residential sector (1.4 Bcm), followed by the industrial, fertiliser and petrochemical industry (close to 1.1 Bcm) with the remainder covered by the power sector (0.4 Bcm). With a relatively high gasification rate, future growth of gas demand is most likely to materialise form the power generation sector. A few power plant projects are currently planned - ELTO Zagreb 130 MW and Crodux 500 MW – however their finalisation is unclear and it appears that these have stalled. Plinacro, Croatia's gas transmission system operator, is not expecting significant gas to power demand surges in the next ten years with gas demand in the power sector reaching only 0.7 Bcm in 2026[18].

Infrastructure

The Government of Croatia (GoC) and key stakeholders in the domestic gas market have shown interest in developing key gas infrastructure projects to diversify the country's gas supply mix further and act as a major transit hub for gas supplies into the West Balkan region. With a high degree of dependence on gas for heating use, industrial production and

[17] Plinacro 10 year Development Plan 2017 -2026
[18] Plinacro 10-Year Development Plan 2017-2026

to a lesser extent power generation, Croatia is looking to secure its gas supplies further. To diversify sources a number of regional and international interconnections are planned.

The most important and likely regional projects to develop are the Croatia LNG terminal and IAP. Their development is interrelated, as IAP can provide access to additional offtake markets (Albania and Montenegro) for LNG landed in Croatia. They do however also potentially stand in competition, as both infrastructure projects will aim to supply parts of the Croatian market which has barely recovered to pre-2011 levels in recent years. While the LNG project is unlikely to be competing with IAP supplies for baseload demand, LNG supply will in all likelihood be used for seasonal demand fluctuations (in Croatia or in markets beyond Croatia that may benefit from transit through IAP) thereby reducing some offtake from IAP. The impact from the LNG terminal on IAP throughput may be relatively small but will ultimately depend on LNG prices and the flexibility of IAP gas supply contracts.

Figure 6 Gas infrastructure development plan 2017-2026

Source: *Plinacro 10 Year Gas Transmission Development plan 2017-2026*

As shown in Figure 6 , the country has a well-established and developed domestic gas transmission network. It currently meets the EU's security of supply standards and benefits from varied supply sources as well as storage units, which can be used for short term response in supply imbalances. The main elements of the current gas infrastructure are as follows:

- *Transportation* system consists of over 2,700 km of pipelines with diameters ranging from 80 mm to 800 mm, operating at pressures of 50 bar and 75 bar. During peak demand approximately 550,000 m3/h are typically transported, but close to 700,000 m3/h has been recorded on days of exceptional demand.

- *Distribution*: according to the association HSUP, in 2012 the overall length of gas distribution networks is 18,100 km.

- *Underground storage* is at Okoli, which has a capacity of 550 mmcm, of which 50 mmcm is reserved for the Slovenian company Geoplin. The maximum send out rate from the storage facility is 5 mmcm/day.

As regards national gas infrastructure, Plinacro's main projects are focused on enabling interconnections with neighbouring countries and for Croatia to act as a gas hub for various sources. The main domestic projects are:

- The gas transmission connection between Omišalj-Zlobin-Bosiljevo-Sisak-Kozarac-Slobodnica. This would only be developed in conjunction with the LNG project on the island of KrK (see next section for more details) to provide access to storage and enable efficient LNG spot market trading to take place. The pipeline would add an additional east-west axis in the northern part of the country and would connect the potential LNG terminal with demand centres in the east of the country and Hungary. The project is a Project of Common EU Interest since 2013 and might therefore get additional traction for development.

- The development of parts of the Baltic-Adriatic pipeline – a connection between Croatia's LNG terminal and Poland LNG terminal on the Baltic Sea coast. This connection would require strengthening of parts of the Croatian gas transmission system connecting the LNG terminal (and the feed in from IAP with the Hungarian border. This connection would be crucial to ensure Croatia's importance as a transit hub and the ability for IAP to transport LNG (and potentially large volumes of Caspian and Middle Eastern) gas to Hungary and beyond.

- Development of a cluster of projects connecting Croatia, Slovenia and Austria, which will enable IAP gas flows to be delivered through Slovenia to the Austrian gas hub at Baumgarten.

The main planned gas transmission network expansions are marked red in the map above.

Importance for IAP

The benefits of IAP to Croatia are manifold. Firstly, it provides an additional and diversified gas supply route to the country. Secondly, it would provide a gas transmission trunk line to the south of the country, where residential and commercial usage could potentially be high. Although residential demand for heating would be constrained. Thirdly, IAP may – if developed to enable north-south flow- facilitate the LNG project's commercial feasibility by providing access to additional offtake markets of Albania, Montenegro and Bosnia Herzegovina. Fourthly, it could increase international transmission flows (transit) through the country and thereby potentially reduce transmission charges.

As being the largest and the only fully developed gas market along the IAP route, Croatia plays a key role in the feasibility of IAP. In particular the ability to transit gas supplied through TAP and IAP northbound and the level of gas offtake Croatia will have from IAP will be key determinants for the feasibility of the project. The former depends on the ability of Plinacro to develop the necessary infrastructure and the latter will depend on the competitiveness of Caspian gas transported through TAP/IAP compared to Italian gas spot markets or LNG imports.

Currently, the Croatian gas transmission system would only able to act as a south-north transit system for 2.6 Bcm into Hungary. For exports to Slovenia and beyond however, the system requires strengthening. Plinacro has recognised this and has proposed the strengthening of the system where bottlenecks for south-north flows exist. Two sections of the Croatian gas transmission system required for gas transit to Slovenia and Hungary feature in Plinacro's latest development plan (2017-2026):

- *Lucko- Zabok-Rogatec* – 69km, 28'' and 75 bar pipeline running parallel to the existing system and expected to be completed by 2019, which will strengthen the connection with Slovenia and make export flows from IAP possible. The cost of this project is estimated at €60 million according to Plinacro. These costs will be considered and included in our tariff calculations.

- *Zlobin-Bosiljevo-Sisak-Kozarac* – 180 km, 40'' and 75 bar pipeline completed by 2020, which is developed in conjunction with the LNG project in Croatia and will enable gas flows to Hungary. The current system has sufficient spare capacity to transport up to 2.6 Bcm along a parallel route and we consider this sufficiently for the international transit volumes we assume in our scenario calculations above and therefore do not include additional costs for exports to Hungary in our calculation below.

As noted above, the development of Croatia's gas market will define the feasibility of IAP. In particular the ability to transit gas northbound and the competitiveness of gas supplied through IAP on the Croatian market. The roadblocks in Croatia for gas infrastructure development in the past has been the lack of competitiveness of gas against lignite. However with gas prices in Europe and the region at remaining low over the past years and the prospect of this remaining so in the foreseeable future, gas could play an increasingly important role in the region's energy mix.

We provide a more detailed gas demand projection and IAP throughput projection in section 3, where we also compare the results with those in the FS.

2.3.4 Bosnia and Herzegovina

The gas market in Bosnia Herzegovina (BiH) is small and fragmented. Gas demand only exists in Sarajevo (and to a lesser extent) in Zenica. The gas system consists of one pipeline that feeds into Sarajevo and is connected with Serbia with an approximate technical capacity of 0.75 Bcm/year. This pipeline accounts for all Bosnia and Herzegovina demand. All gas is imported via Serbia and is purchased from Gazprom or its subsidiaries. Gas demand has been declining over recent years due to gas being uncompetitive as a heating fuel and being displaced by low priced electricity and fuel oil. As of 2017 gas demand was around 0.3 Bcm. There is no storage infrastructure and no LNG opportunities. Currently, no gas is used in power generation.

The generation mix in BiH is dominated by hydro and lignite plants. The annual generation mix is affected by hydrology but, in most years, BiH is a net exporter of electricity. The structure of the market is nominally competitive but is effectively dominated by vertical integration. There are two potential gas to power developments in BiH. Both are located north of Sarajevo and would be connected to the existing transmission grid and a potential extension of the grid with the IAP feeder line. They are:

- ***Kakanj conversion of 1 unit to gas*** - 120 MW. The Kakanj lignite power station is owned by EP BiH and is in need of refurbishment. A potential conversion of one of the units to gas has been discussed for 2019, but is more realistic to materialise in the mid 2020's.

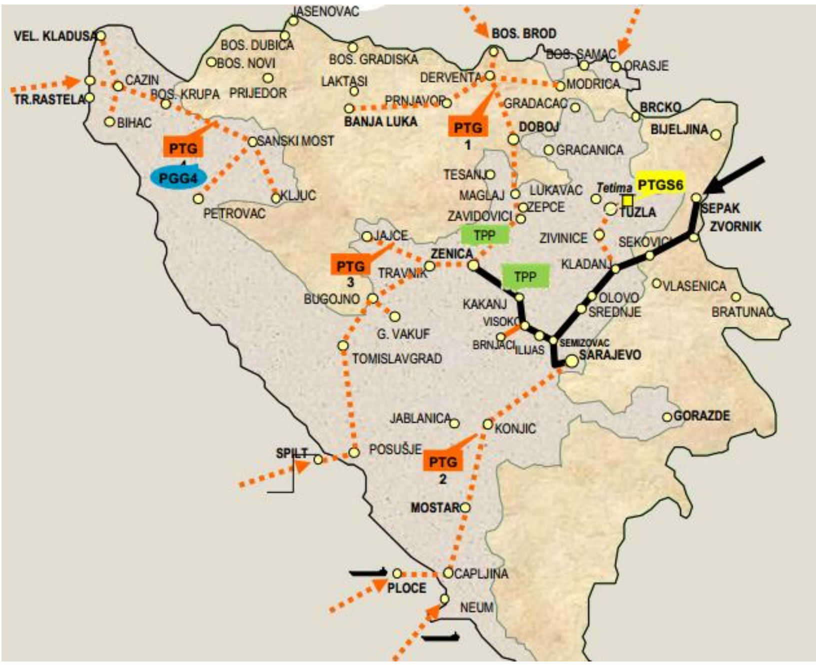
- ***TPP Zenica new proposed 375 MW power plant*** near the existing metal works. It is proposed as a Combined Heat and Power (CHP) plant providing district heat and with a daytime-only operating regime in summer. The project is advanced and is developed through a special purpose vehicle (KTG AG Lugano) which still holds 65% of the shares, a private Hong Kong based investors (10%) and the municipality of Zenica (25%). An EPC contract was signed with a Chinese company but operation is uncertain.

These could together with a gas distribution investment plan contribute to significant gas demand growth in BiH.

Infrastructure

The gas network in BiH currently only consists of a single pipe connecting BiH with Serbia and serving Sarajevo and industrial demand in Zenica. The pipeline has a maximum capacity of 0.75 Bcm, but is only utilised at 40% to 50% across the year. In peak winter months however, the system is constrained and insufficient to supply demand fully This makes BiH's gas supply entirely dependent on Russian gas and one single supply point. On this basis, the Government has proposed a few infrastructure improvements. These are shown in Figure 7. The map also shows the location of the two proposed gas fired power plants in Zenica and Kakanj.

Figure 7 Possible development of gas network in BiH



The impact on gas transmission development in BiH could be substantial. A key hurdle for gas infrastructure development in BiH has been Republika Srpska's (RS) lack of cooperation and agreement. This is undoubtedly down to political interference by Serbia and Russia. With South Stream not a credible gas supply option anymore and with the development of a large gas fired CHP plant, BiH will have to look for more diversified supply routes to minimise the impact of gas interruptions and to meet the EU requirements for security of supply.

The projects shown above are highly uncertain and most have stalled or been discontinued. This is due to several factors including the lack of cooperation by the RS entity (relevant for Bos. Brod-Zenica), the dependence of projects on other projects (Split-Zenica; and Ploce-Sarajevo) or dependence on cooperation of other countries (Rakovica-Bihac-Kljuc).

The most promising extensions of the national transmission system that would secure supply, benefit from support from the EU (as a PMI) and connect major demand centres in BiH is the connection between Croatia and BiH (Zagovzd to Travnik). At a length of approximately 120 km, the project was launched with the highest priority for F BiH. The transmission extension would provide a new entry point for natural gas in BiH and long term option for diversifying sources of supply of natural gas due to the connection with the Croatian transport system.

Importance for IAP

The interconnection with BiH is not part of the main IAP route as presented in the FS. This could however provide an additional offtake and contribute to the project's viability. For BiH, the project could prove an important new supply route. The existing single interconnector from Serbia to BiH is near the end of its technical lifetime and is unable to provide stable supply for existing customers, especially during winter season. In the future, IAP could become the main supply route for BiH, especially for Federation of BiH. Crucially, the volume of gas for offtake will depend on the development of BiH gas transmission networks and the connection of the Croatian border with the transmission system in Travnik, otherwise the offtake will be confined to a small region in BiH. In our assessment below, we aim to estimate demand along the PMI extension to test the sensitivity of our results for BiH offtake.

2.3.5 Kosovo

Kosovo is not part of the currently planned route of IAP. However, the gas interconnector to Albania features as a PECI project and its demand should therefore be considered in this study.

Kosovo currently has no gas demand. Its development will depend on regional gas infrastructure projects connecting Kosovo with either Serbia, FYR of Macedonia or Albania. Our estimate of industrial and residential gas demand is between up to 0.7 Bcm[19]. Residential demand is estimated at 0.4 Bcm and industrial offtake at up to 0.3 Bcm. The Gas Masterplan of Albania provides a more optimistic forecast of 1.1 Bcm by 2040. In our view

[19] See Interim Report of the first phase of this assignment completed in June 2015

this is a level that could only be achieved if the country shifts its power generation development to natural gas, which is highly unlikely (see below).

The cancellation of the South Stream project in December 2014 means that a northern interconnector to Serbia is unlikely, as no supply point and additional volumes exist in southern Serbia. This limits the options for gasification of Kosovo to the interconnector with FYR of Macedonia and/or Albania. While this is not a major roadblock for gas infrastructure investments, it simply means that Kosovo's gasification is entirely reliant on the cooperation of the FYR of Macedonian (or Albanian) government.

Gas will not play an important role in Kosovo's own power generation sector in the foreseeable future. This is due to the following factors:

- ***Government of Kosovo's (GoK) firm commitment to lignite*** – due to significant domestic reserves and support from international finance institutions, the Government is committed to replace the old Kosova A plant with a new 600 MW lignite fired power plant.

- The ***economic viability of lignite over natural gas*** – besides the availability of domestic lignite sources, GoK's decision to replace Kosova A with another lignite plant is based on the significantly lower cost of lignite versus gas.

- ***Underutilised hydro power potential -*** Kosovo has significant underutilised hydro power potential. The Zhur plant and smaller hydro power plants are estimated to have a capacity potential of 545 MW. For a country with peak demand of close to 1,200 MW in 2013 this is significant.

We perceive the Albanian gas interconnection to be highly unlikely to materialise. The electricity transmission interconnector between the two countries means that a gas pipeline between Albania and Kosovo would not be needed. The complementarity of both countries' electricity demand and the planned power generation in Albania suggest that a combined electricity market rather than gas market is more cost effective for both countries.

Importance for IAP

For the purpose of our analysis, we test the impact on the transmission tariffs by connecting Kosovo to IAP. We will test for two different demand scenarios: firstly, our own estimate of 0.7 Bcm, secondly the Albanian Gas Masterplan projection of 1.1 Bcm by 2040 gradually built up from 2025 onwards. The cost of the interconnector is not yet known. We will not include the costs as part of the analysis, but only the additional throughput. This is because the interconnection is not part of the IAP project but would be treated and financed separately.

2.3.6 Markets beyond the West Balkans

Besides gasifying the countries in the West Balkan region, IAP could also supply EU gas markets beyond Croatia. This means that it can act as a major component of the EU's Southern Gas Corridor. Gas could be delivered all the way to the Central European Gas Hub (CEGH) at Baumgarten in eastern Austria through the Croatian, Hungarian and Slovenian networks. This would mean that in theory the entire European market can be supplied by

IAP (through swaps or other trading mechanisms). The first EU markets to reach be reached are however worth considering as highest potential markets for IAP. We therefore provide brief overviews of the Hungarian, Slovenian and Austrian markets below.

Hungary

Hungary is one of the largest gas markets in central eastern Europe with total gas demand of close to 9 Bcm in 2017. Despite going through several transitions, natural gas demand in Hungary has declined in heat and power generation as well as residential sectors, while recovering in the industrial sector. The overall declining trend can be explained by the combination of mild winters in the last few years and development of more energy-efficient buildings. The stagnating pattern of gas consumption is also likely to have resulted from low electricity import prices. Today heat and power generation account for 21% of total gas consumption, commercial and public services for close to 18%, industry for 22%, and residential sector for 34%.

Hungary's gas supply is heavily import-dependent. In the last decades domestic natural gas production has fallen steadily to less than 2 Bcm in 2015, meeting around 20% of total demand. This is projected to decrease further.

Russia has historically been the largest importer of gas into Hungary and today accounts for the majority of Hungarian imports. In the wake of a major gas supply disruption in the winter of 2009 resulting from a dispute between Russia and Ukraine, Hungary has sought to diversify its supply routes and to some extent supply sources. The current long term gas purchase agreement between Gazprom and Hungary runs out in 2021. However there is little doubt that this contract will be extended. With increasing import volumes from Russia in 2017 and the development of the Turkish stream supply route around Ukraine, it is likely that Russia will continue to remain the main supplier to Hungary. Some of the projects seeking to diversify supply to Hungary include:

- **BRUA** – Romania/Hungary interconnection – BRUA involves the construction of a new natural gas trunk pipeline on the Romanian territory, which could act as a transit pipeline for Caspian and Middle Eastern gas but also Russian gas via Turkish stream. The project has already secured funding from the EU, featuring as an EU Project of Common Interest (PCI).

- **Slovak interconnector** – Hungary has increased its gas interconnectors with neighbouring countries, including the Slovak Republic, to improve security and diversity of gas supply. The Slovak Republic-Hungary cross-border pipeline started commercial operation in 2015 with bi-directional gas flows.

- **Croatian interconnector** – the strengthening of the Croatian interconnector is linked to the Croatian LNG project. Hungary has declared interest in the capacity for the Croatian LNG terminal. The signing of a memorandum of understanding between Croatia and Hungary on a common approach towards bi-directional gas transmission also highlights the importance of gas interconnection between the two countries.

This suggests that despite a widely expected continued dominance of Russian supplies in Hungary, the Government is ensuring alternative supply sources can be reached. This is most prominently evidenced by the Hungarian Government's interest in LNG Croatia. The development of IAP and prospective supply of Caspian gas through Croatia into Hungary would further help in this strategy.

While Russia will continue to be the main supplier of gas in Hungary for the foreseeable future, IAP shippers may be able to supply relatively small volumes into the market and compete at the margin. IAP supplies are in all likelihood more competitive than Croatian LNG supplies and would therefore provide a cost-effective alternative for Hungarian offtakers. Hungary should therefore be considered a significant potential offtake market in the development of IAP and in particular for international transmission throughput. A small share of the Hungarian market would represent a significant component of IAP capacity. For example, 10% of the Hungarian market represents roughly 20% of total throughput capacity of IAP. It is important to note however that selling into a market such as Hungary with a strong incumbent supplier as a new entrant is difficult and gas would need to be delivered competitively.

Slovenia

Slovenia's natural gas market is one of the smallest in the EU, totalling around 1 Bcm per year, with most of the natural gas consumed by industry and other non-household consumers. After a multi-year declining trend of natural gas consumption, an increase of 4.5% was recorded in 2016 for the second year in a row.

Gas supply in Slovenia is entirely dependent on imports from neighbouring countries. Since Slovenia cannot rely on its own natural gas sources, storage facilities or LNG terminals, the natural gas market is limited by the interconnections with the transmission networks of Austria (the Ceršak MRS), Croatia (the Rogatec MRS) and Italy (the Šempeter MRS). In order to meet its domestic demand for gas, Slovenia relies on Russia for 42% of its gas imports, on Austria for 35% of the total imports, and to a smaller extent on Algeria (16%) and Italy (7%).

Due to market liberalisation, the share of Gazprom long-term contract decreased in 2015, replaced by short-term contracts concluded at gas hubs and other points in the EU. However, in 2016 the share increased due to a general gas demand rise. The existing long term contract runs out in 2018 with current plans to extend it to 2022.

Several gas pipeline Projects of Common Interest are currently involving Slovenia. In particular, recent gas projects and investments include:

- ❑ **LNG terminal in Krk (HR)** – this project will include the building and operating of the infrastructure necessary for the development of LNG import terminal, aiming at securing energy needs and increasing the security of gas supply through the provision of new routes for the Central and South-eastern European region.

- ❑ **Slovenia – Hungarian interconnection** – this transmission system would facilitate access to Hungarian underground storages, improving Slovenia's security of supply.

- ❑ **Croatia – Slovenia interconnection** – this interconnection would be a crucial component for IAP supply to Slovenia through the Croatian network.

IAP would play an important role in the diversification of supply routes and for enhancing the security of supply in Slovenia, given the absence of gas storage facilities or domestic gas sources. Since a memorandum of understanding with the developers of TAP have already been signed with companies of Croatia, Bosnia and Herzegovina, Slovenia, Montenegro and Albania, there is also potential for cooperation through IAP. Although flow distribution and capacities available to Slovenia as well as other countries would depend on upgrades in the Croatian transmission system. The small size of the Slovenian market together with likely extension of the Gazprom contract however suggests that it is unlikely to act as a significant anchor market for international transmission volumes through IAP.

Austria

Natural gas consumption in Austria reached nearly 9 Bcm in 2015, after a slightly declining trend in the last few years. Given the country's continental climate and strong demand seasonality, natural gas is primarily used in heat and power generation (30% of total demand), and the industry sector (39%), while residential and commercial sectors consume around 17% and 7% of natural gas respectively.

Austria has modest gas reserves and domestic production is likely to remain stable in coming years, meeting only around 20% of demand. The country is highly dependent on gas imports, with 14% of the imports coming from Norway and the remaining supply sourced from Russia through a single supply route, via Ukraine and Slovakia. Gas imports have been increasing in the last few decades. The current Russian gas contract expires in 2027 and was amended in 2015 to reportedly reflect spot market prices.

Austria also plays a significant role as transit country for natural gas, given its strategic location along gas routes from Russia to Italy and southern Germany. Its transit capacity significantly contributes to securing energy supply of its neighbouring countries. As the regional gas market started developing, Austria also began exporting gas in the early 2000s, and its long-term future as gas transit country will depend on routes of Russian gas to Europe, gas export volumes and the possibility of transit alternatives to supply sources from the Black Sea and the Caspian Sea.

The Austrian gas transmission system is composed of pipelines supplying Austria, Germany, France and Central Europe (West-Austria Gas pipeline and Penta West Gas pipeline), Italy, Slovenia and Croatia (Trans-Austria Gas pipeline and South-East Gas pipeline), Hungary (Hungary-Austria Gas pipeline), and the Slovak Republic (Kittsee-Petržalka Gas pipeline).

Austria sources nearly all of its gas imports from Russia and this dependence on a single country and supply route is a concern for security of supply, particularly in light of Central and Eastern Europe gas curtailments and the 2009 Russia-Ukraine crises. Nonetheless, the country has several key geographical advantages given its strategic location on transit routes and storage capacity, which mitigate the risk of gas disruptions. Austria could therefore play an important role in gas offtake from gas shipped through IAP.

2.4 Key drivers for IAP

This section highlights the main factors in the region that will enable the development of IAP. It draws on the discussions and presentations from the previous sections and provides key background to our financial analysis.

2.4.1 Driver 1: Croatia as 'make-or-break' offtake market

At initial stages of IAP development Albania, Montenegro and BiH are unlikely to provide large critical anchor loads for IAP to be commercially feasible. A lack of credible gasification plans fully ratified by Governments, limited scope for gas to power development in the region and a reliance on residential consumers – with slow gradual demand build up rates – means that these markets will be too small to act as pivotal offtakers for IAP until at least 2030. Croatia, as the only well established and sizable gas market connected to IAP will therefore play a crucial role as an offtaker, particularly at early stages of development. The volumes Croatia could source from IAP will depend on the following factors

- *LNG development and contracts*– Although unlikely, the LNG terminal could be in competition with IAP as a supply source to Croatia. Due to the nature of LNG, terminals are usually used to provide short term supply for seasonal fluctuations. This partially explains the very low utilisation rates in Europe for regasification terminals (less than 25%). However, the ultimate utilisation of the terminal will depend on the contractual nature and financing terms of the terminal. If the Croatia LNG is developed on the back of long term fixed supply contract, it could potentially reduce the offtake from IAP. Long term contracts will either be established for the Croatian market or onward markets such as Hungary. In both cases, possible offtake markets for IAP would be served by the LNG terminal. However, as noted above, LNG terminal utilisation in Europe has been low and financing has increasingly moved away from long term contracts towards shorter term contracts. Hence, if the terminal is mainly used for short term trades to adjust for seasonal demand fluctuations, the impact on IAP throughput is likely to be relatively small. In our estimates below we calculate the impact of different LNG utilisation rates on the calculated tariffs.

- *Gas to power developments in Croatia* – Croatia's power generation strategy and the impact of renewable energy targets and environmental commitments on the country's power development plans will crucially determine the offtake volume from Croatia. As noted above, there are only limited plans for gas to power development in Croatia, but for the development of IAP they may provide crucial.

- *Development of southern Croatian gas distribution* – a key advantage of IAP for Croatia is that the pipeline will connect southern regions and municipalities with gas. The development of gas distribution and related infrastructure will therefore be important to maximise the potential offtake of gas in Croatia from IAP. Ideally this should be developed in parallel with IAP to ensure offtake as soon as the pipeline becomes operational.

- *Competitiveness of IAP gas* – the competitiveness of gas delivered through IAP is a key driver and is discussed in greater detail below.

2.4.2 Driver 2: expansion of TAP and access to wider sources

To deliver the necessary volumes (up to 5 Bcm/y) through IAP, associated gas pipelines need to expand their capacity. Currently, TAP can transport up to 10 Bcm of which 8.1 Bcm are already contracted for the Italian market. The expansion of TAP is therefore an important pre-condition for IAP to secure large international transit volumes and become commercially viable. Our understanding is that an expansion to 20 Bcm could be done at relatively low cost. There may be even lower cost options to expand TAP to a lower level that could enable IAP's development.

However crucially this will also require additional sources of supply to be developed and linked into the southern gas corridor. Azeri production may be earmarked for the Turkish market. This means that reliance for supplies into IAP would be on LNG from the Greek terminal at Revithoussa (if technically feasible) or additional supplies from Iran, Iraq, Kurdistan or even the Levant basin in the Eastern Mediterranean. SOCAR's involvement in the IAP project would be crucial to ensure Azeri gas is directed through IAP towards Croatia and further northern offtake markets.

2.4.3 Driver 3: Transit through Croatia

Besides offtake in Croatia, a key driver for IAP's feasibility, particularly at initial stages of development, will be international transit volumes. As the offtake markets along the IAP route are likely to develop slowly and Croatia's import demand is facing gas on gas competition, filling the pipeline with transit gas at the initial stages will be of utmost importance. If this cannot be ensured, pipeline tariffs (which are usually set on the basis of a 5-10 year regulatory period) will inevitably be too high for IAP to provide competitive gas supplies.

IAP can provide a key link between the Southern Gas Corridor and central European spot markets and therefore has great potential for transit gas. However, two main factors will determine whether this will materialise:

- *Investment in Croatian transmission system* – the transmission system in Croatia currently does not have the technical capability to ensure transit flows from Split to the Slovenian border at Rogatec. The additional investment in the Croatian gas transmission system for onward supply to Slovenia is €60 million according to Plinacro. For transit to Hungary from IAP, no additional investment is needed. Although featured in the latest Ten Year Development Plan of the TSO, it is not clear yet how the project will be financed and whether additional support may come from European funding sources.

- *Development of BRUA (or similar) pipeline* – The main infrastructure project that could act as a possible competitor for gas transit through IAP is the BRUA connection. Despite support from the EU, the project has currently stalled with Hungary cancelling open season process for the connection to Austria in July 2017. If BRUA or other projects along similar routes are developed, IAP could find it difficult to secure international transit volumes. IAP may have a first mover advantage if the pipeline together with the strengthening and extension of the Croatian system is developed before BRUA can gain traction again.

2.4.4 Driver 4: competitiveness of IAP sourced gas in Croatia

Gas transported through IAP and delivered to Croatia, Albania and Montenegro will have the same source as gas delivered through TAP into Italy, ie originating from Azerbaijan or the Middle East. For IAP to be feasible, the transmission charge on the pipeline needs to be sufficiently low for gas delivered from the offtake point at TAP to be competitive with other alternative import supply sources of gas.

As Croatia will be the key offtake markets at initial stages of development, IAP will have to provide gas at a competitive price in Croatia. In Albania and Montenegro, this is less relevant as no alternative gas supply sources are likely to emerge (apart from a remote possibility of domestic production). The question for IAP's feasibility in these countries will be largely a political one: should gas play a role in the overall energy mix. The Gas Masterplans in both countries suggest that there is a significant role for gas in these countries to play and that gas can be a competitive fuel source. This means that for Albania and Montenegro there is no gas on gas competition and consumers would simply be price takers depending on the charges from IAP. However, consumers would still have the choice between alternative heating sources of course, which may prove lower cost. For Croatia, this is different: IAP will need to provide a competitive alternative gas supply source compared to existing (and potentially new sources).

Gas transported through TAP will in all likelihood be indexed closely to the Italian gas hub – Punto di Scambio Virtuale (PSV). This means that at the offtake point from TAP (at Fier in Albania), the gas price will be very close to the PSV price. So, for gas transported through IAP to be competitive in Croatia versus gas imported via Slovenia from Italy, the transmission charges on IAP should not exceed the transportation costs from Italy via Slovenia. If IAP charges exceed those of Italian and Slovenian transit charges, consumers in Croatia would always favour imports from Italy. This is a purely economic standpoint and we appreciate that other political factors may affect long term contracts through IAP.

Using the Slovenian and Italian energy regulators tariff calculation tools and assuming an annual transit volume of 0.5 Bcm[20], charge in Slovenia would amount to around 1.45 €c/cm and for Italy at 0.45 €c/cm. Hence a total transmission charge of 1.9 €c/cm. This means that in order to deliver competitive gas into Croatia, the transmission costs of IAP should not exceed 1.9 €c/cm for delivery at the Croatian border. Otherwise, any gas delivered to southern Italy can be supplied to Croatia more competitively.

Typically, LNG imports are used to cover seasonal variations and not provide baseload gas supplies; particularly not in a well-diversified source market as Croatia. However, to obtain an idea on the competitiveness of LNG we estimate potential costs of delivered LNG in Croatia.

It is difficult to project potential LNG prices in Croatia without knowing the supply source. However, with global gas prices increasingly converging, one can use the US spot price as a

[20] Accessible via www.plinovodi.si (Slovenia) and www.snamretegas.it (Italy)

good indicator for the gas commodity costs of LNG. The World Bank in its Commodity Markets Outlook of April 2017 projects these to 3.9 US$/mmbtu in 2025. Liquefaction costs can be estimated at 3.33 $/mmbtu[21], transportation costs at 0.22 $/mmbtu[22] and regasification costs at 0.71 $/mmbtu[23]. The total cost of LNG delivery to Croatia would therefore be 8.16 US$/mmbtu or 24.5 €c/cm.

The cost of extracting and transporting Azeri gas to the Turkish/Greek border was estimated at $1.6/mmbtu in 2006, which today may be closer to $2.0/mmbtu[24] or 7.14 €c/cm. TAP charges are not yet public, but can be estimated at 5.46 €c/cm[25]. This would mean that at IAP/TAP tie in point Azeri gas would cost 12.6 €c/cm, almost half the LNG delivered price in Croatia. Hence, IAP could be sustained with very high tariffs if competing with LNG. We note that these numbers are based on publicly available information and may not capture the full return of Caspian gas producers, so they may be higher. Also contractual terms may be different, which would impact the delivered price.

The analysis shows however that the main competitor for IAP gas in Croatia will be the Italian and Slovenian transmission system and not LNG. We therefore use the 1.9 €c/cm as the key comparator to establish the commercial feasibility of IAP.

As noted above, this is an analytical approach to use a comparator benchmark in our financial analysis that should not be interpreted as a rigid threshold above or below which IAP will only make commercial sense. Instead it provides an indication of a suitable transmission level one would expect.

Driver 5: Possibility of IAP sourced gas to be delivered to CEGH

As noted previously IAP can act as a transit corridor for onward transmission to the Central European Gas Hub (CEGH) in Austria. It is difficult to establish a threshold value for gas transit into a gas hub, as many different supply routes and sources need to be explored. A simple economic approach could consist of estimating the cost of delivered gas at CEGH for different sources. However, this relies on extensive simplifying assumptions and most importantly misses market and regulatory realities of long term gas contracts. The true threshold price to establish whether IAP can supply gas competitively to CEGH will depend on:

- ❑ *Contract terms* - long term take or pay contracts can result in very different prices than short term spot sales.

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[21] Based on $15 Billion CAPEX with capacity of 10 mtpa, operating over 30 year time span and with an expected return of 10%; liquefaction OPEX is 3% of annuatised CAPEX

[22] Based on distance between US and Croatia and shipment cost information from TRI Zen LNG Market report 2013

[23] Based on a CAPEX of 390 million US$ net of a European grant of 110 million US$, ie 280 million US$, capacity of 2 Bcm and full utilisation and OPEX of 5% of CAPEX over a 15 year horizon and 10% return and an exchange rate of 1.1 US$ per EUR

[24] ENCOURAGEED (Energy Corridors for European Markets of gas, Electricity and Hydrogen) WP2 n.6, October 2006

[25] Total investment costs of 4.5 billion EUR, 15 Bcm annual throughput on average over a 25 year period, 12.5% rate of return and 5% of CAPEX as OPEX.

- ***Reactions of incumbents*** – even if supply to the gas hub is competitive, incumbent suppliers can adjust their pricing to squeeze out any supplier.

- ***Offtaker reaction*** – if the shipper through IAP is an unproven supplier, the markets may require further price discounts to factor in risks of non-delivery.

- ***Strategic goals and portfolio returns -*** the sale of gas through IAP may form part of a strategic move of the supplier and therefore is willing to take losses or lower returns in early years of operations. Additionally the sales to CEGH may only form a fraction of the suppliers total sales and they are willing to take losses on this sale for strategic reasons, which can be made up by excessive profits from other parts of the suppliers asset portfolio.

- ***Political factors –*** offtakers may opt for a contract with one supplier over another for political reasons and are willing to pay a higher prices for this.

Economic cost of delivery for international transit therefore is only one component and should not be the only key consideration. We provide estimates of these in the following; however we would note to treat these with great caution due to the limited information on data available and the non-cost factors described above that may determine transit volumes.

IAP – if developed as an international transit route – would compete with the following routes:

- *Azeri gas through TANAP- TAP- Italy- Slovenia route* – The critical factor here are the transmission costs through Italy, as Slovenian charges would apply either way and Azeri gas would be the source for both routes. These would however only be 0.45 €c/cm, which is a tariff that is unlikely to be beaten by IAP. As noted above however; other factors may contribute including the congestion on the Italian transmission system.

- *Azeri gas through TANAP – TAP – Bulgaria – Romania – Hungary route* – This route assumes a new Romanian Bulgaria interconnector to be developed. The key here will be the combined Bulgarian[26] (1.0 €c/cm), Romanian[27] (1.4€c/cm) and Hungarian[28] (0.3 €c/cm) transmission tariffs. This totals 2.7 €c/cm and can be treated as a maximum threshold for transit volumes.

- *Romanian gas through Romania and Hungary route* – The Romanian wholesale gas market is now liberalised; however parts of the domestic gas production (destined) for household use is still regulated at 60 RON/MWh or 12.9 €c/cm. We use this as an approximation for Romanian production costs. Adding the transmission charges in Romania and Hungary would result in a delivered price of 14.6 €c/cm at the Austrian border. Azeri gas prices plus TAP plus Slovenian transmission is 14.0 €c/cm. This would mean that IAP charges (together with Croatian transmission charges) cannot exceed 0.6 €c/cm. This is highly unlikely to be feasible.

[26] Bulgartransgaz website
[27] Transgaz website for 2017-2018 charges
[28] Using the transmission tariff calculator on the website of the Hungarian TSO FGSZ

So, if ignoring the contractual and external factors, which are significant in long term gas contract agreements, and only focusing on cost of commodity and transportation we identify 0.45 €c/cm as the minimum threshold for IAP to compete with the Italian supply route, 0.6 €c/cm as the minimum threshold for Romania gas delivered to CEGH and 2.7 €c/cm as the minimum threshold for a route through Greece, Bulgaria, Romania and Hungary.

The values should be treated with great caution and we would not rule out possible transit flows through IAP if the transmission tariffs exceed these values. Other factors can contribute to still make transit a viable proposition. Most notably insufficient gas supplies from Romania to deliver large quantities over the medium term.

Driver 6: Gasification strategies of Montenegro, Albania and BiH

The importance of gas in the three country's energy mix and the ability to provide anchor loads in these three countries will be another key driver. However, as noted above the scope for significant gas to power developments is limited and distributed gas demand (households, commercial and small industrial) can take a long time. If the Governments in these countries however prioritise their gasification as a main energy and industrial strategy, IAP could be given the required short term offtake. As of mid-2017 however, the commitments are limited to external reports and Masterplan studies.

We will test the sensitivity of these factors in varying scenarios in our financial analysis. The measure to assess the feasibility of the pipeline project will be the cost of transmission along the IAP route.

3 Gas demand and throughput

This section describes the gas throughput scenarios used in the financial analysis. The term 'throughput' refers to the volume of gas transported through the IAP pipeline. While this is closely linked to gas demand projections in each of the countries that IAP is planned to traverse, it is not a given that the full demand of each country will be served. We therefore have adjusted our methodology to consider country specific and location specific parameters to quantify the potential utilisation of IAP in meeting the demand for each country traversed as well as markets beyond. This section covers:

- An overview of the approach adopted in the FS;
- Gas demand and throughput projections for each of the offtake markets of relevance for IAP;
- Total throughput projections including potential transit flows.

3.1 Approach used in the FS

The FS centres its demand analysis around a Model for Analysis of Energy Demand (MAED) for each country that would be connected to IAP. Energy consumption is split between industry, transportation, services, and households up to 2040. The model accounts for socioeconomic, technological (including energy substitution assumptions), and demographic developments, with GDP/capita being the most significant element. GDP forecasts are taken from the International Monetary Fund (IMF), while population projections are taken from the UN Population Division. Final gas demand in the above four sectors is based on expected development of transmission and distribution systems.

In addition to sectoral demand, the IAP FS also accounts for demand from oil refineries and power plants as 'anchor' consumers. The IAEA's WASP computer model for long-term simulation and optimisation of building power plants was used to simulate power plant build under two scenarios: a "coal" scenario where coal power plant development is unrestricted, and a "gas" scenario where the cost of CO_2 emissions is taken into account.

Total gas demand in FS

The total gas demand gas demand projections in the FS amount to 4.5 Bcm in 2020, 6.1 Bcm in 2025, 7.0 Bcm in 2030, 9.4 Bcm in 2035 and between 12 and 14 Bcm in 2040. These projections are overly optimistic to a point where they are unrealistic. The optimised power plant model for example creates an unrealistic rate of natural gas demand growth in the region's power sector. The model's output is a steady, linear rise in natural gas demand in the power sector that would be equivalent to 6 GW of gas fired power generation to be developed in these four countries from 2014 to 2040 or roughly 230 MW of gas fired power generation every year. This is despite the FS also acknowledging that any new power capacity in the country will likely be coal-fired or hydro. The FS recognizes this as a risk to IAP's development, but in our view these projections are unrealistic and we provide alternative projections.

In reality, ENTSO-E's latest TYDP for 2016 suggests Croatia has plans for 350-850 MW of new CCGTs, but these projects have been delayed as Croatian electricity demand growth has stagnated. Bosnia & Herzegovina has no clear plans for new CCGTs and these would likely have to be built in southern Bosnia in order for IAP to be the main gas supplier. Montenegro's gas masterplan only accounts for one 100 MW CCGT and one 300 MW CCGT. Albania's gas masterplan consists of four potential gas-fired plants totalling 700 MW. Even if we optimistically assume that all of these proposed plants are built (and are connected to IAP gas, which would not be the case for the proposed Albanian CCGTs), that only totals 1.95 GW of new CCGTs (roughly equivalent to 1.4 Bcm of demand), which is 3.45-5.25 GW (2.5-3.8 Bcm) short of the FS's projection.

The FS's total projected gas consumption of between 12 and 14 Bcm would imply a consumption of more than 1 Bcm per million population (if optimistically assuming strong positive population growth). This is equivalent to gas consumption ratios in Germany, the UK or Italy. This seems overly optimistic for countries with limited industrial production and significant alternative power generation potential (ie hydro).

The timing of the demand numbers also appear wrong. Current gas demand in the four countries is a little over 3 Bcm. Yet, the FS projects gas demand to reach 4.5 Bcm by 2020. Bearing in mind that Albania and Montenegro have not started any gasification investment programmes, this is a component of the FS that requires realistic up to date alternative assumptions.

FS Throughput assumptions

Regarding throughput volumes of IAP, the FS assumes the following:

- ***Albania*** – the FS assumes all future gas demand will be supplied through IAP and therefore attributes all demand volume as throughput. This is an oversimplified and unrealistic assumption. As per the FS and the subsequent Gas Masterplan of Albania (i) none of the four proposed gas-fired power plants in Albania will be connected to IAP, (ii) 20% of demand from distribution customers will be served from direct TAP offtake (iii) and only one of the potential 4 industrial users will be connected to IAP. [29] The lack of potential anchor consumers in Albania that will actually be fed gas from IAP calls into question how rapidly the FS assumes gas demand will arise in Albania.

- ***Montenegro*** – The total demand in Montenegro is assumed to be covered by IAP. This seems a reasonable assumption to make as no alternative gas supply routes exist.

- ***Croatia*** – A key assumption in the FS is that 1/3 of any projected supply gap for gas in Croatia is covered by IAP. This is unsubstantiated and appears to be an arbitrary assumption. At the very least we would expect a simulation to be done on these flows to assess the importance of this assumption.

- ***Bosnia and Herzegovina*** – as for Croatia, the FS assumes that 1/3 of total BiH demand is filled by IAP. It is not clear why this is assumed and how this is substantiated. The FS projects for 2.5 Bcm of gas being consumed in BiH 25 years

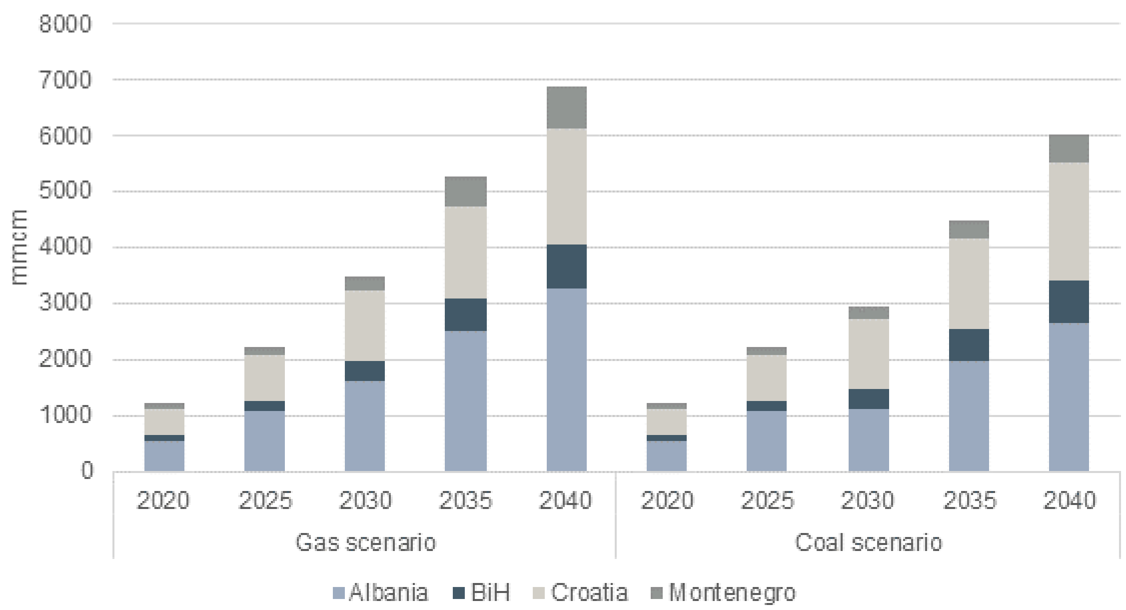
[29] As per ECA's review of Albania's gas masterplan.

after IAP is built, but this rests on two assumptions: a) that an interconnection with IAP is built, and, if such an interconnection is built, b) that the transmission network will be connected with the existing network between Serbia and Sarajevo. Further to the second point, the FS also includes the Bosanski Brod oil refinery as a source of demand for natural gas, totalling about 200 mmcm. However, Bosanski Brod is located in the very northwest corner of Bosnia and Herzegovina (and indeed Republica Srpksa) and is thus very unlikely to be fed natural gas from IAP unless the country's transmission and distribution network is fully developed.

- ***Transit*** - The FS does not appear to account for the possibility of transit flows, which would potentially form a key throughput for IAP, particularly in the early years of the pipeline development when demand is just emerging in Albania and Montenegro.

This results in throughput scenarios as shown Figure 8. With little progress made in developing gas distribution networks over the past years, the numbers appear optimistic. In particular throughput numbers for Albania, which is expected to make up 1 Bcm of total throughput in 2025 rising to over 3 Bcm in 2040 (in Gas scenario) appears unrealistic.

Figure 8 IAP FS throughput scenarios, 2020-40



Source: Based on data of the IAP Feasibility Study 2014.

3.2 ECA gas demand and throughput

We follow a similar approach as the FS. In a first step we estimate gas demand levels on the basis of recently completed energy strategies, masterplan documents and other publicly available sources. We then apply country-specific gas supply assumptions to obtain a reasonable estimate on IAP throughput volumes for each country.

3.2.1 Albania

Gas demand

Albania's gas masterplan provides an estimate of 'potential' natural gas consumption across households, services, transport, agriculture, and industry up to 2040. We interpret this to be a 'maximum' level for natural gas demand and apply our assumed rate of gasification (see Box 1), starting from the year gas begins to flow into the region, to each sector[30] to give us natural gas consumption for each year after IAP is completed.

Box 1 Approach to expected gasification of households, industry, and services

For gas demand by households, industry, and services, we based the share of consumers that become connected to the distribution network (and hence 'gasified') over time on historical rates of gasification in other southeast Europe countries: Austria, Bulgaria, Croatia, Greece, Hungary, Italy, and Romania. The numbers we use are adapted from a previous feasibility study for a gas pipeline system in Macedonia. The assumed gasification rates by sector are shown in Table 2 with the percentages being interpolated for years in between.

Table 2 Assumed gasification progression

Sector	Year 5	Year 10	Year 15	Year 20	Year 25	Year 30
Households	9%	21%	34%	44%	50%	53%
Services	8%	21%	37%	49%	55%	58%
Industry	31%	56%	71%	77%	79%	80%

Source: ECA analysis, Feasibility Study for the Gas Pipeline System in the Republic of Macedonia 2010.

The percentages in Table 2 serve as the 'medium' growth case in gasification, while variants are applied for 'high' and 'low' demand cases. For our 'high' case, we assumed that households and services gasification is 25% higher each year and industry gasification is 10% higher. For our 'low' case, we assume a 25% reduction in gasification for all three sectors.

These percentages are applied to the 'potential' natural gas consumption figures estimated in the Albanian and Montenegrin gas masterplans. They are also used to estimate IAP-fed gas demand in Bosnia and Herzegovina (see Section Table 2).

For Croatia, we follow Plinacro's latest Ten-Year Development Plan (TYDP) for 2017-26's projection of distribution and industrial gas consumption, as well as the expected gas consumption of the fertilizer producer, Petrokemija. The TYDP provides a projection up to 2026, which we then extend to 2050 by linear extrapolation in our 'medium' case. This gives an annual growth rate of 1.5% in distribution and 0.3% in industry. We made slight adjustments to these figures. For our 'low' case, we assume distribution grows at 0.5% per

[30] For Albania, we combined agriculture and industry, and disregarded the transport sector, for which we do not expect significant natural gas demand to emerge. The Albanian gas masterplan only identifies 48 mmcm of *potential* natural gas demand in transport by 2040.

year and industry grows at 0.1% per year. Our 'high' case assumes distribution grows at 2% per year and industry grows at 0.5% per year.

Plinacro assumes Petrokemija's consumption is constant at 538 mmcm. We assume the same for the entirety of our timeframe for our 'low' and 'medium' gasification cases. However, for our 'high' case, we assume Petrokemija increases its gas consumption to 589 mmcm in 2027, which is how much gas Petrokemija was assumed to consume in Plinacro's TYDP 2014-23.

As a final sense check, we corroborated the resulting gas consumption per capita figures for each country under each scenario with historical rates across Europe.

Albania's gas masterplan identifies four gas-fired power plants: Vlorë TPP to begin operating in 2020 as a gas-fired plant, CCGT 1 (expansion of Vlorë) in 2025, CCGT 2 (Korce) in 2030, and CCGT 3 (Kucove) in 2040. While these power plants are projected to total 437 mmcm of natural gas consumption by 2040,[31] none of them are located in areas that will be fed gas from IAP-connected transmission lines. All of them would be fed by direct offtake from TAP.

For our demand scenarios, we assume different rates at which the plans set out in the masterplan are achieved (Table 3). For our 'Best Case', we assume all of the planned power plants are built. In our 'Good Case', we subtract the 2040 200 MW CCGT. Our 'Base case' assumes the first CCGT is not built until 2030 followed by another in 2040. Our 'Worst Case' assumes that the Vlorë TPP does not convert to gas and that only one CCGT is built in 2030. These scenarios correspond to varying degrees of competiveness of gas for power generation in the region, the degree of political will to gasify Albania and the ability to finance such projects.

Table 3 Albania gas-fired power plant development scenarios

	Best Case	Good Case	Base Case	Worst Case
CCGTs in AL	Vlore TPP in 2020 200 MW in 2025 200 MW in 2030 200 MW in 2040	Vlore TPP in 2020 200 MW in 2025 200 MW in 2030	Vlore TPP in 2020 200 MW in 2030 200 MW in 2040	200 MW in 2030

In addition to the proposed gas-fired power plant development plan, Albania's gas masterplan identifies four potential non-power 'anchor' consumers: the Balish refinery, the Fier refinery, Bankers Petroleum, and Kürüm Iron. We assume that these potential consumers become gasified two years after IAP begins operating. However, Kürüm Iron is the only one of these who would be connected to transmission lines feeding from of IAP. We assume that Kürüm Iron becomes gasified two years after IAP becomes operational but this only totals 28 mmcm of consumption.

[31] The Albanian gas masterplan provides assumed gas consumption for each proposed power plant. We use the numbers as provided rather than applying any efficiency or load factor assumptions of our own.

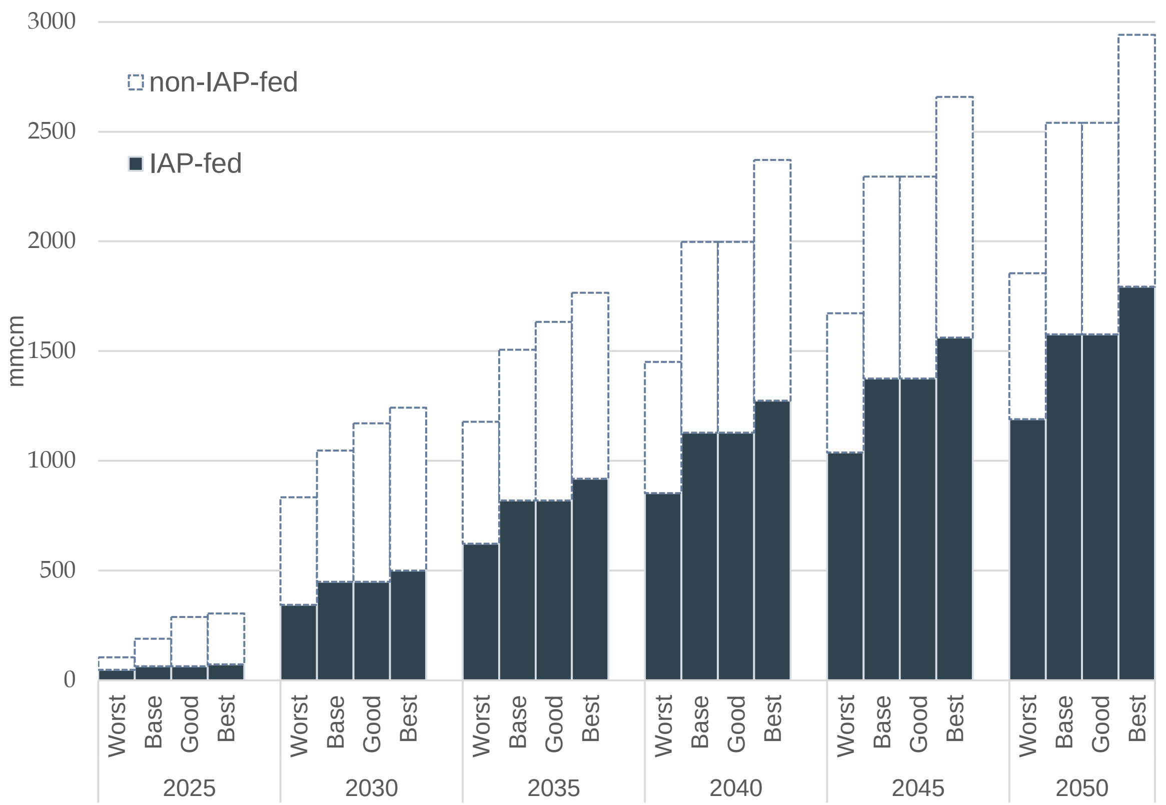
IAP throughput

TAP is currently being built through Albania on its way to Italy and direct offtake from TAP is envisioned to supply Albanian gas. Albanian demand centres along TAP will therefore not be fed by IAP. We have adjusted our IAP demand figures for Albania to only account for regions that will be connected to IAP, as per Albania's gas masterplan. Roughly 20% of households, industry, and services would be served by TAP, as well as all of the Albania gas masterplan's planned gas-fired power plants and most of its proposed potential 'anchor' consumers.

Figure 9 shows the evolution of Albanian demand across our four scenarios. This suggests that even under our most optimistic scenario, Albania's gas market would not exceed 3 Bcm in 2050. IAP would at a maximum serve 1.6 Bcm of the Albanian gas market. The growth would be slow but steady. In our base case scenario IAP would serve 0.5 Bcm in 2030 rising to 1.1 Bcm in2040 and 1.5 Bcm in 2050.

Note that the 'Base Case' and 'Good Case' scenarios are the exact same due to the only variation being in power plant developments, which has no effect IAP-fed gas demand. The variation we see is entirely due to assuming different rates of gasification among the households, services, and industry sectors. While non-IAP-fed gas dominates in the initial years due to having more anchor consumers and power plants, IAP-fed gas grows at a quicker rate due to supplying a larger share of households, industry, and services.

Figure 9 Albania gas demand scenarios 2025-50

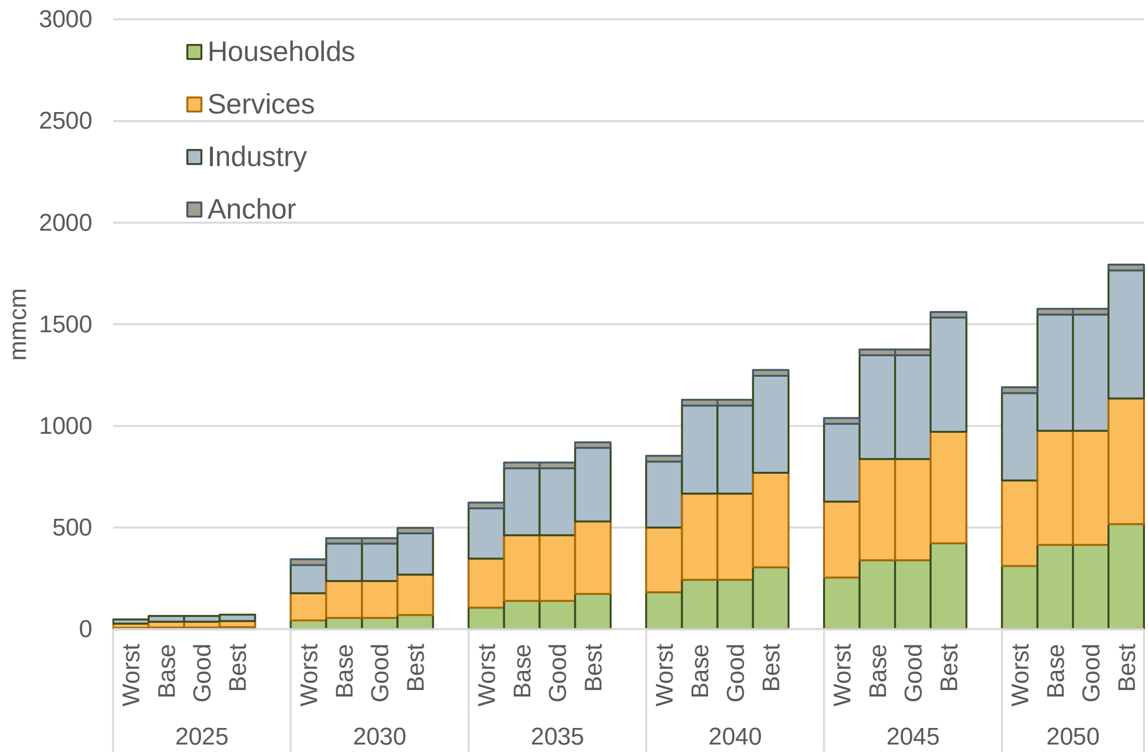


Source: ECA analysis.

While the proposed power plants and most of the proposed anchor consumers would not be directly connected to IAP, their consumption is accounted for when calculating a postage stamp tariff for the entire proposed Albanian gas transmission system. We also account for household, services, and industry demand in the areas of Albania that would be directly fed gas by TAP offtake. We use the same approach of applying a gasification rate to the Albanian gas masterplan's estimate of potential natural gas consumption (see Box 1), scaled by the projected gas demand of these regions relative to the IAP-connected regions. From our review of the Albanian gas masterplan, roughly 80% of expected demand by households, industry, and services would be supplied gas by IAP.

The breakdown of IAP-fed demand across sectors is provided in Figure 10. The only variation across these demand scenarios is the rate at which households, industry, and services are gasified.

Figure 10 Albania IAP-fed gas demand scenarios, by sector, 2025-50



Source: ECA analysis

The figure illustrates that gas to power – as power development plans currently suggest – and anchor customers will not be able to provide anchor load for IAP gas flows. It will mainly be distributed users (households, services and small industry) that will provide the bulk of the offtake along the IAP route. Ultimately therefore the offtake from IAP in Albania will depend on the political willingness to develop distribution in the regions along the coast. Crucially also on the economic feasibility for consumers switching to gas. This assessment is out of the scope of this report and we rely on data of the Gas Masterplan.

3.2.2 Montenegro

Given Montenegro is not currently gasified, all Montenegrin gas demand would be served by IAP. Montenegro's gas masterplan provides a projection of 'potential' natural gas consumption across households, services, and industry. Our gasification growth rate is applied to each of these sectors to arrive at gas demand by sector for Montenegro.

Montenegro's gas masterplan also provides two scenarios for the development of gas-fired power plants. The masterplan foresees a relatively inefficient 100 MW plant being completed as soon as IAP is completed, operating at a fairly low load factor. This would be followed by a more efficient 300 MW CCGT in 2030.

Rather than assume a consistent capacity factor for the two gas-fired plants, the masterplan assumes that the 100 MW plant would start with a load factor of approximately 20% and then gradually increasing its load factor to ~35%. This calculation is based on gas becoming more competitive over time or in order to meet an assumed increase in Montenegrin electricity demand. The 100 MW plant's load factor decreases after 2030 as it is displaced by the 300 MW plant along the merit order curve. The masterplan also projects the 300 MW plant's load factor to gradually increase over time. As a simplifying assumption, we assume that the 100 MW plant operates at a constant load factor of 25% and an efficiency rate of 50%, and the 300 MW plant operates at a load factor of 50% and an efficiency rate of 57%. This translates to annual gas consumption of 41 and 217 mmcm, respectively.

For our 'Good Case' and 'Best Case' scenarios, we have assumed the second gas-fired plant will be slightly larger than the Montenegro gas masterplan envisions at 500 MW. For our 'Best Case', the second gas-fired plant is built in 2027 rather than 2030. Our 'Base Case' follows the gas masterplan, while the second gas-fired plant is not built in our 'Worst Case' scenario (Table 4).

Table 4 Montenegro gas-fired power plant development scenarios

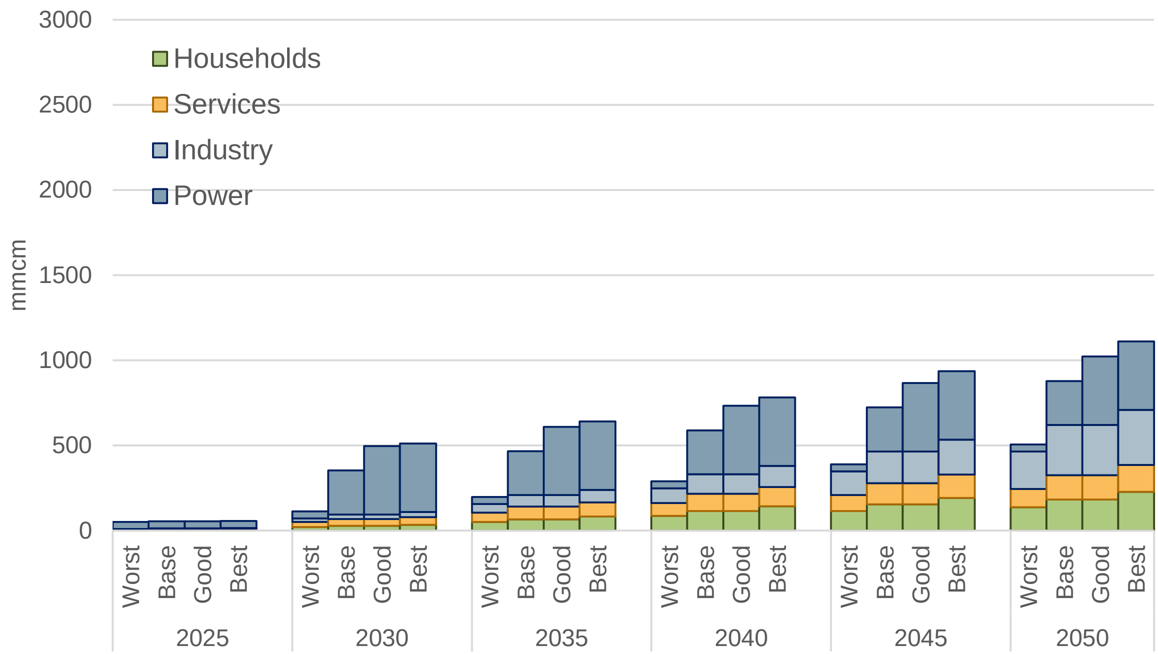
	Best Case	Good Case	Base Case	Worst Case
CCGTs in ME	100 MW in 2025 500 MW in 2027	100 MW in 2025 500 MW in 2030	100 MW in 2025 300 MW in 2030	100 MW in 2025

Montenegro's gas masterplan also provides estimates of how much gas the KAP aluminium plant and the Niksic steel plant would consume should they be gasified and become 'anchor' consumers (80 and 25 mmcm, respectively). However, it is highly unlikely that either plant would be competitive if they were gas-fired (see section 2.3.2), so we do not include them in our summation of Montenegrin gas demand (and neither does Montenegro's gas masterplan).

Figure 11 shows Montenegrin gas demand across our four scenarios. Aside from assuming different rates of gasification, the scenarios also show the impact of different gas-fired power plant developments for Montenegro. In our 'Worst Case', where only 100 MW of gas-fired capacity is developed, there is only 41 mmcm of annual gas-for-power demand. Under our 'Best Case', where both a 100 MW and 500 MW gas-fired power plants are developed, that amounts to 475 mmcm per year. 'Worst Case' scenario aside, power plant gas demand accounts for over half of Montenegrin gas demand up to 2040.

It is clear form our estimation that gas to power will be of key importance for Montenegro to provide offtake anchor load. In all but our 'worst case scenario' gas fired power generation makes up the majority of demand until 2045.

Figure 11 Montenegro IAP fed gas demand, by sector, 2025-50



Source: ECA analysis.

3.2.3 Croatia

Gas Demand

As noted in section 2.3.3, Croatia is already a significant consumer of gas, totalling 2.7 Bcm of gas consumption in 2015. IAP would help to serve gas to the non-gasified southeast of the country and provide an additional supply option.

Plinacro's 2017-26 TYDP expects Croatian gas demand to grow relatively modestly for 2017-26. Petrokemija, the local fertilizer producer, is projected to have flat demand of 538 mmcm per year, which is a 10% reduction on previous years. Industrial demand is only projected to rise at an annual rate of 0.3% and household demand is expected to rise at an annual rate of 1.5%. These figures represent significant declines in projected demand compared to the forecasts in Plinacro's 2014-23 TYDP as gas consumption in Croatia declined by 24% between 2008 and 2014. This is largely due to a decline in industrial activity and power demand. However, Croatia has recently reversed this downward trend, with gas consumption in 2016 being 8.9% higher compared to 2014.[32]

In lack of a detailed and up to date power sector development plan, we have taken a more speculative approach to gas-fired power plant development in Croatia. Croatia's 2009

[32] HEP Gas Supply Ltd, 'Croatian Gas Market Liberalization', Presentation at Central & Eastern European Gas Conference, Zagreb, 15-16 February 2017.

energy development strategy[33] assumed that 1,200 MW of new gas-fired power plants would be built by 2020. However, Croatian electricity demand has since stagnated, with total demand in 2015 being 6% lower than in 2010. In the absence of more recent power capacity projections by Croatian energy authorities, we have used a combination of Plinacro's latest forecast for energy transformation gas demand and the data inputs from ENTSO-E's 2016 TYNDP for guidance.

For power demand for gas, the ENTSO-E 2016 TYNDP expects Croatia to have 1,300 MW of gas-fired power capacity by 2020, compared to Croatia's current total of about 850 MW.[34] However, Plinacro's 2017-26 TYDP projects natural gas demand for energy transformation to grow from 395 mmcm in 2017 to 679 mmcm in 2021, staying constant at 679 mmcm up to 2026. We interpret Plinacro's projected increase in natural gas demand for energy transformation as Croatia's existing fleet of gas-fired plants recovering their load factors as gas becomes more competitive with coal as Croatia's gas-for-energy transformation demand was 685 mmcm as recently as 2012.

For projecting Croatian power plants beyond 2026, we use the four 'visions' of European energy market development from ENTSO-E's TYNDP 2016. The 'visions' are based on either inputs from national TSOs or high-level, Europe-wide scenarios. For Croatia, the four visions are fairly consistent with respect to gas, with three of the four visions projecting Croatia to have 1,700 MW of gas-fired power capacity by 2030. The other vision expects only 1,200 MW of gas-fired power capacity in 2030.

Therefore, for our demand scenarios (Table 5), we vary Croatian gas-fired power plant development between 400 and 900 MW of new capacity being built post-2026, while the existing 850 MW of gas-fired capacity remains constant through replacement and/or refurbishment. In our 'Best Case' and 'Good Case' scenarios, both 400 and 500 MW CCGTs are built, with the second plant being built sooner in the 'Best Case' scenario. For our 'Base Case' and 'Worst Case' scenarios, only a 400 MW CCGT is built, and it is built slightly later in the 'Worst Case' scenario.

Table 5 Croatia gas-fired power plant development scenarios

	Best Case	Good Case	Base Case	Worst Case
CCGTs in HR	400 MW in 2027 500 MW in 2030	400 MW in 2027 500 MW in 2035	400 MW in 2027	400 MW in 2030

IAP throughput

Croatia's need for IAP gas supply will depend on the use of its other supply options, which include domestic production, interconnectors with Slovenia and Hungary, and the possibility of the Croatia LNG terminal.

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33 The Republic of Croatia, Ministry of Economy, Labour and Entrepreneurship, 'Energy Strategy of the Republic of Croatia', Zagreb, June 2009.

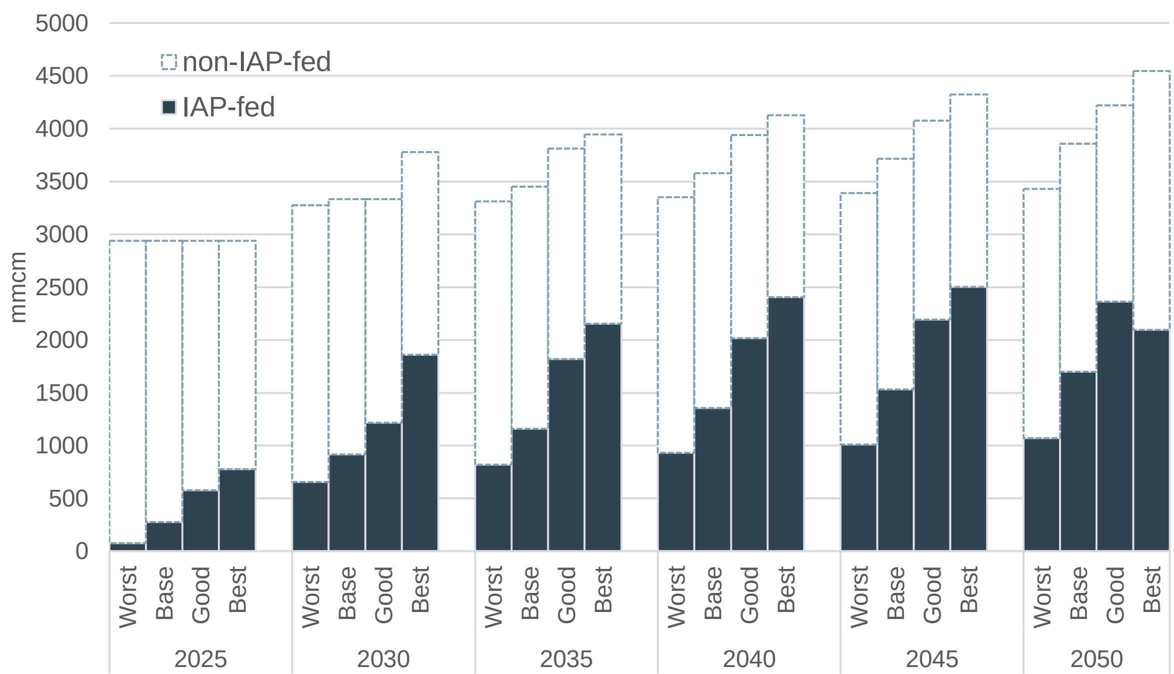
34 Based on a review of HEP's listed power plants: http://proizvodnja.hep.hr/proizvodnja/en/basicdata/thermal/default.aspx

Domestic production has peaked in Croatia and is currently roughly at 1.2 Bcm/y. Plinacro's TYDP 2017-26 assumes production will decline at an annual rate of 10.8%, which we have extended to 2050. In modelling IAP-fed gas demand in Croatia, we assumed a rate of utilisation for the existing interconnectors with Slovenia and Hungary based on historical usage (85% and 10%, respectively). We note however that in 2017 this has reversed and the Hungarian interconnection is now used more. For the purposes of our analysis however this is indifferent. We adjust whether the Croatia LNG terminal is developed and at what utilisation rate as a variable for our scenarios[35]. If Croatia LNG utilisation increases, the need for IAP-fed gas decreases.

A key factor for IAP throughput will also be the price of commodity of LNG compared to Azeri gas price. However to do this assessment quantitatively more information is needed on source of supplies and contract terms. The cost of commodity is unknown and can vary. Initial suppliers may set prices significantly below cost of production as a strategic measure to enter into markets. They may treat returns from other assets to cross-subsidise losses on other assets in their portfolio. Additionally, pricing will depend on the contract terms: long term contracts may have different contractual terms than short term spot sales. Simulating these contract terms is complex and out of the scope of this report. One thing however is clear: if suppliers of Caspian gas can deliver gas to CEGH at competitive prices to secure long term contracts, they will be capable of doing the same in Croatia. If suppliers cannot deliver gas competitively at CEGH, then IAP has no traction. It is for this reason we compare in our tariff analysis below - gas supplies from southern Italy to Austria and IAP and set the transmission charge to 1.9 €c/cm.

Figure 12 shows the split between Croatian gas supplied by IAP and gas supplied by non-IAP sources (other interconnectors, domestic production, and Croatian LNG terminal) across our four demand scenarios.

Figure 12 Croatia gas demand scenarios, 2025-50



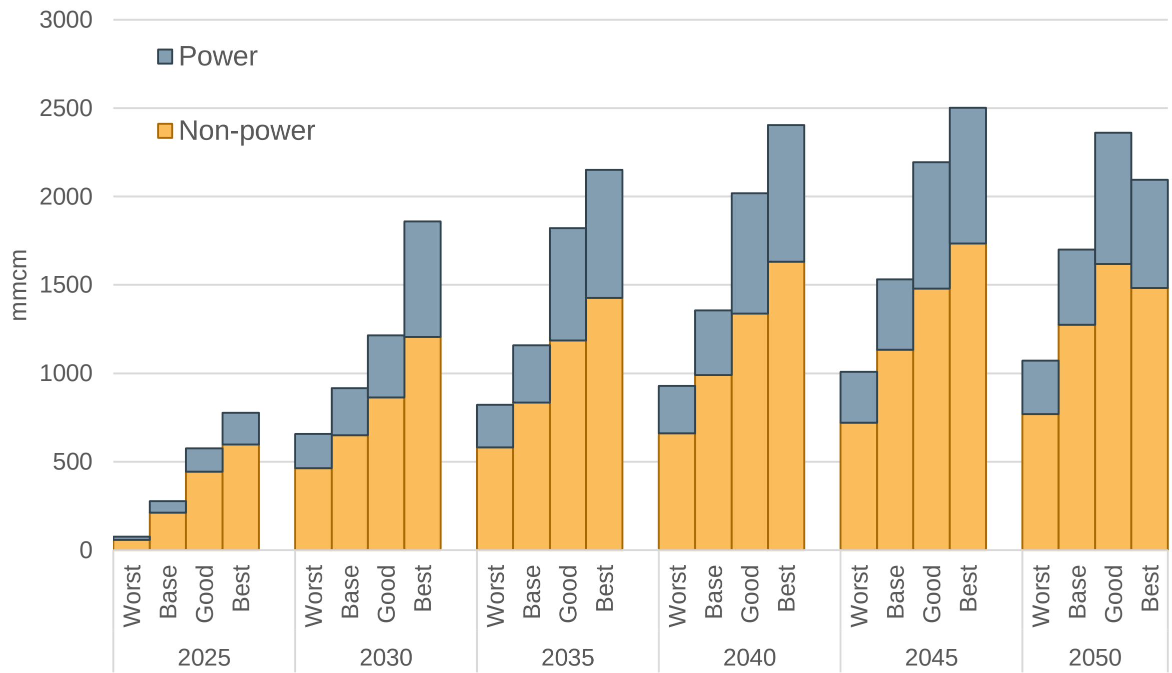
35 Best case: 0% of LNG utilisation, Good Case: 10%, Base Case: 25%, Worst Case: 35%

Source: ECA analysis.

Based on our projections of Croatian demand, IAP serves to fill any remaining supply gaps. Should IAP's capacity be exceeded, we assume Albanian and Montenegrin demand is prioritised, while IAP's share of Croatian demand declines. We thus assume that the other interconnectors and/or the LNG terminal will increase their utilisation in order to meet any Croatian gas demand that IAP cannot serve. This only occurs in the later years of our high demand scenarios.

Figure 13 shows how IAP-fed demand develops for Croatia across our scenarios, split between the non-power and power sectors. It is very apparent how key Croatian gas demand may be for IAP as its demand levels are generally much higher than Albania's or Montenegro's. This is particularly the case in 2025 and 2030, when Albanian and Montenegrin demand only totals 118 mmcm and 801 mmcm in our 'Base Case', while Croatian demand for IAP-fed gas is 276 mmcm in 2025 and 915 mmcm in 2030.

Figure 13 Croatia IAP-fed gas demand scenarios, by sector, 2025-50



Source: ECA analysis.

For the initial years of IAP, we also see that the utilisation of the Croatia LNG terminal can have a big impact on demand. Under our 'Worst Case' scenario where the terminal is utilised at 35% of capacity of a total capacity of 2 Bcm/y (and assuming the Slovenian and Hungarian interconnectors are utilised at 85% and 10%, respectively), IAP is barely used in 2025. This result highlights that IAP's competitiveness with Croatia's other gas supply options will be a key factor in IAP's overall viability. As for Albania, it will be the non-power sector which will provide the key offtake volumes for IAP in Croatia.

Note that IAP supply to Croatia falls in the final years of the 'Best Case' scenario due to IAP being at full capacity (5 Bcm) and our modelling assumption that Albanian and Montenegrin gas demand is prioritised. If IAP hits capacity, we assume Croatia's other interconnectors and/or the Croatian LNG terminal are able to increase their utilisation –

they are initially assumed to be operating below their technical capacities - to meet Croatian demand.

3.2.4 Bosnia Herzegovina

Bosnia and Herzegovina lacks a national gas masterplan, so it is unclear how their gas consumption would develop if an IAP offtake pipeline was connected to the country. In particular there is a high degree of uncertainty on the development of an onward connection to the current main demand centres in Sarajevo and Zenica. The current PMI projects do however provide a connection to Travnik which is connected to the main grid via Zenica. An IAP connection into Bosnia and Herzegovina would however enter through the south, connecting the Cantons of Western Herzegovina and/or Herzegovina-Neretva.

For residential, commercial, and industrial demand, we apply a similar approach as we did for Albania and Montenegro. We assume that BiH demand growth in these sectors occurs at the 'low' pace in Table 2, reflecting that BiH does not appear to have conducted the same amount of planning for natural gas penetration as in Albania or Montenegro. We apply this 'low' rate of demand growth for distribution customers to three different assumptions of IAP's development:

- ***Low BiH gasification***: IAP only feeds gas into BiH's two most southern cantons: Herzegovina-Neretva and Western Herzegovina. This case reflects an IAP offtake pipeline being developed to Mostar for example, but further development stalls.

- ***Medium BiH gasification***: the IAP connection is developed all the way to Sarajevo, with IAP gas covering the two cantons from the Low BiH gasification scenario as well as replacing supply from the Sarajevo pipeline. For the areas for which the IAP pipeline replaces the Sarajevo pipeline, we assume gas demand of 225 mmcm per year, which was the peak demand on the pipeline occurring in 2008.[36] This is to reflect gas demand in the areas served by the existing Sarajevo pipeline returning to peak levels due to receiving reliable IAP-fed gas supply.

- ***High BiH gasification***: we take an optimistic view that the transmission development plan displayed in Figure 7 comes to fruition. In which case, further cantons along the proposed transmission network are connected to IAP's throughput. These include the city of Tomislavgrad in Canton 10, the Canton of Central Bosnia, and further development in the Cantons of Tuzla and Zenica-Doboj.[37]

The three gasification scenarios are summarised in Table 6. While the city of Mostar, located within Herzegovina-Neretva, has an aluminium plant that could be an additional source of industrial gas demand, as is the case for industrial plants in Montenegro (see Section 2.3.2), it is highly unlikely the plant would be competitive with gas-fed energy so we exclude it from our estimates.

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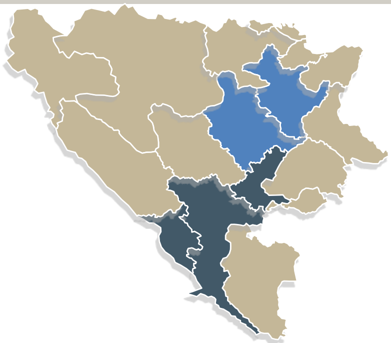
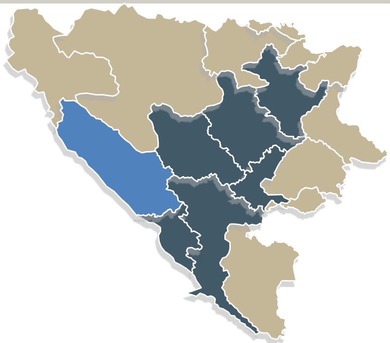
[36] 'Statement on Security of Energy Supply of Bosnia and Herzegovina', Sarajevo, July 2013.

[37] In our calculations, we subtract the populations of Kakanj, Olovo, Visoko and Zenica from the Tuzla and Zenica-Doboj Cantons as they are connected to the existing Sarajevo pipeline and thus their demand is assumed to be covered by the 225 mmcm of gas replacing the Sarajevo pipeline.

Table 6 Bosnia and Herzegovina gasification scenarios

Low BiH gasification	**Medium BiH gasification**	**High BiH gasification**
		
IAP only supplies Cantons of Herzegovina-Neretva and Western Herzegovina and no onward connection to existing gas demand centres exists.	*IAP supplies southern Cantons as well as Sarajevo. Assumes that existing pipeline is refurbished but supplies to the Sarajevo area are covered by new IAP route.*	*IAP supplies reach throughout the planned transmission network of the Federation. IAP becomes the main gas supply point for a gasified BiH.*

Note: Lighter shading reflects Cantons that are not 'fully' gasified by IAP-fed gas. E.g. Tomislavgrad is the only city connected to the gas transmission network in Canton 10 under the transmission development plan displayed in Figure 7.

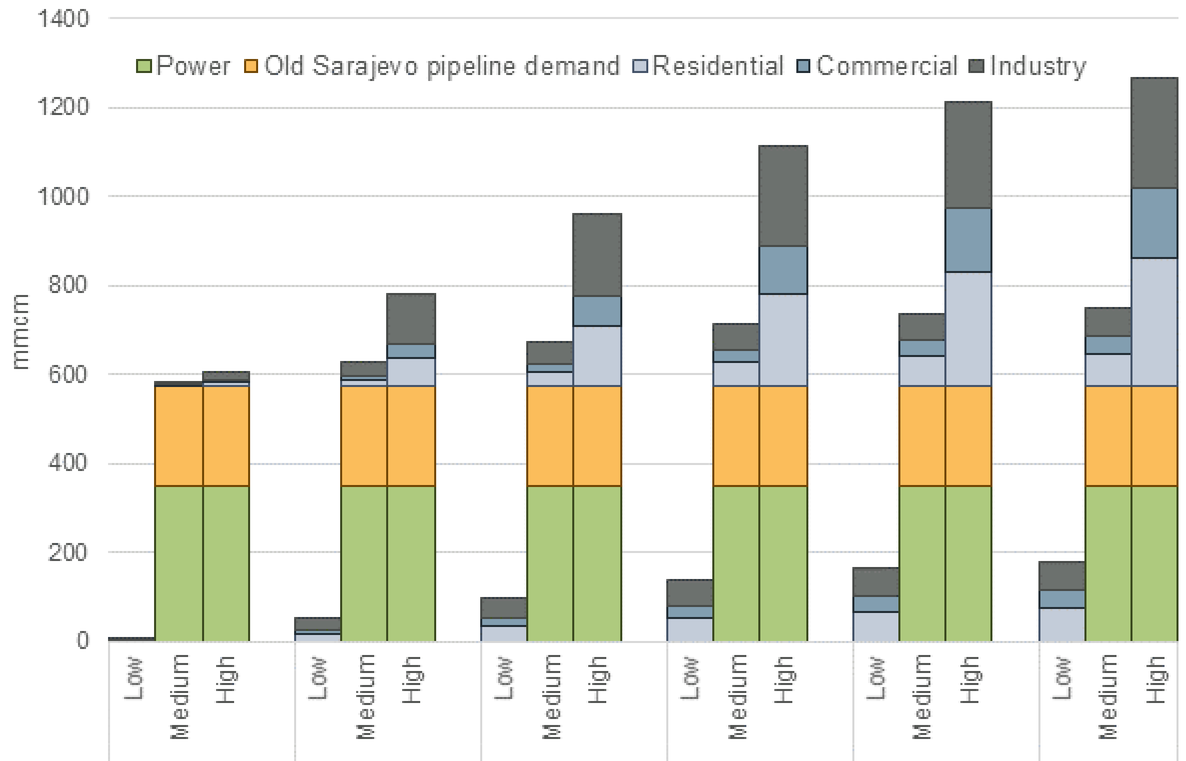
In order to apply the same rate of gasification as in the cases of Albania and Montenegro above, we need an estimate of potential natural gas demand in the region. We assumed a maximum gas demand per capita of 1,200 m^3. This is the peak in gas demand per capita in Austria in 2005.[38] We then combine this number with the populations of the connected Cantons and our assumed low rate of gasification.

For power generation, we assume that the 390 MW gas-fired power plant in Zenica begins operating in 2025. The IAP connection and onward connection within the territory of BiH is assumed to supply gas to this plant, which would operate at a 65% capacity factor with 57% efficiency. The Kakanj conversion is not included in the analysis. As the IAP connection would not reach Zenica in the low case, no gas to power demand is assumed.

Under our modelling assumptions, in the low case, demand from IAP starts at 9 mmcm in 2025, rising to 179 mmcm by 2050. In the medium case, demand met by IAP is 582 mmcm in 2025 (highlighting Sarajevo and the Zenica power plant being key demand anchors compared to the low case), rising to 752 mmcm by 2050. In the high case, demand is initially 607 mmcm in 2025, rising to 1,266 mmcm in 2050. Figure 15 illustrates.

[38] As per the BP Statistical Review of World Energy 2016 and the UN Population Division's 2015 database.

Figure 14 BiH IAP-fed gas demand scenarios, by sector, 2025-50



Source: ECA analysis.

As a base case for our scenarios in Section 3.3.2, we assume that the Bosnia and Herzegovina interconnection will not occur. This is due to the uncertainties of the interconnection on current route plans. We therefore treat the BiH interconnection as a separate sensitivity and discuss the potential impact of such an interconnection in Section 5.4.

3.3 Total throughput projections

3.3.1 Transit flows

Besides country specific offtake volumes, additional volumes that will flow through IAP as international transit are assumed. Transit is assumed to be any gas volumes delivered to markets north of Croatia. Volumes for international transit at this stage of the project are difficult to quantify, as the volumes will depend on:

- The contract underpinning the transit flows, ie long term contracts versus spot market sales
- The destination markets and the development on these markets
- Physical bottlenecks beyond Croatia
- Source of gas supply and the willingness of suppliers to undercut prices in the destination markets.

Ultimately, the level of transit flows would be determined by the competitiveness of TAP gas in Central Europe. We make no assumption about the costs of TAP gas relative to other gas supply options in Central Europe, instead simply assuming higher or lower levels of transit flows with respect to each demand scenario (see variations in section 4.

These factors are extremely difficult to estimate and we therefore treat transit flows as a sensitivity factor. We assume that transit flows will start immediately once IAP is completed (assuming that all necessary investments within the Croatian transmission system are completed), which will allow gas to flow from TAP to Central Europe. We assume that transit flows are constant in all of our scenarios, with the exception of years when IAP's capacity is exceeded, in which case transit flows are reduced to prioritise demand in Albania, Montenegro, Croatia and BiH.

In our 'Best Case' scenario, we assume there is demand for 1 Bcm/y of transit flows. For our lower demand scenarios, we progressively lower transit flows by 200 mmcm/y, with the lowest amount being 400 mmcm/y in our 'Worst Case' scenario. We acknowledge that these are arbitrary scenarios; however they do provide an indication on the sensitivity of the results in our financial analysis. Modelling transit volumes is a complex activity and would rely on a number of simplifying assumptions. Our objective in this report is to show the IAP throughput volumes (including the transit) volumes that could make IAP commercially feasible.

3.3.2 Scenarios

Each modelling assumption has its significant share of uncertainty, so we have constructed four different scenarios that aim to capture a wide range of possibilities for gas demand in Albania, Croatia, Montenegro, and Bosnia and Herzegovina. Table 7 shows how key variables are varied across these demand scenarios.

- Our ***Best Case*** assumes competitively priced natural gas with high transit flows, a higher rate of gasification than regional experience would suggest, full gas-fired power plant development (including development beyond Montenegro's gas masterplan), and that Croatia does not develop the Croatia LNG terminal leaving more Croatian gas demand for IAP to fill

- The ***Good Case*** assumes reasonably high transit flows, a rate of gasification in line with regional experience, an optimistic level of gas-fired power plant development, and that the Croatia LNG terminal is developed but operates at a low level of utilisation

- Our ***Base Case*** assumes transit flows of 0.6 Bcm implying the development of other (rival) transit pipelines, a rate of gasification in line with regional experience, gas-fired power plant development at a slower, and that the Croatia LNG terminal is developed and operates at 25% capacity.

- We finally present a ***Worst Case*** where transit flows are fairly small, achieved gasification rates are lower than regional experience suggests, a minimum of new gas-fired power plants are developed (either due to stagnating electricity demand or a preference for new coal-fired plants), and the LNG terminal is developed and operates at a fairly high capacity of 35%.

Table 7 Scenarios for IAP throughput

	Best Case	Good Case	Base Case	Worst Case
Transit	1.0 Bcm/y	0.8 Bcm/y	0.6 Bcm/y	0.4 Bcm/y
Gasification growth	High	Medium	Medium	Low
HR LNG utilisation	No LNG	10%	25%	35%
CCGTs in AL	Vlore TPP in 2020 200 MW in 2025 200 MW in 2030 200 MW in 2040	Vlore TPP in 2020 200 MW in 2025 200 MW in 2030	Vlore TPP in 2020 200 MW in 2030 200 MW in 2040	200 MW in 2030
CCGTs in ME	100 MW in 2025 500 MW in 2027	100 MW in 2025 500 MW in 2030	100 MW in 2025 300 MW in 2030	100 MW in 2025
CCGTs in HR	400 MW in 2027 500 MW in 2030	400 MW in 2027 500 MW in 2035	400 MW in 2027	400 MW in 2030

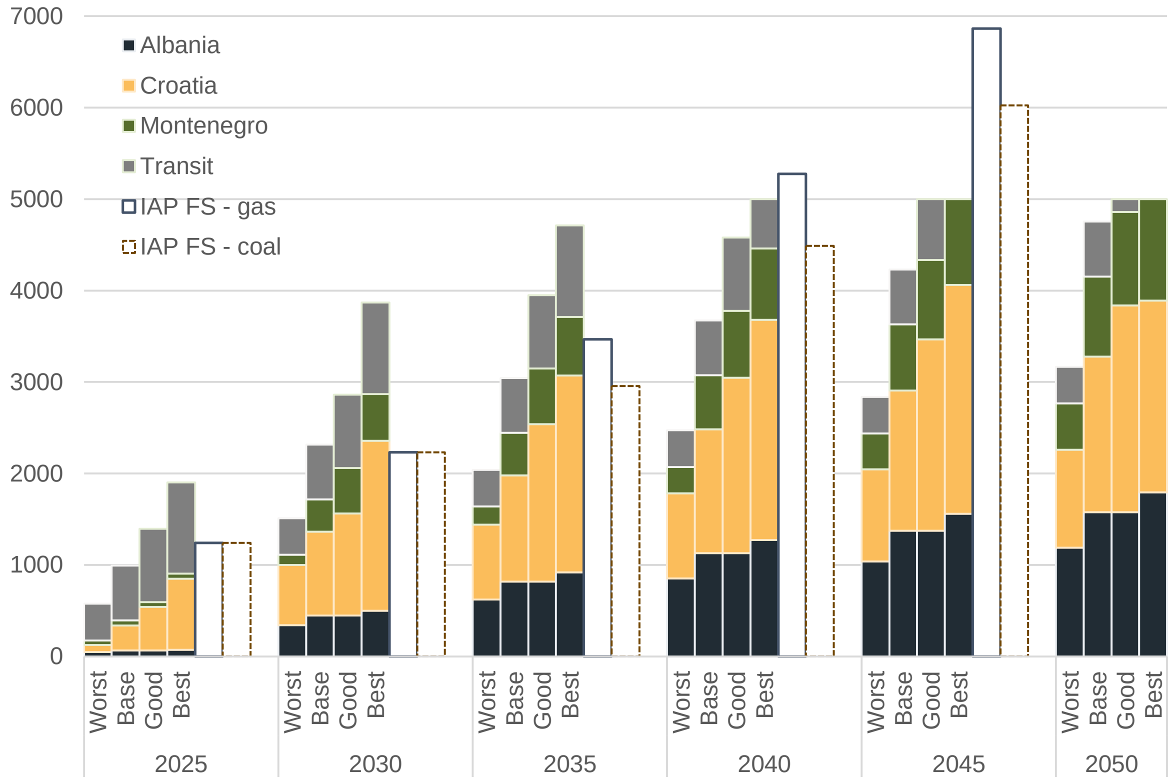
We note that the probability of occurrence of each of these scenarios varies. And different combination of variation factors may occur. The objective of these scenarios is to show the possible range of tariffs under the most extreme of assumptions. Note that we assume that IAP's interconnection with Bosnia and Herzegovina does not occur in any of these four scenario variants. We introduce the potential impact of a Bosnia and Herzegovina interconnection in the financial analysis as a separate sensitivity scenario.

3.3.3 Total throughput projections

Figure 15 compares our four throughput scenarios to the FS's scenarios. Note that we adjusted the timeline from the FS to simulate the start of IAP in 2025. We see that the IAP FS throughput numbers are comparable to our base case numbers until 2040 when there is a marked increase in FS numbers over and above our most optimistic case and even the technical capacity of IAP.

One aspect that cannot be compared is the split up of the demand numbers in the FS as the numbers are not disclosed. However the optimistic assumption of IAP's role in supplying gas to Albania and the lack of any transit volumes in the FS would suggest that the split up is markedly different in the FS, which is important as it would lead to different conclusion on the likely drivers of the feasibility of IAP.

Figure 15 ECA and IAP FS total IAP demand figures, 2025-50



Source: ECA analysis

On the basis of our analysis of throughput volumes, we can confirm the major drivers of IAP feasibility:

- ***Transit is key*** – The bulk of short term gas throughput is expected to come from transit. This will be of critical importance for the project to develop and the high initial costs to be spread among a greater volume of gas, thereby reducing tariffs. Over time, the importance of transit diminishes as the Croatian offtake grows as well as Albanian and Montenegro gas markets are developed. The development of transit capacity in the Croatian system and its competitiveness will therefore be of utmost importance to make IAP a viable project.

- ***Croatia offtake is important –*** providing supplies to the only established gas market on the route will be vital. We estimate these to initially be between 0.1 and 0.8 Bcm (depending on the utilisation of the LNG terminal) and gradually growing with Croatian gas demand growth to around 2 Bcm. This could even be considered a conservative assumption if IAP gas can be competitively delivered into Croatia.

- ***Albania and Montenegro offtake is relatively small –*** The importance of offtake from Albania and Montenegro is modest. While they would be expected to become important offtake markets by 2035, the initial stages of development are unlikely to expect large offtake volumes. Montenegro is small and only has small gas fired power plants as potential offtakers. Albania's large potential industrial offtakers are all located in southern Albania and would be supplied by TAP. Gas fired power plants in Albania are also currently planned around TAP. Albania's offtake would therefore largely be carried by households, services and small industry, which is slow to develop.

4 IAP route and cost review

The focus of this section is a critical review of the technical aspects of the pipeline which are mainly covered in Chapter 5 of the FS, with a brief commentary on the environmental (and social) aspects of the pipeline covered in Chapter 7.[39] The objective is to provide a high level assessment and review of the parameters assumed in the FS and in particular assess whether the cost assumptions made at the time of writing the FS are still valid. The main areas covered are as follows:

- Review of the pipeline route;
- The technical requirements and characteristics of the pipeline (including the number of compressors, materials used, pipeline size, operating pressure etc.);
- The estimated costs of the pipeline, including an overall assessment of CAPEX, OPEX and associated potential cost categories; and
- Other issues not specifically raised in the IAP Report.

4.1 Pipeline route

The approach used by the authors of the FS in relation to determining the pipeline route is a typical one for a project of this type involving a combination of desktop surveys using 1:5,000 and 1:25,000 maps,[40] site visits to points of interest including road, rail and river crossings, and vantage point surveys.[41] Whilst the approach taken is acceptable, some of the detail that one might expect from such an extensive feasibility study appears to have been omitted. For example, whilst Annex 1 of the FS does contain a detailed breakdown of the pipeline passing through different types of terrain, if a full vantage point survey had been undertaken one might have expected to see more detailed cost estimates identifying the number of motorway crossings, major and minor road crossings, and river crossings.

The FS breaks the IAP route into three country specific segments (Albania, Montenegro and Croatia) and then breaks each country segment down into a series of sections. Using the same basic structure as the FS, we provide a brief commentary on the IAP route for each section. The pipeline sections for each country and the elevation profiles are shown in the Annex.

[39] It should be noted that references to social impact of the pipeline on communities have been included although the IAP Report does not really cover this area.
[40] A 1:5,000 scale map will show considerable detail, particularly in urban areas, industrial areas or ports, and will often be used by planners. A 1:25,000 scale map such as an 'Ordnance Survey Explorer' will show most of the detail required for a high-level feasibility study including minor paths, field boundaries and open access areas.
[41] A vantage point survey involves the operative typically driving to the various points where the proposed pipeline route crosses roads and rivers and observing the route from the line of sight available from that vantage point.

This overview of the technical detail in the FS enable us to assess whether costs of the pipeline are accurate. Each segment with an assessment on the provided level of detail in the FS is shown in Table 8.

Table 8 IAP sections and ECA assessment of FS detail

Sections	
Albania	
Section 1: Fier to Ndroq	FS highlights both the agricultural and rocky terrain. In addition, whilst the FS identifies the need for two river crossings, it does not specify the width of each river or the complexity of the crossing. No information is provided on road or rail crossings.
Section 2: Ndroq to Lezha	FS highlights agricultural terrain, populated valleys, narrow gorges, hills and rocky terrain, as well as multiple river crossings. Again, the FS does not specify the width of each river or identify any road or rail crossings.
Section 3: Lezha to Montenegrin Border	FS highlights that the route passes through agricultural land, narrow populated valleys, rocky hills, crossing both the Drinit and Bojana rivers. It fails to identify any road or rail crossings.
Montenegro	
Section 1: Štodra ALB/MNE Border - Bar	FS highlights agricultural and rocky terrain, including a rocky valley, and a river crossing near Kamenički Most In addition, the route passes near to the city of Bar, possibly leading to proximity issues. The FS does not specify the width of the river or the complexity of the crossing, nor does provide it any information on road or rail crossings.
Section 2: Bar - Lastva Grbaljska	FS highlights rocky and hilly terrain as the pipeline route enters the sea, with the subsea section being laid on the seabed. The FS does highlight the need to cross a hill when the pipeline route returns to land. However, no details are provided regarding road, rail or river crossings.
Section 3: Lastva Grbaljska - Rt Dobreč MNE/HR Border	FS highlights that the route passes through a populated area, a rocky area, agricultural land and a mountainous area. It fails to identify any road or rail crossings or the respective distances in the different terrains
Croatia	
Section 1: Prevlaka - Dubrovnik	The IAP route is parallel to the coast, near the airport and then offshore. No information is provided on road or rail crossings.
Section 2: Dubrovnik - Dubrovačko Primorje	The IAP route passes through very hilly and rough terrain plus the challenge of crossing the bay. No details provided on road or rail crossings.
Section 3: Dubrovačko Primorje - Ploče	The route passes through hilly and rough terrain, crosses Pelješac bay and passes the city of Ploče on the west. It fails to identify any road or rail crossings or distances.
Section 4: Ploče – Šestanovac	The route passes through agricultural land followed by mountainous and hilly land. It fails to identify any road or rail crossings.
Section 5: Šestanovac – Dugopolje	The route passes through mountainous and hilly terrain. The pipeline route follows the main highway but the IAP Report fails to identify any road or rail crossings.

While the overall methodology used in the FS seems appropriate, we believe that some factors have been omitted in the FS which may result in an underestimation of the total pipeline costs. In particular we identify the following aspects that may have provided greater clarity in the cost estimation:

- The use of satellite imagery to ensure the chosen routes are using up to date data. For example, commercially available satellite imagery would allow pipeline route designers to identify any new buildings developed near the pipeline route since the maps were drawn, as well as different uses of agricultural land. The latter could be used in establishing more accurate right of way (RoW) costs.

- The identification and costing of road and rail crossings.

- The identification of parts of the pipeline route passing through urban terrain where either the pipeline will need to manage proximity issues, either by greater wall thickness or some other mechanical protection. This may have cost implications.

- More detail is needed regarding the subsea sections of the pipeline, and a recognition of the potential challenges some of the subsea sections might have in relation to deep water or protection issues.

- Whilst the mountainous nature of much of the pipeline route should be recognised in the costing process, there will also be technical and timing challenges of construction in such terrain.

- There is some uncertainty over the final pipeline route. The variation in length for the alternative pipeline routes as per the FS can be as much as 20% to 25%. The FS states that each country may choose to route its segment of the pipeline differently. This adds to the uncertainty over the cost. In light of a lack of detailed information on the routes, we propose to follow the route and length proposed in the FS.

Additionally updated cost figures can be provided since the publication of the FS for the Croatian pipeline sections. Plinacro has conducted more detailed costing and routing estimates for the Croatian sections of IAP over the past years and has shared the results of these costings with the consultant team.

4.2 Technical requirements

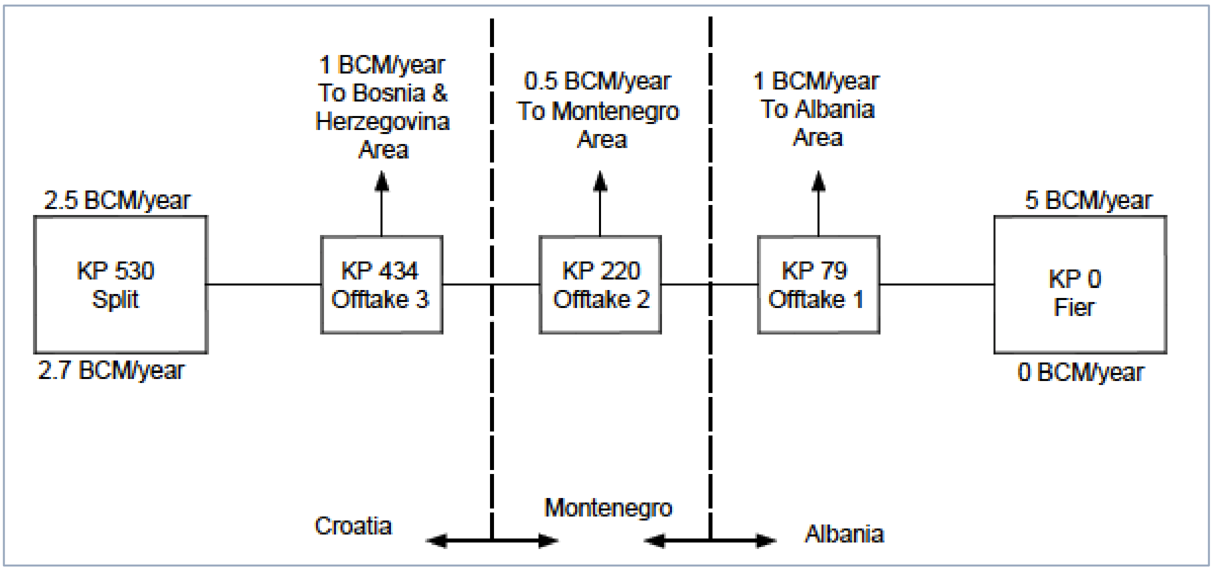
As part of the technical components of the FS, we also review the implied technical requirements and characteristics of the pipeline. The main characteristic covered include the size of the pipeline, the number of compressors used and the design methodology, including materials used, operating pressure etc.

Pipeline size

The FS conclusion on pipeline sizing was based on the results of network analysis and it is not the intention of this report to repeat that analysis. Instead, a simple 'sense test' will be applied using a simplified form of the Weymouth pipe flow equation based on data from the schematic shown in Figure 16 from the FS. The basic parameters used in the analysis for South-North flows are as follows:

- *Inlet pressure from TAP-AG* – 82 Bar
- *Outlet pressure along pipeline* – 50 Bar
- *Maximum flow* – 5 Bcm/Year
- *Pipeline length* – 511 km

Figure 16 Basic flow diagram for IAP



Source: IAP Feasibility Study, COWI

Using a simplified Weymouth pipeflow equations based on the parameters above, we estimate that a maximum offtake of 5.1 Bcm could be served with a 32'' pipeline. This is for a worst case scenarios where no gas offtake would be taken in Albania, Montenegro or Bosnia Herzegovina.

In addition to the above analysis the FS also considers the option of North-South flows from Croatia to Albania. Notwithstanding that such a scenario seems highly unlikely in the absence of an LNG terminal in or near to Croatia, a simplistic analysis of reverse flows was undertaken on the basis of the following parameters

- *Inlet pressure from Croatia* – 60 Bar.[42]

[42] The IAP Report suggests that additional compression will be needed to provide a 60 Bar inlet even though it requires gas at 70 Bar for South-North flows. The IAP Report is silent on whether this compression would simply be the proposed IAP compression reconfigured for use in reverse flow or

- *Outlet pressure along pipeline* – 50 Bar.
- *Maximum flow* – 2.6 BCM/Year.
- *Pipeline length* – 511 km.

The lower capacity for North South flows is due to the lower inlet pressure. In a worst-case scenario, with no gas offtakes to markets in Montenegro and Bosnia Herzegovina, 2.6 Bcm could still flow through a 32" pipeline.

Number of compressors

The suggested approach of not using gas compressors to provide additional capacity or reduce the pipeline size for flows between Albania and Croatia is the right one, since a 32" pipeline is able to manage flows of around 5 Bcm without compression. If 5 Bcm gas is going to be offtaken from TAP and 2.5 Bcm of that gas transported via IAP into the Croatian gas transmission at 70 Bar then gas compression at the interface between IAP and the Croatian gas transmission system may be needed. However, at lower flows say less than 3.3 Bcm it should be possible to provide 70 Bar in Croatia without compression.

Therefore, it would be possible, if IAP is developed using 32" pipeline, to delay the costs of the compressor station and only incur it when flows exceed 3.3 BCM. This is also applies for North-South flows where one gas compressor is needed for throughput exceeding 2.6 Bcm. Given the relatively low cost of compressor stations compared to the overall project investment, we do not consider a delay in the compressor station investment to be of significant difference for the financial viability of the IAP project. We will therefore assume that the project will be developed with a compressor station from the start. This is for both scenarios – North-South flow as well as South-North flow.

Design methodology

When high-pressure gas pipelines are designed, and built throughout the world they are typically designed and built to conform to one of the major high pressure gas pipeline standards. For example, this might be the American gas pipeline standard *ASME B31.8 'Gas Transmission and Distribution Piping Systems'* or the IGEM (UK) gas pipeline standard *IGEM/TD/1 Edition 5 – 'Steel pipelines for high pressure gas transmission'*.

Whilst these standards address a number of issues associated with the design, construction, commissioning and operation of high-pressure gas transmission pipelines, there are several specific areas which are relevant to the IAP FS and its associated cost estimates, which appear to be outside the original scope.

- ***Proximity issues*** – The IAFS does highlight the general principle of proximity issues in relation to the pipeline route but does not identify any significant locations where either thick-walled pipe or mechanical protection of the pipeline might be required. Both of these options have cost implications.

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additional compression installed elsewhere. One assumes that it would be the intention of the operator to simply reconfigure the compressors.

- *The design factor* – The design factor for any given pipeline is a function of its operating pressure, wall thickness and proximity to residential areas. Ideally pipelines operate at a design factor of less than 0.3, although typically many operate between 0.3 and 0.7 and some even operate at design factors of greater than 0.7 or 0.8.[43] However, whilst the IAP FS does allude to the need to establish the pipeline wall thickness in accordance with the ASME 31.8 gas transmission pipeline standard, it does not actually specify the wall thickness. This clearly has cost implications.

- *Material type* – Choice of material type will also have implications for the design factor, wall thickness and cost of construction. This has not been specified in the FS.

- *Operating pressure* – The operating pressure of 82 Bar is within the normal operating envelop for a gas transmission pipeline of this type. Indeed, it should be possible to operate at higher pressures subject to conformity with ASME 31.8.

Assessing and costing these implications for IAP is outside the scope of this report. However it is worth highlighting that by not considering these design details, the cost assumptions made in the FS may not be accurate.

4.3 Cost assessment

This section distinguishes between the Croatian section and the remainder of the IAP pipeline sections. Since the publication of the FS, Plinacro has conducted detailed routing and design studies for the Croatian IAP sections. As Plinacro has many years experience in developing pipelines in Croatia and has procured for and built many gas transmission projects over the past decade, we use the estimates from Plinacro for the Croatian section. Unfortunately, the precise estimation methodology is not made available to us and we can therefore not verify the estimation and calculations from Plinacro.

For the cost estimates of the Albanian and Montenegrin sections we apply our international expertise to provide comparisons and updated CAPEX numbers.

4.3.1 Albania and Montenegro section

The approach taken in the IAP FS can be described as a typical cost estimation model based on breaking the high-level capital costs of the pipeline down into different categories as follows:

[43] Most pipelines codes around the world limit the design factor and resultant design stresses to 72% of the line pipe's specified minimum yield strength (SMYS), although some UK and US codes allow this to rise to 80% under certain circumstances.

- ***Pipeline costs*** – The IAP Report breaks the pipeline route down by country, segment and then finally by terrain types such as flat-agricultural, flat-populated, rocky hill, hilly, river, urban area, rocky, HDD[44], sea entering 2x[45], mountainous, and offshore. The cost of building the pipeline through each of the different types of terrain is then calculated using a simple cost/km metric. In the case of the FS these costs include materials and construction, cathodic protection, optical communication systems, ROW costs[46], project management, and design costs.

- ***Additional facilities*** – In addition to the basic pipeline, the FS correctly includes costs of other facilities that need to be accounted for. These would typically include the following:

  - *Block valves (BVS)* – In addition to valves that are needed for gas offtakes, gas transmission pipelines have block valves at roughly 25km intervals to facilitate general maintenance and safe isolation in an emergency.[47]

  - *Custody transfer metering stations (CTMS)* – Typically these sites include block valves and metering runs.

  - *Pressure reduction / metering stations (PRMS)* – These occur when there is an offtake from the pipeline, in order to reduce the pipeline pressure and meter the offtake.

  - *Pig traps (PT)* – These facilitate access to the pipeline for online inspection.

- ***Compressor stations*** – Only one compressor station is scheduled to be part of IAP and this is located in Croatia. We therefore discuss compressor station costs in the next section. The IAP FS identifies the costs for a 1.5 MW compressor and associated works at €35.9 million.

- ***Operating Expenditure*** – the FS provides a detailed breakdown into all components of operating expenditure (OPEX) resulting in an annual number that is equivalent to 1.6% of the total investment for the project.

We review the assumptions made in the FS for each of these three cost components focusing only on Albania and Montenegro sections. Due to the limited scope of this assignment, the review focuses on a 'sense check' rather than a full due diligence of the cost assumptions made in the FS.

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44 Horizontal Directional Drilling.

45 Sea entering 2 x refers to the cost of connecting a subsea line to the land.

46 'Rights of way' refer to the costs associated with gaining access to the land to build and maintain the pipeline. In some countries, this is called a wayleave, or a lease where ownership remains with the existing land owner, whereas in other countries the land is actually purchased by the pipeline company.

47 Block valves on gas transmission pipelines act as isolation valves to facilitate maintenance and to help in cases of an accident. The minimum required spacing of these valves is prescribed in ASME B31.8, 'Gas Transmission And Distribution Piping Systems'.

Pipeline cost

Whilst pipeline costs can vary considerably by location and terrain, it is possible to provide a 'sense check' with similar metrics from elsewhere. This is done by comparing the weighted average pipeline costs used in the FS with the average pipeline costs in the EU, as published by the Agency for the Cooperation of Energy Regulators (ACER). In Annex 2, we replicate the costs used in the FS and calculates the cost uplift assumed in the FS – the premium to be paid for each terrain type.

Table 9 below compares the corresponding costs in €/metre for different types of terrain in the FS with an overall EU pipeline cost average as published by ACER[48]. The FS data for the whole IAP route (and for the individual Albania and Croatia sections) is generally on line with the average EU all terrain costs – the Albanian and Montenegro weighted average costs[49] of €1,011/m are in line with the EU average €1,061/m.

Although this would seem to suggest that the IAP Report estimates are reasonable, being in line with average costs identified across the EU, it should be noted that the average terrain along the IAP route is very different from the average terrain across the EU. The IAP terrain is very difficult, with 22% of the Montenegro and Albania distance stated in the FS to be Rocky, Rocky-hill, Mountainous or Hilly, and with the pipeline route often going offshore to avoid mountainous routes onshore, which is also expensive. One would therefore expect a significantly higher weighted average of IAP than the EU average rather than a lower average. Curiously, the IAP FS, unusual for such type of analysis, appears to assume no uplift for Hilly terrain (although it does assume uplift for Rocky, Rocky-hill and Mountainous terrain). This suggests that either

- The **uplift factors** are too conservative and may lead to estimated costs significantly below likely actual outcomes; or
- The **baseline investment cost** figure applied of 886 €/m is too low.

Table 9 ME, AL pipeline costs by terrain – FS vs. ACER

Terrain type	Pipeline costs in using IAP FS data, *€/m*		ACER pipeline cost data for EU (indexed 2005-2014), *€/m*[50]		
	AL	ME	Average	Median	St. Dev.
Flat-agricultural	886	899	**1,061**	1,015	416
Flat-populated	920	935			
Rocky-hill	1,050	1,071			
Hilly	886	No data			
Urban areas	1,177	1,205			
Rocky	*NA*	1,004			
Mountainous	*NA*	1,184			

[48] See Annex for details
[49] Weighted by distance
[50] Averaged across all terrain types

Offshore	*NA*	1,164			
Sea entering 2x	*NA*	6,667			
HDD	*NA*	1,984			
River	1,880	1,940			
Weighted Average	**921**	**1,174**			
Uplift for route	1.04	1.31			
% Rocky-hill, Hilly, Rocky and Mountainous	14%	35%			
Cost of pipeline specified in IAP report (€million) [51]	**154**	**108**			

A well-known and widely used publication[52] on gas pipeline costs and uplift factors suggests that the uplift for a pipeline route with more than 50% mountainous/rocky/hilly terrain could be as high as 1.5. The uplift for a pipeline route with more than 20% mountainous/rocky/hilly terrain could even be 1.3, hence the uplift factor applied in the FS of 1.17 is too low and is therefore unlikely to provide realistic results. We apply these factors to each segment of IAP to establish a more realistic uplift factor of 1.3 overall. The resulting costs are shown in **Error! Reference source not found.**. This suggests that the nderestimation of the uplift factors to correct for mountainous terrain in the FS results in pipeline investment costs that may be of the order of magnitude of 17% too low.

Table 10 ECA proposed pipeline cost metric

		AL	ME
Weighted Average cost from FS	*€/m*	921	1,174
Rocky-hill, Hilly, Rocky and Mountainous	%	14%	35%
Revised uplift based on terrain		1.2	1.3
Revised weighted average cost for pipeline	*€/m*	1,063	1,169
Revised estimated cost of pipeline	***€ mm***	**178**	**110**
Difference pipeline cost in FS and ECA estd.	%	+15%	+2%

Comparing the baseline cost parameter for pipeline investment costs of 886 €/m with data published by ACER, it also appears low but within an acceptable range for a project at such early stage of development. However with steel prices today lower than during the drafting of the FS, we largely accept the baseline parameter.

[51] There are some minor calculation errors in the IAP Report and Annex, with figures of both €535m and €542m quoted for pipeline CAPEX (including design). We have back-calculated the figures from the initial assumptions to €538m.

[52] K. Schoots et al., 'Historical variation in the capital costs of natural gas, carbon dioxide and hydrogen pipelines and implications for future infrastructure', International Journal of Greenhouse Gas Control 5 (2011) 1614–1623.

Costs associated with other facilities

The costs associated with Pig Trap Stations, Block Valve Stations, Gas Pressure Reduction and Metering Stations and Custody Transfer Metering Stations appear reasonable. For Albania and Montenegro they are estimated at €13.2 million in the FS. There is limited information in the FS on how these are estimated, but on the basis of our technical expert's industry experience, this is a reasonable investment cost for 18 facilities. We therefore see no reason to alter these cost assumptions.

Other costs

Other costs in the FS for Montenegro and Albania are estimated at a total of €34. 6 million, which breaks down into supervisory work (€5 million) and initial fill in gas and permission, management design and engineering work (€29.6 million). At close to 10% of total costs, these cost estimates are fully within a suitable range of costs at such an early stage of development. The costs associated with the compressor station however appear excessively high, but these only relate to the Croatian sections. The remaining cost parameters stay the same in our analysis.

Operating cost

The operating cost (OPEX) are estimated in great detail in the FS, which is surprising given the lack of detail –and inconsistencies - in the estimation of some of the investment cost parameters. A standard industry measure of estimating OPEX is to apply 2% of total investment costs per annum. The OPEX numbers for the whole pipeline project of between €10.6 and €10.8 million presented in the FS are close to this benchmark at 1.7% of total investment. We see no reason to invalidate the assumption on local taxes, labour cost and right of way operating costs and apply the same parameter, ie 1.7% of OPEX to our updated total investment costs.

4.3.2 Croatian segment

As noted above, Plinacro have recently made their own estimations of all costs associated with the Croatian segment. Upon Plinacro's recommendation, we have used these updated estimates. As the details of these up to date calculation have not been made available to us, we cannot verify the calculations or make a detailed assessment on the Plinacro CAPEX estimates. The estimates are reported by Plinacro to include all costs associated with building the pipeline including right of way, facilities and labour costs.

The Plinacro estimates are shown in Table 11. Plinacro has only shared with us the total investment numbers. We have assumed that facilities and other costs are as estimated in the FS.

The costs are lower when compared to the estimates made in the FS in 2014 and our own cost estimations based on the details published in the FS and using the principles applied in the previous section. The latest Plinacro estimates exceed the FS costs by 8% and ECA's estimates by 22%. We nevertheless use Plinacro's estimates throughout our analysis based on the extensive experience Plinacro has in procurement and construction of gas transmission in Croatia. Note that we test the sensitivity of CAPEX changes on the transmission tariff in our analysis below.

Table 11 Croatian segment Plinacro vs. FS cost

Cost component		Pipeline	Facilities	Other[53]	Compressor	Total
Plinacro estimates	€mm	248.9	9.7	6.4	33.0	**298.0**
FS estimates	*€mm*	*277.9*	*9.7*	*6.4*	*35.9*	**329.9**
ECA estd. based on FS	*€mm*	*344.2*	*9.7*	*6.4*	*3.4*	**363.7**

One aspect that seems overestimated by Plinacro (and the FS) appears to be the cost of the compressor station. We replicate in the table below the average unit costs over the period 2004 to 2015 in the EU as estimated by ACER. This data suggests that the average investment costs of a new gas driven 1.5 MW compressor would be of the order of €3.15 million, a tenfold reduction in the CAPEX estimates made in the FS and by Plinacro. The FS and Plinacro provide very limited details on the estimation of the compressor costs or the sources used and there is very little information we can verify for the cost estimation of the compressors.

We can only conclude that additional costs that may not be captured in the ACER data have been included in the assessment by Plinacro. Based on the recommendation of Plinacro, we therefore use the costs of €33 million.

Table 12 Unit investment cost indicators for compressor stations

Type of Compressor	Output press range (Bar)	Average (2005-14), €/MW	Median (2005-14), €/MW	St. Deviation (2005-14), €/MW
Gas drive, expansion	43 to 115	1,534,459	1,376,428	707,585
Gas drive, new	54 to 140	2,100,609	2,029,648	781,183
Electric drive, expansion	68 to 85	2,931,455	3,168,672	617,825
Electric drive, new	68 to 91	2,801,865	2,620,545	702,306

Source: ACER, 'Report on unit investment cost indicators and corresponding reference values for electricity and gas infrastructure', Table 11, page 24. Costs are indexed by inflation to € in the base year of 2015. [54]

[53] Initial fill in gas and supervision and engineering costs

[54] The costs are 'all-in', which refers to the cost of all activities and material, such as, for example, engineering, permits, construction, commissioning, material procurement, the sum of investing in which covers the costs of the entire project at the time of its commissioning.

4.4 Conclusions on costs

The costs used in the FS and the costs applied in our baseline scenarios are shown in Table 11. As noted above, we apply new uplift factors for the section in Montenegro and Albania and apply the latest estimates from Plinacro for the Croatian section.

Table 13 Cost parameters used in this analysis vs. FS cost

Cost component		AL	ME	HR	Total	Diff.
Pipeline cost[55]	*€mm*	176.6	112.1	248.9	**537.6**	-1%
Pipeline cost – FS	*€mm*	*154.4*	*109.9*	*277.9*	***542.2***	
Facilities[56]	*€mm*	8.9	5.5	9.7	**22.1**	-
Facilities – FS	*€mm*	*8.9*	*5.5*	*9.7*	***22.1***	
Other costs[57]	*€mm*	5.6	3.3	6.4	**15.3**	-
Other costs - FS	*€mm*	*5.6*	*3.3*	*6.4*	***15.3***	
Compressor stations	*€mm*	-	-	33.0	**33.0**	-8%
Compressor stations -FS[58]	*€mm*	-	-	*35.9*	***35.9***	
Total investment cost	*€mm*	192.1	120.9	298.0	**611.0**	**-1%**
Total investment cost –FS	*€mm*	*168.9*	*118.7*	*329.9*	***617.5***	
OPEX	*€mm/y*	3.3	2.1	5.1	**10.5**	**-3%**
OPEX - FS	*€mm/y*	-	-	-	***10.8***	

Overall, we agree with the technical design and route proposed in the FS. We do however note that some factors relating to pipeline routing such as river and road crossing have not been investigated in great detail for estimates in Albania and Montenegro. This could have some repercussions on the cost estimate.

The numbers applied in this analysis are not very different to those in the FS. However it is important to note that this is mainly due to the fact that we have used the latest Plinacro cost estimates for the Croatian section. If applying ECA's estimates based on (EU wide) cost estimates, the costs of the project would be 10% higher. We test for the sensitivity of the CAPEX and OPEX on transmission tariffs in sections below.

With regarding to costs, we estimate the pipeline investments cost in the FS for Albania and Montenegro to be generally underestimated. This is mainly due to an underestimation of the additional costs incurred by building pipelines over mountainous and hilly terrain. The

[55] Includes 'other pipeline costs' estimated at 10% of pipeline costs
[56] This includes Pig Trap Stations, Block Valve Stations, Gas Pressure Reduction and Metering Stations and Custody Transfer Metering Stations as well as 'other costs'
[57] Initial fill in gas and supervision and engineering costs
[58] This includes 'other costs', which have been estimated at 10% of CAPEX costs in the FS.

baseline cost parameter of 886 €/m also appear on the low side but still within a realistic range at such an early stage of development of the project.

Overall and in light of the early development stage of the project, we would expect a variation of at least ±20% of the investment costs presented in the table above.

5 Tariff, financial and economic analysis

This section sets out the results from our financial analysis and compares them with the results from the FS. As in the FS, we use the estimated transmission tariff with a given rate of regulated return as the indicator for the feasibility of the project. Additionally, we present cash flow projections on the basis of the calculated tariffs. The section covers the following:

- A review and summary of the approach and main results of the FS
- A description of the approach adopted in this report and the business models tested
- The resulting transmission tariffs and their sensitivity around key input factors
- The estimation of financial and economic parameters of the project
- The conclusions from our analysis and a suitable framework for developing IAP.

5.1 FS approach and results

The approach in the FS is focused on the calculation of the transmission tariff for IAP that would yield an 8% Internal Rate of return (IRR). The calculated tariff is then compared to a benchmark tariff based on a comparable regional transmission tariff of 2.5 €c/cm to assess whether it is comparable. A tariff level above this threshold value suggests a lack of feasibility of IAP and below the threshold value suggests IAP is a competitive project. The analysis is done for two marginally different demand scenarios (S-gas and S-coal) and tested against the sensitivity of CAPEX, OPEX and supply volumes. The tariffs are calculated for two business models:

- **One standalone project** – IAP is treated as one project and one postage stamp tariff applies with south to north flows.
- **Individual segments** – Each segment is developed by national TSO's and different tariffs apply.

The main analysis considers flows from TAP into Croatia, ie a south-north flow. However, as per EU regulations, IAP will be expected to operate bi-directionally and Croatian LNG or other sources could provide gas flowing from north to south. This seems unlikely since a TAP tie in point will exist. Regardless of the origin of the gas however, the throughput assumptions as outlined in the previous sections remain the same.

The tariff calculated in the FS are shown in Table 14. They all lie above the critical threshold of (2.5 €c/cm) except for the individual segment Montenegro and Albanian tariffs. However, it is not clear how one interprets these tariffs, given that they include Croatian gas volumes flowing through Albania and Montenegro as international transmission. Thus, a shipper, with the objective of transporting gas into Croatia (and potentially beyond) would pay 0.9 plus 1.2 plus 4.1 €c/cm, ie a total transmission charge of 6.2 €c/cm, which would not be feasible.

The sensitivity results in the FS suggest that the highest sensitivity relates to CAPEX variations and supply volumes. OPEX variations have very limited impacts on the transmission tariff. However even in the most optimistic scenario for CAPEX (-30%) and supply volumes (+30%) would the tariffs only reach close to 2.5 €c/cm. The results in the FS therefore suggest that IAP is not a commercially feasible project.

Table 14 IAP FS calculated transmission tariffs

Business model	S-Gas	S-Coal
Standalone Project	3.4 €c/cm	3.8 €c/cm
Individual segments	Croatia: 4.1 €c/cm Montenegro: 1.2 €c/cm Albania: 0.9 €c/cm	

Overall, we agree with the approach of calculating a lifetime transmission tariff and comparing it with a critical threshold benchmark tariff range. We adopt a similar approach; however provide a more detailed assessment of different business models. Besides different input factors for CAPEX and throughput – see sections above - our methodology differs in the following main aspects:

- **Integration of IAP assets into national transmission systems** - The individual segments in the FS are still treated as standalone individual country-specific segments. This is an unrealistic assumption. It is more realistic to assume that the respective IAP section are subsumed into the overall transmission asset base of the respective countries. Hence, the Croatian section would be treated as a part of the overall Croatian regulatory asset base. Similarly, Albania and Montenegro sections would be assumed to form part of their national gas transmission systems and asset bases. The FS was published before the Gas Masterplans of Albania and Montenegro and therefore the authors had no information on the gas transmission asset base expansion in these countries. We can however draw form these studies to estimate the tariffs for the entire system with the IAP segment.

- **Regulated returns –** our tariff methodology is based on ensuring a regulated return on the IAP (and national transmission) asset base. Hence the calculated tariffs in our methodology ensure a return on the assets rather than giving investors a fixed IRR, as is done in the FS. The reason we adopt this approach is because we simulate the integration of parts of the IAP pipeline into national gas transmission systems in at least two of the three business models simulated. This means that IAP would form part of a regulated network of assets and therefore be subject to an allowed revenue or cost plus regulatory regime setting rates of return on assets.

- **Treatment of gas volumes –** because we simulate the integration into national transmission network gas throughputs are treated very differently in our methodology than in the FS for the ‘individual segment’ business model. As the IAP segments will be integrated into the full transmission asset base, the total demand volumes in each country will be the relevant gas volumes for this particular business model, not just IAP throughput.

- **Using existing tariff methodology for Croatia –** In Croatia, the existing entry, exist and commodity charge methodology should apply. We use the latest parameters used by the regulator in the most recent tariff calculation methodology. The FS assumes a postage stamp tariff for the IAP segment in Croatia which is unlikely to be the case.

- **An additional business model: IAP Company + Regulated TSO** – one aspect not considered in the FS is the feasibility of developing IAP as two components: (i) one section connecting Albania and Montenegro only as an international pipeline and (ii) the extension of the Croatian system to the Montenegrin border. As noted in the previous section, Croatian demand and international transmission volumes are key to ensure sufficient throughput in IAP. We therefore construct a scenario where IAP Company would develop the Montenegrin and Albanian sections as a standalone project and the Croatian section is assumed to be integrated into the Croatian asset base. Under this scenario, IAP would still have the full length but would simply have different ownership and financing terms.

Section 5.2 provides more details on our approach and methodology for each of the three business models considered.

5.2 Approach in this report

Our approach is similar to that adopted in the FS. However, we calculate the tariff that would yield a rate of return on the regulated asset base. It is unclear at this stage whether IAP would need to abide strictly to European regulation and legislation or whether exemptions would apply as for TAP. Additionally, it is not clear how the project will be treated – as a standalone pipeline or integrated into national asset bases. If the former an IRR based tariff may be more appropriate. If the latter a regulated return calculation is more appropriate. Because we simulate business models where assets form part of the national transmission base, we have chosen to calculate the tariffs on the basis of a regulated rate of return (8% in our base case scenario) and not on an IRR basis. This makes the tariffs directly comparable across business models and enables us to draw conclusions on which business model is best suited and most likely to yield the most competitive transmission tariffs. To illustrate the financial impact of the calculated tariffs we do present the IRR and show how it changes across business models and throughput variations.

The calculated transmission tariffs is then compared to a benchmark value tariff, which we estimated in section 2.4 at 1.9 €c/cm on the basis of transmission charges in Italy and Slovenia combined. The FS sets this benchmark at 2.5 €c/cm. As noted previously, the lack of details on the BRUA sections (costs, tariffs, regulatory provisions) and TAP tariffs makes it difficult to compare IAP with this route. We therefore use the Italy – Slovenia-Austria route as comparator. The objective of the benchmark number is to provide a threshold against which a feasible transmission tariff can be measured. It should not be interpreted as a clear cut 'make or break' number, as many non-tariff factors will determine whether gas supplied through IAP is competitive.

Our approach is based around the simulation of three business models, which will all have varying methodologies to estimate transmission tariffs. Our approach for each of the three business model is described in the following sections and summarised in Table 15.

Table 15 Transmission tariff methodologies by business model

Business model	Tariff methodology
❶ IAP Company *(standalone project)*	One postage stamp tariff that applies for the entire pipeline irrespective of national gas transmission development and entry and exit points
❷ Regulated TSO *(each TSO develops its own sections and integrates it into its national gas transmission network)*	**Croatia**: existing tariff methodology (entry, exit, commodity) with the inclusion of the Croatian IAP segment CAPEX into Plinacro's regulatory asset base. **Albania**: Postage stamp tariff for the entire Albanian system (excluding TAP) with the inclusion of the Albanian IAP segment CAPEX into the Albanian regulatory asset base. **Montenegro**: Postage stamp tariff for the entire Montenegrin system with the inclusion of the Montenegrin IAP segment CAPEX into the Montenegrin regulatory asset base.
❸ IAP Company + Regulated TSO *(The Croatian segment is integrated into the national transmission network and Albanian and Montenegrin sections are developed by the IAP Company)*	**Croatia**: same as for business model ❷ **Albania and Montenegro:** same as for business model ❶ with the CAPEX for IAP segments in Albania and Montenegro only; Croatian segment integrated into Croatian asset base.

5.2.1 Business model ❶: IAP Company

The first model we investigate is to treat IAP as a standalone project with its own transmission tariffs which will be physically linked to transmission networks in the respective countries. The tariff methodology we use to compare different scenarios is a postage stamp tariff. This means one common tariff applicable to any unit of gas transported through the pipeline regardless of entry or exit point.

The tariff structure of such a standalone international pipeline project could theoretically be an entry-exit charge. Under such a tariff framework exit and entry capacity would be charged at different rates depending on a long run marginal cost methodology. Additionally a commodity charge would apply. This seems to be the pricing structure that the TAP project is in the process of developing and the preferred methodology for the majority of gas transmission tariffs in the EU. However in light of the uncertainty of the precise exit and entry points, the preliminary nature of the cost estimates and the complexity of such calculations, we adopt a postage stamp tariff approach.

The methodology we apply is straight forward. We firstly calculate the allowed revenue of the project, which consists of:

- ***CAPEX* –** as described in section 4, we estimate the CAPEX numbers in the FS to be underestimated by 10%. We therefore apply the updated CAPEX numbers shown in Table 11.

- ***Depreciation*** – we assume a straight line depreciation over a 35 year period of the pipeline asset. While this is a longer time period than that assumed in the FS (24 years), it is in line with the depreciation time period applied in the Croatian gas transmission tariff regime. The asset base is the initial investment of the entire IAP pipeline.

- ***OPEX*** – the operating expenditure has been calculated in great detail in the FS and we adjust only those components that are proportional to the updated CAPEX. The final annual OPEX used is shown in Table 11. Note that we assume a ramp-up of OPEX to the presented numbers in the years of construction.

- ***Allowed return* –** the return over and above the incurred costs applied to the regulatory asset base in every year. The regulatory asset base is the value of the initial assets (investment) net of depreciation. The rate of return is a key input parameter and ranges between 5% and 11%. This would typically be set on the basis of a Weighted Average Cost of Capital (WACC); which is not an exact method and allows for interpretation and project specific risk factors to be included. We assume 8% as our base case[59]. The rate of return is also the discount rate used in our analysis.

- ***Year of operation* –** we assume that 2025 would be the first year of operation of IAP with construction started in 2020. This is a common assumption across all business models.

The allowed revenue is calculated for every year until 2050 and discounted by the required rate of return to obtain a present value of the allowed revenue. This present value is divided by the present value of IAP throughput (see section 3) to calculate a per unit postage stamp transmission charge. This is a standard tariff methodology applied for projects at initial stages of development. It is important to note that this is a long term tariff, ie a tariff reflecting the usage and cost of the pipeline until 2050.

Under this business model a separate IAP company would have to be created, which is responsible for operation and development of the pipeline. More details on the business models and potential related financing arrangements is provided in section 6.

5.2.2 Business model ❷: Regulated TSO

An alternative business model is that each segment of the IAP pipeline is integrated into national gas transmission assets. The resulting tariff for usage of the respective IAP segment would therefore be the transmission tariff prevalent in each country. In terms of ownership, this business model implies that each segment of IAP is operated and owned by the national transmission system owner and operators. As Croatia, Montenegro and Albania are at different stages of development and have different gas transmission expansion plans, it is important to distinguish between each country.

[59] This corresponds to a return on equity of 12%. See section 5.5.

Transmission tariffs: Croatia

Croatia has an existing entry-exit gas transmission tariff methodology. The methodology is based on an allowed revenue approach and detailed as per '*The methodology for gas transmission tariffs*' published by the Croatian Energy Regulatory Agency in June 2013[60]. The latest parameters used for the calculation of gas transmission tariffs over the period 2017 to 2021 were published in March 2017[61]. The tariffs for the current regulatory period are summarised in Table 16[62].

Table 16 Croatian gas transmission tariffs, 2017-2021

		Unit	Average 2017-2021
Entry tariffs for firm capacity	Entry tariff for interconnection	*Kn/kwh/d*	2.6404
	Entry tariff for production	*Kn/kwh/d*	2.3623
	Entry tariff for storage	*Kn/kwh/d*	0.2624
	Entry tariff for LNG	*Kn/kwh/d*	*n.a*
Exit tariffs firm capacity	Exit tariff for interconnection	*Kn/kwh/d*	6.3802
	Exit tariff for Croatia	*Kn/kwh/d*	0.9564
	Exit tariff for different zones	*Kn/kwh/d*	*n.a*
Commodity charge		*Kn/kwh*	0.0018

Source: HERA

Besides the commodity charges, the inclusion of IAP would affect (i) the entry charge for interconnectors, (ii) the exit charge for interconnectors (for international transmission) and (iii) the exit charge for Croatian offtake. Because however the tariff for exit from Croatia is a proportion of the interconnector exit, we only focus on the two interconnector tariffs (entry and exit) and the commodity charge. To calculate the impact on these fees from the inclusion of the IAP segment we use the exact same methodology as HERA. We do no describe the full tariff methodology in this report as it is a complex and a multi-parameter calculation. The details of the calculation are specified in the ECA model provided with this report and in the web-links provided above.

As per the methodology, the payable fee for any shipper will depend on the month the capacity is booked, whether the capacity is interruptible and the over which time period the capacity is booked (daily, monthly, quarterly, and annually). We calculate an average tariff across these different transmission services to have a comparable headline figure with and without the IAP segment. The fees – under current conditions – without the IAP segment are shown in Table 17, adjusted for exchange rate differences and converted into volumetric units (cubic metres).

[60] Accessible via www.narodne-novine.nn.hr/clanci/sluzbeni/2013_07_85_1892.html
[61] Accessible via www.hera.hr/hr/docs/2017/Odluka_2017-03-16_02.pdf
[62] Note that the tariffs are calculated for every year over the period 2017-202. For simplicity we present the average over the five years in the table.

Table 17 Croatian transmission fees payable, average 2017-2021

		Current tariffs
Entry tariff for interconnection	*€c/cm*	0.225
Exit tariff for interconnection	*€c /cm*	0.548
Commodity charge	*€c /cm*	0.262

Source: ECA calculation based on HERA methodology and inputs

As noted above, we follow the exact same methodology as specified in the tariff regulations to simulate a situation where the IAP segment is subsumed into Plinacro's existing asset base. However the inclusion of the IAP segment into the asset base requires changes to some parameters of the calculation and additional assumptions. The changes we apply to the input parameters as a result of the inclusion of IAP are listed in Table 18.

Croatia's gas transmission system currently does not have sufficient capacity to accommodate international transmission flows into Slovenia. According to Plinacro, transit to Hungary of 2.6 Bcm per year is currently possible. The additional investment to ensure international transmission to Slovenia according to Plinacro is €60 million. We therefore add this to the regulatory asset base in our scenario calculations.

Table 18 Assumptions on the inclusion of IAP

Category	**Assumption in this study**
Overall methodology	Simulate the inclusion of IAP segment into Croatia's asset base over the period 2017 to 2021; take average over the five years. Headline figure therefore represents the immediate tariff impact IAP would have on the tariffs in the first five years.
Asset Base	Plinacro regulated asset base of 2017-2021 as reported by HERA plus the CAPEX value of Croatian IAP segment depreciated at a linear 35 year depreciation plus the CAPEX value of necessary investment to the Croatian system for ensuring international transmission flows (€60 million) depreciated over 35 years.
Regulated return	For existing assets and international transmission investment: 5.29% as determined by HERA in the latest price review. For IAP segment we assume an 8% rate of return as in FS
Interconnector entry capacity	HERA assume capacities for 2017-2021 plus the throughput of gas from IAP into the Croatian system. This is also a scenario parameter than can be altered. Only applies if a segment with south-north for IAP is selected.
Interconnector exit capacity	If international transmission volumes are included in the scenario and if the BiH connection is included, the exit capacity is adjusted according to these assumptions
OPEX	As for business model 1

In effect, this business model simulates a situation where the TSO, Plinacro, would decide to develop the Croatian segment of IAP on their own and recover its costs (and returns) through transmission tariffs applied to all Croatian gas consumers. This compares to the postage stamp tariff methodology described in business model 1 where the calculated tariff would only be paid by shippers of gas using IAP.

Transmission tariffs: Albania

In the absence of any existing or proposed gas transmission tariff methodology proposals in Albania, we assume a postage stamp tariff regime as for business model 1. Hence, the IAP segment in Albania would be treated as part of the overall national gas transmission network and one gas transmission applies to all users of the transmission network. As noted in section 2.3.1 Albania currently has no gas offtake and no existing gas transmission network. TAP is currently being constructed but this will be treated as a standalone project (akin to our business model 1) with its own exit and entry tariff methodology. It therefore does not need to be considered in the tariff calculation as it is a separate asset.

The IAP segment would however not be the only transmission asset in Albania. The Gas Masterplan of Albania published in 2016 has ambitious plans of gas transmission development and provides a very detailed investment plan for every transmission pipeline over the period 2020 to 2040. This investment plan is replicated in the Annex.

To calculate the transmission tariff in Albania for this business model, we construct an asset base and depreciation scheduled for the country including the relevant IAP section and excluding TAP. We then apply the same approach as described under business model 1; ie a postage stamp tariff based on a discounted allowed return and discounted gas demand in Albania over the period 2020 to 2050. As in business model 1, the resulting tariff reflects a long term cost and utilisation profile.

Transmission tariffs: Montenegro

We apply the same methodology for Montenegro as for Albania. This means a postage stamp tariff based on other gas transmission investments and total gas demand volumes. As for Albania, Montenegro also recently developed a Gas Masterplan with a detailed gas transmission network development plan. A map of the transmission plan is shown in Figure 5 and the individual segments and associated investment costs are shown in the Annex.

The Gas Masterplan assumes full development of the entire system starting in 2017 and completed in 2020. Our view is that, while the development of the entire Montenegrin gas transmission system could theoretically be developed over a space of three years, it is unlikely to materialise in such a short space of time. This is for a number of reasons including:

- *Availability of gas* – IAP is scheduled to become operational in 2025 in the most optimistic of cases. Developing any segment of the network before IAP would mean that pipelines would be idle and not operational. This does not make commercial sense and would not materialise.

- *Demand development* – Networks grow with demand potential and initial network development will focus on those areas with greatest potential. Any transmission development would therefore initially be focused on one area of the country and not the whole country from the start,

- *Financing* – With pipeline lying idle, uncertain demand and a significant upfront capital investment, it is unlikely that financing for the whole system could be secured. Securing financing for initial segments with secure demand will be easier and more realistic.

We have therefore made assumptions on the timing for pipeline development that are in line with our demand scenarios and are more realistic than those proposed in the Masterplan. As recommended by Montenegrin stakeholders only the Coastal and Central region investments (totalling €177.2 million) are included in the analysis. Transmission investments in the northern region (€39.6 million) will only materialise if transit to Serbia and Kosovo can be secured, which seems unlikely; at least in the medium term.

We assume the same diameter for the pipeline and therefore investment costs. This means that the transmission plan assumed in our methodology is a delayed development plan compared to the Gas Masterplan assumptions. The assumptions we make in our calculation of an integrated gas transmission tariff for Montenegro are shown in the Annex. As per our assumptions, the gas transmission network in Montenegro would be fully developed by 2029.

On the basis of this development, we calculate a lifetime postage stamp tariff as for Albania described above and for the entire IAP segment described in business model 1.

5.2.3 Business model ❸: IAP Company + Regulated TSO

This business model combines the previous two models: it assumes that the Croatian IAP segment would be integrated into the Croatian asset base (business model 2), but that the Montenegrin and Albanian segments are treated as a standalone project (business model 1).

This is the most realistic scenario. Croatia, as an established gas market operator and with an existing gas transmission tariff methodology can easily integrate the Croatian IAP asset into its regulatory asset base. Additionally, Plinacro may want to have full control of the Croatian IAP segment to ensure the segment is compatible with the remainder of the Croatian gas transmission grid.

The uncertainty of gas transmission development in Albania and Montenegro may also lead to the TSO's in those countries to prefer this business model. The development of IAP (and therefore supply of gas into these markets) would not be obstructed by delays in domestic market or system developments. IAP could be developed and gas could be supplied irrespective of national gas transmission regulatory frameworks or national gasification strategy.

The tariff methodology for this business model for Croatia is the same as under business model 2 for Croatia. For Albania and Montenegro we apply the methodology from business model 1, but for the Albania-Montenegro segment only obviously.

5.3 IAP transmission tariffs

This section presents the calculated transmission tariffs on the basis of the methodology described in the previous section. The specifics parameters and assumption for each business model methodology have been described in the previous section. A common set of parameters applies across all calculations and scenarios however and includes:

- ❑ ***Segments*** – we assume that the full IAP project is developed and consequently, gas flows from south (TAP tie-in point) to north into Croatia (and beyond).
- ❑ ***No BiH interconnection*** – our baseline scenarios exclude the BiH interconnection. The inclusion of the interconnector is treated as a separate sensitivity analysis.
- ❑ ***Rate of return*** – the rate of return on the regulated assets assumed is 8% as in the FS
- ❑ ***CAPEX –*** the investment cost of the pipeline is as presented in section 4.
- ❑ ***OPEX –*** the operating cost of the pipeline is as presented in section 4
- ❑ ***Start of operation –*** IAP is assumed to start operation in 2025 after a five year construction period.
- ❑ ***Time horizon –*** the tariffs are calculated to recover costs and yield a return until 2050.
- ❑ ***Croatian infrastructure –*** as outlined in section 4 we make assumptions on Croatian gas supply infrastructure utilisation as follows:
    - ❑ *Interconnector utilisation* – The interconnector to Hungary is assumed to be utilised at its historic average rate of 10% and the Slovenian interconnector at 85%
    - ❑ *LNG* – the level of utilisation varies by scenario. But across all scenarios, the LNG terminal is assumed to be developed in 2022.
- ❑ ***Additional investments*** – as noted in the previous section, additional gas transmission investments in Montenegro and Albania are considered for Business Model 2 and additional investments to ensure international transmission is included in Croatia's asset base.

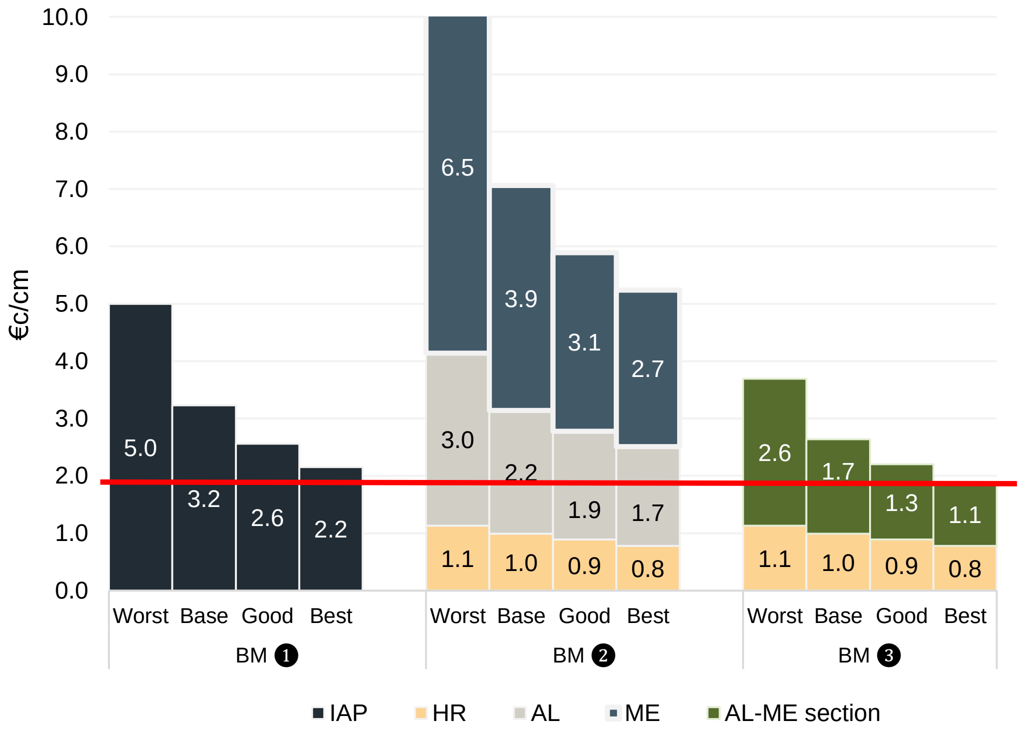
We calculate the scenarios for four main throughput scenarios. These have been described in detail in section 3. We replicate the key parameters in Table 19. The Best Case scenario represents a situation where gas is a highly competitive fuel in the region and gasification efforts are pursued by policymakers throughout the three countries. The Worst Case scenario is defined by a slow gasification rate in the distribution sectors, minimum gas to power developments and a lack of competitiveness of IAP gas versus LNG. The Base Case is formed by our estimate of the most likely parameters and the Good Case is chosen as a sensitivity case between Base and Best.

Table 19 Throughput scenario parameters

	Best Case	Good Case	Base Case	Worst Case
International transmission	1.0 Bcm/y	0.8 Bcm/y	0.6 Bcm/y	0.4 Bcm/y
Gasification growth	High	Medium	Medium	Low
HR LNG utilisation	No LNG	10%	25%	35%
CCGTs in AL	Vlore TPP in 2020 200 MW in 2025 200 MW in 2030 200 MW in 2040	Vlore TPP in 2020 200 MW in 2025 200 MW in 2030	Vlore TPP in 2020 200 MW in 2030 200 MW in 2040	200 MW in 2030
CCGTs in ME	100 MW in 2025 500 MW in 2027	100 MW in 2025 500 MW in 2030	100 MW in 2025 300 MW in 2030	100 MW in 2025
CCGTs in HR	400 MW in 2027 500 MW in 2030	400 MW in 2027 500 MW in 2035	400 MW in 2027	400 MW in 2030

The transmission tariffs calculated on the basis of ECA's methodology are summarised in Figure 17.

Figure 17 IAP transmission tariffs



Source: ECA analysis

We separate the tariffs by throughput scenario to illustrate the sensitivity of tariffs to demand and throughput levels. The figure also distinguishes between the three business models presented above. For Business Model 2 and Business Model 3, we stack the tariffs of the individual countries to show the total transmission costs for a shipper, who may want to use IAP as international transmission pipeline or supply gas to Croatia. The tariff number shown for Croatia is the sum of the interconnector entry charge, interconnector exit charge and commodity charge. The conclusions that can be drawn from these results are:

- ❑ ***IAP tariffs high across scenarios*** - None of the calculated tariffs result in a tariff below our proposed benchmark tariff of 1.9 €c/cm. Even in the most optimistic throughput scenario and business model, the combined transmission tariff reaches just over 1.9 €c/cm. However, this does not necessarily imply that the IAP project is unviable. It does however demonstrate the importance of securing high throughput volumes, particularly at early stages of development.

- ❑ ***Business model 2 has highest tariffs*** - Business model 2 results in the highest tariffs across all throughput scenarios. The tariffs range from 5.2 €c/cm to 10.6 €c/cm, which is far above our benchmark tariff of 1.9 €c/cm. High national tariffs in Albania and Montenegro are the main reason for these tariffs. It follows therefore that business model 2 is the business model with the lowest likelihood of yielding a competitive gas supply through IAP.

- ❑ ***Business model 3 has lowest tariffs*** - Business model 3 results in the lowest combined transmission tariffs. The tariffs are lower than business model 1 (treating IAP as a standalone project), because the costs of the Croatian segment are spread across a greater volume of gas, namely the total gas consumption and international transmission volume of Croatia. The tariffs range from 1.9 €c/cm to 3.7 €c/cm. This suggests that Business model 3 has the greatest likelihood of generating a commercially viable tariff.

- ❑ ***High sensitivity of tariffs to throughputs*** - The results show that the tariffs are highly responsive to throughput and demand assumptions. As noted in section 2.4 international transmission volumes and Croatian gas demand are the key drivers for ensuring throughput in the first ten years of IAP operation. If the project is to be commercially viable, the only chance is for international transmission volumes to be secured from the beginning and gas to be competitively sold through IAP into Croatia.

- ❑ ***Impact on Croatian transmission tariffs modest and even positive for Croatian consumers -*** Integrating the Croatian IAP segment into the regulatory asset base reduces the system transmission tariffs in all but one scenario. In the worst case scenarios transmission tariffs are increased by a maximum of 10%. In the base case scenario system-wide transmission tariffs fall by 3% and in the good and best case, the fall in tariffs would be more than 12%. Current tariffs in Croatia are 1.0 €c/cm[63] and integration of IAP and additional international transmission investment will results in tariffs of between 0.8 and 1.1 €c/cm. This breaks down into the following components:

[63] This is the sum of the current entry tariff 0.23 €c/cm, exit tariff 0.55 €c/cm and commodity charge 0.26 €c/cm.

€c/cm	Existing	Worst	Base	Good	Best
HR - Entry charge	0.23	0.22	0.20	0.19	0.17
HR - Exit charge	0.55	0.51	0.43	0.37	0.29
HR Commodity charge	0.26	0.39	0.36	0.34	0.32
Total	**1.04**	**1.12**	**0.99**	**0.90**	**0.78**

This suggests that any additional impact of IAP on remaining Croatian gas consumers is likely to be positive. However, this crucially depends on the additional investments required to ensure IAP international transit can reach the Slovenian border, which Plinacro estimates at €60 million.

- ***Montenegro and Albania tariffs standalone too high* –** the postage stamp tariffs of Albania and Montenegro gas transmission networks are very high suggesting that the expansion plans proposed in the Gas Masterplans are costed aggressively or too expansive for the projected demand scenarios.

Overall, the calculated tariffs are high and suggest that a commercial case for IAP may be difficult. Only with optimistically high throughput volumes and CAPEX reductions – through subsidies potentially - could the IAP project reach a transmission tariff that would be comparable with an alternative supply route. Our analysis suggests that the lowest tariffs for IAP are achieved by integrating the Croatian segment into the Croatian asset base and treating the Albanian and Montenegrin sections as standalone projects. The project could still be developed as a whole by one Project Company, however the segments of Croatia and Albania- Montenegro should be treated separately for tariff calculation purposes.

5.4 Sensitivity analysis

Besides throughput variations, other parameters can be varied to assess how responsive the tariffs are to the inputs. We test the sensitivity of the following input factors:

- ***CAPEX/grant funding*** – as noted in section 4, the cost numbers at such an early stage of development are highly uncertain. We therefore vary CAPEX numbers around our estimated investment costs by 30%. This can also be interpreted as the impact of grant funding for the pipeline.

- ***Rate of return*** – the rate of return is a key determining factor in the setting of the tariff and we vary it from %5 to 11%.

- ***Inclusion of Bosnia interconnection*** – our base case assumption excludes the BiH connection. We therefor assess the impact of the BiH interconnection in this section.

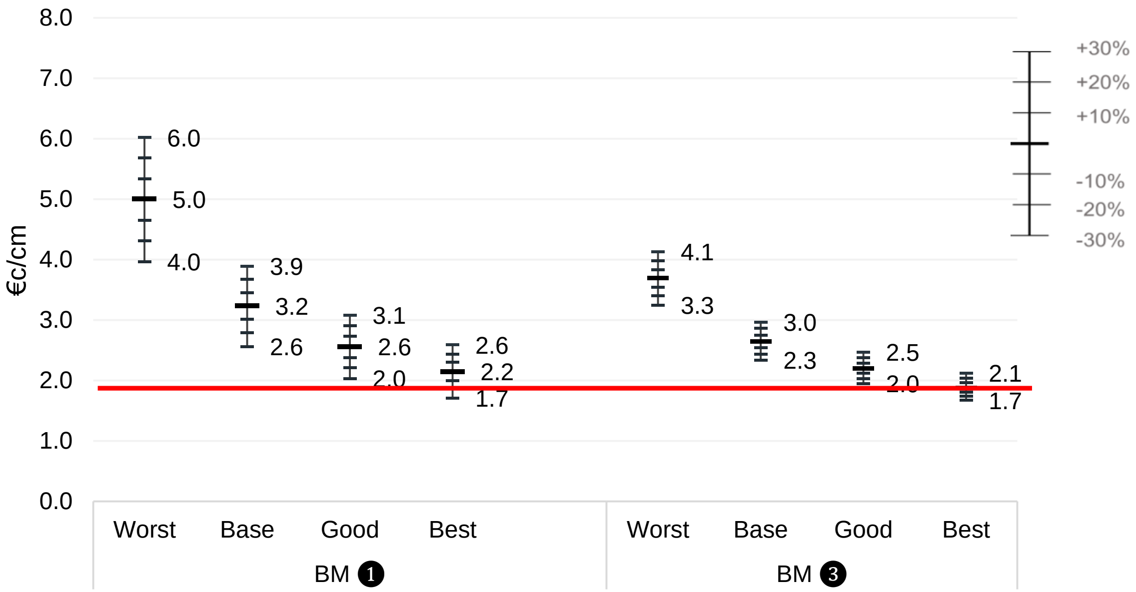
- ***Inclusion of Albania – Kosovo interconnection*** – the interconnection is part of the PECI list and we therefore include it in our analysis to test its impact on the viability of IAP.

The sensitivity analysis is done only for business models 1 and 3, as these are more likely to result in commercially viable tariffs.

CAPEX and grant funding

The sensitivity of tariffs with CAPEX variations is shown in Figure 18. Only in the most optimistic scenario, ie high throughputs and -30% CAPEX do tariffs reach the competitive threshold level of 1.9 €c/cm. The reduction in CAPEX can be interpreted as a portion of the total project costs being grant funded. However, even if up to 30% of the total costs of €611 million will be grant funded, will the commercial feasibility of the project not be guaranteed. Or at least still be highly dependent on ensuring high throughput volumes.

Figure 18 Tariffs with CAPEX variation

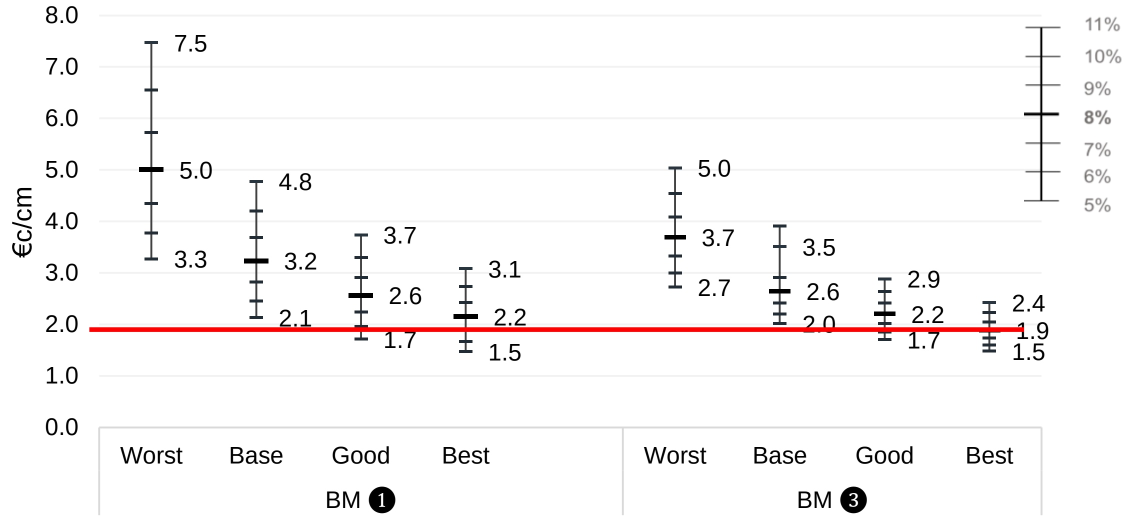


Source: ECA analysis

Rate of return variation

Figure 19 shows the responsiveness of tariffs with the variation of the rate of return from 5% to 11%. The tariffs remain largely significantly above the threshold value of 1.9 €c/cm. Only in high throughput scenarios (Good and Best case) and with returns on assets of 5% and 6% is the tariff below the threshold value. This could be considered a standard rate of return on regulated assets. For comparison, the regulated return on Croatian transmission assets currently is 5.29%. However, tariffs at such low levels would make the project financially unviable. We present the resulting IRR with changes in the regulated rate of return in the subsequent section.

Figure 19 Tariffs with rate of return variation



Source: ECA analysis

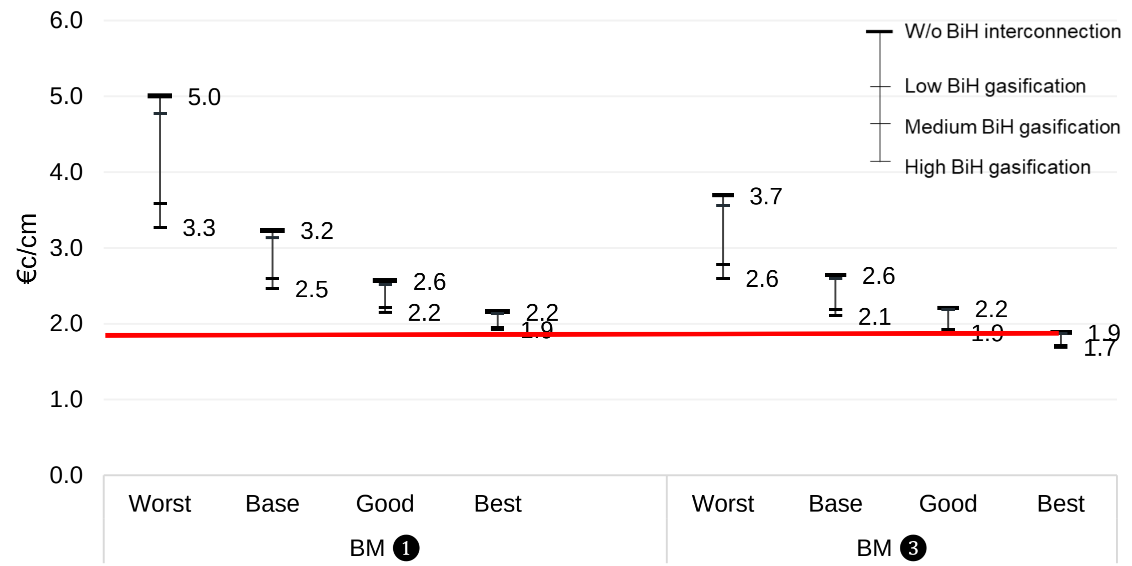
The analysis shows that tariffs are very responsive to the rate of return applied; however the financial impact of setting returns at such low levels would be significant. The IRR of the project would be too low to attract investment as shown in the subsequent section.

BiH connection

An interconnection to BiH will inevitably contribute to higher throughput of IAP and therefore increased commercial viability of the projects. As described in section 2.3.4, it is still uncertain which regions of BiH the interconnection would help to serve and therefore what share of BiH demand would be covered by IAP. We have therefore constructed three throughput scenarios which we test on the transmission tariffs here. The changes in tariffs are shown in Figure 20.

The impact on tariffs form a connection to BiH can be significant and would bring tariffs closer to our estimated threshold level of 1.9 €c/cm. Even in lower throughput scenarios the impact could be beneficial and contribute significantly to the feasibility of the pipeline. However it is important to note that the greatest positive impacts are observed in those scenarios where BiH follows a strategy where IAP becomes the main supply point into the country essentially displacing existing supplies. Additionally, the development of the 390 MW power plant at Zenica will provide a significant anchor offtake. Without the Zenica plant and onward connection of the interconnection, the impact on tariffs is very small.

Figure 20 Tariffs with BiH interconnection



Source: ECA analysis

Albania – Kosovo interconnection

The Albania-Kosovo interconnector features on the list of PECI projects and should therefore be considered in this analysis. The costs of the interconnector are likely to be significant[64], as the pipeline is expected to reach 225 km and run through mountainous terrain. However we do not include the costs in this analysis, as the interconnector is assumed not to form part of the IAP project. It would therefore be financed and treated separately.

The impact on IAP feasibility will be through higher throughput volumes. As noted in section 2.3.5, we are sceptical as to the potential for gas offtake in Kosovo due to lower cost fuel alternatives in the country. However should Kosovo decide to roll out natural gas in the residential and industrial sector, demand could be of the order of 0.7 Bcm by 2040. If power generation is added, this could be as high as 1.1 Bcm. We test for both of these throughput scenarios in this sensitivity analysis.

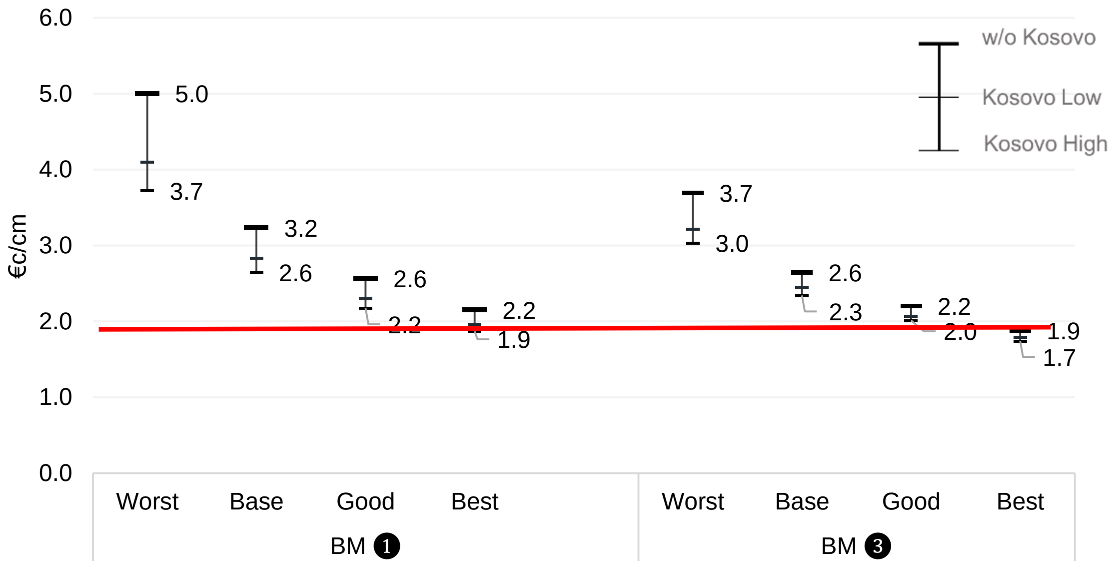
The results are shown in Figure 21. The transmission tariff changes are similar to those for the BiH connection: tariffs drop across all scenarios; however only sufficiently so in the Good and Best case throughput scenario. This suggests that the gasification of Kosovo would improve the feasibility of IAP, but not sufficiently so to tip it over to full financial feasibility on its own.

It is important to note that the throughput numbers assumed here for Kosovo are optimistic, as they assume a full gasification of the country in 15 years plus a switch to gas in power

[64] We calculate the cost of the interconnector to be in the region of €160 million. Using the cost estimates provided by ACER (see Annex) and an assumed length of 225 km provides a rough estimate of CAPEX. We assume a pipeline diameter of between 16'' to 27'', which is sufficient for the expected 35 GWh/d send out rate at an inlet pressure of 82 bar pipeline. For more details on technical parameters of the project: www.energy-community.org/regionalinitiatives/infrastructure/PLIMA/Gas13.html

generation (for the high case), which is highly unlikely. These results should therefore be treated with care. Additionally, the costs of the interconnector are not included in the model, as it is assumed that this would be funded separately. If these are included and estimated at €160 million, tariffs across all scenarios increase significantly.

Figure 21 Tariffs with Kosovo interconnection



Source: ECA analysis

We would not recommend prioritising this interconnection or indeed relying on this to make IAP feasible. Besides its limited impact on the feasibility of IAP, it would require significant grant funding to develop a pipeline that is unlikely to be highly utilised. It would be far better to redirect such grants – should they be available – to the IAP project proper.

5.5 Financial parameters

In this section we present the main financial parameters for Business models 1 and 3. As for the sensitivity analysis, the focus is on these two business models due to their higher likelihood of yielding a commercially viable transmission tariff. We calculate the following parameters for the full IAP Company (Business model ❶) and Montenegro and Albania IAP Company (Business model ❸)[65] segment:

- ***Internal Rate of Return*** – the tariffs calculated above are based on a rate of return on the regulated asset base. As described above, this is not equivalent to the IRR as the regulated return only applies to the asset base, ie the value of the

[65] Note that under Business model 3, the Croatian IAP segment is assumed to be integrated into the overall gas transmission asset base of Plinacro. Assessing the financial impact on Plinacro overall is out of the scope of this report and would require more details on Plinacro's revenue sources. Additionally, the financial analysis serves to show the attractiveness of the project to a potential outside investor into the project. Under Business model 3 however, Plinacro would be financing the Croatian IAP segment and the outside investor would finance the Montenegro and Albania sections as a smaller IAP Company. The cost of debt and financing of the Croatian segment would be recovered through the adjusted transmission tariff in Croatia.

IAP assets. To show the implications of different rates of return on the IRR, we present in this section the relation between regulated rate of return and IRR for business model 1 and 3.

- ***Earnings before interest and tax (EBIT)*** – Earnings before interest and tax is a standard measure of operating profitability calculated as revenues minus OPEX and depreciation.

- ***Net cash flow*** – Net cash flow considers all expenses and revenues 'in real time' and therefore takes into account of debt and equity received, CAPEX, OPEX and interest and tax payments. The net cash flow provides an indication on the liquidity of the commercial operation.

- ***Debt service coverage ratio (DSCR) -*** the DSCR provides a measure of the ability for a commercial operation to recover its annual debt obligations (interest and principal). A DSCR above 100% shows that annual cash flows can recover more than debt service obligations.

For the financial analysis we need to make additional assumptions as summarised in Table 20.

Table 20 Financial parameters

Category	
Equity : debt ratio	30:70
Interest rate	5.5%
Interest rate during construction	5.5%
Loan repayment period	15 years
Tax rate	15% (Albanian tax rate)

As noted above, the regulated rate of return would typically be calculated on the basis of a Weighted Average Cost of Capital (WACC) method. The simple formula for a pre-tax WACC is as follows:

$WACC = g*R_d + (1-g)*R_e/(1-t)$ with

g= *gearing ratio [debt/(debt+equity)]*
R_d= *cost of debt*
R_e = *return on equity*
t = *tax rate*

The WACC or regulated return has been assumed at 8% in our above calculations. Using the parameters in the table above and solving the WACC formula for the return on equity, we calculate that the assumed return on equity for an 8% regulated return is close to 12%[66].

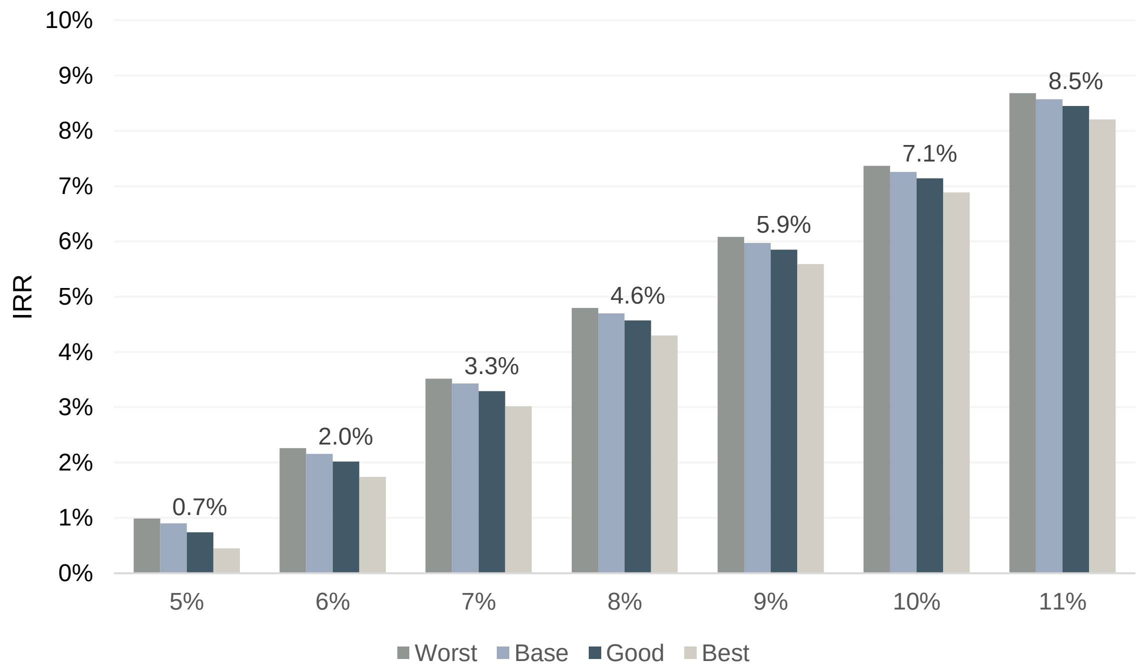
[66] R_e =((WACC- $g*R_d$)*(1-t))/(1-g) = ((8%- 0.7*5.5%)*(1-15%))/(1-0.7)=11.75%

5.5.1 Internal rate of return

The IRR is a standard measure to assess a project's financial viability. It is the discount rate which needs to be applied to a project's net cash flow to result in a net Present value (NPV) of zero. The higher the IRR, the greater are the cash flows and therefore the more commercially attractive the investment. As noted above we calculated the tariffs that would yield a pre-determined regulated return on assets. We present in this section, the IRR for the full IAP and IAP+Croatian segment projects on the basis of the tariffs calculated with different regulated rates of return.

Figure 22 shows the IRR with changes in the regulated return for the two business models with all other base case parameters. The IRR for both IAP+Croatian segment and IAP is the same. This is because the applied regulated returns are simply scaled by the CAPEX. The throughput volumes however remain the same for both business models.

Figure 22 IAP rate of return and IRR – Base Case

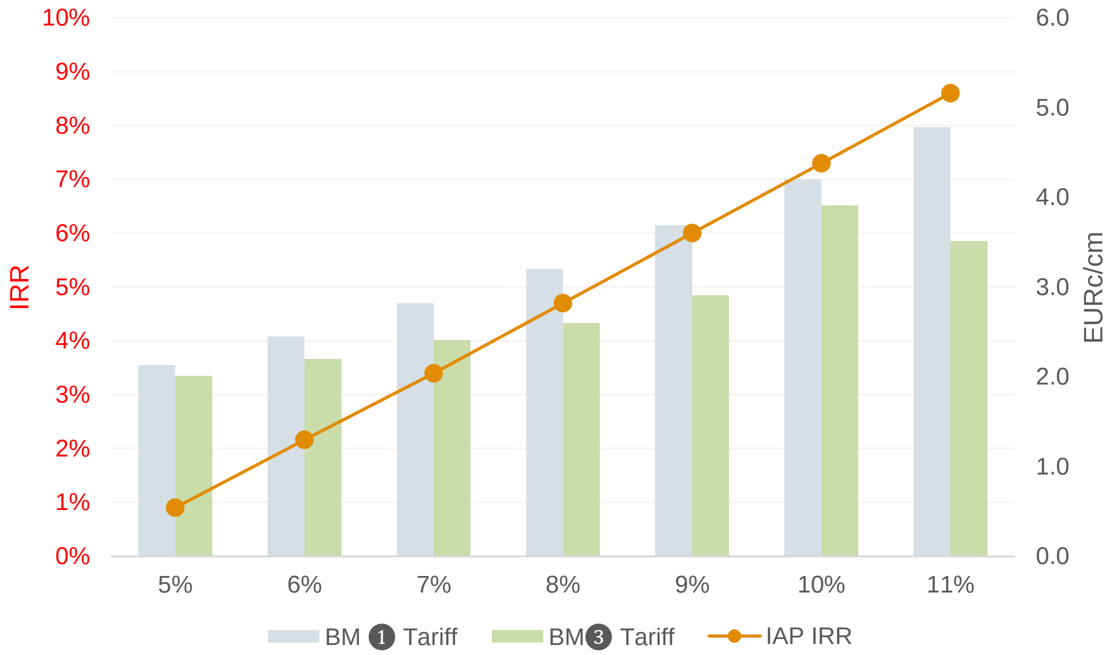


Source: ECA analysis

The IRR across all scenarios is generally low and only reaches a level above 8% (base case level in the FS) with a prescribed regulated return of between 10% and 11%. In light of the high risks associated with this project, this is unlikely to be sufficiently attractive for investors. The main reason for such low rate of internal return are that the profits and positive cash flows accrue at considerably later stages in the project's operation. As noted above, this underlines the importance of ensuring high volume flows through IAP over the first ten years of operation, which cannot be guaranteed when relying mainly on distribution networks that have yet to be developed.

Importantly however, this level of return can only be achieved with an excessively high tariff of between 3.5 €c/cm and 4.8 €c/cm (see figure below). This is likely to be too high to provide commercially viable gas supply to the three countries and most importantly for international transmission.

Table 21 IRR, regulated return and required tariffs - Base case



The only scenario where tariffs can be supplied competitively, ie below 1.9 €c/cm, is one where throughput volumes are very optimistic (Best case) and the regulated rate of return is set at 5% or 6% (see the previous section for this analysis). The implied IRR however would be at or below 2%, which is not sufficiently high to attract private investments. This reinforces the point that IAP is not commercially and financially viable. At least not to such an extent that it would attract private investors without some form of significant grant funding.

This leaves project developers with a choice of either setting tariffs at low levels to ensure maximum throughput for IAP and yielding little returns or setting tariffs at a level where higher returns can be ensured at the risk of choking off demand and throughput.

IRR sensitivity with financing terms

To test the sensitivity of the IRR with different financing terms – interest rates and debt to equity ratio – we simulate scenarios across these for our base case demand and regulated return scenario (8%). We find that the impact of interest rate changes is relatively minor and unlikely to swing the project into a commercially attractive one. The changes in financing terms are more important and have a significant impact on the IRR; but again may not be sufficient to attract private investors. We discuss in more detail the factors affecting the financing terms in the next section.

Table 22 IRR with changing financing terms fort base case and 8% regulated return

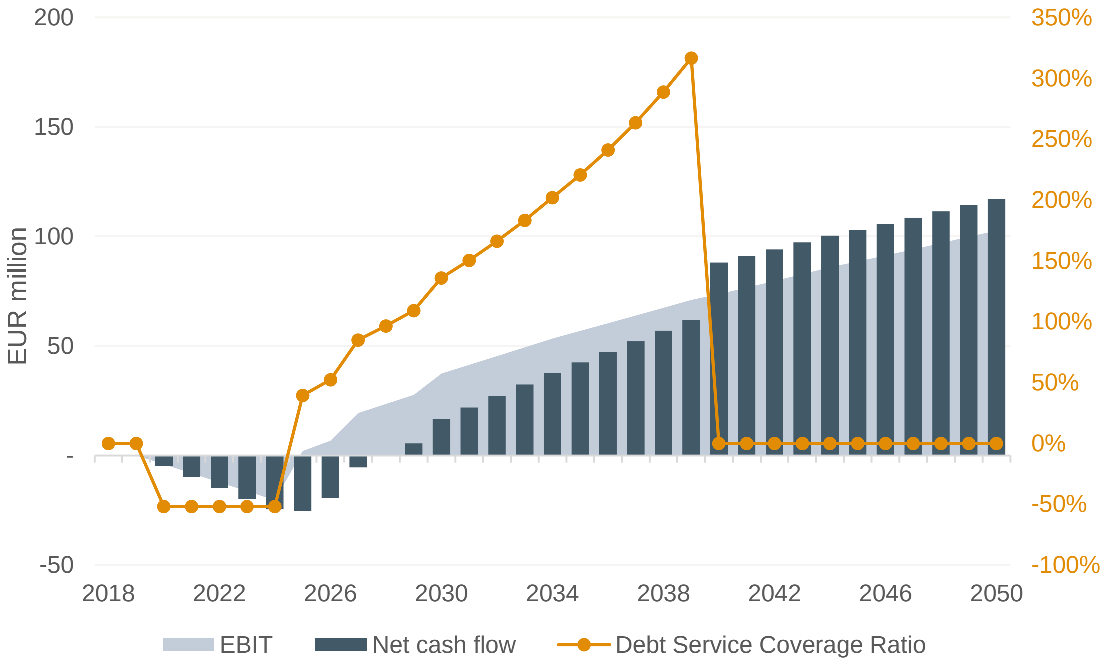
IAP Company & IAP Company + Regulated TSO					
Equity : debt ratio scenarios[67]	*10:90*	*20:80*	*30:70*	*40:60*	*50:50*
IRR	3.8%	4.2%	4.7%	5.2%	5.7%
Interest rate scenarios[68]	*7.5%*	*6.5%*	*5.5%*	*4.5%*	*3.5%*
IRR	4.3%	4.5%	4.7%	4.9%	5.2%

5.5.2 EBIT and Cash flow

We project EBIT and net cash flow only for the base case throughput assumptions. The financial positions in both business models improves markedly by early 2030 after a sustained negative cash flow period. After that however cash flows are positive and the DSCR steadily improves. As above, this shows the 'lagged' benefits of the IAP project. The positive cash flow rewards, regardless of which business model is chosen, only accrue after a period of ten years.

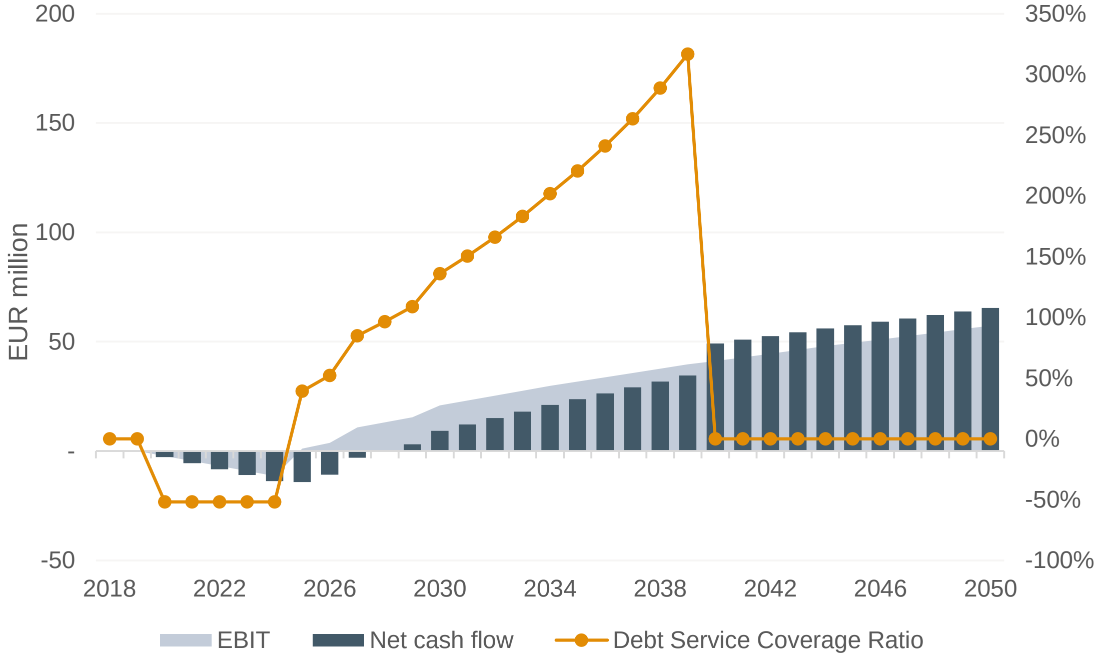
Figure 23 EBIT and Cash Flow, Base case

IAP Company (BM ❶)



[67] With interest rate at 5.5%
[68] With equity: debt ratio of 30:70

IAP Company + Regulated TSO (BM ❸)



Source: ECA analysis

5.6 Economic assessment

In this section we assess the economic impact of IAP. The FS split the economic assessment into direct monetary benefits[69] and the wider regional benefits[70]. The direct monetary benefits were estimated at €177 million and the wider regional benefits are estimated €847 million. The direct benefits have been estimated robustly and in great detail and we will not revisit these. However the wider regional benefits, estimated on the basis of a discounted cash flow analysis of avoided costs includes assumptions that may have changed or require updating. We therefore focus our economic cost benefit analysis on the wider regional impact of the project to test the robustness of the results of the FS.

5.6.1 Approach

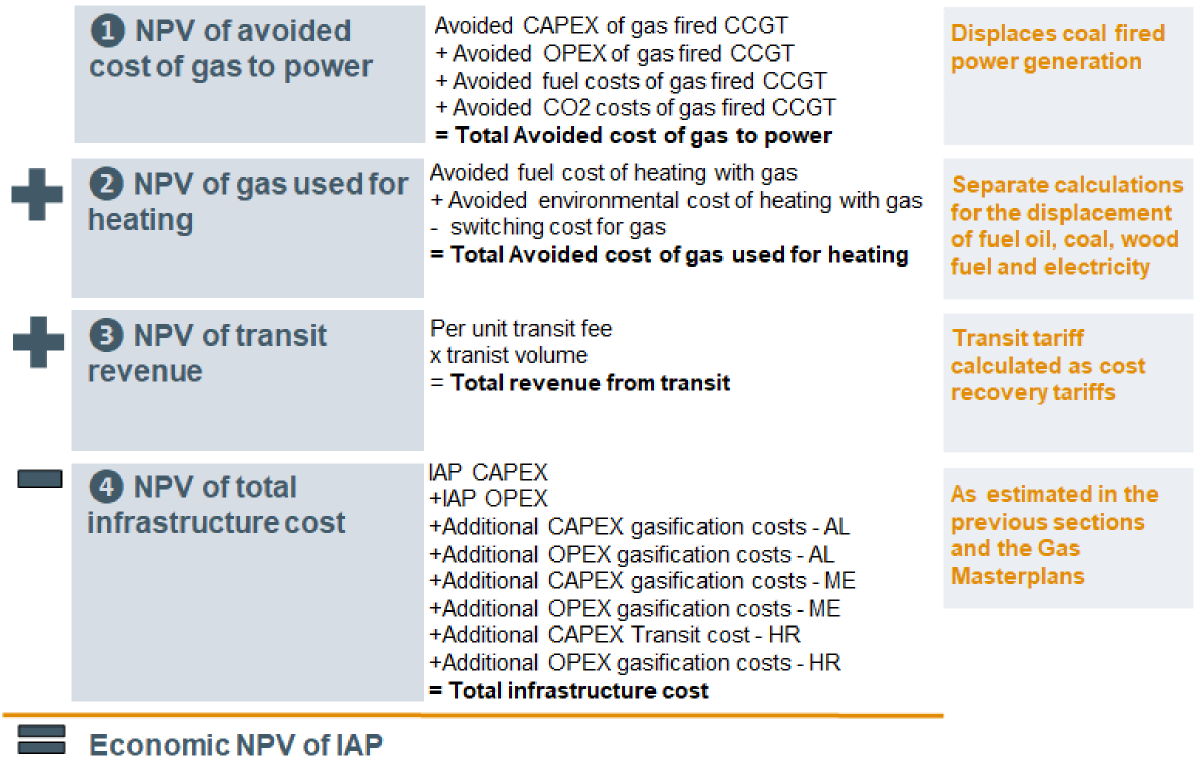
To assess the economic viability of IAP, we compute the net economic benefits by summing the avoided costs of gas to the power and non-power (industrial, commercial and residential) sectors. We adopt a discounted cash flow method, whereby we calculate the avoided financial and environmental cost of gas compared to incumbent fuels and subtract the total cost of the project. Revenues from international transmission are also added as a benefit to the region. This provides an economic Net Present Value (NPV) of the project. The overall approach is summarised in Figure 1.

[69] This includes employment during construction and operation, revenues generated from permit fees, tax revenues associated with the project and other monetary contributions.
[70] This includes avoided cost of fuel displacement in the three countries.

The first component of our analysis is the power sector. For gas delivered to the power sector (17% of throughput in our base case), we assume that gas would displace coal fired power generation only. The main components of the avoided costs from gas in the power sector are:

- ❑ The ***avoided costs in capital and operating expenditures*** are calculated by subtracting the costs from a gas fired CCGT from the same expenses of a coal power plant.
- ❑ We then add the ***avoided fuel costs of gas fired CCGT*** by computing the ratio of gas price to gas efficiency factor and subtracting it from the coal price to efficiency factor ratio.
- ❑ Finally, the **avoided CO2 cost** is found by multiplying the long-run CO2 price by the difference between the coal and gas emission factors.

Figure 24 Economic NPV



Source: ECA

The second component of our economic CBA is the non-power sector. For the non-power sector (62% of throughput), we consider fuel oil, coal, wood fuel and electricity separately. To project which incumbent fuel would be displaced by gas we apply the shares of existing fuel consumption in each country weighted by the volume of gas delivered in each country. This means that we assume that gas displaces incumbent fuels in such proportions as are currently observed in each country. For each fuel we calculate the avoided fuel costs of heating with gas and the environmental cost of heating with gas and then subtract the switching costs for gas.

- The avoided costs of heating with gas are found by subtracting the gas price to heating efficiency factor ratio from the same ratio for fuel oil, coal and wood fuel respectively.
- The environmental cost is computed as the avoided CO2 cost described above.
- We also add a 'switching cost' to gas, which largely consist of the purchase of a gas boiler.

The third component of the economic NPV analysis covers transit revenues. We multiply the transit volumes with the full IAP cost recovery transmission fees calculated in the sections above.

The fourth component of the analysis are the infrastructure costs of gasification, composed of the IAP capital and operating expenditures and the additional costs of gasification in Albania, Montenegro and Croatia.

The total economic NPV is then found by adding the NPV (discounted by a social discount rate) of the total avoided costs of gas to power, the NPV of the total avoided costs of using gas for heating instead of fuel oil, electricity, coal and wood fuel, the NPV of total revenues from transit, and subtracting the NPV of the total infrastructure cost.

Assumptions

The major assumptions used in the analysis are summarised in the table below. Additionally, we assume that all gas delivered to Albania, Montenegro and Croatia will only displace non-gas sources. For all gas transited beyond the region, we assume that IAP supplied gas will displace other existing gas supply.

Table 23 Main assumptions used in the economic NPV analysis

Assumption	Parameter	Comment
Social discount rate	5.5%	Recommended social discount rate used in project evaluations by the European Investment Bank
Time horizon	2017-2050	
CO2 emissions	Coal: 94,600 kg CO2/TJ Gas: 56,100 kg CO2/TJ Fuel oil: 77,400 kg CO2/TJ Wood fuel: 109,600 CO2/TJ Electricity: 0.378 kg CO2/kWh	Based on EIB Carbon footprint methodologies apart from wood fuel, which is based on IEA data. Electricity CO2 intensity us based on IEA sourced CO2 factors in each of the three countries weighted by the share of non-power sector gas throughput delivered to each country

Assumption	Parameter	Comment
Gas throughput offtake	Gas to power: 17% of throughput Gas to non-power sector: 62% of throughput of which - 44% in Albania, - 42% in Croatia and - 14% in Montenegro Gas for transit: 21% of throughput	Based on ECA's gas demand modelling presented in previous sections
Long term CO2 price a	45 €/mt of CO2	Based on average long term CO2 price used in EIB economic evaluations
Fuel price assumptions	*Fuel oil*: 2017 price is 0.64 €/ltr; 1 % per annum growth rate *Gas*: 2017 price is 5 US$/mmbtu; 2.16% per annum growth rate *Coal*: 2017 price is 70 US$/mt; -3% per annum growth rate *Electricity*: 10.6 €c/kWh assumed constant	Croatian base price from IEA statistics; growth rate from World bank Commodity Markets Outlook 2017 World Bank Commodity Markets Outlook Weighted average retail electricity price based on Eurostat data. This excludes any subsidies included in the electricity sector.
OPEX and CAPEX for electricity	CAPEX gas: 1.96 €c/kWh OPEX gas: 0.01 €c/kWh CAPEX coal: 4.61 €c/kWh OPEX coal: 0.04 €c/kWh	Based on Black and Veatch power generation cost report 2012
Efficiency conversion factors	Gas fired CCGT: 57% Coal generation: 40% Heat conversion gas: 70% Heat conversion coal: 60% Heat conversion fuel oil: 55% Heat conversion wood fuel: 30% Heat conversion electricity: 100%	Based on IEA data
Non-power sector fuel displacement	Wood fuel: 40% Coal: 1% Fuel oil: 12% Electricity: 47%	Shares of fuel displaced by gas in the non-power sector. Based on 2016 energy balances published by Eurostat and weighted by the gas throughput to the non-power sector in each country.
Switching cost to gas	1,500 €/dwelling	Mainly covers costs of a installing a gas boiler. Based on switching cost in the UK discounted to take into account of lower costs in the West Balkans.

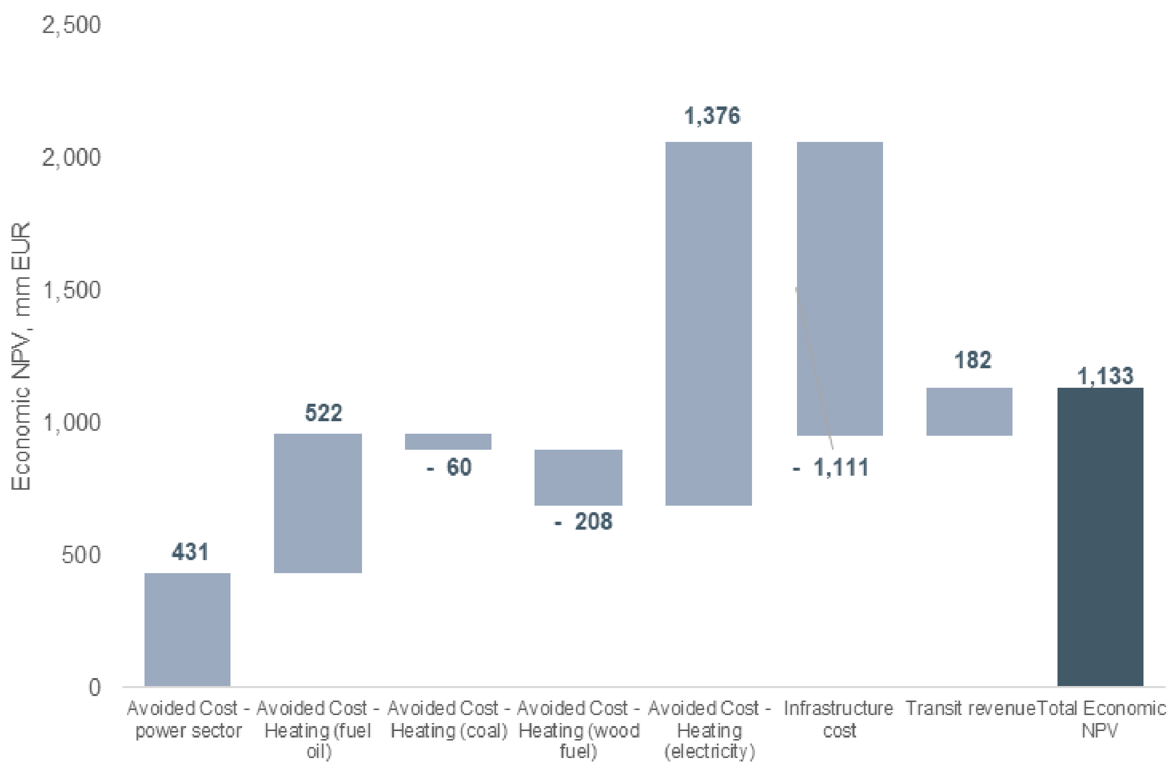
5.6.2 Base case results

The results of our base case throughput assumption suggest that the project is economically viable. The Economic NPV is positive at €1.13 billion and the economic rate of return (ERR) is 13.6% far above the social discount rate of 5.5%. This is in line with the result from the FS, which estimated an economic NPV of €847 million and an ERR of 14.1%.

Figure 25 shows the breakdown of the economic NPV by component. The power sector generates a net benefit of €431 million. Displacing fuel oil in the heating sector generates a net benefit of €522 million. The replacement of coal and wood fuel with gas for heating does not provide economic gain but instead results in economic losses of €268 million. The main driver for these losses are the extremely low prices of these fuels compared to gas. These low costs are significantly higher than any environmental benefits of switching to gas.

Replacing electricity with gas in the heating sector generates the largest economic gain with €1,376 million. Electricity is the most common form of energy used in each of the three countries at household and commercial level. Natural gas – even when including the costs of switching – could provide a very competitive source of heating. Transit provides a small revenue of €182 million.

Figure 25 Economic NPV – Base Case results



Source: ECA

Our analysis shows that it is the supply of gas to the non-power sector that has the greatest impact on the economic feasibility of the IAP project. In particular the replacement of electricity and fuel oil in the heating sector with gas results in the largest benefits to the region. It is therefore important to combine the IAP project with an extensive gasification plan of residential and commercial customers if the project is to achieve economic feasibility.

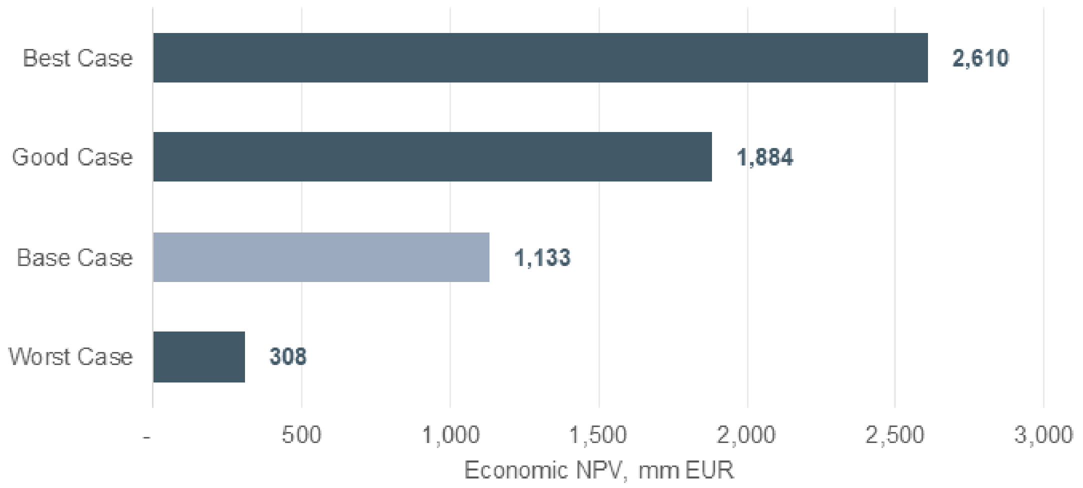
However, even if only targeted at the power sector, the project would be economically feasible.

5.6.3 Sensitivity analysis

Throughput scenarios

The Base Case analysis above was conducted for our Base Case throughput scenario. Applying the same throughput variations as for the financial analysis (see Table 19 in section 5.3), we can observe that the economic NPV changes significantly, but never becomes negative. This suggests that the positive economic impact of the project is robust across all expected throughput scenarios.

Figure 26 Economic NPV – throughput sensitivities



Source: ECA

Key parameter sensitivities

The economic analysis is highly sensitive to the key parameters included in the calculations. We test for the robustness of the results of the base case by varying the following parameters by ± 25%:

- ***Electricity price –*** replacing electricity with gas will crucially depend on the price of electricity. If it is low, the benefits of gasification will be lower as well. Note however that we are not including any subsidies in the electricity price. Montenegro and Albania however are supporting their electricity industries significantly. This should theoretically be taken into account, which would result in higher prices than what we are assuming. It is therefore likely that the true cost of electricity is higher than our base case assumption.

- ***Coal price growth*** – Coal prices impact both the power sector as well as a small part of the heating sector. It is therefore worth assessing the impact on the assumed annual growth rate (-3.04% p.a) of coal.

- ***Fuel oil price growth*** –the price of fuel oil is a key determining factor in the calculation of the total economic NPV, and we vary its growth rate around our estimated value by 25%.

- ***Long-term CO2 shadow price*** – the CO2 price is among the factors influencing the final results of the analysis most. We vary it around the base case to establish how sensitive our results are to the shadow price of CO2.

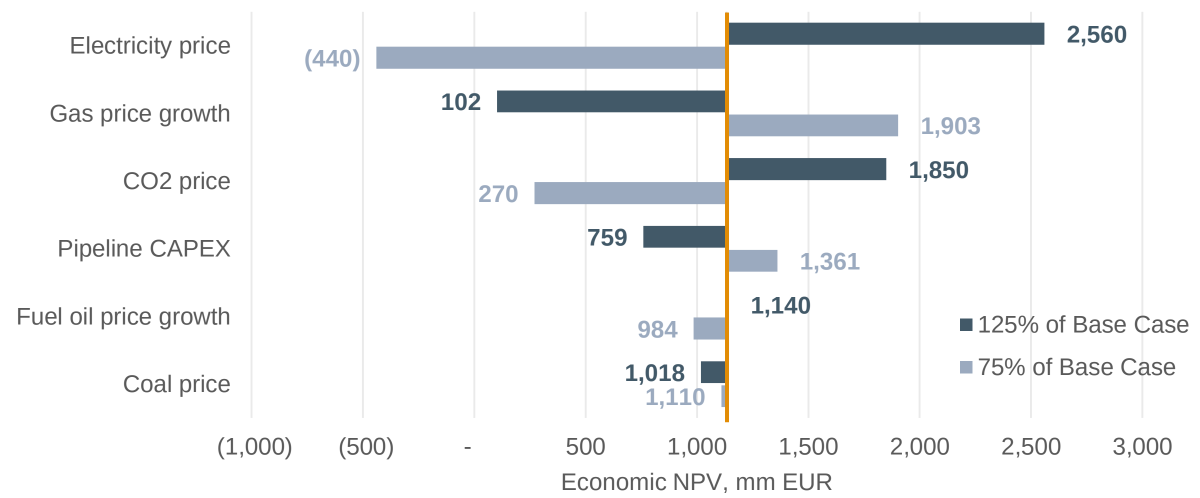
- ***Pipeline CAPEX*** – the costs of the project are not yet finalised, as a precise routing study has not yet been completed. It is therefore likely that costs of the IAP project will change going forward.

- ***Gas price growth*** – the cost savings across all incumbent fuels is measured against the prevailing gas price. Changes in the gas price growth rate will therefore impact the economic NPV across all components of the analysis.

The sensitivity of the above parameters is shown in Figure 27. The results highlight that only under a scenario of very low electricity prices, would the economic NPV become negative. This is unlikely however, as electricity prices have been kept artificially low in Montenegro and Albania due to subsidies given to the electricity sector. These should technically be included in our analysis, but we do not have sufficient information on the level of subsidies. The low electricity price scenario is therefore very unlikely.

After electricity prices, gas prices seems to be the most sensitive parameters. The 125% of Base Case scenario would imply a long run gas price of 7.5 US$/mmbtu as opposed to the Base Case scenario of 6.9 US$/mmbtu. While the Economic NPV at the higher scenario is positive the ERR is below 5.5% at 3.5%. Hence a high gas price would bring the economic feasibility of the project into question. On the other hand a long term gas price of 6.4 US$/mmbtu would result in almost doubling of the Economic NPV. The results are therefore highly sensitive to gas price changes.

Figure 27 Economic NPV – sensitivities



Source: ECA

The assumed long term shadow CO2 price also has a significant impact on the economic NPV of the project. As per our base case we assume a long term shadow price of €45/tonne of CO2. This is in line with EIB best practice. Assuming a long term CO2 price of 33.75 however would reduce the economic NPV to €270 million. Hence the assumption on the social cost of CO2 is a key component in determining the economic viability of the project.

5.7 Grant funding options

The financial analysis shows that grant funding will have to play a very significant role in the development of IAP unless high volumes of international transit can be secured for IAP early on. This section considers the grant funding options and assess the likely grant funding that could be secured.

Albania and Montenegro sections

As a Project of Mutual Interest (PMI), IAP is eligible for grant funding through the **Western Balkans Investment Framework (WBIF)**. WBIF finances investments that contribute to socioeconomic development in line with the EU accession process. It pools funds into a joint grant facility, drawing on funds allocated by the EC's Instrument for Pre-Accession (IPA), as well as grant contributions from the Council of Europe Development Bank (CEB), the European Bank for Reconstruction and Development (EBRD), the European Investment Bank (EIB), KfW, and the World Bank. The WBIF therefore plays a key coordinating role for grant funding support from a variety of donors in the energy sector in the region. Although not a funding agency in its own right but a vehicle of disbursing pools of grant funding, the WBIF could play a crucial role for funding IAP.

For the period 2015 to 2020, €1 billion are available for investments grants in the energy sector. Only PECI and PMI projects are eligible for these funds and the beneficiary countries are Albania, Bosnia Herzegovina, FYROM, Kosovo, Montenegro and Serbia. For IAP, this means that only the Albanian and Montenegrin section would be eligible for Investment grants from WBIF.

The estimated CAPEX costs for these two sections amounts to €313 million. It is not clear how much of this could be covered by WBIF. Firstly investment grant volumes and allocation to energy projects will be reviewed for the period 2020 to 2025, which may or may not mean changes in the level of individual projects' grants. Secondly, WBIF energy project funding will be split across seven other PECI/PMI projects in the gas sector and six electricity transmission projects (packaged as two projects: Trans Balkan corridor and Interconnector between Albania and FYROM). This may only leave a small amount available to fund IAP.

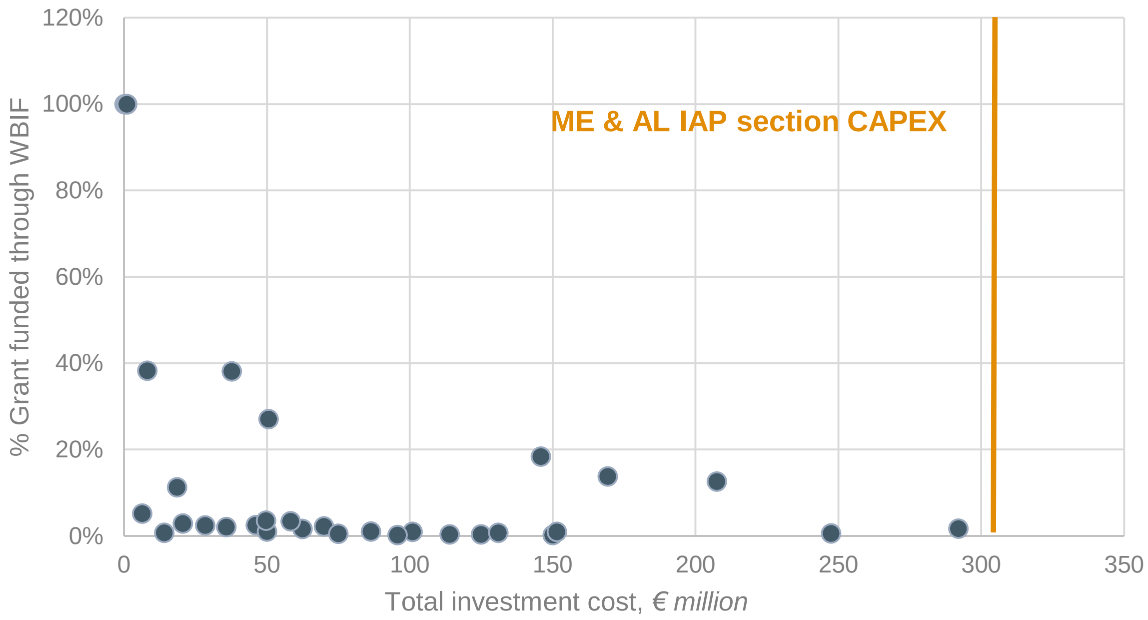
An indication on the possible grant levels provided to IAP from WBIF can be estimated when considering all WBIF grants in the energy sector since its start in 2008 (Figure 28). The following factors can be observed from the graph:

- For projects with a CAPEX exceeding€50 million, the maximum share of total investment costs provided as grants by WBIF is 20%. This share is even decreasing as CAPEX for projects get larger.
- The Montenegro and Albania section of IAP would be the largest energy project ever grant funded by WBIF. Only three projects exceeding €200 million were

supported by grants – IAP is one of them. This suggests that large energy projects are likely to be under particular scrutiny in receiving grant funding from WBIF potentially making it difficult to secure large shares of grants.

- Grants for one individual project have never exceeded €27 million. Would IAP secure, say, 20% of grants, WBIF would roughly double it largest grant to €60 million. This seems like a big step for a facility whose average grant in the energy sector has been €3.9 million per project supported.

Figure 28 WBIF grant funding for energy sector projects 2008-2017



Source: Based on data in the WBIF Monitoring Report, November 2017

On the basis of past WBIF grant funding, it seems highly unlikely that IAP could secure anything more than 10% to 20% of the CAPEX for the Montenegrin and Albanian sections. This would correspond to between €30 million and €60 million. However, this is speculative and much will depend on the strategic importance assigned to IAP, the feasibility of other energy PECI/PMI projects and the next funding round and the allocation of funds to energy projects.

Croatian section

As a member of the European Union, the Croatian section of IAP could be eligible for grant funding through the Connecting Europe Facility (CEF), which involves all 28 member states, plus certain non-EU countries including Montenegro. The Facility provides funding for Project of Common Interest (PCIs). For the 2014-20 period, energy-related PCIs have access to a total of €4.7 billion of support. Eligible gas projects include: transmission pipelines (excluding high-pressure upstream pipelines or local distribution), underground gas storage facilities, LNG terminals, and any equipment or installation essential for the system to operate safely, securely and efficiently or to enable bidirectional capacity. The Croatian section of IAP is not considered a PCI, but could qualify as a PCI. The key features of CEF that are of direct relevance for IAP are:

- Non-EU member countries can be included in funding applications as long as they have the agreement of the member state connected to the proposal and supporting documentation
- Projects are eligible for financial assistance if they demonstrate significant positive externalities, such as security of supply, and the project is commercially not viable according to the business plan and other assessments carried out, notably by possible investors or creditors or the national regulatory authorities.
- Priority gas corridors are a target of PCIs, which include the North-South and Southern Gas Corridor gas interconnections.

The Croatian section of IAP is not a PCI, reducing the chances of securing grant funding. However the PCI list is reviewed every two years and the next list is to be issued in late 2019. This could be an opportunity to apply for PCI status for IAP and secure grant funding. The CEF will typically provide 50% of grant funding for energy projects and this can include 'Studies' as well as 'Works'. Only 9 gas sector projects have received 'works' grants in the current financing period, so it is not certain that - even as a PCI – IAP would secure the funding.

The CAPEX of the Croatian section is estimated at €298 million. In a best case scenario CEF could cover 50% of these costs as a grant.

Total potential funding gap

Based on ECA's transmission tariff simulations, the minimum grant funding required to reduce transmission tariffs to close to 1.9 €c/cm is 60% in the Base Case throughput scenario and 50% in the Good Case scenario. This corresponds to between €300 million and €370 million of grant funding that are required to make the project viable.

Table 24 Estimates of potential grant funding gap

Cost component		AL	ME	HR	Total
Total investment costs	*€mm*	192.1	120.9	298.0	**611.0**
Estimated grant funding requirement[71]	*€mm*	115.3 *(60% of total)*	72.5 *(60% of total)*	178.8 *(60% of total)*	**366.3**
Maximum potential grant from WBIF[72]	*€mm*	*28.8*	*18.1*	*-*	***46.9***
Maximum potential grant from CEF[73]	*€mm*	*-*	*-*	*149.0*	*149.0*
Potential grant funding gap	*€mm*	86.5	54.4	29.8	**170.7**

Applying the grant calculations estimated for each of the sections above and applying it to the Base Case, the total potential minimum grant funding gap is of the order of €170 million

[71] 60% of total CAPEX as estimated in our transmission tariff model to reach a competitive tariff of 2.0 €c/cm in the Base Case scenario.
[72] Assumed to be 15% of investment costs based on historic grant funding levels of WBIF
[73] Assumed to be 50% of investment costs on the basis of historic grant funding levels by the CEF

(see Table 24). The grant funding gap breaks down into €87 million for Albanian, €54 million for Montenegro and €30 million for Croatia.

Note however that this assumes that the Croatian IAP section becomes a PCI project and would receive 50% grant funding form the CEF and the Albanian and Montenegrin sections receive 15%grant funding.

5.8 Conclusions

Our analysis shows that tariffs for IAP – under any of the three business models and throughput scenarios – are in excess of an estimated threshold value that would ensure competitive gas supply. However, a number of factors can be pursued by project developers to significantly improve the commercial viability of the project.

The transmission tariffs are highly dependent on throughput volumes and only under the most optimistic gas throughput case, tariffs – at a regulated return of 8% - would reach close to 2.0 €c/cm, which could be considered competitive. The key drivers for ensuring this tariff level is to maximise throughput volumes at early stages of development. This can be secured if:

- International transmission of gas plays a critical role and reaches volumes of a minimum of 0.8 to 1 Bcm/y.
- The Croatian transmission system is further expanded and developed to accommodate international transmission volumes to Slovenia.
- Croatia's import demand for gas is met by between 40% and 50% from IAP. This would mean very low utilisation of the planned LNG terminal dedicated to Croatian demand and only 85% utilisation on the Slovenian interconnector.
- Gasification efforts of distribution customers in Albania, Montenegro and BiH along the IAP route are expedited and in place within five years of IAP operation.
- Gas to power developments in Montenegro and Croatia to reach a minimum of additional capacity of 1,500 MW within five years of the operation of the pipeline.
- Including a BiH connection and ensure it forms the new main supply route into Bosnia Herzegovina supplying existing demand centres and importantly any newly developed gas fired power plants.

However even if this throughput volume can be secured, the project's IRR is likely to be below 5%. The return on equity – assuming no grant funding – would be 12%, which can be considered good, but in light of the high risks of the project – requirement to secure supply and uncertain offtake - may not be sufficient to attract private funding. Any tariff that would ensure an IRR above 8% (as used in the FS) would far exceed the commercially viable threshold level in our analysis – even in the most optimistic throughput scenario. This is the same conclusion as that reached in the FS.

This means that additional provisions must be made - besides ensuring all necessary measures are taken to maximise throughput in the first five to ten years of operation, as listed in the bullets above – to improve the commercial viability of the project. These are:

- Grant funding of more than 50% of the IAP project. The share of grant funding for IAP that would bring the tariffs to a competitive level in the base case scenario is 60% (€370 million) and 50% in the good case (€300 million).

- Setting tariffs for the Croatian segment separately from the Albania-Montenegrin section. The Croatian segment would be subsumed into the Croatian regulatory asset base and the Albanian-Montenegrin section would have its own separate tariff. While not a guarantee for project viability, this business model would result in the lowest possible total tariff.

- Involving Caspian and Middle Eastern gas suppliers in the project, who may be able to sell gas at a more competitive price in return for ownership of midstream gas operation in the region – this would help to raise the critical threshold level for the transmission tariff. More details on this are described in the following section.

- Provide the project with regulatory exemptions as done for TAP. Although this will not solve the conflict between high tariffs (for financial viability) and low throughputs, it may limit the risks of the project and thereby attract investors.

- Ensure a significant equity portion of the investment. This will be closely related to the business model, risk appetite of investors and financing terms. Our estimates suggest that for every 10% equity provide into the financing of the project the IRR improves by around 0.5% with a regulated return on assets of 8%.

- Attract investors that do not require a high return on this project alone. Investors could be identified that would see IAP as forming part of their overall project portfolio. Hence, they would not rely exclusively on IAP as a major profit centre. Instead they may consider it a vehicle to access markets where higher returns can be made. SOCAR or other Caspian and Middle Eastern gas producers would be obvious candidates, but potentially also other European midstream operators. Additionally the project would form part of an upstream and midstream portfolio and therefore does not need to be commercially viable on its own accord.

- Provide concessionary loans with low interest rates reducing the debt repayment obligations and improving cash flow. For each 1% interest rate reduction (from 5.5% in our base case), the IRR improves by around 0.2% in our base case.

Across all throughput scenarios and the majority of sensitivity tests, we conclude that the economic impact of the project would be positive. Importantly, this will largely depend on the speed of development of decentralised gas demand and the replacement of coal and electricity in the residential, commercial and industrial sectors.

6 Business model and risk analysis

In this section we focus on the viability of implementing the business models, by assessing the risks for each of the business models and highlighting the major obstacles for the implementation of the project. This builds mainly on the FS Business Development Report by expanding the financial analysis undertaken with a detailed risk assessment for each business model. The section is structured as follows:

- ❏ Description of the three business models
- ❏ Risk categories and risk assessment
- ❏ Conclusions on suitable business model and possible risk mitigations

6.1 Business models

We have calculated transmission tariffs for three different business models. The business models vary in terms of ownership, financing and operation of the IAP pipeline. This will inevitably have an impact on the risk profile for each model. The three business models are:

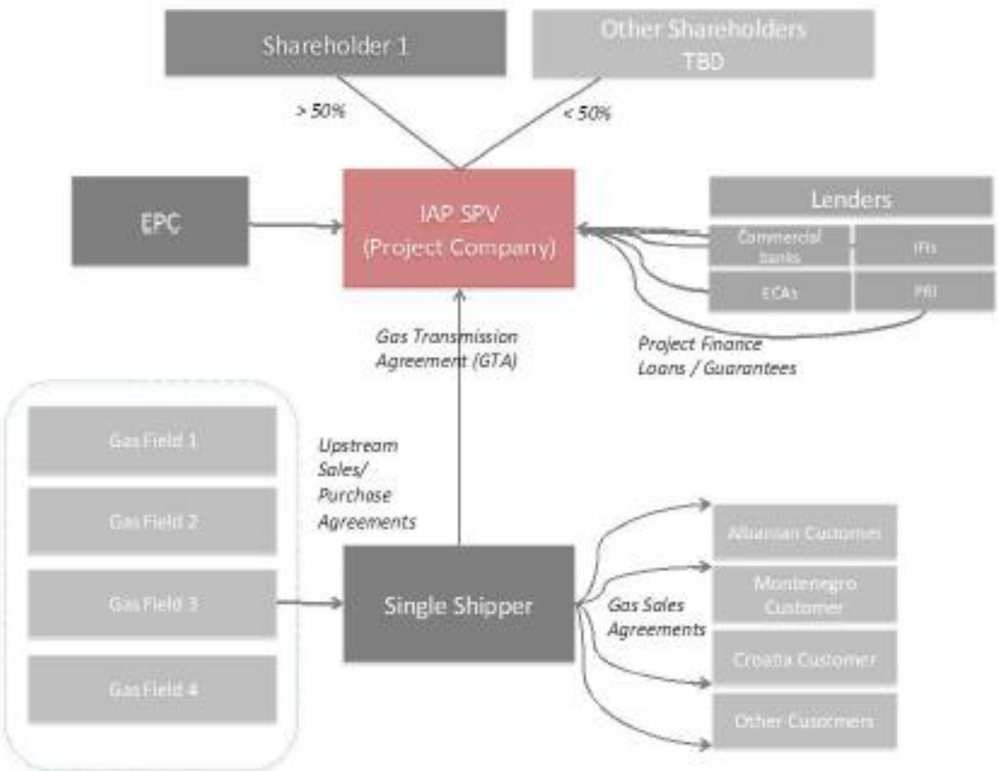
- ❏ **Business model ❶: IAP Company:** one IAP Company develops, owns and operates the pipeline on the back of long term take or pay gas purchase agreements and gas sales agreements with offtakers in each country. IAP would in all likelihood be exempt from EU third party access arrangements and one tariff applies for the whole pipeline.
- ❏ **Business model ❷: Regulated TSO:** IAP is split in three segments, which are all developed and financed by the national TSO's. Tariffs apply that are in line with national regulated transmission tariffs and are based on a cost recovery mechanism of the IAP investment and the wider national networks and national demand levels.
- ❏ **Business model ❸: IAP Company and Regulated TSO:** a combination of ❶ and ❷ where the Albania-Montenegro connection is treated as a standalone project and the Croatian segment is integrated into the Croatian asset base. One tariff would apply for the Albania/Montenegro connection and a separate tariff – in line with the existing tariff regime in Croatia – applies to the Croatian segment.

Business model ❶: IAP Company

As a standalone project, IAP would be treated as one independent transmission pipeline in a similar way as TAP or Nord-Stream. Incidentally this is the most common approach used for large international transit pipelines. This would require an IAP Special Purpose Vehicle (SPV) company responsible for development, procurement, operation and maintenance of the pipeline. In the FS this is considered the 'Single Shipper' and 'Multiple Shipper' model. This SPV could be owned by the national TSO's (Plinacro), upstream producers (SOCAR) or any other potential investor. This model is usually applied in markets and systems with nascent gas demand and one supply and only a small number of large offtake points. The project would have to adhere strictly to EU legislation on third party access (TPA), independent system operation and one regulated tariff.

Typically however, such projects are exempt from TPA[74] and can be financially secured by long term gas take or pay (ToP) gas purchase contracts and gas sales agreements with offtakers. The transmission tariff for this project would be set on the basis of the standalone asset – the IAP pipeline – on the basis of its value, a regulated return (incorporating potential risk factors) and cost recovery. The tariffs can be set on the basis of entry/exit charges or simply as a uniform postage stamp tariff. The latter was adopted in the calculation of tariffs in this business model in the previous section. We replicate the diagram shown in the FS Business Development report for the single shipper model in Figure 29.

Figure 29 Business model 1 - contracts and ownership



Source: FS Business Development Report

Business model ❷: Regulated TSO

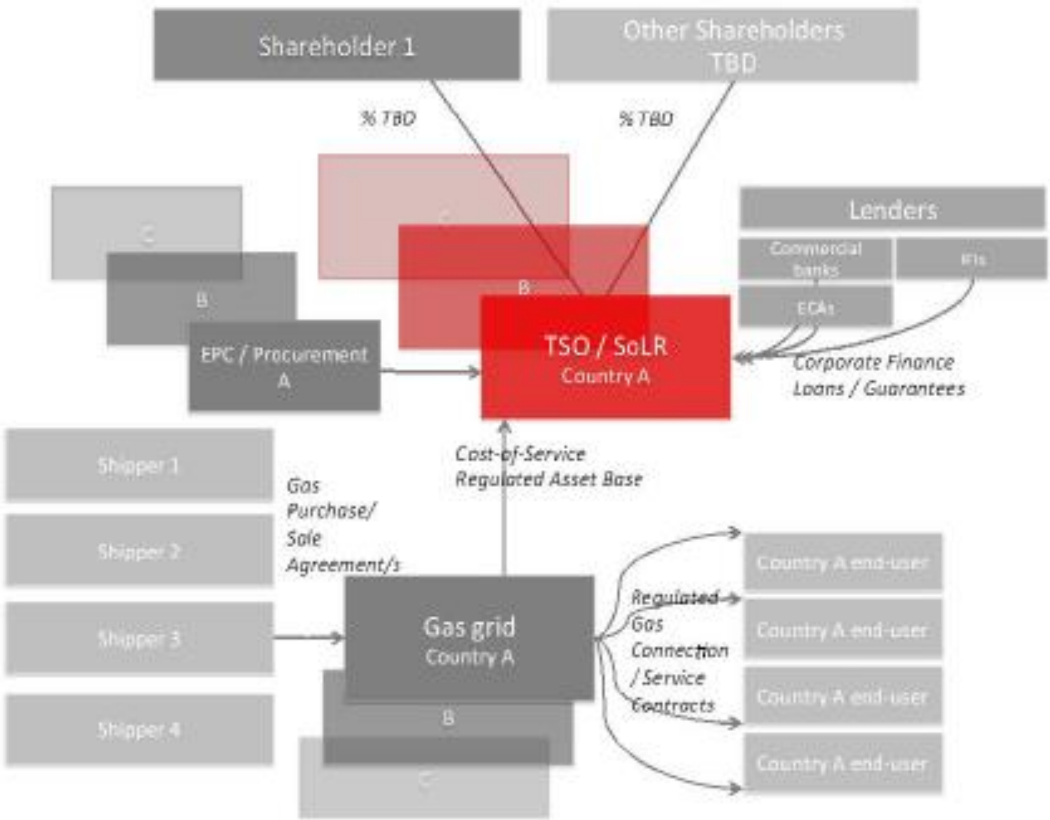
This business model assumes that each pipeline section in each of the three countries is integrated into the national transmission asset base. In the FS this is considered the 'Regulated TSO' model. Each section is therefore financed by the national entity in the country, the costs and an allowed revenue recovered through a tariff and also operated by the TSO in the country. Under this arrangement the costs of IAP would be included in the overall gas transmission asset base and recovered through the volumes of gas transported in

[74] In the FS Business Development report the multiple shipper option is non-exempt

each system. In this business model therefore, the throughput volumes of IAP are less relevant and the total demand developments in each country are of relevance, as the cost of IAP would be recovered from all users in the respective country, not just the offtakers from IAP[75]. Also, the project would not be treated as a standalone project with tariffs recovered to meet a specific IRR, but would receive a regulated rate of return as specified by the regulatory agency in each country.

Any shipper transiting gas through the IAP sections would therefore have to pay three separate transmission charges. In Croatia, an established tariff regime exists and we have assumed that the additional investment for the IAP segment would be included in that calculation. The contracts and structure of the business model are replicated in Figure 30. The multitude of contracts and implementation of national regulatory regimes may make this option the most difficult to implement. Additionally, the competitiveness of IAP would crucially depend on the gas transmission development in each country and changes in tariff regimes in each country, which may prove difficult.

Figure 30 Business model 2 - contracts and ownership



Source: FS Business Development Report

This business model is best suited to system with existing regulator regimes and established gas markets. The existing assets and volumes of demand would be able to absorb the

[75] This is an area where our approach is starkly different to that opted in the FS. Despite simulating this scenario, no consideration IN the FS is given to the wider gas volumes across which the IAP asset would be recovered.

additional cost of the pipeline more easily, ie with less impact on tariffs and crucially the tariff would not be exclusively dependent on the throughput of one particular asset.

Business model ❸: IAP Company + regulated TSO

This business model is a combination of the other two models: the Albania – Montenegro connection would be treated as a standalone project. The Croatian section however would be treated as an extension of the Croatian transmission system. Hence one tariff would apply to the Albania-Montenegro section and one for shippers transiting gas through Croatia, the standard Croatian tariff applies as per the existing tariff arrangements. Because Croatia has an established gas market and importantly an established gas tariff regime, the impact of this additional investment on the asset base would be smaller than treating it as a standalone project which would be entirely dependent on the throughput volumes of one particular pipeline. Albania and Montenegro have no established gas markets or indeed tariff regimes, so using IAP as a standalone project may be more viable.

Under this model, an SPV for the Albania- Montenegro section would be created. The Croatian section would be assumed to be financed and operated by Plinacro. Treating IAP as part of the Croatian transmission system would reduce regulatory costs for the Croatian regulator compared to treating it as a standalone project. No separate tariff regime needs to be developed, and instead the existing arrangement can be maintained with updated asset base, depreciation and return parameters.

We discuss how each of the business models respond to the commercial and financial risks identified in the following section.

6.2 Risk assessment

We identify eight risk categories against which the business models can be measured and compared. The FS provides a detailed risk assessment and mitigating measures for the IAP project in general. The recommendations to mitigate risks in the FS include:

- Partial Risk Guarantees or Partial Risk Insurance to minimise political risk
- Stringent insurance policies to safeguard from 'Force Majeure'
- Agreements for dispute resolution through international arbitration
- Legal and regulatory exemptions
- Long term contracts for the supply of gas as well as for gas sales with take or pay agreements
- Measures to minimise the design and construction risk (market surveys, selection of experienced contractors, assistance in developing construction contracts, independent construction supervisor etc.)
- Setting up debt service reserve and contingency funds

- Follow detailed environmental and social impact procedures.

The conclusions of the FS and the mitigating measures remain valid and the project – regardless under which business model – should adopt these measures. A more pertinent question however is, which of the business models minimises the various risks of the project. To complement the analysis in the FS, this is what this section focuses on.

The objective of our analysis is to provide a more qualitative discussion on the three business model that will help confirm the preferred business model proposed on the basis of our quantitative analysis – transmission tariff calculations. Our approach consists of ranking the three business models within each of the seven risk categories identified in the table below. We then assign an index of severity of impact/importance of each risk (high impact = 3, medium impact =2, low impact=1) and multiply it with the rank of the options to determine which business model mitigates risks best.

Table 25 Risk categories

Category	
Financing risk	All-embracing risk encompassing elements of each of the subsequent risk categories in this table. Reflects the ability to reach financial close on the project financing and in particular risks related to the difficulties of raising long term debt financing and servicing those debts. This depends on having long term security of payments over the term of the debt and the ability of the borrower to fulfil payment obligations. This is a high impact risk category.
Demand/offtake risk	Risk of assurance of demand for gas to guarantee the throughputs and therefore revenues for the project. Any gas purchase contracts will have to be backed by gas sales agreements (GSA). Establish GSAs will depend on the competitiveness of gas, the possible offtakers and their financial viability and the ability for offtakers to purchase a given volume of gas. This is a high impact risk category,
Price risk	The risk associated with the delivered price of gas to the three IAP markets and beyond. This will closely be linked to throughput volumes and required return from the project as well as the value of the gas at entry into IAP. This is a high risk category.
Supply risk	The risks associated with ensuring sufficient gas supply volumes can be purchased and physically supplied through IAP. This is related to the feeder supply capacity (TAP/TANAP), the ability of upstream producers or supply sources (LNG) to feed into feeder lines and the diversity of supply. This is a high risk category.
Cross border trade risk	As a cross border pipeline, IAP would enable gas trade across three countries and potentially more. There are inherent risks in such trades. These are mainly related to regulatory issues, operational issues and tariff issues. This is a low risk category.
Political/institutional risks	The risk associated with setting up the necessary institutional arrangements (TSO, regulators, etc.) to make IAP operational. Straddling three regulatory regimes of which two do not have a gas market or regulatory framework, IAP has a high degree of political risk. Additionally, the project will require close regional cooperation between the three countries, which can be a lengthy process with highly uncertain outcomes. This is a medium risk category.

Category	
Regulatory risk	This risk category focuses on tariffs, codes and operational procedures for the IAP project. The multitude of entities potentially involved in the project, may prove a disincentive for shippers or suppliers to transit or supply gas through IAP. This is a medium risk category.

The most significant risk for the IAP project is to secure sufficient throughput volumes (offtake risk). As noted above, demand in Montenegro and Albania is too small initially to ensure a competitive tariff. Additionally, large offtake points in Albania (industrial users and planned power generation units) are not located along the IAP route, but along the TAP route. Hence the offtake in Montenegro and Albania crucially depends on the development of distribution networks and the financial viability of the offtakers. The former is always a slow process and even if distribution licences are auctioned off, trunk lines connecting IAP to the grids need to be developed and households and medium sized users need to be interested and able to switch to gas. This is a long process and would, according to our estimates, not provide anywhere near sufficient volumes for commercial viability.

This means that the offtake risk can best be mitigated by:

- ❑ Ensuring Croatia's offtake from IAP is significant, and
- ❑ Maximising possible international transmission volumes.

To ensure Croatia's offtake is significant, the *price risk* needs to be considered: IAP will only contribute to Croatian demand significantly if it is not at a disadvantage compared to other supply points (LNG and existing interconnectors). This can be best ensured if the IAP segment in Croatia does not face an independent price but instead faces the same charges as any other supply point and hence the Croatian segment is treated as part of the transmission network. This means that the costs of IAP in Croatia will be carried by all consumers making the price impact minimal and the IAP entry as competitive as any other in Croatia. Treating it separately, will mean that the costs of IAP will only be carried by the limited volumes of gas carried through IAP and limited number of consumers from IAP supplied gas. It follows therefore that the best offtake risk mitigating measure is to treat the Croatian IAP segment as part of the national Croatian transmission asset base. This would also have other benefits in terms of risk minimisation:

- ❑ *Regulatory risk* – the existing regulatory and tariff regime in Croatia could be maintained and no major changes would be needed. It would also avoid having to have in place two separate regulatory regimes within Croatia –on for IAP with exempted TPA and one for the existing system.
- ❑ *Institutional risk* – Plinacro could play the role of IAP TSO within its existing statute of national TSO in Croatia and no new entity would need to be created in Croatia.

International transmission volumes through Croatia and beyond crucially depend on additional infrastructure investments. The selection of IAP business models is secondary in this regard, as the investment in Croatia's infrastructure to ensure international transmission will depend on Plinacro's ability to finance the project and on the willingness of Croatia to act as a gas international transmission country or potentially gas hub.

The *supply risk* is also a major risk to consider for IAP. Supply will crucially depend on the willingness of TAP to enable a tie-in point for IAP. Assuming this happens, TAP can be expanded to 20 Bcm, which we understand is a low cost investment. This is not necessary for IAP viability at early stages; however it will enable IAP to maximise the throughput longer term. TAP shippers need to be willing to agree on gas contracts with offtakers along TAP. This can best be done by (i) having the same owners of TAP as for IAP, (ii) creating one single financially viable shipper that buys gas at IAP/TAP tie in point and on sells to offtakers and (iii) allowing for long term sales agreement and TPA exemptions. This suggests that parts of IAP need to remain an international transmission pipeline (with international investors, not national TSOs) that enjoys EU TPA exemption. This points toward the option of business model ❸, because for the reasons outlined above, the Croatian section should be integrated into the Croatian system.

The *financing risk* with such uncertain throughput volumes is significant and can be mitigated by tying in investors with a diverse investment portfolio (ie where IAP may form part of their investment strategy and they may be able to sustain periods of lower returns on that particular project) and upstream gas resources in the Middle East or the Caspian that can be marketed into Europe via IAP. Regardless of the ownership, long term contracts and TPA exemption will also be key for financing risk mitigation. However, grant funding and concessional loans will remain critical if this project is to develop and attract investors.

The risk assessment for each of the business models is provided in Table 26. From our assessment IAP as a standalone project Business Models ❶ and ❸ are the lowest risk option with a slight advantage to Business Models ❸. This largely confirms our transmission tariff analysis, where these business model yielded the lowest transmission tariffs.

Table 26 Risk assessment

Risk category	Impact (weighting)	Business model ❶	Business model ❷	Business model ❸
Financing risk	High (3)	**Ranking: 1** The business model that mitigates financing risk best. TPA exemption and single shipper model will facilitate the negotiation of long term take or pay contracts. This in turn will underpin the financing of the project and provide certainty to potential investors. Consequently the debt share of the project could be reduced. Which as demonstrated in the previous section can improve the viability of the project. Also, separate and independent (from national TSO's) ownership can help in finding investors with hedging assets.	**Ranking: 3** Least mitigating business model, as access to the IAP sections would have to be in line fully with national regulation (ie Third Energy package provision) and therefore TPA rules. This will make it more difficult for the negotiation of long term contracts through a pooled shipping entity. Additionally, no such regulations in place in Albania and Montenegro creating uncertainty for investors. Also, national TSOs owners of the IAP section making it difficult to hedge the IAP investment with other investments.	**Ranking: 2** Pinacro would need to finance its section; but as EU member state could be eligible to more significant grant funding than if IAP developed under other business models. However offtake in Croatia (and particularly Southern) may be more difficult to secure than under business model ❶ if project results in transmission tariff increases.
Demand/ offtake risk	High (3)	**Ranking: 3** Commercial viability of the project is wholly dependent on the usage and throughput of IAP making the project viability hinge on the usage of that asset and on the creditworthiness of offtakers only along the route of IAP. While contractually, it may be easier to secure long term gas purchase agreements in the single shipper model, this may be of little benefit with a lack of potential offtakers along the IAP route.	**Ranking: 2** Inserting IAP asset into national gas transmission asset base, costs are spread across a larger volume of gas demand. Therefore the project's viability is not exclusively dependent on the usage of this particular asset. So, even if offtake along the IAP pipeline may be low at the beginning and gas networks directly linked to IAP not immediately developed, the tariffs may not need to be set excessively high as costs are recovered from all consumers in the respective countries, not just those requiring supply through IAP.	**Ranking: 1** This is the best option to mitigate offtake risk. Established and large Croatian gas demand is used to spread the IAP-Croatia costs more widely having a lower impact on IAP tariffs; this means that IAP can provide gas into Croatia and beyond competitively, which will secure throughput for the AL-ME connection. AL-ME connection commercial feasibility therefore does not hinge on offtake in Albania and Montenegro, but can take advantage of gas destined to Croatia and as international transmission. Offtake in Albania and Montenegro can then

Risk category	Impact (weighting)	Business model 1	Business model 2	Business model 3
			However, uncertainty of Albanian and Montenegrin overall gas demand and gas transmission and distribution investments does not provide a guarantee for large demand volumes in these countries.	gradually be developed supporting the competitiveness of IAP but not being crucial for it.
Price risk	High (3)	**Ranking: 2** Business model would enable single shipper to negotiate all gas contracts, providing bargaining power for gas purchasing contracts and certainty through long term gas sales agreements.	**Ranking: 3** Recovery of costs of all transmission assets in all countries results in highest combined tariff (see transmission tariff analysis), hence lack of competiveness of gas supplied through IAP with highest price risk.	**Ranking: 1** Integrating costliest IAP segment into Croatian system and spreading costs across total Croatian gas demand results in relatively low tariff impact in Croatia, ensuring competitiveness in Croatia and lower tariffs for AL-ME connection. AL-ME connection single shipper could have the required string bargaining position for purchases from gas suppliers.
Supply risk	High (3)	**Ranking: 1** The supply risk is best mitigated through long term take or pay contracts and involvement of upstream investors, which this business model would enable. Supply risk still high as IAP supply dependent on TAP expansion and TAP shipper agreement to have tie-in and allow access to suppliers into IAP.	**Ranking: 3** Highest supply risk business model, as potential suppliers would need to negotiate contracts individually, not through one shipper and long term take or pay contracts may not be guaranteed as no TPA exemption in place.	**Ranking: 2** Combination of 1 and 2
Cross border trade risk	Low (1)	**Ranking: 1** Treating IAP as a standalone project with one set of regulatory requirements, operational procedures and tariff method	**Ranking: 3** Having three separate tariff regimes, operational codes and other regulatory requirements will increase the cross border trade risk cost.	**Ranking: 2** AL-ME connection would be regulated on its own and could be adjusted to existing regulations and operational procedures in

Risk category	Impact (weighting)	Business model ❶	Business model ❷	Business model ❸
		overcomes minimise any potential cross border trading risks.		Croatia, where an existing gas regulatory regime exists.
Political/ institution al risks	Medium (2)	**Ranking: 2** This business model does not require as significant institutional changes as business model ❷. If the project can be developed by an independent project entity, the political coordination between the countries is relatively small and there is no need to establish national regulators or TSOs. However the treatment of the Croatian segment may create a conflict with Plinacro, as two transmission system operators would exist in Croatia which would require coordination.	**Ranking: 3** Risk is highest, as national institutional arrangements need to be put in place – most importantly regulators and TSOs in Albania and Montenegro – and coordination between three countries need to be ensured. Hence the success of this business model crucially depend on political will to set up the institutional framework and close coordination between the three Governments.	**Ranking: 1** By assigning the Croatian segment to Plinacro and treating the sections in Albania and Montenegro as a standalone project, the benefits of business model ❶ are maintained (limited need for institutional change) but the drawbacks avoided (coordination on Croatian section).
Regulatory risk	Medium (2)	**Ranking: 2** Similarly to the Political and institutional risk, the Croatian section of IAP may create complications. The section would act like an extension of the existing system and should therefore be regulated in the same way as the system as a whole. This may be incompatible with the regulations for the project as a whole (eg TPA exemptions, uniform tariffs, etc.)	**Ranking: 3** The requirement of three separate regulatory frameworks that are fully coordinated is difficult and could prove too challenging to overcome for the project.	**Ranking: 1** Regulatory risk is minimised, as the existing regulatory regime in Croatia would apply to the Croatian segment and AL-ME connection could be regulated as a standalone project. With no existing regulatory arrangements in Albania and Montenegro, these could be developed on the back of the regulations applicable to IAP.
Total risk score[76]		**31**	**51**	**26**

[76] Score is calculated by multiplying the weighting index of the risk category by the rank and summing across risk categories for each business model. The lower the risk score, the least risky the business model

7 Conclusions

IAP can play an important role in the gasification of Montenegro and Albania and importantly in providing a north-south axis into the EU and Croatia for the Southern Corridor diversifying supplies for the EU and other West Balkan countries (eg BiH). Recent developments have provided further impetus for the project including a recovery of gas prices, Croatian gas demand recovery, the development of TAP and the relatively low cost prospect of expansion and ambitious gasification strategies for both Albania and Montenegro.

Despite these positive developments, our assessment is that the project remains commercially marginal. Under our standard throughput scenario, the transmission tariffs would at best be 2.7 €c/cm, which is above our estimated critical threshold level of 1.9 €c/cm. Although this tariff would yield a regulated return of 8% on assets, the IRR would only reach 4.7%.

Our analysis shows however that IAP project developers can pursue a number of strategies that would significantly improve the project variability. Most importantly, measures should be taken to maximise throughput volumes in the short to medium term. The parameters required to bring the throughput volumes to levels that could yield a competitive tariff are:

- International transmission of gas plays a critical role and reaches volumes of between 0.8 and 1 Bcm/y or more. These flows are crucial to improve the viability of IAP as they can provide short term throughput that is vital to recover costs until Albania and Montenegro advance their gasification efforts. IAP should therefore be developed in conjunction with TAP as forming part of the Southern Corridor and opening up a new supply route to the EU.

- Croatia's import demand for gas is met by between 40% and 50% from IAP. This would mean very low utilisation of the planned LNG terminal (for Croatian supplies) and only 85% utilisation on the Slovenian interconnector.

- Gasification efforts of distribution customers in Albania, Montenegro and BiH along the IAP route are expedited and in place within five years of IAP operation.

- Gas to power developments in Montenegro and Croatia to reach a minimum of additional capacity of 1,500 MW within five years of the operation of the pipeline.

- Including a BiH connection and ensure it forms the new main supply route into Bosnia Herzegovina. Depending on the gasification strategies in BiH this could improve IAP feasibility significantly. However only if the connection displaces the existing supply route, provides gas supply to newly developed power plants (eg Zenica 390 MW plant) and gasification efforts for distributed customers are stepped up will a BIH connection have a significant impact on IAP. If the connection to Zenica/Sarajevo is not pursued, the impact will be minimal.

- The Croatian transmission system is further expanded and developed to accommodate international transmission volumes to Slovenia.

Even with optimistic throughput scenarios, the project's IRR would be less than 5%. Any tariff that would ensure an IRR above 8% would far exceed the commercially viable threshold level in our analysis – even in the most optimistic throughput scenario. This is the same conclusion as that reached in the FS.

Further strategies that will help in improving the commercial viability of IAP are:

- Grant funding of more than 50% of the IAP project. The share of grant funding for IAP that would bring the tariffs to a competitive level in the base case scenario is 60% (€370 million) and 50% in the good case (€300 million).

- Setting tariffs for the Croatian segment separately from the Albania-Montenegrin section. The Croatian segment would be subsumed into the Croatian regulatory asset base and the Albanian-Montenegrin section would have its own separate tariff. While not a guarantee for project viability, this business model would result in the lowest possible total tariff for the project as a whole.

- Involving Caspian and Middle Eastern gas suppliers in the project, who may be able to sell gas at a more competitive price in return for ownership of midstream gas operation in the region – this would help to raise the critical threshold level for the transmission tariff. More details on this are described in the following section.

- Provide the project with regulatory exemptions as done for TAP. Although this will not solve the conflict between high tariffs (for financial viability) and low throughputs, it may limit the risks of the project and thereby attract investors.

- Ensure a significant equity portion of the investment. This will be closely related to the business model, risk appetite of investors and financing terms. Our estimates suggest that for every 10% equity provide into the financing of the project the IRR improves by around 0.5% with a regulated return on assets of 8%.

- Attract investors that do not require a high return on this project alone. Investors could be identified that would see IAP as forming part of their overall project portfolio. Hence, they would not rely exclusively on IAP as a major profit centre. Instead they may consider it a vehicle to access markets where higher returns can be made. SOCAR or other Caspian and Middle Eastern gas producers would be obvious candidates, but potentially also other European midstream operators. Additionally the project would form part of an upstream and midstream portfolio and therefore does not need to be commercially viable on its own accord.

- Provide concessionary loans with low interest rates reducing the debt repayment obligations and improving cash flow. For each 1% interest rate reduction (from 5.5% in our base case), the IRR improves by around 0.2% in our base case.

- ❑ Ensure TAP is expanded to 20 Bcm and shippers of TAP are interested and willing to use IAP as an international transmission route. While this expansion is not strictly necessary at the start of the project, it should be pursued to reach maximum utilisation of IAP longer term.

Additionally, we recommend IAP not to be developed as a standalone project for the full proposed length. Instead it should be separated into a Croatian segment that is integrated into the Croatian asset base and a separate section in Albania and Montenegro. This means that for the Croatian segment, the national entry, exit and commodity charges would apply and the cost of the Croatian IAP segment would simply be subsumed into the Croatian regulatory asset base. By spreading the costs of the most expensive segment (Croatia) onto all consumers in Croatia and IAP shippers, tariff levels are the lowest across all investigated business models.

Across all throughput scenarios and the majority of sensitivity tests, we conclude that the economic impact of the project would be positive at €1.13 billion with an economic rate of return of 13.6%. Importantly, this will largely depend on the speed of development of decentralised gas demand and the replacement of coal and electricity in the residential, commercial and industrial sectors.

This business model also has the advantage of (i) minimising offtake risk by not making the tariffs exclusively dependent on IAP throughput volumes, (ii) minimising regulatory risk, as the Croatian segment would be treated like the existing Croatian transmission system and no additional parallel regulatory measures would need to be in place in Croatia, (iii) mitigating financing risk as this approach would have the benefits of an international transmission pipeline (TPA exemption) with long term contract agreements and (iv) minimising institutional/political risk as no new (or parallel) TSO would need to be set up in Croatia.

ANNEXES

A1 Annex 1: technical parameters

A1.1 Pipeline route details

Figure 31 Albanian IAP segment and elevation profile

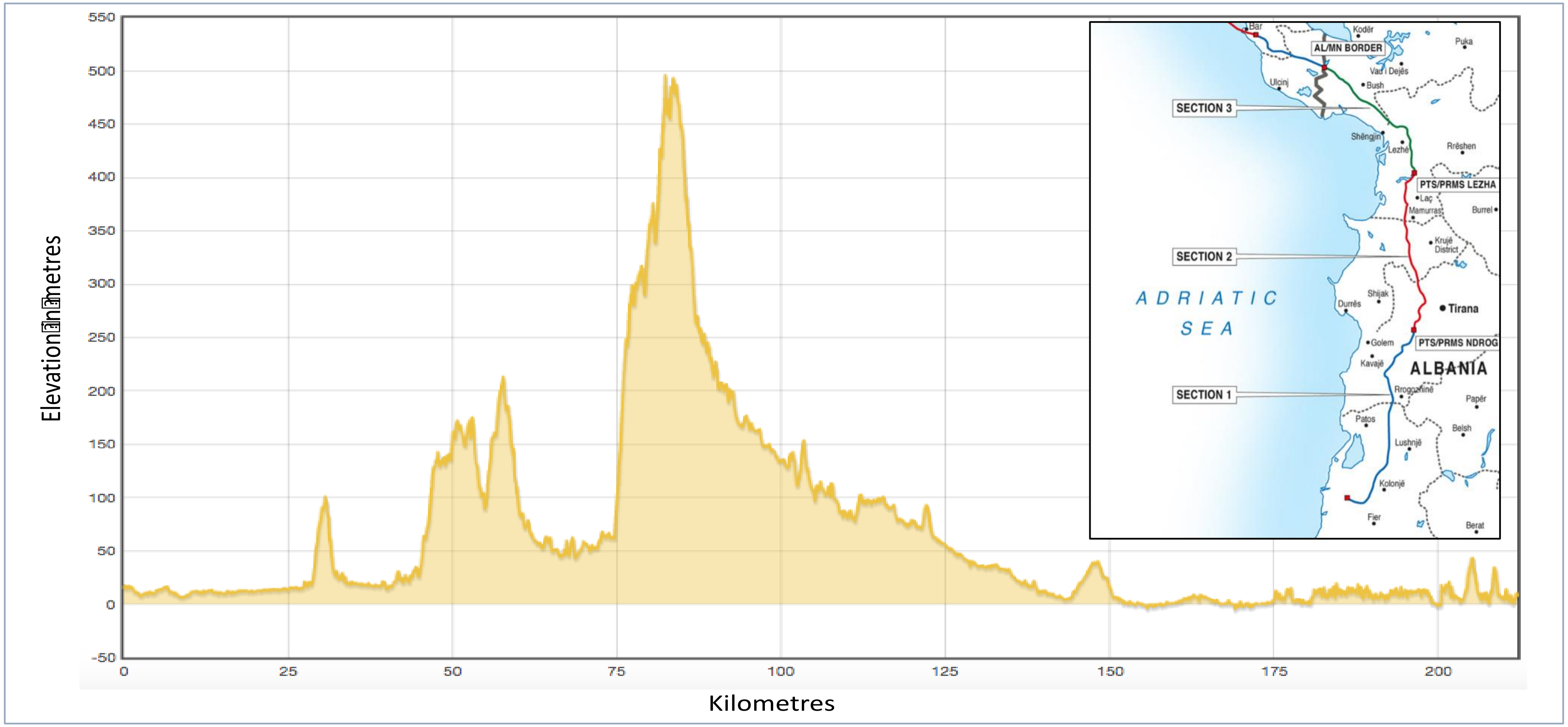


Figure 32 Montenegro IAP segment and elevation profile

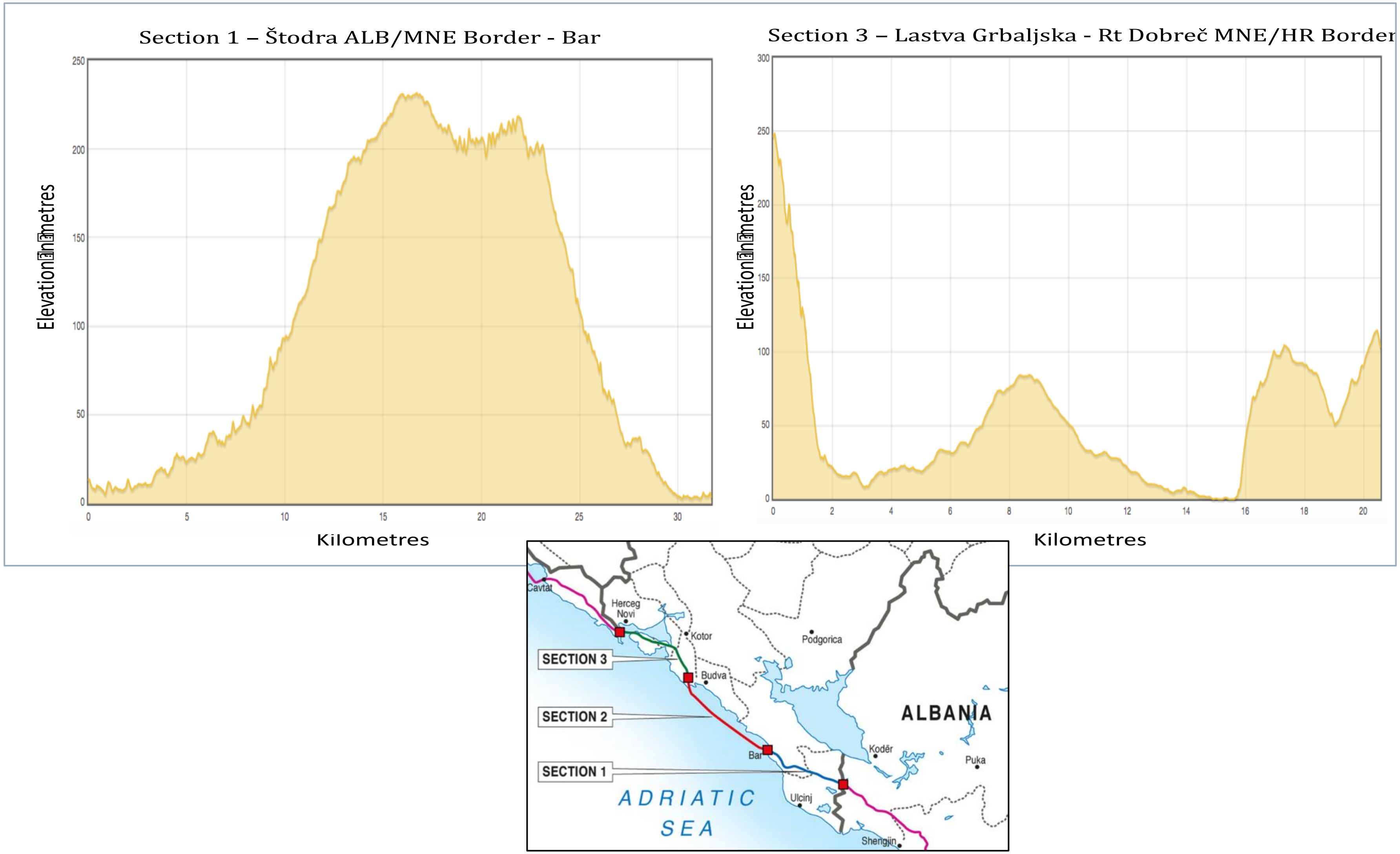
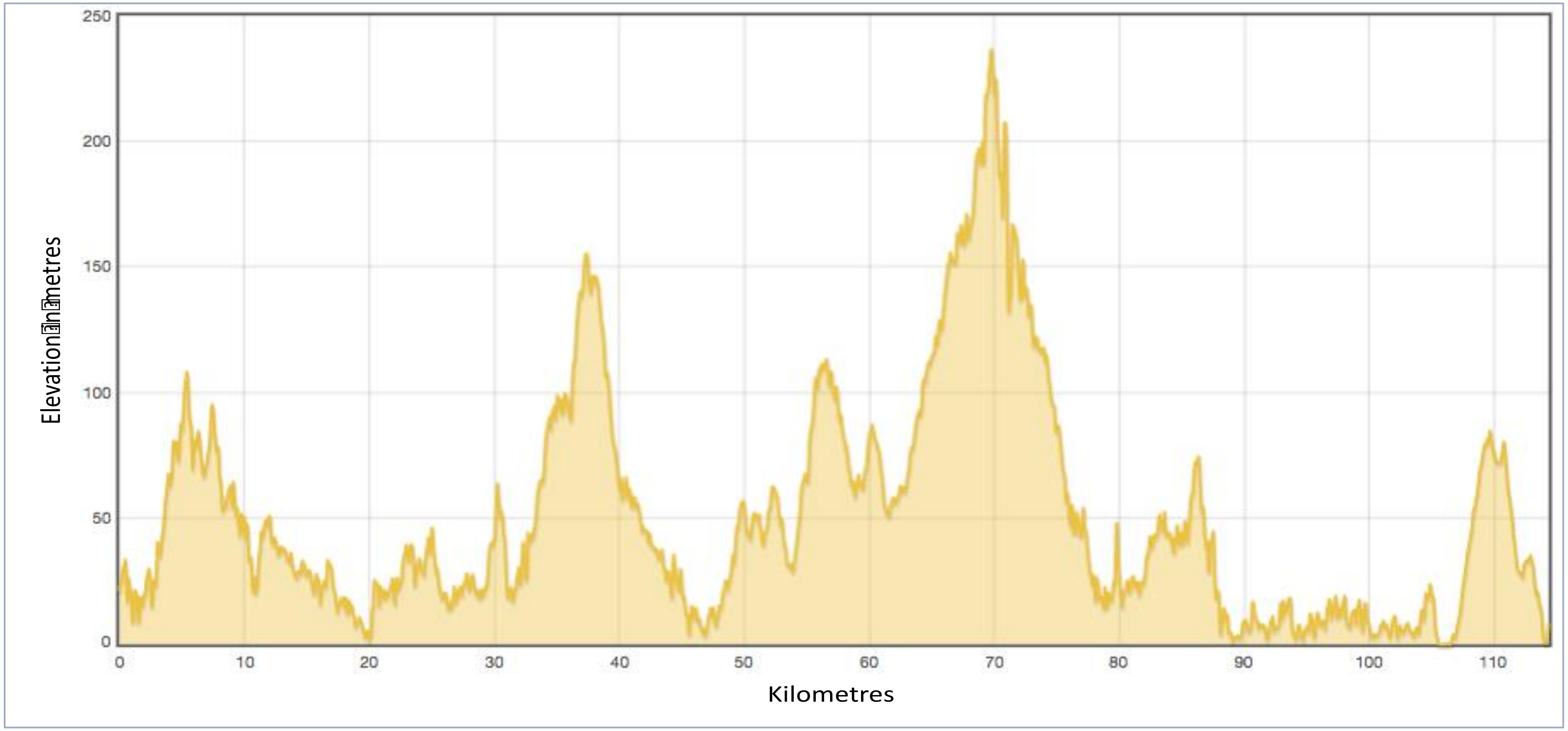


Figure 33 Croatian IAP segment and elevation profile


250
200
150
100
50
0
0
10
20
30
40
50
60
70
80
90
100
110
Kilometres

A1.2 IAP FS capital cost assumptions

This section replicates the pipeline cost data by segment that is used in the IAP FS and calculates the uplift for each terrain.

Table 27 FS Albania pipeline costs by segment

CTMS FIER - PRMS NDROG				
Length km	**Terrain**	**Weight Factor 1-4**	**Total €/m**	**Grand Total €**
43.5	flat-agricultural	1	886	38,532,300
14	Flat-populated	2	920	12,874,400
7.2	rocky hill	3	1,050	7,562,160
2.5	hilly	2	886	2,214,500
0.17	river	4	1,880	310,200
67.37				**61,493,560**
PTS/PRMS NDROG-PTS/PRMS LEZHA				
Length km	**Terrain**	**Weight Factor 1-4**	**Total €/m**	**Grand Total €**
20	flat-agricultural	1	886	17,716,000
30	flat-populated	2	920	27,588,000
3	urban area	3	1,177	3,531,300
6.2	rocky hill	3	1,050	6,511,860
4	hilly	2	886	3,543,200
0.25	river	4	1,880	470,000
63.45				**59,360,360**
PTS/PRMS LEZHA - AL/MN BORDER				
Length km	**Terrain**	**Weight Factor 1-4**	**Total €/m**	**Grand Total €**
29.5	flat-agricultural	1	886	26,131,100
3.2	flat-populated	2	920	2,942,720
4	rocky hill	3	1,050	4,201,200
0.15	river	4	1,880	282,000
36.85				**33,557,020**

Table 28 FS Montenegro pipeline costs by segment				
SCHODER AL/MN BORDER - BVS/PMRS BAR				
Length km	**Terrain**	**Weight Factor 1-4**	**Total €/m**	**Grand Total €**
8	flat-agricultural	1	899	7,195,200
3	flat-populated	2	935	2,804,400
6	rocky	2	1,004	6,021,900
8	rocky hill	3	1,071	8,595,200
0.2	river	4	1,940	388,000
25.2				**24,974,700**
BVS/PRMS BAR - BVS/PRMS LASTVA GRBALJSKA				
Length km	**Terrain**	**Weight Factor 1-4**	**Total €/m**	**Grand Total €**
0.4	flat-agricultural	1	899	359,760
1.5	rocky	2	1,004	1,505,475
1.5	rocky hill	3	1,071	1,605,975
33.1	offshore	4	1,164	38,543,295
1.5	HDD	4	1,984	2,976,000
0.6	sea entering 2x	3	6,667	4,000,200
38.6				**48,990,705**
BVS/PRMS LASTVA GRBALJSKA - RT DOBREČ (CG/HR border)				
Length km	**Terrain**	**Weight Factor 1-4**	**Total €/m**	**Grand Total €**
6.9	flat-agricultural	1	899	6,205,860
3	flat-populated	2	935	2,804,400
3.2	urban area	3	1,205	3,854,560
4	rocky	2	1,004	4,014,600
4.1	rocky hill	3	1,071	4,389,665
7.6	mountainous area	4	1,183	8,990,800
1.2	offshore	4	1,164	1,397,340
0.3	sea entering 2x	3	6,667	2,000,100
30.3				**33,657,325**

Table 29 FS Croatia pipeline costs by segment

PTS/PRMS DUBROVNIK - CTMS PREVLAKA				
Length km	**Terrain**	**Weight Factor 1-4**	**Total €/m**	**Grand Total €**
23	flat-agricultural	1	913	20,999,000
1	flat-populated	2	950	950,000
3.4	rocky	2	1,021	3,471,400
8	rocky hill	3	1,091	8,728,000
7.8	offshore	4	1,183	9,227,400
0.6	sea entering 2x	3	6,667	4,000,200
43.8				**47,376,000**
BVS/PTS DUBROVAČKO PRIMORJE - PTS/PRMS DUBROVNIK				
Length km	**Terrain**	**Weight Factor 1-4**	**Total €/m**	**Grand Total €**
1	flat-agricultural	1	1,032[77]	1,032,000
10.4	rocky	2	1,153	11,991,200
25.1	rocky hill	3	1,233	30,948,300
1.5	HDD	4	2,242	3,363,000
38				**47,334,500**
PTS/PRMS PLOČE - BVS/PTS DUBROVAČKO PRIMORJE				
Length km	**Terrain**	**Weight Factor 1-4**	**Total €/m**	**Grand Total €**
5	flat-agricultural	1	913	4,565,000
21.3	rocky	2	1,021	21,747,300
29.5	rocky hill	3	1,091	32,184,500
8.2	offshore	4	1,183	9,700,600
1.2	sea entering 2x	3	6,667	800,400
65.2				**76,197,800**
PTS/PRMS ŠESTANOVAC - PTS/PRMS PLOČE				
Length km	**Terrain**	**Weight Factor 1-4**	**Total €/m**	**Grand Total €**
15.3	flat-agricultural	1	913	13,968,900
22.5	rocky	2	1,021	22,972,500
28	rocky hill	3	1,091	30,548,000
1	hilly	2	913	913,000
66.8				**68,402,400**
PTS/PRMS DUGOPOLJE - PTS/PRMS ŠESTANOVAC				

[77] It should be noted that the cost estimates (in €/m) for the second Croatian section are different from the other four Croatian sections. We assume this is an error in the table in Annex 1 of the IAP Report, but have reproduced the table as it stands here.

Length km	Terrain	Weight Factor 1-4	Total €/m	Grand Total €
5.2	flat-agricultural	1	913	4,747,600.00
0.3	flat-populated	2	950	285,000.00
0.2	urban area	3	1,232	246,400.00
11.5	rocky	2	1,021	11,741,500.00
18	rocky hill	3	1,091	19,638,000.00
0.02	river	4	2,000	40,000.00
35.22				**36,698,500.00**

A1.3 Uplift metrics

A1.3.1 Applied in FS

Using the data from Annex 1 of the IAP Report it is possible to identify the pipeline metrics used by terrain type.

Table 30 Summary of pipeline cost metrics by terrain

Types of Terrain	Albania		Montenegro		Croatia		Average Terrain Factor
	Pipeline Cost (€/m)	Terrain Factor	Pipeline Cost (€/m)	Terrain Factor	Pipeline Cost (€/m)	Terrain Factor	
flat-agricultural	886	1.00	899	1.00	913	1.00	**1.00**
flat-populated	920	1.04	935	1.04	950	1.04	**1.04**
rocky hill	1,050	1.19	1,071	1.19	1,091	1.19	**1.19**
hilly	886	1.00	-	NA	913	1.00	**1.00**
river	1,880	2.12	1,940	2.16	2,000	2.19	**2.16**
urban area	1,177	1.33	1,205	1.34	1,232	1.35	**1.34**
rocky	-		1,004	1.12	1,021	1.12	**1.12**
HDD	-		1,984	2.21	2,242	2.46	**2.33**
sea entering 2x	-		6,667	7.42	6,667	7.30	**7.36**
mountainous area	-		1,183	1.32	-	NA	**1.32**
offshore	-		1,164	1.29	1,183	1.30	**1.30**

A1.3.2 EU uplift metrics

In 2015 ACER[78] published a report entitled 'Report on unit investment cost indicators and corresponding reference values for electricity and gas infrastructure', which gathered data from across the EU on 293 gas transmission pipelines and 101 compressor stations over a ten-year period. Therefore, the Consultants have been able to use this information to estimate gas pipeline and compressor costs in Europe. The following table, is a summary of results from the ACER report, with the costs relevant to the IAP project highlighted in yellow.

Table 31 Unit investment cost indicators

Pipeline diameter (Inches)	Pipeline pressure range (Bar)	Average (2005-14), €/m	Median (2005-14), €/m	St. Deviation (2005-14), €/m	Average (2005-14), €/m	Median (2005-14), €/m	St. Deviation (2005-14), €/m
		Nominal	Nominal	Nominal	Indexed	Indexed	Indexed
<16"	12 to 85	476	396	277	526	449	282
16" to 27"	12 to 100	630	586	288	706	636	313
28" to 35"	12 to 100	960	917	374	1,061	1,015	416
36" to 47"	63 to 100	1,338	1,257	532	1,460	1,381	554
48" to 57"	75 to 100	2,224	2,211	382	2,427	2,352	398

Source: ACER, 'Report on unit investment cost indicators and corresponding reference values for electricity and gas infrastructure', Table 8, page 20.) Nominal costs are in € at time of construction, Indexed costs are indexed by inflation to € in the base year of 2015.

[78] EU Agency for cooperation of energy regulators.