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Gas Export Pricing & Alternative Gas Export Routes (Central Asia case)

by A. Konoplyanik

Gas Export Pricing & Alternative Gas Export Routes (Central Asia case) [1]

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1. Pricing for non-renewable energies: economic & legal background

There are three key gas pricing mechanisms on non-renewable energy resources that exist worldwide: (i) cost-plus (net-forward) pricing, (ii) (net-back) replacement-value-based pricing, and (iii) exchange (commodities) pricing.

Cost-plus (net-forward) pricing is aimed at extraction by the host-state of Ricardian rent (long-term difference between cost & marginal cost, see *Figure 1*) and is utilized at the *physical* energy market where the traded item is a unit of physical energy. The price calculated by this method equals to consecutive sum-totals of all elements of supply costs plus taxes plus reasonable rate of return from well-head through the energy value chain to the end-user/delivery point.

(Net-back) replacement-value-based pricing is aimed at extraction of both Ricardian and Hotelling rents. The latter is equal to the long-term difference between marginal cost & replacement value of competing fuel(s) (see *Figure 1*) and is utilized at the *physical* energy market as well. The price calculated by this method equals to the weighted average of the costs of replacement fuels at the end-user (at the burner-tip) netted-back through the energy value chain to delivery point if the latter is located upstream from the end-user.

Exchange (commodities) pricing is aimed at extraction of both Ricardian and Hotelling rents, plus/minus windfall profits/losses, the latter aims to cover short-term supply/demand imbalances. Exchange (commodities) price reflects/includes the difference between

[1] Based on author's presentation at Plenary Session IV "Legal framework and opportunities for a regional energy market" of the international Energy Security Conference "Strengthening regional co-operation in Central Asia for promoting stable and reliable energy within Eurasia" co-organised by the Government of Turkmenistan and Organisation for Security & Cooperation in Europe, Ashgabat, Turkmenistan, 3-4 May 2010, and at Plenary Session "Diversification of energy transportation to international markets" at the II International Investment Forum of Turkmenistan, co-organised by the Government of Turkmenistan and Ashgabat, 17-18 October 2010

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supply/demand "equilibrium" price on energy contracts for delivery of energy resource & replacement value of this non-renewable energy resource in question, and is utilized at the *paper* energy market. The traded item is an energy contract – the obligation to deliver a unit of energy (not a unit of physical energy *per se*), utilized through futures, options and/or their derivatives.

Historically and nowadays the dominant export gas pricing mechanism in continental Europe/Eurasia is a net-back replacement value gas pricing with price indexation formulas. This mechanism of non-renewable energy pricing has its economic & legal background.

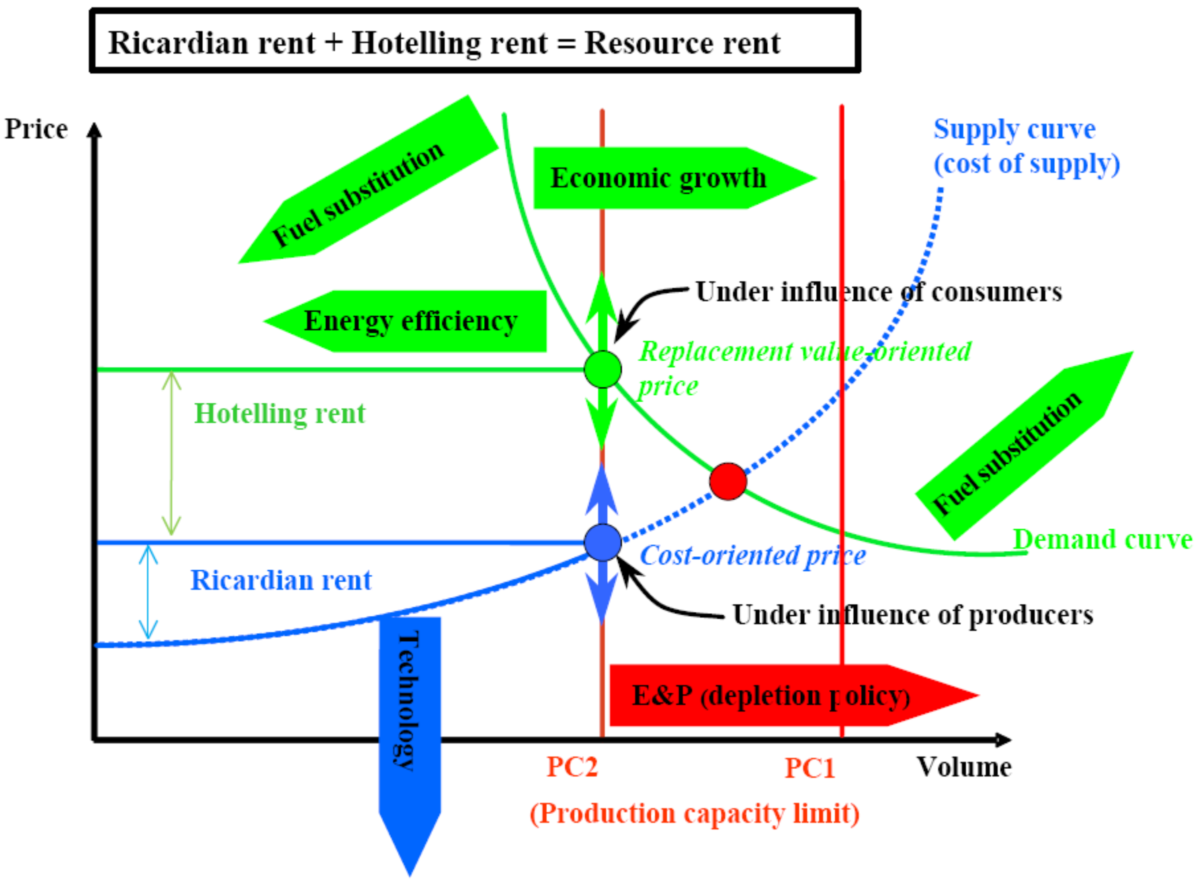

Figure 1. Pricing of Non-Renewable Energy Resource at the "physical energy" markets: Ricardian vs. Hotelling rent

Economic basis: A resource owning state intends to maximize its long-term resource rent which means its intention to receive not the highest export price in the short-term but the highest competitive (marketable) export price in the long-term multiplied by highest possible cumulative recovery of the energy resource in place. This reflects the sovereign right of a resource-owning exporting state to sell gas to export markets with the highest long-term replacement value where it can maximize its long-term market share. In the case of the former USSR, current Russian and/or Central Asian gas exporters one such market is the end-user market of the EU. Due to specificity of replacement value calculation, the end-user market of China provides lower level of contractual formula gas price, all other parameters being equal, compared to the EU, though as a fastest growing market China, compared to mature EU market, can provide a bigger market share (in absolute terms) for such a new exporter as Central Asia.

Prior to 1962 gas pricing in Europe was organised on a cost-plus basis. In 1962, the Netherlands' government has proclaimed its new energy policy aimed at maximization of the long-term resource rent from the development of the then newly discovered (in 1958) super-giant Groningen gas field. This policy document is known as "Nota de Pous" after the name of the then Dutch Minister of Economic Affairs who has presented major principles of the new Dutch gas policy to the Parliament. Based on these principles a concept of long-term gas export contract (LTGEC) was established, known worldwide since as the "Groningen model of LTGEC". Its major characteristic features are: long-term contract, plus pricing formula linked to gas replacement values (prices of gas replacing fuels within competitive energy market), plus regular price review (including both the recalculation of the price level for current period under existing formula and a review procedure of the formula itself), plus net-back to delivery point, plus minimum delivery and take obligations (take-and/or-pay provision), plus protection from price arbitrage to the detriment of exporter (destination clauses), etc. This mechanism provided the opportunity to market gas within an evolving market structure and competitive pricing environment to the mutual benefit of both producer and consumer. All further development of capital-intensive gas infrastructures in Europe and of the European gas industry was based on the implementation of such Groningen-type LTGECs.

Legal basis: Also in 1962, the UN General Assembly Resolution N 1803 confirmed permanent state sovereignty on natural resources (the latter includes, by definition, energy resources as well). This was later reconfirmed by the Energy Charter Treaty's Art.18 regarding sovereignty on energy resources (The ECT was signed in 1994 and entered into force in 1998).

Based on the above, it is the sovereign right of the resource-owning state/exporter of non-renewable energy resource (justified by its fair economic interests and supported by the international law) to determine whether or not to provide politically-motivated concessions for an importing country in the form of either lower export price levels or by establishing such a pricing formula structure that it would lead to the lower export price level, which in both cases means it would share resource rent of the exporting state (usually it would be its Hotelling rent – in part or in whole) with the importing state. This means that implementation of the "cost-plus" pricing principle instead of "net-back replacement value" export pricing within the competitive energy markets (e.g. energy markets with the mix of competing energies) equals to politically motivated formation of export prices. Such practice was broadly used, inter alia, between the USSR and COMECON countries up to the end of the 1980-ies, between Russia and Ukraine since 1992 till 2006 (for the gas originated from Russia), and between Central Asia, Russia and Ukraine between 1992 and 2009/2010 (for the gas originated from Central Asia), etc.

2. Evolution of export gas pricing in continental Europe & FSU: 1962-2010

Figure 2 illustrates the evolution of gas pricing mechanisms within continental Europe and the former Soviet Union (FSU) in the recent decades. The Y-axis indicates the price of gas. The X-axis presents the European gas value chain within its physically existing technical infrastructure from gas producing states in the East (Russia and Central Asian states), though major transit countries in mid-Europe to the end-user markets of the EU member-states. Major cross-border points are indicated at the X-axis, starting at the left from the demand-side and going to the right to the external borders of major gas exporters.

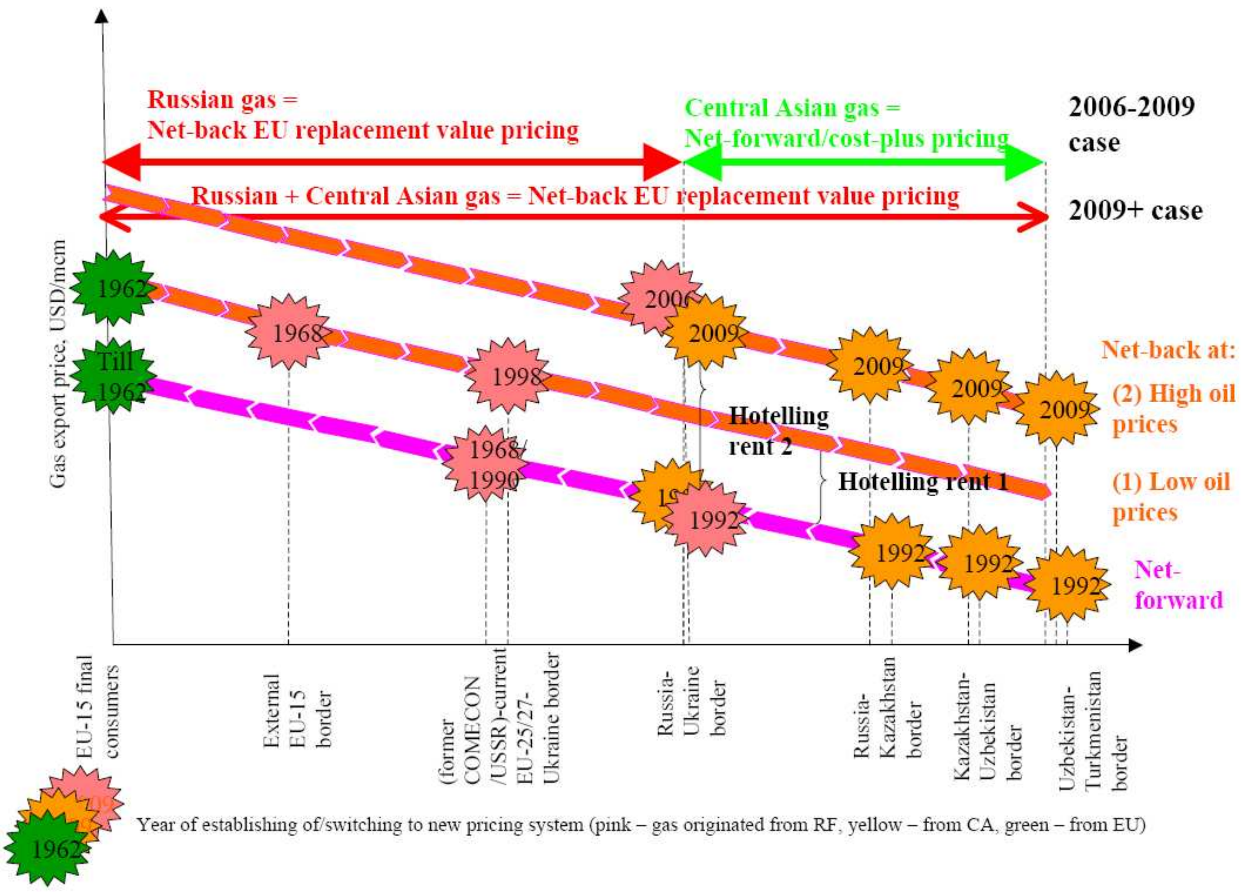

Figure 2. Evolution of gas export pricing in Continental Europe & FSU

If the "cost-plus" principle is used, the price of gas produced in the East and delivered to the end-users at Western markets should be calculated by the net-forward approach from the cost of production at the exporter's well-head (thus increasing the price at delivery points moving in direction from right to the left at *Figure 2*). If the "net-back replacement value" principle is used, the price of gas is calculated as replacement value at the end-use market netted-back to the delivery points (or exporter's border). This decreases the contract price at delivery points moving in direction from left to the right at *Figure 2*. In this case, since the price of gas in European LTGECs is mostly pegged to the price of petroleum products (gasoil/diesel and residual fuel oil), the higher the international oil price, the higher is the contractual price of gas calculated by the “net-back replacement value” principle. This means, that the higher the oil price, the higher the Hotelling rent of gas for its exporting state will be (see *Figure 2*), either utilized by exporter or donated to the importing state in case of political pricing.

As mentioned earlier, prior to 1962 gas pricing in Europe was based on the “cost-plus” principle. In 1962 European gas pricing started to be converted to the “net-back replacement value” principle. It was the time of low and stable international oil prices (less 2 USD/bbl throughout the decade), so the price increase from “cost-plus” price to “replacement value” price was not significant and the transfer went rather smoothly.

Since that time the net-back replacement value principle and Groningen model of LTGEC with pricing formulas, utilizing this principle, has slowly but steadily spread over Europe and FSU in Eastward direction.

In 1968 the first Soviet gas export supplies to the West started (with first contract with Austrian company OMV at the delivery point in Baumgarten at the Slovak-Austrian border) based on a modified Groningen-type LTGEC with a pricing formula based on replacement value principle[3]. At the same time, the COMECON states located on the export route of Soviet gas to Europe received their gas at politically-motivated discounted prices calculated at “cost-plus” principle. After the dissolution of the COMECON system in 1989, the then already politically-independent states of Central Europe still continued to receive their import gas from post-Soviet Russia at the discounted prices until end-1990-ies, when Russian export contracts with them were transformed in line with the European practice – to the Groningen-type LTGECs with pricing based on the replacement-value principle. Since 1998 was the low peak of the oil prices (after the 1997 Asian financial crisis oil prices had shortly fallen to 8 USD/bbl), the import gas price increase due to transfer from “cost-plus” to “replacement-value” principle was insignificant and this transfer from politically-motivated to economically-justified pricing has passed through rather painlessly for the importers and did not result in political tensions.

This was not the case within the FSU area. After dissolution of the USSR at the end of1991, all gas export pricing within the FSU was organized at the cost-plus principle, as it had been earlier organized and was still used in the 1990-ies with the former COMECON states (non-dependent whether Russia was acting as gas exporter in Westward direction or a sole importer of Central Asian gas). It was only in 2006 with Ukraine and in 2007 with Belarus that Russia has started to transfer its export gas pricing with transit CIS states from a cost-plus to the replacement value principle. At that time this transfer referred only to the gas originated from Russia. Replacement value for Russian gas was calculated at the EU end-user market since it was this market (and not the markets of Ukraine and/or Belarus) that provided the highest marketable

[3] For more details of Soviet/Russian gas to Europe contractual structures see, f.i.: A.Konoplyanik. Russian Gas to Europe: From Long-Term Contracts, On-Border Trade, Destination Clauses and Major Role of Transit to …? – *“Journal of Energy and Natural Resources Law”,* 2005, vol.23, N 3, p. 282-307.

price and excessive demand for Russian gas (and thus long-term resource rent – highest Hotelling rent - for the exporter)[4].

Unfortunately, the timing for such transformation - in the middle of current decade - was not as favourable as it has been earlier with the Central European states in end-1990-ies when the oil prices were low. 2006 was the fourth year of continuing growth of international oil prices which increasingly widened the gap between economically-justified replacement-value gas prices and politically-motivated cost-plus gas prices[5]. This explains why this transfer from political towards market-based (or, more correctly: market-oriented) pricing was so economically painful for importing states, why it has increased political tensions between the states in question, and why different intermediate/transition schemes were introduced in order to soften the blow of price increase on the importing states. A major element of softening the burden of the increased gas price for Ukraine, was continuation of supply to Ukraine of Central Asian gas by Russia, which Russia has been buying at the external borders of Central Asian exporters at cost-plus basis. By mixing this gas, at which a relatively low export price continued to be established at a cost plus basis, with the gas originated from Russia, at which a relatively high export price was established at a replacement value basis, the resulted average export price for Ukraine (Ukrainian import gas price) was received as a weighted average of these two ingredients. This was being done at the balance sheets of the Russian-Ukraine Swiss-registered intermediary RosUkrEnergo (which became since January 2006 the sole exporter of Russian gas to Ukraine), resulting in Ukraine to receive a discounted level of imported gas price in the 2006-2008 period. So the mechanism of price discounting for Ukraine at that time was the mixture by Russia of two incoming flows of gas (originated from Russia and from Central Asia) with two different pricing mechanisms into one contractual outgoing flow of gas destined for Ukraine with weighted average price level, discounted to what have been considered as a market-based contractual European price (e.g. the price which provided the highest resource rent value for the exporters).

In 2009 the net-back replacement value pricing principle was expanded to the Central Asian gas (first, in end-2008, fixed purchase price for Central Asian gas for the whole year 2009 was established, and then in end-2009 the pricing principle was adapted by introducing the normal quarterly-based price recalculations within the given formulas since 2010). This had the following consequences within Central Asia – Russia – Ukraine triangle:

For Central Asian exporting states this meant that they finally began to receive full value of the Hotelling rent on their gas exported west-ward, instead of transferring it almost in full to Ukraine. For Ukraine it meant that it stopped to monetize domestically Hotellling rent originated in Central Asia and opportunities to further receive discounted gas import prices since that time depends only on Russia. For Russia this meant that it has to pay the full net-back

[4] For more details, see, f.i.: A.Konoplyanik. Russian – Ukrainian Gas Dispute: Prices, Pricing and ECT. - *“Russian/CIS Energy & Mining Law Journal”,* 2006, N1 (Volume IV), p. 15-19.

[5] See Figure 42 “Russian Prices to the EU and Countries Along the Pipeline” (p.168) in “Putting a Price on Energy: International Pricing Mechanisms for Oil and Gas”, Energy Charter Secretariat, 2007 (www.encharter.org).

replacement value price for Central Asian gas and that it could not donate any more the Ukrainian economy at the cost of Central Asian gas producers, as happened in 2006-2008. Since 2009 onwards Russia has been donating Ukrainian economy at its own cost. Russia introduced 20% discount to the contractual price calculated at net-back replacement value pricing principle for the whole year 2009. For 2010-2019 Russia has introduced a 30% discount for Ukraine to the contractual price calculated at the same principle. This discount was donated at the cost of Russian state budget since it was given as tax allowance to Gazprom in the form of non-payment by the latter of export customs duty equal to 30% of the contract price for this 10-year period. This price discount to Ukraine was given to balance the cost of lease of Sevastopol Navy Base for the further 25 year period 2017-2042 as a swap of obligations between two state budgets.

So, it took almost 50 years to expand the net-back replacement value pricing principle to the continental Europe and the FSU area through the existing EU-oriented gas value chains. But this finalization of expansion of this pricing principle to the Central Asian states in 2009/2010 has its another important consequence, which is strongly under-estimated by the analysts and politicians, and which is the influence of changing pricing mechanisms on the export priorities of the Central Asian gas exporting states.

One needs to remember, that these land-locked gas exporters would like to maximize their Hotelling rent and to minimize their export-related costs and risks. Historically, Russia bought almost all Central Asian gas at cost-plus price at their border and re-sold it at this price plus transportation costs and plus some margin to the CIS states (mostly to Ukraine) thus providing a discounted price to the importers. Now the situation has changed and Russia has been paying the full EU-based replacement value price to Central Asian exporters (even to its own detriment, since it resold their gas to Ukraine in 2009 with 20% discount from this full EU-based replacement value price). Compared to other alternatives, it is more profitable for Central Asian exporters to continue selling their gas to Russia at their external borders at the price linked to the gas replacement value at the EU market (maximization of Hotelling rent) with further transportation of their gas West-ward, both to the Ukraine and/or further to the EU, by Gazprom which leads to exclusion of transit-related costs and risks for Central Asia exporters.

In May 2007 Russia agreed to buy long-term all available gas of Central Asian exporters (to book long-term all available transportation capacity for its supply West-ward) at their external borders at highest possible import price (net-back replacement value at the EU market) and to take all costs and risks by transporting Central Asian gas to end-users by Gazprom. Today the situation has changed, at least temporarily, with regards to the volumes due to decline of gas demand in result of economic crisis. Thus additional volumes of available Central Asian gas might appear at the market. Which export route will win the competition for these volumes? To which export markets these volumes of Central Asian gas will be thus destined in the long-term?

3. Changing export priorities for Central-Asian gas: worldwide

What are today's alternatives for Central Asian export gas routes?

First of all, let's remember that almost all identified non-Russia gas resources and proved reserves in the area are located on the right side of Caspian (see *Figure 3*) except Azeri's Shah-Deniz field with expected 8 BCM of annual production (available for export?) from its second development phase.

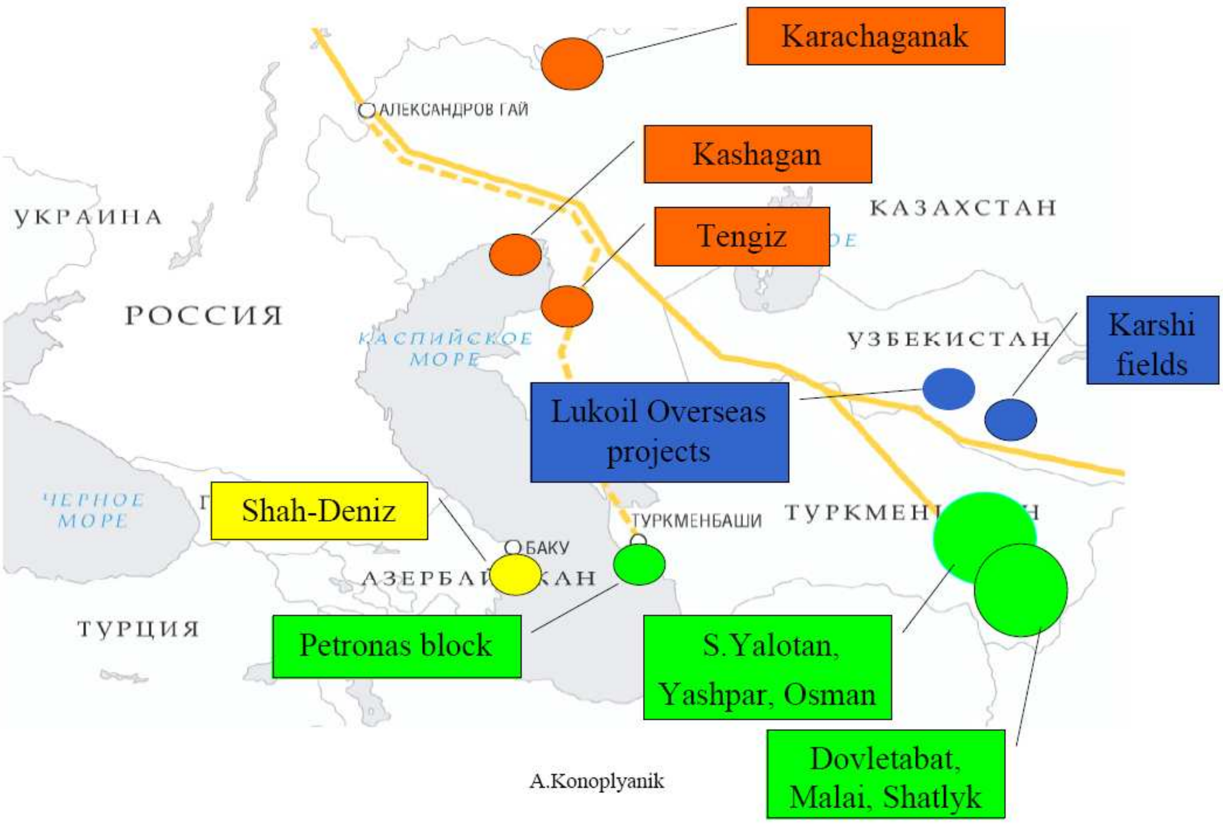

Figure 3. Major Central Asian gas areas

Central Asian gas exporters face the following alternative export gas routes with the starting point in Turkmenistan for mostly all of them as in the richest one in resources/reserves/production/export volumes. These routes are (see *Figure 4*):

(1) Three lines of acting pipelines so-called "Central-Asia – Center "(CAC 1, 2 & 4, the first two lines originates from Uzbekistan) to Russia and further to Europe,
(2) Acting third line "Central-Asia – Center" (CAC 3), which by-passes Uzbekistan, known as Pre-Caspian pipeline (to be expanded according to May 2007 bilateral Russia-Turkmen agreement),
(3) To China via Uzbekistan and Kazakhstan (inaugurated on 14 December 2009),
(4) Discussed gas pipelines to Europe to by-pass Russia (Nabucco and others, which intended to be linked with gas fields of the right bank of Caspian either by offshore trans-Caspian gas pipeline or onshore via Iran),
(5) To Iran (acting for 12 years Korpedje-Hangeran pipeline in the west of Turkmenistan, and inaugurated on 6 January 2010 new Dovletabat-Sarahs-Gurtguyi pipeline in the east of Turkmenistan, plus to be further discussed possibilities of swap deals with south-Iranian gas

fields to give access of Turkmen gas, say, in the form of LNG, to international markets from the Persian Gulf area),

(6) Long-debated pipeline to India and Pakistan via Afghanistan, and

(7) A special case – East-West Turkmen Interconnector, which will be built by 2015. This Interconnector will give to Turkmenistan technical opportunity to maneuver its available gas resources between preferable export destinations. From this author's view, construction of East-West Turkmen Interconnector could (and most probably will) have the revolutionary effect on the whole evolving Eurasian energy market, similar to the multi-dimensional effect that US shale gas developments has stipulated in the international gas markets in recent years[6], firstly, because this Interconnector will physically connect European and Asian gas markets and will act as a "golden chain" in bringing together united gas transportation system of Eurasia, secondly, with few small additional internal lines to be built, it will enable Turkmenistan to have access to all major international markets with its combined resources of on-land eastern and offshore western parts of the country.

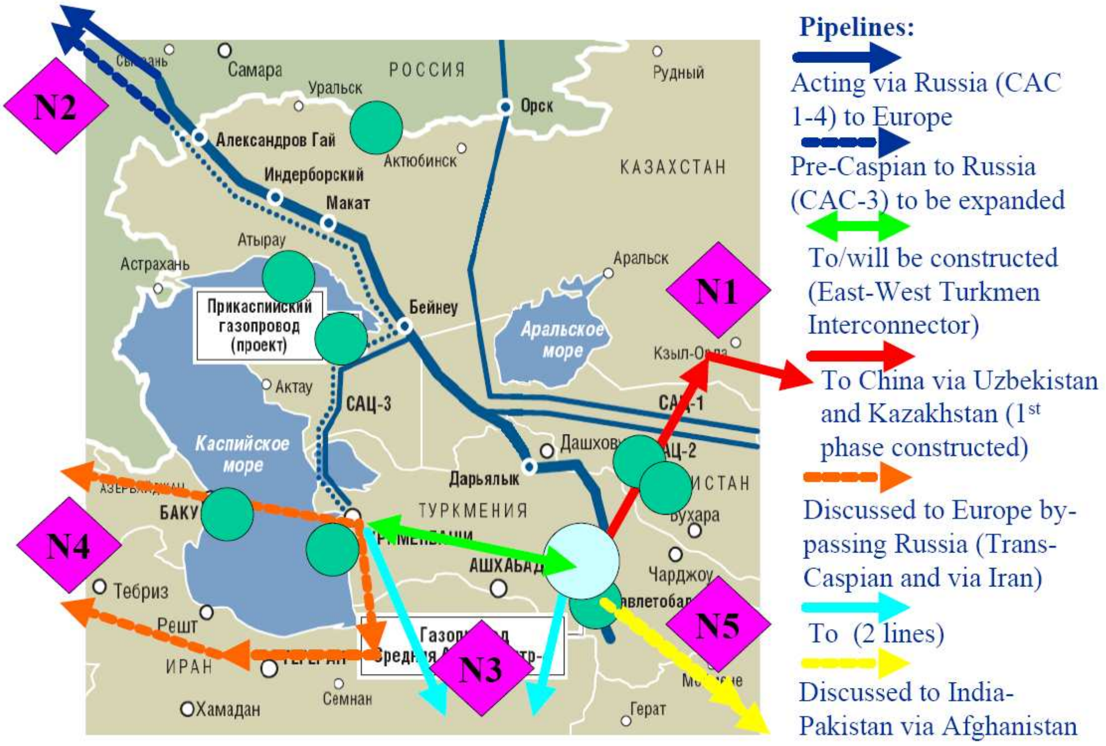

Figure 4. Alternative gas pipelines from Turkmenistan

Changing export priorities of Central Asian gas has its clear economic justification as result of further adaptation of pricing mechanisms in the FSU from political to market-based pricing, and

[6] Increased domestic US shale gas production under diminished gas consumption due to global gas crisis has decreased US import demand for gas. This affected first and most imported LNG, which flows in the Atlantic basin were re-oriented to Europe which also faced decrease of gas consumption due to global economic crisis. This led to oversupply of gas in Europe. LNG deliveries were coming mostly from new projects which, firstly, were to large extent organized on spot basis in order to use preferences of arbitrage deals within Atlantic basin, and, secondly, faced urgent necessity to pay back debt financing under which conditions they were financed and developed. So LNG suppliers were discounting price of their deliveries and provided other preferences to the buyers and thus were winning against less flexible contractual deliveries of pipeline gas in Europe. This has stipulated modernization of long-term gas contracts for pipeline gas both in direction of more flexible contractual provisions (such as take-and/or pay, etc.) as well as to adaptation of pricing formulas towards more sophisticated basket of replacement fuels and other parameters away from pure oil indexation. From my view, these contractual and pricing consequences in European gas market are the most important revolutionary effects of recent US shale gas development.

in particular for Central Asian gas since 2009. Prior to 2009 export pricing on Central Asian gas was based on cost-plus principle at external borders of the exporters. So the export price of Central Asian gas was much lower than its alternative export price defined as net-back replacement value from the EU end-users. This predefined availability of huge Hotelling rent at the importer's disposal which stipulated the struggle for Hotelling rent between potential importers of Central Asian gas. Among those EU and Ukraine cases can be specifically mentioned.

The EU companies were interested to monetize this Hotelling rent by direct purchases of Central Asian gas at their external borders at cost-plus price and by then re-selling it at the EU market at replacement value price. This explains the economic reasoning of the intensive fight of the EU companies, supported by the Commission, for direct access to Turkmen gas in particular and the gas from the right bank of Caspian in general. In addition, direct access to Turkmen gas with its purchases at cost-plus prices with possibility of its resale in Europe has been seen in the EU as an opportunity to create a downward pressure on prices of Russian gas sold by Gazprom at EU replacement value prices. Huge Hotelling rent on Central Asian gas, at that time, would have left a big corridor for price discounts on Central Asian gas against Gazprom's prices.

At the beginning, the intention was aimed to provide transit of Central Asian gas through Russia by receiving access to Gazprom's transportation system based on EU requests of both mandatory third party access to transportation capacities and domestic tariffs for transit of Central Asian gas through Russia (which in this country are lower than export and/or transit tariffs). These EU requests have been referred to its interpretations of the provisions of the Energy Charter Treaty. This explains long-term debates within the Energy Charter on transit-related issues since they reflected long-standing intention of the EU delegation to use their own interpretation of some provisions of the Energy Charter Treaty (ECT) as an opener of Russian gas transportation system for mandatory transit of Central Asian gas to Europe at discounted tariffs. And this was one of the reasons why the EU was so eager to push Russia to ratify the ECT in its current wording - without clarification of few transit-related provisions of the Treaty (requested by Russia as pre-condition of its ratification of the ECT) which, as was shown, might have different interpretations[7]. So the Energy Charter was long intended to be used by the EU as if a mechanism of international law to justify this scenario of bringing Central Asian gas to the EU market via Russia.

When these attempts failed, the second-best option was used jointly by the EU and the US in their attempts to bring Central Asian gas directly to the EU market by-passing Russia. As was stated by the US Atlantic Council, "for the U.S., it would be reasonable to focus on solutions that provide to Caspian producers outlets to free markets, rather than lock them up in a long-term relationship with state-controlled entities. The U.S. and Europe should put their act

[7] Publications on transit-related debate within the Energy Charter in recent years are presented at this author's website at www.konoplyanik.ru/publications.

together to give these countries better access to free, competitive energy markets".[8] But besides this philosophy of opening access to "free and competitive markets" for Central Asian gas, another economic argument can be pointed out: it was huge Hotelling rent (the difference between then actual cost-plus purchasing price of Central Asian gas and its replacement-value expected re-selling price in the EU) that would have stimulated construction of alternative pipelines and that would have been available for EU companies to pay-back such huge investments. But no pipeline would be financed without proved reserves booked for shipment via this pipe and without supply and shipping contracts signed. So I am convinced, that from the very beginning, all alternative routes of gas pipelines to Europe by-passing Russia in the so-called Southern corridor were aimed to receive access to Turkmen and other Central Asian gas not only to feed-up these pipelines and to justify their construction, but to provide the opportunity to monetize in the EU Hotelling rent of the Central Asian producers.

Ukraine had similar intentions – to monetize Hotelling rent of Central Asian gas at Ukraine's domestic market by receiving direct access to Central Asian gas at external borders of the exporters at cost-plus price and by reselling it at Western border of Ukraine (to the EU) at European prices. It managed to only partly implement this scenario, with the help of Russia, in the period 2006-2008, when Central Asian gas was bought by Russia at discounted cost-plus price, was mixed with market-valued Russian gas, and this mixture was sold to Ukraine at the intermediate – weighted average – price, which was higher than cost-plus and lower than net-back replacement value. In order to prevent full monetization of Hotelling rent of Central Asian gas at Ukrainian market, further re-export of this gas to the EU was prohibited by establishing another Russia-Ukraine joint venture UkrGasEnergo, which was the sole buyer of gas from RosUkrEnergo and was obliged to sell it only at the domestic Ukraine market.[9]

Since 1 January 2009 the entire landscape has radically changed. The Russia and Central Asian states have transferred the pricing of Central Asian gas to the commonly used pricing mechanism within/with the EU such as net-back replacement value from the end-user EU market. Today Central Asian exporters receive the highest possible competitive price in delivery points at their external borders . This means that nowadays there are no further incremental economic stimuli for the EU companies to fight for direct purchases of Central Asian gas (there is no incremental price rent – no huge Hotelling rent). This means that since 2009/2010 the EU has been downgraded in the list of export priorities for Central Asian gas.

The same is true for Ukraine which since 2006 has been debating with Russia the "fair" gas pricing principle for gas exported to Ukraine and has been trying to prove that the export price of gas for Ukraine should be defined by its replacement values at the domestic Ukrainian market. This means that should this same principle be applied to Central Asian gas, its net-back

[8] Boyko Nitzov. "Russian Oil and Gas Starts Flowing East", Published on Atlantic Council website (www.acus.org), 01 May 2009.

[9] For further explanations of this mechanism, see, for instance: А.Конопляник. Российский газ в континентальной Европе и СНГ: эволюция контрактных структур и механизмов ценообразования. - ИНП РАН, Открытый семинар «Экономические проблемы энергетического комплекса», 99-е заседание 25 марта 2009 г. – Москва, Изд-во ИНП РАН, 2010 г.

replacement value would have been much lower than the price proposed to Central Asian gas exporters by Russia.

What might be the current export preferences for Central Asian gas and for Turkmenistan in particular? This author's view on the preferential routes for Central Asian gas to competitive Eurasian markets is presented at *Figure 5*. Numbering of the routes in the range presents their diminishing value for Turkmenistan.

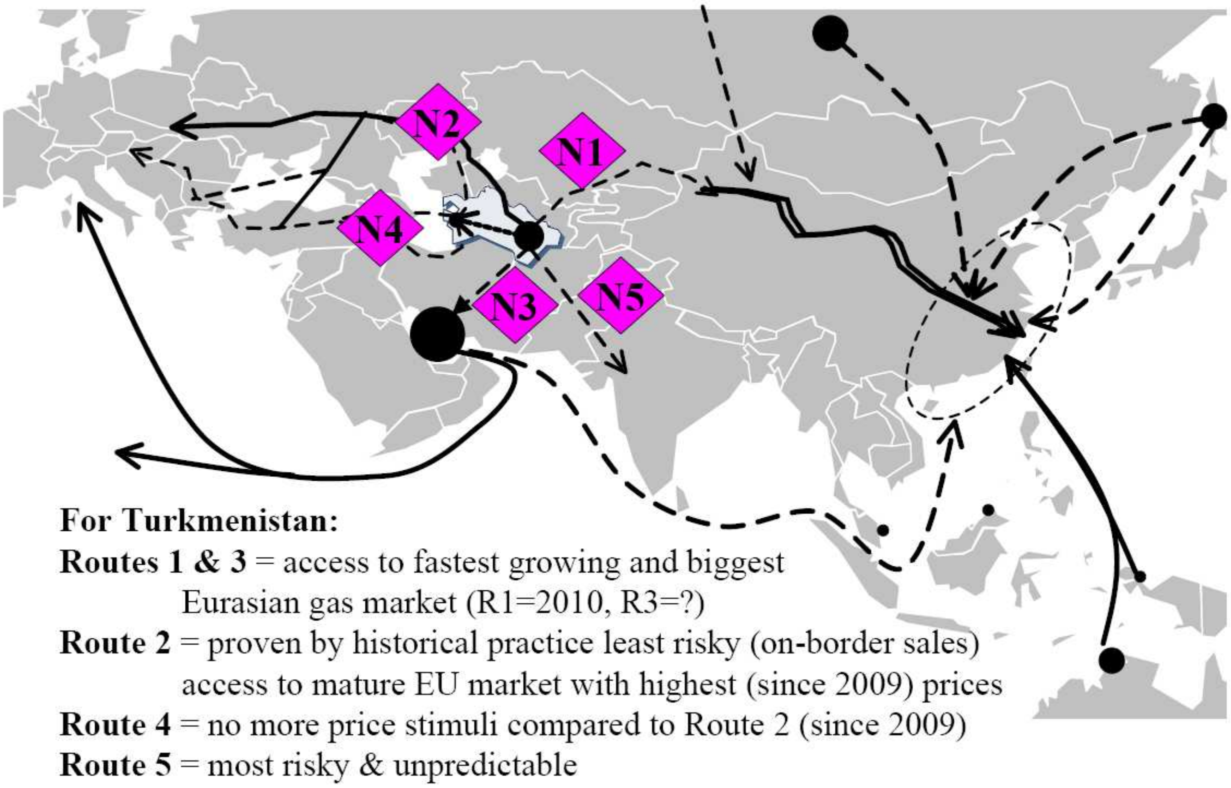

Figure 5. Central Asian Gas at Competitive Eurasian markets

Route N 5 (to India and Pakistan via Afghanistan), from my view, is the most risky and unpredictable and is the last in a row to be expected for practical implementation, at least until the real peace in the Afghanistan would be reached.

Most preferential route is **Route N1** to China – the fastest growing and potentially biggest Eurasian gas market. According to initial agreement between the parties, when the Trans-Asian pipeline, inaugurated on 14 December 2009, will achieve its projected capacity, it will annually bring 40 BCM of Central Asian gas (30 BCM of Turkmen and 10 BCM of Uzbek gas) to China to the entry-point of second line of Chinese East-West pipeline which will bring Central Asian gas further to Shanghai, Guangzhou and more than 10 other provinces and cities of China during next 30 years. In June 2010 the projected annual capacity of the Trans-Asian pipeline was upgraded to 60 BCM. Despite the fact that Turkmen export prices to China are lower and would be lower under replacement value principle compared to European prices, Chinese export route has its clear advantages for Central Asian exporters: China has provided to Turkmenistan financial resources for pipeline construction and its companies are ready to work onshore on the basis of service contracts (as requested by Turkmen Government in regard to onshore fields) rather than on the PSA principles (as preferred by Western companies from the US and the EU not only offshore, as allowed by Turkmen Government, but also onshore, where only service contracts are allowed).

A second priority for Turkmenistan might be Iranian route to the south of that country **(Route N 3)** – to Persian Gulf area and then to the international markets in the form of LNG. Two existing pipelines to the north of Iran will already export 6+8=14 BCM in 2010 with an agreement to increase this figure to 20 BCM. If swap deals are used, when Turkmen gas will feed up industrial and inhabited Iranian North, and Iran will free-up corresponding volumes in the South available for export, it might be legally and contractually the Turkmen – and not Iranian – gas that might be then exported worldwide from (future) Iranian LNG plants (in South Pars area). This might (possibly – but not for sure) enable to by-pass the anti-Iranian US and EU sanctions (and maybe even not to violate with corresponding UN sanctions ?) to the mutual benefit of both Turkmenistan and Iran. But also to the benefit of Russia as well, since according to this scenario neither Turkmen, nor Iranian gas will compete with Russian gas in the mature and competitive EU market – traditional and key export market for Russia. This route will compete for the second place in this hierarchy with existing routes to/through Russia.

Russian routes **(Route N 2)** proved by historical practice to be least risky access to mature EU market (due to Turkmen policy of on-border sales – costs and risks were laid on Gazprom) with highest (since 2009) export prices (due to transition to European pricing formulas, since 2010 – with quarterly review of price level). Unfortunate Russia-Turkmen episode of April 2009 (pipeline explosion) has radically downgraded import volumes of Turkmen gas by Russia. So now Russia (with 42 BCM of imported Turkmen gas in 2007-2008, but only with 9.5 BCM in 2009 against contracted 41 BCM for that year, and contracted 10.5 BCM for 2010, compared with projected increase of Turkmen gas supplies to 70 BCM since 2010, according to 25-year-long bilateral agreement on cooperation in gas sphere signed in 2003) needs to compete with Iran for the second place in this hierarchy.

4. Changing export priorities for Central-Asian gas: westward

Based on the above, since 2009/2010 **Route N 4** (different options enabling direct access of Turkmen gas to the EU market by-passing Russia) has lost its competitive advantage compared to Russian Route N 2. There are no longer additional economic/price stimuli for EU companies in Route N 4 since they have lost expected/foreseeable access to Hotelling rent of Central Asian gas. This rent has "returned" to exporting sovereign states of Central Asia (or: was returned to them by Russia who pays nowadays the net-back EU price for Central Asian gas) and EU companies and EU states would have no more possibility to monetize it at the EU market. Moreover, establishing of new relations in the region and developing new gas value chains will inevitably lead to increased transaction costs both for EU companies and host states.

It seems that the dominant EU/US gas policy in the region has been from the very start to bring Turkmen gas to the west bank of Caspian (either by constructing Trans-Caspian offshore pipeline, or using other alternatives, like by-passing Caspian from the south via Iran onshore – all these options considered as Route N 4 at Figures 3 & 4) to feed-up the Nabucco pipeline. But it seems to me that the prospects of direct incorporation of Turkmen gas into Nabucco project are rather questionable.

The Nabucco project has some competitive advantages, but they are very few at this moment. I consider that this pipeline project has currently the best available procedure among cross-border transit pipelines regarding access to its available capacity – the procedure that can be implemented both by the EU and non-EU contracting parties. It correlates both with the EU Directives and also with common economic and technological sense[10].

But there are still no shipping contracts and/or proved reserves committed to deliveries via Nabucco. Shipping contracts might appear early 2011 in result of "open season" procedure, but they need to be supported by the supply contracts of the producers developing gas fields. On the left bank of Caspian it is only Shah-Deniz-II, that possesses proved reserves that can be used for Nabucco, but, firstly, the Azeri Government (the party to Shah-Deniz PSA via SOCAR) did not express its dedication to supply its portion of the gas produced (tax gas) to Nabucco, and, secondly, there is strong competition between Nabucco and other projected gas pipelines in the area (ITGI, White Stream, etc.) for this projected 8 BCM of Shah-Deniz phase 2 production. We've heard recently about intentions to bring Iraqi gas reserves into Nabucco, but whether they correspond to above-mentioned conditions?

Other proved gas reserves of the sponsors of and potential shippers through the Nabucco pipeline are located on the right bank of the Caspian. This means that these reserves need to be delivered to the left bank of the Caspian Sea first. There are two major options how this can be done (see *Figure 6*): either by an offshore route via the Trans-Caspian gas pipeline or by an onshore route via Iran by-passing Caspian from the south. Both options can be technically solved. But there are significant practical, legal, economic and political barriers on the way of Central Asian gas to the west by-passing Russia to feed-up Nabucco.

Regarding the Trans-Caspian pipeline the major barrier is of a legal character – it is yet the unresolved problem of Caspian delimitation, in which case, according to my knowledge, the major problems are between Turkmenistan, Azerbaijan and Iran. Knowing that one of the major values for the EU is the "rule of law", it is very difficult for me to imagine that the EU will

[10] One of the reasons for this, from my view, is that it is based on the effective draft procedure, that both Russian and the EU experts has agreed upon in the course of preparation of the draft Energy Charter Protocol on Transit (this procedure is incorporated in this draft Protocol as new Art. 10-bis) during few years of their intensive informal bilateral expert consultations in Brussels in 2004-2007 (for more details on this, see, f.i.: A.Konoplyanik. Gas Transit in Eurasia: transit issues between Russia and the European Union and the role of the Energy Charter. – *"Journal of Energy and Natural Resources Law"*, vol. 27, #3, August 2009, p. 445-486). It is also based on the Model Agreements on the Cross-Border Transit Pipelines, developed by the Energy Charter Community and adopted (first edition) in 2007 (see: www.encharter.org).

support in practice the construction of the Trans-Caspian pipeline before all legal disputed questions regarding delimitation are solved.

Regarding the route via Iran the problem is two-fold: the key political barrier is historical US (and most recently UN, and additional to them further US and EU) sanctions on doing business with Iran, under which business deals equal to/exceeding 20 mln USD and corresponding companies would be penalized. The economic barrier on the way of Turkmen gas via Iran to Europe is a potential conflict of interests between the two countries (which problem does not exist, from my view, between Iran and Turkmenistan if the route of Turkmen gas via Iran to the Asian market is chosen). The EU market is mature and very competitive. Even after the end of recession, when it will grow again, it will provide tight competition, making it especially difficult for new entrants. In this regard if Turkmenistan would like to enter the EU market via Iran (direct access of Iranian gas to the EU market might also be prevented by the UN, US and EU sanctions), it will take away potential market share of Iran at this market which Iran would like to receive itself when the US & other sanctions would be finally lifted (which would be definitely in the economic interests of the EU). There were also concerns regarding Turkish transit (long-standing debate between Iran and Turkey on transit of Iranian gas), but as it was reported, on 25 April 2010 the parties has signed agreement which has finally solved this problem (it still need to be seen whether it would be really so).

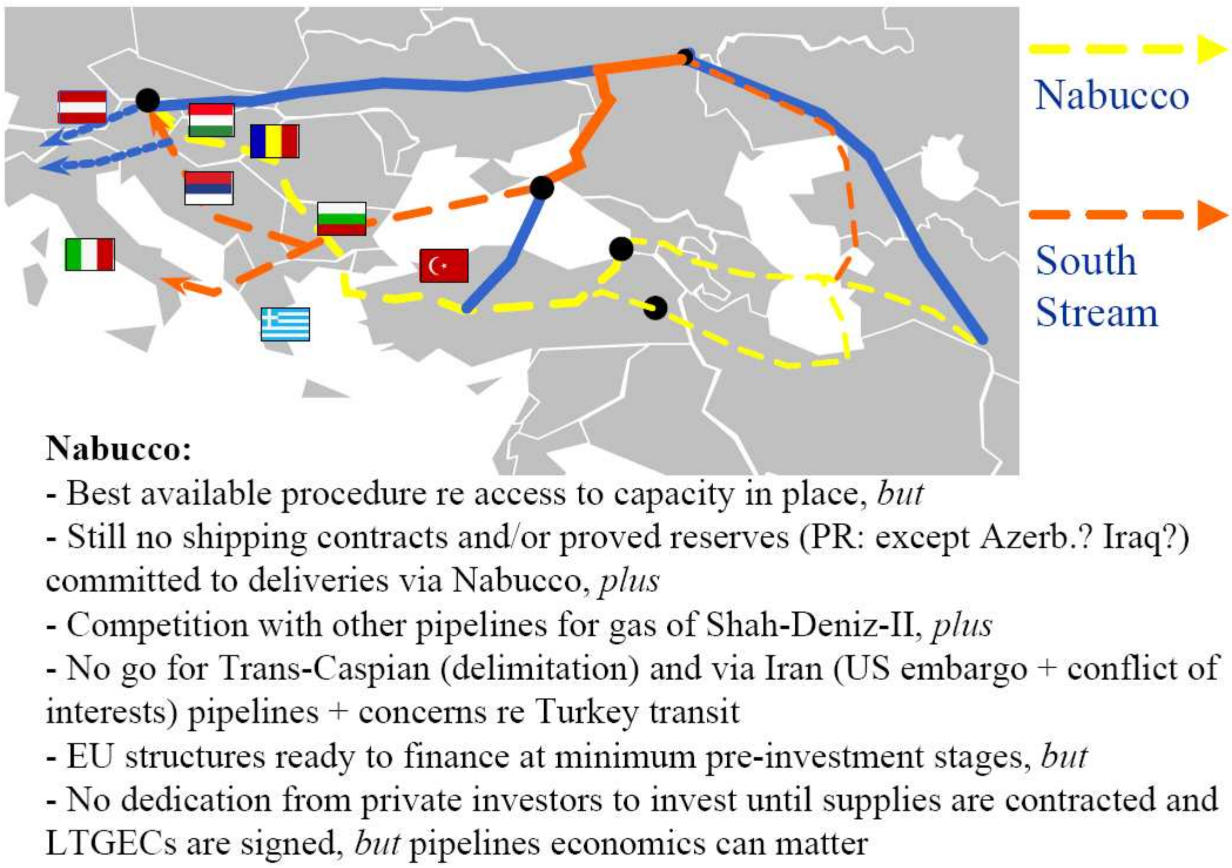

Figure 6. Turkmenistan, Nabucco and South Stream

There is still no clear picture regarding financing of Nabucco. If it is to be developed, it should be financed by project financing which means not by the money of the sponsors (shareholders of the project company), but that at least 70-80% of project investments should be raised at international capital markets. It is traditional practice in project financing that long-term shipping contracts need to be available (as well as long-term supply contracts with the shippers) as a precondition for receiving debt finance (as a security guaranteeing pay-back of the debt capital). EU structures are ready to finance at minimum pre-investment stages of project implementation, but there has been no dedication demonstrated yet from private investors to invest until supplies are contracted and LTGECs are signed. And it is quite clear for me, that international financial institutions, those that are under direct or indirect control of the EU structures (like EIB or EBRD), will not be ready to finance this project alone. When information has been appearing in the press about as if readiness of these financial institutions to present financing to Nabucco project of up to 4 bln USD, it has been rarely mentioned that precondition to open this financing is to provide the guarantees that the throughput capacity of the pipe is fully booked (which means based on “ship or pay” principle).

Of course, a pipeline’s economics can matter, at least in theory. The better is a pipeline’s economics, the lower are the transportation tariffs that provide reasonable rate of return for pipeline investors, and then it would be possible to pay a higher net-back price to Central Asian gas exporters at their external boundaries, calculated from end-user EU market, compared to alternative transportation routes. This might stimulate the exporters to contract their gas with the shippers of the Nabucco rather than with alternative shippers who will present lower net-back price destined for the EU market, if, for instance, transportation via Gazprom’s routes to the EU would be more costly than through Nabucco. And this is the argument of the Nabucco shareholders.

This sounds correct in theory. But, as was mentioned above, there are practical barriers on the way of Central Asian gas west-ward by-passing Russia. These barriers will not stay forever: the problem of Caspian delimitation will be solved, anti-Iranian US and other sanctions will be lifted, but for some time in the short-term and maybe medium-term perspective, when investment decisions on alternative pipelines should be taken by Central Asian states, these barriers will still be in place.

This leads me to the core question: whether in the meantime Central Asian gas would be destined for two markets only: for China and for Russia (both for domestic consumption in Russia and/or for its further delivery to CIS and/or to the EU through existing and/or new pipelines) plus with the opportunity to maneuver gas resources of the region between the two mentioned markets when the East-West Turkmen Interconnector will be built in 2015? It seems to me, that the positive answer need to be given to this question…