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Book

Investing in renewable energy in Azerbaijan : a valuation of three alternative investment scenarios

Investing in Renewable Energy in Azerbaijan: A Valuation of Three Alternative Investment Scenarios

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İntroduction

The government of Azerbaijan has expressed ambitious plans to ramp up the share of electricity generated from renewable and alternative energy. Currently, most electricity in Azerbaijan is produced from fossil fuels, including natural gas. Beyond being the source of almost all electricity produced in Azerbaijan, oil and gas exports form the backbone of the Azerbaijani economy–making it highly susceptible to price volatility in the global markets. Between 2018 and 2020, however, the government aims to increase its capacity for generating electricity from wind, solar and biomass by 420 MegaWatt.[1] Because of the central place that energy takes in Azerbaijan's economy such a change in the country's energy portfolio calls for careful evaluation. Furthermore, the investment comes at a time when Azerbaijan faces significant natural gas export commitments it has made to both Turkey and the European Union. In the case of the latter Azerbaijan has pledged and already made substantial financial contributions to the development of the Southern Gas Corridor which would connect, in part, the European market and the gas reserves in the Caspian Sea. From the European perspective, this project would allow many European countries, especially those in Central and South East Europe, to diversify their gas import sources. Besides a general interest countries should have in diversifying their energy sources in order to mitigate risks of supply shortages, the particular significance of such diversification in this case becomes evident when considering that most of these countries currently rely on Russian gas imports and that relations between the EU and Russia have been deteriorating since Russia's activity in the Crimea. From Azerbaijan's perspective, a successful fulfilment of the export commitments made to the EU may boost its position as a reliable trading partner to the EU. A resulting strengthening of its economic ties to the EU may further contribute to the balanced foreign policy that Azerbaijan has traditionally sought to follow. Thus, a closer look at the investment illuminates the important role occupied by the possibility of increased gas exports, as enabled by increasing the capacity for electricity production form renewable energy sources. In addition, Azerbaijan may function as a role model to other fossil fuel rich states who thereby have the opportunity to mitigate their costs for increasing the share of renewable energy in their domestic energy mix through increased fossil fuel exports. Installing the aforementioned 420 MegaWatt capacity requires an investment of 1,153.4

[1] AREA, 2018.

million AZN. A valuation of this investment shows that its internal rate of return is very low, standing at approximately 1.1%, making it unprofitable as soon as we apply an appropriate discount rate. In contrast, if the investment is coupled with continued production of the natural gas previously used for producing electricity and this gas is exported to Turkey, the project's internal rate of return is elevated to approximately 9.4%, making it robustly profitable, i.e. profitable for a range of appropriate discount rates. Exporting the gas to the EU, rather than Turkey, would also mitigate the costs of the investment in renewable energy, but not to such a degree that would make the investment economically advisable. Evidently, though, such economic considerations may be overridden by other considerations, including a political interest in successful cooperation with the European Union. In section one, we present our results and methodology, how we calculated the net present values and internal rates of return for the different investment scenarios and what data we used in these calculations. Subsequently, in section two, we discuss these results.

Literature Review

The central aim of this paper is to provide a valuation of the investment in renewable energy and illuminate the extent to which gas exports may mitigate the investment's costs. Evidently, there exists an abundance of renewable energy investment valuations, as well as discussions of different approaches to such valuations.[2] However, it is difficult to find such valuations that directly incorporate cash flows resulting from fossil fuel exports enabled by the investment in renewable energy itself. Instead, it may be insightful to compare Azerbaijan's approach to renewable energy, as assessed in the present paper, with those pursued by other fossil fuel rich countries. Choucri, et. al., for instance, provide an analysis of the United Arab Emirates' decision to increase their renewable energy investments.[3] Another case worth looking at is that of Norway, which has been using funds previously generated from oil exports to finance investments in renewable energy.[4] Beyond the

[2] see, for instance, Hürlimann, 2018.
[3] Choucri, et. al., 2010.
[4] see, for instance, Milne, 2018.

investment valuation focus of this paper, Vidadili et. al. provide a comprehensive overview of the developments around renewable energy in Azerbaijan.[5] Simon Pirani has provided insightful analyses of the Southern Gas Corridor's relevance for Azerbaijan.[6]

Section I: Results and Methodology

We analyse the investment at hand from three different perspectives. First, we consider only those cashflows immediately connected with the planned investment in increasing the capacity for renewable energy generation by 420 MW and calculate two net present values using discount rates of five and 9.25 percent as well as the internal rate of return. The investment's internal rate of return stands at approximately 1.1%. The net present value using a five percent discount rate is -AZN308,959,410.75. The net present value using a ten percent discount rate is -AZN481,509,306.17.

Second, we assume that Azerbaijan continues to produce the amount of amount of natural gas that may be regarded as 'substituted' with renewable energy sources and exports it to Turkey instead of using it for generating electricity. Incorporating the relevant costs and revenues (gas production, transport and sale) into our calculations yields a net present value of AZN434,974,588.07 using a discount rate of five percent and a net present value of AZN11,578,901.91 using a discount rate of 9.25 percent. The internal rate of return is approximately 9.4%.

Third, we repeat the above calculation under the assumption that the gas is exported to the EU (Greece), rather than Turkey. The net present values are -AZN178,971,549 and -AZN401,188,454.60 for discount rates of 5% and 9.25% respectively. For this scenario, the internal rate of return stands at approximately 2.9%. As we can easily observe only two net present values turn out positive, namely those for increasing renewable energy generation and exporting the gas thereby 'saved' to Turkey with assumed discount rates of 5% and 9.25%. That investment is also the only one with an internal rate of return (9.4%) that may render it economically advisable. We will discuss these result in more detail in section II.

[5] Vidadili, et. al., 2017.
[6] Pirani, 2016, and Pirani, 2018.

By choosing to complement the first investment scenario, investing in energy generation from renewable sources, with the export of the natural gas thus 'saved' we attempt to accommodate a central government perspective on this investment. On one account the revenues from these exports are viewed as mitigating the costs of the investment, or as increasing its profitability.[7] On a different account, as voiced for instance by Akim Badalov, former Chairman of the recently dissolved State Agency on Alternative and Renewable Energy Sources, one of the main objectives [of the investment] is […] increasing oil and gas products export capacities by saving hydrocarbon resources as much as possible".[8] From the former angle, exporting the gas no longer required for producing electricity is instrumental to the profitability of the investment in renewable energy, which thus takes normative priority. From the latter angle, an increase in renewable energy is justified on the basis that it enables increased revenues from exporting natural gas–thus, exports take argumentative priority. Our evaluation may be seen as an attempt at quantifying the former perspective, rather than the latter. We will address these alternative accounts again in the discussion of our results.

We choose to calculate two net present values with discount rates of 5% and 9.25% for each investment scenario because there exists disagreement on how to arrive at an appropriate discount rate for public investments. The European Commission recommends a benchmark discount rate of 5% for evaluating public investments.[9] This rate is relatively low, primarily representing low risk or risk-free alternative investments. In addition, a low discount rate may be seen as taking into account the social nature of public investments and the idea that it would be inappropriate to assess investments in public goods against profit maximising investment alternatives open to actors like commercial banks and private corporations. Still, we offer another calculation using the Central Bank of Azerbaijan's discount rate of 9.25%.[10] In light of the above-mentioned disagreement, we suggest focussing on the internal rate of return. As the internal rate of return expresses that discount rate which would yield a net present value of zero for the investment in question, the reader may simply compare the discount rate they deem appropriate with the individual internal rates of return provided.

For all individual investment analyses we choose a time frame of 20 years, starting with the first year in which initial investment is made (2018). Therefore, in each calculation we consider the relevant annual cash flows

[7] ibid.
[8] ibid.
[9] European Commission, 2008.
[10] Israfilbayova, 2019.

between 2018 and 2037. By choosing a time frame of twenty years we attempt to reconcile the fact that the longevity of the power plants in question (25-30 years) would suggest choosing a greater time frame and the fact that the decrease of gas price projections' reliability with time may suggest opting for a smaller time frame. Even though the latter consideration would not need to affect our assessment of the first scenario, i.e. increasing renewable energy generation while disregarding the possibility of exporting the gas thus 'saved', we apply the same time frame in evaluating that investment in order to generate comparable values.

Scenario 1:

We will now proceed to present the cash flows for the above-mentioned first investment scenario. Each annual cash flow comprises two values on the costs side and one value on the revenue side. In terms of costs we consider the initial investments, i.e. the resources invested in the establishment of the power plants, and the annual operation and maintenance costs for these plants. On the revenue side we consider the annual revenue generated from the sale of the electricity thereby produced. Beginning with the cost side, in 2018, while there are no operation and maintenance (hereafter o&m) costs and no revenues from selling electricity, AZN434.1 million are invested in the construction of the power plants. This results in a cash flow of -AZN434.1 million for 2018. In the following year, 2019, AZN513 million are invested in the construction of plants, AZN1,737,897.19 are taken to be needed in order to cover o&m costs for producing electricity, and selling this electricity is assumed to yield a revenue of AZN14,617,461.60. The total cash flow for 2019 is thus -AZN48,720,392.62. While the data on annual construction investments are provided by the government, we need to make a few assumptions and calculations in order to arrive at the o&m costs and revenues from selling the electricity for 2019. First, we assume that any plant for which the construction investment is made in full in year x will begin producing electricity in the year that follows (x+1) and that this electricity will also be sold in year x+1. Furthermore, we assume that the individual plants will produce electricity at a constant rate across x+1, x+2, etc. In 2018, the construction investments are fully made for nine solar energy plants and one wind energy plant. Therefore, we assume that these plants will produce electricity throughout 2019, incurring o&m costs and yielding sales revenues.

In order to calculate the operation and maintenance costs for 2019 we need to use results of our calculations of the 2019 revenues from electricity sales. We will thus begin the presentation of our calculations with the revenues from electricity sales. We arrive at these revenues by multiplying the domestic tariffs for selling electricity to consumers, set by the Azerbaijani tariffs council, with the volume of electricity produced in 2019. However, the government only provides data on the annual average electricity production by all 23 power plants taken together. This total annual output amounts to 1,192,500 megawatt-hours. In order to arrive at the electricity production volume of those nine solar power plants and the one wind power plants that are assumed to already produce electricity in 2019, we need to calculate how the overall output of 1,192,500 megawatt-hours is distributed over the individual power plants. These individual power plants have different energy production capacities. A given power plant's capacity denotes the rate at which that power plant generates energy. For instance, if we run a power plant with a capacity of 1 megawatt for one hour, then this power plant will generate energy at a rate of 1 megawatt for a period of one hour. The resulting amount of energy produced is 1 megawatt hour, or 1mWh. In analogy, if we drive a car at 1 km/h for one hour, then the distance the car will have gone after this hour is one kilometre. Here, 1 km/h is our ratio, similar to 1 megawatt, and 1 km is our distance or amount, similar to one megawatt hour. Thus, if we consider the 420 MW capacity to be installed through the investment at hand, we know all power plants together would generate 420 mWh if they were to run for one hour. Multiplying this value by (24*365) yields an output of 3,679,200 mWh, or 3,679.2 million kWh–their total energy output if they ran for one year. However, power plants generally do not generate energy at such full 'nameplate' capacity. Their output may be curtailed by maintenance or shortage of fuel supply. Wind and solar power plants' energy output, for instance, will be limited by the availability of wind and sunshine. However, if we divide a given power plant's actual energy output for a given time (e.g. year) by its output at full nameplate capacity for the same time, we receive that plant's capacity factor. Different kinds of power plants generally have different capacity factors. Nuclear power plants, for example, generally have a much greater capacity factor (averaging at around 92.2% for U.S. nuclear power plants in 2017) than wind power plants (averaging at 34.6% for U.S. wind power plants in 2017).[11] In accordance with the formula mentioned above, we can calculate that the power plants covered by the investment we are evaluating have an average capacity factor of approximately 32.4% as 1,192.500 mWh divided by 3,679,200mWh equals approximately 0.324. Now, we are looking for the individual power plants' capacity factors in order to calculate the

[11] EIA, 2019.

electricity output of the nine solar power plants and the one wind power plant that already produce electricity in 2019. The government provides the individual nameplate capacities of all 23 power plants that are to built. The 420 megawatt generation capacity distribute over the different kinds of power plants as follows: 350 megawatt for wind energy, 20 megawatt for biomass, and 50 megawatt for solar power.[12] In order to simplify our calculations, we now calculate the average capacity factors of these different kinds of power plants, rather than the capacity factors of each individual plant. In order to do so, we express the power plants' average capacity factor of 32.4% as a weighted average in the following fashion: $(350w+20b+50s)/420=0.324$, where w denotes the average capacity factor of the wind power plants, b denotes the average capacity factor of the biomass power plants, and s denotes the average capacity factor of the solar power plants. The Balakhani waste-to-energy plant that already exists in Azerbaijan has a nameplate capacity of 37 megawatt and an actually energy output of 231.5 million kilowatt-hours per year.[13] This results in a capacity factor of approximately 71.4%, as 231,500/(365*24*37)=approx. 0.714. We assume this to roughly equal the average capacity of the biomass power plants to be built and substitute 0.7 for b. If we assume an average capacity factor of 15% for the solar power plants and insert 0.15 for s, we receive an average capacity factor of 33% for the wind power plants. We have chosen 15% for the solar power plants as it is both sufficiently independently plausible, if compared with other countries' solar power plants' capacity factors, and yields a sufficiently plausible average capacity factor for the wind power plants.

We then use the average capacity factors for wind and solar power plants to calculate the amount of electricity produced by the nine solar power plants and the one wind power plant that already operate in 2019. The wind power plant has a total capacity of 56.1 megawatt. Thus, its electricity output in kilowatt-hours for 2019 is calculated to equal 0.33*56,100*365*24, which equals 162,173,880. The nine solar power plants have a total capacity 35.5 megawatt. Their total electricity output for 2019 in kilowatt-hours is thus calculated to be 46,647,000 (=0.15*35,500*365*24). Together, these ten plants produce 208,820,880 kilowatt-hours of electricity in 2019. The tariff for selling electricity to consumers in Azerbaijan is AZN0.07 per kilowatt-hour.[14]

[12] AREA, 2018.
[13] ibid.
[14] Tariff Council of Azerbaijan Republic. This consumer retail tariff is higher than the wholesale tariff. We simply assume that all electricity is sold to consumers.

Therefore, the revenues from selling electricity in 2019 amount to AZN14,617,461.60 (=208,820,880*AZN0.07).

Next, we will present our calculations for the 2019 operation and maintenance costs for these ten plants. Again, the government provides only the total average annual operation and maintenance costs of all power plants taken together, which stand at AZN10,400,000. In order to calculate the o&m costs incurred in 2019, we thus turn to data on average o&m costs in the United States. According to the EIA, utility scale solar energy plants have no annual variable o&m costs but annual fixed o&m costs of AZN38.24 per kilowatt capacity.[15] Wind power plants are stated to have no variable o&m costs but annual fixed o&m costs of AZN82.44 per kilowatt capacity.[16] For biomass power plants the EIA suggests variable o&m costs of AZN9.70 per megawatt-hour of energy produced and annual fixed costs of AZN194.75 per kilowatt capacity.[17] We can use this data to make assumptions about how the average annual o&m costs provided by the government distribute over the different power plants. First, we calculate the total average annual o&m costs for all electricity plants using the U.S. data. As mentioned above, the overall capacity distributes over the plants as follows: 350 megawatt wind, 50 megawatt solar, and 20 megawatt bio. The annual fixed costs thus equal (350,000*AZN82.44+50,000*AZN38.24+20,000*AZN194.75), which equals AZN34,661,000. We can use the average capacity factor for the biomass power plants calculated above to calculate their annual electricity output and, thus, their variable operation and maintenance costs: 20*365*24*0.7*AZN9.7=AZN1,189,608. The sum of these variable and the above fixed costs equals AZN35,850,608. Dividing the average annual o&m costs given by the government (AZN10,400,000) by the annual o&m costs calculated using U.S. value (AZN35,850,608) yields a quotient of approximately 0.29. We then make the following assumption: (annual operation costs using U.S. data)*(0.29)=(annual operation costs for Azerbaijan). Roughly speaking, this assumption expresses that the operation and maintenance costs of a given power plant in Azerbaijan are approximately a third of those for a power plant with the same capacity or output in the United States. Assuming that material costs would be roughly the same in Azerbaijan and the United States, or that maybe they would even

[15] EIA, 2019. We assume the planned solar energy plants to be photovoltaic plants, and thus use the U.S. data for these plants rather than for thermal solar energy plants. For this and all subsequent U.S. Dollar to AZN conversions we have taken an exchange rate of $1=AZN1.70.
[16] ibid.
[17] ibid.

be slightly lower in the United States as they might produce a larger share of material domestically, this assumption is justifiable if the operation and maintenance costs in Azerbaijan excluding material costs, i.e. labour costs, taxes, etc., are lower than a third of those in the United States. How much lower they would need to be would depend on the respective ratios of material costs to other costs. Furthermore, the assumption is applied across solar, wind and biomass power plants. This implies that the ratios of material to other costs are the same for these different kinds of power plants. We will not address these implications further. Under this assumption, we can calculate the operation and maintenance costs of the nine solar power plants and the one wind power plant for 2019 as follows: (56,100*AZN82.44+35,500*AZN38.24)*(0.29)=AZN1,734,897.16. As previously stated, 56,100 is the capacity in kilowatt of the wind power plant and 35,500 is the capacity in kilowatt of the nine solar power plants.

We have now presented the calculations behind the revenues from selling electricity produced and operation and maintenance costs for the operational power plants for 2019. Computing the resulting values with that year's investment in installing power plants, we receive the following cash flow for 2019 of -AZN500,117,435.56. In 2020, the investment in installing power plants amounts to AZN206.300.000. Following the investment in 2019, the power plants operating in 2020 have a total capacity of 185.1 megawatt (133.1 megawatt wind, 50 megawatt solar and 2 megawatt biomass). Following the methodology presented above, the operation and maintenance costs for these power plants are calculated to be AZN3,884,035.19 and together they produce 462,729,480 kilowatt-hours of electricity (384,765,480 kilowatt-hours wind, 65,700,000 kilowatt-hours solar and 12,264,000 kilowatt-hours biomass), yielding a sales revenue of AZN32,391,063.60. These values yield a cash flow for 2020 of -AZN177,792,971.59. In 2021 no more investments in installing additional capacity are made, the total 420 megawatt capacity are operational, producing 1,192,500 megawatt-hours of electricity, yielding a sales revenue of AZN83,475,000. As mentioned earlier, the operation and maintenance costs of AZN10,400,000 for 2021 are provided by government. This yields a cash flow for 2021 of AZN73,075,000. Because we assume that both the retail price and the annual operation and maintenance costs will remain constant throughout the remainder of the period of analysis, all following annual cash flows equal that for 2021.

Scenario 2:

As mentioned earlier, in this scenario we consider not only the cash flows associated with installing new renewable energy plans, as set out above, but also those connected with exporting the natural gas no longer needed for producing the electricity that is instead generated by the new renewable power plants. Thus, each annual cash flow in this scenario will comprise the cash flows presented above and the costs of producing and transporting the gas and the revenues from selling it to Turkey. For 2018, the latter cash flow equals zero as no electricity is yet produced by the renewable power plants and thus no gas is available for export. The total cash flow for 2018 is therefore -AZN434,100,000.

According to the government, the annual volume of natural gas 'saved' once all renewable power plants are operating and producing an annual output of 1,192,500 megawatt-hours is 303.3 million cubic meters.[18] Thus, we would save approximately 0.254 cubic meters of natural gas per kilowatt-hour of electricity produced from renewable energy sources. As previously calculated for scenario one, the power plants that already operate in 2019 will generate 208,820,880 kilowatt-hours of electricity. In effect, in 2019 there will be an additional 53,040,503.52 cubic meters of gas available for export.[19] We assume that the production of 1000 cubic meters of natural gas costs AZN62.19.[20] Hence, the production costs of the gas to be exported instead of being used for electricity production in 2019 amount to AZN3,298,588.91.

Exact data on the costs for transporting the gas from Azerbaijan to Turkey are difficult, if not impossible, to obtain. Next to pipeline operation and maintenance costs, these comprise 'fees' that Azerbaijan must pay to Georgia as natural gas exported to Turkey will move through the South Caucasus Pipeline which crosses Georgia. In lieu of monetary fees Georgia will generally receive part of the gas transported from Azerbaijan to Turkey. For these costs we thus rely on the assumption that Azerbaijan will bear all and only the transportation costs until the gas reaches Turkey. According to one estimation these costs stand at $50 per 1000 cubic meters.[21] Thus, for 2019, we assume that transporting the 53,040,503.52 cubic meters produced to Turkey will cost AZN8,416,997.50.

[18] AREA, 2018.
[19] (0.254 cubic meters)* 208,820,880= 53,040,503.52 cubic meters.
[20] Abasova, 2018.
[21] Pirani, 2016.

We are equally unable to obtain reliable data on the prices at which Azerbaijan sells gas to Turkey. The underlying agreements are not published by the government. We thus simply assume that the gas will be sold to Turkey at the European market price. We also assume that the gas be exported without any lag, i.e. gas saved in 2019 will be exported in 2019. The European market price for natural gas for 2019 is projected to be $7.50 per mmbtu. One mmbtu equals 0.0353 cubic meters. Thus, the export of the natural gas to Turkey in 2019 is assumed to yield a return of AZN24,012,629.35 (=AZN12.825*0.0353*53,040,503.52). The 2019 cash flow associated with the export and sale of gas 'saved' therefore amounts to AZN12,297,042.94. As the 2019 cash flow on the renewable energy side (see scenario 1) is -AZN500,117,435.56, the total cash flow for 2019 is -AZN487,820,392.62.

In accordance with the above methodology we calculate the volume of gas 'saved' in 2020 to be 117,533,287.92 cubic meters (=0.254 cubic meters*462,729,480[kilowatt-hours produced from renewable energy sources]). Producing this amount of natural gas will incur costs of AZN7,309,395.18 (=(117,533,287.92/1000)*AZN62.19). Transporting it to Turkey will cost AZN18,651,357.46. The European market gas price for 2020 is projected to be 7$ per mmbtu and the sale revenues are thus calculated to be AZN49,662,633.01 (=AZN11.97*0.0353*117,533,287.92). These values yield a 2020 cash flow of AZN23,701,880.37 on the gas side. The 2020 cash flow on the renewable energy side is, as previously mentioned, -AZN177,792,971.59. Together, these put the total 2020 cash flow at -AZN154,091,091.22.

In 2021, the volume of saved gas stands at 303.3 million cubic meters, giving rise to production costs of AZN18,862,227, transport costs of AZN48,130,677, and revenues from sales to Turkey of AZN129,804,414.11, assuming a projected gas price of $7.09 per mmbtu. The natural gas export cash flow for 2021 is thus AZN62,811,510.11. The 2021 renewable energy cashflow (see above) is AZN73,075,000. That year's total cash flow stands at AZN135,886,510.11.

For the remaining years of the valuation period the production and transport costs will equal those for 2021, as 2021 is the first year for which we assume all power plants to be operating. The annual sales revenues will depend on the following price projections in U.S. Dollars per mmbtu: 2019: 7.5; 2020: 7; 2021: 7.09; 2022: 7.19; 2023: 7.29; 2024: 7.38; 2025: 7.48.[22] The next available projection is 2030: 8. For the period in between

[22] Comstat.

we assume a constant increase: 2026: 7.58; 2027: 7.68; 2028: 7.78; 2029: 7.88. Beyond 2030 we assume a constant price of $8 per mmbtu. We assume a constant U.S. Dollar / AZN exchange rate. For each year we thus compute these projected prices with the gas production volume of 303.3 million cubic meters and receive the following values for the annual sales revenues: 2022: AZN131,635,223.90; 2023: AZN133,466,033.69; 2024: AZN135,113,762.50; 2025: AZN136,944,572.29; 2026: AZN138,775,382.08; 2027: AZN140,606,191.87; 2028: AZN142,437,001.66; 2029: AZN144,267,811.45; 2030: AZN146,464,783.20; 2031: AZN146,464,783.20; 2032: AZN146,464,783.20; 2033: AZN146,464,783.20; 2034: AZN146,464,783.20; 2035: AZN146,464,783.20; 2036: AZN146,464,783.20; 2037: AZN146,464,783.20. As mentioned above the annual cash flows on the renewable energy side following 2021 will equal that years cash flow of AZN73,075,000. The annual cash flows on the gas side and the annual total cash flows are as follows: 2022: gas=AZN64,642,319.90, total=AZN137,717,319.9; 2023: gas=AZN66,473,129.69, total=AZN139,548,129.69; 2024: gas=AZN68,120,858.50, total=14,119,548,129.69AZN; 2025: gas=69,951,668.29, total=AZN143,026,668.29; 2026: gas=AZN71,782,478.08, total=AZN144,857,478.08; 2027: gas=AZN73,613,287.87, total=AZN146,688,287.87; 2028: gas=AZN75,444,097.66, total=AZN148,519,097.66; 2029: gas=AZN77,274,907.45, total=AZN150,349,907.45; 2030: gas=AZN79,471,879.2, total=AZN152,546,879.20; 2031: gas=AZN79,471,879.2, total=AZN152,546,879.20; 2032: gas=AZN79,471,879.2, total=AZN152,546,879.20; 2033: gas=AZN79,471,879.2, total=AZN152,546,879.20; 2034: gas=AZN79,471,879.2, total=AZN152,546,879.20; 2035: gas=AZN79,471,879.2, total=AZN152,546,879.20; 2036: gas=AZN79,471,879.2, total=AZN152,546,879.20; 2037: gas=AZN79,471,879.2, total=AZN152,546,879.20.

Scenario 3:

For this third investment scenario we consider the effects of exporting the gas ‘saved’ to the EU, rather than Turkey. We assume that the gas will be sold at the same European gas market prices used in scenario two. In fact, the only values in this calculation that vary from those used in the above scenario two are those regarding transport costs. When exporting the gas to Europe, it must, in addition to Georgia, also cross Turkey in order to reach Greece. Again, we assume that Azerbaijan bears all and only the transportation costs until the gas reaches the country to which it is exported. Thus, to the costs for transporting the gas through the South Caucasus Pipeline ($50) add the costs for transporting the gas through Turkey, using the Trans Anatolian Pipeline. These are estimated to be $103.[23] The total transportation costs are thus three more than times those as for exporting the gas to Turkey. The annual costs for transporting the gas to the EU are thus estimated to be as follows: 2019: AZN15,662,330.28; 2020: AZN42,015,799.77; 2021: AZN108,423,684. As full energy output is reached in 2021 and the saved gas thus remains constant post 2021, the transport costs are taken to remain at AZN108,423,684 per year following 2021. The annual cash flows on the gas side and the total annual cash flows are thus as follows: 2018: gas=AZN0, total=(-AZN434,100,000); 2019: gas=AZN5,051,710.16, total=(-AZN495,065,725.40); 2020: gas=AZN337,438.06, total=(-AZN177,455,533.53); 2021: gas=2,518,503.11, total=AZN75,593,503.11; 2022: gas=AZN4,349,312.90, total=AZN77,424,312.90; 2023: gas=AZN6,180,122.69, total=AZN79,255,122.69; 2024: gas=AZN7,827,851.50, total=AZN80,902,851.50; 2025: gas=AZN9,658,661.29, total=AZN82,733,661.29; 2026: gas=AZN11,489,471.08, total=AZN84,564,471.08; 2027: gas=AZN13,320,280.87, total=AZN86,395,280.87; 2028: gas=AZN15,151,090.66, total=AZN88,226,090.66; 2029: gas=AZN16,981,900.45, total=AZN90,056,900.45; 2030: gas=AZN19,178,872.20, total=AZN92,253,872.20; 2031: gas=AZN19,178,872.20, total=AZN92,253,872.20; 2032: gas=AZN19,178,872.20, total=AZN92,253,872.20; 2033: gas=AZN19,178,872.20, total=AZN92,253,872.20; 2034: gas=AZN19,178,872.20, total=AZN92,253,872.20; 2035: gas=AZN19,178,872.20, total=AZN92,253,872.20; 2036: gas=AZN19,178,872.20, total=AZN92,253,872.20; 2037: gas=AZN19,178,872.20, total=AZN92,253,872.20.

Section II: Discussion

Continuing the production of that gas which is substituted by renewable energy sources and exporting it to Turkey strongly mitigates the costs of the investment in renewable energy generation proposed by the Azerbaijani government and raises the investment's internal rate of return from 1.1% to 9.4%. This means that if the government opts for this investment scenario, the project becomes slightly profitable when we apply the relatively high discount rate of 9.25% used by the Central Bank. Taking into consideration the investment's

[23] Pirani, 2016.

social and public nature and applying a lower discount rate of 5% makes that investment scenario very justifiable by raising its net present value above AZN400,000,000. In contrast, higher transportation costs mean that exporting the gas to the EU, rather than Turkey, lowers the investment's internal rate of return to 2.9%. While the fact that this value exceeds the 1.1% internal rate of return for investment scenario one means that exporting to the EU is preferable over discontinuing the gas production and investing solely in renewable energy, the low internal rate of 2.9% still renders the economic justifiability of this investment scenario questionable. Therefore, investment scenario two is not only to be preferred over scenarios one and three, but it appears to be the only economically advisable investment within the analysed set of alternative investments.

Importantly, the economic viewpoint from which we evaluate these different scenarios constitutes only one relevant perspective. Evidently, any of the suggested investments are advisable from a perspective concerned with contributing to the mitigation of climate change. Furthermore, there might be political considerations that can override the presented economic or financial arguments. For instance, over the course of its contribution to the construction of the Southern Gas Corridor connecting it to Europe, Azerbaijan has voiced certain commitments to supply natural gas to the EU. Being viewed as a reliable trading partner by the European Union may outweigh the Azerbaijani government's concerns with increasing the profitability of the investment. Such considerations are beyond the focus and scope of this paper. We are therefore unable to provide a comprehensive and compelling recommendation. However, the present valuation of the different possible investment scenarios illuminates one of the central parameters that should affect any comprehensive evaluation of the proposed investment in renewable energy.

Next, we wish to clarify the particular perspective from which we assessed the investment at hand and how we relate the gas exports to the investment in renewable energy. As alluded to in the previous section, the government's suggestion to couple the investment in renewable energy with exporting the thus available natural gas allows for two alternative interpretations. First, the investment in renewable energy takes priority and continuing the production of the substituted gas and exporting it constitutes a condition under which this investment is profitable or economically advisable. This is the framework within which we conduct the present evaluation. Alternatively, we might assign priority to increasing gas exports. In that case, one would frame the investment as an investment in increased gas exports and the investment in renewable energy and the consequent liberation of natural gas would constitute a possible answer to the question under which conditions the investment in increased gas exports would be profitable or economically advisable. However, from this perspective our assessment allows only for limited range of conclusions. It does allow us to claim that enabling increased exports of natural gas through increasing the generation of renewable energy and reduction of domestic gas consumption would be profitable if the gas is exported to Turkey. However, this does not imply that it is also economically advisable. In order to make this latter claim, we would need to evaluate alternative investment scenarios for increasing gas exports and compare them with the results presented above. For instance, we could, instead of reducing domestic gas consumption, increase the production of natural gas by the same amount as would be made available by increased renewable energy generation at constant domestic electricity consumption. The net present value of such an investment would at least need to be lower than that calculated for releasing gas through increasing renewable energy generation. Assuming that, excluding the investment in installing the additional capacity for renewable energy generation, the costs of producing electricity using renewable energy sources and the costs of producing electricity using natural gas will be relatively similar and the electricity would be sold at the same price, a lower net present value for producing more gas in order to increase exports would imply that this would require investments larger than 1,153.4 million AZN, i.e. the costs of installing the additional capacity for generating renewable energy. We are unable to provide any information on whether this is the case. Alternatively, the profitability of the investment in making natural gas available through increasing the generation of renewable energy would imply its economic advisability if other investment scenarios were not available. Thus, if there exist any insurmountable constraints in regards to increasing the production of natural gas, such as technological limitations, then we could conclude that it would be economically advisable to invest in increasing the generation of renewable energy to enable increased gas exports. Again, we are unable to provide any information on this.

Section III: Conclusion

In conclusion, continuing the production of the gas substituted with renewable energy sources and exporting it to Turkey or exporting it to the EU will mitigate the costs of the proposed investment in renewable energy. However, only exporting the gas to Turkey mitigates these costs to such an extent that the investment becomes robustly profitable, i.e. profitable for a range of appropriate discount rates. At the same time, should the government of Azerbaijan intend to use the liberated gas resources for bolstering the resources for its prospective exports to the European Union, then this may point to the considerable (geo-)political significance that a successful fulfilment of its export commitments has to the Azerbaijani government. This significance may be accounted for by both its traditional ambition to pursue a balanced foreign policy and, relatedly, the governments wish to cement its position as a reliable trading partner to the European Union.

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