Business Strategy Outline
AG-Cycle integration into power production in the US

A. **Economic Benefits.**

AG-Cycle, when integrated into fossil fuels-fired (steam) power plants running on residual fuel oil, shale-oil, natural gas, coal provides direct and secondary economic benefits.

A.1. Direct Economic Benefits are:

- 60% reduction in specific fuel consumption, meaning a lower amount of the fuel required to produce 1 MWh of electricity;

- creation of carbon credits in countries with a carbon credits trading system, such as European Union countries;

- reduced maintenance costs for boilers in coal-fired power plants due to the presence of reducing agents in the flame, resulting in cost savings related to slag removal and disposal;

- further reduction in specific fuel costs due to utilization of cheaper, high vapor content fuels.

A.2. Secondary Economic Benefits are Plentiful and Case Specific, May Comprise the Following:

- extension of the life-cycle of a coal-fired power plants by 10 – 25 years. These plants which were scheduled for decommissioning, can continue operating due to reduced CO_2 and other harmful emissions after integrating AG-Cycle;

- conversion of coal-fired power plants to natural gas-fired (steam) power plants offering multiple environmental benefits. This conversion leads to a four-fold reduction in specific CO_2 emission (i.e. per 1 MWh of electricity) without increase in specific fuel costs;

- substantial increase in the capacity factor[1] of residual fuel oil-fired power plants due to lower specific fuel costs, allowing these plants to operate more efficiently and for longer periods;

- real-time flexibility to switch between liquid and gaseous hydrocarbons for power, heat, and steam production, thanks to the duo-fuel nature of AG-Burner.

Overall, the integration of AG-Cycle brings about direct economic benefits, such as reduced fuel consumption and maintenance costs, as well as secondary economic benefits, including extended plant life, environmental improvements, increased capacity factor, and fuel flexibility.

B. **Factors Affecting AG-Cycle Introduction Strategy:**

B.1. Power Generation Fuel Cost (dollars per million BTU, MMBTU):

This refers to the cost of one million British Thermal Units (MMBTU) of fuel[2]. Higher fuel costs result in higher specific fuel costs for power production. Therefore, integrating the AG-Cycle into power plants with fuels that have higher specific fuel costs will yield greater reductions in fuel consumption costs. For example, the anticipated average specific fuel costs for 2023 are $25.4 per 1 MWh for coal power, $34.1 for natural gas-fired power, and $162.8 for residual fuel oil-fired power (**Annex 1**).

B.2. Price of Carbon Credits:

Some countries and associations have implemented carbon credit trading systems to incentivize the reduction of CO2 emissions, including in the power production sector. For instance, the European Union established the EU Emissions Trading System (EU ETS)[3]. The production of 1 MWh of electricity from a coal-fired power plant emits approximately 1 ton of CO2, equivalent to one carbon credit. Therefore, when assessing specific fuel-associated costs in power production in EU countries, the specific coal cost needs to be supplemented with a carbon credit cost of at least 80 Euros per 1 MWh. (**Annex 2**).

[1] the ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous full power operation during the same period
[2] one MMBTU is equivalent to around 293 kWh of thermal energy (heat)
[3] https://climate.ec.europa.eu/eu-action/eu-emissions-trading-system-eu-ets_en

B.3. Electrical Efficiency of Power Plants:

This refers to the percentage of a fuel's low heating/calorific value (LHV) that is converted into electric energy. AG-Cycle provides greater reductions in specific fuel costs for power plants with lower electrical efficiency, as they require more fuel. Generally, the electrical efficiency does not vary significantly between different fossil fuel (steam) power plants and can be assumed to be around 35% for most business strategy assessments.

B.4. Capacity Factor of Power Plants:

The capacity factor of a power plant is the ratio of the electrical energy produced by a generating unit during a given period compared to the energy that could have been produced at continuous full power operation. The weighted average capacity factor for residual fuel oil-fired power in the US is 16%, while for coal-fired (steam) and natural gas-fired power, it is 49.3%. (**Annex 3**).

B.5. Specific Cost of AG-Cycle Integration:

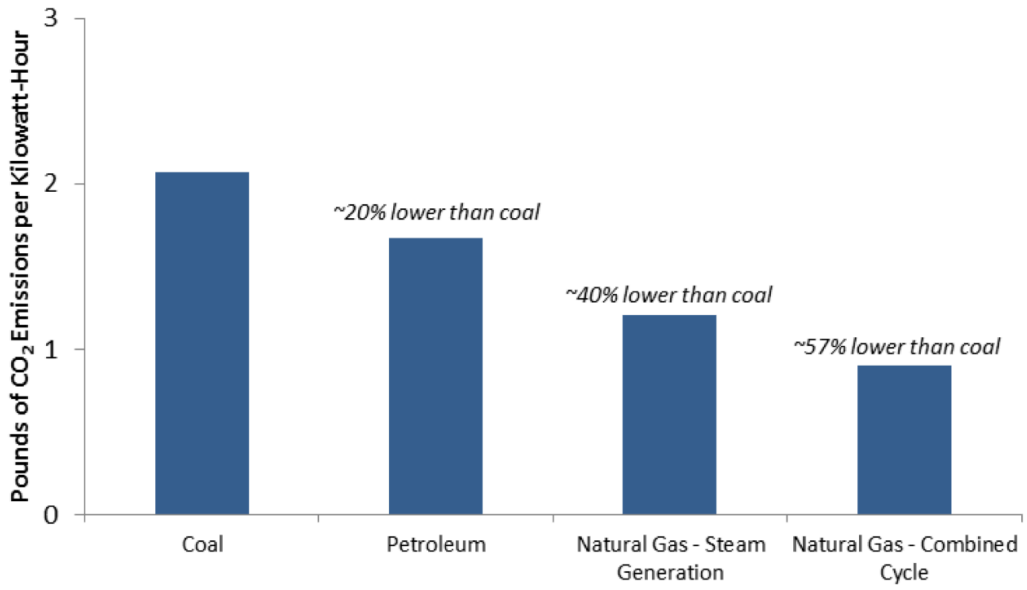
This refers to the cost of project development, equipment production, installation, and commissioning per 1 MW of electric power. Integrating the AG-Cycle into natural gas-fired and residual fuel oil-fired power plants is the simplest and least capital-intensive option, offering the highest sales per cost of fully commissioned equipment. Integration into a coal-fired power plant is approximately twice as capital-intensive due to the additional requirement of installing a system to reduce the acidity of recovered/recycled water. Preliminary estimates suggest a cost of around $110k per 1 MW for coal-fired power plants, compared to $55k per 1 MW for natural gas-fired or residual fuel oil-fired power plants.

B.6. Governmental Environmental Regulations:

Federal and state environmental regulations in power production aim to reduce CO2 emissions. AG-Cycle integration can serve as a solution for operators/owners of coal-fired power plants facing decommissioning. In the short to medium term, integrating AG-Cycle into such plants can ensure compliance with CO2 emission standards by reducing emissions by 60%. In the long term, coal-fired to natural gas-fired conversion, enhanced with AG-Cycle, can further reduce CO2 emissions by an additional 40% as natural gas electricity production emits 40% less CO2

compared to coal electricity[4]. The figure below illustrates the comparison of CO2 emissions between coal and natural gas electricity.

Figure 6. Comparison of Fossil Fuels' Carbon Content in Electricity Generation



Unlike the European Union, the United States has not implemented a federal carbon trading system thus far. However, the adoption of such a system in the US would significantly enhance the economic potential of AG-Cycle within the country.

C. **Strategic Considerations for Introducing AG-Cycle in the US Power Production**.

C.1. Short Payback Period:

A key advantage of the AG-Cycle introduction strategy is its remarkably short payback period, typically ranging from less than one to two years. This is uncommonly short for industrial equipment in the fossil fuel power production sector. The specific payback period for AG-Cycle integration depends on various factors, but the general rule is that the payback period is shortest when:

[4] https://sgp.fas.org/crs/misc/R45453.pdf

- Power generation fuel costs (in MMBTU) or specific fuel costs (per 1 MWh) are highest.
- Carbon credit price (per carbon credit or per ton of CO2) is highest.
- Capacity factor is highest.
- The specific cost of AG-Cycle integration is lowest.

In a country like the US without carbon credits, AG-Cycle integration into residual fuel oil-fired power plants is the most favorable option[5], followed by natural gas-fired power plants. Coal-fired power plants (steam) present the least advantageous option in terms of payback period.

C.2. Three-Segment Scope:

While the residual fuel oil-fired (steam) and natural gas-fired power segments offer significantly shorter payback periods and higher FMV/CAPEX ratios compared to coal-fired power, it's important to note that residual fuel oil-fired power plants constitute less than 6% of the capacity of coal-fired power plants in the US (231,3 GW)[6,7], possibly closer to 3%. Therefore, to maximize the economic potential of AG-Cycle in terms of the project's gross fair market value, coal-fired power plants will also need to be considered in the medium to long term.

C.3. Business Model of Service Provision:

The AG-Cycle introduction strategy is likely to consist of a combination of different elementary strategies, particularly in the initial stages of the project. A snowball strategy, coupled with a thermal energy supply contract and profit-sharing, is expected to be the most economically viable option for the following reasons:

- Due to the rapid recoupment of investments in fully commissioned AG-Cycle equipment within one year for two of the three segments[8], the project can generate

[5] without accounting for secondary economic benefits, for example, the extended life-cycle of a coal-fired power plant scheduled for decommissioning for the additional 10 – 25 years
[6] https://www.publicpower.org/system/files/documents/Americas_Electricity_Generation_Capacity_2022_Update.pdf
[7] Unfortunately, the EIA does not publish data on nameplate capacity of the residual fuel oil-fired (steam) power plants. In 2022, in the US, the overall nameplate capacity of power plants running on residual fuel oil (including reciprocating internal combustion engines and gas turbine generators) was 14 GW. Indirect analysis indicates that in 2022, the nameplate capacity of the residual fuel oil-fired (steam) power in the US was around 7 GW.
[8] The residual fuel oil-fired and natural gas-fired segments

sufficient funds for sustainable growth in those segments without requiring additional external capital investments.

-To ensure a high growth rate, short-term debt can be utilized, backed by future revenues secured through long-term contracts with customers.

- The thermal energy supply service model offers the highest level of protection for AG-Cycle know-how since the equipment remains the property of the project's operator, and production, installation, and maintenance are solely provided by the operator.

- Direct economic benefits can be shared between customers and the project's operator in a 50/50 ratio, eliminating risks for potential customers and allowing them to enjoy economic benefits from AG-Cycle starting from the second year (it is assumed that during the first year, the operator of the project will be receiving all direct economic benefits). This incentivizes potential customers to opt for the service without upfront costs.

- Selling AG-Cycle equipment to customers or licensing the technology, especially in the initial years, carries risks of jeopardizing the protection of the know-how through reverse-engineering. Reliance solely on intellectual property (IP) protection may not be sufficient and should be considered as a secondary line of defense for preserving the know-how.

D. **Estimation Major Economic Parameters for the Project.**

D.1. Fair Market Value (FMV) Estimation:

The FMV of the project for each power production segment and geographic location was calculated by multiplying the following parameters:

- The expected annual fuel cost for the portion of the power production segment covered by AG-Cycle, along with the cost of carbon credits associated with the fuel, if applicable.

- AG-Cycle fuel consumption reduction factor (assumed as 0.6).

- The share of the customer's annual gross economic benefits that the project owner retains as compensation for the use of AG-Cycle, assumed as 0.5.

- The percentage of sales that translates into the project owner's net profit after tax (currently accepted as 0.56, derived from the gross profit factor of 0.8 multiplied by a corporate tax rate factor of 0.7 (for the total corporate tax rate of 30%)).

- The price-to-earnings ratio (P/E) specific to each sub-project, currently assumed as 20.

D.1.1. The estimated FMV for the coal-fired power segment is $46.55 billion (**Annex 4**). If the same scenario occurred in the EU, where a carbon credit trading system is in place, the estimated FMV would be significantly higher at $202 billion[9], considering a carbon credit price of around 80 Euros per ton.

Interestingly, if the widespread implementation of AG-Cycle in the global coal power industry led to a 50% decline in steam coal demand, there could be a potential cross-industrial synergy. The global coal industry, which historically had a weighted average net profit margin of no more than 11%[10] between 2013 and 2020, could recover gross profit losses by increasing the weighted average coal price by only approximately 14%[11].

D.1.2. The estimated FMV for the "US residual fuel oil-fired power" sub-project is $3.22 billion (**Annex 5**).

D.1.3. Considering that 14 GW of coal-fired power in the US was re-fired to natural gas between 2011 and 2019[12], AG-Cycle integration into natural gas-fired power plants is a logical choice due to similar costs and engineering design. The estimated FMV for the "US natural gas-fired power" sub-project is $4.16 billion (**Annex 6**).

D.2. Optimization of Growth, Capital Investment, and Debt:

The Snowball Growth Matrix, a useful analytical tool for projects with sequential business cycles and short payback periods, was employed to optimize the introduction strategy. It determines annual growth and the appropriate mix of

[9] $46.55bn*(1+80*1,06/25.4)=$202bn
[10] https://www.statista.com/statistics/208725/net-profit-margin-of-the-top-mining-companies/
[11] for 20% corporate tax rate
[12] https://www.eia.gov/todayinenergy/detail.php?id=44636

capital and short-term debt. The matrix helps answer the question of how much upfront capital investment is necessary to achieve a specific project's FMV within a designated timeframe.

D.2.1. By integrating AG-Cycle into 80% of the residual fuel oil-fired power segment (5,600 MW in terms of nameplate capacity[13]), the Snowball Growth Matrix estimated an upfront investment of $5.6 million to reach the target FMV of $3.22 billion in 4.5 years, and $2.14 million in 5.5 years. The overall sub-project's capital expenditure (CAPEX) is estimated at $308 million, primarily generated from the sub-project's net profit (**Annex 7**).

D.2.2. Similarly, by integrating AG-Cycle into 80% of the natural gas-fired power segment (11,200 MW in terms of nameplate capacity[14]), the Snowball Growth Matrix estimated an upfront investment of $29.3 million to achieve the target FMV of $4.16 billion in 5.5 years, and $11.2 million in 6.5 years. The overall sub-project's CAPEX is estimated at $616 million, primarily generated from the sub-project's net profit (**Annex 8**).

D.2.3. Retirement of Coal Power Plants in the US:

In 2022, a total of 12,600 MW of coal power capacity was scheduled for retirement, representing 85% of all retired power production in the US[15]. Over the period of 2012 to 2021, an average of 9,450 MW of US coal-fired capacity was retired each year. Among the 55,943 MW of US coal-fired capacity primarily using refined coal, approximately 27% (15,269 MW) has reported plans for retirement between 2022 and 2029[16].

It is highly likely that owners of coal power plants scheduled for retirement in the US would be willing to pay $110,000 per 1 MW of power for AG-Cycle integration. This integration would extend the life-cycle of coal-fired power plants by an additional 10 to 25 years and result in a 30% reduction in fuel costs. In other words, integrating AG-Cycle into coal-fired power plants is expected to require minimal capital expenditure from the project owner. The estimated cost for research and development, as well as commissioning a 50 MW pilot coal-fired unit, is $10 million.

[13] 7,000 MW*0.8=5,600 MW
[14] 14,000 MW*0.8=11,200 MW
[15] https://www.eia.gov/todayinenergy/detail.php?id=50838
[16] https://www.eia.gov/todayinenergy/detail.php?id=54559

D.3. Investments in Means of Production:

The key equipment required for integrating AG-Cycle into fossil fuel-fired power plants is the AG-Burner, which utilizes a hydrocarbon fuel or coal and water.

According to the three-year timeline of the project (see the table below), a small-scale manufacturing facility with an annual production capacity of up to fifty 50 MW AG-Burners will be sufficient to meet the production schedule during the initial three years. However, after approximately two and a half years from the project's commencement, a manufacturing facility with a higher annual production capacity will be needed. The specific production capacity and cost of this manufacturing facility will depend on the strategy. Preliminary estimates suggest that starting from the fourth year, the project's net profit will enable the project owner to independently fund the construction of such a manufacturing facility, eliminating the need for external capital financing.

D.4. Capital Investment Estimate:

Preliminary estimates indicate that the implementation of the strategy outlined in this memo will require a total capital investment of $29.84m. This investment aims to enable the project to achieve a target fair market value of $550m by the end of the third and a half year, $53.93bn by the end of 8 and a half year without accounting for the project's growth potential, licensing related income, and intellectual property value.

E. **Summary of the Project**:

The key project’s parameters for the 8.5-year timeline, are outlined in the table below.

The fair market value estimates for each sub-project are pessimistic because they are based on the industry average capacity factors. It makes sense to assume that due to the sharp reduction in fuel costs, the owners will increase plants' annual operating hours, i.e., the capacity factors will go up.

For simplicity, the estimates are made under the assumption that the reinvested income (sales) is not subject to corporate tax (~30%). This is because the reduction of variable production and installation costs is expected to recoup the tax due to the learning curve and economies of scale. FMVs were estimated with the corporate tax in mind.

Summary of the project's key parameters for the 8.5-year timeline[17]

Parameter/Sub-Project	Residual Fuel Oil-Fired Power	Natural Gas-Fired Power	Coal-Fired (Steam) Power
Target Nameplate Capacity	5,600 MW	11,200 MW	168,400 MW
Assumed Specific Cost of AG-Cycle Integration	$55k/MW	$55k/MW	$110k/MW
CAPEX	$308m	$616m	$18,524m
Specific Cost of Fuel	$162.8/MWh	$34.1/MWh	$25.4/MWh
Capacity Factor	16%	49,3%	49,3%
Expected Fair Market Value (FMV)	$3.22bn	$4.16bn	$46.55bn
FMV/CAPEX	10.45	6.75	2.51
Duration of the Sub-project	6 years	7 years	7.5 years
One-Time Upfront Capital Investment	$2.14m	$11.2m	$10.5m

E.1.Project Timeline:

The project is set to span a three-and-a-half-year timeline, as outlined in the table below. Given the uncertainty of future factors that may impact strategic decisions, a timeline longer than three years is currently not practical.

It is essential to highlight that although a 50 MW AG-Burner is mentioned throughout the document, slightly more or less powerful (up to +/-20%) burner modifications will be used in real life.

[17] Please note that this is a summary of the project's key parameters and does not account for all possible variables and scenarios.

The 3.5-year timeline of the project.

Period (years)/ Sub-Project	Residual Fuel Oil-Fired Power	Natural Gas-Fired Power	Coal-Fired (Steam) Power
0 – 1	Company launching phase: developing and adopting a full-fledged 3.5-year business plan; creating the team; developing IP strategy; establishing facility for R&D, testing, small-scale production of 50 MW AG-Burners with maximum annual capacity of up to forty 50 MW AG-Burners; creating and testing prototype of a dual-fuel (residual fuel oil/natural gas) 50 MW AG-Burner; creating and testing the burner management system (BMS) for 50 MW AG-Burner; creating a procurement system for providing supply of constituent components for AG-Burner small-scale manufacturing and supplementary equipment. Obtaining the certificates. One-time capital investment of **$6m**.		
1 – 1.5	Producing the first AG-Cycle system followed by its integration into a 38.9[18] MW power unit; wherein the system comprises two (2) 50 MW AG-Burners and supplementary equipment. One-time upfront capital investment of **$2.14.**		
1.5 – 2	Covering 38.9 MW of power; two (2) 50 AG-Burners	Producing a full-fledged AG-Cycle system followed by its integration into a 203.5[19] MW power unit; wherein the system comprises twelve (12) 50 MW AG-Burners and supplementary equipment. One-time upfront capital investment of **$11.2m**	
2 - 2.5	Covering 38.9 MW of power; two (2) 50 AG-Burners	Covering 203.5 MW of power; eight (8) 50 AG-Burners	Creating the first 50 MW AG-Burner equipped with systems for slag removal and purification of the recycled water. One-time capital investment of **$4.5m.**
2.5 – 3	Covering 77.8 MW of power; six (6) 50 AG-Burner	Covering 203.5 MW of power; eight (8) 50 AG-Burners	Producing a full-fledged AG-Cycle system followed by its integration into a 50 MW power unit; wherein the system comprises three (3) 50 MW AG-Burners and supplementary equipment. One-time upfront capital investment of **$6**
3 – 3.5	Covering 77.8 MW of power; six (6) 50 AG-Burner	Covering 407 MW of power; eight (8) 50 AG-Burners	Collecting a portfolio of pre-orders for AG-Cycle integration. The prospective customers are to prepay $110k per 1 MW of power. Economic benefits are to be split 50/50 between the customers and the owner of the project.
Total Power	**272 MW**	**1,017 MW**	**50 MW**
FMV	**156m**	**377m**	**17m**

[18] 7,000 MW*0.8/144 times=38.9MW (see page 24)
[19] 14,000 MW*0.8/55 times=203.5 MW (see page 26)

Flexibility in strategic decision-making will be maintained through the projected cash flow of the project. Starting from the fourth year, the project is expected to generate an annual net profit after tax of $34.5 million. The project owners are likely to adopt individual strategies for each combination of "power segment - geographical territory." The following is one example strategy:

- Focus on the growth of the US segments of residual fuel oil-fired and natural gas-fired power due to their favorable FMV/CAPEX ratios of 10.45 and 6.75, respectively.

- Invest approximately $100 million in the construction of a manufacturing facility to produce several thousand 50 MW AG-Burners annually, catering to the US coal-fired (steam) segment. This will enable the achievement of the sub-project's target FMV of $46.55 billion within 7.5 years.

- Enter the EU market of coal-fired (steam) power, where the return on specific CAPEX is expected to be around four times higher than in the US due to the high price of carbon credits in the EU.

E.2. Project's long-term sustainability:

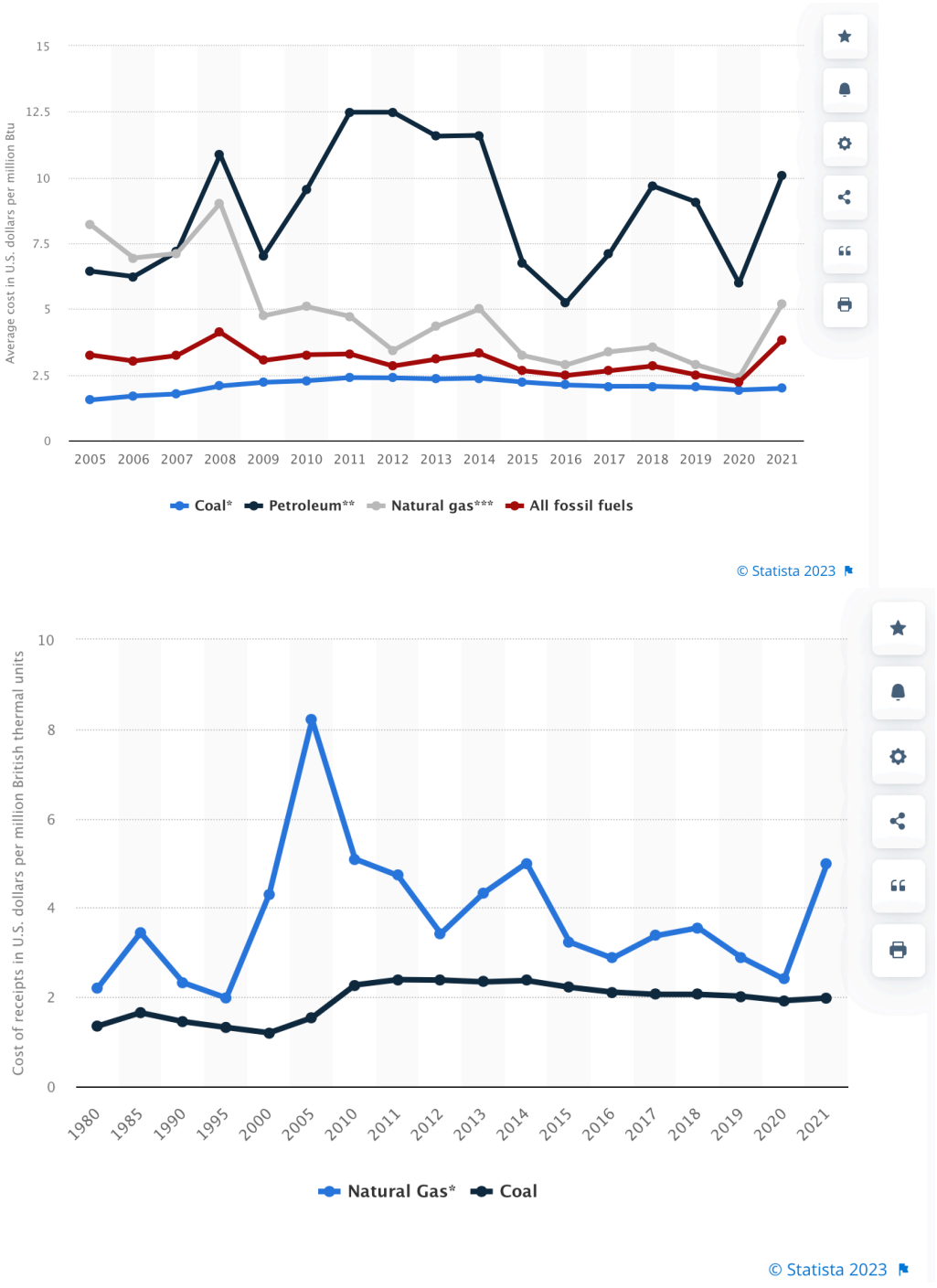
Considering the growing market for green solar PV and wind power, it is important to assess the long-term prospects of AG-Cycle. Solar PV and wind power have low capacity factors, typically ranging from 24.6% to 34.6%. Efficient storage of large amounts of electricity becomes crucial for these renewable energy sources. One utility-scale solution is storage technology based on the repeated production of synthetic hydrocarbons from green hydrogen and captured CO2, followed by combustion for power generation.

While the efficiency of synthetic hydrocarbon production has reached an impressive 81.5%[20], the round-trip efficiency of this energy storage technology remains limited due to the relatively low efficiency of conventional fossil fuel power production. In many cases, AG-Cycle can increase the round-trip efficiency of such energy storage systems by 2.5 times. In other words, AG-Cycle will be necessary for as long as affordable and utility-scale energy storage technology remains in demand, even when fossil fuels are completely phased out by green energy.

[20] http://www.helmeth.eu/index.php/technologies/integrated-p2g-process

Annex 1

Figures below illustrate specific cost of MMBTU for different fossil fuels:[21,22]



[21] https://www.statista.com/statistics/183992/average-costs-of-fossil-fuels-for-us-electricity-generation-from-2005/
[22] https://www.statista.com/statistics/189180/natural-gas-vis-a-vis-coal-prices/

The US Energy Information Administration (EIA) regularly publishes statistical data on power production. Table below outlines power generation fuel costs (per MMBTU):[23]

Table 2. Energy Prices
U.S. Energy Information Administration | Short-Term Energy Outlook - March 2023

	2022				2023				2024				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2022	2023	2024
Crude Oil (dollars per barrel)															
West Texas Intermediate Spot Average	**95.18**	**108.93**	**93.07**	**82.69**	*78.05*	*78.00*	*77.00*	*75.35*	*74.00*	*72.34*	*70.69*	*69.36*	**94.91**	*77.10*	*71.57*
Brent Spot Average	**101.17**	**113.84**	**100.53**	**88.44**	*83.45*	*84.00*	*83.00*	*81.35*	*80.00*	*78.34*	*76.69*	*75.36*	**100.94**	*82.95*	*77.57*
U.S. Imported Average	**89.85**	**107.23**	**91.86**	**78.46**	*75.38*	*75.25*	*74.27*	*72.60*	*71.25*	*69.57*	*67.93*	*66.61*	**92.63**	*74.30*	*68.87*
U.S. Refiner Average Acquisition Cost	**92.62**	**109.86**	**95.20**	**83.54**	*77.53*	*77.50*	*76.52*	*74.83*	*73.50*	*71.82*	*70.18*	*68.83*	**95.36**	*76.58*	*71.07*
U.S. Liquid Fuels (cents per gallon)															
Refiner Prices for Resale															
Gasoline	**278**	**376**	**311**	**267**	*258*	*260*	*255*	*235*	*231*	*238*	*228*	*211*	**309**	*252*	*227*
Diesel Fuel	**301**	**418**	**357**	**364**	*300*	*289*	*279*	*278*	*259*	*242*	*240*	*250*	**361**	*286*	*248*
Fuel Oil	**284**	**419**	**344**	**359**	*281*	*268*	*265*	*269*	*249*	*229*	*222*	*241*	**352**	*275*	*241*
Refiner Prices to End Users															
Jet Fuel	**283**	**400**	**340**	**332**	*319*	*295*	*275*	*268*	*250*	*238*	*232*	*242*	**340**	*288*	*240*
No. 6 Residual Fuel Oil (a)	**252**	**258**	**228**	**201**	*199*	*198*	*198*	*194*	*193*	*186*	*183*	*180*	**236**	*197*	*185*
Retail Prices Including Taxes															
Gasoline Regular Grade (b)	**371**	**450**	**408**	**357**	*337*	*342*	*341*	*323*	*314*	*322*	*312*	*294*	**397**	*336*	*311*
Gasoline All Grades (b)	**380**	**460**	**419**	**369**	*348*	*354*	*355*	*337*	*328*	*336*	*326*	*309*	**408**	*349*	*325*
On-highway Diesel Fuel	**432**	**549**	**516**	**508**	*444*	*425*	*398*	*400*	*389*	*370*	*364*	*372*	**502**	*417*	*373*
Heating Oil	**415**	**555**	**497**	**488**	*409*	*381*	*364*	*383*	*371*	*343*	*329*	*364*	**465**	*392*	*361*
Natural Gas															
Henry Hub Spot (dollars per thousand cubic feet)	**4.84**	**7.77**	**8.30**	**5.76**	*2.81*	*2.87*	*3.26*	*3.63*	*4.17*	*3.81*	*3.96*	*4.21*	**6.67**	*3.14*	*4.04*
Henry Hub Spot (dollars per million Btu)	**4.66**	**7.48**	**7.99**	**5.55**	*2.70*	*2.76*	*3.13*	*3.49*	*4.02*	*3.67*	*3.81*	*4.06*	**6.42**	*3.02*	*3.89*
U.S. Retail Prices (dollars per thousand cubic feet)															
Industrial Sector	**6.82**	**8.24**	**9.27**	**7.53**	*5.65*	*4.10*	*4.18*	*4.83*	*5.58*	*4.86*	*4.87*	*5.46*	**7.90**	*4.71*	*5.22*
Commercial Sector	**10.00**	**11.71**	**14.12**	**12.14**	*10.86*	*10.16*	*10.44*	*8.95*	*8.90*	*9.76*	*10.63*	*9.38*	**11.37**	*10.09*	*9.38*
Residential Sector	**12.32**	**16.57**	**24.94**	**15.63**	*12.72*	*14.73*	*20.17*	*12.33*	*11.35*	*14.78*	*20.89*	*12.87*	**14.82**	*13.51*	*13.07*
U.S. Electricity															
Power Generation Fuel Costs (dollars per million Btu)															
Coal	**2.18**	**2.26**	**2.50**	**2.55**	*2.65*	*2.63*	*2.62*	*2.57*	*2.58*	*2.58*	*2.57*	*2.54*	**2.37**	*2.62*	*2.57*
Natural Gas	**5.96**	**7.39**	**8.23**	**6.90**	*3.98*	*3.08*	*3.31*	*3.87*	*4.59*	*3.94*	*4.02*	*4.44*	**7.24**	*3.54*	*4.23*
Residual Fuel Oil (c)	**16.81**	**26.17**	**26.53**	**21.27**	*17.53*	*17.15*	*16.20*	*15.73*	*15.67*	*15.65*	*14.64*	*14.44*	**21.80**	*16.70*	*15.10*
Distillate Fuel Oil	**21.23**	**30.71**	**26.79**	**24.48**	*23.31*	*22.14*	*21.42*	*21.26*	*20.31*	*18.72*	*18.46*	*19.21*	**24.89**	*22.07*	*19.34*
Prices to Ultimate Customers (cents per kilowatthour)															
Industrial Sector	**7.42**	**8.41**	**9.38**	**8.52**	*7.80*	*8.24*	*9.02*	*8.34*	*7.89*	*8.23*	*9.02*	*8.34*	**8.45**	*8.36*	*8.38*
Commercial Sector	**11.63**	**12.35**	**13.38**	**12.66**	*12.33*	*12.63*	*13.40*	*12.47*	*12.15*	*12.66*	*13.54*	*12.55*	**12.55**	*12.74*	*12.76*
Residential Sector	**13.98**	**15.07**	**15.85**	**15.48**	*15.33*	*15.80*	*15.98*	*15.31*	*15.08*	*15.90*	*16.12*	*15.47*	**15.12**	*15.63*	*15.66*

(a) Average for all sulfur contents.
(b) Average self-service cash price.
(c) Includes fuel oils No. 4, No. 5, No. 6, and topped crude.
- = no data available
Notes: EIA completed modeling and analysis for this report on March 2, 2022.

The table indicates that the anticipated for 2023 average power generation fuel cost (per MMBTU) of coal power is $2.6, that of natural gas is around $3.5, and that of residual fuel oil is around $16,7. In order to convert these numbers into specific fuel cost for power production, i.e. per 1 MWh, the aforementioned numbers have to be multiplied by a factor of 9.75[24].

Accordingly, the anticipated for 2023 average specific fuel costs for coal power is $25.4; that for natural gas-fired power is $34.1; that for residual fuel oil (steam) power is $162,8.

[23] https://www.eia.gov/outlooks/steo/tables/pdf/2tab.pdf

[24] Since MMBTU equals 0.293 MWh, and power plant's electrical efficiency is assumed as 35%, then the conversion coefficient equals 1/(0.293*0.35)=9.75.

In investment decision making process it makes sense to keep power plant location in mind, because cost of coal varies throughout the US regions, as the indicates the following table:[25]

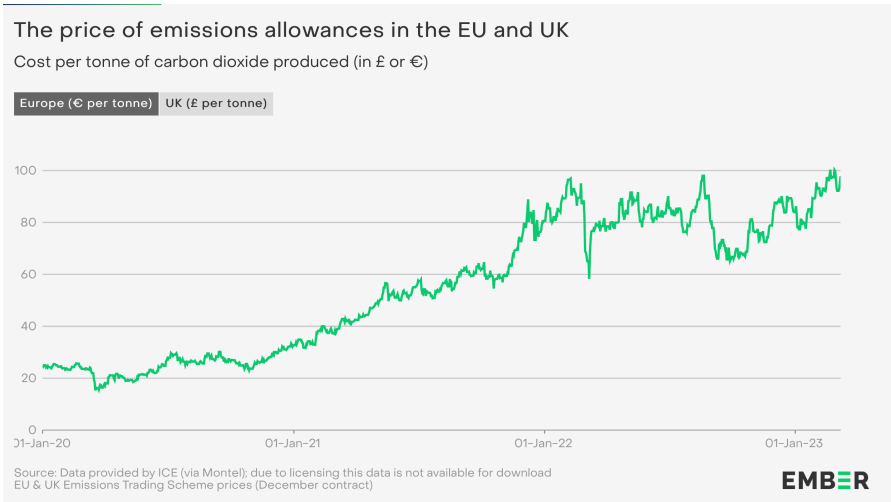
Table 4.10.A. Average Cost of Coal Delivered for Electricity Generation by State, December 2022 and 2021
(Dollars per MMBtu)

Census Division and State	Electric Power Sector			Electric Utilities		Independent Power Producers	
	December 2022	December 2021	Percentage Change	December 2022	December 2021	December 2022	December 2021
New England	**W**	**W**	**W**	**--**	**--**	**W**	**W**
Connecticut	--	--	--	--	--	--	--
Maine	W	W	W	--	--	W	W
Massachusetts	--	--	--	--	--	--	--
New Hampshire	W	W	W	--	--	W	W
Rhode Island	--	--	--	--	--	--	--
Vermont	--	--	--	--	--	--	--
Middle Atlantic	**4.34**	**2.18**	**99%**	**--**	**2.90**	**4.34**	**2.18**
New Jersey	--	W	W	--	--	--	W
New York	--	--	--	--	--	--	--
Pennsylvania	4.34	W	W	--	2.90	4.34	W
East North Central	**2.37**	**2.05**	**16%**	**2.66**	**2.22**	**1.87**	**1.81**
Illinois	1.88	1.76	6.8%	2.11	1.68	1.82	1.77
Indiana	W	W	W	2.99	2.53	W	W
Michigan	W	2.11	W	2.40	2.11	W	--
Ohio	W	W	W	2.78	1.88	W	W
Wisconsin	2.49	2.12	17%	2.49	2.12	--	--
West North Central	**1.85**	**1.71**	**8.2%**	**1.85**	**1.71**	**--**	**--**
Iowa	1.73	1.81	-4.4%	1.73	1.81	--	--
Kansas	1.86	1.43	30%	1.86	1.43	--	--
Minnesota	2.42	2.49	-2.8%	2.42	2.49	--	--
Missouri	1.98	1.79	11%	1.98	1.79	--	--
Nebraska	1.29	1.19	8.4%	1.29	1.19	--	--
North Dakota	1.83	1.68	8.9%	1.83	1.68	--	--
South Dakota	2.56	1.66	54%	2.56	1.66	--	--
South Atlantic	**3.64**	**2.66**	**37%**	**3.71**	**2.76**	**3.16**	**2.23**

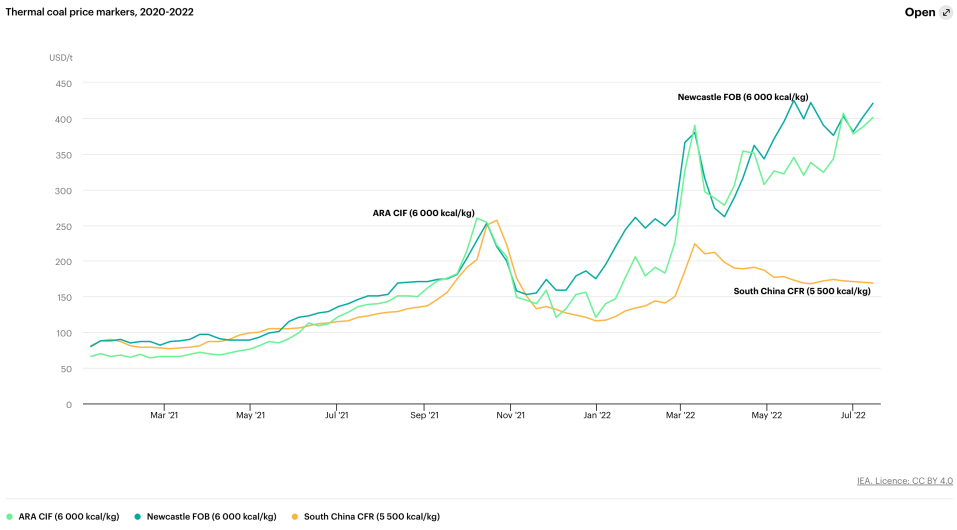
[25] https://www.eia.gov/electricity/monthly/epm_table_figureer.php?t=epmt_4_10_a

Annex 2

Figure below illustrates the growth trend in carbon credit prices in the EU, which for the most part of 2022 – 2023 exceeded 80 Euro per ton:[26]



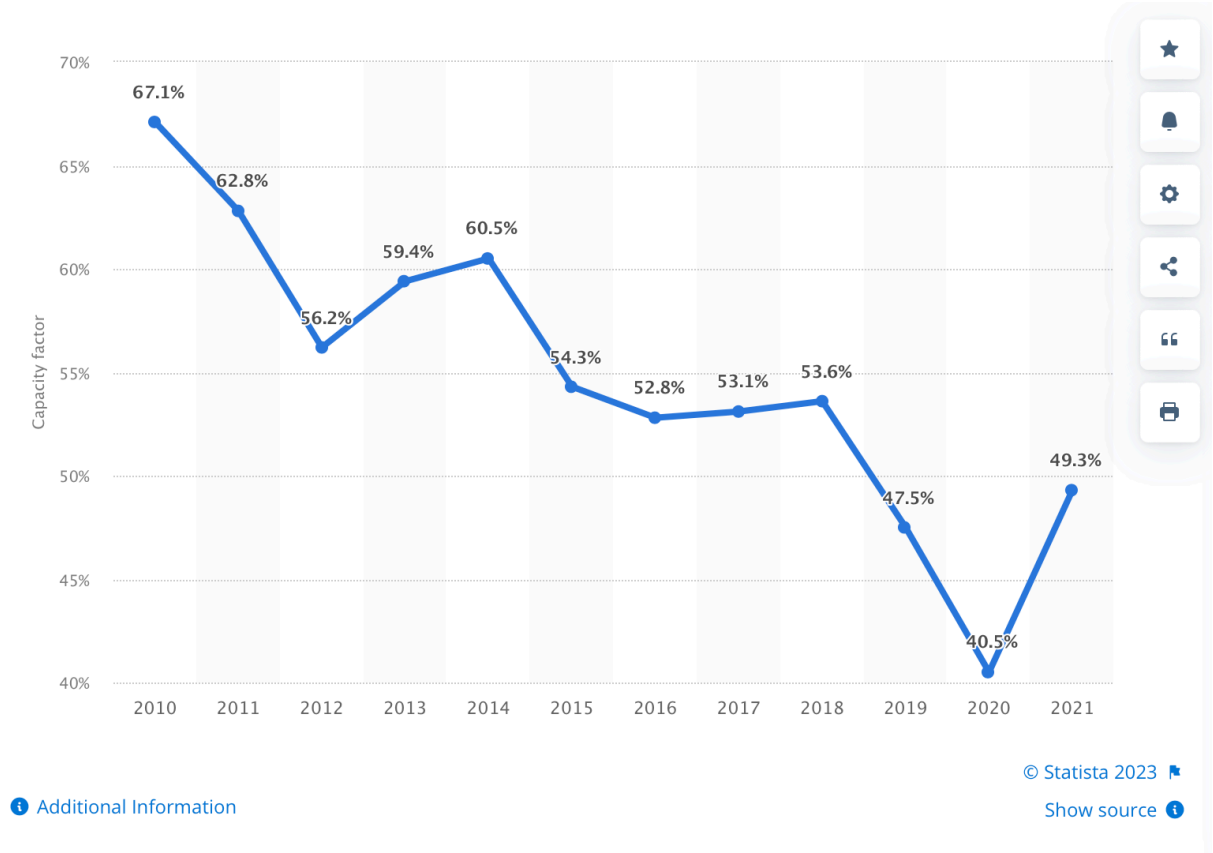
Production of 1 MWh of electricity by a coal-fired power plant is accompanied by emission of approximately 1 ton of CO_2, which is equivalent to one carbon credit. Accordingly, for estimating specific fuel associated costs in power production in the EU countries, fuel costs [27] need to be supplemented with the cost of carbon credits of at least 80 Euro per ton.



[26] https://ember-climate.org/data/data-tools/carbon-price-viewer/
[27] https://www.iea.org/reports/coal-market-update-july-2022/prices

Annex 3

The figure below illustrates a capacity factor for the coal power in the US[28]:

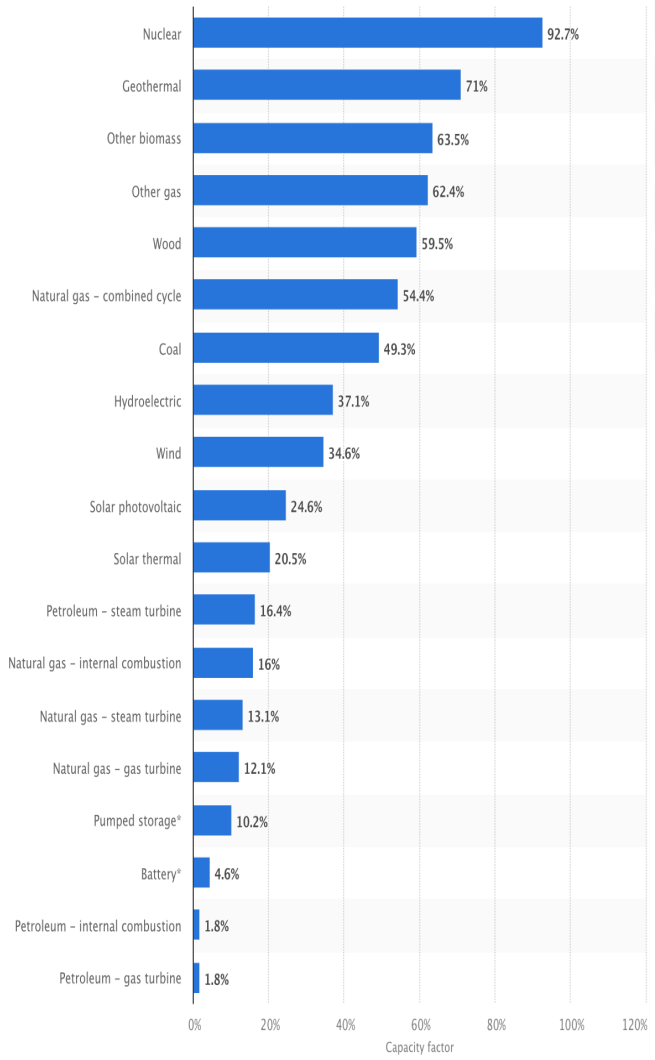


The general rule is that higher gross annual fuel costs reduction per 1 MW of nameplate capacity are attainable at a power plant with the higher capacity factor.

A base load fossil fuel power plant, such as a coal-fired coal power plant, has the greater capacity factor compares with a peaking power plant, such as a simple cycle power plants running on natural gas.

Figure below illustrates the average capacitor factor for different types of power production in the US in 2021:[29]

[28] https://www.statista.com/statistics/744947/capacity-factor-of-coal-power-plants-in-the-us-by-unit-type/
[29] https://www.statista.com/statistics/183680/us-average-capacity-factors-by-selected-energy-source-since-1998/



Collapse statistic

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Annex 4

Once the sub-project of integrating AG-Cycle into 80% of coal power in the US (measured in terms of coal consumption) is successfully accomplished, then, under the assumptions that:

- the (effective) nameplate capacity of the coal-fired power in the US is around 210,500 MW (in 2021)[30];
- the specific cost of fuel (coal) for power production is $25.4 (see page 14);
- the weighted average capacity factor is 49.3% (see page 18);
- the above numbers remain substantially intact by the predetermined future date,

the fair market value (FMV) of "the US coal power" sub-project can be estimated as follows:

210,500 MW * $25.4/MWh * 8,760 hour * 0.8 * 0.493 * 0.6 * 0.5 * 0.56 * 15 =

$46.55bn,

Where:

- 210,500 MW – the (effective) installed capacity of coal-fired power;
- $25.4/MWh – the specific cost of fuel (coal);
- 8,760 – the number of hours in a year;
- 0.493 – the capacity factor;
- 0.8 – the coverage of the coal-fired power in the US by AG-Cycle;
- 0.6 – the AG-Cycle fuel consumption reduction factor;
- 0.5 – the share of customer's annual gross economic benefits that the owner of the project will retain;
- 0.56 – the percentage of sales which translates into project owner's net profit after tax, [0.8*0.7];
- 15 – the P/E ratio.

[30] https://www.eia.gov/electricity/annual/html/epa_04_03.html

Annex 5

The fair market value of "the US residual fuel oil power" sub-project is estimated as:

7,000 MW * $162,8/MWh * 8,760 hour * 0.8 * 0.16 * 0.6 * 0.5 * 0.56 * 15 = $3.22bn,

Where:

- 7,000 MW – the installed capacity of the residual fuel oil fired power in the US;
- $162,8 per MWh – the specific cost of fuel (residual fuel oil) (see page 14);
- 8,760 – the number of hours in a year;
- 0.8 – the portion of the residual fuel oil-fired power in the US covered by AG-Cycle;
- 0.16 – the capacity factor (see figure on page 18);
- 0.6 – the AG-Cycle fuel consumption reduction factor;
- 0.5 – the share of customer's annual gross economic benefits that the owner of the project will retain;
- 0.56 – the percentage of sales which translates into project owner's net profit after tax, [0.8*0.7];
- 15 – the P/E ratio.

It is important to highlight that due to the high specific cost of residual fuel oil, the power plants running on this type of fuel are usually peaking plants with relatively low capacity factor of 0.16.

As soon as the specific cost of fuel for the residual fuel oil- fired power gets reduced by 60% due to AG-Cycle integration, the specific cost of fuel will become two times cheaper than that for reciprocating internal combustion power running on residual fuel oil,[31] potentially causing substantial increase of the capacity factor from current 16%.

[31] Electrical efficiency of a reciprocating internal combustion power plant running on residual fuel oil does not usually exceed 42%, whereas AG-Cycle will increase the effective electrical efficiency of a residual fuel oil (steam) fired plant up to [35%*2.5], i.e. 87.5%.

Annex 6

The fair market value (FMV) of "the US natural gas-fired power" sub-project is estimated as follows:

14,000 MW* $34.1 per MWh * 8,760 hour * 0.8 * 0.493 * 0.6 * 0.5 * 0.56 * 15 = = $4.16bn,

Where:

- 14,000 MW – the installed capacity of the natural gas-fired power in the US;
- $34.1 per MWh – the specific cost of fuel (natural gas) (see page 14);
- 8,760 – the number of hours in a year;
- 0.493 – the capacity factor (see page 18);
- 0.8 – the portion of the natural gas-fired power in the US covered by AG-Cycle;
- 0.6 – the AG-Cycle fuel consumption reduction factor;
- 0.5 – the share of customer's annual gross economic benefits that the owner of the project will retain;
- 0.56 – the percentage of sales which transforms into project owner's net profit after tax, [0.8*0.7];
- 15 – the P/E ratio.

Annex 7

Snowball Growth Matrix and Upfront Investment Calculation

The Snowball Growth Matrix presented below is used to estimate the required one-time upfront investment for achieving the target fair market value of $3.68 billion for the "US residual fuel oil power" sub-project within a specific time period. This estimation is based on integrating AG-Cycle technology into 80% of the targeted 5,600 MW[32] capacity of this power segment.

One MW of residual fuel oil-fired power is expected to generate the following net profit during the first year of operation:

$162.8 per 1 MWh * 8,760 hours * 0.16 * 0.6 * 1 * 0.8 = $109,500,

Where:

- $162.8 per MWh represents the specific cost of fuel (residual fuel oil).
- 8,760 is the number of hours in a year.
- 0.16 is the capacity factor.
- 0.6 is the AG-Cycle fuel consumption reduction factor.
- 1 is the share of the customer's annual gross economic benefits that the project owner retains during the first year.
- 0.8 is the percentage of sales that transforms into the project owner's gross profit (before tax).

Starting from the second year, the net profit amount is expected to be halved, resulting in $54,750. For simplicity, let's assume these values are $110,000 and $55,000 respectively.

The specific cost of integrating AG-Cycle into a residual fuel oil-fired power plant is expected to be no more than $55,000 per MW of power. For simplicity, let's assume it is indeed $55,000 per MW.

Additionally, assume that 6 months are required for production, installation, and commissioning of AG-Cycle equipment, and that sales remain steady each year. Consider the following assumptions:

[32] 7,000 MW*0.8=5,600 MW

- At the beginning of the term "minus 0.5 years," $55,000 is invested in producing, installing, and commissioning 1 MW of power (1st batch).
- At the beginning of the term "1 year," the 1st batch of AG-Cycle equipment is operational.
- During the term "1 year," the AG-Cycle equipment generates a steady gross profit of $110,000.
- During the term "1 year," a $55,000 loan is taken at the beginning of the 1st month of the current term to cover a six-months cash gap.
- During the term "1 year," the $55,000 earned during the first half of the current term, plus the borrowed $55,000, totaling $110,000, is invested in producing, installing, and commissioning the next 2 MW of power (2nd batch).
- During the term "1 year," the $55,000 loan is repaid at the end of the 6th month of the current term.
- At the beginning of the term "2 years," the 2nd batch of AG-Cycle equipment is operational.
- During the term "2 years," the AG-Cycle equipment generates a steady gross profit of $220,000.
- During the term "2 years," a $137,500 6-months loan is taken at the beginning of the 1st month of the current term to cover a six-months cash gap.
- During the term "2 years," the $110,000 earned during the first half of the term, plus the borrowed $110,000, plus the $55,000 earned during the current term by the 2nd batch (2 MW), totaling $275,000, is invested in producing, installing, and commissioning the next 5 MW of power (3rd batch).
- During the term"2 years," the $137,500 loan is repaid at the end of the 6th month of the current term.
- At the beginning of the term "3 years," the 3rd batch of equipment is operational.

This pattern continues according to the outlined matrix. The "Growth" column in the Snowball Growth Matrix indicates the total number of one-time upfront investments (in this case, $55k) made by the end of each term.

The outlined algorithm shows that the project may need a six-month short-term credit to cover a six-months cash gap. Alternatively, suppose the production and installation processes are appropriately optimized, and suppliers agree to provide a trade credit. In that case, avoiding taking short-term credit or substantially reducing

the amount is possible. Also, securing short-term debt financing will become far more accessible as the number of installations mounts.

To integrate AG-Cycle into 5,600 MW of residual fuel oil-fired power in the US, a total CAPEX of $308 million ($55,000 per MW * 5,600 MW) will be required. To estimate the necessary one-time upfront investment to achieve the target fair market value of $3.22 billion for the "US residual fuel oil power" sub-project by the end of a specific term, the total CAPEX of $308 million needs to be divided by the "Growth" value for that term.

For example, if the objective is to reach the target fair market value of $3.22 billion in 4.5 years, the required one-time upfront investment would be $5.6 million ($308 million divided by 55). Similarly, for a term of 5.5 years, the investment needed would be $2.14 million ($308 million divided by 144).

It's important to note that these calculations and estimations are based on the assumptions and figures provided. Adjustments can be made based on actual data and conditions to ensure accurate projections and planning for the integration of AG-Cycle into the residual fuel oil power segment in the US.

Snowball Growth Matrix for residual fuel oil-fired power in the US.

T/B[33]	-0.5	1	2	3	4	5	6	7
1	55	110	55	55	55	55	55	55
2			220[34]	110	110	110	110	110
3				550[35]	275	275	275	275
4					1,430[36]	715	715	715
5						3,740	1,870	1,870
6							9,790	4,895
7								25,630
Growth (times)	1	3	8	21	55	**144**	377	987
One-time Upfront Investment (m)		102.67	38.5	14.67	5.6	**2.14**	0.82	0.31

[33] P stands for “term”; B stands for “batch”
[34] 110*2=220
[35] (55+220)*2=550
[36] (55+110+550)*2=1,430

Annex 8

Snowball Growth Matrix for AG-Cycle Integration into Natural Gas-Fired Power

The Snowball Growth Matrix presented in the previous section can also be applied to other applications of AG-Cycle, with the exception of the last two rows[37]. For instance, when integrating AG-Cycle into natural gas-fired power (such as coal-fired power plants that have been converted to burn natural gas), the main difference lies in the duration of "a term," which will be longer than one year due to an extended payback period. This longer term can be calculated using the formula below (see page 14):

Extended Term = ($162.8 * 0.16) / ($34.1 * 0.5) = 1.53 times,

Where:

- $162.8 represents the specific fuel cost for residual fuel oil-fired power.
- $34.1 represents the specific fuel cost for natural gas-fired power.
- 0.16 is the capacity factor for residual fuel oil-fired power.
- 0.5 is the capacity factor for natural gas-fired power.

To integrate AG-Cycle into 80% of the 14 GW natural gas-fired power capacity in the US, a total CAPEX of $616 million ($55,000 per MW * 14,000 MW * 0.8) will be required. The Snowball Growth Matrix for natural gas-fired power in the US is presented below in the table. Each term, from "1st" to "7th" lasts for18 months.

Note: The Snowball Growth Matrix for natural gas-fired power follows the same pattern as the one described in Annex 7, with the duration of "a term" extended based on the calculated factor of 1.53.

[37] Under assumption that customers will be willing to start receiving economic benefits at a later date, the date being commensurate with a longer payback period. For the natural gas-fired (steam) power in the US, the period extends to 18 months (plus 6 additional months).

Snowball Growth Matrix for residual natural gas-fired power in the US

T/B	-0.5	1	2	3	4	5	6	7
1	55	110	55	55	55	55	55	55
2			220	110	110	110	110	110
3				550	275	275	275	275
4					1,430	715	715	715
5						3,740	1,870	1,870
6							9,790	4,895
7								25,630
Growth (times)	1	3	8	21	55	144	377	987
One-time Upfront Investment (m)		205.3	77	29.3	**11.2**	4.28	1.63	0.62

These estimates can serve as a reference for determining the upfront investment required to achieve a target fair market value in a specific term for the integration of AG-Cycle into natural gas-fired power. It is important to conduct further analysis and adjust these calculations based on the actual cost and performance parameters of the natural gas-fired power plants in consideration.

Self-certification Statements and the Disclaimer

I, Pavel Zabelin, the US citizen, having master's degree in Electrical Engineering, PhD in economics, MBA, registered patent agent before the USPO (#73,280), certify that I drafted the memo in good faith and to the best of my professional knowledge; the potential conflict of interests, which derives from my position as the President of the US-based AG Joule, Corp. and its shareholder, warrants a supplementary expert review of the memo.

I, Damien Blanke, the Australian citizen, having executive MBA degree, certify that I reviewed the memo, edited and amended it in good faith and to the best of my professional knowledge; the potential conflict of interests, which derives from my position as the Director of the US-based AG Joule, Corp. and its shareholder, warrants a supplementary expert review of the memo.

I, Ibada Ahmed, the Kenyan citizen, having bachelor's degree in political science, certify that I reviewed the memo, and in good faith I claim that to the best of my professional knowledge the memo meets the standard of reasonable degree of scientific certainty in the art; the potential conflict of interests, which derives from my position as the Director of the US-based AG Joule, Corp. and its shareholder, warrants a supplementary expert review of the memo.

This memo manifests authors' personal opinion on the outlined subject. Although the authors drafted the memo in good faith and to the best of their knowledge, the authors notify the readers that the memo may not be free from inaccuracies and mistakes, and encourage the readers to exercise due diligence prior to using information presented in the memo for investment decisions.