Decision Time at Poland's PGE

Why a High-Risk, Fossil-Heavy Strategy Doesn't Add Up

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Executive Summary

PGE, Poland's largest utility, is facing a strategic choice that will determine the company's financial stability in the years ahead: stick with its current fossil fuel-heavy generation profile or begin transitioning to a renewable energy-based portfolio to start to address rising environmental and market risks.

The issue forcing this decision is the European Union's new round of air pollution emissions standards that take effect in 2021. These new, stricter standards—agreed to by EU member states last year and listed in a Best Available Techniques Reference Document (BREF)—will hit PGE hard. First, they require environmental upgrades whose cost will undermine the competitiveness of the associated power plants. Second, PGE will hope to use payments under Poland's new capacity market to fund the upgrades, but may find itself less able to secure these, given higher costs as a result of BREF and rising carbon prices. Critically, capacity payments and carbon prices are risks largely or wholly outside PGE's control.

PGE is majority-owned by the Polish government. It is overwhelmingly dependent on coal and lignite for its electricity generation. The company's hard coal and lignite plants accounted for 91% of total generation in 2017, compared with 4% from renewables, with the balance supplied by gas and biomass. The company's bias toward coal increased last year with its acquisition of the Polish assets as part of a strategic divestment by French utility EDF. As a result, PGE is one of Europe's biggest polluters and will be one of the European utilities most affected by the new emissions standards.

Company data for PGE's emissions of nitrogen oxides, sulphur oxides and dust for 2016 and/or 2017 show that just four out of 15 of the utility's smokestacks met the 2021 BREF standards for all three pollutants. In other words, PGE has a choice: it can move to close the non-compliant units and turn to cleaner alternatives, or it can invest to upgrade their environmental performance.

PGE's decision thus far has been to double down on its coal facilities, launching a major programme to upgrade its non-compliant units. In its 2017 annual report, the company said it plans to invest a further PLN 1.9 billion (€475 million)[1] to meet the 2021 standards. In recent announcements PGE has stressed its desire to go green, but we find evidence to the contrary: In 2017, capital expenditures in renewable energy fell 44% to just 1% of the group's total.

This report demonstrates that PGE's coal-heavy approach is misguided and will end up costing the utility much more than pursuing a strategy based on building new renewable energy generation.

To reach that conclusion, we use published BREF capital expenditure data at two of PGE's power plants, and our own estimates for additional costs, to calculate the impact of the new emissions standards on the levelised cost of electricity (LCOE) generation. We estimate BREF compliance would raise generation costs by 15% to roughly €40/MWh for a sample lignite power plant, and by 10% to €50/MWh for a coal-fired combined heat and power (CHP) plant.

For purposes of illustration, we compare these findings for coal and lignite BREF upgrades with LCOE estimates for the cost of electricity generation from new onshore and offshore wind

[1] Throughout this report we assume a Euro-PLN Zloty exchange rate of 0.25

farms and new solar power in Poland. We estimate the cost of onshore wind at €39/MWh, offshore wind at €62/MWh and solar power at €82/MWh. We conclude that ongoing deflation in renewables costs makes them broadly competitive with coal and lignite, while avoiding fuel, power and carbon price risk, and avoiding future cycles of tougher pollution controls.

We identify two key risks associated with PGE's BREF coal power upgrade investments: steeply rising carbon prices in the EU, and an emerging reliance on capacity payments under Poland's new capacity market.

Regarding carbon price risk, we note that EU allowance (EUA) prices have more than trebled over the past year, to €16 at the end of May, and analysts forecast rising prices through 2030. Higher carbon prices pose a particular financial risk for PGE because of its extraordinary reliance on high carbon-emitting coal and lignite. The company's allocation of free EUAs has steadily fallen over the past decade, following market rules, meaning it now has to pay for most carbon dioxide emitted. Resulting higher costs for coal and lignite power plants could mean they run less frequently and less profitably.

Regarding capacity market risk, Poland introduced a capacity market this year modelled on Britain's competitive auction model. PGE will hope that capacity payments cover the capex costs of its BREF upgrades and coal new-build programmes. However, we note that new technologies and interconnections have already disrupted capacity payment-based strategies in Britain, driving record low capacity market prices and forcing older coal units to retire. Such an outcome is a real danger for PGE.

We note other, wider risks to PGE's planned BREF upgrades. These include: low generation diversity which may impair its ability to refinance rising levels of net debt; expected growth in renewables both domestically and via imports which may have a deflationary impact on wholesale power prices and coal running times; EU-backed national investment in demand-side controls which poses down-side risk to PGE's demand projections; and other risks, for example to secure expanded mining concessions, rising mine rehabilitation costs and political risk from environmental activism.

We combine our estimated BREF compliance costs and two key carbon and capacity market risks in a "Hurry versus Wait" analysis, which compares two scenarios in a stylised thought experiment. The Hurry option involves an overnight shift to 100% renewables. The Wait approach maintains PGE's existing energy mix, at 96% coal and gas. The high-renewables scenario is €4 billion more expensive, on a present value basis, before we account for carbon costs and capacity payments. For the high-fossil fuel Wait scenario, even a generous assumption of €5 billion of capacity payments fails to offset €12 billion carbon costs under a €15 carbon price. The overall net result is that the Wait scenario is €3 billion more costly.

This analysis illustrates mutually reinforcing risks to PGE's fossil-heavy strategy. Environmental upgrades to comply with BREF, rising carbon prices and growth in renewables will all reduce the competitiveness of PGE's coal fleet, making it more difficult to compete in capacity auctions. PGE's reliance on future capacity payments therefore constitutes a large, unmitigated risk which is beyond their control. We conclude that PGE should transition to a majority renewables portfolio over the medium term and start that transition by diverting some of its planned air emissions upgrade expenditures to a green growth strategy. The benefits of accelerating a low-carbon transition at PGE include reduced carbon costs and neutralization of climate and pollution regulatory risks.

Given our findings, we offer these questions for PGE's independent shareholders and lenders to consider:

1. **Has PGE's strategy to comply with BREF, and to build new coal and lignite power plants, left the company with too little capital and strategic room for manoeuvre?** PGE is presently marching in the opposite direction of a low-carbon transition, and as a result most of its European utility peers.
2. **Which coal and lignite power plants and CHP units will PGE close, as a result of BREF?** PGE has not yet publicly responded to BREF with any closure plans. Its fleet includes old, non-compliant units where new environmental upgrades have not yet started, which are natural targets for closure, including certain units at the newly acquired Rybnik power plant.
3. **How independent is PGE from its majority shareholder, the Polish government?** PGE's current coal-heavy plan appears closely aligned with the government's policies. Undue strategic influence by the Polish government poses a corporate governance risk for independent shareholders given the lack of alignment with broader EU policies.
4. **What are PGE's real plans after 2020?** The company's "go-green" talk is decidedly light on specifics, for example including a long wish-list of possible interests, but entirely opposite to the actual actions of management over the last year.
5. **Does it make sense to identify a "significant easing of climate policy" as one of three key strategic options, as PGE management is doing?** Given PGE's large carbon exposure, to us it would be wiser to prepare for a much more aggressive tilting of climate policy, for example by committing to a firm target year for full decarbonisation.

Introduction

PGE Overview

PGE is a majority state-owned utility, with the Polish government controlling 57% of the company's shares.[2] The company is Poland's biggest electric utility by volume of electricity generation, generating capacity, volume of sales to end-users and number of customers. The utility's output in 2017 totalled 57 terawatt-hours (TWh), more than a third (36%) of Poland's total net electricity generation of 158 TWh.

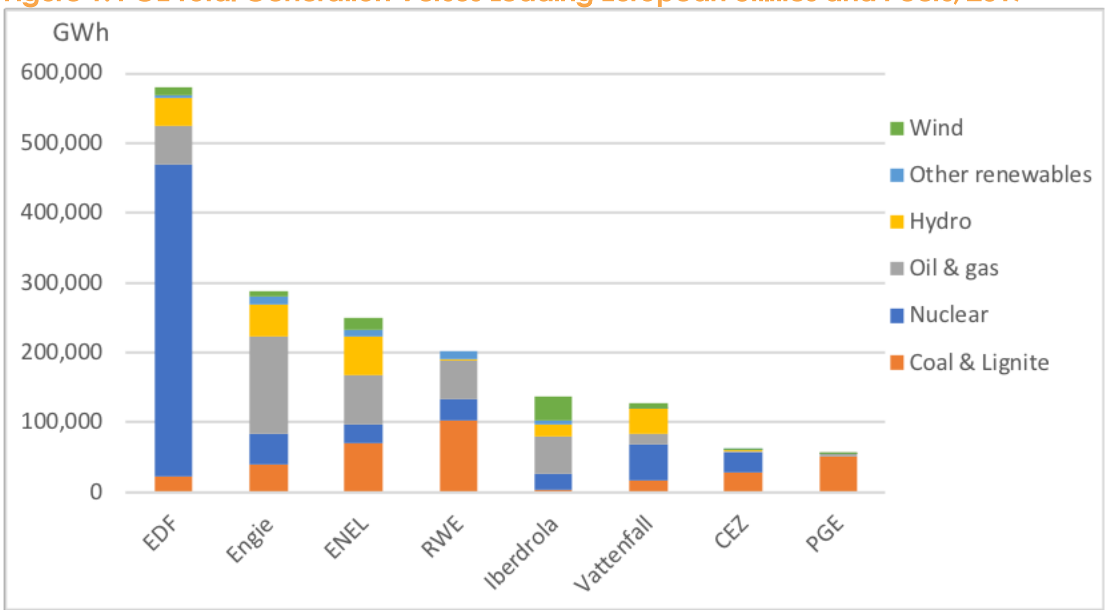
The company's generation is overwhelmingly fossil fuel-based. Coal and lignite (low-grade brown coal) accounted for 91% of the utility's generation in 2017. The remainder is from natural gas (5%), wind power (2%), hydro (2%) and other renewables (0.4%). PGE is more coal-intensive than Poland at large, where coal and lignite accounted for less than 80% of

[2] https://www.gkpge.pl/Investor-Relations/PGE-Group/PGE-BIG-BOOK

national generation in 2017, and wind power for 9%.[3] PGE is also the country's largest lignite miner, accounting for 78% of national production.

Figures 1 and 2 below compare PGE's total generation and energy mix in 2017 with major European utilities including Czech-based CEZ, which is one of its closest peers by region and size. As is evident, PGE is one of Europe's most coal-intensive major utilities, raising questions about its diversity of supply and exposure to environmental and climate regulations.

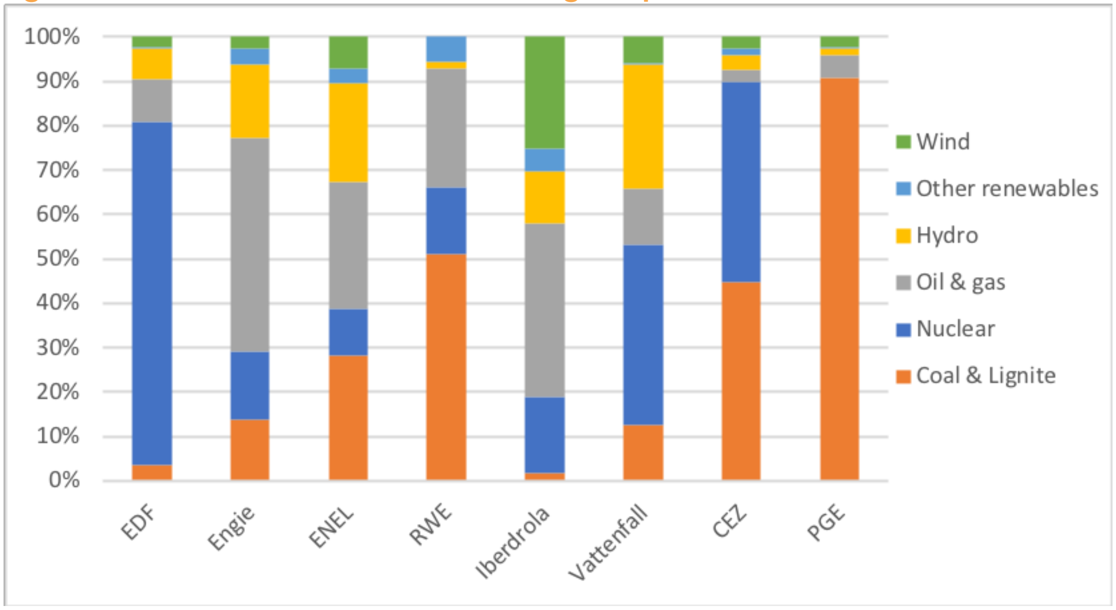
Figure 1. PGE Total Generation Versus Leading European Utilities and Peers, 2017



Source: IEEFA interpretation of utility company 2017 annual reports

[3] Poland's 2017 renewables generation data come from ENTSOE

Figure 2. PGE Generation Mix Versus Leading European Utilities and Peers, 2017



Source: IEEFA interpretation of utility company 2017 annual reports

Continued Coal Investment in 2017

PGE continued its coal-heavy investment focus in 2017. During the year, its capital expenditures and acquisitions in its power generation business were as follows:

Acquisition of EDF coal assets	PLN 4,270 million (€1,070 million)[4,5]
Capital expenditures (capex):	
• Construction of three new coal plant units	PLN 2,775 million (€694 million)
• Existing coal plants	PLN 586 million (€147 million)
• Renewables	PLN 81 million (€20 million)
• Gas (at Gorzow CHP)	PLN 60 million (€15 million)

PGE's capex in 2017 is summarised in Table 1. Conventional generation (coal, gas, biomass) accounted for 73% of group capex. Renewables accounted for just 1.2%, but almost 5% of earnings before interest, taxes, depreciation and amortisation (EBITDA). Renewables capex was down 44% from the previous year, while conventional generation capex dropped 21%. The utility-wide capex reductions may reflect a temporary rebalancing as the company absorbs the PLN 4.3 billion acquisition of EDF's coal assets. However, the disproportionate drop in renewables investment more likely is a reflection of the company's strategy to focus on the construction of new lignite/ coal plants, and upgrades to existing units. The figures below show how PGE's coal focus has narrowed its generation diversity.

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[4] https://www.gkpge.pl/Investor-Relations/PGE-Group/Acquisition-of-EDF-s-assets-in-Poland

[5] Throughout this report we use a €/PLN Zloty exchange rate of 0.25

Table 1. Comparing Size, Performance & Capex at PGE's Renewables & Conventional Businesses, 2017 [6]

		Renewables				Conventional						All PGE
		All	Wind	Solar PV	Hydro	All	Biomass CHP	Gas CHP	Coal CHP	Coal power plants	Lignite power plants	
Generation	2017, TWh	2.19	1.28	N/A	0.91	54.60	0.20	2.87	1.47	11.11	38.95	56.79
	Growth, 2017 v 2016, %	11.73%	18.52%	0.00%	3.41%	5.59%	-53.49%	23.18%	50.00%	3.73%	4.54%	5.81%
	Share of total, 2017, %	3.86%	2.25%	0.00%	1.60%	96.14%	0.35%	5.05%	2.59%	19.56%	68.59%	100.00%
Capacity	FY 2017, MW	2,190	550	1	1,639	14,081	114	1,637	839	4,694	6,797	16,270
	Growth, 2017 v 2016, %	2.58%	3.97%	0.00%	2.12%	32.65%	2.94%	172.62%	231.99%	64.47%	0.00%	27.62%
	Share of total, 2017, %	13.46%	3.38%	0.006%	10.07%	86.55%	0.70%	10.06%	5.15%	28.85%	41.78%	100.00%
EBITDA	FY 2017, PLN mln	364				4,099						7,650
	Growth, 2017 v 2016, %	-0.27%				-1.98%						3.71%
	Share of total, 2017, %	4.76%				53.58%						100.00%
Capex	FY 2017, PLN mln	81				4,899						6,751
	Growth, 2017 v 2016, %	-43.75%				-20.72%						-17.19%
	Share of total, 2017, %	1.20%				72.57%						100.00%

Source: PGE

PGE Strategy: Notes of Interest

Although PGE is a majority state-owned company, funding for its coal and lignite generation new-build and modernisation programmes, as well as its mining concessions, depends in part on private sector capital, including the sale of shares, bonds, Eurobonds and loans.[7] Eurobonds are issued via its subsidiary, PGE Sweden, which lends to PGE Group. In the section below, we highlight several issues that external investors might consider in evaluating current or future loans and/or share purchases.

- Prioritisation of volume over diversity

The lynchpin of PGE's strategy is to maintain its leadership in Poland's power generation sector. To ensure that leadership, the company is building new coal plants, investing to extend the life of its existing coal facilities, and purchasing third-party coal units (from EDF in 2017). The company's three new-build coal plant units (at Opole II and Turow II) alone will absorb nearly a third of its planned capex of PLN 34 billion (€8.5 billion) during its current five-year plan (2016-2020). These investments will give PGE "undisputed leader" status in Poland's power generation sector, but at a cost. This strategy will narrow its generation diversity while widening its exposure to tighter climate and air pollution regulations. PGE is already Poland's largest source of carbon emissions and air pollutants. Given the EU's ambition to decarbonise the power sector entirely in the near- to medium term, PGE's narrow coal-based focus looks extremely risky.

- Low visibility of post-2020 strategy

PGE states that beyond 2020 it will roll out a new capex program based on "selected strategic options, system needs and new market model."[8] However, its present coal- and lignite-based investment strategy will limit the company's flexibility after 2020, where it will be tied to running its new and refurbished coal assets. The time for a new approach, beginning

[6] This includes the acquisition of EDF assets from Nov 14, 2017
[7] https://www.gkpge.pl/Investor-Relations/PGE-Group/PGE-BIG-BOOK
[8] https://www.gkpge.pl/Investor-Relations/PGE-Group/PGE-BIG-BOOK

with a decision to close its oldest, most polluting coal plants, is now, in advance of new, stricter EU air emissions regulations (discussed in detail below) that take effect in 2021. Going forward, PGE lists a host of ideas and new technologies that are of interest, including "energy warehouses, electromobility, car sharing, bike sharing, construction of charging stations, LNG, diffuse energy sources, development of coal gasification installations, photovoltaics, intelligent home solutions, natural gas and demand management." But this is just a list, rather than a strategy.

- Identification of future "significant easing of climate policy" as a strategic opportunity

PGE is planning for a possible easing of climate policy by acquiring new lignite mining concessions to expand its available reserves of 973 million tonnes.[9] This strategy ignores widespread scientific recognition that global climate action is presently lagging climate risk, implying an acceleration rather than an easing of a political response in years ahead. Given PGE's existing fossil fuel bias, a more prudent position would be to begin planning for significantly more aggressive climate policy. A first step for PGE might be to commit to a firm target year for decarbonisation, to align closer with EU climate and energy policy and the Paris Agreement on climate change. In its 2017 management report, PGE rated carbon, fuel and power price risk as high, but falling. In fact, carbon prices have more than trebled over the past year, and continued rises could quickly transform the economics of coal generation in favour of gas, nuclear and renewables.

- Falling generation margins

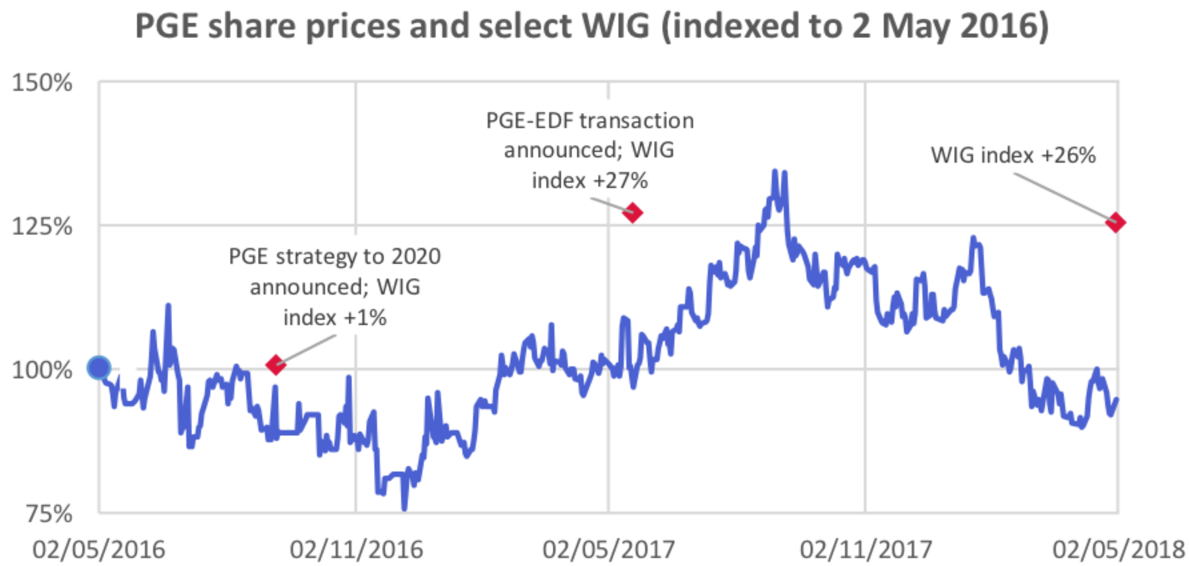
Overall, PGE's conventional generation rose 5.6% in 2017, due both to its EDF acquisition (which is accounted for in the company's reporting from November) and the return to operation of its Belchatow units after maintenance outages. However, EBITDA from conventional generation fell 2%. The drop can be traced to higher carbon costs, higher fuel costs, and lower wholesale power prices. The upshot is, even as PGE boosted its coal and lignite output, it made less money. PGE expects conventional generation EBITDA to fall again in 2018, due to lower lignite generation resulting from its continuing plant upgrades; higher hard coal prices; and higher carbon costs.

- Rising net debt

PGE has traditionally held very low levels of net debt, but its recent increased investment in coal and lignite has made the company cash flow negative. In turn, that has led to a steady rise in net debt (gross debt less cash), to PLN 7.6 billion (€1.9 billion) at the end of 2017, compared with PLN -1.0 billion (minus €250 million) at the end of 2014. Fitch ratings agency expects net debt to rise to three times funds from operations by 2020, a 10-fold increase in leverage compared with 2015. Nearly one quarter of PGE's gross debt of PLN 10 billion as of the end of 2017 falls due in 2019. Against this backdrop, we note that financial markets do not seem to be rewarding PGE for its 2016-2020 strategy, nor have they rewarded PGE for its 2017 acquisition of EDF's coal assets (see Figure 3).

[9] 973 million tonnes of existing lignite reserves are equivalent to about 1.2 billion tonnes of CO_2, if burned, using standard conversions. That is equivalent to more than 3% of global annual CO_2 emissions today of 36 billion tonnes from burning fossil fuels and cement production. https://www.carbonbrief.org/analysis-four-years-left-one-point-five-carbon-budget; To put it another way, PGE's existing lignite reserves are between 0.1% and 1% of the global CO_2 that the world can still emit cumulatively and stay below 2C and 1.5C warming respectively; see IPCC and Carbon Brief https://docs.google.com/spreadsheets/d/1GJSvGUtvgQifLYM0CUVJywaaTdSUJQjFq3qr5eC_Dzg/edit#gid=372766592

Figure 3. PGE Share Price Has Underperformed the Polish WIG Index since 2016



Source: IEEFA; Acousmatics

BREF: EU Limits on Emissions of Toxic Pollutants

What is BREF?

The EU's Industrial Emissions Directive (IED), requires large combustion plants (LCP) to use best available techniques (BAT) to control emissions of toxic air pollutants including nitrogen oxides (NOX), sulphur oxides (SOX), mercury and dust. Acceptable control techniques are updated, approximately every eight years, via a BAT reference document known as BREF. European Union member states agreed to new BREF emissions ranges in April 2017, with full implementation no later than mid-August 2021.[10] The next standards should be published around 2025 and implemented in 2029.

The BREF standards are based on technically and economically viable technologies for reducing emissions of the covered pollutants. The associated emissions levels (AELs) set the reference for EU member state regulators when permitting plants larger than 50 megawatts thermal capacity. There are separate emissions ranges for new and existing installations.

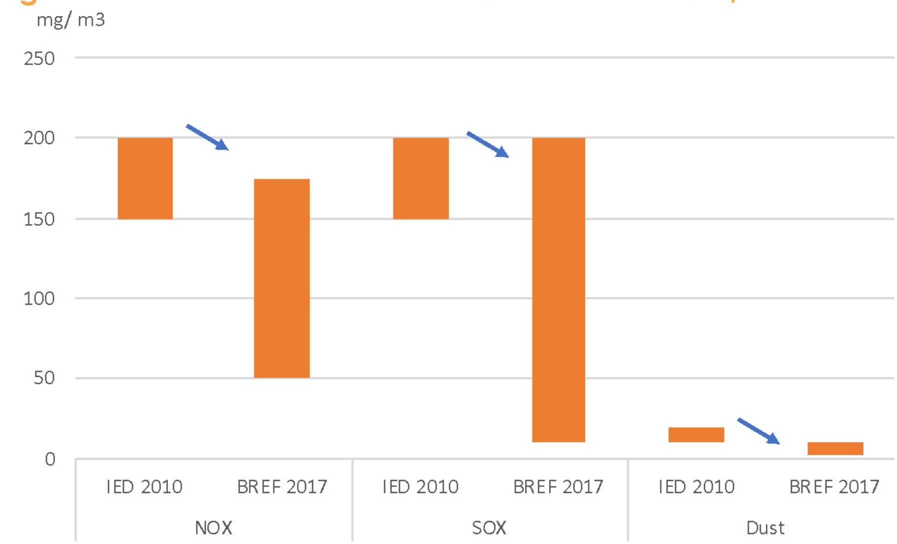
The new standards give owners of non-compliant units three principal choices: close; sell; or upgrade.[11] Regardless of the option taken, the looming 2021 deadline means utilities must decide now how they are going to comply. Closing may require purchasing or building replacement capacity, while upgrading certainly requires a contracting process that could take years. For example, a recent study by the U.S. Energy Information Administration

[10] http://eippcb.jrc.ec.europa.eu/reference/BREF/LCP/JRC107769_LCP_bref2017.pdf
[11] Power plant operators may also seek individual exemptions, or "derogations", from the standards

indicated that installation of these pollution reduction upgrades could take up to 50 months.[12]

In general, the regulatory direction is toward tougher limits on air pollutants. Figure 4 below shows the range of maximum allowed emissions of NOX, SOX and dust for new and existing power plants, as agreed under the Industrial Emissions Directive in 2010, and under BREF 2017. Emissions limits are expressed as annual averages under BREF and as monthly averages under IED. Figure 4 does not account for exceptions, such as far higher allowed SOX emissions under BREF for burning domestic lignite.

Figure 4. Emissions Limits under BREF 2017 Versus IED 2010, for New and Existing Power Plants



Source: IEEFA

PGE's BREF Exposure

BREF compliance is measured at the smokestack ("stack") level, as the mass of pollutant emitted per unit volume of flue gases. In larger power plants, several boilers burning coal may feed exhaust gases into the same smokestack, and there may be several stacks per power plant. For example, Belchatow, Europe's largest power plant by capacity, has 13 boilers and four stacks.

Table 2 below reviews reported emissions rates, in milligrams per cubic metre (mg/m3) of flue gases, for SOX, NOX and dust, at selected PGE power plants and combined heat and power (CHP) plants where data are available. These are stack-level emissions, as reported by PGE in 2016 and 2017. We compare these emissions rates with the allowed BREF ranges to identify the compliant smokestacks. The table shows emissions across 14 smokestacks at eight power plants and CHP units. Of these 14 stacks, just four were BREF-compliant across all three pollutants.

[12] https://www.eia.gov/todayinenergy/detail.php?id=32952

Table 2. Status of BREF Compliance at PGE, Based on 2016 and 2017 Emissions Data

Units	Overview			NOX				SOX				Dust			
				Emissions, mg/m3		Limit, mg/m3	Compliant?	Emissions, mg/m3		Limit, mg/m3	Compliant?	Emissions, mg/m3		Limit, mg/m3	Compliant?
	Fuel	Capacity MWe (gross)	Start date	2017 / when comes online	2016 (actual)	BREF (from 2021)	BREF (from 2021)	2017 / when comes online	2016 (actual)	BREF (from 2021)	BREF (from 2021)	2017 / when comes online	2016 (actual)	BREF (from 2021)	BREF (from 2021)
NEW BUILD															
OPOLE II															
5-6	Coal	1,800	mid-2019	65		85	YES	80		75	NO	7		5	NO
TUROW II	Lignite	448		70		85	YES	60		200	YES	4		5	YES
ORIGINAL PGE															
BELCHATOW															
1	Lignite	370	1981		294.9	175	NO		376.9	320	NO		3.6	12	YES
2-6	Lignite	1,904	1983-1985		180.2	175	NO		130.5	200	YES		3.2	8	YES
7-12	Lignite	2,340	1985-1988		159.3	175	YES		151.8	200	YES		2.8	8	YES
14	Lignite	858	2011		167.5	175	YES		114.2	200	YES		0.4	8	YES
DOLNA ODRA (ZEDO)															
1-2	Coal	454	1974	402	420	150	NO	115	122	130	YES	5	4.7	8	YES
5-8	Coal	908	1975-1977	154	144	150	YES	73	75	130	YES	3	4.1	8	YES
OPOLE															
1-4	Coal	1,532	1993-1997		189.8	150	NO		96	130	YES		7	8	YES
TUROW															
1-6	Lignite	1,533	1963-2000	183	182	175	NO	243	347	200	NO	24	23	8	NO
POMORZANY															
A & B	Coal	134	1959	501	504	180	NO	789	823	200	NO	42	54	14	NO
ACQUIRED FROM EDF															
RYBNIK															
1-8	Coal	1,775	1972-1978	326	333.2	150	NO	141	391.8	130	NO	19	14	8	NO
GDANSK-2															
5, 7, 9 & 10	Coal	217	1973-1994		187.5	150	NO		130.2	130	YES		4	8	YES
KRAKOW LEG															
1-4	Coal	460	1970-1985		348	150	NO		79	130	YES		11	12	YES

Costs and Risks of BREF Compliance

Analysis of PGE Costs

In this section, we measure the cost of achieving BREF compliance, using standard best available technologies. These technologies are flue gas desulphurisation (FGD) for reducing SOX emissions, and selective catalytic reduction (SCR) for reducing NOX emissions.

We use a levelised cost of electricity (LCOE) analysis to measure the cost of BREF compliance per unit of power generation. LCOE is a popular measure of cost because it is relatively easy to calculate, is transparent, and provides a benchmark for comparing the cost of power generation across different energy technologies. Its main drawback is that it focuses solely on generation cost, ignoring wider system costs and benefits. LCOE cost estimates depend critically on assumptions including the cost of debt and equity financing, depreciation period, and capacity factor.

We calculate LCOE BREF compliance costs at two PGE units, the existing Turow lignite power plant and the Bydgoszcz CHP facility. We use PGE's own estimates for overnight capital cost (i.e., excluding financing cost) derived from various official published reports. We complement this information by examining, where possible, information on the projects themselves from contractors.[13] We add our own estimate for financing cost, using a weighted average cost of capital (WACC) of 6.4%. Finally, we use a variety of sources for costs associated with the plants' operation and maintenance, and for variable costs, including fuel and carbon costs.[14] We provide details of our methodology and results in the Appendix.

LCOE Estimates for Lignite and Coal Upgrade Costs

This section examines PGE's planned BREF compliance efforts at four projects:

1. Full "modernisation" at Turow Unit 2 to achieve BREF compliance for SOX, NOX and dust. PGE does not specify which technologies were fitted. This is part of a larger project across Turow Units 1-3. Table 3 below shows the budget for all three units.
2. Desulphurization equipment (wet FGD) Turow Unit 4. This is part of a larger project across Turow Units 4-6. Table 3 below shows the budget for all three units.
3. Desulphurization equipment (semi-dry FGD) at Units 3 and 4 of the Bydgoszcz CHP plant
4. Denitrification equipment (SCR) at Units 3 and 4 of the Bydgoszcz CHP plant.

We select these units because of the availability of specific BREF capex data. They also comprise significant projects: their combined capex is €367 million. In addition, the four offer a good cross section of current PGE projects.

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[13] http://www.alstom.com/press-centre/2013/12/alstom-to-build-an-fgd-plant-for-pge-giek-sa-bydgoszcz-combined-heat-and-power-plant-complex-branch/

[14] https://ens.dk/sites/ens.dk/files/contents/material/file/introduction_lcoe_calculator.pdf; https://www.diw.de/documents/publikationen/73/diw_01.c.524200.de/dp1540.pdf; https://www.energybrainpool.com/fileadmin/download/Studien/Studie_2015-10-20_Greenpeace_Study_on_Lignite_Power_Plants_EnergyBrainpool.pdf

Table 3. Overview of Selected BREF Compliance Projects at PGE

Plant	Unit	Aim of capex project	Upgrade	Description of works planned/undertaken	Budget
Turow	1-3	Adaptation to future BAT conclusions requirements regarding permissible emissions of SO2, NOx and particulate, increase of availability and efficiency, as well as expansion of each turboset's nominal capacity by approximately 15 MWe	Various, no BAT identified by PGE	Comprehensive reconstruction and modernisation, including an upgrade of generator and steam turbines. The upgrades will result in a combined 45-megawatt (MW) output increase, and an increase in efficiency of up to 1,4%.	759
	4-6	To decrease the SO2 emission level to standard required in IED (<=200 mg/Nm3).	Wet FGD	Construction of desulphurization installations	530
Bydgoszcz	3-4	Reduction of SO2 emissions to a level allowing for further use after 2017	Semi-dry FGD, FGD	Construction of flue-gas desulphurisation	125 [1]
	3-4	Reduction of NOx emissions to a level allowing for further use after 2017	SCR	Construction of flue gas denitrification installation	53
Source:		PGE Management reports (2015-17)		**Total**	1467 PLN mln
Notes:	[1]	Includes 73 PLN M for the original FGD instalation by Alstom in 2016, and 52 PLN mln for the 2018 works			367 EUR mln

In our analysis, the LCOE value, expressed in €/MWh, represents the *additional* costs incurred by PGE to make its power plants BREF-compliant. We add these compliance costs to the wider variable costs of the plant. We model these costs for both lignite (Turow, at €34/MWh) and hard coal (Bydgoszcz CHP, at €46/MWh). For our base case LCOE estimates, we assume that the refurbished units will run to 2035 (18 years). We further assume that the units will produce at roughly the same capacity factor as reported by PGE for 2017, at 49% for hard coal CHP units and 75% for lignite units.[15]

Table 4 below summarises our main findings for BREF compliance costs at the four projects, both in euros per MWh, and percentage added cost to the total running cost of the associated power plant. It is important to note that we assume that each plant is no longer incurring capital recovery costs, and so our estimate is likely to be representative of the lower boundary of possible costs (i.e., total generation costs could be higher).[16]

[15] PGE Q4 & FY 2017 Financial and Operating Results presentation, page 15.

[16] It should be noted that Bydgoszcz is a CHP plant, and so it will earn additional revenues from the sale of heat, but this will in turn constrain its operational flexibility.

Table 4. LCOE Findings: The Cost of BREF Compliance

[A]	[B]	[C]	[D]	[E]	[F] = [D] + [E]	[G] = [D] / [E]
Plant	Unit	Upgrade	Upgrade LCOE (€/MWh)	Generating costs (€/MWh)	Total Generating costs (€/MWh)	Upgrade LCOE as a % of generating [1]
Turow	1-3	Various, no BAT identified by PGE	4.9	33.7	38.6	15%
	4-6	Wet FGD	3.5	34.0	37.5	10%
Bydgoszcz	3-4	Semi-dry FGD, FGD extension	3.8	46.4	50.2	8%
	3-4	SCR	1.6	46.4	48.0	3%

Source: IEEFA; Acousmatics; PGE Management reports (2015-17)
Notes: [1] For Units 2 and 4 Turow, and units 3-4 Bydgoszcz

The purpose of these calculations is not to produce a definitive cost of generation. Rather, we show that PGE is increasing its costs materially (and with certainty) in exchange for *potentially* higher but uncertain revenues. PGE's future revenues are uncertain because the utility is exposed to a variety of risks it cannot control under its current strategy. These uncertainties exist over different timescales and are driven by fundamentally different sources of risk, and so are additive, they sum up (see Table 5 below).[17] Many of these risks would not exist or would be largely mitigated if PGE elected to close some of its most polluting units and divert that freed up capex to EBITDA-positive renewables investments.

Table 5. Uncertainties Regarding the Cost of BREF Compliance

Time scale	Years	Key uncertainty (and source of risk)	Key variables	PGE exposure	Potential impact
Long	>5	Effects of technological change and of tighter pollution regulation	Discount rate, policy, technological advances	Large and growing	Stranded investments
Medium	2-4	The principal uncertainty impacting net revenues is related to capacity	Demand growth, new transmission, retirements, new builds, reserve margins	Medium and stable	Compressed operational margins
Short	<1	Cross-commodity short term interactions, weather, liquidity, operational variability	Electricity, fuel, CO_2 allowance prices, unit availability	Large and growing	Compressed operational margins

Source: IEEFA; Acousmatics.
Notes: Red text in "key variables" signals material downside potential for PGE. "PGE exposure" is a qualitative assessment.

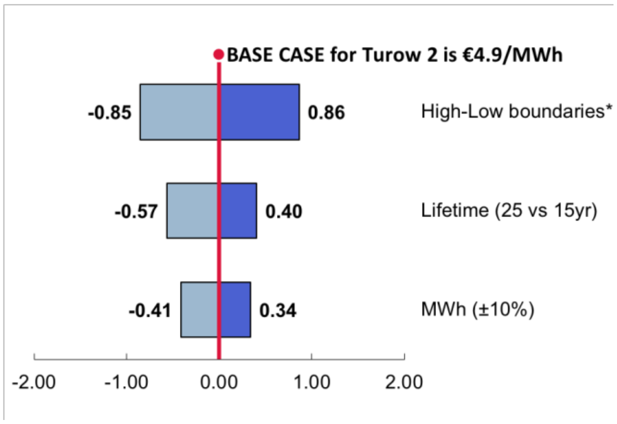
[17] Statistically speaking they are independent random variables. "The variance of a sum of independent random variables equals the sum of their variances". See TW Parkinson, "Market price risks of merchant generation", The Electricity Journal, May 2004

Turning to these uncertainties in more detail, PGE will not be able to control likely future regulation against fossil fuels. Neither will PGE have any control on slowing technology and learning-driven cost reductions in renewables. In turn, this may lead to constrained operation of its assets (fewer MWh produced) and/or to shortened lifetimes (premature closures).

We illustrate the impact of these two key uncertainties (capacity factor and lifetime) by running the same LCOE analysis with different assumptions for the number of MWh produced, and the number of years of operation. Figures 5 to 8 illustrate the impacts on abatement costs if we vary the project lifetime from 18 years to 15 to 25 years and change annual electricity generation by plus or minus 10%. We also combine both ranges, in a "high-low boundaries" case. The figures show that generation costs are materially increased if lifetime or capacity factor are lower than our base case assumptions.

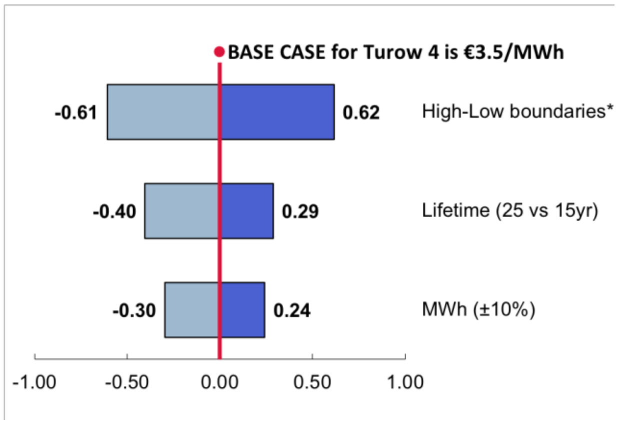
The figures show that, after taking these sensitivities into account, general BREF compliance and modernisation at Turow Unit 2 adds €4-6/MWh; de-SOX at Turow Units 4-6 adds €3-4/MWh; de-SOX at Bydgoszcz Units 3-4 adds €3-5/MWh; and de-NOX at Bydgoszcz Units 3-4 adds €1-2/MWh.

Figure 5. Sensitivity Analysis of BREF Compliance Cost at Turow Unit 2 (Modernisation)



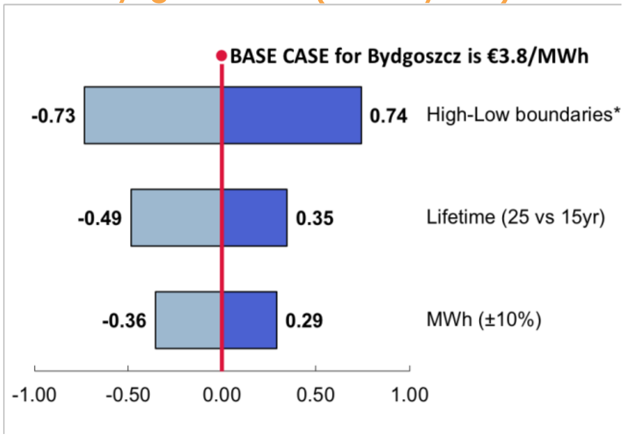
Source: IEEFA; Acousmatics. Note: High boundary represents a combination of a long lifetime and oversized production. Low boundary is the combination of a short lifetime and undersized production.

Figure 6. Sensitivity Analysis of BREF Compliance Cost at Turow Unit 4 (wet FGD)



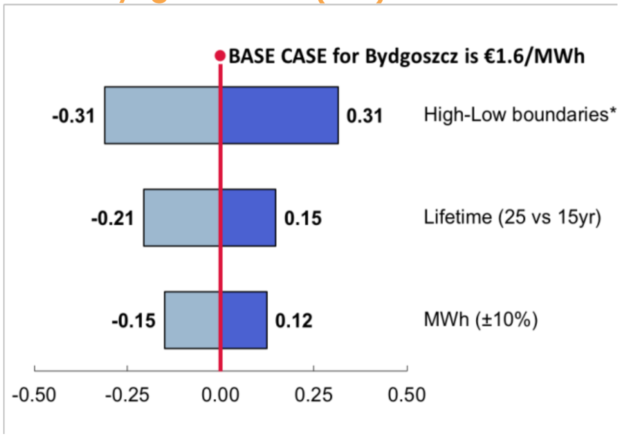
Source: IEEFA; Acousmatics. Note: High boundary represents a combination of a long lifetime and oversized production. Low boundary is the combination of a short lifetime and undersized production.

Figure 7. Sensitivity Analysis of BREF Compliance Cost at Bydgoszcz II 3-4 (semi-dry FGD)



Source: IEEFA; Acousmatics. Note: High boundary represents a combination of a long lifetime and oversized production. Low boundary is the combination of a short lifetime and undersized production.

Figure 8. Sensitivity Analysis of BREF Compliance Cost at Bydgoszcz II 3-4 (SCR)



Source: IEEFA; Acousmatics. Note: High boundary represents a combination of a long lifetime and oversized production. Low boundary is the combination of a short lifetime and undersized production.

LCOE Estimates for Renewables

One of the reasons we used a LCOE approach is that it facilitates cost comparisons with alternative generation options such as renewables. In this section, we apply a similar LCOE approach as described above and in the Appendix to derive corresponding cost estimates for new renewables projects in Poland.

Our renewables estimates used International Energy Agency estimates for capital cost (including connection cost for offshore wind), and projections for cost reductions through 2022.[18] We used a range of published sources for operation and maintenance (O&M) costs.[19] We use World Bank data to estimate the quality of onshore wind and solar resources in Poland,[20] and a combination of historical data and turbine manufacturing data to estimate generation from offshore wind.[21] We discounted these lifetime costs and generation over 25 years using a weighted average cost of capital (WACC) of 5.8%.[22]

Our LCOE models derived onshore wind generation costs of €39/MWh, offshore wind costs of €62/MWh and solar power costs of €82/MWh. These estimates are for contracts awarded now and built in the early 2020s. We note that a 2017 renewables auction in Poland saw solar power bids below 390 PLN (below €95), indicating our LCOE estimate is broadly correct.[23]

We conclude that renewables are broadly competitive with coal and lignite, while avoiding fuel, power and carbon price risk, and future cycles of tougher pollution controls.

Review of Wider Risks

The wider risks to PGE from its BREF compliance investments are similar to those encountered by Europe's other coal-heavy utilities in the last five years. Headwinds have included lower power prices and running times as a result of growth in renewables output, rising carbon prices, and a general trend toward coal phaseout.

As a consequence of its current fossil-heavy strategy, we identify two particular risks faced by PGE: first, failure to secure successful bids for capacity payments; and second, large and increasing costs of carbon emissions to be paid when its units generate power.

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[18] https://www.iea.org/publications/renewables2017/; For onshore wind, we applied an IEA forecast of a 7% drop in global average installed costs from 2016-2022, to $1.4 million/MW from $1.5 million/MW, and applied a 0.82 €/$ exchange rate. For solar, we applied an IEA forecast for a 25% fall in global average installed costs from 2016-2022, to $1.25 million/MW from $1.7million/MW. For offshore wind, we applied an IEA forecast of a 20% fall in global average installed costs (including grid connection) from 2016-2022, to about €2.6 million/MW from the low end 2016 range of €3.3 million/MW.

[19] For onshore wind O&M, we used the mid-point of Deloitte estimated wind farm costs, at 20% of revenues; https://www2.deloitte.com/content/dam/Deloitte/global/Documents/Energy-and-Resources/gx-er-deloitte-establishing-the-wind-investment-case-2014.pdf. For solar O&M, we used actual or expected EBITDA published by Scatec Solar, at 10% of revenues, for its 400 MW portfolio; http://www.scatecsolar.com/Investor. For offshore wind O&M, we used the IEA's estimated 25% of total generation costs.

[20] We assumed a 12.6% capacity factor for solar, based on http://globalsolaratlas.info; we assumed a 34.2% capacity factor for onshore wind, based on https://globalwindatlas.info.

[21] We assumed an output of 4,500 MWh/MW installed, based on historical output of 4,200 MWh/MW at existing Baltic offshore wind farms (https://www.enbw.com/renewable-energy/wind-energy/our-offshore-wind-farms/baltic-2/), coupled with rapid technology improvements (e.g., the 12 MW GE offshore wind turbine that can produce 5,600 MWh/MW). See https://www.ge.com/renewableenergy/wind-energy/turbines/haliade-x-offshore-turbine

[22] We note that we used a lower WACC for renewables, at 5.8%, compared with coal and lignite, at 6.4%. This was based on the view that renewables projects benefit from lower development risk compared with conventional generation because of faster construction.

[23] https://www.pv-magazine.com/2017/07/10/poland-contracts-4-725-twh-of-power-in-renewable-energy-auction-renesola-awarded-42-mw-of-solar/

Capacity Market Risk

Coal-intensive utilities argue that 24/7 generation, also called baseload, will continue to be needed, at least during the transition to a low-carbon energy sector. They therefore contend that baseload should be rewarded with new, additional revenues to pay for assuring system reliability, given that growth in renewables has reduced their revenues in energy-only markets. These arguments have been used to drive legislation creating a capacity market in Poland, which will reward baseload generation including coal and lignite for being available (see Box 1).

PGE is explicit that the capacity market will be critical to funding its BREF upgrades:

"The implementation of a capacity market, being a mechanism enhancing the national energy security, has a positive impact on the economic effectiveness of modernisation projects." [24]

The ratings agency, Fitch, described the introduction of the capacity market as positive for Polish coal generators.[25] That assessment was on the basis of expected capacity market revenues of PLN 4-5 billion annually (net of lower wholesale energy market revenues of around PLN 1.5 billion annually). That compared with estimated, aggregate EBITDA from power generation of PLN 5 billion at the four main state-controlled utilities (including PGE) in 2018. Thus, the capacity market subsidy would substantially boost EBITDA and provide predictability. However, Fitch warned that failure to win capacity contracts would threaten utility credit ratings, given their capex plans and present levels of net debt. Fitch described the capacity payments as critical for the profitability of PGE's new-build coal projects, given otherwise unfavourable market conditions.

Poland has introduced its capacity market at a time of uncertainty at the EU level regarding participation of coal power plants. Specifically, the European Commission has proposed banning capacity payments for all generation emitting more than 550g of CO2 per kWh, which would rule out all coal. This "Clean Energy Package" is presently being negotiated. It will probably include a delayed phase-in period, perhaps of five years for new coal and 10 years for existing coal. If the package were adopted in 2020 with such rules, that would imply an end to newly agreed capacity contracts for new and existing coal from 2025 and 2030. Given that Poland plans to hold its last main capacity market auction in 2025, the impact of this regulation may be small, depending on final provisions that are unknown at present.

[24] PGE 2017 management report
[25] https://www.fitchratings.com/site/pr/10020265

Box 1. Poland's New Capacity Market

Poland introduced in 2018 a fully-fledged capacity market, intending to ensure near and mid-term security of power supply. The market secured European Commission state aid approval in February 2018, removing the last hurdle to implementation.

The first capacity auctions are planned for late 2018. Auctions will be held for capacity between one and five years before delivery. The last auction is scheduled for 2025, implying that the last capacity agreements (implemented from 2030) will expire around 2045.[1] The basic format of the market is a reverse, pay-as-clear auction, offering one, five and 15-year capacity contracts, for existing, modernised and new generation, respectively. "Modernised" capacity is defined as upgrades to generation or demand-side response (DSR) incurring capex of PLN 0.5-3 million per megawatt. New generation should incur capex of more than PLN 3 million/MW. To secure European Commission approval, Polish authorities changed the format of the scheme to make it technology neutral and to allow the participation of cross-border, interconnected capacity (although overseas capacity is treated differently, potentially receiving a lower clearing price, specific to its country or bidding zone).

There are some features of Poland's new capacity market that give preference to non-coal units. DSR can bid for 5-year contracts in the case of new DSR. In addition, pass-through of capacity market costs is different for industrial energy consumers. For these consumers, levies are based on peak-time consumption, providing an additional incentive to provide DSR services. Low-carbon units (emitting below 450g CO_2/kWh) get an extra two years in their capacity contracts, for seven and 17-years in the case of modernised and new units respectively.

Nevertheless, coal is a big winner, and especially recently built or new coal. Coal power plants built after July 1, 2017 qualify as new units, and therefore for 15-year capacity contracts, as opposed to just one or five years. This feature of the scheme clearly favours new-build coal power plants.

[A] Sources for this box are notes published by Client Earth in Poland, and Fitch Ratings; they are available here: https://www.documents.clientearth.org/wp-content/uploads/library/2018-02-07-assessment-of-the-polish-act-on-the-capacity-market-ce-en.pdf; and https://www.fitchratings.com/site/pr/10020265

Carbon Price Risk

The European Union's emissions trading scheme (ETS) requires large carbon-emitting installations to allocate one permit, called an EU allowance (EUA), for each tonne of carbon dioxide emissions. Most electric utilities received some free EUAs until the end of the second trading phase in 2012. But utilities in selected countries including Poland continued to receive a free allocation. That allocation is now shrinking year on year through 2020. The precise rules for any continued free allocation beyond 2020, including any attached conditions, are yet to be agreed, but PGE will have to purchase EUAs to cover most of its carbon emissions.

We make four observations with respect to PGE.

1. Carbon prices are rising as a result of EU carbon market reforms. These reforms are slowly eliminating the EUA surplus that accumulated during and after the global financial crisis. As the surplus is removed, supply and demand will more closely align, and prices will rise. Carbon prices have more than trebled over the past 12 months, to €16 per tonne of carbon dioxide emissions in May 2018, from €5 in May 2017.[26] Prices are expected to rise further. In its latest forecast, Carbon Tracker expects prices to rise to €20 in 2019, and to €25-30 by 2020-21.[27] Thomson Reuters Point Carbon has a less bullish forecast, projecting EUA prices of €25 in 2030.

2. Even as PGE modernises its generation fleet to adapt to BREF pollution standards, it will remain exposed to carbon price risk. Illustrating this effect, PGE's CO2 emissions rose 6.3% in 2017, excluding the effect of the EDF transaction. This was the first increase since 2013 and was due to the return to full generation at the newly upgraded Belchatow units.

3. PGE is further increasing this risk, by acquiring EDF assets, and by planning to bring online its own new-build coal and lignite generation in 2019 and 2020 (Opole II and Turow). The EDF acquisition increased PGE's total 2017 carbon emissions by 21%.

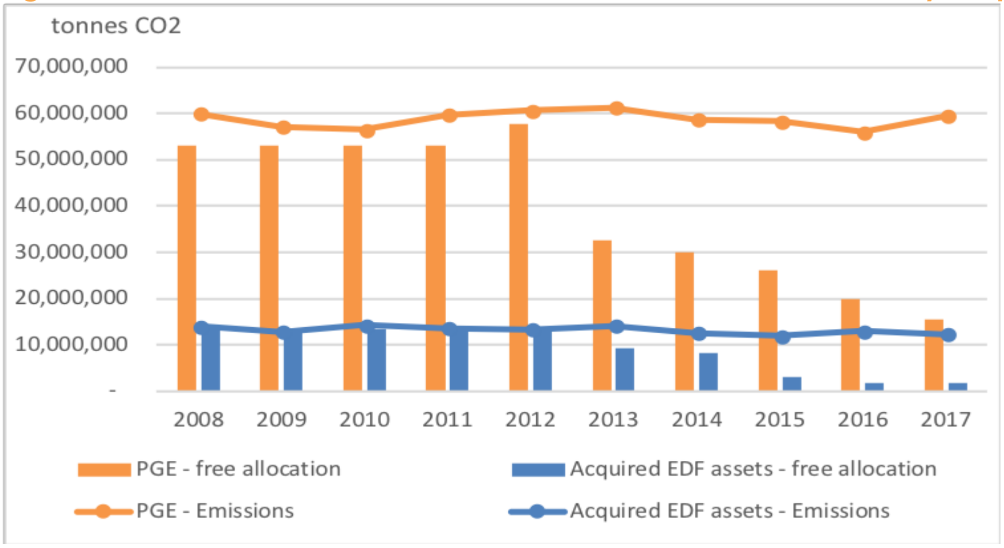
4. PGE's annual allocation of free EUAs has steadily fallen across the present trading phase, which ends in 2020. Its free EUAs started at 30 million tonnes in 2014, dropped to 15 million tonnes in 2017, and will fall to just 0.4 million tonnes in 2020.[28] PGE emissions already far exceed its free allocation, meaning it has a net shortfall that it must cover by purchasing EUAs at market prices. The same goes for the former EDF assets PGE acquired (see Figure 9 below).

[26] https://www.theice.com/products/197/EUA-Futures/data

[27] https://www.carbontracker.org/reports/carbon-clampdown/

[28] https://www.gkpge.pl/Investor-Relations/PGE-Group/PGE-BIG-BOOK

Figure 9. Carbon Emissions and Free EUA Allocation, at PGE and its Newly Acquired EDF Assets



Source: PGE, EU Registry

The Risks of Renewables Growth

Domestic Renewables

Renewables can be divided between flexible sources available on-demand such as geothermal, hydropower and biomass, and variable sources such as wind and solar. Wind and solar are growing fastest, because of rapid cost reductions, rapid deployment times and because they are less limited by geography. Variable renewables pose a particular threat to coal because of very low operating costs, and because their variability places a new emphasis of flexibility among other power sources. To date, European Union countries have dominated global growth in variable renewables, as a share of total generation. Poland has seen slower growth than many EU countries but is still in the top 20 in a global ranking of wind and solar as a share of total generation. Wind generation in Poland doubled in the past four years, to 14.6 TWh in 2017 from 7.3 TWh in 2014. Wind last year reached 9.3% of all power generation and recorded new monthly records in October and December of 14%.[29] However, we note a recent domestic bill may restrict further growth by limiting where wind farms can be built.[30]

Growth in renewables will affect coal in three ways:

1. First, renewables usually have very low operating costs (with the exception of biomass). That means renewables are generally dispatched to the grid first, displacing other generation including coal (which therefore has a lower load factor).

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[29] https://ec.europa.eu/energy/sites/ener/files/documents/quarterly_report_on_european_electricity_markets_q4_2017_final.pdf

[30] https://www.reuters.com/article/us-energy-poland-windfarm/poland-adopts-limits-on-where-wind-farms-can-be-built-idUSKCN0YE17V

2. Second, because they have lower operating costs, renewables tend to lower wholesale power prices.
3. Third, variable renewables such as wind and solar power require balancing by other more flexible sources, depending on their availability. That forces other generation including coal to ramp up and down, or cycle, more frequently. Significantly, such cycling increases emissions, requiring best-in-class abatement to remain BREF-compliant.

Imports via Cross-Border Interconnection

Interconnection to neighbouring countries is sound policy for a country like Poland, with limited domestic diversity of supply, rising electricity demand, a rather narrow buffer of surplus capacity, and a central-east European location with multiple land borders to Lithuania, Ukraine, Slovakia, the Czech Republic, Germany and Sweden.

Poland cross-border interconnection capacity with its neighbours currently totals 7,261 MW, equivalent to 27% of its peak demand of 26,500 MW, an adequate level compared with other EU member states. However, at present there is significant under-utilisation of its interconnection with Germany, in particular. This under-utilisation is caused by a long-standing problem of electricity routing from sellers of renewable power in northern Germany to buyers in Austria via Poland's transmission system. This loop flow occurs because of transmission bottlenecks in central Germany. Poland has responded to the risk that loop flows clog its transmission capacity by using phase shifters and other measures to reduce or block these unintended imports.

A discussion of potential solutions to this problem is beyond the scope of this paper, but we note that options will focus on soft measures such as improved cross-border cooperation, which will be far more cost-effective than massive domestic investment in new coal and other generating capacity. We would therefore expect such measures to prevail, and Polish electricity imports to rise, which, in turn, would put downward pressure on domestic capacity factors and wholesale power prices.

Other Risks

Although beyond the scope of this report, there are two other risks that must be mentioned. First, there is uncertainty over extended environmental permits for mining concessions. For example, PGE says its new Turow power plant unit will use existing lignite deposits, but it has still not confirmed the relevant permits.[31] Second, environmental protests represent an important political risk that has delayed or led to the cancellation of multiple coal power projects around the world. In Germany, for example, vocal opposition has delayed the planned Datteln 4 coal plant for a decade already. PGE and its investors need to factor the potential for similar opposition into the company's power plant upgrade and construction plans.

[31] https://www.gkpge.pl/Investor-Relations/PGE-Group/PGE-BIG-BOOK

PGE's Strategic Choices

Hurry vs Wait

In this section, we consider our LCOE estimates for BREF compliance costs and the two key risks we identified, carbon price and capacity market risk. We apply a "Hurry vs Wait" analysis modelled after Weiss-Murphy (2017)[32], who used the approach to compare the carbon emissions and total system costs of slower versus accelerated renewables deployment scenarios.

We designed two scenarios representing two alternative ways to imagine PGE's future: "fossil heavy" (Wait) and "going green" (Hurry). We assume that under the Wait scenario, PGE management decides to stay the course and commit to a "fossil heavy" future, continuing its present energy mix sourcing 96% of its electricity from fossil fuels. In the Hurry scenario we assume that PGE management abandons fossil fuel generation and switches overnight to a 100% renewables portfolio, "going green".

Following Weiss-Murphy, in our calculations we use only running costs for fossil resources, but full costs including capital costs for renewables.[33] In other words, we are comparing the cost of new renewables with the cost of existing coal and lignite. We use the LCOE analysis discussed earlier for the costs of fossil fuel and renewables generation, adding an assumed annual cost reduction in the case of renewables, continuing the long-run trend.[34] We then sum the expected cash outlays from 2018 to 2045, the last year that PGE could theoretically benefit from capacity payments under Poland's current rules. And we derive the present value of these costs using an assumed 5% discount rate.

Findings

We calculate a present value for costs under the Wait "fossil heavy" scenario of €39.3 billion, and a corresponding cost for the Hurry "going green" scenario of €43.3 billion. It should be no surprise that the Hurry scenario is more expensive, since we do not consider the sunk capital costs of fossil fuels, and because higher renewables costs occur earlier and so are discounted less.

Next, we incorporate our identified key risks/uncertainties, carbon prices and capacity market payments. Regarding carbon prices, we estimate a present value for carbon costs under the Wait scenario of €12.2 billion. We conservatively assume that today's €15 carbon price remains unchanged through 2045, and a carbon intensity of 0.9 tonnes CO_2/MWh

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32 https://www.bu.edu/ise/files/2017/04/BU-ISE-Seminar-Hurry-or-Wait-Dean-Murphy-Jurgen-Weiss.pdf

33 "By using only going forward costs for fossil resources, but full costs including capital costs for new renewable generation, we reflect the economics of our fundamental question: is it worth accelerating the replacement of existing fossil generators with new renewable generation, weighing the additional costs that would be incurred against the benefit of lower cumulative CO_2 emissions?" Weiss and Murphy (2017).

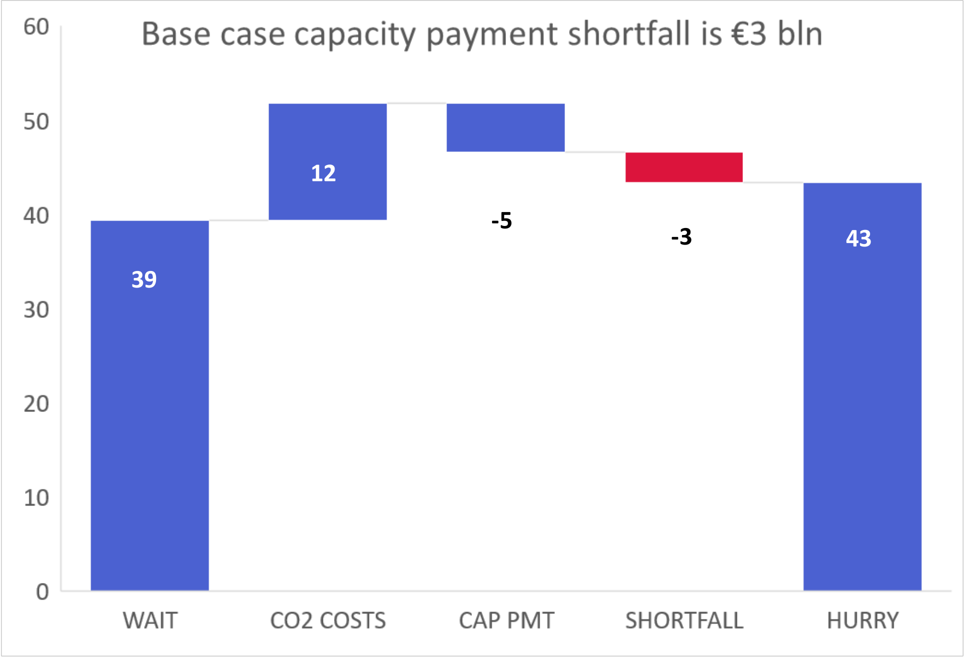
34 Regarding fossil fuels, we take an approximate weighted average of PGE's generation in 2017 (70% lignite, 30% coal) and apply this to our all-in BREF-compliant LCOEs above, to derive a cost of €42/MWh which we hold constant through the 28-year period. Regarding renewables, we average our LCOE estimates above for onshore and offshore wind and solar, assuming these are deployed equally by capacity, deriving an initial cost in 2017 of €60/MWh. We reduce this figure by 3.3% annually to take account of continuing cost reductions, until the cost of new renewables equals the cost of existing coal and lignite in 2028, i.e., €42. After this, we hold the costs of renewables constant.

across the coal and lignite fleet. We note that there are no carbon costs under the Hurry scenario.

Turning to the potential benefit of the capacity market for PGE's coal and lignite, we calculate a present value for capacity payment inflows under the Wait scenario of €5.2 billion. This calculation is based on assumptions that PGE is awarded capacity payments of €2.1/kW-month for every megawatt of installed fossil fuel and biomass generation as of the end of 2017 (14,081 MW), for the maximum possible period.[35] We note that these are extremely generous assumptions. First, the capacity payment is derived from the highest clearing price to date in the U.K. T4 auction, on which the Polish capacity market is based, of £22.50 per kilowatt-year. We note the most recent U.K. clearing price was just £8.40. Second, as a competitive market, there is no way PGE in reality would be successful in all its capacity bids. We assume zero capacity payments under the Hurry scenario.

Figure 10 below uses a waterfall chart to combine the overall net impact of these various generation costs, carbon prices and capacity payments. The €12.2 billion carbon cost makes the Wait scenario considerably more expensive than the Hurry scenario. Subtracting capacity payments of €5.2 billion reduces the difference somewhat, but the fossil heavy option still ends up costing €3.0 billion more than the going green scenario.

Figure 10. The Present Value of a Wait "Fossil Heavy" Scenario is More Expensive than Hurry "Going Green" after Accounting for Carbon Costs and Capacity Payments



Source: IEEFA and Acousmatics

[35] We assume capacity payments are available from 2018-2045. This is an excessively generous assumption. First, actual payments will only start from 2021. Second, any individual unit will only be eligible for a maximum of 15 years of payments. Third, 2045 is the latest possible end-date.

Conclusions

PGE is investing significant capital to bring its oldest coal and lignite power plants into compliance with the EU's new air pollution standards, thereby extending their operating life. The goal behind these investments is to maintain the company's market leader status in power and heat generation in Poland. PGE stresses that there are advantages to being the market leader, but this strategy comes with significant risks. First, there is the risk of lack of diversification in distinct contrast to its peers. Second, this fossil fuel-heavy strategy exposes PGE to massive risk from the EU carbon market and the Polish capacity market. If carbon allowance prices rise over time (not an unlikely event, and largely out of PGE's control) the company will have to spend increasing amounts of capital to cover its carbon emissions. In addition, should PGE fail to secure timely, long-lasting, reliable and appropriately sized capacity payments (also largely out of PGE's control) the consequences could be toxic for PGE, undermining its financial stability.

Our Hurry vs Wait analysis shows clearly that PGE's strategy is heavily reliant on capacity payments, and that these are still not enough. Unfortunately for PGE, there is no certainty that it will secure even these levels of capacity payments. In other words, there is the risk of "fat tail" events for PGE associated with capacity payment cash flows. Our Hurry v Wait analysis suggests that failing to secure capacity payments could pose an existential risk to PGE, given the magnitude of the excess costs associated with that strategy. Even if the fossil heavy scenario were cheaper than all renewables, it would still make sense to insure the company against capacity market and carbon price risks, through a progressive shift to more zero emissions, near zero operating cost renewables generation. The fact that the Wait option (the one essentially being pursued by the company now) is actually much more expensive than the Hurry scenario illustrates just how big and fast a shift this should be.

These two scenarios are designed to be extremes, and a practical solution lies somewhere in between the two. At present, PGE is going fossil heavy, which risks leading the company into a vicious circle. More investments in fossil energy means sinking capital into being available to collect capacity payments, and to pay for carbon emissions. We have shown that it would cost less (in present value terms) for PGE to switch to a majority-renewables portfolio, while also reducing the company's environmental regulatory risks.

Appendix

LCOE Cost Assumptions

LCOE analysis sums the discounted capital and operating costs over the lifetime of an energy asset. This sum is divided by the expected total generation for the same asset. The LCOE then is the cost per unit of electricity generated that makes costs equal revenues on a present value (PV) basis at a chosen discount rate.

We use the formula shown below. We discounted all values according to a weighted average cost of capital (WACC) of 6.4% for coal and lignite generation, derived from assumed costs of debt and equity and capital structure. For example, for the Turow Unit 2 modernisation, the results are as follows:

LCOE = Discounted lifetime totals for (A+B+C+D)/ E = €4.9/ MWh

Annual return of cash to investors (over 18 years)	€14,056/MW
Annual O&M costs (@ 0.5% of capital cost/GWh generated)	€8,263/MW
Annual equity cost (@10%), assuming debt to equity of 70:30	€7,590/MW
Annual debt cost (@6%), after corporate tax (@19%)	€10,626/MW
Annual electricity generation, MWh per MW installed	6,950 MWh

A. **Return of cash to investors**. We apply straight-line depreciation of the upfront capital expenditure (capex) over a certain depreciation period. We derive our capex number from PGE's 2016 management report, which describes BAT compliance works costing PLN 759 million across three Turow units of 250 MW each, or €253,000 per MW. We assume an 18-year depreciation period. This value is benchmarked on the modernisation contract signed by PGE with GE, which aims "to extend equipment lifetime by at least 150,000 hours".[36]
B. **Operating and maintenance (O&M) costs**. We use assumptions taken from the German consultancy Energy Brainpool and from DIW, the German Institute for Economic Research.
C. **Equity costs**. We assume a 70:30 debt to equity split to finance the project. Regarding cost of equity, we assume a 10% return on capital. We ran several sensitivities on WACC and found our results to be relatively invariant (assuming a 20% variation in WACC).
D. **Debt costs**. We assume a 6% lending rate. We factor in Poland's 19% corporate tax rate.
E. **Electricity generation**. We assumed a generous 79% load factor, based on actual generation data from PGE for its lignite units in 2016-17 (2017 = 75.3%), but note the global average coal fired power plant is significantly lower (57% in India, 48% in China).

We add the calculated LCOE of €4.9/MWh of the Turow Unit 2 retrofit, to a modelled cost of generation at the associated 250 MW lignite power plant of €33.7/MWh. We conclude that the retrofit could increase generation costs by 15%, for a total cost of €38.6/MWh.

[36] https://www.genewsroom.com/press-releases/ge-signs-%E2%82%AC40-million-agreement-pge-modernize-polish-power-plant-282623

Risks to Our Thesis

In this study, we find that PGE's ongoing programme to build new coal and lignite power plants plus its recent acquisition of EDF's coal assets in Poland have led to higher levels of net debt, and increased the urgency for the utility to secure contracts under Poland's new capacity market. However, the cost of new environmental regulations and PGE's large exposure to rising European Union carbon prices threaten to undermine the competitiveness of PGE's coal and lignite power plant fleet, making it more difficult to compete in prospective capacity market auctions. We conclude that PGE's fossil fuel-heavy strategy entails serious financial risks, which it should mitigate through a near and medium-term shift away from coal and lignite.

We review briefly some risks to this thesis.

1. PGE becomes more cash-generative, making it less dependent on competing in the capacity market. One area where PGE anticipates earnings growth is in heating provision, partly as a result of its acquisition of EDF assets. PGE expects to lead the district heating market in Poland, to connect new customers, and to increase related earnings. Its strategy is based on expectations of rising heating demand and lower costs. However, we note that the strategy still anticipates stable incomes as a result of successful participation in the capacity market, and is still vulnerable to environmental regulations, while it assumes qualification for free carbon emissions allowances and EU funds for energy sector modernisation.

2. Lower carbon prices allow PGE to compete successfully in the capacity market, and reduces wider risks to its fossil fuel-heavy strategy. EU carbon prices have risen sharply over the past 12 months, and are projected to continue to rise over the next decade as a result of reforms which will reduce an EU-wide surplus of emissions allowances, restoring price tension to the market. However, carbon prices may rise less slowly, if reforms fail to remove the surplus as quickly as expected, or if demand for allowances falls, for example as a result of economic recession, or faster than expected buildout of renewables or phaseout of coal (although these last two events would simultaneously hamper PGE's market revenues).

3. Poland's legal challenge to BREF is successful. Poland brought legal action against the European Commission in October 2017, seeking to annul the new round of emissions limits. Poland both contested the process for revising the emissions ranges, and the levels of those ranges. If successful, Poland may at least delay implementation of the revised BREF, and so limit the cost impact.

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