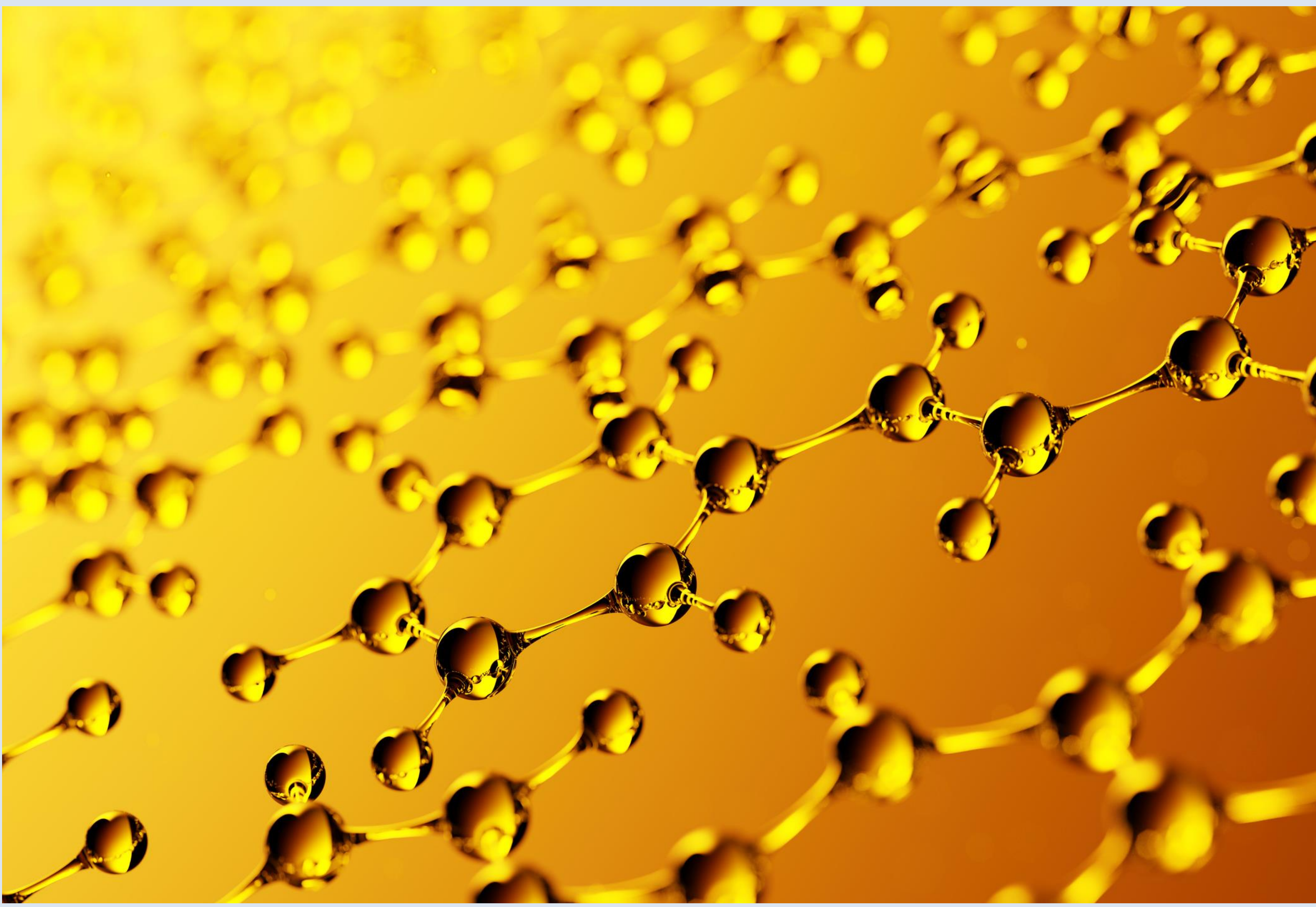

CLUSTER EVALUATION

Evaluation of Hydrocarbon Projects

European Bank
for Reconstruction and Development

EvD ID: SS20-159

March 2021

EBRD EVALUATION DEPARTMENT

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Report prepared by Tomasz Bartos Associate Director, Senior Evaluation Manager, with valuable contributions from Alejandra Palma, Principal Evaluation Manager and assistance of Natalia Lakshina, Assistant Analyst and Stephanie Crossley, Analyst, all from EBRD Evaluation Department.

One Exchange Square
London EC2A 2JN
United Kingdom
Website: www.ebrd.com

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Abbreviations

ADB	Asian Development Bank

AERA	Azerbaijani Energy Regulatory Agency
AfDB	African Development Bank
AIIB	Asian Infrastructure Investment Bank
APG	Associated Petroleum Gas
BAT	Best Available Techniques
Bbl / bpd	Barrels (of oil) / barrel per day
bcm	Billion cubic metres (of gas)
Boepd / boe	Barrel of oil equivalent per day / barrel of oil equivalent
BTC	Baku-Tbilisi-Ceyhan oil pipeline
BSTDB	Black Sea Trade and Development Bank
CEB	Central Europe and the Baltics (EBRD)
CEE	Central Eastern Europe
CHP	Combined Heat and Power
COOs	Countries of Operation (of EBRD)
CO2	Carbon dioxide
COP26	26th Climate Change Conference of the Parties (planned for November 2021)
CSs	Country Strategies (EBRD)
DSCR	Debt-service coverage ratio
EBITDA	Earnings Before Interest, Tax, Depreciation and Amortisation
EEA	European Energy Agency
EH&S	Environment, health and safety
EI	Extractive Industries
EIB	European Investment Bank
EITI	Extractive Industries Transparency Initiative
ESAP	Environmental and Social Action Plan
ETC	Early Transition Countries
ETS	Emission Trading System (EU)
EU	European Union
EvD	Evaluation Department team (EBRD)
FDI	Foreign Direct Investment
FOPC	Financial and Operational Policies Committee
GDP	Gross domestic product
GGFR	Global Gas Flaring Reduction Partnership (WBG)
GHG	Greenhouse Gases
GJ	Giga joule (of energy)
GNG	Galnaftogaz
GWh	Giga Watt hours
ICA	Industry, Commerce and Agribusiness (EBRD)
IaDB	Inter-American Development Bank
IBRD	International Bank for Reconstruction and Development
IED	Industrial Emissions Directive (of EU)
IEG	Independent Evaluation Group (of the World Bank)
IFC	International Finance Corporation
IFI	International Financial Institution
IFRS	International Financial Reporting Standards
INA	Industria nafte d.d. (Croatian oil and gas company)
IPO	Initial public offering
IsDB	Islamic Development Bank
ISO	International Organisation for Standardisation
JBIC	Japan Bank for International Cooperation

Kt / t	Thousand ton / ton
LDPE	Low density polyethylene
LNG and LPG	Liquid natural gas, Liquide petroleum gas
LTT	Legal Transition Team (EBRD)
Mboe / Mbbl	Million barrels of oil equivalent / Million barrels
MIGA	Multilateral International Guarantee Agency
Mmscfd	Million standard cubic feet per day (of gas)
MOL	Hungarian Oil and Gas Public Limited Company
MoU	Memorandum of Understanding
MW	Mega watt
NOx	Nitrogen oxides
OL	Operation Leader
OSHAS	Occupational Health and Safety Assessment Series
OPA	Operational Performance Assessment
OPEC	Organisation of Petroleum Exporting Countries
OPIC	Overseas Private Investment Corporation (now DFC)
PKN	Polski Koncern Naftowy (Polish oil conglomerate)
PMR	Project monitoring report (EBRD)
PSA / PSC	Production Sharing Agreement / Contract
PWYP	Publish What You Pay
RES	Renewable energy sources
SCF	Strategic and Capital Framework (EBRD)
SCP	South Caucasus Pipeline
SDG	Sustainable Development Goals
SEMED	South and Eastern Mediterranean
SGC	Southern Gas Corridor
S&P	Standard & Poor's
SSF	Shareholders' Special Fund
TANAP	Trans-Anatolian Natural Gas Pipeline
TAP	Trans Adriatic Pipeline
TC	Technical Cooperation
TI	Transition Impact
TIMS	Transition Impact Monitoring System
TWh	Terawatt hour
USD	United States Dollar
WBG	World Bank Group

Defined terms

the Bank /the EBRD	European Bank for Reconstruction and Development
The operation teams	staff of the Bank's teams responsible for the Bank's operations
Outputs	The products, capital goods and services which result from an operation
Outcomes	The short-term and medium-term effects directly attributable to operation outputs
Impacts	The positive or negative long-term effects to which an operation contributes, directly or indirectly, intended or unintended
Results	The output, outcome or impact (intended/unintended) of an operation

Executive summary

Between its inception and the end of 2019 the Bank provided €7.6 billion into hydrocarbon projects, 65% of it in the last ten years. The Bank co-financed 142 projects in oil, gas and (to a lesser extent) coal exploration, extraction, transportation, refining and distribution.

This report contains a review of the Bank's hydrocarbon operations. It includes the evaluation of a sample of six projects, which is presented in the broader context of the Bank's past hydrocarbon operations and portfolio analysis. It seeks to identify (to the extent possible, given various limitations) trends, as well as common lessons and themes that are relevant to this sector by utilising findings from the sample assessment and taking into account other recent evaluations. The linkages and incorporation of hydrocarbons into selected country and sector strategies are examined, along with how other IFIs approach hydrocarbons and how the EBRD collaborated with them.

Hydrocarbons have been critically important for several of the Bank's countries of operation (COOs) as a major source of currency earnings, foreign direct investments and employment, as well as instrumental in meeting national demand for energy. Other COOs have been strategically important as transit countries for hydrocarbon transportation. However, most of the Bank's COOs are dependent on hydrocarbon imports, which places energy security at the centre of their development strategies.

Yet, hydrocarbon combustion has been by far the largest source of greenhouse gases (GHG), propelling efforts to reduce their consumption, to the top of the global agenda. Hydrocarbon projects are also controversial because they carry significant financial, environmental, social and reputational risks related to integrity and corruption, environmental damage and health and safety.

From the early 1990s the Bank has played an important role supporting the hydrocarbon sector, although for many years focusing on financing mainly oil and gas extraction in Russia and Azerbaijan. Gradually, the Bank's hydrocarbon activities have become more diverse, both geographically and in terms of sub-sectors. Strategically important oil and gas pipelines and other downstream process projects became more prolific in the 2000s. Evidence from the sample and past evaluations indicates that the Bank was often instrumental in attracting international sponsors and lenders to support hydrocarbon projects, while promoting higher governance and environmental standards.

Until recently, the Bank's financing of hydrocarbons has been growing fast – project numbers have more or less doubled every ten years and they typically accounted for between 4% and 5% of the Bank's total annual commitments. However, the Bank's "Energy Sector Strategy 2019 – 2023" (BDS18-237 Final) approved in 2018, was a turning point for the Bank's work in this sector as, for the first time, it committed the EBRD to refrain from financing upstream oil and coal projects. The COVID-19-related economic crisis and global commitments to link the recovery to climate action have exacerbated the decline of this sector.

It is beyond doubt that the Bank's future hydrocarbon activities will be very different from those in the past, greatly reduced, selective and climate action-supportive. The new Energy Strategy 2019-2023 has shown the general direction for the Bank's engagement in hydrocarbons. However, some ambiguity still exists on the operational level.

EvD's interviews with bankers indicate that greater clarity in respect of the types of hydrocarbon projects which they can, and should pursue, would be welcomed.

The evaluation of six hydrocarbon projects (one in each: Egypt, Greece, Tunisia, Poland, Slovakia and Ukraine) revealed their uneven performance, with their overall ratings ranging from *Good* to *Poor, with most rated as Acceptable.* The latter achieved part of their physical objectives, although typically after long delays and cost overruns. Oil price fluctuations, following a prevailing downward trend during most of the project implementation periods, prompted many upstream industry clients to reduce or suspend their investment plans. This also had detrimental effect on the transition-related results of these projects, which have been typically well below expectations and often difficult to measure due to lacking or conflicting data. Financial results also varied. Over-optimistic oil price projections were frequently observed. All of the debt servicing and repayment commitments under the six projects have been honoured so far, but often thanks to help from the sponsors, rather than cash flow generated from operations.

Main findings:

Policy and strategy context

- Historically, oil extraction in Russia dominated the Bank's hydrocarbon operations. The loss of this market was a challenge. However, over time the Bank balanced its approach, financing more downstream projects in non-hydrocarbon producing countries. Operations in Egypt largely replaced those in Russia in terms of types and volume;
- Demand for the Bank's financing in this politically-sensitive sector has been strong, as foreign investors appreciated an IFI's presence. However, the periods of growth in hydrocarbon prices attracted commercial financing, diminishing the Bank's relevance and additionality;
- The perception of hydrocarbons as a "strategic" sector by most COOs has limited the Bank's options to engage in policy dialogue. However, there have been some modest achievements in selected countries (e.g. Egypt, Ukraine or Azerbaijan), on which the Bank continues to build, expecting stronger results in the future. The Bank's total disengagement from this sector could prevent it from continuing such work;
- Reducing dependence on hydrocarbons has been at the top of the global agenda for many years. However, while most countries were able to reduce their share as sources of primary energy, hydrocarbon consumption has grown exponentially in absolute terms;
- The Bank's Energy Sector Strategy 2019-2023 provides a solid general framework for the Bank's future hydrocarbon operations, however some ambiguity exists among bankers in respect of the types of hydrocarbon projects they still can, and should, pursue.

Project design and performance issues (related to 6 cluster projects evaluated under this review)

- Relevance was enhanced by energy efficiency and/or environmental components, which aligned the projects with the Bank's "green" strategies. These were core components in downstream projects and they were implemented. However, in some upstream projects, these components were secondary to drilling and often delayed or not implemented;

- Additionality was questionable in respect of some corporate loans to very strong, cash-rich clients – the largest corporations in the region;
- Physical investments were only completed in full and on time under one of the sample projects. They were also completed under another one but with a substantial delay, while intended investments were only partially implemented under the remaining projects. Falling oil prices forced many clients to reduce or change investment plans;
- It has been difficult to trace and verify the application of the Bank's proceeds in most projects and, in some cases, it is not entirely clear what the Bank has actually financed. Cash-generating drilling was prioritised and financed first from the loan proceeds, rather than the TI-related components which, according to the Board reports, were to be funded by the Bank;
- Under several projects the Bank was by far the largest source of funding, with the sponsors/clients actually providing only a fraction of the amounts indicated as their intended contribution in the Board reports;
- Due to questionable additionality (and a controversial sector), most projects had a very complex transition structure, with TI benchmarks ranging from 7 to 32, some of them with vague or absent linkages to the project's components. Transition results were modest;
- Private sector expansion in an industry dominated by state enterprises was often the main transition objective. It was usually achieved, however, in some COOs (Tunisia, Egypt) hydrocarbon extraction concessions for key oilfields are often majority-held by state companies, thus in such cases the Bank's financing of drilling operations also strengthened the public sector;
- Most projects included highly technical, quantitative transition benchmarks, often related to the achievement of environmental or energy efficiency targets, which in some cases were poorly monitored (or unmonitored) by the clients, had wrong or no baselines, or were over-ambitious;
- Two projects included policy dialogue components, which were partially achieved, contributing to improvements in health and safety regulations and the APG utilisation law;
- Pollution abatement equipment was installed at refineries and substantially reduced emissions, however this was not always reflected in improved ambient air quality;
- Several upstream projects reviewed experienced financial difficulties, caused mainly by falling hydrocarbon prices, affected by changes in demand and supply, often resulting from unpredictable political or economic upheavals. Technical, geological and labour issues also contributed to underperformance;
- Strong sponsors, robust project financial structures (some with sponsor guarantees/undertakings) and diversified, resilient business models, proved to be critical when oil prices dropped, and ensured that all the loans were serviced/repaid.

Country and sector strategies

- The majority of the Bank's country strategies (CSs) reviewed referred to hydrocarbons in the context of transition challenges, often in terms of energy security, resource depletion, GHG emission and efficiency of their use;
- Most strategies targeted natural gas as the priority hydrocarbon sub-sector for the Bank to support. However, until recently, the Bank's portfolio has been dominated (in terms of the number of projects) by those supporting oil. Gas pipelines dominated in volume terms;
- Some country strategies did not refer directly to hydrocarbons. However, the need to improve energy security was often cited and constituted the main justification for the Bank's engagement in hydrocarbon projects there;
- Almost all diagnostic papers stressed that regulatory, legal and institutional frameworks were too inadequate or unstable to support sustainable energy projects and in some cases specifically hydrocarbons (even in EU countries). However, relatively few projects from the Bank's overall hydrocarbons portfolio addressed these areas;
- Most of the new strategies present a monitoring approach, including for hydrocarbon-related operations, with outputs/outcomes and tracking indicators. However, in some cases only one indicator has been assigned to track several activities, while in others the baselines are missing or assumed to be zero;
- All CSs approved since the inception of the new transition qualities include a description of the challenges and diagnostics for the *Green* quality, which promotes diversification of energy sources, generally away from hydrocarbons and with a preference for renewables.

Hydrocarbons at other IFIs

- The current policies of almost all IFIs permit financing of certain types of hydrocarbon projects. However, most IFIs have been gradually phasing them out, and in practice all of them limit such engagement (particularly in thermal coal and oil);
- In 2020 IFIs and bilateral development agencies took steps towards unification of their approach to hydrocarbons. However, very small progress was achieved, while some IFI opted out from any commitments;
- In January 2021 EIB became the first IFI with a clear policy commitment to refuse financing for any hydrocarbon-related projects.

Recommendations:

At the strategic level:

- Prepare either an Approach Paper to Hydrocarbon Operations for consultation with the FOPC or a series of Business Information Sessions for the Board addressing this issue. The engagement with the Board should aim at enabling greater clarity for the Board and the bankers as to operational priorities and scope of the Bank's intended operations in the hydrocarbons sector. It should identify an approach that takes into account the Bank's multiple transition objectives and SCF 2021-25 priorities. Such a paper or presentations should provide a higher degree of specificity than that of the current Energy Sector Strategy and cover policy dialogue and TC objectives for selected countries, including those to be achieved in cooperation with other IFIs. Ensure that the discussions with the Board are minuted and the agreement reached is formally recorded;
- Strengthen the Bank's leading position among IFIs in decarbonising selected industrial sectors in selected countries (e.g. petrochemical and refining), through proactive development of new projects involving these sub-sectors.

At the project level:

- For any new hydrocarbon projects ensure greater clarity of the Board reports, particularly in respect of the application of the loan proceeds and sponsor/client contribution;
- Ensure that in principal (and as it is a common practice in project finance) the sponsor/client contribution is invested up front;
- Continue policy dialogue with selected partners, focusing on broader energy policy support, including to the extent possible, better utilisation of hydrocarbon sustainability funds. Closely coordinate this with other IFIs;
- Ensure that hydrocarbon price forecasts are subject to robust sensitivity analysis.

1. Introduction

1.1. Background to the review

Hydrocarbon projects (see box 1) have been of high importance to both the Bank and its countries of operation (COOs), being a major source of foreign direct investments (FDIs), a key foreign exchange earner and critical to meeting national demand for energy. Hydrocarbon operations are also a principal source of employment, particularly in remote areas, as well as tax and royalty fee revenues, for many COO governments.

Box 1. Hydrocarbons - definition and key facts *(from Investopedia)*

A **hydrocarbon** is an organic chemical compound composed exclusively of hydrogen and carbon atoms. Hydrocarbons occur naturally and form the basis of **crude oil, natural gas and coal**. They are highly combustible, producing carbon dioxide, water, and heat when burnt. Therefore, they are highly effective and sought after as a source of fuel. Hydrocarbons occur naturally throughout the world, originating from plant and animal fossils that have been compressed by temperature and pressure over millennia. They are mostly found deep underground, in porous rock formations.

Hydrocarbons are of vital importance for world's economy. They account collectively for roughly 85% of global energy consumed. Oil is the single biggest contributor to the world's energy mix, at 34% of consumption, followed by coal at 27% and natural gas at 24%. But hydrocarbons quietly seep into other aspects of our lives: from paint, washing detergents and nail polish to plastic packaging, medical equipment, mattress foams, clothing and coatings for television screens, etc. In 2019 global demand for oil reached a record 100 million barrels a day, driven by the needs of rapidly industrialising emerging markets. The US is the number one oil producer at 17 million barrels per day (Mbbl/d) - 18% of the world's output, with Saudi Arabia 12 Mbbl/d (12%) and Russia 11 Mbbl/d (11%). However, the early-2020 oil price war and the COVID-19 pandemic drove oil prices to record lows in April 2020. The oil prices partly recovered since then, however oil markets remain extremely volatile and global production has changed (see annex 7).

There is a serious environmental cost of using hydrocarbons as a primary source of energy. Greenhouse gasses released during the combustion of hydrocarbons are contributing estimated 75% to climate change, while the process of oil and gas extraction can damage the environment or groundwater of the extraction site.

The hydrocarbon sub-sector is important in different ways to different COOs. Russia (former COO), Azerbaijan, Turkmenistan and Kazakhstan, for example, are among the world's top hydrocarbon producers, while Georgia, Turkey, Ukraine provide significant transport routes. However, most COOs rely heavily on hydrocarbons imported from other COOs and are energy intensive; therefore the sector is critical for their energy security and economic growth. For these reasons, the COOs have sharply differing national hydrocarbon strategies, some of which are more compatible than others with the EBRD's objectives. Some countries, e.g. Azerbaijan, are potentially overly reliant on hydrocarbons, and need to diversify their economies, taking into account the limited lifetime of natural resources and climate change. Finally, the concept of energy security differs between countries producing hydrocarbons and those importing them. For the latter, it implies a dependable energy supply from multiple independent sources at fair, preferably low, prices. For producers, energy security means security of demand from foreign customers at fair, preferably high, prices.

Hydrocarbon projects have also been important for the Bank, accounting on average for between 4 and 5% of its ABV, and they constitute by far the largest part of the Bank's Natural Resources operations. Many international investors have shown a preference for financing their hydrocarbon projects with International Financial Institutions (IFIs) due to their sensitive nature and the perceived ability of IFIs to provide political risk coverage, associated particularly strongly with hydrocarbon projects in many COOs.

The Bank's hydrocarbon operations encompass eight types of projects, ranging from upstream to downstream (excluding any support to power generation from hydrocarbons, which was not covered by this review):

- Oil and gas exploration and extraction (support for upstream oil was discontinued in 2018)
- Thermal coal mining (discontinued in 2018)
- Support activities for oil, gas and coal mining
- Remediation services (preventing or responding to oil spills)
- Pipeline transportation of oil and natural gas (trans-national pipelines)
- Petroleum refineries (modernisations, privatisations)
- Gasoline stations (modernisation, network expansions)
- Natural gas distribution, including storage (national and regional pipelines and storage)

Despite their critical importance, concerns related to climate change and environmental risks have induced many IFIs to limit or phase out their support for hydrocarbons (see chapter 5). Also, the Bank's new "Energy Strategy 2019-2023" marks a turning point in the Bank's approach to this sub-sector as it does not envisage the financing of any coal mining or coal-fired electricity generation operations, or any oil extraction or other oil upstream projects, with an exception of those supporting APG flaring reduction.

1.2. The review's objectives, structure and methodology

Given the profound shift in the Bank's approach to hydrocarbons, this report aims to take stock, looking back at the Bank's achievements in the hydrocarbon sub-sector – in physical, environmental and particularly transition/policy change terms. It seeks to identify trends, as well as common lessons and themes that are relevant to this sector. EvD believes this could be of interest because only a few of the more recent hydrocarbon projects have been fully evaluated, and EvD has not made a more holistic assessment of the Bank's hydrocarbon operations since 2010, when they were included in a broader Extractive Industries review[1]. That review covered the Bank's activities in this sector up to the end of 2009. This report picks up where the last one ended, i.e. it reviews the Bank's hydrocarbon portfolio signed between 2010 and end-2019. It also evaluates a sample of six "cluster" projects from this portfolio and, taking into account other recent evaluations, tries to identify prevailing trends and commonalities in hydrocarbon projects.

The process for selecting the six "cluster" projects (see annex 1) was described in detail in the Approach Paper for this review[2] and closely coordinated and agreed with the Natural Resources team. All cluster projects are related to oil extraction, processing or distribution, with two of them supplemented with only minor gas extraction operations. This reflects the Bank's focus on the oil sub-sector, as well as the fact that most natural gas-related projects have not yet been completed and thus are not ready for evaluation, while a few of those which were implemented, have already been included in other studies[3]. Nevertheless, the key gas and coal projects are described in this

[1] PE10-479S - Extractive Industries Sector Strategy Review, August 2011 (see the next section for more information)
[2] SS20-159 Hydrocarbons Projects – Approach Paper, March 2020
[3] It also reflects the fact that all Mongolian coal mining projects were evaluated under the recent study, while all other coal projects are in Corporate Recovery and thus unsuitable for full evaluation at this time.

review and their current status has been taken into account in the assessment of the Bank's activities in this sector. Importantly, the review incorporates findings and conclusions from other relevant recent evaluations, which covered some hydrocarbon operations (see section 1.3).

The evaluation starts with a short historical background, presenting the evolution of the Bank's approach to hydrocarbons and briefly describes relevant sector strategies, as well as the Bank's landmark projects in this sub-sector from the early days. It is followed by an examination of the Bank's portfolio during the review period (2010 – 2019), which is then compared with that of the preceding 10-year period. The review then examines how hydrocarbons have been treated under the Bank's selected country strategies. The main evaluation is summarised in section four, which presents a brief assessment of the cluster projects' performance under three key evaluation criteria (relevance, effectiveness and efficiency), and identifies trends and commonalities in these projects' performance. A summary of approaches of other IFIs to hydrocarbons closes the review. Detailed evaluation results and other analysis supporting the findings are presented in the annexes.

This review had certain limitations. Due to COVID-19 pandemic, no site visits or client interviews were possible for the evaluations. Data and information were obtained mainly through desk studies of documents and monitoring reports, as well as bankers' interviews. Three projects had self-evaluations (OPAs) prepared (PKN, MOL and Serinus). Moreover, for three evaluations (MOL, PKN and Galnaftogaz) EvD obtained by email written information/responses to questions directly from the clients. EvD was advised not to approach three remaining clients due to ongoing project/loan restructuring (Energean and Serinus) or due to relations being terminated with such clients (PICO). It is also recognised that due to a tight completion timeframe for this review, the sample of projects evaluated was relatively small compared to the Bank's overall portfolio in this sector, although (as explained in the following section) an effort was made to incorporate in it the findings and observations from earlier evaluations of the Bank's hydrocarbon projects.

1.3. Past evaluations of the Bank's hydrocarbon operations

So far, there have been two evaluations of the Bank's hydrocarbon projects:

Extractive Industry (EI) Review (PE03-256S) published in July 2004, evaluated most of the Bank's early operations in the Natural Resources sector to 2003 (although it ignored downstream projects, such as refineries, petrol stations, etc.). It provided four recommendations:

- Prepare a new sector strategy (rather than a policy);
- Move from enforcing national, EU and WBG standards to adding value through pollution prevention, cleaner production and promotion of sustainable development in the EI sector;
- Focus more on reducing GHG, through promotion of off-sets and energy efficiency;
- Improve internal procedures to track all EI activities, i.e. in the FI and trade facilitation.

The Bank developed a new Energy Operations Policy, adopted in 2006, which covered the oil and gas sector. However, subsequent documents approved in 2013 and then 2018 were Energy Sector Strategies, which also covered oil, gas and thermal coal. There is also some evidence that, over time, the Bank moved towards more pollution prevention projects in this sector (as shown by two of the refinery projects included among the cluster projects under this review). Also, the third recommendation has been largely taken into account as the Bank gradually began to put more emphasis on energy efficiency and climate change issues, culminating in the Green Economy Transition Approach in 2015, with "Green" becoming one of new transition qualities in 2017. There is no evidence that the fourth recommendation was followed.

The second evaluation of the Bank's hydrocarbon projects formed part of the **Extractive Industries – Sector Strategy Review** (PE10—479S), published in August 2011, which covered the Bank's activities to end-2009. Its main recommendation was for the Bank to prepare a separate Mining Strategy (which was duly done, i.e. BDS17-215). It also recommended that the new Mining Strategy contain a section on the Bank's policy with regard to environmental and social aspects. This was incorporated in the new strategy under a chapter dedicated to EHS&S issues. The final recommendation of this study called for policy dialogue to incorporate the use of sustainability funds (created by governments from royalties paid by private exploration companies), as well as adherence to EITI. There is no evidence that the first part of this recommendation was followed. However, the Bank has been helping Mongolia to implement EITI provisions and it also promoted EITI in other countries.

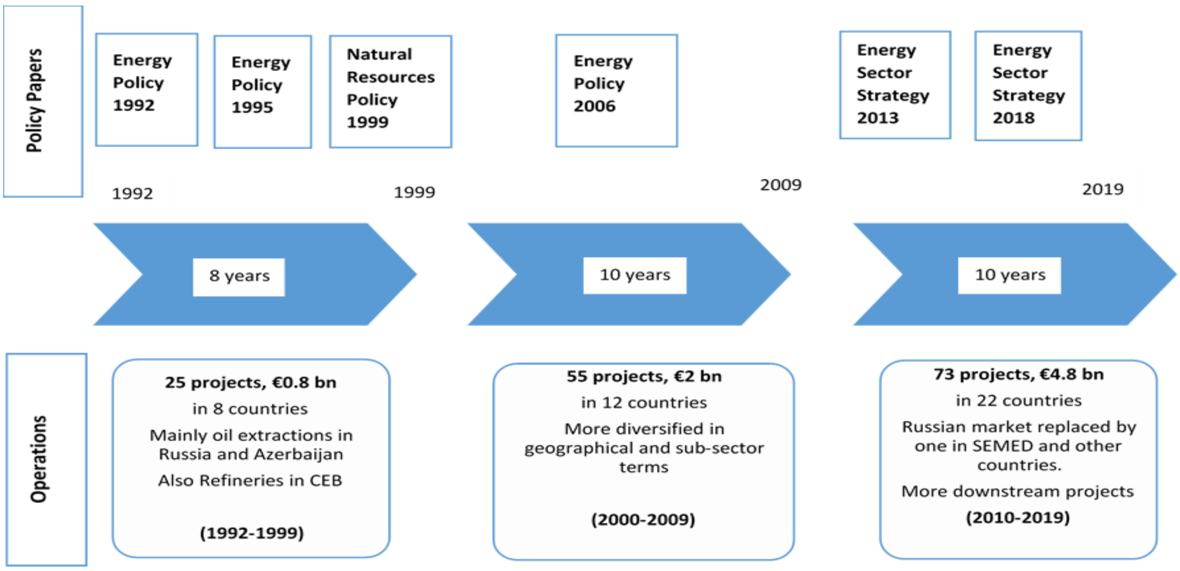
In addition to the two extractive industries sector evaluations mentioned above, which directly evaluated the Bank's hydrocarbon-related activities, EvD conducted a **Review of the EBRD Energy Sector Strategy** (SS17-105), published in April 2018. It focused on Energy strategy itself, with limited portfolio analysis of the Bank's operations in the Power and Energy and the Natural Resources sectors. Its key recommendation was to prepare a new sector strategy, which could provide meaningful guidance for future operations in all Energy sub-sectors. Its final piece of advice was directly related to hydrocarbons and called on the Bank to clarify its approach to this sub-sector, including methodology for screening new projects. This has been partially done under the current Energy Strategy (although ambiguities remain, as explained in this report). As part of the country case studies under the Review of Energy Sector Strategy, EvD evaluated most of the Energy sector projects in Kazakhstan, including three from the 2010-2019 hydrocarbon portfolio: Petrom Kazakhstan, Bozoi Gas Storage and Gas Network Modernisation. It stressed the importance of the role of the Bank and other IFIs in filling the financing and policy advice gap in this sector. The project assessment noted the early pre-payment and limited results stemming from the Petrom project and the more robust achievements of the two gas projects. It also observed long-term nature of their environmental objectives, i.e. their impact in terms of targeted GHG reduction, energy savings, etc. could be verified only after 2025. In recent years EvD has also completed two more thematic evaluations covering selected hydrocarbon projects, and the relevant conclusions have been utilised in this review:

- **Mining Operations in Mongolia**, November 2019 (PE18-602) – it covered all four coal mining projects (MAK I, Leighton, MMC debt and Sharyn Gol) among the 14 reviewed. It highlighted a low level of achievement of outputs, delays, cost escalation and lack of definition or follow up on use of the loans' proceeds, leading to reputational concerns. The Bank successfully assisted selected Mongolian companies to comply with EITI.
- **Regional Integration**, March 2020 (SS19-136) – this review concentrated on the transport sector, however it also included one very important hydrocarbon project – the Trans-Anatolian Pipeline (TANAP), a vital part of the Southern Gas Corridor from Azerbaijan to Europe, through Turkey (see its summary in annex 4).

2. Evolution of the Bank's approach to hydrocarbons

- In the 1990s the Bank played a critical role helping attract FDIs to the hydrocarbon sector, mainly in Russia and Azerbaijan; these projects largely supported oil extraction and promoted better corporate governance, environmental standards, and best practice. The modernisation of oil refineries in Central Europe was also financed;
- The Bank did not establish a dedicated Natural Resources Policy until 1999, relying instead on the Energy policies and country strategies to provide a general direction for its operations;
- In the first decade of the 2000s the number of projects doubled, and the volume tripled. The Bank's hydrocarbon operations became more diversified, both geographically and in terms of sub-sectors, e.g. supporting the remediation of oil fields;
- One third of the volume financed oil and gas pipelines, many of which were strategically important (BTC, Southern Caucasus). Coal mining made its debut, but with only two small projects it remained marginal. Aiding the privatisation of Petrom in Romania was the Bank's most important achievement;
- The 2006 Energy Operation Policy and the 2013 Strategy were centred on power utilities and gave little guidance for hydrocarbon project selectivity. They were broadly set and were largely followed, with the Bank continuing to focus on Russia and the Caspian Sea, with increasing emphasis on energy efficiency and environmental protection;
- In 2010-2019 volume more than doubled again. This decade was characterised by the end of operations in Russia, successfully substituted by those in the new COOs. Support for strategically important pipelines continued, while the financing of downstream processes increasingly replaced extraction projects. Coal mining remind marginal with six projects.
- The 2018 Energy Strategy forbid coal and oil upstream projects (except when they reduce GHG or flaring). The following year, gas midstream projects were transferred to the SIG, while Natural Resources team joined the ICA Group.

Figure 1. Timeline of the Bank's involvement in hydrocarbons



The Bank's work with hydrocarbons can be divided into **three periods**, each lasting roughly 10 years. Figure 1 shows a timeline with key events, while subsequent chapters describe them.

2.1. The Bank's support for hydrocarbons in the 1990s

In the first decade of transition, the Bank played a critical role in the hydrocarbon sub-sector, first and foremost in Russia, financing up to 70% of the annual oil and gas FDIs there. Moreover, the Bank was also the largest financier of hydrocarbon projects in Azerbaijan and an important provider of funds for modernising oil refineries in Central Europe. However, the Bank didn't establish a dedicated policy or strategy for the Natural Resources, Extractive Industries or Hydrocarbon sectors until 1999, relaying on the very general **Energy Policies of 1992** (BDS92-018F) and **1995** (BDS95-004F) which largely supported power utilities, and linked to a hydrocarbon section in country strategies, to guide its operations. This "light touch" approach was somewhat surprising given that several of the Bank's COOs were among the world's top hydrocarbon producers, which played a pivotal role in their economies.

The Bank's first hydrocarbon operation was the Petroleum Pilot Modernisation Project, a €24.3 million equivalent loan signed in 1992 with the Romanian government and designed to update infrastructure and support the restructuring of the state-owned petroleum conglomerate Petrom, in the expectation of its ultimate privatisation (which happened after two more pre-privatisation loans). However, by the end of the following year the Bank had already signed three hydrocarbon extraction projects in Russia (Western Siberia Oil & Gas Rehabilitation, Polar Lights and Komi Arctic Oil), which made EBRD a leader in financing oil and gas FDIs in Russia that year (see table 1).

As this table illustrates, over the following years the Bank's share of hydrocarbon FDIs financing in Russia gradually decreased, although it still held the top financier's position in this sector. The Bank's role only substantially diminished after the Russian crisis, when oil and gas prices increased, encouraging commercial banks to finance such investments more prominently.

Table 1. The EBRD's share of financing of the Russian oil and gas sector in the 1990s (USDm)

Year	1993	1994	1995	1996	1997	1998	1999
Total EBRD investments into Russia oil and gas sector	175	57	23	55	18	109	28
Total FDIs into Russian oil and gas sector	250	250	297	261	383	365	1,205
Share of EBRD financing of FDIs into Russian oil and gas sector	70%	29%	8%	21%	5%	30%	2.3%

In all, the Bank signed 10 operations in Russia for €440 million equivalent, accounting for 40% of the number and 54% of the total volume signed in the hydrocarbon sub-sector in the 1990s. This is not surprising, given Russia's position as one of the world's top oil and gas producers, as well as being relatively open to FDIs, while undergoing profound transformation, associated with high political, legal and market risks. These risks made it difficult for commercial banks to finance large oil and gas project on their own, preferring to syndicate with an IFI (about 40% of such projects were syndicated). The Bank's loans in Russia were used almost exclusively to finance the development of new oil and gas extraction fields or the expansion of those that already existed. The largest, "flagship" project was Sakhalin II phase 1, signed in 1998 for over $116 million equivalent (see box 2). The first phase was relatively successful but the Bank's attempt to finance the second phase vividly illustrated the risks to which projects in this sector were exposed.

Box 2. Sakhalin II Oil projects, phase 1 and 2 – EBRD's early hydrocarbon operations

In 1998 the Bank committed to a $116 million senior loan to cofinance the $780 million Sakhalin II phase 1 project, which entailed the development of an oil field and an offshore gas field in the Sakhalin Island (part of a $22 billion multi-phase development). OPIC and JEXIM provided loans equal to that of the Bank. The project was expected to bring a demonstration effect, facilitating the implementation of a production-sharing agreement (PSA) in Russia and enhancing fiscal stability for companies operating in the Russian natural resources market, facilitating FDIs. Also, the borrower's environmental practices, including its commitment to public consultation, was hailed as having a transition impact. However, the development was situated in areas previously little touched by human activity, thus it was heavily criticised by environmental groups.

The phase 1 project implementation was largely successful (as evaluated under PE02-202). The PSA was signed between the consortium and the Russian government and on-shore oil extraction started. The Bank ensured environmental risks were mitigated and it also engaged in policy dialogue regarding the wider economic development of the Sakhalin Island. The Bank was asked to cofinance phase 2.

However, after the first phase, the original consortium of Marathon Oil, McDermott and Mitsubishi changed as the first two partners sold their shares to Shell/Royal Dutch, which decided to proceed with the offshore gas exploration. This increased budget dramatically, as well as the reputational risk for the Bank as the gas pipeline was heavily criticised due to environmental issues. Moreover, the Russian government realised that the PSA's royalties negotiated by the consortium were about half of the market rate. Legal proceedings regarding the perceived violation of Russian environmental regulations were initiated. In 2006 the Russian government ordered the termination of the project. Under legal and political pressure, the consortium sold a majority stake to Gazprom. Upon the change of sponsorship to the state-owned Gazprom, the Bank decided not to sign the - virtually fully prepared and negotiated phase 2 loan. This phase was completed in 2009, financed mainly by Gazprom and the Russian government.

Azerbaijan followed as a distant second among the countries benefitting most from the Bank's hydrocarbon financing in the 1990s, with the Bank cofinancing five operations for an aggregate of €90 million equivalent (11% of the total provided in this sector). All of them financed the same project - Chirag Early Oil - and represented separate loans to five of the project's sponsors (AMACO, Lukoil, Turkish Petroleum, etc). These were important operations as they initiated exploitation of the Chirag field, which later provided oil for an emblematic BTC pipeline (see the next section). The Bank also signed oil and gas extraction operations in Turkmenistan (Dragon Oil) and Ukraine (Poltava Oil and Gas).

Another type of hydrocarbon financing at that time supported the modernisation of oil refineries, mainly in Central Europe. The Bank signed eight such operations for an aggregate €225 million equivalent (28% of the total). They included loans to the above-mentioned Petrom in Romania, four projects with Slovnaft in Slovakia, and one each in Hungary (MOL), Slovenia (Slovenski Plinovodi) and Uzbekistan (Fergana Refinery). Interestingly, despite Kazakhstan being one of the major oil and gas producers, the Bank hasn't had any operations in this sector there as it was uncomfortable with the governance issues (i.e. with the presidential family controlling key companies). Almost all projects were private (except for some refineries, whose modernisation programmes were financed as part of their preparation for privatisation). In total, during the eight year period 1992-1999 the Bank signed **€815 million equivalent under 25 projects supporting hydrocarbons in eight countries**. This indicates a modest average of 3.2 projects and €101 million equivalent volume per year. However, the actual signings were extremely uneven, with two "boom" years (1993 and 1998) when about €200 million was signed each year, and below €70 million in the remaining years.

This illustrates how unpredictable the hydrocarbon financing business has been, closely correlated to the commodity price cycle (see annex 6), as well as to the market and political situation in a given country. Lower commodity prices and higher political risks (early 1990s and the Russian crisis in 1998) boosted demand for the Bank's financing, while higher oil and gas prices and relative stability dampened it. No coal mines were financed during that time as the World Bank had been working on their privatisation in most COOs. Nevertheless, hydrocarbon financing accounted for about 5% of the total committed by the Bank in this period and the results were generally positive, see box 3.

Box 3. 2004 Extractive Industries Evaluation (PE03-256S)

The evaluation concluded that the Bank's oil and gas projects performed relatively well (54% were rated successful or better with the rest partly successful) and better than those in the mining sub-sector (which had a number of unsuccessful projects). It highlighted that the Bank was a critical player in the early 1990s, undertaking several "first-of-a-kind" projects. They supported the private sector in its initial investments in the region and helped attract international sponsors and commercial lenders (40% were syndicated). Under these projects, the Bank was able to promote international corporate governance and environmental standards, as well as industry best practice. The evaluation stressed that the EBRD-financed projects were more transparent with respect to environmental and social issues than other private projects in the hydrocarbon sector. However, it also pointed out that some of the transition objectives failed, e.g. the PSA was introduced for the first time to the Russian oil sector under Sakhalin II phase 1 but then discontinued by the Russian government.

In 1999 the Board approved the first **Natural Resources Operations Policy** (BDS99-022F), which had a clear focus on oil and gas operations. It included a diagnostic annex covering the main producer countries. The challenges identified in this policy were related to the need to increase private participation, improve the regulatory and institutional framework, reduce transport bottlenecks and ensure competitive market access. It also identified the need for high business conduct and environmental standards. It set four operational priorities:

- Focus on Russia (North and Far East) and the Caspian Sea
- Promote privatisation, particularly in Central and Eastern Europe
- Promote reduction in GHG emissions
- Support pipeline development

The first two priorities largely continued the Bank's approach to date (as explained above). The promotion of GHG emission reduction and the prominence given to pipelines were new. This gave direction but the Policy was too broad and general to provide meaningful guidance for the selection of operations. The next section summarises how it was implemented.

2.2. Hydrocarbon projects during 2000-2009

The 1999 Natural Resources Policy anticipated a transition role for the EBRD in the hydrocarbon sector, particularly in Russia. This did not materialise. Instead, the new Russian administration asserted and consolidated the state's role in the sector, introducing the "strategic resources" concept, which limited full and open competition.

Consequently, the Bank started financing smaller projects with private companies, some in the extraction business, others providing services to larger oil and gas enterprises. Russia remained the main client but with a lower share as this period was characterised by a greater diversification of the Bank's operations, in both geographical and sub-sectoral terms, see figures below.

Figure 2. Hydrocarbon operations 2000-2009 by region, number and volume

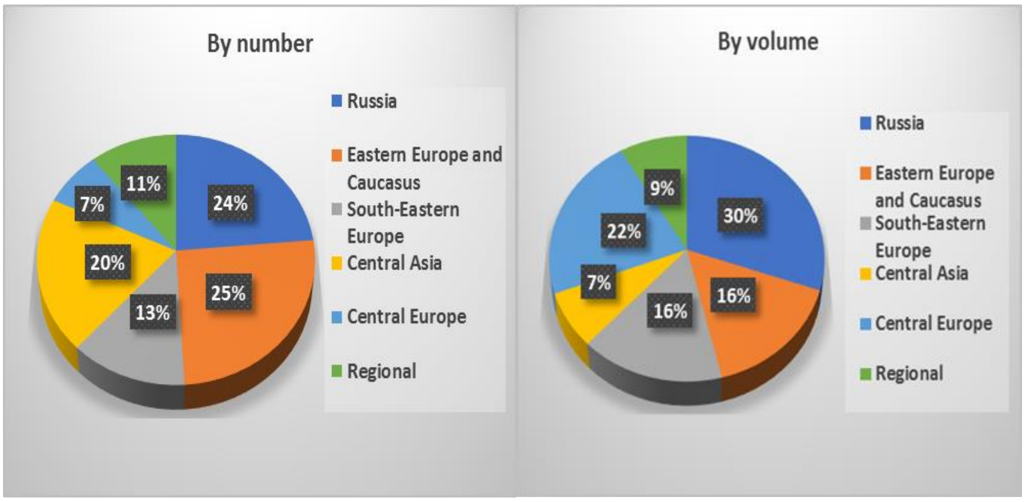
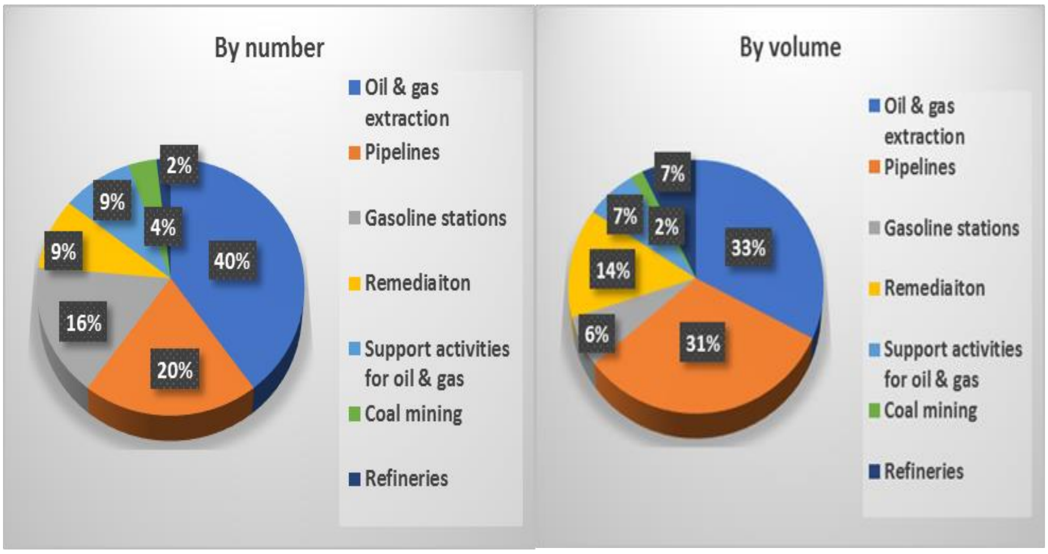


Figure 3. Hydrocarbon operations 2000-2009 by sub-sector, number and volume



Although the Bank's hydrocarbon operations had expanded to cover 12 countries, Bank policies constrained engagement in some hydrocarbon-rich countries. For example, no new projects were signed in Turkmenistan and Uzbekistan, while in Kazakhstan the Bank managed only four hydrocarbon-related projects for an aggregate of €90 million. However, three of them financed Bautino Atash Marin base, designed to serve the offshore Shah Deniz fields in the Azeri shelf of the Caspian Sea (also financed by the Bank). Long delays in developing these fields resulted in the failure of all Bautino projects, which remain in Corporate Recovery to this day.

An important feature of this period was the expansion of the Bank's hydrocarbon operations to include non-producing countries (e.g. Albania, Georgia, Bulgaria, Croatia,). This was mainly due to the financing of downstream operations, such as gasoline stations, refineries, pipelines and gas storage. In all, downstream process projects accounted for 38% of the total number and 44% of the volume. This trend continued during the next period.

High-profile projects began to feature in the Bank's pipelines portfolio, none more so than the Baku-Tbilisi-Ceyhan oil pipeline (BTC), see box 3. In addition to this ground-breaking project, which brought Azeri oil to international markets, the Bank financed 10 other pipelines for €547 million (with BTC representing 31% of the total volume), including critical connections through Georgia for the

Southern Gas Corridor. Gas storage projects (included in the pipelines category) also made their debut with MOL's Szereg underground reservoir, one of the largest projects at €200 million.

Box 4. Baku – Tbilisi - Ceyhan Oil Pipeline Project (BTC)

In 2003 the EBRD approved a US$0.25 billion 12-year loan to cofinance the Baku-Tbilisi-Ceyhan oil pipeline (BTC). This 1,768 kilometres pipeline was to bring, for the first time, Azeri oil from the Caspian Sea, through Georgia and Turkey to the port of Ceyhan on the Mediterranean Sea, so it could be easily available for worldwide transportation by tankers. The Bank kept €87 million of the loan, syndicating the remainder. The IFC, export finance agencies such as US-Exim, JBIC, Nexi, Hermes, SACE, Coface, ECGD, OPIC, and a number of commercial banks such as Société Générale, ABN Amro, Citibank and Mizuho, cofinanced this mega-project for a total value of US$3.8 billion.

BTC was developed by 11 oil companies, including BP, Statoil, ConocoPhillips, ENI, INPEX, ITOCHU, SOCAR, TOTAL, TPAO and UNOCAL. It is operated by BP. For Georgia, the project was to become the first major alternative source of energy to its traditional supplies from Russia. For Azerbaijan and its Caspian oil, it was a milestone, opening the export route to international markets. The political and strategic significance of the project attracted media attention, while its technical, financial and legal complexity illustrates challenges often faced by large cross-border projects. It involved two lead project sponsors, 12 main financiers and over 20 consultants, technical and legal advisers. The project was very challenging environmentally, drawing attention from civil societies. The EBRD and IFC engaged in six public meetings and conflict resolution, which provided lessons for future pipeline projects (see annex 4 on TANAP/TAP).

The construction was successfully completed in 2005 with a 'first oil' ceremony taking place at the Turkish Ceyhan terminal on the Mediterranean Sea in the presence of the Turkish, Azeri and Georgian heads of state and government. EvD's 2008 evaluation rated the project overall **partly successful** due to a delay in implementing the Regional Development Initiative, which was designed to contribute to sustainable development activities in various sectors of the economy after the completion of the BTC construction. Through this programme the Sponsors wished to visibly contribute to the region and thus enhance their long-term business. However, at the time of the evaluation the programme was delayed and EvD's report suggested that the project results be re-evaluated around 2010 (which did not take place).

Moreover, the Bank began to finance the remediation of oil fields and with five projects at €288 million in aggregate, this became the third largest sub-sector (after extraction and pipelines). These projects were designed to have an important environmental impact, which was particularly relevant to the Bank as it was undergoing rapid "greening" in this period.

Another new sub-sector – coal mining, had a less environmentally-friendly reputation. It was initiated in 2007 with the MAK I project in Mongolia, followed by Energy Resources/MCC Equity two years later. These mid-size projects (€35 million in aggregate) were reviewed by EvD as part of the **Mongolian Mining Cluster (PE18-602).** It noted low level of achievement of their intended outputs, delays, cost escalation and lack of definition or follow up on use of the loans' proceeds. On positive side, the TC provided under the MAK I project was credited with spearheading further investments into the smokeless coal plant, which resulted in the reduction of Ulaanbaatar's air pollution.

Thirteen operations (23%) in that decade were equity, accounting for €235 million (12%) of the total financing. These were relatively small investments, except for the Petrom privatisation (€55 million).

In 2006 the Board approved a new Energy Operations Policy (BDS06-093F). It increased the focus on sustainability; sector reform and transition to improve the investment climate, policy dialogue and the private sector. Despite some new elements, in relation to hydrocarbons it was largely a continuation of the 1999 Natural Resources Operations Policy, with an emphasis on private sector participation, improving the regulatory and institutional framework and setting high standards of business conduct and environmental protection. As did its predecessors, it lacked specificity, clarity of objectives, as well as results and monitoring frameworks.

Its implementation was evaluated in the **Extractive Industries Sector Review (PE10-479S)**, which noted, similarly to the previous evaluation, that overall, oil and gas projects performed satisfactorily and better than their "cousins" in the mining sub-sector, with 60% of hydrocarbon projects rated "successful". However, a review of individual evaluations and validations reveals some serious failures, such as Frontera (Regional), an oil extraction project, focused on Azerbaijan. Its sponsors were politically well-connected but lacked experience and commitment (which did not help them when most of the wells they drilled turned out dry), however, the outstanding loan was fully recovered through sale of the assets to CNPC. The Thessaloniki-Skopje pipeline suffered due to political tensions between Greece and North Macedonia. Also, the aforementioned Bautino project demonstrated risks related to oil service companies, while Clean Globe Oil Spill Remediation was only marginally implemented and lost most of its investment. Also, the MT Petrol stations project in Mongolia missed its transition objectives.

Conclusions

Overall, the evidence indicates that during the first decade of the 2000s, the Bank largely followed the operational priorities set in the 1999 Natural Resources and 2006 Energy Operations Policies:

- **Focus on Russia and the Caspian Region** (Azerbaijan and Kazakhstan) – the share of this region in the Bank's hydrocarbon portfolio decreased but still accounted for 43% of the total volume and the number of projects. This was achieved despite the introduction of restrictions on FDIs in hydrocarbons by Russia and the continued reputational risks in this sector persisting in Kazakhstan.
- **Support for privatisation** - an important achievement during that time was the Bank-assisted privatisation of the vertically integrated conglomerate, Petrom, in Romania, which was accompanied by pre-privatisation, privatisation and post-privatisation financing. Privatisation was also supported elsewhere in Central Europe as the Bank worked with Hungary's MOL and Croatia's INA, financing the modernisation investments of the latter, which helped when two years later it was taken over by the former.
- **Pipelines** - almost a third of the portfolio financed pipelines. These were often critically important operations, contributing to energy security and regional integration.
- **Promotion of sustainability in the hydrocarbon sector -** five operations financed oil spill protection and the remediation of oil fields and four others targeted environmental rehabilitations (at MOL, INA, Petrom and Lukoil). A TC related to a coal mining project in Mongolia (MAK I), contributed to the reduction of air pollution there.

2.3. The Bank's hydrocarbon portfolio 2010-2019

The **2013 Energy Sector Strategy** (BDS13-291F), largely built on the 2006 Energy Operations Policy, restating the importance of markets, private participation and cost-reflective pricing. It increased the emphasis on energy efficiency and the role of renewables. One innovation was the incorporation of shadow carbon pricing methodology for coal-fired power generation as part of project screening. EvD's **2018 Review of the Energy Sector Strategy** (SS17-105) concluded that this strategy had elements of strength but many weaknesses, such as key disconnects in linkages from challenges to operations, which prevented effective guidance on project selectivity. The shadow carbon pricing methodology developed under this strategy has never been used but it effectively prevented financing of coal-related projects (it was replaced by a new one in 2018).

Although the new strategy brought little change to the Bank's hydrocarbon operations, external events during 2012-2014 did. They brought about the Bank's shift away from Russia and towards new markets in the SEMED region and in other new COOs. It initially seemed that the suspension of the Bank's operations in Russia in 2014 would have a profoundly detrimental effect on its hydrocarbon operations, as this country had always been by far the Bank's largest hydrocarbon market, accounting for about one third to a half of its financing volume. However, during the previous decade and at the beginning of the 2010s the Bank had already, largely successfully, increased the geographical diversity of its support for hydrocarbons. Still, during the first three years of the new decade, three projects supporting hydrocarbon were signed in Russia for an aggregate €185 million.

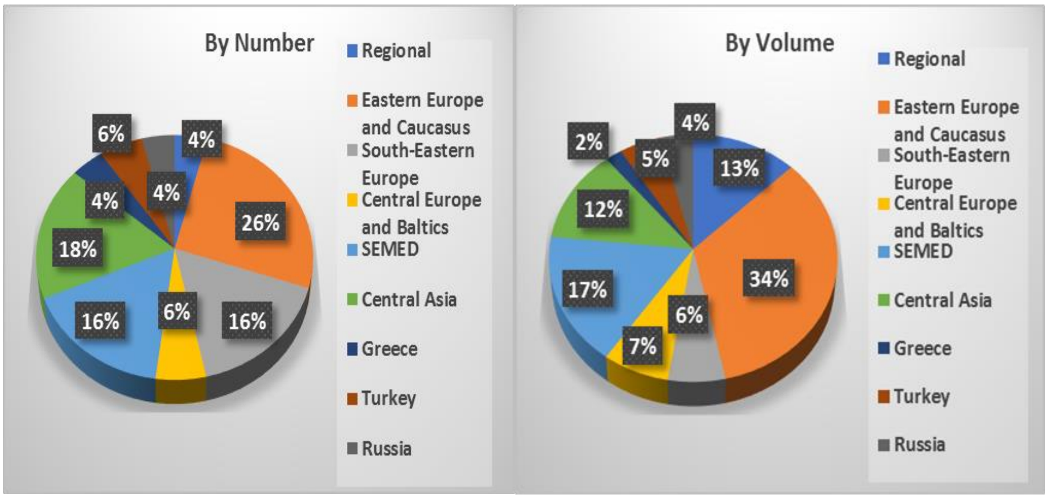
The new COOs are not particularly blessed with hydrocarbon reserves, although Egypt and Tunisia do have oil and gas, with the former now ranked as the world's 30th largest oil producer, churning out 0.5 million barrels p/d (on par with Romania). The Bank signed its first hydrocarbon project in Egypt in 2013 (KEC Gas Flaring Reduction for €22.7 million), which was fully disbursed and implemented. By the end of 2019, ten hydrocarbon projects had been signed in Egypt and two more in SEMED (one in both Morocco and Tunisia). In aggregate, the new region accounted for €0.8 billion (17% of the total volume and 16% of the project number). Also, other new COOs (Turkey and Greece) delivered seven projects for €320 million (7% of the total volume). The volume of hydrocarbon operations in Egypt alone was higher than that in Russia in the previous decade, testifying that the Bank has successfully compensated for the loss of the Russian hydrocarbon market with those in the new COOs.

Other features of this decade in respect of hydrocarbons were the revival of operations in CEB, as well as tapping into new markets in the Western Balkans and elsewhere. These were mostly non-hydrocarbon producing countries and the Bank financed mainly downstream process projects there. Among them, the financing of refinery modernisations, absent for a decade, made a big comeback to the tune of € 0.7 billion. They were focused on energy efficiency and emission reductions, similar to the projects that formed the cornerstone of the Bank's operations in the 1990s. They were implemented in Poland, Hungary/Slovakia, Croatia and Estonia. In the Western Balkans, gas transportation and storage were financed in Bosnia and Herzegovina, as well as in Serbia.

However, the Bank's largest hydrocarbon market in 2010-2019 was Eastern Europe and the Caucasus with 19 projects (26% of the total) and €1.6 billion volume (34% of the total). This was due mainly to two large Shah Deniz gas field development projects and the huge TANAP gas pipeline, all three in Azerbaijan, which accounted for over €0.8 billion[4]. Moreover, the Bank continued its prolific operations in Ukraine with 11 projects for €677 million – making it a surprising number one country in terms of the number of projects and third in terms of volume. See figure 4.

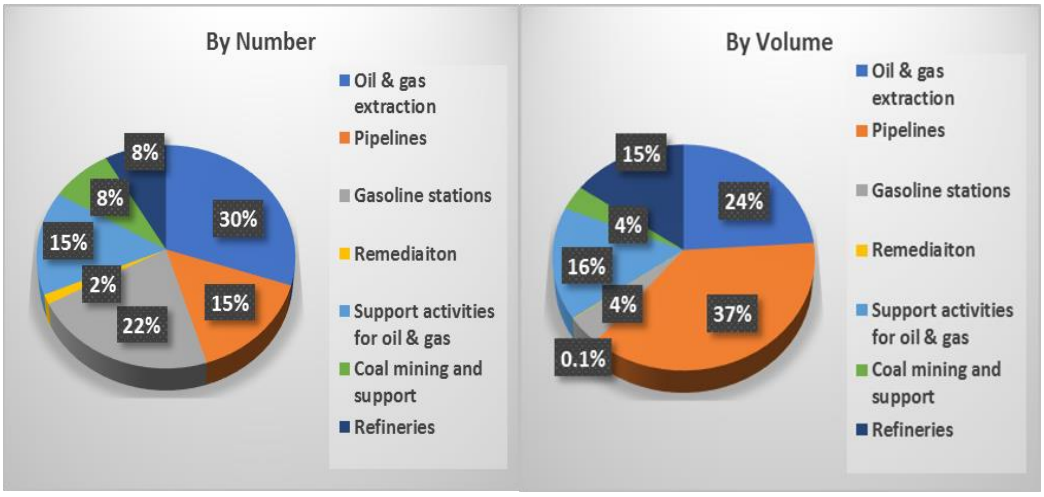
[4] For evaluation of TANAP project, see SS19-136 Regional Integration or annex 4 in this review for its summary.

Figure 4. Hydrocarbon projects 2010-2019 by region



The sub-sectoral structure of the Bank's hydrocarbon operations underwent a less dramatic change, although downstream operations dominated. Oil and gas extraction projects remained the most numerous (22) accounting for almost one third of the total. However, their share of volume shrank to 24%, as pipeline and gas storage took over as the leading sub-sector in volume terms (€1.7 billion, accounting for 37% of the total). Figure 5 illustrates the sub-sectoral structure in this period.

Figure 5. Hydrocarbon projects 2010-2019 by sub-sector



In total, **73 projects for €4.8 billion** were signed during 2010 - 2019 (32% and 140% increase respectively on the previous period). In summary, the key characteristics of the Bank's support for hydrocarbons in the 2010s as compared to 2000 - 2009 were as follows:

- **Average project size almost doubled** (€66 million, up from €36 million), mainly thanks to large gas pipeline projects such as TANAP, TAP, EGAS or Naftogaz. In total there were 15 hydrocarbon-related projects amounting to over €100 million, compared to four in the previous period;
- **Virtual absence of Russian projects** (only three), which had dominated the previous decade's portfolio with 33 projects and accounting for 30% of the total volume;

- **Azerbaijan became the Bank's largest client,** in the hydrocarbon sector **followed by Egypt and Ukraine.** This was due to large projects concentrated in these countries (TANAP, Shah Deniz x2, EGAS, SOPC, Naftogaz x3);
- Greater **geographical diversification** with operations in 22, rather than 12 countries. New COOs, particularly Egypt (second largest client), compensated for the loss of the Russian market;
- **The volume of financing in Eastern Europe and Caucasus increased more than fivefold,** making it by far the top region;
- The balance between upstream and **downstream** operations, reversed in favour of the latter, growing from 45% to 55% during the decade;
- **Oil and gas extraction**, the top sub-sector in the 2000s, kept its crown for the number of projects, but the percentage of its share dropped. It also shrank to a quarter of the total in volume terms;
- The number of **gas pipelines and storage** projects was exactly the same in both periods (11), however in the 2010s they became the **largest sub-sector in volume terms**, growing almost two fold (180%) from €0.6 billion to €1.7 billion and accounting for 37% of the total;
- The number and volume of **smaller projects increased substantially**, particularly in the gasoline stations and support activities, while remediation (third largest in volume terms during the 2000s) became insignificant;
- Environmentally-friendly projects, promoting energy efficiency, made a **comeback with oil refineries** in CEB (they were popular in the 90s but virtually disappeared in the 2000s);
- The number of **coal-related projects tripled in the last decade**, while their volume increased fivefold. However, they remained relatively marginal (4% of the volume). They were implemented in only two countries – Mongolia (3) and Ukraine (3);
- The value of the **state operations increased eightfold** and their share jumped from 9% to 29% of the total volume (to €1.4 billion), although their numerical increase was less dramatic (from five to eight). This was due to large pipeline projects (all state) and the financing of Naftogaz Gas Purchase Facility (Ukraine) and SOPC (Egypt);
- **Appetite for equity reduced almost threefold**. In the 2000s, projects involving equity accounted for a quarter of the number and 11% of the volume, while in the recent decade their share shrank to eight and two percent respectively. The failure of such operations as Bautino and Clean Globe (mentioned above) contributed to the Bank's cautious approach;
- Hydrocarbons accounted for 4.3% and 5% of the Bank's total commitments in each period.

The increase in the state operations resulted in the Bank's more robust engagement in the sector's policy dialogue, particularly in the three countries where most of such a financing was provided – Azerbaijan, Egypt and Ukraine - please see annex 4 for details on the Bank's engagement in Azerbaijan and section 4.3.3 on policy dialogue in Egypt. As for Ukraine, since 2014 the Bank and other IFIs have been working on reforming and liberalizing its gas market, which greatly benefited from such a joint support and which transformation was successfully completed in 2019. EBRD has also played an important role in supporting the government's efforts to restructure the national oil and gas company Naftogaz, providing advice and financing of EUR 540 million under three operations.

Figures 6 and 7 compare the regional and sub-sectoral volume distribution in both periods.

Figure 6. Regional distribution of hydrocarbon financing in 2000-2009 and 2010-2019

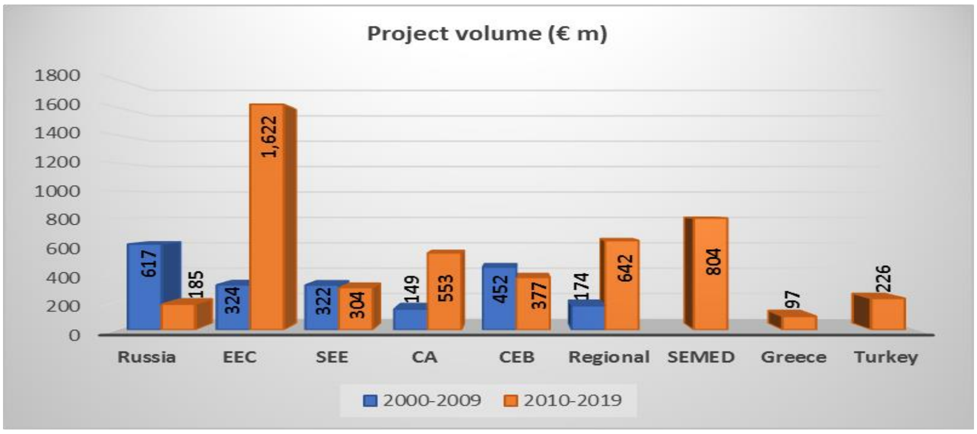
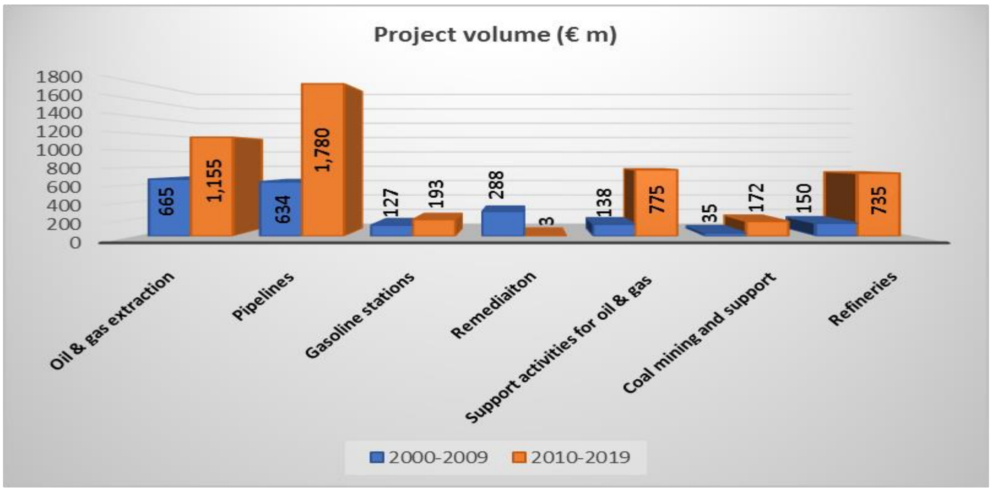


Figure 7. Sub-sectoral distribution of hydrocarbon financing in 2000- 2009 and 2010-2019



In 2018 the Board approved the new **Energy Sector Strategy 2019 - 2023** (BDS18-237 Final) which largely followed the recommendations of EvD's 2018 Energy Strategy Review (see section 1.3), although in accordance with the current template for sector strategies, it is limited in scope. Nevertheless, the new strategy is based on solid diagnostics (presented in annexes) and contains the Performance Monitoring Framework (PMF) with useful indicators, although defined in general terms only, as more detailed targets for this and other sectors are now set in the country strategies (see section 3). This Energy Sector Strategy clearly states for the first time that the Bank **will not finance thermal coal and upstream oil projects** *"except in rare and exceptional circumstances where the projects reduce greenhouse gas emissions or flaring"*.

However, this strategy provides only relatively general guidance on what the Bank can still do in hydrocarbons. Its "Cleaner oil and gas chains" section states that *"hydrocarbons investment will need to be consistent with nationally determined contributions (NDCs) and be subject to the Bank-wide Shadow Carbon Pricing Methodology for use in EBRD projects with high greenhouse gas emissions"*. Unlike the Shadow Carbon Pricing methodology proposed under the 2013 Energy

Sector Strategy, this one applies to all sectors, rather than coal-generation only. It has already been applied to economic assessment of five projects approved by the Board by October 2020. The new Strategy contains a few more but still broad statements related to hydrocarbons, e.g. *"the Bank will continue to support upstream gas activities that benefit our COOs (e.g. activities that replace coal or provide energy security or flexibility)"*.

Slightly more specific are the references to the *"support for energy efficiency improvement along oil and gas value chains"*, as well as "*LNG, fuel stations and private sector entry and the development of comparative and resilient markets"* as types of transactions eligible for the Bank's financing. These are useful, but still broadly-defined directions. Also, references to hydrocarbons in the country strategies, although they do appear, do not provide sufficient guidance on types of projects the Bank intends to do in this sector (see chapter 3). Such lack of specificity may be contributing to some ambiguity, which now exists among bankers (see next section) on what the Bank can actually do in this sub-sector. This is in contrast to the mining sub-sector, which now has its own strategy (Extractive Mining Industries Strategy BDS17-215). It provides clearer guidance on what the Bank will do in mining, which countries will be principal targets, how it will cooperate with other IFIs, etc. The current Energy Sector Strategy is geared more towards power and energy operations and provides limited guidance for hydrocarbon projects. In EvD's, view this gap should be filled by the Bank's mid-term (rolling) operational plan in the hydrocarbon sub-sector, which would be more specific in targeting concrete projects in selected countries/regions, combining them with policy dialogue and TCs objectives, and identifying areas for cooperation with other IFIs. The main parameters of such plans would be earlier discussed with the Board – see the first recommendation in section 6.2.

2.4. Organisational arrangements for the Bank's hydrocarbon operations

Most of the hydrocarbon projects were developed and implemented by the Natural Resources team[5], which for many years was part of the Energy Group. They accounted for about three quarters of this team's total business volume and the number of projects signed (the rest being related to ore/metal mining). However, as of January 2019 this team became part of the Industry, Commerce and Agribusiness (ICA) Group, while part of its activities (financing gas pipelines, public gas storage and LNG terminals serving power plants) were transferred to the Energy Eurasia and Energy EMEA teams, which form part of the newly created Sustainable Infrastructure Group (SIG). The rationale for this change was that gas pipelines, gas storage and LNG terminals form part of "infrastructure" and they are usually public, regulated assets, thus they fit better with SIG as it specialises in financing the regulated infrastructure sector.

Reportedly, the Natural Resources team was moved into the ICA Group to realise synergies between its mining business and some Manufacturing and Services (M&S) projects, particularly in the mining of mineral fertilisers (i.e. potash salts and phosphate rocks). Previously, the M&S team had financed only a few potash and rock phosphate mining projects, but the growing demand for fertilisers suggests there is good potential for more of them in the future. The Natural Resources team's mining expertise could then be used to develop such projects, applying the high mining

[5] During 2014-2018 hydrocarbon projects in Central Asia and the Caucuses were developed and implemented by the ERCCA team.

standards set in the Extractive Mining Industry Strategy. However, EvD understands that there is ambiguity as to which team is to pursue such projects. Moreover, fertiliser mining seems a relatively marginal activity, particularly for the Natural Resources team when compared to hydrocarbons (and other metals mining) and thus energy-related line of business.

The Natural Resources team expects that, given the loss of its upstream oil (and now also gas-related infrastructure) business, as well as the Bank's general reluctance to finance hydrocarbons, the relative proportions of its mining and hydrocarbon businesses will soon reverse, i.e. the latter will account for about 20-25% of the total, while the former will dominate.

In the meantime, the Natural Resources team and SIG try to cooperate and coordinate their natural gas activities, on the understanding that any upstream gas project opportunities might be pursued by the former, while infrastructure financing will fall to the latter. However in practice this does not always work, as clients tend to be large vertically integrated companies, engaged in gas exploration as well as the related transport and storage. Early experiences indicate that it takes substantial time and effort to fully coordinate client relations and especially to agree on a coherent message to convey to the clients. However, the deployment of Special Client Managers from the country teams in Ukraine and Egypt have helped coordinate relations with the large state-owned integrated gas companies in these countries, so it may be replicated elsewhere.

Based on interviews with EBRD bankers, EvD understands that some of them have the impression that the EBRD's current official strategy towards hydrocarbons (i.e. allowing some types of projects) is not always followed and that some Management and Board members discourage any engagement in this sub-sector. This can be confusing, not only for the bankers but also for potential clients. Thus more clarity on what type of hydrocarbon projects, in which countries and under which conditions, the Bank can and should finance, would be beneficial.

2.5. The Bank's future hydrocarbon operations

The Bank's Strategic and Capital Framework 2021-2025, recently endorsed by its Governors, clearly points to the EBRD's future as a "green bank". To what extent could operations in the hydrocarbon sub-sector contribute to this goal?

According to Banking team, investment in such operations will be much more limited, and certainly more selective than in the past, while their focus will be different, following (very broad) guidelines defined in the Energy Sector Strategy 2019-2023. However, they expect that the Bank will still be able to play a limited role in this sector because:

- Energy generation conversion from hydrocarbon-based to clean energy sources is expected to take many years even in the foremost Western economies. Hydrocarbons will probably continue to dominate their energy systems (despite acceleration of transition to renewable energy sources (RES) during the COVID-19 pandemic, see annex 7);
- In the meantime, the energy and carbon intensity of oil and gas companies in the COOs remains particularly high (e.g. despite attempts to limit it, carbon emissions from oil refineries in Greece, Poland, Romania increased in 2005-14, while those from most Western refineries decreased[6]);

[6] https://www.ifpenergiesnouvelles.com/sites/ifpen.fr/files/inline-images/NEWSROOM/Regards%20%C3%A9conomiques/Etudes%20%C3%A9conomiques/Panorama%202016/VA%20Panorama%202016/11-Panorama-2016-VA_EtatDesLieuxSecteurRaffinage.pdf

- Even as RES gradually take an increasing share in energy generation, their intermittent character means that hydrocarbon-based energy would need to play some role for the foreseeable future. Some hydrocarbon-based generators (i.e. gas companies) would remain indispensable as a back-up for RES;
- Methane emissions from oil and gas networks remain the second largest cause of global warming. COOs are responsible for a significant quota of these emissions, therefore to ensure they are reduced in the shortest possible term, the Bank could play an important role, providing policy advice and financing for such emission abatement projects;
- While engaging selectively in hydrocarbon projects, the Bank could continue to engage in policy work directed towards accelerating decarbonisation and scaling up RES. This has started in some countries but it typically requires longer-term engagement with incremental TC sub-projects to achieve more substantial results.

3. Linkages of country strategies to hydrocarbons

- Around 80% of the country strategies (CSs) reviewed referred to hydrocarbons in the context of transition challenges, often in terms of energy security, resource depletion, GHG emission and efficiency of their use;
- Most strategies targeted natural gas as the priority hydrocarbon sub-sector for the Bank to support. However, until recently, in terms of the number of projects, the Bank's portfolio has been dominated by those supporting oil (gas pipelines dominated in volume terms);
- Some country strategies did not refer directly to hydrocarbons. However, the need to improve energy security was often cited and constituted the main justification for the Bank to support hydrocarbon projects in a given country;
- Almost all diagnostic papers stressed inadequate or unstable regulatory, legal and institutional frameworks for supporting sustainable energy projects and in some cases specifically hydrocarbons (even in EU countries). However, very few projects addressed these areas;
- Most *new* strategies present a monitoring approach, including for hydrocarbon-related operations, with outputs/outcomes and tracking indicators. However, some indicators are inadequate, as only one indicator is assigned to track several activities. In addition, baselines are missing or assumed to be zero;
- All strategies approved under the new transition qualities include a description of the challenges and diagnostics for the *Green* quality, which promotes diversification of energy sources, generally away from hydrocarbons.
- A large proportion of the key transition challenges related to hydrocarbons fell under the *Resilient* transition quality, which promotes diversification of energy sources (i.e. supporting pipeline projects);
- Some strategies (mainly in the hydrocarbon-rich countries) seem to pursue conflicting objectives as they envisage the Bank both supporting hydrocarbon industries and moving away from hydrocarbon sources of energy.

These main findings are based on EvD's review of ten country strategies (CS) and related diagnostic papers. Three evaluated projects were approved under the reviewed strategies (Ukraine, Slovak Republic and Poland). Three other cluster projects were approved before the first CS of their respective countries were finalised (Egypt, Greece and Tunisia), so the first CSs prepared for these countries were reviewed. The most current CS for all of the six cluster countries were also analysed. Five country diagnostics papers (prepared to inform the most recent strategies 2016-2018) were also part of the study. Moreover, four additional CSs were analysed for countries where the EBRD has implemented several hydrocarbon projects (Azerbaijan, Kazakhstan, Mongolia and Romania). Annex 5 contains a full analysis of the linkages between hydrocarbons and the 18 strategic documents (CSs or diagnostic papers). This section presents a summary of the key references.

Egypt - There was no Strategy for Egypt when the PICO Oil and Gas (44491) project was approved in 2014. The PICO project was developed and signed shortly after the Bank signed an MOU with three key Egyptian oil and gas companies, focused on APG reduction (although PICO's sponsor was not one of its signatories). The first approved **Strategy for Egypt (2016)** highlighted the transition challenges in the power/hydrocarbon sector, which included a fully state-owned gas transmission sector, with private sector involvement limited to gas distribution, fuel subsidies contributing to road congestion and an undiversified power generation base with limited capacity, rapid growth in power demand and gas supply shortages, which have given rise to supply concerns. The strategy proposed four strategic orientations to guide the EBRD's engagement in Egypt, with two referring to hydrocarbons: *Priority 1: Support Egypt's Private Sector Competitiveness.* The operational focus was to support the agribusiness, manufacturing and natural resources sectors. The Bank was to promote backward and forward integration by providing finance to domestic anchor investors (including oil producers in remote areas). *Priority 2: Improve Quality and Sustainability of Egypt's Public Utilities,* including promotion of gas market reforms. In terms of Operational Focus in the state-dominated oil and gas sector, the Bank was to selectively finance projects in the midstream oil and gas sub-sector, including state-owned.

Greece - Energean Oil (47822) was approved before the Greek strategy was finalised in 2016. In this **Strategy for Greece** none of three priority pillars made specific reference to hydrocarbons. Priority 3 envisaged *Support for private sector participation and commercialisation in the energy and infrastructure sectors to enhance regional integration and improve quality of utility services.* It was very general but could be seen as providing some justification for Energean project. The Operational Focus of Priority 3 states that the Bank will support transport, logistics and energy infrastructure enhancing Greece's integration with regional markets, including gas and power interconnections. In support of recent progress on gas market liberalisation, the Bank would seek to finance private distributors. No upstream exploration of oil was mentioned.

Tunisia - project Serinus (44744) was approved in 2013, before the first CS for Tunisia was finalised at the end of 2018. It followed a Diagnostic Paper published the same year (see annex 5). In this **Strategy for Tunisia,** one of four strategic priorities was related to GET and hydrocarbons. It envisaged increased renewable energy capacity, more diversified energy mix and greater private sector participation in the energy sector. To this effect, four activities were proposed. One of them was intended to provide finance for medium-scale oil and gas operators, with a focus on private sector operators and gas flaring reduction investments. The tracking indicator for this objective was total renewable electricity installed (MW). The second objective was increased energy, resource and water efficiency. One of the three activities proposed under this objective was to develop and finance supply-side resource efficiency solutions (e.g. upgrade of existing power plants, high efficiency conventional gas-fired power generation, gas and electricity transport and distribution, transmission modernisation). The tracking indicators for this set of activities were energy and water savings.

Slovak Republic - MOL/Slovnaft (43869) was approved in 2012 under the 2009 **Strategy for the Slovak Republic**, which did not have any direct references to hydrocarbons. However, one of the strategic priorities referred to *investments in infrastructure, energy security and energy efficiency* (very broad but corresponding to some extent to the cluster project). Also, challenges related to natural resources (in the annex) included those concerning the gas sector, i.e. although a very small producer of natural gas, the country was an important transit corridor. Also, its per capita natural gas consumption was very high, with more than 80% of Slovak households connected to the natural gas network. Most of the coal produced was used for electricity production. The main domestic oil and gas operators have been corporatised and partially privatised.

Poland - project PKN Orlen (42609) was approved under the 2010 **Strategy for Poland**, which among the challenges identified, were those related to hydrocarbon sectors such as delayed privatisation in the coal sector. In 2007 the government reversed sector unbundling by consolidating some state-owned coal mines and electricity generation/distribution and supply companies into four vertically integrated energy groups. The restructuring and privatisation of the mining sector remains a key challenge. In 2009, there was one successful IPO of a coal mine. The State Treasury still holds shares in multiple natural resources companies. In theory, the Polish gas market is now open and all customers can choose their supplier. In practice, PGNiG dominates the upstream oil and gas segment, is the main importer, and controls gas storage and distribution. State subsidies to the mining industry remain an issue of concern. The operational priorities in energy and energy efficiency include support for privatisation in the energy, oil and coal sectors, as well as the promotion of gas market development.

Ukraine – Galnaftogaz III (45462) was approved in 2013 under the 2011 **Strategy for Ukraine**, which noted that the country is a major net importer of oil and gas, and an important transit country. The energy sector suffered from years of serving primarily quasi-fiscal or political, rather than commercial, objectives. Improving governance and transparency in the sector, as well as commercialisation and unbundling of NAK Naftogaz (a state company responsible for extraction, refinement and transportation of oil and gas), would be needed to strengthen its ability to raise additional finance to modernise the gas transit system and develop Ukraine's natural resource base. The state-run coal sector remains inefficient, with many mines being financially unviable. Challenges to private investment into oil and gas extraction include price regulations as well as administrative obstacles. The Bank's operational focus in the natural resources sector included: support of modernisation of the gas transit system and corporatisation and unbundling of the state owned NAK Naftogaz, and the possible provision of energy efficiency finance; support for greater local sourcing of oil and gas, reducing dependency on imports; further support of the private sector; and support of mining projects, leading to greater transparency, improvement of health and safety standards or energy efficiency.

For linkages between hydrocarbons and more recent strategies as well as those of Romania, Azerbaijan, Kazakhstan and Mongolia see annex 5. In conclusion, in its country strategies, the Bank recognises the critical importance of hydrocarbons for many of its COO's economies, particularly those at the lower transition level. Therefore, development of hydrocarbons is often part of the Bank's strategic priorities in these countries (e.g. Mongolia, Egypt, Azerbaijan, Kazakhstan). Nevertheless, risks of working in hydrocarbons are recognised. Thus, the Bank's commitment to this sector is often conditional on systemic reforms, including the liberalisation of market access, as well as improved regulation, transparency and corporate governance. The latter is often addressed in the Bank's projects, however the involvement in wider reforms is much more difficult given its "strategic" nature. The sample projects were all with private clients, what offered limited opportunities for the Bank to engage in such reforms (although projects Energean in Greece and PICO in Egypt demonstrate that it was possible – see section 4.3.3. for more info). Also TANAP's earlier evaluation proved that the Bank was able to engage on the higher policy level in this sector (see annex 4). The recently growing portfolio of larger, state projects (primarily gas pipelines, many under implementation), creates opportunities for the Bank to step up its efforts in this respect, pushing for systemic reforms in this sector.

4. Performance assessment of selected projects

Three projects selected for this evaluation financed upstream hydrocarbon processes – mainly oil extraction and exploration, while the other three supported downstream processes - two investments in oil refineries/petrochemical plants and one expansion of a fuel stations network (see annex 1).

No gas pipeline projects were selected because an important pipeline project (and one of very few completed so far) – Southern Gas Corridor or TANAP (OpId 48376), for the transportation of Azeri gas through Turkey to the Greek border - was evaluated a year ago as part of the Regional Integration review (SS19-136). Also, no coal projects were included as EvD completed an evaluation of Mongolian mining projects (PE18-602) in 2019, which covered all three coal mining/processing projects (half of the Bank's coal-related project portfolio).

Results from these recent evaluations were taken into account when analysing the trends and commonalities of the Bank's hydrocarbon projects. The evaluation of the six cluster projects is presented in annex 2, their results frameworks in annex 3 and the TANAP evaluation in annex 4. Table 2 summarises the results of these evaluations. Principal issues identified for each evaluation category are described in the following sections.

Table 2. Summary of evaluation rating[7] of 6 cluster projects and TANAP project (evaluated as part of the Regional Integration Review in 2019)

Cluster Project, Country	Relevance and Additionality	Results	Efficiency	Overall Performance
PICO Oil and Gas, Egypt	*Fully satisfactory*	*Partly satisfactory*	*Partly satisfactory*	*Acceptable-*
Energean Oil I and II, Greece	*Fully satisfactory*	*Largely unsatisfactory*	*Partly satisfactory*	*Acceptable-*
Serinus, Tunisia	*Fully satisfactory*	*Largely unsatisfactory*	*Largely unsatisfactory*	*Poor*
PKN Orlen, Poland	*Partly satisfactory*	*Partly satisfactory*	*Partly satisfactory*	*Acceptable+*
MOL/Slovnaft, Regional	*Partly satisfactory*	*Largely unsatisfactory*	*Fully satisfactory*	*Acceptable*
GNG - Galnaftogaz III, Ukraine	*Fully satisfactory*	*Partly satisfactory*	*Partly satisfactory*	*Good-*
TANAP, Azerbaijan	*Excellent*	*Fully satisfactory*	*Not rated*	*Good*

4.1. Overall performance

- Project relevance ranged from adequate (partly satisfactory) to relatively strong (fully satisfactory) as all had important energy efficiency and/or environmental improvement components, which aligned them with the Bank's "green" country/sector strategies and initiative. However, being non-cash generating, these components were often delayed or not implemented;
- Additionality was questionable in the case of two corporate loans, which were with very strong clients – top two corporations in the region. TANAP's relevance was rated excellent as EBRD's loan supported a project, which was strategically important for energy supply diversification (thus energy security) in Europe;
- PKN and TANAP were the only projects which completed their physical investments in full and on time. MOL accomplished them with a substantial delay. The majority of planned capital investments under the PICO and GNG projects were completed, but only a relatively small part of those under Energean and Serinus projects were implemented, mainly due to the drop in oil prices, as well as technical or labour issues;
- It has been difficult to trace and verify the application of the Bank's proceeds in all projects and in some cases it is not entirely clear what the Bank actually financed. Refiners refused to provide information on application of proceeds citing confidentiality;
- Cash-generating drilling was prioritised over components that generated expected TI.
- Under several projects the Bank was by far the largest source of funding, with the sponsors/clients providing only a fraction of the amounts indicated as their contribution in the Board reports;

[7] Ratings for each category are based on the following scale of: Excellent – Fully Satisfactory – Partly Satisfactory – Largely Unsatisfactory - Unsatisfactory. The overall performance rating scale is: Outstanding – Good – Acceptable – Poor – Very Poor ("-" or "+" may be added to the overall performance rating).

- Most projects had a very complex transition structure, with TI benchmarks ranging from 7 to 32, some of them with vague or absent linkages to the project's components. The transition-related results of most projects were relatively modest;
- Some hydrocarbon projects (PICO, Energean, TANAP, MAK I Mongolia) included policy dialogue components, which objectives were typically partially achieved, contributing to regulatory improvements in the hydrocarbon sector, health and safety regulations in line with EU directive and the implementation of EITI standards;
- Private sector expansion in an industry dominated by state enterprises was often the main transition objective. It was achieved in most cases but its impact was more questionable in Tunisia and Egypt, where hydrocarbon extraction concessions were majority-held by state companies, which benefited from JVs with private partners;
- Most projects experienced financial difficulties, caused mainly by falling hydrocarbon prices, affected by changes in demand and supply, often resulting from political or economic upheavals. Technical, geological and labour issues also contributed to underperformance;
- Strong sponsors, robust project financial structures (some with sponsor guarantees/undertakings) and diversified business models proved to be critical when oil prices dropped, and ensured that all the loans were serviced;
- With the exception of MOL all of the loans under cluster project were partially cancelled, prepaid or refinanced.

4.2. Relevance

The relevance of four cluster projects was assessed as "Fully satisfactory" and that of the other two "Partially satisfactory". This is apart from TANAP, whose relevance was rated "Excellent" due to its strategic importance for energy supply diversification (thus energy security) for the whole of Europe. It enabled the transportation of Azeri gas from the Caspian Sea through Turkey to the Greek border for the first time, strengthening the continent's energy security by enabling the diversification of its gas supply sources. The Trans-Adriatic Pipeline connecting TANAP through Greece and Albania to Italy (and the rest of Europe) was also cofinanced by the Bank (completed in November 2020). Interconnections from TANAP to the Balkan countries and the rest of central Europe are under construction or planned.

The relevance of most hydrocarbon projects was relatively solid as they included energy efficiency and/or environmental improvement components, which aligned them well with the Bank's "green" country/sector strategies and initiatives. These components ranged from the reduction of Associated Petroleum Gas (APG) flaring and marine water protection (in offshore oil extraction operations), to the replacement of obsolete burners and the financing of pollution abatement equipment at oil refineries. However, while under downstream projects these components constituted key physical investments financed by the Bank, under upstream projects they were often additional to the main drilling activities. Therefore in such cases they were often seen by the clients as non-cash generating "icing on the cake", thus not a priority, and were often delayed or abandoned altogether under adverse market conditions. Some clients referred to them as "discretionary investments"- therefore the first to be taken off the list of investments when oil prices fell (more on this in the next section).

Verification of the cluster projects' additionality was included in the relevance assessment. While fully verified for the Galnaftogaz, PICO and Energean projects (mainly due to the limitations of their domestic financing markets), it is more questionable for PKN and MOL. In EvD's view, the Bank's additionality in oil refinery projects in EU countries was limited, as these companies were and are among the largest corporates in the Bank's COOs and generally cash-rich. For instance, for many years (and still) Poland's PKN Orlen has been rated the largest company in central Europe by revenues ($36.1 billion in 2019) and one of most profitable. Hungary's MOL has been trailing close behind it as number two in the region ($26.8 billion in revenues). Domestic banks have been fighting for their business, while both companies have been successfully issuing long-term debt on their domestic and international capital markets. They are undisputed market leaders, not only in specialised oil refining but also as petrol retailers, owning and operating the largest fuel station networks in the region (PKN is the fifth largest fuel retailer in Europe). Although the Bank's financing clearly targeted energy efficiency and environmental improvements (in both cases to meet obligations under the EU directive), this financing potentially allowed them to divert their own funds to further strengthen their market positions in other sub-sectors. Moreover, both companies have had relatively aggressive acquisition policies, spending hundreds of millions of Euros on buying other hydrocarbon-related assets in their countries and abroad, demonstrating their financial strength and further enhancing their dominant market position – an even less desirable development given that the state still has a considerable influence over them.

The Bank effectively avoided doing business with oligarchs, however in some cases the ultimate beneficiaries of the Bank's clients can be traced to individuals (Serinus) or families (PICO) who are among the richest in their countries. However, relevance of both projects was rated as "fully satisfactory", as they contributed to private sector expansion in SEMED countries, where oil sector has been dominated by state players. Nevertheless , the relevance of Serinus project was questioned when NGOs sent a letter to the Bank implying that it would involve fracking and extraction of minerals containing harmful substances (as reported by Bankwatch). This was subsequently dismissed by the sponsor and the Bank and no fracking took place (the project largely disintegrated anyway).

However, in other cases, the Bank's clients were mid-size private companies, which were beneficial to support in the context of a sector dominated by state-owned large conglomerates, and fully in line with the relevant sector and country strategies. This was the case with Energean – the only private hydrocarbons producing company in Greece, whose oil market is dominated by state-owned Hellenic Petroleum. Also, by providing incremental financing, the Bank (and IFC) helped the small, private Galnaftogaz (GNG) become the largest fuel retailer in Ukraine.

The financial additionality of almost all of the projects was eroded at the implementation stage, as part (sometimes large) of their financing was ultimately cancelled, prepaid or refinanced (see more in the next section). Therefore, in some cases a long tenor or large loan amount, which was part of the Bank's additionality justification, proved to be unnecessary.

4.3. Effectiveness

Effectiveness was assessed as "partly satisfactory" for half of the projects, and "largely unsatisfactory" for the others, as all of them, to a greater or lesser degree, fell short of achieving their intended results. Only TANAP (evaluated outside of the cluster in 2019) was rated "fully satisfactory". Overall, this is rather a disappointing result and points to the high implementation risks faced by hydrocarbon operations – both in terms of physical investments and transition-related components.

4.3.1. Physical implementation

Almost all of the cluster projects experienced difficulties in implementing their capital investments. It transpires that only PKN Orlen completed them in full and on time (although they were not precisely defined in the Board report). In general, EvD noted the following issues with the implementation of the cluster projects:

- The evaluability of most of them was poor as the Board reports were often vague as to what the Bank's loan was to finance, with the use of funds section sometimes missing, or capex components defined in very general terms, e.g. "drilling activities"[8];
- A financial contribution from sponsors/clients was required and promised (particularly in project-type finance for upstream processes). However, in some cases only a fraction of intended amount was actually contributed by the client, while the Bank remained by far the largest provider of funds for such projects (see box 5);

Box 5. Energean and Serinus projects

Energean, Greece, oil extraction – the Board report contained a financing plan, indicating that the Bank's $75 million senior loan would finance the construction of an offshore wellhead platform, APG utilisation and environmental investments (i.e. components supporting the project's transition impact), while an $84 million "internally generated cash" contribution from Energean would finance the drilling of 17 offshore oil wells. However, as the Bank's loan was fully disbursed and Energean did not have any cash, the proceeds were applied to drilling because this was perceived as a priority, cash-generating component. As the client encountered technical and geological problems, almost the whole loan was spent on drilling ten new wells and work-overs of existing wells. However, this didn't helped the client to generate much cash, as it asked the Bank to arrange further financing of $105 million to implement the rest of the project. The Bank attracted BSDTB, Romanian Eximbank and a private bank to provide a new loan. So far, half of the new amount has been spent on constructing the offshore wellhead platform but only half of it has been completed. APG utilisation was abandoned, and only the less costly environmental components have been implemented. The sponsor did contribute to the repayment of the loan's instalments (as internally generated cash flow was insufficient), however it is unclear how much was contributed to the capex of the project, if anything.

Serinus, Tunisia, oil extraction - the project envisaged the development of five oil fields, where 11 new wells were to be drilled and exploited (worked-over). The Bank's $45 million financing was to cofinance the client's "internally generated cash" contribution of $106 million. Due to falling oil prices and labour strikes only two wells were drilled at the Sabria field, majority owned by a state company. The drilling costs were to be shared, with the state providing the majority of the financing, leaving about $15 million to be covered by Serinus. As none of the other capex originally envisaged (acquisition of drilling and service rigs) was realised, it transpires that the remaining $30 million Bank financing was used for existing wells work-over, stimulation and repairs (expensive due to challenging geological conditions). According to the client's financial statements, its own equity contribution to the project amounted to $17.7 million, which is a fraction

[8] This issue was also highlighted in the "Mongolian Mining" evaluation PE18-602

of the originally intended amount ($106 m) and appears mainly to have financed partial repayment of the loan, rather than the capex.

- No upstream oil extraction project wholly achieved its intended drilling objectives (e.g. two out of 11 planned wells drilled, two fields to be developed, only one completed, etc.). New drilling platforms or rigs have not been constructed/acquired. This was mostly due to falling oil prices but also technical/geological problems and labour strikes;
- As drilling was prioritised, implemented up-front and costlier than estimated, other (often transition-supportive) components were delayed or not implemented (e.g. APG utilisation, some environmental investments), due to all funds being exhausted on drilling;
- Most downstream projects suffered long implementation delays due to technical issues or political upheavals (the latter affected Galnaftogaz during the Ukrainian conflict);
- Loans under all projects but MOL have been partially cancelled, prepaid or refinanced, see table 3.

Table 3. Cancellation and prepayment/refinancing of cluster projects

Project	Original loan (million $)	Disbursed (million $)	Cancelled (million $)	Pre-paid or refinanced (million $)
PICO	50	37.5	12.5	37.5
Energean	75 (+20 sub-loan)	75+20		22.5 m
Serinus	40 (+20 sub-loan)	25+20	15	
PKN Orlen	250	180	70	180
Galnaftogaz	20 (+160 others)	12.8 (+107.5)	7.2 + 52.2	

4.3.2. Outcomes related to physical implementation

- Upstream projects did not achieve production increase targets due to only partial implementation of the drilling programmes. PICO did achieve the target on one of its fields but failed on another, Energean's production was about 30% below target, while that of Serinus was marginal;
- Some of the planned environmental and energy efficiency-boosting investments were implemented. However, their outcomes (e.g. amount of energy or pollution reduced) were often unclear due to lack of measurement[9], conflicting data or an unclear baseline; those confirmed were beneficial but typically below the ambitious targets;
- Pollution abatement equipment and measures for refineries were implemented but resulted in little improvement in the air quality. However, the TC provided under the MAK I project in Mongolia was credited with spearheading further investments into the smokeless coal plant, which resulted in the reduction of Ulaanbaatar's air pollution;
- Some projected outcomes described in the Board reports (e.g. production capacity increase, sale of excess energy to the grid) were mis-stated as they were not intended by the clients and never materialised.

[9] It is noted that similar issues were identified in respect of hydrocarbon project evaluations in Kazakhstan (Review of the EBRD Energy Sector Strategy) SS17-105)

Notable transition-related achievements under the cluster projects included transposition of the EU safety directive on offshore oil drilling (2013/30/EU) into Greek law, together with the secondary legislation, guidelines, a rulebook and emergency response plans; better awareness of APG issues among officials and the industry in Egypt (see box 6). Moreover, the projects helped introduce corporate governance improvements at upstream oil companies (including compliance with EITI in Egypt and PWYP in Tunisia), as well as improved environmental management and practice at most of the client companies. Table 4 summarises the cluster project results.

Table 4. Summary of cluster project results

Cluster Project, Country	Physical objectives	TI objectives achieved (or mostly achieved)	TI objectives not achieved
1.PICO, Egypt	Out of 17 wells planned, 21 drilled in Amal field. But additional well drilling in Zaafarana and the Floating Production Storage and Offloading facility upgrade not implemented.	Out of 32 benchmarks 20 achieved (mostly based on info from the team/TIMS), ranging from growth of PICO's market share to the implementation of social policy and its components, biodiversity studies preparation and disclosure of payments in line with EITI	12 benchmarks considered not achieved, including four related to staff training, energy efficiency and APG flaring targets (no info on those)
2.Energean, Greece	10 wells drilled out of 17 planned, with delays and substantial cost overruns. Offshore platform about 50% built with fouryears delay, APG utilisation abandoned, environmental improvements partially implemented.	-implementation of the metering and pollution prevention systems/sensors -adoption of the secondary legislation, guidelines and rules for implementation of EU safety Directive -emergency response plan for offshore operations in line with best practice adopted	-reduction of electric and energy consumption from 350 to 150 kWh/bbl -APG utilisation -installation and utilisation of the Lambda platform -a second SIP platform installed in the Mediterranean sea -completion of nine wells with dual-completion methodology -the Greek authorities adopted a transparent model for monitoring upstream licenses and bids
3.Serinus, Tunisia	Two wells drilled out of 11 planned, with delays and substantial cost overruns. Plus existing wells' work-overs, stimulations and repairs. New rigs not contracted, horizontal drilling not undertaken	-implementation of an integrated Environmental and Social management system -disclosure of payments to Tunisian authorities in accordance with PWYP -clear HR policies adopted -implementing treatment and monitoring of drilling mud and liquid discharges -increased oil and gas production from (some) existing wells (reportedly achieved for some wells)	-increased oil and gas production according to the model -increase in net proven oil reserves -Increased capacity at existing processing facilities at Sabria field -securing dedicated drilling and service rigs and internalisation of drilling works

4. PKN Orlen, Poland	Obsolete K1 boiler replaced with energy efficient K8 at the refinery's CHP, as well as flue gas desulphurisation and other pollution prevention installed on seven other boilers, largely on time.	-compliance of CHP EBRD-financed boiler with EU IED one year ahead of deadline -compliance of whole CHP with EU IED ahead of deadline - ISO 50001/ EN16001 energy management system (completed) and integrated with the certified carbon management system (not completed) - Partial achievement	-Plock refinery's carbon intensity equivalent to 15% most efficient installations in its sector in the EU ETS -develop and implement carbon management system as part of the Company's ISO integrated system for the Plock refinery and the whole group -adoption by three refineries in COOs of an integrated carbon and energy management system -external sales of electricity to the grid at 788 GWh
5.MOL/Slovnaft, Slovakia	Refurbishment of old steam cracker completed (but the final work completed five years later than planned). Also installation of a new LDPE unit and decommissioning of two old units (out of three planned) completed	-decommissioning of three old LDPE units (two decommissioned, one left as a back-up)	-energy savings from refurbished cracker over 4.5 mJ/kg, NOx reduction 60%, CO2 14% (reduced but less than targets) -Compliance with EU IED by end 2014 (achieved only by end 2019) -LDPE unit to meet BAT standards of direct/primary energy consumption less than 2.8/3.2 GJ/t and water consumption 1.8 m3/t (achieved for water only) -Slovnaft plant's carbon intensity equivalent to 10% most efficient petrochemical plants in Europe -one refurbished and integrated petrochemical plant in COOs using BAT and reaching its CO2 performance -implementation and certification of integrated energy and carbon management system
6.Galnaftogaz, Ukraine	Out of 64 new high-volume gas stations planned (the majority in under-served areas) 47 were built and 46 were leased (by 2020) mainly in under-served areas (leasing preferred to building as risk increased due to conflict in Ukraine) Infrastructure for tank storage and LPG modules developed. Terminal tank storage near Yuzhny port not developed. Convenience stores expanded by 25 and restaurants by two, safety and monitoring equipment installed.	-share of high quality fuel stations to grow to 25% in the south, to 13% in the north-east. Partly achieved as the share grew to 27% in the south but remained 12% in the north-east (due to conflict in Donetsk) Partial Achievement -Safety consultant reviewed GNG's storage -implement investments proposed by the consultant in 4 storage locations (implemented in 10) -four actions/benchmarks related to Road Safety Management Plan development and implementation	

Observations on the transition-related frameworks and TI achievements of hydrocarbon projects:

- Generally complex transition frameworks and objectives. According to the Banking team, the controversial sector and/or weak additionality of some projects, prompted OCE/EPG to impose excessively numerous benchmarks and TI objectives to ensure their acceptance by senior Management and the approval by the Board;
- Some transition objectives did not link to the actual project/investments (e.g. road safety, association with international bodies, disclosure of payments to Mexican authorities). Some important objectives (e.g. integration of energy and carbon monitoring systems at refineries) did not have clearly identified funding source (and did not happen);
- Some environmental and energy savings targets were excessively ambitious, others were never intended by the client (e.g. sale of electricity to the external grid under the PKN project, capacity increase or the reduction of certain pollutants under the MOL project);
- Improvements were often achieved but were much more modest than targets and took longer than expected;
- Although Galnaftogaz expanded its network of stations offering high quality fuel, a significant drop in Ukrainian per capita income led to a drop in demand.
- The Bank's monitoring reports (PMRs, TIMS) did not always provide complete and correct information (e.g. for PICO, MOL and PKN). There were gaps in information following the departure of OLs (PICO);
- PKN refused to provide information on cost of investments financed from the Bank's loan, citing commercial confidentiality. Some data in respect of environmental indicators received by EvD from Slovnaft/MOL contradicted that previously received by the team.

4.3.3. Technical cooperation and policy dialogue

Technical cooperation and policy dialogue was overall quite limited given the size of the Bank's lending and the needs for regulatory and institutional strengthening. However, it is understood that: (i) all cluster projects were with private sector clients, thus limiting opportunities for policy dialogue, and (ii) this sector has been in general perceived as strategic and politically-sensitive by most countries and therefore it offered the Bank less opportunities to engage in policy dialogue.

Nevertheless, two cluster projects (Energean and PICO), as well as those earlier evaluated TANAP and MAK I coal project in Mongolia, included multiple technical cooperation and policy dialogue activities. Most TCs were implemented and policy dialogue conducted, resulting in some notable achievements, although generally falling short of the expectations. The results of policy dialogue conducted under the cluster projects are summarised in box 6 and those related to TANAP are described in annex 4.

Box 6 – Policy dialogue under the cluster projects

Energean, Greece – policy dialogue was to be conducted through technical assistance (TC project 6489, budget €445, 000 - the "Development of the Greek Hydrocarbons Sector"), intended to assist the Greek Ministry of Energy and the hydrocarbon regulator the Hellenic Hydrocarbons Resources Management (HHRM) in: (i) creating an efficient and transparent economic model that could be used to assess and monitor the different parameters of upstream licences and bids; and (ii) implementing the European Offshore Safety Directive, including guidelines, rulebook and emergency response plan. The first part of the TC was not implemented as, following its change of management, the HHRM informed the Bank that it already possessed expertise in this area (which the old management lacked). However, the second TC was duly implemented, the EU Directive was fully transposed into the Greek law, the secondary legislation was drafted, guidelines and the rulebook developed. Also an emergency response plan for offshore operations in line with best practice was prepared by the consultants and adopted by the HHRM.

PICO, Egypt – was implemented following the MOU between the Bank and three key Egyptian oil companies, which aimed at the reduction of APG emissions. The Bank prepared two associated TCs, both related to APG utilisation. The first was to be undertaken in coordination with the LTT (budget of €100,000) and was to entail: (i) a legal study to propose improvements to the template for new Production Sharing Contracts (PSCs) to incentivise APG utilisation; and (ii) provide capacity building assistance to a specific agency or department of the Ministry of Petroleum to implement the changes. The second TC, titled "Associated Petroleum Gas Flaring Study for Egypt" was to: (i) review potential APG utilisation opportunities at PICO's fields, and; (ii) organise an industry-wide workshop on APG flaring reduction. Both TCs were implemented. The first, by Economic Consulting Associates Limited (ECA), resulting in the report "APG Flaring in Egypt – Addressing Regulatory Constraints", published in November 2017. It made a comprehensive set of recommendations on gas flaring regulatory reform, which would increase levels of APG utilisation. Six sets of concrete and far-reaching steps/actions were recommended. However this report did not provide any recommendations on the PSC template changes and only a very minor change was introduced, i.e. one sentence stating: *"if associated gas is not utilized, EGPC [a state partner company] and the Contractor [a private partner] shall negotiate in good faith on the best way to avoid impairing the production in the interests of the parties."* In EvD's view this addition did not change much as it does not oblige parties to address the APG issue. It is also noted that the LTT was consulted at the very beginning but it was not further involved in the implementation of this TC. The second TC was implemented by Carbon Limits AS, a Norwegian consultancy, which identified possible bankable APG projects, including at PICO's fields, part of which were implemented. The consultants and the EBRD organised a number of workshops and conferences (two of them together with the World Bank) in order to publicise and, to some extent, educate relevant officials about the need to address APG utilisation. The Bank also signed an MoU with the Egyptian authorities for a long-term strategic partnership on APG. Another, recently completed TC (implemented by RINA Consultants), followed up on ECA's TC. It prepared guidelines on APG measurement, reporting and verification (MVR). An economic test was also developed. It is expected that the Ministry will formally adopt these deliverables and that they will be systematically rolled out for all new upstream concessions. The recommended MRV tools were piloted in 2019-2020 in fields operated by two companies (GPC and KPC). These actions effectively constitute the implementation of one of the first steps recommended by the ECA consultants under the original TC towards improving the regulatory framework for PSCs in Egypt.

As these examples demonstrate, policy dialogue in the politically-sensitive hydrocarbon sector has been challenging, bringing partial results so far. When focused on more neutral areas, such as support for adopting the EU Directive on offshore safety, it was clearly more successful than attempting to develop a licensing model and improve bidding procedures. Even addressing APG flaring, highly important for the "greening" of this sector, proved challenging. The changes introduced so far to the standard Production Sharing Contract between an Egyptian state company and a private investor, alert both parties to the issue of APG flaring but do not oblige them to do anything about it. However, after the termination of the original TC the Bank continued its dialogue with the Egyptian authorities through a follow-up TC, and more meaningful improvements to the regulatory framework might be achieved there in the future.

Beyond the cluster projects, the Bank supported the development of a new energy regulatory regime under the TANAP project. The new law was finalised, however it is not fully aligned with the EU's Third Energy Package and still needs final approval to become binding. Under its Mongolian coal mining projects the Bank assisted in the successful implementation of the Extractive Industries Transparency Initiative (EITI), which improved the governance of the Mongolian mining sector. The TC provided under the MAK I project was credited with spearheading further investments into the smokeless coal plant, which resulted in the reduction of Ulaanbaatar's air pollution.

4.4. Efficiency

Four cluster projects (66%) achieved "partly satisfactory" financial results because they fell well short of the expectations projected at approval. Nevertheless, their performance was satisfactory in the context of a difficult external environment and they serviced the Bank's debt. Only the MOL/Slovnaft project was assessed "fully satisfactory", while Serinus was on the other side of the spectrum, rated as "largely unsatisfactory". TANAP was not rated for efficiency, as it was only recently completed and was not planning to generate a positive cash flow until 2020.

It is noted that MOL's financial performance had to be assessed on the basis of its overall results, rather than measured against the Bank's original projections. The projections presented in the Board report were limited to two years (up to 2014, despite the loan's maturity falling in 2022). The Banking team was not able to find the original forecast model. Nevertheless, MOL's results have been consistently good by any standard and met its corporate targets (2019 EBITDA was over $2.4 billion), while its investment credit rating has been stable (BBB- from S&P). This is because the resilience of MOL's business model to hydrocarbon price fluctuations is relatively strong. Unlike other clients in this cluster, MOL has a relatively diversified structure, with large petrochemical and retail lines of business.

The financial performance of other clients, particularly those in the upstream oil extraction business, was strongly affected by oil and gas prices, which have been fluctuating, following a prevailing downward direction over most of the cluster projects implementation periods. Average annual crude oil prices peaked in 2011 (at $102 bbl) exactly when the first cluster project (PKN) was signed. Since then, they gradually fell to $38.7 bbl in 2016, increasing briefly to $61.3 bbl in 2018, only to fall again slightly the following year, before crashing to negative values in April 2020 and recovering somewhat to $36.2 bbl by November. Annex 6 provides a more detailed analysis of oil price fluctuations with figure 3 illustrating price changes, while pinpointing the cluster project inception dates and the timing of the important world events, which impacted these changes. It clearly demonstrates how certain events influenced mainly supply volume (e.g. technological innovations enabling shale oil and gas extraction in the US in 2015, tensions and conflicts in the Middle East in 2012 and OPEC's decision to cut supply in 2017). More recently, the end to oil supply cuts under the OPEC's agreement with Russia, combined with the worldwide surge of COVID-19 epidemics, which dampened demand, resulted in oil prices falling to unthinkable negative values in April 2020, as there were no buyers and producers were unable to store excess oil. Decreasing oil prices largely explain the financial performance of the cluster projects, which generally fell short of expectations. Some projects experienced additional difficulties, e.g. technical and geological problems (Energean), labour disputes[10] (Serinus), war conflict (Galnaftogaz). However, faced with rapidly falling oil prices and other difficulties, most clients were able to limit their losses by cutting production and investments, relying on sponsors (or their corporate structures) to ensure operations remained going, while debt has been serviced. The Bank cooperated closely with the clients, restructuring some loans (e.g. extending tenors), waiving financial covenants and partially cancelling the loans. Even under the Serinus project in Tunisia, which was only marginally implemented and generated serious losses, cash to repay the senior loan was obtained from the sponsor's operations in Romania, while the sub-loan was restructured by the project and Corporate Recovery teams (93% of its principal was repaid, while USD 3.5 m was converted into the company's shares).

Overall, the evaluation of the six hydrocarbon projects revealed that their performance was uneven, with overall ratings ranging from *Good* to *Poor, with most rated as Acceptable.* The latter achieved part of their physical objectives, although typically after long delays and large cost overruns. Oil price fluctuations, following a prevailing downward trend during most of the project implementation periods, prompted many clients to reduce or suspend their investment plans. This also impacted the transition-related results of these projects, which have been typically well below expectations and often difficult to measure due to lacking or conflicting data. The financial results were also varied. Over-optimistic oil price projections were frequently observed. All of the debt servicing and repayment commitments have been honoured so far, but often thanks to the sponsors' help, rather than the cash flow generated from these operations.

5. Hydrocarbon Approaches at other IFIs

- Half of the cluster projects (three) were cofinanced with other IFIs. The Bank provided between 12% and 60% of the total IFI financing, leading in one project with the BSTDB and following the IFC's lead in two others;
- Based on available reports, inter-IFI cooperation went reasonably well under all cluster projects. Other IFIs particularly appreciated the EBRD's coordinating role in monitoring environmental and social performance under the complex TANAP project;
- One client pointed to the different reporting formats required by different IFIs. A more universal format could have resulted in substantial efficiency gains for the client;
- The current policies of almost all IFIs permit financing of certain types of hydrocarbon projects. However, most of them are gradually phasing out hydrocarbons and in practice, all of them limit such engagement. In January 2021, EIB became the first IFI to cease financing any hydrocarbon-related projects.

[10] These disputes were not company-specific but country-wide labour strikes, which affected also other companies in Tunisia.

5.1. Cooperation with other IFIs on cluster projects

Project	Year	Cofinancing (USD millions)
44491 PICO Oil and Gas	2015	EBRD: 37.55 (43% of IFI loans) **IFC**: 50
47822 Energean Oil	2016	EBRD: 77.50 (60% of IFI loans) **BSTDB**: 52.50
45462 Galnaftogaz Loan III	2013	EBRD: 12.78 (11% of IFI loans) **IFC**: 15 **IFC**: 85

Equity and parallel loans not included

Three of the six cluster projects were cofinanced with other IFIs. The IFC was the cofinancier in two of the projects, taking the lead on both. The EBRD and the IFC have cofinanced four operations with Galnaftogaz, two of which were also cofinanced with the Black Sea Trade and Development Bank (BSTDB). Galnaftogaz Loan III (a cluster project) was the fourth syndicated loan. Moreover, a new operation - Galnaftogaz Loan IV, cofinanced with both the IFC and the BSTDB, was signed in June 2020. In terms of monitoring and reporting, the client had dedicated internal departments, which collected information and drafted reports. The client noted that reports were prepared for each organisation separately. Most of the information required and reported was the same, but needed to be presented in different formats. Significant time and resources were spent on each report. Efficiency gains in time and resources could be obtained by streamlining reporting (a similar finding was also highlighted in EvD's recent Regional Integration review SS19-136).

In respect of the PICO project, the Bank and the IFC developed a corporate governance action plan (CGAP) together, focused on the Board's and Committees' composition and authority, independent directors, internal and external audit, and corporate secretary. It was successfully implemented by the client. When managing and implementing the project became challenging, the EBRD and the IFC were able to navigate the breakdown of the relationship with the client. They ultimately jointly requested the repayment of the loan. Both IFIs worked on a complex refinancing that was fraught with difficulties and delays, which they ultimately achieved.

The Bank's cooperation with the BSTDB under the Energean project started early, however the BSTDB did not obtain an approval from its credit department to co-finance this project. The Bank invited the BSTDB again later on when the project hit difficulties and the client needed additional financing. This time the BSTDB stepped in (together with other financiers), providing additional loans of €105 million, part of which refinanced some of the Bank's exposure to Energean. EvD understands that the project and the loan are currently (end of 2020) being restructured, with the EBRD and the BSTDB working on it together.

The large gas pipeline projects were often co-financed by several IFIs. Under the TANAP project, the Bank provided 22% of the total IFI financing alongside the World Bank (IBRD and MIGA) and the AIIB. This project's client had a generally positive view of IFI cooperation and coordination. They praised the coordinating role of the World Bank, which made an important contribution to resolving practical and political issues. Moreover, there is evidence that the IFIs cooperated during the preparation of the energy regulatory legislation in Azerbaijan, supporting provisions related to the regulator's independence, which were politically sensitive.

There have also been practical benefits for IFIs from participating jointly in this mega-project. The EBRD (being a latecomer to TANAP) effectively leveraged the work of the World Bank, e.g. in terms of due diligence, which enabled it to process the approval relatively quickly. On the other hand, the

AIIB commented that their team, as well as other IFIs, highly appreciated the EBRD consultant's coordination of the environmental and social performance monitoring of this complex project. The client also stressed that the IFIs coordinated well with them, e.g. combining visits and meetings, thus minimising the client's workload. Benefiting from common IFI monitoring of the environmental and social performance was possible because harmonising their E&S policies has been a priority for the IFIs since at least the 2005 Paris Declaration on Aid Effectiveness; this has largely been achieved and is now regularly monitored during the E&S policy update cycle of each IFI. For example, the EBRD has benchmarked the IFIs' E&S policies, revising its own in 2014 to be consistent with those of the IFC and the EIB. One area that was highlighted as potentially requiring better IFI harmonisation in the future is mobility for the disabled (in relation to road safety).

5.2. Approach to hydrocarbons by other IFIs

In November 2020 during the "Finance in Common Summit", IFIs and development agencies made a pledge to "increase the pace and coverage" of investment in renewable energy, energy efficiency and clean technologies. Importantly, they agreed to link the targets and metrics assessing the impact of their interventions to those of the Paris Agreement. They did not commit, however, to phase out fossil fuel financing. Oil and gas were not mentioned, but coal was. The summit's closing declaration outlines plans for the IFIs to redirect their strategies, investment patterns and activities to help achieve the SDGs and the objectives of the 2015 Paris Agreement. The IFIs pledged to *"work towards adopting a tougher stance on the narrower issue of investment in coal - responsible for a large share of the world's carbon emissions - in time for the next round of global climate talks in Scotland in 2021".* The IFI's also committed to *"consider the range of fossil fuel investments in our portfolios, avoid stranded assets, and work towards applying more stringent investment criteria, such as explicit policies to exit from coal financing in the perspective of COP26".*

Some IFIs pushed for a more definitive commitment to phase out support for hydrocarbons, however others were not yet ready for that. It is hoped that such a first of-its-kind joint declaration will provide a springboard for action and more ambitious goals in the future. The AfDB, the EBRD, the EIB, the IsDB, the Council of Europe Bank (CEB) and the International Fund for Agricultural Development (IFAD) signed the closing declaration, while the ADB and the AIIB refrained from it.

For years the EBRD was perceived among IFIs as the leader on climate change prevention, however more recently the EIB has emerged as the most vocal on this subject and bold enough to adopt policies (some controversial and hotly debated) effectively preventing it from supporting any hydrocarbon-related projects, including natural gas pipelines. Most other IFIs have policies enabling them to finance some types of hydrocarbon projects, usually with the exception of coal and new oil fields development (similar to the EBRD). Table 4 gives a snapshot of these policies, while annex 8 provides more details.

Table 4. IFI policies on financing hydrocarbons

Financing Policy Specifics	ADB	EIB	WB/IFC	AfDB	EBRD	IsDB	IaDB
Coal mines	No, with exceptions	No	No	Yes, with conditions	No	No	No
Coal power plants	Yes, with conditions	No	No with exceptions	Yes, with conditions	No	No new	No
Oil exploration and development	No, with exceptions	No	No, with exceptions	No	No	No	No
Existing oil fields exploitation	No, with exceptions	No	Yes	Yes	No	No	No
Oil-based power plants	Yes, with conditions	No	Yes	Yes	Yes	No new	Yes
Oil transportation, refining, storage	Yes	No	Yes	Yes	Yes	No	Yes
Gas exploration and exploitation	Yes	No	No, with exceptions	No	Yes	No	No with exceptions
Gas power plants	Yes	No	Yes	Yes	Yes	No new	Yes
Gas transport, storage, distribution	Yes	until 2022	Yes	Yes	Yes	No	Yes

In recent years IFIs have already increased their aggregate financing in support of climate change prevention from $25 billion in 2015 to over $60 billion in 2019. However, major differences exist among their approach to hydrocarbons. For instance, shadow carbon pricing methodology (for testing the suitability of proposed projects for support) has been discussed for several years but so far no agreement has been reached on applying a common shadow carbon price. Thus for the time being, different IFIs apply different shadow carbon prices in their project analysis.

6. Findings and recommendations

This section presents key findings related to the policy and strategy context, while those regarding cluster projects design and performance, country and sector strategies, as well as hydrocarbon policies of other IFIs are summarised at the beginning of this report (pages vii-viii).

6.1. Findings

Policy and strategy context

- Historically, oil extraction in Russia dominated the Bank's hydrocarbon operations. The loss of this market was a challenge. However, over time the Bank balanced its approach, financing more downstream projects in non-hydrocarbon producing countries. Operations in Egypt largely replaced those in Russia in terms of types and volume;

- Demand for the Bank's financing in this politically-sensitive sector has been strong, as foreign investors appreciated an IFI's presence. However, the periods of growth in hydrocarbon prices attracted commercial financing, diminishing the Bank's relevance and additionality;

- The perception of hydrocarbons as a "strategic" sector by most COOs has limited the Bank's options to engage in policy dialogue. However, there have been some modest achievements in selected countries (e.g. Egypt, Ukraine and Azerbaijan), on which the Bank continues to build, expecting stronger results in the future. The Bank's total disengagement from this sector could prevent it from continuing such work;

- Reducing dependence on hydrocarbons has been at the top of the global agenda for many years. However, while most countries were able to reduce their share as sources of primary energy, hydrocarbon consumption has grown exponentially in absolute terms;
- The Bank's current Energy Sector Strategy provides a solid general framework for the Bank's future hydrocarbon operations, however some ambiguity exists among bankers in respect of the types of hydrocarbon projects they still can, and should, pursue.

6.2. Recommendations

At the strategic level:

- Prepare either an Approach Paper to Hydrocarbon Operations for consultation with the FOPC or a series of Business Information Sessions for the Board addressing this issue. The engagement with the Board should aim at enabling greater clarity for the Board and the bankers as to operational priorities and scope of the Bank's intended operations in the hydrocarbons sector. It should identify an approach that takes into account the Bank's multiple transition objectives and SCF 2021-25 priorities. Such a paper or presentations should provide a higher degree of specificity than that of the current Energy Sector Strategy and cover policy dialogue and TC objectives for selected countries, including those to be achieved in cooperation with other IFIs. Ensure that the discussions with the Board are minuted and the agreement reached is formally recorded;
- Strengthen the Bank's leading position among IFIs in decarbonising selected industrial sectors in selected countries (e.g. petrochemical and refining), , through proactive development of new projects involving these sub-sectors.

At the project level:

- For any new hydrocarbon projects ensure greater clarity of the Board reports, particularly in respect of the application of the loan proceeds and sponsor/client contribution;
- Ensure that in principal (and as it is a common practice in project finance) the sponsor/client contribution is invested up front;
- Continue policy dialogue with selected partners, focusing on broader energy policy support, including to the extent possible, better utilisation of hydrocarbon sustainability funds. Closely coordinate this with other IFIs;
- Ensure all hydrocarbon price forecasts are subject to robust sensitivity analysis.

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ANNEX 1 – CLUSTER PROJECTS

OpID	Project Name	Country	Bank's loan - million	Signed	Short description
Hydrocarbons extraction (upstream process)					
44491	**PICO Oil and Gas**	Egypt	$37.5	6.2015	Corporate loan to PICO – a mid-size Egyptian oil company, part of a larger club deal of up to USD 200 million, to finance the expansion of the Amal and Zaafarana fields. The project's transition impact was based on: (i) supporting a medium-size independent player in a sector dominated by state-owned companies; (ii) demonstration of efficiency improvements with the reduction of APG flaring and CO2 emissions; (iii) setting higher standards for corporate governance and business conduct by introducing EITI principles and by meeting best international EH&S standards; and (iv) contribution to the ongoing policy dialogue aimed at promoting the commercial utilisation of Egypt's APG domestic natural gas resources.
47822 48358	**Energan Oil** **Energan II**	Greece	$75 + $20	5.2016	Senior and subordinated loans to finance the drilling of five production wells at the Prinos off-shore field, workover and well stimulations and the construction and installation of the oil platform, followed by the drilling of seven wells in this field. The project's TI was aiming at: (i) Setting Standards of Corporate Governance and Business Conduct by adopting an ESAP, bring the Project and existing operations in line with the Bank's E&S requirements and improve EHS performance.; facilitate upgrades to energy facilities; establish a new modern metering system for oil, water, and gas production from each well; install state-of-the-art pollution prevention systems, such as low-emission combustion systems and de-oiling units; and sensors to measure and reduce emissions. Also, a commitment not to flare gas beyond safety reasons; (ii) Frameworks for Markets: TC assisting the Greek Ministry of Energy and the hydrocarbons regulatory body (HHRM) create an efficient/transparent economic model that could be used to assess and monitor the different parameters of upstream licences; as well as to develop the Greek upstream regulatory framework, including guidelines and rules book for implementing the EU Directive on safety in offshore oil and gas operations (TC of EUR 445, 000); (iii) Demonstration of New Products: introduction of new technologies promoting efficiency, such as innovative off-shore mobile drilling platform.
44744	**Serinus**	Tunisia	$25+ $20	11.2013	$40 m senior and $20 m convertible loans to Serinus Energy - a mid-sized, private Canadian oil and gas company - to support the exploitation and development of four oil and gas concessions in Tunisia (Sabria, Chouech Essaida, Ech Chouech, and Sanrahr). Its TI was related to the increase of private ownership in the Tunisian upstream oil sector, the transfer of skills from the company to the newly acquired Tunisian operations, and setting higher standards for corporate governance and business conduct.

Hydrocarbons processing - oil refineries and petrochemical plants (downstream process)					
43869	**MOL-Slovnaft**	Regional	€120	7.2012	Senior loan to MOL, Hungary's premier oil an energy company, to support the refurbishment of the old steam cracker and the integration of a new Low Density Polyethylene (LDPE) unit (which was to replace the 3 existing units) at the Slovnaft refinery and petrochemical complex in the Slovak Republic. MOL was a long standing EBRD client. TI based on: (i) the demonstration of efficiency and environmental management improvements at the petrochemical plant (BAT introduction), leading to a decrease in energy and input fuel consumption and in CO2 emissions. (ii) demonstration of an integrated emission and energy management system at the complex level (i.e. integrated for the refinery, petrochemical unit and power plant), which will be externally certified and monitored. (iii) the petrochemical unit meeting the carbon intensity benchmark set by the EU ETS phase 3 to be in the 10% least energy intensive petrochemical units in Europe, and receiving enough free allowances to offset its emissions.
42609	**PKN Orlen**	Poland	$180	6.2011	€ 250 million A/B loan to PKN Orlen - the largest oil company in CEE, in parallel to a syndicated refinancing package of up to €2.7 billion of existing debt. Additionality based on the maturity (stretching from 5 to 7 years) and on the environmental conditionalities. TI based on the demonstration effect of energy efficiency and environmental management improvements at the corporate level, including (i) compliance of the CHP plant with new EU industrial emission directives through the introduction of BAT before the regulatory deadline, (ii) the introduction of a carbon and energy management system, which could be monitored and verified; and (iii) improvements in the energy intensity performance of the Plock refinery complex, to meet the level of the top 15% most efficient installations in the EU. This was to make a positive demonstration effect to other Polish companies that are in the process of upgrading their plants.
Hydrocarbons distribution - Petrol stations networks (downstream process)					
45462	**Galnafto-gaz III**	Ukraine	$12.8	11.2013	A/B loan of USD 80 million to Galnaftogaz to finance the expansion of its fuel stations network in the underserved south and east of Ukraine. Intended as part of the company's USD 200 million capex, including to extend the energy efficiency programme initiated under the previous loan to cover an environmental upgrade of tank storage facilities. The project was to promote use of higher quality (more environmentally-friendly) fuel. Bank's 6th transaction with this company, co-financed with IFC and BSTDB. In terms of TI, the project was expected to have incremental transition impact through setting higher energy efficiency and EH&S standards. It was to extend GNG's market leading energy efficiency standards of station operation to new areas and extend SEI measures to tank storages. Also, the company was to be EBRD's first private sector sponsor of a comprehensive road safety programme and was to provide a compelling national platform for EBRD's road safety initiative in Ukraine.

Annex 2 – CLUSTER PROJECTS EVALUATIONS

1. PICO, Egypt (44491)

Background

A $50 million committed and $50 uncommitted corporate, revolving, reserve-based loan to Cheiron Finance Limited (PICO) – a mid-sized private Egyptian oil company - comprising part of a larger club loan of up to $200 million, signed in 2015, to finance the expansion of the Amal and Zaafarana oil fields. The project's transition impact was based on: (i) supporting a medium-sized independent player in a sector dominated by state-owned companies; (ii) the demonstration of efficiency improvements with the reduction of APG flaring and CO_2 emissions; (iii) setting higher standards for corporate governance and business conduct by introducing EITI principles and by meeting best international EH&S standards; and (iv) contributing to the ongoing policy dialogue aimed at promoting the commercial utilisation of Egypt's domestic natural gas resources.

As part of the latter, a €100,000 TC was to support a legal study on improving the regulatory framework for Production Sharing Contracts (PSC) in Egypt. In coordination with the LTT, it was to propose improvements to the PSC template and provide capacity building to the Ministry of Petroleum to implement the changes. Moreover, the project was to support the ongoing TC project "APG Flaring Study for Egypt" funded by SSF, whose objectives were to review current practices, case studies and identify key improvements in market regulations, which could incentivise investments in flaring reduction. The project was co-financed by the IFC and HSBC, with loans totalling $100 million.

Relevance

At approval, the Project was aligned with the (very broadly defined) priorities of the 2012 Country Assessment for Egypt (BDS12-249), such as: (i) support the development of a private sector through financing and improving investment conditions; (ii) improve energy efficiency to support energy security and enhance economic competitiveness; and (iii) pay particular attention to environmental issues. Also, the Project was intended to contribute to the implementation of the 2013 Energy Strategy (BDS13-291) via strengthening the hydrocarbon value chain and supporting oil and gas companies that can help introduce international standards in the sector, and support smaller companies that can play a role in building more diverse and competitive markets. Finally, the operation followed the 2013 Sustainable Resource Initiative (BDS13-52) in addressing APG flaring, i.e. helping to minimise waste and increase the utilisation of energy resources. EvD notes that according to the World Bank's GGFR, Egypt is one of the 15 countries with the largest volume of gas flared in the world. Therefore the focus on addressing this was fully justified and it transpires that this component was implemented although its exact results are unclear due to a lack of data (see the next section).

Financial additionality was verified at origination as several international commercial banks had either decreased their exposure to Egypt or exited during the two year period preceding the operation. The revolving reserve-based loan (RBL facility) was originally for up to $300 million. PICO could only raise $165 million of this in committed funds and it would have proved very difficult, if not impossible for the Client to raise additional sums without the Bank's involvement. The EBRD's attributes were its expertise in energy efficiency/gas flaring reduction, ESH&S matters and corporate governance. The materialisation of these, in terms of results, was mixed, as detailed in the next section.

The relevance and additionality of the operation were somewhat eroded by the fact that in December 2019 the client effectively prepaid the Bank's loan. It was refinanced by five commercial banks (see more in the following section). Nevertheless, the project's relevance is considered ***fully satisfactory***[11] as its financial additionality was strong at the time of approval, while its objectives were reasonably well aligned with the Bank's strategic priorities and the majority of these objectives have been achieved.

[11] Ratings for each category are based on the following scale of: **Excellent – Fully Satisfactory – Partly Satisfactory – Largely Unsatisfactory - Unsatisfactory**. The overall performance rating scale is: **Outstanding – Good – Acceptable –Poor – Very Poor** ("+" or "–" may be added to overall performance rating).

Results

$37.5 million was disbursed from the Bank's loan, while the remaining $12.5 million was cancelled (and the uncommitted tranche never committed). Moreover, in December 2019 the Bank's and the IFC's existing exposure was pre-paid through commercial refinancing as the client preferred a term, rather than reserve-based loan and decided to consolidate its debt under a facility provided by five commercial banks. Due to the Bank's inability to provide new financing (prevented by the new Energy Strategy, which forbade financing of upstream oil operations), the Bank's relations with the client deteriorated at the end of the project. EvD was advised not to contact the client for this evaluation. This, combined with *de facto* absence of the OL, who departed the Bank recently, and the poor quality of PMM reports, posed a challenge to assessing this project. Nevertheless, EvD was able to obtain some relevant information from Bank staff involved in different aspects of this operation, although some of it has not been verified.

Outputs: The project's investment components related to the Amal field were implemented during 2014 - 2015. As reported by the Bank's Petroleum Engineer, the Amal-17ST well (for gas extraction) was drilled, a new offshore platform ("Platform C") was installed and has been in operation since. Also, PICO drilled five new oil wells at the Amal field – 8, 23 and 23A, as well as short string wells 17 and 18. PICO also recompleted three wells - 9, 13 and 16, and installed a flow station, a gas treatment and gathering system and a 1.3 km gas pipeline. Moreover, PICO implemented investments related to gas capture, increase of water handling capacity and APG flaring reduction, mainly in the Amal field.

However, the investments envisaged for the Zaafarana field (well drilling, platform A modification and the upgrade of the Floating Production Storage and Offloading (FPSO) facility) were not implemented. PICO presented a plan to improve the quality of the separated water treatment at the Zaafarana FPSO with the aim of reducing the hydrocarbon content in the water before its disposal off-board. Some actions were undertaken but they were insufficient to achieve the stipulated water quality.

In terms of TCs and policy dialogue and other "soft" project components, most of their outputs were achieved. The Board report stipulated that there would be two TCs implemented:

- A TC legal study on improving the regulatory framework for Production Sharing Contracts ("PSC") in Egypt, to be undertaken in coordination with the LTT and a budget of €100,000. It would entail: (i) a legal study to propose improvements to the template for new PSCs; and (ii) the provision of capacity building assistance to a specific agency or department of the Ministry of Petroleum to implement the changes.
- A TC project "Associated Petroleum Gas Flaring Study for Egypt" funded by the EBRD SSF: (i) a review of potential APG utilisation opportunities at PICO's fields; (ii) an industry-wide workshop on APG flaring reduction, organised with PICO and other operators.

The first TC was implemented by Economic Consulting Associates Limited (ECA), resulting in the report "APG Flaring in Egypt – Addressing Regulatory Constraints", published in November 2017. It made a comprehensive set of recommendations on gas flaring regulatory reform options that would help to improve the existing regulatory framework and thereby increase levels of APG utilisation. Six sets of concreate steps/actions were recommended. However, this report did not provide any recommendations on the PSC template changes and a very minor change was introduced, i.e. one sentence stating: *"if associated Gas is not utilized, EGPC and the Contractor shall negotiate in good faith on the best way to avoid impairing the production in the interests of the parties."* In EvD's view this addition did not change much as it does not oblige the parties to address the APG issue. It is also noted that the LTT was consulted at the very beginning but it was not further involved in the implementation of this TC.

The second TC was implemented by Carbon Limits AS, a Norwegian consultancy, which identified possible bankable APG projects, including at PICO's fields. The consultants and the EBRD also organised a number of workshops and conferences (two of them jointly with the World Bank) in order to publicise, and to some extent educate relevant officials about, the need to address APG utilisation (in lien with the "capacity building" component of the TC). The Bank also signed an MoU with the Egyptian authorities for a long-term strategic partnership on APG.

Moreover, biodiversity studies and impact assessments for the Amal, Zaafarana, Geisum and Tawila fields, together with associated Action Plans, were completed in 2016 and 2017 as planned.

However, none of the many planned PICO staff environmental training activities were implemented, i.e. there was no individual training and/or certification through the Institute of Environmental Management and Assessment and the International Association for Impact Assessment for PICO and its joint venture operating company staff. PICO did not become a member of the International Petroleum Industry Environmental Conservation Association ("IPIECA"). Reasons for this failure are unclear.

Better outputs were achieved in respect of corporate governance improvements. The EBRD and the IFC developed a corporate governance action plan (CGAP), which PICO adopted. Actions focused on board and committee composition and authority, independent directors, internal and external audit, corporate secretary etc. were implemented. For instance, a Board of Directors with clear terms of reference and an Internal Audit Department were created, an Audit Committee was set up and a Group Restructuring Plan, as well as a policy of compliance with EITI were adopted.

Outcomes: The key outcome of this project was to be the increase of PICO's oil and gas production from the Amal and Zaafarana fields, which was partly achieved. The 2013 production base for oil quoted in the Board report was 4030 boepd for Amal and 4384 boepd for Zaafarana. No target for the increase was defined, however the financial model presented in the Board report provided the production forecast/targets for each field, ranging from 2500 to 5300 for Amal and 3400 to 4000 for Zaafarana. Based on the client reports, PICO achieved these targets for Amal, but not for Zaafarana. Production increased gradually in the Amal field (where most of the investments were made), peaking at an average 8000 boepd in November 2014 (almost 100% increase on the base value) and then declining and becoming more or less stable at about 5300 boepd for most of the project duration (about 30% above base). Reportedly, the field activities carried out by the operator and capex allowed stable oil production to be maintained by repairing (working over) existing wells and drilling additional wells. However, after November 2014, field production did not increase further mainly due to field pressure depletion, higher water cut and higher gas-to-oil ratio. Nevertheless, production from Amal is treated as increased as it stayed consistently above 2013 levels and also remained at the upper forecast value for most of the project duration.

However, the Client did not achieve an increase in oil production from its Zaafarana field. There, production was at an average level of 3015 boepd in 2018 (30% below the 2013 level) and 18% below the forecast for that year. As average daily production from Zaafarana stayed below 2013 levels for the entire duration of the project, it is treated as not achieved. The Bank's Petroleum Engineer reported that the Zaafarana field continued its production from existing wells and currently there was no intention to develop it by drilling new wells and/or working over existing wells.

As for increasing gas production, The Board report did not include a base 2013 production level, however the two most recent quarterly reports (4Q18 and 1Q19) indicate that such production was about 25% "above the banking base case", therefore this outcome is seen as achieved.

The Project appears to have achieved its desired outcomes from investments related to gas capture and water handling capacity increase. The Bank's Petroleum Engineer confirmed that the Amal offshore platforms are connected to the onshore Gas/Oil separation plant, which has an oil processing capacity of 7,800 boepd, water processing capacity of 3,700 bpd and gas handling capacity of 70 Mmscfd. The separated gas is sent to the gas processing plant Unit 304 for gas processing. The condensate and GPL are stripped from the wet gas and the dry gas is then sent to the grid for sales. Based on this account, the outcome of improved gas capture and water handling is deemed achieved.

An important outcome (also from a transition impact perspective) was to be the reduction of APG flaring at the Amal field to nearly zero. It transpires that this objective has also been achieved as the Bank's Petroleum Engineer reported that gas produced at the Amal is fully processed and sold. The gas flaring is minimal since the company tries to maximise its gas and LPG sales. As with any gas treatment/processing facility, some technological gas flaring is inevitable and, in fact, required for operational safety reasons. Therefore, gas flaring occurs only at the processing sites onshore and it is minimal. During the Bank Engineer's site visits to the Amal processing facility no gas flaring was observed.

The project had 32 transition benchmarks and even more assertions on potential "soft" outcomes. Most of them (20) are deemed achieved (although often based on a team member's statement or TIMS) and 12 not achieved (confirmed as not achieved or due to lack of information). Some examples:

- ESH&S systems certified to ISO 14001 and OHSAS 18001 standards - Cheiron's Head Office and joint venture assets have certified management systems to organise processes that identify, assess and then manage quality, environmental and health and safety related risks. The management systems of all Egyptian assets and the Cheiron Head Office are certified to ISO 9001 (quality) with the exception of Norpetco (a non-Reserve Based Loan asset) where a programme to gain certification is underway. Management systems for environmental and health and safety are certified to ISO 14001:2015 and OSHAS 18001. The Company's transition from OSHAS 18001 to ISO 45001 has started, with Amal and Cheiron's Head Office expected to achieve certification during 2020.
- a grievance mechanism for PICO's staff was implemented in 2016/2017.
- a Stakeholder Engagement Plan was implemented in 2016/2017.
- a comprehensive Social Policy and Social Impact Assessment was implemented in 2019.
- a Biodiversity Action Plan was adopted in 2017.
- Disclosure of payments made to the authorities in EBRD countries of operations (Egypt and Romania) and beyond (Mexico) in line with EITI principles – this was achieved according to TIMS, although EvD hasn't found any evidence of it.
- a Group Restructuring Plan – this was implemented and PICO's corporate structure simplified according to the Portfolio Manager.

<u>Not achieved:</u>

- outcomes related to training and/or certification through the Institute of Environmental Management and Assessment and International Association for Impact Assessment for PICO and other Joint Venture staff as no such training or certification took place (four benchmarks);
- PICO and two other oil companies have not become members of the International Petroleum Industry Environmental Conservation Association (two benchmarks);
- there is no evidence that two other companies in Egypt reduced flaring by 50%;
- there is no data on PICO's APG processing to obtain dry gas or LPG;
- there is no data confirming that PICO's APG utilisation level reached 50% and then 75% , although the Bank's Petroleum Engineer stated that during his visit flaring was minimal (two benchmarks).

In respect of other outcomes, there is some evidence of improved cooperation between the Bank and the Egyptian authorities in the area of sustainable energy in the oil and gas sector following the signing of an MoU, however the results of the cooperation have been modest so far (conferences and workshops). Progress has also been reported on the Bank's initiative to reduce gas flaring. A recently completed TC, following up on ECA's TC (this time run by RINA consultants), prepared guidelines on APG measurement, reporting and verification (MVR). An economic test was also developed. It is expected that the Ministry will formally adopt these deliverables and that they will be systematically rolled out for all new upstream concessions. The recommended MRV tools were piloted in 2019-2020 in fields operated by two companies (GPC and KPC). These actions effectively constitute the implementation of one of the first steps recommended by the ECA consultants under the original TC towards improving the regulatory framework for PSCs in Egypt.

Impacts: The company's market share is reported to have increased by 1.2% (presumably to 2.4% as the base provided in response to DAQs was 1.2%). However, EvD notes that based on 2018 results, (latest available) Egypt's oil production declined by 2.5% compared with the 2013 level. Also, PICO's combined oil production from the Amal and Zaafarana fields declined even more during the same period, i.e. 7%. Therefore, if PICO's market share really grew, it was not due to the project-related investments.

One important impact of this project was to be the improved financial performance of the client. Please see the following section for details, however it transpires that PICO achieved generally impressive EBITDA and a net profit. This was achieved on revenues, which were lower than those in 2013, however close to those projected by the Bank for 2018 (although substantially short for 2017).

An increase of oil and gas sector investments in Egypt was achieved. By Q3 2019, Egypt recorded investments of $30 billion in the petroleum sector - the highest level ever. The sector achieved the largest contribution to GDP by about 25%, in addition to its contribution of 44% in foreign direct investment (*Egypt Today*).

The reduction of flaring and CO_2 emissions from oil and gas production in Egypt was partly achieved. The annual oil and gas production-based CO_2 emissions, measured in tonnes per year, increased by 7% between 2014 and 2018 (*Our World in Data based on Global Carbon Project*). On the other hand, gas flaring volumes decreased by 17% during the 2015-2019 period (*World Bank*).

The impact of aligning PICO's corporate governance with international best standards (including a better environmental, social and H&S record) was partly achieved. Given the generally very poor level of E&S performance and enforcement of E&S standards in Egypt, the project brought about an improvement. Some examples include the completion of an extensive biodiversity survey and clean-up of the abandoned produced water and sludge pit and its conversion into profitable activities; the development and approval of sustainability policy and procedures; and the hiring of new general directors for two out of three joint ventures. The General Manager has been vested with the responsibility for implementing the PICO's environmental and social procedures (E&S).

A reduction of the environmental impact from PICO's new investments was also partly achieved. At the EBRD's request and as part of the ESAP, the client developed and began implementing a procedure for an E&S assessment of its activities. It has also hired an international HSE director, as well as an independent E&S advisor to oversee the E&S aspects of its activities. PICO also entered into a framework contract with ERM, an international E&S consulting company, for conducting appropriate E&S impact assessments of its new investments.

The expected impact on PICO's employees was to render them competent in environmental management and assessment. While none of the international training (agreed as TI benchmarks) was undertaken by the Company, the staff of both PICO HQ and JV attended a number of trainings organised either by EBRD in Egypt (environmental and social risk management training; biodiversity capacity building training) and/or in-house training conducted by independent E&S expert hired by PICO. TI benchmarks were identified outside the ESAP and followed-up directly by the OL with the top management of the Client. This impact is assessed as partly achieved.

Finally, in terms of impact deriving from corporate energy efficiency and the APG flaring reduction programme implemented, no data was available for any of the benchmarks. These are thus considered not achieved: target volumes of dry gas and oil per year obtained at Amal due to APG processing; CO_2 emission reduction at Amal; energy from wet gas recovered; and other oil and gas companies reducing APG flaring. It is noted however that, as reported by the Bank's Petroleum Engineer, APG flaring at the Amal field has been minimal.

The Bank's financing was about one third of the originally planned volume. The project was largely implemented in respect of the Amal field but not the Zaafarana field. It achieved many of its numerous and ambitious transition objectives, although evidence for some is scarce. With some hesitation, EvD rates its overall results as ***partly satisfactory.***

Efficiency

Based on the recent Credit Summary, PICO's FY 2018 revenues ($74.3 million) were only 70% of those pre-project: ($106 million) in 2013. They decreased by 2% compared to FY 2017 ($75.1 million). However they were pretty close to those projected at approval for 2018 ($77.5 million) although 2017 revenues were 25% below those projected ($100 million). Nevertheless, the EBITDA margin (84.4%) significantly improved in FY 2018 (62.9% in 2017), from 63.6% in 2013. It stayed well above its peers' margin of about 50%. Net profit first halved (from $40.5 million in 2013 to $20.5 million in 2016) but then grew slightly in 2017, to substantially increase in 2018 to $48.9 million (65% margin).

By the end of 2019, the Client had acceptable debt service capacity based on well-proven reserves with a good operational track record and loan structure using customary Reserve Based Loan (RBL) features, subject to no material deterioration in operations. Nevertheless, it reported payment delays from the Egyptian General Petroleum Corporation (sole off-taker under the PSC) and lack of hard currency liquidity resulting in payment difficulties in December 2018 and June 2019, which were satisfactorily resolved. The client repeatedly failed to satisfy the conditions for redetermination of the borrowing base and roll-over and the RBL facility. Following several waivers they still failed to comply with their obligations. The loan became due and payable on demand and was refinanced in December 2019 by commercial banks. The efficiency of the project is assessed as ***partly satisfactory***.

Overall rating

The Project achieved many of its physical and transition objectives. Its outcomes contributed to larger impacts such as an increase of oil and gas sector investments in Egypt, a decrease in levels of gas flaring and lesser environmental impact from PICO's new investments.

However, there were serious shortfalls in terms of its physical implementation (no new investments were made in the Zaafarana field) and expected transition impact (none of several environmental training objectives were met). Achievement of some other benchmarks has been doubtful as there is an acute lack of data, e.g. on the actual volumes of APG utilised, energy saved, CO_2 reduced, etc. The results of the policy dialogue have been very modest so far. No real change, which would incentivise oil companies to invest in APG, has been introduced to Egypt's regulatory framework or PSC template. Only a minor, inconsequential addition was made to the latter. However, there are some hopes that in the future some progress might be made as the recently completed follow-up TC resulted in clear guidelines for measurement, reporting and verification of associated gas. EvD understands that more work is planned.

It is noted that the loan was prepaid, however this was mainly due to a change in the Bank's strategic priorities and its reluctance to provide new financing for oil extraction. The project is rated overall as ***acceptable***, as despite many shortcomings it achieved the majority of its operational and transition objectives, and generally maintained an acceptable financial performance throughout its duration.

Key findings:

- Hydrocarbon projects' clients may stop satisfying a loan's conditions/covenants and ultimately prepay it in reaction to the Bank's refusal to provide new financing due to the change in its strategic priorities (exit from upstream hydrocarbon financing);

- High capital expenditures are needed for investments in gas flaring reduction. Low gas prices, and small and dispersed volumes of gas flares, further reduce the economics of investing in APG utilisation. Stronger policy incentives are required to encourage a reduction in gas flaring;
- As oil and gas companies are firmly focused on profitability, continuity and a certain level of seniority on the Bank's side is required to ensure the achievement of transition-related objectives. The departure of an OL may result in a loss of gravitas and the ability of the Bank to deal assertively with such clients.

Operational considerations:

- Upon the departure of an OL, ensure proper transfer of project know-how to a new OL, including the status of transition objectives, and introduce them to key client personnel, to maximise the chance of a project achieving the desired results.

2. Energean Oil and Energean II, Greece (47822 and 48358)

Background

In 2016 the Board approved a senior, secured, revolving, reserve-based loan of $75 million to Energean Oil and Gas S.A. (Energean or the Company). The loan was to finance a number of capital investments, intended to increase the production from two offshore oil fields, Prinos and Prinos North, and develop the nearby Epsilon field (the project). The Board also approved a $20 million subordinated loan (Energean II project) to finance Energean's hydrocarbon exploration at four blocks in Greece and Montenegro. The total cost of both projects was estimated at $185 million. The Company was to contribute $90 million ($84 million to Energean and $6 million to Energean II) from "internally generated cash flow".

The project was located off Greece's north-eastern coast in the Kavala region, and included drilling of 10 new production wells, workover and well stimulation activities at Prinos fields, as well as the construction and installation of a wellhead platform at Epsilon field, followed by the drilling of seven additional wells in this field. In addition, the implementation of the Associated Petroleum Gas (APG) utilisation system, other infrastructure improvements and the installation of pollution prevention and monitoring systems, were important parts of the project, supporting its transition impact. Transition impact was also expected through two TCs assisting the Greek Ministry of Energy and the hydrocarbons regulatory body (HHRM) to create an efficient and transparent economic model that could be used to assess and monitor the different parameters of upstream licences and to develop the Greek upstream regulatory framework, including guidelines and a rule book for implementing the EU Directive on safety in offshore oil and gas operations (both TCs of €445,000). It was also expected to derive TI from the demonstration of new products, i.e. the introduction of new technologies promoting efficiency, such as an innovative off-shore mobile drilling platform in the Epsilon field and oil wells drilled using dual completion methodology, to be applied for the first time in Greece. Energean Oil and Gas SA is a subsidiary of Energean PLC, an LSE-listed company with about £1 billion capitalisation.

Relevance

At the time of project approval the Bank didn't have a country strategy for Greece, only a Country Assessment (BDS14-358/F). The Board report argued that the project and assessment were consistent, as the assessment set "improving energy efficiency" and "improving competitiveness for companies and improving energy security" as its key priorities. In EvD's view, the latter priority was too broad to provide any guidance in project selectivity, while the energy efficiency component was largely not implemented (the energy intensity of Energean's operations in Kavala decreased only marginally as APG reduction was put aside due to other priorities).

Also, supporting the case for relevance, the Board report claims that "the project was to support the introduction of new technologies such as the Epsilon platform, together with state-of the-art pollution prevention and metering systems". Verification of this claim seems questionable as the Epsilon platform is still under construction (delayed by more than three years), while key elements of the pollution prevention system were not implemented (only the less costly ones and the pollution monitoring system). However, EvD agrees that some other arguments in the Board report supporting additionality were more plausible, e.g. that the "energy sector in Greece lagged behind European standards in terms of competition and innovation and needed support", and that "the country's energy security would improve due to exploration of national resources". Also, the Bank was to engage in policy dialogue regarding the implementation of best international practices in the safety of offshore operations, as well as in the creation of a more enabling environment to attract investments in the oil sector. These attributes of the Bank's additionality have been verified, as most of the related actions took place and brought benefits (see the next section).

In EvD's view the project was better aligned with the Energy Sector Strategy (BDS13-291 (Final), 10 December 2013) than the country assessment. This strategy endorsed "wider private participation" and "support to smaller companies" in the oil and gas sector. It also stated that "the Bank will support private participation and competition in the sector in the face of rising state intervention, combining it with policy dialogue to improve licensing regimes and reduce restrictions on foreign ownership." Energean has been (and still is) the only private Greek oil exploration company (the much larger Hellenic Petroleum is state-owned). By supporting a private operator and engaging in policy dialogue with the Greek state, the Bank addressed this priority well. Also, by supporting domestic oil production, as opposed to imports, the project encouraged the development of a deeper and more liquid energy market, which was another priority highlighted in the sector strategy. Finally, the Board report pointed out that the transaction was consistent with the Green Economy Transition Approach (BDS15-196/F) as "besides supporting oil drilling it was to finance important energy efficiency improvements of the off-shore and onshore facilities through a combination of new equipment and management systems". As mentioned, the energy efficiency component of this project has largely failed, therefore this aspect of the project's relevance has not been verified.

The project was in line with Greece's own energy strategy as it promoted the exploration of domestic oil resources. Oil is the dominant energy source in Greece, accounting for 50% of its total energy supply. Greece used to produce substantial amounts of oil in the 1980's but due to underinvestment in the sector domestic production has declined to marginal volumes, leaving imports to fill the gap. Since 2012 the Greek government has been taking steps to stimulate exploration efforts and revive its oil industry but the overall economic and political situation in the country has kept major investors at bay, thus the focus on supporting the domestic ones. In 2020 the importance for the Greek government to demonstrate the country's ability to exploit its off-shore energy resources in the eastern Mediterranean has been amplified by the divergent views of other countries in the region on the rights to exploit such resources (although Prinos and Epsilon fields were not part of those debates as they are clearly in Greece's territorial waters).

In terms of additionality, the senior loan was reserve-based, with a five year maturity and a 2.5 year grace period, while the sub loan was over six years with repayment spread across 12 instalments during the last year. The Board report argued that the "international banks were reluctant to take Greek risk, while Greek banks did not have either the funding capacity or the technical expertise to invest in the oil & gas sector". EvD generally agrees with this statement. The subsequent loan restructuring, (with the BSTDB and the Romanian Exim Bank taking large tranches and only one commercial bank taking a relatively small tranche), confirmed the difficulty of attracting commercial financing to such projects. Moreover, the importance of the Bank's participation became evident when the project hit problems in 2018 and the Bank's help was needed to arrange additional financing and restructure the project. Therefore the Bank's additionality is considered fully verified.

Although some arguments with regard to relevance were clearly overstated, the project responded generally well to the energy sector strategy, as the client was the only private company in this sector in Greece, while the revival of domestic oil exploration played a particularly important role in this country's energy strategy. Given this, and the fact that the project's additionality has been fully verified, this category is rated overall as ***fully satisfactory.***

Results

The Board report financing plan indicated that the Bank's senior loan would finance the construction of an Epsilon wellhead platform (promoting new technology), APG utilisation and SRI investments (the "SRI" acronym was not explained but is assumed to be related to the Bank's Sustainable Resources Initiative). It also stipulated that Energean would finance the drilling capex at the Prinos field with its internally generated cash flow of $84 million.

However, as Energean reported "cash shortages", the Bank's senior loan was used entirely to finance Energean's drilling campaign at the Prinos field, as this was a cash-generating investment and seen by the client as a priority. The loan was entirely disbursed in 2016-2017, however the drilling campaign suffered technical and geologically related problems and subsequent cost-overruns..

In 2018 Energean asked the Bank to arrange over $100 million of new financing, which was needed to fund the most important (from the Bank's transition and additionality perspective) project components: the Epsilon platform, APG utilisation and environmental improvements.

The Bank obliged and found new financiers – BSTDB, Romanian Exim bank and Banca Comerciala Intesa Sanpaolo Romania which, together, provided $127.5 million of new financing. As part of this new arrangement, the EBRD's senior loan was reduced by $22.5 million (actually refinanced by part of BSTDB's tranche) and the $52.5 million outstanding balance's tenor was extended by two years. In effect, only two years after the start of the project, the Bank's $75 million senior loan was entirely utilised and $105 million of new financing was needed (and provided) to continue the project. It remains unclear how much, if any, of its own equity or cash flow the Company invested in the project at that time. The Bank obliged and found new financiers – BSTDB, Romanian Exim bank and Banca Comerciala Intesa Sanpaolo Romania which, together, provided $127.5 million of new financing. As part of this new arrangement, the EBRD's senior loan was reduced by $22.5 million (actually refinanced by part of BSTDB's tranche) and the $52.5 million outstanding balance's tenor was extended by two years. In effect, only two years after the start of the project, the Bank's $75 million senior loan was entirely utilised and $105 million of new financing was needed (and partly provided) to continue the project. It remains unclear how much, if any, of its own equity or cash flow the Company invested in the project at that time. The Information Memorandum of 11 June 2020 "Reporting Operational Change via BOI" claims that "the equity injections from Energean PLC to the project have been over $ 50 m from the third quarter of 2019 to date". If this is correct, it would mean that $125 million was spent on drilling 10 wells, as well as existing wells' work-over and stimulation - in EvD's view, extremely steep price (the project team explained that most of equity was used to actually repay the first instalment of the Bank's loan).

However, even the new financing package has not resulted in the expected outcomes. In 2018, after about a year's delay, Energean contracted GSP - a Romanian oil exploration company - requesting that they build the Epsilon platform, to be financed by the Romanian Eximbank and Banco Intesa loans ($50 million and $25 million respectively). GSP has been building the platform in Constanta's shipyard, and so far it is about eighteen months behind schedule due to alleged "GSP's lack of funds to pay its suppliers", although EvD notes that by mid-2020 BSTDB, Eximbank and Intesa had disbursed almost $50 million to finance it. Despite this, the platform was reportedly only about 50% built by then. A report from March 2020 indicated that Energean and GSP planned to put the platform building contract on hold, due to the COVID-19 pandemic and oil price collapse. It is therefore unclear when and whether the platform will be completed. If it is, it will suffer a substantial delay and cost overruns.

As to the APG utilisation, energy efficiency and environmental components of the original project, key elements (see below) were put on hold, because as reported by the team, due to the current situation (pandemic and oil price collapse) Energean decided not to implement any "discretionary" investments.

In **output terms,** the main achievement of the project were 10 new wells – eight drilled at Prinos, and one at each at Prinos North and Epsilon. They have been producing oil, although during 2016-20 Energean's production volume was approximately 35% below that originally planned. The completion of 10 new wells satisfied one of the "overall objectives" set for the project. However, the drilling campaign entirely exhausted the Bank's senior loan, which, according to the Board report, was destined to finance more "TI-friendly" components. Moreover, single string methodology was employed for the drilling, rather than double string (which is innovative, and was intended to contribute to the project's demonstration effect). This was because Energean encountered asphaltene precipitation in the seabed wells and in the reservoir around the wells. In addition to causing delays and cost overruns, this prevented the application of double string methodology and Energean turned to the more traditional single-string drilling, which worked in these conditions.

Energean also installed the low emission combustion system, de-oiling units and pollution measuring sensors. This was positive but it marks the extent of the achieved outputs. The cornerstone of the project was to be the Epsilon platform, due to its innovative technology (mobility), the potential for demonstration effect and, importantly, the expectation that it would amplify Energean's oil production and profits. As explained above, the construction has been delayed by four years so far, compared to the original plan (it was to be completed by the end of 2017), and it is unclear when and whether it will be completed. Other important components which have not yet been implemented are the skid-mounted dew point conditioning unit for APG recovery (or rehabilitation of the power plant/construction of CHP), gas compressors and the refurbishment of a gas pipeline.

Only one expected **outcome** stemming from this project's investment components can be treated as partially achieved, i.e. the environmental performance of Energean's operations improved in selected areas. Due to the installation of some of the environmental systems, a 15% reduction in water use intensity was reported, while due to the installation of pollution measuring sensors, Energean is now better informed about such pollution. However, direct CO2 emissions from Energean's operations have increased. EvD notes that the Bank targeted an annual 110-200 kt reduction in CO2 emissions, mainly stemming from the planned APG utilisation. This did not transpire and the client reported that direct CO2 emissions increased by a quarter (10kt) during 2019, compared to pre-project levels, while indirect CO2 emissions (energy purchased from the grid) decreased by a quarter (12kt). It is unclear why a 110-200kt reduction in emissions was planned - the baseline level of existing pollution was not quoted at approval in 2016. According to the client's reports, there was no scope for the reduction as Energean's operations emitted 85 kt CO2 in 2017.

EvD understands from the team that in October 2020, Energean reached an agreement with the Public Power Corporation ("PPC") of Greece to source 100% of electricity for its Prinos area assets from renewable energy at a marginal increase in electricity costs. It should result in the reduction in annual CO2 emission by 25,000 t. The key outcome expected from this operation – doubling oil production from an average of 2,668 bpd to 5,303 bpd between 2016 and 2021 will not be achieved. During 2016-19 production increased to an average of just 3,464 bpd (or by 30%). In 2020, due to an oil price collapse, only 2,000 bpd is expected to be produced and 2021 is unlikely to be better.

Another expected outcome was to be a major reduction of energy consumption (from 350 kWh/bbl to 150 kWh/bbl or 57%). The client did not provide data per barrel but reported a marginal drop in the energy intensity of its operations, from 212 to 207 MJ/boe (2%).

The project's expected **impacts**, defined mainly as Energean's improved financial performance (including additional revenue from APG utilisation), did not materialise (see the next section for details). Also, the expectations of an improved environment in the Kavala region (lower air and water pollution) cannot be seen as achieved due to higher direct CO2 emissions and no change reported in water pollution. The Board report also expected the project to have a positive impact on Greek economy and employment as it stipulated that about 70% of the Epsilon platform would be built in Greece (this aspect of the project was commended by the Director for Greece at its approval). However, as Energean contracted a Romanian contractor, this expectation will not be fulfilled.

Similarly to the project's investment element, its "soft" components - technical cooperation and policy dialogue - only achieved about half of what was expected. A €445,000 TC project was to support the development of the Greek hydrocarbons sector: (i) assistance to the Hellenic Hydrocarbon Resources Management (HHRM) in implementing the EU Offshore Safety Directive, and (ii) development of an upstream economic model for tendering and licence monitoring. Another small TC (€17,500) was to finance a review of the APG utilisation options.

The first component of the main TC was fully achieved. The Bank's consultants helped in the preparation of the guidelines and a rule book to implement EU Directive 2013/30/EU. They also prepared an emergency response plan for offshore operations. The directive was fully transposed into Greek law and according to the consultant's report "it was implemented in practical terms at Greek oil and gas operations". The consultants run a workshop for the Greek safety inspectors, as well as for the management of

Hellenic Petroleum and Energean (the only Greek oil companies). It is plausible to maintain that these measures contributed to zero accidents reported at Greek oil and gas off-shore operation sites in 2018.

However, the second TC component has not been implemented. Reportedly, after Board approval the management of HHRM changed and indicated to the Bank that the initiative was no longer a priority, given the expertise of the recently appointed management in that particular area. EvD notes that the Greek oil and gas exploration licensing regime could be perceived as improved in recent years, with eight licenses granted in the last two years, compared to three granted in five years before the project. However, this increase cannot be attributed to the project as this TC was not carried out. It probably occurred because the overall economic situation in Greece has improved, and foreign investors now have more positive perception of the opportunities there. The small TC did assist in the review of the APG utilisation options although, Energean decided not to implement APG utilisation, so it succeeded only on the output level.

Overall, out of nine TI benchmarks set for this project three can be considered as achieved: (i) implementation of the EU directive on off-shore oil and gas operations safety, (ii) emergency response plans for offshore operations, and (iii) the implementation of the metering and pollution prevention systems - this was vaguely defined but as several components of the environmental improvement package have been implemented, in EvD's view this benchmark can be treated as largely achieved.

As for the **Energean II** project (financed by the Bank's a $20 million subordinated loan), its financing was also entirely disbursed by 2017 and it supported the client's exploration drillings in two onshore blocks (Ioannina and Aitoloakarnania), as well as Katakolo and Montenegro. Most preparatory works for exploitation of these blocks have been completed, however as of 2Q20 all further exploration and, importantly, exploitation work was put on hold due to CO-19 and the oil price collapse. Nevertheless, this effort brought some benefits, for example, Energean's hydrocarbon reserves increased by 11%. However, it is understood that the expected license for exploration of the Aitoloakarnania block has not been obtained. Thus, this component's planned outcome (commercial development of Energean's assets) and impact (Energean increasing its production and revenues) have not been achieved.

Overall, although the project achieved some useful outputs (10 new wells were drilled and exploited, as well as pollution monitoring and preparatory exploration have been completed), its result have been extremely modest given that $95 million of the Bank's original financing package was disbursed and spent, as well as alleged $50 million of the sponsor's equity (and most of the additional $105 million from other financiers). In particular, it is unclear why the Bank did not require the sponsor to invest its equity (or cash generated from operations) into the project first (as is the Bank's normal practice). The absence of this requirement resulted in the EBRD loan being fully disbursed with unclear (or at least much lower than originally pledged) contribution from the sponsor.

The Bank's policy dialogue through the first part of its TC yielded positive outcomes and salvaged the project's transition-related results, which otherwise could be seen largely as a failure. Overall, the project's results are rated ***largely unsatisfactory***.

Efficiency

The Prinos oilfield is Energean's only cash-generating asset and the Bank's forecast assumed that the company would increase oil production from this field exponentially and that the new Epsilon field would enter into operation in late 2017, doubling production. However, due to technical and geological problems (described above), delays with contracting and constructing the Epsilon platform, as well as harsh weather conditions, actual production has been substantially lower than forecast in 2016 and in recent years lower than the updated forecast of 2017. The first year of the project (2016) was generally successful as the disbursement of the Bank's senior loan propelled the drilling of new wells and oil production reached an average of 3550 bbl/day, a 32% increase on the previous year. However, it dropped by 20% the following year when the technical problems appeared, only to increase again in 2018 by 45% (when double string drilling methodology was abandoned in favour of the single string option) before dropping 20% in 2019 to 3,300 bbl/day - a level below that recorded in 2016. Due to the current pandemic and oil price collapse, 2020 production is expected to drop another 45% to about 1800 bbl/day.

In relation to the Bank's projections, 2019, oil production was about 45% below the original projections and is expected to be even lower in 2020. Moreover, additional revenues from APG sale or savings from the introduction of energy efficiency measures (factored into Energean's projected financial performance at approval) did not materialise as neither of these components took place (the former was to account for about 20% of the total revenues). This substantially lower oil production has not been mitigated by the achievement of a higher average price per barrel than that forecast. Said price was 10-60% higher during 2016-19 (although it is expected to be much lower in 2020).

As a result, Energean's revenues and EBITDA only exceeded the original projections in 2016 and were substantially lower during the other years. In 2017 the Bank updated the projections with more realistic production figures, mainly factoring in the significant delays in the development of the Epsilon project (originally expected to come on stream in Q4 2017), as well as the absence of revenues from APG. The new projections were highly conservative and in 2018 the client exceeded them easily, by over 100%. However, in 2019, the projected revenue level was just met, while EBITDA was slightly below. Also during that year, Energean registered a substantial net loss of $60 million, due to a $71.2 million one-off impairment charge concerning its Prinos oil assets because of the reduction in oil price assumptions, as well as a change to the production forecast to reflect the current performance. In all, during the project period the company only made a profit in 2017 and 2018 (about $10 million in each year).

Overall, Energean's financial performance has been disappointing compared to the original expectations, mainly due to the delays with putting the Epsilon platform into operation (said platform still being under construction). Energean fared better in comparison with the updated forecast, however in 2019 its actual profitability was still far from the forecast. Due to the COVID-19 pandemic and the oil price collapse in the first quarter of 2020, Energean's average production dropped to a very low level and is expected, on average, to be 60% below the projection. However, so far Energean has serviced its senior loan as agreed, although mainly thanks to the sponsor's equity injections, which reportedly amounted to $85 million during late 2019 and entire 2020. All financial covenants (including DSCR and Debt to Equity ratio) have been waived on the basis of an additional Letter of Comfort from the sponsor, Energean PLC, confirming continued support to the project. The sub-loan has a semi-bullet repayment due during 2023. With some difficulty, and mainly due to the sponsor's constant support in the form of equity injections, the project's overall financial performance is assessed as ***partly satisfactory***.

Overall rating

The project is on the border between *acceptable* and *poor.* It achieved very limited results in terms of physical outputs, with the key component still under construction and the probability of its completion uncertain. This is particularly disappointing, given that $95 million of the Bank's original financing package and additional funds from other lenders, have been spent. Importantly, the absence of a demonstration of new techniques, technologies, and APG utilisation, as well as the failure of one of the two policy dialogue initiatives/TCs, resulted in very modest transition achievements. The development of the key project component – the Epsilon platform - has been delayed by three years and counting.

However, the project has not been a total failure as it helped a domestic company to exploit national resources, reviving an industry critical for the reduction of imports in a country under substantial economic stress. Moreover, the Bank led the efforts to transpose the EU off-shore oil and gas safety directive and implement it in practice – a rare example of the Bank's policy dialogue in this sector. Also, Energean introduced some improvements in its operations, benefiting the Kavala region's environment, while the exploration activities completed under Energean II laid a foundation for future exploitation when and if the market environment improves. The client's financial performance has been far from that projected at approval but is relatively close to the updated forecast, while the loan has been serviced, despite the pandemic and oil price collapse. Therefore, overall, the project is rated ***acceptable -***.

Key findings:

- At a time of adverse market conditions, oil companies may perceive project components supporting transition as “discretionary” investments and put them on (more or less permanent) hold;
- As oil and gas companies operate in a highly volatile environment, they may not be able to generate internal cash flow to contribute towards the project;
- Hydrocarbon exploration (or extraction) projects are exposed to acute technical and geological risks, which often materialise.

Operational considerations:

- In high risk projects (e.g. upstream hydrocarbons), the agreed client contribution should be always required in full, up front. It should be a key condition precedent to the Bank’s loan disbursement;
- In order to ensure the implementation of transition-related components (particularly in high risk hydrocarbon projects), the Bank should agree and covenant the use of its loan proceeds accordingly;
- In hydrocarbon field development projects, the Bank should review procurement strategy and schedule for the key large components it is to finance.

3. Serinus, Tunisia (44744)

Background

In 2013 the Bank extended a $40 million senior loan and a $20 million convertible loan to Serinus Energy - a mid-sized, private Canadian oil and gas company - to cofinance the development and exploitation of four oil and gas concessions in Tunisia (Sabria, Chouech Essaida, Ech Chouech, and Sanghar fields). The project aimed to drill 17 new oil wells, as well as work- over and stimulate several existing wells, introduce horizontal drilling (fracking), and to acquire or contract two drilling rigs. The total project cost was to be $166 million, with Serinus providing $106 from internally generated cash. The project’s TI was to be achieved through increased private ownership in the Tunisian upstream oil sector, the transfer of skills from the company to the newly acquired Tunisian operations, and the setting of higher standards for corporate governance and business conduct, including the introduction of ESMS, HR policies, the disclosure of all payments to public authorities and a plan for treating liquid discharges. At the time of project approval and implementation, Serinus was owned by Kulczyk Investment SA, a company owned by Jan Kulczyk, a well-known Polish entrepreneur with interest in many sectors around the world. The company was listed on the Warsaw and Toronto stock exchanges.

Relevance

The 2006 Energy Operations Policy (BDS06-093) and the Energy Sector Strategy (BDS13-291) (approved in December 2013, shortly after project approval) both stressed the dominance of state enterprises in the oil and gas sector across the COOs, especially in the upstream segment. This was echoed in the Tunisia Country Assessment (BDS12-199), which confirmed that state-owned enterprises are dominant upstream and downstream in the oil, gas and power sectors, where private participation is still limited. Therefore, exploring possible investments in oil and gas projects and supporting mid-cap foreign investors was set as an operational response. Also, the Bank’s Country Strategy for Tunisia (BDS/TN/18-1) foresaw the provision of finance to medium-scale oil and gas operators, with a focus on the private sector, although it prioritised gas flaring reduction investments in an attempt to align its objectives with the Green Economy Transition. The Board report also pointed out that the size and the term of the loan were not available on the market, while a convertible loan was innovative for the Tunisian market. The Bank was also to play a role with its attributes (promoting ESAP and corporate governance improvements).

As for achieving its main strategic objective – an increase of private participation in the sector, EvD notes that the dominant field producing most of oil, was Sabria field, which was only 45% held by Serinus and 55% by the state-owned ETAP oil company. Together with Chouech Es Saida field (100% owned by the sponsor), it produced over 90% of total production of Serinus in 2013-2016. Then in 2017-2018 all the fields apart from Sabria were in shut-in as they were uneconomic to operate. Therefore although the project did nominally expand private sector’s participation in Tunisian hydrocarbon sector, one could argue that a large part of the project revenues went to a state oil company, strengthening it and potentially delaying or preventing its reforms/privatisation/etc. EvD also notes that Serinus was ultimately owned by Mr Jan Kulczyk, at that time the richest man in Poland, with a net worth valued by Forbes at $4 billion, with interests in different sectors across the world.

The main additionality argument rested on an innovative financing structure for this project, not available in Tunisia. A part of the loan was convertible (required due to capital structure of the project company) and no other lender would provide such a loan.

With some hesitation, EvD rates the overall relevance of this project ***fully satisfactory***.

Results

The loan was signed at the end of 2013, however in May 2014 the price of crude oil started falling from $108 bbl to about $45 bbl by year end. It hit $31 bbl – its lowest point - in January 2016. Therefore, since October 2014 the crude oil price has remained substantially lower than $81 per barrel – the price that the EBRD used for its stress case scenario at project approval.

The dramatic drop in the price of oil had a profound impact on Serinus's drilling campaign, i.e. the company decided to substantially curtail its original plans. In addition, the operation suffered from labour disputes, which interrupted the production of hydrocarbons on several occasions (these were country-wide and affected many oil producers, not only Serinus). All of Serinus's concessions were shut in a number of times in 2015 and 2016. Additionally, the Sabria field was shut in between May and September 2017 and another concession was shut in for more than two years between February 2017 and July 2019.

In February 2015, the EBRD and the Company amended the senior loan agreement, reducing the total senior loan commitment from $40 million to $28.7 million, of which the EBRD eventually disbursed $25 million. Also the $20 million convertible loan was fully disbursed. In January 2017 the EBRD classified the project as Corporate Recovery Category 3 and, in October, agreed with Serinus to restructure the project to improve the expected recovery of the Bank's overall exposure. In September 2019, the Company fully repaid the senior loan.the team reported that after its work with Corporate Recovery team, 93% of the convertible loan's principal was repaid, while $3.5 m part of it was converted into company's shares.

Outputs: The company failed to implement the investment programme mainly due to the crash in oil prices and continued labour strikes (these were country-wide, affecting all oil producers). Only two new wells were drilled in Sabria (out of the intended 17 across four concessions)

The project's main achievements relate to the adoption of higher corporate standards. The Company has: (i) introduced an integrated Environmental and Social Management System, (ii) introduced the disclosure of all payments to the Tunisian authorities according to PWYP principles, (iii) published clear HR policies and, (iv) developed specific plans for the treatment and monitoring of drilling mud and liquid discharges.

These are extremely modest achievements, given that $45 million of the Bank financing was provided. According to the Board report, drilling a well in the Sabria field was to cost $17 million, of which Serinus was to cover 45% and ETAP (Serinus's state-owned partner in the development of this field) 55%. Therefore the two wells which were drilled should have cost Serinus $15.3 million. As ESMS and other improvements were low-cost, according to the project team, it transpires that the remaining balance of the disbursed loan (almost $30 million) was spent on "wells work-over and stimulation".

EvD also notes that the project design sets the Bank as the majority financier, which is in breach of the EBRD's policy of providing up to 35% of a project's costs. The financing plan did envisage Serinus contributing $106 of internally generated funds, but this was not required upfront, and ultimately neither generated nor needed as the project was barely implemented. Serinus's accounts indicate that during 2013-2017 it spent $17.7 million of its own cash on its Tunisian operations. In EvD's view this was mainly to service the EBRD loan.

Outcomes: The project's outcomes have been disappointing. There has been very limited success with regards to increasing proven oil reserves and oil production. Production from the Sabria and Chouech Essaida oil fields was 1,348 boe/day in 2015, but it decreased to 1,180 boe/day in 1H2016 and in 2017 the fields were shut down due to labour strikes. Overall oil production has never reached the target of 2,000 bbl/day and in 2018 it plummeted to 352 bot/day due to the shutdown of the Chouech Essaida field. It has been marginal in 2019 and 2020.

Until 2016, the Company was on track to achieve targeted net proven reserves (an increase from the 3,199 Mboe certified in 2013). However, in 2017 the figure fell to 3,178 Mboe and then 2,246Mboe in 2018 due to lower investments by the company. The final TIMS review dated 30 November 2019 does not expect the net proven reserves to increase in the near future. The exact capacity utilisation at the existing Sabria processing facilities has not been documented, although it is very unlikely the capacity utilisation increased from 60% to over the 90% target benchmarked.

With regards to skills transfers, no progress was made. The Company is reportedly still using third parties for drilling and workovers, and it has generally lowered its production, mainly due to the depressed commodity prices. As the Company's main concern is to remain afloat, it is not expanding and therefore not securing dedicated drilling and service rigs (as was expected under the project).

Reportedly, the drilling mud and liquid discharges have been treated and monitored in full alignment with PR3 and the plan, therefore it is considered that due to the project the Company improved its environmental standards and practices. However, this needs to be seen in the context of very limited oil production, and therefore limited impact from the improvement. Overall, out of nine TI benchmarks, four are considered achieved.

Impacts: the key objective of this operation was to increase private participation in the Tunisian hydrocarbon exploitation sector. Although four concessions were granted to a private company, it partially developed only one of them – the Sabria field, which it held as a minority partner (45%) with ETAP - Entreprise Tunisienne d'Activites Petrolieres, a state-own company which controls 75% of hydrocarbon production in Tunisia. As ETAP held 55% of Sabria's concession, one could argue that by helping to develop it, Serinus (and to some extent the Bank) supported the further proliferation of the state sector in the Tunisian oil and gas business.

Serinus did adopt international best practice for the disposal of waste and of water produced by drilling activities, and by introducing PWYP standards it helped to set higher transparency standards in the industry in Tunisia. However, again due to its unsatisfactory operational performance, the impact has been marginal.

Overall, the project's main investment component has not been implemented, due to the crash in oil prices and continued labour strikes. Consequently, private production of oil and gas and private ownership of oil and gas reserves did not increase. The company did not develop in-house drilling expertise as it did not acquire or lease any dedicated drilling and service rigs. The project did accomplish its objectives concerning improved corporate governance and business conduct standards, therefore the project is not seen as a complete failure. However, these achievements failed to make a stronger impact due to the company suffering from long periods when it was non-operational. It is also noted that the company spent $45 million to achieve results which were originally estimated to cost about $15 million. The results of the project are rated ***largely unsatisfactory***.

Efficiency

The Company did not achieve its projected financial performance. Starting with the sharp drop in oil prices during the second half of 2014 the Company continuously struggled to generate cash flows to complete the investment programme in Tunisia. The situation deteriorated further with intensifying labour disputes (which were country-wide, affecting many other oil producers) and the consequent shutdown of the Company's concessions. Under these circumstances, the Company substantially lost its ability to expand production and generate cash in Tunisia. Therefore, on a number of occasions the Company's financial performance fell below the level envisaged at approval. For instance, with very limited production in 2017, EBITDA was negative whereas it was projected to be $130.6 million at approval.

In October 2017, the EBRD and the Company restructured the terms of the two outstanding debt facilities. The main purpose of the restructuring was to enable Serinus to carry on its investment programme in Romania, revive its operations and start generating positive cash flows. The restructuring extended the maturity of convertible loan facility from June 2021 to June 2023. At the time of restructuring the outstanding principal of the senior loan was $5.4 million with an original maturity of March 2019. The Company started to generate cash in April 2019 with operations commencing in Romania. It also issued new shares for $3 million to repay the EBRD debt (for the second time, having listed on AIM in 2018, raising $12.7 million). Thanks to that, Serinus fully repaid the senior loan in September 2019 – six months later than the date agreed at the restructuring. Subsequently, the project and Corporate Recovery teams negotiated the repayment of 93% of the convertible loan's principal (while $3.5 m was converted into the company's shares).

Overall, Serinus's financial performance has fallen substantially below that projected during entire life of the project. However, the company repaid the Bank's senior loan almost on time and almost all of the convertible loan's principal. . This category is rated ***largely unsatisfactory***.

Overall rating

The project achieved very little with $45 million of the Bank's financing and the sponsor's relatively small contribution. Arguably, the project timing was particularly unfortunate as it started almost at the exact moment when the price of crude oil more than halved. The limited drilling which happened under the project took place in the field, the majority of the concession for which was co-held by a state-owned company, i.e. most of the revenue produced by the project went to the state sector partner. The client introduced all agreed transition-related changes and improvements, however due to the implementation of only relatively small part of its drilling programme, this had almost no wider impact. The operation was a financial failure, however the client was able to generate sufficient cash from its other assets to repay the senior loan and almost all of convertible loan. Due to the failure of the key investment component and the lack of a wider positive impact, the operation is rated overall ***poor***.

Key findings:

- As with some COOs, the hydrocarbon field concessions may be required to be majority-held by a state company, the Bank financing may contribute to the strengthening of a public partner;
- Hydrocarbon operations, particularly upstream, are acutely exposed to oil price fluctuations, which are very difficult, if not impossible, to forecast;
- In the absence of an upfront equity contribution, the sponsor may end its co-financing when the oil price drops. This may leave the Bank as the principal financier of often poor and risky projects (and is in breach of the policy limiting the Bank's exposure to 35% of project costs).

Operational considerations:

- In project finance (particularly for upstream hydrocarbons), the Bank should require the sponsor to make an upfront equity contribution toward the project, before or *pari-passu* with the Bank's loan disbursements, rather than expecting funds to come from "internally generated cash" during the project (which often does not materialise);
- Oil exploitation projects, the repayment of which depends solely on the sale of crude oil, should have strong mitigating measures against oil price fluctuation, including the sponsors' support should oil prices drop to an agreed minimum.

4. PKN Orlen Energy Efficiency and Emission Reduction Loan, Poland (42609)

Background

In 2011 the Bank provided a € 250 million A/B corporate loan to PKN Orlen - the largest oil company in CEE (by revenues), in parallel with a package of up to €2.75 billion provided by commercial banks to refinance existing debt. The Bank's loan was to finance the replacement of a boiler at the Combined Heat and Power (CHP) plant and the provision of emission reduction equipment for seven remaining boilers. TI was to be achieved through the demonstration effect of energy efficiency and environmental management improvements at the corporate level, including (i) compliance of the CHP plant with EU's Industrial Emission Directive (IED) through the introduction of BAT before the regulatory deadline, (ii) the introduction of an integrated carbon and energy management system, which could be monitored and verified; and (iii) improvements in the Plock refinery complex energy and carbon intensity performance, raising it to the level of the EU's top 15% most carbon efficient installations. This was to make a positive demonstration effect to other Polish companies that are in the process of upgrading their plants to improve their competitiveness, provided it is shown that the targeted measures go beyond the norm for the sector in Poland and the Company's current business practices. An additional benefit was to be drawn from the increased competition in the power generation market, if PKN was able to sell a significant surplus of electricity from the CHP to the market.

Relevance

The loan had a strong environmental and energy efficiency focus, which responded well to the Bank's strategies and policies applicable at that time (Strategy for Poland BDS/PO/10-01 and Energy Operations Policy BDS06-093). PKN maintains that it borrowed from the EBRD as it wanted to diversify its lender base at the same time as it refinanced its debt, and also that it was attracted by the Bank's expertise and reputation in designing and financing environmental and energy efficiency projects. According to the Board report, the Bank's additionality was based on the longer maturity (stretching the locally available five year financing to seven years) and on the environmental conditionalities.

In EvD's view, although the type of investment financed was in line with the Bank's priorities, its additionality was weak. According to Deloitte's "500 Top Companies of Central and Eastern Europe 2012", in 2011 PKN was by far the largest company in the region by revenue (€26 billion). The Bank's loan, although large, was only 8% of a financing package provided to PKN by commercial banks at that time. Importantly, only €180 million of the loan was disbursed, the rest was cancelled and the loan prepaid after five years, i.e. the two years of additional loan maturity turned out to be unnecessary. Already at that time, PKN had embarked by itself on a focused environmental and energy efficiency investment campaign (as described on its website), which culminated in the recent (August 2020) adoption of an ambitious target to become carbon neutral by 2050 (one of the first among the large Polish industrial companies). In this context, it seems that the Bank's environmental conditionalities have not played such a critical role. There were also some issues with setting some of the project's environmental and energy targets (see below), which might indicate that the Bank's expertise was less than perfect. The relevance of this loan is rated ***partly satisfactory***.

Results

€180 million of the €250 million approved loan was disbursed and €70 million was cancelled.

Outputs: the two key investment components (replacement of the obsolete boiler at the refinery's CHP plant and the installation of pollution abatement equipment on seven other boilers) were completed largely on time and reportedly below budget (although PKN refused to provide information on the exact costs and the application of the loan proceeds, citing commercial confidentiality).

Outcomes: These investments yielded only part of the expected benefits. It was expected (and also set as one of the TI benchmarks) that the boiler's replacement would increase electricity production by 20-30%, which in turn would enable PKN to sell electricity to the municipal grid operator and generate additional revenues. However, PKN informed EvD that replacing the boiler was not expected to result in an increase of electricity production. Moreover, PKN's external electricity sales have always been marginal, only taking place in winter. Accordingly, PKN reported that following the boiler replacement its electricity production capacity has remained the same, while its actual production increased by 4% only and this excess has been consumed internally by the refinery (as is the case with the entire output of the boiler). On the other hand, the target for increased heat production has been exceeded more than two fold (7% targeted, 16% achieved). However this excess has also been utilised internally by the refinery. EvD understands that the reason for failed electricity production might have been the decision to switch the boiler almost entirely to the heat mode, due to economic incentive to do so.

The new boiler reduced CO^2 emission by 48,000t per annum – exceeding the 16,000t per annum of "direct" reduction expected at approval. Nevertheless, these expectations were supplemented by an additional "indirect" reduction of 126,000t derived from the anticipated sale of electricity to the grid. As this has not happened, the expected CO^2 reduction target can be treated as only partially achieved.

There have also been mixed results in achieving longer term outcomes and impacts out of this investment – timely completion of the boiler's replacement ensured that PKN met the EU's IED ahead of Poland's EU Accession Treaty derogation deadline. Unfortunately, this has not helped PKN to become one of the top 15% most carbon efficient oil refineries in the EU ETS, as was

expected. PKN has not qualified to receive free carbon emission permits (it paid PLN 207 million for such permits in 2019). Also, PKN was not able to provide data on the energy intensity of the new boiler, although it is likely that it was reduced.
In terms of emission abatement equipment, the flue gas desulphurisation (FGD), electrostatic precipitants and exhaust emissions catalytic denitrogenation equipment were duly installed on seven CHP boilers, contributing to PKN meeting the EU's IED ahead of the deadline. SOx, NOx and dust emission were reduced by 80-97%, however the NOx target emission seems to be wrongly calculated/overambitious (i.e. it was reduced by 80%, more than the targeted 60%, but its current absolute value of 118 mg/Nm3 still does not meet the target of 100 mg/Nm3). Also, only the less ambitious of the two targets set for SOx emission was achieved. Nevertheless, these investments made a substantial contribution to the Plock refinery meeting BAT and the EU's IED standards. According to PKN, the Plock refinery exceeds said standards, i.e. emissions are about 3x less than those allowed under the IED for SOx and dust, and 10% below that for NOx. However, there is no evidence that this has had any demonstration effect on other Polish companies (as was implied in the Board report).

The TI potential of this project was constrained because the Company already had sophisticated corporate, business and environmental practices (it had an energy management system in place; it was listed on the Warsaw Stock Exchange, etc). Moreover, there were concerns that the project could strengthen the dominant player in the oil refining/petrochemical and fuel retail market in Poland and the leading company in the CEB region. PKN's "private" credentials were questioned as the Polish Treasury held its blocking stake (27.5%), had veto rights over key strategic decisions and appointed PKN's management.

Nevertheless, the project's transition framework listed seven TI benchmarks and the Board report made several additional assertions on the project's potential for a wider impact on PKN and the Polish refining sector in general. Probably due to the Bank's relatively weak additionality, many of the benchmarks were quite ambitious, e.g. the refinery to become one of 15% most carbon efficient refineries in Europe under EU-ETS. As mentioned, this has not materialised. An "Overview of the Refining Industry in the EU ETS" of 2016 indicates that between 2005 and 2014 CO^2 emission from Polish oil refineries actually increased, while that from most western refineries substantially decreased (all Polish refineries but one were owned by PKN). Another benchmark stipulated the increase of energy sales to the municipal grid. This has not materialised either, as explained above (likely due to PKN's switch of the CHP boiler production entirely to heat).

Three benchmarks were related to the integration and certification to ISO of two management systems – for energy (already existing at the refinery) and for carbon (to be developed), which were to cover first the Plock refinery and then the whole PKN corporate structure, and were also to be adopted by three or more other refineries in the region (testifying to the project's demonstration effect). PKN duly certified its energy management system to ISO 50001, however it failed to develop the carbon management system. PKN explained that this system was not obligatory under the Polish law.

Overall, out of seven benchmarks, two were achieved – both essentially the same – for CHP to comply with EU environmental standards ahead of the Accession Treaty's derogation deadline, and to comply with EU IED standards. One additional benchmark can be treated as partly achieved – certification of the energy system to ISO standard, although there was no integration with the carbon management system, which was not developed. It is noted that the final TIMS report states that the carbon management benchmark was achieved, while the one related to the certification of the energy management system was not (in reality it was the other way around).

In terms of larger **impacts**, the project included a demonstration effect benchmark in relation to the integration of energy and carbon management systems. This benchmark is also considered by TIMS as achieved (citing Petrom, INA and MOL which reportedly integrated such systems). However, EvD does not consider it achieved as, if others integrated their systems, it was certainly not due to PKN's integration, which did not take place.

The Board report also asserted that the project would contribute to the increased refining capacity in Poland (from 493k b/d to 578k b/d by 2015). PKN reported that such a capacity now amounts to 583 kbbl/d, therefore this target is considered achieved. Moreover, the project was to help to increase Poland's share of the CEE oil refining market from 4.8% in 2010 to 5.3% in 2015. This also seems to have been achieved as PKN reported that the Polish share of the CEE oil refining market (including Austria and Germany) was 14.7% in 2019. However, it is doubtful whether the project made any contribution to either achievement as the replacement boiler did not result in increased electricity generation capacity, while the management systems integration (expected to improve the efficiency of the refinery management) did not happen.

Overall, the project's results have been mixed. On the output level the planned investments were completed, mostly on time and within budget, ensuring that the deadline for EU IED compliance was met one year in advance as planned. However, the carbon management system and its integration with the energy management system were not implemented. The investments substantially reduced CO_2, NO_x and SO_x pollution from Poland's largest oil refinery, ensuring Poland met its international obligations. Nevertheless, this is where the project's benefits end. Its transition results have been modest. The overall project results are rated ***partly satisfactory***.

Efficiency

This was a corporate loan to a large conglomerate. The oil refining business has been exposed to highly unpredictable macroeconomic factors such as crude oil price fluctuation, Brent/Ural differentials, refining margins, etc. The analysis of the 2013-2016 loan period indicates that the Bank's assumptions made for the first two years were substantially over-optimistic, less so for 2015 and not optimistic enough for 2016. The EBITDA and net profit level during 2013-14 were about 4x lower than projected. In 2015 EBITDA was still lower than projected but only by 25% (€1.5 billion vs €2 billion projected) and the profit was in line with projections (over €1 billion).

Disappointing results in the early years were driven by lower refining margins especially at the beginning of 2014, as well as significant non-cash asset impairments recorded that year. This was predominantly driven by the contraction of the refining margin and Brent-Ural (B/U) spread, which started to decrease towards the end of 2012. The refining margin decreased from 5.7 USD/bbl in 2012 to 4.2 USD/bbl in 2013, while the B/U differential decreased from 1.3 USD/bbl to 0.9 USD/bbl. The refining margins improved later that year, however EBITDA turned negative due to non-cash provisions related to the impairment of assets. During the reporting period PKN Orlen strengthened its performance in retail (quickest growing segment) and petrochemical segments (driven by an increase in petrochemical margins), which jointly generated a profit in 2015. Refining margins and U/B differentials improved further in 2016 resulting in PKN's EBITDA and the net profit exceeding the projections by 30% and 300% respectively. This was a positive development, however PKN's suddenly increased liquidity was the main reason for the prepayment of the Bank's loan. During 2013-2015 the Company maintained a generally healthy balance sheet, with assets of €11.3 billion in 2015 and €10.9 billion in 2014, about 50% of which were financed by equity. PKN remained one of the strongest credits among industrial companies in Poland (as illustrated by its gradually improving ratings and the relatively low pricing of its corporate bonds). Net debt to EBITDA remained in accordance with the loan agreement covenants.

The most recent financial results indicate that 2019 was generally a successful year for PKN (profit of €1 billion on €2 billion EBITDA and €24 billion revenue). However, it expects (as do all companies in this sector) that 2020 will be a poor year due to the COVID-19 crisis and oil price collapse (with Brent at $30 bbl and U/B at $0.1 per bbl in Q2). Nevertheless, PKN projects a positive 2020 net profit, largely due to a one-off accounting gain related to the purchase of the energy company - Energa S.A., at a bargain price. In 2020 PKN has been at the centre of the Polish energy industry consolidation, being in the process of acquiring many other companies, including the only other oil refiner (Lotos), as well as the largest Polish upstream company PGNiG. Although designed to create a large and very strong vertically integrated conglomerate, able to compete globally with the industry's heavyweights, this consolidation carries the risk of creating a monopolistic, government-controlled entity, i.e. from the EBRD's perspective, this could be seen as a reversal of transition due to elimination of competition in the Polish oil refining market.

Notwithstanding recent developments, PKN's financial performance during the project period has been mixed – substantially below expectations in the early years, then meeting and even exceeding them in the last two years. The efficiency of the project is rated ***partly satisfactory***.

Overall rating

The project ensured that the largest industrial corporation in central Europe met the EU's Industrial Emissions Directive before the Accession Treaty derogation deadline – an important achievement for the country's reputation. However, almost none of the project's more ambitious objectives (which justified the Bank's participation, given the weak additionality) have been achieved. The project's transition results were modest, while some of the objectives and targets were inaccurately designed (e.g. expectations of excess electricity sales and some of the environmental targets). Early prepayment of the loan may indicate that PKN didn't see much value in developing longer-term relations with the Bank. However, in recognition of the project's full and timely physical implementation (unique among cluster projects), and its environmental impact (reduced CO2, NOx and SOx emission) it is rated overall ***acceptable+***.

Key findings:

- Government-controlled companies, particularly in the oil and gas sector, are often required to follow the government's strategic priorities, which are not always in tune with the Bank's transition objectives, such as the promotion of greater competition. Projects with such companies may carry reputational risk for the Bank;
- Weak additionality (e.g. projects with large market leaders) necessitates a complex transition structure and ambitious benchmarks. However their functionality is limited without agreed monitoring and reporting frameworks;
- Oil companies (including refineries) are exposed to particularly high extrinsic risks related to variables such as oil prices, spreads and differentials. While negative trends in such variables increase the Bank's credit risk, positive trends carry the risk of a windfall for the client and subsequently, loan prepayment;
- Large oil companies are particularly reluctant to "go the extra mile", beyond the legally required obligations, for example in relation to emission monitoring systems, pollution abatement, etc. Unless such measures (key transition components of most projects) are covenanted as legally binding commitments, they are unlikely to materialise (as priorities and circumstances often change).

Operational considerations:

- Due to the increased risk of loan prepayment due to the sudden increase of hydrocarbon prices, loan agreements in this sector should have strong prepayment clauses;
- Complex transition structures should be accompanied by detailed monitoring and reporting frameworks with agreed milestones and defined dates for completion of various components;
- When setting TI objectives for a client to become one of the best among peers e.g. in emission reduction, take into account that its peers will also strive to improve their emission record, making it difficult for the client to achieve the target.

5. MOL/Slovnaft Energy Efficiency, Regional (43869)

Background

In 2012 a €120 million senior corporate loan was signed with MOL, Hungary's premier oil and energy company, to support the refurbishment of the old steam cracker (used for cracking naphtha in the production of petrochemicals) and the installation of a new Low Density Polyethylene (LDPE) unit (which was to replace the three existing units) at the Slovnaft refinery and petrochemical complex, MOL's subsidiary in the Slovak Republic. The TI of this project was based on: (i) the demonstration of efficiency and environmental management improvements at the petrochemical plant (BAT introduction), leading to a decrease in energy and input fuel consumption, as well as a reduction in CO^2 emissions. (ii) demonstration of an integrated emission and energy management system at the complex level (i.e. integrated for the refinery, petrochemical unit and power plant), which was to be externally certified and monitored. (iii) the petrochemical unit meeting the carbon intensity benchmark set by the EU ETS phase 3 to be in the 10% least energy intensive petrochemical units in Europe, and receiving enough free allowances to offset its emissions. MOL was to contribute €183 million of its own cash to co-finance these investments.

Relevance

The Bank has worked with MOL since the early 90s and this was its fifth project with the company. This cooperation resulted in MOL improving its business standards, environmental compliance, stakeholder engagement and energy efficiency, providing it with a competitive advantage and increasing Hungary's regional energy security. The Bank also worked with MOL to prioritise its investment programme to maximise energy efficiency benefits and emissions reduction. In recent years, the EBRD's loans have supported MOL's gas storage in southern Hungary and the INA refinery in Croatia, which was previously acquired by MOL.

This project, with MOL's Slovak subsidiary, was firmly focused on energy efficiency and environmental improvements – priorities in the Bank strategies for Hungary (BDS/HU/11-1) and the Slovak Republic (BDS/SK/08-01). Energy efficiency and environmental improvements were also the cornerstone of the Bank's 2006 Energy Operations Policy and the 2013 Energy Strategy. Importantly, the project aimed to refurbish Slovnaft's steam cracker, which was one of the exemptions granted to the Slovak Republic in its EU Accession Treaty and which was required to comply with EU IED by 1st January 2016. Thus, the nature of the project was well aligned with the Bank's strategic priorities. EvD notes however, that the expectations of these benefits materialised only partially and suffered a very long delay. The loan was signed in mid-2012, when the fallout from the financial crisis of 2009 was still strong. At that time MOL had a revolving facility with commercial banks, with a tenor of only three years. The Bank's loan was structured as an 8.5 year unsecured corporate loan – a tenor not available on the market but necessary for such large investments (it was later extended for one more year).

Nevertheless, EvD notes that MOL was, and still is, the second largest corporation in Central and Eastern Europe (after Poland's PKN Orlen). Two years after signing the Bank's loan (October 2014) MOL was able to extend its revolving credit facility to five years and successfully syndicated a new $1.5 billion facility with a group of 15 commercial banks. Following this syndication, MOL requested a number of changes to the Bank's loan to align the conditions and reflect the company's improved financial position since 2012. Thus the Bank's loan was restructured in March 2015 (with lower loan pricing, a 12 month extension to the tenor and financial covenants aligned with the new facility).

However, EvD agrees that the availability of funding for large capital investments with a long pay-back period remained scarce in both Hungary and Slovak Republic and was further constrained by limited liquidity in the banking sector, limited credit room for MOL due to the existing exposure, and reduced country limits due to Hungary's credit rating downgrade. Overall, the relevance of this project is rated ***partly satisfactory***.

Results

There are discrepancies (in some cases substantial) between the reports received by the banking team from the client during project implementation and the information obtained by EvD from Slovnaft in 2020. What is certain, is that the project has moved very slowly, and although two of the main investment components were eventually completed, they were considerably delayed (the deadline for compliance with EU IED was not met), while the related benefits are generally well below expectations and the project's TI benchmarks.

Outputs: Based on the monitoring reports, the steam cracker had been refurbished by the end of 2016, while according to the information received from Slovnaft in 2020, the refurbishment was only completed at the end of 2019. Following EvD's additional queries, Slovnaft confirmed that *"yes, until 12/2019 we were not complying with EU IED emission limits, however the steam cracker boiler's NOx emissions were included in the Transitional National Plan, providing Slovnaft with an extended deadline until 06/2020. After replacing burners in 12/2019 we are in compliance with the NOx limits".* Thus, it transpires that the steam cracker was refurbished in phases. One part of the refurbishment was completed by the end of 2016 (two years later than planned) but another important element, i.e. the replacement of the boiler burners was completed only at the end of 2019 (three years later). The cracker's compliance with EU's directive was only then finally ensured (five years later than planned). Thus, this output is considered partially achieved. The second of the main components (accounting for 80% of the total project costs or €260 million) was the installation of a new LDPE unit and the decommissioning of three old units. This was achieved, with a new LDPE unit installed and commissioned in 2017. Two of the old units were decommissioned, while one is still working for about two month per year as a back-up to utilise excess ethylene. MOL did not provide information on the cost of the components or the exact amount of its own contribution but the Bank's loan was fully utilised (unique among cluster projects).

Outcomes: The project was expected to bring substantial energy efficiency and environmental benefits, as well as long-term benefits for Slovnaft in terms of increased production and petrochemical sales, increased prestige from its compliance with the EU IED directive one year in advance and by qualifying as one of the 10% most carbon-efficient refiners in Europe (under its ETS system). Only one of these expectations seems to have been achieved – Slovnaft reported an increase of about 25% in the production and sales of its petrochemical products. However this cannot be attributed to the steam cracker's increased capacity (expected at approval to grow by 25%) as, according to Slovnaft, the cracker's capacity remained constant. However, the production of LDPE products increased, probably due to the project, although not to the extent anticipated. The Board report expected that the production of LDPE tubular units would grow from 150,000 per annum to 350,000 by 2020, however the output was 220,000 in 2019 and an increase is not expected in 2020. Also, the improvement in its energy performance following the refurbishment of the steam cracker has so far been considerably lower than what was envisaged at approval in terms of energy saving, i.e. energy consumption reduced by 4% (1.37mJ/kg of product), rather than 14% or 4.5 mJ/kg targeted at approval.

The biggest discrepancies in reported data relate to emissions reduction. This could have been avoided if baseline data had been provided for all key indicators. However, as it wasn't, based on recent information received from Slovnaft it transpires that between 2014 and 2019, CO2 emissions from the steam cracker increased by 40% to 350,000 t, rather than reducing by the expected 14%. It is, however, noted that based on earlier reports received by the team, CO2 decreased between 2018 and 2019 by 13%, i.e. the emission might have increased substantially during the first years of refurbishment, before being slightly reduced in later years, although still staying very much above the base quoted by Slovnaft for 2014 (250,000 t). Nevertheless, as the steam cracker burners were not replaced until 2019, its 2020 CO2 emission results (not yet available) might be much more encouraging.

The information provided to EvD by Slovnaft also shows that NOx emissions from the steam cracker increased by 48%, rather than reducing by 60% as benchmarked. Again, earlier reports received by the team show a gradual reduction of NOx by 6% per annum during 2017-2019. However as the NOx base value was provided (237,000 t), the current value of 351,000 t represents a substantial increase. In this case as well, the new burners might help in achieving an NOx reduction in 2020. More positively, Slovnaft reported that the new cracker uses 23% less externally fired fuel (close to the target of 30%) and 12% less (or 23% less as per earlier PMM) water.

With regard to the new LDPE units, the major achievement was a 55% reduction in its energy use. However, in absolute terms it was nowhere near what the Bank expected it to be, i.e. the TI benchmark required LDPE to meet BAT standards of direct energy consumption of less than 2.8 GJ/t and primary consumption less than 3.2 GJ/t. However, Slovnaft reported that in 2019 consumption was 4.7 GJ/t, down from the 10.5 GJ/t average recorded during 2008-2012. This was an achievement but fell substantially short of the ambitious target. However, the LDPE unit did achieve the water consumption value required under BAT, i.e. 1.6 vs. max 1.8 m3/t of product. Nevertheless, due to energy reduction benchmarks not being met, the BAT compliance of LDPE units cannot be treated as achieved (EvD understands that the team received an earlier report from the client stating that LDPE meets BAT requirements with "all values about 10% less than guaranteed values". However EvD considers this information imprecise and treats the most recent information from Slovnaft, with the values stated, as more reliable).

Another important outcome (and TI benchmark) of this project was to be the inclusion of Slovnaft petrochemical facilities among the 10% most carbon efficient petrochemical plants under the EU ETS system (phase 3 carbon intensity benchmark of 0.702 t CO_2 per ton of product, i.e. CO_2 reducing by 42%), mainly thanks to the new LDPE units. Again, Slovnaft reduced its CO_2 emissions but not as dramatically as benchmarked, i.e. the reduction was a modest 1.6% over 2014-2019 from 1.2 to 1.18 tCo2/t of produced ethylene and propylene.

This project also had a "setting standards of corporate governance" component, which called for the integration and certification of Slovnaft's energy and carbon management systems into one, at the refinery and petrochemical plant level. However, it was unclear who would fund it and there was no dedicated TC or consultancy support. It seemed that Slovnaft would implement it but other priorities took over and this component (a TI benchmark) was not implemented. No information was available on the replication by other companies in the region of a similar refurbishment and investments, combined with system integration and reaching BAT standards (another TI benchmark); however as the system wasn't integrated and BAT standards were not met under this project, any positive information in that regard would be irrelevant.

Overall, out of seven TI benchmarks, one can be considered as partially achieved – the decommissioning of the three LDPE units, as two were decommissioned and only in 2017 (when the new units were commissioned), rather than by end-2014 as per the benchmark deadline. The remaining six TI benchmarks failed, although EvD recognises that some of them (particularly the expectations of large energy savings and pollutants emission reductions) were very ambitious.

In terms of larger **impacts**, the project did help Slovnaft improve its competitiveness. Thanks mainly to the new LDPE unit, its petrochemical products have been reportedly of much higher quality than they were before the project. Thanks to this, Slovnaft increased its market share in Germany, Czech Republic and Austria to an aggregate 37% estimated by Slovnaft (with 7-14% being mentioned in the Board report as expected). Although another expectation - Slovnaft entering new markets - did not materialise. Its overall share of LDPE products in CEE increased from 11% to 13% (however the base for this share quoted in the Board report – 20%, seems to be wrong as Slovnaft confirmed that it has never enjoyed such a high share of the CEE market). EvD notes that "CEE market" was not defined and it could be understood differently by Slovnaft/MOL than by EBRD.

The remaining expected impacts cannot be considered achieved. It would be difficult to attribute larger environmental and energy savings benefits to the project. Slovnaft provided relatively detailed data on Bratislava's air quality, which indicate no change in NOx and a marginal improvement in CO emissions pre- and post-project. Also, as it failed to qualify as one of the most carbon efficient facilities, Slovnaft has been unable to obtain free carbon permits and paid €18 million for them in 2019. Finally, it is noted that according to EEA, Slovakia registered the second largest decrease (-3.8%) in the energy intensity index among EU countries during 2005-2017 (no more recent data is available), industry being the largest contributor to this decrease. However, it would be difficult to assert that the project made any contribution to this, as the LDPE unit was commissioned only in 2017, while energy savings from the refurbished steam cracker were minimal.

Overall, the project's two main investment components were implemented, although with a long delay, missing by four years an important deadline, which was a key argument for its support by the Bank. The benefits yielded by this investment have been mainly commercial, but well below expectations in terms of environmental and energy performance. Almost none of the TI objectives were achieved (although they were ambitious), therefore the results of this project are rated ***largely unsatisfactory***.

Efficiency

The financial projections contained in the Board report only extend up to 2014 (two years), while the Bank's loan was for 8.5 years (and was later extended for one additional year - till January 2022). The banking team was not able to provide longer projections when requested by EvD. Therefore this assessment is based on MOL's overall performance, rather than in relation to the Bank's forecast.

The analysis of Credit Reviews and PMMs from 2014-2018 indicates that MOL has delivered a consistently strong financial performance. The year 2019 was characterised by a deteriorating external environment with lower oil and gas prices and weaker downstream margins. However, MOL was able to generate EBITDA of $2.44 billion, slightly above the target and almost at the same level as in 2018. Organic capex increased substantially to $2 billion, as MOL invested in strategic upstream projects (including a 9.5% stake in the Azeri-Chirag-Gunashli oil field and a 9% stake in the Baku-Tbilisi-Ceyhan pipeline for a total of $1.5 billion). Despite this, free cash flow remained positive at $0.36 billion, although net debt almost doubled to USD1.8 billion. Net debt/EBITDA also doubled to 0.8 from 0.4, and net gearing increased to 19% from 12%. However, this level of debt was considered safe and MOL's credit rating remained unchanged: BBB- (Fitch), BBB- (S&P) and Baa3 (Moody's), with Stable outlook. Nevertheless, MOL's downstream profitability was adversely affected by a deteriorating refining margin ($4.2/bbl, down 22% year-on-year) and petrochemical margins (down by 7% to 372 EUR/t).

Despite the adverse market situation in 2020 (oil price collapse and lower refining margins, combined with the Covid pandemic) MOL's mid-term prospects are considered reasonably good, mainly due to its diversified base (strong petrochemical production sector and retail). Downstream refinery and petrochemical margins are expected to be in the range of $4-5/bbl and €300-400/t respectively. Based on this, MOL expects to deliver around $2.5 billion EBITDA in 2020, rising gradually to $2.8-3.0 billion by 2023, when the newly acquired upstream assets start contributing. Overall, MOL's financial performance has been good, however it cannot be assessed in comparison to the Bank's forecast as no such forecast is available. This category is rated ***fully satisfactory***.

Overall rating

This project's overall results have been disappointing, as almost none of the transition impact objectives set at approval have been achieved. Moreover, project implementation suffered long delays, missing the deadline for EU IED compliance by four years – the key rationale for the provision of Bank finance. However, the project was ultimately completed, it brought commercial benefits to MOL/Slovnaft, as well as some energy savings and environmental benefits, although they fell short of (ambitious) TI benchmarks. It is also noted that as the steam cracker refurbishment has only recently been completed, the related energy savings and environmental benefits will only be measured for 2020 (and will be available in 2021). There is a chance that that they might meet or prove to be close to the targets set for the project. Finally, MOL's financial performance has been strong, even in the context of a depressed oil refining market. Thanks to its resilient corporate structure, with large petrochemicals production (boosted by the project), MOL is also expected to survive the current economic crisis relatively well. Therefore the project is rated overall as ***acceptable***.

Key findings:

- The measurement of a project's energy efficiency and environmental impacts can create confusion when there are changes to the client's staff. Different individuals may measure them differently, adopting different base values and making it difficult to compare or reconcile with earlier measurements.
- Governance or policy-related ("soft") components of large industrial projects, which are not supported by a dedicated TC or a pre-approved client budget, may be deprioritised by the client and may remain unimplemented.

Operational considerations:

- For projects aiming at reducing energy use and emissions, the Board reports should clearly state the base values (prevailing at the time of approval) of energy use and emissions.
- For large industrial projects, the rationale for which is based on expected energy savings or environmental benefits, the Bank should consider contracting consultants to manage the measurement of such impacts.

- Set more achievable emission and energy savings targets for large industrial operations, taking into account that increased production will probably result in increased emissions and energy use.
- Ensure that important (from a TI perspective) "soft" components of large industrial projects have an agreed budget, fully funded by the client or the Bank, and are ideally supported by an implementation consultant.

6. Galnaftogaz, Ukraine III (45462)

Background

PJSC Galnaftogaz (GNG) is a publicly traded company, and the largest private operator of fuel stations in Ukraine. In 2013 the EBRD and the IFC provided a $180 million financing package to GNG divided as follows: $80 million from the EBRD ($20 million A loan and 60 million B loan syndicated to three Austrian banks) and $100 million from the IFC ($20 million A loan and $80 million syndicated to the BSTDB). The package was to finance the expansion of GNG's fuel station network in the underserved south and east of Ukraine. Intended as part of the company's $220 million capex financing, the operation sought to extend the energy efficiency programme initiated under the previous loan to cover an environmental upgrade of tank storage facilities. The proceeds would finance the continued growth of its chain of fuel stations, upgrade its oil storage depots, and expand its integral network of convenience stores, coffee-shops and restaurants, and prolong the tenor of $50 million of its working capital financing. The project was to promote the use of higher quality (more environmentally-friendly) fuel.

The project was expected to have incremental transition impact through setting higher energy efficiency and EH&S standards. It was to extend GNG's market leading station operation energy efficiency standards to new areas and extend SEI measures to tank storage. Also, the company was to be the EBRD's first private sector sponsor of a comprehensive road safety programme and was to provide a compelling national platform for the Bank's road safety initiative in Ukraine.

Relevance

GNG is a major player among the Ukrainian oil product retailers, where the retail fuel market is a very competitive sector, characterised by five leading retailers controlling approximately 62% of the total number of stations. The EBRD, alongside the IFC, has a long-standing relationship with GNG. This was the sixth loan, providing a continuation of the support to this client dating back to 2005, when GNG was a small local distributor.

The project was aligned with the Bank's 2006 Energy Policy (BDS06-093), as it financed the oil and gas downstream sector (prioritised by this strategy), which "seeks to reduce the lack of consistency in production and quality assurance from wholesalers or retailers". The operation sought to take advantage of opportunities to transfer knowledge and improve approaches, and to increase competition and product quality. The project was also in line with the Strategy for Ukraine 2011-2014 (BDS/UK/11-1(Rev 1)), which sought additional private sector support in downstream activities and called for the cross-sectorial priority of energy efficiency.

The Banks' additionality stemmed from contributing to the mobilisation of loan syndication, assisting the IFC in leading the syndicate, and supporting a well-performing existing client. At the time of approval, the Ukrainian commercial banking sector did not have enough resources to finance new capital expenditures requiring long-term financing. The available funding was usually provided at short term tenors, which were not suitable for financing a network expansion. The sponsored syndication would enable GNG to obtain longer term finance, unavailable from commercial sources without IFI participation.

In EvD's view, the Bank's financial additionality arguments had some weaknesses, given (i) GNG's successful restructuring of its debt profile, extension of the debt maturity, and commercial cofinancing; (ii) the objectives of the project being closely aligned to the previous syndicated loan (Op ID 42470), and (iii) the net increase being relatively small ($12 million). However, EvD agrees that as the total package amounted to $180 million, it would not have been possible to borrow this amount at a long tenor in Ukraine in the absence of EBRD syndication. This is still true despite the fact that the last tranche of the financing package ($65 million) was cancelled as GNG revised its capex programme downwards following the 2014 conflict in Ukraine (which could not have been foreseen at origination), and following advice from the A/B lenders.

The Bank's additionality was realised through successful mobilisation and syndication, and also partly through financing and environmental conditionalities. The conflict in Ukraine rendered this market even more difficult. Up till now, the EBRD continues to offer a tenor longer than the market average and its terms and conditions, including for example longer grace periods, are rarely available in Ukraine. The country continues to experience weak corporate lending (with a 6.6% y-o-y contraction in 2019). The project's relevance is assessed as ***fully satisfactory*** due to its alignment with the Bank's strategies and its additionality, which was largely realised.

Results

The project experienced setbacks, due to the conflict in Ukraine, which started in 2014. In its wake, GNG's expansion capex was substantially reduced. The Bank disbursed $12.8 million from its A loan, while altogether, $115 million was disbursed from the financing package and $65 million was cancelled at the end of 2015. Also, a significant drop in income per capita in Ukraine led to a drop in demand for high quality fuel, prompting the client to limit its ambitions in this area.

Outputs: The key component of the project – fuel stations expansion, was only partly completed, not exactly in the planned locations, and much later than expected. The Board report stipulated that by the end of 2014 the client would build 64 fuel stations under the project. However, due to the conflict, which escalated most in eastern and southern Ukraine, the expansion programme was put on hold (e.g. 11 stations were to be built in the Crimea, which was annexed by Russia). A reduced programme was reinstated in 2016. The location of the new stations was also adjusted as war continued in eastern Ukraine and the Crimea was inaccessible. By the end of 2018 the client had built 34 new stations. The most recent report from mid-2020 indicates that by then the client had added a total of 47 fuel stations since the project started, reaching the total of 415. GNG also reported leasing 46 additional stations since the project started, which has probably been a better strategy, given the current uncertainty. It is unclear how many stations were built with the funds from the financing package, however the available data indicates that it was about half of the planned number. New fuel stations were built in Kharkiv, Chernivtsi, Kherson, Odesa regions, Kyiv city, Ivano-Frankivsk, Lviv, and Volyn regions – thus the investments spanned not only the south and east but also the west and north of the country.

The fuel tank investments and the LPG module were completed in ten locations, largely following the recommendations of Mott McDonald's study. However, only about half of the planned budget in dollar terms was spent on this. Moreover, the Yuzhny port terminal oil storage facilities were not completed due to the conflict. Other smaller improvements and upgrades were partly implemented – 25 convenience stores and coffee-shops, as well as two restaurants were added. GNG also implemented repairs to buildings, tank parks, pumps, fire safety equipment, and a digital video control system, purchased hardware IT infrastructure, and installed cameras throughout its station network. Most of these refurbishments are considered partly achieved because the amount of investment was lower than anticipated. Finally, the refinancing of short-term loans with long-term loans was fully achieved as expected with $50 million (43% of total of the funds disbursed from the EBRD/IFC financing package).

All "soft" outputs related to energy efficiency and environmental improvements were completed: preparation of the GHG Reduction Programme, a road safety management plan, a training package for GNG's drivers, and a case study on road safety management in the private sector. A corporate social responsibility programme on road safety was adopted (although it was significantly delayed). Among its activities, it donated sets of reflective materials to children, road safety textbooks to students, provided afterschool traffic safety classes, and offered training on safe travel in cars with children. Reportedly, the Road Safety Management Plan was prepared and implemented and road safety training sessions are being held for drivers. The team reports that a case study on road safety management in the private sector has been prepared, although it does not seem to appear on the Client's website.

Outcomes: the project was also only partially successful in attaining its intended outcomes. It partially achieved the main objective of augmenting the client's share of high quality fuel stations in the south and north-east regions, again due to the conflict prevailing there for most of 2014-2016. Nevertheless, by mid-2016 the share of stations offering high quality fuel in the south had increased from 23% to 27%, exceeding the 25% target. However the share of comparable stations remained unchanged in the north-east. By 2020, the south's share stagnated while, reportedly, the total share of high quality fuel stations in both markets oscillated between 30-40%. The country suffered a substantial plunge in per capita income, which resulted in a declined demand for high quality fuel. Nonetheless, GNG's total market share per number of fuel stations in Ukraine increased from 16.8% in 2018 to 18.1% in 2019. GNG also became the largest fuel retailer in Ukraine by number of stations.

Moreover, thanks to the partial implementation of other investments, tank storage safety, as well as customer experience and safety, improved (although not to the extent planned). Also, as GNG's short-term working capital loans were converted into a long-term loan, GNG saved about $6 million, comparing the 2013 and 2016 interest costs on a similar amount of debt (2013-2015 short term loan interest was about 7-10% for USD tranches and 15-25% for UAH tranches, while it was reduced to about 6% under the EBRD/IFC facility).

In terms of transition-related objectives, the Client implemented the recommendations and executed the investments proposed by Mott McDonald under the GHG Reduction Program. The Company reports that these were actioned in 10 tank storage locations, above the initial target of four locations (although only about half of the planned USD budget was spent, some of this underspending might be attributed to the UAH devaluation). In addition, the objective of training GNG employees was achieved, with 300 GNG drivers participating in safety and fuel economy courses.

On the other hand, there is no evidence that the Project achieved the majority of the policy and road safety benchmarks. GNG did not report the establishment of the policy related to road traffic safety, the assignment of roles, inception of reporting on road safety, or introduction of actions to reduce accidents. Also, whereas the case study on road safety management in the private sector was prepared, it was not published as expected - its actual use and application could thus be questioned. Lastly, there was no information available to confirm the Client's participation in the EBRD's road safety initiative "Safe Villages". This programme was intended to raise road safety awareness at both local and regional levels and to decrease road risks along the main transport corridors (focusing on the EBRD-financed road sections).

Impacts: the project did not result in GNG improving its financial and operational performance during implementation. Growth in revenues, profitability and cash flows in this period were stopped by the conflict, and suffered a substantial drop. The financial performance benchmarks set at approval were not achieved. First, between 2013 and 2015 revenues halved from $1.8 billion to $0.9 billion against an expected increase of 35% for this period. Second, in contrast to the anticipated 37% EBIDTA growth, it actually shrunk 33% from $129 million to $86 million in 2015. Nevertheless, more recently, GNG's performance has been on an upward trend as revenues rose back to $1.5 billion and EBIDTA improved to $143 million in 2019.

The Project achieved its main energy efficiency and environmental impacts. The Client reports that vapour losses were reduced by 30%-40% and that the efficiency of pumps increased by 10%-20%. However, EvD could not evaluate the extent to which the project led to a reduction in GHG emissions as no information was produced. An important shortcoming is that benchmarks were not adequately defined at the outset. The Project's approval document did not provide baselines on these measures, and neither did the transition impact monitoring reports. This precludes the assessment of the indicators before and after the intervention.

As for road safety, the number of accidents, fatalities and injuries has decreased every year in Ukraine as a large number of relevant programmes and infrastructure improvements have been implemented, including by GNG, thus there is a problem with attribution. The Project is considered to have made some contribution to this decrease, although again, the benchmarks were not adequately defined at approval (no baselines or targets). Also, GNG was not able to provide an evidence of a reduction in accidents/incidents caused by GNG drivers.

The conflict in Ukraine has profoundly affected the project and reducing its scope was the right decision. Overall, more than half of the outputs are considered delivered. However, 43% of the financing package was used just to refinance GNG's short terms loans - beneficial for GNG but less attractive for the Bank from a TI perspective. Nevertheless, GNG ultimately reached the business expansion target in 2020 – six years later than planned (although counting also the leased fuel stations). Also, the increase in the share of high quality fuel stations in underserved regions didn't materialise until 2020. The dip in per capita income led to a decrease in the demand for high quality fuel during the conflict. The majority of network upgrades and refurbishments were completed. In terms of TI, out of seven benchmarks, four are considered achieved and three partly achieved. GNG's financial and operational performance during implementation fell well below that targeted under the "overall project objectives", although it has recovered in recent years. Taking into account the extraordinary circumstances (war breaking out in the regions where the project's main investments were to be located), and that ultimately most of its main objectives were achieved, including a large part of the planned TI, the project's results are rated ***partly satisfactory***.

Efficiency

Ukraine and GNG's business suffered under unsettling political and macroeconomic conditions during the 2014-2016 crisis. Base case projections did not account for this turmoil. Actual performance was lower than pre-crisis assumptions. One year into the project and during the first year of the conflict, GNG's revenues were 30% lower than expected, but EBIDTA was only 5% below its projection. Nevertheless, it incurred a net loss of $50 million compared to a net profit of $70 million the year of signing (gross loss was $68 million against a gross profit of UDS91 million in 2013).

In 2015, revenues and EBIDTA were halved from the previous year, with net profits barely accounting for under 4% of the projections. No other net or gross losses were registered for the rest of the implementation period. Overcoming the crisis marked a recuperation across financials at end-2016, yet revenues represented only a third of expectations, while EBIDTA and net profits reached approximately half of what was projected. Notably, this upward trend has been sustained ever since. At mid-2019, GNG was in compliance with all existing financial covenants. At end-2019, the Client's continued efficiency improvement of its network resulted in an increase of average daily sales per fuel station of 8% y-o-y, and an increase in average retail margins of 37% y-o-y. Gross margins increased as price adjustments lagged Hryvnia appreciation. EBITDA was a record high $143 million, 91% up y-o-y, and compared to original projections, it was only 10% short of the target. Net profits reached 84% of the projected figures.

In terms of sustainability and future outlook, GNG's updated business plan indicates that the Client expects to generate a $125 million EBITDA in 2020 on the back of further retail market recovery, a small expansion of the fuel station network, and growth in the profitability of other business lines such as agricultural and fertiliser trading. The latter are to be supported by GNG's latest transaction with the EBRD, the IFC and the BSTDB: Galnaftogaz Loan IV.

GNG has honoured its obligations to the EBRD and other creditors over the past 15 years, notwithstanding the crisis. It has improved its liquidity and decreased leverage as it steps into its mature stage. The balance of the loan, $2.3 million, matures and is expected to be repaid at the end of November 2020. The efficiency of the operation is rated ***partly satisfactory***.

Overall rating

The project was relevant as it was aligned with the Bank's current country and sector strategies at the time of approval. The Bank's additionality even increased after the loan signing as the conflict in Ukraine substantially limited the access of Ukrainian corporate borrowers to credit markets. The results of the project were mixed, with key objectives such as business/network expansion and the increase of stations selling high quality fuel only attained long after the project's initial timeframe. Transition impacts were largely achieved. The financial performance was below projections during implementation, but has made a solid recovery and is expected to further improve. Road safety objectives were achieved on a macro level, and, whereas attribution is difficult given the multiple programmes and interventions in the country, the project is considered to have made a contribution to this success. At the more measurable company level, EvD was not able to obtain evidence to verify the achievement of several indicators.

The results and performance of the project were affected by the 2014-2016 conflict and economic crisis in Ukraine, which led to a reduction in capex investments and the partial cancellation of the loan. Despite the conflict, by 2019 GNG was able to increase its total market share to 18.1% and become the leading premium chain and the largest fuel retailer in the country. With some difficulty, but taking into account the special circumstances and ultimate achievement of most of the key objectives, overall the project is rated ***good -.***

Key findings:

- Well-managed clients demonstrate resilience even in very difficult crisis situations. A reduction and shift in the timing of a capex programme can enable recuperation from a crisis, and improved financial performance;
- It is difficult (if not impossible) to attribute the outcomes of a project's "soft" components, such as training or educational activities, to larger macro level impacts without clear baselines, as well as an agreed impact measurement and reporting system.

Operational considerations:

- For transactions with repeat clients, a brief but detailed summary of the results of each past transaction should be included in the proposals for new operations;
- Training and educational components should include a plan that evaluates results against a defined ex-ante baseline. For instance, in this project, the number of accidents/incidents caused by GNG drivers before the delivery of road safety training. The monitoring programme should require the regular measure of this indicator in defined periods.

Table 1. Summary of evaluation rating of cluster projects

Cluster Project, Country	Relevance and Additionality	Results	Efficiency	Overall Performance
PICO Oil and Gas, Egypt	*Fully satisfactory*	*Partly satisfactory*	*Partly satisfactory*	*Acceptable*
Energean Oil I and II, Greece	*Fully satisfactory*	*Largely unsatisfactory*	*Partly satisfactory*	*Acceptable -*
Serinus, Tunisia	*Fully satisfactory*	*Largely unsatisfactory*	*Largely unsatisfactory*	*Poor*
PKN Orlen, Poland	*Partly satisfactory*	*Partly satisfactory*	*Partly satisfactory*	*Acceptable+*
MOL/Slovnaft, Regional	*Partly satisfactory*	*Largely unsatisfactory*	*Fully satisfactory*	*Acceptable*
Galnaftogaz III, Ukraine	*Fully satisfactory*	*Partly satisfactory*	*Partly satisfactory*	*Good-*

ANNEX 3 – RESULTS FRAMEWORKS

This annex presents the Results Frameworks prepared ex-post by EvD for six cluster projects and agreed with the project teams. The text in colour summarises the results of each intended output, outcome and impact, with objectives in green considered achieved, in blue partially achieved and those in red not achieved.

Egypt: PICO (44491) - Results Framework

Assumptions	Inputs	Outputs	Outcomes	Intended Impacts
-PICO secures a license extension from the Egyptian authorities to overhaul the FPSO -Price deck of USD 68.50/bbl assumed for the Facility. -The Geisum and Tawila license become a Borrowing Base Asset under the Facility For the Geisum & Tawila fields inclusion temporarily postponed until	EBRD: USD 50 m committed and USD 50 m uncommitted loan (USD 37.5m disbursed) IFC: USD 50m loan HSBC Bank AS: USD 50m loan TC: EUR 100k grant TC project "Improving Regulatory Framework for PSC in Egypt" funded by the EBRD SSF Undefined PICO's own resources	1. Stemming from capital investments: • Amal field: Gas 17 exploration well drilled - New Offshore Platform installed ("Platform C") - Well 8 drilled - Wells 9, 13 and 16 Recompleted - Flow Station/Producing Platform installed - Treatment, Gathering Systems installed - 12" x 1.3 Km Pipeline completed **Achieved**. All installed and in operation (and additional 4 wells drilled: Amal 23, Amal 23A, Amal 18 short string and Amal 17 short string). • Zaafarana field: - Floating Production Storage and Offloading ("FPSO") facility upgraded	1.Gas capture and water handling capacity in the field increased **Achieved**. The Amal offshore platforms are connected to the onshore Gas/Oil separation plant. The separation plant has a processing capacity of 7,800 BOPD, water processing capacity of 3,700 BPD and gas handling capacity of 70 MMSCFD. The separated gas is sent to the gas processing plant Unit 304 for gas processing. The condensate and GPL are stripped from the wet gas at Unit 304 and the dry gas is then sent to the grid for sales. 2.Higher production rates Base: 2013 gross average oil production (Board Report): Amal: 4030 boepd Zaafarana: 4384 boepd **Partly achieved.** Based on recent data, this was achieved for Amal field, but not achieved for Zaafarana field.	1.Growth of PICO's market share in Egypt by 1-3% by 2020 (from 1.2% base) **Reportedly achieved.** PICO's market share grew by 1.2%. However EvD notes that based on 2018 results, (latest available) Egypt's oil production declined by 2.5% compared with 2013 level. Comparing these 2 periods, PICO's production from Amal and Zaafrana declined 7%. So, if PICO's market share grew, it was not due to project-related investments. 2.PICO's financial performance improved **Partly achieved.** FY 2018 revenues (USD 74.3m) were only 70% of those pre-project: (USD 106m) in 2013.

PICO completes a phased bio-diversity survey in order to satisfy EBRD and IFC environmental requirements		**Not Achieved.** PICO presented a plan to improve the quality of the separated water treatment at the Zaafarana FPSO with an aim to reduce the hydrocarbon content in the water before its disposing off board. There were laboratory analysis reports sent by PICO and indicating that certain actions were undertaken, but that was not enough to achieve the stipulated water quality - Additional well drilled **Not Achieved**. The Zaafarana field continued its production from existing wells and there was no firm intention to facilitate its development by drilling new wells and/or working over existing wells. Based on available technical reports and discussions with the relevant PICO personnel, there were no plans to drill additional infill wells at Zaafarana.	Amal's average oil production for 3Q18, 4Q18 and 1Q19 were respectively: 5438, 4209, 6003 boped. And for Zaafrarana: 3305, 2826, 3716.	They decreased by 2% compared to FY 2017 (USD 75.1m). However they were pretty close to those projected at approval for 2018 (USD 77.5 m), although 2017 revenues were 25% below those projected (USD 100 m) EBITDA margin (84.4%) significantly improved in FY 2018 (62.9% in 2017), from 63.6% in 2013. It stayed well above peers' margin of about 50%. Net profit first halved (from USD 40.5 m in 2013 to USD 20.5 m in 2016) but then grew slightly in 2017, to substantially increase in 2018 to USD 48.9 m (65% margin). This is impressive, however the Board report did not provide EBITDA and net profit projections (only CF). Based on revenues (close to projection for 2018 and shortfall for 2017) as well as generally impressive margins in recent years, this is assessed as partially achieved.

		2. Stemming from policy-related activities: • Legal study with recommendations on improvements to the regulatory framework and to the Production Sharing Contracts (“PSC”) template. **Partly achieved**. legal study with recommendations on improving regulatory framework completed but no evidence of recommendations to the PSC template • Capacity building assistance provided to a specific agency or department of the Ministry of Petroleum to implement the changes to PSC. **Achieved–** numerous workshops organised for MoP and wider audience • Country-wide viable opportunities for reducing flaring and increasing APG utilisation in upstream oil activities in Egypt identified through a study	3. Study recommendations implemented (i.e. new PSCs signed according to a new template) **Not achieved –** a subtle, one-sentence addition to the PSC was introduced, encouraging the parties to PSC to negotiate in good faith to address APG. However a follow up TC was undertaken and there are some prospect that part of the broader recommendations from this study, improving regulatory framework for PSC will be implemented 4.Officials at the Ministry of Petroleum competent and versed in the new PSC and APG issues. **Achieved–** based on several workshops organised by consultants it is deemed that officials at MoP gained better knowledge of APG issues	3. Increase of oil and gas sector investments in Egypt **Achieved**. According to Petroleum Minister Tarek el-Molla.in Q3 2019: Egypt recorded investments of USD30 bil in the petroleum sector, recording the highest rates ever. The sector achieved the largest contribution to GDP by about 25%, in addition to its contribution of 44% in foreign direct investment (FDI). *Source: Egypt Today* 4.Flaring and CO2 emissions from oil and gas production in Egypt reduced **Partly achieved**. • Annual oil and gas production-based emissions of carbon dioxide (CO_2), measured in tonnes per year: 223m in 2014; 237m in 2017; 239 m in 2018, i.e. increase by 7%. *Source: UNWPP* • Gas flaring volumes 2015-19 (billion cubic meters): 2.83 in

		Achieved. The study on gas flaring recovery opportunities has been completed and the TC work has moved on to an analysis of the legal framework. • An industry-wide workshop on APG flaring reduction, organised with PICO and other operators **Achieved**: workshop organised in 2016 with WB. • MoU between EBRD and the Egyptian authorities for a long-term strategic partnership on APG signed **Achieved**: A Memorandum of Understanding between EBRD and EGPC, EGAS and GANOPE was signed in February 2015 for cooperation in the area of sustainable energy in the oil and gas sector.	5. Measures reducing flaring implemented by PICO and other oil companies in Egypt, as recommended in the study **Partly achieved** – as reported, there is no flaring at Amal field, however it is unlikely any changes were made at Zaafarana field as very few investments were made there.	2015; 2.83 in 2016; 2.34 in 2017; 2.26 in 2018; 2.34 in 2019, i.e. **17% decrease** . *Source: World Bank. © 2020 Global Gas Flaring Reduciton Partnership (GGFR)*
		3. Stemming from the implementation of ESH&S-related policies (in the framework of Social Policy, Social Impact Assessment ("SIA"), a Stakeholder Engagement Plan ("SEP") and grievance mechanism of which a biodiversity mitigation forms part): -Phase 1, Phase 2 and Phase 3 of a Biodiversity Study for the Amal and Zaafarana fields completed	6.ESH&S systems certified to ISO 14001 and OHSAS 18001 standards **Achieved**: Cheiron's head office and joint venture assets have certified management systems to organise processes that identify, assess and then manage quality, environmental and health and safety related risks. The management systems of all Egyptian assets and the Cheiron Head Office are certified to ISO 14001:2015 and OSHAS 18001 management systems for	5.PICO's corporate governance in line with international best standards (including better environmental, social and H&S record). **Partly Achieved** (?) Given the generally very poor level of E&S performance and enforcement of E&S standards in Egypt, the Project has achieved a drastic improvement in Pico's E&S performance. Some examples

		-Phase 1, Phase 2 and Phase 3 of a Biodiversity Study for the Geisum & Tawila fields completed **Achieved**: Phase I, II and III of the Biodiversity Study for the Geisum & Tawila fields were completed by April 2016. -Study for Amal and Zaafarana **Achieved**: Yes, all three fields were covered by relevant marine and terrestrial biodiversity surveys; Geisum and Tawila being a priority given that these fields are located in the areas that was designated as a protected area by the Egyptian government (post-commencement of the oil and gas exploration and production activities). A Biodiversity Action Plan was developed in 2017. -Individual training and/or certification through the Institute of Environmental Management and Assessment ("IEMA") and the International Association for Impact Assessment ("IAIA") of: -PICO staff -Joint Venture Operating companies staff	environmental and health and safety respectively. The Company's transition from OSHAS 18001 to ISO 45001 has started with Amal and Cheiron's Head Office expected to achieve certification during 2020. The transition from OSHAS 18001 to ISO 45001 system was never required by the agreed ESAP. Otherwise the Company and the JV achieved relevant ISO 14001 and ISO 18001 certifications as required by the ESAP. All assets and the head office are also certified to ISO 9001 (quality) with the exception of Norpetco (a non-RBL asset) where a programme to gain certification is underway. 7. Stakeholder Engagement Plan implemented **Achieved**: implemented in FY 2016/2017 8. a grievance mechanism implemented **Achieved**: implemented in FY 2016/2017. 9. a comprehensive Social Policy and Social Impact Assessment implemented **Achieved**: implemented in 2019. 10. a Biodiversity Mitigation Strategy and Impact Assessment adopted	include the completion of a very extensive biodiversity survey and clean-up of the abandoned produced water and sludge pit and turning it into a profitable activities. Pico has also developed and approved Sustainability Policy and procedures. Pico have also hired new General Directors for 2 out of 3 JVs, and GM have been vested with the responsibility for implementing the Company's E&S procedures. 6.Lesser environmental impact from PICO's new investments **Partly Achieved** At the request from the Bank and as part of the ESAP, Pico has developed and started implementing a procedure for E&S assessment of its activities. Pico has also hired an international HSE director, as well as an independent E&S advisor to oversee the E&S aspects of its activities. Pico have also entered into a framework contract with ERM, an international E&S consulting company, for conducting appropriate E&S impacts

		Not Achieved. - Membership with the International Petroleum Industry Environmental Conservation Association ("IPIECA") **Not Achieved**: PICO has not become a member of IPIECA	**Achieved**. A Biodiversity Action Plan was developed in 2017. 11. at least 15 individuals within PICO oil & gas companies trained and/or certified through the Institute of Environmental Management and Assessment **Not Achieved**: no information why this was not achieved. 12. at least one individual at each of the three Joint Venture Operating companies (Amapetco, Zafco and Petrogulf) (three individuals in total) trained and/or certified through the Institute of Environmental Management and Assessment **Not Achieved**: The Company did not disclose why this was not achieved. 13. at least 15 individuals within PICO oil & gas companies trained and/or certified through the International Association for Impact Assessment **Not Achieved**: The Company did not disclose why this was not achieved. 14. at least one individual at each of the three Joint Venture Operating companies (Amapetco, Zafco and Petrogulf) (three individuals in total) trained and/or certified through the International Association for Impact Assessment	assessments of its new investments. 7.PICO's employees competent in environmental management and assessment **Partly achieved** While none of the international training, agreed as TI benchmarks, was undertaken by the Company, the staff of both Pico HQ and JV staff attended a number of trainings organized either by EBRD in Egypt (environmental and social risk management training; biodiversity capacity building training) and/or in-house training conducted by independent E&S expert hired by Pico. TI benchmarks were identified outside the ESAP and followed-up directly by the OL with the top management of the Company.

			Not Achieved: The Company did not disclose why this was not achieved.	8.At least two other oil and gas companies become members of the International Petroleum Industry Environmental Conservation Association. **Not Achieved**: IPIECA membership by other companies was not triggered by EBRD
	PICO's own resources	4. Stemming from activities related to Corporate governance improvements: • Corporate Governance Action Plan ("CGAP") adopted including: **Achieved**. EBRD and IFC developed a corporate governance action plan (CGAP). Actions focused on the board's and committees' composition and authority, independent directors, internal and external audit, corporate secretary etc., but nothing on EITI. • Creation of a Board of Directors with clear terms of references **Achieved**: The company has completed all the mandatory items of the corporate governance plan. • Creation of Internal Audit Department / Internal Auditor **Achieved**: The company has completed all the mandatory items of the corporate governance plan • Creation of an Audit Committee **Achieved**: The company has completed all the mandatory items of the corporate governance plan • Group Restructuring Plan adopted.	15.Group Restructuring Plan implemented (PICO's corporate structure simplified) **Achieved –** according to Portfolio Manager, legal restructuring of PICO took place in 2018, as part of the Bank's loan re-financing. 16.Disclosure of payments made to the authorities in EBRD countries of operations (Egypt and Romania) and beyond (Mexico) in line with EITI principles **Achieved**. According to the team, key summery of payments (under PSC) published	

		Achieved. The company has completed the corporate restructuring plan • Policy of compliance with EITI adopted **Achieved**. No information on a *policy* but TIMS reports that the Company has completed the corporate restructuring plan and has reportedly begun to disclose payments made to the authorities in EBRD COOs (Egypt and Romania) and beyond (Mexico) in line with EITI principles. The corporate governance action plan (CGAP) had nothing on EITI.		
	PICO's own resources	5. Corporate Energy Efficiency and APG Flaring Reduction Programme implemented (including investments at Amal field and beyond) **Achieved**. The plan has been adopted by Pico and implemented at Amal field (but not beyond).	17.Nearly zero flaring at the Amal field – **Considered achieved**. Reportedly gas produced at the Amal field is processed and sold. The gas flaring is minimal since the company tries to maximize the gas and LPG sales volumes. Some technological gas flaring occurs only at the processing sites onshore and it is minimal.	10. 8 bscf of dry gas and 400,000 bbl per year obtained at Amal due to APG processing **No data** – deemed not achieved CO2 emission reduction at Amal of at least 100,000 tonnes per year on average **No data**– deemed not achieved. 11. 1,500 TJ of energy from wet gas recovered on average from the Amal field **No data** – deemed not achieved

				12. At least two other oil and gas companies have reduced APG flaring in their oil fields in Egypt by at least 50% in addition to those benchmarked under previous projects **No data**– deemed not achieved.
		Risks to Achievement of Outputs:	**Risks to Achievement of Outcomes:**	**Risks to Achievement of Impacts:**
		Development Risk: The forecast production levels are not achieved due to the failure of the planned well and field upgrade works or that the Zaafarana FPSO is too old and ageing or that the Zaafarana license is not renewed beyond 2017.	Reserves Risk: Reserves are insufficient to cover required debt repayments. Operations Risk: Risk that the assets underperform due to a lack of operator expertise. Foreign Exchange and Interest Rates Risk: The Company's cash-flows are reduced due to movements in FX and interest rates.	Commodity Price Risk: Oil prices go below the price deck of USD 68.50/bbl assumed for the Facility. Offtake and EGPC Risk: Risk of non-performance under the license/off-take agreements and risk that EGPC is unable to make payments to PICO.

Assumptions	Project Inputs:	Project Outputs:	Project Outcomes:	Intended Impacts:
Attractive assets with the costs in the first quartile of the industry cost curve Competent management and technical team with a credible development plan Full export of oil under off-take contract with BP Reserves confirmed by ERC Equipoise consultancy (later estimates increased) at 1P – 16 (23) mb, 2P - 30 (37) mb, 3P – 48.5 mb	USD 75 million EBRD revolving reserve-based loan (reduced to USD 52.5 m under Energan II) – 5y, extended to 7y USD 127.5 m from BSTDB and RomExim bank USD 84 m from Energean's internal Cash Flow	1. Drilling of 17 new wells - 9 at Prinos (with dual completion methodology), 1 at Prinos North, 7 at Epsilon; and 5 workover wells and simulations [first €20 m to refinance BP's bridge loan for wells] **Partly achieved.** 10 new wells drilled (however using single string methodology due to geological impediments) – 8 at Prinos, 1 at Prinos North and 1 at Epsilon (drilling stopped in 2020 due to oil prices). No info on workover wells 2.Construction of a mobile off-shore self-installing platform (SIP-2/Lambda at Epsilon) – by 12.18 (by 9.19 after a new contract for it signed) **Not achieved (as yet)**. Under construction in Romania financed from a new loan ($30m paid by mid-'19, 50% completed by end 19, expected 2 or more years delay). 3. Installation of energy efficiency and pollution control equipment: - skid-mounted dew point conditioning unit for APG recovery (or rehab of the power plant/construction of CHP)	1. Increased oil production from 2,668 bpd to 5,303 bpd average during 5.16 - 5.21 (100%) **Not achieved.** During 2016-19 increased to an average 3,464 bpd (30%). In 2020, due to oil price only 1,800 bpd expected 2. Reduced energy consumption from 350 kWh/bbl to 150 kWh/bbl **Not achieved.** Marginal drop in energy intensity from 212 to 207 MJ/boe 3. at least 95% of APG sold to the grid (33 mil m3 per year) **Not achieved** (0 sold) 4. Reduced CO2 emission by 110-200kt per year	1.Improved competitiveness of Energean (improved financial performance) **Partly achieved**. Performance improved during 2017-18, decline (loss) 2019-20 2.Positive impact on Greek economy and employment (70% of the Epsilon platform to be built in Greece) **Not achieved.** 0% built in Greece, all in Romania 3. Additional revenue from APG sale €200 mil over 15 years (~ €13 mil per year) **Not achieved** (0 revenues from APG)

Assumptions	Project Inputs:	Project Outputs:	Project Outcomes:	Intended Impacts:
Sub-loan to be refinanced via a bond placement or internally generated cash	USD 20 million EBRD subordinated loan. 6y, extended to 9y USD 6 m from Energean's internal CF	**Key elements not achieved.** APG put aside due to lower production and other priorities -gas compressors and refurbishment of gas pipeline Not implemented - low emission combustion system -de-oiling units installed -pollution measuring sensors installed	**Unclear data.** Reported direct CO2 emission increased by a quarter (10kt) but indirect (energy purchased from the grid) decreased by a quarter (12kt) No scope for 110-200kt reduction as emission in 2017 was 85kt 5. improved environmental performance (modern water and ww systems); advanced pollution prevention and measuring systems **Partly achieved**. Measuring systems installed. Water use intensity reduced by 15% but direct CO2 emission increased.	4. Improved environment in Kavala region (lower air and water pollution indicators) **Not achieved** (on regional level) – higher direct CO2 pollution from the drilling site. But lower indirect CO2 emission (overall CO2 pollution stable btw 2017-19); no change in water
		4. New oil exploration, incl. 2d&3D seismic acquisition, interpretation, geological modelling, development studies, signature bonus (if Aittokarnania license awarded)	6. Commercial development of Energan's reserves **Not achieved**, no production from newly explored fields	5. Increased oil production and revenues of Energean **Not achieved**

Assumptions	Project Inputs:	Project Outputs:	Project Outcomes:	Intended Impacts:
		Partly achieved. Explorations in 2 onshore blocks (Ioannina and Aittokaarnania), as well as Katakola and Montenegro conducted. Most preparatory works completed, however as of 2Q20 all exploration put on hold. Reserves increased by 11%. Aittokarnania license not obtained.		
Readiness of HHRM and the Ministry to adopt consultants' advice and introduce changes	€445,000 TC1 funds for Development of Greek Hydrocarbons Sector (i) assistance to HHRM in implementing EU Offshore Safety Directive, and (ii) development of an upstream Economic Model for Tendering and Licence Monitoring €17,500 TC2 funds – for review of options for APG utilisation Unidentified input to policy dialogue	5. Guidelines and a rules book to implement EU Directive 2013/30/EU **Achieved**. Comprehensive set of rules and guidelines developed. 6. Developed upstream Economic Model for upstream tendering and license monitoring **Not achieved**. After Board approval the management of Hellenic Hydrocarbon Resources Management (HHRM) changed and indicated to the Bank that such initiative was no longer a priority given the expertise from the recently appointed management in that particular area 7. Report with APG utilisation recommendations **Achieved**, report completed	7. EU Directive 2013/30/EU fully implemented in practical terms at Greek oil and gas operations **Achieved** 8. More streamlined licensing regime (quicker vs past, less complaints filed, more licenses granted) **Achieved** (8 licenses granted in last 2 years, compared to 3 in 5 years before the project). Attribution questionable 9. Recommended APG utilisation option implemented **Not achieved**. No evidence of implementation	6. Increased safety of Greek oil and gas operations (less incidents and accidents) **Achieved**, in 2018 zero accidents reported 7. More Greek hydrocarbons resources being developed **Achieved**. More licenses issued in recent years largely due to improved economic and market environment and the effectiveness of the new HHRM management following the implementation of an appropriate regulatory/legal framework in 2016. 8. APG utilised as planned **Not achieved**

Assumptions	Project Inputs:	Project Outputs:	Project Outcomes:	Intended Impacts:
		7. Policy dialogue with the Ministry of Environment, Energy and Climate Change aiming at improved regulatory regime (including workshops, training sessions, etc) **Achieved,** PD conducted, (training, workshops delivered)	10. Strengthen institutional capacity of the Ministry and HHRM **Achieved** (based on training provided)	9. Greek hydrocarbons sector attracting more international investors **Achieved.** Evidence of more applications for licenses from foreign investors (2 in 3 pre-project years, 5 in 3 post-project years)
		Risks to Achievement of Outputs:	**Risks to Achievement of Outcomes:**	**Risks to Achievement of Impacts:**
		-Technical risks related to drilling and oil platform construction -reserves risk (lower than expected) -EE and environmental measures seen as low priority and delayed/not implemented -Reluctance of HHRM and the Ministry to cooperate to decommission old crackers	-Risks of insufficient resources dedicated from the Ministry/HHRM	-Risks related to macro-economic situation in Greece -Risk related to price of oil

Serinus Energy project – Results Framework

Project Inputs:	Project Outputs:	Project Outcomes:	Contribution to Sector/Country-level Impacts:
Senior Loan - USD 40 million with 7 year tenor and 1 year grace period **Convertible Loan -** USD 20 million with 8 year tenor and bullet repayment either in cash or shares of Serinus (Bank's potential shareholding in Serinus to be limited to 5%) **Client's re-invested cash flows -** USD 106 million	**Oil and gas concessions in Sabria, Chouech Essaida, Ech Chouech and Sanrahr further developed** • 11 new wells drilled in Sabria and 6 in Chouech Essaida • Work-overs and well stimulation completed • Horizontal wells developed • Service rig acquired and one or more drilling rigs contracted **Not achieved** – only 2 wells drilled in Sabria. No rigs acquired. Workovers and stimulation largely completed	**Good financial and operational performance** • Oil and gas production volumes increased from average daily production of 1,420 bbl/d in April 2013 to 2,000 bbl/d • Utilization of capacity at the Sabria processing facilities increased from 60 to more than 90 per cent by end 2017 • Maintain Debt/EBITDA at max. 2.75x and DSCR at min. 1.5x **Not achieved** – marginal production volumes	**Private ownership expanded** • Net proved reserves increased (3,199 Mbbls certified in 2012) over the period from 2014 to 2017 **Not achieved** – reserves increased to 3571 Mbbls in 2015 but dropped to 2,246 Mbbl in 2018 **Skills transferred** • Drilling works internalized, Serinuse's staff trained **Not achieved**, outside contractors employed

Project Inputs:	Project Outputs:	Project Outcomes:	Contribution to Sector/Country-level Impacts:
	Corporate governance standards improved • Environmental and Social Management System developed and implemented • Clear human resource policies developed, published and disseminated • Plans for the treatment and monitoring of drilling mud and liquid discharges developed and implemented • Payments to Tunisian authorities disclosed according to PWYP principles **All achieved**	**Improved environmental performance and standards** • Drilling mud and liquid discharges treated and monitored in full alignment with PR3 **Achieved** although amounts treated are small due to marginal oil and Gas production	**International best practice for the disposal of waste and of water produced by drilling activities introduced** **Achieved,** although limited impact due to marginal volumes of oil produced **Higher transparency standards in the industry in Tunisia set** **Achieved**, although wider impact doubtful due to marginal activities of this company
	Risks to Achievement of Outputs:	**Risks to Achievement of Outcomes:**	**Risks to Achievement of Impacts:**
	Difficulties and delays in the physical execution of the project Non-cooperation of ETAP in Sabria development Oil and gas price risk	Expiration of licenses prior to the full achievement of operational objectives due to delays Oil and gas price risk Production stoppage due to political and social volatility	Risks associated to reserves estimation Drilling works not internalized due to failure in securing of dedicated drilling and service rigs

PKN Orlen Energy Efficiency and Environmental Project - Results Framework

Assumptions	Project Inputs:	Project Outputs:	Outcomes Short Term:	Outcomes Long Term	Intended Impacts:
Need to comply with EU Accession Treaty by 1.1.2016 Opportunity and need to improve energy efficiency and environmental performance of PKN Orlen Technical capacity at PKN to replace the boiler and install emission abetment equipment	€ 250 million EBRD loan (7 years)	1.Replacement of obsolete K1 boiler with energy efficient K8 at PKN's CHP (by mid 2012) **Achieved.** Completed in 2012	1. Increased electricity generation capacity at CHP by 20% or 70 MW (from 345 to 415 MW) **Not achieved**, unchanged (359 MW now) and increased heating capacity by 7% or 142 MW (from 2,024 MW) **Achieved,** increased by 16% (or 299 to 2153 MW) 2. Reduced carbon emission by 142k T CO2/year (16k directly & 126k low carbon exports to grid) **Partly achieved**, reduced by 48k T directly (2019 compared to pre-project) no indirect reduction (no export) 3. Reduced energy intensity of PKN No data 4. Contribution to reduced Fuel Loss/Own Consumption rate (base 12%) – **Achieved.** 11% (new installations, inc. de-dusting, require more fuel)	1. Increased electricity sales to the grid by 30% (from 550 GWh to 788) **Not achieved**, no sales. For own use only 2. Early compliance with EU's IED (and Accession Treaty) – boiler by mid 2012 - installations by 2015 **Achieved** 3. PKN in top 15% of most carbon efficient plants in the sector among EU ETS, **Not achieved** as peers improved as well (but many measures taken to reduce GHG)	1.Improved competitiveness of PKN (and improved financial performance – revenue from electricity sales) **Partly achieved**. Improved revenues but no income from electricity sales. 2.Contribution to reduced energy intensity of Polish economy. **Not achieved.** No evidence of such contribution. 3. If PKN within 10% of EU ETS benchmark, emission allowance for free (currently 20% above) **Not achieved**. In 2016 PLN130 m spent on carbon permits

Assumptions	Project Inputs:	Project Outputs:	Outcomes Short Term:	Outcomes Long Term	Intended Impacts:
		2. Installation on 7 boilers of: -flue gas desulphurisation (FGD) -electrostatic precipitants -catalytic denitrogenating of exhaust emissions **Achieved** in 2015 (one in 2016)	5. Reduction of sulphur emission SOx by 80% (to below 100mg/Nm3 and later 50mg) **Achieved (first target)**. Reduced by 97% (61 mg/Nm3) 6.Reduction of dust emission by 90% to below 10 mg/Nm3 **Achieved**. Reduced by 84% to 6 mg/Nm3 7. Reduction of NOx emission by 60% to below 100 mg/Nm3 **Not achieved.** Reduced by 80% (to 118 mg/Nm3) – wrong base/overambitious (all comparing 2009 with 2019)	4. Demonstration of BAT adaptation **Achieved.** Current emission about 3x below those permitted by IED however demonstration effect unknown.	4. Cleaner air in Plock. **Achieved**. Some evidence (from internet) that ambient air quality improved 5. Less respiratory and other disease in Plock/Poland no data
Need for PKN's balance sheet restructuring/debt refinancing	€2.75 billion parallel commercial loan (5 years)	3. refinancing of PKN debt **Achieved**	8. Improved financial performance of PKN **Achieved.** Financial performance (revenues and EBITDA) growing to 2019, decline in 2020.		6. Poland's oil refining market share in CEE to increase from 4.8% in 2010 to 5.3% in 2015 **Achieved.** In 2019 14.6% in CEE (incl. Austria & Germany) based on capacity (4.2% in EU)

Assumptions	Project Inputs:	Project Outputs:	Outcomes Short Term:	Outcomes Long Term	Intended Impacts:
	Undefined client's input (part of ESAP)	4. Implementation of ISO 50001/EN16001 energy management system and its integration with carbon management system **Partly achieved** – energy system ISO 30001 certified but carbon management system not developed (not integrated with energy)	9. ISO certified integrated carbon and energy management system (with continuous energy use and emissions monitoring) > annual disclosure of performance >targets for Plock refinery >targets for PKN Group **Not achieved**. Carbon management system not developed	5. Demonstration and replication of system integration by other refineries in CEE **Not achieved**, no integration at PKN	7. Enhanced reputation of PKN as innovative and environmentally-friendly No data, but if so, no impact from the project
		Risks to Achievement of Outputs:	**Risks to Achievement of ST Outcomes:**	**Risks to Achievement of LT Outcomes:**	**Risks to Achievement of Impacts:**
		Technical risks related to boiler's and emissions abatement equipment's installation ISO certification and system integration seen as low priority, delayed or not implemented	-Risks related to boiler and emissions abatement equipment operation -Risks of insufficient resources dedicated to system integration and operation	- insufficient capacity of CHP to generate surplus for export. Unwillingness or insufficient capacity of grid to receive exports of electricity Insufficient performance (or better performance by other plants) for PKN to qualify to top 15% of EU ETS refineries	Risks related to macro-economic situation in Poland/EU Improved performance of competing refineries

MOL/Slovnaft Energy Efficiency Project - Results Framework

Assumptions	Project Inputs:	Project Outputs:	Outcomes Short Term:	Outcomes Long Term	Intended Impacts:
Need to comply with EU IED directive by 1.1.2016 Opportunity and need to improve energy efficiency and environmental performance of SLOVNAFT Technical capacity at SLOVNAFT to replace the steam cracker and install LDPE unit	€ 120 million EBRD loan (18.5 years) All disbursed €183 million of MOL's own sources Provided	1. Refurbishment of old steam cracker (€43 m) one year in advance of EU deadline (i.e. by 1.1.2015) **Partly achieved**, refurbishment finished (burners replaced) only in 12.2019 - 5 years later than planned (according to info EvD received from Slovnaft) However, some earlier reports claimed it was refurbished by end of 2016, i.e. two year later than planned – this was likely partial refurbishment	1.Increased furnace capacity by 25% and steam production by 40% **Not achieved**, capacity not increased 2.Reduced CO^2 emission by 17% **Not achieved**. CO2 emission increased by 40% compared with pre-project (but 12% reduction between 2018 and 2019). 3. Reduced energy consumption by 14% (> 4.5 mJ/kg product) **Not achieved**, reduced by 4% (by 1.36 mJ/kg) 4. Reduced externally fired fuel by 30% **Partly achieved** Reduced by 23% 5. Reduced water use **Achieved.** reduced by 12% (23%) 6. Reduced NOx emission 60% from 200 mg/Nm3 to 120mg/Nm3 **Not achieved**. NOx emission increased 48% to 351 mg/Nm3 (but reduction 7% 2018 and 2019)	1. Increased production and sales of petrochemicals **Achieved.** Both increased about 25% compared with pre-project levels (although not due to steam cracker's capacity increase) 2. Early compliance with EU's IED (and Accession Treaty) by 1.1. 2015 **Not achieved** - low emission burner installed only 12.19 – 5 years later than planned (or 2 years later according to earlier reports) 3. SLOVNAFT in top 10% of most carbon efficient petrochemical plants among EU ETS (phase 3 carbon intensity benchmark of 0.702 T CO2 T per product) **Not achieved** –reduced from 1.2 to 1.18 tCo2/t (1.6%)	1.Improved competitiveness of SLOVNAFT (and improved financial performance) **Achieved** – significant quality improvement of LDPE products 2.Contribution to reduced energy intensity of Slovak economy **Not achieved**. Slovakia registered the second largest decrease (-3.8%) in energy intensity index among EU countries between 2005-2017, industry being the largest contributor to this decrease (EEA). However project did not contribute to it (reduction of energy consumption target not achieved) 3. Free CO2 emission allowance (surplus emission integrated with MOL's overall CO2 emission management) **Not achieved.** €18 m paid in 2019 for CO2 permits

Assumptions	Project Inputs:	Project Outputs:	Outcomes Short Term:	Outcomes Long Term	Intended Impacts:
		2. Installation of a new LDPE unit and decommissioning of 3 old units (€260 m) **Achieved**. New LDPE unit installed (2 units decommissioned, 1 still working 2 month/year to utilise excess ethylene)	7. Reduced CO2 emission by 13% (combined effect 30% reduction to 0.695 TCO2/T of product, annual reduction by 80,000 T) **Not achieved** – reduced to 1.18 tCO2/t of product (1.6%). Refinery level reduction by 3% 97 t in 5y) 8. Reduced energy consumption by LDPE to less than 3.2 GJ/t prod **Not achieved**. Reduced from 10.49 to 4.75 GJ/t or 55% 9. Reduced raw materials input by 5%. No data	4. Demonstration of exceeded BAT standards: -Direct Energy <2.8 GJ/T pro -Primary Energy<3.2 GJ/T prod. **Not achieved** 4.75 GJ/t now (but according to earler reports all 10% less than "guaranteed values") Water consumption <1.8 m3/T product **Achieved** - 1.66 m3/ t PE for the year 2018 5. Diversification of petrochemical product portfolio and meeting automotive industry's demand (150k tubular unit base projected to grow to 350k in 2020) **Not achieved**. Grew to 220k units in 2019 (2020 growth unlikely)	4. Cleaner air in Bratislava **Not achieved**. No impact (marginal decrease of CO, no change in NOx emissions) 5. Less respiratory and other disease in Bratislava/Slovakia No data, impact unlikely 6. Increased CEE market share for LDPE products (base 20%) **Achieved**, but in fact base 11%, now increased to 13% 7. Captured new markets (export to Germany projected at 14% and Austria/Czech Rp 7% of total) **Partly achieved**. No new markets captured but combined share of exports to these 3 countries is now 37% of total LDPE production

Assumptions	Project Inputs:	Project Outputs:	Outcomes Short Term:	Outcomes Long Term	Intended Impacts:
	Undefined client's input	4. Implementation of externally certified integrated energy and carbon management system **Not achieved**. 2 management systems but not integrated or certified.	11. certified integrated carbon and energy management system (with continuous energy use and emissions monitoring > annual performance disclosure >targets for Bratislava refinery >targets for SLOVNAFT Group **Not achieved**	6. Improved operational efficiency and environmental performance **Partly achieved**. Marginal improvements as per above 7. Demonstration and replication by other refineries in CEE **Not achieved**	7. Enhanced reputation of SLOVNAFT as innovative and environmentally-friendly **Not achieved**. No evidence of this.
		Risks to Achievement of Outputs:	**Risks to Achievement of ST Outcomes:**	**Risks to Achievement of LT Outcomes:**	**Risks to Achievement of Impacts:**
		-Technical risks related to cracker's and LDPE unit's installation -Reluctance to decommission old crackers -Certification and system integration seen as low priority, delayed or not implemented	-Risks related to Cracker's and LDPE unit's operation -Risks of insufficient resources dedicated to system integration and operation	- Insufficient capacity of the cracker to generate surplus. - Insufficient demand for LDPE products -Insufficient performance (or better performance by other plants) for SLOVNAFT to qualify to top 15% of EU ETS refineries	Risks related to macro-economic situation in Slovakia /EU Improved performance of competing refineries

Ukraine: Galnaftogaz Loan III (45462) - Results Framework

Assumptions	Inputs	Outputs	Outcomes	Intended Impacts
Demand for high-quality fuels is sustained, and the current trend continues A significant drop in income per capita in Ukraine led to a drop in demand for high quality fuel. Customers in existing stations in the area prefer higher levels of service offerings regardless of cost variation EBRD/IFC's debt exposure (A loans) to the Company remains below 9% of GNG's total debt + equity.	USD180m corporate loan package in partnership with IFC: - USD12.8m A loan for EBRD - USD15m A loan for IFC - USD140m B loan (syndicated by IFC and EBRD) - USD 40 m GNG cash flow GNG contributed 25mln from its cash flow There were ~1000 (?) consultancy contracts	1.1 Construction of 64 new high-volume gas stations (majority in under-served areas $105m planned) **Achieved** # of fuel stations (FS) owned by GNG/*leased & operated by GNG* Board approval: Oct 2013: 368/*360* Loan signed: Nov 2013: 395/*366* PMM reported: Dec 2018: 402/*382* Info from client: July 2020: 415/*406* i.e. 47/*46* - 93 added (half constructed, half leased) FS were built in Kharkiv, Chernivtsi, Kherson, Odesa regions and in Kyiv city. Also in Ivano-Frankivsk, Lviv, Volyn regions. 1.2 Storage terminal near Yuzhniy port ($11m planned) **Not achieved** Yuzhny oil terminal was first included but later excluded from this project by the client, as part of the loan was cancelled.	1. Increase in the share of high quality fuel stations **Partially Achieved** -from 23% to 25% in South (mainly Crimea) Mid 2016: Share of high quality fuel stations increased from 23% to 27% in the South. Q3 2020: still 27% the current percentage in the South - from 12% to 13% in North-East Mid 2017: the share of high quality fuel stations remained unchanged at 12% in North-East due to war conflict. Q3 2020: the current percentage in the South region and in the North–East region combined is approximately 30-40% in total. A significant drop in income per capita in Ukraine led to a drop in demand for high quality fuel. No further progress is therefore expected so the benchmark is considered to be partially achieved.	1. GNG improved financial and operational performance: - Growth in revenues, profitability and cash flows (during implementation): **Not achieved** due to conflict in Ukraine. Financial performance decreased substantially during the implementation period (see below) but it improved in recent years. - GNG revenues to increase by 35% in 2015 compared to 2013 **Not achieved**, revenues decreased 50% (from $1.8 bil to $0.9 bil) during this period. But increase to $1.5 bil in 2019 - EBITDA grows by 37% **Not achieved**. EBITDA decreased 33% (from $129 m to $86 m in 2015) However it improved to $143 m in 2019

Assumptions	Inputs	Outputs	Outcomes	Intended Impacts
		2. development and improvement of infrastructure for tank storage and LPG modules at fuel stations ($ 15m) **Partly Achieved** $8.6 m spent (at 2013 exchange rate), as follows: 4Q2013-2015: Spent ~UAH 28.8 mln on tank storage improvements. Works were done in all TS: Brody, Vinnytsya, Halych, Hrebinky, Lviv, Rivne, Stryy, Uzhhorod, Chernyakhiv, Yarmolyntsi). Mostly made capital repairs of buildings, tanks park, pumps, fire safety. 4Q2013-2015: spent 42.4 mln on installation of 24 LPG-modules at FS 3.expansion of the network of convenience stores/restaurants ($10m) **Achieved** 4Q2013-2015: 25 stores + 2 restaurants opened 4. refurbishment of FSs with upgrades related to monitoring and control ($29m)	2. Improved tank storage **Achieved** Implemented improvements in all 10 fuel depots in operation. 3. Improved customers' experience (restaurants and cafes) **Considered achieved** based on the addition of 25 new stores 4. Improved FSs safety **Achieved** Client states that cameras at FS deter potential thieves. They also help solve different conflict situations with clients and between workers and to control operational processes.	

Assumptions	Inputs	Outputs	Outcomes	Intended Impacts
		Partially Achieved $13.4 m spent (based on 2013 exchange rate), as follows: UAH 8.5 mln on Digital Video Control System UAH 84.6 mln on Hardware IT infrastructure during 4Q2013-2015. UAH 17.2 mln on cameras installation on all GFS network. 5. conversion of ST WC loans ($50m) into a long term loan **Achieved.** The short-term working capital was converted into a long-term loan. 2013-2015 interest of STL was about 7-10% for USD tranches and 15-25% for UAH tranches. About 6% was received from EBRD/IFC at the same time.	5. Decreased financing costs of GNG **Achieved** Interest expenses decreased from $31 m in 2013 to $25 in 2016	

	TC: - Input by GNG - Input by the Bank's Road Safety Framework	6. GHG Reduction Programme prepared (specifications for storage facilities upgrades **Achieved** Mott McDonald was hired and the report with recommendations was produced 7. Road Safety Management Plan prepared jointly by a consultant and GNG and implemented by GNG. (by end of 2014) **Achieved** The plan has been prepared and is being implemented by the client. 8. Development and delivery of a training package for GNG's drivers on safe and eco driving techniques. (by end of 2014) **Achieved** This has been developed, and trainings were held for drivers. 9. Case study on Road Safety Management in the private sector prepared jointly by GNG and the Bank and published on its website (by end of 2015)	6. Implementation of investments proposed by the consultants in GHG Reduction Programme - at least 4 tank storage locations. (by end of 2015) **Achieved** The consultant has been hired, the report with recommendations has been produced. We used recommendation of Mott McDonald during last upgrading of our TSs. The client claims that recommendations were actioned and investments made in at least 10 locations. Following the delivery of the report, the client has reported that recommendations were actioned and investments made in at least 10 locations. The benchmark is therefore considered to have been achieved. 7. Policy related to road traffic safety established, roles assigned, reporting on road safety established, actions to reduce accidents introduced **Considered not achieved.** No clear information was received on this 8. A number of GNG employees trained	2. Reduced vapour loss, higher efficiency of pumps and waste water treatment (reduced GHG emissions, compering pre/post project) **Achieved** Vapor losses were reduced by 30-40%. Increase efficiency of pumps by 10-20%. 3. number of fatalities, injuries and accidents reduced (comparing pre and post project) **Considered achieved** The number of road accidents in Ukraine has been decreasing every year however attribution is difficult. There have been a large number of programs and infrastructure improvements. It is likely GNG's programme made some contribution to it. 4. Reduction of accidents/incidents caused by GNG drivers (pre/post project) **Considered not achieved**. No data received.

		Achieved The case study has been prepared. 10.Adoption by GNG of a Corporate Social Responsibility programme on road safety and participation of GNG in the national awareness campaign 'Safe Villages' (by end of 2014) **Achieved** CRS Programme has been adopted **Considered not achieved** No evidence of participation in EBRD's "Safe Villages" campaign.	**Achieved**. ~300 drivers have participated in driving safety and fuel economy courses 9. Case study published **Considered not achieved**, no evidence of such publication provided. The team reports that a case study on Road Safety Management in the private sector has been prepared, although it does not appear on the OKKO's website. The news section of the website does however feature an article on the Road Safety Day at "OKKO" network. GNG has adopting a Corporate Social Responsibility programme on road safety, although with significant delay. 10. GNG participating in the Bank's programme **Considered not achieved**, no evidence for it.	5 and 6. Reduction in road accidents, including pedestrians (pre/post project) **Considered achieved.** The number of road accidents in Ukraine has been decreasing every year however attribution is difficult. There have been a large number of programs and infrastructure improvements. It is likely GNG's programme made some contribution

Assumptions	Inputs	Outputs	Outcomes	Intended Impacts
		Risks to Achievement of Outputs:	**Risks to Achievement of Outcomes:**	**Risks to Achievement of Impacts:**
		Outputs are not considered a priority within GNG and are not produced to high quality or are delivered with delays.	FX Risk: The Company's earnings are Hryvna denominated while its core borrowings are in USD. This could undermine its overall ability to service debt obligations and dent profitability. Supply risk: All distributors of high octane/low sulphur fuel in Ukraine rely on imports.	Operational Risk: Speed and extent of competitive response to emulate the standards being set by Galnaftogaz, which depends notably on the growth in new car purchase and in wages, which are expected to influence positively the demand for high quality fuel versus low quality fuels. Regulatory Risk: - Government actions negatively impact the economics of the sector. - Refineries lobby for import duties that negatively affect the bulk of independent retailers - Strong "recommendations" on maximum retail prices promulgated by the Ministry of Fuel and Coal with the underlying threat that they become mandatory

ANNEX 4 – SOUTHERN GAS CORRIDOR (TANAP)

EXCERPTS FROM THE EVALUATION COMPLETED AS PART OF

“REGINAL INTEGRATION REVIEW” SS19-136, MARCH 2020, updated in DECEMBER 2020

Southern Gas Corridor (TANAP) – a gas pipeline project in Azerbaijan and Turkey, OpId 48376

Background

In 2017 the Bank joined the financing of the Trans-Anatolian Pipeline (TANAP), which was to become an important part of the Southern Gas Corridor (SGC) – a cross-regional mega-project for the total value of US$40 billion, designed to bring Azeri gas to Europe for the first time. The Bank provided a US$0.5 billion sovereign-guaranteed loan to SGC joint stock company, owned by the Republic of Azerbaijan and SOCAR (Azeri state oil company). The loan’s proceeds were to be used as part of or a US$5.4 billion commitment of SGC to the TANAP project, which the main part was the pipeline stretching for a 1,850 km from the Georgian-Turkish border to the Turkish-Greek border. The other institutions co-financing this commitment were the World Bank, AIIB, MIGA, SOFAZ (Azeri state fund) and UFK (Republic of Germany’s guarantee agency).

TANAP is a vital part of the SGC group of projects, which includes the development of the Shah Deniz 2 gas field, the South Caucasus Pipeline (SCP and its expansion - a pipeline leading through Azerbaijan and Georgia) and the Trans-Adriatic Pipeline (TAP – crossing Greece, Albania and the Adriatic sea to Brindisi in Italy, completed in November 2020), with a total pipeline length of 3,500 km.

The SGC project has been designated by the EU as a key priority for its energy security - a “Project of Common Interest”. The pipeline was to enable transportation of 16 bcm/y of natural gas per year from the Shah Deniz 2 field, of which 6 bcm/y would go to Turkey and 10 bcm/y to Europe. An important technical feature of TANAP was to be its ability to expand, i.e. to enable the doubling of its capacity in the future by adding compressor stations (subject to relatively small additional investments).

The transition impact of the project was to be realised though resilient and regional integrating qualities. The former was to materialise through the introduction of a regulatory law in Azerbaijan, in line with the EU’s Third Energy Package to support the establishment of an independent energy regulator, as well as through the implementation of the Compliance Action plan at the SGC company (Risk Management, Compliance Officer, ethical conduct). Finally, the government was to implement the recommendations of the Council of European Energy Regulators (CEER) developed under the TC.

In terms of integration, natural gas was to become available to Europe and Turkish regions (10 bcm/y and 5.7 bcm/y respectively by 2021), and third party access was to be introduced in line with best regulatory practices on expansion of capacity, to account for 20% of such an expanded capacity. Interestingly, although the entire investment under this project was in Turkey, the project was not classified as Turkish or Regional but Azeri (based on the borrower’s domiciliation, sovereign guarantee and transition impacting mainly Azerbaijan).

Relevance

The project’s regional integration focus was in line with the Bank’s Country Strategy for Azerbaijan (BDS/AZ/13-1(F)), which called for *“enhanced regional trade via the diversification of hydrocarbons export routes and which favour regional integration of energy infrastructure”.* The Bank was to support projects, which *“promote energy security and integration*”, specifically *“investments alongside SGC”.* The project was also in line with the Bank’s

Green Economy Transition (BDS15-196) approach as it promotes the transition to low-carbon energy, as well as with Energy Sector Strategy (BDS13-291 and its update CS/FO16-07). The latter document put the emphasis on improving energy security by diversifying routes and promoting integration.

Azerbaijan's new "Strategic Road Map" for the energy sector is still under development. However, other strategic documents, e.g. "Azerbaijan – Sustainable Development of Energy – Gaps in Energy Efficiency and Ways to Eliminate Them" (2019), make explicit reference to regional integration and the project in particular. The latter document states that "*The basis for development will be integration into global and regional value chains".* It then specifically points to TANAP as a vital part of this integration approach, which is expect to be fully realised after 2020 when TAP is completed.

The European Commission's 2014 Energy Security Strategy referred to this project as critically important to the diversification of Europe's gas supply and thus its energy security. Seventeen percent of EU's energy mix comes from gas but this is to grow to about a quarter. Europe's own natural gas resources cover about 50% of its needs but will reduce to 35% by 2025. Many countries rely on gas imports from only one supplier. Thus the SGC is of vital importance for the diversification of EU supply.

In terms of additionality, the Bank was one of several IFIs financing the project. The total amount of funding required the participation of major IFIs active in the region. An 18-year maturity (critical to enable project finance-style repayment) was not available in Azerbaijan, while other IFIs were already at the limit of exposure to TANAP.

Finally, the project was a natural continuation of four earlier projects already financed by the Bank (SCP, Shah Deniz I, II and the latter's extension), which supported the development of the gas fields feeding into the SGC and its Azeri-Georgian section, therefore it complemented the Bank's prior engagement in the sector well.

Due to its high degree of compatibility with the Bank's strategic objectives, as well as those of EU and Azerbaijan, the relevance of this project is rated ***excellent***.

Results

The loan was entirely disbursed and about 80% of its proceeds were applied retroactively to five previously signed construction contracts, as planned. The project was completed on time with substantial savings of almost a quarter of the budget (US$6.5 billion spent vs. US$8.6 billion budgeted). For this reason, financing initially considered from the UFK and EIB was not taken. In June 2018 gas started to flow to Turkey (the Eskishehir station), while a year later (June 2019) the construction of the entire TANAP to the Greek border was completed. During the first year gas was delivered to Turkey as planned and in July 2019 the throughput was doubled (information on the exact amount of gas delivered is confidential). The target throughput of 5.7 bcm/y was achieved in July 2020. According to TANAP and SGC companies, all required infrastructure is in place to receive this amount of gas, as well as to accommodate additional gradual throughput of 10 bcm/y when TAP becomes operational in early 2021.

In 2016, as part of the preparations for financing TANAP, the Bank signed an MOU with the Azeri government on the establishment of an energy regulator. The AERA (the Azerbaijani Energy Regulatory Agency) was established by the President of Azerbaijan in 2017 and is now operational with 200 staff. Since then the Bank has led IFI efforts to support the development of a regulatory legal framework and build capacity at AERA. So far, several workshops have been organised with CEER (Council of European Energy Regulators) on specific topics of regulation, and a TC assignment was launched devoted to: i) drafting a regulatory law, largely in line with the EU acquis and ii) training AERA's staff. The latter is under implementation and so far there have been two engagements, with Azeri regulators trained by Dutch and Latvian colleagues.

The draft Law on the Regulator was prepared under the Bank's TC co-managed by LTT and EPG. By the end of 2019 the consultants produced a consolidated version integrating the comments received from the government, state agencies and market players. The law was to be officially submitted to the Cabinet of Ministers and Presidential Administration in 2020. However, understandably, addressing COVID-19 pandemic, the collapse of oil prices, as well as an emergency related to geopolitical events took precedence for the Azeri government's actions. The approval is now hoped for in 2021.

EvD notes that although the law was prepared largely in line with the EU's Third Energy Package, there are concerns whether the draft law would be timely approved by the government considering its ambitious alignment with the Package. Considering the lengthy consultation and approval process, as well as a Presidential decree which declares support for the new draft law, there is a reasonable chance that it will ultimately be approved.

The adoption of the draft law is highly important, as currently the regulator reports to the Ministry of Energy and is not independent. The new draft law changes this ensuring regulator's independence and accountability, including by the appointment of the regulator's Head by the President of the Republic and by guaranteeing the institution's financial stability. The Council of European Energy Regulators (CEER) has been working on the preparation of operational recommendations for AERA. It is not yet clear whether they will be implemented but cooperation is reportedly going well.

Another ongoing TC related to this project supports the Azeri authorities on the design and implementation of an auction for renewable energy projects. Auctions are the primary mechanism envisaged under the RES Law for supporting RES investments (the Bank did not participate in drafting this law but was consulted on the draft and provided substantial comments, most of which were adopted). This TC started in September 2019 and during 2020 the consultants has been progressing with design of the auctions and underlying contractual frameworks and documentation. The auctions are planned to be launched in 2021. The outcome of the TC is seen as relevant for the TANAP project because if RES are to play a more prominent role in the Azeri energy generation mix, more gas will be available for export.

SGC company confirmed the implementation of corporate governance improvements (risk management, compliance officer and ethical conduct code), which were conditions precedent to loan effectiveness the Bank's loan. Moreover, the SGC company signed an information sharing agreement with the newly established Azerbaijan Commission on Transparency in Extractive Industries to provide reports as required by this commission. As to third party access (final 2 TI benchmarks), it will be possible to verify their achievement only if and when TANAP and TAP are expanded (for now all their capacity has been booked for 25 years and access of a third party would not be technically possible). According to all stakeholders the expansion is highly likely to take place (see the regional integration section below). Although, as stated in the Board report "TANAP's expansion is dependent on the availability of additional gas beyond the currently committed 16 bcm/y of gas produced by Shah Deniz 2, which might come from Azerbaijan and/or from other suppliers around the Caspian sea", SGC confirmed that proven reserves of gas in Shah Deniz 2 field are above 1.3 trillion cm, while a demand test conducted by TAP (see below) confirmed high additional demand for Azeri gas. Therefore the probability of the TANAP extension materialising is seen as high. If this happens, third party access will be granted in accordance with EU regulations but applicable only to the expanded part (TAP obtained an exception from EU third party access regulations for its initial 10 bcm/y capacity). However, EvD notes that in response to DAQs, Banking stated that a *"set of third party access rules should be developed and adopted before the expansion decision for TANAP is made. Adopting these rules, would have wider applicability than the specifics of this project"*. Although so far, there is no evidence of the Bank working towards "wider application" of third party rules in Turkey or Azerbaijan, the TI benchmark for it is only 2026. Therefore one could argue that it would have been premature working on it now.

Beyond TI benchmarks, the construction of TANAP made a positive contribution to the Anatolian economy. 13,000 people were employed during construction and the company implemented a comprehensive Social and Environmental Investment Programme (SEIP) along the pipeline's route, with a budget of US$84 million, encompassing over a thousand diverse projects. Key achievements of this programme included the provision of clean drinking water to 91 villages, irrigation systems for 23 villages, equipping of ambulances for 33 hospitals, training of almost two thousand teachers and provision of a programme for children with autism. Some other villages were provided with waste disposal equipment or solar energy generators. Disadvantaged groups and women were prioritised. In terms of land acquisition, out of 21 thousand parcels, 55% were purchased through amicable settlements, while the remainder of the owners asked for higher compensation and acquisitions were settled through court suits. The pipes have been buried underground (or under water) throughout the whole length of TANAP and are not seen as a major risk for the environment. Part of the EBRD's added value to the project (highly valued by other IFIs) has been the commissioning of an integrated environmental and social monitoring team.

The physical implementation of this project was successful, even exemplary. However, there are still uncertainties related to most TI benchmarks, partly because these related to Integrated quality are due only in 2021 – one and 2026-two (the regulator is not yet independent, the law is not yet approved and is unlikely to be fully in line with the EU's Third Energy Package, while the achievement of some other benchmarks will be possible only if TANAP expands). All of these are likely to happen in the future. With some caveats (and taking into account the early stage and likelihood of future developments), the results of this project are rated ***fully satisfactory***.

Efficiency

Actual Cash Flow Available for Debt Service (CFADS – the key financial performance indicator presented in the Board report) has been consistently less negative during 2017-2019 than projected for this period. This was due to the lower capex. 2020 is the first year that TANAP's CFADS is expected to turn positive – as only then TANAP planned to achieve full capacity of its pipeline for delivery to Turkey. This capacity was achieved and currently (end of 2020) the project team awaits Q4 2020 report. However, H1 2020 report indicates that CFADS was positive. However due to limited data so far, this category ***is not rated***.

Status of associated projects

In total, the Bank's financing of Azeri gas field developments and different parts of the SGC amounts to US$2.38 billion. During 2005-2015, the Bank provided five loans to develop the Shah Deniz 1 and 2 gas fields (US$810 million in aggregate) through financing of Lukoil, one of the field's shareholders. All projects were implemented and contributed to the availability of gas for TANAP and TAP. In 2005 the Bank also provided US$70 million loan to Lukoil for South Caucasus Gas Pipeline (through Azerbaijan and Georgia), which enabled TANAP and TAP. Most of Lukoil loans have now been repaid.

In 2018 the Bank provided EUR$1 billion (half syndicated) for the **Trans-Adriatic Pipeline (TAP)**. The loan co-financed funding from a number of IFIs to construct a 878 km pipeline linking TANAP's westernmost end at the Turkish-Greek border, through Greece, Albania and under the Adriatic Sea to Brindisi in Italy, to connect with the Italian (and European) gas network. TAP was completed in November 2020 and it is expected that the first gas will flow through it at the beginning of 2021. After a rump up period, TAP will carry 10 bcm/y.

Out of the Bank's COOs, Greece booked 1 bcm/y and Bulgaria 0.94 bcm/y. The rest of TAP's capacity was booked by energy majors from France, UK, Germany, Italy, and Switzerland. However TAP will have a physical "reverse flow feature", so theoretically companies from these seven countries could sell part of its gas to other countries, benefiting some other COOs. However, the full impact of TAP will only be realised if and when it is expanded. Both TANAP and TAP are designed to expand relatively easily but will require major investments, although at a lower level than the current projects (very early estimates of investments required to expand TANAP are about US$ 1 billion and the time to complete them four years). Demand tests conducted by TAP confirmed eight additional parties interested in purchasing gas (confidentiality prevents it from disclosing from which countries). However, it is likely that countries such as Albania (TAP features two exit points in this country) and North Macedonia indicated their interest in receiving Azeri gas. Moreover TAP is setting the foundation for a northward Ionian-Adriatic Pipeline (IAP) through Montenegro, Bosnia and Croatia (total 5 bcm/y envisaged), which is planned as the gateway for Azeri/Caspian gas to the Western Balkans. TAP is seen as a backbone of the West Balkan Ring, a multi-project initiative aimed at creating a regional gas market.

The TAP project's TI is centred on closer integration of the Albanian gas system with that of EU. The Bank contributed to the Gas Master Plan (prepared under the EU-financed WBIF project), which developed a strategy for a sustainable and interconnected gas system in Albania. The EBRD's TC supports the development of and capacity building of the legal and regulatory functions of Albgaz, the newly established transmission and distribution company. Albgaz is to play a critical role in the maintenance of TAP but also in the future gasification of Albania. Consultants started work in mid-2018 and, according to Banking, their work is on track. TAP also provided €6.7 million investment support for a project to develop of gas connectivity.

ANNEX 5 – LINKAGES BETWEEN HYDROCARBON SECTOR AND COUNTRY STRATEGIES

This annex analyses linkages between country strategies related to six cluster projects countries (Egypt, Greece, Tunisia, Slovakia, Poland), as well as four other countries (Romania, Azerbaijan, Kazakhstan and Mongolia), which are prime hydrocarbons-producing countries and where the Bank conducted activities in this sector.

Egypt - there was no Strategy for Egypt at the time the PICO Oil and Gas (44491) project was approved in 2014. Following a diagnostic paper the first strategy was approved in 2016.
Private Sector Diagnostic: Egypt (2016) - One of the key challenges identified related to the lack of adequate market-based incentives, which held back investments, including in oil and gas Challenges related to hydrocarbons were as follows:

- The lack of full access by the private sector to hydrocarbon import and transmission infrastructure. Low tariffs, which don't reflect the real and opportunity costs; legal restrictions on the import and supply of oil and gas outside of state-owned enterprises.
- Uncertainty as to the planned oil and electricity subsidy and power market reforms. For oil products, the environment of low oil prices presented a window of opportunity to press ahead with reforms, with a credible timeline for the private sector to work with.
- Relatively weak contract sanctity in upstream oil and gas. Continuing payment arrears to oil and gas producers, constraints on currency convertibility, and some ongoing disputes regarding the redirection of exports to the domestic market.

The diagnostics highlighted opportunities for the private sector. However, it stressed the need for a predictable and attractive investment climate, which among other benefits would support a better use of the country's oil and gas resource base.

Strategy for Egypt (2016) - the transition challenges in the power/hydrocarbon sector included a fully state-owned gas transmission sector , with private sector involvement limited to gas distribution, fuel subsidies contributing to road congestion and an undiversified power generation base with limited capacity, rapid growth in power demand and gas supply shortages, which have given rise to supply concerns. More recently, the prioritisation of using gas for power generation has forced industries to use coal and pet coke, escalating the carbon intensity of the economy. Gaps remain in regulation and its implementation. The strategy proposed four strategic orientations to guide the EBRD's engagement in Egypt. Two of them referred to hydrocarbons:
Priority 1: Support Egypt's Private Sector Competitiveness. The operational focus is to support the agribusiness and manufacturing natural resources sectors. The Bank will promote backward and forward integration by providing finance to domestic anchor investors (including oil producers in remote areas). *Priority 2: Improve Quality and Sustainability of Egypt's Public Utilities,* including, promote gas market reforms. In terms of Operational Focus in the state-dominated oil and gas sector, the Bank was to selectively finance projects in the midstream oil and gas subsector, including state-owned.

Greece - the first project, Energean Oil (47822) was approved in 2016 before the 2016 Greek strategy was finalised. Energean II (48358) was also approved in 2016. The team made reference to the **Country Assessment (BDS14-358/F) for Greece**, which promoted the improvement of energy efficiency as a key priority for the Bank in Greece. It also called for the improvement of competitiveness and energy security. The project's Board document explained that the energy sector in Greece lagged behind European standards in terms of competition and innovation. The introduction of new technology such as the Epsilon platform, together with state-of-the-art pollution prevention systems and modern metering would contribute to addressing this challenge.

Strategy for Greece (2016) - none of three priority pillars made specific reference to hydrocarbons. Priority 3 envisaged *Support for private sector participation and commercialisation in the energy and infrastructure sectors to enhance regional integration and improve quality of utility services.* It was very general but could be seen as providing some justification for the cluster project. The Operational Focus of Priority 3 states that the Bank will support transport, logistics and energy infrastructure enhancing Greece's integration with regional markets, including gas and power interconnections. In support of recent progress on gas market liberalisation, the Bank will seek to finance private distributors. No upstream exploration of oil was mentioned.

Tunisia - project Serinus (44744) was approved in 2013, before the first CS for Tunisia was finalised at the end of 2018.

Tunisia Diagnostic Paper (2018) - the paper pointed to instability and dire security conditions, which led to contractions in tourism, oil and gas extraction, logistics, and mining. The dominant position of SOEs was stressed, some of which benefit from legal or de facto monopolies in certain sectors, including oil. For the past twenty years, energy and carbon intensity (CO2/TPES) has been slowly decreasing, largely attributed to a fuel-switch from oil to natural gas in energy production, but energy consumption has more than doubled between 1994 and 2015. Tunisia's reliance on imports has been increasing for both oil and gas, with the domestic gas production dropping, while concerns regarding the transit of Algerian gas to Italy have been growing.

Strategy for Tunisia (2018) - the key Transition Challenges were largely repeated from the diagnostic paper. One of four strategic priorities was related to GET and hydrocarbons. It envisaged increased renewable energy capacity, more diversified energy mix and greater private sector participation in the energy sector. To this effect, four activities were proposed. One of them was intended to provide finance for medium-scale oil and gas operators, with a focus on private sector operators and gas flaring reduction investments. The tracking indicator for this objective was total renewable electricity installed (MW). The second objective was increased energy, resource and water efficiency. One of the three activities proposed under this objective was to develop and finance supply-side resource efficiency solutions (e.g. upgrade of STEG existing power plants, high efficiency conventional gas-fired power generation, gas and electricity transport and distribution, transmission modernisation). The tracking indicators for this set of activities were energy and water savings.

Slovak Republic - MOL/Slovnaft (43869) was approved in 2012 under the 2009 CS.

Strategy for the Slovak Republic (2009) - there were no direct references to hydrocarbons in this CS. However, one of the strategic priorities referred to *investments in infrastructure, energy security and energy efficiency* (very broad but corresponding to some extent to the cluster project). Also, challenges related to natural resources (in the annex) included those concerning the gas sector, i.e. although a very small producer of natural gas, the country was an important transit corridor. Also, its per capita natural gas consumption was very high, with more than 80% of Slovak households connected to the natural gas network. Most of the coal produced was used for electricity production. The main domestic oil and gas operators have been corporatised and partially privatised. From 2009, the government has had greater control in setting gas prices for households and SMEs. The government was subject to infringement proceedings for failure to appropriately implement rules aimed at increasing the capacity and transparency of gas and electricity markets.

The Slovak Republic diagnostic paper (2017) - no direct references to hydrocarbons appear in the body of the paper, however annex 1 presents an overall assessment for each of the six transition qualities, which refer directly or indirectly to natural gas. Under *Integrated* poor energy security was stressed (96% of gas imported from Russia). Investments in renewable energy, as well as interconnections with Hungary (for electricity) and gas (with Poland) were required. The planned Eastring gas pipeline to Bulgaria and Romania was also highlighted as being on the government priorities agenda. Under *Green*, the paper stressed that energy and carbon intensity in the Slovak Republic still remains among the highest in the EU. The legal and institutional framework for supporting sustainable energy projects was not yet fully adequate.

Strategy for the Slovak Republic (2017) - no direct references to hydrocarbons are found in this document, however there were a number of indirect references, largely repeated from the diagnostic paper (referred to above).

<u>Poland</u> - project PKN Orlen (42609) was approved in 2011 under the 2010 CS.
Strategy for Poland (2010) - among the challenges identified were those related to Natural Resources and hydrocarbon sectors, such as delayed privatisation in the coal sector. In 2007 the government reversed sector unbundling by consolidating some state-owned coal mines and electricity generation/distribution and supply companies into four vertically integrated energy groups. The restructuring and privatisation of the mining sector remains a key challenge. In 2009, there was a successful IPO of Bogdanka coal mine. The State Treasury still hold shares in multiple natural resources companies (PGNiG, Lotos, OLPP, PKN Orlen, PERN). In theory the Polish gas market is now open and all customers can choose their supplier. In practice PGNiG dominates the upstream oil and gas segment, is the main importer and controls gas storage and distribution. State subsidies to the mining industry remain an issue of concern.

The operational priorities in energy and energy efficiency include support for privatisation in the energy, oil and coal sectors, as well as the promotion of gas market development, commercial gas storage and gas distribution development with a particular focus on growing competition in these areas.

Poland Diagnostic Paper (2017) - the report singles out five key constraints that are holding back private sector growth in Poland, including *diversifying the energy mix away from hydrocarbon sources and improving energy efficiency*. The paper elaborates on several aspects of this constraint:

- *Poland has energy intensity more than two times higher than the EU average, which is encouraged by large deposits of fossil fuel*. More than half of the total primary energy supply still comes from coal, followed by crude oil, and 80% of the energy production is from coal. Poland is the ninth largest producer of coal in the world.
- *There is considerable potential for efficiency in energy generation, distribution and demand*. From the supply side, significant efficiency could be gained through the reduction of coal-based technologies.
- *As a by-product of high energy and carbon intensity, Poland is among the most air polluted countries in the EU in terms of particulate matter*. About half of pollutants are generated by residential heating, largely caused by obsolete boilers and low-quality coal.
- *Lack of consistency and instability of regulations prevents Poland from capturing the opportunities in emerging industries linked to new energy sources.*

An annex presents an overall assessment for each of the transition qualities, including *Resilient*: The country reduced its dependence on natural gas from Russia, and more than two-thirds of the annual consumption can be sourced via LNG supplies or western or southern interconnectors; *Green*: high energy and carbon intensity (see above) Might be reinforced in the future given the pipeline of 14 new coal-fired power plants. *Well-governed*: The state control in mining and gas remains substantial. Governance of such companies could be weakened by politically-motivated interventions.

Strategy for Poland (2018) - key findings of the diagnostic paper were repeated. The CS set three priorities for the Bank, with Priority 2 (GET) having five objectives but neither they nor their activities make any direct references to hydrocarbons. They centred on energy efficiency, renewable energy and reduction of air pollution. Under one of the objectives for donor co-financing, the CS referred to the reduction of the country's dependence on coal.

<u>**Ukraine**</u> – Galnaftogaz III (45462) was approved in 2013 under the CS for Ukraine 2011.

Strategy for Ukraine 2011 - the CS noted that the country is a major net importer of oil and gas, and an important transit country. The energy sector suffered from years of serving primarily quasi-fiscal or political, rather than commercial, objectives. Improving governance and transparency in the sector, as well as commercialisation and unbundling of NAK Naftogaz (a state company responsible for extraction, refinement and transportation of oil and gas), would be needed to strengthen its ability to raise additional finance to modernise the gas transit system and develop Ukraine's natural resource base. The state-run coal sector remains inefficient, with many mines being financially unviable. Challenges to private investment into oil and gas extraction include price regulations as well as administrative obstacles.

The Bank's operational focus in the natural resources sector included: support of modernisation of the gas transit system and corporatisation and unbundling of the state owned NAK Naftogaz, and the possible provision of energy efficiency finance; support for greater local sourcing of oil and gas, reducing dependency on imports; further support of the private sector; and support of mining projects, leading to greater transparency, improvement of health and safety standards or energy efficiency.

Ukraine Diagnostic Paper 2018 - it noted that the energy market remains highly oligopolistic. Unbundling of gas storage and transmission activities has not advanced. Regulated gas tariffs are not maintained at import parity/cost recovery level. The challenges of the energy sector, in terms of supply security, included 100% of gas imported from the European competitive markets; outdated infrastructure; and a strong dependence on gas transit for government revenues (c. US$ 2.5 billion).

Under *Resilient*, Ukraine needs to improve the trading climate to attract more international companies to its gas market. Key reforms include the corporatisation and unbundling of Naftogaz, liberalisation of the retail and upstream sectors. To maintain cost reflective gas prices, tariff correction must continue on the basis of a permanent adjustment mechanism. *Integrated*: Ukraine has one of the most extensive gas transit and transmission systems in the world, one of the largest available gas storage capacities in Europe and many exit points with its western EU neighbours. The current Russian-Ukrainian gas transit contract expired at the end of 2019 and there is uncertainty with regards to its replacement.

Strategy for Ukraine (2018) - the transition challenges were largely repeated from the diagnostic paper. The CS presented five strategic priorities, with priority 3 aimed at strengthening energy security through effective regulation, market liberalisation, diversified and increased production, and energy efficiency, but no specific reference to hydrocarbons was made. Priority 5 was to improve integration by facilitating trade and investment, expanding infrastructure links, and supporting convergence with EU standards. This priority pointed to the existing highly developed gas transit connectivity infrastructure. It called for support to further energy connectivity by promoting convergence with ENTSO-E and ENTSO-G and financing cross-border interconnectors (linking with Priority 3).

<u>Romania</u> - Strategy for Romania (2020) - in terms of challenges, the importance of reducing dependence on coal (25% of electricity demand is met by coal-fired power plants) is stressed under *Green*. Investment and policy support is needed in regions with significant fossil fuel dependence. *Resilient* transition challenges include the instability of the legal and regulatory environment of the energy sector as Emergency Ordinance no 114/2018 radically changed the rules on the gas and electricity market overnight, undoing previous progress on market liberalisation.

The Strategic Priorities include*: Promote Investments in Sustainable Infrastructure and Regional Development*, one of the three key objectives is *Improved quality of sustainable infrastructure for effective/efficient economy interactions*. It specifies possible activities: (i) Invest in both electricity and gas transmission and distribution networks to increase efficiency; (ii) Finance power/gas interconnection projects; (iii) Support decarbonisation and transition from coal; and (iv) Policy engagement and investments to support off-shore gas-fields development and responsible and sustainable mining.

<u>Azerbaijan</u> - Strategy for Azerbaijan (2019) – it underscores Azerbaijan as one of the fastest growing economies globally due to an abundance of hydrocarbon resources. At the same time, rapid expansion of the oil and gas sector led to crowding out of other industries and to a low diversification of the economy. In 2018, the share of oil in total GDP was 39.8% and the resource sector was almost 92% of exports. A key transition challenge is the heavy reliance on the resource sector, which exposes the economy to volatility in global oil prices and impedes economic diversification. Civil Society points to considerable corruption and unsatisfactory transparency as a remaining challenge, mainly for the extractive sector and public procurement.

One of the strategic priorities for the Bank is*: Support for Green Economy Transition and Regional Connectivity,* including developing and financing supply-side resource efficiency investments (modernisation of gas-fired generation capacity, cleaner and more efficient technologies in the extractive value chain). Moreover, the Strategy notes that in 2017, the Board of the Extractive Industries Transparency Initiative (EITI) suspended Azerbaijan's membership. Subsequently, the Azerbaijani authorities decided to withdraw from it. In a resource-rich country like Azerbaijan, revenue reporting is vital in combating corruption. Azerbaijan has nevertheless pledged its continued commitment to the principles of international transparency and accountability in the extractive industries and has established the national Extractive Industries Commission.

<u>Kazakhstan</u> - Strategy for Kazakhstan (2017) - the Strategy notes the need to boost private sector competitiveness and generate balanced, sustainable growth that extends beyond Kazakhstan's hydrocarbon resources. Further steps are needed to reduce the state's still-outsized role in the economy and create a more competitive private sector, particularly in the non-extractive industries. Three strategic orientations are presented, two of them relate to hydrocarbons: *Balancing the roles of the state and the private sector*. State support and industrial policy have not led to large-scale private sector development outside of the extractive sectors. Key Transition challenges include: (i) Samruk–Kazyna (SK) - holding company for most SOEs and quasi-state-owned companies, which generate more than half of Kazakhstan's GDP, and retain a dominant position in several sectors including mining; and (ii) the hydrocarbon sector accounts for more than 30% of the country's GDP and more than half of its export revenues, and remains dominated by SOEs (~60% of assets in the oil sector are part of SK).

The Bank's Operational Response and Policy Dialogue regarding these gaps proposes providing financial support to independent private operators and promoting the privatisation of selected SOEs in the extractive sector, remaining active in supply chain development and continuing its role in subsoil legislation reform. The other priority is *Promoting green economy transition* to address challenges such as: (i) Kazakhstan being the largest emitter of greenhouse gases (GHG) in Central Asia; (ii) lack of market incentives to enable transition to a low-carbon economy in the power sector; (iii) air pollution caused by combustion of petroleum products or coal by motor vehicles and industry and power plants. The worst polluting industries include coal mining. Under its Operational Response the Bank aims to: (i) Prioritise the financing of resource efficiency and renewable energy projects, including natural gas projects (potential exists in mining and energy sectors). (ii) Support control methods throughout the extractive sector, working with mining and oil and gas companies along the whole value chain. (iii) Support the switch from coal and heavy fuel oil to natural gas. (iv) Development of pipeline connections to support regional gasification and energy security and integration into regional gas markets. (v) Support utilisation of associated petroleum gas to decrease GHG emission. (vi) improve the gender responsiveness of mining and energy projects.

<u>Mongolia</u> - Strategy for Mongolia (2017) - the Strategy highlights Mongolia's vast natural resources in the context of a still nascent private sector. All three Strategic Themes/Directions make reference to hydrocarbons to a greater or lesser extent:

Theme 1: advocates greater diversification of the economy/exports, away from minerals, including coal.

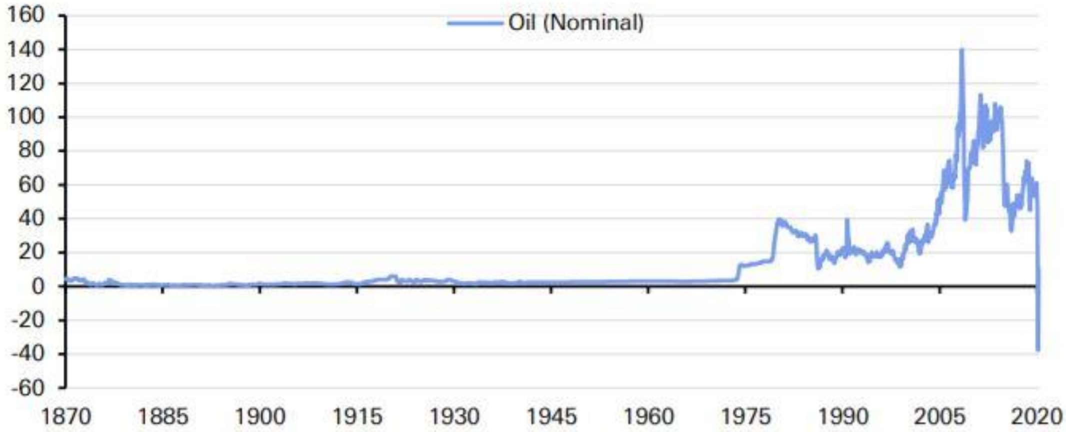
Theme 2: calls for leveraging a well-governed mining sector to enhance sustainability and maximise value creation. The development of large expansion and exploration projects is to be the key driver of economic growth. The effective implementation of mining sector projects can also provide opportunities to enhance competitiveness and value-added content of domestic industries linked to mining through supply chains. The Bank will continue to support responsible mining and will seek to deepen value-chain opportunities. Related transition challenges include: regulatory practices in the mining sector; natural resources domestic industries remain low on the value chain; linkages between the mining sector and local suppliers are underdeveloped; and regulation in the mining sector needs improvement. In response, the Bank plans to finance projects in the extractive sector (although no major increase in mining investments is envisaged in the medium term); Improve conditions in the natural resources sector, support EITI and improve existing mining legislation; Develop the upstream mining value chain; Support deeper processing of minerals with significant export potential; Establish the Geological Information System database and create a map of the country's mineral deposits; as well as promote women's participation in the mining sector.

Theme 3: calls for improving the quality and sustainability of infrastructure services through increased efficiency, commercialisation and "green" solutions. Modernising and further developing Mongolia's infrastructure is crucial to meeting growing demand from mining, facilitate mineral exports and support non-extractive sector development. Related transition challenges include: Modernisation of the power generation system to meet the growing power demands from mining; and strengthen capacity for carbon finance projects. The Bank's operational response to these gaps is to contribute to the development of state-of-the-art, green and least carbon-intensive energy solutions.

ANNEX 6 - PRICE OF OIL

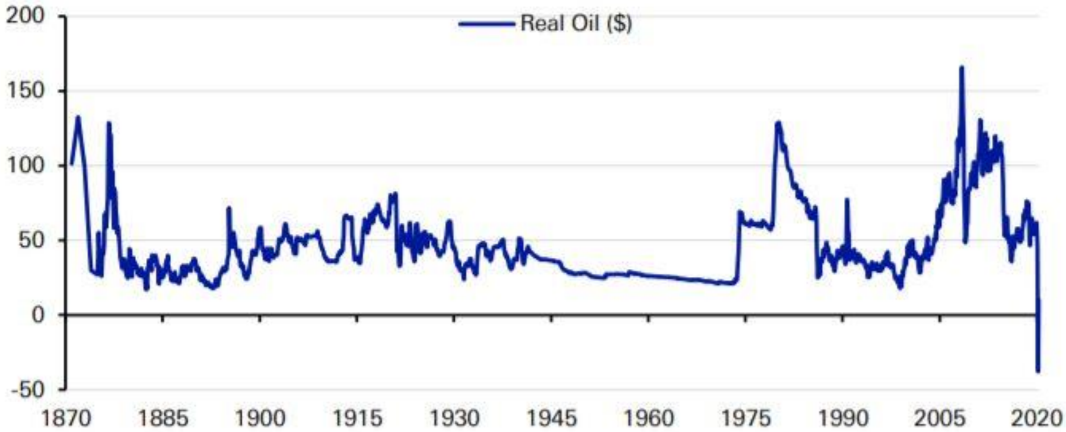
Historically, crude oil prices remained relatively stable until the early 1970s (see figures 1), although it was more volatile in real USD terms (see figure 2). Since then, political, economic, and other events have rocked the oil landscape. In 2020, the coronavirus pandemic sent prices plummeting.

Figure 1: The cost of a barrel of oil in nominal terms



Source : Deutsche Bank, Global Financial Data

Figure 2: The cost of a barrel of oil in real USD terms



Source :Deutsche Bank, Global Financial Data

The main factors impacting the price of oil have been:

- Global supply and demand. However, in reality, traders' market perceptions influence oil prices more than actual global supply and demand do;
- Value of the U.S dollar. All oil contracts are traded in U.S. dollars, so oil prices follow its;
- New large oil reserves discoveries or new technologies enabling low-cost extraction of old reserves. For instance, with shale oil extraction, the United States became the largest oil producer in the world.
- Extraordinary events. E.g. in 2020, oil prices plunged to a negative value in the wake of an abrupt drop in worldwide demand due to the COVID-19 pandemic.

Oil Prices in the 1960s and 1970s

Global oil prices generally ranged between $2.50 and $3.00 a barrel until 1970. That's about $17 to $20 a barrel when adjusted for inflation. The United States was the world's dominant oil producer at that time. It regulated prices. Domestic oil was plentiful. Cheap oil and gas made the expansion of interstate highways, interstate trucking, and auto ownership part of the American Dream. But multiple changes have occurred since then.

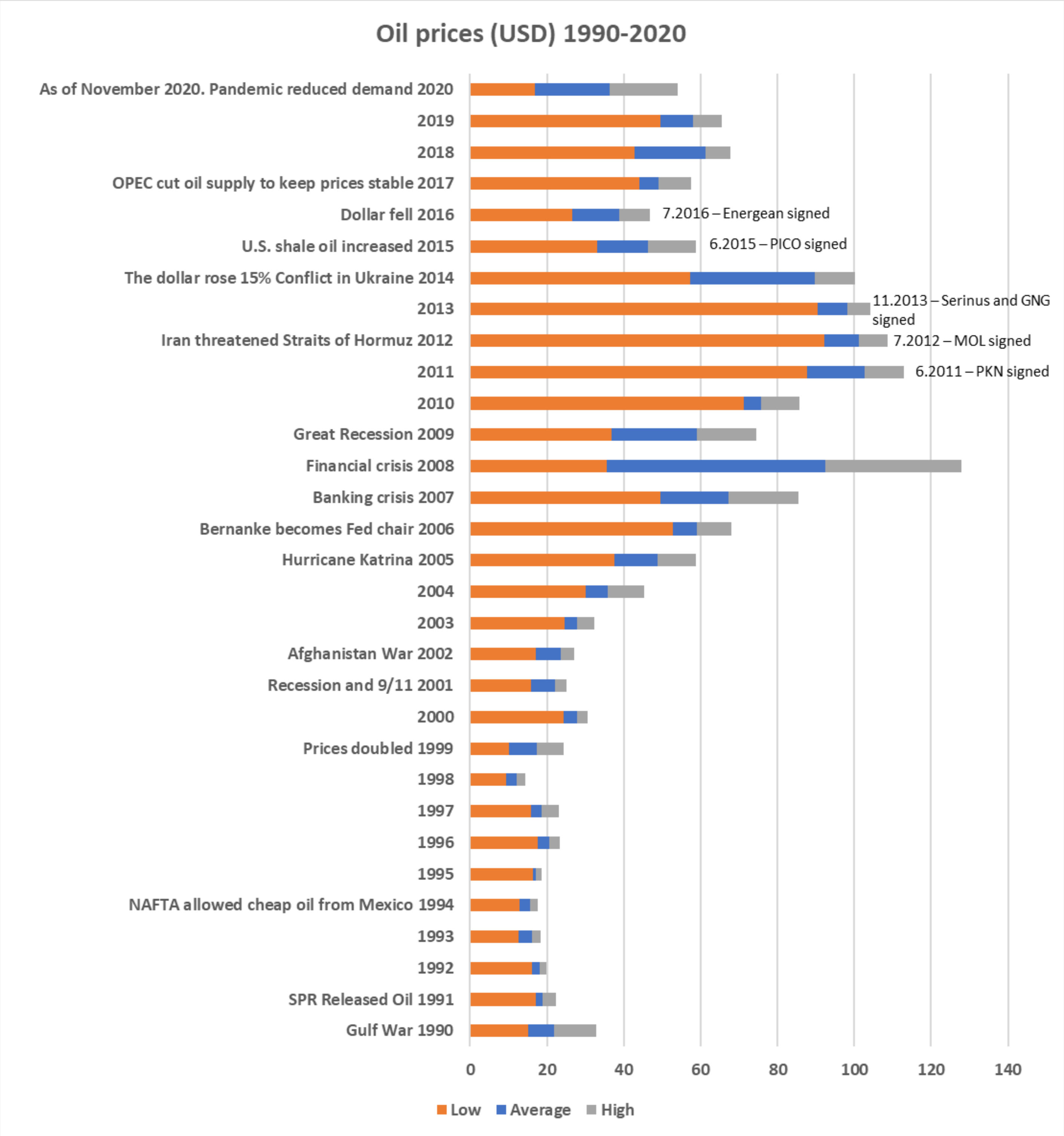
In 1960, Saudi Arabia and other foreign oil-exporting nations formed OPEC. They wanted more control over their most valuable natural resource. In 1971, regulators allowed U.S. companies to pump as much oil as they wanted. They began using up surplus reserves. As supply fell, prices rose. America became vulnerable to future shortages. But OPEC didn't really begin impacting oil pricing until President Richard Nixon effectively took the U.S. dollar off of the gold standard in 1971. The value of the dollar plummeted, taking oil revenues down with it.

OPEC halted oil exports to the United States in 1973. Its primary goal was to boost oil prices. It also wanted to punish America for its support of Israel in the Yom Kippur War. Congress created the Strategic Petroleum Reserve to ensure an adequate supply of petroleum products and prevent future shortages.

Oil Prices 1990 – 2020

One could be forgiven for thinking that crude oil prices hardly moved between 1990 and mid-2020 as they were similar at the beginning and end of that period, averaging $22-25 bbl. However, the mid-2020 oil prices were due to an extraordinary event – the COVID-19 pandemic, which profoundly distorted oil markets (see more below). During the last 30 years oil prices have fluctuated significantly, rising to an average of $92.5 bbl ($127 maximum) in 2008 during the financial crisis, dropping to an average of $59 bbl the next year due to a post-crisis depression, only to rise again during the next two years, before experiencing a gradual fall in 2011-2016. During the last four years the price of oil has been equally volatile. Figure 3 illustrates this "roller-coaster", with highlighted key events impacting the oil price changes and the cluster project signing dates.

Figure 3. Oil prices during 1990 – 2020



Source: https://www.thebalance.com/oil-price-history-3306200

Why Oil Prices Are Volatile

Since the 1970s, oil prices have become more volatile. They're affected by more than the laws of supply and demand. Oil prices are determined by oil futures contracts on the commodities markets. This means that commodities traders control oil prices. They'll drive prices up even if they only *think* there will be a surge in demand, such as during the summer driving season. They'll lower prices if they think there will be a drop off. That usually occurs as demand falls in the winter.

U.S. Shale Oil Production

In 2015, new U.S. production of shale oil increased global oil supply. By Jan. 19, 2016, the addition to supply had driven global oil prices down to a 13-year low of $27.36 per barrel. By November, OPEC had had enough. It cut production to revive prices. By April 2019, global prices topped $71/b. They remained in that range until early 2020.

Coronavirus Pandemic

In January 2020, many governments began restricting travel and closing businesses to stem the coronavirus pandemic. Demand for oil began falling. In the first quarter of 2020, oil consumption averaged 94.4 million barrels per day, down 5.6 million b/d from the prior year.

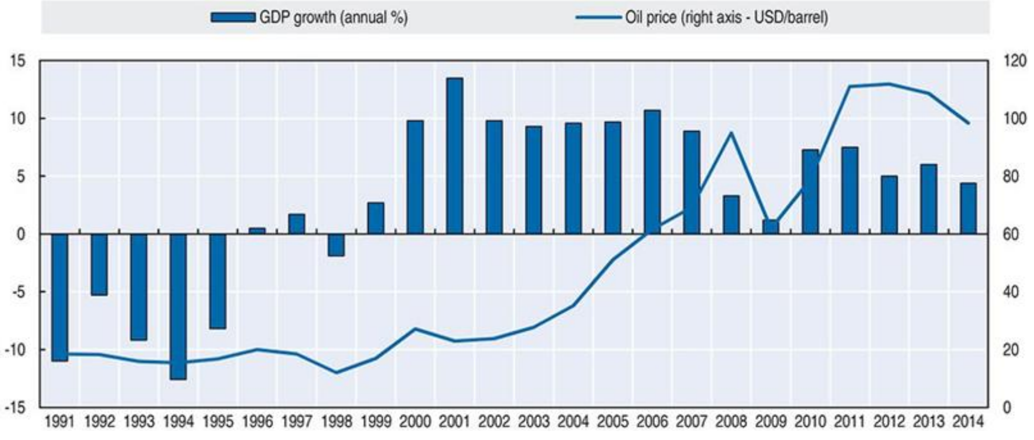
Through the first quarter, OPEC and its members were abiding by an agreement to limit production. That agreement expired March 31, 2020. At the March 6, 2020, meeting, Russia refused to lower production. OPEC responded by announcing it would increase production. As storage facilities filled, prices plummeted into negative territory. No one wanted delivery of oil, since there was hardly any place to store it. As of April 20, 2020, prices for a barrel of oil had fallen to -$36.98 globally.

On April 12, 2020, OPEC and Russia agreed to lower output to support prices.

Oil Price Dependency

The economies of some countries are highly dependent on hydrocarbon prices, particularly those in the Middle East. However, the same dependence can also be observed among some of the Bank's COOs. The case in Russia (a former COO) provides an illustration of this phenomena. After it recovered from the post-Soviet economic crisis, Russia's GDP growth from 2006 onwards was relatively closely correlated with oil price movements (see figure 3).

Figure 4. Relation of oil prices to Russia's GDP growth



Annex based on information from:

https://www.thebalance.com/oil-price-history-3306200

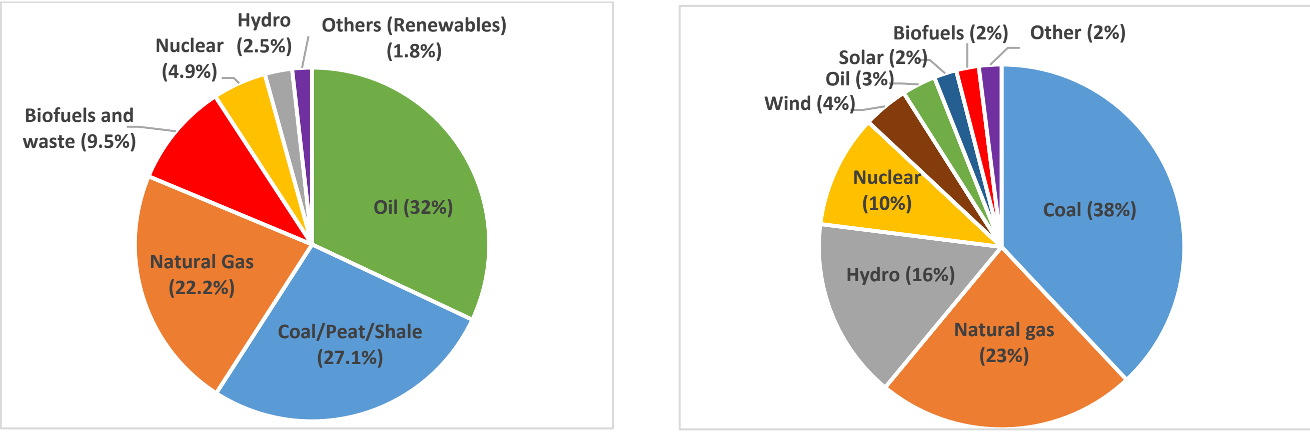
https://www.marketwatch.com/story/about-150-years-of-oil-price-history-in-one-chart-illustrates-crudes-spectacular-plunge-below-0-a-barrel-2020-04-22

ANNEX 7 – HYDROCARBON CONSUMPTION AND EFFORTS TO LIMIT IT

1. Global hydrocarbon consumption levels

The dependence of the world economy on hydrocarbons as a primary energy source, as well as a source of electricity generation, remains high. Data from the International Energy Agency (IEA) indicates that in 2017 hydrocarbons accounted for 81.3% of the former and 64% of the latter (see figure 1).

Figure 1.World total prime energy supply and world energy electricity generation by sources



Source:ourworldindata.org/fossil-fuels

2. Reduction in hydrocarbon consumption relative to other energy sources in the Bank's COOs

Over the last few decades most countries have worked towards reducing their dependence on hydrocarbons. However, so far the results have not been impressive. The fossil fuel share of the global economy dropped by just one percentage point between 2010 and 2019, despite plummeting clean-energy costs, rapid advances in battery technology and 25 years of high-level UN climate conferences. Four-fifths of the energy consumed last year still came from oil, natural gas or coal, according to the International Energy Agency. Other technologies, from small-scale nuclear power to carbon capture and storage to green hydrogen, that will be critical to decarbonising the energy system, remain peripheral.

The process of reducing hydrocarbon consumption has been uneven and generally slower among the Bank's countries of operation (COOs) than in the most developed countries. Table 1 below demonstrates reductions in the share of fossil fuels in primary energy in all COOs, achieved during the last 30 years. Romania, Bulgaria, Ukraine, Slovakia, Croatia, Greece and Turkey were the most successful, reducing their dependence by 10 to 20 percentage points, similar to the more advanced countries such as UK and Germany. However, this was still well below the level achieved by leaders, such as Denmark (31 percentage points reduction).

Most COOs made relatively modest progress in this area, reducing dependence on fossil fuels by a single digit percentage point, with some post-Soviet republics, such as Belarus, Kazakhstan, Turkmenistan and Uzbekistan, barely exceeding a change of one percentage point. There were two outliers among the COOs, which countered the downward trend – Lithuania, which substantially increased its dependence on hydrocarbons, i.e. by 20 percentage points (probably due to the decommissioning of the Ignalina nuclear plant) and Egypt, which increased its dependence by three percentage points (likely due to its improved access to fossil fuels, following the discovery of domestic deposits).

Table 1. EBRD's countries of operation - reduction of hydrocarbons in their primary energy sources

EBRD Countries of Operations	Fossil fuels as % in primary energy sources		
	1989	2019	Relative change
Azerbaijan	99.22	97.52	-2
Belarus	99.99	99.37	>-1
Bulgaria	86.30	70.06	-19
Croatia	89.41 (in 1990)	78.11	-13
Cyprus	100	95.67	-4
Egypt	93.10	95.44	+3
Estonia	100	92.40	-8
Greece	98.09	87.27	-11
Hungary	88.14	80.62	-9
Kazakhstan	97.58	96.89	>-1
Latvia	88.13	80.86	-8
Lithuania	76.04	91.59	+20
Macedonia	95.39	89.29	-6
Morocco	96.01	92.91	-3
Poland	99.68	93.26	-6
Romania	95.07	75.62	-20
Russia	91.95	87.88	-4
Slovakia	84.10	69.80	-17
Slovenia	69.19 (in 1990)	64.31	-7
Turkey	90.28	81.43	-10
Turkmenistan	100	99.99	>-1
Ukraine	92.19	75.11	-19
Uzbekistan	97.07	96.75	>-1
Peer countries (for comparison)			
UK	91.44	79.16	-13
Germany	88.12	77.42	-12
Denmark	99.18	68.43	-31
Spain	80.09	73.93	-8

Source: ourworldindata.org/fossil-fuels

Figure 2 below tracks the changing share of hydrocarbons in selected COOs' primary energy sources during the last 30 years. It shows a gradual increase of said share in Egypt, starting at the turn of the century and then stabilising during the last decade; Kazakhstan's share, which is virtually unchanged; relatively modest reductions achieved by Poland and more robust changes in Greece, with a slight acceleration in both countries during the last ten years; an uneven curve in Turkey, with its share growing in the first decade of the current century, with a relatively sharp decline after 2009; as well as consistent and impressive reductions in Romania and Ukraine, from about 95 % to 75%.

The acceleration in the reduction rate since 2009 in most countries might be due to the first climate action package (3x20%) agreed by EU countries in 2008, stipulating a reduction of GHG, as well as an increase of RES and energy efficiency – all by 20% by 2020 (compared to 1990 levels).

Figure 2. Changes in the share of hydrocarbons as the primary energy source in selected COOs

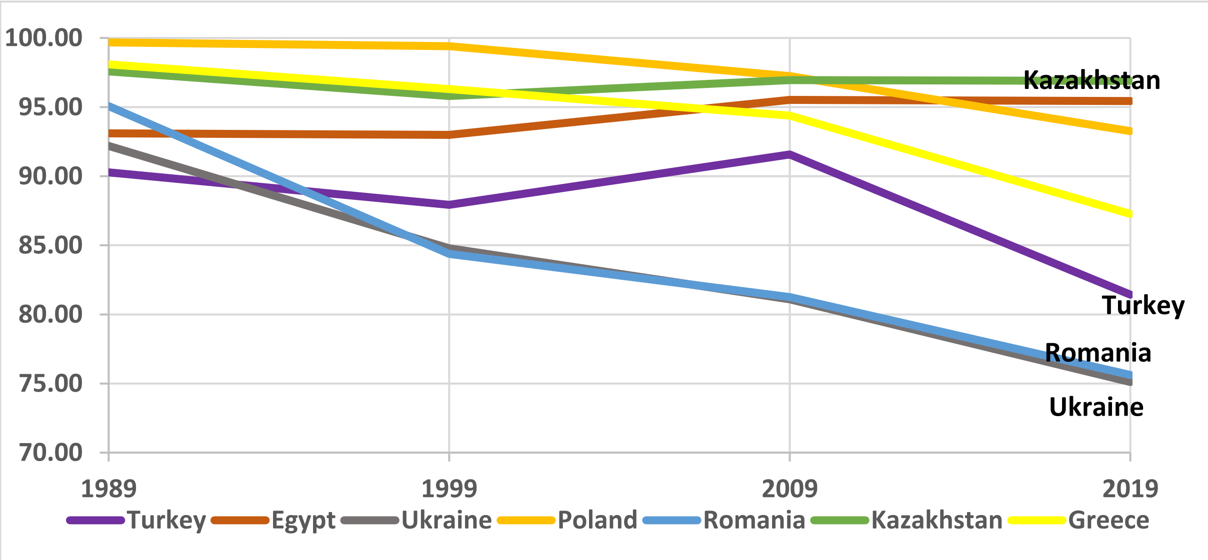


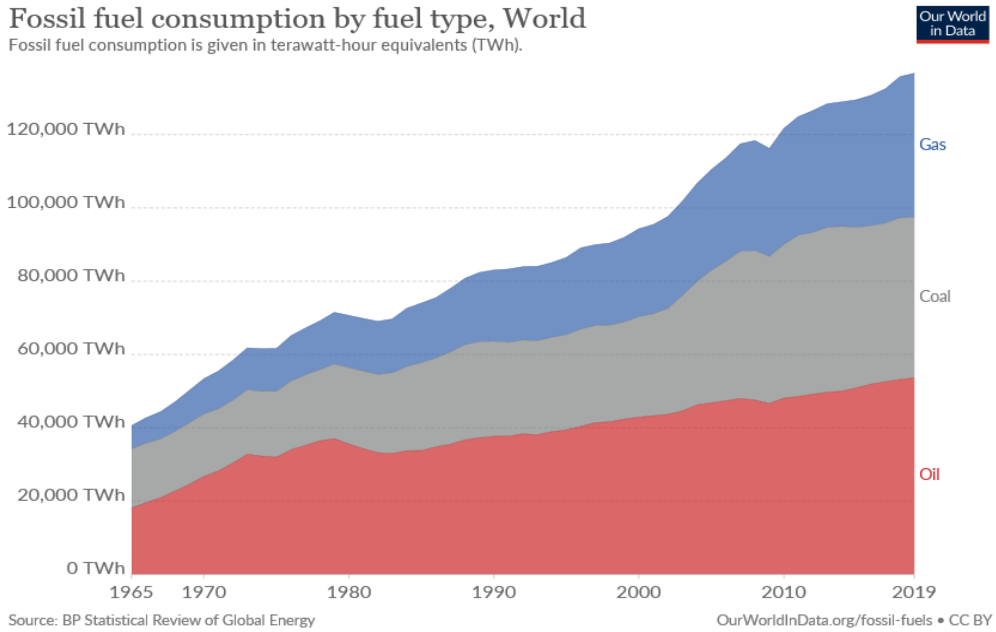
Table 1 and figure 2 illustrate the difficulties experienced by all COOs in reducing their dependence on hydrocarbons, and the time it took them to do so, even by relatively modest rates. Thanks to a greater awareness of the detrimental effects of hydrocarbon combustion on climate change (which is now at the top of the global agenda) and the better policies currently supporting a faster reduction of hydrocarbon dependency, particularly in Europe (see section 4 below), it is plausible to expect the rate of reduction to increase. Early data from energy markets indicate that the COVID-19 pandemic may accelerate the transition from hydrocarbons to RES (see section 5 below for more info).

However, even if the best performers among the Bank's COOs (Romania and Ukraine) maintain their impressive reduction rate from the last 30 years, their dependence on hydrocarbons in 2060 will still remain at about 50%. And this reduction rate could prove challenging for most of the other Bank COOs, indicating that hydrocarbons may remain a dominant source of energy for COOs for foreseeable future.

3. Absolute level of hydrocarbon consumption

However, despite the ability of some countries to reduce consumption of hydrocarbons relative to other sources of energy, said consumption has grown exponentially in absolute terms due to the growth of the world economy, which has been creating an ever increasing demand for energy (with only a small and short-lived dip due to the economic crisis of 2008-9), see figure 3 below.

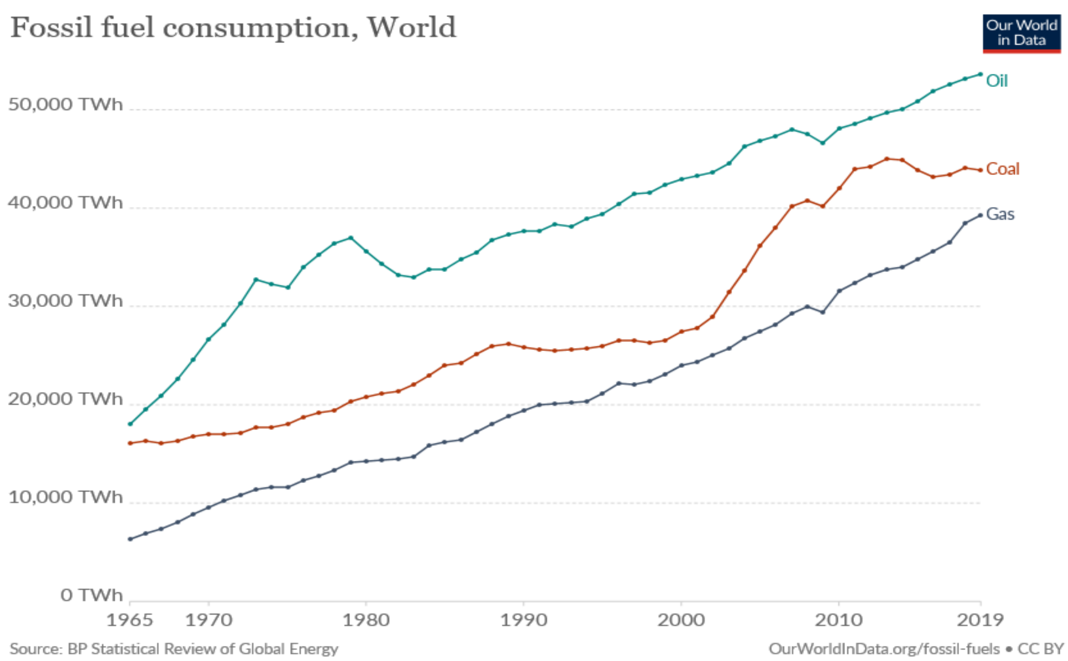
Figure 3.



The only positive trend which can be observed in absolute hydrocarbon consumption, is a drop in coal consumption (albeit relatively small), falling from a peak of about 45,000 TWh (registered in 2013) to about 43,000 TWh in 2016, although subsequently this largely levelled out at about 44,000 TWh (see figure 4).

Nevertheless, the global consumption of oil and gas have been growing continuesly throughout the last 20 years, the former by about 10,000 TWh and the latter by almost 20,000 TWh (see figure 4)

Figure 4.



The exponential increase in hydrocarbon consumption in absolute terms confirms the importance of employing a holistic approach in the quest to limit their use, with energy demand reduction (mostly through efficiency improvements) being as important as support for RES, together with adequate policy to incentivise their development. For many COOs, key importance in this area have the EU's climate change prevention policies and initiatives, which are aligned with this approach. The next section summarises them.

4. Policies and initiatives of the European Commission towards reduction of hydrocarbon consumption

The policies of the European Commission have profound effect on the approach of many COOs (not only those members of the EU) to hydrocarbons. The EU is one of the signatories to the Paris Agreement, which aims to limit global warming to well below 2°C and to pursue efforts to limit it to 1.5°C. EU has undertaken a number of concrete initiatives to achieve this goal, including:

<u>2020 goals</u>

The EU's first package of climate and energy measures was agreed in 2008 and sets targets for 2020:

• reducing greenhouse gas emissions by 20% (compared to 1990)

• increasing the share of renewable energy to 20%

• making a 20% improvement in energy efficiency

To achieve these goals, the EU has developed, and later reformed, the EU emissions trading system (ETS) which aims to cut down greenhouse gas emissions in particular from energy-intensive industries and power plants. In the buildings, transport and agriculture sectors, national emission targets have been set, as part of the effort sharing regulation.

The EU is already ahead of these targets. By 2018, greenhouse gas emissions had been reduced by 23% that is three percentage points above the initial 20% target.

<u>2030 goals</u>

In 2014, the 2030 climate and energy framework was agreed with a more ambitious set of targets for the period 2021-2030. By these targets, the EU is committed to cutting its greenhouse gas emissions by at least 40% by 2030, compared to 1990.

The framework contains policies and goals to make the EU's economy and energy system more competitive, secure and sustainable. It also reformed the ETS, adopted monitoring and reporting rules, and stated the need for national climate and energy plans and long-term strategies.

<u>EU emissions trading system</u>

In February 2018, the EU adopted revised rules for the EU emissions trading system (ETS). Set up in 2005, it is the world's first major carbon market and remains the biggest one. It sets a cap on how much CO2 heavy industry and power stations can emit. The total volume of allowed emissions is distributed to companies as permits which can be traded.

CO2 emissions from transport

In April 2019, stricter emission limits for cars and vans were decided upon to ensure that from 2030 onwards new cars will emit on average 37.5% less CO2 and new vans will emit on average 31% less CO2 compared to 2021 levels. Between 2025 and 2029, both cars and vans will be required to emit on average 15% less CO2.

Limits for trucks and other heavy-duty vehicles were adopted in June 2019. New rules will require manufacturers to cut CO2 emissions from new trucks on average by 15% from 2025 and by 30% from 2030, compared with 2019 levels.

Circular economy

In May 2019, the EU adopted a ban on single-use plastic items (produced mostly from hydrocarbons). By this ban, the EU set stricter rules for those types of products and packaging which are among the top ten most frequently found items polluting European beaches. The new rules ban the use of certain throwaway plastic products for which alternatives exist.

Clean Energy Package

The EU adopted new pieces of legislation which are part of the clean energy package:

•a revised directive on energy efficiency

•a revised directive on renewable energy

•a governance regulation

The package is key to the achievement of the 2030 climate and energy goals and defines the collaboration and control mechanisms for EU member states in the energy sector.

The 2050 climate neutrality goal

In December 2019, EU leaders endorsed the objective of achieving a climate-neutral EU by 2050. Poland could not commit at that stage to implement this objective and the European Council agreed to table the matter at a future meeting.

EU leaders asked the Council to take forward the work on the European Green Deal. They recognized the need to put in place an enabling framework to ensure a cost-effective, as well as socially balanced and fair transition to climate neutrality, taking into account different national circumstances.

Green Deal

The goal of Green Deal is that while tackling the existential threat of climate change, the EU will pursue economic growth in ways which create better jobs and enhance people's well-being. The Green Deal includes measures such as:

- investing in environmentally-friendly technologies
- supporting innovation
- helping the development of cleaner forms of transport
- decarbonising the energy sector
- ensuring buildings become more energy efficient
- working internationally to improve standards around the world

The EU aims to spend 30% of its 2021-2027 budget on tackling climate change.

Moreover, **Just Transition mechanism** has bene established to provide €100 billion to directly support Green Deal, in particular:

- People and communities most vulnerable to the transition: facilitate employment opportunities and offer reskilling while improving energy-efficient housing and fighting energy poverty.
- Companies and sectors in carbon-intensive industries: help make the transition to low-carbon technology attractive to investment and provide loans and financial support, while also investing in research and innovation and in the creation of new firms.
- Member states or regions which have a high dependence on fossil fuels: invest in new green jobs, sustainable public transport, renewable energy, digital connectivity and clean energy infrastructure.

Increased 2030 target

In October 2020, the European Council discussed the Commission's communication on 'Stepping up Europe's 2030 climate ambition', including the proposed emissions reduction target of at least 55% by 2030, and the actions required to achieve that ambition.

EU leaders consider that the updated target should be delivered collectively by the EU in the most cost-effective manner possible. All member states will participate in this effort, taking into account national circumstances and considerations of fairness and solidarity.

The European Council invited the Council to take work on this forward. Leaders invited the Commission to conduct in-depth consultations with member states to assess the specific situations and to provide more information about the impact at member states' level.

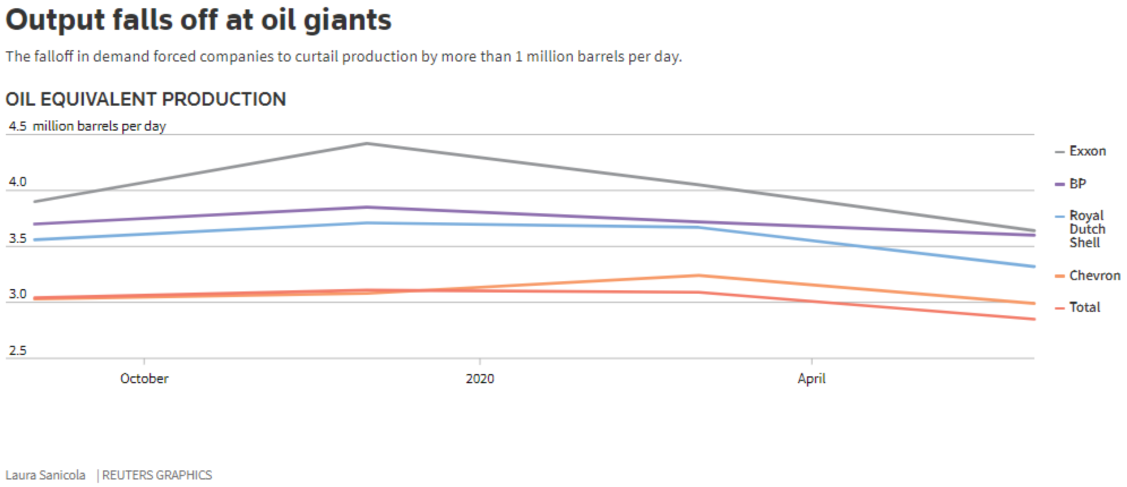
However, despite the above initiatives, it is noted that EU countries spent €159 billion on energy subsidies in 2018. Nearly a third of that went on fossil fuels. Fossil fuel subsidies among the EU's 27 countries increased by 6% from 2015-2018, though some, including Austria, Denmark, Estonia and Hungary, bucked the trend. The handouts include support from governments and public bodies to coal, gas and oil, in the form of grants, loans, tax incentives or price support. The EU Commission intends to reform EU tax rules in 2021, to tackle exemptions for some fuels.

5. *Impact of COVID-19 pandemic on the hydrocarbon industry*[12]

The COVID-19 19 pandemic is having a devastating impact on the hydrocarbon industry. The world-wide consumption of coal is estimated to dropped in 2020 by 7%. However, the extent of this decrease varied widely from country to country. In the first half of this year coal had only 2% share in the UK's electricity generation mix (down from 40% in 2012). In the first half of 2020, coal-generated electricity also dropped in the EU's two largest coal burning countries – Germany and Poland by estimated 30% and 10% respectively as compared to 1H 2019. In the US, coal-generated electricity was 20% lower already in 2019 as compared to 2016 and is expected to have dropped further in 2020.

[12] Section based on the articles: "Oil giants' production cuts come to 1 million bpd as they post massive write-downs", Reuters, 9 August 2020, "Big fossil fuel groups all failing climate goals", Financial Times, 7 October 2020 and "Coal's endgame, the dirtiest fossil fuel is on the back foot", The Economist, 3 December 2020.

Demand for oil and gas plummeted, causing oil and gas prices to plunge in April 2020 the cost of crude even dropped below zero (see annex 6). In the second quarter of 2020, the world's five largest oil companies collectively cut the value of their assets by nearly $50 billion and slashed production rates due to the drastic fall in fuel prices and demand caused by the pandemic. This dramatic reductions in asset valuations and decline in output show the depth of the hydrocarbon industry's crisis. Fuel demand at one point was down by more than 30% worldwide, and by mid-2020 remained well below pre-pandemic levels. Several oil executives said they took massive writedowns because they expect demand to remain impaired for several more quarters, as people travel less and use less fuel due to the pandemic.

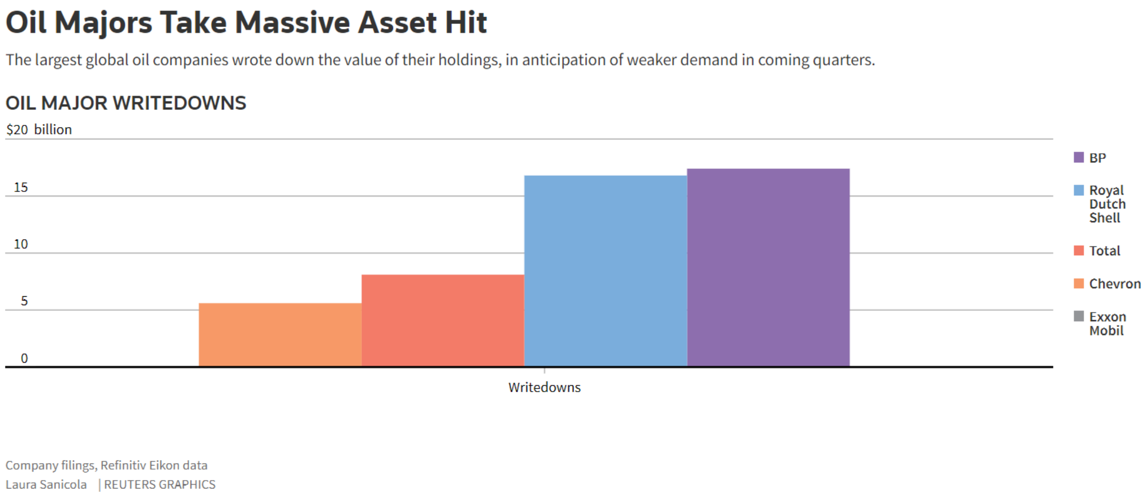


All the companies above booked sizeable impairments, with the exception of Exxon Mobil XOM.N. But an ongoing re-evaluation of Exxon's plans could lead to a "significant portion" of its assets being impaired, it reported, and signal the elimination of 20% or 4.4 billion barrels of its oil and gas reserves.

By contrast, BP BP.L took a $17 billion hit. It said that in the coming years it plans to re-centre its spending around renewables and less on oil and natural gas.

Weak demand means oil producers must revisit business plans to pump only what generates cash in excess of overhead costs. It will be a low-cost production mode through the end of 2021, and to 2022 to the extent that there are new development plans.

BP has previously said it plans to cut its overall output by roughly 1 million barrels of oil equivalent per day (boepd) by the end of 2030 (from its current 3.6 million boepd).



Of the five, Exxon is the largest producer, with daily output of 3.64 million boepd, but its production dropped 408,000 boepd between the first and second quarters. The five majors, which include Chevron Corp CVX.N, Royal Dutch Shell RDSa.L and Total SA TOTF.PA, also cut capital expenditures by a combined $25 billion between the quarters.

COVID-19 pandemic may accelerate transition from hydrocarbons to clean energy sources[13].

Early data indicates that the world's GHG emissions during the first quarter of 2020 were about 10% lower than an year earlier. Those for the second quarter are likely to be even lower. One reason is a drop of demand for energy, however another is that RES have been increasing their share in global electricity even as consumers used less power. The energy transition —defined as the shift from hydrocarbon-based fuels to clean energy — appears to have remained intact, despite fears that COVID-19 would blow it off course too.

Vast new spending is under way as the world's energy system begins a colossal transformation — away from infrastructure that has sustained the petroleum era and the global economy for more than a century, towards a reinvented energy system that will drive down greenhouse gas emissions. Goldman Sachs estimates that investment in decarbonising the energy industry — renewables, carbon capture, hydrogen and the upgrading of power infrastructure — will reach $16 trillion over the next 10 years.

The oil industry, one of the planet's biggest sources of emissions, is increasingly on board — but divisions are stark. BP, one of the sector's oldest players, this year (2020) began its second attempt in recent history to rebrand itself as a post-petroleum company, pledging aggressive decarbonisation targets and to build a huge renewables business. Shell, Total and Equinor have made similar commitments. Their rivals in the US, ExxonMobil and Chevron, have been slower on the turn, even while the market has punished oil and gas stocks.

Exxon, once the world's most valuable company by market capitalisation, has been eclipsed in value this year by Tesla, Accenture and, most recently, NextEra, an American utility plotting a clean-energy future. Exxon says it will continue to focus on its "core competencies" in petroleum. Its management stated*: "We believe in the fundamentals of the oil and gas business. We believe societies and economies will continue to need oil and gas. In the upcoming years, the alternatives really can only fulfil a small amount, or a relatively modest amount, of the overall demand that exists.* " This assertion touches on one of the biggest debates of the transition — over just how quickly demand for fossil fuels will fall and the supply of low-carbon alternatives can rise.

BP reckons that, if the world decarbonised quickly enough to limit the rise in temperatures by 2100 to 2C above pre-industrial levels, global oil consumption would almost halve by 2050. But this outlook involves much slower economic growth, a leap in the taxation or other charges applied to carbon consumption, and rapid take-up of electric vehicles. BP's net-zero scenario sees oil demand plunge over the next 30 years to just 26m barrels a day in 2050, barely more than a quarter its level last year. Such a scenario would upend global politics as it reduced the strategic importance of the world's big crude producers. It could also demolish the industry as it is known. According to Carbon Tracker, an energy strategy think-tank, oil majors would "obviously" have no future in a world in compliance with the decarbonisation targets agreed by world leaders in the Paris climate accord *"Don't listen to the siren voices of the incumbents telling you they have a future. They have no future."*

Accenture, a consultancy, is not so sure. It believes that demand for oil will also fall steeply — though not as steeply as BP predicts. But, even if consumption in 2050 is 60%-80% of today's level, most of the production needed to meet it will come from fields that are not yet in production. *"There is a role to play in providing hydrocarbons,"* says

[13] This section is based on a Financial Times article "Fossil fuel suppliers face battle for survival as transition bites", FT 6 October 2020.

David Rabley, a managing director at Accenture. But oil producers will have to decide whether they become broad energy companies, with renewables and hydrocarbons; or focus on low-cost and cleaner oil and gas production to be a "last man standing" in the sector; or pivot entirely to become providers of clean energy, such as green hydrogen or renewables.

But it is "unthinkable" that every oil company will make it through the transition, Mr Rabley argues. "A company like Exxon has a lot more optionality to pick across those roles — they have presence across the value chain, they have an incredible bench of capabilities," he added. "But the window is going to close on them before long. We're at the point where it's decision time." Oil majors also pin their hopes on natural gas. They have poured billions of dollars into new liquefied natural gas infrastructure, allowing the fuel to be super-chilled and shipped globally, and even BP's forecasts expect rapid uptake of LNG. Producers like Shell argue that natural gas will for decades remain a "bridge fuel", providing baseload power generation that intermittent solar and wind power cannot. This too is increasingly questioned by climate change proponents, who say that "fossil gas" must also be phased out of the energy system if the world is to decarbonise fully.

A recent study from the University of California, Berkeley, said the US could generate 90% of its electricity from clean energy by 2035, "dependably, at no extra cost to consumer bills and without the need for new fossil fuel plants". The 15 years would allow existing coal- and gas-fired plants time to recover their costs before closing. The shift in the cost of capital investors charge to companies will be decisive. Renewables projects now command a cost of just 3%-5% =, versus up to 20% for long-term oil projects, reckons Goldman Sachs. This will help European oil majors in particular, as they plough $170 billion into renewables by 2030, increasing their share of the global renewables market from 1% to 10%, the bank says.

But the energy transition away from oil and gas also risks a spike in the price of those fossil fuels, as investors stop backing new supply projects before consumers are ready to stop consuming the energy they would deliver. "We could have a very tight oil and gas market because supply is slowing down but demand continues unabated," says an analyst at Goldman Sachs.

However, for now, no major oil, gas or coal company is on track to align their business with the Paris climate goal of limiting the global temperature rise to well below 2°C by 2050, new (October 2020) research shows, that despite net-zero emissions pledges. A partnership between London School of Economics academics and investors that manage $21tn in funds, called the Transition Pathway Initiative (TPI), assessed 125 oil and gas producers, coal miners and electricity groups on their preparedness for a lower-carbon economy. They were measured on "carbon performance", which factors in the carbon intensity of the products they produce and sell, emissions reduction targets and how they would fare under three models: should governments meet existing national emissions pledges, a scenario in which temperatures rise by 2C; and one where they rise by less than 2°C.Of the 59 major oil, gas and coal players assessed, only seven are on track to align with the emissions pledges governments made as part of the 2015 Paris Agreement — Royal Dutch Shell, Spain's Repsol, France's Total, Eni of Italy, Equinor of Norway as well as miners Glencore and Anglo American. But even compliance with existing national pledges would leave the world on track for 3.2°C of warming, according to the UNEP. Others say it could be even higher.

Only three oil and gas companies — Shell, Total and Eni — are getting closer to the 2C scenario although their emissions reduction targets and low-carbon investment plans are still not quite enough to bring them into line with that benchmark, let alone lower. Fossil fuel companies have been under pressure from investors and environmental activists to take greater accountability for their role in enabling climate change. Several European oil and gas majors, including Shell, BP and Repsol, have in recent months announced net-zero emissions pledges. In the new report, BP was not cited as a leader in action on climate change, despite its announcement in August 2020 of ambitious plans to cut oil and gas production by 40 per cent over the next decade.

According to the TPI's study, the company's new emissions targets for its operations and production covered products made using its own and third-party crude but not those it trades, which made up more than half of everything it sold last year. BP said its aims supported its net zero ambition, adding that its path was consistent with the Paris goals. A growing divide also exists between those such as BP that prioritise the reduction of absolute emissions versus those including Shell and the TPI that focus on carbon intensity — which takes into account the amount of greenhouse gas emissions per barrel of oil and gas produced. Critics of the intensity metric say the measure can fall even if companies continue to expand their production and generate higher absolute emissions, which is what ultimately matters for the climate. Others argue that a business's absolute emissions can fall through asset sales or a commodity downturn without it decarbonising. ExxonMobil and Chevron of the US are doubling down on hydrocarbons rather than seeking to diversify into cleaner business such as their European counterparts. In the electricity sector, 39 of the 66 utility companies analysed are aligned with the Paris pledges, while 22 are in line with the tougher benchmark of below 2°C.

ANNEX 8 – IFIs APPROACH TO HYDROCARBONS

This annex summarizes the policies of the main IFIs related to financing of hydrocarbons.

Asian Development Bank (ADB)

Energy Policy (June 2009) states that ADB:

- will not finance coal mine development, except for captive use by thermal power plants.
- will not finance oil field development, except for marginal and already proven oil fields.
- will selectively support coal-based power projects if cleaner technologies are adopted and adequate. mitigation equipment and measures are incorporated into the project design.
- will support coal-based power plants using subcritical boiler technology if found to be justified after due diligence.

In other words, ADB will maintain its current policy of not directly financing coal mine development except for captive use by power plants. This is the case when a substantial part of the production of thermal coal is tied to long-term fuel supply contracts, or administrative allocation, for power plants. However, ADB will not finance when a coal mine is envisaged to be developed to sell thermal coal to the open markets or is linked through international trading channels to power generation in another country because the transaction will be considered market-based.

- will continue to support financing natural gas-based power plants due to their environmental benefit.
- will continue to finance modern, small, oil-based power plants for island communities, in remote areas, and sparsely populated areas where other options are not feasible.
- will continue its policy of not financing any oil and gas field exploration projects due to the associated risks.
- will not, in general, fund oil field development projects. But if necessary, ADB will consider assistance to develop marginal and already proven oil fields, if such developments are economically sound.
- will provide support for refining, transportation, and distribution of petroleum products. It will continue to provide assistance for gas field development, transportation and distribution of gas.

ADB's energy policy is scheduled to be reviewed in Q4 2021. In regards to the new policy's stance on fossil fuels and coal, Yongping Zhai[14], Chief of the Energy Sector Group, indicates that ADB will support its member countries to reduce their dependence on coal and eventually phase out coal power generation. This will be achieved by setting standards and requirements, such as emission intensities and minimum efficiency levels, while introducing low-carbon and climate-resilient technologies including carbon capture and storage. The updated policy will provide guidance and screening criteria on the use of fossil fuels to avoid conflicts with the broader international goals.

ADB's Independent Evaluation Department's conducted a sector-wide evaluation of the ADB Energy Policy and Program (2009–2019) in August 2020. One of the recommendations is to review and update the energy policy to prioritize climate change mitigation and adaptation. It recommends to formally withdraw financing of new added capacity of coal-fired power and heat generation plants, help member countries phase out coal-based energy and mitigate the environmental and health impacts of the existing coal fleet, introduce sound screening criteria for other fossil-fuels, and align the policy with ADB's Strategy 2030 and their sector transformation, complemented with a detailed Implementation guidance document.

[14] https://www.adb.org/news/features/qa-new-energy-policy-accelerate-asia-energy-transition (10 November 2020)

European Investment Bank (EIB)

In its **Energy Lending Policy: Supporting the Energy Transformation** (November 2019), EIB reached a compromise to end the financing of unabated fossil fuel projects, including gas, from the end of 2021. The Policy indicates that the Bank will phase out support to:

- the production of oil and natural gas;
- traditional gas infrastructure (networks, storage, refining facilities);
- power generation technologies resulting in GHG emissions above 250 gCO2 per kWh of electricity generated, averaged over the lifetime for gas-fired power plants seeking to integrate low carbon fuels, and
- large-scale heat production infrastructure based on unabated oil, natural gas, coal or peat.

EIB considers phasing out fossil-fuels a significant change. To manage it, EIB will continue to approve projects already under appraisal until the end of 2021. Also, during this period, the Bank can approve gas infrastructure projects included under the 4th list of Projects of Common Interest co-financed with EU budget. Climate groups have considered these as loopholes given that they can still make European countries dependent on fossil fuels. EU's Projects of Common Interest can be supported before 2022. At the time of the policy approval, over 50 gas projects were eligible for such a support.

World Bank Group (WBG)

The 2013 World Bank Group's **Energy Sector Directions Paper** states that the WBG:

- will provide financial support for greenfield coal power generation projects only in rare circumstances (such as meeting basic energy needs in countries with no feasible alternatives to coal and a lack of financing for coal power). The Operational Guidance for World Bank Group Staff: Criteria for Screening Coal Projects under the Strategic Framework for Development and Climate Change (March 2010) will apply to all greenfield coal power projects undertaken in such exceptional circumstances;
- will finance oil and gas if these are the most feasible energy options available. If short-term options include those with moderate or high greenhouse gas emissions, complementary support will also be provided in the medium term to harness lower-emission options.
- will scale up its engagement in natural gas, including assist countries develop national and regional gas markets and, where it makes economic sense, use natural gas as an alternative to coal, moving away from locking into coal infrastructure.

During the 2017 "One Planet Summit" in Paris, the WBG made a policy change pledge for the effective implementation of the Paris Agreement's goals. It stated that it would end financial support for oil and gas exploration by 2019. In exceptional circumstances, consideration would be given to financing upstream gas in the poorest countries if there was a clear benefit in terms of energy access for the poor and the project's fit within the countries' Paris Agreement commitments (this exclusion did not apply to technical assistance).

Nevertheless, in October 2020, Urgewald, a German environmental lobby group, released a study ahead of the World Bank's 2020 Annual Meetings, which indicated that the WBG has invested over USD 2 billion in fossil fuels projects during the past two years. The WBG responded in a statement that it stopped financing upstream investments in oil and gas in 2019, but continues to support resource-dependent developing countries with advice on energy solutions that are economically viable. It added that dependable energy services are key to prevent and fight COVID-19. Moreover, it stated that WBG has been collaborating with governments, the private sector, and other partners to re-purpose and accelerate energy operations to provide clean, reliable and affordable energy to hospitals and other critical health facilities.

African Development Bank (AfDB)

The 2012 **Energy Sector Policy** addresses the coal subsector and states its commitment to supporting its member countries achieve universal access to energy in an environmentally sustainable manner. Coal-fired power generation is likely to form part of such an approach to help Africa increase its access to modern energy at an affordable cost. To ensure that any Bank support for coal-power generation is consistent with this approach, five criteria were set: Development impact; Transitioning towards green growth; Environmentally responsible; and Offsetting measures.

For the oil and gas subsector, "to boost oil and gas supplies on the continent for the benefit of all, thereby alleviating the burden of imported energy and increasing energy security", AfDB will:

- support the environmentally and socially sound production, processing, distribution and export of African hydrocarbons;
- support power generation from oil and gas;
- promote policies, principles, and practices that enhance transparency in the exploitation of the resource, as well as in the use and distribution of the revenues; and (iv) support the optimal use of oil and gas resources to secure equitable and intergenerational long-term benefits;
- not support oil and gas exploration activities.

President Akinwumi Adesina told delegates at the "Climate Action Summit" in September 2019 of the Bank's efforts to shutter coal-fired power plants, stating that AfDB was "getting out of coal". The Bank's USD 500 million green baseload scheme was to be rolled out in 2020 and set to yield USD 5 billion of investment to help African countries transition from coal and fossil fuel to renewable energy. The Bank's Ten-Year Strategy (2013-2022) was adopted in 2013. One of its overarching objectives is the transition to green growth, since then, the Bank has increasingly been investing in renewables, at some point even reaching 100%.

AfDB's Independent Development Evaluation department presented their evaluation of the AfDB's support to the energy sector (1999-2018) to the Board in November 2020, ahead of the upcoming Board discussion on "Africa's Transition to Clean Energy in the context of the Bank's Energy Policy". This meeting may provide a possibility of revising the policy. However, it is unlikely that the Bank would completely withdraw from investing in oil, gas and coal due to the number of countries that intend to exploit their endowments for development. The evaluation confirmed that although oil and gas projects accounted for 8.5% of all energy sector projects during 2012-2015, there were none financed in the subsequent three years.

Islamic Development Bank (IsDB)

IsDB's Energy Sector Policy: Sustainable Energy for Empowerment and Prosperity's (December 2018) has two pillars. The first pillar - the "Increased Access to Modern Energy Services", states that the Bank will examine the provision of energy forms, such as oil and gas and of the relevant downstream infrastructures, based on the principles of safety, operational efficiency and sustainability. Under the second pillar – "Scale up of Renewable Energy", it intends to play a catalytic role in promoting renewables, especially solar energy, as part of its sustainable energy development goal and as an alternative to fossil fuels.

IsDB's Sustainable Finance Framework (November 2019) presents exclusion criteria. The following types of activities are excluded from IsDB's financing:

- upstream fossil fuel extraction and production (including gas, coal and oil);
- new standalone fossil fuel electricity production;
- energy efficiency of coal infrastructure;
- energy efficiency projects that lead to an increase in CO_2 emissions;

- processing, storing, marketing of gas, coal, and oil;
- refining of oil;
- distribution or transport of fossil fuels;
- heavy duty vehicles, infrastructure for fossil fuels (e.g., fuel stations) or bunker fuelled shipping infrastructure.

Inter-American Development Bank (IaDB)

IaDB's Environmental and Social Policy Framework (September 2020) presents a list of activities inconsistent (exclusions) with its commitments to address the challenges of climate change and promote environmental and social sustainability:

- Thermal coal mining or coal-fired power generation and associated facilities;
- Upstream oil exploration and development projects;
- Upstream gas exploration and development projects.

Under exceptional circumstances and on a case-by-case basis, consideration will be given to financing upstream gas infrastructure where there is a clear benefit in terms of energy access for the poor and where GHG emissions are minimized, projects are consistent with national goals on climate change, and risks of stranded assets are properly analysed.

In November 2020, an Extractive Industries Sector Framework, focusing on fossil fuels (oil, gas, and coal) and mining was presented to the Policy and Evaluation Committee. It is expected to be reviewed by the Board by year-end. It is the first of its kind in the sector and will outline important aspects of the Bank's operational vision. The focus will be on reinforcing the institutional, legal, and regulatory framework for the extractive industries. It will not focus on direct investments in mining projects for oil, gas, and coal exploration and development.