CIAB

COAL INDUSTRY ADVISORY BOARD

International Coal Policy Developments in 2012

OCTOBER 2012

Contents

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FOREWORD FROM THE CIAB CHAIRMAN

The *Coal Industry Advisory Board* (CIAB) is a group of high level executives from coal-related industrial enterprises, established by the International Energy Agency Governing Board in July 1979 to provide advice to the IEA from an industry perspective on matters relating to coal. There are currently 45 CIAB Members representing 21 countries, typically Chief Executives or senior executives from coal mining, transportation and machinery companies, from major power generation or other coal consuming companies, or from industry trade associations.

The original task of the CIAB was to assist the IEA in the practical implementation of the "Principles for IEA Action on Coal" – measures aimed at ensuring a ready supply and trade of coal to underpin energy security. In recent years the CIAB has focused additionally on developments in the technology of coal use required to enable coal to contribute to energy security in this era of increased coal use by developing economies; climate change concerns; and on issues arising from increasingly liberalised energy markets, such as the restructuring and privatisation of coal and electricity industries in many countries.

The CIAB produces this *"International Coal Policy Developments"* report annually for the Governing Board, Standing Committees and Secretariat of the International Energy Agency. The IEA now produces an annual *"Medium-Term Coal Market Report"* so this CIAB report focuses primarily on policy issues and includes only brief coverage of market developments, also acting as a report to the IEA on CIAB work undertaken during the year. It draws on contributions from Associates of CIAB Members to highlight policy and other issues that CIAB Members regard as pertinent to the development of coal as a secure, clean and competitive energy source.

We hope that this report will also be of interest to a wider audience.

J. Brett Harvey
CIAB Chairman

1 CIAB POLICY ADVICE

1. These perspectives are drawn from coal industry knowledge and experience reflected through regular discussions at CIAB meetings, individual contributions to this paper and the CIAB's 2012 work programme. They focus on the wider aspects of coal's on-going role in the global energy economy, as policy makers address the challenges of energy security and climate change mitigation while global energy consumption continues to increase as the world's growing population aspires to high levels of economic and social development.

2. At present 19% of the world's population, 1.3 billion people, lack access to electricity and on New Policy Scenario projections there will still be 1 billion people without such access in 2030[1]. To meet the UN Millennium Development Goal of eradicating extreme poverty by 2015, 395 million more people need access to electricity. There is a strong correlation between electrification and improvement in the United Nations' Human Development Index.

3. These aspirations for higher electricity consumption typically result in increased coal demand, of which there has been yet more evidence over the last year. World coal consumption grew by 5.4% in 2011, while both China and India increased coal consumption by over 9%. In comparison, global primary energy demand only grew by 2.5%. Coal accounted for over 30% of world energy consumption in 2011 and its share is now over 70% in China and nearly 53% in India[2].

4. IEA energy scenarios[3] predict rising global energy demand and a continued reliance on fossil fuels for the next twenty five years, driven primarily by the rapid growth in electricity and energy needs of developing economies such as China and India. These scenarios also illustrate the necessary role for coal in a sustainable energy future. But government policies continue to deny the need to urgently address the implications for CO_2 emissions mitigation targets. Policy instruments that only encourage a switch to natural gas and renewable energy sources do not constitute a long-term sustainable response to the CO_2 emissions mitigation challenge.

5. The WEO 2011 450 Scenario, showing a possible path to limiting the global temperature increase to $2^{O}C$, admits the reality of continued growth in coal demand to 2020 but relies on a rapid substitution of nuclear and renewable electricity generation and a halving in coal used for electricity generation in the subsequent fifteen years in order to achieve the climate mitigation target. The coal industry continues to have serious concerns regarding the growing disconnect between the 2DS scenario[4] to 2050 and the reality of rapidly growing energy demand and coal use in non-OECD countries. Within the industry, the 2DS scenario is seen as impossibly challenging, particularly for China and India.

6. The IEA's scenarios are widely used to inform policy and investment decisions and projections of declining coal use continue to discourage the necessary investments in coal supply and use. A renewed longer-term rational approach to reducing greenhouse gas emissions is urgently required, with a greater focus on encouraging the development and deployment of advanced technologies for all fossil fuels and large-scale demonstrations of carbon capture and storage (CCS) in order to achieve sustainable mitigation of CO_2 emissions.

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[1] IEA "World Energy Outlook 2011", Chapter 13
[2] *"BP Statistical Review of World Energy June 2012"*
[3] IEA "World Energy Outlook 2011"
[4] An IEA *"Energy Technology Perspectives 2012"* scenario to 2050, compatible with the 450 Scenario

7. Concerted effort is required to educate the public that coal will remain a very significant part of the global energy economy for many decades to come. There is evidence of increasing public opposition, nationally and at local level, to the investment projects necessary to meet growing coal demand and the CCS demonstration projects that will mitigate CO_2 emissions from coal use.

8. Inadequate and irregular investment in coal production, supply and use infrastructure, particularly for internationally traded coal and in the commercial deployment of advanced coal technologies and carbon capture and storage, could precipitate medium to longer term security of supply concerns. But the direction of current policy is far from explicit in its support for investment in future coal use.

9. Several studies have confirmed the view that addressing climate change without the development of CCS for fossil fuel-fired power plants will substantially increase the costs to world economies; yet progress on the demonstration and commercial deployment of CCS remains woefully slow. Achievement of the G8 objective of broad deployment of CCS by 2020 looks unlikely, given softening government support for CCS and funding difficulties experienced by commercial companies participating in CCS demonstration projects. Most CCS demonstration projects have not proceeded to construction as a result of high costs and lack of funding.

10. The sale of CO_2 for enhanced oil recovery (EOR) provides one opportunity to reduce these lifetime project costs by securing an additional revenue stream. The use of CO_2 for EOR is a mature oil production technology that has been used for over 30 years and global capacity for CO_2 storage using EOR in known oil basins is estimated to be 130 billion tonnes. Governments should work with the petroleum industry to identify current and future demand for CO_2 for EOR and ensure that this opportunity is fully considered in strategies to support first of a kind commercial scale CCS demonstration projects.

11. National governments must also provide a legal framework for long-term carbon storage, which must provide, amongst other things, certainty around the responsibilities for the long-term monitoring requirements and liability for storage after a sequestration facility has been closed. At the same time, industry and governments need to engage the public on the issue of carbon storage and its safety.

12. The concurrent policy objectives of energy supply security and greenhouse gas emissions mitigation can only be effectively addressed through the parallel development and deployment of ALL potential energy sources and climate change mitigation technologies. There must be greater focus on innovative research into cleaner, better ways of using coal, including advanced technologies and CCS. Basic research needs to be encouraged.

2 CIAB ACTIVITIES IN 2012

13. The CIAB's role is to advise the IEA Governing Board and Secretariat on matters related to coal production, transport, trade and utilisation as well as on environmental issues associated with coal use. The 2012 work programme was discussed at the CIAB Executive Committee Meeting in November 2011, when a number of topics related to coal's future contribution to international energy markets against the background of CO_2 emissions mitigation policies were considered. The Executive Committee regarded several topics as worthy of study, but recognised that delivering this broad span of work is beyond the normal resource capacity of the CIAB. Accordingly, it was agreed that bids should be sought from external organisations to address the topics in a comprehensive report. This work was kindly supported by a number of CIAB Members' companies[5].

14. Details of this work and other CIAB 2012 work items are given below. In addition, the CIAB interfaces with the IEA Secretariat through regular working contact, its annual CIAB Plenary meeting for CIAB Members and Associates, and two Associates meetings each year.

21st Century Coal: Advanced Technology and Global Energy Solution

15. Following due process the Electric Power Research Institute (EPRI) was selected to co-ordinate work on the report, to which Advanced Resources International (ARI) and RWE Power also contributed. The report addresses the progress of high efficiency and other advanced coal-fuelled generation technologies, the promise associated with enhanced oil recovery in restoring momentum for carbon capture, and the flexibility of coal-fuelled power plants to ensure stable electricity supply:

    - *Coal and the CO_2 Challenge* discusses the benefits of and need for coal, the issues around coal use especially related to CO_2 emissions, and roadmaps to improve coal use and help mitigate issues around it
    - *Evaluation of Advanced Coal-fuelled Electricity Generation Technologies* provides insights into ground breaking technology innovations for advanced coal plants to improve efficiency and reduce emissions including CO_2;
    - *Carbon Capture, Utilisation and Storage* (CCUS) focuses on the exciting potential for enhanced oil recovery (EOR) and the need for and status of CCUS demonstrations; and
    - *Flexibility of Coal-fuelled Power Plants for Dynamic Operation and Grid Stability* assesses the critically necessary feature of fossil-fuelled power plants to operate dynamically on grids with intermittent wind and solar energy inputs.

    The draft report will be presented and discussed at the November 2012 CIAB Plenary meeting, following which the report will be published.

CIAB Coal Information Working Group

16. This working group was formed in early 2011 to co-ordinate collection of a range of non-confidential industry information covering all aspects of the coal production value chain to support preparation of the IEA's *"World Energy Outlook 2011"* and *"Medium-Term Coal Market Report 2011"*. It is led by Mr. Carlos Fernández *(Senior Coal Analyst, IEA)* and has again formulated a questionnaire and collected relevant information during April 2012

[5] Anglo American, CONSOL Energy Inc., J-POWER, Joy Global Inc., Norfolk Southern Corporation, Peabody Energy Co. Inc., Rio Tinto, Xstrata Coal Pty Ltd.

to support IEA analytical work for coal aspects of its 2012 publications.

17. Individual working group members also respond to specific IEA ad-hoc information requests. In particular, the CIAB aims to provide input that improves understanding of;

    - prospects for, and barriers to, coal industry investment;
    - coal markets and trade;
    - coal in non-OECD countries, particularly the influence of rapid growth in coal use by China and other developing economies;
    - the role of coal in alleviating energy poverty;
    - the effects of ageing coal use infrastructure on coal demand and energy security, for example through electricity production flexibility in times of energy crisis; and
    - new uses of coal including coal-to-liquids, coal bed methane and coal gasification.

CIAB-supported secondments to the IEA

18. In recognition of the IEA's desire to improve its analysis and coverage of coal markets, the CIAB has financially supported the provision of PhD students from the Institute of Energy Economics at the University of Cologne (Energiewirtschaftliches Institut an der Universität zu Köln, or EWI) for several months during 2011 and 2012. These individuals have contributed to *"World Energy Outlook"* coal market analysis and substantially supported preparation of the IEA's new *"Medium-Term Coal Market Report"*. If sufficient financial support can be provided through CIAB Members, consideration will be given to extending this or a similar arrangement into 2013.

CIAB Clean Coal Technologies working group

19. The CIAB Clean Coal Technologies Working Group (CCTs WG), under the leadership of Mick Buffier, Associate to CIAB Member Mr. Peter Freyberg (Chief Executive, Xstrata Coal, Australia), has engaged with the IEA Secretariat on the development of its IEA High Efficiency, Low Emissions (HELE) Coal Technology Roadmap. Several CIAB Associates have participated in HELE Coal Technology Roadmap meetings held in Paris in June 2011 and June 2012.

Plenary Meeting discussion sessions

20. In order to widen the discussion of topics relevant to coal with senior representatives of the IEA, CIAB Members and others made a series of presentations at the November 2011 CIAB Plenary meeting. The topics discussed were:

    - Climate Change Targets and Technology Developments;
    - Developments in Major Regional Coal Markets; and
    - Public Policy Developments and Coal Investment.

    A note of these discussions is available on the CIAB website at http://www.iea.org/ciab/papers/CIAB_Plenary_Discussion_Report_Nov_2011.pdf

21. The November 2012 Plenary meeting will include presentations and discussions on:

    - An Inconvenient Reality – the continuing role of coal to 2050 in the energy mix and the need for low emission technology;
    - "21st Century Coal: Advanced Technology and Global Energy Solution"; and

- A Way Forward.

IEA Greenhouse Gas R&D Programme

22. The CIAB has continued its formal sponsorship of IEA GHG, financed by contributions from CIAB Members. A CIAB representative attends IEA GHG Executive Committee meetings and the interface is managed through a small group of CIAB Associates led by Ms. Gina Downes, Associate to CIAB Member Dr. Steve Lennon. The group's aim is to influence the IEA GHG work programme by submitting ideas for IEA GHG Executive Committee consideration, encouraging CIAB participation in IEA GHG events, co-ordinating responses to draft IEA GHG reports, and disseminating IEA GHG reports and other output to CIAB Associates and then into the relevant parts of their organisations.

IEA Publication "Resources to Reserves"

23. The IEA is planning to publish a report updating its September 2005 publication and for the first time including coverage of coal resources and reserves. The CIAB has previously prepared material for the sections of the report covering coal, co-ordinated by the CIAB Energy Security working group with comprehensive support from BGR (the German Federal Institute for Geosciences and Natural Resources). Further updated data and commentary on draft text was provided in August 2012 and publication is expected in November 2012.

Expert review of draft IEA reports

24. A number of CIAB Associates have acted in an individual capacity as expert reviewers for draft IEA publications including *"World Energy Outlook 2012"*, *"Energy Technology Perspectives 2012"* and *"Pre-treatment of Low Rank Coals"*.

CIAB report "International Coal Policy Developments in 2012"

25. This paper has again been drafted by the CIAB Executive Co-ordinator based on contributions and comments from CIAB Associates. It serves as a report to the IEA Governing Board on CIAB work during 2012, covers coal-related policy developments during the year and makes policy recommendations to the IEA. Only a brief overview of coal markets is included.

3 COAL IN WORLD ENERGY MARKETS

26. The world's coal reserves are extraordinarily large and widely dispersed, with proved reserves of 860 billion tonnes and a reserves/production ratio of 112 years[6]. Coal is safe and easy to transport, and it can be readily stored. Reflecting these attributes, as well as the reserves base of developing economies including China and India, the use of coal continues to grow strongly relative to other fossil fuels.

3.1 Overview

27. ***Total world primary energy consumption***[7] grew by 2.5% in 2011, in line with the ten-year average but much slower than in 2010, where the 5.1% growth showed recovery from the negative growth in 2009. Growth in China and India was 8.8% and 7.4% respectively and those two rapidly growing economies now account for almost 26% of total world primary energy consumption. Fossil fuels account for 87% of total world energy consumption. OECD total primary energy consumption fell by 0.8%, to account for 45% of the world total.

28. World ***coal*** consumption grew by 5.4% in 2011, again faster than the 10-year average of 4.6%, while both China and India increased coal consumption by over 9%. Coal accounted for 30.3% of world energy consumption in 2011 and its share is now over 70% in China and nearly 53% in India. Coal consumption in China approached half (49.4%) of global coal consumption in 2011, and India about 8%

29. According to IEA figures, coal consumption has grown at a rate of over 2.4% a year on average over the last thirty years. More notably, this growth has accelerated to over 4.4% on average over the last eleven years.

30. Historically, IEA statistics show coal accounting for 24-27% of world energy use and its share was 27%[8] in 2009. The IEA's New Policies Scenario[9] assumes the introduction of cautious new measures to implement the broad policy commitments that have already been announced, including national pledges to reduce greenhouse gas emissions. In this scenario, the IEA expects total world primary energy use to grow by 1.3% a year on average to 2035 and coal use to grow by 0.85% a year. Coal's share will show very slight growth to 27.6% in 2020, before declining to 24.2% in 2035, with coal demand growing by 24.5% in total over the whole period. These projections for coal demand growth are slightly higher than WEO2010 projections.

31. In the 450 Scenario, which analyses how global energy markets could evolve if countries take co-ordinated action to restrict the global temperature increase to 2°C, total world primary energy use is projected to increase by 1.4% a year to 2020, but only by 0.3% a year between 2020 and 2035, averaging 0.8% a year over the whole period. In this scenario, coal's share of the total market declines slightly to 26.2% in 2020 before declining more rapidly to 15.6% in 2035. In that year, coal demand is 30% lower than in 2009. But achievement of the outcomes required in this scenario to restrict the global temperature increase to 2°C remains very challenging. In the face of yet another year of observed strong growth in world coal demand, in particular in China and India, the mechanisms by which such a reversal in the current trends of fossil energy use and carbon intensity growth would be delivered are far from clear.

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[6] Source: *"BP Statistical Review of World Energy June 2012"*

[7] Figures in this paragraph are derived from *"BP Statistical Review of World Energy June 2012"*.

[8] There are definitional differences between BP and IEA figures. Coal's share of primary energy consumption in 2009 is 27.15% based on IEA figures and 29.09% based on BP figures.

[9] OECD/IEA *"World Energy Outlook 2011"* (2011)

32. With appropriate policy and investment signals, coal has the ability to meet further long term increases in demand, to support economic growth and to enhance the security of world energy markets through the development of national coal resources and increased international trade. Current indications[10] are that proved coal reserves (405 billion tonnes of sub-bituminous coal and 456 billion tonnes of anthracite and bituminous coal) at the end of 2011 are sufficient to satisfy the current production rate for 112 years. This is far higher than reserves/production ratios for oil (54 years) and natural gas (64 years), while the wide dispersion of coal reserves in benign geographies reduces the risk of supply disruption relative to other fossil fuels.

3.2 International Coal Trade

33. Thermal seaborne coal trade continued its growth in 2010 and 2011, increasing by 5.9% in 2010 and by a massive 10.9% to 791 million tonnes in 2011. Over the last 10 years, thermal seaborne coal trade has more than doubled, showing average growth of 41 million tonnes a year compared to average growth of 18 million tonnes a year in the previous ten years. Seaborne coking coal trade declined by 3.4% to 238 million tonnes in 2011, following a 30% increase in 2010. Australia remains the largest hard coal (thermal and metallurgical coal) exporting country, with 285 million tonnes of exports (nearly 25% of the world market) in 2010[11]. Although Australia's export volume remained broadly constant, half of the 90 million tonnes increase in hard coal trade (seaborne and other) was met from increased exports from Indonesia.

34. After peaking at nearly US$148/tonne on average in 2009 however, the price of steam coal delivered to North West Europe declined to US$60/tonne in 2009 and has increased steadily to US$121/tonne in 2011. China remains the key driver of international coal markets. In 2009 it transformed from a net coal exporter to a net coal importer, with net imports of 126 million tonnes in 2009 and 160 million tonnes in 2010. The massive size and potential rate of change of its domestic coal production and consumption, the latter driven by increasing industrial demand and electricity consumption, makes it a potential source of future market price volatility.

Asian Market

35. The long-term importance of thermal coal in Asia is illustrated by the following coal-fired power industry developments:

    - Indonesia – GDF Suez's 815MW coal-fired plant will be the first supercritical plant in the country and the largest generating unit on the Java-Bali grid
    - Cambodia – Ratchaburi Electricity is building a 1,800MW coal-fired plant in Koh Kong province
    - Philippines – Alcantara Sarangani Energy's US$400 million, 200MW coal-fired unit broke ground in November 2011
    - Vietnam – PHI Group is installing a 2,000MW coal-fired unit and also building a 3,000MW coal plant with Sao Nam Group.

36. Growth in demand for metallurgical coal to 2020 is expected to be mainly driven by China and India. The domestic supply of high quality hard coking coal in China has failed to keep pace with demand. India, with its very limited supply of such coal, is highly reliant on

[10] *"BP Statistical Review of World Energy June 2012"*., page 30
[11] IEA "Coal Information 2012", Part III, Tables 3.3 and 3.4

imports.

Thermal Coal

37. The Australian Government's official analyst, the Bureau of Resources and Energy Economics (BREE), projects that contract prices for thermal coal may drop 37% by 2017 because of a rise in shipments from countries including Indonesia and Colombia. Thermal coal prices are forecast to fall to US$82/tonne for annual supplies starting 1 April 2017. In 2012, thermal coal spot prices are forecast to ease to around US$115/tonne due to increased supply from Australia and Indonesia and increased coal exports from the US into Asia. In fact, the "Newcastle spot price" has fallen below $100/tonne for thermal coal recently, partly reflecting increased USA tonnage entering Asia. Japan's electricity producers agreed to pay a record US$129.85/tonne for coal in 2011 and recently settled the 2012 contract at US$115.25/tonne.[12]

38. According to the Colombian Embassy in Canberra, Colombia is particularly focused on the Asia Pacific region for coal exports. It aims to export 75 million tonnes of thermal coal this year and is looking to expand to 120 million tonnes in four years and 200 million tonnes by 2020. It has the advantage of two Caribbean ports and one Pacific one. So it is well placed to play an increased export role. There is a need to upgrade infrastructure considerably and do further geological mapping (with only half the country's prospective areas mapped).

39. Over the past few years Chinese thermal coal imports have been trending upwards with coal exports now at an all-time low. Much of the increased Chinese imports are being sourced from Indonesia, Colombia and South Africa rather than Australia for cost-competitiveness reasons.

Metallurgical Coal

40. Metallurgical coal exports from Australia decreased by 16% in 2011 to 133 million tonnes due to the impact of heavy rains and flooding in January 2011 that reduced Queensland production for much of the year.[13] Due to environmental safeguard requirements by the Queensland Government, the removal of water from mine pits has been slow. As a result the actual impact of the abnormal rains and flooding events resulted in a 17.8% reduction in exports.[14] The Queensland black coal industry and Queensland Government have a number of strategies in place to deal with above-average rainfall events in the future.

41. Given the supply shortage, high-cost USA metallurgical coal exports to Asia are currently well above historical levels. However, despite the expected stronger growth in seaborne metallurgical coal demand between 2011 and 2020 compared to the decade to 2010,[15] BREE's forecasts for metallurgical coal prices in real terms are US$289/tonne in 2011 falling each year to US$183/tonne in 2017. Given shortages in metallurgical coal supply, previously undeveloped basins in Mongolia and Mozambique are being developed. Over the period to 2017, BREE expects these two countries to emerge as important new metallurgical coal exporters.

[12] BREE, *Resources and Energy Quarterly*, March 2012, pp 49 - 50.
[13] Ibid, pp 82, 83 and 86.
[14] The Queensland Resources Council reports that shipments from Queensland coal terminals in calendar year 2011 were 153.78 million tonnes, down 17.8%, or almost 33 million tonnes, on 185.76 million tonnes in 2010.
[15] Marcus Randolph (2011), *Steelmaking materials briefing*, 30 September, available on the BHP Billiton website.

3.3 Regional Developments

United States of America

42. Given current market conditions, investment in coal production is likely to be minimal, although increases in international demand for steam coal and metallurgical coal may offset some of the lost domestic demand.

43. In 2011, US Coal exports were 107.4 million short tons[16], more than double the 2001 exports of 49.6 million short tons, and a substantial increase over 2010 exports of 81.8 million short tons. 2011 exports included 37.2 million short tons of steam coal, 69.5 million short tons of metallurgical coal, 0.3 million short tons of lignite and 0.4 million short tons of anthracite, as compared to 2010 exports of 25.0 million short tons of steam coal, 56.2 million short tons of metallurgical coal, 0.3 million short tons of lignite, and 0.3 million short tons of anthracite[17].

44. In 2010, six seaports accounted for 94% of coal exports - Norfolk, Baltimore, New Orleans, Mobile, Detroit and Seattle. The Norfolk seaport is the largest coal port, exporting about 40% of the total. There is a nation-wide effort to expand coal export terminals. Current US port export capacity is 199.7 million short tons. Planned port expansions would eventually boost this by 186.5 million short tons to 386.2 million short tons.[18].

45. The industry has experienced further consolidation and this is likely to continue in the short term. A number of coal mines have been idled and a number of new mine startups have been delayed due to demand weakness. Patriot coal has announced the idling of several mines that produced a combined 2.4 million tons in 2011, Arch Coal expects to reduce volume by 25 million tons compared to 2011 and Alpha Natural Resources, Consol Energy, and others are also idling mines.

46. The current US energy mix is 20.4% coal, 25.5% natural gas, 32.6% petroleum, 8.5% nuclear and 9.3% renewable energy. The combination of mild weather and low natural gas prices, due to record levels of production, is causing a shift towards more natural gas use in electricity generation. High levels of natural gas storage will prolong this situation at least through the summer and autumn, followed by some shift back to coal usage in electricity generation as consumers work through the large gas storage overhang and as weather conditions revert to normal. However, US coal consumption is projected to decline by 8% in 2012, compared to 2011[19], attributable to both market factors and policy factors.

47. The primary market factor is the sharp drop in the price of natural gas in the US, largely due to development of shale gas resources, and its impact on fuel use by the electric power sector. It is difficult to overstate the impact on US energy markets resulting from the development of shale gas. As recently as five years ago, the USDOE/EIA projected that liquefied natural gas (LNG) imports would be needed to replace rapidly declining production rates for natural gas in the US. In 2007, EIA forecast that imported LNG would supply 14% of total US natural gas consumption in 2020 and 17% in 2030.[20] By 2010, LNG importers were filing for bankruptcy[21], citing a lack of activity. The US DOE has now

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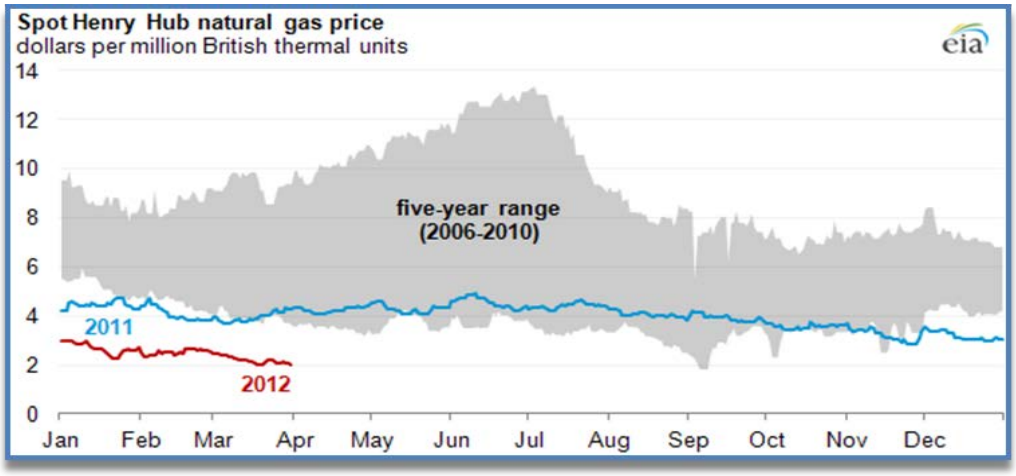
[16] 1 short ton equals 0.90718 metric tonnes
[17] National Mining Association, USA, "Facts at a Glance (Coal)", July 2012.
[18] National Mining Association, USA, "US Coal Export Terminals-2011", July 31, 2012.
[19] Short Term Energy Outlook, USDOE/EIA, 10 April 2012, http://205.254.135.7/forecasts/steo/ .
[20] Annual Energy Outlook 2007, DOE/EIA-0383(2007), February 2007, http://www.eia.gov/oiaf/archive/aeo07/index.html .
[21] Oregon liquefied gas developer NorthernStar files for bankruptcy, *The Oregoinan*, May 5, 2010.

approved permits for export LNG contracts which total 14 billion cubic feet per day[22], which is equivalent to about 20% of total US production in 2011. The increased production of domestic natural gas has led to declining prices, which were at a ten year low in April 2012 (see chart below).[23]

US Natural gas prices



48. The end-use market most sensitive to these price changes is electric power production. EIA projects that in 2012 coal-fired power generation will decrease by about 0.5 billion kWh/day, which is about 10% of the current total, and will be replaced by natural gas-fired power generation.[24]

49. The major policy factor is federal environmental regulation of emissions from coal-fired power plants. In addition, state and Federal mandates focusing on renewable portfolio standards and "fair access" to the power transmission infrastructure can impact decisions on technology deployment. Regulatory uncertainty and tight budgets for infrastructure maintenance also impact coal mining and coal transportation although these issues tend to be more regional in nature.

50. Over the next decade potential regulatory policy changes regarding carbon dioxide emissions from coal use may limit construction of new coal-based energy conversion facilities, including power plants, to a small number of projects receiving government subsidies for innovative carbon capture utilisation and storage (CCUS) systems. Electric power plants consumed 93% of the 1 billion tonnes of US coal production in 2011, and these existing power plants may be subject to similarly aggressive policies regarding greenhouse gas emissions.

51. Other environmental regulations are also influencing near-term coal use in the US. Three key rules adopted during the past year were related to control of sulphur dioxide (SO_2) and nitrogen oxides (NO_X) from existing power plants[25], control of hazardous air pollutants from new and existing coal-based power plants[26], and new source performance standards for emission of particulate matter, SO_2, and NO_X from new power

[22] Applications Received by DOE/FE to Export Domestically Produced LNG from the Lower-48 States (as of March 23, 2012), USDOE, http://www.fossil.energy.gov/programs/gasregulation/LNG_Summary_Table_3_23_12.2.pdf .
[23] Spot natural gas prices near ten year lows during winter 2011-2012, USDOE/EIA, http://www.eia.gov/todayinenergy/detail.cfm?id=5910 .
[24] Op. Cit., Short Term Energy Outlook.
[25] Interstate Transport of Fine Particulate Matter and Ozone, USEPA, 76FR48208, August 8, 2011.
[26] National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units, and Standards of Performance for Fossil-Fuel-Fired Electric Utility Units, USEPA, 77FR9304, February 16, 2012.

plants.[27] While some of these rules are being challenged in court, several utilities that rely heavily on coal-fuelled electricity generation have subsequently announced plans to retire multiple coal units, citing environmental compliance requirements as a primary reason.[28]

52. However, there are some positive influences on future coal use in the USA. The first is the use of captured CO_2, referred to as carbon capture utilisation and storage (CCUS), for enhanced oil recovery (EOR), which can offset a portion of the cost of CO_2 capture. The second is the use of coal to provide high value products, such as chemicals or transportation fuels, either in single-product coal conversion facilities or in "poly-generation" facilities which produce electricity and other products from coal. The third area is continued research, development, and demonstration of advanced coal technologies, including CCUS, which could lower the cost of electricity and other products derived from coal. Each of these three areas will be influenced by evolving US government policies toward coal.

Australia

Energy Mix

53. Australia's National Electricity Market (NEM) covers Queensland, New South Wales, Victoria, Tasmania and South Australia. Within that market, black and brown coal-fuelled power plants currently account for about 56% of electricity generation capacity but coal-fired base-load power plants supply about 78% of total output, natural gas has 26% of generation capacity and produces 12% of output, and renewable energy comprises 16% of capacity and about 7% of output. As shown in the table below, Victoria (with 91% of principal electricity generation based on coal), New South Wales (89%) and Queensland (82%) rely on black and/or brown coal more heavily than the other jurisdictions.

[27] Ibid.
[28] See, for example, AEP Notifies Reliability Organizations of Planned Plant Retirements, where AEP identified 4,600 MW of coal capacity that would be retired, which is about 18% of total AEP coal generating capacity. http://www.aep.com/newsroom/newsreleases/?id=1754 . Similarly, Southern Company announced that it would likely retire 4000 MW of coal-fired capacity as a result of the rules. http://www.southerncompany.com/news/iframe_pressroom.aspx .

Australian Principal Electricity Generation by State and Fuel Type in 2009-10

Fuel type	NSW & ACT	Victoria	Qld	SA	WA	Tas	NT
Coal (%)	91.4[a)]	91.2	82.3	31.2	48.1	0	0
Natural gas (%)	5.6	2.0	4.9	46.7	48.0	11.5	85.0
Hydro (%)	2.4	4.3	0.9	0	0	83.7	0
Wind (%)	0.6	2.5	0	22.1	3.7	4.8	0
Biofuels (%)	0	0	0.05	0	0	0	0
Oil Products (%)	0	0	0.08	0.05	0.1	0	15.0
Coal Seam Methane (%)	0	0	11.8	0	0	0	0
Total generation (GWh)	70,407	56,436	60,014	14,621	17,439	9,891	1,569
Energy sent out (GWh)	65,269	51,916	56,445	14,009	17,067	9,780	1,538
Energy purchases[(b)] (GWh)	5,728	1,200	1,994	315	683	43	376
Net imports[(c)] via interconnectors (GWh)	7,797	-3,853	-5,695	618	0	1,132	0
Trade losses (GWh)	177	169	48	19	15,364	10,558	1,725
Total Available Energy (GWh)	78,617	49,095	52,697	14,923	17,750	10,906	1,914

Source: Energy Supply Association of Australia, *Electricity Gas Australia 2011,* Table 2.5 and 2.6.

Notes: (a) Excluding the ACT, NSW relies on black coal for 89 per cent of its electricity generation.

(b) Purchased from IPPs, non-grid and embedded generation.

(c) Victoria and Queensland are the only net electricity exporters in the NEM.

54. Energy network investment in the current five year regulatory cycle (roughly 2011 to 2016[29]) is running at historically high levels of just over $8 billion a year. This is made up of $35 billion in electricity distribution, over $7 billion in electricity transmission and $3 billion in gas distribution. These forecasts represent an increase on investment in the previous five-year regulatory periods of around 62% in electricity distribution, 82% in electricity transmission and 74% in gas distribution (in real terms). In addition to this investment task, various generators will need to re-finance existing investments. In the current credit-constrained environment, raising the necessary finance to meet these investment requirements represents a significant challenge.

55. The proportion of renewable energy in Australia's energy mix will increase as a result of the Australian Government's Renewable Energy Target, which requires that 20% of electricity must come from renewable sources by 2020. However, the remaining 80% will continue to come from fossil fuel sources, primarily coal.

56. Coal's share of domestic electricity generation, while declining, is still projected to be 42% in 2034/35 under BREE's moderate gas price scenario. According to BREE's modelling, if the gas price on Australia's east coast rises more sharply, due to international parity

[29] There are some departures from those dates in certain jurisdictions. See Table 3.5 in Australian Energy Regulator (2011), *State of the energy market 2011.*

pricing as export activity becomes established (as assumed in its high gas price scenario), then the demand for both black coal and brown coal goes up – the supply of electricity does not come from renewables.[30] Under this scenario, black coal power stations produce 4,000GWh more in 2019/20 and 23,000GWh more in 2034/35 relative to the more moderate gas price scenario[31]

New Coal-fired Capacity

57. Expansion of Eraring Energy's Eraring Power Station to increase coal fired capacity by 240MW continued in 2011. This involves upgrading the remaining two of its four units so that all four will have a 720MW capacity.[32] The project is scheduled for completion in 2012 at a capital cost of $245 million. The Western Australian coal-fired Muja Power Station is situated 225 kilometres south east of Perth. Stages A and B, closed in April 2007, are currently being refurbished and will be recommissioned in late 2012. This refurbishment is a joint-venture between Verve Energy and Inalco, known as Vinalco, and the units are planned to operate as mid-merit peaking plant with a 10 to 15 year lifespan. The 220MW A and B refurbishment project is expected to cost A$150 million.[33]

58. Bow Energy is developing the 30MW coal seam gas-fired Blackwater Power Project in Queensland at an estimated capital cost of A$35 million which is scheduled to be completed in 2012.

59. No other coal-fired power plants are expected to be commissioned or decommissioned over the next five years.

60. At the end of October 2011 there were 53 non-renewable electricity generation projects at a less advanced stage, the majority of which (42) are gas-fired with four black coal fired projects (one in Queensland and three in WA) and four brown coal fired projects (one in Victoria and three in South Australia).[34]

Coal Production

61. In 2011 Australia produced about 350 million tonnes of black coal and 74 million tonnes of brown coal. Only black coal is exported and Australia is the largest exporter of seaborne coal in the world. This trade represents about 4% of world coal production.[35] In 2011-12 Australia's coal exports are forecast to earn over A$49 billion.[36]

62. According to BREE, black coal exports increased at an average annual rate of 3.3% between 2006/07 and 2010/11, encouraged by strong global demand and supported by commissioning of new mines, rail networks and ports in Queensland and New South Wales. Over the five year period coal exports have increased from 74% to about 80% of total coal production. This expansion in coal production and exports has been underpinned by on-going industrialisation in Asia, particularly in China and India.

63. BREE estimates that Australia currently has some A$23.7 billion in "Advanced" coal mining projects and associated infrastructure (Table 2 in the Appendix A). These would

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[30] Bureau of Resources and Energy Economics (2011), *Australian energy projections 2034-35*, December, Table 12, p 42. The high gas price scenario assumes gas prices increase by around 40% in the latter part of the projection period relative to the more moderate price scenario.
[31] Ibid, Table 11, p 36.
[32] Eraring Energy (2011), *Annual Report*, p 2.
[33] Verve Energy website, www.verveenergy.com.au/projects/more-projects.
[34] BREE's *Major Electricity Generation Projects*, November 2011, p 12.
[35] In 2010, the world produced over 7.2 billion tonnes of black and brown coal. Australia produced around 420 million tonnes and exported 290 million tonnes. Exports represented 4% of total black and brown coal produced. See the International Energy Agency, *Coal Information 2011*, Tables II.2, II.3, and Australia table 3.
[36] Bureau of Resources and Energy Economics, *Resources and Energy Quarterly*, March 2012, p 178.

involve more than 74 Mt of coal production by 2014. “Less advanced” coal mine projects have a potential capital expenditure of over A$46.6 billion that could add over 540 Mt of new capacity if all projects were to proceed – although that is unlikely as they are to some extent competing for the same market.[37] Further, the mining industry has recently raised concerns about escalating capital and operating costs in Australia, and many projects are coming under review.

Major coal mining projects and related infrastructure, October 2011 (A$m)

Mining project investment[(a)]	Queensland	New South Wales
Advanced (i.e. Under construction or committed)	9,809	4,034
Less advanced projects	33,463	5,757
Infrastructure project investment		
Advanced	7,280	2,570
Less advanced projects	2,000	< 5,414
TOTAL	**52,552**	**17,974**

Source: Bureau of Resources and Energy Economics, Minerals and energy Major development projects, October 2011.

Notes: (a) “Advanced” projects are those under construction or committed to by company boards. “Less Advanced Projects” are those under consideration but which have not yet received final investment approval by a company’s board

Indonesia

64. 70 to 80% of coal produced by mining companies is sold on long term volume contracts with prices mainly linked to international price indices. The Government of Indonesia (GOI) allows a maximum 12 month time length for spot price contracts. Generally, contracts use the Indonesian Coal Price Reference at time of delivery. The ICPR is published monthly by GOI, based on four international price indices. It is also used to calculate the royalties and Corporate Indonesia Tax to be paid by coal mining companies and it defines a ceiling price for domestic sales. Sales at a lower price are permitted, but royalties and Corporate Indonesia Tax liabilities are still calculated using the ICPR. There are no export taxes, levies or duties are payable.

Russia

65. Coal accounted for 12.3%, oil 35%, and gas 52%, of total fossil fuel consumption in Russia in 2011. Energy sources for electricity generation were thermal 67.8%, nuclear 17% and hydro-electric 15.2%. Coal is mainly used for electricity production, where it accounts for 28.3% of the fossil fuel consumption.

66. Total coal’s share of electricity production is affected in the short-term by weather and the level of water reserves for Siberian hydropower plants. In the medium and long-term, coal consumption will be driven primarily by relative levels of domestic gas and coal prices.

South Africa

67. The percentage of coal exported to the Pacific from South Africa grew from 38% in 2009

[37] “Advanced” projects are those under construction or committed to by company boards. “Less Advanced Projects” are those under consideration but which have not yet received Final Investment Approval by a company’s board.

to about 60% in 2011. Another feature of exports to these countries (especially India and China) is that the grades required for the Pacific market are lower (5,500kCal/kg, 20-22% ash) than those required for the Atlantic Market (6,000kCal/kg, 10-15% ash). The former specification suits most South African collieries, as they are mining reserves of lower grade. In general, the quality of the domestic coal (calorific value on average of 19GJ/tonne versus international requirements of on average 25GJ/tonne) is not suitable for the export market unless it is beneficiated, which may in turn impact on average qualities available to domestic markets..

68. In the recent past, coal exports have been limited by the rail capacity to transport the coal to the ports but current investment plans are being directed to relieving this bottleneck. About R200 billion of Transnet's seven-year rolling capital investment programme will be directed towards the upgrade and expansion of South Africa's key commodity export corridors. A large proportion of this investment will be used for the Richards Bay coal corridor (rail line), which links the coal fields of the Mpumalanga Highveld to the port at Richards Bay over a distance of approximately 700km.

69. The investment in the coal channel could increase coal rail capacity by 44% from 68Mt last year to 98Mt by 2018/19, which would exceed the 91Mtpa current port capacity at Richards Bay Coal Terminal, South Africa's largest coal export terminal.

70. Only 6 new large mine projects were commissioned in 2011. Collectively, these projects are expected to add 55 million tonnes per annum of saleable coal to the existing production, although some of the older mines are due for closure. Most other coal deals are mergers or ownership changes. There are many smaller new mines (some 20 to 30) termed 'juniors' i.e., collieries with a total combined output of less than 1million tonnes per annum.

71. South Africa's traditional coalfields (mainly those in Mpumalanga province) in the "Central Basin" provide 85% of the current coal production. They have been extensively exploited and at present only small blocks of reserves remain, not suitable for large mines (>10Mtpa output) as developed in the past. The remaining coalfields, especially those in the Limpopo province, will require a significant investment in infrastructure to mine and transport their products to local and export markets. Much of this coal is not suitable to mine by conventional methods and coal qualities also differ from the Central Basin.

72. Coal contributed approximately 87% of the 250.5TWh of electricity available for distribution in South Africa in 2011 and approximately 30% of the liquid fuel requirements. Nuclear power contributed around 5% and hydroelectric power (including pumped storage and imported options) a further 7% to South Africa's electricity supply.

73. Two new Eskom coal-fired electricity generation stations, Medupi and Kusile are under construction. The 9.6GW of capacity will be commissioned in stages, between 2013 and 2018.

74. The Integrated Resource Plan (IRP) 2010 does make provision for small amounts of private coal-fired generation from 2015/16, but this may slip because no specific projects are approved yet. The 450MW Khanyisa project is expected to be the first large-scale IPP since the enactment of the IRP 2010. Coal will be supplied to Khanyisa from Anglo American Thermal Coal's (AATC) discard dumps and its entire generation capacity will be made available to Anglo Platinum, thereby releasing Anglo Platinum's current demand back into the electricity market.

75. A further 500MW of coal fluidized bed (CFB) capacity coming online in 2019/20 will be confirmed in the 2012 revision of the IRP. The remaining 4.75GW of coal capacity included in IRP2010 is not allocated to a specific technology and could be replaced during subsequent revisions of the IRP should the assumptions and their impact on the

quantitative models change.

76. Sasol's next coal-to-liquid project (Mafutha project) in the Waterberg has been put on hold indefinitely; instead a conventional mine will be developed, adding at least 15-20 million tonnes per annum to supply. This is however unlikely to be commissioned before 2016.

77. Last year, Eskom indicated it had contracted 80% of its required cumulative coal supply up to 2020, with 47% of the coal bought on cost-plus contracts, 24% on fixed-price contracts and 29% on short-to medium-term contracts. The much higher price of coal obtained through short term contracts contributed a third to the reported 29.2% increase in the primary energy costs of the state-owned electricity supplier and hence the cost (and price) of electricity supply..

Germany

Coal Demand

78. Last year coal was again the second most important energy source after oil in German primary energy demand, which was 456.4 million tonnes coal equivalent in total. Hard coal and lignite together accounted for 24% of primary energy demand (57.5 million tonnes coal equivalent of hard coal and 53.3 million tonnes coal equivalent of lignite).

79. Coal is mainly used for power production. In 2011, power generation from coal was 240.6TWh (41.7% of a total 577.3TWh net electricity production). 138.0TWh was based on lignite and 102.6TWh on hard coal. The second most important coal consumer was the steel industry, which used 16 million tonnes coal equivalent of hard coking coal and coke.

80. According to recent official figures from the Working Group on Energy Balances[38] hard coal use decreased by 0.7% in 2011 compared to the previous year, but actually there are some signs of a much stronger decline of 2.4% or 1.4 million tonnes coal equivalent. Reasons for the weaker demand include higher generation from renewable sources and the unusually mild winter. Therefore, coal did not benefit from the earlier nuclear energy phase out, one part of Germany's shift in its energy policy ("Energiewende").

81. More than 82% (47.5 million tonnes coal equivalent) of German hard coal demand in 2011 was met by imported sources for power generation, pig iron and/or steel production and for the heating market. Most important origins for German hard coal and coke imports were Colombia (24%), Russia (23%), the USA (17%), Poland (13%), Australia (9%) and Republic of South Africa (6%).

Electricity Generating Capacity

82. The total installed power plant capacity (net) in Germany was 167.8 GW at the end of 2011. The split by energy source (in brackets the values of the previous year):

Installed Power Plant Capacity by Energy Source in Germany (net, GW)

Energy Source	End 2010	End 2011
Nuclear	20.5	12.1
Hard coal	27.9	27.6
Lignite	20.4	19.8

[38] Source: AGEB: "Energieverbrauch in Deutschland im Jahr 2011", website http://www.ag-energiebilanzen.de

Natural gas	24.9	25.8
Oil	5.8	5.5
Pump storage	5.7	5.7
Wind power	27.2	29.1
Photovoltaic	17.5	25.0
Other renewable	10.4	10.9
Other	6.1	6.2
TOTAL	**166.4**	**167.8**

Source: BDEW, 2012

83. Renewable sources were the fastest growing segment of installed electricity generating capacity in 2011. Installed wind capacity increased by 1.9GW and photovoltaic installations increased by 7.5GW. The sharp increase in solar power is due to the German Renewable Energy Act which finances new solar installations via a feed-in-tariff.

84. Fossil-fired plant investments amounting to 13.5GW have been made in recent years, with start of construction between 2006 and 2008 and with start of operations planned between 2010 and 2014. 8.4GW of this is hard coal-fired, 2.8GW is lignite-fired and 2.2GW is natural gas-fired. The efficiency of the new coal builds is about 46% (LHV, hard coal) and more than 43% (LHV, lignite). The largest hard coal projects include Hamburg-Moorburg (Vattenfall, 1.6GW), Hamm (RWE, 1.6GW) and (E.ON, 1.1GW) and the largest lignite project is Neurath (RWE, 2.2GW), which came on line in the first half of 2012.

Hard Coal Production

85. Hard coal production in 2011 was 12.3 million tonnes coal equivalent (6.8% lower than in 2010), hard coal imports were 47.5 million tonnes coal equivalent (2.4% higher than in 2010), 0.3 million tonnes coal equivalent was exported and 2 million tonnes coal equivalent was added to stockpiles.

86. At the end of 2011, there were five hard coal mines in operation in Germany with a total saleable output of 12.1 million tonnes. Domestic coal production continued to fall from a total of 12.9 million tonnes saleable in 2010 as the result of the closure of the Ost Mine, the last mine with significant coking coal output, in September 2010.

87. Mines currently operating and production levels (in 2011) include:

- West (2.8 million tonnes)
- Prosper Haniel (3.2 million tonnes)
- August Victoria (2.7 million tonnes)
- Saar (1.4 million tonnes)
- Ibbenbüren (anthracite, 2.0 million tonnes)

The Saar mine is scheduled to close at the end of May 2012 and the West mine at the end of this year.

Lignite Production

88. There are twelve opencast lignite mines in operation in Germany, with a total production of 176.5 million tonnes (54.4 million tonnes coal equivalent, 1.0 of which was exported) in 2011. In the Rhenish basin, RWE Power AG produced 95.6 million tonnes from its three opencast mines Hambach, Inden and Garzweiler. The five Lausatian mines of Vattenfall

Europe Mining (Cottbus-Nord, Jänschwalde, Welzow-Süd, Nochten and Reichwalde) produced a total of 59.8 million tonnes. The MIBRAG mines in the Central German basin, Profen and Vereinigtes Schleenhain, owned by CEZ and J&T, produced 19.0 million tonnes. Romonta mined 0.5 million tonnes, mostly used for montan wax production. E.ON produced 1.6 million tonnes in the opencast mine Schöningen near Helmstedt.

The Netherlands

89. In the Dutch energy mix, well developed infrastructure and access to gas fields mean that natural gas is more important than coal. Nevertheless, in 2010 11.7 million tonnes of hard coal were imported, of which 7.3 million tonnes were used for power production.

90. In 2010 the 4GW of Dutch coal-fired capacity delivered approximately 25% of the total electricity consumption of 119TWh. Almost all coal plants co-fire biomass up to 30%, with a sector average of 10%. The major source of biomass is white wood pellets, imported mainly from North America and Scandinavia.

91. Three new coal plants with a total capacity of 3.5GW are under construction for commissioning before 2014. All these power plants are carbon capture ready (a permit obligation) and will be able to co-fire biomass between 10% and 50%.

Poland

92. Hard coal and lignite prevail in the energy mix in Poland, although the share of coal is decreasing slightly each year:

Polish Energy Mix (%)

Energy Source	2008	2009	2010
Coal	59.3	57.6	56.9
Oil	21.2	21.7	22.2
Natural gas	13.4	13.7	13.3
Other	6.1	7.0	7.6
TOTAL	**100.0**	**100.0**	**100.0**

Source: Polish Statistical Office

93. The current *Energy Policy for Poland until 2030*, adopted by the Ministry of Economy in November 2009, projects broadly stable coal demand, increasing slightly from 11.22 million tonnes oil equivalent to 12.16 million tonnes oil equivalent in 2015 and then declining to 9.72 million tonnes oil equivalent by 2030. Fuel switching to natural gas and renewable energy in electricity production is foreseen, with the introduction of nuclear power after 2023.

94. Analysis of public statements by Polish equipment producers and electricity and heat producers suggest investment plans at the tendering stage for 8,000MW of coal-fired power plant and 2,000MW of natural-gas fired power plant. Even taking into consideration potential switching to natural gas, biomass, other renewables or nuclear power, these plans suggest that coal-fired power generation capacity will be sufficient to meet the coal demand projections of the *Energy Policy for Poland until 2030*.

95. Hard coal production amounted to around 76 million tonnes in 2010 and 75.4 million tonnes in 2011. Polish hard coal producers foresee slight increases in hard coal production this year and in following years.

96. Hard coal imports into Poland, mainly steam coal, increased from 14.2 million tonnes in 2010[39] to more than 14.7 million tonnes (estimated) in 2011. Hard coal exports in 2011, mainly coking coal, were 5.8 million tonnes, about 46% less than in 2010. Excise duties on coal and coke trade, with some exemptions, came into force on 2nd January 2012, although they are not expected to have a significant effect on domestic coal production.

97. Lignite production and consumption remained stable at about 62.8 million tonnes in 2011.

98. Underground coal gasification research is being carried out within the frameworks of the Polish National Programme for Scientific Research and Development and the European Research Fund for Coal and Steel.

Turkey

99. Estimated lignite reserves at the end of 2011 are 11.75 billion tonnes in total, of which 91.8% are proved. New lignite reserves have been found at Trakya (495 million tonnes), Manisa-Soma-Eynez (170 million tonnes), Eskisehir-Alpu (300 million tonnes), Afşin-Elbistan (1.9 billion tonnes) and Konya-Karapınar (1.72 billion tonnes). 86% of total reserves are in state ownership. Total Lignite production declined between 2002 and 2004 as power station demand for the fuel declined, reaching its lowest point at 43.7 million tonnes in 2004. However, production then increased steadily to reach 76.2 million tonnes in 2008, driven by government energy policy favouring domestic lignite-based electricity generation. In 2011, Turkish Coal Enterprises (TKI), the biggest state-owned lignite producer, produced 33.4 million tonnes of lignite while the second biggest, Electricity Generation Company EUAS, produced 31.6 million tonnes of lignite and the remaining 5 million tonnes (approx.) was produced by the private sector.

100. Lignite is consumed in three sectors: thermal power stations, industry and households, but power generation is the main consumer. While the share of lignite in electricity generation reached its highest value of 47% in 1986, this had declined to 17% by 2011 as a result of an increase in the use of natural gas in electricity generation. 45.4% of electricity generated in 2011 used natural gas. In 2009 one new asphaltite based power station, Silopi, commenced operation and in 2011 a 600MW imported coal based power plant at Canakkale started operating.

101. Typically, Turkey produces about 2-3 million tonnes of hard coal annually and according to the Turkish Statistics Establishment figures, imported 24 million tonnes of hard coal in 2011, 60% of which was sourced from Russia and Colombia, and the remainder from USA and South Africa.

[39] Source: Polish Geological Institute

4 POLICY DEVELOPMENTS

4.1 Overview

102. IEA scenarios project total energy demand increases of 23-51% to 2035 (from 2009), depending on the extent of action taken to mitigate increases in greenhouse gas emissions[40]. In order to maintain a stable and affordable energy supply whilst keeping economic, social and environmental objectives in balance, it is essential that energy be obtained from a wide variety of sources.

103. The challenge of greenhouse gas emissions reduction affects all fossil fuels, particularly coal because it is the most carbon intensive fossil fuel. The following paragraphs highlight recent policy developments that demonstrate this challenge for the coal industry.

104. In summary, progress has again been slow. Policy and regulatory developments continue to be unfavourable to sustaining coal production and use. Furthermore, in some countries public opposition to coal use is hardening, largely as a result of the erroneous perception that world energy growth can be satisfied and climate change mitigation targets met in parallel with declining coal use. An example of this opposition is provided by a Greenpeace document entitled *"Stopping the Australian Coal Export Boom"* that includes proposals for civil disruption campaigns and support for litigation by communities. Such opposition to coal mining and coal exports is likely to continue in Australia. In the USA, a raft of impending new environmental regulations affecting coal use will likely stall development of any new coal-fired electricity generating capacity for many years, while the lack of an integrated energy policy adds to future uncertainty.

105. Subsidies continue to be offered for uneconomic renewable energy, mostly wind and solar power, while support for the development of carbon capture and storage demonstration projects is reducing rather than increasing. The development of potential carbon storage sites is becoming particularly difficult; and focus in the USA is turning to the use of CO_2 for enhanced oil recovery as a means of improving CCS demonstration project economics.

106. In Australia, the new Minerals Resource Rent Tax and carbon taxes will unfavourably impact the economics of coal mining and act as disincentives to investment. Similarly, in South Africa the concept of a *"Resource Rent Tax"* (RRT) on all minerals, triggered after a normal return on investment has been achieved and thus reducing the impact on marginal or low grade deposits, is being considered.

107. These developments are set out in further detail below. In the coal industry's view, their effect on the ability to maintain the role of coal in carbon-constrained world, particularly in OECD economies, remains a major concern for electricity supply and energy security.

4.2 The Role of Coal

United States of America

108. Coal-fired power plant capacity reductions of 45-90 GW are expected over the next few years as a result of continuing low gas prices and regulatory developments. New Source Performance Standards for pulverised coal boilers are so restrictive that manufacturers will not guarantee performance; and the EPA's GHG Rule proposes that CO_2 emissions from new coal-fired power plant should equal those from gas-fired plant over a 30 year

[40] OECD/IEA "World Energy Outlook 2011" (2011)

period, with a requirement to install CCS within 10 years although CCS will not be commercially available within that timescale.

Japan

109. Following the accident involving the nuclear power plants in Fukushima, political and scientific judgments on the use of nuclear power plants are still uncertain. By May 2012 all of Japan's nuclear capacity was shut down, and as of 25 September only two units (2.4GW) have restarted. The remainder (52 units or 46.5GW) will not be returned to service before next summer. Under these circumstances, the Advisory Committee for Natural Resources and Energy has examined desirable power generation portfolios for 2030 (see table below) with respect to the balance between the "Three Es": economic efficiency, energy security and environment.

Generation Portfolio (percentage for each power source)

		Nuclear	Renewable Energy	Thermal	CHP and onsite generation
2010		26.4	10.5	56.9	6.2
"Basic Energy Plan" 2030 Projections[(a)]		45.4	19.6	22.8	12.1
2030 Projections under discussion[(b)]	Zero Nuclear option	0	35	50[(c)]	15
	35% Nuclear option	35	25	25[(d)]	15

Source: Advisory Committee for Natural Resources and Energy.

Notes: (a) Cabinet approved the Plan in June 2010, before the nuclear accident. It includes an additional 14 nuclear units to be built by FY2030.

(b) The discussion includes options between zero and 35% dependence on nuclear power, and all options assume 10% energy conservation from the total generation in 2010.

(c) 23% points coal, 20% points natural gas; 4% points other.

(d) 16% points coal, 5% points natural gas; 4% points other.

110. In its new "Innovative Energy and Environment Strategy", the Japanese government revealed on 14 May 2012 its target of reaching zero nuclear generation in the 2030s. However, in light of the government's forthcoming regulation to halt operation of nuclear units when they reach 40 years old, achievement of zero nuclear generation in the 2030s looks impossible. Prime Minister Noda has stated that the government will make efforts to promote renewable energy so as to achieve the goal.

South Africa

111. The Integrated Resource Plan (IRP2010) was enacted on 6 May 2011. This plan will be revised every two years. The "Policy-adjusted" electricity generation scenario is based on an electricity growth projection of 2.9% per annum on average. By 2030, it is projected that coal will supply 65% (>90% currently), nuclear 20%, hydro 5%, gas 1% and renewable energy 9% of the electricity demand.

112. The scenario makes provision for the addition of 9.6GW of nuclear power, 6.3GW of coal (non-committed new build between 2010 and 2030), 17.8GW of renewable energy, and 8.9GW of other generation sources (natural gas, diesel OCGT and import hydro) between 2010 and 2030. The 6.3GW of coal new build is scheduled for 2014-2030 and will comprise pulverized coal, fluidized bed combustion, co-generation, own build and

imports. IRP2010 also includes over 3.4GW of projected energy efficiency demand-side management interventions. Implementation of the plan would see a 34% decline in emissions intensity from the sector by 2030, although none of the nuclear or additional coal-fired build has yet been approved.

Germany

113. The politically driven accelerated evaluation of Germany's energy policy shift to more renewables and higher energy efficiency has made some progress in 2011/12. But there are still a large number of unresolved questions, including investments for expansion of the electricity network required by increased use of wind power. The German Federal Council (Bundesrate) recently failed to pass a bill to cut solar electricity subsidies. Many investment barriers to building new power plants, especially fossil-fired power plants, remain due to high capital costs and permitting difficulties; while off-shore wind parks lack grid connections and investments in the transmission grid. So the investment situation is unclear because of the uncertain political and economic climate, and the lack of support for investment projects from local populations. Additionally there are increasing concerns about higher electricity and energy prices.

114. The German federal government long-term energy concept to 2050 focuses on meeting climate goals while still maintaining reliable energy sources and power supplies at affordable prices. Long-term goals include:

- a reduction in primary energy demand by 20% by 2020 and by 50% by 2050 compared to 2008 levels;
- reductions in greenhouse gas emissions (GHG) of 40% by 2020, 55% by 2030, 70% by 2040 and as much as 80-85% by 2050 compared to 1990 levels; and
- 80% of power sourced from renewable sources by 2050.

115. In the Energy Concept of September 2010, the German coalition government agreed to a controversial lifetime extension for existing nuclear plants. The effects of the Japanese earthquake have caused individual countries to re-assess their nuclear power programmes. Many countries, including China, have announced additional safety checks on current and proposed plants; and other countries still assessing their responses are expected to propose similar action.

116. The most significant immediate response was from Germany, which announced the temporary closure of 8.4 GW of nuclear capacity comprising the seven pre-1980 reactors and Krümmel. No political party in Germany supports the longer term use of nuclear energy, which will be completely phased out by 2022.

117. On 30th May 2011 the German government agreed that the seven oldest reactors and Krümmel will remain permanently closed. In addition, three newer reactors are to go offline between 2015 and 2019 and the remaining six will close between 2021 and 2022. There is no provision for this agreement to be revised by future governments.

118. All political parties are in favour of increased use of renewable energies, which contributed 10.9% to primary energy consumption and nearly 21% to power production in Germany in 2011. A prerequisite is a massive investment in electricity grids. In a draft national network development plan produced by the largest utilities in May 2012, it is estimated that for this energy transition Germany needs 3,800 km of new high-voltage lines and the modernization of 4,000 km of existing electricity highways. The report estimated that this will cost approximately €20 billion; and that an additional €12 billion investment would be required by 2022 for connection of offshore wind parks to the electricity grid.

119. The closure of nuclear plants is expected to result in higher coal use. According to a study done for the German Industry Federation (BDI), the lost nuclear output would be partly replaced by increased generation from existing coal-fired units, where operation could be extended 6-7 years, and output from new coal-fired stations currently under construction. In addition, any reduction in nuclear capacity is also likely to mean higher gas burn for power production. Finally, Germany is expected to become a net importer of electricity, in contrast to its position as a net exporter in recent years.

The Netherlands

120. There is widespread anti-coal sentiment in the Netherlands. Over recent years, opposition from environmental organisations has focussed on the three coal-fired power plants under construction and has resulted in permitting delays, negative publicity and lack of support for coal from a majority of politicians. Although the new coal plants are highly efficient (46%), and will reduce CO_2 by co-firing biomass, politicians and the Dutch public still consider these coal plants to be "big polluters".

121. After the collapse of the Dutch government in April 2012 a temporary coalition proposed a set of measures to fulfil the European budget requirements. This budget deal contains €13 billion of tax increases, cost cuts and reforms. The proposed introduction of a coal tax and a levy on natural gas are especially important for the power sector. The proposed coal tax will probably amount to €13.73/tonne of coal, when used for energy production. The impact of the tax on Dutch coal-fired power plants would imply a considerable reduction in running hours and possible closure of a large share of coal-fired capacity because increased electricity generation costs in the Netherlands will hardly impact European wholesale price levels.

4.3 Climate Policy

United States of America

122. The USA has so far not adopted comprehensive legislation addressing climate change. In 2009, the House of Representatives passed HR 2454, the "Cap and Trade" Bill, but it did not take effect because it did not pass the Senate. The bill remains, however, as a possible indicator of policy direction in the USA because its goals were similar in effect to those announced by the current US Administration. In addition to supporting the Copenhagen agreement[41], which established a goal of limiting global temperature increases to 2 degrees Celsius, the Administration has set a goal of producing 80% of US electricity "from clean energy sources" by 2035[42]. The US Environment Protection Agency projected that, under HR 2454, US coal consumption in 2050 would decrease to approximately 50% of today's consumption[43]. The US DOE/EIA projected impacts through to 2030 and concluded that the bill would reduce US coal use by 35% by 2030[44]. Even though neither the legislation nor the policy has been implemented by Congress, it remains as a potential blueprint for future action.

[41] Copenhagen Agreement, http://en.wikipedia.org/wiki/Copenhagen_Accord .
[42] State of the Union Address, President Obama, January 25, 2011, http://www.whitehouse.gov/the-press-office/2011/01/25/remarks-president-state-union-address .
[43] EPA Analysis of the American Clean Energy and Security Act of 2009 H.R. 2454 in the 111th Congress, USEPA, June 23, 2009.
[44] Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009, USDOE/EIA, August 2009.

Australia

123. Legislation to introduce a *Carbon Price Mechanism* from 1 July 2012 successfully passed into law late in 2011. The regime involves a carbon tax for three years from 1 July 2012, followed by an emissions permit trading scheme from 1 July 2015. The tax is to commence at a nominal rate of $23 per tonne with the price increasing annually over the next two financial years at a fixed rate.

124. Sectors covered under the regime include coal mining and the electricity industry. The carbon tax thus applies to fugitive emissions from coal mining (other than from decommissioned coal mines) and emissions associated with the generation, transmission and distribution of electricity. The estimated cost of the carbon pricing scheme on the black coal industry is A$8 billion over the first ten years. The Government is providing limited assistance to the industry of A$1.264 billion for some 25 “gassy” mines. Eligible coal mines are mines that had a fugitive emissions intensity in 2008/09 of at least 0.1 tonnes CO_2-equivalent per tonne of saleable coal produced. The Government also announced a A$70 million Coal Mining Abatement Technology Support Package to assist coal mines in developing and deploying new technologies to reduce their emissions.

125. The Australian Government will establish an *Energy Security Fund* and a new *Energy Security Council* to advise on support measures to address energy security risks. The Fund covers 3 areas:

    - *Contract for Closure Program* – the Government had sought to negotiate the orderly exit of some of Australia’s most emissions-intensive, coal-fired generators to remove up to 2,000MW of capacity before 2020. The aim of this scheme was to assist in replacing existing, highly emissions-intensive electricity assets with cleaner energy generation and give new investors time to develop replacement generation capacity.

      Eligible generators were invited to respond to the Invitation for Expressions of Interest by 21 October 2011. Five generators were invited to proceed to the negotiation phase, although negotiations were unsuccessful and the Australian Government has since announced that it will not proceed with the Contract for Closure Program.

    - *Assistance for strongly-affected generators* – some transitional assistance is being provided to the most emissions-intensive, brown coal-fired power stations in Australia on the basis that they would be most impacted by the carbon price. This assistance will be provided as a mixture of payments and allocated permits. Assistance is allocated on the basis of emissions intensity above 1 tonne CO_2-equivalent per megawatt hour. This will disadvantage black coal-fired generators as it may perversely provide higher emitting power plants with a competitive advantage over lower emitting power plants.

    - *Loan support* - the Government will offer short-term loans to generators to help finance their purchase of carbon permits and support the re-financing of existing debt if commercial loans are unavailable.

126. The carbon tax is opposed by the Opposition, which has undertaken to remove it if it is successful at the next federal election, due by late 2013. As a result, business uncertainty for long term investment in coal-fired generation continues.

Russia

127. In 2011 Russia stated that it would not adopt post-Kyoto targets, although already approved projects won't be affected. The Ministry of Economic development approved a total of 15 Joint Implementation projects, which are initiatives aimed at improving energy

efficiency in steel production, cement production, and power generation. One project, coal mine methane utilisation at Kirova mine in the Kuzbass region (Siberia), has already been implemented.

Japan

128. The Central Environment Council is discussing domestic environmental policies and their impacts on the national economy in 2020 and 2030, interacting with the Advisory Committee for Natural Resources and Energy.

129. In 2009, the Japanese Prime Minister intended to reduce GHG emissions by 25% from 1990 levels, as a mid-term objective towards 2020. Also the government's "Basic Energy Plan", approved by the Cabinet in 2010, indicates a reduction of 30% in GHG emissions by 2030. The extent of achievable reductions in GHG emissions depends on the proportion of nuclear power in the generation portfolio, and the Central Environment Council estimates that the reduction in GHG emissions will be between 10% (0% nuclear share) and 40% (35% nuclear share) in 2030.

130. Each fossil fuel currently has its own tax rate imposed: coal JPY700/tonne; LNG JPY1,080/tonne; and oil JPY2,040/kilolitre. This "fossil fuel tax" will be increased by JPY289/tonne of CO_2 emitted, irrespective of fossil fuel type, from October 2012. Thus, the fossil fuel tax on coal (JPY700/tonne) will increase to JPY920/tonne. The tax will be raised incrementally to reach JPY1,370/tonne by April 2016. Government revenue from the incremental tax on every fossil fuel (JPY289/tonne of CO_2 emitted), amounting to JPY260 billion per annum on average, will be used to promote renewable energy and energy savings.

South Africa

131. South Africa's National Climate Change Response White Paper, adopted in October 2011, covers both climate change mitigation and adaptation. The paper proposes using a National Greenhouse Gas (GHG) emissions trajectory range, based on South Africa's pledge at in Copenhagen (COP15), against which mitigation efforts will be measured.

132. The use of a carbon budget is proposed, with sectoral/sub-sectoral carbon budget allocations and emission reduction targets. The introduction of an appropriate carbon pricing mechanism, e.g. a carbon tax, is also supported. Concerns have been expressed regarding the potential impact of a carbon tax being introduced on top of a carbon budget approach, in order to lower South Africa's carbon emissions by 34% as against a 'business as usual' trajectory by 2020.

133. A discussion paper regarding the proposed pricing mechanism was released for public comment by National Treasury earlier in 2011; and a revised paper is expected before the end of 2012. The proposal is currently for a tax to be imposed on Scope 1 (direct) emissions, using a phased approach that includes exemption thresholds for the first five years and a small (5-10%) offset allowance being permitted in addition to the exemption. The most recent indication is that the tax will be implemented during 2013 at R120/tonne CO_2eq with 10% per annum nominal escalation up until 2020 at which time it could be replaced with a legislated cap. It is not yet clear at what point in the supply chain the tax would be levied. To the extent that the tax would affect the regulated costs of electricity production, it would be passed through to consumers. As yet there is no border tax proposed on export coal.

134. The White Paper identifies a suite of "Near-term Priority Flagship Programmes" for implementation or up-scaling. Of relevance to the coal industry are a Renewable Energy Programme which is linked to IRP 2010, an Energy Efficiency and Energy Demand Programme for demand side management, and a Carbon Capture and Sequestration

Programme. Cabinet approved the Carbon Capture and Storage Roadmap on 4 May 2012, which proposes a test injection for 2017.

135. An audit of all other policies and legislation must be undertaken within two years of the National Climate Change Response White Paper's release to ensure alignment with its objectives and to promote the integration of climate change resilience into all sectoral planning instruments.

4.4 Clean Coal Technologies

United States of America

136. At present, uncertainty over siting requirements and long-term liability issues associated with the underground storage of CO_2 have deterred project developers, financiers and insurers from moving forward with CCS. Some of the key issues that must be resolved in order to foster widespread commercialization of CCS include:

- determining responsibility for post-closure monitoring;
- avoiding application of the federal Superfund program to injections of CO_2;
- avoiding characterization of CO_2 as a waste and CCS activities as waste disposal to avoid triggering expensive "cradle to grave" regulations of the Resource Conservation and Recovery Act (RCRA); and
- resolving property rights issues, including pore space ownership, trespass and interstate issues relating to CO_2 transportation and placement.

137. Despite the policy and market conditions with potentially negative impacts on future coal use in the USA, coal related research including CCS is proceeding. Technical reports[45] and concept papers[46,47,48] have explored the potential for CO_2 from power plants to be used for enhanced oil recovery (EOR) to offset a portion of the cost of carbon capture. The DOE coal research program is shifting to a much greater emphasis on integrating EOR with carbon capture. The recent annual International Clean Coal Conference was focused on "State of Clean Coal Technology, Carbon Capture, Utilisation, and Storage."[49]

138. Although some commercial-scale CCS demonstration projects have been abandoned, others are moving forward. Two coal gasification projects, which can produce both electricity and high value chemical products, are proceeding in the USA with government assistance. Poly-generation offers an approach to help improve coal project economics over the longer term. An overview of the projects in which the US DOE is participating can be found at the NETL website[50] and details of additional active demonstration

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[45] Improving Domestic Energy Security and Lowering CO2 Emissions with "Next Generation" CO2-Enhanced Oil Recovery (CO2-EOR), June 20, 2011, DOE/NETL- 2011/1504, http://www.netl.doe.gov/energy-analyses/pubs/storing%20co2%20w%20eor_final.pdf .

[46] The Value of Enhanced Oil Recovery, D.Carter, Presented to The CO2 Carbon Management Workshop, Houston, TX, December 5, 2011.

[47] Carbon Dioxide Enhanced Oil Recovery: A Critical Domestic Energy, Economic, and Environmental Opportunity, National Enhanced Oil Recovery Initiative, February 2012, http://neori.org/publications/neori-report/ .

[48] Reducing the Cost of CCUS for Coal Power Plants, USDOE/NETL-2012/1550, January 31, 2012, http://www.netl.doe.gov/energy-analyses/pubs/RedCostCCUS.pdf .

[49] http://www.netl.doe.gov/publications/press/2011/110810_international_clean_coal.html .

[50] DOE Carbon Storage Program, http://www.netl.doe.gov/technologies/carbon_seq/overview.html ; DOE/NETL Advanced CO2 Capture R&D Program: Technology Update, May 2011, http://www.netl.doe.gov/technologies/coalpower/ewr/pubs/CO2Handbook/CO2-Capture-Tech-Update-2011_Front-End%20Report.pdf .

projects can be found at several other websites.[51,52,53] Successful completion of these projects is focused on driving down the cost of emission control technologies including CCS with the goal of ensuring the future of coal use in the US.

Australia

139. The Australian Government last year announced funding cuts to CCS programs in the 2011/12 Budget, but no further amendments, deferrals or other changes in funding were made in the 2012/13 federal Budget.

140. The *National CCS Council* was established in March 2011 to advise the Australian Government on the accelerated development and deployment of CCS in Australia. It comprises representatives of the coal and gas industry, governments, researchers and coal and gas-fired power generators. The Council produced a report *"Carbon Capture and Storage in Australia - Contributing to a Clean Energy Future"* in December 2011 for the Minister for Resources and Energy. It was subsequently released as part of its submission to the Government's Energy White Paper consultation process.[54]

141. The Australian Government short-listed four CCS Flagship demonstration projects in 2009 which received initial pre-feasibility funding:

- *Wandoan Power Project*, a 330MW Integrated Gasification Combined Cycle (IGCC) with CCS (Queensland);
- *ZeroGen, a* 400MW IGCC with CCS (Queensland);
- *Collie South West Hub*, integrated geosequestration infrastructure with 3.3 million tonnes per annum capacity (Western Australia); and
- *CarbonNet*, integrated geosequestration infrastructure with 3-5 million tonnes per annum capacity (Victoria).

142. The Queensland Government subsequently announced that it would not pursue an IGCC power plant and instead would focus its efforts on identifying suitable CO_2 storage, with $50 million available for this work. The focus on storage is supported by the coal industry, which is examining the Carbon Transport and Storage Company (CTSCO - the storage arm of the Wandoan project) proposal for CO_2 storage in the Surat Basin while also considering alternative capture options for an integrated CCS project in Queensland. The CTSCO project is still completing its pre-feasibility study and aims to drill a data well by the end of 2012.

143. On 11 June 2011 the Minister for Resources, Energy and Tourism, The Hon Martin Ferguson, announced the Government's decision to select the Collie South West Hub project under the Flagship program. The project would progress under a staged and gated approach, with an initial focus on proving up sufficient geological storage.

144. On 10 February 2012, Minister Ferguson announced the CarbonNet project as the second project selected for funding through the feasibility stage. Up to A$100 million (A$70 million from the Australian Government and A$30 million from the Victoria Government) will be available for the feasibility stage work which will be predominantly

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[51] MIT Carbon Capture & Sequestration Technologies, http://sequestration.mit.edu/tools/projects/index.html .
[52] USDOE/NETL Carbon Capture and Storage Database, http://www.netl.doe.gov/technologies/carbon_seq/database/NETL%20CCS%20Database%20Directions.pdf .
[53] GCCSI Large-scale Integrated Projects, http://www.globalccsinstitute.com/projects/browse .
[54] The report can be downloaded from: www.ret.gov.au/energy/Documents/ewp/draft-ewp-2011/Submissions/215.NationalCCSCouncilpart2.pdf.

focussed on modelling and testing of potential CO_2 storage sites. The CarbonNet project aims to capture carbon emissions from power plants, industrial processes and new coal-based industries in Victoria's Latrobe Valley and store it in nearby geological basins.

145. The Government has agreed to reconsider Queensland's Wandoan project in 2013 subject to conditions predominantly related to progressing pre-feasibility studies and the availability of program funding.

146. The ZeroGen project has been completed and the project wound-up. This was due to the project being unable to locate a suitable storage site for the commercial-scale power plant within its allocated tenements and also because it was decided that IGCC technology would not be further developed for the Queensland Flagship. A project knowledge dissemination exercise has been completed and the electronic version of the final project reports will be disseminated by the Global CCS Institute.

147. Callide Oxyfuel reached a major milestone with the start of commissioning of oxy-firing technology on 15 March 2012. The first stage of the project involves retrofitting oxyfuel technology to Callide A Power Station in Central Queensland.

Japan

148. As the part of J-POWER's Osaki CoolGen Project in Hiroshima, construction of a 170MW IGCC plant will commence this summer, subsidized by government. Test operation will start from 2016, followed by a demonstration test of CO_2 capture from 2019 to 2020.

149. A CCS demonstration test will begin, also supported by government, this year. It aims to capture CO_2 from oil refinery plants, transport it by pipeline and store it under the sea in southern Hokkaido. It is planned to start CO_2 sequestration at a rate of 100,000 tonnes of CO_2 per annum in 2015 and to finish all tests by 2020.

150. Examining the technological maturity and financial viability of CO_2 capture and sequestration as a part of the coal chain before 2020, these two demonstration tests are expected to prove the commercial viability of CCS as a clean coal technology.

South Africa

151. The Carbon Capture and Storage roadmap was approved by Cabinet on 4 May 2012. CCS is considered one of the options to reduce CO_2 emissions, particularly for more concentrated CO_2 emission streams such as from coal-to-liquids processes. The current focus of this roadmap is on a test injection in 2017.

152. The South African Centre for Carbon Capture and Storage (SACCCS) has completed and published the *"Atlas on Geological Storage of Carbon Dioxide in South Africa"*. From this atlas, SACCCS has identified two prospective basins for further seismic testing and drilling to test the suitability of each basin for a test injection in the order of 10,000 tons of CO_2 in 2017. Characterization activities will commence in early 2013.

153. In addition to geosequestration opportunities, Eskom is undertaking research into algal sequestration and also pre-feasibility studies into co-firing biomass in current power stations up to levels of 10%.

Germany

154. At the end of May 2012 the first federal state, Mecklenburg-Vorpommern, prohibited the underground storage of CO_2. At the end of June 2012, Germany's parliament passed the Carbon Dioxide Storage Act (KSpG). However, this law sees only limited options for storing CO_2 in Germany. Maximum permissible CO_2 storage quantities are 1.3 million

tonnes per annum for an individual storage facility and 4 million tonnes per annum for Germany as a whole. Moreover, the federal states may lay down that trialling and demonstrating permanent storage is admissible only in certain areas or inadmissible in certain others. Still, the Act does provide the possibility of building border-crossing carbon dioxide pipelines to transport the CO_2 from capture plants in Germany to storage facilities located abroad. In this way, Germany's CCS law may make a contribution toward the creation of a future European CO_2 infrastructure.

155. The main R&D fields of action for power plants are the optimization and underpinning of on-going production processes, the further development of innovative technologies to commercial maturity and the development of new future-geared options. As a primary measure to reduce CO_2 emissions, a further increase in efficiency is a fundamental objective for all future power-plant technologies. Achieving increases in the efficiency of conventional power stations by developing materials that permit higher operating parameters, and coal pre-drying, are particularly important.

156. The preliminary work on coal-fired power plants with an efficiency of 50% continued. The target is the development of materials that permit steam parameters of 700°C and 350 bar, an increase in efficiency of four percentage points. Another materials development priority is to support the capability for fast load-changing in future power stations, which is increasingly important as the fluctuating feed-in of renewable energy sources increases. RWE Power and Vattenfall are participating in the COMTES+ project which is being promoted by both Germany and the EU to test thick-walled components of nickel-base alloy.

157. Fluidized-bed drying with internal waste-heat utilisation (WTA) is being developed to commercial maturity by RWE Power. A prototype plant with a capacity of 110 tonnes/hour is testing the pre-drying of lignite in association with the fluidized-bed process at the BoA unit of the Niederaußem power plant. This drying technology has the potential to boost the efficiency of a lignite power station by a further four percentage points. The demonstration plant has furnished proof of the commercial usability of the WTA technology for new power-plant units. The focus of further trials is on avoiding performance losses caused by coal quality by taking counter-measures.

158. A joint project between Brandenburg's Cottbus-based technical university, Vattenfall Europe Mining & Generation, MIBRAG and other partners from industry is further pursuing the concept of pressurized fluidized-bed drying, which is likewise expected to increase power plant efficiency by approximately four to five percentage points. Within the scope of the test operations at the Schwarze Pumpe pilot plant, further basic investigations and process-technology optimizations are being carried out to develop the technology to commercial-scale maturity.

159. Separating the carbon dioxide from power plant flue gas and storing it in deep geological formations can massively lower the CO_2 emissions from coal-based power stations. In a joint project between RWE Power, the Linde Group and BASF, a technique for capturing CO_2 from flue gas is being developed and trialled at the Niederaußem power plant for application in conventional power stations and as retrofit option. Following successful completion of the initial trial phase a long-term test to 2013 was commenced with the most suitable scrubbing agent. CO_2 scrubbing will also be used for one year in combination with the high-performance flue-gas desulphurization (FGD) plant REAplus, trialling a further minimization of SO_2 and dust emissions.

160. In addition to CCS, RWE Power is also developing solutions for making use of CO_2 (Carbon Capture and Utilisation) and has various research projects to develop the different CO_2 utilisation options in the long term. Projects using CO_2 as the direct feedstock for plastic manufacture, or in combination with hydrogen produced using electrolysis from excess renewable electricity to produce a synthesis gas with multiple

uses, are being pursued. Also, biotechnological CO_2 utilisation is being pursued with the biotech company BRAIN. To tap new business fields outside the electricity and heat market, options for using lignite with gasification technologies are also being investigated.

161. Faced with the current situation in the national legislative procedure for a CCS law, Vattenfall discontinued planning for its Jänschwalde CCS demonstration project on 5 December 2011. In recent years, Vattenfall had invested huge financial and personnel resources to develop CCS technology. Despite the lack of political support, Vattenfall will continue pursuing CCS climate-protection technology, specifically in regard to transnational CO_2 infrastructure. The company is also holding on to its concept of lower-emission power plants at Jänschwalde.

162. Research work on the oxyfuel pilot plant at Schwarze Pumpe is being continued as planned. The focus is still on burner tests, trials for CO_2 scrubbing and the ADECOS project, which started in September 2011 with the aim of further developing oxyfuel technology in collaboration with leading German universities and component vendors. For the first time in May and June 2011, a total of some 1,500 tonnes of CO_2 was transported from the oxyfuel pilot plant to Ketzin and injected into geological formations within the scope of the CO2MAN project supported by the Potsdam geological research centre.

163. Vattenfall is also driving forward research projects to develop CCU solutions. These include the continuation of work on CO_2 utilisation for algae growth in the "green MiSSiON" pilot plant at the Senftenberg co-generation power station, and participation in a cooperative research project to develop processes with integrated gasification and gas cleaning for lignite and hard coal at the Munich technical university.

164. E.ON has several CCS research projects and pilot projects across its European power plant portfolio. In Germany, E.ON has formed several partnerships with Fluour/Siemens for pilot projects at power plants in Staudinger and Wilhemshaven. The Wilhemshaven project is a post-combustion pilot commissioned in early 2012. The solvent technology being used has additional capabilities, in particular the ability to handle dust and a variety of gas contaminants including sulphur oxides and nitrous oxides. The project will show whether the technology can achieve a capture rate of at least 90% of the CO_2 in the exhaust over the full power plant load regime, and how it works in the presence of small amounts of other acidic gases. Tests will also be conducted to see how variations in the solvent formulation perform and whether energy and cost-saving features are effective under normal operating conditions.

Turkey

165. Within EU 7th Framework Programme, TKI and other partners (THERMAX and IITMadras from India, ECN from the Netherlands, CNRS-ICARE from France, and Hacettepe University from Turkey) applied for a Clean Coal Technologies topic *“ENERGY.2011.1: Optimizing gasification of high-ash content coals for electricity generation”*. The Project was accepted and initiated on 1 November 2011 and is coordinated by CNRS-ICARE.

The Netherlands

166. Recently, no new CCS projects have been announced; and the two current projects are reporting possible delays. An important issue is the EU-ETS price level of only €7/tonne of CO_2, which has a very negative impact on all CCS business cases. This price level also impacts the revenues of the so-called new entry reserve (NER) auction, which is a source for European CCS project funding.

Poland

167. There is no specific progress on CCS in Poland, although due to the very large share of coal in the Polish energy mix clean coal technologies are not limited to CCS. The National Programme for Scientific Research and Development called "Advanced Technologies for Energy Generation" comprises four research topics covering:

- highly efficient technologies for zero emission coal-fired power plants integrated with CO_2 capture;
- oxy-combustion technologies for pulverized and fluidized bed boilers integrated with CO_2 capture;
- coal gasification technologies for highly efficient production of fuels and energy (Underground Coal Gasification included); and
- integrated technology for fuel and energy production from biomass, rural wastes and others

4.5 Coal Production

United States of America

168. The US Army Corps of Engineers (USACE) is authorized to issue permits for certain activities in US waters pursuant to the Marine Protection, Research, and Sanctuaries Act, Section 404 of the Clean Water Act, and Section 10 of the Rivers and Harbors Act. On 7 April 2012, the Portland District Office of USACE issued a notice seeking public comment on an application to establish a facility in the Port of Morrow, Oregon, to export Powder River Basin coal to Asia.[55] Part of the review process for a permit includes a determination of whether a detailed Environmental Impact Statement is appropriate, pursuant to the National Environmental Policy Act.

169. In response to the notice, the US EPA wrote[56] to the USACE urging careful consideration of a range of possible environmental impacts associated with the port facility, as well as "cumulative impacts" from a number of new export facilities being proposed for western coals, citing "the cumulative impacts to human health and the environment from increases in greenhouse gas emissions, rail traffic, mining activity on public lands, and the transport of ozone, particulate matter, and mercury from Asia to the US."

170. In addition to regulating certain port activities, the US Government holds title to the coal mineral estate of 570 million acres of public land, located primarily in the western US. The Department of Interior, Bureau of Land Management (BLM) is responsible for leasing much of that land for productive purposes.[57] Prior to the issuance of a new lease, BLM must make a determination of whether the leasing decision will require a relatively straightforward Environmental Assessment, or a relatively complex Environmental Impact Statement (similar to the USACE process associated with issuing a permit to a port facility). BLM reports that 41% of US coal is produced on federal lands. It is unclear at this point what the outcome of the EPA action regarding coal export permits will be. Similarly, potential policy changes regarding federal land leasing for coal mining are speculative at this time.

171. The effective freeze by government on surface mining permits in Central Appalachia and

[55] Portland District Regulatory Program, USCAE, http://www.nwp.usace.army.mil/regulatory/ .
[56] Letter from K. Kelly, Director, Office of Ecosystems, Tribal and Public Affairs, USEPA, Region 10, to S. Gagnon, Project Manager, USACE, April 5, 2012.
[57] Coal Operations, USDOI/BLM, http://www.blm.gov/wo/st/en/prog/energy/coal_and_non-energy.html .

to a lesser extent Northern Appalachia has had an effect on the ability to increase coal production in those regions; and potentially impacts surface mining operations in other regions. The Stream Protection Rule proposed by the Office of Surface Mining also poses a serious challenge and could significantly reduce coal availability if put into effect.

172. The conflict between EPA and mountain top mining interests recently reached US District Courts. In October 2011, Judge Reggie Walton, of the US District Court for the District of D.C., overturned EPA's "Enhanced Coordination Process" for state mining permits that had been used to closely examine mining operations in West Virginia and other Appalachian states[58]. After a hearing on the current coal permitting process before the House Appropriations Committee in February 2012, an EPA spokesperson said that "the District Court decision does not affect EPA's Clean Water Act authority to protect communities in Appalachia from the public health and environmental impacts caused by poor coal mining practices." In March 2012, United States District Court judge, Amy Berman Jackson, said that the EPA's unilateral decision in January 2011 to rescind the waste disposal permit for the Spruce No. 1 mine in Logan County, WV, exceeded the agency's authority and violated federal law[59]. These court decisions contrast with EPA's public responses and continue the uncertainty surrounding mountain top mining.

Australia

173. A number of issues could negatively influence future coal production growth. Mining costs will rise as a result of the high Australian dollar, increasing labour costs, skilled labour shortages, poor transport infrastructure and increasing equipment costs. Anti-coal campaigning is attacking the industry's social licence to operate. For example, Greenpeace has produced a document entitled *"Stopping the Australian Coal Export Boom"* that includes proposals for civil disruption campaigns and support for litigation by communities. Such opposition to coal mining and coal exports is likely to continue, based on issues potentially including claimed risk of damage to the Great Barrier Reef due to increased coal shipments. Finally, a number of significant policy developments are outlined below.

174. The *Carbon Price Mechanism* (see Section 4.3) became effective from 1 July 2012. It is a tax on coal mining fugitive emissions not borne by any of Australia's competitors and could potentially affect the country's competitiveness in international coal markets.

175. A 6 cent/litre increase in excise duty/taxation for diesel fuel used in transport by mining, generators and certain other operations also became effective from 1 July 2012. This change is a result of the Government imposing an effective carbon price on businesses liquid and gaseous fuel emissions through the existing fuel tax regime. Miners will also face an indirect carbon cost through increased input costs in particular rail and domestic shipping (from 1 July 2012), and heavy road transport (from 1 July 2014).

Minerals Resources Rent Tax (MRRT)

176. The MRRT is a result of a Heads of Agreement with the Australian Government and leading mining companies and is broadly consistent with the mining industry's underlying principles of tax reform. It was effective from 1 July 2012. Taxpayers with small amounts of MRRT assessable profits (i.e. less than A$50 million per annum) will be excluded from the MRRT. Also, the three key determinants of how the rent tax applies to profits – the effective tax rate, the tax base and the immediate write-off of new capital expenditure –

[58] West Virginia, Office of the Governor, http://www.wv.gov/news/governor/Pages/10-06-11GovernorApplaudsUSDistrictCourtRulinginFavorofWestVirginiainMiningSuit.aspx
[59] Court Reverses E.P.A. on Big Mining Project, New York Times, http://www.nytimes.com/2012/03/24/science/earth/court-reverses-epa-saying-big-mining-project-can-proceed.html?_r=1

are more commercially realistic than the original proposal. In particular, the treatment of existing projects is better with taxpayers able to choose an option where the tax base is defined at market value with depreciation provisions over 25 years.

177. Clearly any profits tax reduces the profitability of projects over their life and thus must have some impact on investment decisions. However, there are two important practical aspects of the tax that reduce its impact:

178. The MRRT will be applied to coal and iron ore at a “headline” rate of 30% but there is also a 25% extraction allowance, leaving the actual nominal rate at 22.5%. In addition, the MRRT itself is tax deductible at the corporate tax rate.

179. Furthermore, the tax is only applied after a series of allowable deductions:

- The MRRT will provide a full credit for state royalties paid by a taxpayer in respect of a mining project. This means there should be no double taxation. In addition, if a company has paid more state royalty payments than its MRRT liability then it can carry forward the excess payments and deduct them against future MRRT obligations (though excess royalty credits cannot be transferred to other projects). Unused credits for royalties paid will be uplifted at the long term government bond rate plus 7%, as with other expenses. Unused royalty credits will not be transferrable between projects or refundable.
- Under the MRRT capital expenditure will be immediately written off rather than applied over many years. This will allow mining projects to access mining investment depreciation deductions immediately (for the purposes of the MRRT), and means a project will not have an MRRT liability until it has made enough profit to pay off its up-front investment. The MRRT will carry forward unutilised losses at the government long term bond rate plus 7%.
- A company with both new and existing projects can offset new project MRRT losses against MRRT profit relating to another project. It is also important that MRRT losses can be transferred to offset MRRT profits derived within a company group. This supports mine development because it means a taxpayer can use the deductions that flow from investments in the construction phase of a project to offset the MRRT liability from another of its projects that is in the production phase.
- The MRRT will provide recognition of past investments through a credit that recognises the market value of that investment, written down over a period of up to 25 years. Unlike other costs, this starting base will not be uplifted.

180. The MRRT will recognise the particular characteristics of different commodities, by applying a taxing point close to the point of extraction, and using appropriate pricing arrangements to ensure only the value of the resources extracted is taxed.

181. To facilitate implementation of the new arrangements the Australian Government established a Policy Transition Group (PTG) led by Resources Minister, The Honourable Martin Ferguson and Mr Don Argus, former Chairman of BHP Billiton. The recommendations of this Group were accepted in full by the Government. The Government also recognised the important contribution made by the PTG and has continued the engagement with industry through establishing a Resource Tax Implementation Group to support the legislative drafting stage, consistent with the PTG recommendations.

Increased land use measures at the Federal and State level

182. Conflicts between the minerals and agricultural sectors continue to emerge around access to “prime agricultural land”. While water and food security are said to be the matters of concern, the key issues of substance are stakeholder knowledge and

confidence with respect to the regulatory requirements for exploration and mining. The Australian, New South Wales (NSW) and Queensland Governments are responding to the increased pressure to address these land use conflicts by introducing new legislation and policy initiatives that seek to manage competing interests.

183. The coal seam gas (CSG) industry illustrates the current challenges faced by government to balance the interests of agricultural landholders and other stakeholders (including petroleum, coal and other mining companies) seeking access to land.

184. In December 2011, the Standing Council on Energy and Resources (which comprises the Commonwealth, State, Territory and New Zealand Ministers responsible for energy and resources) agreed to develop and implement a harmonised framework for CSG to address key areas of community concern based on four key themes:

- water management;
- multiple land use framework;
- best practice standards; and
- co-existence.

185. In February 2011, the Queensland Government established a multi-disciplinary “one-stop” enforcement unit which will monitor compliance with legislative requirements, investigate formal complaints from landholders and prosecute offences where required. Officials have also developed a CSG/LNG Compliance Plan, which envisages planned and unplanned audits and inspections and reviews of licensee monitoring data.

186. In addition, the Queensland Government has recognised the importance of agriculture and the need to strike a balance between the agricultural, resource and development industries, through its Strategic Cropping Land Act 2011. The Act establishes Strategic Cropping Protection Areas and a Strategic Cropping Management Area, together with transitional arrangements for existing projects and proposed projects that are already undergoing environmental impact assessments.

187. The impact on the resources industry so far has been an increase in the cost of operating in strategic cropping land areas with the law requiring a resource proponent to avoid, minimise and mitigate. Although the protection of highly productive cropping areas warrants a sensible level of regulation on the mining industry, the complex, inconsistent and scientifically unsound foundations underpinning the recent laws is unnecessary and creates greater investment uncertainty.

188. In May 2011, the NSW Coalition Government introduced transitional arrangements to address land use conflicts under its Strategic Regional Land Use Policy. The policy, which was a key point in its 2011 election campaign, led to an immediate 60 day moratorium being placed on the granting of 'new' coal, coal seam gas and petroleum exploration licences in NSW.

189. On 6 March 2012, the NSW Government took the next steps in delivering its Strategic Regional Land Use Policy. This involved detailing how it proposes to minimise land use conflicts and protect high-quality agricultural land and associated water sources in specific regions under the “Draft New England North West Strategic Regional Land Use Plan” and “Draft Upper Hunter Strategic Regional Land Use Plan”.

190. A comprehensive review of the NSW planning system is being undertaken in addition to the release of the Strategic Regional Land Use Policy initiatives. The NSW planning review has much broader application than just the mining and CSG projects. It remains to be seen how each of these initiatives, and in particular the Draft Land Use Plans, will be

integrated into the proposal for a new planning system. However, it is expected that the theme of regional and strategic assessments, which is also a common theme at the Commonwealth level and across other States, will feature.

191. The full review of the Planning and Assessment Act has caused significant delays and uncertainties for mining proposals. It is vital to the energy security of NSW that the development of coal mining projects is assessed without delay and with a consistent whole of government approach. While the planning system must necessarily balance the impacts of projects on individuals and the environment with the needs of the people of the state, it is imperative that the system does this in a way that provides certainty and efficiency.

192. In addition, the coal industry is concerned that the implementation of the Strategic Land Use Policy and Aquifer Interference Policy will result in duplication and will impose unnecessary additional assessment and costs. The proposed definitions of strategic agricultural land are very broad and will unnecessarily sterilise mineral resources.

Environmental Protection and Biodiversity Conservation (EPBC) Act

193. The duplication of environmental laws at State and Commonwealth levels is a concern to industry. A recent study by academics at the Australian National University estimates the direct costs arising under the EPBC Act alone have been A$820 million over the past decade, with little demonstrable improvement in environmental outcomes. Costs from the failure to appropriately align approval processes across different levels of government are much higher.

194. There is a need to overhaul of the EPBC Act as part of streamlining and simplifying national project approvals processes. The mining industry is arguing that the Commonwealth should have a strategic role based on full implementation of bilateral agreements for assessment and approvals processes, endorsement of regional planning instruments that meet EPBC requirements and strategic investment and planning support.

Commonwealth/Queensland Government Great Barrier Reef (GBR) strategic assessment and the UNESCO GBR review

195. The Australian and Queensland governments are to undertake a comprehensive strategic assessment of the GBR World Heritage Area and the adjacent coastal zone. The goal is to create an agreed, long-term plan for sustainable development within the GBR Region that provides greater certainty for industry and decision-making in the area, while ensuring the values of the World Heritage Area are protected into the future.

196. There are two key components of the strategic assessment – a marine component and a coastal component. The marine and coastal ecosystems are intrinsically linked and their function is inter-related. The Great Barrier Reef Marine Park Authority and the Queensland Government will work together to analyse impacts at the marine/coastal interface from activities such as shipping, water quality management in reef catchments and island management, with the aim of completing the initiative over the next 18-24 months.

197. The period of public consultation on the draft terms of reference for the Commonwealth and Queensland Marine Park strategic assessments has closed. Comments received are being considered and the final Terms of Reference are being prepared.

198. In a related development, UNESCO undertook a monitoring mission to assess any activities that may have impacted on the Outstanding Universal Value (OUV) of the GBR. UNESCO delivered its report on 5 June 2012. The report finds that “The property has a history of strong management practices of which many are of high quality and an

example to other marine protected areas." However the report does express concern about "the unprecedented scale of coastal development currently being proposed within and affecting the property…", and refers to 45 development proposals. Of those 45 developments, 3 are proposed coal mines some 500km inland and two are coal terminals. The report also expresses concern about a projected 260% increase in coal port capacity (to 953 million tonnes of coal) within a decade, with an associated increase in shipping traversing the GBR. This projected increase in coal port capacity is a gross overestimate of any reasonable estimate of port capacity increases likely in the next 10 years. In summary, coal mining related concerns are a minor feature of the report.

Indonesia

199. A domestic market obligation (DMO) policy was imposed by the Government of Indonesia (GOI) in 2010 to secure coal supplies for domestic uses including electricity power generation, cement, pulp and paper, and the textile industry. There are no further production obligations and mining companies are able to export any remaining production. However, debate among members of parliament, government officials and the media is now questioning this position and raising the possibility of imposing an export tax on low rank coal, an export ban or a production quota to secure the future domestic supply of coal. The Natural Energy Council will therefore formulate a long term coal policy to ensure that supplies are sufficient to meet future domestic needs.

200. The Geological Agency has estimated that Indonesia currently has 28 billion tonnes of proven coal reserves and an annual production capacity of 400 million tonnes per annum. With no limitation on the expansion of coal production, reserves could be exhausted in less than 70 years. The Geological Agency also estimates that the Ministry of Energy and Mineral Resources has a further 160 billion tonnes of reserves, still requiring detailed exploration before they can be classified as proven and mineable. However, their classification and development may be constrained by land use conflicts. Development and exploration must await completion of GOI's regional spatial planning maps, but it is quite clear that some reserves will never be explored or developed because they will be designated as protected forest, national parks or agricultural land.

Russia

201. In January 2012 the Government approved a Long-term strategy for the coal industry up to 2030, including an increase in coal production from 323 million tonnes in 2010 to 430 million tonnes in 2030 and an increase in exports from 116 million tonnes to 170 million tonnes over the same period.

202. In 2011 changes in the mineral extraction tax rate took effect. Lower levels of tax rates apply to new coal deposits, deposits with difficult geological conditions, and remote coalfields.

203. The Russian President and Prime Minister held several meetings on the development of the coal industry in 2012. It was agreed that the following measures should be implemented, not earlier than 2013-2014:

- a new mineral extraction tax regime applicable to new coal projects;
- labour law changes aimed at productivity improvement (cutting vacation length, switching from 6-hour to 8-hour shifts in underground mining etc.);
- an update of the Rostekhnadzor (the Federal Service for Ecological, Technological and Nuclear Supervision) regulatory framework, focused on adopting new coal mining technologies instead of restricting their use; and on improving safety conditions, reducing accidents and reducing injury risks associated with coal mining; and

- a long-term tariff policy for rail transportation of coal.

204. The Government declared support and incentives for new projects aimed at increasing coal transportation capacity that are worked out in great detail (key areas of supply are the Asia-Pacific markets)

205. The Government supported achievement of an agreement between the largest coal companies and "Russian railways" (RZhD), the government-owned national rail carrier, to coordinate long-term development plans.

South Africa

206. The ruling political party, the African National Congress (ANC) published a policy discussion paper in March 2012 entitled "State Intervention of the Minerals Sector: Maximizing the Developmental Impact of the Peoples Mineral Assets".

207. The discussion paper is for the minerals industry as a whole, but coal related options are:

- to issue concessions on all "known" mineral deposits by public tender, as with the disposal of other state assets, to maximise developmental impact to get the best possible deal for the mineral assets. The bidders could push up the tax rate, linkages (backward & forward), and investments, including knowledge investments;
- to use state ownership of coal mineral rights to *apply cost-plus pricing* conditions on producers for their domestic on-sales for select "strategic" mineral feedstocks (coal & limestone) for power generation (as per coal into polymers);
- to expand the regulation of energy prices (National Energy Regulator of South Africa) to include energy feedstock (coal);
- to reserve appropriate coal and limestone resources for Eskom to develop (with the State Minerals Company) or contract (cost - plus prices);
- for the State (Eskom) to purchase critical thermal coal and limestone deposits;
- to instruct Transnet to only allocate coal export rail/port capacity to coal mineral exporters once Eskom's needs have been satisfied at cost plus prices;
- in respect of the expansion of Ermelo-Richards Bay (Coalink) Railway capacity, to assess the efficacy of a user concession of the main users (Anglo Coal, BHPB, Sasol, Exxaro, Total, et al) along the lines of the RBCT, but make it dependent on first transferring mining rights to Eskom of their coal seams/fractions for Eskom's security of supply over the life of the resource/mine in question; and
- in regard to the Limpopo Coalfields Railway (Waterberg and adjacent Botswana resources, Soutpansberg, Limpopo fields); for the Ministries of Transport, of Energy and of Public Enterprises to commission a study of the most viable export route for exploiting these resources (and adjacent resources in Botswana) to optimise the long-term cost effectiveness of the different options (Rand/tonne/kilometre in year 20), the collateral impact of the infrastructure in terms of stimulating other economic sectors, and intra-regional trade and development.

208. Also proposed in this paper is the concept of a *"Resource Rent Tax"* (RRT) on all minerals which will be triggered after a normal return on investment has been achieved, thus reducing the impact on marginal or low grade deposits. A study on the mining sector proposed the introduction of a RRT of 50% on all mining. Income from the RRT could be kept in an offshore Sovereign Wealth Fund to protect the South African economy when the strength of the rand appreciates.

4.6 Coal Utilisation

United States of America

209. EPA's pending clean air regulation will have a substantial impact on the energy mix. The cumulative impacts of the Cross State Air Pollution Rule (CSAPR), the Mercury and Air Toxics rule (MATS) and the Greenhouse Gas New Source Performance Standard Rule (NSPS), among others, will lead to the retirement of a substantial amount of coal-based electricity generation capacity and its replacement by natural gas-fired electricity generation. Coal-fired power plants may also be retrofitted with scrubbers or converted to natural gas. A combination of this clean air regulation and low gas prices has already resulted in the announcement of approximately 40GW of coal-fired electricity generating plant retirements and conversions. Moreover, these policies will likely eliminate future coal plant construction so that future increases in electricity demand will have to be met by other fuel sources.

210. Until recently the presence of emissions trading markets and GHG-related policy uncertainty appear to have had little or no impact on coal demand. However, with the Supreme Court ruling in Massachusetts vs. EPA and the subsequent rulemakings related to GHG emissions, it has become increasingly difficult to permit and finance coal-fired power plant construction. Power producers are increasingly turning to natural gas-fired power plant construction.

211. Under existing statutory authority, all new power plants permitted in the US must apply the best available control technology (BACT) for CO_2 emissions, as well as for conventional air pollutants. In March 2011, US EPA issued guidance[60] on how BACT would be determined. To date, no permit has required application of CCS technology, but these determinations are made on a case-by-case basis and tend to become more stringent over time. On 13 April 2012, EPA proposed a rule limiting CO_2 emissions from new fossil fuel-based power plants to 1,000 pounds CO_2/MWhr of generation.[61] The effect of this rule, if adopted, would be to require natural gas-fired power plants to have an efficient design and coal-based power plants to apply CCS technology. Although this rule would impact only new facilities, US EPA has signed a legally enforceable settlement agreement to adopt regulations limiting CO_2 from existing coal-fired power plants as well.[62]

212. In respect of grid reliability issues, the increased complexity arising from transmission planning rules issued by FERC coupled with pending new EPA regulations described above have raised concerns about the risk to generators operating under a Section 202(c) Federal Power Act "emergency" order. The intersection of these rules might place generators in a non-compliance position under environmental laws. This concern has led to proposed new legislation in the House, the "Resolving Environmental and Grid Reliability Conflicts Act of 2012" and the "Hydropower Regulatory Efficiency Act of 2012"[63]. This is a relatively new development, but the underlying issue has resulted in a large number of actions and revisions to FERC orders. The implications of these orders, which concern transmission access, public policy requirements and different cost

[60] PSD and Title V Permitting Guidance for Greenhouse Gases, USEPA, March 2010.
[61] Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 77FR22392, April 13, 2012.
[62] Settlement Agreements to Address Greenhouse Gas Emissions From Electric Generating Units and Refineries, USEPA, http://www.epa.gov/airquality/cps/settlement.html .
[63] SEC Wire, U.S. Environmental Protection Agency Assistant Administrator, Office of Air and Radiation Gina McCarthy, Prepared Testimony House Energy and Commerce Subcommittee on Energy and Power Hearing on Resolving Environmental and Grid Reliability Conflicts Act of 2012 and the Hydropower Regulatory Efficiency Act of 2012, as released by the Committee, May 9, 2012, http://www.elp.com/index/from-the-wires/wire_news_display/1662860648.html

allocation methods for different types of facilities, greatly complicate planning. Controversy surrounds the orders with arguments being made that the rules can be unfair to various generating technologies[64].

Australia

213. In 2010 the Prime Minister made an election commitment to introduce emissions standards and a "CCS-ready" standard for all new coal-fired power generation by the end of 2011. Funding was allocated in the 2011/12 Budget to support implementation of this Initiative. With the introduction of Australia's carbon pricing mechanism from 1 July 2012, the Australian Government subsequently announced that the "CCS-ready" standard would be withdrawn. Queensland still has a similar standard in place.

Russia

214. The Government has approved the long-term strategy for the coal industry up to 2030. Key points are:

- overall growth in domestic coal demand from 190 million tonnes in 2010 to 220 million tonnes in 2030;
- growth in power plant coal demand from 102million tonnes in 2010 to 120 million tonnes in 2030; and
- a reduction of local heating coal demand from 23 million tonnes in 2010 to 14 million tonnes in 2030.

215. Plans for a coal consumption increase in the cement industry and deep coal processing have been put forward.

216. The Government encourages long-term contracts between large coal producers and electricity generating companies, with all such contracts to be reported at one of the commodity exchanges. The share of coal supplied on long-term contracts increased last year.

South Africa

217. Eskom has previously stated its intention to develop a 2,100MW combined cycle gas power station utilising gas generated through underground coal gasification (UCG) technology. The company has been investigating the technology since 2007 and has successfully demonstrated production of the gas at a pilot project at the Majuba power station.

218. The biggest advantage of UCG is to utilise coal that was previously regarded as un-mineable. This was a problem at the Majuba power station, where the coal could not be economically exploited for use in conventional power stations due to extensive dolerite intrusions. There are numerous additional advantages including more efficient resource extraction, reduced impact on land surface from mining and ash disposal, and relatively fewer air emissions. However, there is also need for stringent operational control and monitoring to ensure no adverse sub-surface environmental effects.

219. Sasol New Energy (SNE) was created to focus on developing options and new technologies for Sasol to utilise in a carbon- and water-constrained world. To reduce CO_2 production during operation and integrate new technologies into current processes, SNE is exploring renewable and lower-carbon energy options such as solar and wind power,

[64] AOL Energy news April 3, 2012, http://energy.aol.com/2012/04/03/wellinghoff-details-his-approach-to-power-capacity-market-design

as well as hydroelectric, clean coal and natural gas-based power opportunities. Carbon capture and storage is being targeted to sequester the CO_2 produced in the Fischer-Tropsch process.

The Netherlands

220. To meet the Dutch renewable target set by the EU, one third of all power produced must come from renewable sources in 2020, with biomass co-firing and wind energy being the main sources. The current level is approximately 10%.

221. The Dutch renewable energy system is in a transition phase from a subsidy-based system to (probably) a certificate system or supplier obligation by 2015. The subsidies for biomass co-firing are phasing out in the coming years. To keep co-firing at the same level until a new system is in place, the Dutch power producers operating coal-fired power plants have agreed to a so-called “Green Deal” with the Dutch government. Under this deal the sector promises to keep co-firing at the current level of 10% (e/e) in the 2012-2014 period, partly self-funded by the coal-fired power producers. In return the government has agreed to aim to introduce a supplier obligation system in 2015.

Turkey

222. The year 2012 has been declared "domestic coal year" in Turkey, a government policy initiative to give high priority to the use of domestic lignite resources for electricity generation. Strategies and action plans were developed and project applications started in 2012. In June 2012 the Adana-Tufanbeyli lignite deposit was leased to the private sector for electricity generation, followed by the Denis deposit in August 2012. After 6-year investment periods, power plants (600MW and 450MW respectively) will be installed at each lignite deposit, and studies on possible leasing of other lignite deposits continue.

5 CONCLUDING REMARKS

223. The information given in this report describes developments over the last year in environmental/energy policy in various countries from the perspective of individuals active in the coal, electricity and transport industries.

224. Section 1 contains the industry's policy recommendations derived from the body of the report and other CIAB work, while other sections have highlighted relevant developments in international policy frameworks that potentially impact the investment necessary to sustain coal's role in supporting energy security in increasingly carbon constrained world energy markets.

225. During the last year, the focus of CIAB work has been on supporting the IEA Secretariat in understanding and modelling the particular challenges for coal, bringing the expertise of CIAB Members and their Associates to the issues through meetings, workshops and interaction with the IEA Secretariat. The CIAB has also commissioned and participated in the preparation of a report designed to provide policy makers with an overview of selected topics critical to developing "21st Century Coal".

226. Of particular concern to the coal and associated industries has been the slow progress on the development of advanced coal technologies and CCS, which the coal industry sees as essential to the continuation of coal's role in meeting energy demand, particularly in rapidly growing economies including China and India.

CIAB, 24 October 2012