COAL INDUSTRY ADVISORY BOARD

International Coal Policy Developments in 2015

16 OCTOBER 2015
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views of their companies, organisations or of the IEA.
FOREWORD FROM THE CIAB CHAIRMAN

The Coal Industry Advisory Board (CIAB) is a group of high level executives from coal-related 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 38 CIAB Members representing 18 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 more recent years the CIAB has focused additionally on developments in 21st Century Coal technology and the role of coal in addressing the world’s energy poverty challenges.

Each year, “International Coal Policy Developments” is produced for the Governing Board, Standing Committees and Secretariat of the International Energy Agency. It focuses primarily on policy developments, also acting as a report to the IEA on CIAB work undertaken during the year. It is based on contributions from Associates of CIAB Members to highlight policy and other issues that are pertinent to the development of coal as a secure, clean and competitive energy source.

The CIAB Policy advice set out in Section 1 has been drawn from coal industry knowledge and experience reflected through regular discussions at CIAB meetings, individual contributions to this paper and the CIAB’s work programme. It focuses on the wider aspects of coal’s ongoing role in social development and the global energy economy, and is intended to assist policy makers in addressing the energy challenges of our time.

Mr. Gregory H. Boyce
CIAB Chairman
Executive Chairman
Peabody Energy
1 CIAB POLICY RECOMMENDATIONS

These four policy recommendations draw on the findings of CIAB studies in recent years including:

- The Global Value of Coal (2012);
- 21st Century Coal: Advanced Technology and Global Energy Solution (2013);
- The Impact of Global Coal Supply on Worldwide Electricity Prices (2014); and

They describe actions that the CIAB regards as essential to guiding policy makers and leaders on the history and promise of technological development in approaching the issue of coal and the CO₂ challenge. The recommendations will be of relevance to the IEA, policy makers and leaders at COP21, and international financial institutions as they seek to achieve the goals of universal modern electricity access and meaningful greenhouse gas emissions reductions. Further detail can be found in the CIAB’s submission to the IEA for its “Special Report on Energy and Climate”¹ which was published in June 2015 in advance of the COP21 meeting.

1: Articulate the extensive role which coal is expected to play in the global energy mix to 2040 and beyond.

1. Coal is playing a major role in supplying electricity to meet the world’s enormous energy needs. In fact, both developed and developing countries are turning to coal to produce the power and steel necessary to sustain, and improve, their citizens’ quality of life and the industrial competitiveness of their economies. The future use of increasing quantities of coal worldwide is inevitable if the world is to avoid a damaging energy crunch and support the needs of developing nations. It supplies nearly 30% of global energy use and provides 40% of the world’s electricity. Metallurgical coal is an essential ingredient in steel-making and much of the world’s cement is produced using coal.

2. Coal is the world’s most prevalent and widely distributed fossil fuel. Its global distribution provides energy security across broad political arenas; and affordability and price-stability are also key reasons why nations rely heavily on coal-based electricity generation.

3. In developing economies, coal can provide the quantities of affordable electricity required to support social energy access and industrial/economic development goals. Coal has significant benefits as an energy source to aid global efforts to expand economic growth. In many developing economies it is the only practical, and in some cases the only available, large scale energy option. Advanced coal technologies mitigate the carbon emissions of coal combustion, allowing nations to reduce energy poverty and meet climate change objectives concurrently.

4. Coal-fueled electricity plant can also operate flexibly and competitively in partnership with increasing, but intermittent, wind and solar PV electricity in-feeds to maintain stability on electricity grids. A case study based on the German power market concluded that existing

¹ http://www.iea.org/ciab/CIAB_Submission_to_IEA_Special_Report_on_Energy_and_Climate.pdf
coal power plants can operate flexibly in response to the dynamic market required by increased renewables on the grid. Furthermore, future security of coal supply is necessary to keep wholesale electricity prices stable. Lastly, countries around the world have been utilising coal’s versatility in other ways, initiating an increasing number of projects converting coal to liquid fuel, substitute natural gas or chemicals.

5. The provision of secure, low-cost, reliable electricity, the development of infrastructure and the option to produce liquid fuels are three specific ways in which coal directly contributes to greater economic growth, job creation, and higher personal income and wealth. It is essential for decision makers to understand that these benefits are retained and expanded by greater deployment of advanced coal technologies, and that there are numerous specific examples of successful deployment.

2: Explain the CO\(_2\) mitigation potential of high-efficiency, low emission (HELE) coal-fueled power generation and the necessity of international financial support for such projects.

6. Significant CO\(_2\) mitigation benefits can be achieved in the short term by supporting deployment of HELE coal technologies. These technologies are commercially available now and, if deployed, could reduce greenhouse gas emissions from the entire power sector by around 20%. Increasing the efficiency of coal-fueled generation by one percentage point reduces CO\(_2\) emissions by 2-3%. Recognition should be given to the immediate greenhouse gas mitigation benefits of coal-based HELE technologies, which are high on the list of effective actions (by volume of GHG emission mitigation) and potentially more than three times as effective in reducing CO\(_2\) emissions as the global deployment of all non-hydro renewable energies combined.

7. In addition, coal combustion technologies continue to evolve. There is further potential beyond current HELE technology for future deployment of advanced ultra-supercritical and Integrated Gasification Combined Cycle (IGCC) plants. These technologies are likely to be commercially available around 2020 with efficiencies approaching 50%.

8. Furthermore, high efficiency 21st century coal-fueled power plants with state-of-the-art emissions controls have significantly reduced emissions of nitrogen oxide (NO\(_x\)), sulphur dioxide (SO\(_2\)) and particulate matter (PM). These emissions have reduced by 70% since 1990 in the U.S.A.; even as the volume of electricity produced from coal has remained broadly constant, coal generation continues to provide approximately 40% of U.S.A. electricity generation, and the country’s power prices are among the lowest in the world. Reduction of these air pollutants is of critical importance at the local and regional level to address air quality and related health concerns; and many modern HELE coal-fueled power plants are also now fitted with mercury control technology.

9. Policy actions to promote the deployment of HELE coal-fueled power plant technologies have also been proposed in the IEA’s “Energy Technology Perspectives 2012” and “World Energy Outlook 2013” publications; the latter focussing particularly on the role of coal in Southeast Asia in its ‘Efficient ASEAN Scenario’.

10. Further, the World Coal Association has launched its PACE\(^4\) initiative with the objective of bringing together governments, technology providers, public and private financiers,

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\(^3\) IEA Coal Industry Advisory Board, *The Impact of Global Coal Supply on Worldwide Electricity Prices*, IEA Insights Series, 2014

amongst others, to overcome the barriers to the deployment of HELE plants in developing countries.

3: Reiterate the imperative of carbon capture, utilisation and storage for meeting global climate objectives and call for increased international action and financial support to deploy this technology.

11. Deployment of HELE plants is also a key first step towards the deployment of carbon capture, storage and utilisation technology (CCUS), which is critical to achieving global climate objectives and reducing the economic costs of limiting CO₂ emissions. Recent research by the Intergovernmental Panel on Climate Change (IPCC) noted that failing to deploy CCS causes the cost of climate action to rise by about 140%, but that the most likely outcome is that the 2°C target could not be reached at all. This echoes similar findings in a number of recent reports from the IEA, which has called for 20 large scale CCS projects to be built by 2020.

12. The Global CCS Institute reports there are 13 large-scale CCS projects in operation around the world, with a further nine under construction. Despite this progress, technology-neutral policies, government funding, incentives, and continued robust research to reduce costs are needed to attract investment for additional large-scale CCS projects and enable sustainable deployment of the technology. Support for GHG emissions mitigation technologies has so far been focussed largely on renewable energy, with the result that CCS is not being deployed currently.

13. Two key issues are critical to making CCUS a reality:

1. Public sector support – Governments and international financial institutions should join with industry to finance CCS projects, but the policy settings must also be right. Policy parity should be established for all low emission technologies. For example, feed-in tariffs and other subsidies provided for renewable technologies have not been applied to CCUS technology.

2. Storage mapping – Long term storage remains a significant challenge for CCS. In many developing countries, where coal-based electricity is forecast to grow significantly for many years to come, significant work is required to better quantify and characterise storage sites to ensure captured carbon is securely and safely stored. (Some developed countries also require further mapping).

4: Provide CCUS technology with policy parity with other low emission energy technologies in international climate mechanisms.

14. Recent years have seen significant policy moves made against coal technology in order to pursue climate objectives. This has included financing policies of multilateral development banks and campaigns, supported by the United Nations, to disinvest from coal.

15. The IEA made an important contribution to this debate in the “World Energy Investment Outlook 2014” by highlighting the risk of unintended consequences from such action. We encourage the IEA to call the attention of governments and international bodies to its

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5 Intergovernmental Panel on Climate Change, Climate Change 2014 Synthesis Report, IPCC Fifth Assessment Report, 2014
6 Global CCS Institute, Global Status of CCS, 2014
assessment that in the 450 Scenario:

"World investment in coal-fired capacity totals $1.9 trillion (25% higher than in the New Policies Scenario), of which $800 billion is for plants fitted with carbon capture and storage (CCS). Furthermore, without financial support, countries that build new capacity will be less inclined to select the most efficient designs because they are more expensive; consequently raising CO₂ emissions and reducing the scope for the installation of CCS. In addition, many of the countries that build coal-fired capacity in the 450 Scenario need to provide electricity supply to those who are still without it, a problem that may be resolved less quickly if investment in coal-fired power plants cannot be financed."

16. The IEA should be clear that investing in advanced coal technologies is an essential part of global action to meet emissions objectives and achieve the intended outcomes of COP21.
2 CIAB ACTIVITIES IN 2015

17. The CIAB’s 2015 work programme was formulated following discussions at the November 2014 CIAB Executive Committee and Plenary meetings, and further work by CIAB Associates at their meeting in Johannesburg early in 2015 translated this guidance into a detailed work programme. Two items of work; the engagement of a widely respected energy consultancy to provide coal-related input to the IEA for “World Energy Investment Outlook 2015” on behalf of the coal industry, and the preparation of a study on the socio-economic benefits of advanced coal-fuelled generation projects, have involved significant financial cost to the CIAB. The CIAB expresses much gratitude to many CIAB Members’ companies who contributed further funds, in excess of normal CIAB membership dues, to support the second item of work.

18. The 2015 work programme has included a number of activities, some of which are continuations of 2014 work. 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.

Study on “The Socioeconomic Impacts of Advanced Technology Coal-Fueled Power Stations”

19. Discussions at the November 2013 CIAB Plenary meeting included a session on multi-lateral development bank financing of advanced coal-fuelled electricity generation projects. It became clear that several of these banks, led by the World Bank, have investment policies detrimental or positively opposed to such financing. These policies could result in developing countries being unable to install the most advanced coal-fired power plant technology and losing the associated potential for greenhouse gas emissions mitigation.

20. The purpose of the study is to demonstrate and quantify the economic and socio-economic benefits of advanced coal-fuelled electricity generation projects around the world. Case studies have been written on projects in India, Germany and China. The work was carried out by independent consultants financed by CIAB Members’ companies, and in some cases with information and staff support from those companies.

21. The work has been guided by an editorial committee of CIAB Associates and it forms part of wider initiatives to involve and inform multi-lateral development banks of the need to finance advanced coal-fired electricity generation projects in developing countries. A draft of the study report was made available for consideration by CIAB Members at their Plenary meeting in November 2014. Following their comments the paper underwent final editing, and formatting to comply with IEA publication standards. It will be published in 2015 as an IEA Insights paper.

Contribution to the IEA publication “Special Report on Energy and Climate”

22. At the Plenary Meeting in November 2014 the CIAB Chairman proposed that, rather than initiating new studies in 2015, the CIAB should produce a document that summarises the key messages from CIAB reports published over the last few years and draws out key messages to inform the IEA’s recommendations in its proposed “Special Report on Energy and Climate” in advance of the COP21 meeting.

23. Following discussions at the February Associates meeting, CIAB Associate Cartan Sumner (Peabody Energy) attended an IEA workshop in March with other stakeholders to discuss input to the report; thereafter a small working group drafted a white paper in consultation with CIAB Members and Associates, delivered to the IEA on 27 March.
24. The IEA published its “Special Report on Energy and Climate” in June, as part of its WEO 2015 report series and as input to the COP21 in Paris in December 2015. With permission from the IEA, the CIAB input has been made publicly available on the CIAB website.7

*Contribution to the IEA publication “World Energy Outlook 2015”*

25. Again last year, the CIAB commissioned the services of a renowned international energy consultancy to provide to the IEA its independent data and expertise (for IEA’s sole use) on elements of world coal mining and transportation, as input to IEA analysis for its World Energy Outlook 2015 publication. The work took the form of data input and interaction with the consultant over a number of subsequent months on topics including coal demand, supply, infrastructure and water stress in India and China, and global coal industry trends. A workshop was also held in June 2015.

26. This activity forms part of a continuing CIAB initiative to improve coal market input to IEA scenario and energy market modelling.

*CIAB Coal Information Working Group*

27. Since 2011, the CIAB has also supported coal aspects of IEA analytical work and publications through its Coal Information Working Group. This 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 the IEA’s coal focus in “World Energy Outlook 2011” and the new “Medium-Term Coal Market Report”. It is led by Mr. Carlos Fernández (Senior Coal Analyst, IEA) and has continued to provide this support every year by providing information in response to a questionnaire. Individual working group members also respond to specific IEA ad-hoc information requests.

*CIAB-supported secondments to the IEA*

28. In recognition of the IEA’s desire to improve its analysis and coverage of coal markets, since 2011 the CIAB has sponsored 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 each year to substantially support preparation of the IEA’s “Medium-Term Coal Market Report”. Despite the significant financial commitment involved, the CIAB has again been pleased to provide this support in 2015.


29. The Energy Security working group, under the leadership of CIAB Associate Dr. Hans-Wilhelm Schiffer (RWE, Germany) produced the IEA Insights paper “The Impact of Global Coal Supply on Worldwide Electricity Prices” in 2014. Dr. Schiffer and members of the working group are currently working on a paper entitled “The Role of Coal for Energy Security in World Regions”. This paper comprises input from CIAB Associates in various countries or world regions including the European Union (EU-28), U.S.A., Canada, Australia, Japan, China, India and South Africa.

30. For each of these regions/countries, conclusions are drawn on the role that coal plays in supporting secure energy and electricity supply. In many cases, typically developing

7 http://www.iea.org/ciab/CIAB_Submission_to_IEA_Special_Report_on_Energy_and_Climate.pdf

- 6 -
economies, coal is the only fuel source capable of providing the quantities of affordable electricity required to support social energy access and industrial/economic development goals. In other cases, typically developed economies, coal-fired electricity plant acts flexibly and competitively in partnership with increasing, but intermittent, wind and solar PV electricity in-feeds to maintain stability on electricity grids. In all cases, the use of advanced coal-fired generation technologies can contribute to supply security and the minimization of environmental impacts.

31. The first draft of the report has been sent to CIAB Associates for comment and will be made available to CIAB Members at their Plenary meeting in November 2015, after which it is planned to publish it as an IEA Insights paper.

CIAB Clean Coal Technologies working group

32. CIAB Clean Coal Technologies Working Group (CCTs WG) members support IEA activities in a number a of ways each year. The group had been led for some years by CIAB Associate Mick Buffier (Glencore, Australia), but he has recently passed the group’s leadership to Alex Zapantis (Rio Tinto Copper & Coal, Australia). Some recent examples include:

- comments on draft chapters of the IEA publications “Tracking Clean Energy Progress” and “Energy Technology Perspectives”;
- participation in an IEA information gathering mini-workshop on regulating non-CO₂ emissions from coal-fired power plants, held in Paris immediately before the June 2014 CIAB Associates meeting; and
- facilitating attendance by appropriate personnel from Associates’ companies at a joint ERIA/IEA workshop on “Coal-fired Power Generation in Southeast Asia” held in Jakarta on 3 September 2014.

IEA Greenhouse Gas R&D Programme

33. The CIAB has continued its formal sponsorship of IEA GHG. A CIAB representative attends IEA GHG Executive Committee meetings and the interface is managed through a small group of CIAB Associates, led by Mr. Cartan Sumner (Peabody Energy). 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.

Plenary Meeting discussion sessions

34. The November 2014 Plenary meeting included presentations and discussions on:

- European Energy Security;
- The Future of Coal in the Developing World; and
- Advanced Coal Technology: Recent Progress and the Road Ahead.

A note of these discussions is publicly available on the CIAB website.⁸

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3 COAL IN WORLD ENERGY MARKETS

35. The world’s coal reserves are extraordinarily large and widely dispersed, with proved reserves of 892 billion tonnes at the end of 2013 and a reserves/production ratio of 110 years.\(^9\) 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 more strongly than other fossil fuels.

3.1 Overview

36. **Total world primary energy consumption**\(^\text{10}\) growth declined to 0.9% in 2014 (1.8% in 2013), well below the ten-year average of 2.0%. Growth in emerging economies (2.4%) dominated this growth, but remained well below its 10-year average of 4.2%. Primary energy demand fell by 0.9% in OECD countries, fell by 3.9% in the EU, increased by 1.2% in the U.S.A. and fell by 3.0% in Japan. Although primary energy demand growth in China is slowing (3.7% in 2013, 2.6% in 2014), it nevertheless accounts for 23% of world’s energy consumption, compared to 17.6% for the U.S.A. and 12.5% for the European Union. Fossil fuels continue to account for the vast majority (86%) of total world energy consumption.

37. **Coal** demand grew at the same rate as natural gas (0.4%) in 2014, but oil grew by 0.8%, nearly matching the growth in total primary energy demand. China increased its coal consumption by 2.5% and India by 7.0%. Coal accounted for 30% of world energy consumption in 2014 (natural gas 23.7%, oil 32.6%). Its share is 66% in China and over 56% in India. Coal consumption in China accounted for over half (50.5%) of global coal consumption in 2014, India over 9%, and the U.S.A. 11.7%.

38. According to IEA figures, coal consumption has grown at a rate of nearly 2.4% a year on average over the 31 years since 1973. More notably, it has achieved growth of 3.7% a year since the turn of the century, a period that included a major global economic downturn.

39. Historically, IEA statistics show coal accounting for 24-27% of world primary energy use, although its share reached 29.0%\(^\text{11}\) in 2012. The IEA’s New Policies Scenario\(^\text{12}\) 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 1.1% a year on average to 2040, but coal use to grow by only 0.5% a year. It projects coal’s share to decline to 28.0% in 2020, 26.0% in 2030 and 24.3% in 2040. This would be a significant reversal of the historical trend.

40. The IEA’s 450 Scenario analyses how global energy markets could evolve if countries take co-ordinated action consistent with having around a 50% chance of achieving the goal of limiting the global temperature increase to 2°C. In this scenario, total world primary energy use is projected to increase by 1.0% a year to 2020, but only by 0.37% a year between 2020 and 2040, averaging 0.6% a year over the whole period. Coal’s share

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\(^{10}\) Figures in this and the following paragraph are from “BP Statistical Review of World Energy June 2015”. Quoted growth rates are leap year adjusted.

\(^{11}\) There are definitional differences between BP and IEA figures. For example, coal’s share of primary energy consumption in 2011 was 28.9% based on IEA figures (calculated from WEO 2013, p572) and 29.7% based on BP figures (calculated from BP Statistical Review of World Energy, June 2013, p33 and 40.

of the total market declines to 27.0% in 2020 before declining rapidly to 19.8% in 2030 and 16.6% in 2040. In that year, coal demand is projected to be 33% lower than in 2012.

41. In reality, and in light of past experience, such a reversal in the long-established growth trend in coal use looks unlikely; and this needs to be recognised by policy makers. Coal has the potential to meet further long term increases in demand, to support economic growth, to improve access to electricity for the 1.3 billion people currently without it, and to enhance the security of world energy markets. With appropriate policy and investment signals, it can also contribute significantly to reducing CO₂ emissions from electricity supply by employing advanced coal technologies and carbon capture and storage.

42. Current indications¹³ are that proved coal reserves (488 billion tonnes of sub-bituminous coal and lignite and 403 billion tonnes of anthracite and bituminous coal) at the end of 2014 are sufficient to sustain the current production rate for 110 years. This is far higher than reserves/production ratios for oil (52.5 years) and natural gas (54.1 years), while the wide dispersion of coal reserves in benign geographies reduces the risk of supply disruption relative to other fossil fuels.

¹³“BP Statistical Review of World Energy June 2015”, page 30
3.2 Regional Developments

United States of America

Domestic Energy Mix
[Note: all energy projections by the Energy Information Administration (EIA) do not take into account the impacts of future environmental regulations or regulations that have been proposed but not finalised, such as EPA’s Clean Power Plan.]

43. U.S.A. energy consumption grew by 2.9% in 2013 and by 1.2% in 2014. Trends by fuel type are displayed in the figure below.14

44. Primary domestic energy production increased by 3.4% on 2013 and 6.6% in 2014. The most significant area of growth was in crude oil production, which increased by 15% in 2013 and 17% in 2014. Domestic coal production (in Btu) declined by 3% in 2013 and increased by 1% in 2014 (see figure below).15

14 “Monthly Energy Review July 2015,” Table 1.3, USDOE/EIA.
15 “Monthly Energy Review July 2015,” Table 1.2, USDOE/EIA.
45. Annual electricity generation in the U.S.A. has been essentially constant since 2010. Variation by fuel over a longer term period is displayed in the figure below. The most significant changes since 2000 have been a significant decrease in coal-based generation, and a significant increase in electricity generation by natural gas.

46. Perhaps the most striking aspect of the projection shown below of U.S.A. energy consumption is that total consumption is projected to grow at only 0.3% per year, compared to a projected growth in Gross Domestic Product of 2.4% per year (in constant dollars). Steam coal consumption, on a BTU basis, is projected to grow by 0.2% per year, while metallurgical coal consumption is projected to decrease by 0.7% per year.16

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Coal Production

47. According to the Energy Information Administration (EIA), the U.S.A. has the largest recoverable coal reserves in the world. The U.S.A. is capable of meeting domestic demand for coal for roughly 280 years (260 billion tons\(^{17}\) total reserves/925 million tons of coal consumed in 2013).

48. Coal is mined in 25 states and is responsible for over 700,000 U.S. jobs. Wyoming is the largest coal-producing state, followed by West Virginia, Kentucky, Pennsylvania, and Illinois.

49. Of the nearly 983 million tons of coal mined in the U.S.A. in 2013, nearly 578 million tons were mined West of the Mississippi River and over 405 million tons were mined in the East. According to EIA, domestic coal production was 917 million tons in 2014, and is projected to fall slightly to 897 million tons in 2015 and 894 million tons in 2016.

50. Alpha Natural Resources filed for voluntary bankruptcy and reorganization on 3 August 2015. The bankruptcy process will allow Alpha “to reorganize and emerge as a financially viable business that is better positioned to compete in the US and global markets”\(^{18}\).

51. Patriot Coal Corporation also filed for bankruptcy protection in May 2015, as did Walters Energy in July. Both are undergoing court-supervised reorganization.

52. Murray Energy is now the U.S.A.’s largest underground coal producer. In addition to acquiring a number of producing mines from CONSOL, it acquired a controlling economic interest in Foresight Energy in the Illinois Basin.

Coal Use

53. 93% of the coal consumed in the U.S. is used to generate electricity. Coal is also used in the steel, paper, cement, and plastics industries, and to produce activated carbon (for

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\(^{17}\) 1 US short ton = 1.1023 metric tonnes  
\(^{18}\) Alpha Natural Resources press release, 3 August 2015
water purification) and carbon fibres (for fuel cells and electronics).

54. In *Electricity Generation* coal was responsible for 38.7% of electricity produced in 2014, more than any other source of electricity, with natural gas providing 27.4%, nuclear power 19.5%, hydro-electricity 6.3% and other renewable energy (wind, solar, geothermal, and biomass) 6.9%. Coal-fired electricity generation decreased by 0.2% in 2014 compared to 2013 and is projected to provide 35.8% of U.S.A. electricity in 2015 and 36.2% in 2016. Natural gas is projected to generate 29.1% of U.S.A. electricity in 2015 and 29.5% in 2016. Coal is projected to remain the dominant fuel for electricity generation in the U.S.A. through to 2040.

55. Regarding the U.S.A.’s coal-fired electricity generation fleet, there is some uncertainty regarding how states will comply with the US Environmental Protection Agency’s (EPA) recently promulgated “Clean Power Plan” (CPP) regulations. The chart below presents EIA projections of its “Reference Case” coal-based electricity generating capacity, which do not reflect the EPA regulation, the EIA’s estimated impact on coal capacity from the rule as it was proposed on 18 June 2014, and the EPA’s analysis of its final rule (shown as three green diamonds on the chart). The EPA’s analysis of the effect of its final rule shows more coal unit retirements than either EIA or EPA had predicted for the proposed rule. Relative to the 300GW of coal-based capacity operating in 2012, and including EIA’s projected addition of 1GW of new coal capacity, EPA’s projections imply 106GW of coal retirements by 2020, 114GW by 2025, and 118GW by 2030.

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56. Separately, the American Coalition for Clean Coal Electricity (ACCCE) monitors announcements of planned closures made by coal-fired power plant owners. In mid-2015, announced coal-fired electricity generation capacity closures by 2025 amounted to 73GW (468 units) located in 41 states, including approximately 16GW that are converting to either natural gas or biomass. Most of these retirements and conversions are attributed to EPA policies, amounting to over 62GW (393 units) in 36 states of which approximately 13GW is converting to either natural gas or biomass. Ohio, Pennsylvania, Alabama, Kentucky, Indiana, and Georgia have the most closures attributed to EPA policies.

57. **Electricity Prices**: the average family spent $110/month on electricity in 2013 and the average retail price for electricity in 2014 was 10.45 cents per kilowatt-hour (c/kWh). Nineteen states that generate, on average, less than 9% of their electricity from coal pay an average of 13.7c/kWh for their electricity, 31% more than the national average. Thirty-one states that, on average, generate more than 55% of their electricity from coal pay an average of 9.27c/kWh, 11% less than the national average.

<table>
<thead>
<tr>
<th>Actual and Projected Natural Gas and Coal Prices for Electricity Generation ($/MMBtu delivered)</th>
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<tbody>
<tr>
<td><strong>Year</strong></td>
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<tr>
<td>Natural Gas</td>
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<td>Coal</td>
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*Source: EIA, March 2015*

58. The EIA projects that natural gas prices for electricity generation will increase by nearly 42% between 2014 and 2030 (in constant dollars), while coal prices are projected to rise by 19% over the same period. Longer term projected fossil fuel prices for U.S.A. power generation are provided below.\(^{20}\)

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Coal Export Projects

59. The Millennium Bulk Terminal Coal Export Facility project in Longview, Washington, is in the permitting phase with key draft environmental impact study (“EIS”) to be published for comment in late 2015. It will revitalise an existing bulk commodity port facility on the Columbia River (between Washington and Oregon States) to accommodate the export of 44 million tonnes of coal by 2018 at an estimated cost of $600 million. Lighthouse Resources, formerly known as Ambre Energy, is the majority owner and Arch Coal is the primary minority owner of the project.

60. Ambre Energy’s Port of Morrow Coyote Island Terminal Coal Export Project in Boardman, Oregon, would bring up to 8.8 million short tons of coal a year by train from Montana and/or Wyoming to Boardman. The company would store the coal in covered storage buildings at the Port of Morrow before transferring it to barges using an enclosed conveyor system and transporting it down the Columbia River to Port Westward. A number of state and Federal permits have been received, and on 31 March 2015 the State of Oregon Department of Environmental Quality issued a water quality certification giving reasonable assurance that the project will meet state water quality standards.

61. Pacific International Terminals, a subsidiary of SSA Marine, has proposed the Gateway Pacific Terminal at Cherry Point, Bellingham, Washington. This is a deep-water marine terminal to handle exports of up to 54 million dry tonnes/year of bulk commodities, primarily coal. A draft Environmental Impact Statement (EIS) is in preparation, with the final EIS targeted for 2017 and possible operation by 2020.

Canada

Domestic Energy Mix

62. Canada’s primary energy demand in 2013 comprised 7.7% coal, 37.6% crude oil, 36% natural gas, 4.5% natural gas liquids and 14.1% hydro and nuclear. Canada’s primary energy demand mix has changed in the past 10 years. Demand for coal declined from 12.1% of primary energy demand in 2002 to 7.7% in 2013, largely due to the reduced domestic consumption for coal-fired generation as a result of environmental policies. Coal contributed nearly 9% of primary energy production in Canada and about 10% of
Canada’s total electricity generation. As of April 2014, Ontario phased-out coal-fired generation units and coal is no longer in use.

63. It is expected that domestic demand for coal will be stable in the mid-term as there are no major policy changes proposed. In the longer term, domestic demand for coal used in electricity generation could be impacted as a result of federal emission regulations that took effect in July 2015. They apply a stringent performance standard to new coal–fired electricity generation units and old units that have reached the end of their useful life. Several units will be affected, starting from 2019.

**Coal Production and Export**

64. As international coal prices remain at low levels, the coal sector has been witnessing closure of less profitable mines, reduction of workforce, and changes and delays in investment in new mines and infrastructure.

65. Major U.S.A. metallurgical coal producer Walter Energy idled Canada’s Wolverine and Brule mine in 2014. Prior to this action, it had suspended operations at Willow Creek mine in 2013. Anglo American suspended operations at the Trend mine in 2014. Since spring 2015 there have been no coal mines in operation in the Peace River Coalfield.

66. Several mine projects have been deferred, including the planned restart of Teck’s Quintette coal mine, which would produce 3-4 million tonnes per year of coking coal for export.

67. Despite restructuring and consolidation, several export mine investments made in the high-price period are expected to come online in the medium term.

68. HD Mining’s Murray River project is close to the completion of the environmental assessment review conducted by British Columbia Environmental Assessment Office. HD Mining proposes to develop an underground mine with a production capacity of 6 Mt of coking coal per year for export over 31 years. The Donkin mine project on Cape Breton Island, Nova Scotia, received environmental approval in 2013 and is expected to produce 2.75 million tonnes per year by 2016 and exports through Sydney port. Coalspur’s Vista project in Alberta, which had received all regulatory approvals, was ready for mine construction but is now delayed. The project is targeting 12 million tonnes per year of bituminous thermal coal for export once it completes its two-phase mine development.

69. Canada produced 69 million tonnes of coal in 2014. 18 large coal mines were in operation, all located in western Canada (9 in British Columbia, 7 in Alberta and 2 in Saskatchewan). Close to half of the production was coking coal, almost all of which was exported. Canada exported 34.5 million tonnes of coal in 2014, valued at $4.2 billion. Of the total, 31 million tonnes was coking coal, valued at $3.9 billion. The coal sector directly employed about 9,800 people in 2014, most located in remote areas of Canada.

70. Four companies produce coking coal or PCI coal for export; Teck Resources Ltd., Walter Energy Inc. and Anglo American Plc’s Peace River Coal Inc. in British Columbia, and Grande Cache Coal Corporation in Alberta. Two companies produce bituminous thermal coal for export; Westmoreland Coal Company and Vitol Group’s Hillsborough Resources Ltd. Westmoreland is mainly engaged in production of sub-bituminous and lignite coal for coal-fired power generation in Canada together with TransAlta Corporation, which produces sub-bituminous coal for its own power generation plants.

71. All of Canada’s export coal mines are located in British Columbia (B.C.) and Alberta and require transport averaging 1,100 kilometres to export ports and terminals in B.C. on the West Coast. In 2014, about 37 million tonnes was hauled by two rail operators, Canadian
National (CN) and Canadian Pacific (CP). Canadian ports handled some 50 million tonnes of coal in 2014.

72. Port Metro Vancouver has two terminals: Westshore Terminals, the largest coal export terminals in North America, and the Neptune Terminals. The Ridley Terminals is located at Prince Rupert in northern B.C. There is a coal terminal located in the Port of Thunder Bay in Ontario (Great Lakes) and the international Coal Pier is located at Sydney, Nova Scotia (Atlantic Ocean).

73. In recent years, Westshore, Neptune and Ridley Terminals have seen over $1 billion invested in efficiency and capacity improvements, including the addition of around 30 million tonnes in coal handling capacity in the next few years.

74. In August 2014, Port Metro Vancouver approved the proposed direct transfer coal facility at Fraser Surrey Docks (FSD) after a thorough review process. The facility is to handle around 4 million tonnes per year of coal from the U.S.A., barged down the Fraser River to Texada Island for storage before it is exported.

75. The government of Canada, provincial governments, major ports and railways are working together on the Asia Pacific Gateway and Corridor Initiative (APGCI). The initiative aims to deliver investment in a strong transportation corridor facilitating delivery of various commodities to Asia Pacific markets. The government of Canada has invested over $1.4 billion in strategic infrastructure projects. Provinces and major ports, airports and railways have also invested significantly into B.C. Lower Mainland and Prince Rupert ports, road and rail connections across Western Canada and North America, major airports and border crossings.

Brazil

Domestic Energy Mix

76. There are proposed changes in mining legislation and regulation but they are not expected to affect coal production prospects in Brazil. Investment in new mines is needed to maintain the level of production to support the increased dispatch of the coal-fired power plants in future years.

77. In December 2014, the Brazilian interconnected electrical system had a total installed capacity of 132.6GW comprising 83.2% renewable energy (66.9% hydro, 16.3% other), 15.3% thermal fossil, (2.4% coal, 12.9% other fossil) and 1.5% nuclear. In 2014, 75.5% of electricity was generated by renewables, 20.7% by thermal fossil and 3.0% by nuclear. Brazil has been facing prolonged dry weather since 2013 which has led to low reservoir levels for hydroelectric power plants. This year the wet season (December-April) closed with the lowest level of water storage seen for 40 years, and all thermal capacity will be required to run to maintain electricity supply. If water storage in the southeast region falls to 10% in November 2015, very high rainfall will then be needed to avoid power cuts in 2016.

Coal Utilisation

78. There will be increased focus on wind and hydropower developments in the forthcoming years. The Brazilian Government’s power policy has been to promote renewable generation and coal projects and its GHG reduction policies kept coal projects out of energy auctions from 2009 to 2012. However, electricity generation accounts for only a very small proportion of Brazil’s greenhouse gas emissions and, due to the persistent drought affecting hydroelectric power plants’ reservoirs, the Government decided to
foster thermal generation. Since 2013, all thermal power plants have been fully dispatched in order to save water in the southeast reservoirs during the dry season (May-November).

79. Currently there are no restrictions on new coal-fired power generation in Brazil, and so far there has been no evidence of constraints imposed by banks’ lending policies that could constrain developments of new advanced coal-fired electricity generation projects. In November 2014 a new 340 MW fluidised bed coal plant project was awarded, with construction due to start in 2015 for completion by 2019. A new 2.8 million tonne/year open pit mine will be required to supply this project, and its second phase that will be submitted as a project for the 2016 Energy Tender.

80. The Power Regulatory Agency ANEEL has applied pressure to increase the efficiency of the old power plants. One of them, the 20MW São Jerônimo Power Plant, was shut down in 2014. However the 20MW Figueira Power Plant, which is as old as São Jerônimo, was retrofitted with a new boiler. Also, the 126MW Candiota Fase A power plant will be closed by the end of 2015 due to pressure from the Federal Environmental Agency. To comply with ANEEL rules, discussions have been opened with the Brazilian Government to set up a modernisation program to increase efficiency from 28% to 35%.

81. As Brazil currently has limited growth in natural gas production, one coal company is conducting a feasibility study for an SNG project to supply gas to the south of Brazil.

82. There is also interest in producing fertilizer from coal. Last year Brazil imported 82% of its nitrogen fertilizer requirements and these are forecast to triple by 2050, so such projects may provide an attractive business opportunity.

Australia

Domestic Energy Mix

83. As shown below, oil is Australia’s largest source of energy, accounting for 37.7% of consumption in 2012-13 followed by coal (33.1%), gas (23.6%) and renewables (5.6%). In recent years, the share of natural gas in the energy mix has increased due to greater uptake in the electricity sector and some growth in industrial use, particularly in the non-ferrous metals sector.

Primary energy consumption fuel mix: Australia and its six states, 2012-13

<table>
<thead>
<tr>
<th>Fuel</th>
<th>% of Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil</td>
<td>37.7%</td>
</tr>
<tr>
<td>Coal</td>
<td>33.1%</td>
</tr>
<tr>
<td>Gas</td>
<td>23.6%</td>
</tr>
<tr>
<td>Renewables</td>
<td>5.6%</td>
</tr>
</tbody>
</table>

Australia’s electricity generation by fuel type, 2002-03 to 2012-13

84. Since 2009-10, Australia’s electricity generation has been declining in response to falling electricity demand, reflecting structural change, slower population growth, the impact of government policy and efficiency improvements.

85. Trends in the mix of generation in the National Electricity Market (NEM) are shown below.\(^{21}\) In the twelve months to June 2015, brown coal generation increased due to growth in exports from Victoria to South Australia (where it is backing up wind intermittency in favour of higher cost gas peaking plant) and to Tasmania (where it is displacing hydro). Black coal generation remained fairly constant for the first three quarters. This was due to increases in output from the six Queensland black coal power stations largely offsetting the fall in supply from the five NSW ones. In the fourth quarter, Queensland production grew more strongly reflecting higher demand from large industrial users.

Changes in NEM electricity generation by fuel type, Australia June 2006 to July 2015

![Graph showing changes in NEM electricity generation by fuel type]

Source: Consultants pitt&sherry, August 2015 based on NEM data.

86. Residential consumers have largely driven the absolute fall in demand in the NEM, falling 13% from 2010 to 2014.

87. Since 2010, demand by large industrial consumers has also fallen, largely due to structural change in Australia’s energy-intensive industries. In Victoria, there has been a further decrease this year following Alcoa Australia’s closure of its Point Henry aluminium facility and Yennora rolling mills in December 2014. Demand by general business consumers remained almost unchanged between 2006 and 2014.

88. The reduction in black coal consumption in recent years is due to falling use in domestic electricity generation and steel production. Nonetheless, as coal is a relatively low cost and abundant energy source in Australia, it is expected to remain the dominant source of electricity generation. The share of coal in electricity generation is projected to remain broadly constant (64% in 2014-15 and 65% in 2049-50).\(^{22}\)

**Coal production**

89. In 2014, thermal and metallurgical coal prices reached five and seven year lows respectively. Since March, various coal industry analysts have downgraded their outlook for prices over the next three to four years. For thermal coal, the larger supply overhang

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\(^{21}\) The NEM interconnects five regional market jurisdictions (Queensland, New South Wales – including the Australian Capital Territory – Victoria, South Australia and Tasmania). It operates on one of the world’s longest interconnected power systems, covering a distance of around 5,000 kilometres.

now appears to be priced in. However, for metallurgical coal a key uncertainty is the outlook for Chinese steel demand.

90. Since 2013, efforts by Australian producers to increase productivity and improve capital efficiency have realised substantial cost savings. With weak prices persisting, producers continue to focus on reducing operating costs rather than pursuing expansion opportunities. The cyclical decline in seaborne thermal and metallurgical coal prices has also led to delays and reduced investor participation in various new projects. Companies have also reduced exploration activities.

91. Australia’s thermal coal production is estimated to have declined slightly from 248 million tonnes in 2013-14 to 246 million tonnes in 2014-15 and is forecast to be 249 million tonnes in 2015-16. This reflects increased production from new projects after taking into account production losses from scheduled mine closures.

92. Despite the challenging operating environment, thermal exports are estimated to have increased by 3% to 200 million tonnes in 2014-15.23


China

94. GDP growth in China slowed in 2012 and coal demand has been shrinking. Coal use fell by 2.9% from 2013 to 2.81 billion tonnes coal equivalent in 2014, the first fall since the year 2000, and is predicted to fall from 66% of primary energy demand in 2014 to 55% by 2030. It will continue to dominate China’s energy mix, although coal demand may peak earlier than previously predicted (2020).

Coal Consumption and Coal’s Role in Primary Energy Consumption

95. The Bohai-Rim Steam Coal Price Index has fallen by 52% from its 2011 high point, to RMB414/tonne in April 2015, causing most large coal producers to reduce production by about 10% from 2014 levels; and in Q1 2015 80% of coal companies in China were losing money.

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To address China’s air pollution issues, policy objectives include the clean, efficient use of coal for power generation, including ultra-low emission coal-fired plant (i.e. lower emissions than gas plant), the modernisation of the coal-based chemical industry and reduction of small-scale coal burning. Only 53% of coal is used for power generation; and at the end of 2014 coal-fired generating capacity was 826GW.

The development of coal conversion to other fuels is developing rapidly, with many coal-to-liquids, methanol-to-olefins, and synthetic natural gas plants under construction. However, the economics of the coal conversion industry remains subject to oil price fluctuations and regional water availability issues.

**Japan**

*Domestic Energy Mix*

In FY 2014\(^{24}\), the electric power industry in Japan produced 910TWh (gross) of electricity in total. Coal-fired power generation operated as baseload and accounted for 31.0% of total electricity generation in FY 2014.

### Electricity Production in FY 2104 by fuel type

<table>
<thead>
<tr>
<th>TWh (%)</th>
<th>Coal (31.0)</th>
<th>Natural gas (46.2)</th>
<th>Oil (10.6)</th>
<th>Nuclear (0.0)</th>
<th>Hydro (9.0)</th>
<th>Renewables &amp; others (3.2)</th>
<th>Total (100.0)</th>
</tr>
</thead>
<tbody>
<tr>
<td>282</td>
<td>420</td>
<td>96</td>
<td>0</td>
<td>82</td>
<td>30</td>
<td></td>
<td>910</td>
</tr>
</tbody>
</table>

Source: The Federation of Electric Power Companies of Japan

By September 2013, all nuclear power units in Japan (54 units, 49GW as of 31 December 2010) were offline following the March 2011 Fukushima Daiichi accident. But by 31 August 2015, 24 units (24GW) had applied to the Nuclear Regulation Authority to resume operations against tougher safety regulations put in place after the 2011 accident.\(^{26}\) Following a decision to decommission several reactors there are 43 nuclear units (42GW) in Japan, excluding those under construction or planned, as of the end of

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\(^{24}\) Japanese fiscal year corresponds from April to March e.g. “FY 2014” indicates “April 2014 to March 2015”. The same shall apply hereafter.

\(^{26}\) [https://www.nsr.go.jp/data/000067275.pdf](https://www.nsr.go.jp/data/000067275.pdf)
August, 2015.\(^{27}\)

100. In early August, Japan’s Nuclear Regulatory Authority (NRA) approved operation of Kyushu Electric Power Co.’s Sendai 1 nuclear reactor for a further 10 years. The reactor was re-connected to the grid on 14 August and resumed commercial operations on 10 September 2015.\(^{28}\)

**Coal production**

101. Japan produces only a very small amount of coal, amounting to 1.3 million tonnes in FY 2014. In FY 2014, Japan imported 187.7 million tonnes of coal in total, 4.0% lower than the previous year. Details are shown below:

**Coal Imports in FY 2013 and 2014 (million tonnes)**

<table>
<thead>
<tr>
<th>CY</th>
<th>Anthracite</th>
<th>Thermal coal</th>
<th>Coking coal</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>5.5</td>
<td>111.5</td>
<td>78.6</td>
<td>195.6</td>
</tr>
<tr>
<td>2014</td>
<td>5.1</td>
<td>110.2</td>
<td>72.3</td>
<td>187.7</td>
</tr>
</tbody>
</table>

*Source: Trade Statistics of Japan*

**Thailand**

**Domestic Energy Mix**

102. Over the period 2005 to 2014 the proportion of gas and lignite/imported coal in primary energy consumption increased, while the proportion of oil decreased. Primary energy consumption remains dominated by gas and oil.

**Primary Energy Consumption 2005-2014 (million tonnes oil equivalent)**

[Primary Energy Consumption Chart]


**Coal Use**

103. In 2014, Non-Electricity Generating Authority of Thailand (EGAT) accounted for 45% of


\(^{28}\) [http://www.kyuden.co.jp/en_information_150910.html](http://www.kyuden.co.jp/en_information_150910.html)
Thailand’s electricity generation, independent power producers (IPPs) 38%, and other sources including imports 17%. Natural gas supplied 64% of electricity generation, coal 20%, Renewable energy 9%, imported hydro-electricity 7% and oil 1%. EGAT coal reserves have been gradually depleted and EGAT mine-mouth coal-fired power stations consume almost all domestic production, about 16.9 million tonnes.

**Indonesia**

104. In 2014, Indonesia’s target coal production level was 425 million tonnes, of which 92 million tonnes (22%) was available for domestic use under the Domestic Market Obligation (DMO). 85% of that 92 million tonnes was allocated to the state electricity generating company (PLN), with the remainder sold to the cement and fertiliser industries.

105. Indonesian Government objectives include enhancing energy security, optimising coal resource utilisation and maximising government revenue from coal production. The Ministry of Energy and Mineral Resources has announced that it will consult stakeholders on a proposal, based on the Mid-Term National Development Plan 2015-2019 (RPJMN), to increase the DMO to 60% of the 400 million tonne production target in 2019.  

106. A plan to raise royalties for coal mining companies that hold a Mining Business Permit (Izin Usaha Pertambangan, abbreviated IUP) to 13.5% of the coal FOB sale price is currently postponed. Other measures to achieve government objectives include a ban on exports of low quality coal and a reduction in foreign coal asset ownership.

**South Africa**

**Coal Production**

107. 2014 saw Glencore Tweefontein optimisation project (primarily export) reach 85% completion, on time and under budget. No major contracts were signed for any of the greenfield projects that are urgently required to supplement and/or replace several of the existing dedicated power station collieries that will ramp down from around 2015.

108. Production at the Grootegeluk mine expansion to supply the new Medupi Power Station ramped up during 2014. However, continued delays on the power station project have resulted in a slower than planned production increases at the mine. Eskom is understood to be taking small quantities of coal for testing in its Central Basin stations, but is also paying significant penalties.

109. ResGen’s Boikarabelo mine in the Waterberg secured funding in 2013 and announced that the project has received its mining permit and water use licence. Construction of the first phase is underway but the project has suffered delays due to contractor insolvency, meaning that production will now begin during the first half of 2016.

110. Waterberg Coal is also expecting its first shipments of export coal to take place in Q3 2016, building up to 4 million tonnes a year by 2020. It will also supply lower grade coal to an IPP bidding in the Department of Energy’s Coal IPP Procurement Programme.

111. Sasol is currently delivering on an intensive capital replacement programme that will see

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Sasol Mining replace 60% of its capacity over the next five years at a total cost of R14 billion. The following four projects will replace or extend the life of current mines:

- the Impumelelo project (8.5 million tonnes a year) that will replace the existing Brandspruit mine is under construction and on track to reach full operation during H1 2015;
- the Shondoni project that will replace the old Middlebult mine from 2015/16 will produce 10.5 million tonnes a year and is under construction;
- the Thubelisha project is nearing completion and will extend the life of the Twistdraai Colliery beyond 2043, supplying coal for Sasol synguels, the export market and domestic markets; and
- the Tweedraai project will replace part of the Syferfontein mine as an opencast operation.

### Coal Exports

112. South Africa is the fifth largest global coal exporter and has a geographic advantage that allows it to supply both the Atlantic and Pacific markets. Once a primary exporter to the EU, South Africa now serves both markets. In 2014 exports to the EU grew to 25%, from 20% the previous year, while those to the Far East decreased to 60%, from 65% in 2013. Future trends focus on the Middle East and Africa, although the EU market could still be a potentially large market for South Africa.

113. While export demand and price remained subdued in 2014, longer term demand is generally forecast to rise, primarily driven by growth of Indian coal imports from around 110 million tonnes in 2012 to an estimated ~180 million tonnes by 2018.

114. Transnet has committed to a Phase 1 upgrade of the existing railway line from Lephalale to Mpumalanga from its current capacity of 4 million tonnes a year to 23 million tonnes a year by 2018. Transnet also committed to a total investment of R300 billion over seven years on the rail network in South Africa. Included in this are plans to expand the capacity of the current railway line to Richard Bay Coal Terminal from 73 million tonnes a year to 81 million tonnes a year. BHP Billiton has signed a 10 year take or pay contract on the coal export line worth R2.4 billion a year.

115. The Richards Bay Coal Terminal (RBCT) Company CEO, Nosipho Siwisa-Damasane announced in 2013 that the company was ‘working on plans’ to increase the capacity of the terminal to 110 million tonnes a year in order to “meet the expected rise in demand from Asia”. No detail on these plans has come to light, but the upgrade of the railway line to Richards Bay is currently the bottleneck. In 2014, a record 71.3 million tonnes was exported through RBCT, which has a current capacity of 91 million tonnes a year.

116. Grindrod still has plans to expand its existing Navitrade facility at Richard’s Bay in conjunction with investment group RBT Resources. The envisaged expansion is for up to 20 million tonnes a year and Thabiso Bhuku, Commercial Director at Grindrod, was quoted as saying that the company expects to "break ground in the first quarter of 2014 and ramp up to 20 million tonnes a year over the next three to five years on a phased basis”. The expansion is reportedly linked to the construction of an inland coal terminal that would enable junior miners to consolidate volumes for export.

117. A review of major export projects previously scheduled for completion by 2018 suggests that very little development is taking place on the larger projects and most projects appear to be on hold.
Coal Use

118. Peak electricity demand in South Africa has decreased from 36,212MW in 2011 to 31,419MW in 2015. However, although the total installed capacity in the country is 44,084MW, unplanned outages and routine maintenance have meant 25% of that capacity is currently offline. The resulting gap between demand and supply ranges between 1,000 and 3,000MW; and consequently Eskom has had to implement controlled load shedding since mid-November 2014. Open Cycle Gas Turbine (OCGT) plants running on diesel oil and pumped storage plants are operating at baseload to avoid load curtailment where possible, although these are intended to be peaking stations due to their very high running costs.

**Installed Electricity Generation Capacity in South Africa**

<table>
<thead>
<tr>
<th>Type</th>
<th>Installed Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal-fired Power Stations (Eskom)</td>
<td>37,745</td>
</tr>
<tr>
<td>Nuclear Power Station (Eskom)</td>
<td>1,910</td>
</tr>
<tr>
<td>Hydroelectric (Eskom)</td>
<td>2,000</td>
</tr>
<tr>
<td>OCGT (Eskom)</td>
<td>2,426</td>
</tr>
<tr>
<td>Wind (Eskom)</td>
<td>100</td>
</tr>
<tr>
<td>Renewable (IPPs)</td>
<td>~1,500</td>
</tr>
</tbody>
</table>

119. The Renewable Energy Independent Power Producer Programme (REIPPP) has resulted in 79 projects being commissioned since 2011, with 1,500MW of the total of 5,200MW that will be added to the grid from these projects already online. Successful bidders from the fourth Bidding Window were announced in early April 2015. In addition to the REIPPP projects, Eskom’s 100MW Sere windfarm is now operating at full capacity. In spite of the rapid increase of the share of renewable energy sources to 1.6%, coal continues to provide the majority (86.5%) of South Africa’s electricity.

120. Eskom is currently building what will be two of the biggest coal-fired power stations in the world. Medupi and Kusile (each 4,800MW) to be commissioned in stages. The first 800MW unit at Medupi was synchronised to the grid in March 2015. The first unit of the 4,800MW Kusile coal-fired power station is expected to be synchronised during the first half of 2017. With more than 90% of South Africa’s electricity already coming from coal, building new coal-fired power stations further increases the country’s dependency on coal. The new stations both use relatively low grade coal, with boiler design coal specifications of 20.4MJ/kg for Medupi and 18.6MJ/kg for Kusile.

121. Eskom has not yet concluded a coal supply agreement for the New Largo project to supply the Kusile Power Station and it is now unlikely that the mine will be developed in time to supply the full ramp up of the power station. The project also faces several environmental challenges, which could delay the necessary permitting.

122. The 1332MW Ingula Pumped Storage Scheme is due to be fully operational by the end of 2015.

**New Build Electricity Generation Capacity**

<table>
<thead>
<tr>
<th>Type</th>
<th>Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal-fired Power Stations (Eskom)</td>
<td>9,546</td>
</tr>
<tr>
<td>Pumped Storage</td>
<td>1,332</td>
</tr>
<tr>
<td>Renewable (IPP)</td>
<td>~3,700</td>
</tr>
</tbody>
</table>

123. Given the current electricity crisis, the Department of Energy announced the first round (2,500MW) of the coal base-load independent power producer programme in December 2014 with the successful bids to be announced by the end of 2015. Processes are also
being put in place to procure 3,100MW of gas-fired capacity and 800MW of cogeneration capacity.

124. Should all the IPP capacity be delivered to the grid as planned, it will see 19,000MW of additional capacity by the early 2020s.

125. The current electricity capacity shortage and continued construction delays on the new power stations mean that Eskom continues to run its existing power plants at higher load factors; and requires coal qualities closer to the upper end of its contracted ranges as it operates closer to the operational limit of its plants. Several of the “tied-collieries” are, and will continue to be unable to provide these qualities at the required tonnages.

126. In addition, Eskom has increased the planned operating lives of most of its power stations and re-commissioned three older stations that were mothballed in the 1980’s. Eskom’s long term coal supply contracts, several of which end within the next 10 years, cannot provide this additional coal and those mines facing depletion need to be replaced with projects that develop new coal resources.

127. Eskom will increasingly compete with the export market for coal from non-dedicated resources. It has contracted approximately 80% of its required cumulative coal supply up to 2020, with approximately 70% of this purchased on long term cost-plus or fixed-price contracts and 30% on short- to medium-term contracts (generally less than a 3-year duration), so it is unlikely that coal supply will affect the economics of operation at existing power plants. It has entered into Memoranda of Understanding with two junior miners to progress potential supply projects in the Waterberg. Of the two, Resgen’s Boikarabelo mine appears to have the most promise and the company claims to have off-take agreements for the full 6 million tonnes a year of phase 1 production. The full ramp up of both the Resgen and the Sekoko/Firestone Waterberg projects remains dependent on greater rail capacity being available to transport the coal to the Central Basin power stations, and on an increased supply of water to the region.

128. Eskom has stated its intention to develop a 2,100MW combined cycle gas power station utilising gas generated through underground coal-gasification (UCG) technology. Eskom has been investigating the technology since 2007 and has successfully demonstrated production of the gas at a pilot project at the Majuba power station. Eskom continues with the feasibility studies for the project, although the target date of 2017 for commercial UCG operations has slipped due to environmental permitting delays.

129. In the longer term, Eskom expects its coal demand to increase by 28% to around 160 million tonnes a year by 2025 from current levels of around 125 million tonnes a year, largely due to the introduction of Medupi and Kusile Power Stations; and its total coal supply requirement between 2014 and 2050 could be as high as 4,591 million tonnes, of which as much as 2,480 million tonnes is unsecured by existing contracts. Over R100 billion needs to be invested in the domestic coal mining and coal transportation industry by 2018 to avoid major coal supply shortfalls after 2020. Beyond 2025, its coal demand is expected to decline to eventually reach about 40 million tonnes a year by 2050 due to the planned electricity sector in line with the Integrated Resources Plan to lower carbon emissions from the electricity sector. However, some suggest that the decline in demand from 2025 will be due to increasing power prices and structural issues caused by lack of coal supply.

**Russia**

130. In 2014 the overall situation of the Russian coal market remained relatively unchanged. Raw coal output totalled 358.2 million tonnes (1.7% higher than the 2013 figure of 352.0 million tonnes). Domestic coal consumption decreased by 3.9% from 177.6 million tonnes
in 2013 to 170.6 million tonnes in 2014. Significant Ruble depreciation encouraged coal export growth to increase to 154.8 million tonnes (10.6% higher than in 2013). In response to the weakening macroeconomic situation, total investment fell by 27.9% to RUB 58 billion, postponing or cancelling large development and infrastructure projects. During the year rail availability began improving due to technological enhancements and the start of projects to increase rail capacity in the Far East region.

**Coal Production**

131. No significant changes were observed in asset ownership and new capacity development during 2014, although 9 million tonnes a year of additional production capacity was commissioned:

- the Zarechnaya company commenced a new enterprise, Karagalinskoye Mine Office, at Kuzbass with a total project capacity 1.5 million tonnes a year;
- the Kyzasski open-cut mine was launched at Kuzbass (project capacity – 4.5 million tonnes a year); and
- the Taybinski open-cut mine was commissioned in Kuznetski coal basin, with a total project capacity of 3 million tonnes a year.

132. At this moment there are two large projects in the Far East, both nearing completion:

- the Urgalugol complex development, with a capacity of 8 million tonnes a year; and
- development of the Elga coal deposit, with a first stage capacity of 9 million tonnes a year.

133. In the current market environment, Russian coal producers are cutting their investment programmes. During the year the Russian Government approved a list of key development projects in the Far East region and committed to provide financial support for their realisation. Two projects from this list are coal-orientated:

- development of the Inaglinsk production complex; and
- production ramp up at Urgalugol, including further development of the deposit.

**Coal Use**

134. Russian electricity generation comprises about 17% hydropower, 17% nuclear power and 66% thermal power. Coal takes nearly 27% of thermal power fuel consumption. The Russian Government recently developed its Energy Strategy, which implies that coal’s share in overall energy consumption will remain constant in the long-term. According to current Russian electricity generation company plans, coal will slowly increase its share in the electricity generation energy mix in the Siberia region by 10 million tonnes over the next 5-7 years, while Russian European regions are expected to reduce their coal consumption for electricity generation purposes.

135. There were no significant changes regarding coal-fired electricity generation in 2014. 4.9GW of new generation capacity was commissioned within the framework of Power Delivery Contracts during the year. Additionally, there are two electricity generation capacity construction projects in the Far East with government financing that are currently at the design stage.
Finland

Domestic Energy Mix

136. The production of electricity in Finland amounted to 68.3TWh in 2013, 1% higher than the previous year. The production of district heat went down by 7% and that of industrial heat by 1%. The use of renewable fuels increased in the production of electricity and heat. The use of fossil fuels grew, as 38% more hard coal was used than in the previous year. In contrast, the use of natural gas and oil declined. The use of peat decreased by 13% cent from the previous year.\(^\text{30}\)

**Fuel use in electricity and heat production 2012–2013**

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>2012</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>Black liquor</td>
<td>120</td>
<td>120</td>
</tr>
<tr>
<td>Other wood fuels</td>
<td>80</td>
<td>80</td>
</tr>
<tr>
<td>Hard coal</td>
<td>60</td>
<td>60</td>
</tr>
<tr>
<td>Natural gas</td>
<td>40</td>
<td>40</td>
</tr>
<tr>
<td>Peat</td>
<td>20</td>
<td>20</td>
</tr>
<tr>
<td>Other energy sources</td>
<td>10</td>
<td>10</td>
</tr>
<tr>
<td>Oil</td>
<td>5</td>
<td>5</td>
</tr>
<tr>
<td>Other fossil fuels</td>
<td>10</td>
<td>10</td>
</tr>
<tr>
<td>Other renewables</td>
<td>5</td>
<td>5</td>
</tr>
</tbody>
</table>

137. In 2013 total electricity consumption went down by 1% to 84.0TWh. 81% was produced domestically and 19% comprised net imports from Nordic countries and Russia, which were 10% lower than in the previous year. Imports of electricity from the Nordic markets decreased because of a worse water situation than in the previous year.

138. Altogether 36% of electricity produced in Finland was produced from renewable energy sources (11% lower than the previous year), of which over half was hydro-power (24% lower) and almost all of the remainder was wood (7% higher). 33% was produced by nuclear power, 26% used fossil fuels (24% higher, with hard coal 50% higher) and 4% used peat (14% lower).

\(^{30}\) Data in this paragraph is derived from statistics on the production of electricity and heat compiled by Statistics Finland.
Electricity and Heat Production by Production Mode in 2013

<table>
<thead>
<tr>
<th></th>
<th>Electricity, TWh</th>
<th>District heat, TWh</th>
<th>Industrial heat, TWh</th>
<th>Fuels used, PJ 1)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Separate production of electricity</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Hydro power</td>
<td>12.7</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>- Wind power</td>
<td>0.8</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>- Nuclear power</td>
<td>22.7</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>- Condensing power 2)</td>
<td>8.9</td>
<td>-</td>
<td>-</td>
<td>87.8</td>
</tr>
<tr>
<td>- Total</td>
<td>45.0</td>
<td>-</td>
<td>-</td>
<td>87.8</td>
</tr>
<tr>
<td><strong>Combined heat and power production</strong></td>
<td>23.3</td>
<td>26.1</td>
<td>43.7</td>
<td>411.3</td>
</tr>
<tr>
<td><strong>Separate heat production</strong></td>
<td>-</td>
<td>8.4</td>
<td>8.5</td>
<td>71.6</td>
</tr>
<tr>
<td><strong>Total production</strong></td>
<td>68.3</td>
<td>34.5</td>
<td>52.2</td>
<td>570.7</td>
</tr>
<tr>
<td><strong>Net imports of electricity</strong></td>
<td>15.7</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>84.0</td>
<td>34.5</td>
<td>52.2</td>
<td>570.7</td>
</tr>
</tbody>
</table>

1) In calculating total primary energy used, hydro power, wind power and net imports of electricity are converted using a factor of 3.6PJ/TWh. Nuclear energy is converted at an efficiency ratio of 33% (10.91PJ/TWh).

2) Condensing power includes condensing power plants, shares of condensing electricity of combined heat and power production plants, and peak gas turbines and similar separate electricity production plants.

**Coal Production**

139. There is no coal production in Finland. Finnish import volumes of coal depend on the rainfall in Nordic countries, with import volumes lower during rainy years and higher during dry years. Over the last 15 years, average coal import volumes have been a little less than 5 million tonnes a year and have ranged from 3 million tonnes in 1999 to 9 million tonnes in 2003; with values ranging from €70 million to more than €300 million a year. Approximately half of all coal is imported from Russia and is susceptible to the risk of trade sanctions against Russia strengthening. Other sources of coal imports include Australia, South Africa, Indonesia, China, Colombia, Poland and the United States of America.

140. Quality requirements for metallurgical coal used in steel production are more rigid, with coal sourced mainly from Australia and the United States.

**Coal Use**

141. The electricity market in the Nordic countries has quite a stable price level, which does not favour coal condensing power plants. The general attitude is against coal use, but there are no legal barriers to investments for using coal.

142. According to Statistics Finland’s preliminary data, consumption of hard coal decreased by 17% in the January to March 2015 period compared with the corresponding period of 2014. Consumption as a fuel in the generation of electricity and heat amounted to 1.1 million tonnes, (around 27PJ energy content) and consumption of hard coal is now 36% lower than the early 2000s average.
### Consumption of Hard Coal in 2014 and 2015 (preliminary, 1,000s of tonnes)

<table>
<thead>
<tr>
<th>Period</th>
<th>2014 Quantity (1000 t)</th>
<th>2015 Quantity (1000 t)</th>
<th>Annual change %</th>
</tr>
</thead>
<tbody>
<tr>
<td>January</td>
<td>579</td>
<td>410</td>
<td>-29</td>
</tr>
<tr>
<td>February</td>
<td>359</td>
<td>351</td>
<td>-2</td>
</tr>
<tr>
<td>March</td>
<td>336</td>
<td>303</td>
<td>-10</td>
</tr>
<tr>
<td>April</td>
<td>271</td>
<td></td>
<td></td>
</tr>
<tr>
<td>May</td>
<td>243</td>
<td></td>
<td></td>
</tr>
<tr>
<td>June</td>
<td>168</td>
<td></td>
<td></td>
</tr>
<tr>
<td>July</td>
<td>260</td>
<td></td>
<td></td>
</tr>
<tr>
<td>August</td>
<td>266</td>
<td></td>
<td></td>
</tr>
<tr>
<td>September</td>
<td>305</td>
<td></td>
<td></td>
</tr>
<tr>
<td>October</td>
<td>361</td>
<td></td>
<td></td>
</tr>
<tr>
<td>November</td>
<td>338</td>
<td></td>
<td></td>
</tr>
<tr>
<td>December</td>
<td>363</td>
<td></td>
<td></td>
</tr>
<tr>
<td>YEAR TOTAL</td>
<td>3,849</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Q1</td>
<td>1,274</td>
<td>1,064</td>
<td>-17</td>
</tr>
<tr>
<td>Q2</td>
<td>682</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Q3</td>
<td>832</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Q4</td>
<td>1,061</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Source:** Consumption of hard coal, Statistics Finland

143. The warmer January than last year in part influenced the use of hard coal in separate electricity production, which was 44% lower in the January to March period than in the corresponding period of the previous year.

144. Hard coal consumption in Finland typically fluctuates seasonally, explained partly by the natural variation in the need for electricity and heat between the summer and winter seasons, partly by the water situation in the Nordic countries affecting the demand for condensing power production, and partly by the contribution of wind power.

145. At the end of March 2015, stocks of hard coal totalled 3.5 million tonnes, 26% higher than a year earlier.
Germany

Energy Mix

146. In 2014, primary energy demand in Germany fell by 5.0% to total 448.1 million tonnes of coal equivalent (Mtce), in large part due to weather effects. Coal plays a critical role in the country's energy mix after oil and gas. Hard coal and lignite together covered 25.1% or 112.5Mtce of primary energy demand, made up of 58.8Mtce hard coal (-6.3% on 2013) and 53.7Mtce lignite (-3.4% on 2013). In the primary energy mix last year, the proportion of energy from renewable sources was 11.3% (50.7 Mtce). \(^{31}\)

147. In 2014\(^ {32}\), CO₂ emissions from fuel combustion in Germany fell by 5.2% (a reduction of 41 million tonnes) to 751.6 million tonnes CO₂e. Emissions from steam coal generation were down 8.2% to 146.4 million tonnes and emissions from lignite fuel fell by 2.2% to 175 million tonnes, in line with trends in primary energy consumption. In the total period from 1990 to 2014, CO₂ emissions declined by 238 million tonnes or 24.0%. \(^{33}\)

\(^{31}\) Source: AGEB Yearly Report 2014
\(^{32}\) Preliminary data from the Environmental Federal Office (UBA)
\(^{33}\) Preliminary estimates from Environmental Ministry (Umwelt Bundesamt) Press Information, 31 March 2015.
Coal Supply

German Coal Balance in 2014\textsuperscript{34} (million tonnes coal equivalent)

<table>
<thead>
<tr>
<th></th>
<th>Hard Coal</th>
<th>Lignite</th>
</tr>
</thead>
<tbody>
<tr>
<td>Inland production</td>
<td>7.8</td>
<td>55.2</td>
</tr>
<tr>
<td>+ Imports</td>
<td>48.4</td>
<td>0.1</td>
</tr>
<tr>
<td>= Supply</td>
<td>56.2</td>
<td>55.3</td>
</tr>
</tbody>
</table>

Lignite Production

148. In 2014, lignite production in Germany’s four mining regions fell 2.6% from 183.0 million tonnes to 178.2 million tonnes, equivalent to 55.2 Mtce. Extracting lignite from opencast mines requires the removal of the earth layers above the coal. In 2014, a total of 879 million cubic metres (Mcm) of overburden was moved, equivalent to an extraction ratio of 4.9:1 (cubic metres of overburden per tonne of coal).

149. There are twelve opencast lignite mines currently operating in Germany. In the Rhenish basin, RWE Power AG produced 93.6 million tonnes in 2014 (down 5.1%) from its three opencast mines Hambach, Inden and Garzweiler. In a statement issued by the state government of North Rhine-Westphalia on 28 March 2014, it reaffirmed that the 3\textsuperscript{rd} resettlement section of the Garzweiler opencast mine is necessary for energy-policy reasons. Simultaneously, the state government announced a new guideline decision on lignite policy. The political goal of the new guideline decision, which is to be taken in 2015, is “that there will be no need for another resettlement planning procedure after the third resettlement section. Consequently, the Garzweiler II Lignite-Mining Plan (dated 31/03/1995) will have to be amended accordingly in order to adjust the mine boundaries.”

150. Since 1 January 2014, the five Lausatian mines (Cottbus-Nord, Jänschwalde, Welzow-Süd, Nochten and Reichwalde) of Vattenfall Europe Mining and the lignite-fired and pumped-storage power stations of Vattenfall Europe Generation AG (VE-G) have been merged into the Vattenfall Group’s Mining & Generation Business Unit (BU) and produced a total of 61.8 million tonnes in 2014, the third highest output on record.

151. The MIBRAG mines in the Central German basin, Profen and Schleenhain, increased production to 20.9 million tonnes. Despite reduced load levels, 19.5 million tonnes of raw lignite was supplied to domestic customers at the Schkopau and Lippendorf power plants.

152. In addition, since the start of 2014 Helmstedter Revier GmbH, which includes the Buschhaus power station and the Schönningen opencast mine, has been a wholly-owned subsidiary of MIBRAG. According to current plans the Schönningen mine will be depleted in 2017, after which the power plant will receive its entire coal supply of about 2 million tonnes from the Central German mining area.\textsuperscript{35}

Hard Coal Production

153. According to data from the German Coal Association (GVSt), domestic hard coal

\textsuperscript{34} Preliminary information from the Statistik der Kohlenwirtschaft e.V.
\textsuperscript{35} Maaßen, Uwe and Dr. Hans-Wilhelm Schiffer, “Germany's lignite industry in 2014”.

- 32 -
production increased by 0.9 % to 7.8 Mtce in 2014. All hard coal mining will be phased out by December 2018 with the end of subsidies following an agreement reached in 2007 and corresponding national regulations as well as the 2010 EU decision on state aids for the facilitation of the closure of non-competitive coal mines. The country only has three remaining mines in operation:

- Auguste Victoria steam coal mine (closure planned for Jan 2016);
- Prosper steam coal mine; and
- Ibbenbüren anthracite mine.

154. Following closure of these mines, buyers will be forced to procure 100% of their coal from the international import market, compared with the current 86%.

155. German hard coal imports include steam coal, coking coal and coke. In 2014, the country’s most important sources for the 32.5 Mtce of steam coal imports include: Russia (30%), Republic of South Africa (16%), the U.S.A. (16%) and Colombia (15%). For coking coal, where import demand was 9.9 Mtce, the major sources were U.S.A. (30%), Canada (21%), Australia (21%) and Russia (18%).

156. German import steam coal prices follow price developments in the international seaborne market. These are usually linked to an underlying API#2 or API#4 spot price index with an adjustment for coal quality and/or mode of delivery.

**Coal Use**

157. Due to its high moisture content (approximately 55%) and low energy content, transporting raw lignite across long distances is not economical and it is mainly used in plants close to the opencast mines or upgraded to make lignite products.

158. The primary use of lignite in Germany (159.1 million tonnes or 89% of all production) is for power generation by utilities. In addition, 15.0 million tonnes was by the lignite-mining industry to make solid products and 2.1 million tonnes was used to generate electricity in mine-mouth plants. Sales of raw lignite and changes in stocks accounted for the last 2.0 million tonnes. Lignite provided over 24.9% of total electricity generation in 2014, making it the second most important energy source after renewable energy (25.8%). Hard coal provided 18.9%, nuclear energy 15.5% and gas 9.6%.

159. Total lignite-based gross power generation was 155.7TWh in 2014. Installed lignite power-plant capacity totalling 22,627MW (gross) at the start of 2015. It achieved an average of 6,770 full-load operating hours in 2014, which is far above the utilisation of most coal or gas units.

160. In Germany, hard coal is used primarily in electricity generation (67%), within the steel industry (30%) and for the heating market (3%). In 2014, coal-fired generation totalled 274.1TWh or 43.8% of a total 625TWh of gross electricity production. 155.7TWh was fuelled by lignite and 118.4TWh by hard coal. Renewable energy sources accounted for 27.3% of the country’s electricity demand.

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37 Maaßen, Uwe and Dr. Hans-Wilhelm Schiffer, “Germany's lignite industry in 2014”.
38 Maaßen, Uwe and Dr. Hans-Wilhelm Schiffer, “Germany's lignite industry in 2014”.
39 Source: AGEB Yearly Report 2014 (preliminary estimates)
161. Coal and lignite plants act as the main swing suppliers in the market, lowering production when obligatory "must-run" inputs from wind and solar photovoltaic are high and ramping up when renewable inputs are low. Utilities continue to work to increase the flexibility of their existing fleet by reducing minimum power levels and increasing the flexibility gradient to ramp up and down output in short time windows for their coal, lignite and even nuclear power plants.

162. Currently there are discussions to add a new emissions levy starting in 2017 of €18–20/tonne of CO₂, in addition to the price of EU carbon allowances to old coal and lignite plants. The aim is to reduce emissions specifically by an additional 22 million tonnes a year by 2020.\(^\text{40}\)

163. The Federal Energy Regulator (Bundesnetzagentur) reports that 4,550MW of new \textit{coal-fired electricity generating capacity} is expected to come online by 2025, making up only 14% of the expected total 33,486MW of planned new power capacity in the next decade.

164. In 2015, two coal units are to be commissioned; a 911MW unit from Grosskraftwerk Mannheim (GKM) and the 827MW Moorburg A unit owned by Vattenfall. There are no details on the commissioning dates for over 2,820MW of planned capacity including the 765 MW Westfalen D (RWE), 1,000 MW Stade (Dow) and 1,055 MW the Datteln 4 (E.ON) stations.\(^\text{41}\)

165. In the mid-term the over-capacity is expected to remain. The latest transmission system operators' (TSO) assessment of the balance of load and demand on the system shows that Germany will still have 9.6GW of surplus capacity in 2015, 8.8GW in 2016 and 9.8GW in 2017. The Federal Energy Regulator expects 3.8GW of installed coal capacity (see table below) and a total of 12.3GW of all fossil and nuclear capacity to be decommissioned by 2018. In the long-term, the Federal Energy Regulator expects that 7.6GW of conventional capacity will be permanently closed and 4.8GW temporarily

\(^{40}\) McCloskeys Weekly Coal Report, May 1st, 2015.

\(^{41}\) McCloskeys Coal News, Apr 17, 2015.
closed by 2025, and that 12.1GW of nuclear capacity will be closed by 2022.\textsuperscript{42}

### Coal-fired Power Plants for Decommissioning in Germany 2014-2018\textsuperscript{43}

<table>
<thead>
<tr>
<th>Coal plants due for decommissioning 2014-2018</th>
<th>Company</th>
<th>Planned decommissioning date</th>
<th>MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>hard coal 2</td>
<td>EON Krafteerleichtungswerke</td>
<td>2014</td>
<td>130</td>
</tr>
<tr>
<td>Ostalb unit 3</td>
<td>EON Krafteerleichtungswerke</td>
<td>2014</td>
<td>113</td>
</tr>
<tr>
<td>Ostalb unit 1</td>
<td>EON Krafteerleichtungswerke</td>
<td>2014</td>
<td>99</td>
</tr>
<tr>
<td>Ostalb unit 2</td>
<td>EON Krafteerleichtungswerke</td>
<td>2014</td>
<td>96</td>
</tr>
<tr>
<td>Weserordnungsamt unit E3</td>
<td>MIEK</td>
<td>2014</td>
<td>86</td>
</tr>
<tr>
<td>Schlesien 35MW unit D</td>
<td>EON Krafteerleichtungswerke</td>
<td>2014</td>
<td>343</td>
</tr>
<tr>
<td>Schlesien 35MW unit F</td>
<td>EON Krafteerleichtungswerke</td>
<td>2014</td>
<td>675</td>
</tr>
<tr>
<td>Neptun</td>
<td>EON Krafteerleichtungswerke</td>
<td>2014</td>
<td>343</td>
</tr>
<tr>
<td>Schlesien unit 3</td>
<td>EON Krafteerleichtungswerke</td>
<td>2015</td>
<td>203</td>
</tr>
<tr>
<td>Schlesien unit 4</td>
<td>EON Krafteerleichtungswerke</td>
<td>2015</td>
<td>203</td>
</tr>
<tr>
<td>Schlesien unit 5</td>
<td>EON Krafteerleichtungswerke</td>
<td>2015</td>
<td>203</td>
</tr>
<tr>
<td>Schlesien unit 3 (for Zschadus)</td>
<td>EON Krafteerleichtungswerke</td>
<td>2015</td>
<td>203</td>
</tr>
<tr>
<td>Schlesien unit 1</td>
<td>EON Krafteerleichtungswerke</td>
<td>2015</td>
<td>314</td>
</tr>
<tr>
<td>Schlesien unit 3</td>
<td>EON Krafteerleichtungswerke</td>
<td>2015</td>
<td>165</td>
</tr>
<tr>
<td>Schlesien unit 2</td>
<td>EON Krafteerleichtungswerke</td>
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<td>EON Krafteerleichtungswerke</td>
<td>2015</td>
<td>165</td>
</tr>
<tr>
<td>Schlesien unit 3 (for Zschadus)</td>
<td>EON Krafteerleichtungswerke</td>
<td>2015</td>
<td>165</td>
</tr>
<tr>
<td>Schlesien unit 1</td>
<td>EON Krafteerleichtungswerke</td>
<td>2015</td>
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<td>Schlesien unit 3</td>
<td>EON Krafteerleichtungswerke</td>
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<td>165</td>
</tr>
<tr>
<td>Schlesien unit 4</td>
<td>EON Krafteerleichtungswerke</td>
<td>2015</td>
<td>165</td>
</tr>
<tr>
<td>Schlesien unit 5</td>
<td>EON Krafteerleichtungswerke</td>
<td>2015</td>
<td>165</td>
</tr>
<tr>
<td>Total coal decommissioning 2014-2015</td>
<td>3,050</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Spain

166. One of the main issues affecting Spanish coal mining is the restructuring that is being implemented through the agreement signed by the Ministry of Industry, Energy and Tourism, the coal trade unions and coal mining companies in October 2013. It is known as the “Framework for action in the coal mining sector and in the coalfield areas, 2013-2018”; and is the result of European Union Council Decision 210/787/EU, 10 December 2010, on state aid to facilitate the closure of uncompetitive coal mines.

167. In accordance with this framework, underground mining receives decreasing production aid that will completely disappear by the end of 2018: it has already fallen by 89% from 2011 to €33 million in 2014. Opencast mining receives no production aid from 1 January 2015.

168. Furthermore, mining companies reduced production by 11% from 2013 to 3.9 million tonnes in 2014, in response to lower demand.

Turkey

Energy Mix

169. Total domestic energy production in 2013 was 31.944 million tonnes oil equivalent comprising:

- Coal 48.2% (hardcoal 3.0%, lignite 43.7%, asphaltite 1.5%);
- Other Solid Fuels 13.5% (wood 8.5%, animal and plant wastes 5%);
- Oil 7.8%
- Natural Gas 1.4%; and

\textsuperscript{42} McCloskeys Coal News, Oct 31, 2014.
\textsuperscript{43} Federal Energy Regulator, McCloskeys Coal Report, Apr 15\textsuperscript{th}, 2014.
- Renewables 28.9% (hydro 16.0%, geothermal 3.6%, biofuel 0.2%, wind 2.0%, solar 2.5%, heat 4.6%).

170. Total domestic energy consumption in 2013 was 120.29 million tonnes oil equivalent comprising:

- Coal 28.8% (hardcoal 14.7%, lignite 11.0%, asphaltite 0.3%, coke 0.2%, petcoke 2.6%);
- Other Solid Fuels 4.6% (wood 2.3%, animal and plant wastes 1.3%);
- Oil 28.2%
- Natural Gas 31.3%; and
- Renewables 7.64% (hydro 4.2%, geothermal 1.0%, biofuel 0.04%, wind 0.5%, solar 0.7%, heat 1.2%).

**Coal Production**

171. According to official figures, coal production declined by 10 million tons to 60.4 million tons in 2014 (2.0 million tons hard coal, 57.5 million tons lignite, and 0.9 million tonnes Asphaltite).

172. The majority of coal was produced by the state-owned companies Turkish Coal Enterprises (TKI) and the Electricity Generation Company (EUAS), with about 10% produced by private sector companies. TKI and EUAS production includes amounts produced by private sector companies acting as leaseholders or contractors to these state-owned companies.

173. State–owned companies’ lignite production decreased in 2013 and 2014 because of the privatisation of two lignite based power plants and their associated mines. The state owned Electricity Generation Company (EUAS) produced 31.5 million tons of saleable lignite in 2011, but this had decreased to 18.96 million tonnes by 2014. The Elbistan-Collalar Mine Disaster in 2011 was another factor contributing to this decline in EUAS production.

174. State-owned Turkish Coal Enterprises' (TKI) coal production decreased to 14.9 million tonnes in 2014. Contributing factors were the privatisation of mines which feed the Seyitömer, Yatagan, Kemerkoy and Yenikoy power plants and reduced production at Soma resulting from the mine disaster there in May 2014.

**Coal Use**

175. Total electricity generation in 2014 was 250.4TWh (provisional estimate), sourced from hard coal (14.6%), lignite (14.6%), natural gas and LNG (48.7%), hydro (16.1%), wind (3.3%), geothermal (0.9%) and other sources (2.1%). Total installed capacity in 2014 was 69.5GW, of which 14.6GW was coal-based capacity.

176. All lignite-based power plants and one domestic hard coal-based power plants were owned by EUAS; although this structure is changing because all state-owned power plants are included in the privatisation programme, some with associated lignite mines.

177. In 2013 two lignite based power plants (Sivas-Kangal and Seyitomer) together with associated lignite mines were given to private sector; in 2014 one domestic hard coal-based power plant (Catalagzi) and three lignite-based power plants (Yatagan, Yenikoy and Kemerkoy) were also privatised with associated lignite mines; and the privatization of Soma B, Tuncbilek and Orhanieli power plants was approved in March 2015.
178. In order to increase the share of domestic lignite in electricity generation, a total of 1,280MW of domestic lignite and asphaltite based capacity is under construction at Adana-Tufanbeyli-EnerjiSa, Bolu-Goynuk, Eskisehir-Mihalicik, and Sirnak-Silopi.

179. Additionally, TKI-owned lignite deposits at Adana-Tufanbeyli-TKI, Soma-Deniş, Bursa-Keles, Bingöl-Karliova and Kütahya-Derin Sahalar were leased to the private sector in 2012 and 2013 to support installation of about 1,770MW of electricity generation capacity within the next 6 years.
4 POLICY DEVELOPMENTS

4.1 Overview

180. In order to maintain a stable and affordable energy supply whilst keeping economic, social and environmental objectives in balance, it is essential that energy should be obtainable from a wide variety of sources including coal. IEA scenarios project total energy demand increases of 17-50% to 2040 (from 2012), depending on the extent of action taken to mitigate increases in greenhouse gas emissions.44

181. Policy makers should therefore provide frameworks that facilitate adequate infrastructure investment for coal production, supply and use, particularly for internationally traded coal, the commercial deployment of advanced coal-fired electricity technologies, and carbon capture and storage. However current policies in IEA Member countries continue to provide no support for this objective.

182. The challenge of greenhouse gas emissions reduction affects all fossil fuels. Several studies have confirmed the view that addressing climate change without the development of CCS for fossil fuel-fired power plants will substantially increase costs to world economies. Achievement of the G8 objective of building 20 large scale CCS projects by 2020 is on track. However, despite some positive developments such as the Boundary Dam CCS demonstration in Canada, significant international effort is required to demonstrate CC(U)S technology to provide a line of sight to commercial availability. It is very disappointing that the U.S.A. government has withdrawn support for the FutureGen 2.0 project. However, there are 13 large scale CC(U)S projects operating around the world with a further nine under construction. Those under construction include the first CCS project in the iron and steel industry and two further power station projects as well as the Gorgon LNG project in Western Australia.

183. In many countries official energy policy positions and public opposition to the use of coal continue to harden, largely as a result of the erroneous perception that world social development, economic growth and energy growth aspirations can be satisfied, and climate change mitigation targets met, while at the same time promoting declining coal use. This is resulting in a lack of investment in coal production and electricity generation capacity, especially in the current climate of low coal prices, which gives rise to very real future energy and electricity security concerns.

184. Many multilateral development banks, led by The World Bank but with notable exceptions in the African Development Bank and the Japan Bank for International Cooperation, now have policies that exclude support for investment in coal mining and advanced coal generation technologies. These policies jeopardise universal energy access targets and the more efficient, cleaner, use of coal particularly in developing economies.

185. In North America, a raft of impending new environmental regulations affecting coal use still appears likely to result in the closure of significant amounts of coal-fired electricity generating capacity and stall any new plant development. Despite the increasing focus on the use of CO$_2$ for enhanced oil recovery, delivery of CCS demonstration projects remains difficult.

186. The Environmental Protection Agency’s proposed CO$_2$ regulation for existing power plants was finalised on 3 August 2015. Under its Clean Power Plan, designed to reduce greenhouse gas emissions by 32% from 2005 levels by 2030, EPA proposes mandatory CO$_2$ “goals” for each state’s power sector and requires states to submit individual or multi-

state plans to meet those goals. Simultaneously, emission standards for new power stations were finalised. These set CO₂ emissions standards that can be met by combined cycle gas turbine power plants, but effectively require CCS to be fitted to new coal power plants, even if the most efficient current generating technologies are employed. These regulations are the major cause of the projected closure or conversion of more than one third of the current 300GW fleet of coal-fired power stations over the next five years.

187. In Germany, while there has been limited support for lignite mining and associated power generation, the remaining hard coal mines will close by 2018, resulting in greater hard coal and electricity imports. No new fossil-fuelled power plant will be built because the financial returns are insufficient; and increasing volumes of renewable energy feeding into the electricity grid will require the existing coal-fired power plants to operate increasingly in flexible back-up mode.

188. 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 a carbon-constrained world, particularly in OECD economies, remains a major concern for electricity supply and energy security.
4.2 Energy Policy and the Role of Coal

Australia

Energy White Paper

189. In April 2015, the Australian Government released its Energy White Paper which identifies significant opportunities for Australia to meet the energy needs of developing economies in Asia, with energy demand expected to increase by one-third by 2040. It highlights the need for continuing reforms to streamline project approvals and other regulatory barriers to mining. It also provides a timely reminder of the critical role played by low cost energy, built on coal-fired power, which has long been an essential element of Australia’s competitive advantage.

190. The Energy White Paper provides a commitment to an ongoing partnership with the coal industry to develop low emissions coal technologies. It also recognises that increased use of high efficiency, low emissions (HELE) coal combustion technology will be important in making fossil fuels more sustainable. For this reason, it warns on page 57:

“It is critical that developing countries have access to finance options that encourage the uptake of world best coal-fired power stations. Recent decisions by the World Bank, European Investment Bank and the European Bank for Reconstruction and Development to limit investment in coal-fired power plants limit the ability of countries to access finance for least cost and low emissions energy technologies”.

Japan

191. On 11 April 2014, the Japanese Cabinet approved Japan’s new Strategic Energy Plan. The aims of the plan are:

- to realise a robust, practical and multi-layered energy supply structure;
- to create a flexible and efficient demand and supply structure by electric market reforms; and
- to improve energy self-sufficiency by the development and introduction of domestic energy resources etc.

192. In the plan, coal is revalued as an important base-load power source in terms of stability and cost effectiveness, which will be utilized while reducing its environmental impact by using efficient thermal power generation technology.

193. On 16 July 2015, the Ministry of Economy, Trade and Industry (METI) determined Japan’s target energy mix for 2030, which consists of 27% gas, 26% coal, 3% oil, 20 to 22% nuclear, and 22 to 24% renewable energy including hydro-electricity.

194. The electricity market reform plan is under way in Japan. As one of its milestones, the liberalisation of the electricity generation and retail markets is scheduled to begin on 1 April 2016. Many companies, including new entrants, are recognising the competitiveness of coal-fired power plant; and have announced new coal-fired power

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station projects amounting to approximately 10GW by 2020 and over 15GW by the mid-2020s, implying increased coal demand in Japan after 2020. The Minister of Environment is concerned about the planned increase in coal-fired capacity in terms of its possible effect on achieving the greenhouse gas emissions target that Japan will submit to COP21.

**Thailand**

195. Thailand’s energy policy objectives are to: secure energy supply by increasing domestic oil production, gas production and renewable energy use; promote fair energy pricing through price re-structuring and taxation appropriate to different types of oil; and increase energy conservation through increased efficiency.\(^\text{48}\)

196. The Power Development Plan 2015 (PDP2015)\(^\text{49}\) contains an objective to maintain a 15% reserve margin above peak demand and is based on the following changes in installed electricity generating capacity between 2015 and 2036:

**Installed Electricity Generation Capacity in Thailand 2015-2036**

<table>
<thead>
<tr>
<th>Type</th>
<th>Installed Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capacity at end 2014</td>
<td>37,612</td>
</tr>
<tr>
<td>Retirements</td>
<td>-24,736</td>
</tr>
<tr>
<td>New Capacity, of which:</td>
<td>57,459</td>
</tr>
<tr>
<td>Clean coal (3 plants)</td>
<td>7,390</td>
</tr>
<tr>
<td>Natural gas (15 plants)</td>
<td>17,478</td>
</tr>
<tr>
<td>Nuclear (2 plants)</td>
<td>2,000</td>
</tr>
<tr>
<td>Gas turbine (5 plants)</td>
<td>1,250</td>
</tr>
<tr>
<td>Cogeneration</td>
<td>4,119</td>
</tr>
<tr>
<td>Renewable</td>
<td>12,105</td>
</tr>
<tr>
<td>Pumped storage hydropower</td>
<td>2,101</td>
</tr>
<tr>
<td>Imported</td>
<td>11,016</td>
</tr>
<tr>
<td><strong>TOTAL at end 2036</strong></td>
<td><strong>70,335</strong></td>
</tr>
</tbody>
</table>

*Source: Power Development Plan 2015, Ministry of Energy (PDP2015)*

197. The mix of fuels’ used for power generation is shown below. Compared with 2014, imported hydro-electricity and renewable energy are projected to increase, coal has slight upward potential, natural gas will decline significantly, and there is potential for some nuclear power generation by 2036. Compared with the last revision of PDP2010, the aspirations for natural gas are substantially lower, with higher percentages of hydro-electricity and renewable energy.

\(^\text{48}\) Source: EPPO 2015, Ministry of Energy, Thailand’s Strategy for biogas development, March 2015

Estimated Fuel Mix for Power Generation in PDP2015 (%)

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>Sept. 2014 (%)</th>
<th>2026 (%)</th>
<th>2036 (%)</th>
<th>2030 (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Imported Hydro</td>
<td>7</td>
<td>10 - 15</td>
<td>15 - 20</td>
<td>10</td>
</tr>
<tr>
<td>Clean Coal incl. lignite</td>
<td>20</td>
<td>20 - 25</td>
<td>20 - 25</td>
<td>19</td>
</tr>
<tr>
<td>Renewable</td>
<td>8</td>
<td>10 - 20</td>
<td>15 - 20</td>
<td>8</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>64</td>
<td>45 - 50</td>
<td>30 - 40</td>
<td>58</td>
</tr>
<tr>
<td>Nuclear</td>
<td>-</td>
<td>-</td>
<td>0 - 5</td>
<td>5</td>
</tr>
<tr>
<td>Diesel/Fuel Oil</td>
<td>1</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>TOTAL</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
</tr>
</tbody>
</table>

*Source: Power Development Plan 2015, Ministry of Energy (PDP2015)*

**Other ASEAN countries**

198. Other ASEAN countries also have government plans for expansion of coal-fired electricity generation capacity as follows:

- Indonesia from 18GW (42%) in 2014 to 58GW (51%) in 2024\(^{50}\);
- Vietnam from 4.9GW (18%) in 2012 to 75GW (51%) in 2030\(^{51}\);
- Philippines from 5.0GW (33%) in 2013 to 13.9GW (46%) in 2030\(^{52}\); and
- Malaysia from 7.7GW (31%) in 2014 to 12.7GW (37%) in 2020\(^{53}\).

**South Africa**


**Integrated Energy Plan (IEP)**

200. The National Energy Act (34 of 2008) specified the need for an Integrated Energy Plan to guide the development of energy policies, guide the selection of technologies and set the framework for regulations, taking into consideration future demand, environmental, social and economic factors.

201. This overarching Plan informs the development of various parts of the energy policies and roadmaps, such as the Integrated Resource Plan for Electricity. The IEP was developed in 2012 and circulated for public comment in 2013.

**Integrated Resource Plan (IRP)**

202. The Department of Energy published a revision of IRP2010 in November 2013 for public comment. However, this revision has not been promulgated to date. The key highlights of the revised plan are as follows:

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50 Electricity Power Supply Business Plan (RUPTL) 2015-2024  
51 Power Master Plan VII 2011-2030  
52 Philippine PEP 2012-2030  
53 Malaysia Electricity Supply Outlook 2014
• alignment of economic growth rates with the lower rates in the National Development Plan (NDP) and a reduction in electricity intensity, driven by a move away from electricity intensive industries;
• alignment of economic growth rates with the lower rates in the National Development Plan (NDP) and a reduction in electricity intensity, resulting in a substantially lower electricity demand outlook than the previous plan and a ~10% reduction in peak demand and installed capacity in 2030;
• a move away from fixed capacity planning to a more flexible approach that better allows for current uncertainties over multiple factors, including the potential for shale and other gas developments, the global agenda to combat climate change, the costs of nuclear capacity and future fuel costs;
• a 2-3 year delay of the decision for new nuclear build, allowing for further exploration of the shale gas potential;
• a requirement for a total additional 1000 - 1500MW of fluidised bed coal generation capacity from 2019 as a preferred implementation of the “Coal 3” programme and utilising discard coal;
• a preference to pursue regional hydro, gas and coal generation projects, apparently on the basis that the costs will be competitive and the emissions will not accrue to South Africa;
• a continuation of the current renewable programme with additional annual capacity increase rounds (1,000MW of PV capacity, 1,000MW of wind capacity and 200 MW of CSP capacity); and
• no commitment yet to building coal-fired electricity generation capacity to replace the current fleet, and the inclusion of an option to extend the lives of Eskom’s existing fleet from 50 to 60 years.

203. From a coal perspective, the implication of the life extension option is an increase in Eskom’s un-contracted coal requirements from ~2.0 billion tons to ~2.4 billion tons up to 2050. This is significant as the South African Coal Roadmap (SACRM) indicated that sufficient coal remained in the Central Basin to meet Eskom’s 2.0 billion ton un-contracted requirement and permit only a small expansion of coal exports to around 85 million tonnes a year. A major disconnect therefore remains between the IRP (which does not specifically envisage any major new coal fired power stations that could unlock Waterberg coal exports before 2030) and the various plans (including the NDP) to significantly increase the country’s coal export logistics capacity and promote development of the Waterberg region. This raises the risk of scarce capital being invested in stranded logistics assets, and an increase in competition between domestic coal users and coal exports.

204. The IRP 2013 revision has also not been approved in parliament. A 2015 revision is planned.

**Russia**

205. In June the Russian Government adopted a new version of the Development Program “Russian Coal Industry 2030” which implies a total coal output increase up to 480 million tonnes by the end of 2030 along with labour productivity growth from the current level of 2,370 tonnes per employee up to 9,000 tonnes per employee. According to the Program, the rate of renovation of productive capacities will increase from the current 21% to 100% in 2030.
Germany

206. Germany is in the middle of an energy conundrum managing the impacts of the “Energiewende”, with a transition in energy supplies dominated by a renewable base and a nuclear phase-out aimed at achieving sustainable development and affordability while encouraging increased energy efficiency across demand segments. As the Energiewende pushes forward despite the difficult market conditions, the challenge is twofold: persistently weak demand; and the cancellation of many new build projects and the mothballing of other assets resulting from low wholesale pricing, while consumer prices for electricity stay at high levels. Additionally, there are transmission bottlenecks due to limited grid connectivity between the well-supplied north and the high demand areas in the south.

207. Key policies and legislation impacting the coal and utility industry include the following measures.\(^{54}\)

**Nuclear Phaseout (2011)** outlines the plan and timeline to close the remaining 12GW of nuclear power plants by 2022.

**National Renewable Energy Action Plan (2010)** is the starting point for the roadmap to reach the first legally binding 18% share for renewable energy by 2020 to meet the EU Renewables Directive.

**Energy Concept to 2050 (2010):**
- Is a roadmap with targets for adopting affordable reliable renewable energy sources to meet consumption through to 2050;
- sets targets for the reduction of gross energy consumption and electricity consumption in 2020 and 2050, which should reduce GHG emissions by -40% by 2020, -55% by 2030, -70% by 2040 and -80-95% by 2050 compared to 1990 levels;
- sets a target for renewable energy sources of gross energy consumption of 18% in 2020, 30% in 2030, 45% by 2040 and 60% by 2050; and
- sets a target for renewable energy sources of gross power consumption of 35% in 2020, 50% in 2030, 65% by 2040 and 80% by 2050.

- provides the framework and support for renewables and the expansion of wind and solar in the energy mix;
- defines corridor growth rates (in MW/a) for renewable technologies in segments where financial support rates decrease to control renewable growth rates and subsidies; and
- states that financial support for renewables should be determined by auctions by 2017 at the latest.

**Strategic Power Plant Reserves (2012)** sets out mechanisms to ensure grid stability due to the closure of older power plants by utilities. It details the rules setting up the winter reserve and a re-dispatch reserve and compensation scheme for reserve plants using the EEG subsidies. Because this is a preliminary and temporary measure, Germany continues to investigate other reforms (i.e. to the wholesale market) for capacity markets in the long run, like its neighbours Poland, Great Britain and Belgium.

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\(^{54}\) IHS ENERGY European Power Country Profile, Feb 2015.
Spain

208. Coal-fired power plants are affected by Directive 2010/75/EU of the European Parliament and the Council of 24 November 2010 on industrial emissions (integrated pollution prevention and control). The new emission limit values apply from January 2016 and the directive introduces some flexibilities for existing Large Combustion Plants or for plants operating a limited number of hours:

- The first option is a Transitional National Plan (TNP) to allow existing LCPs additional time to comply with the emission limit values. The TNP is time-limited to the period 1 January 2016 to 30 June 2020. Spain has already submitted a TNP to the European Commission, which will review it and determine by June 2015 at the latest whether it satisfies the requirements.

- The second option is a Limited Lifetime Derogation or LLD where existing LCPs may be exempted from compliance with the emission limit values but operating hours are restricted to no more than 17,500, starting on 1 January 2016 and ending no later than 31 December 2023.

Spanish electricity companies must adopt a final decision between the different options by October 2015 at latest.

209. Spanish coal fired power plants are also affected by the finalisation on 31 December 2014 of Royal Decree 134/2010, which created a mechanism of restrictions in the power market for guaranteeing supplies of indigenous coal. This mechanism allowed the use of indigenous coal in order to guarantee a supply to electricity consumers.

210. Nevertheless, the “Framework for action in the coal mining sector and in the coalfield areas, 2013-2018” (see Section 3.2, Spain) establishes that electricity production from indigenous coal sources must be guaranteed. In this regard, the Spanish Government is now developing a new mechanism to ensure this coverage.

Turkey


212. These papers focus on policies to decrease dependency on energy and give high priority to the use of domestic resources, particularly lignite for electricity generation. To achieve these objectives, policy targets are to:

- accelerate the installation of domestic lignite based power plants using clean coal technologies, for which the Afsin-Elbistan lignite region is seen as having great potential;
- increase coal exploration studies;
- maintain the momentum of R&D studies on coal, particularly on coal gasification and liquid fuel production technologies;
- improve investment incentives for coal based power plants; and to
- rehabilitate existing coal-fired power plants.
213. In order to reduce delays in coal-fired electricity generation investment, a draft of the “Coal Strategy Paper on Accelerating Electricity Generation from Domestic Coal” was issued in 2014. Some investment incentives for domestic lignite mining and lignite-based power plant installation were also put into effect in 2013. Council of Ministers’ Decision No. 2013/4288 on investment incentives for coal–based power plants provides for:

- waiver of VAT and Customs Duty;
- support for investment location, interest and insurance premiums paid by employers; and
- tax reductions.
4.3 Climate Policy

**United States of America**

214. President Obama’s Climate Action Plan aims to reduce overall U.S.A. greenhouse gas emissions by 17% from 2005 levels by 2020. In addition, the country’s contribution to the COP21 discussions in Paris later in 2015 sets an economy-wide target of reducing greenhouse gas emissions by 26-28% from 2005 levels by 2025. The electricity sector is a key focus for these plans.

*Carbon Requirements for New Fossil Fuel-Fired Power Plants*

215. In early 2014, EPA re-proposed New Source Performance Standards (NSPS) to control CO\(_2\) emissions from new fossil fuel-fired power plants under the Clean Air Act. The proposal required new coal units to meet a CO\(_2\) emissions rate of 1,100 pounds per megawatt-hour. Achieving this rate requires the use of carbon capture and storage technology (CCS) and, therefore, effectively bans new coal plants because at its current stage of development CCS is prohibitively expensive. The proposed NSPS would increase reliance on natural gas to generate electricity and impede further development of CCS.\(^{55}\) Industry groups recommended CO\(_2\) emission rates that would allow efficient new coal plants to be built without CCS.

216. The EPA released a final rule to limit greenhouse gas emissions from new power plants on 3 August 2015, along with a final rule for existing power plants (see below). The final rule requires new natural gas-fired power plants to meet a CO\(_2\) emissions rate of 1,000 pounds per megawatt-hour and new coal-fired power plants to meet a CO\(_2\) emissions rate of 1,400 pounds per megawatt-hour from the beginning of its lifetime. Effectively, the standards for natural gas plant require the use of combined cycle gas turbine technology, while those for coal still require CCS.

*Clean Power Plan – CO\(_2\) Limits on Existing Electricity Generation*\(^{56}\)

217. The EPA’s proposed CO\(_2\) regulation for existing power plants was announced in June 2014 and was finalised on 3 August 2015. The EPA received more than 1.4 million comments including thousands of pages of substantive comments on the proposal.

218. Under its Clean Power Plan, designed to reduce greenhouse gas emissions by 32% from 2005 levels by 2030, EPA proposes mandatory CO\(_2\) “goals” for each state’s power sector and requires states to submit individual or multi-state plans to meet those goals. EPA describes the goals as “rate-based goals,” and for each state includes an “interim goal” for the period 2020 to 2029, and a “final goal” beginning in 2030.

219. These mandatory goals were derived by EPA based on four “building block” measures identified by the agency. The building blocks include: 1) making heat rate improvements at coal-fired power plants, which EPA assumes for each state could result on average in a 6% CO\(_2\) emissions reduction from the affected coal-fired electric generating units; 2) shifting away from coal-fired generation and operating the state’s natural gas combined cycle plants at a 70% capacity factor; 3) shifting away from coal-fired generation and expanding use of existing nuclear and renewable energy generation; and 4) reducing the

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\(^{55}\)“Status of Major EPA Regulations Affecting Coal-Fired Electricity Generation”, 25 January 2015, ACCCE.

use of electricity through energy efficiency programs that EPA assumes for each state could improve electricity savings by up to 1.5% annually. As an alternative, EPA also proposes that a state could convert its assigned “rate-based goals” into an equivalent “mass-based goal.”

220. Under the proposal, each state would be required to submit a plan to meet its mandatory goals to the EPA for approval and suggest the following strategies:

- demand-side energy efficiency programs;
- renewable energy standards;
- efficiency improvements at plants;
- dispatch changes;
- co-firing or switching to natural gas;
- construction of new Natural Gas Combined-Cycle plants;
- transmission efficiency improvements;
- energy storage technology;
- retirements;
- expanding renewables like wind and solar;
- expanding nuclear;
- market-based trading programs; and
- energy conservation programs.

EPA encourages states to consider including cap-and-trade programs in their state plans.

221. Under the final rule, states must submit a final plan or an initial submission with a request for extension by 6 September 2016. Final plans must be submitted no later than 6 September 2018 and fully implemented within 15 years. These plans need to include emissions standards that are “quantifiable, verifiable, non-duplicative, permanent, and enforceable.” In each plan, states are required to include detailed information, including identification of all affected entities, a description of the plan approach and geographic scope, identification of the state emission performance levels for affected entities that would be achieved through implementation of the plan, and demonstrations relating to projected emission performance levels.

222. These state plans need to be approved by the EPA Administrator and could not be changed without EPA approval. If a state fails to submit a plan, or EPA finds a submitted plan unsatisfactory, the agency would impose a federal implementation plan, a model of which has not been developed by the agency. Once approved, all measures included in the plans would be federally enforceable.

223. EPA is also creating a Clean Energy Incentive Program (CEIP) to reward early investments in wind and solar generation, as well as demand-side energy efficiency programmes implemented in low-income communities, that deliver results during 2020 and/or 2021.

Canada

224. The Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations took effect on 1 July 2015. They apply a performance standard to new coal-
fired electricity generation units and units that have reached the end of their useful life. The performance standard is set at 420t/GWh, which is the emission intensity level of natural gas Combined Cycle technology. End-of-useful-life is generally described as 50 years from the unit’s commissioning date but units that were commissioned before 1975 will reach their end-of-useful-life after 50 years of operation or at the end of 2019, whichever is the earlier. Units commissioned in or after 1975 but before 1986 will reach their end-of-useful-life after 50 years of operation or at the end of 2029, whichever is the earlier. New and end-of-useful-life units that incorporate technology for carbon capture and storage may apply for an exemption from the performance standard until 2025.

225. The regulations are expected to result in a cumulative reduction in GHG emissions of 214 million tonnes, equivalent to removing some 2.6 million personal vehicles per year from the road in the first 21 years. They are promoted as an important step towards meeting Canada’s GHG reduction target of 17% from 2005 levels by 2020.

226. The legislation relates to the domestic use of subbituminous coal and lignite. It will impact domestic coal-fired generation but not the production and export of coking coal or bituminous grade thermal coal, which are expected to increase as global demand increases.

**Australia**

**Direct Action: Emissions Reduction Fund and Safeguard Mechanism**

227. Legislation to implement the Emissions Reduction Fund (ERF) came into effect on 13 December 2014. This is the centrepiece of the Australian Government's suite of policies to reduce greenhouse gas emissions. Other elements include the mandatory Renewable Energy Target, fuel standards and energy efficiency standards on appliances, equipment and buildings.

228. The ERF is a market based mechanism that provides incentives for emissions reduction activities across the Australian economy. This is achieved via a taxpayer-funded reverse auction to purchase the lowest-cost abatement from eligible projects, which must use an approved methodology for measuring and verifying abatement.

229. A methodology for new coal waste gas projects – using methane for power generation or flaring – has been approved. The methodology is generally suited to new mines or for significant expansions. Further methodologies for coal mine abatement are under consideration.

230. The first ERF auction was held on 15 April 2015, at which the federal Government purchased over 47 million tonnes of abatement at an average price of $13.95/tonne of CO₂-e.

231. The Government is now working with businesses and the community to finalise the design of the safeguard mechanism, the final element of the Fund. The safeguard mechanism will ensure that emissions reductions purchased by the Government are not offset by significant rises in emissions elsewhere in the economy. These rules will be finalised in late 2015 and the safeguard mechanism will commence on 1 July 2016.

232. The Government’s general proposal is to set an emissions baseline at the highpoint over the five years to 2013/14 and then to require a company to make good by buying credits if it exceeds this. In its draft proposal, the Government recognised the need for the mechanism to take account of unique circumstances in the coal sector because coal mine fugitive emissions rise over time with expanded production, changing coal seam
gassiness, depth of coal deposits and other factors beyond the operator’s control. The Government has also recognised that the scheme should not place an artificial constraint on growth in production.

**Australia’s post 2020 greenhouse gas abatement target**

233. Australia was one of the few nations that met its obligations under the first commitment period of the Kyoto Protocol (2008-2012). It is also on track to meet its second commitment period (2013-2020) target of minus 5% on 2000 emissions levels by 2020.

234. Australia is unique among the developed OECD nations, with one of the fastest growing populations and the largest share of resources (minerals, gas and agricultural) in its economic mix. The International Council on Mines and Metals, in a report released early in 2015, found Australia the most dependent developed country and one of only two developed countries in the top 70 that rely on resources. This means the economic cost of the 2020 target is higher than for most developed nations.

235. For example, Australian Treasury analysis at the time the 2020 target was negotiated showed that it would result in a loss of gross national product three times that experienced by the EU in pursuing a minus 20% target. Independent research demonstrates that the 2020 target represents a comparable economic contribution to the global emissions reduction effort of key developed nations, including the European Union and the United States, and is more ambitious than those of Canada and Japan.

236. On 11 August, the Australian Government announced an emissions reduction target range of 26 to 28% off 2005 levels as Australia’s Indicative Nationally Determined Contribution. The 26% offer is a minimum while the 28% would be met if circumstances allow.

237. The Australian Government’s announcement noted that the commitment represents a reduction of 50–52% of per capita emissions, one of the highest cuts in the developed world, and a reduction of emissions per unit of GDP of 64–65%. On that basis, Australia’s target ‘will exceed those of the United States, Japan, the European Union, Korea, and Canada’.

**Japan**

238. According to the latest data available published by the Japanese Ministry of Environment in April 2015, greenhouse gas (GHG) emissions in FY 2013 were 1.408 billion tons CO₂

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57 Between 1990 and 2012, Australia’s economy nearly doubled in size and its population grew strongly. However, greenhouse gas emissions were limited to 103 per cent of 1990 levels over the period 2008-2012, which was well below the Kyoto Protocol’s first commitment period target for Australia of 108 per cent.


59 This has been recognised by Australia since the beginning of the Kyoto Protocol. See the Hon. Senator R. Hill, Statement to the Fourth Conference of Parties to the UNFCCC, Buenos Aires, 1998.


61 V Bosetti and J Frankel, A Pre-Lima Scorecard for Evaluating which Countries are doing their Fair Share in Pledged Carbon Cuts, Viewpoints, The Harvard Project on Climate Agreements, November 2014.

equivalent, 1.2% higher than the previous year and 0.8% higher than FY 2005.63

239. On 17 July 2015, the Government of Japan submitted its GHG emissions reduction target for 2030 to UNFCCC, in which Japan will reduce GHG emissions by 26.0% by FY 2030 from its emissions in FY 2013.64

Thailand

240. Thailand’s is targeting 25% renewable and alternative energy by 202165, is promoting deployment of waste to energy and bio-based energy, and is introducing feed-in tariffs for power generation.

241. It is targeting a 30% reduction in energy intensity by 203666, compared to 2010 levels, focussed on the industrial, buildings and transportation sectors. For the power sector, the target is to reduce CO₂ emissions from 0.506 kgCO₂/kWh in 2013 to 0.319 kgCO₂/kWh in 2036.67

South Africa

242. The South African Government has made ambitious, though conditional, commitments to climate change at previous COP meetings: committing to reduce emissions by 34% from Business as Usual (BAU) in 2020 and 42% from BAU by 2025. These commitments were on the condition that a global climate agreement is reached and on international financing and technological assistance.

243. The following policy instruments are currently under development:

- Carbon Tax (2016)
- Carbon budgets at company level (2016 – 2020)
- Desired emission reduction outcomes (to 2050)
- Intended Nationally Determined Contributions

Carbon Tax

244. The National Treasury will implement a Carbon Tax from 1 April 2016, as announced in its 2015 budget review, but no mention has been made regarding alignment of the tax with other instruments such as the carbon budgets.

245. The proposed tax structure published in 2013 still stands i.e. R120/tonne escalating at 10% per annum, with a 60 – 90% tax free threshold depending on trade exposure, offsets and processes. The tax will be levied on Scope 1 emissions and, in the electricity sector, will be passed on to the consumer. Although shrouded in uncertainty, a second phase of the tax would see the emissions-free threshold being phased out by 2024, after which it is possible that the tax could be replaced by an absolute cap from 2025.

246. An environmental levy in the electricity tariff has been increased by 2c/kWh to a level of

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66 Energy Efficiency Development Plan 2015 – 2036 Revision
5.5c/kWh, which is now higher than the proposed carbon tax (4.8c/kWh) for the first 5 years. The linkage between this levy and the carbon tax was explained to be that, in the absence of a carbon tax, the levy serves to promote energy efficiency and encourage lower greenhouse gas emissions.

**Carbon Budgets**

247. Carbon budgets will be applied at a company level by the Department of Environmental Affairs and will only apply to Scope 1 (direct) emissions. The first five years (2016 to 2020) will be a trial period in which the approach to the instrument will be evaluated with a view to developing a mandatory system for introduction in 2021. For this Phase 1, the budgets will not be aligned to any overall national or sectoral budget, but will be allocated based on historical emissions for existing operations and take account of existing expansion plans (proof of which will be needed) and business-as-usual projections. The budgets will also allow for changes to absolute emissions as a result of changes in emissions intensity due to changes in general operations, market conditions, etc. There will be no penalties for companies that exceed their carbon budget.

248. The purpose of Phase 1 will be to test the system and to trial a greenhouse gas (GHG) reporting system, which is currently under development. Companies will report annually against a five year pollution prevention plan aligned with their budget, to indicate progress in meeting carbon budgets, or why this is not possible. At the end of five years, companies will true up their emissions against the budget for the full period and set targets for the next period.

**Desired Emission Reduction Outcomes (DEROs)**

249. These are aspirational and are not intended to be used as compliance limits. The DEROs will be developed for the same sectors that will be covered by carbon budgets in the first phase. Short (to 2020), medium (2021 – 2030) and long term (2030 – 2050) DEROs will be developed.

250. The long term DEROs will be ambitious and aspirational to meet the national objectives for low carbon development and will have two functions: 1) to prevent the technology lock-in characteristic of high emission pathways; and 2) to allow decision-makers to cultivate an appropriate range of future mitigation options. Currently, long term DEROs are aligned with what is required by science for the IPCC two degree scenario.

251. Medium term DEROs encourage a transition to a low carbon economy and take into account that 2030 is within the investment horizon for current infrastructure investments and so mitigation goals for 2030 will have a direct policy outcome.

252. Short term DEROs will be attainable through reasonable effort (application of existing technologies and mix-of measures, including carbon tax).

**Intended Nationally Determined Contributions (INDCs)**

253. South Africa plans to submit their INDCs to the UNFCCC for COP 21 in the third quarter of 2015. Development has commenced and current thinking is that they will be based, and build on, the commitments already made.
European Union

254. Renewable Targets for the European Union remain unchanged for 2020:

- 20% reduction in GHG emissions;
- 20% share of renewable energy; and
- 20% improvement in energy efficiency.

255. In October 2014, the European Council approved new targets for 2030 which include:

- 40% reduction in GHG emissions from 1990 levels;
- 27% share of renewable energy (i.e. 45% share in renewable electricity); and
- at least “27% energy savings”.

Finland

256. The price of emission allowances has been low in the EU Emissions Trading System, which has resulted in coal being more competitive and replacing peat in some power plants in Finland. For the longer term, climate policy is driving investment plans towards renewable energy sources and Finland’s goal is to increase the use of renewable energy to 38% by 2020.

Germany

257. The Climate Protection Action Plan 2020 (December 2014) outlines new measures to reach the 40% reduction target in CO₂ emissions (an additional 78 million tonnes reduction) by 2020 from 1990 levels. These include reductions of 25-30 million tonnes through energy efficiency, 22 million tonnes from the power sector, 10 million tonnes from the transport sector 7.7 million tonnes from industry and 3.6 million tonnes from agriculture.

Turkey

258. With Decision 26/CP.7 of the Seventh Conference of Parties (COP7) in 2001, Turkey was deleted from the list of Annex-II countries under the United Nations Framework Convention on Climate Change (UNFCCC). Moreover, Decision 26/CP.7 enshrined an invitation to all parties to recognise the special circumstances of Turkey relative to Annex-I Countries, placing it in a different situation.

259. Turkey subsequently became a party to the UNFCCC in 2004, after establishing the Coordination Board on Climate Change (CBCC) through Prime Ministerial Circular 2001/2. The CBCC was restructured in 2004 after Turkey became a party to the UNFCCC and in 2010 its remit was expanded with the participation of new members. There are 11 technical working groups established under the CBCC.

260. Law no 5836 on the Endorsement of Turkey’s Ratification of Kyoto Protocol to the UNFCCC was published in the Official Gazette on 17 February 2009. Following the publication of a Council of Ministers Decree, “Ratification Instrument”, declaring Turkey’s accession to the Kyoto Protocol in the Official Gazette on 13 May 2009. The ratification

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instrument was submitted to the UN Secretariat General on 28 May 2009 and Turkey officially became a party to the Kyoto Protocol on 28 August 2009. Turkey does not participate in the Kyoto flexibility mechanisms: CDM, JI and IET. However, to improve its capacity and to prepare itself for the Post-Kyoto Period, Turkey has gained experience with Voluntary Carbon Markets (VCMs).

261. The “National Climate Change Strategy” document for the years 2010-2020, approved by the Higher Planning Council in 2010, identifies priority activities to be carried out in the sectors for mitigating climate change, as well as urgent measures for adapting to climate change. The National Climate Change Action Plan (NCCAP), prepared in order to implement NCCS, includes strategic principles and targets for 2011-2023.

262. NCCS states that “low and zero greenhouse gas emission technologies, primarily renewable energy and clean coal technologies as well as nuclear energy, shall be fostered, R&D activities on clean technologies and energy resources shall be carried out and domestic industries shall be supported in these ventures”.

263. On 25 April 2012, a new regulatory framework on “Monitoring of GHGs Emissions” was adopted. The first year for monitoring is 2015, with reporting for that year in 2016.
4.4 Clean Coal Technologies

United States of America

FutureGen 2.0

264. The US Department of Energy ordered the “shut down” of the FutureGen 2.0 project in January 2015, premised on Congress not extending the availability of obligated funds beyond 30 September 2015. The U.S. Congress is considering an extension of these funds at this time.

Southern Company’s Kemper County IGCC Project

265. Progress continues with Southern Company’s Kemper County IGCC project which is currently under construction with expected completion in 2016. This Mississippi lignite mine-mouth operation consists of air blown gasification technology producing 524MW on syngas (additional 58MW with natural gas). The plant will capture 65% of its total CO₂ emissions, which will be dispatched via pipeline to be used for enhanced oil recovery. The $6.2 billion plant will use about 150 million tons of lignite over the plant’s expected 40-year life.

US Department of Energy’s Regional Carbon Sequestration Partnership Initiative

266. The US Department of Energy recently announced that its collection of projects under its Regional Carbon Sequestration Partnership Initiative had successfully and safely captured 10 million tonnes of carbon dioxide. One project alone, Air Products and Chemical, Inc. in Port Arthur, Texas, has captured 2 million tonnes.

National Energy & Technology Lab, Carbon Capture and Storage Database – Version 5 (updated November, 2014)

267. The US Department of Energy’s National Energy & Technology Lab (“NETL”) has published a new and updated version of its Carbon Capture and Storage (CCS) Database. The database includes active, proposed, and terminated CCS projects worldwide. Information in the database regarding technologies being developed for capture, evaluation of sites for carbon dioxide (CO₂) storage, an estimation of project costs, and anticipated dates of completion is sourced from publically available information. The CCS Database provides the public with information regarding efforts by various industries, public groups, and governments towards development and eventual deployment of CCS technology. As of November 2014, the database contained 274 CCS projects worldwide. The 274 projects include 69 capture, 60 storage, and 145 for capture and storage in more than 30 countries across 6 continents. While several of the projects are still in the planning and development stage, 128 are actively capturing and injecting CO₂.69

Clean Coal Funding

268. With the Fiscal Year 2016 funding process underway, it appears that funding for the US Department of Energy’s coal R&D programs will rise. In May 2015, the U.S. House of Representatives passed its version of the appropriations bill. The Senate is working on its

69 http://www.netl.doe.gov/research/coal/carbon-storage стратегический программный поддержка/данные
own version that, if passed, would be reconciled with the House. Early reports indicate that the Senate funding level will also improve upon the amount from the prior fiscal year.

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**Canada**

269. Canada has become a global leader in carbon capture and storage (CCS) technologies development, deployment and demonstration. The world’s first large-scale coal-fired generating unit with CCS technology, the SaskPower Boundary Dam unit 3, began commercial operations in the autumn of 2014. The $1.4-billion facility has reduced emissions of CO₂ by 90%, SO₂ by 100%, NOₓ by 27%, PM10 by 90% and PM2.5 by 90%.

270. The captured and stored CO₂ is sold under a 10-year contract to Cenovus Energy, a Calgary-based oil company. In addition to CO₂, captured SO₂ will be converted to sulphuric acid and sold for industrial purposes including manufacturing of fertilizers. Fly ash will also be sold for use in ready-mix concrete, pre-cast structures and concrete products.

271. The SaskPower CCS project has powerful implications for Canada and the world on the continued use of coal in electricity generation, particularly use of low grade coals in an environmentally acceptable way.

**Brazil**

272. Up to now, there have been no policies, regulations or legislative developments that have affected the prospects for Carbon Capture and Storage (CCS) or CCUS demonstration and deployment in Brazil. The coal industry is promoting CCS R&D. Based on that, important carbon capture projects have been approved in Brazil.

273. The Beneficent Association of Santa Catarina Coal Industry (SATC) in cooperation with U.S. Department of Energy’s National Energy Technology Laboratory (NETL) have worked in a project to develop two advanced sorbents able to capture CO₂ released from coal-fired power plants. The possible innovation is the use of local coal fly ash as raw material to synthesize sorbents. Zeolites and amine-enrichment, supported by mesoporous silica are the main candidates.

274. Furthermore, a carbon capture laboratory will be built at SATC, with infrastructure for sorbents synthesis, physical-chemical analyses and pilot-scale tests. This first project has
been funded by the Santa Catarina state Research and Innovation Foundation (FAPESC).

275. A second project was approved by a power generation company (CGTEE/Eletrobras Group) and a 100KWth pilot plant using a Moving Bed Temperature Swing Adsorption CO\textsubscript{2} capture process will be tested. The process, originally patented at laboratory scale by Adsorption Research Inc., will be verified to reduce the energy penalties in the carbon capture processes.

276. The two projects received an investment at around $3.0 million and both will support inclusion of clean coal technologies in the Brazilian Government’s strategic plan.

Australia

Federal Government Developments and the role of CCUS

277. On 5 March 2015, the federal parliament passed into law amendments to Australia’s offshore petroleum and greenhouse gas storage laws. This represents an important step towards the establishment of a single national regulator for all safety, structural integrity and environmental management matters for the offshore petroleum industry. It also streamlines greenhouse gas storage titleholders’ applications and nominations when there is more than one holder of a single title.

278. The prospects for CCUS in Australia are limited. Thus the focus has been more on geological storage, demonstration of capture technologies and related R&D work. CCUS may become feasible in the future in areas such as offshore Victoria. However, the Bass Strait oil wells do not require enhanced oil recovery at this point in time.

Developments in CCS R&D and geological CO\textsubscript{2} storage

279. In October 2014 an industry-led Leadership Roundtable for the Development of Low Emissions Technologies for Fossil Fuels was established. The Roundtable’s role is to share information on relevant low emission technology activities across Australia and overseas and to identify potential new studies and activities that could address current gaps and future needs. These may include technologies for high efficiency/lower emission generation, fugitive emission abatement and CCS.

280. Australia’s current contribution to the international RD&D effort includes:

- Victorian Otway CO\textsubscript{2} Storage Project. In October 2014 the Australian Government committed a further A$25m to continue the development of the underpinning science behind geological storage of CO\textsubscript{2}. In particular, experiments with new trapping mechanisms are under way and, if successful, will greatly increase the global storage capacity.

- The Queensland Callide Oxyfuel power project successfully concluded in March 2015 having completed 10,000 hours of operation. It involved a world-leading demonstration of oxy-fuel capture technology, retrofitted to a 30MW boiler at Callide A power station. Oxy-fuel is one of the two leading technologies for capturing CO\textsubscript{2} from power stations; the other is Post-Combustion Capture. Importantly, the Callide project demonstrated how Oxy-fuel technology can be applied to existing and new power stations.

- The Chevron operated Gorgon Joint Venture’s investment in the world’s largest commercial-scale CO\textsubscript{2} injection facility is currently under construction in Western Australia.
• The search for storage sites in Queensland, NSW, Victoria and WA is intensifying. Three different forms of geology are being studied including conventional anticline in Victoria, Horizontal Migration Assisted Trapping (MAT) in Queensland and both horizontal and vertical MAT in Western Australia.

• The Australian National Low Emissions Coal Research & Development research program involves a broad R&D program supporting Australian CCS demonstration projects.

• A new low emissions technology R&D competitive grants program with calls for applications made in August 2015. Funds of A$25m are available.

• An Australian Government funded project is assessing the feasibility of a post combustion capture IGCC facility in China. This is an initiative of the Australia-China Joint Coordination Group on Clean Coal Technology.

• A$15 million feasibility study of a proposed CCS research and demonstration project in the Surat Basin in South East Queensland. The project proponent is the Carbon Transport and Storage Company, which is wholly owned by Glencore.

Japan

281. Construction of the oxygen-blown IGCC Osaki Project (1x 166MW unit) in Hiroshima Prefecture, jointly operated by J-POWER and Chugoku Electric Power Company, started in March 2013. Operation of the IGCC power plant is scheduled to commence in March 2017. Further stages will add CO\(_2\) capture and develop an Integrated Gasification Fuel Cell (IGFC) plant thereafter.

282. In addition, two air-blown IGCC projects (2 x 540MW units) have been announced by Tokyo Electric Power Company in Fukushima Prefecture. The company aims to start the operations at the beginning of the 2020s, but there is no plan for CCS on the project.

283. Japan and Australia were jointly demonstrating Oxy-Fuel and CCS CO\(_2\) recovery of 20,000 tons a year in the Callide power station in Australia from 2012. The project completed successfully in March 2015.

284. Japan CCS Co., Ltd. is developing demonstration CCS facilities from 2012 to 2016 in the Tomakomai area of Hokkaido, Japan; and actual CO\(_2\) storage of more than 100,000 tonnes a year is scheduled to begin from 2016.

285. The Japanese government is also planning further CCS demonstration projects in other areas.

Thailand

286. Thailand emits approximately 120 million tons of CO\(_2\) per year (excluding the transportation sector; and the power sector is the largest emitter. The largest CO\(_2\) sources and oil fields are in the north of Thailand, and 10 billion tonnes of theoretical a CO\(_2\) storage capacity have been identified in saline aquifers and in oil and gas fields. The cluster of offshore sink options provides the best opportunity for CCS demonstration projects.

72 http://www.japanccs.com/?lang=en
South Africa

287. The Carbon Capture and Storage (CCS) roadmap was endorsed by Cabinet on 4 May 2012. The pilot CO2 storage project is behind schedule (original target date was 2017). It is likely that drilling and seismic testing will take place during the course of 2015 for geological characterisation. A firm date for the delayed test injection has not yet been given.

Finland

288. There are no depleted oil-fields, depleted gas-fields or saline aquifers suitable for CO2 storage in Finland. Captured CO2 would need to be transported to the nearest possible disposal sites in Latvia, Denmark, Poland, Germany and the North Sea.

289. Some CCS research projects have been carried out. The CCS Finland project evaluated the possible use of CCS in Finland. It started at the beginning of 2008 and ended in February 2011, with the objective of investigating how CCS could be applied in Finnish conditions as a technological measure for the reduction of greenhouse gas emissions.

290. The Carbon Capture and Storage Program (CCSP) is a consortium of 18 industrial partners and 9 research partners that has been running from 2011 to 2015 with an annual budget of about €3 million. Its objectives are: to develop CCS-related technologies and concepts, leading to essential pilots and demonstrations by the end of the program; to create a strong scientific basis for the development of CCS technology, concepts and frameworks; and to establish active, international CCS co-operation. Main research areas are:

- **CCS concepts and technologies**: Solutions for combined heat and power (CHP) plants, multi-fuel power plants, bio-CCS, and heavy industry. Chemical looping combustion (CLC), mineral carbonation and other novel technologies.

- **Monitoring technology**: Development of methods and technology for monitoring of CO2 capture and storage.

- **Framework for CCS**: Regulation, sustainability and public acceptance of CCS. Infrastructure and CO2 storage capacity.

- **CO2 utilization**: CO2 as a feedstock in industrial processes, CO2 capture by algae cultivation.

Germany

**Carbon Capture Storage Legislation (2012)**

291. The legislation stipulates the conditions under which carbon can be stored underground in Germany. Following a compromise with the regional states, the allowed amount of annual CO2 storage was reduced from 3 million tonnes to 1.3 million tonnes and the liability period was moved up from 30 to 40 years for site operators. State-wide moratoriums on storage will not be allowed, but regional states can exclude certain areas from being host to storage sites.73 There is no realistic prospect of commercial applications of CCS technology in Germany in near future.

73 IHS Global Steam Coal Country Profile: Germany, Sept 2013.
Carbon Capture Projects in Germany

292. Despite the negative outlook for CCS within Germany, a number of pilot projects and research continue. The main R&D fields of relevance to power plants are the optimisation of ongoing production processes, the further development of innovative technologies to commercial maturity, and the development of new options for the future. As primary measure to avoid CO₂, a further increase in efficiency is essential. These include, but are not limited to, the following:

- Still ongoing again this year, 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. New materials were developed that permit steam parameters of 700°C and 350bar so that an increase in efficiency of four percentage points can be achieved.

- RWE Power, Linde Group and BASF are improving a technique for capturing CO₂ from flue gas and testing it at the Niederaußem power plant, for possible use in conventional power stations and as a retrofit option. This technique is currently being trialled in a long-time test. Since it was commissioned, the plant has been in operation for 34,000 hours and has achieved 97% availability.

- Also RWE is further developing a technology in a bench-scale test rig at Niederaußem for storing large amounts of excess electricity generated from renewables in the form of chemical energy while simultaneously using CO₂ from power plants. This technology, referred to as "power-to-gas" technology, involves the conversion of electricity generated from renewable energy by water electrolysis into hydrogen, which then catalytically reacts with CO₂ to form methane.

- Research activities were completed in Apr 2014 at the oxyfuel pilot plant at Schwarze Pumpe. Since its commissioning in September 2008, it has been in operation for a total of 19,200 hours; with 10,650 tonnes of CO₂ being liquefied, including 1,510 tonnes of captured CO₂ that was delivered to the Ketzin research storage facility.

- Since 2015, Steag and international partners are developing a project for CO₂ storage combined with power-to-liquids technology at the Lünen power plant. The aim is to convert CO₂ emissions from coal combustion into methanol.

Turkey

293. Since Turkey has candidate country status for European Union (EU) membership, harmonisation of Turkish legislation on coal with EU legislation is underway, including application of the EU Large Combustion Plant Directive from 2010. All new coal based power plants must comply with this directive, with the selected technology for new lignite based power plants being Circulating Fluidised Bed (with FGA if necessary).

294. With the exception of one power plant (Can PP, 320MW), all remaining lignite-fired power plants and one domestic hard coal-fired power plant use sub-critical technology. All domestic coal-fired power plants are required to be modernised to meet LCPD requirements by 2019.

295. A number of imported coal based power plants use supercritical technology. In addition, there are a number of pilot-scale lignite gasification projects in Turkey, one of which is an EU 7th FP project in collaboration with India, France and Holland.
4.5 Coal Production and Transportation

United States of America

Office of Surface Mining, Stream Protection Rule

296. The US Department of the Interior’s Office of Surface Mining has a long running rulemaking effort to revise the standards for mining activities in or nearby streams (Stream Buffer Zone rule, or “SBZ”). The proposed rule would severely limit both surface mining operations (by severely regulating surface water runoff) and underground longwall mining operations (by regulating surface subsidence). It would replace the current flexible standard (Approximate Original Contour restoration standard) with a new “original form and function” standard. The final rule is expected to be issued this summer and industry groups will challenge the rule in court.

297. National Mining Association has projected that the new SBZ rule “could put between 55,150 and 79,870 direct mining jobs at risk” and decrease recoverable coal reserves “between 30.4 and 41.5 percent”.

Bureau of Land Management, Coal leasing on Federal lands

298. The US Department of Interior’s Bureau of Land Management is responsible for the leasing of coal reserves on Federal lands (primarily in the Mountain West, including Colorado, Utah, Montana, and Wyoming). Various non-governmental organisations (NGOs) are challenging coal lease sales and more specifically, are attempting to stop all coal leasing until the impacts on climate change are assessed. The NGO groups are also seeking a revision of the coal valuation rules in an effort to stop lease sales.

Mine Safety & Health Administration, Coal Dust

299. The US Department of Labor’s Mine Safety & Health Administration (“MSHA”) issued a new regulation on 1 May 2014, setting new limits on respirable coal mine dust in underground mines, which will be phased in. In addition, the rule mandates the use of Continuous Personal Dust Monitors beginning in 2016. The new levels are the subject of court challenges.

Waters of the United States (WOTUS)

300. On 21 April 2014 EPA and USACE jointly proposed regulations revising the definitions of waters subject to the jurisdiction of the federal government or “waters of the United States” (“WOTUS”). The proposed rule would change the definition of “waters of the United States” under the Clean Water Act (CWA) to areas where water flows intermittently, and allow the agencies to make determinations on a case-by-case basis.

Australia

Environment Protection and Biodiversity Conservation (EPBC) Act

301. Major projects in Australia sometimes require more than 70 different primary and secondary approvals, licences, permits and authorisations and there is substantial variation in the process between different state and territory jurisdictions. The Australian Government’s objective in its one-stop shop policy for environmental approvals is to remove duplication between state and Commonwealth regulation and thereby reduce the cost and time it takes to assess projects.

302. To enable the one stop shop, the Australian Government needs to enter into separate bilateral agreements for assessment and approval with each state and territory. Revised assessment bilaterals are now in place with all jurisdictions and draft approval bilaterals have been released for all but the Northern Territory. The federal Government is negotiating with the Senate on EPBC Act reforms to allow the implementation of approval bilaterals.

303. In the meantime, the Minerals Council of Australia is pursuing a range of other administrative reforms to improve the operation of the EPBC Act and the operation of the “Water Trigger”, which is a specific requirement under the Act for coal seam gas and large coal mining developments.

Transportable Moisture Limit (TML) for coal

304. The International Maritime Solid Bulk Cargoes (IMSBC) Code classifies solid bulk cargoes based on hazard/risk as:

- ‘Group A’ cargoes that may liquefy if shipped at a moisture content exceeding their Transportable Moisture Limit (TML);
- ‘Group B’ cargoes that possess a chemical hazard, which could give rise to a dangerous situation on a ship; and
- ‘Group C’ cargoes which are neither liable to liquefy (‘Group A’) nor possess chemical hazards (‘Group B’).

The Schedule to the IMSBC Code headed ‘COAL’ indicates that a coal cargo may either be ‘Group A and B’ or ‘Group B’ only.

305. Under the ‘02-13 amendments’ to the Code, which took effect on 1 January 2015, the ‘Group’ identified in any individual bulk cargo schedule (and thus in the associated Shippers’ Declaration) changed from being recommendatory to mandatory. Consequently, coal shippers can no longer rely on the ‘Hazard’ (particle size) criterion of the ‘COAL’ schedule to determine if their cargoes have the potential to liquefy. Rather, coal shippers have to determine if any of their products have a TML using one of the three procedures prescribed by the IMSBC Code (the Flow Table Test, the Penetration Test).

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75 Bilateral agreements reduce duplication of environmental assessment and approval processes between the Australian and state/territory governments by allowing the Commonwealth to “accredit” particular state/territory assessment and approval processes. There are two types of bilateral agreement under the EPBC Act – assessment bilateral agreements and approval bilateral agreements. If a proposed action is covered by an assessment bilateral agreement, then that action is assessed under the accredited state/territory process. After assessment, the proposed action still requires approval from the Commonwealth Environment Minister under the EPBC Act. If a proposed action is covered by an approval bilateral agreement, then it will be assessed and approved by the state/territory. No further approval is required from the Commonwealth Environment Minister under the EPBC Act.
306. Since none of the TML tests stipulated in the IMSBC Code are directly applicable to typical (-50mm) Australian shipped black coals, the Australian black coal industry’s research program, ACARP, has developed a Modified Proctor/Fagerberg Method for Coal. This procedure, which was reviewed by Dr Ralph Holmes of the Commonwealth Scientific and Industrial Research Organisation (CSIRO), is the culmination of world-leading research valued at more than A$2.4 million.

307. In September 2014, the Australian Government provided interim information on the ACARP project to the First Session of the International Maritime Organization (IMO) Sub-Committee on Carriage of Cargoes and Containers.

308. On 12 December 2014, the Australian Maritime Safety Authority issued an exemption to Australian coal shippers allowing the use of the modified method. ACARP is undertaking additional scientific work to reproduce, replicate and further confirm the test. The Minerals Council of Australia has sought feedback from coal shippers outside Australia through several industry bodies, including the World Coal Association, the Coal Exporting Terminal Operators’ Association and the International Council on Mining and Metals.

309. The Australia Government subsequently asked the IMO to consider adopting the Modified Proctor/Fagerberg test for coal at the 2015 September session of the Sub-Committee on Carriage of Cargoes and Containers. This recommendation has received broad support from IMO member states subject to review by an IMO Correspondence Group.

Great Barrier Reef/World Heritage Committee Update

310. In June 2015, the World Heritage Committee (WHC) considered Australia’s progress report on management of the Great Barrier Reef (GBR). It decided against placing it on the list of World Heritage properties ‘in danger’**, but will closely monitor the situation over the next four years.

311. Australia has made major improvements on all the issues where the WHC has called for progress, including:

- a comprehensive approach to strategic planning through the Reef2050 Long Term Sustainability Plan (LTSP);
- limits to capital dredging and capital dredge disposal (including a ban on capital dredge material placement within the Great Barrier Reef World Heritage Area and Marine park);
- limits to port development to within existing priority ports; and
- on-going commitment to water quality improvements, with a particular focus on sediment and nitrogen loads.

312. The Australian and Queensland governments have demonstrated their long term commitment to the implementation of the Long Term Sustainability Plan (LTSP), primarily through the investment of more than A$2 billion to protect the Reef over the next decade. Some of these funds will be distributed through the GBR Reef Trust through which proponent’s financial offset commitments will also be deployed. This is in addition to existing controls on port development and shipping, the management of which is highly sophisticated and world class.

313. The resources industry has a long history of responsible operation alongside the GBR and is fully committed to its long-term protection. For example, the industry:
• directly contributes to a range of conservation programs (costing around A$40 million a year) and provides significant in-kind support for scientific research; and
• plays a lead role in the development of effective international, national and state regulations intended to prevent marine pollution, limit the risk of ship collisions/groundings and, by extension, environmental harm.

314. The industry accepts that such activities are necessary to ensure it remains a reliable supplier of high quality coal and minerals from the ports adjacent to the GBR. It also believes that this is what Australia’s overseas customers expect.

Queensland - Mineral and Energy Resources (Common Provisions) Act 2014 (Qld) (MER Act)

315. The MER Act was passed in late 2014, but much of the Act has not yet commenced. It represents the first step in the Modernising Queensland Resources Acts Program, which is likely to take three to four years to complete. The aim is to bring together the five existing mineral and energy related Acts and related regulations under one unified tenure system. The Act also introduced an arrangement for coal and gas parties to co-develop where their tenures overlap. This new overlapping tenure framework is a world first with the ultimate aim to maximise extraction of both valuable resources.

316. Although the goal is to streamline various resource related Acts, the Queensland Government has taken the opportunity to propose some additional amendments, including land access, opt-out agreements, access agreements, restricted land and public notification and overlapping tenure. Some of these amendments were contentious and the new Queensland Government made an election commitment to reverse some of these changes. As such, the final form and commencement date of this Act remain unclear.

Queensland - Regional Planning Interests Act 2014 (Qld)

317. The Queensland Parliament passed the Regional Planning Interests Act on 20 March 2014. This Act gave effect to the Queensland Government’s “next generation” regional plans to manage land use conflicts in regional Queensland between resource projects important to the economic growth of Queensland and existing agricultural land use.

318. The Act makes it an offence to carry out, or allow to be carried out, a resource activity or regulated activity in an area of regional interest without a regional interest authority. A resource activity includes mining exploration activities as well as petroleum and gas exploration activities.

319. Areas of regional interest are defined as being a priority agricultural area, a priority living area, a strategic cropping area or a strategic environmental area and these areas must be shown on a regional plan or a map to be included in the regulations to the Act.

320. The first tranche of regional plans made under the Act included plans for the Darling Downs and Central Queensland, which both came into effect on 18 October 2014. Central Queensland accounts for 40% of the state’s coal production. The Darling Downs includes large reserves of thermal coal in the Surat Basin.

Queensland - Harmonization of safety and health requirements for overlapping coal/CSG titles

321. Under Queensland law, tenements for coal mining and for coal seam gas (CSG) mining often overlap. In order to maximise the utilisation of both the coal and the gas resources,
the Queensland Resources Council prepared a joint industry paper in 2012. Many of the paper’s proposals now form part of the MER Act. Some of the concepts and principles from the industry paper have also been translated into amendments to the Coal Mining Safety and Health Act 1999 (Qld) and the Petroleum and Gas (Production and Safety) Act 2004 (Qld).

322. The new health and safety overlapping tenure provisions require joint interaction management plans and provide an alternative dispute resolution process for independent arbitration. These amendments are aimed at achieving cooperation on safety issues between Queensland’s coal and CSG industries whilst they work together to achieve the best commercial outcomes for both industries and for Queensland.

**New South Wales - Coal Allocation Framework**

323. The NSW Government has formed a Coal Exploration Steering Group (CESG) to develop a new framework for allocating coal exploration titles in NSW. This follows recommendations by the NSW Independent Commission Against Corruption in its October 2013 report on how to reduce corruption risks in the coal allocation process. CESG has an independent chair and includes members from key government agencies.

324. CESG released a discussion paper in November 2014 entitled “Improving NSW’s Process to Allocate Coal Exploration Licences”. The discussion paper outlined a high-level process and a range of issues that CESG considered regarding both competitive and non-competitive allocations. CESG subsequently provided a report to the Government. In September 2015 the Government provided industry with an opportunity to comment on draft legislative amendments that seek to establish the coal allocation framework, which are expected to be introduced to the Parliament by mid-October 2015. A feature of the draft legislation is the use of Ministerial orders to make provision for details of the coal allocation process.

**New South Wales - Draft Industry Action Plan for the NSW minerals industry**

325. The NSW Government released the Minerals Industry Taskforce’s Draft Industry Action Plan in November 2014 for public comment. The plan aims to address the fall in mining capital expenditure in NSW and increase the value of mineral production by 30% by 2020. The Industry Taskforce was appointed by the NSW Government to prepare the draft plan and includes a range of industry, union, government, business and academic members.

326. The draft plan includes recommendations covering the policy framework for exploration and mining, fees and royalties applied to the industry and supporting skills and infrastructure.

327. The NSW Premier and Minister for Planning subsequently announced proposed changes to improve processing times for State Significance Development, which includes mining projects. These changes aim to halve processing times for an application. A key component of this reform is the Integrated Mining Policy, which aims to deliver streamlined, whole of government policy for the assessment, approval and compliance of mining operations in NSW.


328. On 1 February 2015, the Work Health and Safety (Mines) Act 2013 (NSW) and Work Health and Safety (Mines) Regulation 2014 (NSW) commenced. These new Mine Safety
Laws operate in conjunction with the Work Health and Safety Act 2011 (NSW) and replace the previous health and safety legislation relevant to the mining industry. The purpose of the new laws is to improve the consistency of work health and safety requirements for mines and implement reforms developed as part of the workplace health and safety harmonisation process.

South Africa


329. The Parliamentary approval process for the MPRDA 2014 Amendment Bill was sent back to the National Assembly for reconsideration by President Zuma, in terms of Section 79 of the Constitution.

330. Briefly, the main amendments to the MPRDA of concern are:

- Government will be able to enforce the volume and the price at which strategic minerals have to be sold domestically to encourage local downstream industry. The main targets are likely to be iron-ore and coal, for steel and power. Under the Bill, the Minister has broad discretion to set the percentages, quantities, qualities and timelines for beneficiation in regulations.

- The amended Section 9 of the MPRDA abolishes the "first-in, first-assessed" (FIFA) principle which has applied to the processing of applications for mineral rights in South African mining law for over a century. The Bill introduces a form of tender system to replace the FIFA regime. Under this, the Minister must invite applications before applicants may apply for rights to particular minerals and land under the MPRDA.

- One of the main changes in the approved Bill pertained to State participation in petroleum licences which will affect the oil and gas industries. Under the Bill, the State will acquire an automatic 20% free carried interest in all new exploration and production rights. Following the recent amendments, the State is "entitled to a further participation interest in the form of acquisition at an agreed price; or production-sharing agreements". This participation, which was limited to 30% under previous versions of the Bill, is now apparently unlimited. It is also not clear what "an agreed price" means or how a deadlock will be broken where the state is "entitled" to an interest, but cannot agree with the exploration company in question on a price for such interest. This will impact negatively on the country's plans to find and develop domestic gas feedstock including offshore gas and shale gas owing to the large risk to potential investors.

- The amended Act states that a right holder is no longer indemnified from liability for environmental damage after the issue of a closure certificate and the liability of mining companies for unknown, latent or residual environmental damage remains potentially perpetual.

- The Amendment Bill contains more than 30 instances where key rules will be decided by regulation, decided on by the Minister of Mineral Resources. It is opaque and can be changed rapidly. It provides none of the certainty that investors need.

National Environmental Management Act (NEMA: 107, 1998)

331. As of 8 December 2014, the Minister of Mineral Resources is the competent authority with regard to mining environmental issues, and has control over licencing and enforcement. However, the DMR will now apply and enforce the National Environmental
Management Act (107 of 1998).

**Waste Management licenses for residue stockpiles and deposits**

332. As of 2 September 2014, Waste management licenses (WMLs) are required from the Minister of Mineral Resources for residue stockpiles and deposits relating to prospecting, mining, exploration or production activities under the National Environmental Management Waste Act (Waste Act).

**Asset ownership**

333. There has been significant merger and acquisition (M&A) activity in the South African coal mining industry in the past few years, much of it taking place under the banner of Black Economic Empowerment (BEE). Further M&A activity is expected to result from Eskom’s Black Emerging Miner Strategy, in terms of which it will procure more than 50% of its coal requirements from black-controlled coal miners by 2018.

334. In July 2014, Exxaro entered into a binding agreement to purchase 100% of Total Coal S.A. and its export marketing rights under Richard Bay Coal Terminal for $472 million. Total Coal S.A. recorded 4.5 million tonnes of combined sales in 2013, the majority of which was export coal. The reason for the divestment given by Total Coal is that it (their coal business in South Africa) was a noncore asset.

335. Exxaro also announced its Thabametsi coal mine adjacent to its Grootegeluk mine in the Waterberg. Feasibility studies are underway and should be complete by mid-2015. It will supply 17 million tonnes a year to power stations and 2.8 million tonnes a year to other markets.

**Russia**

336. In August, under the guidance of the Russian Energy Ministry, the Coal-Chemical Industry Development Plan was accepted. The Plan will enable creation of a sustainable environment for advanced coal processing technologies development and implementation.

337. During 2014 the Coal Professionals Training and Retraining System Improvement Concept was implemented. Key measures aim to improve the quality of staff training for blue-collar and engineering jobs.
4.6 Coal Utilisation

**United States of America**

**Utility MATS Rule (Mercury and Air Toxics Standards Rule)**

338. EPA finalised the “Mercury and Air Toxics Standards” rule, or MATS (also known as Utility MACT Rule), in December 2011. MATS requires existing and new coal-fired electricity generating units to install emission controls for certain hazardous air pollutants by April 2015, with case-by-case one-year extensions available. The D.C. Circuit Court of Appeals upheld MATS. However, the US Supreme Court agreed to consider whether EPA should have considered costs in determining whether it is “appropriate” to regulate hazardous air pollutant emissions from power plants. A decision is likely this summer.

339. However, MATS compliance will continue while the Supreme Court is considering the rule. EPA estimated the annual cost of MATS to be $9.6 billion (2007$) in 2015 but did not provide an estimate of the total cost of the rule. Consultants to the industry (NERA, retained by ACCCE & NMA) projected the following for MATS: an annual cost of $10.4 billion (2010$) in 2015; total compliance costs of $94.8 billion; peak year job losses of 180,000 to 215,000 in 2015; and up to 23 GW of coal plant capacity retiring by 2015. As of January 2015, over 61 GW coal capacity had announced retirement due to EPA regulations. For almost all retirements, MATS was named as the cause.

**Ozone Regulation**

340. EPA proposed a new National Ambient Air Quality Standard for ground-level ozone in November 2014, which would tighten the limit to 65-70 parts per billion, and is seeking comment on setting the limit as low as 60 parts per billion. EPA must finish the rule by 1 October 2015. A new, stricter ozone limit could cause additional coal plant retirements – if the standard is set at 65 PPB, retirements could range from 44 to 65 GW, depending on the outcome of the Clean Power Plant rulemaking.

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77 Excerpted and edited from “Status of Major EPA Regulations Affecting Coal-Fired Electricity Generation”, 25 January 2015, ACCCE.
5 CONCLUDING REMARKS

341. Coal will continue to play an essential role in world energy markets for the foreseeable future, both to maintain energy and electricity supply security in developed economies and to meet the demands for modern energy access for people in developing economies. Fulfilment of this role against the background of calls to mitigate increases in greenhouse gas emissions requires policies that encourage the installation of advanced coal-fuelled power generation technologies, particularly in developing economies, and the commercial demonstration and deployment of Carbon Capture and Storage. The inadequacy of current policy frameworks, and the reluctance of some multi-lateral development banks to finance advanced coal generation projects, are issues that must be urgently addressed.

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

343. Section 1 contains the industry’s policy recommendations derived from the body of the report and other CIAB work; while other sections report on CIAB activities during 2015, highlight relevant developments in regional markets, and describe changes in policy instruments that potentially impact the investment necessary to sustain coal’s role in world energy markets.

344. During the last year the CIAB has; a) provided the IEA with white paper recommendations based on recent CIAB work and reports as input to the IEA “Special Report on Energy and Climate”, published in June as part of its WEO 2015 report series and as input to the COP21 in Paris in December 2015; b) initiated a study on “The Role of Coal for Energy Security in World Regions”; and c) commissioned the services of a renowned international energy consultancy to provide to the IEA its independent data and expertise, focussed primarily on coal demand, supply and infrastructure in India and China, to support the analysis and preparation of “World Energy Outlook 2015”. The CIAB has also pursued several other initiatives and work tasks which are set out in Section 2 of this report; and brought the expertise of CIAB Members and their Associates to coal industry issues through meetings, workshops and interaction with the IEA Secretariat.

CIAB, 16 October 2015