Natsurv

Water and Wastewater Management in the power generating industry

(Edition 2)

WATER RESEARCH COMMISSION

TT 853/21

NATSURV 16

WATER AND WASTEWATER MANAGEMENT IN THE POWER GENERATING INDUSTRY

(Edition 2)

Report to the
Water Research Commission

by

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EXECUTIVE SUMMARY

This project aimed to review Natsurv 16: Water and Wastewater Management in the Power Generating Industry, to obtain an overview of operations, specific water use, specific effluent volume, and the extent to which best practice is being implemented, when compared to international benchmarks.

The previous edition of the power generation Natsurv compiled by van Zyl & Premlall was published relatively recently (2005) compared with many other Natsurvs that were published in the 1980s. At the time that the previous Natsurv was written, the industry was starting to show a greater commitment to taking measures to reduce the water intake and pollution potential of power generating stations, including the installation of dry cooling and dry ashing systems, the installation of desalination plants to treat mine water which can be used to supplement raw water sources, as well as improved management and operation of processes such as the Zero Liquid Effluent Discharge philosophy that encompasses a number of measures such as reuse, recycling and cascading water use.

Water use and comparison with previous Natsurv

Conventional fuels (nuclear and fossil fuels) withdraw significant quantities of water (this is seawater in the case of nuclear) over the life cycle of energy production, especially for thermoelectric power plants operated with a wet-cooling system.

In 2005 when the previous Natsurv was published, South Africa produced 192 000 GWh of electricity, consuming approximately 245 000 Ml of water. The specific raw water consumption in 2005 was found to be 1.95 l/kWh for recycling wet-cooled coal-fired plants, 0.09 l/kWh for dry-cooled coal fired plants and 0.258-0.306 l/kWh for nuclear: an average specific water consumption of 1.28 l/kWh over all technologies. In 2018/2019, South Africa produced a total of 234 407 GWh for distribution, over 42 000 GWh (18%) more than in 2005, consuming 292 344 Ml of water; 47 344 Ml more than in 2005.

In 2013/2014, the specific raw water consumption was 2.2 l/kWh for wet-cooled stations, and 0.12 l/kWh for dry cooled stations. Overall power generating and cooling technologies, the 2013/2014 specific water consumption was 1.35 l/kWh, which was in line with Eskom's water use target. From 2014/2015 to 2016/2017 the specific water consumption increased above Eskom's target of 1.35 l/kWh, but this reduced to 1.3 l/kWh in 2017/2018. Unfortunately, the good progress made in 2017/2018 was not realised over the 2018/2019 year with a specific water consumption of 1.41 l/kWh, which missed the target of 1.36. This was attributed to poor water management practices and operational inefficiencies at power stations due to water leaks, water wastage through overflowing tanks, low load factors, several unit trips and boiler filling, as well as slow implementation of water strategy action plans aimed at addressing poor water management practices at the stations. There has therefore been an increase in specific water use of 0.27 l/kWh (9.2%) since the 2005 Natsurv.

In 2005, the total dry-cooled installed capacity in South Africa was 10 477 MW, which was approximately 33% of the total installed capacity for coal fired stations. As of March 2019, the installed dry-cooled capacity for the coal fired power stations was 13 806 MW, 34% of the total installed coal fired capacity of 40 170 MW. Once the New Build plants Kusile and Medupi are fully commissioned, the installed dry-cooled coal-fired capacity will increase to 20 188 MW, 50% of the installed coal fired capacity.

In 2005, a maximum specific water intake of 2.5 l/kWh at wet-cooled power stations and 0.8 l/kWh at dry-cooled power stations was recommended. 15 years later, despite inefficiencies and high consumption of the return to service stations, the specific water use for wet-cooled stations is still well within this target and far exceeds the dry-cooled target of 0.8 l/kWh, with the average dry-cooled water use at 0.12 l/kWh.

In the previous Edition of Natsurv 16, renewable power generation such as wind turbines and solar was not considered. Due to the growing importance of these technologies and their potential future impact, a review has also been conducted into their water use, even though it is comparatively small. Concentrating solar power plants have specific water use similar or in excess to that of coal fired power stations (0.3 l/kWh for dry cooling and 3 l/kWh for wet cooling) due to the requirement for cooling and location in areas with high temperatures.

A summary of the water use per technology for South Africa's power generation is presented below.

Power Plant Type	Cooling Type	Raw Water Use (L/kWh)	Boiler Water Use (l/kWh)	WSR	Climatic Zone
Coal Fired Existing	Wet closed cycle	2.04 to 2.38	0.062 to 0.12	Olifants	Cold interior
Coal Fired Existing	Indirect-dry	0.12	0.07	Olifants	Cold interior
Coal Fired Existing	Direct dry	0.12	0.02	Limpopo	Hot Interior
New super-critical coal-fired	Direct dry	0.12	0.02	Limpopo	Hot Interior
New Coal-fired fitted with FGD	Direct dry	0.32	0.02	Limpopo	Hot Interior
Open-cycle gas turbine	NA	0.02	NA		
Combined-cycle gas turbine	Direct dry	0.013			
CSP	Direct dry	0.3	0.06	Limpopo	Hot Interior
CSP	Hybrid cycle	0.4 to 1.7	0.06	Limpopo	Hot Interior
CSP	Wet closed cycle	3	0.06	Limpopo	Hot Interior
Solar PV[a]	NA	NA	NA	NA	Distributed
Wind	NA	NA	NA	NA	Distributed
Nuclear	Once through seawater	NA	NA	NA	Coastal

WSR = water supply region; FSD = flue gas desulfurization; CCS = carbon capture and sequestration; NA = not applicable; CSP = concentrating solar power.

a. Water to wash solar PV panels is not considered.

Solar photovoltaic (PV) and wind energy exhibit the lowest demand for water and could perhaps be considered the most viable renewable options in terms of water withdrawal and consumption. Moreover, the observed water usage in these renewable energy technologies is predominantly in the manufacturing processes and the abstraction of material for construction, such as rare earths.

Comparison with international benchmarks

South Africa's water use for power generation was not benchmarked against international water use in the previous Natsurv. This was done in this revision.

On average in South Africa, 1 kWh of electricity consumes about 1.4 l of water across all technologies. This is in line with the world average of 1.2-1.5 l/kWh.

Water demands of between 2.04 and 2.38 from the predominantly wet-cooled closed loop thermal power plant fleet are somewhat above the typical mean intensity of 1.7 l/kWh reported by National Renewable Energy Laboratory (NREL) for subcritical coal power plants cooled with wet-recirculating systems; this can be attributed to the decreasing thermal efficiency and increasing age profile of the power plants. Water consumption figures for South Africa's dry cooled power plants, however, are amongst the best performing in the world. Water use for the direct dry stations (Matimba and the New Build Plants Kusile and Medupi) of 0.12 l/kWh is in line with international estimates of 0.1 l/kWh. The lower water usage profiles for dry cooled power plants can be attributed to state-of-art cooling technologies and lower age profile of these power plants. Wet-cooled water consumption is bound to increase based on current trends; this can be mainly attributed to the decreasing efficiency of wet cooled power plants.

Water supply and associated risks

Water for Eskom's coal fired power stations is sourced from several dams and supplied to the power stations through a series of supply schemes. The majority of South Africa's WMAs are under severe duress. This issue gets worse when considering the fact that most of the coal-based power plants are within regions partially or severely constrained in terms of water.

Eskom's RTS power plants namely Camden, Komati and Grootvlei, which are water intensive power plants, are in the severely constrained WMAs namely Olifants and Inkomati. The RTS power plant water consumption factor and total water consumption profile are higher compared to the base load fleet primarily because of lower performance parameters, such as reduced efficiency. Measures aimed towards increasing the efficiency of the RTS or gradual decommissioning could bring considerable changes to the forecasted WMA deficits. The gradual retirement of the RTS fleet could provide added water capacity in these WMAs. The savings of roughly 35 gigalitres associated with the decommissioning of the RTS fleet and operation of the New Build power plants Medupi and Kusile, could account for almost 15% of the forecasted deficit of 234 gigalitres by 2025, which is roughly the amount of water used by one of the larger wet cooled power stations such as Kriel, Tutuka, Matla or Lethabo. Retirement of the RTS fleet must be performed in conjunction with the commissioning of New Build power plants.

Water supply to South Africa's coal-fired stations is not considered to be at risk over the short- to medium term due to healthy dam levels. However, the Department of Water and Sanitation (DWS) is experiencing severe financial constraints, which may affect its ability to manage existing, and implement new bulk water infrastructure to ensure water security to Eskom. Engineering work has commenced on the Lesotho Highlands Water Project Phase 2, which is now scheduled to be commissioned by 2025. Until then, water availability in the Vaal River system will remain at risk, with dam levels in the Vaal River system declining. DWS is implementing various initiatives to mitigate against future water security risks in the integrated Vaal River system.

Medupi Power Station's flue gas desulphurisation (FGD) retrofit requires additional water from the Mokolo Crocodile Water Augmentation Project (MCWAP) Phase 2 project by the revised date of June 2026, which takes account of the rework required at Medupi. The estimated water delivery from MCWAP was originally January 2024 but this has moved out to April 2025. Failure to commission the FGD plant within the agreed timelines may render Eskom in breach of World Bank loan agreements and their emission licence, which would result in the units not being able to operate.

An inherent lack of abundant freshwater resources in South Africa, coupled with increasing populations and changing rainfall patterns create a need for efficient and innovative changes in water usage.

Impact of water quality

Poorer water quality leads to lower cycles of concentration in the cooling towers, increasing the amount of effluent generated and increasing the need for onsite water purification. This implies that more water is required for the same energy output. According to results of the survey between 3 and 20 cycles of concentration are applied among the various power stations, indicating the impact of variability in source water quality. Moving water abstraction from the ideal quality to impacted water quality requires additional treatment to be used, which requires additional energy, thus raising its cost.

Effect of climate

The climate of the region in which the power station is situated has a large impact on the cooling system efficiency. The impact of climate change as areas become hotter will have an impact on the cooling efficiency of the heat exchangers of both wet and cooled plants. In wet cooled plants this may result in greater water use to maintain the same cooling efficiency, whereas in dry cooled plants an increase in ambient air temperature will impact the thermal power generation capacity. Climate variability will impact on yield of water resources and infrastructure availability at local, catchment and national level, this is a major risk to water and energy security in South Africa. The higher ambient temperatures will also impact on the efficiency of dry cooled power stations with the predicted higher rainfall impacting on the coal supply chain.

Future outlook

The envisaged in the Draft IRP 2018 that the energy mix by 2030 will consist of 34 000 MW of coal (46%); 1 860 MW of nuclear (2.5%); 4 696 MW of hydro (6%); 2 912 MW of pumped storage (4%); 7 958 MW of solar PV (10%); 11 442 MW of wind (15%); 11 930 MW of gas (16%) and 600 MW of concentrated solar power (1%).

The development of new power stations beyond Eskom's current New Build programme will need to consider the quality and availability of water resources, lead times for the development of new water supply infrastructure, as well as climate change impacts. An important result from the Long Term Adaptation Scenarios study was the observation that South Africa's national water supply system, which is the result of many years of proactive planning to deal with a high level of natural variability in water resources and is highly integrated because of the extensive use of IBTs, appears to provide a relative high level of resilience to future climate change, although possibly at the cost of higher pumping rates and negative effects on environmental flow requirements. The potential effects of climate change on the water-energy nexus will need ongoing investigation to assess adaptation options, specifically for the power sector.

It is vital to consider all aspects of the energy life cycle to enable isolation of stages where significant amounts of water are used. That said, despite challenges of aging infrastructure South Africa is a world leader in water saving energy generation with respect to dry cooling, zero liquid effluent discharge policy and renewable energy investment as a factor of GDP. Eskom's practice of zero liquid-effluent discharge encourages the use of dry cooling in new coal plants, even though dry-cooled plants are on average 10 percent more capital intensive and 2 percent less efficient than wet-cooled plants, and therefore more coal intensive, with higher atmospheric pollutant loads. Thus, the benefit of reduced water consumption at a dry-cooled power plant comes at the cost of increasing other environmental burdens.

The role of coal in electricity generation will be a dominant factor up until locally available resources start to diminish. However, technologies that utilise water efficiently will have to play a more dominant role in order to preserve national water security.

The South African Coal Roadmap provides a multi-scenario analysis of the future possibilities and interventions in the local coal industry. The coal roadmap proposes four possible routes ranging from business as usual (which include life extensions to the current fleet) to South Africa leading the world in reducing coal footprint by employing ultra-super critical power stations and underground coal gasification (UCG), cyclic pulverised fuel (PF) and Fluidised Bed Combustion (FBC) based technologies. South Africa predominantly will have to employ a route that is a combination of all scenarios to move towards a less coal intensive society while trying to negate the challenges encountered in supply and demand.

Proposed new coal technologies such as UCG and FBC technologies are expected to lower water usage and emissions. The risk associated with UCG technology, where very deep coal seams are burnt underground, is the contamination of underground water reserves. FBC technologies are proposed to be viable for the Waterberg coal field which has large reserves of high ash and low-calorific value coal. On the other hand, emission reduction mechanisms such as retrofitting existing power plants with flue gas desulphurisation (FGD) are expected to increase the water footprint of power plants.

To add to the uncertainty, the physical location of the coal power plant, which affects factors such as humidity, evaporation and altitude is an important consideration when operational water consumption must be estimated.

Water management cuts across many areas of the plant, and therefore more efficient use of water will be achieved by improved planning, maintenance, and operations at all of Eskom’s power stations.

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TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1 Introduction

The Natsurv reports for different industries have been well used since they were developed by the sector in the 1980s. However, South Africa and its industrial sectors have either grown or in some cases shrunk considerably since the 1980s. Thus, the landscape has changed. New technologies and systems have been adopted by some of the industries, and therefore, certain information contained in the national surveys can be regarded as obsolete. Furthermore, initiatives like the UN CEO mandate, water stewardship, water allocation and equity dialogues, among others, suggests growing awareness related to: water use, water security, and waste production. Thus, it was considered an opportune time to review the water and wastewater management practices of the different industrial sectors and make firm recommendations. This project aims to review Natsurv 16: Water and Wastewater Management in the Power Generating Industry, in order to obtain an overview of operations, specific water use, specific effluent volume and the extent to which best practice is being implemented, when compared to international benchmarks.

The previous edition of the power generation Natsurv compiled by van Zyl & Premlall was published relatively recently (2005) compared with many others that were published in the 1980s. At the time that the previous Natsurv was written, the industry was starting to show a greater commitment to taking measures to reduce the water intake and pollution potential of power generating stations, including the installation of dry cooling and dry ashing systems, the installation of desalination plants to treat mine water which can be used to supplement raw water sources, as well as improved management and operation of processes such as the Zero Liquid Effluent Discharge philosophy that encompasses a number of measures such as reuse, recycling and cascading water use. In the previous Edition of Natsurv 16, renewable power generation such as wind turbines and solar was not considered. Due to the growing importance of these technologies and their potential future impact, a review has also been conducted into their water use, even though it is comparatively small.

2 Methodology

A thorough literature review of the South African power generating industry was conducted, as well international water uses for power generation in order to benchmark South Africa's performance and to identify future technologies.

In order to gather the relevant information of water use and water management in the power generating industry, a water use and management questionnaire was disseminated to Eskom as well as to renewable energy producers. Eskom keeps detailed records of its specific water use, reporting average figures annually. The questionnaires aimed to determine the specific water consumption volumes at each power plant in relation to the amount of power generated so as to identify the specific water use for that plant and cooling technology employed.

The following information was requested in the questionnaires:

- Total installed capacity of power station
- Amount of power generated
- Power consumed
- Raw water source
- Water volume withdrawn from source
- Water consumption volume
- Water volume discharged (if any)
- Specific water uses, e.g. cooling, washing, ashing, steam generation, and the associated percentage volumes
- Raw water source

- Typical raw water quality
- Raw water quality impacts experienced, and treatment methods employed to manage this
- Water quality impacts contributed by the power station.

Based on the information received in response to the questionnaires as described above, certain areas of scope were highlighted that would impact decision making in electricity-based water usage and were investigated further. This included:

- Mapping of water usage of coal power plants in comparison with water inventories in water deficient water management areas
- Determine the impact of emission mitigating technologies on water usage
- An assessment of water usage patterns for new coal technologies
- Water usage patterns in renewable energy technologies.

The questionnaires aimed to gather data to allow further analysis and research in the above areas to provide an improved inventory of water consumption technologies associated with electricity generation.

Information was also requested on the following in terms of best practice:

- Water sub metering
- Energy sub metering
- Monitoring and targeting
- Heat recovery
- Water foot printing
- Carbon foot printing
- Life cycle analysis
- Water pinch analysis
- Energy management training
- Water management training
- Solid waste segregation
- Rain water harvesting
- ISO 14000 (Environmental management)
- ISO 9001 (Quality Management)
- ISO 50001 (Energy Management)

3 The South African power generating industry

South Africa produced a total of 234 407 gigawatt-hours (GWh) for distribution in 2018/2019 (Table 1).

3.1 Power generated by Eskom

Most power stations in South Africa are owned and operated by Eskom. These plants account for 95% of all the electricity produced in South Africa and 45% of all electricity produced on the African continent. Eskom also directly provides electricity to around 45% of all end-users in South Africa with the other 55% being resold by redistributors (including municipalities) (AEA, 2013). Eskom operates a wide portfolio of power generation technologies which includes thirteen coal-fired power stations, four gas/liquid turbine, five hydroelectric (two conventional and three pumped storage) and South Africa’s only nuclear power station (Figure 1, Table 2). The two reactors at Koeberg are (as of 2017) the only commercial nuclear power plants on the African continent and account for around 5% of South Africa's electricity production. Low and intermediate waste is disposed of at Vaalputs Radioactive Waste Disposal Facility in the Northern Cape. Four additional hydroelectric stations are installed and operational but not used for capacity management purposes (Eskom Holdings SOC Ltd, 2018).

In 2017/2018 Eskom burnt 115.49 Mt of coal in its coal fired power stations, which excluded 1 901kt burnt during the commissioning of Medupi Units 5 and 4, and Kusile Unit 1. In 2018/2019 113.8 Mt of coal were burnt which included that used in Medupi Units 4 and 5 and Kusile Unit 1, having completed their first year after commissioning (Eskom Holdings SOC Ltd, 2018, 2019).

Renewable energy sources include wind, solar power, biomass, landfill gas and small hydro technologies. Eskom purchases renewable energy from Independent Power Producers (IPPs), coupled with their own investment in renewables, including the Sere Wind Farm, the four small hydroelectric plants in the Eastern Cape and eight rooftop and ground-mounted PV commissioned sites. Sere Wind Farm contributed 331GWh to the national grid during the 2017/2018 financial year, with an average load factor of 36.05% and an average availability factor of 98.77%. The small hydro plants in the Eastern Cape recorded total energy sent out of 11GWh during the financial year (March 2017: 20GWh) due to low rainfall in the catchment areas. The eight rooftop and ground-mounted PV commissioned sites in operation sent out 4.02GWh of energy during the year (Eskom Holdings SOC Ltd, 2018).

Table 1: Electricity Output for 2016/2017 to 2018/2019

Electricity Output	GWh net (2016/2017)	GWh net (2017/2018)	GWh net (2018/2019)
Power sent out by Eskom stations	220 166	221 936	218 939
Coal fired stations	200 893	202 106	200 210
Hydroelectric stations	579	709	1 029
Pumped storage stations	3 294	4 479	4 590
Gas turbine stations	29	118	1 202
Wind energy	345	331	328
Nuclear power station	15 026	14 193	11 580
IPP purchases	11 529	9 584	11 344
Wheeling	2 910	2 266	2 750
Energy Imports from SADC countries	7 418	7 731	7 355
Total electricity available (generated by Eskom and purchased)	242 023	241 517	240 388
Total consumed by Eskom	4 808	6 031	5 981
Total available for distribution	**237 215**	**235 486**	**234 407**

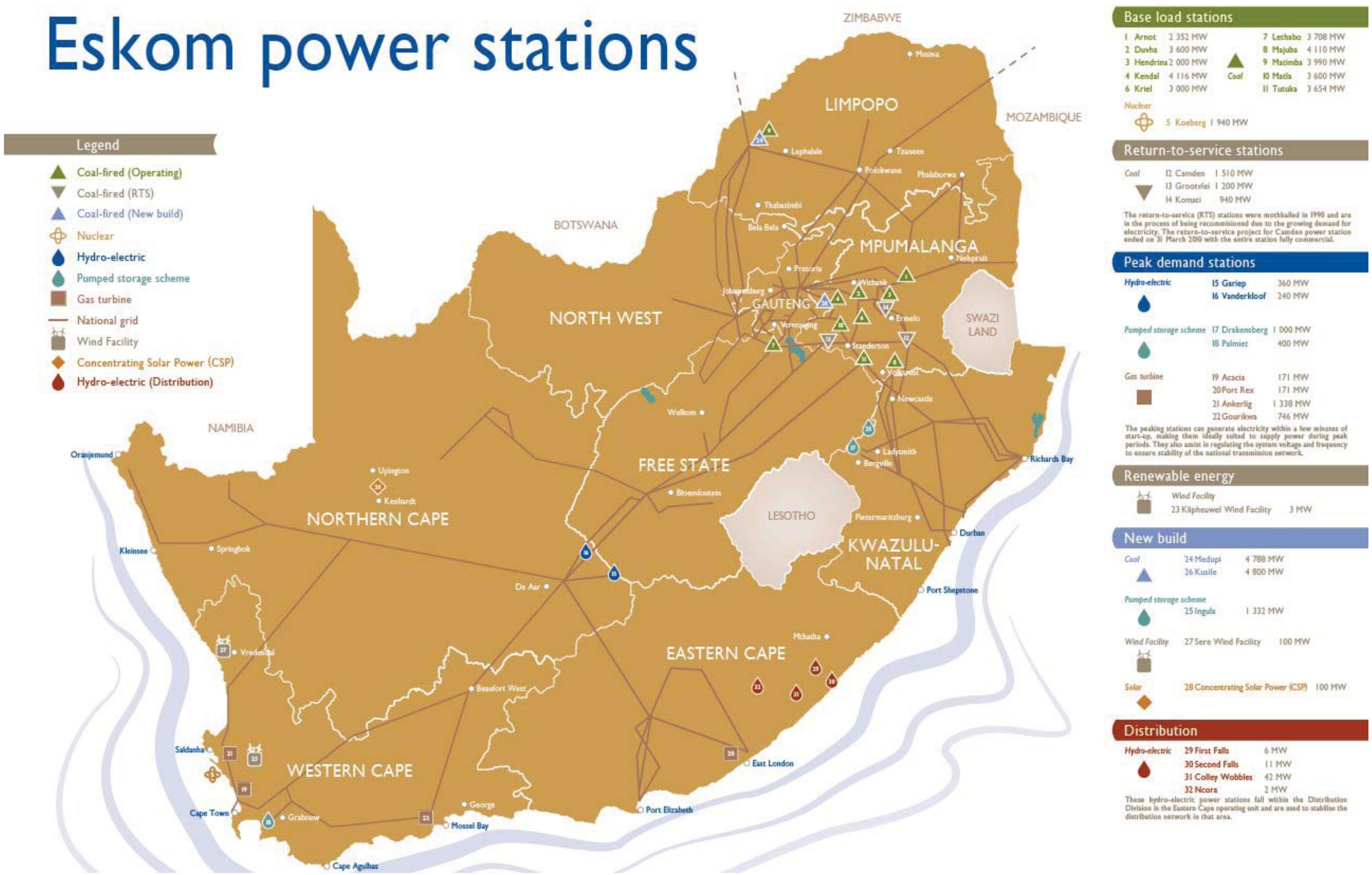


Figure 1 Location of Eskom power stations

(http://www.eskom.co.za/Whatweredoing/ElectricityGeneration/PowerStations/Pages/Map_Of_Eskom_Power_Stations.aspx)

Table 2: Eskom power station capacities as at 31 March 2019

Name of station	Location	Years Commissioned	Number and installed capacity of generator sets (MW)	Total Installed Capacity (MW)[1]	Nominal Capacity (MW)[1]
Base load stations					
Coal-fired (15)				**40 170**	**36 479**
Arnot Power Station	Middelburg, Mpumalanga	1971-1975	1 x 370; 1 x 390; 2 x 396; 2 x 400	2 352	2 232
Camden Power Station (RTS)	Ermelo, Mpumalanga	1967-1969; 2005-2008	3 x 200; 1 x 196; 2 x 195; 1 x 190; 1 x 185	1 561	1 481
Duvha Power Station[2]	eMalahleni, Mpumalanga	1980-1984	5 x 600	3 000	2 875
Grootvlei Power Station (RTS) [2]	Balfour, Mpumalanga	1969-1977; 2008-2011	4 x 200; 2 x 190	1 180	570
Hendrina Power Station[2]	Middelburg, Mpumalanga	1970-1976	5 x 200; 2 x 195; 1 x 170; 1 x 168	1 728	1 293
Kendal Power Station	eMalahleni, Mpumalanga	1988-1992	6 x 686	4 116	3 840
Komati Power Station (RTS) [2]	Middelburg, Mpumalanga	1961-1966; 2009-2013	4 x 100; 4 x 125; 1 x 90	990	410
Kriel Power Station	Bethal, Mpumalanga	1976-1979	6 x 500	3 000	2 850
Kusile Power Station	Ogies, Mpumalanga	2017	1 x 799	799	720
		Under construction	5 x 800	-	-
Lethabo Power Station	Vereeniging, Gauteng	1985-1990	6 x 618	3 708	3 558
Majuba Power Station	Volksrust, Mpumalanga	1996-2001	3 x 657; 3 x 713	4 110	3 843
Matimba Power Station	Lephalale, Limpopo	1987-1991	6 x 665	3 990	3 690
Matla Power Station	Bethal, Mpumalanga	1979-1983	6 x 600	3 600	3 450
Medupi Power Station	Lephalale, Limpopo	2015-2017	3 x 794	2 382	2 157
		Under construction	3 x 794	-	-
Tutuka Power Station	Standerton, Mpumalanga	1985-1990	6 x 609	3 654	2 510
Nuclear (1)					
Koeberg	Cape Town, Western Cape	1984-1985	2 x 970	**1 940**	**1 860**
Peaking Stations					
Gas/liquid fuel turbine stations (4)				**2 426**	**2 409**
Acacia Power Station	Cape Town, Western Cape	1976	3 x 57	171	171

Name of station	Location	Years Commissioned	Number and installed capacity of generator sets (MW)	Total Installed Capacity (MW)[1]	Nominal Capacity (MW)[1]
Ankerlig Power Station	Atlantis, Western Cape	2007-2009	4 x 149.2; 5 x 148.3	1 338	1 327
Gourikwa Power Station	Mossel Bay, Western Cape	2007-2008	5 x 149.2	746	740
Port Rex Power Station	East London, Eastern Cape	1976	3 x 57	171	171
Pumped storage schemes (3)[3]				**2 732**	**2 724**
Drakensberg	Bergville, Free State	1981-1982	4 x 250	1 000	1 000
Ingula	Ladysmith, KwaZulu-Natal	2016-2017	4 x 333	1 332	1 324
Palmiet	Grabouw, Western Cape	1988	2 x 200	400	400
Hydroelectric stations (2)[4]				**600**	**600**
Gariep	Norvalspont, Free State-Eastern Cape border	1971-1976	4 x 90	360	360
Vanderkloof	Petrusville, Northern Cape	1977	2 x 120	240	240
Total used for capacity management purposes				**47 868**	**44 072**
Renewable energy					
Wind energy (1)					
Sere	Vredendal, Western Cape	2015	46 x 2.2	**100**	**100**
Total Capacity including renewable energy				**47 968**	**44 172**
Other hydroelectric stations (4)[5]				**61**	**-**
Colley Wobbles	Mbashe River, Eastern Cape		3 x 14	42	-
First Falls	Umtata River, Eastern Cape		2 x 3	6	-
Ncora	Ncora River, Eastern Cape		2 x 0.4; 1 x 1.3	2	-
Second Falls	Umtata River, Eastern Cape		2 x 5.5	11	-
Total Eskom power station capacities (30)				**48 029**	**44 172**
Available nominal capacity - Eskom owned					**91.97%**

[1] The difference between installed and nominal capacity reflects auxiliary power consumption and reduced capacity caused by the age of plant.

[2] Due to technical constraints and economic reasons, the following units were removed from the nominal base:

- Duvha Unit 3 (575 MW nominal)
- Grootvlei Units 4, 5 and 6 (550 MW nominal)
- Hendrina Unit 3 (185 MW nominal, removed in 2017/18) and Units 1 and 9 (345 MW nominal, removed in 2018/19)
- Komati Units 1, 2, 3, 6 and 8 (485 MW nominal).

[3] Pumped storage facilities are net users of electricity. Water is pumped during off-peak periods so that electricity can be generated during peak periods.

[4] Use restricted to periods of peak demand, dependant on the availability of water in the Gariep and Vanderkloof dams.

[5] Installed and operational but not included for capacity management purposes.

3.2 Energy supplied by Independent Power Producers (IPPs)

3.2.1 South African renewable Energy IPP Procurement Programme

The South African Renewable Energy Independent Power Producer Procurement Programme (REIPPPP) is a competitive tender process that has been designed to facilitate private sector investment into grid-connected renewable energy (RE) generation in South Africa.

In the South African renewable Energy IPP Procurement Programme, bidders must pass both general and technology-specific sub-criteria under the Environmental Qualification criterion and provide evidence that all requisite environmental consents listed in the RFP have been obtained by bid submission.

3.2.2 Environmental qualification

Because South Africa is a water scarce country it is crucial that each bidder identifies whether their project (including construction activities) will require an Integrated Water Use Licence under the National Water Act. This includes providing copies in the bid response of all studies done to determine the project's water needs and activities. For this purpose, "water use" is not limited to water extraction but also includes numerous water-related activities, such as diverting or polluting a watercourse, disposing of wastewater (for example, when cleaning the mirrors or panels depending on the technology) and storing water to serve the facility.

To reduce the burden on the Department of Water Affairs (DWA), the licence itself is only required to be in place before signature of the PPA. However, upon bid submission any bidder requiring a water allocation must provide a written confirmation of this approved allocation from the local Water Services Provider (usually the municipality) or, where this is insufficient and a Water Use Licence will be required, provide a non-binding confirmation of water availability from the DWA.

The primary requirement across all technologies is an Environmental Authorization per project, in the name of the Project Company, as required by the South African National Environmental Management Act. To achieve this the Project Company must prepare an Environmental Impact Assessment Report (EIAR) or Basic Assessment Report (BAR). The former is required when a project's capacity exceeds 20 MW or it covers an area greater than 1 hectare, while a BAR is typically for projects with a capacity of 10-20 MW.

Because CSP projects tend to be situated in water scarce areas, they require specific water consents by bid submission. This includes written confirmation of the water availability for their projects by the Department of Water Affairs, as well as proof that an application for an integrated water use licence has been made (or legal opinion that it is not necessary). Lastly, biomass, biogas and landfill gas projects require a waste management licence or legal opinion that it is not necessary (Eberhard & Naude, 2017).

3.2.3 Generation licenses

South Africa has a well-defined, centrally controlled electricity generation planning and procurement system. The Electricity Regulation Act of 2006 (amended in 2007), and associated Electricity Regulations on New Generation Capacity, issued in November 2010 and May 2011, assign responsibility to the Minister of Energy to develop an Integrated Resource Plan and to make “determinations” on what new generation capacity is needed, from which sources, and whether it should be from Eskom or an IPP. The regulator, in issuing generation licenses, is bound by these determinations.

To date there have been three such Determinations for the REIPPPP. The first determination in August 2011 called for 3 725 MW of renewable energy to be in commercial operation by the end of 2018. This was supplemented by subsequent determinations in 2012 and 2015 for 8 500 MW of renewable energy before 2025 (Table 3). The programme currently has 3 976 MW of renewable energy capacity operational. An additional 1005 MW produced by gas turbine IPP is operational (Table 4). In April 2018, Eskom signed agreements with 27 RE-IPP projects totalling 2 405MW (Eskom Holdings SOC Ltd, 2018). During the 2018/2019 year, the targeted 202 MW of renewable IPP capacity was commissioned, with 447 MW of renewables expected to be commissioned during the 2019/2020 year – 32 MW of wind and 415 MW of solar photovoltaic (PV) energy (Eskom, 2019).

Table 3: Ministerial Determinations in respect of Renewable Energy Technologies (under the REIPPPP and SP-IPPP)

	MW Allocated by Minister of Energy to Date				
Technology	**First Determination (August 2011)**	**Second Determination (October 2012)**	**Third Determination (August 2015)**	**Total**	**Percentage of Total**
Onshore wind	1 850	1 470	3 040	6 300	48%
Concentrating solar power	200	400	600	1 200	9%
Solar PV	1 450	1 075	2 200	4 725	36%
Biomass	13	48	150	210	2%
Biogas	13	48	50	110	1%
Landfill gas	25	0	0	25	0%
Small hydro (≤40 MW)	75	60	60	195	1%
Small projects (1-5 MW)	100	100	200	400	3%
Total	**3 725**	**3 200**	**6 300**	**13 225**	**100%**

(Source: Ministerial Determination 1 August 2011 and Government Gazettes No 36005, 19 December, No 39111, 18 August 2015)

Table 4: IPP operational capacities by type as of 31 March 2019

Name of station	Total Operational Nominal Capacity (MW)
Nominal capacity of Eskom-owned power stations	**44 172**
Independent power producers (IPP) Capacity	**4 981**
Concentrating solar power	500
Gas/liquid fuel	1 005
Hydroelectric	14
Landfill	8
Solar PV energy	1 474
Wind	1 980
Total nominal capacity available to the grid - Eskom and IPPs	**49 153**

3.3 Cooling technologies

There are different technologies used for cooling for thermo-electric power generation, each of which possesses advantages and disadvantages. These include once-through (open-loop) cooling, closed-loop (wet) cooling, dry (air) cooling and hybrid cooling.

It should be emphasised that water is also used for non-cooling plant processes such as for operation of flue gas desulfurization (FGD) devices, ash handling, wastewater treatment, and wash water. However, cooling water usage is by at least one order of magnitude larger than the other uses.

A summary of the various cooling technologies applied in thermo-electric power generation is presented below.

3.3.1 Once-Through (Open-Loop) Cooling

Once-through cooling (OTC) systems withdraw water from a natural water body (such as a lake, river, ocean, or manmade reservoir). The water is pumped through system's heat exchanger to condense the low-pressure steam at the exhaust of the turbines (see Figure 2 for a schematic) where it is warmed about 8-17°C depending on system design, after which it is returned to the original source. The amount withdrawn varies from 95-190 l/kWh. Although none of the water is consumed within the plant, some consumptive loss results due to evaporation from the receiving water body because of the increased temperature of the discharge. The amount of water lost due to evaporation is difficult to accurately calculate because of site specific factors (e.g. temperature differential, wind speed, ambient humidity), but it has been variously estimated as 0.5-2% of the withdrawn amount, 0.38-1.5 l/kWh (Bushart, 2014).

Although these plants do not consume much water (i.e. they return about 99% of the water to the source), the availability of water is critical to plant operation because of the substantial demand. This makes these plants vulnerable to droughts, high-temperature events, and competition for water resources (Thopil & Pouris, 2016).

OTC is not without environmental impact issues. Withdrawal of water can cause impingement and/or entrapment and mortality of fish and shellfish on intake screens, while smaller organisms (e.g. small eggs, larvae, juvenile fish, and shellfish) can pass through intake screens and enter a plant's cooling system, where they can experience a high mortality rate due to the thermal and physical stresses. The discharge of heated water can also lead to negative environmental impacts on the aquatic community, including habitat.

Recirculating cooling systems can reduce impingement and entrainment by as much as 90% or more, but their cost can make the option problematic for some power plants. Less costly protection technology alternatives (e.g. fish-friendly traveling water screens including fine mesh, barrier nets, velocity caps, behavioural deterrence, wedge wire screens) can attain similar performance depending on site-specific hydraulic, biological, and plant operating characteristics (Bushart, 2014).

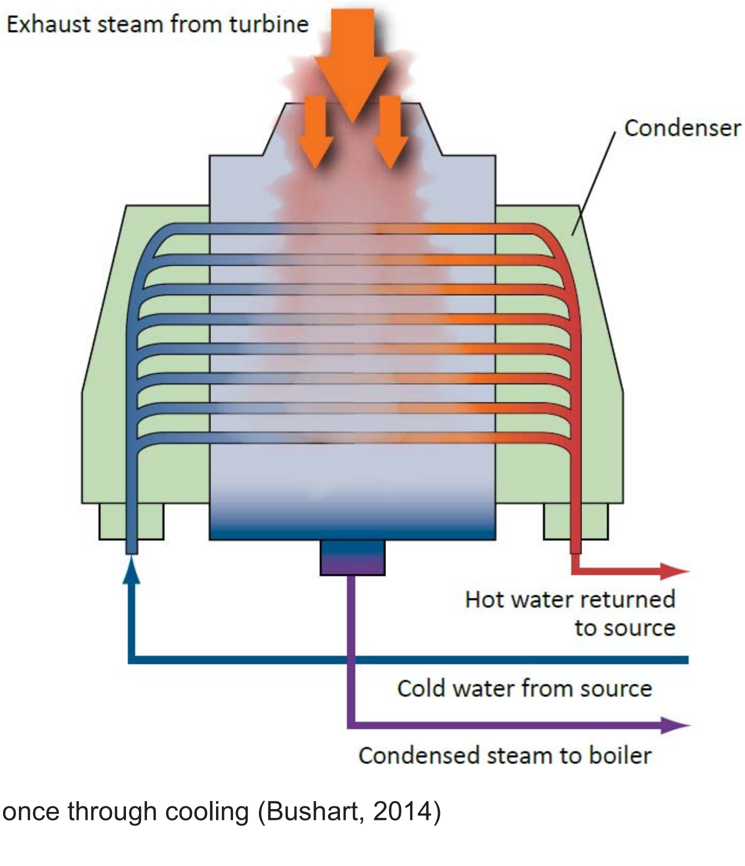


Figure 2: Water flow in once through cooling (Bushart, 2014)

3.3.2 Recirculated Wet (Closed-Loop) Cooling

While once-through cooling relies on the high thermal capacity of water, closed-loop cooling relies on the high-energy requirements of water evaporation. Recirculated wet cooling is like OTC in that cold water flows through the tubes of a steam condenser and steam condenses on the outside of the tubes. However, instead of being returned to the source, the heated water leaving the condenser is pumped to a cooling device such as a tower, pond, or canal, where it is cooled by evaporation of a small portion of the water. The cooled water is then recirculated back to the condenser tube inlets (Figure 3). Cooling towers involve 95% less water withdrawal than OTC systems, however, approximately 85% of the total quantity of water supplied evaporates through the open cooling towers. Additional water is lost through blowdown (i.e. removal of a fraction of the recirculating water to manage the mineral content), and drift (i.e. less than 0.0005% of the water is lost as droplets are entrained and carried out of the tower) (Bushart, 2014). The water source can be from the ocean, a lake, a river, a cooling pond or a canal. Due to stringent regulations concerning open-loop cooling, closed-loop cooling has become the technology used since the 1970s (Thopil & Pouris, 2016). Most of the Eskom's coal fired power stations are cooled through a conventional re-circulating system in which cooling takes place via evaporation in an open cooling tower. Typically, the cooling water is led through heat exchanger(s) systems and is cooled by contact with an airstream in a cooling tower where most of the heat is discharged to the environment through evaporation.

As a result of evaporation, windage and drift the cooling water systems must be supplemented. Evaporation causes a concentration of salts in the cooling water recycle process, which in turn limits the recycle volumes. To overcome this, Eskom practices alkalinity control of the cooling water, using acid neutralisation (at two plants) or cold lime softening by precipitation (at six plants). By controlling and optimising these processes cooling water effluent volumes are minimised (AEA, 2013).

Water consumption of wet cooled is bound to increase based on current trends. This can be mainly attributed to the decreasing efficiency of wet cooled power plants. Suggested measures to increase efficiency include actions such as coal and air flow optimisation, heat loss recovery, coal drying and improved coal quality (Thopil & Pouris, 2016).

Although water withdrawal is reduced, recirculated wet cooling systems have several cost- and energy efficiency-related disadvantages compared to OTC: 1) capital costs are typically twice as much as OTC, 2) they typically have higher parasitic load for the fans, and 3) they have a potential for power generation capacity reductions on hot days (Bushart, 2014).

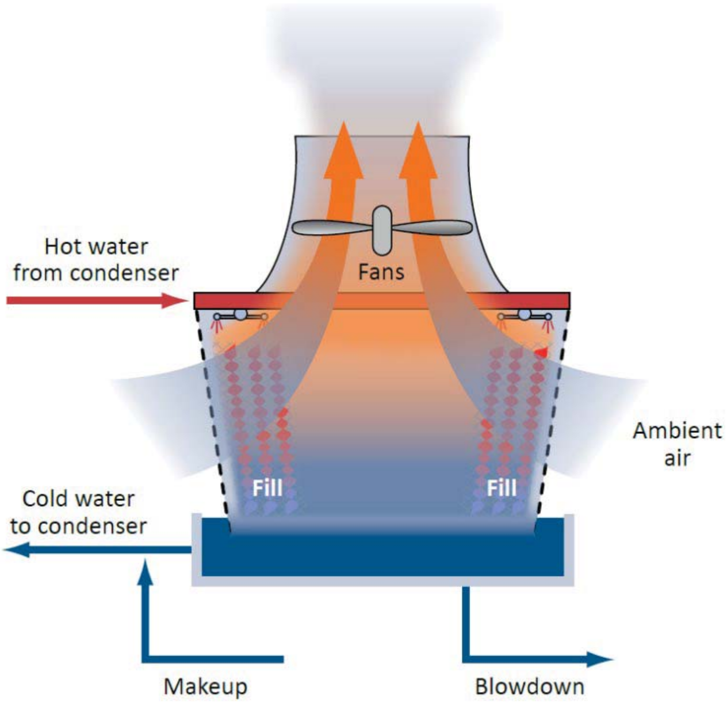


Figure 3: Water flow in a wet cooling tower (Bushart, 2014)

3.3.3 Dry Cooling

Dry cooling systems are very similar to closed-loop systems, but air replaces water to cool the circulating cooling fluid, thus eliminating water withdrawal and consumption. However, this greatly impacts plant efficiency due to a lower thermodynamic theoretical maximum (Carnot cycle) and high electricity use for powering the massive fans used in cooling (Thopil & Pouris, 2016). Dry cooling systems can be either direct or indirect. Direct dry cooling systems condense turbine exhaust steam in an air-cooled condenser (ACC) (Figure 4). Indirect dry cooling systems utilize a cooling water loop to condense turbine steam in a conventional surface condenser or a contact condenser (i.e. Heller system). The cooling water, which has been heated by the condensing steam, is then recirculated to an air-cooled heat exchanger before being returned to the condenser (Bushart, 2014).

The condensing temperature, in the case of direct dry cooling, or the cold-water temperature, in the case of indirect dry cooling, is impacted by the ambient temperature and humidity and dry cooling will perform less well than wet cooling, particularly in hot and dry climates where the use of such technologies is most desirable. The average loss of output is about 2% annually but can be as high as 25% at the peak of summer when demand is at its highest and when the steam condensing temperature (and hence the turbine exhaust pressure) is substantially higher than it would be with wet cooling. Although dry cooling achieves significant water savings, the capital cost of such a system is about 10 times more than that of an open-loop system. Dry cooling systems are more expensive than conventional wet cooling techniques when considering the infrastructural investments required.

Water consumption factor forecasts of dry cooled power plants (ranging from 0.1 l/kWh to 0.15 l/kWh) are expected to be one order of a magnitude lower than wet cooled power plants (ranging from 2.2 l/kWh to 2.4 l/kWh) (Thopil & Pouris, 2016).

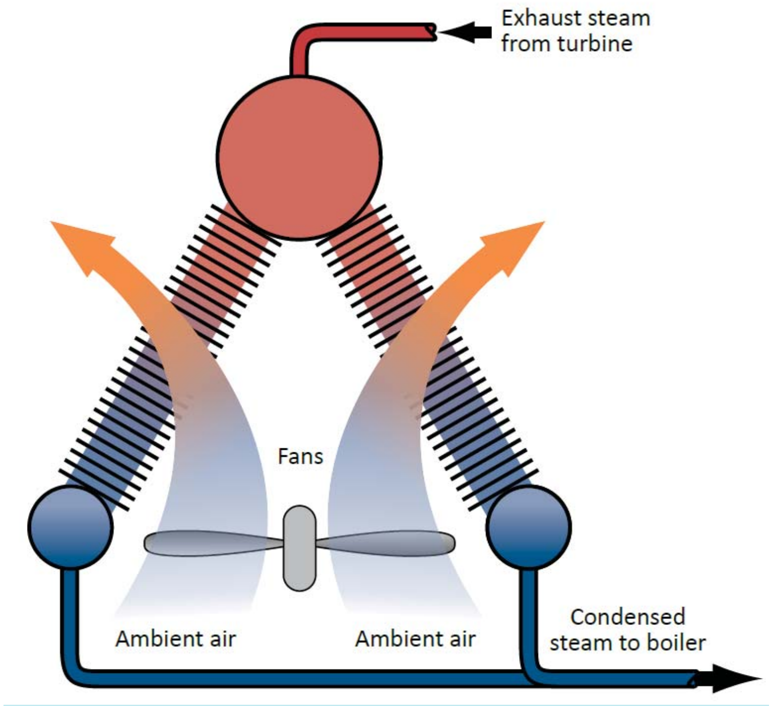


Figure 4: Direct dry cooling (Bushart, 2014)

3.3.4 Hybrid Cooling

Hybrid cooling technology uses a combination of wet and dry cooling systems, where wet and dry cooling components can be used either separately or simultaneously. This way, the system can operate both the wet and dry components together or rely only on dry cooling to avoid water use, economically reducing water requirements of the wet systems by up to 80%. Hybrid cooling uses bundles of cooling elements arranged in concentric rings inside the cooling tower. Heat is conducted from the warm water by these cooling elements, which have cool water flowing through them. Cooling water that flows through the elements is then cooled down by cold air passing over and then returned to the condenser (Figure 5). This system is referred to as a closed system since there is no loss of water due to evaporation. Dry cooling techniques differ in the respect that heat exchange occurs between hot steam leaving the turbine blades and a heat exchanger. Air passing through the exchanger is supplied by multiple electrical fans. The heat forms steam that is removed by the air within the exchanger thereby condensing the steam back into water. (Thopil & Pouris, 2016).

Capital costs for hybrid cooling systems usually fall midway between recirculated wet and dry cooling systems, and significant amounts of water may still be needed, particularly during the summer. A hybrid system will also be subject to all of the operation and maintenance issues of both cooling systems (e.g. fan power, blowdown, cooling water treatment, freeze protection). Therefore, it is most suitable for sites where conservation is required, but some water is still available for partial evaporative cooling to shave hot-day efficiency penalties (Bushart, 2014).

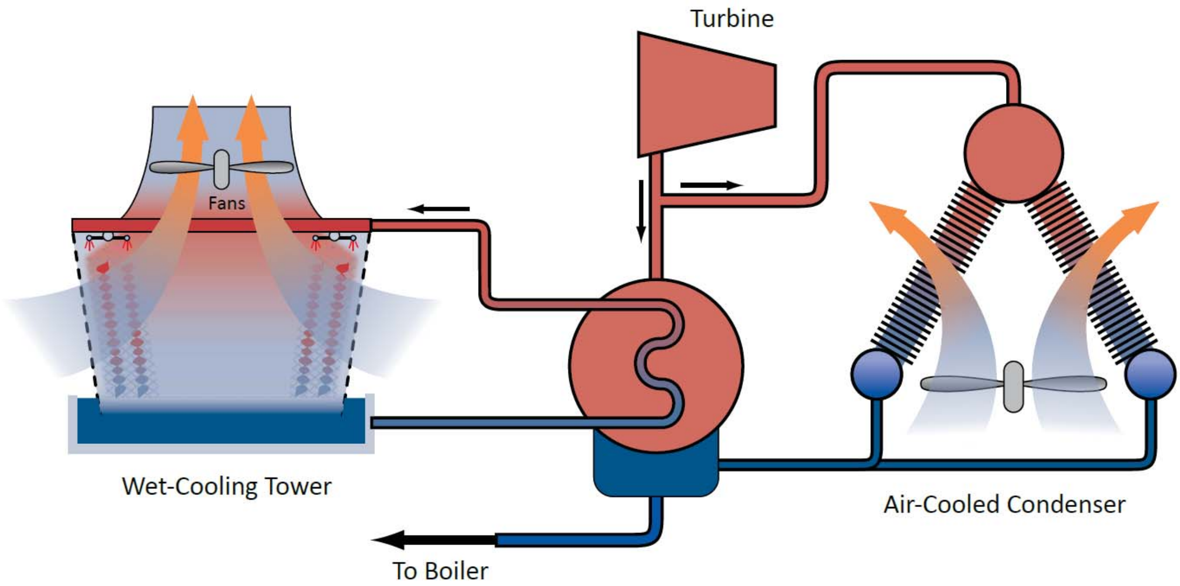


Figure 5: Hybrid cooling (Bushart, 2014)

3.3.5 Effect of climate on cooling

The climate of the region in which the power station is situated has a large impact on the cooling system efficiency. While wet cooled stations may be more water intensive, these systems may also require smaller heat exchangers than dry cooled stations. In areas with high ambient temperatures very large heat exchangers, usually more than double the size of wet cooled exchangers are required for sufficient cooling in dry cooled systems. The cooling heat capacity of water is 4.186 kJ/kg, whereas for air it is only a quarter of this at 1.1 kJ/kg of air.

The impact of climate change as areas become hotter will have an impact on the cooling efficiency of the heat exchangers of both wet and cooled plants. In wet cooled plants this may result in greater water use to maintain the same cooling efficiency, whereas in dry cooled plants an increase in ambient air temperature will impact the thermal power generation capacity. Local climate affects the amount of water evaporated for a given cooling load. In warm humid environments, cooling towers must be larger and will use more fan power than would be the case at drier sites to reject the same heat load while achieving the same cold-water temperature. Under humid conditions, the fraction of heat transferred to the atmosphere by evaporation is less than it would be in a hot, dry climate-perhaps as low as 70-75%, as opposed to 85-90% for drier climates. (Hensley, 2006) This can result in a difference in the water consumption rate of 0.227-0.454 l/kWh between the two sites.

Cooling towers reject heat to the environment both by evaporation (latent heat transfer) and by convection (sensible heat transfer) from the hot water to the cooler air. The portion of the heat load transferred by evaporation and, hence, the water consumption rate of a cooling tower for a fixed heat load is greater (~85 to 90%) in dry conditions than in humid conditions (~70 to 75%). Therefore, cooling water requirements for similar power plants can differ substantially from site to site.

3.3.6 Source water quality impacts

The use of lower quality source water inevitably increases the total amount of water that must be taken into the plant, due to the need to treat the water prior to use, either before it reaches the plant or inside the plant boundaries. All treatment processes generate a reject brine stream in addition to the product water; this typically increases the make-up requirements by 25-35%.

For most uses, this is not a major issue. However, for cooling towers, the use of high salinity make-up, such as seawater or saline groundwater, can dramatically increase the make-up requirements. Cooling tower blowdown is required for all towers to maintain circulating water quality within acceptable limits. For good quality make-up, towers are typically run between 5-10 cycles of concentration (cycle of concentration is the ratio of the concentration of the blowdown to that of the make-up water). Higher cycles might be possible, but water savings reach a point of diminishing returns at cycles above 10. Seawater make-up, however, limits the cycles of concentration to 1.4 to 1.6. (Maulbetsch, 2010) The make-up water requirements increase dramatically at these low cycles of concentration. This is discussed further in section 0.

4 Water use in electricity production in South Africa

Water resources are under considerable pressure in South Africa with concerns including the growing water scarcity and the conflicting demands for the right to use water, the lack of access to water to meet basic human needs, depleted environmental flows, population and economic growth and the implications of climate change. 2030 projections depict a net deficit of around 2.7 billion m^3, increasing to 3.8 billion m^3 under plausible climate changes scenarios.

Thermoelectric power generation is a broad category of power plants consisting of coal, nuclear, oil, natural gas, and the steam portion of gas-fired combined cycles. Thermoelectric generation represents the largest segment of electricity production in several countries including South Africa. Water is a critical resource in the operations of all thermoelectric power generation, accounting for around 2% of South Africa's national freshwater resources (AEA, 2013). While only using 2% of water resources (Figure 6), power generation represents about 15 percent of gross domestic product (GDP). Eskom is classified as a Strategic Water User with high assurance of water supply (>99.5%). Many of the country's inter-basin transfer (IBT) schemes were developed specifically to supply water to power plants.

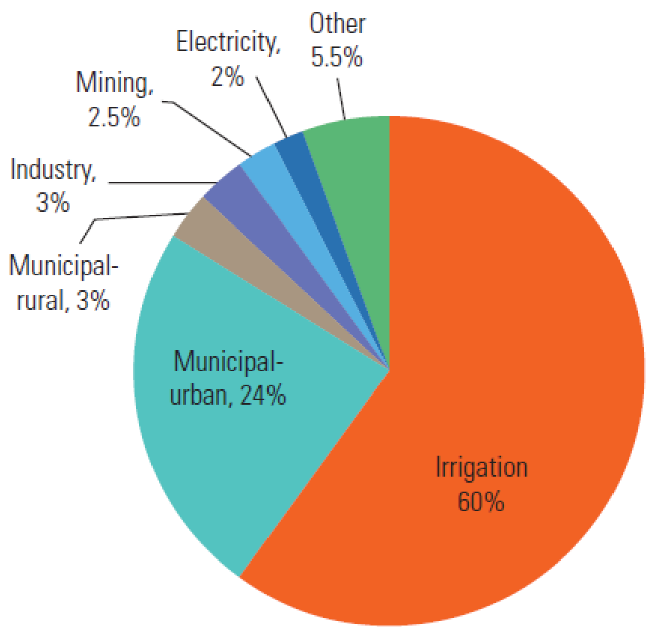


Figure 6: Estimate of water use, by sector (DWAF, 2004)

4.1 Coal-based power generation

As discussed in Section 3.1, South Africa has 13 coal power plants of which ten are base load power plants while three are return to service power plants used for peak demand times, with two New Build stations. The current fleet of coal power plants use a combination of technologies for cooling (Table 5). Of the 10 existing base load coal power plants, eight use wet recirculation cooling technologies while three (Kendal, Majuba and Matimba) use combination wet circulation cooling and dry cooling approaches. The two New Build stations, Medupi and Kusile, make use of direct dry cooling. Of the three return to service stations, Camden and Komati make use of wet recirculation cooling, while Grootvlei uses a combination of wet recirculation for four units, and dry recirculation for two units.

Including the dry-cooled units of the Majuba and Grootvlei plants, which have both wet- and dry-cooled units, the existing net capacity of dry cooled units is approximately 9,700 MW. This accounts for about 30 percent of Eskom's coal plant stock. The commissioning of the Medupi and Kusile plants would increase the contribution of dry-cooled net capacity to approximately 18,000 MW, approaching 50 percent of Eskom's coal-based capacity. As in the case of the Kusile and Medupi plants, all new power plants are to feature supercritical design (World Bank, 2017).

Eskom's power stations are concentrated mainly in three water management areas: Upper Olifants River Water Management Area, Upper Vaal River Water Management Area and Limpopo Water Management Area (Table 5). Water is sourced from several dams in and around these water management areas and supplied to the power stations through a network of pipelines and pumping systems (see Section 4.1.1). The sourcing of water is based on the quantity needed and the quality; raw water quality in the power generation process needs to be better than that sourced for potable production required for domestic use. Approximately 97% of this water is used at wet cooled power stations which are more susceptible to water quality impacts. These quality impacts eventually translate into using a larger quantity of water. Other water uses include steam generation, ashing, washing and air emission and abatement. Water use per station for the 2013/2014 year is presented in Table 5.

Table 5: Cooling techniques employed by Eskom's coal fired plants, water use per station for 2013/2014, and relevant Water Management Area (World Bank, 2017)

Category	Power Station	Cooling technique	Raw water use (l/kWh)	Boiler water use (l/kWh)	Water Management Area	Interior Climate Zone
Base load	Arnot	Wet recirculating	2.22	0.157	Olifants	Cold
	Duvha	Wet recirculating	2.2	0.062	Olifants	Cold
	Hendrina	Wet recirculating	2.61	0.231	Olifants	Cold
	Kendal	Indirect dry	0.12	0.07	Olifants	Cold
	Kriel	Wet recirculating	2.38	0.12	Olifants	Cold
	Matla	Wet recirculating	2.04	0.077	Olifants	Cold
	Matimba	Direct dry	0.12	0.02	Limpopo	Hot
	Lethabo	Wet recirculating	1.86	0.076	Upper Vaal	Cold
	Majuba	Wet recirculating (3 units) and direct dry (3 units)	1.86 (wet)[a] 0.12 (dry)	0.076 (wet)[a] 0.02 (dry)	Upper Vaal	Cold
	Tutuka	Wet recirculating	2.06	0.097	Upper Vaal	Cold
Return-to-service	Camden	Wet recirculating	2.31	0.078	Upper Vaal	Cold
	Grootvlei	Wet recirculating (4 units) and indirect dry (2 units)	1.71	0.18	Upper Vaal	Cold
	Komati	Wet recirculating	2.49	0.105	Olifants	Cold
New Build	Medupi	Direct dry	0.12[b]	0.02[b]	Limpopo	Hot
	Kusile	Direct dry	0.12[b]	0.02[b]	Olifants	Cold

[a] From Lethabo

[b] Estimated from Matimba

Eskom has developed and is implementing a comprehensive water strategy for all coal-fired power stations, which is based on maintaining their strategic user status and complying with applicable legislation. All power stations have developed water strategy implementation plans, focusing on actions to reduce water use and ensure compliance. The net raw water consumption and specific water consumption by power stations for 2013/2014 to 2018/2019 is presented in Table 6, and the relevant targets in Table 7. From 2014/2015 to 2016/2017 the specific water consumption increased above Eskom's target of 1.35 l/kWh, but this reduced to 1.3 l/kWh in 2017/2018. Unfortunately, the good progress made in 2017/2018 was not realised over the 2018/2019 year with a specific water consumption of 1.41 l/kWh, mainly due to both financial and power system constraints. Specific water use for the generation of electricity for the 2018/2019 year was worse than the target of 1.36, due to:

- Poor water management practices and operational inefficiencies at power stations due to water leaks, water wastage through overflowing tanks, low load factors, several unit trips and boiler filling
- Slow implementation of water strategy action plans aimed at addressing poor water management practices at the stations.

Water management cuts across many areas of the plant, and therefore more efficient use of water will be achieved by improved planning, maintenance, and operations at all of Eskom's power stations.

The total annual water cost for 2018/2019 was R2 142 446 860.48.

Table 6 Eskom water consumption from 2013/2014 to 2018/2019

	2013/2014	2014/2015	2015/2016	2016/2017	2017/2018	2018/2019
Net Raw water consumption (Ml)	317 052	313 078	314 685	307 269	276 335	292 344*
Specific water consumption by power stations (l/kWh distributed)	1.35	1.38	1.44	1.42	1.3	1.41*
Total Nominal Power Station Capacity (MW)	41 995	42 090	42 810	44 134	45 561	44 172

*Medupi Units 4 and 5 and Kusile Unit 1, having completed their first year after commissioning, have been included in the calculation of KPIs for 2018/19.

Table 7 Eskom water consumption targets from 2013/2014 to 2018/2019

	Actual 2016/2017	Actual 2017/2018	Actual 2018/2019	Target 2018/2019	Target 2019/2020	Target 2021/2022
Specific water consumption by power stations (l/kWh distributed)	1.42	1.30	1.41	1.36	1.35	1.33
Net Raw water consumption (Ml)	307 269	276 335	292 344*	n/a	n/a	n/a

4.1.1 Water supply to the coal fired power stations

Water for Eskom's coal fired power stations is sourced from several dams and supplied to the power stations through a series of supply schemes, as illustrated in Figure 7. The relevant supply scheme supplying each station, together with the system yield and transfer capacity is presented in Table 8.

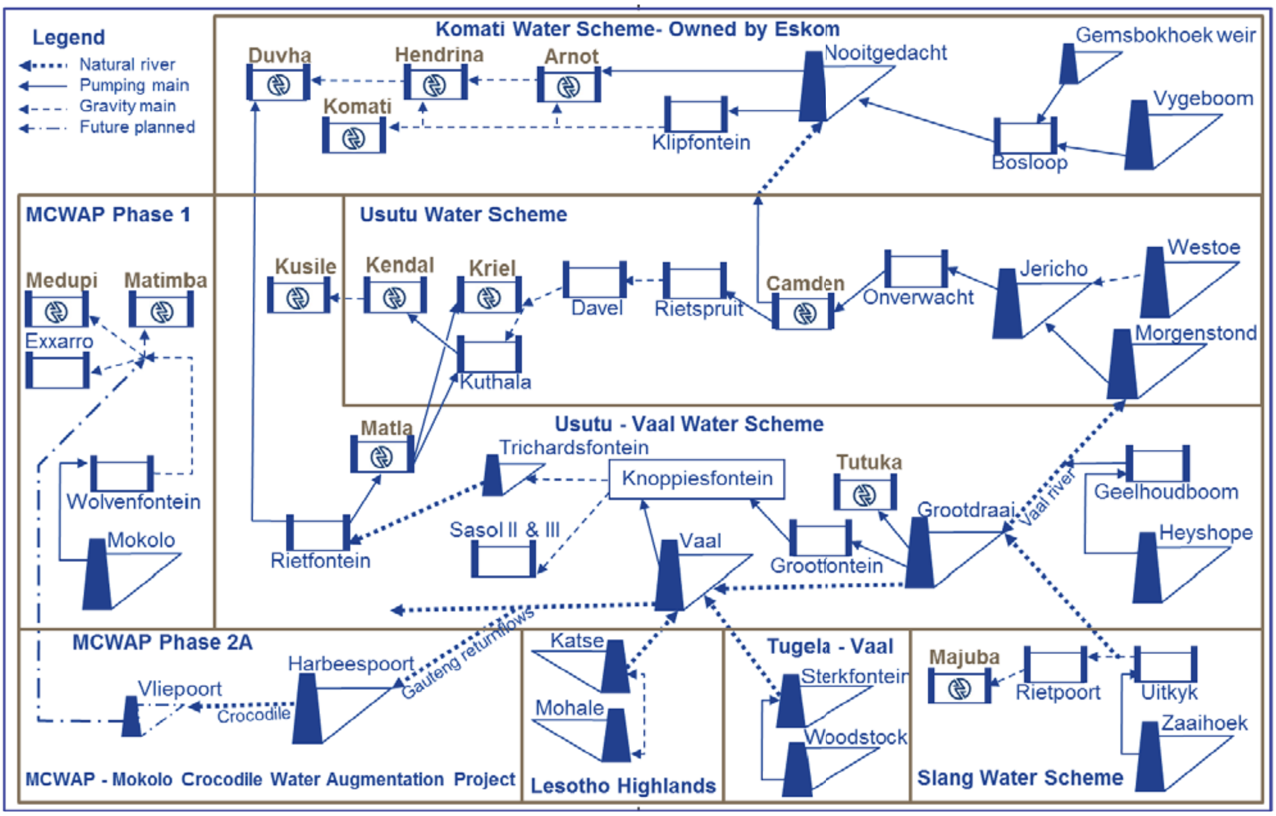


Figure 7: Eskom water supply schemes

Table 8: Water schemes per power station

<table>
<tr><th>Water User</th><th colspan="2">Water Scheme</th><th>System Yield M(m³)/a</th><th>Transfer Capacity M(m³)/a</th><th>Eskom Licence M(m³)/a</th></tr>
<tr><td>Arnot
Duvha*
Hendrina
Komati</td><td rowspan="5">Vaal River Eastern Sub-System</td><td>Komati</td><td>92 (86)</td><td>118</td><td rowspan="5">360.3</td></tr>
<tr><td>Camden
Kriel*
Kendal*
Kusile*
Transfer to Komati</td><td>Usutu</td><td>66</td><td>104</td></tr>
<tr><td>Tutuka
Matla
Kriel*
Duvha*
Kendal*
Kusile*</td><td>Usutu-Vaal Phase 1</td><td>119</td><td>172</td></tr>
<tr><td>Heyshope to Grootdraai
Heyshope to Usutu</td><td>Usutu-Vaal Phase II</td><td>52</td><td>148</td></tr>
<tr><td>Majuba
Transfer to Grootdraai</td><td>Slang</td><td>45</td><td>76</td></tr>
<tr><td rowspan="2">Lethabo
Grootvlei</td><td colspan="2" rowspan="2">Vaal</td><td rowspan="2">N/A</td><td></td><td>53</td></tr>
<tr><td></td><td></td></tr>
<tr><td>Matimba
Medupi</td><td colspan="2">MCWAP Phase 1</td><td>16</td><td>30</td><td>14.5</td></tr>
</table>

* Power Stations with more than one source of water supply

4.1.1.1 Vaal River Eastern Sub-System (VRESS)

The Vaal River Eastern Sub-System (VRESS) supplies water to eleven of Eskom's power stations and is part of the Integrated Vaal River System (IVRS). The following water schemes within this sub-system supply water to Eskom:

- Komati Water Scheme (KWS)
- Usutu Government Water Scheme (UGWS)
- Usutu-Vaal Government Water Scheme Phase 1 & 2 (UVGWS)
- Slang Water Scheme

These schemes have over the years been interconnected and at present almost function as one big scheme (Figure 7, Table 8). Although the Department of Water and Sanitation (DWS) still determines and makes use of scheme specific yields when modelling the system, only the combined yield of the system is considered. The VRESS is supported by a pipeline link from the Vaal Dam and is called the Vaal River Eastern Sub-System Augmentation Project (VRESAP). The VRESAP can transfer a maximum of 160 Million m^3 per annum ($M(m^3)/a$) and is used as the primary support for the UVGWS and links the VRESS with the important water supply from the Lesotho Highlands Water Project. This pipeline also allows DWS to do maintenance on the Vlakfontein canal.

Eskom has a bulk water use licence on the VRESS of 360.3 M(m^3)/a. This licence includes 11 power stations and also possible future use of water at the Underground Coal Gasification (UCG) plant near Majuba. The licence is valid until 31 October 2025 and can be reviewed on a 5-year interval.

4.1.1.1.1 *Komati Water Scheme*

The Komati Water Scheme consists of Nooitgedacht and Vygeboom Dams on the Komati River. Vygeboom Dam is supplemented with water from the adjacent Gladdespruit, where a weir diverts water into a canal, from where it flows into the Vygeboom Dam. The KWS supplies water to Komati, Hendrina, Arnot and Duvha Power Stations, The Nooitgedacht and Vygeboom Dams as well as the Gemsbokhoek weir were constructed by DWS to provide for the requirements of these power stations. Water is pumped from Vygeboom Dam to Bosloop / Gemsbokhoek weir from where it is pumped further to Nooitgedacht Dam. Two pump stations, Wintershoek and Nooitgedacht, pump the water via five pipelines to the four power stations.

The system was designed to only supply part of the water requirement of Duvha Power Station. The rest would be supplied from the Usutu-Vaal Scheme from Grootdraai dam via Trichardsfontein dam to Witbank Dam. From Witbank Dam the water is then pumped via Naauwpoort pump station to Duvha. Due to the water from Grootdraai being polluted along the way, a new pipeline was constructed by DWS to transfer water from Rietfontein directly to Duvha. This project is called the Komati Water Scheme Augmentation Project (KWSAP) and normally supplies 45% of Duvha’s water requirements. It can also supply Duvha’s full requirements during maintenance on the Hendrina Duvha pipeline.

The combined yield of the KWS is 92 M(m^3)/a with a total supply capacity to the power stations of 117 M(m^3)/a. The KWS is also supported from the Usutu Scheme with the Camden to Lillyput pipeline (UK Link). This pipeline supplies water into the upper reaches of the Boesmanspruit that is a tributary of the Komati River and flows into Nooitgedacht Dam. The transfer capacity on the UK Link is 30 M(m^3)/a.

4.1.1.1.2 *Usutu Government Water Scheme (UGWS)*

The Usutu Government Water Scheme consists of the Westoe Dam on the Usutu River, Jericho Dam on the Mpama Spruit, Morgenstond Dam on the Ngwempisi River and the Churchill diversion weir on the Bonnie Brook. The Eskom users are mainly Camden and Kriel Power Stations, but water can also be supplied to Matla, Kendal and Kusile Power Stations. It also supplies water to the towns of Ermelo, Davel and Kriel. Water can also be transferred to the Komati Sub-system via the UK Link.

Water is transferred under gravity from Westoe Dam and pumped from Morgenstond Dam into Jericho Dam. From Jericho Dam water is pumped to Onverwacht reservoirs on the catchment divide and then flows to Camden Power Station. Transfer to the Usutu system is also possible from the Heyshope Dam via Morgenstond Dam (see section 4.1.1.1.4).

Camden Power Station supplies water on two supply links: Camden to Kriel and Camden to Lillyput (UK Link). The pump station consists of three pumps that are normally used with two duty and 1 standby configuration. This mode of operation is however difficult to achieve over long periods due to supply constraints from Jericho. When pumping to Nooitgedacht, Usutu supply to Kriel is stopped except for short periods of pumping to keep Rietfontein and Davel reservoirs full for third party use.

Kuthala pump station takes water from the Matla reservoirs (Usutu-Vaal) or directly from the Kriel (Usutu) pipeline from where water is pumped to Kendal Power Station reservoirs. From Kendal reservoirs the water is also distributed to Kusile Power Station with a new gravity feed pipeline.

The combined yield of the UGWS is 69.1 M(m^3)/a with a total supply capacity from Jericho of 104 M(m^3)/a. The Usutu system can be supported from the Heyshope dam up to 44 M(m^3)/a.

4.1.1.1.3 *Usutu-Vaal Government Water Scheme (UVGWS) Phase 1*

Grootdraai Dam is the primary storage in the UVGWS Phase 1. It supplies water to the Tutuka Power Station directly through a dedicated pump station and pipeline. It also supplies water to Matla, Kriel, Kendal, Kusile and Duvha power stations for Eskom and the Sasol plants in Secunda via the Grootdraai pump station.

Grootdraai pump station pumps water to Knoppiesfontein diversion via the Vlakfontein canal and Grootfontein pump station. The VRESAP pipeline from Vaal Dam also delivers water at Knoppiesfontein (see section 4.1.1.2).

From Knoppiesfontein water is diverted between Eskom and Sasol. The Sasol water flows to Bossiespruit dam close to Secunda and the Eskom water flows to Trichardsfontein dam next to the town of Trichard. Trichardsfontein dam also provides approximately 30 days of storage for Eskom. This reduces water supply risk to the power stations supplied from the UVGWS. From Trichardsfontein water flows to Tweedraai dam, a flood control dam operated by Sasol. After Tweedraai dam the water is diverted in a canal with the Syferfontein pump station, also operated by Sasol from where is flows into Rietfontein weir.

Rietfontein consists of a weir and three pump stations. Two pump stations supply water to the Matla reservoirs from where the water is distributed to Matla, Kriel Kendal and Kusile power stations. It also supplies water to Duvha Power Station through the new KWSAP pipeline (see section 4.1.1.1.1).

4.1.1.1.4 *Usutu-Vaal Government Water Scheme (UVGWS) Phase 2*

UVGWS Phase 2 consists of Heyshope Dam, Heyshope pump station that pumps water into the Heyshope canal. The water flows to Geelhoutboom from where it is pumped into the Balmoral canal. From the Balmoral canal water gets diverted to Morgenstond Dam for the UGWS and it also flows into the Klein-Vaal River that ends up in Grootdraai Dam.

Heyshope dam is the primary support for the UVGWS and the UGWS and can add a total yield of 113 M(m^3)/a. The required transfer is determined on an annual basis during the Vaal River System: Annual Operating Analysis process.

The total infrastructure capacity from Heyshope Dam is 148 M(m^3)/a with 44 M(M^3)/a to the UGWS if required.

4.1.1.1.5 *Slang Water Scheme*

The Slang Scheme consists of Zaaihoek Dam and pump station and supplies water to Majuba Power Station and is also a secondary support for Grootdraai Dam (UVGWS). It has a total yield of 61.4 M(m^3)/a with 32 M(m^3)/a required for Majuba. Water is pumped from Zaaihoek to Uitkyk reservoir from where it gravity feeds to Rietpoort reservoir and then to Majuba.

Water can be transferred to the UGWS by releasing water into the Perdewaterspruit from the pipeline between Uitkyk and Rietpoort reservoirs.

4.1.1.2 Vaal Dam

The Vaal Dam supplies water directly to Grootvlei Power Station and Lethabo Power Station. It also supports the UVGWS with the Vaal River Eastern Sub-System Augmentation Project (VRESAP).

Water to Grootvlei is pumped from the Vaal dam via a low lift and high lift system. The infrastructure capacity is 22 M(m^3)/a. The pump stations and pipeline are owned and operated by Eskom.

Water to Lethabo Power Station is pumped from the Lethabo Weir in the Vaal River. This weir is downstream of the Vaal dam from where water is released. The pumping system is owned and operated by Rand Water. The infrastructure capacity to Lethabo is 64 M(m^3)/a.

The VRESAP was implemented to meet the growing water demands of Eskom and Sasol. The scheme transfers water via a 115 km long pipeline from the Vaal Dam, near Vaal Marina, to Knoppiesfontein Diversion Structure which discharges the water either into Trichardtsfontein (Eskom) or Bosjesspruit (Sasol) dams. The system consists of an intake, pump, and pipeline system and has a transfer capacity of 160 M(m^3)/a.

4.1.1.3 Mokolo and Crocodile West Water Schemes

The Mokolo Water Scheme was commissioned in 1980 and consists of the Mokolo Dam with a pump station and pipeline system, to supply water to Matimba Power Station, Grootgeluk Mine and the town of Lephalale. With the construction of Medupi Power Station, Phase 1 of the Mokolo Crocodile West Augmentation Project (MCWAP) was constructed to increase the capacity from Mokolo Dam. This included a new pump station and an additional pipeline and currently supplies Matimba, Medupi, Grootgeluk Mine and the town. The Mokolo Scheme is now incorporated into the MCWAP Phase 1.

The system would in future not be able to supply the full requirements of all the users. Negotiations are currently underway to implement an augmentation scheme from the Crocodile River. This project is called the MCWAP Phase 2b and will after completion include the MCWAP Phase 1. The Crocodile River receives return flows from many Gauteng effluent treatment plants that will be used by Medupi and other users. This will effectively link the MCWAP with the IVRS.

4.1.2 Water supply risks

Despite Eskom being classified as a Strategic Water User, the ability to meet this assurance is at risk in the medium to long term due to:

- Competing interests, increasing water demands and growing water deficits, illegal water use, water losses, and climate change impacts.
- Inadequate maintenance and reliability of water supply infrastructure.
- Pollution of water resources making water unusable or driving up costs of treatment and waste management
- Internal water management practices

Water supply to South Africa’s coal-fired stations is not considered to be at risk over the short to medium term due to healthy dam levels. However, the Department of Water and Sanitation is experiencing severe financial constraints, which may affect its ability to manage existing and implement new bulk water infrastructure to ensure water security to Eskom.

The Department of Water and Sanitation (DWS) has reported that engineering work has commenced on the Lesotho Highlands Water Project Phase 2, which is now scheduled to be commissioned by 2025. Until then, water availability in the Vaal River system will remain at risk, with dam levels in the Vaal River system declining. DWS is implementing various initiatives to mitigate against future water security risks in the integrated Vaal River system.

To assist with water security in Gauteng, Eskom committed in 2017 to use the Drakensberg Pumped Storage Scheme to pump at least 285 million cubic metres of water per year over three years from the Thukela River into the Sterkfontein Dam, which feeds into the Vaal River System. However, due to DWS infrastructure challenges this could not occur during the 2018/2019 year. Nevertheless, Eskom will continue to make the Drakensberg Pumped Storage Scheme available to allow for this when needed.

Medupi Power Station's flue gas desulphurisation (FGD) retrofit requires additional water from the Mokolo Crocodile Water Augmentation Project (MCWAP) Phase 2 project by the revised date of June 2026, which takes account of the rework required at Medupi. The estimated water delivery from MCWAP was originally January 2024 (Eskom Holdings SOC Ltd, 2018) but this has moved out to April 2025 (Eskom Holdings SOC Ltd, 2019). Failure to commission the FGD plant within the agreed timelines may render Eskom in breach of World Bank loan agreements and their emission licence, which would result in the units not being able to operate (Eskom Holdings SOC Ltd, 2018).

4.1.2.1 Impact of climate change on water supply

With respect to climate change, Sub-Saharan Africa is thought to be one of the more vulnerable regions in the world. Although there is general agreement that temperatures will continue to rise, uncertainty surrounds the potential impact of climate change on precipitation (Schulze, 2006). Four possible scenarios have been identified by the Long-Term Adaptation Scenarios (LTAS) developed by the flagship research program of the Department of Environmental Affairs (DEA, 2013a):

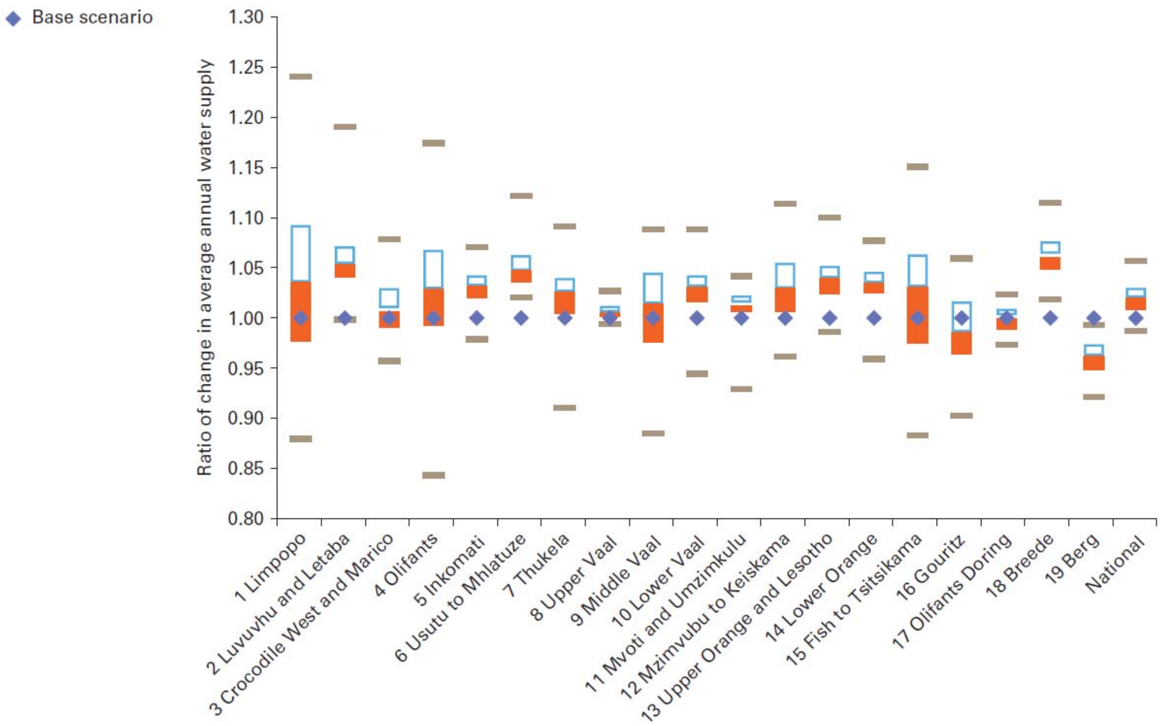
- Warmer (<3˚C above temperatures for 1961-2000) and wetter, with more frequent and extreme rainfall
- Warmer (<3˚C above temperatures for 1961-2000) and drier, with increasingly frequent drought and somewhat more frequent extreme rainfall
- Hotter (>3˚C above temperatures for 1961-2000) and wetter, with much more frequent extreme rainfall
- Hotter (>3˚C above temperatures for 1961-2000) and drier, with substantial increases in drought and somewhat greater frequency of extreme rainfall.

The LTAS concluded that temperatures will continue to rise, but the level of increase would be dependent on the outcomes from global mitigation efforts. Under a business-as-usual scenario, South Africa faces a hotter future, with average increases of >3˚C by the end of the 21st century. In the event of improved global cooperation, then significant reductions in Greenhouse gases (GHGs) will mean merely a warmer future for South Africa. For both scenarios, potential impacts would affect all regions; inland areas would experience greater increases than coastal zones and the mountains. The prevailing consensus is that drying is likely to occur in the western part of the South Africa, particularly in the southwestern Cape, while the eastern parts of the country would receive more precipitation, with some potential for seasonal shifts (DEA, 2013a).

Under both the "hotter" and "warmer" futures, precipitation remains the great unknown, although it was generally agreed that variability would increase under both scenarios; the hotter scenario would bring greater variability. Precipitation and its impacts would vary across regions. A scenario of increased precipitation in the coal supply areas could impact on the coal supply chain.

Rising temperatures are also likely to lead to higher demands from competing water users, notably agriculture (irrigation). Increasing temperatures and changing streamflow dynamics could also negatively affect water quality, already a concern for power stations and other water users in South Africa and requiring, in some cases, additional water for dilution (DWAF, 2009).

In terms of water supply, the LTAS studied the biophysical impacts across a range of climate futures, using a rainfall runoff model at a quaternary scale, as well as a water-resources yield model configured at a secondary-catchment scale for all of South Africa, including the major water-supply infrastructure, dams, and inter-basin transfers (IBTs) (DEA, 2014). These national models were used to investigate the potential impacts on water supply to the urban, industry and agriculture sectors in each water management agency (WMA), and they were used to contribute to an Integrated Assessment Model assessing the potential economic impacts of climate change at a national scale and at the level of individual WMAs. This study found that South Africa's national water supply system, highly integrated because of its IBTs and designed to deal with highly variable conditions, appears to be resilient even in the face of climate change. There will likely be a cost, however, in greater pumping rates and negative impacts on environmental flow requirements (DEA, 2013a). The potential impacts of climate change on the average annual water supply for each of the 19 WMAs according to the LTAS is shown in Figure 8.



Note: The boxes in this graph represent the upper and lower quartiles and the rectangles represent the maximum and minimum value from all model scenarios.

Figure 8: Impacts of climate change on average annual water supply, by Water Management Area (Cullis et al., 2015)

A range of possible climate futures is presented under the unconstrained emissions scenario (UCE). On average, the results show the potential for slight increases in total water supply (+2.3%) by 2050 and a range of impacts on different WMAs. For example, all scenarios show a likely reduction in the average annual water supply to Cape Town, part of the Berg WMA (WMA 19). Water supply to Gauteng (WMA 3 and 8) is not significantly impacted by climate change, primarily because of the integrated nature of the Vaal system, as well as the increase in supply as a result of the construction of the Polihali Dam in Lesotho. In short, the economic model found climate change had only a limited impact on the national economy through the water sector (DEA, 2014).

Climate change may or may not affect the availability of water for power plant cooling and other uses, but it very well could affect the efficiency of cooling through increased temperatures, which, in turn, could increase the relative benefits of wet-cooled over dry-cooled power stations. However, an analysis of the efficiency response to temperature for the new dry-cooled Medupi station showed that plant efficiency is stable for more than a three-degree rise in ambient temperature. Because these coalfired plants are in such arid environments, they have been over engineered. This is a potential area for future research, however, especially if the potential for periodically very high temperatures is considered.

In February 2018, Eskom's Koeberg Nuclear Power Station launched a mobile groundwater desalination plant to supply the station's water needs, thereby easing pressure on the City of Cape Town's water supply. The desalination plant is part of Koeberg's three-pronged water management strategy to address the current water shortages in the Western Cape, to ensure that the plant is able to provide safe and sustainable electricity. The strategy includes reducing the power station's daily water usage, storing adequate water on site and considering alternative water supplies such as ground and sea water. Koeberg can operate for about two weeks without off-site potable water. The desalination solution was therefore very important to ensure continuity of supply. Koeberg already saves about 22 billion litres of fresh water per year, as its condensers are cooled by means of sea water, which is returned to the sea after use (Eskom Holdings SOC Ltd, 2018).

Eskom's RTS power plants namely Camden, Komati and Grootvlei which are water intensive power plants are located in the severely constrained WMAs namely, Olifants and Inkomati. The RTS power plant water consumption factor and total water consumption profile are higher compared to the base load fleet primarily because of lower performance parameters, such as reduced efficiency. The gradual retirement of the RTS fleet could provide added water capacity in these WMAs. Depending on the retirement of the RTS fleet, total water requirements could be reduced by 12% to 15%. Such a measure would bring a reduction of approximately 40 gigalitres of water per annum, which is roughly the amount of water used by one of the larger wet cooled power stations such as Kriel, Tutuka, Matla or Lethabo. Retirement of the RTS fleet has to be performed in conjunction with the commissioning of New Build power plants (Thopil & Pouris, 2016).

The development of new power stations beyond Eskom's current New Build programme will need to consider the quality and availability of water resources, lead times for the development of new water supply infrastructure, as well as climate change impacts.

4.1.3 Raw water quality

Raw water qualities for 2018/2019 for the various schemes is presented below.

Table 10 Water quality for Komati Water Scheme (2018/2019)

Parameter	Komati		
	Average	Max	STDEV.P
Electrical conductivity (mS/m)	210	876	136.46
pH	7.28	9.82	1.35
Calcium as Ca (mg/l)	15	980	76.41
Magnesium as Mg (mg/l)	11	50	7.08
Sodium as Na (mg/l)	8.2	37	5.82
Potassium as K (mg/l)	3.2	8.7	1.75
M-Alkalinity as $CaCO_3$	53.05	52.1	31.46
Fluoride as F (mg/l)	0.075	0.48	0.20
Chloride as Cl (mg/l)	8.51	38.12	6.00
Ammonia as NH_3-N (mg/l)	-0.005	0.3	0.18
Boron as B (mg/l)	0.02	0.07	0.96
Nitrate as NO_3-N	-0.02	7.87	1.11
Phosphate as PO_4 mg/l	-0.09	1	0.21
Sulphate as SO_4 (mg/l)	24.28	440	56.57
Aluminium as Al (mg/l)	0.01	2.7	0.35
Iron as Fe (mg/l)	0.05	2.3	0.38
Manganese as Mn (mg/l)	-0.005	10	1.07
Chemical Oxygen Demand mg/l	11	85	14.88
Total chromium as Cr (mg/l)	-0.005	0.01	0.16
TDS (mg/l)	134.5	742	87.87
Turbidity(NTU)	3.33	295	26.93
Suspended Solids (mg/l)	15.59	836.76	106.34

Parameter	Komati		
	Average	Max	STDEV.P
Total Hardness as $CaCO_3$	72.74	420.55	55.94
Ca Hardness as $CaCO_3$ mg/l	37.46	214.79	28.01
Mg Hardness as CaCO3 mg/l	49.38	205.76	38.97
Nickel as Ni (mg/l)	-0.005	0.06	0.16
Lead as Pb(mg/l)	-0.01	-0.007	0.17
Selenium as Se (mg/l)	-2	-0.002	187.21
Strontium as Sr mg/l	0.1	0.65	0.20
TOC (mg/l)	5.59	21.1	3.68
Cyanide as CN (mg/l)	-0.025	-0.025	0.17
Cadmium as Cd (mg/l)	-0.005	-0.005	0.16
Cobalt as Co (mg/l)	-0.005	0.18	0.16
Vanadium as V (mg/l)	-0.005	0.02	0.16
Copper as Cu (mg/l)	-0.005	0.05	0.14
Zinc as Zn(mg/l)	-0.005	0.4	0.15
Anions Cal	**114.806**	**249.353**	**54.63**
Cat cal	**115.292**	**222.092**	**51.84**
Bal Cal	**-1.41**	**15.283**	**5.88**

Table 9: Raw water qualities for the Usutu Scheme (2018/2019)

Parameter	Usutu			
	Med	Min	Max	STDEV.P
pH	7.51	6.87	8.63	0.45
Conductivity (µS/cm)	95.2	34.6	643	119.77
TDS (mg/l)	59	19	322	58.76
Salinity	0.07	0.02	54.2	17.56
Temperature	19.24	15.29	33.63	4.56
ORP	134.6	-11	237	48.21

Table 10: Raw water qualities for the Usutu-Vaal Scheme (2018/2019)

Parameter	Usutu-Vaal				
	Average	Min	Max	STDEV.P	n
Ca Hardness as $CaCO_3$ (mg/l)	42.28	23.2	2825	199.28	197
$CaCO_3$ Precipitation Potential	11.65	-20.3	623.4	108.24	34
Chloride (mg/l Cl)	8.02	3.94	67.1	10.06	37
Conductivity (µS/cm)	151.70	111	1450	93.67	199
Potassium (mg/l K)	2.41	1.49	3.86	0.53	35
m-alkalinity (mg/l as $CaCO_3$)	53.18	40.4	75.7	6.76	199
Mg Hardness (mg/l as $CaCO_3$)	20.58	-2763.3	42.4	199.39	197
Sodium (mg/l Na)	7.21	5.09	9.79	1.07	36
NO_3 (mg/l N)	0.60	0	1.03	0.18	37
p-alkalinity (mg/l $CaCO_3$)	0.01	0	1.3	0.10	199
pH	7.54	6.9	8.41	0.30	199
SiO_2 (mg/l)	5.04	1	16	2.71	36
Sulphate (mg/l SO_4)	31.21	6.44	570	91.17	37

Parameter	Usutu-Vaal				
	Average	Min	Max	STDEV.P	n
Temperature	19.97	13.3	23.8	1.76	196
Total organic Carbon (mg/l)	4.52	0	17.7	1.88	77
Total Hardness (mg/l $CaCO_3$)	62.86	38.7	75.8	4.76	197
Turbidity (NTU)	6.67	0.6	50.8	5.82	199

Table 11: Water quality for the Upper Vaal (2018/2019) (within Usutu-Vaal Scheme)

Parameter	Upper Vaal			
	Average	Min	Max	STDEV.P
Alkalinity Total mg/l $CaCO_3$	106.61	-0.343	320	74.89
Aluminium as Al (mg/l)	1.85	-0.005	59	7.65
Ammonia as N (mg/l)	1.94	-0.005	40	6.22
Arsenic as As (µg/l)	-0.85	-1	2.7	0.60
Calcium as Ca (mg/l)	36.91	6.56	320	46.14
Cadmium as Cd (mg/l)	-0.01	-0.005	-0.005	0.00
Chloride as Cl (mg/l)	23.02	1.1	110	19.18
Cyanide as CN (mg/l)	-0.03	-0.025	-0.025	0.00
Chemical Oxygen Demand mg/l	15.39	-1	75	16.85
Conductivity (µS/cm)	515.73	102	4083	557.69
Cobalt as Co (mg/l)	0.02	-0.005	0.88	0.12
Total chromium as Cr(mg/l)	0.00	-0.005	0.03	0.01
Copper as Cu (mg/l)	0.01	-0.005	0.2	0.02
DOC (mg/l)	8.76	1.53	38.8	5.07
Iron as Fe (mg/l)	1.90	-0.005	54	6.41
Fluoride as F (mg/l)	0.16	-0.03	1.54	0.22
Mercury as Hg (µg/l)	-1.00	-1	-1	0.00
Potassium as K (mg/l)	6.06	1.49	26	4.04
Magnesium as Mg (mg/l)	22.09	3.16	190	27.94
Manganese as Mn (mg/l)	0.94	-0.005	24	3.22
Sodium as Na (mg/l)	30.68	5.4	175.7	27.07
Nickel as Ni (mg/l)	0.07	-0.005	8.87	0.68
Nitrate as N (mg/l)	0.91	-0.02	13.38	2.33
Oxygen Absorbed as O_2 (mg/l)	2.92	0	14.4	2.15
Lead as Pb (mg/l)	-0.01	-0.01	0.02	0.01
pH @ 25°C	7.30	2.62	9.04	1.26
Phosphate as PO_4 mg/l	0.75	-0.005	8.34	1.75
Ortho Phosphate as PO_4 mg/l	0.46	-0.09	29	2.32
Antimony as Sb (mg/l)	0.00	-0.005	0.04	0.01
Selenium as Se (µg/l)	-1.88	-2	6.5	0.95
Sulphate (mg/l)	125.19	2.64	2190	316.16
Strontium as Sr mg/l	2.79	0.008	270	25.96
TDS (mg/l)	338.73	54	4437.7	472.72
TOC (mg/l)	10.52	1.83	75.1	9.10
Ca Hardness as $CaCO_3$ mg/l	92.18	16.38	799.2	115.23
Mg Hardness as $CaCO_3$ mg/l	87.60	13	781.89	104.07
Total Hardness as $CaCO_3$ mg/l	182.98	29.38	1548.17	229.25

Parameter	Upper Vaal			
	Average	Min	Max	STDEV.P
TSS mg/l	75.91	-10	2276.96	202.84
Turbidity (NTU)	14.02	0.16	141	18.58
Vanadium as V (mg/l)	0.01	-0.005	0.36	0.03
Zinc as Zn(mg/l)	0.21	-0.005	30	2.28

Table 12: Water quality for Crocodile West (MCWAP Scheme)

Parameter	Crocodile West			
	min	max	median	STDEV.P
pH	7.36	10.18	8.28	0.73
Conductivity (mS/m)	47.80	820.00	74.80	137.96
Calcium as Ca (mg/l)	15.00	59.00	43.00	11.67
Magnesium as Mg (mg/l)	12.00	37.00	25.00	5.49
Sodium as Na (mg/l)	-0.01	116.40	66.92	15.70
Potassium as K (mg/l)	7.00	13.00	8.70	1.31
M-ALK (mg/l $CaCO_3$)	125.00	224.00	205.00	32.58
Chloride as Cl (mg/l)	53.03	150.00	83.81	20.68
Sulphate as SO_4 (mg/l)	50.81	130.00	79.36	15.06
Nitrate as NO_3N (mg/l)	-0.02	3.84	0.67	0.94
Fluoride as F (mg/l)	-0.03	0.44	0.18	0.14
Chemical Oxygen Demand (mg/l)	-1.00	52.00	16.00	12.92
Iron as Fe(total) (mg/l)	-0.01	2.10	0.01	0.34
Manganese as Mn (mg/l)	-0.01	0.56	-0.01	0.12
Chromium as Cr (mg/l)	-0.01	0.01	-0.01	0.01
Ca Hardness as $CaCO_3$ (mg/l)	37.46	147.35	107.89	29.78
Mg Hardness as $CaCO_3$ (mg/l)	49.39	152.26	104.94	23.48
Total Hardness as $CaCO_3$ (mg/l)	86.84	292.12	207.41	49.29
Aluminium as Al (mg/l)	-0.01	2.80	0.04	0.52
Zinc as Zn (mg/l)	-0.01	0.10	-0.01	0.02
Nitrite as NO_2-N (mg/l)	-0.02	0.66	-0.02	0.15
Phosphate as PO_4 (mg/l)	-0.09	0.50	0.15	0.17
Barium as Ba	0.01	0.29	0.08	0.05
Boron as B (mg/l)	-0.01	0.44	0.06	0.08
Lead as Pb	-0.01	0.03	-0.01	0.01
Suspended solids	-10.00	335.23	116.49	132.59
SiO_2	0.02	16.00	8.22	4.58
Copper as Cu (µg/l)	-0.01	0.06	-0.01	0.01
Cobalt as Co (µg/l)	-0.01	0.01	-0.01	0.00
Cadmium as Cd (µg/l)	-0.01	0.01	-0.01	0.00
Total Organic Carbon TOC	4.29	17.80	8.28	3.12
Anions Cal	**294.89**	**514.77**	**375.48**	**59.31**
Cat Cal	**260.86**	**489.97**	**344.14**	**55.67**
Bal Cal	**-9.64**	**1.31**	**-6.18**	**3.71**

4.1.3.1 Water quality impacts and treatment requirements

According to Eskom (2008), typical water quality impacts of coal fired power generation include:

- Problematic pollutants such as sulphates (SO_4) and mobile salts such as sodium (Na)
- Organic pollutants requiring introduction of mobile salts to mitigate impacts
- Permanent hardness because of acid mine drainage impacts. For example, in Witbank Dam permanent hardness causes Mg and Ca to be limiting parameters
- Trace metals emanating from mine water.

Typical Eskom Threshold Water Quality Values for the cooling water systems are presented in Table 13.

Table 13: Typical Eskom Threshold Water Quality Values for the cooling water system

Parameter	Concentration	Units
Sodium	500	mg/kg as Na
Chloride	400	mg/kg as Cl
Sulphate	750-1500*	mg/kg as SO_4
M Alkalinity	120-160**	mg/kg as $CaCO_3$

*Dependant on quality of concrete.

**Based on crystal modification program implemented.

Poorer water quality leads to lower cycles of concentration in the cooling towers, increasing the amount of effluent generated and increasing the need for onsite water purification. This implies that more water is required for the same energy output. According to results of the survey between 3 and 20 cycles of concentration are applied among the various power stations, indicating the impact of variability in source water quality. An example of the impact of different water qualities on water use at a typical power station is presented in Table 14. Moving water abstraction from the ideal quality to impacted water quality requires additional treatment to be used, which requires additional energy, thus raising its cost. Desalination plants can increase water costs by R10 to R20/Ml (excluding brine disposal). At the Duvha power station, a diversion pipeline was constructed to bypass polluted areas of the Olifants river system at a cost of R1.5 billion. Proposed water transfers from the Crocodile River to the Waterberg would supply water of lower quality than the existing local supply and would require further treatment for power plants.

Table 14: Impacts of Different Water Qualities on Water Use at a typical Power Station

Parameters	Source One (Usutu)	Source Two (Usutu-Vaal)
Water Quality (mg/l SO_4)	4.3	32.4
Cooling tower evaporation (ML/d)	94.18	94.18
Cycles of Concentration	**30**	**8.5**
Treatment requirement (ML/d)	13.04	78.2
Effluent generated (ML/d)	3.2	12.6

Poor water quality may cause possible de-zincification of condenser tubes. The condenser is an integral part of the power generation unit and when chemical excursions occur, de-zincification (pitting) of the condenser occurs. This requires the condenser either to be repaired/plugged or replaced at great cost.

An increase in chemicals in the ash disposal system due to poor raw water quality and increased chemical reagents used in water treatment has the potential to impact groundwater in the long term.

Eskom continues to pursue a philosophy of zero liquid effluent discharge under normal climatic conditions (see Section 7.1.2.3), by cascading water from one use to the next until final use in the effluent water systems of the power station. Poor water quality would require power plants to manage additional effluent to adhere to Eskom's policy of zero liquid-effluent discharge. The company conducts ongoing research to understand the impact of stack emissions on water quality and to implement appropriate mitigation.

Eskom has undertaken to take co-operative action to mitigate the impact of water quality on its business and has entered into a joint initiative agreement with the major coal mines to explore the use of excess mine water at the power stations and the treatment thereof and will continuously look at improvements on power station operational water efficiencies and water treatment regimes.

Deteriorating raw water quality requires collective action by DWS and water users, including Eskom, to protect water resources and deal with polluters to prevent water from becoming unusable or driving up costs of treatment and management of waste. If not resolved, it will require Eskom to increase their water purification capability (Eskom Holdings SOC Ltd, 2019)

A robust operational water management system is required to deal with varying water quality, and compliance by power stations with Water Use Licence conditions and the reporting thereof must be ensured.

The following raw water treatment processes are applied at Eskom stations:

- Coagulation
- Flocculation
- Water softening/conditioning
- Disinfection
- Sand filtration
- Desalination
- Evaporation

Further information on water treatment technologies applied at specific sites is discussed in Section 7.1.2. Approximately 10% of raw water that is treated is used by third parties.

4.1.4 Forecasting future water use factors for South African coal fired power stations

Since long term generation output forecasts or water usage factors are not available for individual South African coal-fired power plants, a mathematical forecasting model was developed by Thopil & Pouris (2016) to estimate generation output. Their pathway to estimate (or forecast) the water usage consumption was based on the development of a model combining steps uniquely developed for their study and from those mentioned within the methodology used by the US Department of Energy's (DOE) National Energy Technology Laboratory. The forecasting model relied on historical water consumption and electricity generation data for each of Eskom's power plants, from the year 1989 to 2012, obtained from Eskom's data archives. The forecasting technique was based on a moving average forecast to accommodate average yearly values of water usage and generation output estimates.

Multiple scenarios were developed based on technology type and time of introduction of new technologies. Examples of multiple scenarios include consideration of Return to Service (RTS) power plants, Camden, Grootvlei and Komati. These power plants were considered to have system thermal efficiencies smaller than the existing base load power plants. The reduced system thermal efficiency for RTS fleet was taken into consideration when calculating the water consumption factors. The RTS fleet was modelled based on the assumption that it would be retired by the year 2020 when the New Build power stations of Medupi and Kusile were planned to be fully operational (also considering possible delays). The first units of Medupi and Kusile were modelled to be operational in the year 2015 and 2016 respectively. The water consumption factor profile of Medupi and Kusile was estimated by following the water consumption factor profile of Matimba power station which also uses dry cooling technology. However, an improved system thermal efficiency factor was considered for the New Build power plants because of the supercritical technology used which would add to improved efficiencies.

The scenarios were therefore developed for three separate categories based on generation profile, namely base load, RTS and New Build.

A second classification was done based on the type of cooling technology used within the current base load and RTS fleet as well as the New Build power plants, which was be differentiated as wet cooling or dry cooling.

The results of the analysis are presented below, based on generation profile and cooling technology. It should be noted that all data points within the results up to an including the year 2012 were from data provided by Eskom which was used to make projections.

4.1.4.1 Base load analysis

The base load water consumption factor profile, which includes the power stations Arnot, Hendrina, Duvha, Kriel, Kendal, Tutuka, Matla, Lethabo, Matimba and Majuba, is presented in Figure 9.

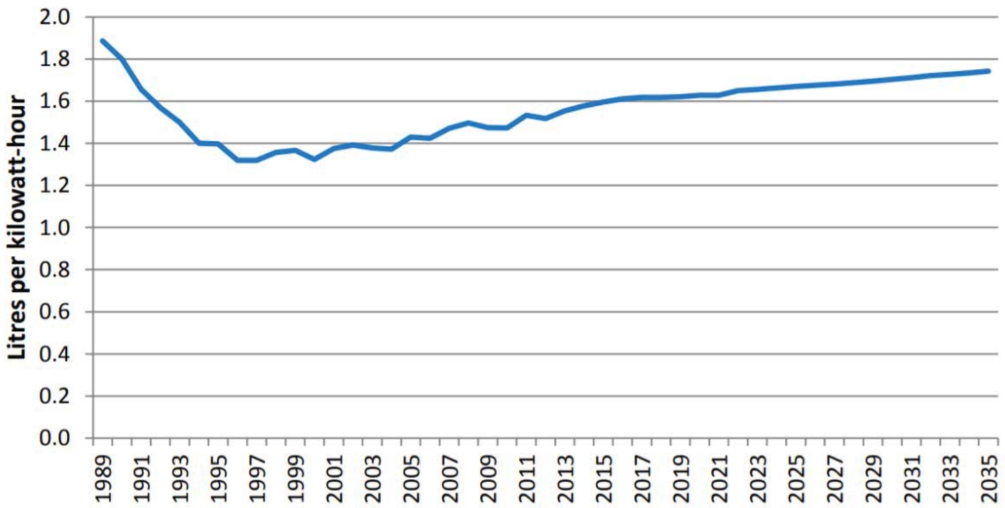


Figure 9: Base load power plant water consumption factor projection

There was a sharp decline in water consumption in the early nineties. This was attributed to the addition of the dry cooling power plants, Kendal and Matimba which helped to lower the overall base load consumption factor. However, since the mid-nineties there has been a steady increase with the increase being sharper within the last five years. The recent increase is attributed to the addition of the RTS power plants which are older and less efficient than the base load fleet. The profile from the year 2014 onwards is a projection based on decreasing system thermal efficiencies and historical consumption factors. The consumption factor profile is derived from projected generation output which is shown in Figure 10.

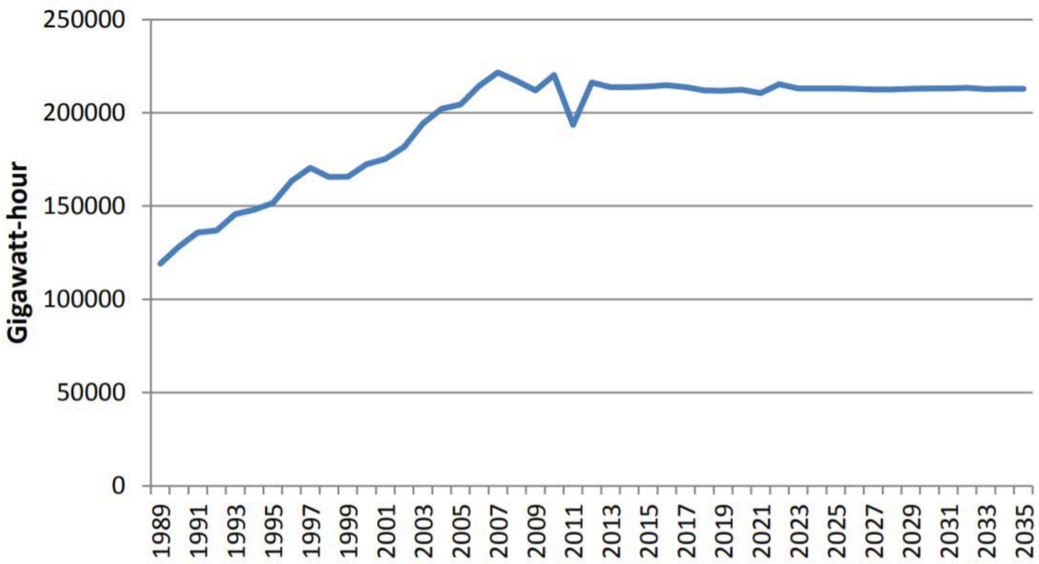


Figure 10: Base load power plant generation output projection

The base load generation output remains steady in line with roughly 213 Terawatt.hour (TWh) which is in line with the scenario that South Africa's base load capacity is being operated at maximal levels. This situation is primarily the reason why new-build power plants are being built. Combining the projections of base load capacity and water consumption factors the total water consumption is projected as shown in Figure 11.

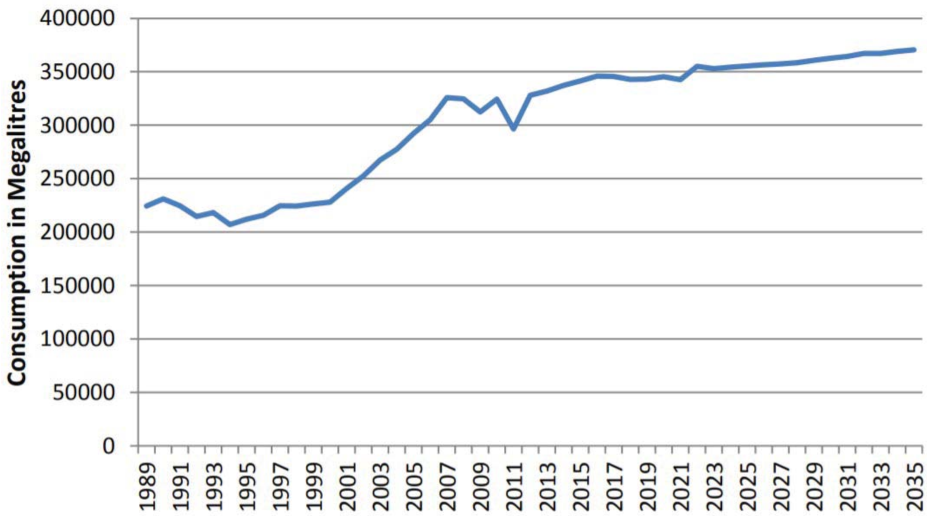


Figure 11: Base load total power plant total water consumption projection

Based on the projection in Figure 7 the total base load water consumption will increase from 332 gigalitres in 2013 to roughly 370.5 gigalitres in 2035 which is marginally more than a 10% escalation over the period. The steady increase in water consumption can be attributed mostly to the deteriorating system thermal efficiency, the so-called α-value, and the marginally increasing generation output.

4.1.4.1 Wet cooled base load analysis

Wet cooled base load plants include all base load plants other than Kendal and Matimba, which are dry cooled. Majuba which uses a combination of both wet and dry cooling techniques is categorised as a wet cooling plant since it generates the majority of the electricity through wet cooling techniques. Figure 12 shows the consumption factor profile for the wet cooled base load power plants.

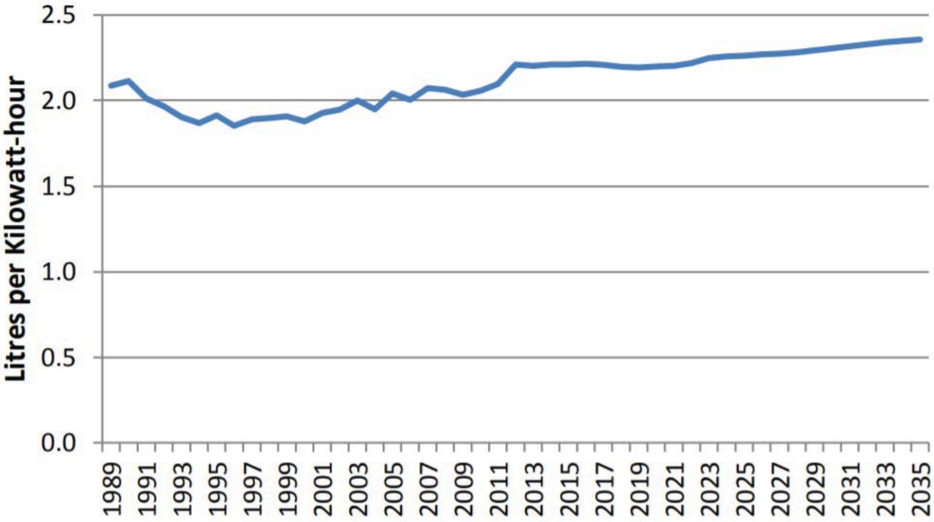


Figure 12: Wet cooled base load water consumption factor projection

Figure 13 shows the total water consumption from wet cooled base load power plants. It can be noted from the graph that total water consumption of individual power plants increases at a very gradual pace.

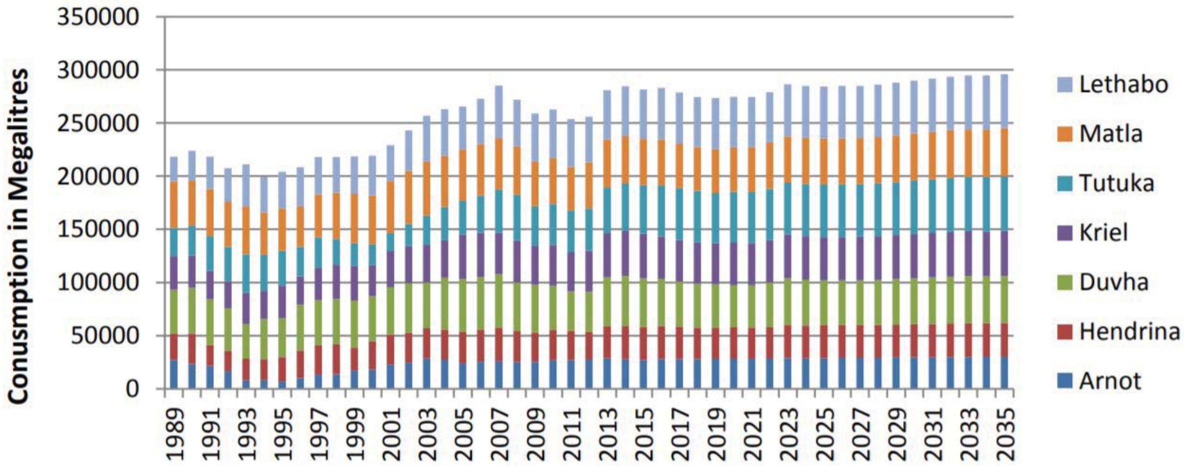


Figure 13: Wet cooled power plant total water consumption projection

Water consumption of wet cooled is bound to increase based on current trends; this can be mainly attributed to the decreasing efficiency of wet cooled power plants. Suggested measures to increase efficiency include actions such as coal and air flow optimisation, heat loss recovery, coal drying and improved coal quality.

4.1.4.2 Dry cooled base load analysis

The dry cooled power stations include Kendal and Matimba which are newer amongst the base load power station fleet. Figure 14 illustrates the consumption factor profile for the dry cooled base load power plants.

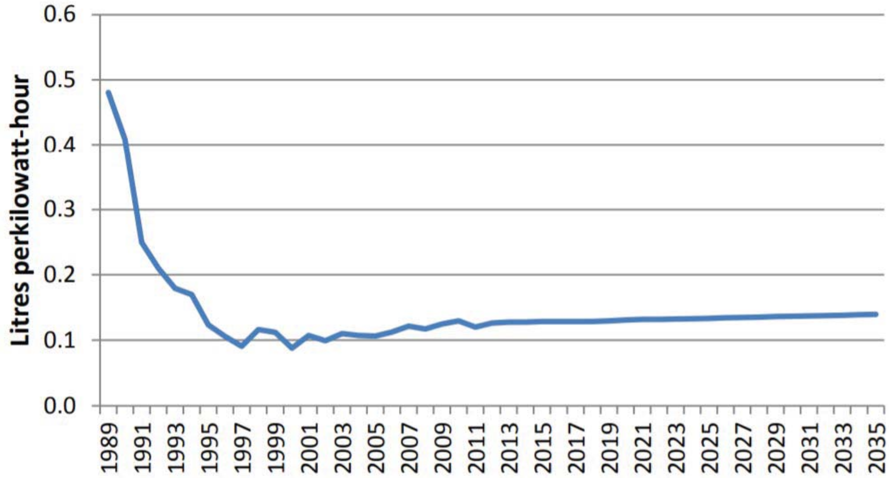


Figure 14: Dry cooled base load water consumption factor projection

Water consumption factor forecasts of dry cooled power plants (ranging from 0.1 l/kWh to 0.15 l/kWh) are expected to be one order of a magnitude lower than wet cooled power plants (ranging from 2.2 l/kWh to 2.4 l/kWh). Figure 15 indicates the total water consumption projections from dry cooled base load power plants. Comparing Figure 13 and Figure 15 shows the difference in total water consumption between power plants using wet and dry cooling technologies. The New Build power plants that will be using dry cooling technologies are expected to perform more efficiently than the existing dry cooled power plants because of the use of super critical boilers.

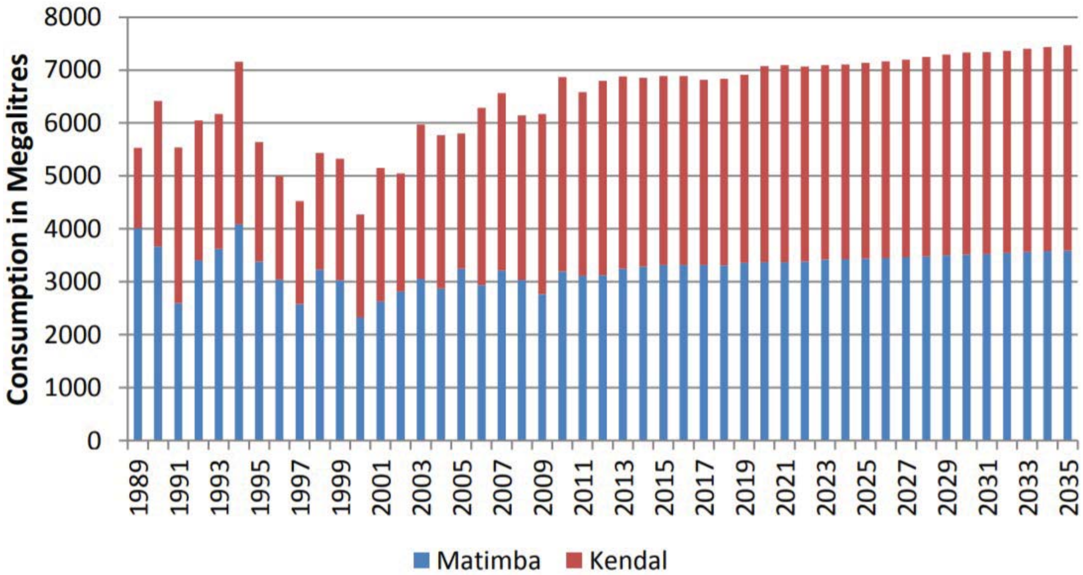


Figure 15: Dry cooled power plant total water consumption projection

4.1.4.3 Return to Service analysis

The RTS fleet includes the power stations of Camden, Grootvlei and Komati which were re-commissioned between the years of 2006 and 2009 to aid the stretched base load capacity. It is assumed that these power stations will be put out of service once the New Build power stations are fully operational. As a conservative choice these power stations were assumed to be operational until the year 2020, although based on delays that have been experienced in construction of the New Builds these plants will be in service for some time still. The water consumption factor for the RTS fleet is expected to reach 3 l/kWh by the year 2020 (Figure 16). The RTS power plant water consumption factor and total water consumption profile (Figure 17) are higher compared to the base load fleet primarily because of lower performance parameters, such as lower system thermal efficiencies.

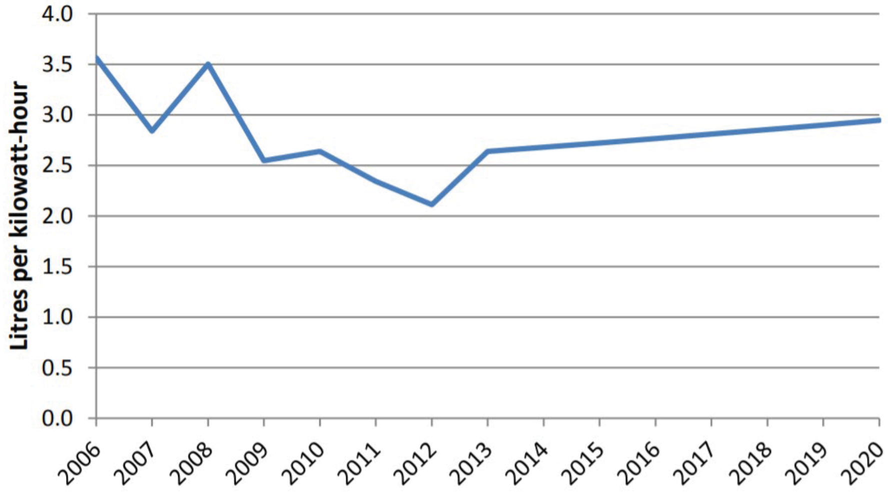


Figure 16: RTS power plant water consumption factor projection

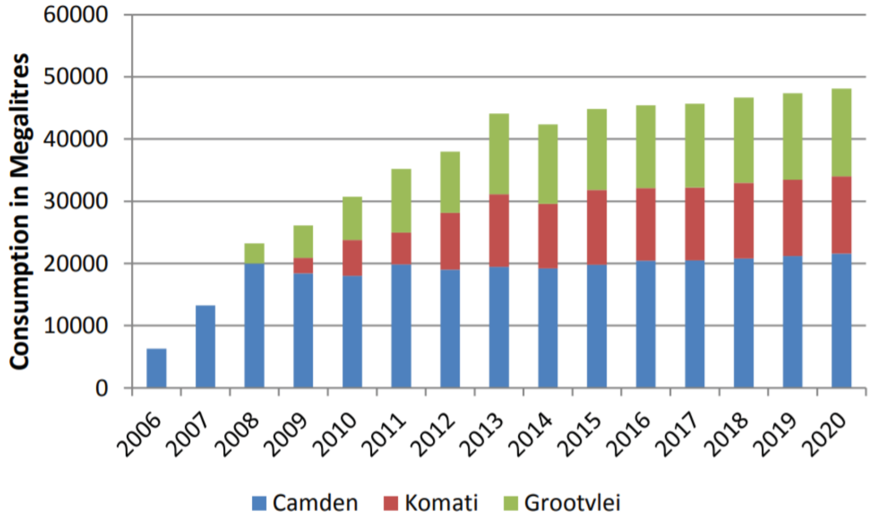


Figure 17: RTS total power plant water consumption projection

The inference therefore is that though the RTS fleet provides vital added supply during periods of peak electricity demand, the rate of water consumption associated is higher. Therefore, it is vital, from a water perspective, to retire the RTS fleet in conjunction with the commissioning of New Build power plants. RTS power plants are located in severely water constrained WMAs, Olifants and Inkomati. The gradual retirement of the RTS fleet could provide added water capacity in these WMAs.

4.1.4.4 New Build analysis

The New Build power plants of Medupi and Kusile use dry cooling technologies combined with supercritical boilers which result in better power plant performance and efficiency. Since no prior data is available for either power plant the water consumption factor profile of Matimba which also uses dry cooling technology was used as a baseline. Both Kusile and Medupi were assumed to provide an average system thermal efficiency of 42%, which is the average international rating for dry cooled, supercritical coal power plants, as opposed to an average 32% for the current base load subcritical power plants. Figure 18 provides the average water consumption factor projection for both New Build power plants.

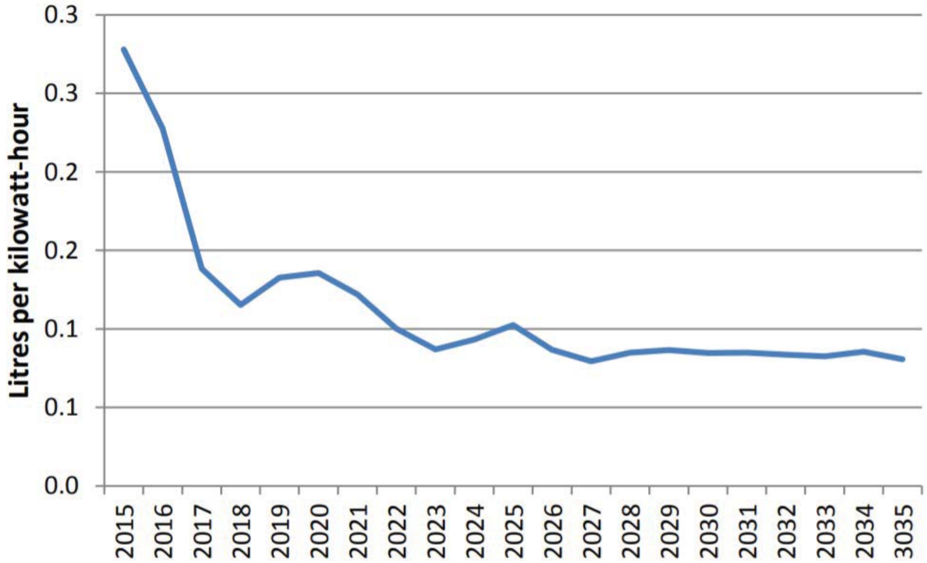


Figure 18: New Build power plant water consumption factor projection

The choice of 57% capacity factor is based on the average capacity factor of coal power plants (Department of Energy & Climate Change, 2015). However, for a supercritical power plant the capacity factor is expected to reach 80% once all units are fully operational. The generation output was projected based on the addition of 800MW units each year starting from 2015 and 2016 for Medupi and Kusile respectively and being operated with a capacity factor of 57% which is the average capacity factor for modern supercritical power plants. The total water consumption projection was then determined from generation output and water consumption factor and depicted in Figure 15.

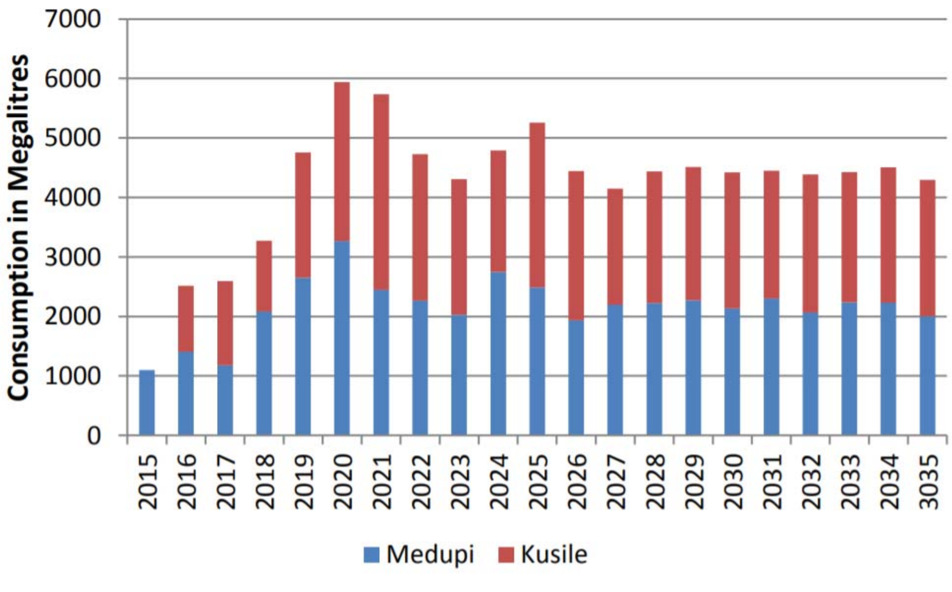


Figure 19: New Build power plant total water consumption projection

The initial increase in water consumption in dry cooled power plants is associated with, initial furbishment water usage before full commissioning, being added into total water usage.

4.1.4.5 Combined case

Figure 20 provides the combined consumption factor projections for the various categories of technologies and power plant profiles.

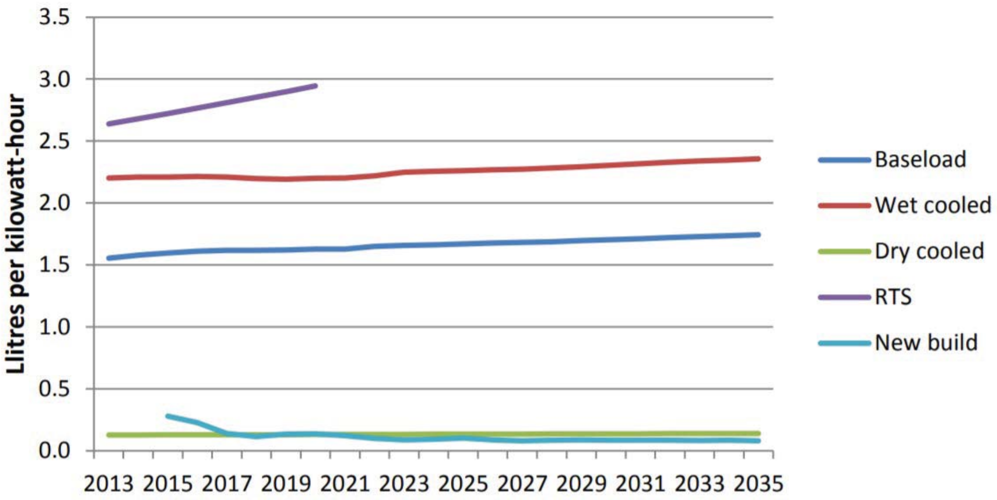


Figure 20: Combined water consumption factor projection

It is important to note that the base load projection shown in Figure 20 is an average of the dry cooled and wet cooled base load power plants. The RTS consumption factor profile is significant higher when compared with other technology types. Therefore, it should be recognised that that the RTS fleet, though vital in supplying peak demand capacity, is an added burden on the water consumption profile. This fact can be reiterated when observing the total water consumption profile of all coal-based power plants as shown in Figure 21.

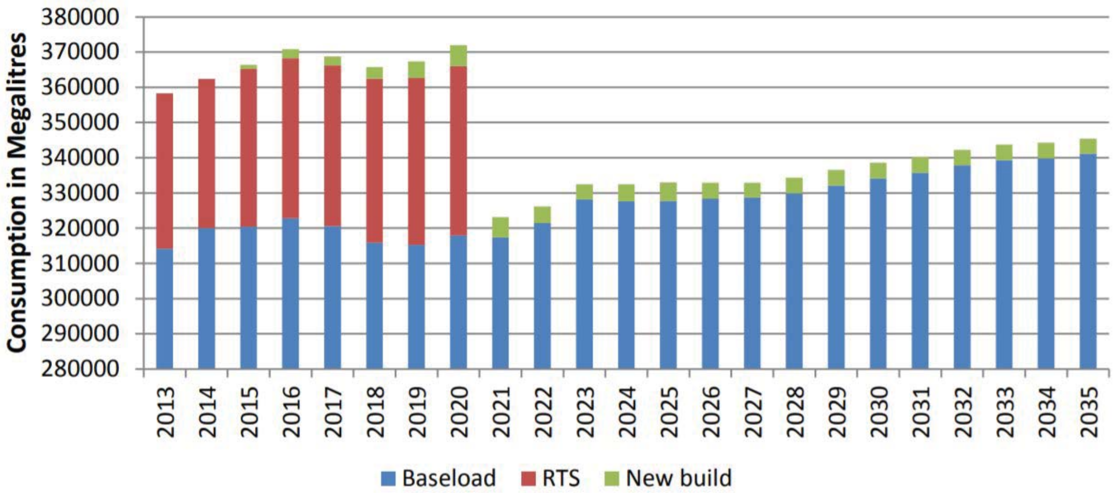


Figure 21: Combined coal power plant water consumption projection

It is essential to note that the y axis in Figure 21 is adjusted to scale to emphasise the contribution of the RTS fleet. It can therefore be observed that retiring the RTS fleet provides a water saving benefit of roughly 13% although the electrical output contribution of the RTS fleet is roughly between 2 to 3%.

As shown in Figure 21, total water requirements are expected to increase from roughly 360 gigalitres in 2013 to just above 370 gigalitres in 2021. Depending on the retirement of the RTS fleet, water requirements could be reduced by 12-15% to 320 gigalitres. Such a measure would bring a reduction of approximately 40 gigalitres of water per annum, which is roughly the amount of water used by one of the larger power stations such as Kriel, Tutuka, Matla or Lethabo. The shortfall caused in capacity by the retirement of the RTS fleet will be compensated for by the phased addition Medupi and Kusile. The New Build power plants are expected to consume 4 to 5 gigalitres thereby creating a net saving of 35 gigalitres, when the RTS fleet is decommissioned.

Another important finding is the difference between the weighted average consumption factor and the normal average consumption factor of the entire coal fleet. The weighted average water consumption factor which is measure of the average water consumption based on the percentage of electricity produced by each technology type compared to the average water consumption, is depicted in Figure 22.

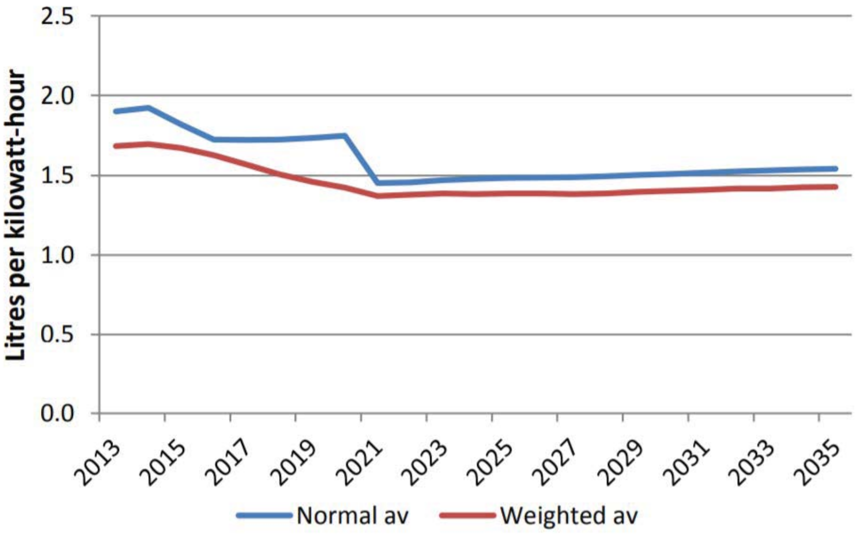


Figure 22: Coal fleet average consumption forecast (weighted vs average)

It can be observed that while the weighted average closely shadows the normal average the variations are more subtle. The variations are negated once the RTS fleet was assumed to be retired by the year 2020 and the new-build power plants fully operational. The weighted average can be better understood by analysing the percentage share of the various fleet technologies (Figure 23).

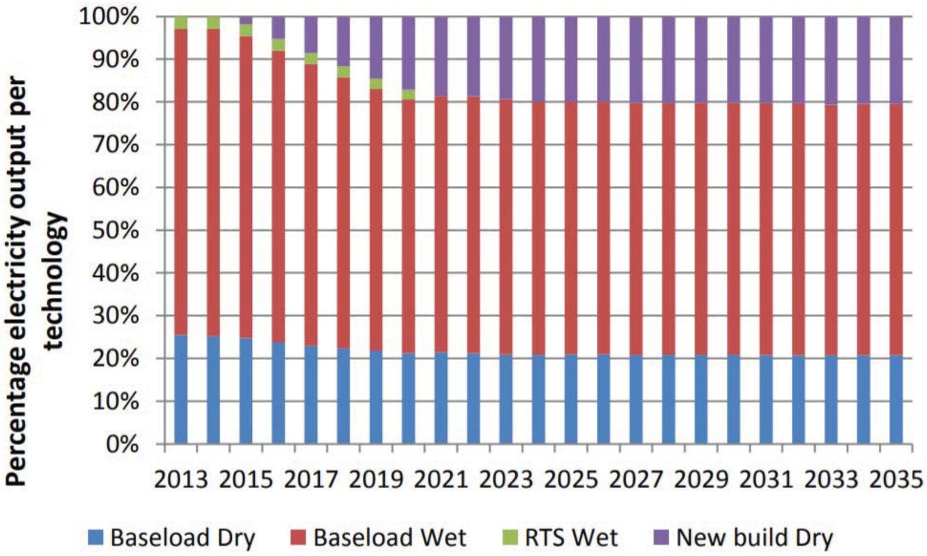


Figure 23: Electricity output per technology fleet forecast

Closer observation shows the weighted average tends to follow the percentage share curve of the wet cooled base load and the New Build fleets which have the most dominating variations. In future it is expected that as the newer coal power plants are built and older power plants are retired, the New Build fleet will be entirely integrated into the base load fleet thereby changing the coal power plant fleet to be based more on dry cooling dominated technology.

An important concurrent finding is the forecast of total electricity generated. The forecasts show that the expected output from the coal power plant fleet could reach 260 TWh by the year 2035. These forecasts are in accordance with the expected installed capacity of 36900 MW being operated at a capacity factor of 80%. The expected forecast is depicted in Figure 24.

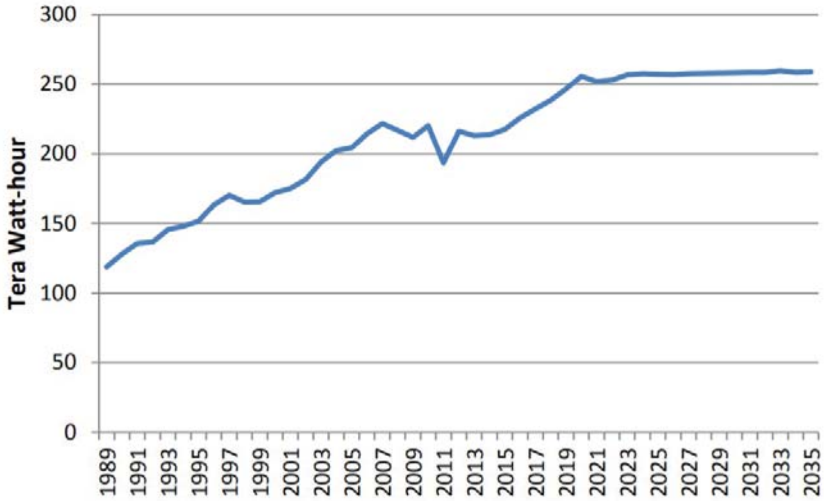


Figure 24: Combined coal fleet generation forecast

Average water consumption forecasts for South Africa's wet cooled power plants (Figure 13) are higher compared to average water consumption figures for wet recirculating subcritical power plants for other countries, which can be attributed to the decreasing thermal efficiency and increasing age profile of the power plants. However, water consumption figures for South Africa's dry cooled power plants (Figure 15) are amongst the best performing in the world. The lower water usage profiles for dry cooled power plants can be attributed to state of art cooling technologies and lower age profile of these power plants. This is discussed further in Section 9.

4.2 Nuclear power

A nuclear power plant uses a uranium to produce energy. It cannot, however be compared to fossil dependent plants such coal, oil and gas fired power stations. The energy generated by a nuclear plant is dependent on low enriched uranium, rather than fossil fuels, as a source of fuel to produce heat. Heat is generated during a nuclear reaction process called "fission". Fission is the process of splitting the nuclei of atoms into smaller particles such as protons, electrons and neutrons.

A reactor has components for controlling the fission process to avert excessive heat generation. Energy is generated in the reactor and heats up water, which co-produces steam and drives a turbine. The turbine is connected to a generator, which ultimately produces electricity. The fission process of uranium is used as a source of heat in a nuclear power station in the same way that the burning of coal, gas or oil is used as a source of heat in a fossil fuel power plant.

Producing energy with the fission process is far more efficient compared to other processes using fossil fuels. For example, approximately 44 GWh of electricity are produced from one tonne of uranium. To produce the same amount of electrical power from fossil fuels, the process would require the burning of over 20 000 tonnes of black coal or 8.5 million cubic metres of gas (World Nuclear Association).

The Koeberg Nuclear Power Station is built adjacent to an abundant water source (the ocean) and hence uses the direct cooling method to cool down its system. This method uses once through cooling to cool down the internal water system and circulates the water back into the ocean at an increased temperature. Water consumption is marginal, with a small proportion of the withdrawn water being consumed. The small amount of water consumed and/or lost refers to the evaporation that occurs when the water circulated back into the ocean and being a few degrees warmer than the ocean temperature. Use of seawater reduces the competition for fresh water. Nevertheless, the elevated temperature of the discharged water may affect the ecosystem at the discharge point.

South Africa has one nuclear power plant (Koeberg) currently in operation, with an installed capacity of 1 940 MW, and a nominal capacity of 1 860 MW, a capacity factor of 96%. Koeberg Nuclear Power Station has three different water systems, known as the primary, secondary and tertiary circuits. The three water systems are used to cool down the heat produced by the fission energy process. In the primary water system, water is used to remove heat from the nuclear reactor and carry this heat to the steam generators. The water is recirculated to the reactor by means of a pump. The primary water system is radioactive, but is a closed system and does not come into contact with the other two systems and therefore does not contaminate the water in these systems. No water consumption is involved in this system. The secondary water system is also a closed system; sea water is used in the steam generator for steam production, which drives the turbines and generator for electricity production. The steam leaving the turbine is condensed and circulated back to the steam generator. The tertiary system is used in the condensers. The cooling water system for the condensers uses seawater to cool the steam in the condensers. Once it has cooled the steam down, it is returned to the sea.

Water use for a nuclear power station such as Koeberg is extensive (mostly seawater) but uses a negligible volume of fresh water.

Koeberg uses seawater flowing at 80 000 litres/second to cool the condensers. Using these values, the intensity of water use during generation has been estimated as 192.5 l/kWh (Sparks et al., 2014). This value is consistent with findings from other studies.

Due to acute water shortages in the region, Eskom announced in May 2017 that it would install a small desalination plant at Koeberg, initially to produce water solely for the plant. Eskom also agreed to support the Cape Town authorities if they choose to progress plans to install a small-scale desalination unit for municipal use at the Koeberg site, to produce 2500 to 5000 m^3/d, as a demonstration plant for a larger project.

4.3 Renewable energy generation

Not all technologies that generate power from Renewable Energy Sources require water. Wind and PV installations require almost no water for their operation. A summary of water use of renewable sources in South Africa is presented in Table 15.

Table 15: Water use according to cooling type for renewable energy sources in South Africa (World Bank, 2017)

Power plant type	Cooling type	Raw water use (l/kWh)	Boiler water use (l/kWh)	Water Supply region	Climatic zone
Concentrated solar power	Direct dry	2.22	0.157	Limpopo	Hot interior
Concentrated solar power	Hybrid cycle	2.2	0.062	Limpopo	Hot interior
Concentrated solar power	Wet recirculating	2.61	0.231	Limpopo	Hot interior
Solar PV[a]	NA	NA	NA	NA	Distributed
Wind	NA	NA	NA	NA	Distributed

[a] Water to wash solar panels is not included. This is yet to be quantified in South Africa

4.3.1 Concentrated solar power

Concentrated solar power plants (CSP) use mirrors to redirect sunlight on to a specific point to heat a fluid. The heat in the fluid is then used to drive generators and produce power. There are four technical designs used for CSP, the parabolic trough, power tower, linear Fresnel, and the Dish Stirling.

Parabolic trough

A solar trough collector consists of a linear trough-shaped parabolic collector, which moves around a single axis to follow the sun. Solar radiation is concentrated onto an insulated absorption tube in the centre of the collector and runs the full length of the collector. The collector uses a carrier fluid to transport the collected heat to a storage medium or the turbine.

Power tower

The power tower uses many mirrors, which all track the sun and move on multiple axes to focus the sun's radiation onto a single receiver point. Like the solar trough, the power tower uses a working fluid to transport the heat to a storage medium or a turbine.

Linear Fresnel

Similar to the long arrays of a parabolic trough CSP system, a Linear concentrating collector field consists of a large number of collectors in parallel rows. These are typically aligned in a north-south orientation to maximize annual and summer energy collection. The mirrors are laid flat on the ground and reflect the sunlight to the pipe above. Like trough and tower, Fresnel can also incorporate storage in a power block, or generate steam for direct use.

Dish Stirling (Parabolic dish)

A parabolic dish system consists of one or more parabolic dishes, which concentrate the radiation into a single point. This point can hold a collector, which holds a carrier fluid or a sterling engine, which is coupled to a dynamo.

As a thermoelectric generation technology, CSP withdraws similar amounts of operational water to pulverized coal technology, with important differences in terms of cooling technology. However, because CSP systems commonly are in remote areas and often use evaporation ponds for water disposal, consumption volumes typically equal withdrawals regardless of technology (Solar Millennium LLC, 2008).

The parabolic trough, power tower and linear Fresnel technologies can use wet, dry or hybrid cooling systems. The dish Stirling does not require a cooling system (the heated fluid is hydrogen).

CSP plants using steam cycles require cooling to condense the steam exiting the turbines. Sparks et al. (2014) reported that these plants withdraw 0.5-5 l/kWh and consume 0.3-5 l/kWh, which was in agreement with finding from other studies; 2-3 l/kWh reported by IEA-ETSAP & IRENA (2013).

Concentrated Solar Power offers potential for combined power generation and desalination. Areas that have a high Direct Normal Irradiance (DNI) usually have limited or no water resources and therefore wet-cooled CSP plants may compete for scarce water resources unless alternatives of CSP, including optimally sited dry cooling, CSP saline water cooling and CSP desalination, are investigated (Govender et al., 2016). Concentrated Solar Power plants using dry cooling reduce water consumption by 90% but when the ambient temperatures exceed 30-35°C, the plant efficiency is reduced and less electricity is produced; compared with wet cooled CSP plants, electricity production is typically reduced by 7% and the capital cost increased by 10% in dry cooled plants (IEA-ETSAP & IRENA 2013). Sites need to be chosen that have a suitable combination of cost of energy and cost of water to maximise the energy cost efficiency of CSP plants while still minimising water consumption

Table 16: Summary statistics of selected, harmonized estimates of water consumption and withdrawal for major life cycle stages and production pathways for CSP-generated electricity (Adapted from Meldrum et al., 2013)

	Consumption (l/kWh)				**Withdrawal (l/kWh)**			
	Median	**Min**	**Max**	**n**	**Median**	**Min**	**Max**	**n**
Dish stirling	0.00	0.00	0.00	2	0.00	0.00	0.00	2
Fresnel	0.26	0.26	0.26	1	0.26	0.26	0.26	1
Power tower: cooling tower	0.21	0.20	0.23	5	0.20	0.20	0.20	1
Power tower: dry cooling	0.01	0.01	0.01	1	0.01	0.01	0.01	1
Power tower: hybrid cooling	0.04	0.02	0.07	2	0.04	0.02	0.07	2
Trough: cooling tower	0.24	0.15	0.50	26	0.25	0.23	0.29	2
Trough: dry cooling	0.02	0.01	0.04	20	0.02	0.01	0.02	11
Trough: hybrid cooling	0.09	0.03	0.09	3	0.09	0.09	0.09	1

4.3.2 Photo-voltaic solar power

Photovoltaic (PV) panels convert sunlight directly into electricity by absorbing photons and releasing electrons. These free electrons are captured on an electrode and result in an electric current, which can be used as electricity (SEA, 2009). Concentrated photovoltaic technology (CPV) uses optics such as (Fresnel) lenses or curved mirrors to focus large amounts of sunlight (radiation) onto a small area of a photovoltaic cell to generate electricity more efficiently than traditional PV (Soitec, 2013). As shown in Table 17, water use for operations is minimal. Experimental evidence demonstrates that although frequent washing increases output, it likely leads to economic losses (Sahm et al., 2005). DOE (2012) reports that few operators wash PV panels in actual practice. The higher water use of concentrated PV likely reflects certain shared operational characteristics with CSP, such as a need for mirror washing.

Table 17 Summary statistics of selected, harmonized estimates of water consumption and withdrawal for major life cycle stages and production pathways for PV-generated electricity (Adapted from Meldrum et al., 2013)

	Consumption (l/kWh)				**Withdrawal (l/kWh)**			
	Median	Min	Max	n	Median	Min	Max	n
Flat panel	0.001585	0.000264	0.006868	9	0.002	0.000	0.007	9
Concentrated PV	0.008189	0.00634	0.020605	4	0.008	0.006	0.021	4

The water use during generation is linked to the cleaning/washing of the PV-panels. International literature suggests figures of 0.015 l/kWh for CPV and PV (NREL, 2002; Fthenakis & Kim, 2010). How often cleaning occurs in SA is not yet quantified. It is likely to be dependent in part on the (climate) area where the system is installed.

4.3.3 Wind power

The generation of electricity by wind energy is using the kinetic energy of air. The average annual energy generated on a wind farm typically varies between 0.05 and 0.25 GJ/m^2 (Blok, 2006). In South Africa, there is currently only one large scale wind farm in operation (in Jeffrey's Bay in the Eastern Cape). There are also initial plans for other such farms (particularly in the Eastern Cape). In addition, there are two small-scale wind farms in operation, viz., Klipheuwel and Darling. As part of the Renewable Energy Independent Procurement Programme (REIPPPP), the Department of Energy has awarded 20-year Power Purchase Agreements (PPA) to several wind projects, which will increase the wind power percentage of South Africa's electricity provision in the future. According to the Integrated Resources Plan for Electricity 2010-2030 (2010), South Africa plans to install 8.4 GW of wind energy supply by 2030.

Wind turbines require no fuel and little, if any, washing and maintenance, so operational water use is very low (Table 18).

Table 18 Summary statistics of selected, harmonized estimates of water consumption and withdrawal for major life cycle stages and production pathways for wind generated electricity (Adapted from Meldrum et al., 2013)

	Consumption (l/kWh)				**Withdrawal (l/kWh)**			
	Median	**Min**	**Max**	**n**	**Median**	**Min**	**Max**	**n**
Onshore	0.000132	2.64E-05	0.000528	10	0.000264	0.000264	0.000264	2
Offshore	2.64E-05	2.64E-05	0.000264	4	0.000528	2.64E-05	0.000793	9

Wind energy does not require water for its generation (assuming the land used is still offered for other uses such as agriculture) (Gleick, 1994; Martin & Fischer, 2012). Water use for the turbine construction phase has been deemed negligible (Gleick, 1994). There is also likely negligible water use in the washing or the turbine blades from time to time. The water uses in the production of rare earth elements such as neomycin does not impact on water use in South Africa, but they do impact on the water footprint globally.

4.3.4 Hydroelectricity

Hydropower provides approximately 16% of the total world electricity supply and may be considered a reasonably clean and low-cost renewable source of energy (Hoekstra et al., 2011; Mekonnen & Hoekstra, 2012). In contrast, hydropower in South Africa accounts for a very small percentage of the total power, at only 2%. Martin and Fischer (2012) note that just under half of this is from run-of-river plants (Gariep (260 MW), Vanderkloof (240 MW) which are both on the Orange River) and 60% of this is from pumped storage plants (e.g. Drakensberg (100 MW) and Palmiet (400 MW)). In addition, 4% of hydropower is imported from the Cahora Bassa Dam in Mozambique, and limited imports from Lesotho and Zambia (Eskom, 2011).

Hydroelectricity is generated by harnessing potential energy in the flow of water to drive electricity turbines. Rivers and streams may be re-directed, and dams constructed to feed hydro generators. There are a number of different methods for hydropower generation, the most common and relevant for South Africa being conventional dams (e.g. Gariep Dam in South Africa), pumped storage (e.g. Palmiet pumped storage scheme in the Western Cape of South Africa) and run-of-river schemes (this is a potential option for small-scale hydro in South Africa).

Hydro is by nature the most water-intensive source of energy in terms of withdrawal. However, it is limited in terms of its water consumption. It can be suggested that no water is used in the process of hydropower generation, since the water used in generation is returned to the water resource and it hence qualifies as in-stream water use. However, it can be argued that evaporation losses associated with the hydropower plant are significant and that hydroelectricity is a significant consumer of water (Hoekstra et al., 2011; Mekonnen & Hoekstra, 2012).

Important considerations are evaporation and seepage. Gleick (1994) estimated a range of hydropower evaporation values, varying from a minimum of 0.04 l/MWh, to a maximum of 210 m^3/MWh, with an average of 17 m^3/MWh.

4.3.5 Bioenergy

Bioenergy is globally the largest renewable energy source, contributing to over 50% of total renewable energy. Bioenergy also contributes over 10% towards final global energy consumption. Biomass is derived from natural sustainable organic sources such as decomposing material from plants or animals. It also includes wood, agricultural crops, municipal waste, and manure. Bioenergy is formed when biomass is converted and then directly used as fuel or converted into liquid fuel or gases.

Technology application varies depending on the source content. Biomass can directly be used as a co-fired energy source during electricity generation. During this process traditional fossil fuels such as coal or natural gas together with biomass can be incinerated to generate heat for electricity generation. Water consumption in Electricity plants is approximately 2 l/kWh, whereas it is negligible in cogeneration plants.

It can also be traditionally applied by combusting natural biomass in home appliances such as coal or gas stoves. Furthermore, biogas technologies include anaerobic biogas digesters that generate gas for home cooking and heating purposes. The production of ethanol to be used in biodiesel also goes through various industrial processes, but the final technology application is in vehicles (EREN, 2000).

Biomass is water intensive, but this water would have been used in the production of crops regardless. Thus, these two renewable energy sources have a perceived high impact on water resources. It should be noted, however, that in South Africa, biofuel generation is by means of waste-from-crops only. In this case the water consumption could be disregarded altogether.

5 Coal and diesel usage and ash production

Except for the Majuba plant, all coal-fired plants are linked to a coal mine which supplies the plants via a run-of-mine design, the majority of which are conveyor systems. Three calorific grades of coal can be defined: high, low, and discard. Current power generation technologies rely on low-grade coal, although future Fluidized Bed Combustion technologies will use discard coal (see section 5.1). Table 19 lists the calorific value design range of the fleet of plants built for low-grade coal. An average calorific value of 21 MJ/kg is obtained for low-grade coal by weighting plant capacity and efficiency (World Bank, 2017).

Table 19 Estimated calorific value design ranges for plants built for low grade coal

Power Station	Value Applied
Arnot Camden Tutuka	22-24 MJ/kg
Kriel Duvha Grootvlei Hendrina Komati Majuba Matla	20-22 MJ/kg
Kendal Matimba Medupi Kusile	18-20 MJ/kg
Lethabo	16-18 MJ/kg

Average quality and use of coal in the coal fired power stations as well as diesel/kerosene use in open-cycle gas turbines is presented inTable 21, together with ash and carbon dioxide (CO_2) production figures for

2013/2014 to 2018/2019. The average calorific value of coal supplied was under 20 MJ/kg between 2013/2014 and 2018/2019, except for 2016/2017.

The kWh produced per kg of coal for each power station is presented in Table 20. The calorific value of coal supplied to each station was not available, however, it was calculated for each station assuming a thermal efficiency of 31%, as presented in Table 21 for the 2018/2019 year. The average calorific value for coal supplied across the stations was 19.4 MJ/kg (Table 21); this was used to calculate the thermal efficiency per power station as an indication.

Table 20 kWh per kg coal for 2018/2019

	Monthly kWh/kg coal												Average kWh/kg coal	MJ/kg Primary energy equivalent[1]	Efficiency based on average coal calorific value[2]
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar			
Arnot	1.73	1.78	1.54	1.82	1.70	1.71	1.62	1.68	1.72	1.44	1.64	1.76	**1.68**	**19.49**	**31.40%**
Camden	1.69	1.75	1.27	1.68	1.74	1.64	1.52	1.67	1.36	1.41	1.46	1.50	**1.56**	**18.08**	**29.13%**
Duvha	1.88	1.76	1.80	1.78	1.77	1.89	1.83	1.83	1.66	1.80	1.76	1.90	**1.81**	**20.96**	**33.77%**
Grootvlei	1.55	1.51	1.73	1.65	1.44	1.88	1.56	1.65	1.72	1.67	1.61	1.77	**1.64**	**19.09**	**30.76%**
Hendrina	1.56	1.62	1.83	1.59	1.50	1.40	1.53	1.59	1.44	1.55	1.51	1.67	**1.57**	**18.18**	**29.28%**
Kendal	1.60	1.65	1.61	1.63	1.59	1.56	1.51	1.58	1.56	1.57	1.56	1.46	**1.57**	**18.26**	**29.41%**
Komati	1.66	1.71	1.68	1.63	1.53	1.38	1.50	1.83	2.81	1.91	1.96	1.61	**1.77**	**20.53**	**33.08%**
Kriel	1.82	1.81	1.59	1.73	1.57	1.67	1.82	1.77	1.76	1.70	1.71	1.93	**1.74**	**20.20**	**32.54%**
Kusile	2.21	2.14	2.04	2.06	1.98	1.36	4.14	1.61	0.00	0.00	0.00	1.70	**1.60**	**18.62**	**29.99%**
Lethabo	1.35	1.40	1.48	1.40	1.42	1.41	1.43	1.46	1.50	1.49	1.43	1.38	**1.43**	**16.60**	**26.74%**
Majuba	1.75	1.86	1.80	1.78	1.76	1.72	1.73	1.76	1.78	1.79	1.73	1.70	**1.77**	**20.50**	**33.02%**
Matimba	1.88	1.88	1.83	1.87	1.92	1.95	1.97	1.95	1.94	1.94	1.94	1.68	**1.90**	**22.01**	**35.46%**
Matla	1.78	1.80	1.79	1.78	1.81	1.79	1.76	1.93	1.97	1.81	1.64	1.77	**1.80**	**20.93**	**33.72%**
Medupi	2.09	2.18	2.21	2.09	2.04	2.14	2.08	2.05	1.99	1.95	1.97	2.01	**2.07**	**23.98**	**38.64%**
Tutuka	1.78	1.73	1.70	1.71	1.74	1.71	1.57	1.59	1.62	1.57	1.69	1.61	**1.67**	**19.37**	**31.21%**
												Average	**1.70**	**19.79**	**31.877%**

[1] Calculated calorific value of coal, assuming 31% efficiency as per Table 21

[2] Average coal calorific value of 19.24 MJ/kg across all stations for 2018/2019 (see Table 21)

Table 21 Eskom primary energy production figures 2013/2014 to 2018/2019

	2013/2014	2014/2015	2015/2016	2016/2017	2017/2018	2018/2019
Coal purchased (Mt)	122	121.7	118.7	120.3	115.3	118.3
Coal burnt (Mt)	122.41	119.2	114.8	113.7	115.5	113.8
Average calorific value (MJ/kg)	19.77	19.68	19.57	20.05	19.81	19.24
Average ash content (%)	28.56	27.63	28.19	28.62	30.92	30.98
Overall thermal efficiency (%)	31.3	31.4	31.1	31.2	31.2	31
Diesel and kerosene usage for OCGTs (Ml)	1148.5	1178.6	1247.8	10	37.8	385
Ash produced (Mt)*	34.97	34.41	32.59	32.61	31.65	33.23
CO_2 produced (Mt)**	233.3	223.4	215.6	211.1	205.5	220.9
CO_2 produced (kg/GWh)**						1 096 804

*See Table 23 for detailed ash production figures for wet and dry cooled stations

**Calculated figures based on coal characteristics and power station design parameters based on coal analysis and using coal burnt tonnages. Figures include coal-fired and gas turbine power stations, as well as oil consumed during power station start-ups and includes the underground coal gasification pilot plant.

Eskom has an energy management plan in place. Table 22 presents the consumption figures as received from Eskom for various energy sources, where available, and annual costs for 2018/2019.

Table 22 Energy Source consumption figures for 2018/2019

Energy source	Unit cost	Annual consumption	Annual cost	Comments
Gas (LPG)	R16.98 per kg	258 842 kg	R 4 395 352.86	LPG is a regulated by the department of energy and a new price is published monthly. R16.98 is an average annual price for financial year 18/19 less a supplier discount of R5.84
Diesel for generators	R13.6941 per litre	385 040 033 litres	R3 768 M	All OCGTs are within zone 01A.
Diesel for trucks (excluding coal haul trucks)	R14.3781 per litre			Coal stations have different delivered prices as they are in different magisterial zones which are 08C, 09C, 13C, 10C, 07C, etc. 08C price is used for demonstration purposes only.
Petrol	R13.9240 per litre			Coal stations have different delivered prices as they are in different magisterial zones which are 08C, 09C, 13C, 10C, 07C, etc. 08C price is used for demonstration purposes only.
Fuel oil		479 176 755.73 Kg	R4 057 541 717.98	Fuel oil rates are per kg/ton and changes months. Therefore, it’s not possible to provide the unit cost per year

Ash produced in the coal fired power stations is in two forms, fly ash and bottom ash. Fly ash is composed of the fine particulates that are driven out of coal-fired boilers together with the flue gases. Bottom ash is that ash that falls to the bottom of the boiler's combustion chamber. The quality of the fly ash is directly dependant on the quality of the coal. The ash produced in power generation is a waste product that is an environmental pollutant requiring careful management, and that which impacts on water use and water quality depending on the amount of water required for dust suppression and ash wetting for transport to ash dumps.

Bottom ash is currently dumped on ash dumps, although there is some potential for use of this material in the brick and block manufacturing industry. Heavy metals are typically found in the bottom ash, not in the fly ash. Waste brine at the power station is typically disposed of on the ash dumps. Depending on the ash quality there may be potential for environmental pollution. Quantities of coal burnt per station as well as the ash production figures are presented in more detail in Table 23. Dry ashing is done at Kendal, Lethabo, Majuba, Matimba and Tutuka power stations.

Depending on its quality, fly ash is a potentially useful by-product of coal fired power generation. It can be used to replace a portion of the clinker in cement, which is an expensive cement component. This is not possible for high strength cement but is a regular practice for domestic cement applications.

Ash Resources is a company that focuses specifically on the beneficiation of fly ash. Ash is classified, and the quality determined according to the requirements of the EN450 Standard, which specifies the loss on ignitions (residual carbon content of the ash) requirements for specific uses. Ash Resources therefore fulfils a quality control function for the industry. Other than the coal quality itself, the ignition temperature in the power station is therefore also a determinant in the quality of the fly ash, to meet the required LOI standards. At this stage ash from the Lethabo power station is the preferred ash, as the quality is consistent due to more consistent coal mineralogical quality as well as plant operations. Ash resources also sources ash from Kriel and Matla power stations. Transport costs are a consideration as the product is of low value and must be near the cement manufacturing facilities. Eskom currently also use their fly ash for water treatment purposes, and there is competition between onsite use and by-product off take agreements.

Table 23 Ash production figures for 2018/2019

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total
Dry Ashing Plants													
Kendal													
ash %	34.45	34.46	33.94	32.77	33.15	33.87	33.40	32.03	32.21	32.52	31.44	30.11	
Coal burn [ton]	1 256 279.00	1 404 795.00	1 269 058.00	1 269 706.00	1 089 283.00	1 265 831.84	1 171 851.00	1 010 489.00	832 273.80	1 033 383.00	797 067.00	954 685.90	
Ash produced [ton]	432 824.30	484 072.83	430 683.58	416 044.99	361 146.33	428 702.69	391 443.82	323 617.99	268 078.47	336 010.48	250 625.04	287 483.80	**4 410 734.32**
Lethabo													
ash %	41.02	41.40	41.28	43.17	41.18	41.46	40.70	39.36	38.74	40.85	42.36	42.29	
Coal burn [ton]	1 013 389.98	1 358 204.82	1 402 238.00	1 476 467.00	1 283 080.23	1 456 453.91	1 418 006.00	1 093 795.47	1 148 252.00	1 230 916.00	1 212 150.03	982 624.50	
Ash produced [ton]	415 722.97	562 296.80	578 857.87	637 346.51	528 359.61	603 772.97	577 128.44	430 539.77	444 809.86	502 792.26	513 466.75	415 551.90	**6 210 645.71**
Majuba													
ash %	28.59	26.20	26.35	27.14	26.93	26.08	25.18	25.38	26.52	25.60	25.94	26.73	
Coal burn [ton]	1 033 287.07	1 016 854.87	1 099 240.00	1 175 067.00	1 098 114.30	1 196 969.36	1 112 437.00	1 231 940.75	1 220 717.00	1 181 262.00	1 133 172.43	1 197 615.00	
Ash produced [ton]	295 416.88	266 415.98	289 624.79	318 921.89	295 728.33	312 194.87	280 155.58	312 622.95	323 708.15	302 398.58	293 991.05	320 116.98	**3 611 296.01**
Matimba													
ash %	34.10	34.65	35.11	34.28	34.18	33.71	33.33	33.69	34.56	33.84	34.64	34.11	
Coal burn [ton]	1 038 396.05	1 075 251.70	1 127 221.00	1 230 337.00	1 267 495.00	1 201 904.00	1 301 304.00	1 253 490.56	1 143 752.00	1 145 871.00	1 023 250.58	1 267 666.00	
Ash produced [ton]	354 093.05	372 620.09	395 717.88	421 702.40	433 257.02	405 133.02	433 759.09	422 306.53	395 234.58	387 808.93	354 479.06	432 403.15	**4 808 514.80**
Tutuka													
ash %	27.25	27.39	28.77	26.45	24.10	25.68	26.07	26.07	30.46	26.61	26.10	26.20	
Coal burn [ton]	703 638.56	877 904.22	946 633.70	853 771.20	912 186.82	643 012.20	818 947.80	718 591.57	705 563.70	593 454.90	559 695.57	743 396.40	
Ash produced [ton]	191 726.03	240 495.54	272 374.91	225 817.14	219 816.23	165 136.34	213 477.17	187 336.53	214 919.64	157 937.81	146 098.23	194 806.88	**2 429 942.46**

Wet Ashing Plants													
Arnot													
ash %	23.06	23.06	23.93	22.81	22.84	23.42	22.47	23.15	23.51	23.49	22.90	22.43	
Coal burn [ton]	495 059.40	513 817.59	486 832.90	506 109.20	518 543.47	562 891.34	586 125.00	531 245.74	433 389.10	426 831.60	411 412.10	437 923.80	
Ash produced [ton]	114 166.54	118 492.40	116 501.11	115 431.77	118 423.25	131 810.91	131 708.27	122 988.91	101 899.23	100 283.10	94 200.41	98 238.40	**1 364 144.29**
Camden													
ash %	23.24	23.70	22.88	23.55	24.64	25.34	21.58	24.41	23.11	23.55	22.81	24.30	
Coal burn [ton]	406 196.48	424 931.58	449 439.10	364 319.90	328 060.41	366 973.44	377 668.60	372 182.17	489 141.30	315 566.40	279 751.58	317 456.10	
Ash produced [ton]	94 404.12	100 705.29	102 840.65	85 780.54	80 818.34	93 005.38	81 506.93	90 847.43	113 037.62	74 303.78	63 800.15	77 153.90	**1 058 204.13**
Duvha													
ash %	29.61	30.36	28.94	29.91	29.97	29.93	29.43	29.12	28.37	36.02	28.33	28.52	
Coal burn [ton]	466 899.81	590 754.92	648 132.10	567 238.80	452 698.67	396 048.43	514 232.60	529 158.03	476 220.60	445 015.30	487 882.06	585 939.90	
Ash produced [ton]	138 247.17	179 339.02	187 542.86	169 645.27	135 695.52	118 537.30	151 319.63	154 104.58	135 110.45	160 312.31	138 233.58	167 096.58	**1 835 184.25**
Grootvlei													
ash %	27.02	26.10	26.10	28.29	25.56	26.61	27.40	31.00	28.58	26.98	27.97	28.86	
Coal burn [ton]	119 335.24	130 699.93	97 782.68	124 234.90	150 960.27	62 832.90	129 261.40	142 962.57	142 109.30	179 031.10	179 060.79	177 181.90	
Ash produced [ton]	32 242.70	34 112.68	25 521.28	35 147.48	38 583.41	16 722.64	35 411.55	44 319.01	40 620.51	48 308.98	50 081.19	51 137.73	**452 209.15**
Hendrina													
ash %	26.15	25.80	26.28	25.39	25.68	25.65	24.69	25.55	25.65	25.37	23.82	25.46	
Coal burn [ton]	464 717.49	451 686.00	296 842.80	434 495.00	438 091.00	432 509.00	429 358.00	426 665.00	433 432.40	318 316.00	267 487.00	332 998.90	
Ash produced [ton]	121 544.95	116 534.99	77 998.62	110 314.86	112 504.92	110 934.58	106 025.97	109 009.66	111 174.24	80 759.63	63 715.51	84 795.24	**1 205 313.19**
Komati													
ash %	22.07	24.10	22.03	22.75	24.25	23.34	22.09	19.16	19.20	20.18	21.00	25.49	
Coal burn [ton]	133 566.81	118 244.83	126 622.60	89 421.84	131 717.31	90 396.01	121 313.80	51 766.31	40 669.66	111 670.40	97 375.36	99 604.78	
Ash produced [ton]	29 483.87	28 497.00	27 888.93	20 340.01	31 947.07	21 098.46	26 804.16	9 920.39	7 809.95	22 534.49	20 452.42	25 389.17	**272 165.94**
Kriel combined													
ash %	27.05	26.36	27.21	25.19	27.30	26.39	25.83	26.60	26.20	25.96	26.17	24.66	
Coal burn [ton]	603 279.85	556 470.01	675 953.90	639 504.30	765 900.91	602 774.03	574 959.20	586 828.85	595 625.20	722 382.10	640 300.95	582 122.70	
Ash produced [ton]	163 187.20	146 685.49	183 927.06	161 077.14	209 111.09	159 068.69	148 539.27	156 116.31	156 068.45	187 537.83	167 594.04	143 550.12	**1 982 462.70**

Kusile													
ash %	25.60	26.20	26.32	27.36	27.14	27.04	22.03	16.62	28.30	29.90	30.06	27.43	
Coal burn [ton]	54 162.90	182 668.49	224 300.86	182 534.80	179 517.34	187 155.68	59 380.74	54 850.68	1 143.69	102 309.50	0.00	135 552.44	
Ash produced [ton]	13 867.96	47 863.40	59 030.51	49 941.28	48 717.83	50 602.85	13 080.69	9 115.94	323.67	30 590.54	0.00	37 185.53	**360 320.20**
Matla													
ash %	26.86	29.34	29.56	31.28	32.50	28.72	26.71	27.00	27.50	27.00	28.99	27.03	
Coal burn [ton]	895 718.38	902 816.17	834 270.70	784 724.20	757 780.37	865 940.64	1 073 580.00	938 140.68	878 279.70	988 497.90	810 114.75	768 704.00	
Ash produced [ton]	240 626.59	264 871.73	246 582.89	245 497.04	246 247.10	248 727.16	286 700.08	253 297.98	241 526.92	266 894.43	234 881.11	207 768.85	**2 983 621.88**
Medupi													
ash %	33.66	33.36	34.18	34.43	34.78	33.79	33.79	34.49	34.31	34.34	34.24	33.70	
Coal burn [ton]	603 529.48	619 390.28	497 166.30	476 483.70	508 408.85	356 867.63	356 543.50	440 268.50	439 664.00	260 060.00	233 329.25	272 984.00	
Ash produced [ton]	203 117.91	206 638.57	169 931.44	164 053.34	176 800.70	120 570.87	120 461.36	151 866.48	150 870.61	89 308.63	79 900.92	91 999.10	**1 725 519.94**

5.1 Impact of future coal technologies

The South African Coal Roadmap (SANEDI, 2013) provides a multi-scenario analysis of the future possibilities and interventions in the local coal industry. The coal roadmap proposes four possible routes ranging from business as usual (which include life extensions to the current fleet) to South Africa leading the world in reducing coal footprint by employing ultra-super critical power stations and underground coal gasification (UCG), cyclic pulverised fuel (PF) and Fluidised Bed Combustion (FBC) based technologies. South Africa predominantly will have to employ a route that is a combination of all scenarios to move towards a less coal intensive society while trying to negate the challenges encountered in supply and demand.

Proposed new coal technologies such as UCG and FBC technologies are expected to lower water usage and emissions. The risk associated with UCG technology, where very deep coal seams are burnt underground, is the contamination of underground water reserves (Atkins Consultants, 2004). Eskom's Majuba UCG pilot plant is a pioneering project in this technology which receives little public attention because of proprietary concerns. FBC technologies are proposed to be viable for the Waterberg coal field which has large reserves of high ash and low-calorific value coal (SANEDI, 2013).

On the other hand, emission reduction mechanisms such as retrofitting existing power plants with flue gas desulphurisation (FGD) (Section 6.2.1) are expected to increase the water footprint of power plants. The indicative water consumption factors of some of the advanced technologies are presented in Table 24. These need to be verified with actual operational figures. To add to the uncertainty, the physical location of the coal power plant, which affects factors such as humidity, evaporation and altitude is an important consideration when operational water consumption must be estimated (Thopil & Pouris, 2016).

Table 24 Indicative water consumption factors for new coal technologies

Technology Type	Water Consumption (l/kWh)
Pulverised fuel with FGD	0.25
Pulverised fuel with carbon capture storage	0.1
Fluidised bed coal	0.16

5.2 Carbon capture

The construction of a carbon capture demonstration plant in South Africa is planned (Sparks et al., 2014) although considering the capital investment required to retrofit the existing power stations, it remains to be seen whether this technology will be taken up. Carbon capture and storage technology (CCS) reduces emissions of carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O). However, this technology reduces energy capacity and increases water consumption at coal fired electricity plants (Wilson et al., 2012). CCS technology requires more fuel to produce the same amount of energy as non-CCS technology. Water withdrawal and consumption for CCS power plants is estimated to be between seven and fifty times greater than the water required for non-CCS technology; the water impact of CCS is therefore very high.

6 Comparison with previous Natsurv report

In 2005 when the previous Natsurv was published, South Africa produced 192 000 GWh of electricity, consuming approximately 245 000 Ml of water. The specific raw water consumption in 2005 was found to be 1.95 l/kWh for recycling wet-cooled coal-fired plants, 0.09 l/kWh for dry-cooled coal fired plants and 0.258-0.306 l/kWh for nuclear: an average specific water consumption of 1.28 l/kWh over all technologies. In 2018/2019, South Africa produced a total of 234 407 GWh for distribution, over 42 000 GWh (18%) more than in 2005, consuming 292 344 Ml of water; 47 344 Ml (19%) more than in 2005.

In 2013/2014, the specific raw water consumption was 2.2 l/kWh for wet-cooled stations, and 0.12 l/kWh for dry cooled stations. Overall power generating and cooling technologies, the 2013/2014 specific water consumption was 1.35 l/kWh, which was in line with Eskom's water use target (see section 4). From 2014/2015 to 2016/2017 the specific water consumption increased above Eskom's target of 1.35 l/kWh, but this reduced to 1.3 l/kWh in 2017/2018, but again increased to 1.41 l/kWh in 2018/2019 missing the target of 1.36. There as therefore an increase in specific water use of 0.27 l/kWh (9.2%) since the 2005 Natsurv.

In 2005, the total dry-cooled installed capacity in South Africa was 10 477 MW, which was approximately 33% of the total installed capacity for coal fired stations. As of March 2019, the installed dry-cooled capacity for the coal fired power stations was 13 806 MW, 34% of the total installed coal fired capacity of 40 170 MW. Once the New Build plants Kusile and Medupi are fully commissioned, the installed dry-cooled coal-fired capacity will increase to 20 188 MW, which will be 50% of the installed coal fired capacity.

In 2005, a maximum specific water intake of 2.5 l/kWh at wet-cooled power stations and 0.8 l/kWh at dry-cooled power stations was recommended. 15 years later, despite inefficiencies and high consumption of the return to service stations, the specific water use for wet-cooled stations is still well within this target and far exceeds the dry-cooled target of 0.8 l/kWh, with the average dry-cooled water use at 0.12 l/kWh.

In the previous Edition of Natsurv 16, renewable power generation such as wind turbines and solar was not considered. Due to the growing importance of these technologies and their potential future impact, a review has also been conducted into their water use, even though it is comparatively small. Concentrating solar power plants have specific water use similar or in excess to that of coal fired power stations (0.3 l/kWh for dry cooling and 3 l/kWh for wet cooling) due to the requirement for cooling and location in areas with high temperatures.

South Africa's water use for power generation was also not benchmarked against international water use in the previous Natsurv. This is considered in this report, see section 9.

6.1 Future cooling technologies

Advanced cooling technology development is focused on research to improve the efficiency of existing cooling technologies and to discover techniques, designs, and applications that reduce the economic disadvantages and improve the efficiency associated with alternative technologies. Other important considerations for improvements include reducing the size or footprint of cooling systems, utilizing alternative coolants instead of potable water, and enhancing condensation, evaporation, and sensible heat transfer mechanisms.

Research and development on advanced cooling technology for power plants is focused on several targets. For reducing water consumption in wet cooling systems, research is aimed at less evaporative loss in cooling towers, more efficient and compact liquid-cooled heat exchangers, or condensers, and more efficient once-through cooling designs. For dry cooling systems, research has focused on reducing condensing temperatures by improving the air-side heat transfer coefficient without significantly increasing ACC size or air-side pressure drop (fan horsepower) and developing improved methods for control of flow-assisted corrosion inside the tubes. In this arena, EPRI is pursuing early-stage, high-risk concepts and developing advanced technologies with game-changing potential for reducing freshwater withdrawal and consumption and improving energy conversion efficiency at existing power plants.

EPRI research on advanced cooling includes the following select technology investigations, as reviewed by Bushart, 2014.

6.1.1 Thermosyphon Cooler System

Hybrid cooling systems typically incorporate conventional wet cooling towers and air-cooled condensers, with the latter operating most of the time and the former employed to mitigate performance penalties at high ambient temperatures. A novel hybridization concept, developed by Johnson Controls, applies a dry-heat-rejection technology, called thermosyphon cooling (TSC), which was originally developed for space conditioning in buildings. TSC units, consisting of an evaporator and an air-cooled condenser, pre-cool the hot water from the steam condenser prior to the wet cooling tower.

By reducing the heat load on the cooling tower, TSC hybrid systems have the potential to reduce annual evaporative losses, makeup water requirements, and blowdown volumes by up to 75% without sacrificing electrical output on the hottest summer days. Relative to other dry cooling options, TSC technology promises easier, more flexible, lower-cost integration at existing plants and in New Builds in incremental, modular sections, with minimal plant outages required.

6.1.2 Dew-Point Cooling Tower

The cold-water return temperature of traditional recirculating wet cooling towers can be limited by the temperature and humidity of the ambient air. To address this issue, EPRI, in collaboration with the Gas Technology Institute (GTI), is investigating a concept called dew-point cooling to attempt to reduce the cold-water return temperature further. This technology enhances the standard tower performance by constructing dry channels between wet channels in the tower, with a thin-walled fill material, and exploiting evaporative cooling on the wet side of the fill to cool the ambient air passing over the dry side. This pre-cooled air is then used for contact evaporative cooling with the condenser water.

Dew-point cooling offers the potential to improve the water efficiency as well as the overall efficiency of thermal power plants with conventional wet and hybrid wet-dry cooling towers. Preliminary evaluations indicate that tower fill replacements that allow the pre-cooling of ambient air could significantly reduce evaporative losses and makeup water requirements.

6.1.3 Eco-WD Cooler

The Eco-WD Cooler (wet-dry cooling tower), developed by EVAPCO, has the potential to conserve water and energy at power plants by employing an innovative wet-dry cooling tower technology. This cooling tower technology works in wet-dry mode during the hot summer months and in dry mode the remainder of the year. In wet-dry mode, hot water is initially cooled through air-cooled heat exchangers and further cooled through heat exchanger bundles sprayed with treated water. In dry mode, the spray system is turned off, and the system uses no water for evaporative cooling. In addition, the Eco-WD Cooler has a limited visible condensate plume in wet-dry mode and no visible plume in dry mode. The technology could be easily retrofit to plants currently using all-wet cooling.

6.1.4 Hydrophobic Condenser Tube Surface Treatment

The design of steam condensers is based on film wise condensation since condensing steam will form a water layer on the surface of the condenser tube. This film of condensed water acts as an additional barrier to the heat transfer process. Significant enhancement of the heat transfer efficiency can be achieved by forcing the condensate to bead up into droplets, which can be swept off the surface by the steam flow, a process known as dropwise condensation. However, to date, there has not been a reliable means of generating dropwise condensation under industrial conditions for long periods, since the required coatings and surface modifications deteriorate with use. NEI Corporation has developed a hydrophobic surface treatment, called SuperCNTM, which has shown potential for promoting dropwise condensation in industrial condensers.

The treatment results in a durable, micron-thick coating on condenser tubes, leading to dropwise condensation. Research currently underway is investigating the application characteristics and customer incentives of the hydrophobic surface treatment technology.

Results indicate that the hydrophobic coating can be applied to the shell side of an existing, in-place heat exchanger with a flow coating method in a cost-effective way. The coating was shown to have significantly better abrasion and scratch resistance than a pristine stainless-steel substrate. In testing, the coated tube maintained its high hydrophobicity after three months of durability testing, with alternating conditions of continuous condensation and ammonia vapor conditioning. A cost-benefit analysis of the coating technology also suggested that potential savings are available from the application of hydrophobic coating to surface condenser tubes.

6.1.5 Hybrid Dry/Wet Dephlegmator

The chief disadvantages of dry cooling systems are power capacity reductions and efficiency penalties during periods with hot temperatures. EPRI is sponsoring research at the University of Stellenbosch in South Africa to address this issue. The research is focused on developing a new design for the part of an ACC called the dephlegmator, which provides a secondary condenser that facilitates vapor flow through the primary condensers and flushing them of any non-condensable gases.

This research project proposes to develop a novel hybrid (dry/ wet) dephlegmator (HDWD) that would replace the conventional all-dry dephlegmator unit in an ACC. The HDWD consists of two stages; the operating mode of the second stage can be controlled in response to changing ambient conditions. During periods of low ambient temperature, when air cooling is sufficient, the second stage is operated dry. During hotter periods, deluge water is sprayed over the plain tubes, and the second stage is operated as an evaporative condenser. It is believed that this technology has the potential to increase power production on the hottest days as compared to conventional ACCs. It would also use less makeup water than wet cooling tower systems and less water than currently used by dry cooling with evaporative pre-cooling of the inlet air.

6.2 Flue gas desulphurisation in South Africa

Eskom's Kusile power station has achieved a first in Africa in terms of the implementation of clean-fuel technology. The power station's new wet flue gas desulphurisation plant has achieved a 93% efficiency rate in the removal of sulphur oxides. This ensures the clean and environmentally friendly production of coal. The air-quality control system was installed by General Electric (GE) and ensures that Kusile is the most efficient and cleanest coal power plant in Eskom's fleet.

The Medupi power plant will be backfitted with wet FGD (WFGD) once the secondary water supply becomes available. Until then there is insufficient water available to supply operation of six units with FGD. Once completed Medupi will be the largest dry-cooled power plant in the world. The implementation of dry cooling reduces the water consumption from approximately 2 l/kWh to 0.14 l/kWh and came with an energy penalty of roughly 1.75% on the overall thermal efficiency of the plant. If retrofitted the WFGD plant will be a consumer of water in the power plant however due to the implementation of the various water reduction measures the water requirement of the power plant with WFGD (power plant with WFGD≈ 0.35 l/kWh) is still expected to be lower when compared to the conventional wet-cooled power plants (power plant without WFGD ≈ 2 l/kWh) within Eskom's fleet (Eskom, 2018). For all units, wet FGD was preferred over dry FGD, due to removal capacity and having a saleable by-product, i.e. gypsum. This preference was also partly in recognition of the fact that a dry FGD has a size limitation. Eskom does note that Medupi and Kusile plants alone will produce more gypsum than the South African market can sustain. So, there will be a gradual roll out of this and other (NOx) air quality abatement measures.

The Integrated Resource Plan of 2010 assumed all new coal capacity to be fitted with FGD, which suggests this is firm policy for coal capacity beyond Medupi and Kusile (DoE, 2011). Existing plants, given low sulfur levels in the low-ash coal used, all meet the 2015 compliance levels for SO_2 but would require FGD retrofitting to meet the 2020 compliance levels. However, after Eskom argued that high capital costs, long outage times (estimated at 120-150 days), constraints on supply of limestone sorbent, and water scarcity militate against FGD retrofitting, applications for a five-year postponement of SO_2 regulations were granted in February 2015 to all affected Eskom plants by the Department of Environmental Affairs. It remains unclear whether any fleet retrofit of FGD will take place.

6.2.1 Water-Saving FGD Technologies

Coal combustion can lead to the formation of sulfur dioxide (SO_2) and small amounts of sulfur trioxide (SO_3). Further amounts of SO_3 are generated in the selective catalytic reduction (SCR) system, which is widely used for NOx control. These oxides can lead to environmental and health problems. Consequently, both international and national regulations have been implemented that limit the amount of sulfur oxides (SO_x) and other pollutants that can be emitted from coal-fired power plants. A wide range of commercial flue gas desulfurization (FGD) processes are available to remove SO_x from the flue gas. Wet scrubbing is by far the most common system with over 80% of installed capacity worldwide.

However, these systems require large supplies of water. FGD technologies that reduce water usage are becoming more important due to the large number of systems being installed globally. Reducing water usage for FGD is particularly important for power plants in arid regions of the world and areas subject to drought. These include areas in Australia, China, South Africa, and the U.S. In addition, the per capita availability of water is declining, and therefore competition between agricultural, urban/domestic, and industrial water use is likely to intensify. This will increase pressure on power plants to lower their water consumption.

Cooling is responsible for most water usage at many plants. The FGD unit is the second-largest consumer of water, closely followed by the boiler (Zhai et al., 2009). Adding a CO_2 capture (amine-based) system increases the FGD makeup water consumption by approximately 45-50% for both subcritical and supercritical plants. This is partly because a very low flue gas SOx level (<10 ppm) is needed to avoid contamination of the amine solvent. For sites utilizing a dry/air cooling system instead of a wet tower, or once-through seawater cooling, the water consumption of the FGD wet scrubber is proportionally much higher: It can easily be responsible for 40-70% of the total site water usage. Carpenter (2014) reviewed FGD processes that consume less than 60% of the amount of water used in conventional limestone wet scrubbers and may provide options for lower water consumption while still meeting air emission requirements.

6.2.1.1 Semi-Dry Scrubber Technologies

Dry scrubbers are the second most common FGD system installed on coal-fired power plants with less than 10% of global installed capacity. Two principal types of dry scrubbers are in use today:

- Spray dry scrubbers (SDS), also called spray dry absorbers or lime spray dryers
- Circulating dry scrubbers (CDS).

Both systems use a calcium-based reagent (calcium hydroxide) which is introduced as a slurry in SDS or, in some CDS designs, as a dry powder with separate injection of water. All the water introduced into the SDS/CDS vessel is evaporated, and therefore no wastewater is generated. So, although they are termed dry scrubbers, they do, in fact, consume water and are more accurately classified as semi-dry FGD systems. They typically consume approximately 60% less water than wet scrubbers (Carpenter, 2012)

6.2.1.2 Spray Dry Scrubbers

Around 40 GW of coal-fired capacity worldwide are equipped with SDS, the majority of which are installed in the U.S. In the SDS process (Figure 25), a concentrated lime slurry is introduced into the top of the absorber vessel through rotary atomizers or dual fuel nozzles. These atomize the slurry creating a fine mist of droplets containing the reagent, which reacts with SO_2 and SO_3 in the downward flowing flue gas to form calcium sulfite and sulfate. Simultaneous cooling of the flue gas occurs.

The flue gas exits the absorber and passes through the particulate collector where the reacted sulfur compounds, fly ash, and unreacted sorbent are removed. The clean flue gas is then emitted to the atmosphere through the stack. A portion of the solid products collected from the bottom of the scrubber and the particulate collector is typically mixed with wastewater from elsewhere in the plant and recycled back to the scrubber to improve sorbent utilization, as well as to promote droplet drying in the SDS vessel. The flue gas typically takes approx. 12-15 sec to pass through the scrubber.

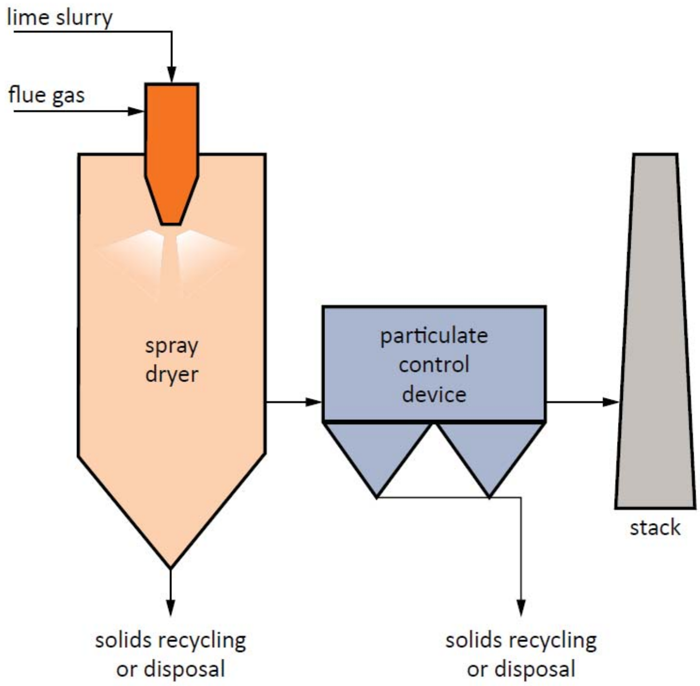


Figure 25: Spray dry scrubber system

6.2.1.3 Circulating Dry Scrubbers

The total global capacity of utility units using CDS is approximately 15 GW (Jones & Weilert, 2011) There are units in Europe, Asia (in particular China), and the U.S. Unlike SDS, CDS are up-flow reactors in which the flue gas and calcium hydroxide reagent are introduced at the bottom of the reactor. The removal of SOx can take place either in a fluidized bed [circulating fluidized bed (CFB) scrubbers and gas suspension absorbers] or in an entrainment process (NID™).

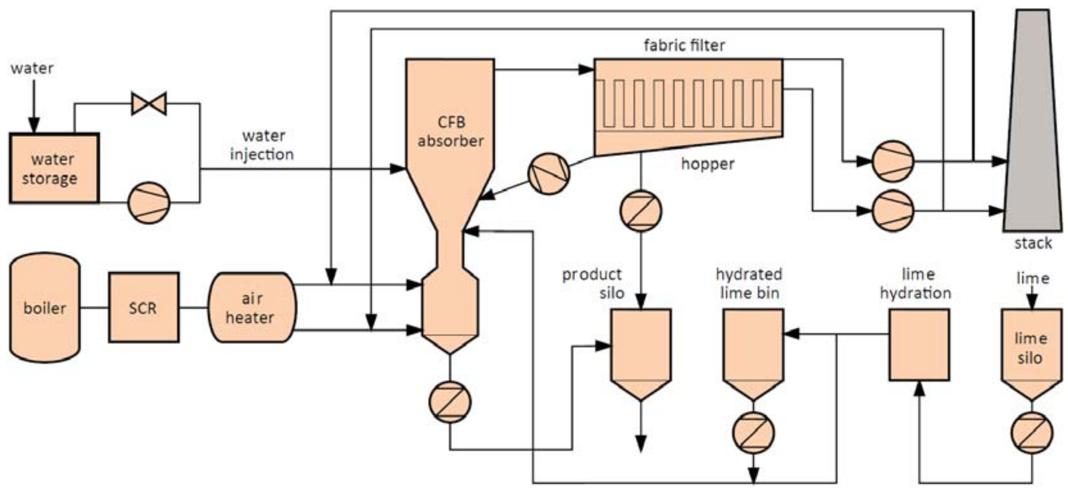


Figure 26: CFB scrubber system at Dry Fork power plant

6.2.1.4 Circulating Fluidized Bed Scrubbers

A flow diagram of the CFB system at the Dry Fork power plant near Gillette, Wyoming, U.S., is given in Figure 26. The flue gas enters the CFB reactor through a bank of venturis. These increase the velocity of the flue gas before it mixes with the dry hydrated lime (calcium hydroxide) and recycled solids to create the characteristic fluidized bed. The fluidized bed allows a high degree of contact between the flue gas and solids for the desulfurization reactions to occur. In some designs, the fresh sorbent and recycled solids are injected above the venturis, whereas other designs introduce them below the venturis. Just enough water is sprayed into the fluidized bed to both humidify and cool the flue gas to the optimum level for the desulfurization reactions to occur, but no more than can be fully evaporated. Therefore, no wastewater is produced.

A multistage humidification system has been applied in China in which the water is injected at several levels. This approach distributes the water more evenly throughout the reaction zone, and the time that the humidity content is above the critical moisture point is extended. This increases the effective residence time for the desulfurization reactions. SO2 removal efficiency increased by over 1% when the water was injected in two stages, while the total water consumed was the same as that consumed in single-stage humidification (Gao, et al., 2010).

The Gas Suspension Absorption process was developed in Denmark by FLS Miljø (now FLSmidth) and is installed on only a few power plants. The process is like CFB scrubbers but has an integral cyclone for recirculating the solids via a recirculation box to the fluidized bed reactor.

6.2.1.5 NID™ System

Alstom's Novel Integrated Desulfurization (NID™) technology is installed on over 60 coal-fired power plants in Europe, Asia, and the U.S. The unique feature of NID™ technology (Figure 27) is its J-shaped duct reactor, which has a square cross section and is integrated with a pulse jet fabric filter or, less commonly, an electrostatic precipitator. Fresh reagent and the solid products collected from the fabric filter are hydrated in the humidifier mixer by the addition of water. The humidified calcium hydroxide mixture is then injected near the bottom of the NID™ absorber into the upward flowing flue gas. With the high solids-to-water ratio, evaporation occurs rapidly, cooling and humidifying the flue gas, while flash drying the particulates. No water is sprayed into the absorber, unlike CFB scrubbers. The chemical reactions and drying times within the absorber take less than 2 sec (Buecker & Hovey, 2011).

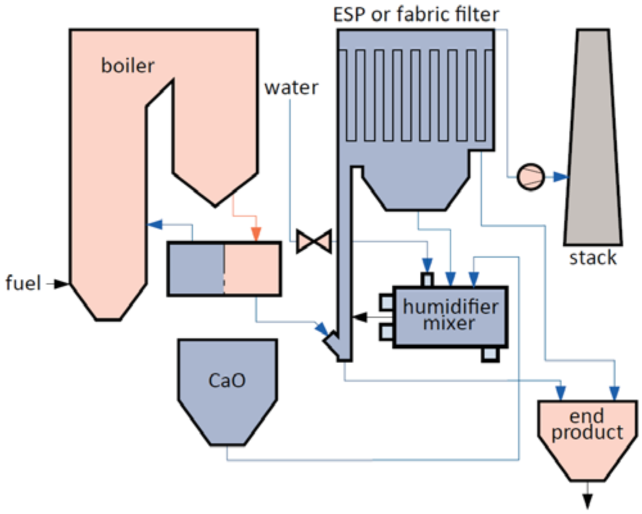


Figure 27: NID^{TM} process (Electric Power Research Institute, 2007)

The water consumption of the different types of semi-dry scrubbers is similar, and they all consume about 60% less water than wet scrubbers. SDS are typically used on small to medium-sized units burning low- to medium-sulfur coals. CDS can be applied to larger units burning low- to high-sulfur coals. Single-unit CFB scrubber designs of up to 750 MW are now available (Bönsel et al., 2012). SO_2 removal efficiency is 90-98% for SDS, and over 98% for state-of-the-art CDS, a value approaching that for wet scrubbers. In addition, dry scrubbers remove nearly 99% of SO_3, over 95% of the HCl, HF, and other acid gases, and over 95% of mercury (especially if a mercury sorbent is also used). An advantage of the systems over wet scrubbers is that they capture more SO_3 and oxidized mercury. Wet scrubbers typically capture only about 50-80% of oxidized mercury.

Both SDS and CDS systems have a good turndown capability, enabling operation at low loads, and there is no significant difference in their load-following ability. A CDS system, though, consumes more reagent than a SDS for the same conditions of coal sulfur and SO_2 removal efficiency (Jones & Weilert, 2011). Power consumption is similar at less than 1% of a power plant's output. This is lower than the approximately 1.2 to 2% consumed by wet scrubbers. Although investment costs are lower for SDS and CDS than for a similar-sized wet scrubber, operating costs are generally higher mainly due to the higher sorbent costs: Lime is more expensive than limestone. Unlike wet scrubbers, dry scrubbers produce no wastewater (and hence no wastewater treatment facilities are required), and the by-products are dry and therefore more easily handled. Unfortunately, there is no market for the by-products, whereas saleable gypsum is produced in the limestone wet scrubbing processes. Disposal of the by-products can be expensive.

6.2.1.6 Dry Technologies

Dry sorbent injection processes offer the least water consumption of the FGD processes discussed. They consume no water, or only a minimal amount if the sorbent needs hydrating or the flue gas is humidified to improve SO_2 removal efficiency.

They account for roughly 2% of installed FGD capacity worldwide. The sorbent can be directly injected at several locations, as shown in Figure 28; actual injection locations will be plant specific because not all the units shown are necessarily present in every power plant. Unlike the wet and dry scrubber processes, the flue gas is not passed through a separate desulfurization vessel – the sorbent is injected directly into the furnace (furnace sorbent injection, FSI), the inlet to the economizer (economizer sorbent injection, ESI), or duct (duct sorbent injection, DSI). Hence there is a smaller footprint and thus the technology is easier to retrofit. The solid reaction products, unreacted sorbent, and fly ash, are collected in the downstream particulate control device.

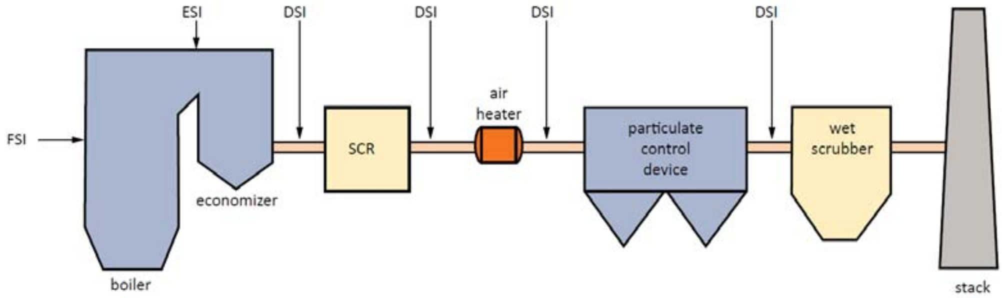


Figure 28: Possible sorbent injection locations

Sorbent injection systems are one of the simplest and cheapest commercial FGD systems to install and operate. The major cost is the sorbent itself. Limestone or hydrated lime (calcium hydroxide) is commonly injected into the furnace as these sorbents can withstand the high temperatures within the furnace.

Generally, sodium-based sorbents are more reactive than calcium-based ones, resulting in a higher SOx removal efficiency. But they are more expensive. A co-benefit of FSI and DSI is the capture of some of the HCl, HF, and mercury in the flue gas, although this does depend on the sorbent used. The by-products are dry, and thus are relatively easy to handle and manage; no wastewater is produced. Sorbent injection systems are best suited to small- or medium-sized power plants (depending on the sorbent) burning low- to medium-sulfur coals, and where only a moderate SO_2 removal efficiency is required. The main drawback of the sorbent injection processes is their lower SO_2 removal efficiency compared to wet and semi-dry scrubbers. Injecting sodium-based reagents, such as sodium carbonate-based ones, into the duct can remove only approximately 70-90% of SO_2, but 90-98% of the SO_3. SO_2 removal efficiency with calcium hydroxide is lower. Power consumption is low, approximately 0.2% of the plant's output. Capital costs are less than for semi-dry and wet scrubbers, but operating costs can be high, mainly due to the cost of the sorbents.

6.2.1.7 Multi-Pollutant Systems

Multi-pollutant processes remove several regulated pollutants in one system and may be more cost-effective than installing a series of traditional systems that remove the same number of pollutants. Two of the commercial systems that effectively consume negligible amounts of water are the ReACT™ and SNOX™ processes.

6.2.1.7.1 *ReACT™ Process*

The ReACT™ (Regenerative Activated Coke Technology) process has been, or is being, installed on coal-fired units in Japan, Germany, and the U.S. It employs a dry activated coke sorbent which is regenerated. Over 99% of SO_2 and SO3, 20-80% NO_x, >90% of mercury (both elemental and oxidized), and approx. 50% of the remaining particulates are removed in the process when burning low- to medium-sulfur coals (Peters, 2011). The ReACT™ system is installed after the particulate control device. The process consists of three stages: adsorption, regeneration, and by-product recovery (Figure 29). The flue gas enters through the side of the adsorber where it passes through the bed of coal-derived activated coke that is moving slowly downward. SO_2, SO3, NO_x, and mercury are removed by the sorbent through adsorption, chemisorption, and catalytic reactions. Ammonia is injected into the duct upstream of the adsorber and into the regenerator to promote the removal of SO_2 and NO_x.

No water is added to the system as no flue gas humidification or saturation is required. As a result, only 1% of the water required by limestone wet scrubbers is consumed. Power consumption is lower than wet scrubbers at approx. 0.7% of the plant's gross output. No liquid wastes are produced. Mercury can be recovered from the activated coke and the spent activated coke can be sold and utilized in other applications. However, ReACT™ may not be economical for high-sulfur coals.

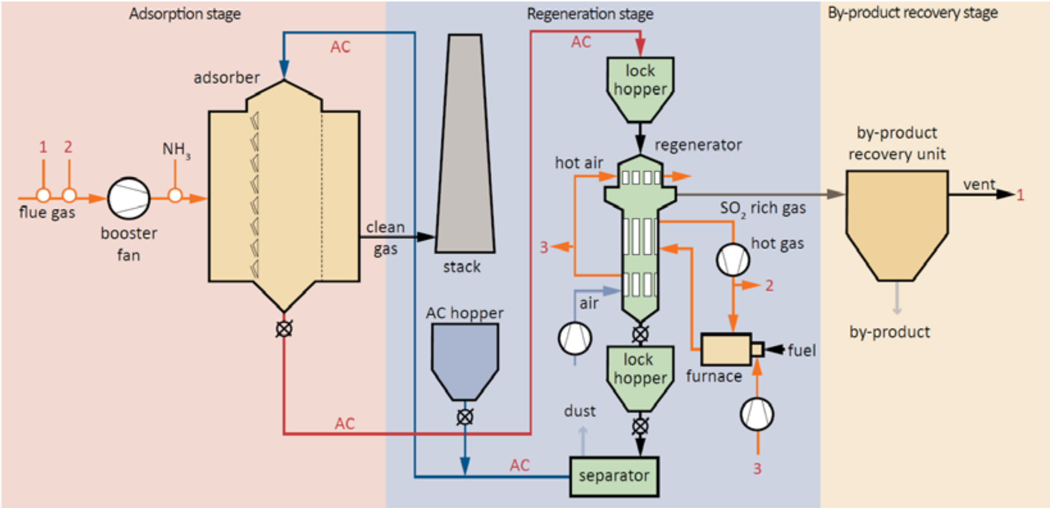


Figure 29: ReACT[TM] Process (Peter, 2011)

The numbers 1, 2 and 3 represent the streams that re-enter the process)

6.2.1.7.2 *SNOX™ Process*

The SNOX™ process, developed in Denmark, is a dry regenerative catalytic process that removes up to 99% of SO_2, SO_3 and NO_x, and essentially all of the remaining particulates (Schoubye & Ibæk, 2012). The flue gas exiting the particulate control device is reheated in a heat exchanger to approx. 400°C and ammonia is injected before it enters the SCR reactor (Figure 30). Here NOx is catalytically reduced by ammonia to nitrogen and water. The flue gas is then heated and SO2 is catalytically oxidized to SO_3 in a second reactor. Later designs have integrated the two catalytic reactors into a single vessel. The flue gas exiting the oxidation reactor passes through the hot side of the heat exchanger where it is cooled as the incoming flue gas is heated. SO_3 reacts with water in the flue gas to form sulfuric acid vapor, which is then condensed into 94-95% concentrated sulfuric acid in the WSA (Wet Sulfuric Acid) condenser. The process was designed for high-sulfur fuels and thus is more cost effective for high-sulfur coals. No water is consumed in the process and saleable sulfuric acid is produced. The process also recovers heat from the flue gas. It has been estimated that, for a 500-MW coal-fired power plant, the heat recovery would be more than the supplemental power needed for the SNOX™ plant and could provide a potential net gain equivalent to 8 MW (National Energy Technology Laboratory, 2000).

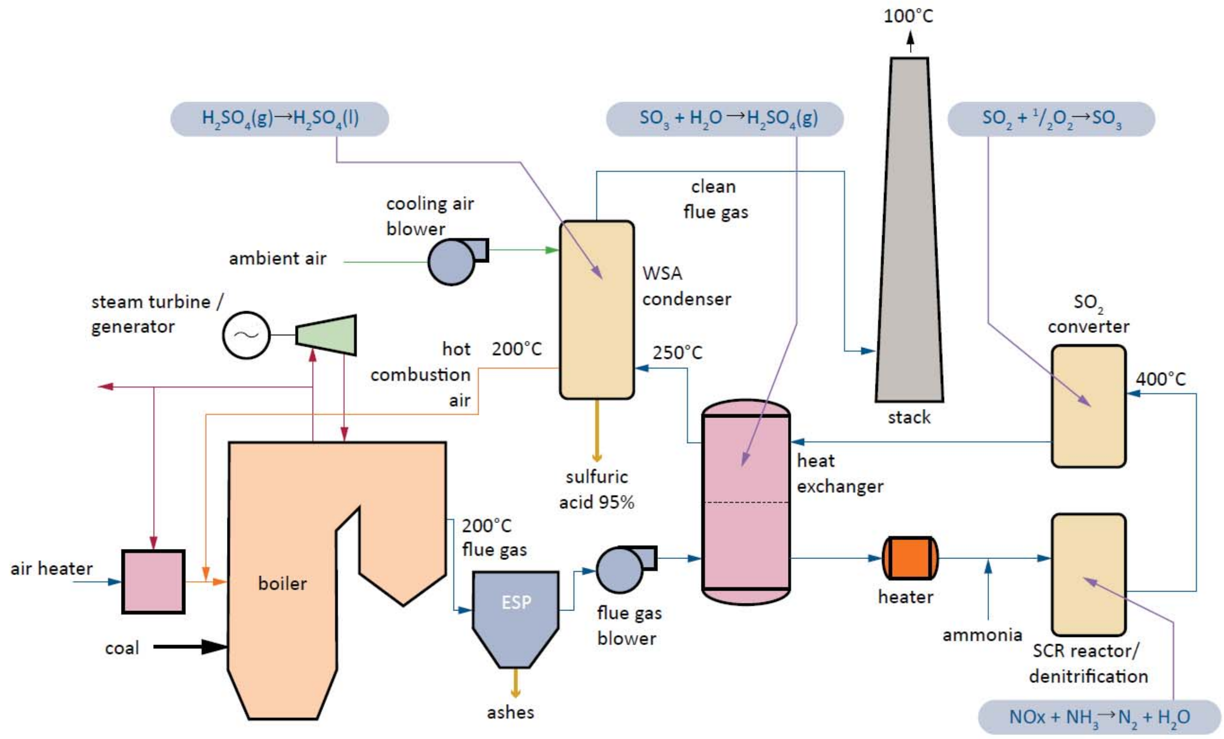


Figure 30: SNOX™ process (Lindenhoff, P., 2011)

6.2.1.8 FGD concluding remarks

There are several commercial low-water FGD systems available that are suitable for coal-fired power plants in areas where water is scarce. These are either essentially dry, such as the sorbent injection, SNOX™, and ReACT™ processes, or have a relatively low water usage. Moreover, technologies that produce a low-temperature flue gas with low SOx and water vapor contents, such as ReACT™, could lower CO_2 scrubbing costs, if future regulations require CO_2 to be captured.

7 Water saving strategies

As can be seen in the preceding sections electric power generation requires reliable access to large volumes of water. This need persists at a time of declining supply, when regions of the world are experiencing water constraints due to population growth, precipitation fluctuations, and changing demand patterns. At the same time there is the demand for reduction in carbon emissions, the technologies for which are also water intensive (Macknick et al., 2011).

Although water needs are plant specific, for most pulverized coal-fired power plants over 90% of water demand is drawn for cooling. As a result, research organizations worldwide are seeking to optimize power plant water utilization by developing technologies to reduce the largest single use: cooling. Thermal power plants cannot operate without adequate cooling; steam from the electricity generation turbine must be cooled to minimize back pressure on the turbine. Improved cooling allows for power plants to operate at an overall higher efficiency.

Freshwater use impacts can be reduced by utilizing dry cooling or by using non-freshwater sources as a cooling medium. Initial work suggests that the performance penalty for CSP facilities switching from wet cooling to dry cooling results in an annual reduction in output of 2%-5% and an increase in the levelized cost of producing energy of 3%-8%, depending on local climatic conditions (Turchi et al., 2010). Using national averages, the annual performance penalty for switching from wet cooling to dry cooling for nuclear plants is 6.8%, combined cycle plants 1.7%, and other fossil plants (including coal and natural gas steam plants) 6.9% (EPA, 2009). Further efforts are needed to evaluate performance and cost penalties associated with utilizing dry or hybrid cooling systems for fossil fuel facilities using carbon capture technologies. Utilizing reclaimed water, such as municipal wastewater, is another approach that could lessen the impact of the power sector on freshwater resources and wastewater treatment facilities. The legal and physical availability of municipal wastewater, especially in rural areas, may be a limiting factor to its widespread usage, and the cost and performance penalties of utilizing such sources must be investigated further (EPRI, 2003).

The choice of cooling system may play an important role in the development of our future electricity mix. Differences between cooling systems can have substantial environmental impacts on local water resources. Employing wet cooling technologies imposes an inherent trade-off between relatively high water consumption and relatively high water withdrawals, which has important implications for regional cooling system policies and regulations. A reduction in withdrawals (but a corresponding increase in consumption) may benefit a watershed that has an abundance of water but may lead to concerns in an area that is already lacking water. A shift away from, for example, once-through cooling systems in coastal areas that withdraw saline water, to inland recirculating systems such as cooling towers that primarily consume freshwater, will impact watersheds and water availability differently depending on local conditions. The use of alternative cooling technologies may serve as an energy security benefit for utilities and communities, given uncertainties in future scenarios of water availability and expected vulnerabilities for power plants (Dai, 2010, NETL, 2010). Reduced levels in bodies of water, or substantial increases in the temperature of these bodies of water, may require thermal power plants to run at lower capacities or to shut down completely, as was seen in France in 2003 (Poumadère, 2005). Utilizing dry cooling or non-freshwater sources avoids some of the risks associated with these drought and climate change scenarios.

All Eskom power stations have developed water strategy implementation plans, focusing on actions to reduce water use and ensure compliance. Progress against plans is monitored and reported, and initial actions have been closed out (Eskom Holdings SOC Ltd, 2018).

Eskom has introduced several innovative technologies and approaches over the last two decades to save water. These include dry cooling, desalination of polluted mine water for use at the power stations, and technical improvements on treatment regimes to maximize the beneficial use of water.

7.1 Water recovery, recycling, and re-use

The ongoing drive to conserve water has been extended to a wide variety of innovative processes to recover, recycle and reuse the water already in use in the power plant. This calls for treating the water to isolate and remove the contaminants that invariably build up as the plant systems and subsystems perform their functions, and to send the treated water back into use. The goal is to reduce the amount of fresh water required for makeup at the front end, and to reach a point of minimized water use or even zero discharge at the back end.

Different uses in the plant have different requirements for the purity of the water. The requirements for boiler make-up are higher, for example, than those for cooling, and those for cooling have higher requirements than those for the limestone slurry used for scrubbing SOx out of the flue gas. In some situations, blowdown from one system can be used directly as make-up to another system. In other cases, blowdown can be treated and then recycled to the original process or sent to another process.

In general, if water is to be treated for reuse, it is preferable to treat it completely for the highest possible level use, and then let the water cascade down to lower uses, rather than clean it up just a little bit for an intended intermediate use. This is a rule of thumb, but not absolute; reuse strategy is quite plant specific.

Table *25* below shows the uses of water in terms of descending water quality requirements.

Table 25 Water quality by use

Water Use	Water Quality Requirements
Boiler/reactor feedwater	Highest quality
Gas turbine inlet cooling	High Quality
Domestic use	Medium quality
Cooling tower	Medium quality
Ash sluicing	Low quality
Limestone slurry for FGD	Low quality

Blowdown from the boiler and cooling tower, along with waste slurry from the FGD operation and the sluicing of ash, are typically sent to the disposal ponds, although blowdown from the boiler is sometimes sent to the gas turbine. The solids settle to the bottom, while the clear water at the top (the supernatant) is treated and recycled back into the plant. In many plants, the ash or sludge is actively dewatered through a filtering process (e.g. drum filter), rather than waiting for the solids to settle out by gravity alone.

Eventually, what is left is a concentrated residual of wastewater. This waste can be sent to an evaporation pond on site for further concentration/drying into a solid, or actively treated to a solid state in an evaporator/crystallizer. The residue is then disposed of as solid waste.

7.1.1 Zero-Liquid Effluent Discharge (ZLD) Water Recycle Treatment

Power plants have been using water treatment processes to recycle waste streams for many years. Generally, there are two commonly used treatment technologies for recycling plant wastewater; reverse osmosis (RO), evaporator and evaporator-crystallizer systems. RO is a process, shown schematically in Figure 31 that utilizes pressure to force water through a membrane leaving most of the dissolved salts behind.

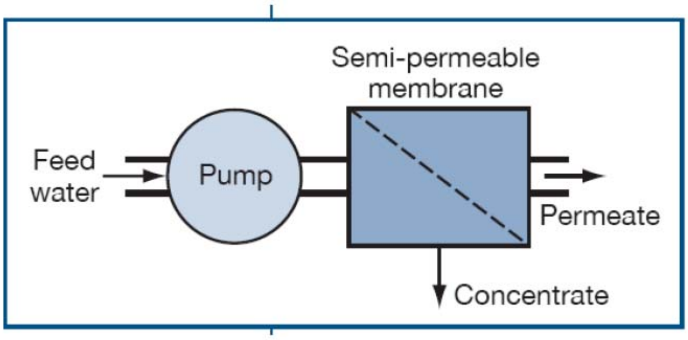


Figure 31: Reverse osmosis system schematic

RO can remove up to 99.5% of the salts in water when used in this manner. Reverse osmosis systems are typically comprised of a softening/silica removal step, followed by filtration, final softening and then RO. Softening removes salts from water that can form mineral deposits (e.g. calcium, magnesium, and silica). Mineral deposits must be removed because they interfere with the performance of the RO process by covering up the membrane surface where salts are rejected. Filtration removes particulate matter that also inhibits water passage through the RO membrane. Waste streams generated by the RO process consist of solid waste from the softening system, waste brine from the final softening system and a waste brine stream from the RO. The system can be designed to recover 75% to 85% of the waste streams.

Evaporation processes essentially distillate purified water from contaminated wastewater. The water to be treated is heated, evaporating a portion of the flow. The evaporated steam is compressed and condensed producing the high-quality water and leaving a further concentrated brine behind. A schematic of a vertical, falling film evaporator, typical of current design, is shown in Figure 32.

Evaporator/crystallizers take the concentrated brine stream from the evaporator and evaporate the remainder of the free water leaving only moist solids behind for ultimate disposal, resulting in a zero-liquid discharge system. A schematic of a ZLD crystallizer is shown in Figure 33 (EPRI, 2008).

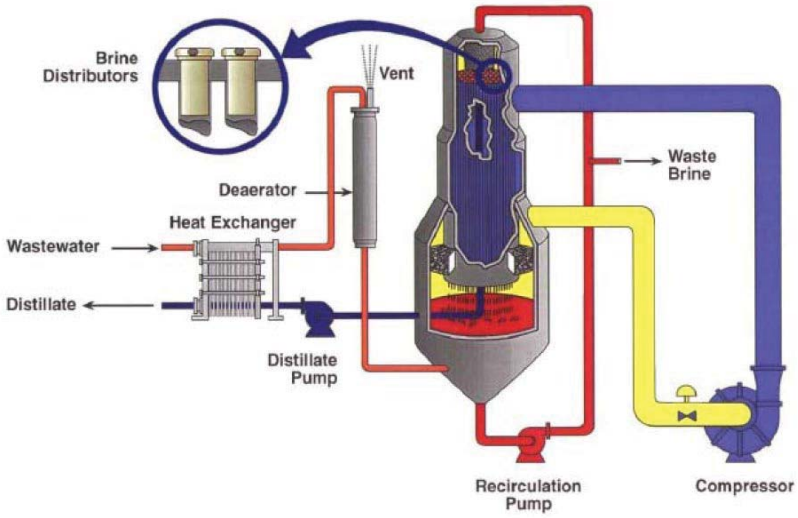


Figure 32: Vapor compression falling film evaporator schematic

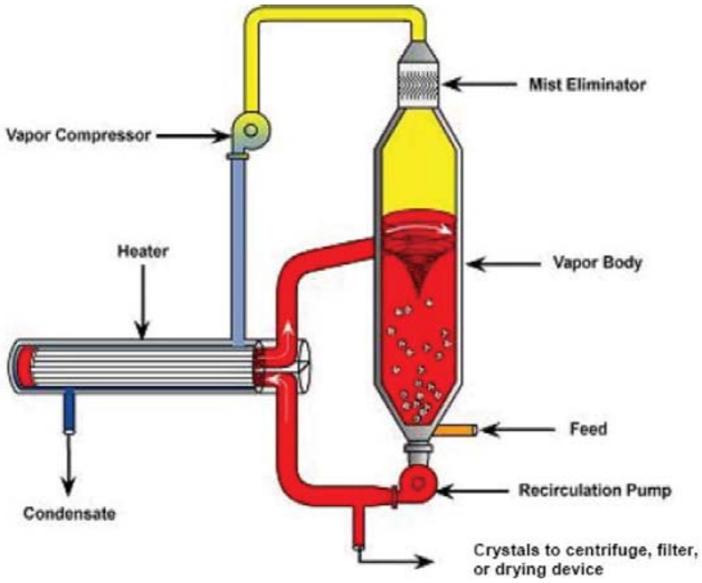


Figure 33: Crystallizer Schematic

7.1.1.1 Freeze desalination

Production of water that is fresh from brackish water, industrial brines and leachate can be achieved through the utilization of the concept of freezing and cooling (Zikalala et al., 2017). Freeze desalination is a process for treatment of brackish water through harvesting and melting the ice crystals thereby producing freshwater (Lin et al., 2017). It works on the principle that solutes are rejected as ice is produced (Adeniyi et al., 2012). Freezing as a process involves the abstraction of energy from water to produce ice that can be separated from the liquid phase. The basic principle that governs the freezing process is the crystallization that isolates the contaminants in the solution through ions. When the water is frozen slowly, ice crystals float to the water surface while the contaminants are gradually concentrated in the mother liquor. When the ice is separated from the mother liquor and washed, the concentration of the remaining dissolved solids in the melted water is very low. As the ice is harvested the concentration of the contaminants increases until minerals that reaches saturation concentration begin to crystallize, the temperature and concentration at which the minerals begin to crystallize is called the eutectic freeze point (Choudry, 2017).

Lower theoretical energy requirement, flexibility on different salinity levels together with composition of feed in-process brine, and reduction in the potential for scaling, corrosion, and fouling issues are the advantages of freeze desalination in comparison with other processes (Bhide & Shaligram, 2016).

The other unique advantage of freeze desalination is the energy requirement that is low in comparison to evaporative desalination. This is because the latent heat of is 334kJ/kg meanwhile the latent heat of vaporization water is 2340kJ/kg, thus freezing need mechanical power while evaporation needs heat (Adeniyi et al., 2012; Gomadurai et al., 2017; Samsuri et al., 2015).

The estimated cost of desalination by freezing can be reduced from \$1.85/m^3 in thermal desalination process to \$0.93/m^3. (El Kadi & Janajreh, 2017).

7.1.2 Eskom's Application of water saving technologies to achieve water efficiency

Eskom has an environmental policy that includes policies on the following:

- Water management
    - Stormwater management
    - Groundwater management
    - Environmental impact
- Effluent management
- Energy management

Eskom aims for continuous improvement and information on environmental issues such as water optimisation and effluent reduction is communicated to all employees.

Eskom has undertaken a number of electricity demand side management measures to influence the manner in which its customers use electricity to increase the beneficial use of the commodity. Although water conservation has not been the primary motive for these initiatives, water savings have been generated. For every kilowatt-hour of electricity that is saved, on average approximately 1.26 litres of water are also saved.

As a result of the implementation of these measures, overall specific water consumption was reduced significantly from 2.85 l/kWh in 1980 to 1.35 l/kWh in 2011 (AEA, 2013).

Over the coming years, Eskom aims to further increase efficiency to reduce water consumption. Both coal-fired new-build projects at Medupi and Kusile, will use dry-cooling technology, which will significantly reduce the relative water consumption per unit of electricity produced, by as much as 90% compared to a wet-cooled station.

As part of its long-term plan Eskom also intends to apply several new innovative water-saving technologies. Its water management strategy sets out how it aims to reduce freshwater intake at power stations and to re-use effluent. In addition, Eskom has engaged with the DWA national water resources planning directorate to ensure that water resources and infrastructure planning needs are factored into the national water resources strategy.

Through these measures, Eskom aims to bring down water consumption per unit of electricity produced from the current 1.35 litres per kWh to 0.99 litres per kWh in 2030, representing a reduction of approximately 26%. Should these measures prove effective, instead of requiring 397 million m^3 of water to generate electricity in 2030, it is projected that only 270 million m^3 will be required (Figure 34).

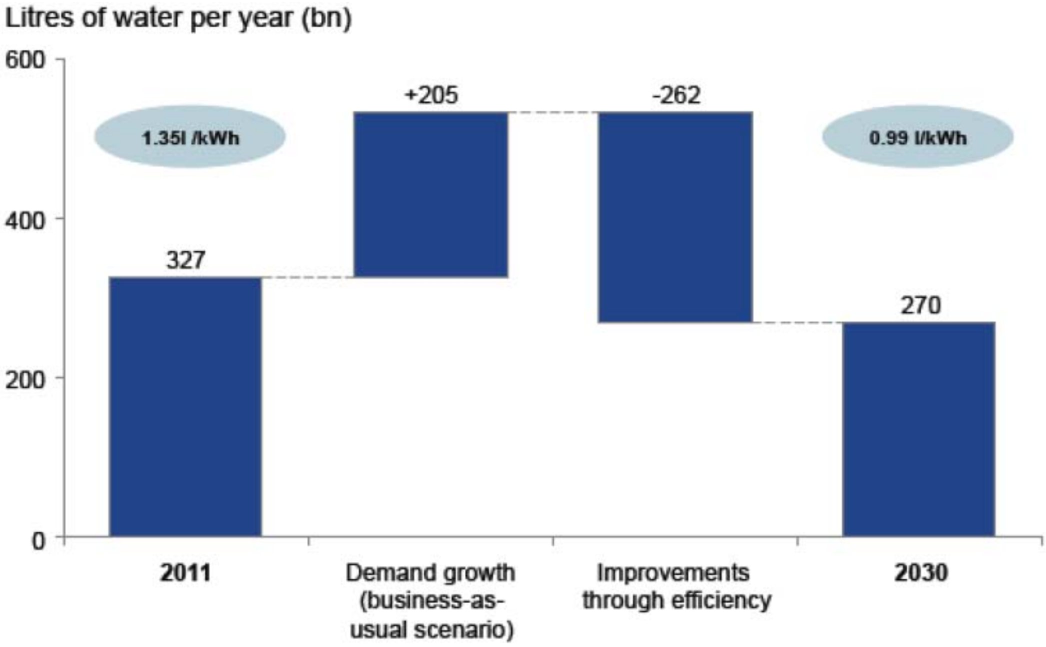


Figure 34: Forecast annual water use in coal fired power stations

7.1.2.1 Dry cooling technology

With South Africa's historically scarce water resources, Eskom has been a world leader in dry-cooled coal-fired power plants for more than 30 years. The utility operates both the world's largest direct-dry-cooled (Matimba Power Station) and indirect-dry-cooled (Kendal Power Station) plants. Since it does not rely on evaporative cooling for the functioning of the main systems overall power station water use is approximately 15 times lower than a conventional wet-cooled power station. In 2010-2011, the Eskom fleet consumed a total of 327 million m^3 of water for power generation. Without innovative, efficient cooling systems in place, the consumption would have been 530 million m^3.

Matimba Power Station has an installed capacity greater than 4000 MW. It makes use of closed-circuit cooling technology reducing water consumption to around 0.1 l/kWh of electricity distributed, compared with about 1.9 litres on average for the wet-cooled stations (19 times less than an equivalent wet-cooled power plant). Matimba uses about 3.5 million m^3 of water per year, compared to an equivalent wet cooled power plant, which would use 50 million m^3. The choice of dry-cooled technology for Matimba was largely influenced by the scarcity of water in the area.

Eskom calculates a number of significant energy and cost penalties for dry cooling when compared with wet cooling. One penalty involves increased power demand for cooling fans. At each of Matimba's six units, the dry cooling system uses 48 fans that are 30 m in diameter. Fan operation corresponds to an auxiliary power demand of 72 MW, or 2% of the plant's total generating capacity. In addition, generation performance at a dry-cooled plant is sensitive to meteorological conditions. In particular, high ambient temperature and high winds can result in reductions of generating capacity of up to 10-15%.

Kendal Power Station near Witbank in the Mpumalanga Province is the largest indirect dry-cooled power station in the world with an installed capacity of greater than 4100 MW. The plant employs six natural-draft dry-cooling towers, each 165 m tall. Water from a standard surface condenser is circulated to the towers, where it enters a series of heat-exchange elements at the base of the cooling shell. Air enters the bottom periphery of the towers, is heated by passing over the heat-exchange elements, and rises in the tower, pulling in cooler ambient air from the bottom. The system does not require fans. Water consumption at the plant is around 0.08 l/kWh.

The move to dry cooled technology has resulted in estimated combined savings more than 70 million m^3 per year.

All fossil-fuelled new-build Eskom power plants are dry cooled, and the utility is in the process of constructing new dry-cooled plants at Medupi and Kusile. Medupi Power Station, currently under construction, will surpass Matimba as the largest direct-dry-cooled plant. Medupi will have six units with a total installed capacity of approximately 4800 MW. The footprint of the ACC at Medupi is 108 × 669 m, or the equivalent of 10 football fields. The design at Medupi incorporates several lessons learned at Matimba, including extended spacing between the ACC and turbine hall to minimize impacts from wind.

Through deployment of ACC for dry cooling, there is a distinct advantage of no risks of contaminated water ingress. However, in the absence of cooling-water ingress, make-up water becomes the principal ingress route for most common dissolved/suspended contaminants other than carbon dioxide. The second major route is via the condensate polishing regeneration. The target value of boiler make-up water for the Eskom ACC plants is 0.06 µS/cm and there is a limit value of 0.07 µS/cm (Galt et al., 2009). The values set by Eskom are stricter than all other international guidelines, like those of VGB54, Electric Power Research Institute (EPRI) and KEMA (now DNV GL, The Netherlands). The lowest theoretical conductivity value of water at 25°C is 0.055 µS/cm. When this value is achieved (mostly in a lab), there are no other compounds present except for water and its ionized cation and anion forms respectively hydronium (H_3O^+) and hydroxide (OH^-). In practice demineralization units and international guidelines provide specifications for make-up water between 0.10 to 0.20 µS/cm at 25°C. This water can be made from demineralized units, which however depends on the raw water source. At this site there are two to three different sources of water, namely river and dam water. Exceptional effort in pre-treatment and polishing must be made to reach this stringent value. Additionally, these power stations most also abide to the Zero Liquid Effluent Discharge (ZLED) policy of Eskom (Section 7.1.2.3) and associated water use licenses. The only water leaving an Eskom plant is treated domestic sanitary effluent (treated sewage) and uncontaminated storm water. This implies that brine and wastewater streams produced at the water process plant (demineralization plant) warrant further treatment in the ZLED (APEC, 2016).

Eskom recommends the use of ACC if the aim is to save water in water-scarce areas. From a chemistry perspective, special attention is required to mitigate Flow Accelerated Corrosion (FAC) in the water/steam cycle. Eskom's plants apply an elevated pH level of oxygenated treatment (Alkaline OT) to condition their water/steam cycle. Also, high make-up water is required. Eskom's operational experience is that these values are easily met with no additional operational cost other than expected. These costs are higher when adopting less stringent water quality requirements. Eskom can realize the make-up requirements (conductivity target ≤0.6 µS/cm) as the demineralization plant has been specifically designed to cope with this requirement. The water treatment plant (WTP) is equipped with several continuous electro-deionisation polishing units (CEDI), Reverse Osmosis (RO) and Ultra-Filtration (UF) separation steps capable of processing river water (and stored water) as a raw water source. Eskom applies, and highly recommends, a full flow condensate polishing plant to ensure water quality requirements within the water/steam cycle are met.

It is planned that by adopting the next generation of high efficiency boilers (clean coal technologies), the high efficiency will offset the energy penalty associated with operating ACC.

7.1.2.1 Desalination

Where power station design permits, Eskom has endorsed a policy of zero liquid effluent discharge (ZLED) at its wet cooled stations in which water is cascaded from good to poor quality uses until all pollutants are finally captured in the ash dams. The effective use of this practice has seen the company introduce the use of desalination plants at Lethabo and Tutuka. These treatment processes allow the company to introduce polluted mine-water from the tied collieries for re-use at the power stations. This assists with the prevention of negative environmental impacts on both the surface and groundwater. This process uses microfiltration and reverse osmosis to treat the water. While the capital and operational costs are high, the process delivers permeate water recovery rates of 87% and 80% respectively. The benefit to Eskom is a reduced water intake for the two stations, with a combined potential saving of around 5 million m^3 per annum (AEA, 2013).

7.1.2.1 Water infrastructure

Over the past 40 years Eskom has worked closely with the South African Department of Water and Sanitation (DWS) to development of an extensive network of pipelines and dams (Section 4.1.1). These projects, primarily aimed at providing a secure water supply to the power stations and their associated collieries, has had a significant impact on the viability of supplying water to both industries in the area and water for domestic use.

7.1.2.2 Water metering and monitoring

The DWS measures the water they supply to Eskom's power stations. A metering procedure has now been adopted which has seen the implementation of 'revenue' class meters that measure to a level of accuracy of 0.5%. This is an improvement on the previously accepted 5% level of accuracy. During the process of supplying raw water to the power stations, water is stored in a reservoir to mitigate interruption of supply.

The number of meters differs per power station. The minimum requirements for measuring of significant streams are presented below. Eskom is in the process of phasing in metering, which will assist in the development of accurate water balances. All these streams must be measured with a flow meter:

Raw water

- Raw water received (can be reservoir inlet or reservoir outlet, site specific)
- Raw water to third parties
- Raw water to water treatment plant, i.e. demineralised water and portable water (can be metered separately, site specific)
- Raw water to Fire range (site specific)
- Raw water to service water range (site specific)
- Raw to cooling water
- Raw to Flue Gas Desulfurisation

Potable water

- Potable water produced
- Potable water to head tanks (could be the same as potable water produced where there are no unmetered supplies/tap offs before the head tank)
- Potable water to third parties
- Potable water to consumers
- Potable water to fire range (site specific)
- Potable water to cooling water treatment plant – calculate/account/estimate for, not essential to measure (site specific)
- Potable water production effluent (sandfilter or MF or UF backwash water)

- Clarifier sludge discharged (account for/estimate)
- Filtered water to third party (Matla/Kriel)
- Potable water to irrigation (site specific)

Demineralised water

- Demineralised water plant inlet (cation inlet)
- Demineralised water plant outlet (demineralised water produced)
- Demineralised water to low-pressure and/or high-pressure range (site specific)
- Total demineralised water to station
- Demineralised water to each unit, i.e. total make up to each unit (normal and emergency make-ups)
- Demineralised water to condensate polishing plant (CPP) (backwashes, regens and transfers)
- Clarifier sludge discharged (account for/estimate)
- Demineralised water including semi-treated/filtered water) used for regeneration of iron exchange (IX) plant and spent regenerants
- Demineralised water for CIPs (site specific)
- Demineralised water for flushing of membranes (account for/estimate)

Supplementary water

- Polluted mine water recovered to the treatment plant (site specific)
- Treated mine water recovered to treatment plant (site specific)
- Treated sewage recovered from own sources to treatment plant
- Treated sewage recovered from third parties (site specific)
- Storm water harvested in raw water reservoirs, station drains dam and ash dump/dump system (Account for/estimate)
- Water recovered from station drains
- Water recovered from other dams

Cooling water

- Cooling water blowdowns to ashing system (Specific to wet ashing stations)
- Cooling water clarifier sludge (account for/estimate)
- Ash water recovered to cooling water: required for specific sites recovering the water
- Seepage recovered to cooling water: required for specific sites recovering the water

Sewage

- Raw sewage to treatment plant (legal requirement)
- Sewage from third parties to treatment plant (legal requirement, site specific)
- Final effluent discharge (legal requirement)
- Treated sewage for internal use (irrigation, ash dams, ash dumps, etc.) (Site specific, depending on WUL conditions)

Wastewater

- Reject water to ash dams/dust suppression/evaporation ponds (legal requirement (WUL))
- Permeate produced (to cooling water, demineralization plant, etc. (site specific)
- Wastewater licenced for water use (such as dust suppression) (site specific according to WUL)
- Station drains inflow (includes station drains common inflow, inflows into each station drains dam for both clean, dirty, and mixed drains)

Auxiliary cooling

- Open circuit
  - Potable water make-up to auxiliary cooling
  - Filtered water make-up to auxiliary cooling
  - Blow down to station drains
- Closed circuit
  - Demineralised water make-up to auxiliary cooling
  - Unitised demineralised water make-up to auxiliary cooling

Rainfall

Rainfall must be measured within the power station boundaries and recorded daily.

7.1.2.3 Eskom's Zero liquid effluent discharge policy

Eskom has a Zero Liquid Effluent Discharge (ZLED) philosophy driven by the company management since mid-1990 which means operations at stations should normally not result in any spillages into the environment. For Eskom, this implies that brine (from RO units or polishing units) is discharged on ash dump sites. The ash content of the coal can reach as high as 45%. On the ash dump sites water is needed for dust suppression, irrigation for rehabilitation plant life and for stabilization of the dump. Thus, degraded water is used for this purpose instead of fresh water. According to the survey less than 10% of incoming water is disposed as effluent. The exact quantity is not known due to insufficient metering. This was raised at Water Forums internally as a requirement for compliance to Norms and Standards.

Table 26 and Table 27 indicate examples of the effluent disposal practices for Eskom's dry and wet cooled systems. Most of the wastewater is disposed on the ash systems, with some being recycled to the cooling water systems. Domestic wastewater may be disposed to the local sewer. Less than 10% of water is reused; again, the exact quantities are not known due to insufficient metering. Flocculation, acid treatment and lime treatments are applied to water for re-use.

Table 26 Effluent management in dry cooled systems

	Dry Cooled Systems				
Power Stations:	**Matimba**	**Kendal**	**Majuba**	**Medupi**	**Kusile**
Effluent Treatments / Recycled Water:					
Sand Filter Backwash	Recycled to CW		Recycled to CW		
Raw Water Clarifier Sludge	Recycled to CW	Ash System	Recycled to CW		
Cooling Water Blowdown	Ash System		Ash System		
Cooling Water Sludge	Ash System		Ash System		
Spent Regenerants	Ash System	Ash System	Ash System		

Table 27 Effluent management in wet cooled systems

	Wet Cooled Systems				
Power Stations:	**Duvha**	**Kriel**	**Matla**	**Lethabo**	**Tutuka**
Effluent Treatments / Recycled Water:					
Sand Filter Backwash	Recycled to CW	Ash System	Recycled to CW	Ash System	Recycled to CW
Raw Water Clarifier Sludge	Recycled to CW	Ash System	Recycled to CW	Ash System	Recycled to CW
Cooling Water Blowdown	Ash System	Recovered as is into CW	Ash System	Recovered as is into CW	Ash System
Cooling Water Sludge	Ash System	Ash System	Ash System	Ash System	Ash System
Spent Regenerants	Ash System	Ash System	Ash System	Ash System	Ash System

As a result of legislation, it is anticipated that as of 2021, co-disposal of regeneration brine may be prohibited. Eskom would need to investigate brine concentrators and crystallisation, as discussed in section 7.1.1.

7.1.3 Stormwater management

Eskom has a storm water management plan in place. Chemical storage areas are bunded, but waste storage areas are not. Storm water drains are not clearly marked.

8 Best Practice

A summary of the best practice aspects surveyed for Eskom is presented in Table 28.

Table 28 Best Practice indicators

	Planned	Comments
Water sub metering	In process and Implemented	Eskom reimplemented the Water Accounting Framework Standard across Eskom stations The measure to which stations complies with this standard differs. It is currently observed to not be satisfactory. An audit on the measure of compliance with this standard is recommended
Energy sub metering	Implemented	Energy submetering is implemented
Monitoring and targeting	In process and Implemented	Eskom has implemented monitoring and targeting at various levels. Tracking of implementation success is done according to monthly performance reviews, annual audits and others
Heat recovery	In process and Implemented	The generation efficiency shows the relationship between energy input and use, Eskom retains some “heat” after condensing for re-heating. Cogeneration, i.e. the practice of converting waste thermal heat from exhaust and cooling systems to additional power, is in process
Water foot printing	Implemented	Eskom is aware if its total use from each catchment. Various strategies have been implemented to reduce this footprint
Carbon foot printing	Implemented	Eskom is aware of its carbon footprint. Accordingly, Eskom designed its climate change strategy and is investing in renewable energy. Eskom uses specific procedures to determine the Carbon Emissions Factor
Life cycle analysis	In process	This is considered during design of larger projects
Water pinch analysis	Implemented	WPA is a systematic technique for reducing water consumption and wastewater generation through integration of water-using activities or processes This is a strategic intent at Eskom
Energy management training	Implemented	
Water management training	Implemented	
Solid waste segregation	In process	Currently not successful

	Planned	Comments
Rainwater harvesting	In process	In strategy, not yet implemented
ISO 9001	Implemented	Yes (quality management)
ISO 14001	Implemented	Yes (environmental)
SANS 1702	Implemented	Competency of testing and calibration. Eskom make use of contracted services that comply with SANS 17025
OHSAS 18001	Implemented	OHSAS 18001 certified

9 International water use comparison and benchmarking

An abundant supply of good quality water is of great benefit to the operations and economics of power production. Historically, proximity to such a water source, as well as to fuel, transmission access and load centre, has been a primary requirement for siting power plants. However, in recent times water has become a more contentious siting issue as population and economic growth have put increasing pressure on water resources. Power plants must compete with the demands of municipalities, agriculture, and industry for surface and groundwater supplies. Water costs are rising, and the long-term trend is for increasing environmental restrictions on the use and discharge of water by all users.

By far the largest use of water by power plants is for cooling; that is, for condensing the steam flowing out of the turbine generator and using the water to carry the rejected heat into the atmosphere. Other major uses of water in the power plant include flue-gas scrubbing, ash sluicing, boiler make up, gas turbine inlet cooling, dust control, and domestic activities.

In the future, the competition for water will require electricity generators on a global scale to go further to conserve fresh water supplies. There are several avenues. One is to find innovative ways to recycle water within the power plant. Another is to use water-saving or dry technologies wherever possible as for cooling, scrubbing and ash handling. A third is to use wastewater supplies from municipalities, agricultural runoff, brackish ground water, or seawater. All these approaches alter the economics of power generation. Recycling often requires capital equipment and the cost of chemicals to treat and upgrade the water quality. Dry technologies require little or no water, but are usually more capital intensive, and typically exact a penalty in terms of plant performance. Finally, wastewater must be acquired, delivered, and treated before it can be used in the power plant. All these water-conserving options raise the cost of power generation (EPRI, 2008).

Water requirements for electric power generation are highly variable. They are influenced by several factors, but most significantly by the type of plant, fuel, and choice of the power plant cooling system. Secondary influences are the local climate, the source of water, the environmental regulations to which the plant is subject, and the choice of water management system to be employed.

In defining water use, it is important to distinguish between water withdrawals and water consumption. As defined by the US Geological Survey (USGS), water withdrawals are defined as ‘the amount of water removed from the ground or diverted from a water source for use’ (USGS, 2009). Water consumption is a subset of the withdrawals category and refers to the amount of ‘water withdrawn that is evaporated, transpired, incorporated into products or crops, or otherwise removed from the immediate water environment’ (USGS, 2009).

Several studies have applied the concept of the water footprint to the energy sector for electricity generation by consolidating estimates of water use coefficients for a range of energy technologies (Barker, 2007; Gleick, 1994; DOE, 2006; Macknick et al., 2011; Mulder et al., 2010; Mielke et al., 2010). The results of these studies collectively demonstrated that the quantity and quality of water demanded varies significantly by energy process and technology, from rather negligible quantities of water used for wind and solar electricity generation to vast, agricultural-scale water use for the cultivation of biofuel feedstock crops. Hence, the selection of technologies deployed for energy production within a given location has important implications on regional water use. Spang et al. (2014) explored the geographic distribution of water use by national energy portfolios by introducing a consistent indicator to empirically assess coupled water-energy systems. By defining and calculating an indicator to compare the water consumption of energy production for over 150 countries, they estimated that approximately 52 billion cubic meters of fresh water is consumed annually for global energy production. Further, in consolidating the data, it became clear that both the quality of the data and global reporting standards should be improved to track this important variable at the global scale. The authors used the metric “water consumption for energy production” (WCEP). The WCEP indicator used is conceptually similar to the water footprint but is more specifically defined as a detailed estimate of regional surface and groundwater consumed by the processes and technologies specifically for producing electricity.

The WCEP indicator focuses on water consumption, rather than withdrawals, as the key water use variable. While both consumption and withdrawals are important variables to consider within the broader regional management of water, water consumption is especially useful in understanding the impact of energy sector operations on the water sector. Consumption represents an exclusionary use of water where use by one user directly prevents other users from accessing that quantity of the resource, providing a direct measurable impact on water security and sustainability. In contrast, water withdrawals may be returned to the water source (albeit at a potentially lower quality) to be used again by other consumers or by the natural environment, and hence represent a more equivocal metric for assessing regional water impact.

Water consumption varies significantly by generation technology, fuel type, and cooling type at the scale of the individual power plant. While water is used for a variety of processes in the production of electricity (e.g. flue gas desulfurization, washing solar panels), most of the water use is for cooling in thermoelectric power plants. Because of its high specific heat, water is an ideal heat transfer medium for cooling steam after it exits the generator turbine. Some power plants use seawater for cooling or even dry cooling technologies (using air rather than water for heat transfer), but most power plants consume freshwater for cooling (Platts, 2010).

Data on international power plants was extracted and processed from Platts World Electric Power Plants (WEPP) Database (2010). Regional aggregation in the WEPP database is as follows: Africa; Australia, New Zealand, & Oceania; Asia; Commonwealth of Independent States (CIS); Europe; Latin America; Middle East, and North America. While the WEPP database is relatively comprehensive for generator technology and fuel type, it only contains cooling technology information for roughly 37% of relevant power plants in the database. For power plants with no cooling type specified, the cooling portfolio mix by generator and fuel type exhibited in the rest of the country (or region, as necessary) was assumed.

The WEPP database provides information on power plant capacity, but not annual production. To convert the installed capacity of the power plants to an estimate of annual electricity production, each technology was assumed to have operated at its capacity factor, as estimated by the National Renewable Energy Laboratory (NREL, 2010), also shown in Table 29. Converting installed capacity to estimated annual electricity generation is calculated using:

Estimated Generation = Installed Capacity *Capacity Factor*365 days/year *24 h/day.

To cross-validate the power generation amounts for each power plant technology calculated from the WEPP database capacity data, the total energy generation portfolio was normalized to national electricity production data from the EIA for 2008 (EIA, 2011).

Table 29 Electricity generation categories with capacity factors, water consumption factors and data sources (modified from Spang et al., 2014)

Electricity Generation Category[a]			Capacity factor[d]	Water Consumption factor (l/kWh)			
Fuel	Technology[b]	Cooling[c]		Estimate[e]	Min	Max	Source[f]
Coal	ST	CT	0.85	2.599	1.818	4.165	[1]
		OTF	0.85	0.947	0.378	1.199	[1]
		CP	0.85	2.063	1.134	2.650	[1]
		AIR	0.85	0.097	0.097	0.097	[1][g]
Nuclear	ST	CT	0.9	2.725	2.196	3.370	[2]
		OTF	0.9	1.516	0.378	1.516	[2]
		CP	0.9	2.308	1.516	2.725	[2]
Gas/oil	ST	CT	0.85	2.765	2.120	4.165	[2]
		OTF	0.85	1.098	0.720	1.552	[2]
		CP	0.85	1.022	1.022	1.022	[2]
		AIR	0.85	0.097	0.097	0.097	[1][g]
	CC	CT	0.85	0.796	0.176	1.134	[2]
		OTF	0.85	0.378	0.076	0.871	[2]
		CP	0.85	0.907	0.907	0.907	[2]
		AIR	0.85	0.014	0.014	0.454	[2][g]
	GT	NA	0.85	0.191	0.191	1.289	[2]
Biomass	ST	CT	0.68	2.092	1.818	3.654	[1]
		OTF	0.68	1.134	1.134	1.134	[1]
		AIR	0.68	0.097	0.097	0.097	[1][g]
Waste heat	ST	CT	0.68[h]	2.092	1.818	3.654	[1][i]
		OTF	0.68[h]	1.134	1.134	1.134	[1][i]
		CP	0.68[h]	2.308	1.516	2.725	[2][j]
		AIR	0.68[h]	0.097	0.097	0.097	[1][g]
Geothermal	ST	CT	0.84	2.650	2.650	2.650	[2]
		OTF	0.84	1.134	1.134	1.134	[1][i]
		CP	0.84	1.476	1.134	1.818	[1][i]
		AIR	0.84	1.098	1.022	2.383	[2]
Solar	ST	CT	0.32	3.067	2.801	3.254	[2]
		AIR	0.32	0.097	0.097	0.097	[2]
	PV	NA	0.2	0.022	0.004	0.097	[2]
Wind	NA	NA	0.39	0.000	0.000	0.004	[2]

[a] All data for global electricity production comes from two sources: Platts (2010) and EIA (2011).

[b] Electricity generation technology types: ST = steam turbine; CC = combined cycle; GT = gas turbine; PV = photovoltaic; NA= not applicable.

[c] Thermoelectric cooling technologies: CT = cooling tower; OTF = once-through freshwater; CP = cooling pond; AIR = dry cooling.

[d] NREL (2010).

[e] All water consumption factor estimates are for the median values, which is consistent with estimates in the literature.

[f] Sources for water consumption factor estimates [1]: Macknick et al. (2011) [2]; Meldrum et al. (2013).

[g] Inferred from the Macknick et al. (2011) estimate of Solar ST-AIR because it was the only steam turbine-linked estimate of dry cooling water consumption.

[h] The NREL (2010) study did not provide a capacity factor estimate for waste-heat-based steam turbine generators, so the relatively conservative estimate for biofuel-based power plants was applied.

[i] Inferred from the Macknick et al. (2011) estimate of Biomass ST-CT and ST-OTF because it was assumed that waste heat and geothermal were both lower grade fuel sources, like biomass relative to coal, gas and nuclear.

[j] Inferred from the Meldrum et al. (2013) estimate of Nuclear ST-CP as the least water-efficient comparable ST-CP technology.

Figure 35 consolidates the water consumption factors for electricity-generating technologies by fuel source, generation technology, and cooling type (where applicable). For thermoelectric production systems, evaporative cooling towers (CTs) show significantly higher consumption than once-through cooling (OTC) systems and cooling ponds (CP). As an aside, even though OTC systems consume less water, they withdraw between 20 to 50 times more water than CT systems (Meldrum et al., 2013). While the bulk of this water is returned to the original waterway (albeit with an associated thermal pollution load), this high withdrawal demand leaves the power plant considerably vulnerable in times of regional water shortages (NETL, 2009).

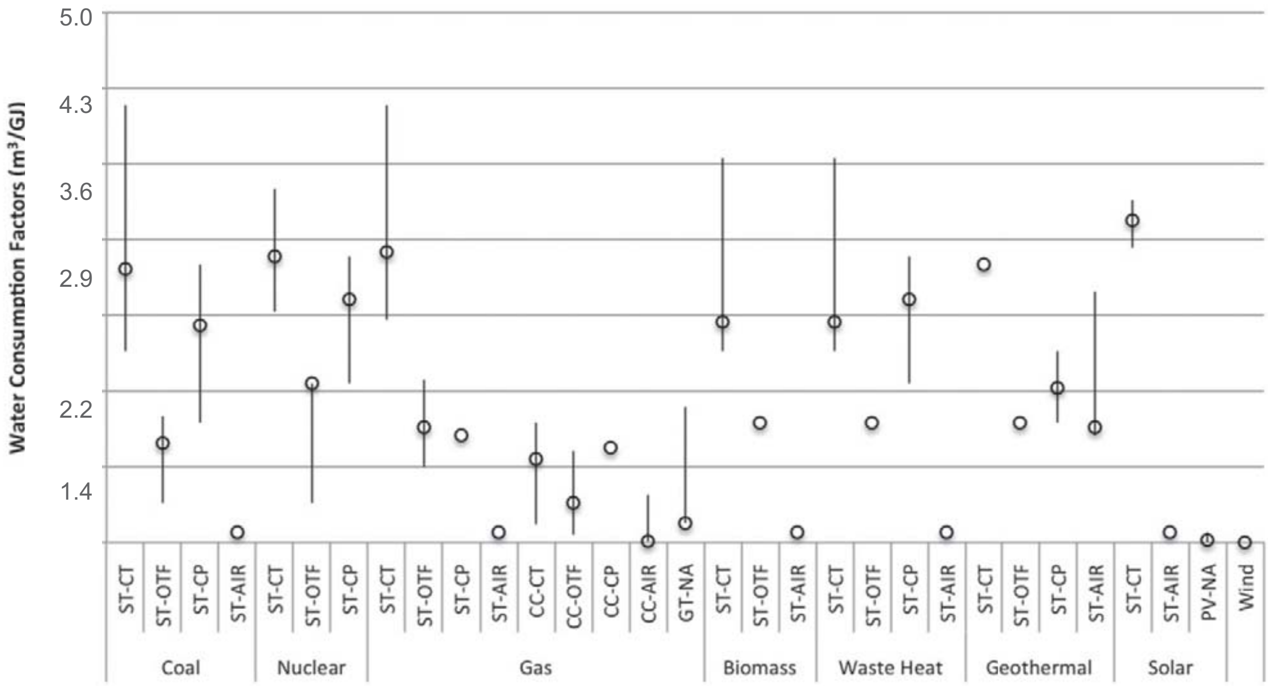


Figure 35: Consolidated estimates of water consumption factors for electricity generation

Notes: electricity generation technology types: ST = steam turbine; CC = combined cycle; GT = gas turbine; PV = photovoltaic; NA= not applicable.

Thermoelectric cooling technologies: CT = cooling tower; OTF = once-through freshwater; CP = cooling pond; AIR = dry cooling.

While dry cooling systems look like a great technology option in terms of reducing water consumption, they carry an efficiency penalty of about 2% (DOE, 2006) for the power plant, thereby reducing the electricity output per unit fuel input. In other words, dry cooling leads to both an economic penalty (higher capital costs and higher operating costs from reduced production per unit fuel), as well as increased carbon emissions per unit energy produced for fossil fuel-based plants (DOE, 2006).

In contrast to other electricity technologies, solar photovoltaic (PV) and wind power production consume only marginal quantities of water, mostly associated with the occasional requirement to wash PV panels and wind turbine blades (Meldrum et al., 2013). Because these figures are so small in comparison to other categories, a summary of the water use for renewable sources as discussed by Meldrum et al. (2013) is presented below.

Meldrum et al. (2013) assessed the life cycle water withdrawals and consumptive uses for both renewable and non-renewable electricity generation technologies: coal, natural gas, nuclear, concentrating solar power (CSP), geothermal, photovoltaics (PV), and wind, based on available literature.

9.1 Comparison of South Africa's water use with International averages

A summary of the water use per technology for South Africa's power generation (World Bank, 2017) is presented in Table 30. This is based on the per station data presented in Section 4.1 and Section 4.3.

On average in South Africa, 1 kWh of electricity consumes about 1.4 litres of water (Table 6) across all technologies. This is in line with the world average of 1.2-1.5 l/kWh (UN WWAP, 2014).

Water demands of between 2.04 and 2.38 from the predominantly wet-cooled closed loop thermal power plant fleet (Table 30) are somewhat above the typical mean intensity of 1.7 l/kWh reported by National Renewable Energy Laboratory (NREL) for subcritical coal power plants cooled with wet-recirculating systems (Macknick and others, 2011); this can be attributed to the decreasing thermal efficiency and increasing age profile of the power plants. However, when compared with the international estimate for wet cooled steam turbine coal fired plants of 2.6 l/kWh as calculated by Spang et al. (2014) (Table 29) South Africa's systems are performing close to international averages.

Water consumption figures for South Africa's dry cooled power plants are amongst the best performing in the world. Water use for the direct dry stations (Matimba and New Build plants) of 0.12 l/kWh is in line with international estimates of 0.1 l/kWh. The lower water usage profiles for dry cooled power plants can be attributed to state of art cooling technologies and lower age profile of these power plants.

Table 30 Water use in South Africa's power generating options

Power Plant Type	Cooling Type	Raw Water Use (l/kWh)	Boiler Water Use (l/kWh)	WSR	Climatic Zone
Coal Fired Existing	Wet closed cycle	2.04 to 2.38	0.062 to 0.12	Olifants	Cold interior
Coal Fired Existing	Indirect-dry	0.12	0.07	Olifants	Cold interior
Coal Fired Existing	Direct dry	0.12	0.02	Limpopo	Hot Interior
New super-critical coal-fired	Direct dry	0.12	0.02	Limpopo	Hot Interior
New Coal-fired fitted with FGD	Direct dry	0.32	0.02	Limpopo	Hot Interior
New Coal fired with CCS	Direct dry	0.18	0.025	Limpopo	Hot Interior
Open-cycle gas turbine	NA	0.02	NA		
Combined-cycle gas turbine	Direct dry	0.013			
Combined cycle gas turbine with CCS	Direct dry	0.019			
CSP	Direct dry	0.3	0.06	Limpopo	Hot Interior
CSP	Hybrid cycle	0.4 to 1.7	0.06	Limpopo	Hot Interior
CSP	Wet closed cycle	3	0.06	Limpopo	Hot Interior
Solar PV[a]	NA	NA	NA	NA	Distributed
Wind	NA	NA	NA	NA	Distributed
Nuclear	Once through seawater	NA	NA	NA	Coastal

WSR = water supply region; FSD = flue gas desulfurization; CCS = carbon capture and sequestration; NA = not applicable; CSP = concentrating solar power.

a. Water to wash solar PV panels is not considered.

9.2 Water Consumption for Energy Production (WCEP) for all technologies

Once the data for energy production by each energy category was consolidated on a country-by-country basis, Spang et al., 2014 used the water consumption factors as presented in Table 29 to calculate the WCEP values by using the following equation:

$$\text{WCEP (m}^3\text{)} = \text{Energy Production} * \text{Water Consumption Factor}$$

The WCEP estimates for each energy category were then summed to get an estimate of total water consumption for each country in the study's entire energy production portfolio (Figure 36). The global WCEP estimates for both fuel production and energy generation are presented in Figure 37. While this Natsurv report focuses on water use during energy generation only, it is interesting to note the impact of fuel generation as a water use factor.

The global WCEP was estimated at approximately 52 billion cubic meters of fresh water. Of this global WCEP volume, oil and gas production had the highest proportional WCEP (40%) relative to the additional energy categories of coal, nuclear fuel, biodiesel, ethanol, coal-based electricity (steam turbine, ST), nuclear ST electricity, other non-renewable electricity (oil ST, gas ST, combined cycle, and gas turbine), and renewable electricity (biomass ST, waste heat ST, geothermal ST, solar ST, solar PV, and wind), as shown in Figure 36. It is also worth noting that the amount of water consumed at the global scale for ethanol production is roughly equivalent to global water consumption for coal-fired power plants, even though global ethanol production represents approximately 1/100th the energy content of global coal-fired electricity production. Finally, in terms of renewable energy, the total WCEP for all renewable electricity production is roughly 1/10th the total WCEP for biofuel production. Hence, while renewable electricity may represent opportunities for reducing both water consumption and carbon emissions, the water impact of biofuels requires important consideration as the world's regions seek to transition to lower-carbon energy portfolios.

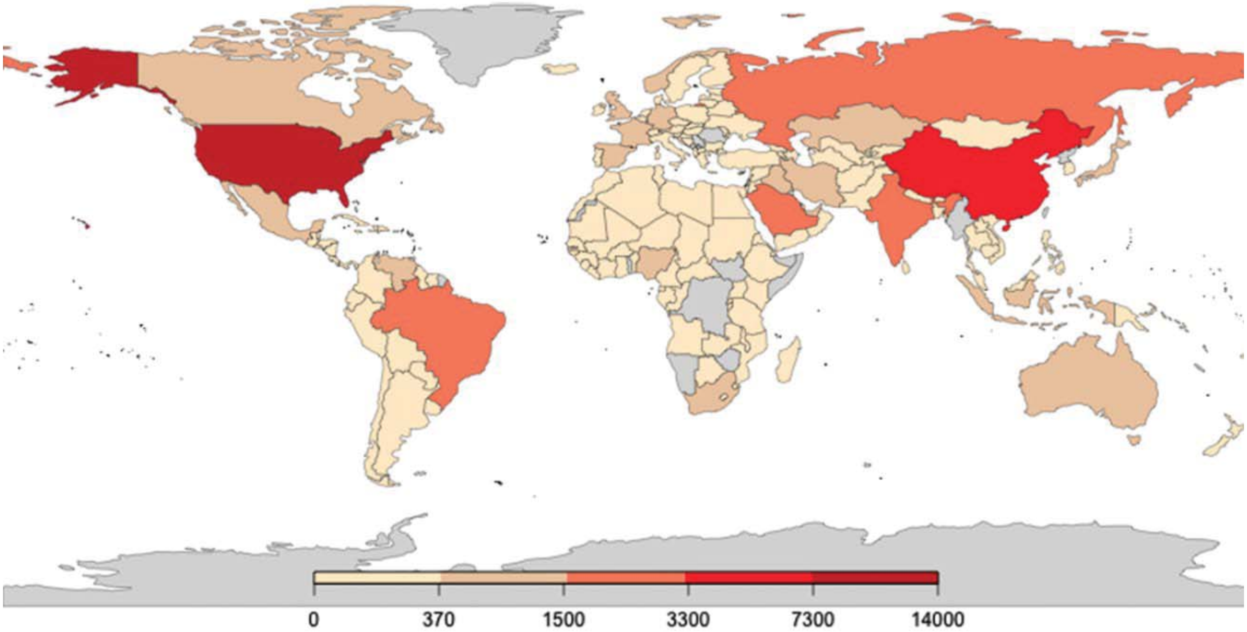


Figure 36: Total water consumption for energy production (WCEP) 2008.

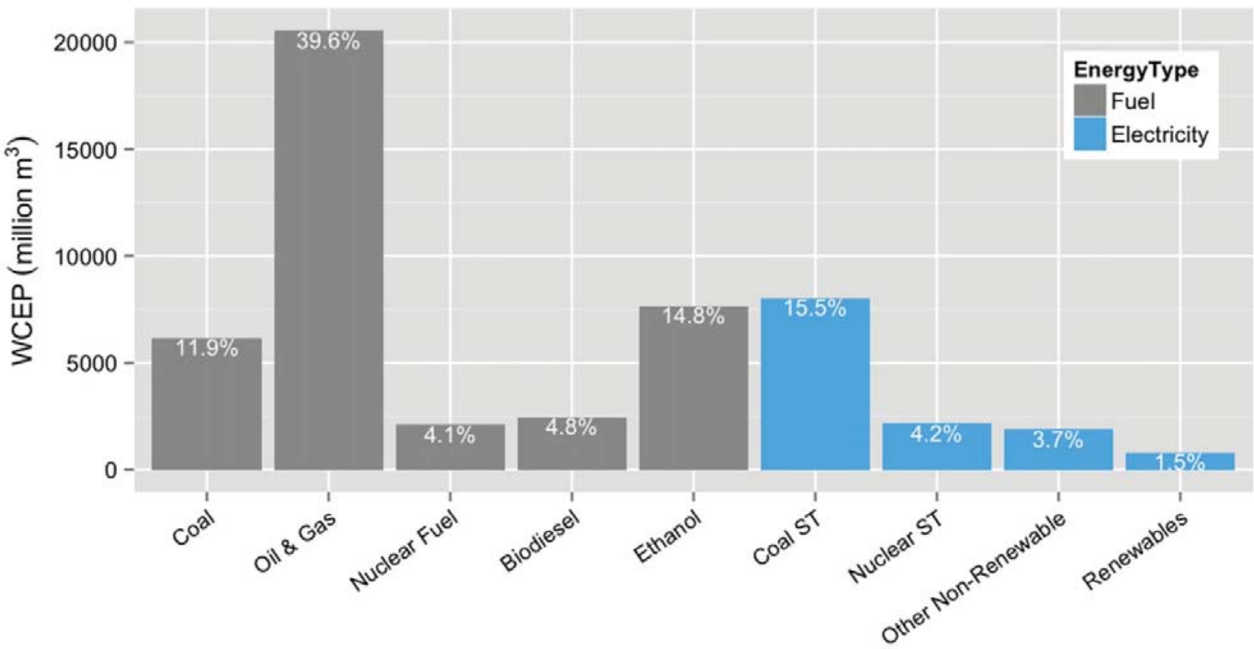


Figure 37: Total global WCEP by major energy category

Figure 38 presents the WCEP for each energy category for the top 25 countries. It can be seen that South Africa is in 16th position, with the majority of water use going to coal production, followed by electricity generation, then nuclear fuel production.

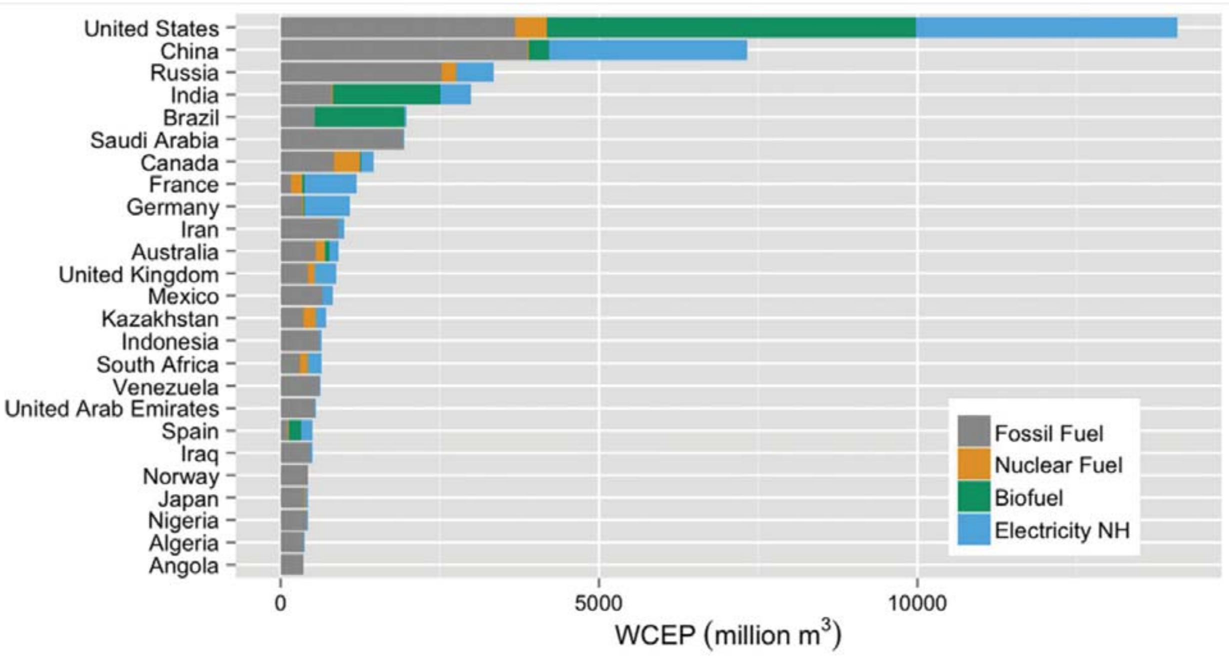


Figure 38: Total WCEP by energy category, 2008

Global fossil fuel WCEP was estimated at 26 727 million m^3. National level estimates of fossil fuel WCEP by sub-category are provided in Figure 39 (for the top 25 countries). The results show that total consumption of water for fossil fuel production is dominated by countries that are large in physical size and population (BRIC countries: Russia, China, Brazil, and India), economically productive (Organisation for Economic Co-operation and Development [OECD] countries: United States, Canada, Mexico, Norway, and the United Kingdom, among others) and major petroleum producers (Organization of the Petroleum Exporting Countries [OPEC] countries: Saudi Arabia, Iran, Venezuela, the United Arab Emirates, Iraq, among others). The production and refining of crude oil dominate the portfolio of every country in the ranking, except for China, India, and Indonesia, and Australia, where coal production consumes the most water. In terms of total water use for fossil fuel production, South Africa is in position 24, with the majority of water use for coal production and a small amount to oil refining. While South Africa's total fossil fuel WCEP is low relative to other countries, the WCEP for coal extraction and processing is relatively larger than moany other countries in the top 25.

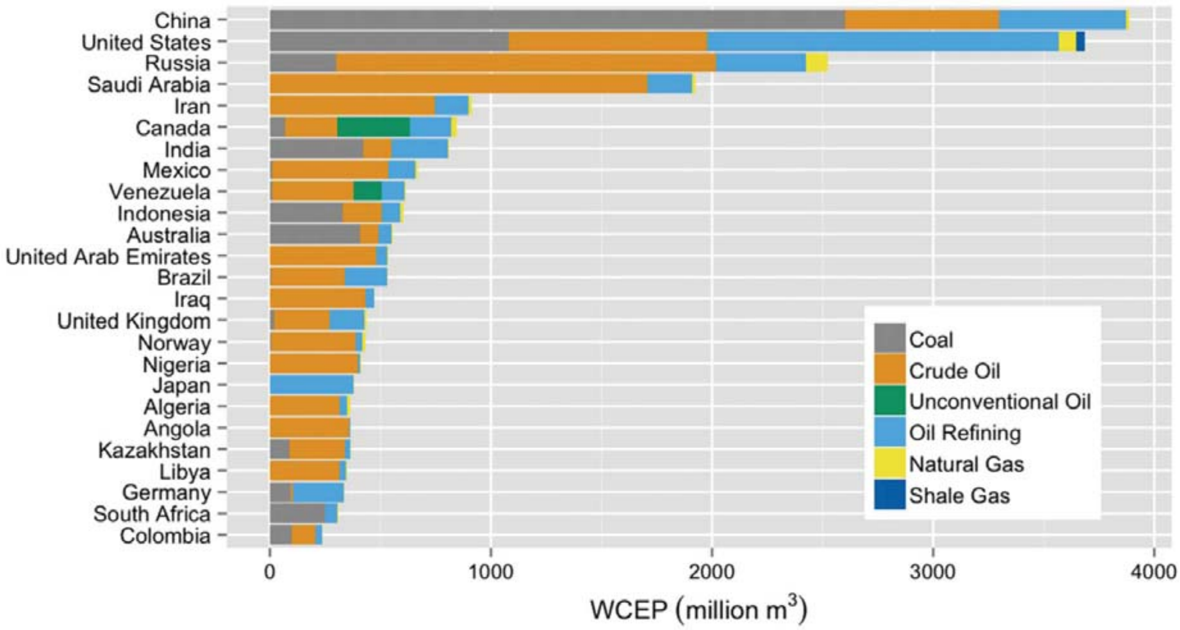


Figure 39: WCEP for fossil fuel extraction and processing, 2008

The scale of nuclear fuel production at the global level is significantly more limited than fossil fuel production in terms of both available uranium deposits as well as nuclear fuel production. Consequently, the total consumption of water for nuclear fuel production worldwide (2117 million m^3) is a full order of magnitude less than that for fossil fuels (26 727 million m^3). Water consumption coefficients were applied to each stage of the nuclear fuel cycle, including uranium ore mining and processing, milling, conversion, enrichment, fabrication, and reprocessing to produce the results shown in Figure 40. Many top nuclear fuel producers process the fuel at multiple stages of the nuclear fuel cycle (Canada, United States, Russia, France, and the UK), but the operations of some countries (Kazakhstan, Australia, South Africa, Niger, Uzbekistan, and Kyrgyzstan) are more limited to ore mining and processing. Meanwhile, Canada, with the second largest nuclear fuel WCEP, uses significantly more water for uranium milling than any other country, yet hardly uses any water for enrichment. This highlights the role of trade in balancing the cycle of uranium production across multiple countries and, therefore, the differentiated water consumption impacts across these participating countries.

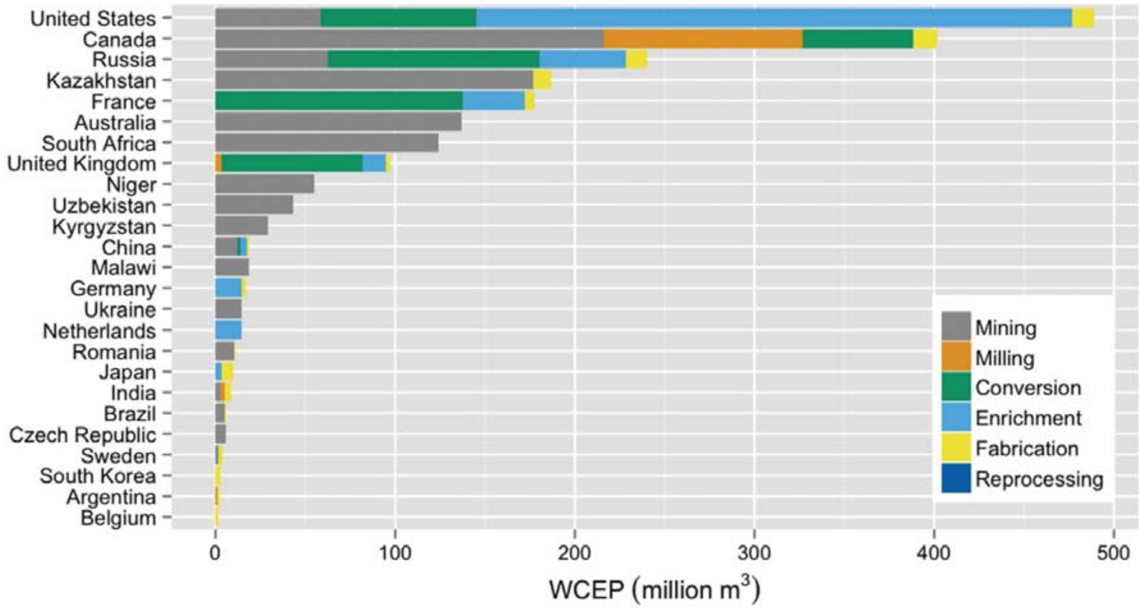


Figure 40: WCEP for nuclear fuel extraction and processing, 2008.

WCEP for electricity generation at the global scale represents about 12 895 million m^3 of water. Figure 41 presents eight major categories of electricity generation technologies, including: coal-based steam turbine (ST), gas- and oil-powered ST, nuclear ST, biomass and waste heat ST, geothermal ST, solar ST, combined cycle, and gas turbine. Wind and solar PV were not included in the graphic because their WCEP are so low relative to the other technologies that they do not appear at this scale of presentation. The United States and China are the largest water consumers in this energy category, with these two countries accounting for approximately 56% of total global water consumption for electricity production. Both countries depend mostly on coal-based power plants, and as a result, water consumption for coal power plants represents 59% of total electricity WCEP in the United States and 98% in China. France and Germany follow next with high levels of water consumption, with significant consumption for both countries coming from nuclear electricity (87% and 36%, respectively). South Africa is in 9th position in terms of water use for electricity generation, with the majority of water being used in coal steam turbine plants.

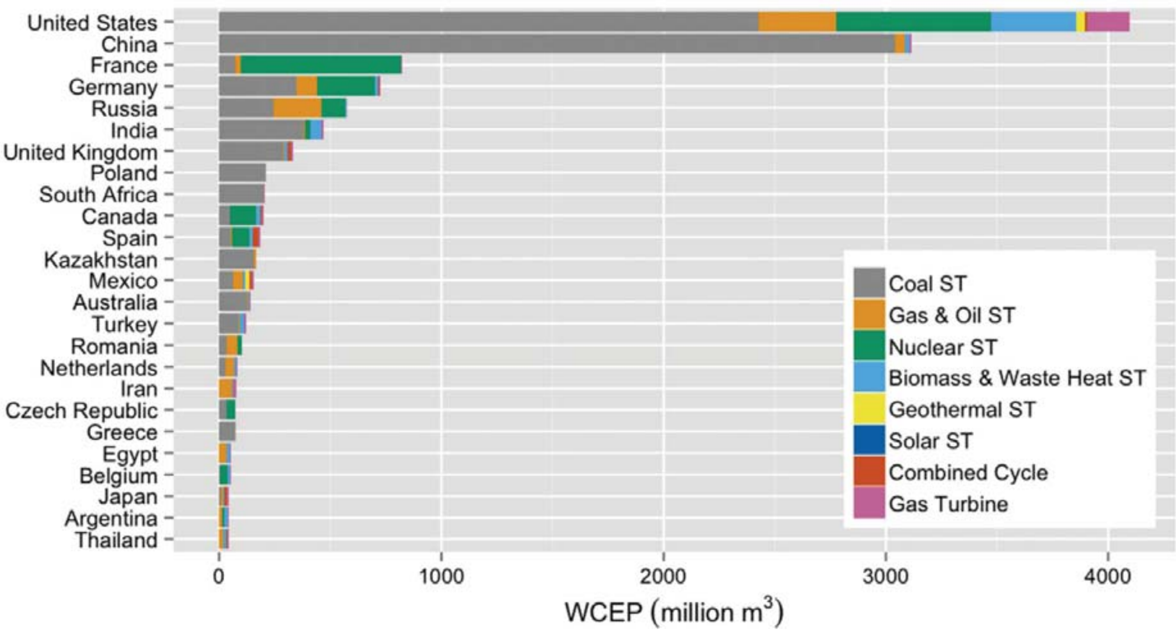


Figure 41: WCEP for electricity generation (non-hydro), 2008.

9.3 The shift to renewable energy

If we want to reduce our global greenhouse gas emissions, the world has to transition from an energy system dominated by fossil fuels to a low-carbon one (this is what most countries have set long-term targets to achieve within the Paris climate agreement).

Except for carbon capture and storage (CCS) technology, we have two options to achieve this: renewable technologies (including bioenergy, hydropower, solar, wind, geothermal, and marine energy) and nuclear energy. Both options produce very low CO_2 emissions per unit of energy compared with fossil fuels. We call this process of transitioning from fossil fuels to low-carbon energy sources ‘decarbonisation’.

Our progress over the last decade tells an interesting story. Figure 42 maps the share of renewable, nuclear, and fossil fuel sources in global electricity production. As a summary, over the last decade (2005-2015) the share of renewables in our electricity mix has increased by approximately 5-6 percent. However, over this same period, the share from nuclear production has decreased by almost the same amount (5-6 percent). Since 2005, natural gas and coal have increased their share by one and two percent, respectively whereas the contribution from oil has declined by two percent.

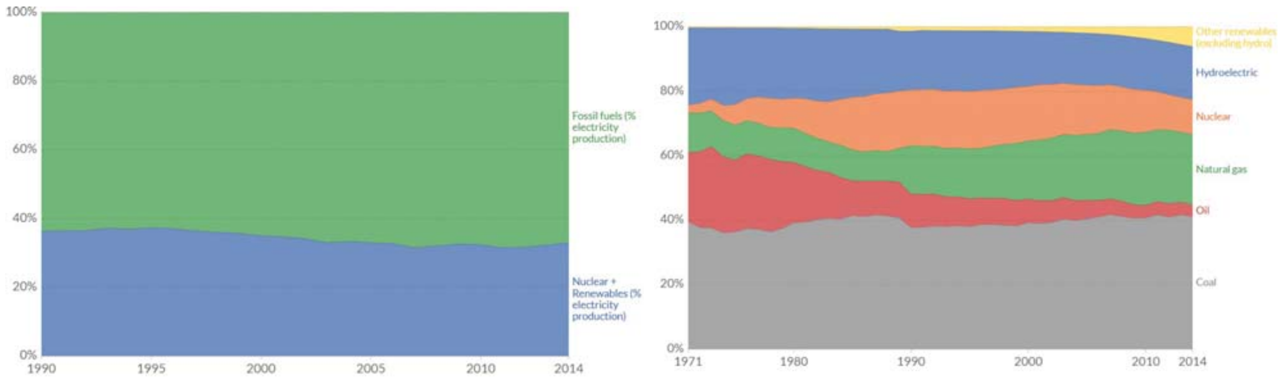


Figure 42: Global electricity production measured as the percentage contribution from fossil fuels (coal, oil and gas) and low-carbon sources (nuclear, hydropower, biomass, wind, solar, geothermal and marine power) (Source: International Energy Agency (IEA) via the World Bank, accessed from https://ourworldindata.org/energy

Overall, this means that our total share of low-carbon electricity production is almost the same as a decade ago. In fact, if we compare the share of electricity produced by low-carbon sources (renewables and nuclear) in 2015 to that of 1990, we see that it has dropped by around three percent. Progress on electricity decarbonisation has been stalled over the last decade because of a growing aversion to nuclear energy. Figure 43 presents a global map of the share of electricity production from renewable sources as of 2014.

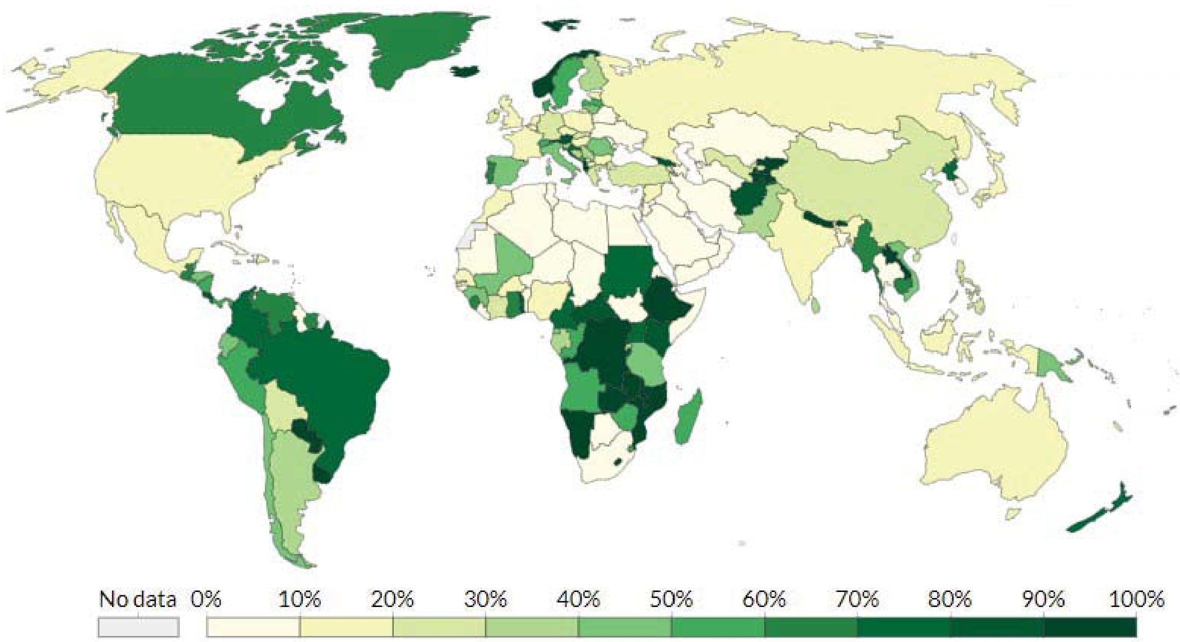


Figure 43: Share of electricity production from renewable sources as of 2014. This includes biomass, hydropower, solar, wind, geothermal and marine energy, but excludes nuclear sources

(Source: World Bank Sustainability for All (SE4ALL), accessed from *https://ourworldindata.org/grapher/share-of-electricity-production-from-renewable-sources*)

Shifting our energy systems away from fossil fuels towards renewable technologies will require significant financial investment. Global investments in renewable technologies from 2004 to 2015 (measured in billion USD per year) are shown in the graph in Figure 9. In 2004, the world invested 47 billion USD. By 2015, this had increased to 286 billion USD, an increase of more than 600 percent. Investment has grown across all regions, but at significantly different rates. China is now the largest single investor in renewable technologies, investing approximately the same as the United States, Europe and India combined.

Combining Chinese and Indian investment with its neighbours, Asia & Oceania is the largest continental investor. Europe's investment has been through a significant growth-peak-reduction trend, peaking in 2011 at 123 billion USD before declining to 49 billion USD in 2015. Investment in the Middle East & Africa remains relatively small but has shown significant growth over the last ten years (after investing only 0.5 billion USD in 2004).

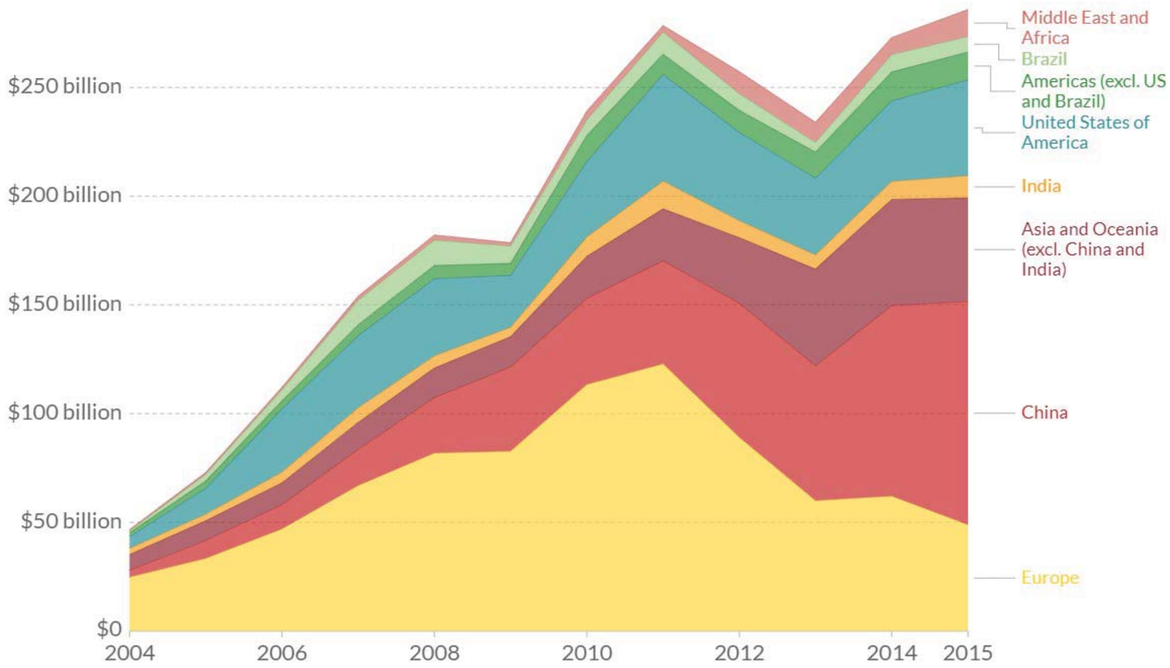


Figure 44: Renewable energy investment, 2004-2015 in billion US dollars by region

(Source: International Renewable Energy Agency 2017, accessed from https://ourworldindata.org/grapher/renewable-energy-investment)

Levels of absolute investment as shown in Figure 45 tell an important story, but they take no account of the size of investments relative to a country's economy. We might expect that the largest economies would also be the largest investors. If we want to assess which countries are making a fair 'contribution' or 'share' to investment in clean energy, it is useful to assess investment contributions as a percentage of a country's gross domestic product (GDP). Investment contributions as a percentage of GDP are plotted for the largest single-country investors in Figure 45.

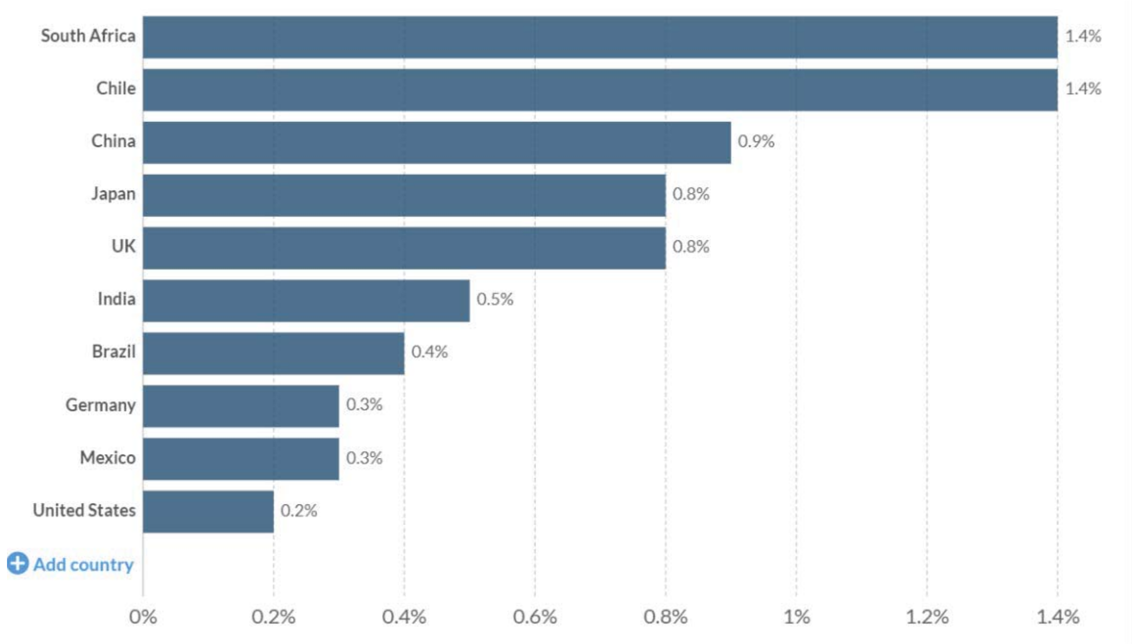


Figure 45: Renewable energy investment as % of GDP, 2015 (Source: Bloomberg New Energy Finance, World Bank, accessed from *https://ourworldindata.org/grapher/renewable-energy-investment-of-gdp*)

This tells a slightly different story. Most countries invest less than one percent of GDP in renewable technologies, except for South Africa and Chile, which make an impressive contribution at 1.4 percent in 2015. When normalised to GDP, China remains one of the largest investors, at 0.9 percent. Interestingly, despite being the second largest investor in absolute terms, the United States invested only 0.1 percent of its GDP in 2015.

Indeed, when it comes to relative contributors to renewable energy, low-to-middle income transitioning economies typically invest more than high-income nations. This may be partly explained by the fact that these nations are likely to be investing a higher percentage of their GDP into energy provision and expansion overall (whereas high-income nations typically have well-established energy systems). Nonetheless, most high-income nations have set ambitious greenhouse gas reduction targets in their commitments to the Paris climate agreement.

Achieving these targets will require significant investments in low-carbon technologies.

10 South Africa's Integrated Resource Plan

On 27 August 2018, the Department of Energy released the updated Draft Integrated Resource Plan (Draft IRP 2018) for commentary. The aim of the Draft IRP 2018 is to address the point of departure between the assumptions made in the IRP 2010 and the legislative mandate for electricity supply-demand optimisation based on a least-cost path. The following are notable changes:

- electricity consumption continues to decline on an annual basis. Current usage is comparable to those of the year 2007. For the financial year ending March 2018 the actual total electricity consumed is some 30% less than the figure projected in the IRP 2010
- Eskom's existing generation plant performance is not at expected levels. Eskom's own reports show that plant availability is below the IRP 2010 assumptions of 80% and above
- to date, an additional 18,000MW of new generation capacity in the form of coal, pumped storage and renewable energy has been committed to, with most of the capacity already connected to the grid and the rest to be realised by 2022
- reduced cost of new generation technologies
- actualisation of the least-cost option
- reduced carbon emission obligations on South Africa; and
- the phased decommissioning of Eskom's power generation facilities as they reach the end of their life spans over the next 32 years.

Taking the new key assumptions and milestones into account, the Draft IRP 2018 details a number of policy adjustments. These include the retention of annual build limits for the period up to 2030; the inclusion of 1,000MW of coal-to-power in 2023-2024, based on two already procured and announced projects (these being Khanyisa and Thabametsi, both to be built by the private sector as part of the government's independent power producers' programme); the inclusion of 2,500MW of hydropower in 2030 to facilitate the Grand Inga Hydropower Project Treaty which South Africa has entered into with the Democratic Republic of Congo; and 8,100MW from gas.

The 2010 Integrated Resource Plan (IRP) included an administrative decision to impose 9.6 GW of nuclear capacity as a fixed assumption, with the first 1.6 GW to come online in 2023. The reasoning, as stated in the IRP, was "to account for the uncertainties associated with the costs of renewables and fuels" and to "provide acceptable assurance of security of supply in the event of a peak oil-type increase in fuel prices and ensure that sufficient dispatchable base-load capacity is constructed to meet demand in peak hours each year" (DoE, 2011). Three coastal sites for future nuclear plants – Banatamsklip and Duinefontein in the Western Cape and

Thyspunt in the Eastern Cape – have been identified thus far, and they have undergone environmental impact assessments (Van Wyk, 2013; World Nuclear Association). It can be assumed that plants here would use seawater for cooling, as is the case with Koeberg. Interestingly, there is limited mention of nuclear-powered energy in the updated Draft IRP 2018 due to the costs associated with nuclear power and the government's commitment to the least-cost approach. In addition, the Draft IRP 2018 states, in line with existing policy, that nuclear power will be procured solely by Eskom and not via an IPP. However, IRP 2019, released in October 2019, called for the country to construct two small modular nuclear reactors by 2030. The document also called for the completion of a 20-year operating lifetime extension at the Koeberg plant to ensure continued energy security beyond 2024, ensuring security of supply.

11 Conclusion

There is limited data for South Africa on all aspects of water usage in the production of energy, accounting in part for the significant variations in the values of water intensity reported in the literature (with some approximations). It is vital to consider all aspects of the energy life cycle to enable isolation of stages where significant amounts of water are used. That said, despite challenges of aging infrastructure South Africa is a world leader in water saving energy generation with respect to dry cooling, zero liquid effluent discharge policy and renewable energy investment as a factor of GDP.

The majority of South Africa’s WMAs are under severe duress. This issue gets worse when considering the fact that most of the coal-based power plants are within regions partially or severely constrained in terms of water. The following comments can be highlighted to enable decision making.

Eskom’s RTS power plants namely Camden, Komati and Grootvlei which are water intensive power plants are located in the severely constrained WMAs namely, Olifants and Inkomati. The savings of roughly 35 gigalitres associated with the decommissioning of the RTS fleet and operation of the New Build power plants Medupi and Kusile, could account for almost 15% of the forecasted deficit of 234 gigalitres by 2025.

While Medupi is in the moderately constrained WMA of Limpopo, Kusile is located in the severely constrained Olifants WMA. Therefore, Kusile will have a larger water saving impact within the respective WMA.

The role of coal in electricity generation will be a dominant factor up until locally available resources start to diminish. However, technologies that utilise water efficiently will have to play a more dominant role in order to preserve national water security.

Measures aimed towards increasing the efficiency of the RTS or gradual decommissioning could bring considerable changes to the forecasted WMA deficits. However, decommissioning of the RTS fleet must be done in concurrence with the commissioning of New Build power plants. Additionally, the socio-economic costs and benefits related to decommissioning inefficient power plants and switching to less water intensive power generation must be carefully considered. The financial implications for the utility and the country have to be deliberated before large utility scale technologies are implemented.

An inherent lack of abundant freshwater resources in South Africa, coupled with increasing populations and changing rainfall patterns are bound to create a need for efficient and innovative changes in water usage. Though the agricultural sector is the predominant consumer of freshwater resources, the industrial and power generation sector also have considerable water usage footprints.

Conventional fuels (nuclear and fossil fuels) withdraw significant quantities of water (this is seawater in the case of nuclear) over the life cycle of energy production, especially for thermoelectric power plants operated with a wet-cooling system. The quality of water is also adversely affected in some stages of energy production from these fuels. Biomass is water intensive, but it should be noted that in South Africa biofuel generation is by means of waste-from-crops only so this water would have been used in the production of crops regardless. Solar photovoltaic (PV) and wind energy exhibit the lowest demand for water and could perhaps be considered the most viable renewable options in terms of water withdrawal and consumption. Moreover, the observed water usage in these renewable energy technologies is predominantly upstream.

The envisaged in the Draft IRP 2018 that the energy mix by 2030 will consist of 34,000MW of coal (46%); 1,860MW of nuclear (2.5%); 4,696MW of hydro (6%); 2,912MW of pumped storage (4%); 7,958MW of solar PV (10%); 11,442MW of wind (15%); 11,930MW of gas (16%) and 600MW of concentrated solar power (1%).

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