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Modelling the Water Energy Nexus in South Africa

Task 1 Report: Development of Regional Marginal Water Supply Cost Curves

University of Cape Town Energy Research Centre and World Bank

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List of Acronyms

ADC	Annual depreciation cost
AMD	Acid Mine Drainage
CPV	Concentrated photovoltaic
CSAG	Climate Systems Analysis Group
CSP	Concentrated solar power
CUC	Capital Unit Cost
DEA	Department of Environmental Affairs
DWA	Department of Water Affairs
EC	Energy cost
ER	Energy requirement
IBT	Inter-basin Transfer
IPP	Independent Power Producers
IRP	Integrated Resource Plan
IWRS	Integrated Vaal River System
KZN	Kwa-Zulu Natal
L1S	Level 1 Stabilization
LHWP	Lesotho Highlands Water Project
LTAS	Long Term Adaptation Scenarios
MAP	Mean annual precipitation
MCWSAP	Makolo and Crocodile West Water Supply Augmentation Project
MWSC	Marginal Water Supply Cost
NWRS	National Water Resources Strategy
OCGT	Open Cycle Gas Turbine
PV	Photovoltaic
PWTC	Primary water treatment cost
REIPPPP	Renewable Energy Independent Power Producer Programme Projects
SWTC	Secondary water treatment cost
UCE	Unconstrained Emissions
UCW	Unit cost of water

URV	Unit Reference Value
WDMC	Waste Discharge Management Charge
WMA	Water Management Area
WRMC	Water Resources Management Charge
WSDC	Water Supply Distribution Cost
WSEC	Water Supply Energy Cost
WSSIC	Water Supply Scheme Infrastructure Charge
WUOC	Water use opportunity cost

1 Introduction

1.1 Modelling the Water Energy Nexus

Energy and water are intricately connected: We use energy to help us clean and transport the fresh water we need, and we use water to help us produce the energy we need. This is the water-energy nexus (Gleick, 1994). Both energy and water are critical aspects of any economy, and yet despite their strong interdependence the two sectors are often managed independently (Hussey and Pittock, 2012). Developing an integrated approach to modelling the water-energy (and food) nexus is critical to supporting the development of effective national policies and regulations to ensure continued economic development and growth in a sustainable way (Bazillian et al, 2011; Rodriguez et al, 2013).

The link between water and energy is shown graphically in Figure 1.

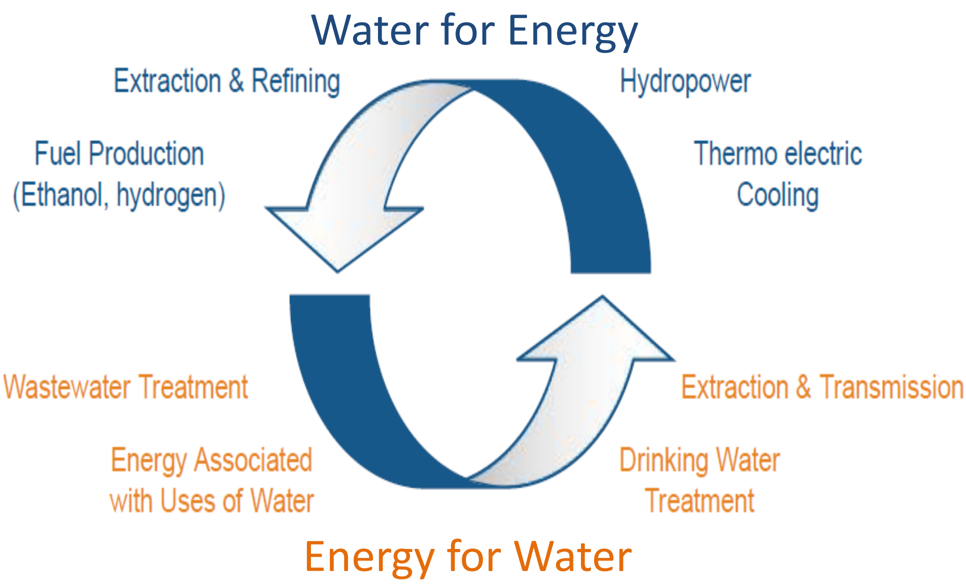

Figure 1: The link between water and energy defining the water-energy nexus (Source: WEC, 2010)

In many parts of the world, however, water availability is becoming more constrained through the combined effects of increasing demands, reducing water quality, and climate change. This presents a significant threat to future energy production (WEC, 2010). Similarly ever increasing water demands require consideration for more energy intensive technologies such as inter basin transfers (IBT), desalination and re-use of waste water (Hussey and Pittock, 2012). This will add additional energy demands to an already energy constrained world. Unless these additional demands can be met through alternative energy options, the increasing energy demands will result in increased production of greenhouse gas (GHG) further contributing the problem of climate change and potentially leading to increased water supply shortages. This is referred to as the Water-Energy nexus.

Investigating the significance of these linkages and how they affect future water and energy planning requires the integration of water constraints into energy models and energy constraints into water supply models. Ultimately this could lead to a single integrated model of the water-energy nexus to support future policy planning and decision making for both.

1.2 A South African Case Study

The aim of this study is to better incorporate water supply constraints into an existing energy model in order to support decision making at a national level towards a water-sustainable energy future in South Africa. The focus is on the "water for energy" part of the nexus as shown in Figure 1.

Specifically the objectives of this study are to incorporate water supply constraints into an existing energy model so as to account for (1) the true cost of water supply, (2) the spatial mismatch between water supply and the location of power plants, (3) the full cost of water supply to the energy sector including water supplied to mines, (4) the opportunity costs of alternative water uses in a country with limited water resources and increasing demands, and (5) the sensitivity of future energy-water system to climate change. In addition the study aims to complete the circle by accounting for variability in the energy price in the cost of water supply for power production.

South Africa was identified for a case study given its well documented water scarcity, the importance of water for energy in South Africa, the extensive knowledge and strong analytical capacity for addressing the water-energy issue in the country, and the fact that the country is starting to plan water and energy in an integrated manner. Modelling and planning experience in South Africa can provide valuable knowledge for other countries facing similar constraints (Rodríguez et al, 2013).

The following tasks and sub-tasks are planned for this South African case study:

- Task 1: Develop marginal water supply cost schedules
    - Task 1a: Define water resource areas (WRA) of interest, corresponding to the regions in the SATIM
    - Task 1b: Derive incremental costs of water supply for energy purposes
    - Task 1c: Determine climate change impacts on identified WRAs
    - Task 1d: Derive updated water supply cost curves for climate change scenarios
- Task 2: Developing a "water smart" SATIM model (SATIM-W)
- Task 3: Conduct Energy – Water Model Simulations
- Task 4: Prepare Phase 1 Project Report

A possible Phase 2 will consider additional scenarios and options for further integration of the water and energy models, as well as linkage with economic models and lessons learnt from Phase 1.

2 Energy Supply Options

This section contains a brief summary of the current and future energy options for South Africa in the context of the water-energy nexus and used to identify key areas of interest for the development of regional marginal water supply costs to be included in modelling the future energy. Energy supply in South Africa is dominated by a single power producer, ESKOM, with coal fired power stations which contribute more than 86% of the current electricity supply as shown in Figure 2.

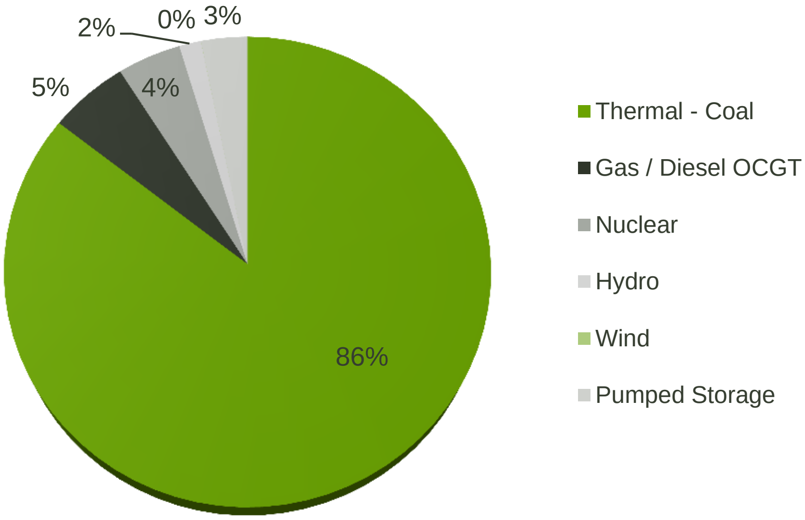

Figure 2: Current installed capacity for electricity supply in South Africa

The locations of current and future supply options for ESKOM in South Africa are shown in Figure 3.

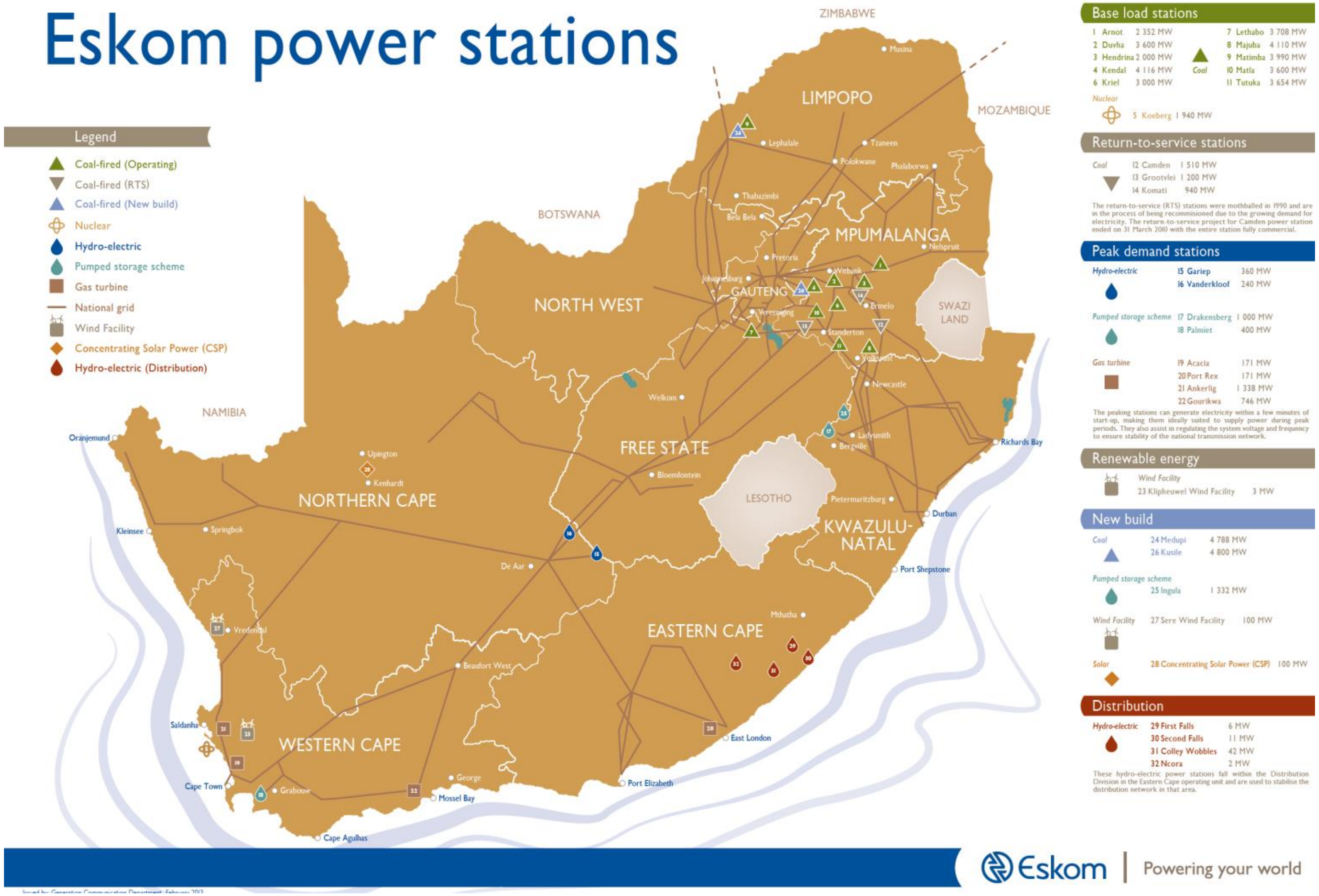

Figure 3: Location of current and future power stations in South Africa (Source: www.eskom.co.za).

The current and future energy supply options are described below in terms of electricity supply from coal (Section 2.1), nuclear (Section 2.2), renewables (Section 2.3), and open cycle gas turbines (Section 2.4), as well as biofuels (Section 2.5) and shale gas for liquid fuels (Section 2.6).

2.1 Coal

2.1.1 Base Load Coal

The existing coal fired power stations of South Africa and the new “coal fleet” (e.g. Medupi and Kusile) occurs in two distinct areas as indicated in Figure 3 with separate water supply options and future development plans. The existing Matimba power station (3 990 MW) and planned Medupi power station (4 788 MW) are located near the town of Lephalale in the Limpopo province and receive water via the Mokolo and Crocodile River transfer scheme.

The bulk of the existing fleet, including the Arnot (2 352 MW), Duvha (3 600 MW), Hendrina (2 000 MW), Kendal (4 116), Kriel (3 000 MW), Lethabo (3 708 MW), Majuba (4 110 MW), Matimba (3 990 MW), Matla (3 600 MW), and Tutuka (3 654 MW) power stations are all located in Mpumulanga and receive water from a highly complex system of dams and inter-basin transfers as part of the integratetd Vaal River system as shown in Figure 4.

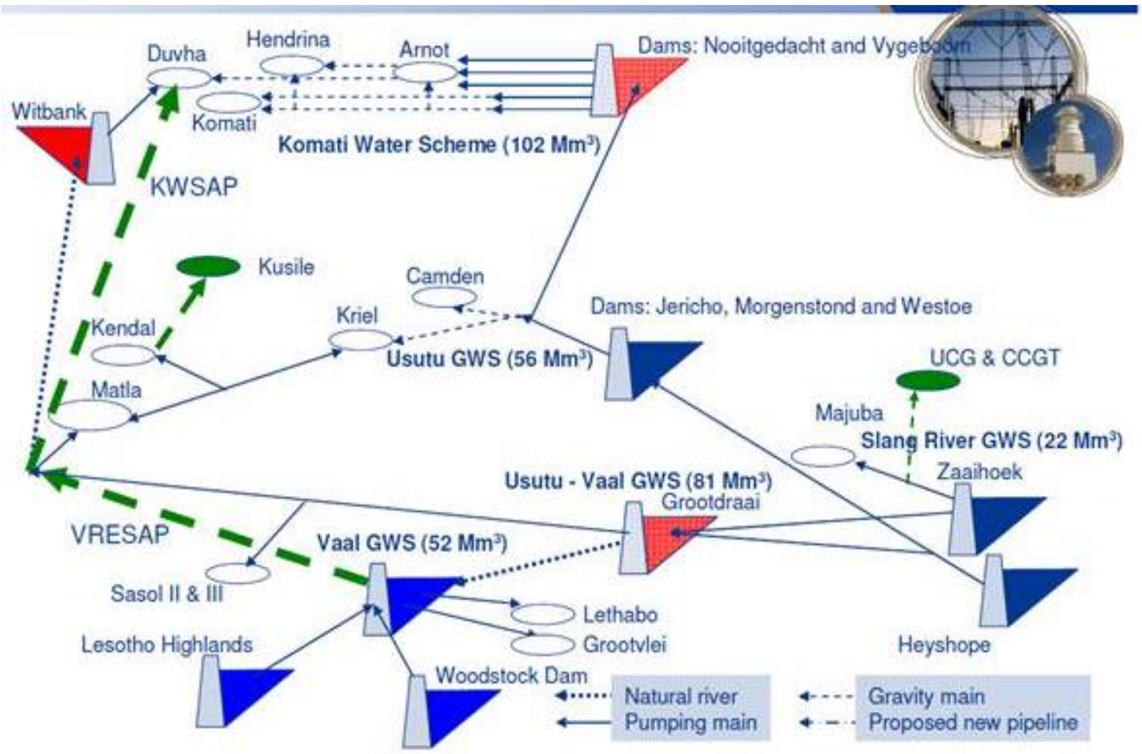

Figure 4: Water supply for ESKOM power stations as part of the integrated Vaal River system. (Source: ESKOM)

The construction of two new base load coal power stations, namely Medupi and Kusile will be completed by 2019 and will constitute 23% of Eskom's power generation. No further large Eskom built base load coal power station are expected to be constructed before 2022. When Medupi and Kusile power stations are fully operational it has been estimated that the combined water use will be approximately 52 M.m^3 per annum or 14% of Eskom's water use (Inglesi-Lotz and Blignaut, 2012).

Medupi power station is situated in Limpopo province close to the town of Lephalale (Figure 3). The construction of Medupi has been delayed with first unit at Medupi now scheduled to come on line in mid-2014 and the last unit in 2017, with a maximum installed capacity of 4,764 MW consisting of six 794MW units. The power station has a project lifespan of 50 years. Due to water scarcity concerns and limited water availability Medupi will be dry-cooled, unlike the historically installed wet-cooled capacity in the country (African Development Bank, 2009). The intention is to retrofit Medupi with flue-gas desulphurisation (FGD) to control emissions six years after each unit has been commissioned (Creamer, 2014). The Grootegeluk colliery will supply Medupi with coal. Medupi power station will receive its water via the infrastructure built for the Mokolo and Crocodile West Water Augmentation Project (MCWAP) as shown in Figure 5.

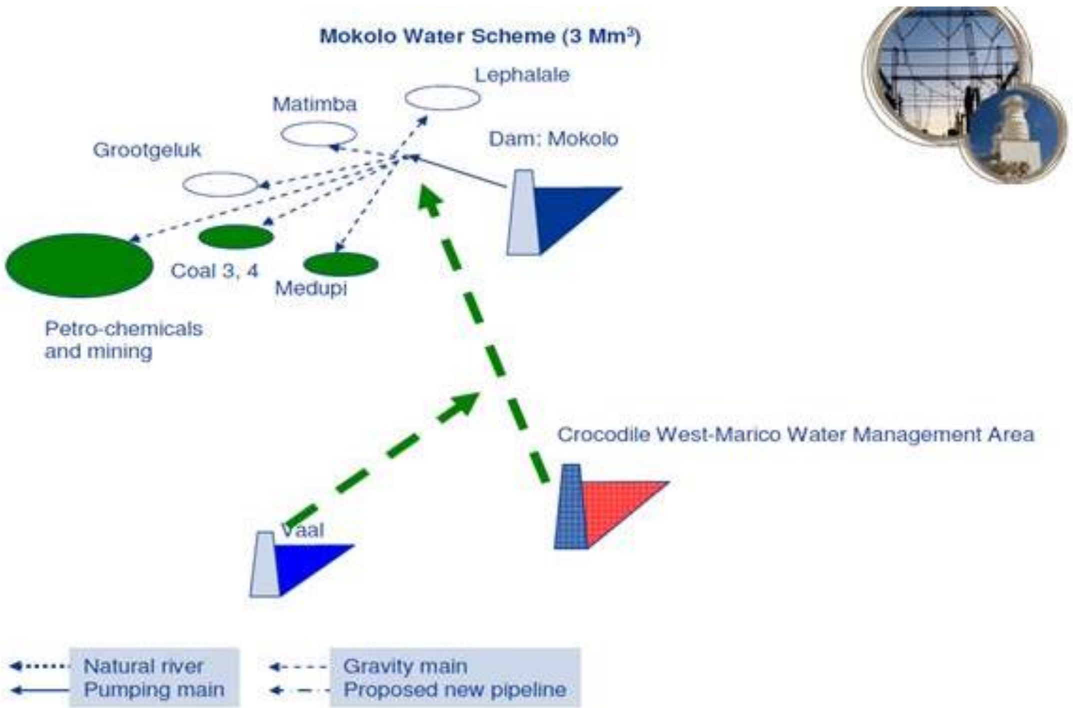

Figure 5: The Mokolo and Crocodile West Water Augmentation Project (MCWWAP)

Kusile power station located in Emalahleni, Mpumalanga and is in close proximity to the existing Kendal power station. It is a coal fired, dry-cooled power station and will utilise the FGD technology like Medupi. When completed in 2019 Kusile will have an output of 4800 MW. The likely source for the coal is the Anglo American's New Largo mine (Creamer, 2014) and the water will be supplied via the Integrated Vaal River System (IVRS).

2.1.2 New Coal Options

The 2010 Integrated Resource Plan (IRP) has provision for coal fired power stations under the new plant options. These are smaller than the large scale Eskom base load coal power stations. The Eskom ten-year Transmission Development Plan (2013-2022) makes the assumption that three new coal power station operated by independent power producers will be constructed. Coal 1 will be in the Mpumalanga Province in the Witbank area, and Coal 2 will be in the Limpopo Province in the Lephalale area. The final 2010 IRP allocation of 1000 MW from 2019 to 2022 will be situated in either Mpumalanga or Limpopo Provinces. Creamer (2014) reports that in August 2013 the South Africa government endorsed the planning process for a new commercial coal power station. However, no statement was made on whether the construction and operation would be by Eskom or an Independent Power Producer (IPP).

2.1.3 Return-to-Service Coal Fired Power Stations

In 2003 Eskom began a programme to bring three decommissioned coal-fired power station back into service. The power stations namely Camden (1520 MW), Grootvlei (1200 MW) and Komati (1000MW) are all situated in Mpumalanga. The return-to-service programme was completed in 2013, however, there is on-going upgrade of the rail and road infrastructure that supply the power station with coal.

2.2 Nuclear

South Africa's only existing nuclear power station is Koeberg in the Western Cape and has a capacity of 1800 MW (DWA, 2010). The updated IRP (2013) stated that no new nuclear plants would be required before at least 2025 and under a low growth scenario not before 2035. Any future nuclear power plants will however be located along the coast where seawater can be used for cooling. Hence the availability of freshwater resources is not a constraint for future nuclear power generation.

2.3 Open Cycle Gas Turbine (OCGT)

There are four existing Open Cycle Gas Turbine (OCGT) power plants located near Cape Town, Saldanha, Mossel Bay and East London (Figure 3). Two additional plants are in the process of being constructed namely the 670MW Avon facility in KwaZulu-Natal and the 335MW Dedisa plant in the Eastern Cape (GDF Suez, 2013). The OCGT power plants will be owned and operated by IPPs. The gas turbines will use diesel as primary fuel and will have water injection to control the nitrogen oxide emissions. The Avon power plant is located near Shakaskraal 45 km north-east of Durban in Quaternary catchment U30E. The Dedisa plant is 20km north-east of Port Elizabeth near to the Coega Industrial Development Zone in Quaternary catchment M30B. Commercial operation at Dedisa is expected in 2015 and at Avon in 2016 (Creamer, 2013).

2.4 Hydropower and Pumped Storage

South Africa currently has two hydropower stations located at the Van der Kloof and Gariep Dams as well as a number of pump-storage schemes for peaking power (Figure 3). The current hydropower dams, however are not operated specifically has hydropower dams, but instead generate hydropower as a by produce of releases made for other downstream demands. Hydropower is also imported from Lesotho via the Lesotho Highlands Scheme, and Mozambique from Cahora Bassa dam. As hydropower is a non-consumptive water use, water availability is not considered a constraint in the SATIM-W model and therefore regional water supply costs are not developed.

The Ingula pumped storage power station is expected to be fully operational in 2014 (Creamer, 2014). The Ingula scheme is on the border of the Free State and KwaZulu-Natal (KZN) and will have a generating capacity of 1,332MW. It consists of two dams 4.6 km apart: the Bedford Upper Dam (Free State) and the Braamhoek Lower Dam (KZN). The power station will operate during peak energy consumption and will pump water back up to the upper dam during periods low demand.

2.5 Renewable Energy

South Africa has a high level of renewable energy potential particularly in regard to its solar resource. The South African government has implemented a criteria based competitive bid process for IPPs. This Renewable Energy Independent Power Producer Programme Projects (REIPPPP) has so far had three bid windows. The following sub-sections describe the various renewable options, the likely locations and their potential water use for wind, concentrated solar, solar photovoltaic, hydropower including pump storage and other renewable options.

2.5.1 Wind Generation

The Sere Wind Farm Facility is located at Skaapvlei Farm within the Matzikama Municipality, in the Western Cape, South Africa. The Sere wind farm will have a capacity of up to 100 MW, avoiding nearly 4.7 million tons of carbon emissions over 20 years. Wind generation requires minimal water in the operation phase for washing and consumption by operators. A summary of the generation capacity of the approved wind energy projects are presented by province in Table 1.

Table 1 Approved Wind REIPPPP per province (including bid window 3 projects)

Province	Capacity (MW)
Eastern Cape	1003.2
Northern Cape	662.8
Western Cape	317.6
Total	1983.6

2.5.2 Concentrated Solar

Two types of concentrated solar have been considered under the REIPPPP bid widows, they are:

- Concentrated photovoltaic (CPV), and
- Concentrated solar power (CSP).

CPV technology makes use of optics such as lenses or curved mirrors to concentrate sunlight onto a small area of solar PV cells to generate electricity. This technology type converts the concentrated sunlight directly to electricity via the photovoltaic effect and is considered to be more cost effective than conventional PV solar cells in that it requires a smaller area of photovoltaic material per GWh produced. Similar to CPV technology, CSP uses mirrors or lenses to concentrate sunlight onto a small area to generate electricity directly via a heat engine, e.g. a steam turbine.

Five projects from the REIPPPP with a generation capacity of 400MW (3x100MW and 2x50MW) have been approved for the Northern Cape after the third bid window. Eskom is also developing a CSP demonstration project near Upington (Creamer, 2014). All the concentrated solar projects that have been approved are situated in the Lower Orange catchment are likely to be dry cooled.

The conventional PV and CPV technologies require significantly less water (19 ℓ/MWh) than the CSP system which needs approximately 3 420 ℓ/MWh during the operational period. This is because PV and CPV convert solar power directly into electricity and water is only required for cleaning of the panels, while CSP uses solar power to generate steam which drives a turbine in the same way as other thermal power stations (coal or gas) which requires water for steam generation and cooling.

2.5.3 Solar Photovoltaic (PV)

Conventional PV technology converts solar radiation in electricity via arrays of cells that include silicon or a similar material (Jacobson and Delucchi, 2011). No water is used in the generation of electricity in the cells. The PV panels do, however, need to be cleaned for optimal efficiency. Mulilo Renewable Project Developments (Pty) Ltd have estimated that the water consumption during the cleaning of panels that have an installed capacity of 1 MW would be on the order of 2000 litres of water. The panels will be cleaned at least twice a year and due to environmental concerns it is most likely that no chemical will be used in the cleaning.

A significant amount of generation capacity has been reserved for PV projects across South Africa under the new build options in the 2010 IRP with over 3300 MW by 2022. A summary of the generation capacity of the approved PV energy projects is presented by province in Table 2.

Table 2 Approved PV REIPPPP per province (including bid window 3 projects)

Province	Capacity (MW)
Eastern Cape	69.6
Free State	199.0
Limpopo	118
Northern Cape	884.2
North West	79.3
Western Cape	133.8
Total	1483.9

2.5.4 Other Renewables

Under the REIPPPP scheme other renewable technology projects have been approved and are summarised in Table 3. The water supply constraints on these are not considered in this case study.

Table 3 Other approved renewable technology projects per province (including bid window 3 projects)

Technology	Province	MW
Biomass	KwaZulu-Natal (Mkuze)	16
Landfill gas	Gauteng (Johannesburg gas to electricity)	18
Small Hydro	Free State	4.4
	Northern Cape	10

2.6 Biofuels

The National Biofuels Industrial Strategy of South Africa (NBIS) was published by the Department of Minerals and Energy in 2007. The crops recommended for bioethanol in the national strategy are sugarcane and sugar beet for bioethanol and canola, soya beans and sunflower for biodiesel. The two main crops that have been excluded for biofuel use are maize for reasons of food security and Jathropa for its potential as an invasive alien. Jewitt *et al*. (2009) identified the climatic optimum growth area for various biofuel crops. Large areas of KwaZulu-Natal, Eastern Cape and Mpumalanga were deemed climatic suitable for canola, soybean, sunflower, sugar beet and sugarcane.

In the second National Water Resources Strategy (NWRS) the Department of Water Affairs (DWA) has indicated that there should be no irrigated crops used for biofuels (DWA, 2013). This includes sugar beet and sugarcane production for bioethanol. In addition, any tree crops used for biofuels would need to be assessed as Stream Flow Reduction Activities (DWA, 2010). Hence currently biofuels crops are not considered to have an impact on current and future water resource availability of constraints and are therefore not considered at this stage in the current case study. In future, however this may change given other pressures to enhance biofuel production in South Africa.

2.7 Shale Gas

Extensive shale gas reserves have been located in the Karoo area of South Africa between 2500 and 4000m below the surface. The Karoo is a semi-arid to arid area and fresh water is a critical constraint to future economic growth (Le Maitre *et al*., 2009). There are a number of environmental concerns associated with hydraulic fracturing with main ones being:

- large amounts of clean water are required for fusing with chemicals that are used to split underground rocks so that the shale gas can be extracted;
- polluting surface and underground water through hydraulic fracturing process, and
- pollution of groundwater from leaking casing during and after extraction of the shale gas.

The possible sources of water for hydraulic fracturing identified by Vermeulen (2012) are:

- the development of local groundwater supplies (the boreholes are likely to be considerable deeper than the current 100m average depth of Karoo boreholes);
- transporting surface water to the required site by road or rail from outside the Karoo;
- piping desalinated seawater, and
- piping water from the Orange River.

Exploration rights have been granted to companies in the following areas (see Figure 6):

- Anglo - Northern Cape and Free State;
- Bundu – Karoo (Eastern Cape);
- Falcon – Karoo (Eastern and Western Cape);
- Sasol - Free State and Eastern Cape and KwaZulu-Natal, and
- Shell – Karoo (Eastern Cape, Northern Cape and Western Cape).

Shell have stated during their public meetings in various Karoo towns that they would not use Karoo groundwater and said that the required water would be brought in by road, but did not state the source of the water. The alternative water supply options are however likely to be very expensive.

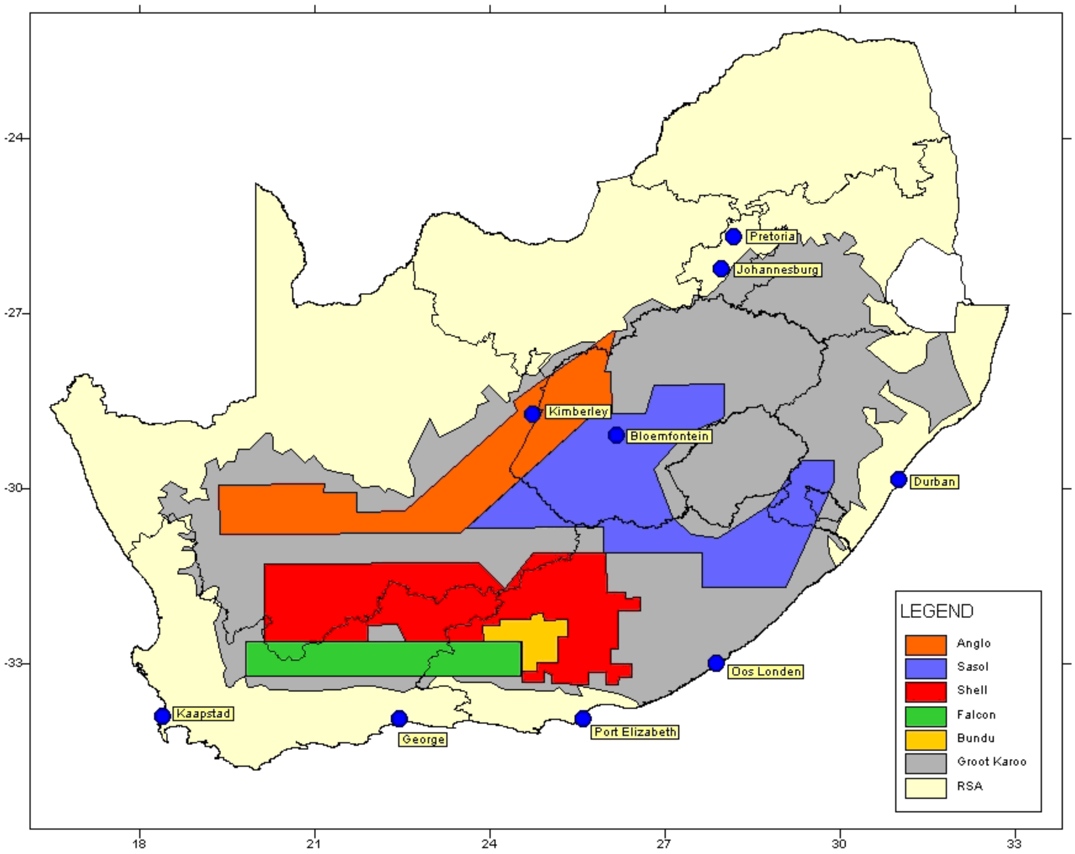

Figure 6: Hydraulic Fracking exploration rights (after Steyl and van Tonder, 2013)

3 The Water Energy Nexus

3.1 Water for power production

The focus of this study is on modelling the water for power part of the water-energy nexus and not the power for water supply side. In order to determine the significance of the spatial variability in water prices on future power generation technologies it is important to also consider the average water use of each technology and put this in context of the overall generation costs. Estimates of the average water use intensity factors for different technologies used in South Africa are given in Table 4[1].

Table 4: Average water use efficiencies for power generation technologies (after Blignaut et al, 2011)

Technology	Average Water Use for Production (m^3 / MWh)	Source
Coal: Dry cooling with FGD[2]	0.56	DOE, 2011
Coal: Dry cooling without FGD	0.31	DOE, 2011
Coal: Traditional wet cooling	1.35	Eskom, 2011
CSP with parabolic trough	0.30	Macknick et al, 2011
Solar PV	0.098	Macknick et al, 2011

In addition to the above average water use for production, coal fired power stations have an additional water use requirement associated with the mining of the coal for use in the power station. The water used to mine 1 ton of coal can be calculated as approximately: 160 litres per ton (extraction) + 42 litres per ton (dust control) + 38 litres per ton (coal washing) + 229 litres per ton (evaporation) = 469 litres per ton (after Wassung, 2010). A large proportion of this water can however be recycled. For example, about 47% of the water used by Anglo Coal is recycled (Holman 2008). Assuming an average 45% of the water can be recycled the net new water requirements is approximately 259 litres per ton. According to ESKOM, the average amount of coal required to produce 1 kWh of electricity is 0.56 kg (ESKOM, 2009). Hence the contribution from mining to the total water requirement for electricity from coal is around 0.144 m^3 / MWh that must be added to the values in Table 4.

In modelling the water-energy nexus for South Africa the water requirements for the production of fuel for the power plants (i.e. coal) is calculated separately from that or energy production and cool at the power plant to account for possible differences in the location of the coal mine and the power plant. This could be used to investigate the cost impacts of locating the power plant close to the coal field and transporting the water, or locating near to the water source and transporting the coal.

[1] These will be updated in Task 2 with more recent estimates of water use intensities.
[2] Flue gas desulphurization (FGD)

3.2 Key water resource areas

South Africa is a water-scarce country (annual freshwater availability is less than 1,700m3 per capita), with limited average rainfall of about 450 mm/yr and unevenly distributed water resources (DWAF, 2004). South Africa has an annual mean-runoff value of only 40 mm per capita, one seventh of the global average of 260 mm, and rainfall and river flow are highly variable, erratic, and seasonal.

Added to this is the fact that much of South Africa's key economic centres, including the urban and industrial centre of Gauteng, key mining areas and power stations, are located in areas of low water availability far from major water sources where local demands exceed local supply. South Africa however has had a very proactive approach to water supply which has resulted in a highly developed and integrated water supply system of large dams and many inter-basin transfers to balance supply and demand (Figure 7). South Africa, for example, has the most number of registered dams in Africa, and the sixth most number of registered large dams globally (ICOLD, 2013).

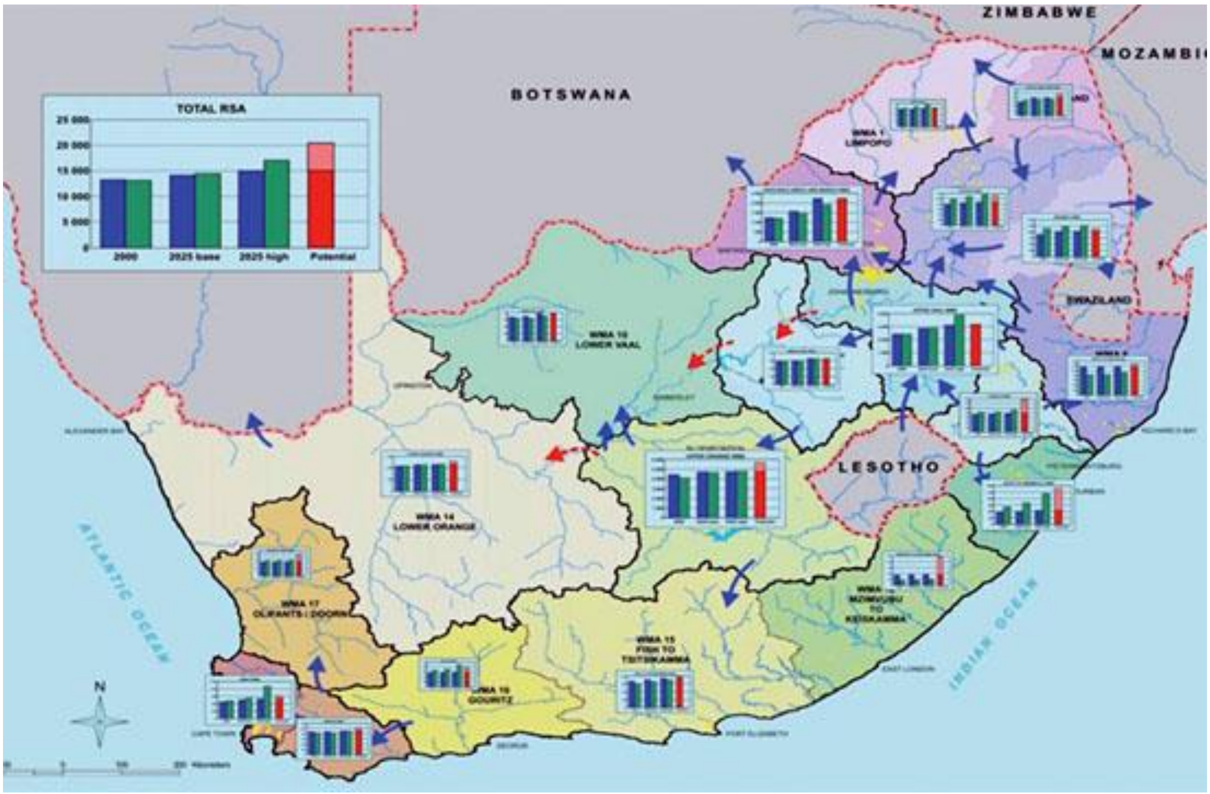

Figure 7: Water resource availability and major inter basin transfers (IBT) in South Africa (DWA, 2004)[3]

[3] The blue bars indicate the available resource in each WMA, while the green bars indicate the total demand and the red bars indicate the resource development potential. The blue arrows indicate the major IBT schemes including transfers for power generation and international exports.

Although power generation accounts directly for only about 2% of the total water demand of the country (DWA, 2012), it is considered to contribute about 15% to the GDP and creates 250,000 jobs (GCIS, 2011). Power generation is also considered to be a key strategic industry thereby requiring a very high level of assurance of supply and good water quality. As a result many of the large IBTs in the country have been developed specifically to supply water to the power stations.

Despite significant improvements in the water use efficiency of power generation, it will continue to be a major source of demand for water in the future. A summary of the current planned future power station developments in South Africa are shown in Table 5 along with the estimated water requirement. The key priority areas for modelling the water-energy nexus in South Africa are:

- Upper Olifants
- Integrated Vaal System
- Lephalale area - Crocodile West/Mokolo Water Supply System
- Orange River System.

Table 5: Summary of future power generation options and water requirements

Plant Type	Location	Estimated Completion Date	Installed Capacity (MW)	Water Management Area	Likely Water Source	Water Use * (m^3/MWh)
Base Load Coal	Medupi, Lephalale	2017	4800	Limpopo	Mokolo Dam and Crocodile West	0.56
	Kusile, Delmas	2020	4800	Olifants	Upper Komati and Vaal Systems	0.56
New Coal	IPP1, Emalahleni	2015	600	Olifants	Upper Komati and Vaal Systems	1.35 (if wet cooling) 0.56 (if dry cooling)
	IPP2, Lephalale	2015	600	Limpopo	Crocodile West	1.35 (if wet cooling) 0.56 (if dry cooling)
	IPP3, Emalahleni or Lephalale	2022	1000	Olifants or Limpopo	Vaal	1.35 (if wet cooling) 0.56 (if dry cooling)
Concentrated Solar Power	Upington	2020	400	Lower Orange	Lower Orange	0.38
Wind	Sere Wind Farm, Vredendal	Dec 2014	2.3	Berg	Berg	0.00
Solar PV	De Aar, Prieska, Upington corridor	From 2013 onwards	1484	Lower Orange	Lower Orange	0.10

* Refer to Table 4.

3.2.1 Upper Olifants

The estimated current water requirements in the Olifants catchment are presented in Table 6 and show that the water resources of the Olifants River system are close to being fully utilised. The future water balance shows a deficit for the whole system by 2030 (Table 6). A major contributor to this deficit is the implementation of the ecological reserve, provisionally to be phased in during 2020 to 2025, which will reduce the water available for extraction by about 200M.m^3 per year. Power generation accounts for 23% of the current demand in the catchment. Despite plans for additional power generation capacity in the catchment, ESKOM does not anticipate a significant increase in the total water demand as the planned new power stations will be dry cooled and will replace the existing wet-cooled power stations. After about 2025 it is anticipated that there might even be a gradual decrease in the total water demand for power generation in the catchment.

Table 6: Summary of Current Water Requirements (2010) in the Olifants System (Aurecon, 2011)

Management Zone	Irrigation (M.m^3/a)	Domestic & Industrial (M.m^3/a)	Mining (M.m^3/a)	Power Generation (M.m^3/a)	Total Requirements (M.m^3/a)
Upper Olifants	254	109	21	228	612
Middle Olifants	93	39	24	0	156
Lower Olifants	161	21	36	0	218
Total	**508**	**169**	**81**	**228**	**986**

Table 7: Olifants 2030 Water Balance (Aurecon, 2011)

Management Zone	Total Water Resource (M.m^3/a)	Water Requirement (M.m^3/a)	EWR (M.m^3/a)	Water Balance (M.m^3/a)
Upper Olifants	618	648	80	(110)
Middle Olifants	227	214	51	(38)
Lower Olifants	202	230	69	(97)
Total	1047	1092	200	(245)

Only limited potential for water resources development to meet the future water supply deficit exists within the catchment after which the demand will have to be met by transfers from outside the catchment in addition to the existing IBTs. The feasible augmentation options include those below.

- Olifants River Dam: construction of a dam in the middle Olifants close to Rooipoort.
- Ekurhuleni Effluent: it is possible to pump treated effluent from the East Rand. The water would need to be treated to meet acceptable phosphate levels for discharge into the Olifants.
- Acid mine drainage reuse: the acidic water that is being discharged from disused coal mines in the upper Olifants can be treated and reused to meet the water demand in municipalities.
- Import from Vaal Dam: water could be transferred from the Vaal River System to the upper Olifants. The infrastructure required includes a pipeline and pump station.
- Desalination of seawater: although technically feasible it is likely to be prohibitively expensive.

- Transfer of Zambezi water: for this to be feasible from a cost perspective it would need to bepart of a scheme that supplied Lephalale and Pretoria as well as the Upper Olifants.

The use of Ekurhuleni effluent and water imported from Vaal Dam would mean that the Vaal River augmentation would be expedited. The removal of alien invasive plants and the prevention of illegal irrigation could increase the water yield in the Upper Olifants by 16.1 M.m^3/a.

3.2.2 Integrated Vaal River System

The supply area of the Integrated Vaal River System extends beyond the catchment boundaries of the Vaal River (see Figure 8). It supplies around 12 million people with water (mainly in Gauteng), Eskom's power-stations and Sasol's petro-chemical plants in Mpumalanga, and various mines in the North-West and Free State. Additionally the system will also supply water for the development of the Waterberg coal-fields near the town of Lephalale in the Limpopo WMA (DWA, 2009).

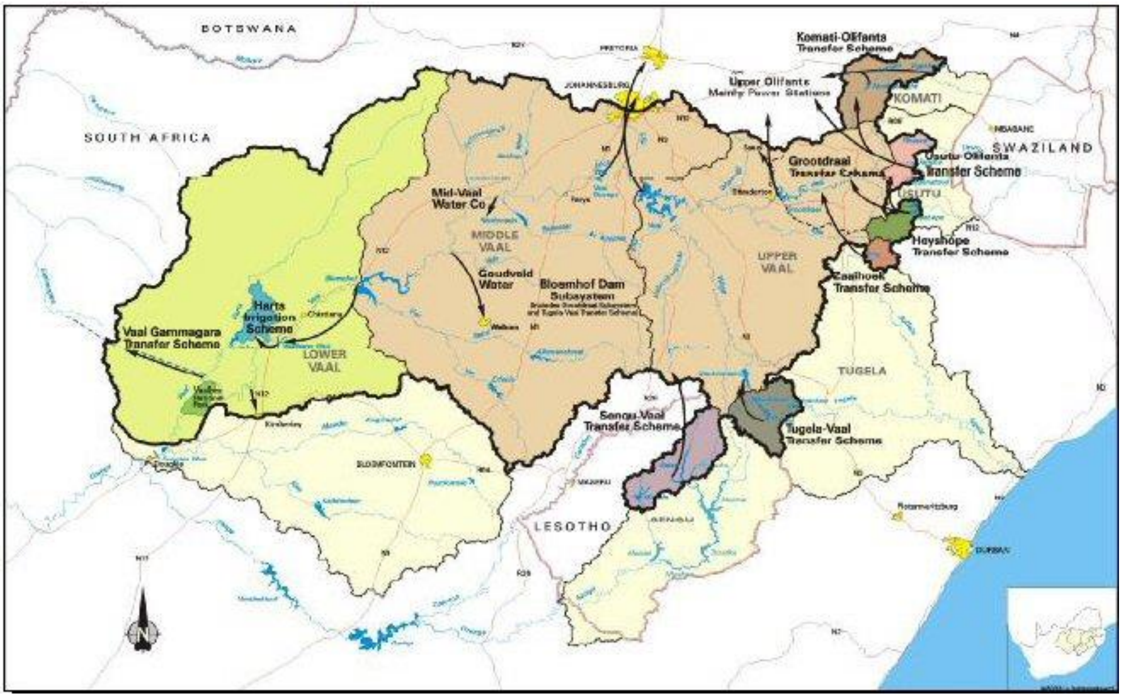

Figure 8: Catchments comprising the Integrated Vaal River System (DWA, 2009)

Currently many of Eskom's coal fired power stations are supplied with water from the Integrated Vaal System (see Table 8). Although the Kusile power station is under construction and an additional power station is planned for the Olifants catchment, the water transfers from the Upper Komati and Vaal Systems will be increased to meet the demands of these new power stations and the water balance of the Olifants River system itself will not be affected by these developments. The water supply to the existing coal power stations in the Upper Olifants has been estimated at 228 M.m^3/a (Aurecon, 2011).

Table 8: Currently registered water abstractions for power stations in the Integrated Vaal System (Eskom, 2012)

Catchment	Power station	Water Supply (Mm^3/a)
Komati	Arnot, Hendrina, Komati, Duvha	93.92
Usutu	Camden, Kriel, Matla	50.97
Usutu-Vaal	Duvha, Kriel, Tutuka, Matla, Kendel	88.00
Vaal	Lethabo, Grootvlei	52.41
	TOTAL	**285.30**

The water quality in Grootdraai Dam and Vaal Dam is influenced by the water quality of the transfers from Lesotho, Thukela, Zaaihoek and the Usutu transfer schemes. The water quality of the transfers is currently of an acceptable quality for the use in the power stations. There is however concern that in the future the quality of the water in Grootdraai Dam will deteriorate due to acid mine drainage (AMD) water from closed mines and that the salinity will increase from the Vaal Barrage to Bloemhof Dam because of urbanisation and mine discharges (DWA, 2009). The water quality assessment showed that Vaal Dam, Vaal Barrage and Bloemhof Dam are eutrophic to hypertrophic and require significant additional releases of high quality water from the Lesotho Highland Water Project (LHWP) to maintain an acceptable water quality standard.

To meet the increasing water demands due to development in Gauteng, the Vaal River System was augmented via major inter-basin transfer schemes from higher rainfall area such as the upper Thukela and Usuthu River and the Orange River in Lesotho via the LHWP. The current and future anticipated water requirements for Vaal systems are presented in Table 9 (Coleman *et al.,* 2007).

Table 9: Summary of future water requirement for the Vaal system (Coleman et al, 2007)

Major Water User Groups	Annual Water Requirement (Mm^3/a)				
	2010	**2015**	**2020**	**2025**	**2030**
Rand Water	1338	1417	1481	1568	1666
Mittal Steel	17	17	17	17	17
ESKOM	381	407	416	417	417
SASOL (Sasolburg)	27	30	33	37	41
SAOL (Secunda)	104	108	112	117	123
Midvaal Water Company	35	35	35	35	35
Sediberg Water	41	41	41	42	43
Other towns and industries	163	167	167	167	168
Vaalharts/Lower Vaal Irrigation	542	542	542	542	542
Other irrigation	599	500	500	500	500
Wetland/River Losses	326	327	329	330	331
TOTAL	3573	3591	3673	3772	3883

As the system is already over allocated, additional augmentation options are required to meet future water demands for the integrated Vaal River system. The feasible augmentation options include:

- Treatment and reuse of Acid Mine Drainage (AMD) water;
- LHWP Phase II, Polihali Dam;
- Orange-Vaal transfer (Boskraai Dam with phased pipelines);
- Thukela-Vaal transfer: Mielietuin and Jana Dams;
- Mzimvubu-Vaal transfer;
- Zambezi-Vaal transfer, and
- Desalination of seawater.

The proposed reconciliation between supply and demand for the Vaal River is shown in Figure 9.

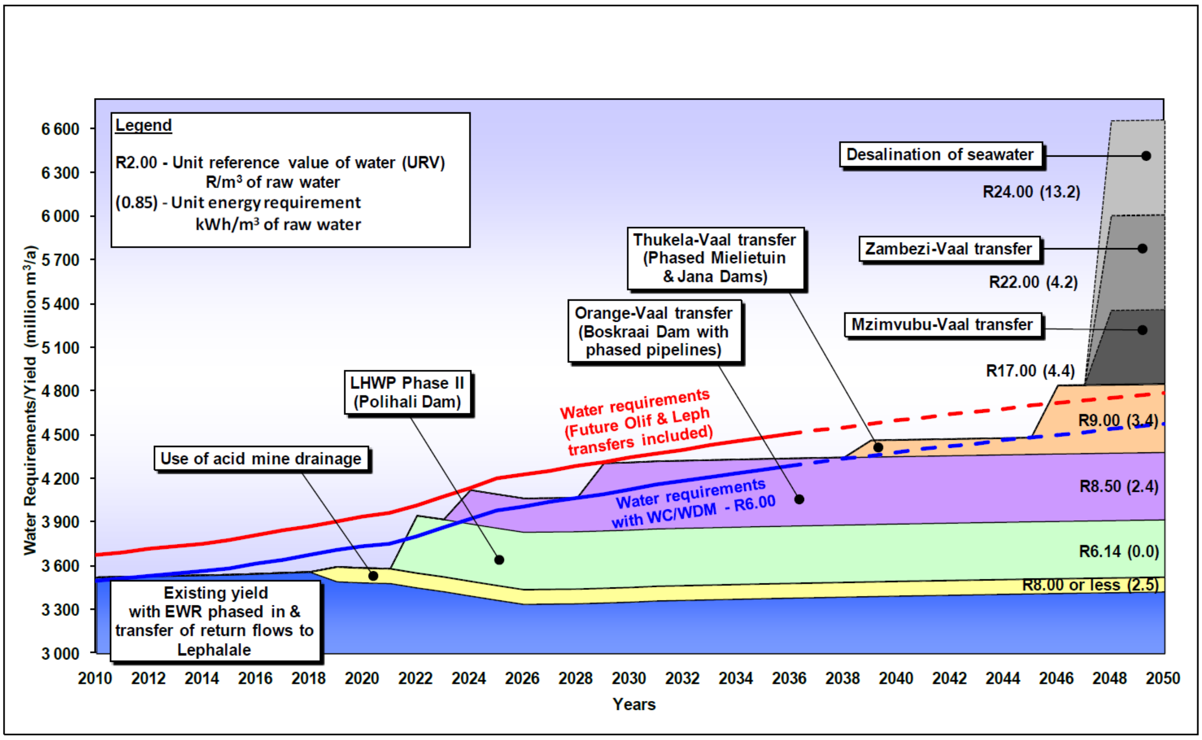

Figure 9: Reconciliation of water demand and supply for the Vaal River system (DWA, 2010).

3.2.3 Lephalale area – Crocodile West/Mokolo System

The development of the Waterberg coalfield west of Lephalale, the construction of several coal-fired power stations and the establishment of other industrial users such as SASOL will dramatically increase water demand in the area. The expected growth in demand up to 2030 for the Lephalale area is presented in Table 10. Currently power generation uses only about 4.3 Mm^3/a or 18 % of the total demand (DWA, 2010). By 2030 it is expected that the water demands from ESKOM power stations will increase to 79 Mm^3/a with an additional 20 Mm^3/a required for coal mining and 15 Mm^3/a required for IPP. This is a total 113 Mm^3/a or 54 % of the future demand.

Table 10: Lephalale water requirements per major user group (DWA, 2010)

Major User Group	Annual Water Requirement (M.m^3/a)									
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2020**	**2025**	**2030**
Eskom	4.3	4.3	4.9	6.8	9.3	10.9	14.3	50.9	77.6	77.6
IPPs	0.0	0.4	0.9	0.9	1.5	4.4	13.2	15.6	15.6	15.6
Coal Mining (for power generation)	0.0	0.0	1.1	2.7	4.4	5.3	6.8	14.1	20.0	20.0
Exxaro Projects	3.0	3.2	3.7	4.7	6.6	9.2	10.8	16.9	16.2	19.2
SASOL (Mafutha 1)	0.0	0.0	0.4	6.1	6.6	9.9	25.2	43.5	43.5	44
Municipality	5.6	5.9	7.7	10.4	12.0	13.6	14.5	20.4	21.2	21.6
Sub-Total	12.9	13.8	18.7	31.7	40.4	53.4	84.8	161.4	194.1	198
Irrigation	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
Total	**23.3**	**24.2**	**29.1**	**42.1**	**50.8**	**63.8**	**95.2**	**171.8**	**204.5**	**208.4**

The available water resources in the area are already over allocated. The future demand will be met initial from the underutilised Mokolo Dam and then via transfers from the Crocodile West catchments. The Mokolo/Crocodile West system and its location in regard to the Vaal System is shown in Figure 10.

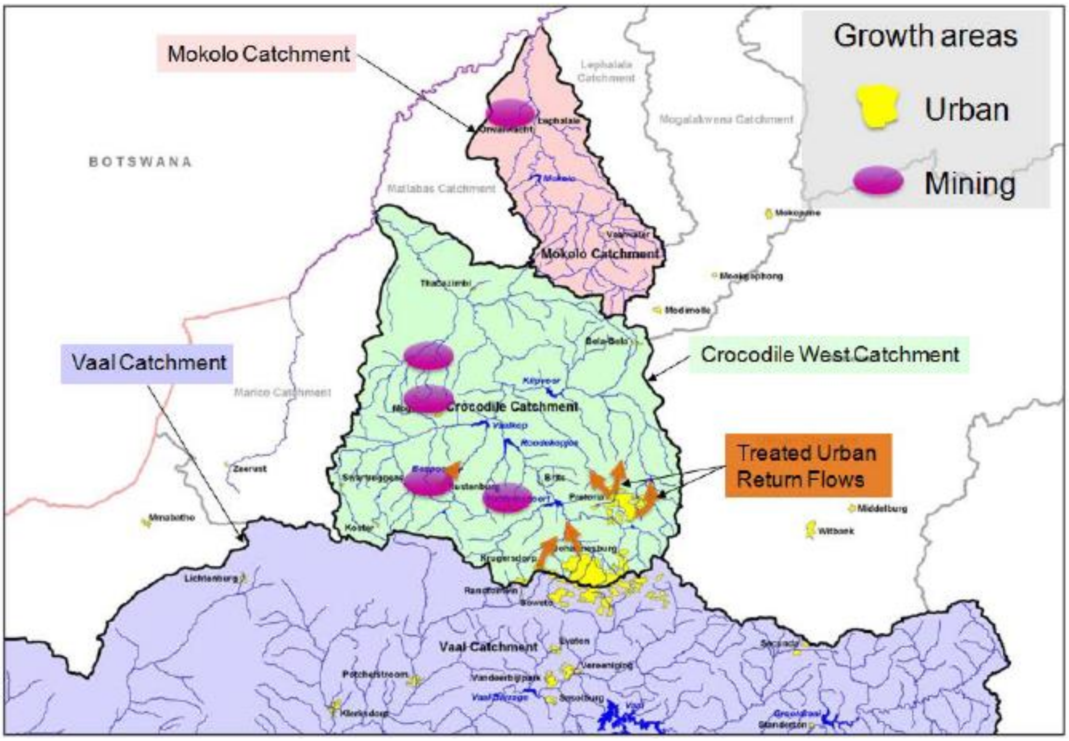

Figure 10: Location of the Crocodile West and Mokolo System (DWA)

The current water use plan for the area states that water from the Crocodile River will be transferred to the Waterberg coalfields to meet the demand growth. This water for the most part will consist of the growing return flows from the northern urban and industrial areas of Gauteng (DWA, 2010). However, the impacts on the Reserve and flows to the Limpopo must be considered as the Crocodile West reconciliation strategy study shows that this return flow may not be sufficient (DWA, 2010).

Feasible options for future water supply augmentation to the Lephalale area include:

- Mokolo-Crocodile Augmentation Project Phase 1: Mokolo Dam;
- Mokolo-Crocodile Augmentation Project Phase 2: Crocodile West;
- Reuse of effluent from the Vaal catchment;
- Transfer from Vaal system: from Vaal Dam;
- Transfer from the Zambezi, and
- Desalination of seawater.

The proposed reconciliation between supply and demand for the Lephalale area including the Crocodile West and Makolo system and augmentation from the Vaal River is shown in Figure 9.

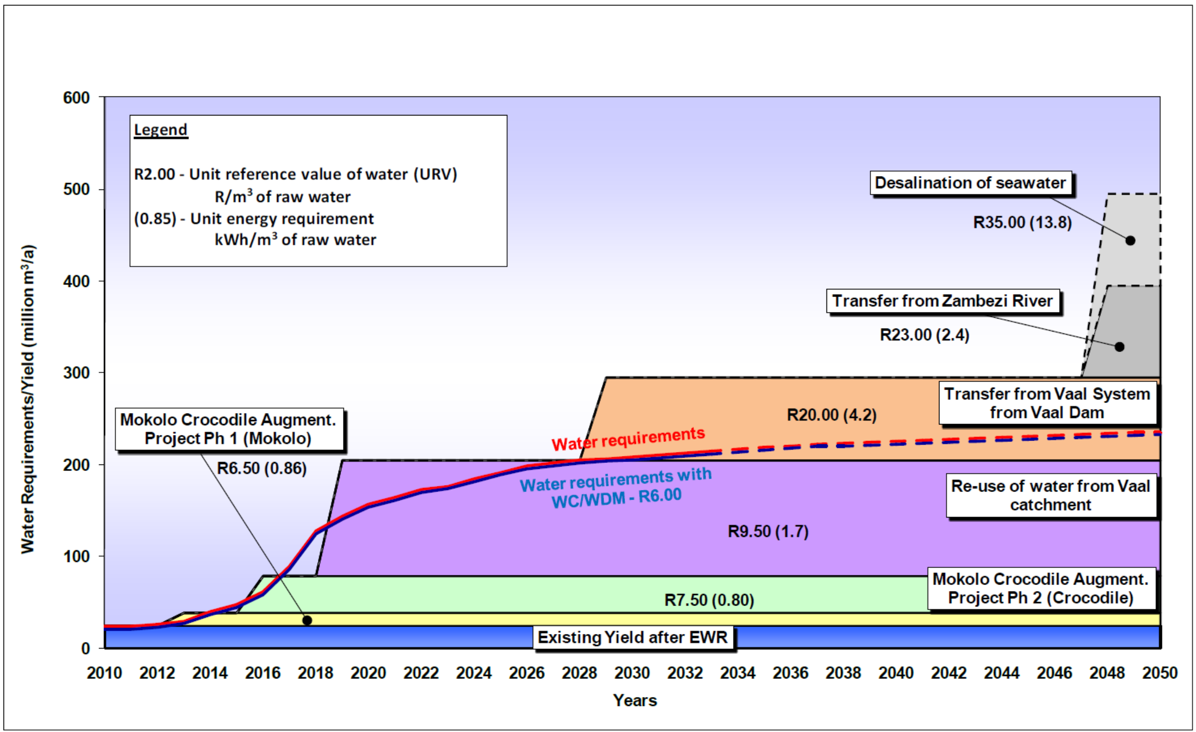

Figure 11: Reconciliation of water demand and supply for the Lephalale system (DWA, 2010).

3.2.4 Orange River System

The Orange River System has a catchment area of approximately 0.9 million km^2 and flows in a westerly direction from Lesotho to the Atlantic Ocean (see Figure 12). There is a west-east rainfall gradient in the orange catchment with the mean annual precipitation (MAP) in some areas of the Northern Cape being below 100 mm per annum near to the Atlantic coast where as some part of the Orange catchment in Lesotho have MAP in excess of 1 200 mm per annum (Schulze, 2006). The natural runoff for the Orange River basin has been estimate at 11,600 Mm^3 per annum. The current runoff that is discharged at the river mouth has been estimated at 5,500 Mm^3 per annum.

Figure 12: The Orange River System (DWA)

In terms of energy and water demand the growth areas in the Lower Orange catchment will be from concentrated solar power (CSP) and potentially the recovery of shale gas. The estimated water requirements for the Orange River System are summarised in Table 11.

Table 11: Current and future water demands for the Orange River System (WRP, 2012)

Major User Group	Annual Water Requirement (M.m^3/a)			
	2012	**2015**	**2020**	**2025**
Irrigation	2 229	2 284	2 382	2 466
Domestic/Urban Demand	217	268	288	311
Lesotho Highlands Transfer Katse Dam to Vaal Dam	713	780	780	780
River requirement	615	615	615	615
Operating requirements	180	180	180	180
River Mouth Environmental requirement	288	288	288	288
CSP	0	5	20	20
TOTAL	**4 242**	**4 420**	**4 552**	**4 660**

Initially, water requirements for the large-scale rollout of CSP were not deemed to be a major barrier with Eskom's 100MW plant projected to require 0.38 M.m^3 of water per year for cooling and cleaning the mirrors (Edkins *et al*., 2009). However, according to the Department of Energy (DOE, 2013) it is expected that by 2030 3.3 GW will be supplied from CSP along the Orange Rive. This would require approximately 13 M.m^3 of water annually. Approval for the construction of CSP plants has already been given on farms close to Upington, Pofadder and Groblershoop.

The source of the water required for hydraulic fracturing to recover the extensive shale gas deposits in the Karoo has yet to be determined. There are however very few surface water sources available in the area with many towns already experiencing severe water shortages. The nearest large surface water supply option is from the Orange River or one of its tributaries. In order to develop a provisional MWSC for fracking it has been assumed that water will be obtained from the Gariep Dam and transported to the likely site. The alternative of using local groundwater resources is also considered, although the availability of groundwater is uncertain and requires detailed analysis.

Currently the water balance of the Orange River system reflects a slight surplus (DWA, 2010). By 2020, however the system is expected to be in deficit due to expected increases in demands and additional augmentation options will be required. The feasible augmentation options include:

- Boskraai Dam;
- Mzimvubu-Kraai transfer: Ntabelanga Dam, and
- Desalination of seawater.

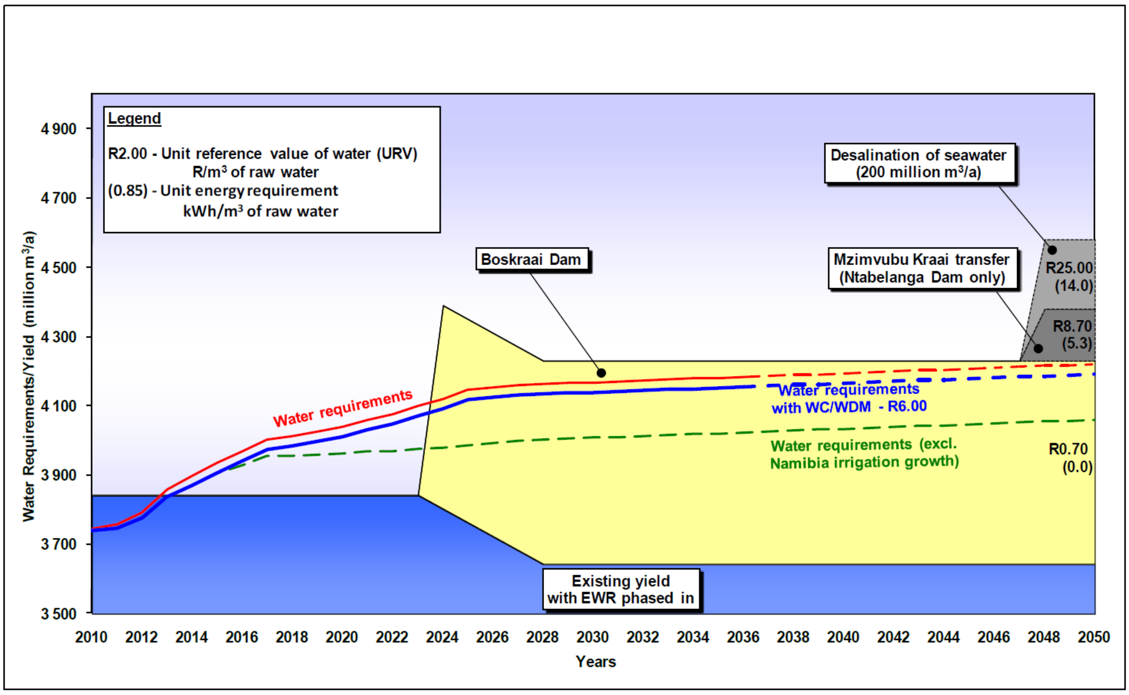

Figure 13: Reconciliation of supply and demand for the Orange River system (DWA, 2010).

3.3 Potential Climate Change Impacts

3.3.1 Climate Change Scenarios for South Africa

Sub-Saharan Africa is considered to be one of the more vulnerable regions in the world to climate change and while there is a general agreement that temperatures will continue to increase, there is still much uncertainty about the potential impact on precipitation (Schulze, 2011). A recent review of existing climate models identified four possible future scenarios as part of the Long Term Adaptation Scenarios (LTAS) flagship research program of the Department of Environmental Affairs (DEA, 2013):

- **Warmer (<3˚ C above 1961-2000) and wetter** with greater frequency of extreme rainfall
- **Warmer (<3˚ C above 1961-2000) and drier** with an increase in the frequency of drought events and somewhat greater frequency of extreme rainfall events;
- **Hotter (>3˚ C above 1961-2000) and wetter** with substantially greater frequency of extreme rainfall events, and
- **Hotter (<3˚ C above 1961-2000) and drier** with a substantial increase in the frequency of drought events and somewhat greater frequency of extreme rainfall.

These impacts would also vary quite significantly for different regions as summarised in Figure 14.

Scenario	Limpopo/ Olifants/ Inkomati	Pongola-Umzimkulu	Vaal	Orange	Mzimvubu-Tsitsikamma	Breede-Gouritz/ Berg
1: warmer/ wetter	↑ spring and summer	↑ spring	↑ spring and summer	↑ in all seasons	↑ in all seasons	↓ autumn, ↑ winter and spring
2: warmer/drier	↓ summer, spring and autumn	↓ spring and strongly ↓ summer and autumn	↓ summer and spring and strongly ↓ autumn	↓ summer, autumn and spring	↓ in all seasons, strongly ↓ summer and autumn	↓ in all seasons, strongly ↓ in the west
3: hotter/wetter	Strongly ↑ spring and summer	Strongly ↑ spring	↑ spring and summer	↑ in all seasons	Strongly ↑ in all seasons	↓ autumn, ↑ winter and spring
4: hotter/ drier	Strongly ↓ summer, spring and autumn	↓ spring and strongly ↓ summer and autumn	↓ summer and spring and strongly ↓ autumn	↓ summer, autumn and spring	↓ all seasons, strongly ↓ in summer and autumn	↓ all seasons, strongly ↓ in the west

Figure 14: Summary of possible climate cahnge impacts on precipitaion for six hydro-climate zones in South Africa determikned from the LTAS analysis of available climate models (DEA 2013).

The LTAS study concluded that while there was a general consensus on the fact that temperatures would continue to increase into the future, the level of increase would be dependent on the outcomes from global mitigation efforts. Under a business as usual scenario South Africa would likely experience a much "hotter" future with an average increase in temperature greater than 3˚C by the end of the century. If however there was improved global co-operation on climate change and a significant reduction in greenhouse gas emissions then South Africa would like face only a "warmer" future. For both scenarios the potential impacts would apply for all regions of the country, but with inland areas likely to experience greater increases than coastal zones and the mountains. Under both the "hotter" and "warmer" futures there was still much uncertainty about the possible impact on precipitation, although it was generally agreed that the variability would increase under both scenarios, but more so under the "hotter" scenario.

A study undertaken by WIDER in support of the National Treasury and also contributing to the LTAS applied a risk based approach to assessing climate risk in South Africa. This study considered a hybrid frequency distribution (HFD) analysis of over 6800 possible climate futures derived from the MIT Integrated Global Systems Model (IGSM, Sokolov et al., 2009 and Webster et al., 2011) using outputs from 17 of the 22 available global circulation models (GCM) under both an Unconstrained Emissions Scenario (UCE) and a Level 1 Stabilization (L1S) scenario (Schlosser et al., 2011). The study also compared the results with available regional downscaled models including both statistical (empirical) downscaled models from the Climate Systems Analysis Group (CSAG) at the University of Cape Town (UCT) (Hewitson and Crane, 2006) and dynamic downscaled models from the Council for Scientific and Industrial Research (CSIR) (Engelbrecht et al, 2011). The potential economic risks for the range of possible climate futures was then assessed using a set of integrated biophysical models for water, agriculture and transport infrastructure (roads) linked to a computational general equilibrium model (CGE) of the economy at national level and at the scale of individual WMAs (Thurlow, 2008).

A comparison of the results from the HFD analysis and the regional climate models for potential impacts on the average annual precipitation by 2050 in hydrozone 1 (Limpopo, Olifants and Inkomati) and hydrozone 4 (Orange River) is given in Figure 15. These results show the wide range of potential impacts on precipitation as well as the fact that the HFD analysis encompasses the results from the regional downscaled models, but also provides a few more extreme scenarios for consideration. The median impact in both zones the models shows a slight reduction in the average annual precipitation, but with quite a wide range of potential impacts both positive and negative.

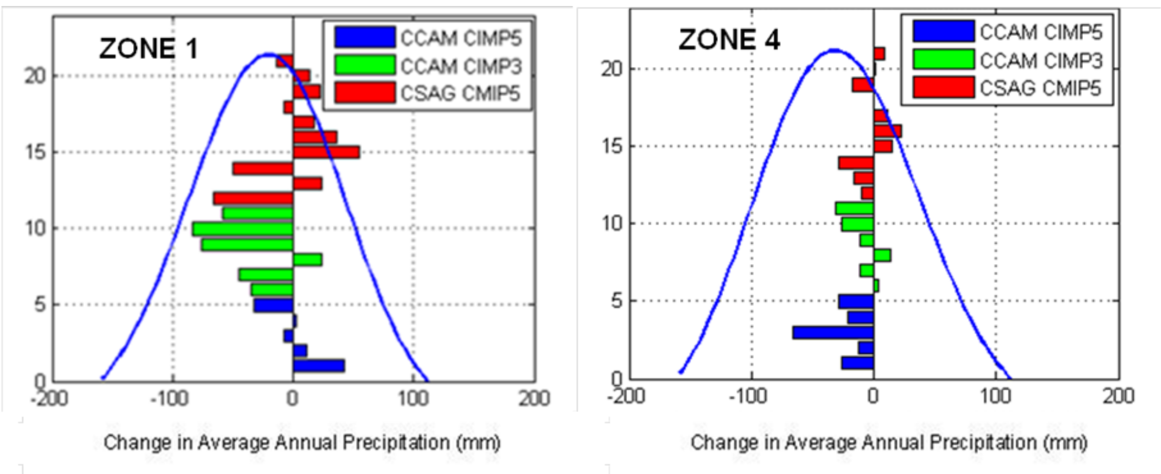

Figure 15: Potential increase in average annual precipitation in mm/year for the period 2040-2050 for the hydro-climatic zones 1 (Limpopo, Olifants and Inkomati) and 4 (Orange River). Comparison of the hybrid frequency

distribution (HFD) of UCE scenario from the IGSM model with outputs from a number of statistically (CSAG) and dynamically (CCAM) downscaled regional climate models for South Africa.

3.3.2 Impacts on future water supply

As part of the WIDER and LTAS risk based study, the potential biophysical impacts of a range of possible climate futures was analysed using a rainfall runoff model at quaternary scale, as well as a water resources yield model configured at secondary catchment scale for the whole of South Africa that includes all the major water supply infrastructure, dams and inter-basin transfer systems (DEA, 2014). These national water models were used to investigate the potential impacts of climate change on future water supply to the urban, industry and agriculture sectors in each water management area as well as contributing to an integrated assessment model (IAM) to assess the potential economic impacts of climate change at a national scale and at the level of individual WMAs.

A key result from this study was the observation that the national water supply system of South Africa, which has been planned to deal with a high level of natural variability and is highly integrated as a result of all the IBTs appears to provide a high level of resilience to climate change, although potentially at a cost in terms of increased pumping rates and potential negative impacts on environmental flow requirements (DEA, 2013).

Precipitation

The ratio of potential climate change impacts on the average annual precipitation by 2050 from multiple models under the UCE mitigation scenario relative to the base scenario in each secondary catchment is shown in Figure 16 (DEA, 2014). The solid line indicates the median impact of all the climate scenarios and the shaded and dotted lines show the range of potential impacts. The heavy dashed line indicates a reduction of around 3.6% in the median impact on the average annual precipitation for all secondary catchments across the country.

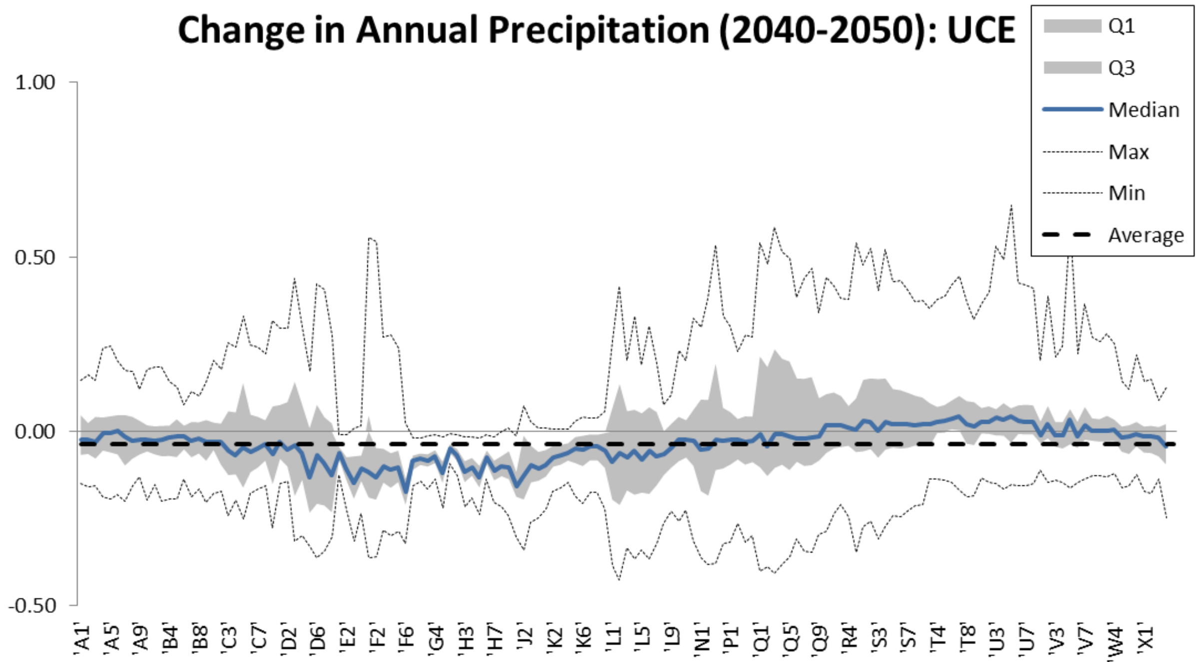

Figure 16: **Range of potential impacts on the change in the average annual precipitation for the period 2040 to 2050 in each secondary catchment of South Africa under the UCE climate scenario.**

Despite a wide range of uncertainty across much of the country there is a clear indication across most of the country that in all climate scenarios there is reduced precipitation in the F, G and H secondaries which are located in the south-west of the country including the west coast, the Berg River and the Breede River catchments. In contrast the catchments in the east of the country (T and U) show a general increase in the average annual precipitation, but even here about a quarter of the scenarios show a decrease.

Future coal fired power stations are likely to be located in catchments A (Limpopo), B (Olifants) and C (Vaal), which show a slight reduction (-3%) in the median impact on the average annual precipitation by 2050, but with a wide range of possible impacts from around -18% to +18%. Future CSP plants will be located in the lower Orange River basin (D4 to D8) which has a median impact of on average a 10% reduction in average precipitation, but water supply in this region is not dependent on local precipitation, rather on the runoff from upstream catchments including the Upper Orange and Vaal.

Catchment Runoff

The results from the LTAS study using the HFD analysis of possible climate futures under the UCE scenario in terms of the potential impact on the annual runoff for different secondary catchments across the country is shown in Figure 17. These results show a reduction in streamflow for the western half of the country (D to K) and in particular the south Western Cape catchments (F, G and H) in all the climate models. In contrast there are some very large potential increases in runoff for the east coast (Q to W) which could result in increased flooding risks.

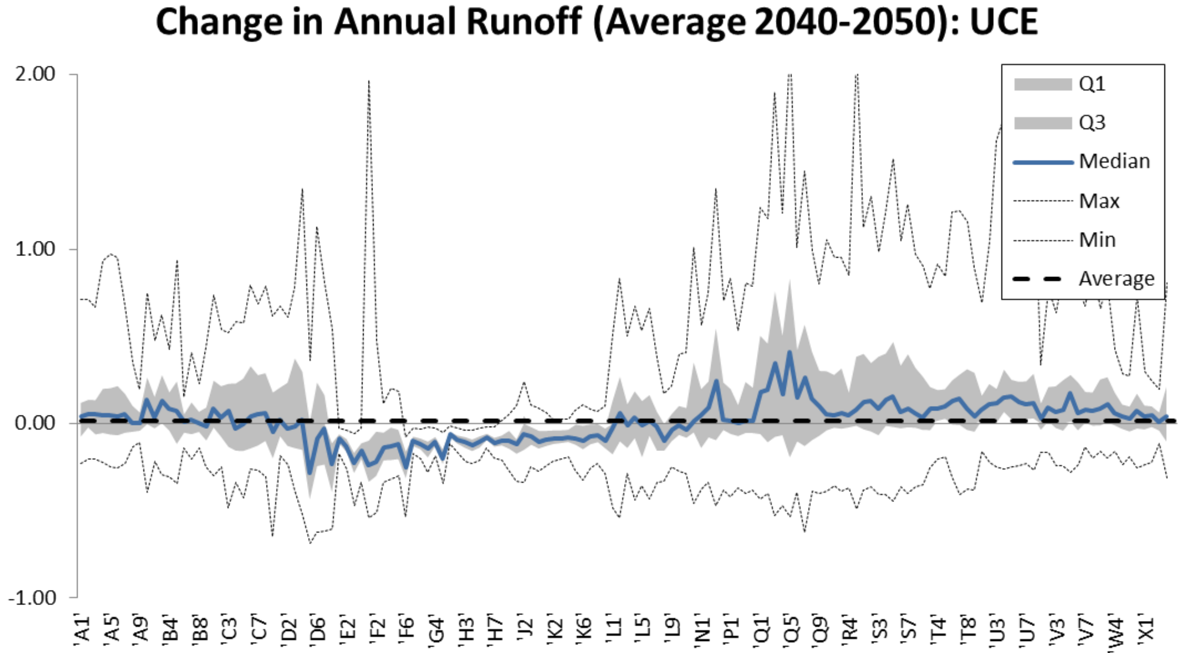

Figure 17: Range of potential impacts of climate change on the average annual catchment runoff for all secondary catchments for the period 2040 to 2050 due to the UCE scenario relative to the base scenario.

Future coal fired power stations are likely to be located in catchments A (Limpopo), B (Olifants) and C (Vaal), which show a median impact of around zero change or a small increase in the average annual runoff by 2050, but with a wide range of possible impacts. Future CSP plants will be located in the Orange River basin (D) which has a median impact of on average a 5% reduction in catchment runoff, but also with a wide range of potential impacts with up to as much as 50% reduction in some areas.

Irrigation Demand

While there is a wide range of uncertainty regarding the impacts of climate change on precipitation and catchment runoff across the country, the consensus of increasing temperatures under all future climate scenarios will result in an almost certain increase in evaporation and associated irrigation demands in all regions of the country.

The results of the HFD analysis of potential impacts of climate change on irrigation demand (DEA, 2014) show some variation across the country as seen in Figure 18. The average median impact across secondary catchments is 6.4 ± 1.9 % for the UCE scenario and a slightly lower average median scenario impact of 3.8% ± 1.5%. While some very wet scenarios show a small reduction in future irrigation demands in the Limpopo (A), Olifants (B), Vaal (C) and Orange (D) catchments, other very dry scenarios show possible increases in average annual irrigation demand of up to 25%.

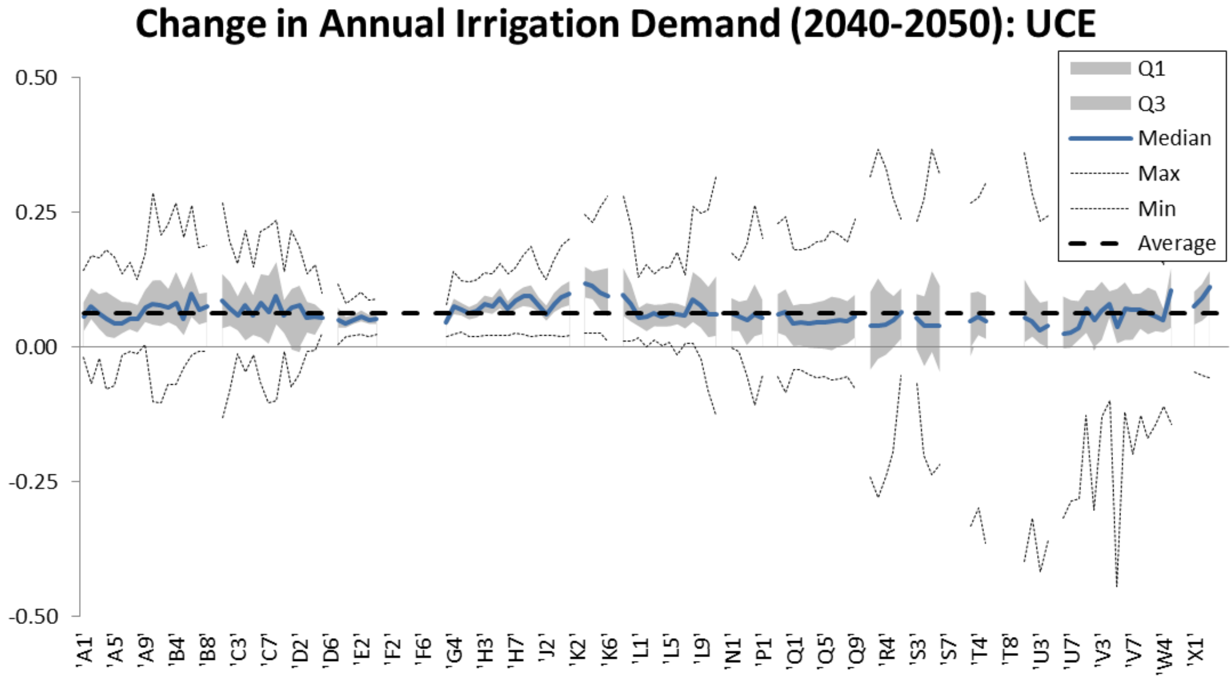

Figure 18: Range of potential impacts of climate change on the average annual irrigation demand for the period 2040 to 2050 due to the UCE scenario relative to the base scenario (DEA, 2014)

Water Supply

The range of potential impacts of climate change on the average annual water supply for each of the nineteen WMAs is shown in Figure 19 based on the results of the LTAS study (DEA, 2014).

On average the results show the potential for a slight increase in the total water supply to the country (+2.3%) by 2050, but with a wide range of possible impacts for individual WMAs. All the model scenarios however show a likely reduction in the average annual water supply to Cape Town which is located in the Berg WMA (WMA 19).

These results show how water supply to Gauteng (WMA 3 and 8) is not significantly impacted by climate change, primarily as a result of the integrated nature of the Vaal system as well as the increase in supply as a result of the construction of the Polihale Dam in Lesotho. This observation is considered to be one of the primary reasons why the results of the economic model found only limited impact of climate change on the national economy through the water sector (DEA, 2014).

It is important to note that the above results are based on a national scale analysis, although giving results at secondary catchment and WMA scale. This analysis required substantial simplification of the existing water supply infrastructure as well as other local impacts on precipitation, catchment runoff and water supply. The analysis was also based on time series simulation and determined in terms of the potential impact on the average annual supply, and did not consider particular impacts during critical periods or the potential for increased frequency of droughts and extreme events. More specific results in selected WMAs or catchments requires more detailed water supply models as well as stochastic analysis of alternative base line and future scenarios to determine the potential impact on the total system yield and not just in terms of potential impacts on average annual supply.

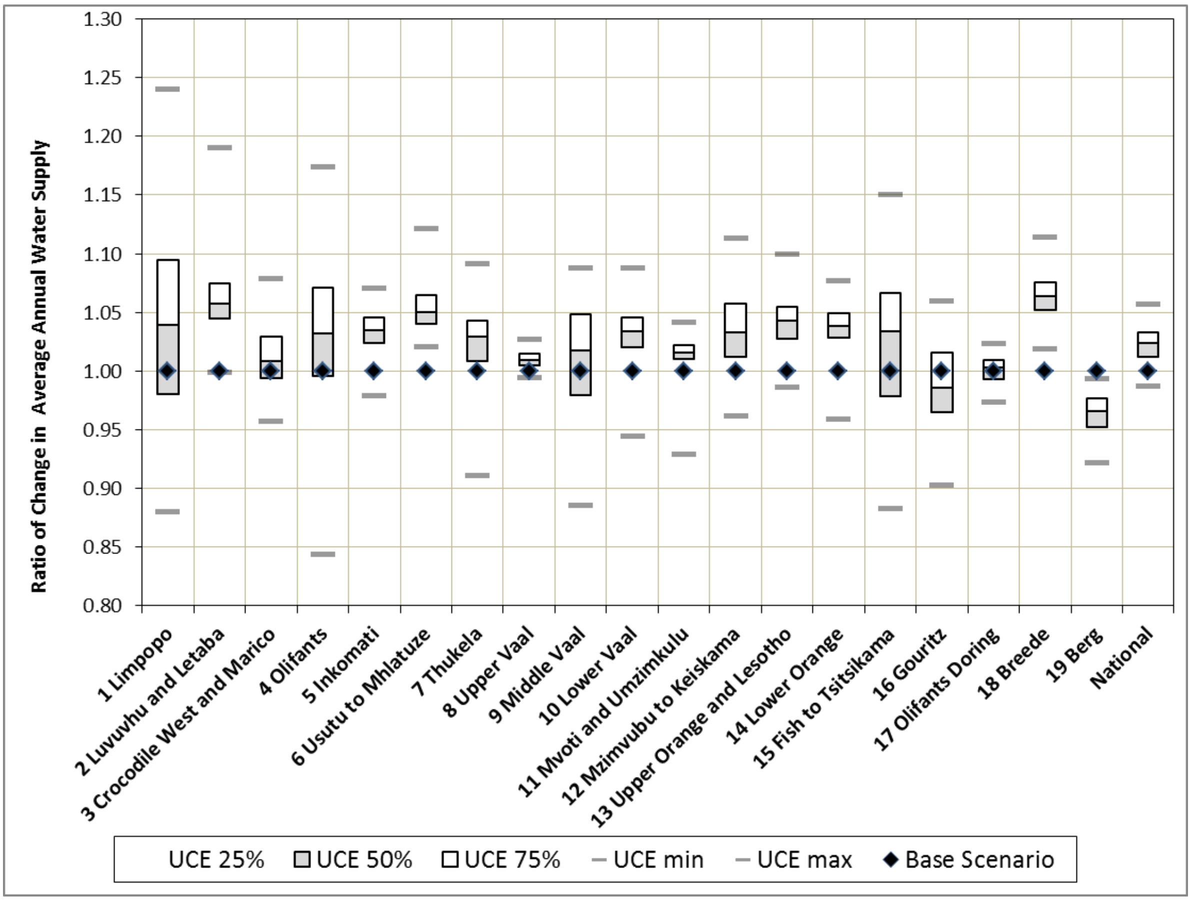

Figure 19: Ratio of change in the average annual water supply (2040 to 2050) to each WMA and in total to SA resulting from a range of possible climate futures under the UCE mitigation scenario.

Hydropower Potential

Hydropower is currently not a major contributor to energy production in South Africa. Some provisional results of the potential impact of climate change on future hydropower potential in South Africa are shown in Figure 20 (after DEA, 2014). These results show the potential impact on the average annual hydropower production from Van der Klolf Dam, currently South Africa's largest hydropower plant, and at Hartebeesport Dam where Department of Water Affairs (DWA) is considering installing a new hydro-power plant under two future mitigation scenarios: Unconstrained Emissions (UCE) in blue and a Level 1 stabilisation (L1S) scenario in red.

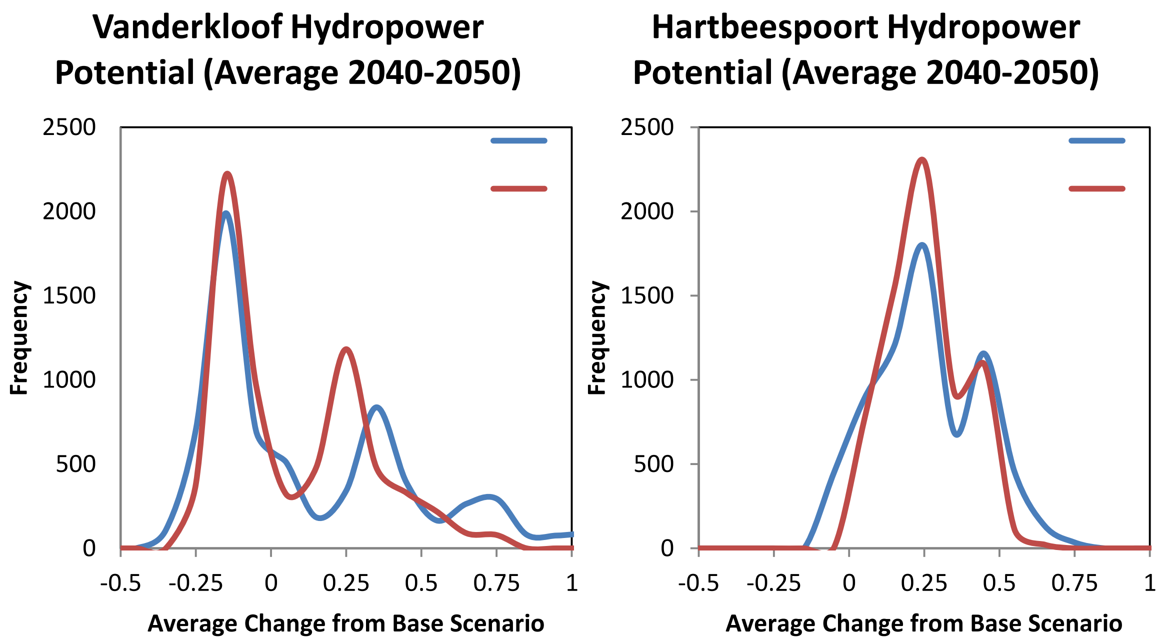

Figure 20: Hybrid frequency distribution of the change in the average annual hydropower potential for the Van der Kloof and Hartbeespoort Dams for the UCE and L1S climate scenarios (DEA, 2014)

These results suggest that there is potential for reduced hydropower production at existing power stations, but the potential for increased hydro-power potential in other parts of South Africa through the retrofitting of existing dams in certain areas of the country likely to experience increasing precipitation and runoff. This should be investigated further. Another major source of hydro-power is also from outside of South Africa where the potential impacts of climate change, particularly on the flow in the Zambezi River, should also be considered as this provides a potential large renewable energy source for South Africa.

3.3.3 Impacts on the Water-Energy Nexus

As described above future climate change is likely to impact both the supply and demand for water. Current predictions suggest that temperatures are likely to increase in the future, but that there is still some uncertainty in terms of future precipitation with the possibility of both increases and decreases in the average annual precipitation. Under both scenarios however, there is likely to be an increase in the variability of precipitation and an increase in the risk of flooding.

There are a number of ways in which climate change might impact on future energy production in South Africa that should be considered. These are summarised below:

Increasing temperatures:

- Increased water requirements for wet cooling;
- Reduced efficiency of dry-cooled power stations;
- Potential decreased efficiency of power generation due to warmer intake waters for cooling;

- Possible increased risk of eutrophication and added treatment costs for intake water;
- Increased water demands from other sectors resulting in an increased value of water, and
- Increased power demands for irrigation, refrigeration and air conditioning.

Increased variability in precipitation

- Decreasing MAP –
  - Reduced supply from existing sources leading to higher unit costs for water supply and possible early adoption of more expensive supply options;
  - Reduced availability from existing sources leading to increased value of water, and
  - Reduced potential for hydro-power.
- Increasing MAP –
  - Reduced water supply stresses and reducing unit costs of water supply;
  - Increased potential for hydro-power, and
  - Increased flooding risk particularly for transmission lines and sub-stations.

The primary impact of climate change in terms of water supply to the power stations will be a potential reduction in the availability of water and an increase in the relative cost of water given the likely increases from other users, particularly from agriculture. DWA however has a range of potential water supply augmentation options available in order to supply future increases in demand. Given the importance of power production to the country, if there is a reduction in the available yield from existing sources due to climate change, this will most likely result in earlier than planned implementation of alternative more expensive water supply augmentation options, as well as increasing the unit cost of these schemes as they are able to deliver less water at the same price.

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4 Water Supply Costs

4.1 Background

Under this study (Task 2) the South Africa TIMES (SATIM) model will be altered to allow for alternative water supply costs associated with different technologies and located in different regions of the country. The updated regional cost curves for water supply will also allow for the inclusion of externality costs such as the water requirements for mining, water treatment costs, water quality risks (e,g, AMD) and the opportunity costs for alternative water uses in the catchment. The development of the marginal cost curves will align the modelling of future energy supply options and costs with the revised pricing strategy for DWA which requires users to cover the full life cycle cost of water supply.

The objective for developing a regional marginal cost curve for water supply for alternative energy technologies is to account for the true cost of water supply in modelling the relative cost-benefits of these alternative energy options. The optimization of future energy technologies is done using the South Africa TIMES (SATIM) energy model developed by the Energy Research Centre (ERC) at the University of Cape Town (UCT) (ERC, 2013). Currently the SATIM model includes a standard cost for water supply for all technologies. As noted by Blignaut et al (2010) the use of a national average water tariff in no way reflects the scarcity of water nor the socio-economic cost of erroneous allocation of water to suboptimal applications. It also does not account for the spatial variability of water across South Africa and the huge costs incurred building and operating large transfer schemes to bring the water to the location of the power plants at high level of assurance.

For comparison Blignaut et al (2010) uses an average annual water supply cost of R 6 /m^3, while the actual tariff for water to the new Medupi power station by way of the Mokolo and Crocodile River (West) Water Augmentation Project (MCWAP) is R16.16 /m^3 (DWA, 2014). Given the relatively large volumes of water used, particularly for traditional wet cooled power stations, incorporating the real cost of water into any analysis of future generation technologies is therefore likely to be significant.

4.2 Regional Marginal Water Supply Cost

The development of the regional marginal water supply cost (MWSC) is intended to account for the true cost of water supply to different energy technologies and in different regions of the country taking into account the significant spatial variability in water availability across South Africa. The MWSC are based on the principle of full cost accounting, i.e. they account for both physical costs as well as operational costs of water supply infrastructure, but also additional externalities including treatment and water quality impacts and opportunity costs for alternative water uses. The MWSC is reflective of the estimated cost for using an additional cubic meter of water in a specific region and at a specific time based on the anticipated total demands in that region as well as the estimated costs for future water supply infrastructure and raw water supply schemes. The MWSC is then multiplied by the average water requirement for energy production to determine the total price for water (WP):

$$WP = w. MWSC$$

Where WP is the total price for water (R/kWh), such that
w is the average water consumption of the plant (and associated mining) (m^3/kWh), and
MWSC is the total regional marginal water supply cost of water (R/m^3)

The MWSC is an annual cost and is developed according to the *Revised Water Pricing Strategy for Raw Water* (DWA, 2012) principals of the DWA. The MWSC is determined in R/m^3 on an annual basis according to the basic equation given below:

$$MWSC = WRMC + WSSIC + WDMC + WSDC + WSEC + PWTC + SWTC + WUOC$$

Where the individual components making up the TRMC are described below:

- Raw water price (DWA, 2012)
  - Water resources management charges (WRMC), which cover the charges required to manage water resources within the designated WMA.
  - Water supply scheme infrastructure costs (WSSIC), which cover the development and use of bulk water supply infrastructure including the cost of planning and design, capital loan repayment, operations and maintenance, energy, and annual depreciation.
  - Waste Discharge Mitigation Charges (WDMC), which cover the charge for discharge of water containing waste into a water resource or onto land.
- Water supply delivery costs (WSDC) includes the capital and O&M costs for transporting water from the nearest bulk water source to the location of a power generation plant or mine.
- Water supply energy costs (WSEC) includes the cost for pumping water either as part of the raw water supply scheme or included in the delivery cost to the power station or mine and is a function of the average cost for electricity in South Africa.
- Primary and secondary water treatment costs (PWTC and SWTC) include the additional cost of treating water to a basic water quality standard (primary) plus the additional treatment (secondary) of a portion of the water requirements to a higher level of quality through for example the use of reverse osmosis (RO) to reduce the salinity of the source water.

Other costs such as the opportunity cost of water supply, i.e. the forgone benefits of allocating water for power production as opposed to other users in the region and the added externality costs of power production including health and environmental impacts should also be considered, but are not calculated as part of the regional MWSC for this study. For coal fired power stations in particular the externality costs are particularly high as shown by Blignaute et al, (2011).

4.2.1 Water Resources Management Charge (WRMC) Calculation

The DWA sets a water resources management charge to cover the costs of the management of the water resource in the country and including water resources planning, allocation and conservation. The WRMC is calculated separately for each WMA as shown in Table 12. The WRMC is calculated based on the WMA from which the water is sourced and should be calculated proportionally to the water supply from different WMA in the case of inter-basin transfers (DWA, 2013).

Given that the WRMC is a relatively small component of the overall raw water cost and to keep the calculations simpler, the WRMC for the WMA in which the planned power plant or mine will be located was used to determine an appropriate WRMC. As can been seen from Table 12 the error that this simplification might introduce is only a few cents per cubic meter.

Table 12: Annual Water Resources Management Charge for each WMA (2014/2015)[4]

WMA ID	WMA	Domestic & Industrial (c/m^3)	Irrigation (c/m^3)	Forestry (c/m^3)
1	Limpopo	3.32	2.4	1.32
2	Levubu Letaba	4.25	2.18	1.47
3	Crocodile Marico	3.16	2.28	1.09
4	Olifants	3.24	1.98	1.23
5	Inkomati	2.21	1.61	1.17
6	Usuthu Mhlathuze	1.57	1.23	0.66
7	Thukela	1.41	1.5	0.69
8	Upper Vaal	2.58	2	1.26
9	Middle Vaal	2.7	2	
10	Lower Vaal	2.09	1.66	
11	Mvoti Mzimkhulu	2.8	2.61	1.61
13	Mzimvubu Keiskama	3.29	2.56	1.69
13	Upper Orange	0.82	0.44	
14	Lower Orange	1.98	1.28	
15	Fish Tsitsikama	2.28	1.72	0.84
16	Gourtiz	5.28	1.78	1.06
17	Olifants Doorn	3.99	1.78	1.06
18	Breede	3.29	1.74	0.65
19	Berg	5.59	1.78	1.39
	AVERAGE	2.94	1.82	1.15

4.2.2 Water Supply Scheme Infrastructure Costs

The DWA pricing strategy requires commercial users to pay the full unit cost of water (UCW) for any new schemes required to supply their current and future water demands. For large schemes typically required to provide water to power plants or mines, these are usually funded off-budget using the Trans Caledon Tunnel Authority (TCTA) as the implementing agency. TCTA enters into an implementation agreement with DWA, and DWA then enters into a water supply agreement with the

[4] http://www.dwaf.gov.za/Projects/WARMS/Revenue/charges2014.aspx

end-users. The implementing agreement determines the annual tariff required to cover the capital unit cost (CUC) of the scheme, an annual depreciation cost (ADC), the fixed annual operations and maintenance charge (OMC), and the variable energy costs (EC) and divided by the yield of the scheme (Y):

$$UCW = \frac{CUC + ADC + OMC + EC}{Y}$$

Capital Unit Cost

The capital unit cost (CUC) for each scheme is calculated according to the following equation:

$$CUC = \frac{rC}{1-(1+r)^{-n}}$$

Where C is the total capital cost of the scheme'
r is the annual interest rate, and
n is the loan repayment period (in years).

Annual Depreciation Cost

The annual depreciation cost (ADC) is calculated according to the following equation and for the specified depreciable portion and estimate total useful life of the scheme according to Table 13.

$$ADC = \frac{Replacement\ value\ x\ Deprecible\ portion\ \%}{Expected\ Useful\ Life}$$

Table 13: Depreciable portion and expected useful life for different water supply infrastructure components

Component	Depreciable Portion (%)	Estimated Useful Life (years)
Dams and Weirs	10	45
Canals	40	45
Tunnels	10	45
Pump Stations	40	30
Siphons & Concrete Pipelines	30	45
Steel Pipelines	75	30
Buildings	100	40

Operations and Maintenance Costs

The operations and maintenance (O&M) cost include fixed and variable costs which can be attributed directly to administrating, operation and maintenance schemes. In order to allow for consideration of the impact of variable energy prices, the annual fixed and variable O&M costs are calculatedly separately from the annual energy cost (EC) for pumping. The fixed O&M costs are typically assumed to be a certain percentage of the total capital cost, and the variable associated with the process is used. The annual energy cost is calculated using estimated annual unit energy requirement of the scheme (kWh/m^3) and the specified average energy cost (e) in R/kWh.

Ultimate marginal cost of future water supply schemes

The DWA has undertaken an extensive study to synthesise the results from the different reconciliation studies for the primary water supply systems across the country in order to determine the ultimate potential future marginal cost of water supply across South Africa (DWA, 2010). In order to reconcile future supply with demand in each region, a unit reference value (URV) was calculated for each future water supply option, up to and including desalination as the ultimate future water supply option in all regions, even for inland areas of the country. The URV is the net present value of capital and operational costs for each scheme over a specified period (35 years was used in the DWA study) divided by the net present value of the future water supply at an 98% level of assurance over the same period (i.e. 35 years) and based on an annual discount rate of 8%.

The potential water supply schemes are then ranked in terms of the URV and an approximate timeframe for implementation is determined by comparing the potential yield from the individual schemes with the future water demands in the region (DWA, 2010). An example of the reconciliation of water supply options with future water demands in the Lepelalhe area (the location of future coal fired power stations) is given in Figure 21. From Figure 14 it is clear that the marginal cost of water, i.e. the cost of using an additional m^3 of water, is determined by the total demand in the area which determines what additional schemes are required to supply this demand. In order to compare traditional surface water options, with desalination and re-use options and additional R2 $/m^3$ was added to the URV for traditional sources to account for the fact that re-use and desalination results in treated water, while the traditional options still require additional treatment to basic standards.

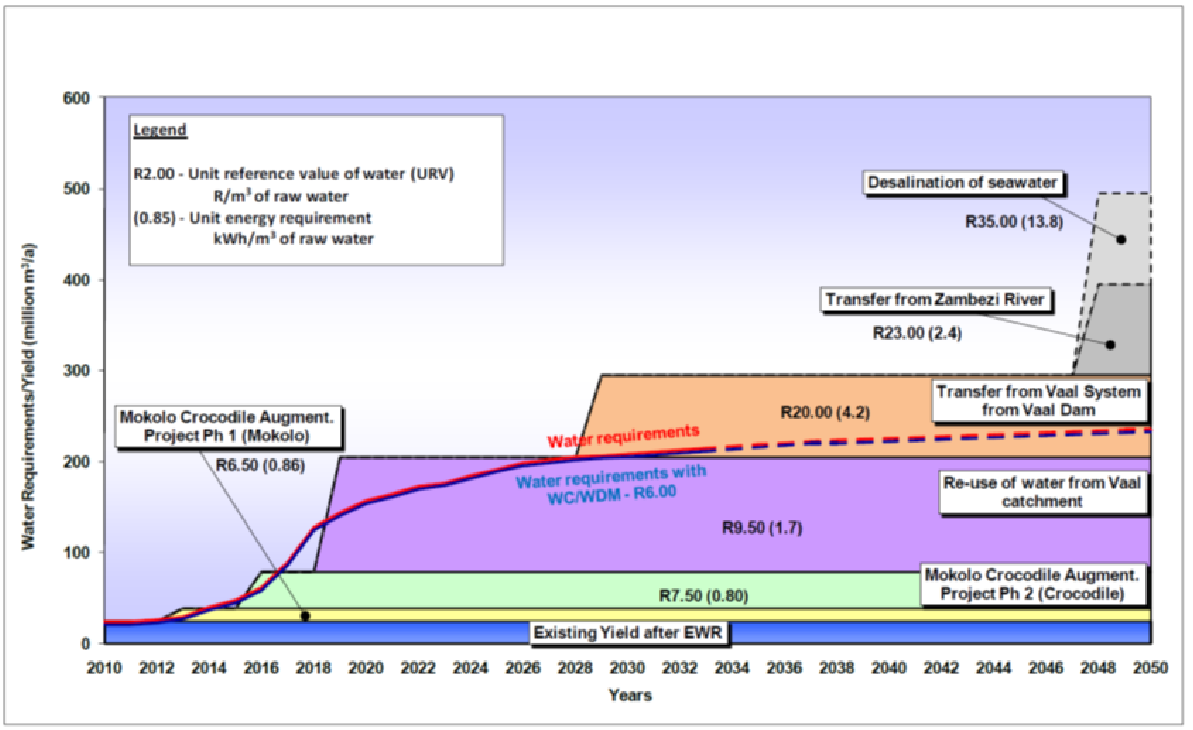

Figure 21: Reconciliation of future water supply options for the Lephalale water supply area (DWA, 2010)

The unit cost of water supply

The URV is useful for the comparison of alternative options but it is different from the unit cost of water supply (UCW) as it does not take into account loan repayment costs for the CUC. The URV therefore is used in economic analysis for comparing alternative water supply options, while the UCW is used in financial considerations to determine the total cost of water supply. The CUC and the ADC can however be derived from the capital and operational cost for each future water supply scheme. Data provided in the *Ultimate Marginal Cost Report* (DWA, 2010) can also be used to estimate the annual O&M costs, the unit energy costs (R/m^3). These results are given in Section 4.1.

The following assumptions are applicable to the calculation of the UCW for the different schemes:

- Loan repayment period for the CUC (t) = 25 years;
- Loan repayment interest rate for the CUC (r) = 12 %
- Average depreciable proportion of all schemes = 40%
- Average expected lifetime of all scheme = 40 years
- The energy requirement (ER) was obtained from the DWA marginal cost report (DWA, 2010.).
- Average energy cost (e) = R0.90 /kWh
- Based date for URV calculations = 2014
- Initial date for first delivery for URV calculations = 2016
- Total number of years of supply for URV calculations = 34 years
- Annual discount rate for URV calculations = 8%
- Unless otherwise specified the annual maintenance cost (MC) was estimated at approximately 0.265% of the capital cost (DWA, 2010), and.).
- All costs have been escalated to 2014 prices based on an average rate of 5.3% over 5 years.

4.2.3 Waste Discharge Management Charge

The draft Pricing Strategy (DWA, 2013) makes allowance for a waste discharge management charge (WDMC). This calculation of the WDMC is very complex as it is based on the waste discharge load and not the concentration and is targeted at the individual polluter based on the proportion of load that they contribute to the system. The implementation of the waste discharge charge system however is still being piloted in South Africa (Pegram, 2013) and information is not yet available on how much the charge will be determined and how it might affect future power production.

Eskom however operates a Zero Liquid Effluent Discharge (ZLED) policy from all its power plants. Hence ESKOM is not required to apply for a licence to discharge waste and there should be no resulting WDMC. Indirectly however, there will likely be a WDMC imposed on coal mining associated with the power plant and this will most likely include the additional costs for the treatment of acid mine drainage (AMD). The additional costs for treatment of AMD are addressed in Section 4.2.

4.2.4 Water supply delivery cost (transmission)

Without a detailed investigation of individual power plants, it is difficult to determine the requirements for additional infrastructure to transport water from the primary water supply source or scheme to a planned power plant. The following assumptions have therefore been used in order to determine a representative water supply delivery cost (WSDC) for each of the different technologies.

- For coal in the Lephalale area (for all future water supply schemes):
  - Assumed 5 km gravity pipeline from Lephalale, and
  - Pipeline sized to supply a total future demand of 30 Mm^3/a.
- For coal in the Upper Olifants (Imported from Vaal Dam and reuse of AMD)
  - Pipeline from dam in the Upper Olifants.
- For coal in the Upper Olifants (imported from the Zambezi)
  - Pipeline from Mokopane.
- For CSP in the Lower Orange (for all future water supply schemes)
  - Assumed 5km pipeline pumping directly from the river, and
  - Designed to supply 0.27 Mm^3/a required for a single 100MW power plant.
- For hydraulic fracking using water from the Lower Orange River
  - Option 1: road transport from Gariep Dam using a fleet of water tankers each with capacity of 30 kL over a distance of 600 km in both directions;
  - Option 2: Pipeline (rising main) from Gariep Dam, and
  - Option 3: local groundwater abstraction at 4 L/s from an average depth of 500 m.

The estimated capital cost, fixed annual operating costs, energy requirement and resultant unit reference value (URV), capital unit cost (CUC), energy cost (EC) and O&M cost for each delivery options are also given in Section 4 and should be added to the scheme costs to determine the representative total water supply costs for the different technology options. Note that these are very provisional estimates as more accurate estimates would require additional details of a particular scheme including information on pipeline length and alignment and pumping rates. In particular, detailed studies are required in terms of identifying future water supply options for hydraulic fracturing as local surface water resources are very limited in the area and there are concerns about possible groundwater pollution or the impact of extracting groundwater to use for the wells.

4.2.5 Primary Water Treatment Costs (PWTC)

It is important to note that many of the inter-basin transfers (IBT) that supply water to ESKOM's existing power plants are required to provide water of suitable quality as well as to provide the necessary quantity of water required for the power plant. Determining the additional treatment costs for water supplied to future power stations (coal and CSP) is therefore very complex and special measures are often incorporated into the design. For example, water can be mixed from two different sources or kept separate (as is the case for Medupi) to minimise the treatment costs for different components of the process. As an initial estimate we have made a number of assumptions in order to incorporate a cost for both primary treatment, i.e. to get the water up to a basic water quality standard (similar to potable water quality standards) and secondary treatment to provide high quality water required in the steam cycle of a thermal power plant. These assumptions are described below.

Raw water quality varies quite significantly dependent on the source and the local conditions, without a detailed study of individual source water quality it is hard to make a general assumption about regional differences in the costs to treat water to a basic standard. A large part of the treatment cost is the cost for transporting the water from the source to the treatment facility. Having accounted for this the basic components of a standard water treatment plant (WTP) are similar. For this reason we have assumed an average cost for primary water treatment in all regions. DWA (DWA, 2010) notes that while water treatment costs do not vary much and an average cost would be around R 2 / m^3 (2010).

4.2.6 Secondary Water Treatment Costs (Demineralization)

While a basic level of water quality is required for cooling and coal washing, much higher water quality is required for use in the steam cycle of a thermal power station. This typically requires a process of reverse osmosis (RO) to reduce the salinity of the source water, but only for a small percentage of the total water requirement of the plant. Irrespective of the generation technology (wet or dry cooled) the amount of water required to be treated to a higher water quality standard for the steam cycle is similar. As CSP is also dependent on a similar steam cycle it is assumed that the annual secondary water treatment costs (SWTC) for CSP are similar to that for coal.

The cost of RO is very sensitive to variability in the source water quality. ESKOM undertook a study to investigate the impact of variable source water quality on the secondary treatment costs for Medupi power station. Medupi will receive water from the Mokolo River and the Crocodile River. The water from the Mokolo is of much better quality with a total dissolved salts (TDS) concentration of 93 mg/L, but not sufficient to meet the full power station demand. The water from the Crocodile River is of poorer quality with an average TDS of 947 mg/l due to the impact of return flows from urban and industrial activities in the catchment as well as mining and the final design report recommended a split storage reservoir to keep the two different waters separate in order to more efficiently utilise the better water quality water for the critical processes. The results from this study were used to determine a provisional estimate of the unit SWTC as indicated in Table 14.

Table 14: Calculation of unit cost of water for demineralisation by RO for Medupi power station

Source		Mokolo River	Mixture	Crocodile River
TDS	**(mg/L)**	**92.8**	**453.9**	**947**
CAPEX	(R 2010)	88,300,000	121,300,000	154,300,000
OPEX*	(R 2010)	1,458,298	6,345,568	6,845,590
Power Required	kW	791	1067	1067
Electricity Price	R/kWh	0.9	0.9	0.9
Power Costs	(R 2010)	7,072,976	13,915,757	14,415,779
Volume	m^3/a	3,122,064	3,122,064	3,122,064
CUC[+]	R/m^3	3.79	5.20	6.62

Source		Mokolo River	Mixture	Crocodile River
O&M	R/m^3	2.73	6.49	6.81
UCW	R/m^3	6.52	11.69	13.43
Installed Capacity	MW	4800	4800	4800
Marginal Cost	**R/MW**	**4240**	**7604**	**8733**

*Annual operations and maintenance cost excluding power requirements
+ Loan repayment over 20 year period @ 12% interested rate

The annual water requirement for demineralisation at Medupi is given as 3,122,064 m^3/a or 650 m^3 per MW of installed capacity. The estimated unit SWTC for RO for demineralisation therefore varies from R 6.52 /m^3 to R 13.43 /m^3 for the different source water qualities or between R4240 and R8733 per MW of installed capacity. As shown in Figure 22 the SWTC is well described by a power function:

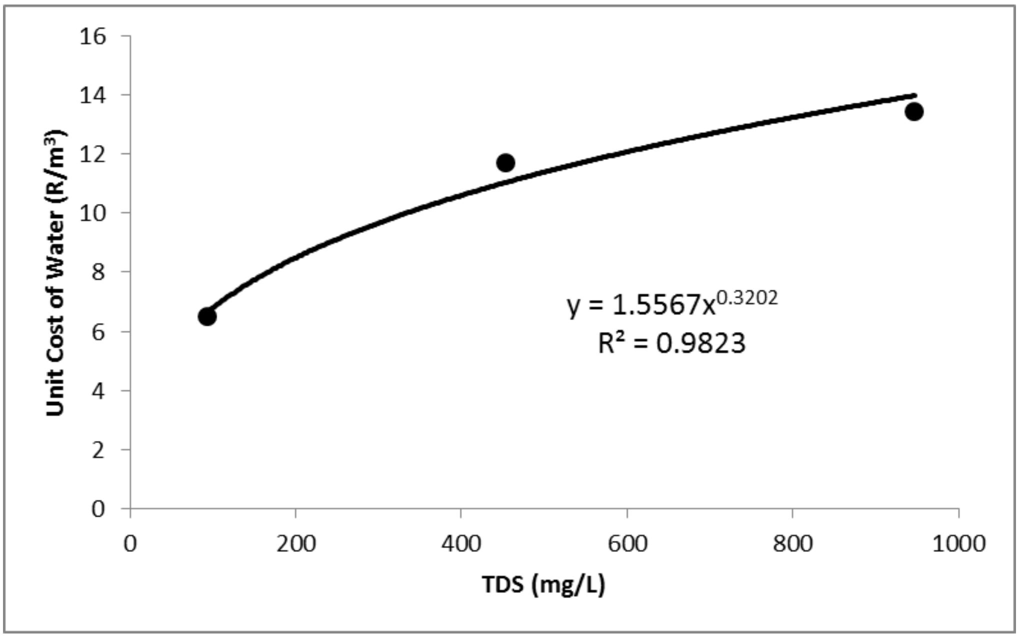

Figure 22: Relationship between the unit cost of water (R/m3) and the source water TDS for secondary treatment for the demineralization of feed water by reverse osmosis for Medupi Power station.

This relationship can be used as an initial estimate of the secondary treatment costs for future power stations, both coal fired and concentrated solar power. The recent State of the River Report shows that the water quality of the lower Orange River is generally very good, while the water quality in the Lephale area is good to very good (Figure 23). As described above for Medupi however, future water supplies are unlikely to come from local sources with good water quality (e.g. the Crocodile River) but will come from areas of lower water quality such as the Mokolo River and ultimately the Vaal River.

As an example the average TDS in the Lower Orange, where future CSP plants are likely to be located increases from around 200mg/L at Prieska, downstream of the confluence with the Vaal River, to around 450mg/L at Violsdrift (DWA, 2013). Based on an average TDS of say 300 mg/L for the lower Orange a provisional estimate of the SWTC for CSP would be around R10/m^3.

In contrast future coal fired power stations located near Lephalale will most likely be dependent on water from the Crocodile River, augmented with return flows from the Vaal River. These waters will be closer to the higher TDS resulting in a UCW for secondary treatment of closer to R13/m^3. Assuming a similar water requirement for demineralization per megawatt of installed capacity for CSP as for Medupi, results in an average secondary treatment cost for demineralisation of around 6300 R/MW for CSP and of around 9100 R /MW for future coal in the Lephalale area.

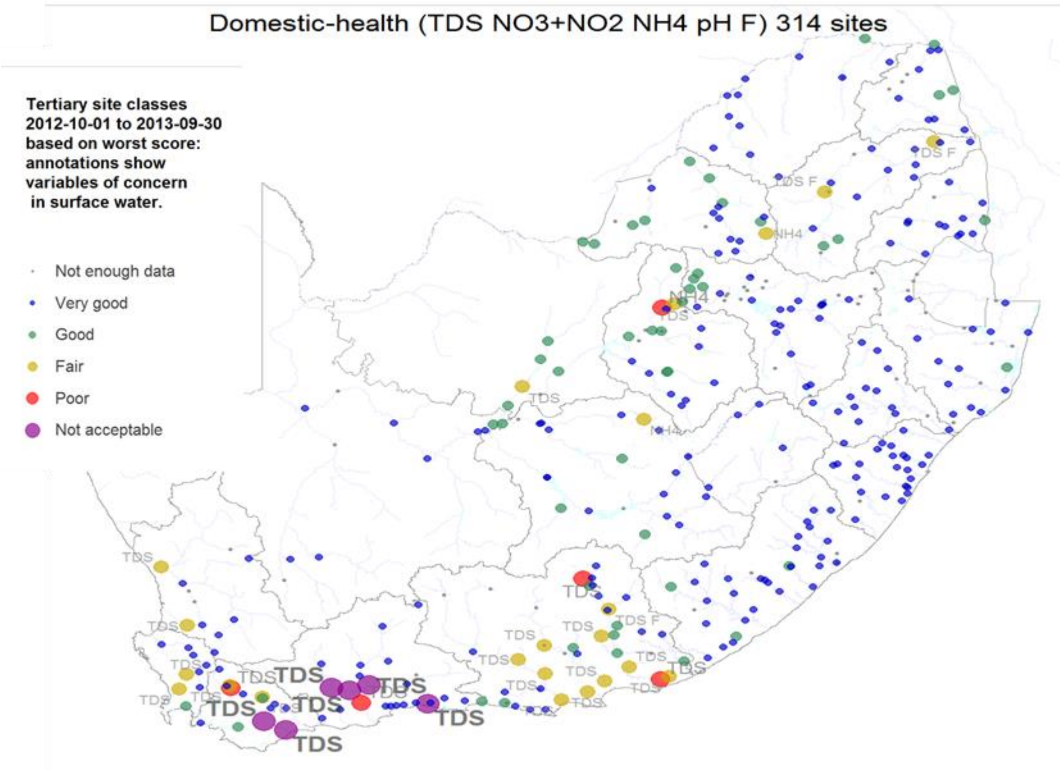

Figure 23: Variation in source water quality for the 2013 Annual State of the Rivers Report (DWA, 2013)

The existing power stations in the Olifants catchment receive good quality water from the Tugela and Usutu Rivers and are designed for an average source water quality of around 140mg/L (DWA, 2009). Using the same assumptions as described above results in an average SWTC for these plants of around R8 /m^3 or R4900/MW. These plants however appear to be much more sensitive to variations in TDS than for Medupi as shown in Figure 24 based on data from the DWA study (2009).

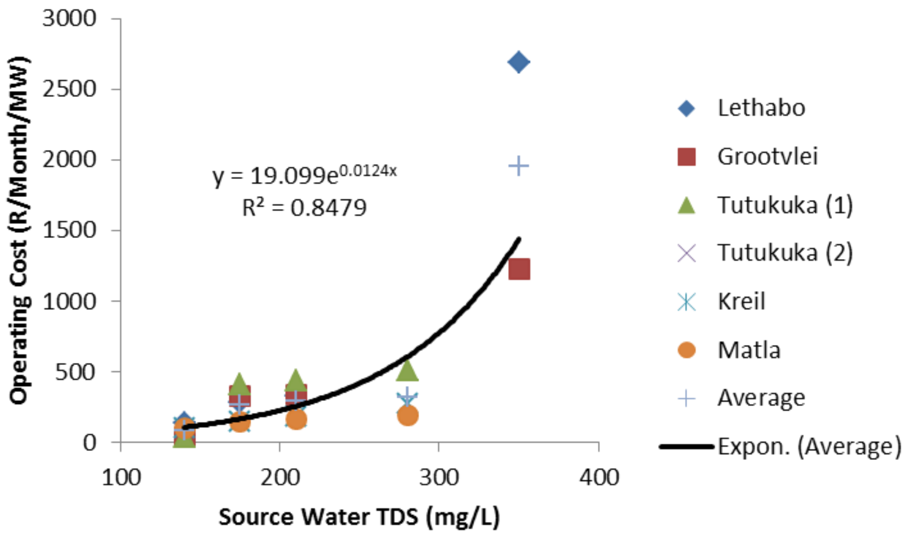

Figure 24: Sensitivity of the annual operating costs for ESKOMs existing coal fired power stations to variations in the source water quality as measured by TDS. (Data from DWA, 2009)

It is however important to note that more detailed studies are required to determine the final primary and secondary treatment cost on a plant specific basis and that these costs are normally included in the overall power plant costs when determining the total energy cost for a specific power plant.

4.3 Acid Mine Drainage Costs

Acid mine drainage (AMD) results when untreated waters from mining activities are allowed to decant into the natural environment. These waters have a very low pH resulting from interactions with the mineral pyrite which is present in most coal and gold deposits across South Africa (McCarthy, 2011).

The low pH and other heavy metals that results when these waters decant into the surrounding environment result in costly environmental and socio-economic impacts (Hobbs and Kennedy, 2011). AMD is identified in the National Water Resource Strategy (NWRS) as being a significant threat to the sustainability of water resources in the South Africa (DWA, 2013). The NWRS however, also identifies the treatment of AMD as a possible future water supply option particularly for industrial and mining process which could potential include power generation.

The treatment of AMD is considered as a potential future water resource in the Olifants and Vaal catchments although at approximately three time the cost of existing surface water options (DWA, 2010). The treatment of AMD water to supply future water demands also does not address the environmental problem of impact streams, as it is only cost effective to treat a proportion of the total flow required to meet future water demands (McCarthy, 2011).

Quantifying the cost of treatment of AMD from coal mines is difficult and location specific. A recent study by DWA estimated the total capital cost for the development of the infrastructure for treating of AMD from the Witwatersrand gold fields to be around R3 billion rand with an annual operating cost of

R703 million. This equates to an average cost for treatment of between R14/m^3 and R21/m^3 (DWA, 2013). Although not specified, the treatment cost for AMD from coal mines are considered to be lower than for gold mines due to lower mine depths and lower pH and salinity impacts.

AMD is present in a number of areas in South Africa as shown in Figure 22, but relative impact varies due to the geology, the mining practices and the climatic and hydrological conditions. A summary of the relative factors affecting AMD in different parts of the country is given in Figure 23. This summary shows that while the coal mines located in the Waterberg area to supply future coal fired power stations could have a potentially severe impact on the environment, the volume of water necessary to be treated is low due to the relatively dry conditions (Hobbs and Kennedy, 2011).

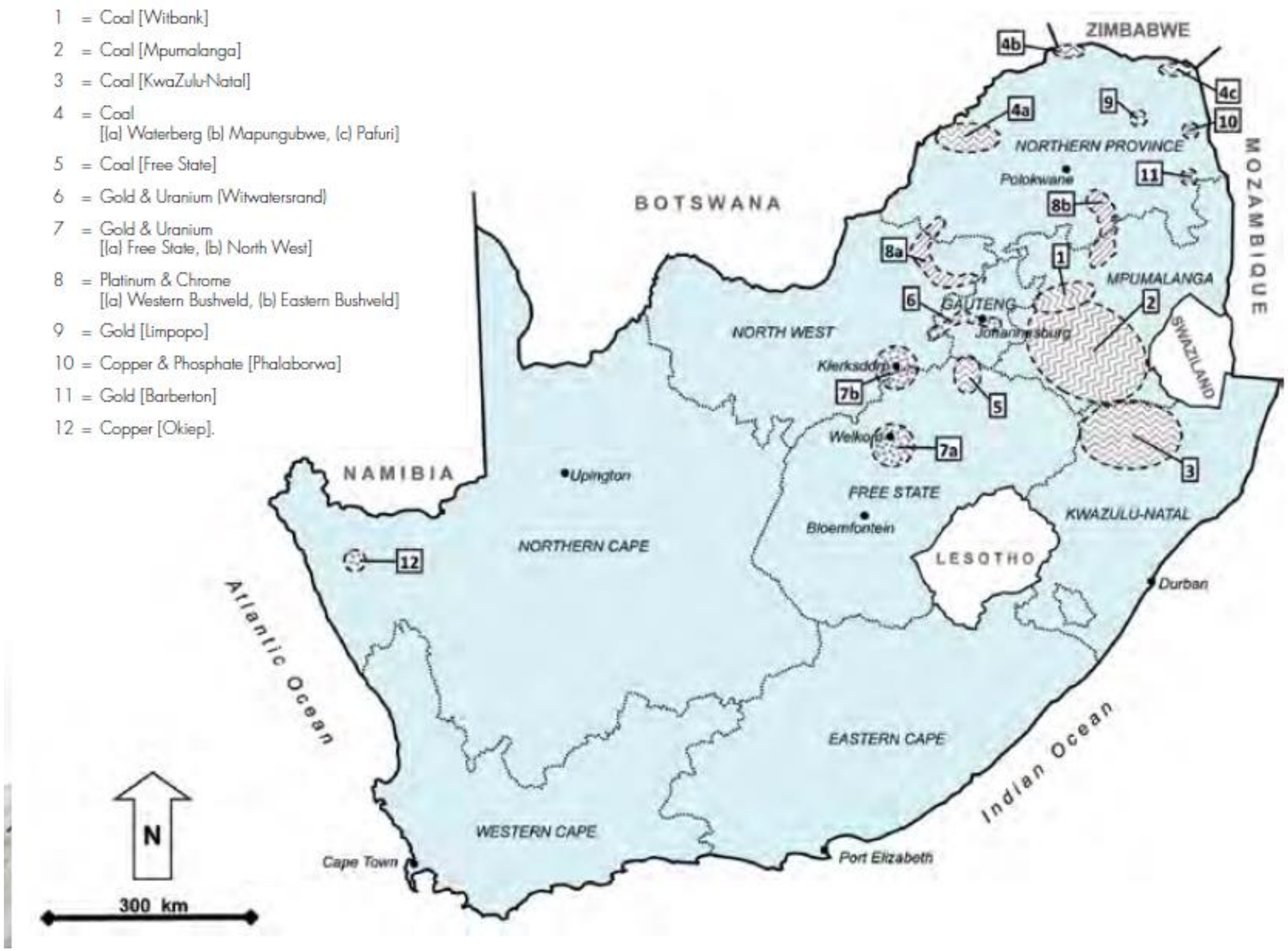

Figure 25: Mining areas and minerals particularly susceptible to the formation of AMD. Source: Hobbs and Kennedy, 2011.

ASPECT	MINING AREA															
	Witbank	Mpumalanga	KwaZulu-Natal	Waterberg	Mapungubwe	Pafuri	Free State	Witwatersrand[a]	Free State	North West	Western Bushveld	Eastern Bushveld	Limpopo (Giyani)	Phalaborwa	Barberton	Okiep
BASIC CHARACTERISTICS																
No. on Figure 15	1	2	3	4a	4b	4c	5	6	7a	7b	8a	8b	9	10	11	12
Major mineral(s) mined	Coal							Gold & Uranium			Platinum & Chrome		Gold	Copper & Phosphate	Gold	Copper
Age of mining (y)	>100	>30	>100	20	0	>20	>50	>120	>50	>50	40	<20	>20	60	>110	>100
Activity status	Active + New	Active + New	Closed	Active + New	Proposed New	Active	Active + New	Active + Closed	Active	Active	Active	Active	Active + Closed	Active	Active + Closed	Active
Remaining lifespan[1] (y)	25-30	40-50	10	200	>10	<10	15-20	5-50	20	20	50	50-100	20	15	<20	<50
Mine type[2]	OC + shallow UG	OC + shallow UG	Mainly UG	Mainly UG	OC + UG	UG	Mainly UG	Mainly UG	UG	UG	UG	UG	UG + artisinal	OC + UG	UG + artisinal	UG
DIAGNOSTIC VARIABLES																
Conditions (wet/moist)	Very wet	Very wet	Wet	Moist	Moist	Moist	Wet	Very wet	Wet	Wet	Moist	Moist	Wet	Moist	Wet	Moist
Basic chemistry: pH	<4	<4	<5	<5	<6	<7	<6	<4	<4	<4	<7	<7	<5	<7	<5	<4
Basic chemistry: TDS (g/l)	>4	>4	<4	<2	<2	<2	<4	>5	>4	>4	<2	<2	<2	<2	>4	<4
Basic chemistry: Radioactivity[3]	1	1	1	2	1	1	1	3	2	2	1	1	1	1	1	0
Basic chemistry: "Problem" elements	Al, Cd, Co, Cu, Fe, Hg, Mn, Pb, SO_4, Zn		Al, Cu, Fe, Mn, SO_4, Zn	Al, Fe, Mn, U, Zn	Al, Fe, Mn	Al, Fe, Mn, Ni	Al, Cu, Fe, Mn, SO_4, Zn	Al, Cu, Fe, Hg, Mn, Th, U, SO_4, Zn	Al, Cu, Fe, Hg, Mn, Th, U, Zn	Al, Cu, Fe, Hg, Mn, Th, U, Zn	Al, Cd, Cr, Fe, Ni, Mn, SO_4, V, Zn	Al, Cd, Cr, Fe, Ni, Mn, SO_4, V, Zn	Al, As, Cu, Cd, Fe, Hg, Mn, SO_4, Sb, Zn	Al, Cu, Fe, Hf, Mn, PO4, SO_4, Th, U, Zn	Al, As, Cu, Cd, Fe, Hg, Mn, SO_4, Zn	Al, Cd, Cu, Mn, Ni, Sr, Zn,
Water availability for mining	Yes	Yes	n/a In closure	limited	Limited	Limited	Yes	Yes	Yes	Yes	Limited	Highly limited	Highly limited	limited	Limited	limited
Mine water treatment infrastructure required	Moderate	High	Moderate	Moderate	Low	Low	Low	High	Moderate	Moderate	Low	Low	Moderate	Low	Moderate	Low
Volume of mine water to be treated	High	High	Moderate	Low	Low	Low	Moderate	High to very high	Moderate	Moderate	Low	Low	Low	Low	Low	Low
Current aquatic environmental state[4]	−1 D	−1 D	0	+1	0	0	0	−1 D	−1	−1	0 D	0 D	0	0	−1	0
Environmental impact[b] if status quo maintained	Severe	Severe	Moderate	Potentially severe	Potentially moderate	Light	Moderate	Potentially very severe	Moderate	Moderate	Light	Light to moderate	Moderate	Light to moderate	Moderate to severe	Light
Priority for water supply/ ecosystems	Very high	High	Moderate	High	Moderate	Low	Moderate	Very high	Moderate	Moderate	Low	Low	Low	Very low	Moderate	Low

NOTES
(1) Estimated
(2) OC = opencast, UG = underground
(3) Associated with host rock/ore
(4) −1 = poor, 0 = neutral, +1 = pristine, D = declining trend

COMMENTS
(a) Comprises the Witwatersrand Basin, i.e. the Evander, East Rand, Central Rand, West Rand and Carletonville gold fields.
(b) Does not consider environmental aspects related to the atmosphere (e.g. acid rain, airborne dust), heritage, culture, etc.

Colour coding should be interpreted as follows: **Red** = Intervention certainly required in the short-term; **Orange** = Intervention probably required in the medium-term; **Yellow** = Intervention possibly required in the long-term.

Figure 26: Tabulated listing of characteristics and variables that describe the main mining areas susceptible to AMD. Source: Hobbs and Kennedy, 2011.

In addition to the natural conditions reducing the potential risk of AMD in the coal mining areas, the requirements for environmental management plans (EMP), and limited alternative water supply options in the area, results in most contaminated surface and groundwater from the mining activities being captured and treated for possible reuse in the mining operations (Golder and Associates, 2013) further reducing the potential impacts and externality costs of AMD. Despite these measures AMD is still a significant risk for coal fired power stations. As described in Section 3.2, the estimated externality cost of the AMD risk for coal mining for power generation in South Africa is around 2c/kWh (Edkins et al, 2010), although other estimates put this cost as high as 38c/kWh (Pretorius, 2009).

4.4 Climate Change Scenarios

In terms of the potential climate change impacts on water supply to future power stations, Table 15, shows a range of potential impacts in the average annual irrigation demand which would affect the competition for water and hence its relative value in the catchment, as well as the potential impacts on the average annual availability of supply to all sectors including agriculture and industry. While all WMAs show a likely increase in irrigation demands, the WMAs of interest for future power generation show on average a potential for an increase in the average annual water supply. This however results not only from local catchment runoff, but also water imported from other regions to meet the demand.

Table 15: Range of potential impacts on the average annual irrigation demand and water supply to the 19 Water Management Areas (WMA) of South Africa by 2050 based on a hybrid frequency distribution (HFD) analysis of possible climate change impacts under an unconstrained emissions scenario (UCE) derived from the MIT Integrated Global Scenario Model (IGSM) (extracted from Cullis et al, 2014).

Percentage Change From	Avg. Annual Irrigation Demand					Avg. Annual Total Water Supply				
Base (CC Scenario/Base -1)	Min	25%	50%	75%	Max	Min	25%	50%	75%	Max
1 Limpopo	-1.5%	2.8%	4.8%	8.9%	15.1%	-12.0%	-2.0%	3.9%	9.5%	24.0%
2 Luvuvhu and Letaba	0.0%	4.7%	7.4%	10.3%	18.1%	-0.2%	4.5%	5.7%	7.4%	19.0%
3 Crocodile West/Marico	-6.3%	5.2%	7.4%	10.9%	16.4%	-4.2%	-0.6%	0.8%	2.9%	7.9%
4 Olifants	-5.4%	4.4%	7.5%	11.4%	22.0%	-15.7%	-0.5%	3.2%	7.1%	17.4%
5 Inkomati	-5.0%	4.8%	8.8%	11.3%	22.5%	-2.1%	2.3%	3.5%	4.5%	7.1%
6 Usutu to Mhlatuze	-12.1%	3.3%	6.0%	8.8%	17.4%	2.0%	4.0%	5.0%	6.4%	12.2%
7 Thukela	-18.1%	2.2%	7.0%	9.9%	23.3%	-8.9%	0.9%	3.0%	4.3%	9.1%
8 Upper Vaal	-9.3%	4.5%	7.4%	13.0%	19.6%	-0.6%	0.4%	0.9%	1.5%	2.7%
9 Middle Vaal	-5.3%	1.2%	7.7%	12.6%	21.0%	-11.5%	-2.0%	1.7%	4.9%	8.8%
10 Lower Vaal	-1.0%	3.0%	5.9%	9.2%	14.8%	-5.5%	2.0%	3.3%	4.5%	8.8%
11 Mvoti and Umzimkulu	-35.3%	0.4%	4.3%	8.8%	27.1%	-7.1%	1.0%	1.6%	2.2%	4.2%
12 Mzimvubu to Keiskama	-10.7%	-0.8%	5.2%	10.0%	24.6%	-3.8%	1.2%	3.3%	5.8%	11.3%
13 Upper Orange	-1.9%	1.8%	6.2%	9.7%	16.0%	-1.4%	2.7%	4.3%	5.5%	10.0%
14 Lower Orange	1.3%	3.8%	4.9%	6.7%	10.4%	-4.1%	2.8%	3.8%	4.9%	7.7%
15 Fish to Tsitsikama	-3.7%	2.0%	5.2%	9.0%	19.6%	-11.8%	-2.2%	3.3%	6.7%	15.1%
16 Gouritz	2.2%	6.6%	8.1%	10.0%	16.0%	-9.7%	-3.5%	-1.5%	1.5%	5.9%
17 Olifants Doring	2.1%	4.2%	5.0%	5.9%	8.8%	-2.6%	-0.7%	0.3%	0.9%	2.3%
18 Breede	2.2%	5.9%	7.3%	8.7%	13.2%	1.9%	5.2%	6.3%	7.6%	11.4%
19 Berg	2.2%	5.0%	5.9%	7.0%	11.0%	-7.8%	-4.7%	-3.4%	-2.3%	-0.7%
National	**-0.8%**	**4.5%**	**6.3%**	**8.8%**	**11.8%**	**-1.3%**	**1.2%**	**2.3%**	**3.3%**	**5.7%**

These results can be used to develop possible future climate change scenarios for investigating the sensitively to climate change of the MWSC curves for water supply to the planned power stations. Provisional wet and dry climate change scenarios for changes in the average annual water supply and the average annual demands in the four WMA directly applicable to future power generation are given in the Table 16 based on the upper and lower quartile results given in Table 15.

Table 16 Change in the average annual water demand and supply by 2050 for a wet and dry climate change scenario in each of the four WMAs directly applicable for future energy production in SA

Region	Water Supply		Annual Demands	
	Wet	Dry	Wet	Dry
1 Limpopo	9.5%	-2.0%	2.8%	8.9%
4 Olifants	7.1%	-0.5%	4.4%	11.4%
6 Usutu to Mhlatuze	6.4%	4.0%	3.3%	8.8%
8 Upper Vaal	1.5%	0.4%	4.5%	13.0%
14 Lower Orange	4.9%	2.8%	3.8%	6.7%

5 Results

5.1 Regional marginal costs for water supply

The estimated capital cost, operating cost and the total unit water cost (UWC) for the planned bulk water supply infrastructure to each of the water supply areas identified as being critical to future energy production in South Africa are given in Table 17. These costs give a good indication of the overall cost of water supply to each area. For example the current draft marginal tariff for the Mokolo Crocodile water augmentation project (MCWAP) is around R11.27 per m^3. The results also show how water prices are likely to increase quite significantly in the future as demands increase and more expensive and energy intensive transfer schemes are required to supplement local resources which have all but been excluded in most areas. It is however important to note that a large proportion of the identified future demand is to meet the environmental water requirements (EWR) in these regions. The enforcement of the EWRs is still a major uncertainty for future supply.

The results show how much more expensive it is to transfer water to the areas of future coal production such as Lephalale, the upper Olifants and the Vaal system, as compared to alternative energy options such as CSP that use water from the Orange River. For example the UWC for the Boskraai dam on the Orange River which would supply water for CSP is less than R1/ m^3 while the Mokolo Phase 1 transfer scheme to Medupi and future coal fired power stations is over R11/m^3.

The estimated capital and operational costs for delivery of water from the bulk infrastructure scheme to the power plant is given in Table 18. Note that these are very rough estimates as no details of individual plants or pipeline routes are currently available. What is interesting to note is the relative high cost of pumping from the Orange River to a CSP plant (R 4/m^3) compared to gravity pipelines from Lephalale to the new coal power plants (R0.40/m^3). This makes up for some of the differences in the bulk water supply infrastructure cost although. The results also show that it is very expensive to pipe or truck water from the say the Gariep Dam to supply fracking in the Karoo given the long distance (≈300km). Local groundwater sources are much more cost effective for fracking but there are serious concerns about the sustainability of this as an option.

The impact of increasing demand on the marginal water supply cost is shown in Figure 24. This shows a plot of the cumulative increase in water supply at a given level of assurance of supply relative to the marginal cost of the additional water supply options necessary to provide for increasing demands in each of the critical water resources areas of South Africa considered in this study.

Table 17: Estimated unit water cost (UWC) for planned bulk water supply infrastructure to four regions critical for future power generation (Prices in Rand 2014).

Water Supply Region	Scheme Description	ID	Scheme Yield ($M.m^3/a$)	Energy Requirement (kWh/m^3)	Capital Cost ($R \times 10^6$)	Annual O&M Cost ($R \times 10^6$)	CUC* ($R \times 10^6$)	ADC$ ($R \times 10^6$)	OMC ($R \times 10^6$)	EC# ($R \times 10^6$)	UWC ($R/m^3/a$)	Net UWC (R/m3/a)	Note
Lephalale (Limpopo)	Mokolo Croc Phase 1	A1	28	0.85	2078	12	265	16	12	21	11.20	11.20	
	Mokolo Croc Phase 2	A2	169	0.8	10280	49	1311	77	49	122	9.22	9.22	
	Reuse and transfer from Vaal	A3	126	0.87	1437	44	183	11	44	99	2.67	11.89	1
	Transfer from Vaal	A4	90	1	3027	18	386	23	18	81	5.64	14.86	1
	Transfer from Zambezi	A5	100	2.44	17097	88	2180	128	88	220	26.16	31.16	2
	Desalination of seawater	A6	100	13.82	24691	438	3148	185	438	1244	50.15	48.15	3
Upper Olifants	Olifants Dam	B1	55	0	1466	4	187	11	4	0	3.67	3.67	
	Use of acid mine drainage	B2	31	2.2	1934	54	247	15	54	61	12.16	10.16	3
	Transfer from Vaal River	B3	190	1.07	5058	32	645	38	32	183	4.73	9.15	4
	Transfer from Zambezi River	B4	95	3.6	21922	117	2795	164	117	308	35.62	40.62	2
	Desalination of seawater	B5	100	13.82	16791	401	2141	126	401	1244	39.12	37.12	3
Vaal	LHWP II (Polihali DAm)	C1	437	0.00	14117	27	1800	106	27	0	4.42	4.42	5
	Use of AMD	C2	38	2.51	2150	136	274	16	136	86	13.48	11.48	3
	Thukela-Vaal Transfer	C3	522	3.35	25967	80	3311	195	80	1574	9.88	9.88	
	Orange-Vaal transfer	C4	517	1.99	21998	84	2805	165	84	926	7.70	7.70	
	Mzimvubu transfer scheme	C5	631	4.38	49117	227	6262	368	227	2487	14.81	14.81	
	Transfer from Zambezi	C6	650	4.21	61744	333	7872	463	333	2463	17.12	22.12	2
	Desalination of seawater	C7	100	13.6	9253	270	1180	69	270	1224	27.43	25.43	3
Lower Orange	Boskraai Dam	D1	227	0	1188	3	152	9	3	0	0.72	0.72	
	Mzimvubu kraai Transfer	D2	165	5.26	5164	48	658	39	48	781	9.25	9.25	
	Desalination of seawater	D3	100	14.1	13204	373	1683	99	373	1269	34.24	34.24	

Notes:
* Annual capital loan repayment over a period of 25 years at 12% interest
$ Assumes 30% depreciation portion and an average lifetime of 40 years
# Based on R0.90 /kWh electricity cost.
1 Requires additional cost of transfer to Lephalale
2 $R5/m^3$ royalties for transfer from Zambezi
3 Excludes $R2/m^3$ water treatment cost
4 Additional cost of water from LHWPII
5 Excludes cost for hydropower station

Table 18: Estimated unit water cost for delivery of water from bulk infrastructure supply scheme to power plant location.

Region	Description of Final Delivery from Bulk water scheme to power plant	ID	Annual Supply ($M.m^3$)	Capital Cost ($R \times 10^6$)	O & M Cost ($R \times 10^6/a$)	Energy Requirement (kWh/m^3)	Fuel Cost ($R \times 10^6$)	CUC* ($R \times 10^6$)	ADC$ ($R \times 10^6$)	OMC ($R \times 10^6$)	EC# ($R \times 10^6$)	UWC ($R/m^3/a$)
Lephalale (Limpopo)	Gravity pipeline from Lephalale	A1	30	87	0.1	0		11	1	0	0	0.39
Upper Olifants	Pipeline from Olifants Dam	B1	30	3139	9.1	0.41		400	24	9	11	14.80
	Import Vaal Dam - pipeline from dam in Upper Olifants	B2	30	479.5	1.7	0.41		61	4	2	11	2.58
	Reuse AMD - pipeline from dam in Upper Olifants	B3	30	479.5	1.7	0.41		61	4	2	11	2.58
	Zambezi water - pipeline from Mokopane	B4	30	3740	11	1.38		477	28	11	37	18.44
Lower Orange	CSP - Pipeline pumping directly from Orange River	D1	0.27	6.64	0.26	0.32		1	0	0	0	4.57
	Hydraulic fracturing – road transport	D2	0.015	1.5	0		0.91	0	0	0	1	74.17
	Hydraulic fracturing – pipeline	D3	3	2678	6.7	1.30		341	20	7	4	123.91
	Hydraulic fracturing – groundwater	D4	0.1	3.1	0.008	4.01		0	0	0	0	7.87

*Annual capital loan repayment over a period of 25 years at 12% interest

$Assumes 30% depreciation portion and an average lifetime of 40 years

#Using R0.90 /kWh electricity cost.

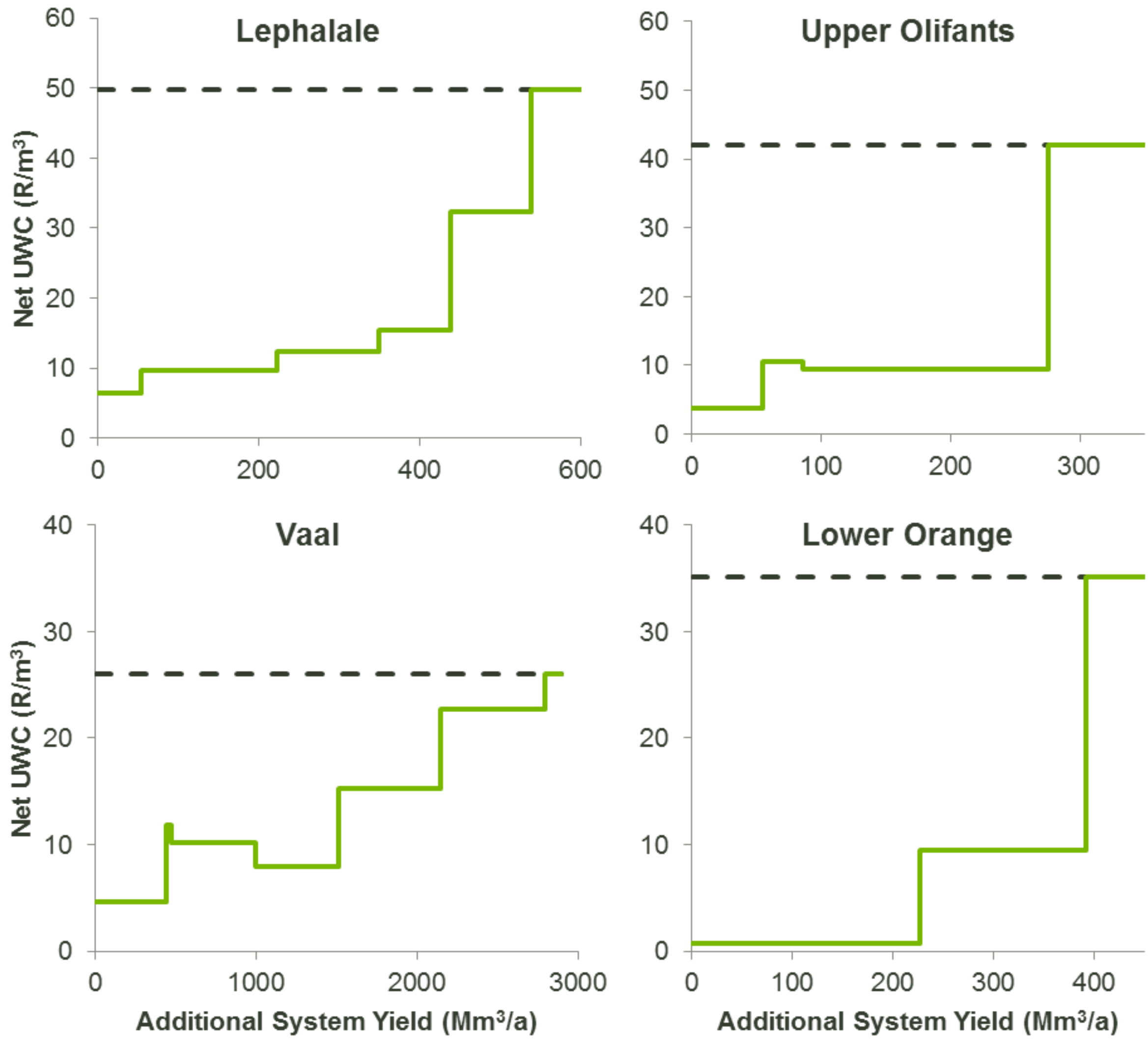

Figure 27: Increasing net unit water supply cost (UWC) necessary to increase the available yield in different key water resources areas of South Africa to meet increasing demands including future power generation water requirements.

5.2 Case study of alternative generation technologies

A more detailed study of the impact of incorporating variable regional marginal water supply costs of the most appropriate future energy technologies will be investigated using the SATIM-W model developed during Task 2 of the project. In anticipation of this study, the results of a simple case study comparing the unit water supply costs for two different technologies located in two different regions are presented here. The case study results of an analysis of the relative water and other opportunity costs for two alternative future energy production technologies (coal and CSP) are described below.

The results of this case study show the importance of accounting for the real cost of water as well as the spatial variability of water availability through the development of total regional MWSC for power generation. The results are presented for three future time periods, 2020, 2030 and 2040. The consideration of different time periods is important as other demands in the catchment are likely to increase meaning that even more expensive water supply options will be required in the future.

The DWA Ultimate Marginal Cost Report (DWA, 2010) was used to estimate the future demand for each time period and the related marginal water supply scheme required. Future coal power stations were considered to be located in the Lephalale area in the Limpopo WMA. By 2020 the total water demands are expected to be around 150Mm^3/a, requiring the second phase of the Mokolo-Crocodile Transfer scheme. By 2030 the total water demands are expected to be 200Mm3/a, requiring the transfer of reused water from the Vaal Rive System. By 2040 the total water demands are expected to be 225Mm^3/a, requiring additional transfers from the Vaal River System which is ultimately supplied with water from the LHWPII (i.e. Polihale Dam). For this analysis no climate change impacts have been considered. The sensitivity to climate change will be considered in future phases of the study.

Future CSP plants were considered to be located in the Northern Cape, along the lower Orange River accessing water directly from the river. The planned increase in the yield to the lower Orange River as a result of the completion of the Boskraai Dam is likely to be sufficient to meet the local demands well into the future. For this analysis we assumed that by 2040 additional water transferred from the Mzimvubu Kraai system would be required for comparison with future long term supply to Lephalale.

The calculation of the MWSC for both options at each time period is given in Table 19. The opportunity cost is calculated as the difference in the cost of water supply per megawatt hour of energy production. In addition to the opportunity cost based on the relative cost of water supply infrastructure to the two regions, the total opportunity cost is also calculated by including estimates of the opportunity cost for alternative allocations of water in each region, and other externalities including potential impacts on greenhouse gas emissions (GHG), health, and other mining externalities.

These results show a significant opportunity cost of R 6 / MWh up to almost R 8 / MWh for CSP over new coal based only on the regional differences in the bulk water supply infrastructure costs. The greatest impact is in terms of the opportunity cost for alternative water use allocations where the relative cost for coal, which competes with other potential users in Gauteng is R 440 / MWh compared to CSP which potentially competes with agricultural water uses along the Lower Orange. This is however perhaps misleading as much of Gauteng’s water ultimately comes from the Orange river tributaries through the LHWP, and this analysis does not take into account the wider economic impacts of different water use activities in different parts of the country (see for example Hassan et al, 2009). Still the opportunity costs based on the water availability and scheme costs for bulk water supply infrastructure costs along is significant and favours increase development of CSP in future.

Table 19: Comparison of the bulk water supply and total externality opportunity costs for water allocation to coal and CSP energy technologies

			≈ 2020		≈ 2030		≈ 2040	
	Year		≈ 2020		≈ 2030		≈ 2040	
	Technology		Coal (Dry)	CSP	Coal (Dry)	CSP	Coal (Dry)	CSP
	Region		Lephalale	Orange	Lephalale	Orange	Lephalale	Orange
	Demand	(Mm^3/a)	150	4000	200	4100	225	4150
BULK WATER SUPPLY COSTS (BW)								
Water Resource Management Charge	WMA ID		1	14	1	14	1	14
(Refer to Table 12)	WRMC	(c/m^3)	2.4	1.28	2.4	1.28	2.4	1.28
Bulk Water Supply Scheme	Scheme ID		A2	D1	A3	D1	A4	D2
(Refer to Table 22)	WSSIC	(R/m^3)	9.22	0.72	11.89	0.72	14.86	9.25
Regional Supply Opportunity Cost		**(R/m^3)**		**8.50**		**11.18**		**5.61**
Water Supply Delivery Scheme	Description		A1	D1	A1	D1	A1	D1
(Refer to Table 23)	WSDC	(R/m^3)	0.39	4.57	0.39	4.57	0.39	4.57
Primary Treatment Cost	PWTC	(R/m^3)	2	2	2	2	2	2
Total Regional Marginal Costs	TRMC	(R/m^3)	11.64	7.30	14.31	7.30	17.28	15.83
TRMC Opportunity Cost				**4.34**		**7.01**		**1.45**
Water Use Efficiency	Fuel Supply	(m^3/MWh)	0.144		0.144		0.144	
(Refer to Table 4)	Production	(m^3/MWh)	0.560	0.296	0.560	0.296	0.560	0.296
	TOTAL	(m^3/MWh)	0.704	0.296	0.704	0.296	0.704	0.296
Total Bulk Water Supply Cost		(R/MWh)	8.20	2.16	10.08	2.16	12.17	4.69
Total Bulk Water Opportunity Cost		**(R/MWh)**		**6.03**		**7.92**		**7.48**

5.3 Sensitivity of water supply costs to future energy costs

A critical component of the average annual operating cost and the overall unit cost of water for future water supply options is the total energy cost. This is also highly sensitive to fluctuations in the electricity price and should be considered when evaluating the relative costs of water in the future.

The DWA study of ultimate marginal costs of water supply across South Africa (DWA, 2010) gives an estimate of the unit power requirement (kWh/m^3) for the planned bulk water supply schemes in each region. The URV for each scheme was calculated based on an initial energy cost of R0.60/KWh up to 2020 and R0.90/kWh after that. The current price of electricity in South Africa is currently at R0.90/kWh and it is likely that additional costs, above inflation increases, will be incurred in the future to address the current back log in generation capacity. The results are shown in Figure 28.

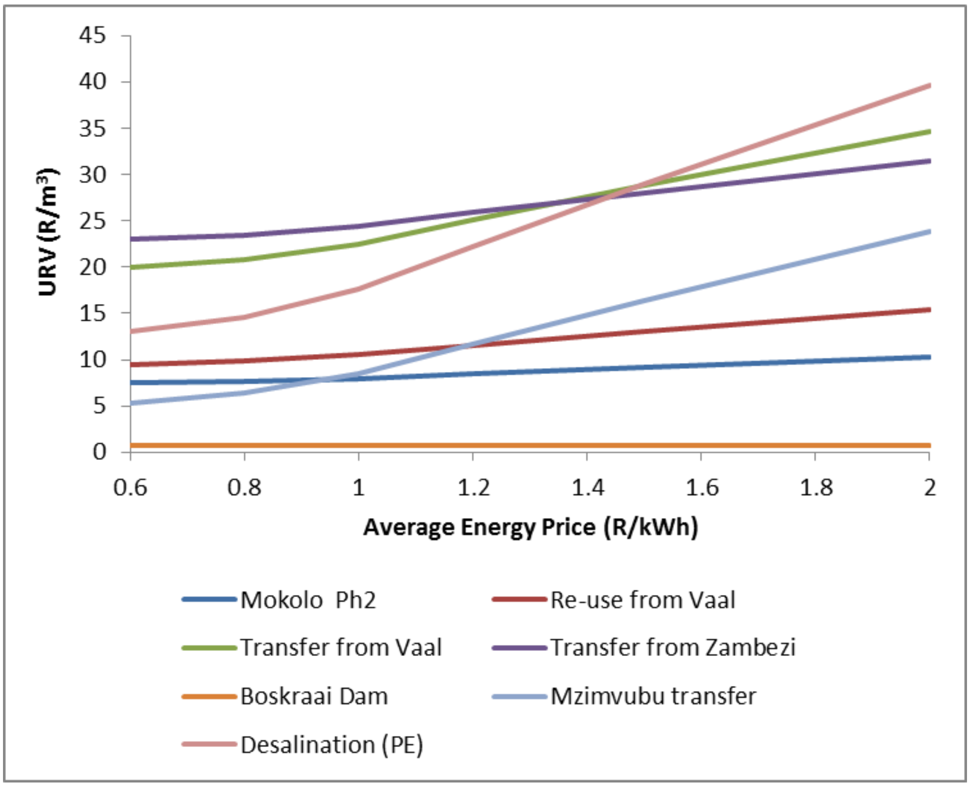

Figure 28: Sensitivity of future water supply scheme costs to changes in the energy price

Given the different levels of energy requirement, the future water supply schemes are more or less sensitive to fluctuations in the energy price. For example, the Boskraai dam on the Orange River has no major pumping requirements and is thus insensitive to future fluctuations in the energy price. Desalination of sea water or the transfer of water from the Zambezi however is very energy intensify and therefore highly sensitive to changes in the energy price. Separating out the energy cost from the annual maintenance costs provides another link in modelling the water-energy nexus as the unit cost of water supplied to the power stations is sensitive to the alternative future energy mix which in turn defines the average energy cost. This link in the water-energy nexus will also be investigated further using the linked SATIMES-W model for South Africa under Task 2 of the current study.

6 Conclusions

The objective of this phase of the project was to develop regional marginal cost curves for water supply to locations for current and future plant energy generation technologies in South Africa. The resultant cost curves ensure that a more representative estimate of the true cost of water supply to energy technologies located in different parts of the country is considered in modelling future alternative energy supply options in South Africa. This modelling will be undertaken in further phases of this study using the adjusted South African TIMES energy model (SATIM-W).

In anticipation of the more detailed modelling study using SATIM-W as simple case study was undertaken using the derived regional marginal cost curves to compare the financial implications of two alternative energy options; coal in the Lephalale area or CSP along the Orange river. The results showed that it was ten times more expensive to deliver water to the proposed coal fired power stations than to a CSP plant located along the Orange River. This combined with the better water use efficiency for the CSP resulted in a opportunity cost of R 6.03 per MWh for investing in coal rather than CSP for the immediate future and increasing to R 7.92 per MWh by 2030. This represents a significant additional cost, but when compared to the current price of electricity (R 0.90 per kWh) it represents less than 1% of the final energy price and thus not likely to influence the decision making on future energy options based on financial considerations only.

The improved efficiency of water use for CSP and the opportunity cost for other water users in the two areas should, however be considered if water is treated as a limited resource, and not just a cost item. By combining the water use efficiency and opportunity cost with the higher costs for water supply a stronger case could be made for investing in more CSP (or other alternative energy options) compared to ESKOM's current plans for more coal. The relative cost of water supply is also significantly impacted by the energy price, with water supply options to the planned coal fired power stations having a greater energy requirement than for CSP resulting in increased pumping costs.

An initial analysis of the potential impacts of climate change, showed that the existing highly integrated water supply distribution system, including many large dams and inter-basin transfer schemes, potentially provides some resilience to future variability in rainfall and runoff across South Africa. Much of the existing infrastructure system has been specifically developed to supply water of suitable quality to the coal fired power stations. Hence it is not clear that climate change will have a negative impact on the availability of water to supply the current and future energy needs of South Africa. Increasing demands from other sectors, particularly agriculture, may however increase the opportunity costs for allocation of water to energy production as compared to other water use activities. These need to be investigated further and possible also taking into account the potential impacts of climate change on other regional sources of energy particularly hydropower from the Zambezi and Congo Rivers.

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