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DRAFT INTEGRATED RESOURCE PLAN UPDATE (ASSUMPTIONS, BASE CASE RESULTS AND OBSERVATIONS) NOVEMBER 2016

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BACKGROUND

BUSA is a confederation of business organisations including chambers of commerce and industry, professional associations, corporate associations and unisectoral organisations. It represents South African business on macro-economic and high-level issues that affect it at the national and international levels. BUSA's function is to ensure that business plays a constructive role in the country's economic growth, development and transformation and to create an environment in which businesses of all sizes and in all sectors can thrive, expand and be competitive.

As the principal representative of business in South Africa, BUSA represents the views of its members in a number of national structures and bodies, both statutory and non-statutory. BUSA also represents businesses' interests in the National Economic Development and Labour Council (NEDLAC).

KEY MESSAGES

This submission is underpinned by a comprehensive analysis of the Integrated Resource Plan update (assumptions, base case results and observations) commissioned by BUSA from Genesis Analytics.

The following five key messages which can be derived from this analysis are that

- the Base Case must be the least cost case which will serve as the departure point for policy adjustment. In recent years, Renewable energy costs have fallen to levels that are competitive with conventional technologies. Renewable energy also has significant non-cost benefits, such as less lumpy capacity additions and shorter lead times. The constraints on Wind and Solar PV in the Draft 2016 IRP is a major deviation from the approach adopted in the 2010 IRP, where the base case represented an unconstrained least-cost option. Lifting these constraints would eliminate the need for Nuclear under the base case. The reductions in the costs of renewables used appear modest when compared to the learning rates observed from academic literature. For example, in the Draft 2016 IRP, Solar PV costs are expected to fall by only 20% and Wind by 10% over the 35 year IRP period. The learning rates derived from academic literature indicate that costs would decline by a significantly greater margin over that period.

- a more conservative approach to demand should be adopted. There is a real risk that projected demand over the IRP period is overestimated. In addition, the constant exchange rate assumption has the potential of understating the cost of capacity additions for technologies with long lead times, resulting in additional capacity being built prematurely and creating an unsustainable electricity price path.
- current economic circumstances make demand growth projections difficult; a more flexible approach to deployment of new capacity should be preferred in order to minimise the risk of oversupply and consequential fiscal pressure and higher tariffs.Lead times are shorter for renewable technologies than those for Coal and Nuclear, which make the building of Wind or Solar PV farms more flexible and thus more responsive to changing demand conditions, which is important in an economy where there is a lot of uncertainty surrounding future electricity demand.
- The higher proportion of renewable energy in the mix will require a different approach to the management of the grid. In this regard, a review of the structure of the electricity industry to accommodate a more flexible system should be pursued.
- The significant move away from coal in the longer term will be disruptive to the coal value chain. It is therefore imperative that the actual impacts are understood and mechanisms put in place to mitigated. In the current base case, it is only by 2030 that a large-scale shift will occur.

In conclusion, BUSA welcomes the opportunity to comment on this important document and trusts that the comprehensive comments submitted will assist Government to revise the approach in a way that delivers balanced IRP that meets the expectations and need of our society in a way that also addresses a number of policy imperatives.

INTRODUCTION

BUSA welcomes the opportunity to comment on the draft Integrated Resource Plan (assumptions, base case and observations). The Integrated Resource Plan is an element of the Integrated Energy Plan required in terms of the National Energy Act and in terms of that Act is required to deal "with issues relating to the supply, transformation, transport, storage of and demand for energy in a way that accounts for—

(a) security of supply;
(b) economically available energy resources:
(c) affordability;
(d) universal accessibility and free basic electricity;
(e) social equity;
(f) employment;
(g) the environment;
(h) international commitments;
(i) consumer protection; and
(j) contribution of energy supply to socio-economic development."

The current Integrated Resource Plan for electricity (IRP 2010) is restricted to generation as is the documentation released for comment in November 2016. The

Integrated Energy Plan recognises that an electricity plan should deal with all aspects of electricity supply from generation to supply to the customer and recommends that although transmission and distribution are dealt with in other plans, the IRP should assess these in detail. BUSA supports this recommendation but it has not been included in the IRP documents released for public comment. BUSA therefore recommends that the final draft of the 2016 IRP addresses this issue.

This submission is based on three broad areas as follows:

- Base case
- Assumptions underpinning the base case
- Update scenarios to be modelled

BASE CASE

The base case presented in the IRP update (November 2016) was clarified with the department as not being a least cost case but an updated base case developed using the same assumptions used in the IRP 2010 but updated based on a variety of changes in the environment in which the IRP must be located.

These include:

- Changed electricity landscape in particular electricity demands and the underlying relationship with economic growth
- New developments in technology and fuel options
- Scenarios for carbon mitigation strategies
- Affordability of electricity and its impact on demand and supply

While it is recognised in the updated IRP that affordability is an issue that needs to be addressed, there is no indication in the report that the final IRP 2016 will include a tariff path as was the case with IRP 2010.

BUSA believes that the tariff implications of its capacity addition decisions need to be understood as part of the decision-making process. Comparison of the projected tariffs over the IRP period across the various presented scenarios should form part of the proposed IRP.

In respect of the base case presented for IRP 2016, BUSA believes that the approach adopted in IRP 2010, namely that the least cost or cost optimal option forms the base case as the departure point for imposition of adjustments as tested through scenarios.

In the 2010 IRP, the base case scenario represented the least cost, or cost-optimal option for capacity additions given the Levelised Cost per unit of Energy (also known as lifetime cost per unit of energy) (LCOE) assumptions that were available at the time. All additional scenarios reflected the consideration of qualitative measures such as regional development and employment opportunities. This approach was confirmed in the following statement extracted from the 2010 IRP document:

"This scenario was derived based on the cost-optimal solution for new build options (considering the direct costs of new build power plants), which was then "balanced" in accordance with qualitative measures such as local job creation"[1]

[Own emphasis]

The Draft IRP 2016 also confirms that that the base case is meant to be the "least cost plan".[2] Unfortunately the capacity additions assumed under the base case are not cost-optimal. More specifically, the base case:

Contains self-imposed constraints on the addition of Renewable Energy. During the Draft 2016 IRP period, the addition of Solar PV and Wind generation capacity does not exceed 2,200 MW per annum. The Draft 2016 IRP document does not provide any legitimate reasons for this limitation. In fact, the imposed limit is very close to what industry has already demonstrated it could build in a year. According to analysis undertaken by CSIR, a "re-optimized" scenario (using the same modelling software and assumptions) which contains no limitations on Solar PV and Wind capacity additions would be R90 billion per year cheaper by 2050 than the current Draft 2016 IRP base case.[3] This reflects the significant reductions in Renewable Energy costs observed during the four bid Windows and the implied learning rates derived from these falls in costs.

Contains an over-reliance on conventional technologies for capacity additions. Under the base case, Coal and Nuclear technologies are expected to add 35,000 MW of generation capacity to the grid. The LCOE of these two technologies have increased markedly since 2010 to the extent that they have become on par or less cost competitive than renewable technologies. The Draft 2016 IRP also notes that the base case is highly sensitive to "changes in assumptions such as various primary fuel costs and emission assumptions".[4]

Modelling the base case

A fundamental criticism of the imposition of this constraint at this stage of the IRP process is that the base case should represent the least-cost option for South Africa's new build generation capacity, which is free from any artificial

[1] 2010-30 IRP, page 6.
[2] Draft 2016 IRP, page 26.
[3] CSIR; "Comments on the Integrated Resource Plan 2016 Draft" (7 December 2016), page 29.
[4] 2010-30 IRP, page 27.

constraints. Constraints that represent policy positions should then be included as scenarios, which are done at a later date once the base case has been agreed upon.

The DoE's approach to modelling the base case in 2016 is inconsistent with recommendations made by the Ministerial Advisory Council on Energy ("MACE"). This group, appointed by the Minister of Energy, made the following recommendation with respect to modelling the base case:

"Consistent with the approach used in IRP 2010, the scenario that forms the Base Case must be least cost and free of any policy adjustments. The Working Group therefore recommends that the annual new-build limits imposed on Solar PV and Wind are removed and this unconstrained scenario…forms the Base Case for the IRP 2016."[5]

It is perplexing that this constraint has been imposed in the base case, as the DoE appears to have had the same understanding of a base case in relation to alternative scenarios in 2010. In a document that defines "generation mix", which is part of the 2010 IRP input parameters documentation, the DoE states:

"The mix of generating capacity is determined as an output of the IRP model. Although it is possible to limit or enforce technologies, this may only be done as part of the scenario studies, following government policy inputs."[6]

[Emphasis added]

The constraints on Wind and Solar PV in the Draft 2016 IRP is a major deviation from the approach adopted in the 2010 IRP, where the base case represented an unconstrained least-cost option. The effect of these constraints is that the model chooses these technologies up to the artificially imposed limits, where after it chooses the next least-cost options, which are Coal and Gas. Coal is also constrained because of CO_2 emissions targets, which thus necessitates the addition of Nuclear into the fleet in 2037. Thus in essence the impact of imposing these new constraints into the base case is that new nuclear build is required. Lifting these constraints, in conjunction with decreasing the cost of these technologies in line with the actual costs from Bid Window 4 Expedited, results in new Nuclear build no longer being required.[7]

Accordingly, the base case should be reworked with no constraints on any technologies being imposed. This least-cost base case can then be adjusted as per the scenarios chosen by the DoE. Capacity constraints on Wind and Solar PV, and indeed any other conventional or Renewable Energy, should be made in appropriate scenarios if there are technical, economic or other policy related rationales for imposing them.

It is understood that the carbon constraint incorporated into the policy adjusted IRP has been retained in the base case presented. This means that the carbon constraint scenario envisaged in the update scenarios will be imposed on an

[5] http://www.sapvia.co.za/wp-content/uploads/2016/12/311016-MACE-WG-note-on-IRP-2016-FINAL.pdf.
[6] http://www.doe-irp.co.za/IRPPrm/IRP%20Parameter%20-%20S11%20Generation%20Mix.pdf. A full list of all the input parameters can be found at: http://www.doe-irp.co.za/IRPPrm.html.
[7] CSIR (7 December 2016) Comments on the Integrated Resource Plan 2016 Draft: South African Integrated Resource Plan 2016 public hearing.

existing carbon constrained base case, which essentially amounts to imposition of a duplicate carbon constraint, which cannot be supported.

ASSUMPTIONS UNDERPINNING THE UPDATED BASE CASE

Comments on the assumptions used in the updated base case are presented below.

TECHNOLOGY COST ASSUMPTIONS

The technology cost assumptions contained in the Draft 2016 IRP differ significantly from the cost assumptions contained in the 2010 IRP. This is to be expected as capital costs as well as operations and maintenance costs change over time, while fuel costs change in response to commodity price fluctuations. In addition, normal inflationary increases are expected for all types of costs.

As with the 2010 IRP, the Draft 2016 IRP contains some cost assumptions for each of the conventional and renewable technologies. These cost assumptions were extracted from the Electric Power Research Institute ("EPRI") studies[8], which were conducted in 2010 and 2015 for the DoE, and from the REIPP Bid Window 4. One of the key cost metrics EPRI computes, but is not contained in the Draft 2016 IRP, is the levelised cost of electricity ("LCOE"). This metric incorporates fuel costs, operations and maintenance ("O&M") costs as well as capital costs to arrive at an average cost per megawatt hour ("MWh"). The LCOE equates to the sum of all the costs divided by the expected MWh output over the lifetime of a plant and adjusts costs for inflation as well as discounts to account for the time value of money.[9] This metric allows for a proper cost comparison between different generation technologies, even when they have unequal lifetimes, capacity and load factors.[10]

As the Draft 2016 IRP excludes LCOE estimates, a proper comparison of costs across generation technologies requires the extraction of LCOE data from the EPRI studies. Using LCOE data the changes in costs over time for all relevant conventional generation technologies are quantified below. For renewable technologies, the DoE's cost estimates from the REIPP Bid Window 4 were used. Specifically, LCOE estimates derived in January 2010 were compared to LCOE estimates derived in January 2015.

As shown below, conventional generation technologies have become significantly more expensive since 2010 on a ZAR per MWh basis. Conversely, renewable technologies have become more cost competitive. This finding should have

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[8] See Electric Power Research Institute (2010), Power Generation Technology Data for Integrated Resource Plan of South Africa and Electric Power Research Institute (2015), Power Generation Technology Data for Integrated Resource Plan of South Africa.

[9] Renewable Energy Advisors, available: http://www.renewable-energy-advisors.com/learn-more-2/levelized-cost-of-electricity/.

[10] U.S. Department of Energy, Office of Indian Energy, Levelised cost of energy, available: https://energy.gov/sites/prod/files/2015/08/f25/LCOE.pdf.

significant implications for the DoE's base case scenario, particularly with regards to additions to generation capacity over the IRP period.

Conventional technology cost assumptions

Conventional generation technologies in the case of the IRP refer to Coal and Natural Gas technologies. The relevant Coal technologies considered in the 2010 IRP and the Draft 2016 IRP comprise of Coal pulverized, Coal FBC and Coal IGCC[11]. The natural Gas technologies comprise of OCGT and CCGT[12]. Using EPRI studies conducted in 2010 and 2015, the LCOE for these conventional generation technologies were compared. For each technology, the 2010 LCOE (expressed in January 2010 terms) was compared to the 2015 LCOE (expressed in January 2015 terms). This comparison is shown in Table 1 and Table 2.

Table 1: Change in costs for conventional Coal technologies

<table>
<tr><th></th><th></th><th colspan="2">Coal pulverised with FGD</th><th colspan="2">Coal FBC with FGD</th><th colspan="2">Coal IGCC</th></tr>
<tr><th></th><th>Units</th><th>2010</th><th>2015</th><th>2010</th><th>2015</th><th>2010</th><th>2015</th></tr>
<tr><td>Rated capacity</td><td>MW, net</td><td>4,500</td><td>4,500</td><td>1,500</td><td>1,500</td><td>1,288</td><td>1,288</td></tr>
<tr><td>Fuel cost</td><td>ZAR/MWh (Jan 2010/Jan 2015)</td><td>146.5</td><td>247.2</td><td>151.2</td><td>271.7</td><td>146.4</td><td>245.7</td></tr>
<tr><td>Variable O&M</td><td>ZAR/MWh (Jan 2010/Jan 2015)</td><td>44.4</td><td rowspan="2">186.6</td><td>99.1</td><td rowspan="2">220.5</td><td>14.4</td><td rowspan="2">212.3</td></tr>
<tr><td>Fixed O&M</td><td>ZAR/MWh (Jan 2010/Jan 2015)</td><td>61.1</td><td>49.1</td><td>111.5</td></tr>
<tr><td>Capital cost</td><td>ZAR/MWh (Jan 2010/Jan 2015)</td><td>338.8</td><td>638</td><td>286.6</td><td>655.5</td><td>468.1</td><td>932.9</td></tr>
<tr><td>LCOE</td><td>ZAR/MWh (Jan 2010/Jan 2015)</td><td>590.9</td><td>1,072</td><td>585.9</td><td>1,148</td><td>740.4</td><td>1,391</td></tr>
</table>

[11] FBC stands for "Fluidized Bed Combustion" and IGCC stands for "Integrated Gasification Combined Cycle."
[12] OCGT stands for "Open Cycle Gas Turbine" and CCGT stands for "Combine Cycle Gas Turbine."

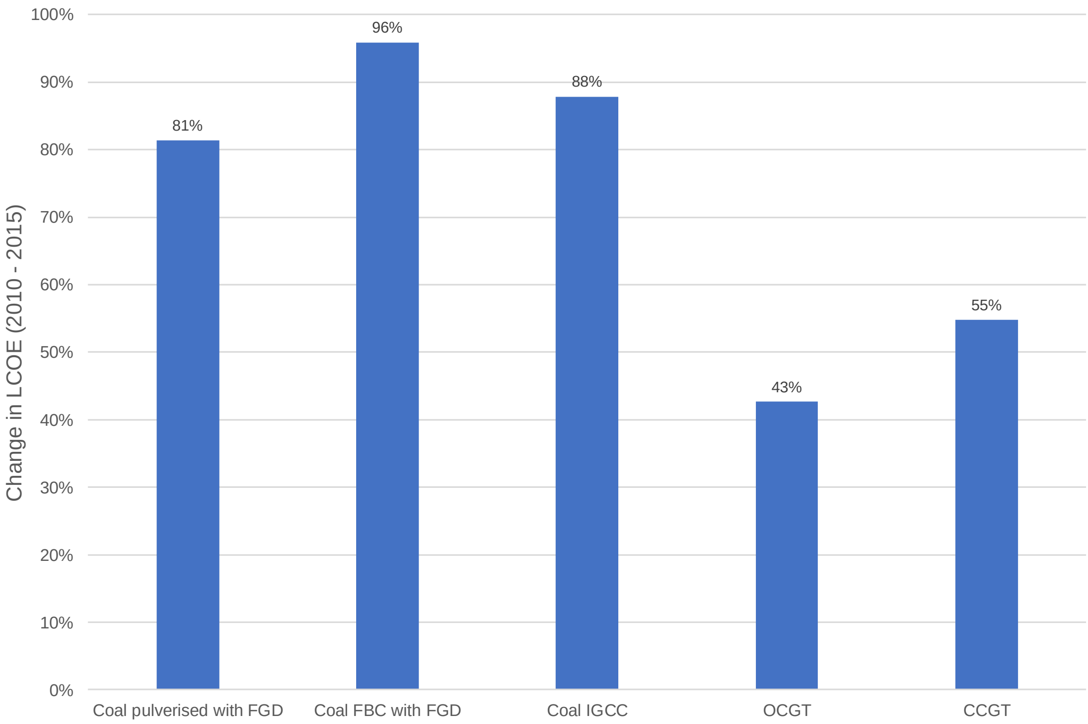
Table 2: Change in costs for conventional Gas technologies

<table>
<tr><th></th><th></th><th>OCGT</th><th></th><th>CCGT</th><th></th></tr>
<tr><th></th><th>Units</th><th>2010</th><th>2015</th><th>2010</th><th>2015</th></tr>
<tr><td>Rated capacity</td><td>MW, net</td><td>114.7</td><td>132</td><td>711.3</td><td>732</td></tr>
<tr><td>Fuel cost</td><td>ZAR/MWh (Jan 2010/Jan 2015)</td><td>502.1</td><td>596.4</td><td>315.2</td><td>382.9</td></tr>
<tr><td>Variable O&M</td><td>ZAR/MWh (Jan 2010/Jan 2015)</td><td>0</td><td rowspan="2">170.2</td><td>0</td><td rowspan="2">54.6</td></tr>
<tr><td>Fixed O&M</td><td>ZAR/MWh (Jan 2010/Jan 2015)</td><td>77.5</td><td>18.1</td></tr>
<tr><td>Capital cost</td><td>ZAR/MWh (Jan 2010/Jan 2015)</td><td>817.4</td><td>1226</td><td>126.8</td><td>274.7</td></tr>
<tr><td>LCOE</td><td>ZAR/MWh (Jan 2010/Jan 2015)</td><td>1,397</td><td>1,993</td><td>460.1</td><td>712.2</td></tr>
</table>

Sources: EPRI 2010 and 2015, Power Generation Technology Data for Integrated Resource Plan of South Africa.

This comparison shows that from 2010 to 2015, significant increases in LCOE occurred across all the conventional generation technologies. The increases ranged from 43% (OCGT) to 96% (Coal FBC with FGD). Coal technologies in general showed the highest increases in costs. In most cases, capital costs were the main driver, however, O&M ("operations and maintenance") cost increases were at or above 50% for all of the technologies. Figure 1 shows the increases in LCOE across the different conventional generation technologies.

Figure 1: Increase in LCOE for different conventional generation technologies (2010-2015)



Sources: EPRI data and Genesis calculations.

The increases in the LCOE for all the conventional technologies means that tariffs calculated under the Draft 2016 IRP will be higher than the tariff levels calculated under the 2010 IRP. In addition to costs increasing, the amount of conventional generation capacity additions assumed in the Draft 2016 IRP is close to 5,700MW higher than the amount assumed in 2010 IRP, as shown in Table 3.

Table 3: Capacity additions using conventional generation technologies (up to 2030)

MW	Coal	CCGT	OCGT	Total
2010 IRP	5,000	1,896	5,750	12,646
Draft 2016 IRP	5,250	7,320	5,772	18,342

Sources: 2010 IRP and Draft 2016 IRP

To test the validity of EPRI's 2015 LCOE estimates for conventional generation technologies, the LCOE estimates reflected in the Energy Information Administration's (EIA) Annual Energy Outlook report for 2016 for these same technologies. Table 4 shows these LCOE estimates and the individual cost components, for the following three conventional technologies:

Advanced Coal with CCS, CCGT, and Conventional Combustion Turbine. The $US estimates reflected in the EIA report were converted to South African Rand.

Table 4: US conventional energy costs (ZAR/MWh)

Technology	Capital cost	Fixed O&M	Variable O&M	Total LCOE
Advanced Coal with CCS	1,239	117	407	1,779
CCGT	177	18	529	741
Conventional combustion turbine	522	83	764	1,413

Source: U.S Energy Information Administration (2016), Levelised Cost and Levelised Avoided Cost of New Generation

Resources in the Annual Energy Outlook 2016, page 7, available: https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf.

The EIA provides costs in 2015 US dollars. These costs were converted to ZAR using the average monthly exchange rate from January 2015 to December 2015. The exchange rate data is sourced from the South African Reserve Bank.

A comparison of the above LCOE estimates with the EPRI LCOE estimates shown in Table 1 and 2 indicates that the EPRI estimates are somewhat conservative for Coal and CCGT, and may underestimate the lifetime costs of these technologies. Although the EIA's LCOE estimates for Conventional Combustion Turbine is somewhat lower than EPRI's LCOE estimate for OCGT, it is possible that these technologies are not sufficiently similar to allow for a meaningful comparison.

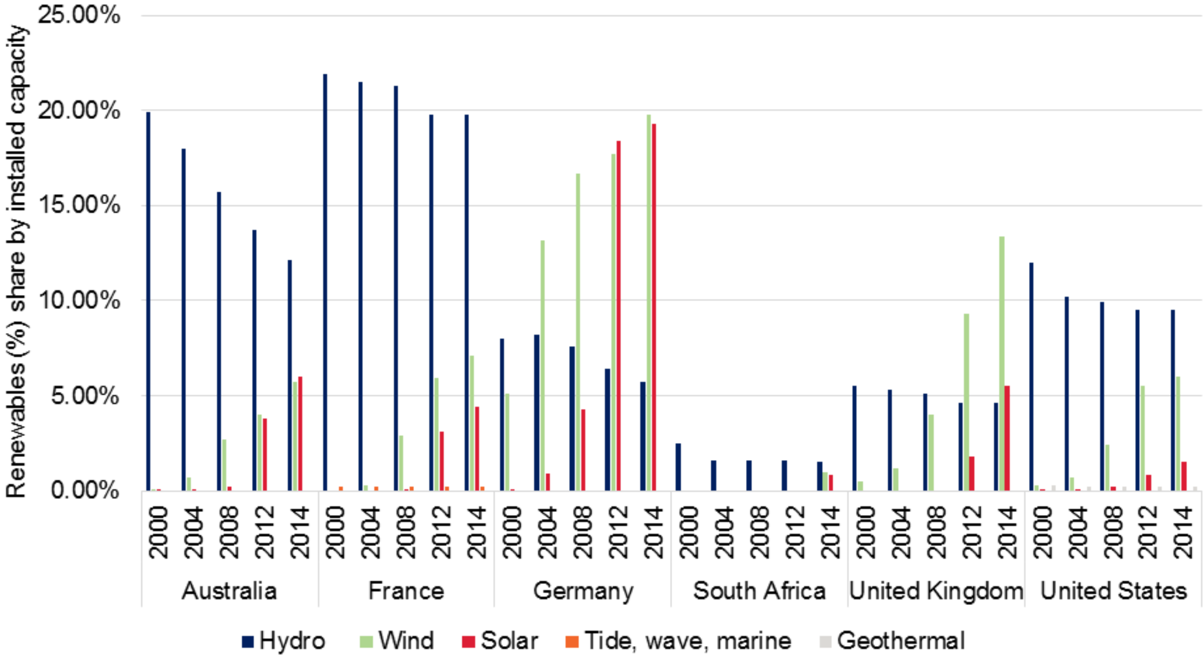
In summary, this comparison analysis shows that conventional technology costs have increased markedly since the publication of the 2010 IRP. Given that the Draft 2016 IRP assumes a greater reliance on conventional technology, the expected tariff levels over the IRP period will be higher than the levels calculated for the 2010 IRP.

International experience on installed capacity

The installed Renewable Energy capacity in Australia, France, Germany, South Africa, the UK and the US for the period 2000 to 2014 is presented in figure 3. This shows the significant change in the structure of installed capacity; the share of renewables has increased, while the share of non-renewables such as combustible fuels has decreased. Despite having excellent Wind and Solar resources, South Africa is lagging behind the leading nations in terms of adding

Renewable Energy capacity to the grid and in terms of the total proportion of installed capacity made up of Renewable Energy technologies, were reviewed.[13]

Figure 2: Renewables percentage share by installed capacity (2004 – 2014)



Source:
Genesis'
Source:

Source: Genesis' calculations. Energy Statistics Database, United Nations Statistics Division, 2016. Notes: 1. Gas is not included in the Energy Statistics Database. 2. Non-renewables consist of Combustible fuels and Nuclear.

There has been a push in recent years for countries to develop Renewable Energy policies, and at the end of 2015, 146 countries had Renewable Energy policies in place.[14] Worldwide, targets for Renewable Energy as a share of overall electricity capacity continue to be a primary means for governments to express their commitment to Renewable Energy deployment. The following countries have some of the highest targets for Renewable Energy as a share of overall electricity capacity in the world:

[13] In 2015, Renewable Energy accounted for approximately 9.7% of installed capacity; CSP, PV, Wind and Hydro accounted for 0.38%, 2.52%, 2.80% and 4% respectively. As a percentage of total installed capacity, the share of renewables is targeted to reach approximately 27.49% by 2030. Source: Draft 2016 IRP, page 24.

[14] Renewables 2016. Global Status Report. page107. Accessed: http://www.ren21.net/wp-content/uploads/2016/06/GSR_2016_Full_Report.pdf.

In Africa, the Republic of the Congo, Eritrea, Gabon and Namibia established targets of 70% or greater for Renewable Energy as a share of overall electricity capacity.[15]

In Latin America, targets for Renewable Energy as a share of overall electricity capacity were led by Costa Rica (100% by 2030), Uruguay (95% by 2017), Belize (85% by 2027), Guatemala (80% by 2030) and Bolivia (79% by 2030).[16]

In 2015, Renewable Energy generating capacity saw its largest annual increase, with an estimated 147 GW of renewable capacity added. The world now adds more Renewable Energy capacity annually than it adds (net) capacity from all fossil fuels combined.[17]

In Europe renewables accounted for the majority (77%) of new EU generating capacity, and the region continued to decommission more capacity from conventional sources than it installed. For example, between 2000 and 2015, the share of renewables in the EU's total power capacity increased from 24% to 44%, and as of 2015, renewables were Europe's largest source of electricity.[18]

In the US, renewables accounted for nearly 14% of electricity generation. Wind and Solar were the leading sources of new power capacity in 2015, exceeding Natural Gas capacity additions.

Countries across Latin America and the Caribbean also achieved high shares of electricity generation with renewables. For example, Costa Rica generated 99% of its electricity with renewable sources, while Uruguay generated 93%.

Renewable technology cost assumptions

The Draft 2016 IRP also provides costs for Renewable Energy technologies.[19] The two largest Renewable Energy technologies by far in terms of planned capacity additions are Wind and Solar Photovoltaic ("Solar PV"). For these technologies, the Draft 2016 IRP does not use EPRI data but instead uses cost estimates from the DoE's IPP (Independent Power Producers) office, which was based on the weighted average prices from power purchase agreements from the REIPP bid Window 4. These cost estimates are not expressed as LCOE, but rather as detailed costs components, i.e. overnight construction costs, fixed O&M and variable O&M. Accordingly, this comparison of the costs for Solar PV and Wind between 2010 and 2015 is done using the cost components rather than the LCOE.

The comparison of costs for Wind is shown in Table 5. Overnight capital costs for Wind have increased by 33%, whereas fixed O&M expenses have increased by 108% from 2010 to 2015.

[15] Ibid. page 108.
[16] Ibid. page 109.
[17] Ibid. page 32.
[18] Ibid. page 34.
[19] Draft 2016 IRP, page 18.

Table 5: Change in costs for Wind technology

	Units	2010	2015
Total overnight cost	ZAR/kW (Jan 2010/2015 ZAR)	14,445	19,208
Fuel cost	R/GJ	0	0
Fixed O&M Cost	R/KW/Year	266	554
Variable O&M Cost	R/MWh	0	0

Sources: EPRI 2010 and 2015, Power Generation Technology Data for Integrated Resource Plan of South Africa.

The comparison of costs for Solar PV is shown in Table 6. Overnight capital costs for concentrated PV increased by 24%. Conversely, fixed O&M fell by 43%, which has resulted in Solar PV becoming more cost competitive.

Table 6: Change in costs for Solar PV

	Units	2010	2015
Rated capacity	MW net	10	10
Total overnight cost	ZAR/kW (Jan 2010/2015 ZAR)	37,225	46,052
Fuel cost	R/GJ	0	0
Fixed O&M Cost	R/KW/Year	502	287
Variable O&M Cost	R/MWh	0	0

Sources: EPRI 2010 and 2015, Power Generation Technology Data for Integrated Resource Plan of South Africa.

A key variable for determining the likely future costs is the learning rate, i.e. the reduction in costs arising from technology manufacturers accumulating experience. This is particularly relevant for renewable technologies, which are relatively new. The Draft 2016 IRP contains so called learning rates for Solar PV and Wind. However, given the lack of detail on how these rates are derived, there are a few concerns to be noted.

Firstly, the learning rates in the Draft 2016 IRP are presented as ZAR per KW, whereas this variable is generally expressed as a percentage decline in the cost of production of one unit for a doubling in the cumulative installed capacity.[20] Thus, the presented learning rates cannot be verified as it is not clear how they are being used to determine future Wind and Solar PV costs.

The reduction in ZAR per KW costs appear modest when compared to the learning rates observed from academic literature. For example, in the Draft 2016 IRP, Solar PV costs are expected to fall by only 20% and Wind by 10% over the 35 year IRP period. The learning rates derived from academic literature indicate that costs would decline by a significantly greater margin over that period.[21]

It appears that the learning rates were derived from the DoE Renewable Bid Window 4.[22] There have been subsequent bid Windows and therefore it would be more accurate to make use of the most up-to-date cost assumptions when determining learning rates as it reflects more realistic future costs. There were significant reductions in Renewable Energy technology tariffs in the latest bid Windows. For example, the Council for Scientific and Industrial Research ("CSIR") have been able to determine the difference in the average Renewable Energy tariffs between Bid Window 4 (used in the Draft 2016 IRP) and the latest bid Window (Bid Window 4 Expedited). These differences are shown in Table 7.

Table 7: Average tariffs (ZAR/KWh) from IRP assumptions and Bid Window 4 Expedited

Technology	IRP 2016 assumptions (Jan 2015)	Bid Window 4 expedited (Apr 2016)
Solar PV	0.93	0.62
Wind	0.81	0.62

Source: CSIR (2017), Least cost electricity mix for South Africa: Optimisation of the South African power sector until 2050, page 7, available: http://www.crses.sun.ac.za/files/news/RSA%20Re-Optimisation%20-%20CSIR%20-%2016Jan2017.pdf.

In the CSIR modeling the Bid Window 4 tariff is maintained as constant with no further cost reductions assumed over modeling period. Even under such conservative cost assumptions for wind and PV, the model selects both these technologies as the least-cost options.

[20] Industrial Development Corporation, Green economy report: The cost of renewable energies, August 2012, Page 8, available: https://www.idc.co.za/images/download-files/research-reports/IDC_RI_publication_Cost%20Evolution_Renewable_Energies.pdf.

[21] https://www.andrew.cmu.edu/user/ilimade/Ines_Azevedo/papers/Rubin_2015.pdf. This study established the mean learning rates (i.e. % cost reduction from doubling of cumulative installed capacity) for Solar PV as 12% and 16.5% for Wind. Given that installed capacity is expected to grow exponentially over the IRP period, the reduction in costs is likely to be significantly greater than these percentages.

[22] Draft 2016 IRP, pages 18 and 13.

Between Bid Window 4 and Bid Window 4 Expedited, average tariffs for PV and Wind fell by 33% and 23% respectively. Thus, by ignoring the tariffs in the latest bid window, the reduction in costs are not considered, resulting in Renewable Energy technology costs being artificially high. This will have implications given that the base case scenario in the Draft 2016 IRP is meant to be a least cost model.

BUSA therefore recommends that the latest actual costs tariff as per Bid Window 4 (expedited) be used for the base case.

COGENERATION COST ASSUMPTIONS

Although cogeneration is not currently included in the base case, it is recommended that its exclusion be reconsidered in terms of the case made below.

The use of information supplied by the sugar industry in the lead up to the IRP 2010 development, with indexation for the ensuing 6 years, leads to an appropriate assumption. Firstly, the sugar industry is not a proxy for all cogeneration in South Africa. The recent cogeneration capacity research study[23] shows that the sugar industry has only 191 MW of the total estimated 1 379 MW of cogeneration installed in South Africa. This represents only 14% of the total and is solely the combined heat and power as produced in that industry from the bagasse residue from the sugar cane milling processes.

The second reason that the use of sugar industry data from 2010 is not representative of the broader cogeneration technologies is that no value was placed on the heat portion of the cogeneration outputs. The heat is valued at zero cost and carries no input costs and no capital costs. In the 2010 submission the heat was assumed to be free-issue to the sugar manufacturing process. This is a valid assumption for that industry, as the bagasse has historically had a waste disposal cost associated with it and has not been seen as a cost component.

This is not the case in most other cogeneration applications, where there is a real cost of primary fuel, and the costs both for fuel and capital are apportioned to both the heat and the power components of the outputs. With some of the input costs and capital apportioned to heat, the power component thus accounts for less input and capital costs, and so the LCOE for the power component is proportionately less. In simple terms, the majority of cogeneration power from other industries is likely to be cheaper than that assumed for the sugar industry.

Nuclear cost assumptions

The Draft 2016 IRP does not use EPRI data for nuclear technology costs. Rather, it makes use of "hybrid costs" based on a study commissioned by the DoE Nuclear Branch. This study incorporates Asian costs, which are significantly lower than the nuclear costs observed in western countries. This study is not properly cited and it at the time of publication of

[23] "South African Cogeneration Review Study" 27 February 2015 sponsored by GIZ

the IRP update was not publicly available.[24] BUSA subsequently requested the report from the department and it was agreed that it would be supplied. However, at the time of writing this information had not yet been provided. The Draft 2016 IRP provides no justification on why the hybrid cost data is used instead of the EPRI data.

The Draft 2016 IRP cost assumptions are significantly lower than the cost assumptions disclosed in the 2015 EPRI study, which assumes Areva Nuclear technology. Table 8 shows the differences in the detailed cost elements between the two sources.

Table 8: DoE and EPRI costs for Nuclear technology

	Unit	Draft 2016 IRP	2015 EPRI (Areva)
Rated capacity	MW, net	1,400	1,600
Total overnight cost	ZAR/kW (Jan 2010/2015 ZAR)	55,260	79,432
Lead-times and project schedule	Years	8	6
Fuel cost	R/GJ	7.35	7.35
Heat Rate	kJ/kWh	10,657	10,340
Fixed O&M Cost	R/KW/Year	885	755
Variable O&M Cost	R/MWh	34	42.4

Sources: Department of Energy, Integrated Resource Plan Update, Assumptions, base case and observations: Revision 1, November 2016, page 16.

EPRI (2015), Power Generation Technology Data for Integrated Resource Plan of South Africa, page 8-1.

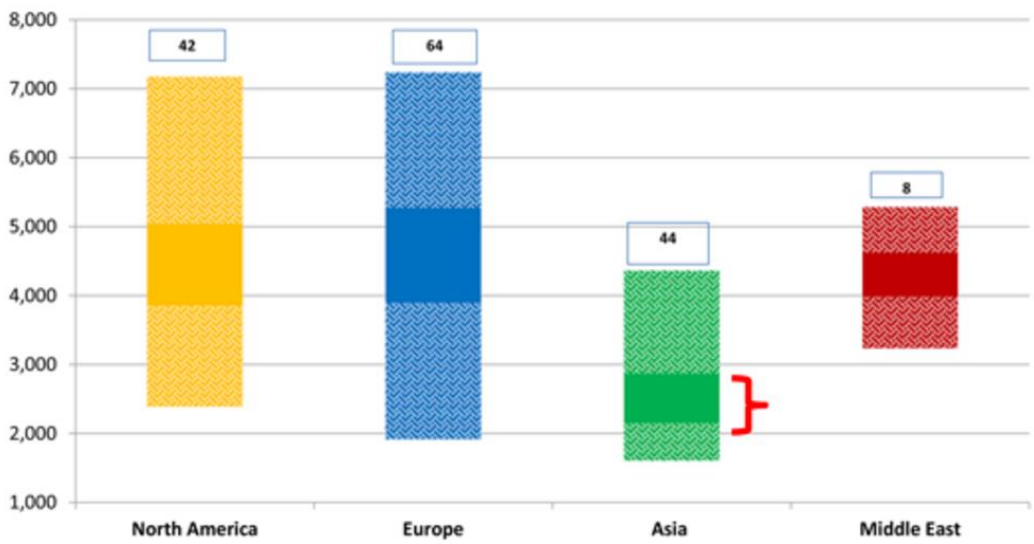
The Draft 2016 IRP assumes significantly lower overnight capital cost and variable O&M costs. Although LCOE estimates are not provided, the differences in the above cost components will mean that the LCOE derived using the Draft 2016 IRP assumptions would be significantly lower than the LCOE derived using EPRI data. This would be

[24] Draft 2016 IRP, page 9.

problematic if the Draft 2016 IRP assumptions are not applicable to South Africa, and the base case scenario will incorrectly infer that nuclear technology is a cost optimal solution.

As explained above, nuclear technology costs derived from Asia are generally lower than the nuclear costs derived from the West.[25] This is illustrated in Figure 3, which shows the range of overnight capital costs by region, in 2013 US dollars, and was constructed from data from publications and studies covering a period from 2008 to 2014.

Figure 3: Overnight capital costs for Nuclear power plants (2013 USD/kW)



Source: World Nuclear Association (2017), The Economics of Nuclear Power, available: http://www.world-Nuclear.org/information-library/economic-aspects/economics-of-Nuclear-power.aspx.

Lovering, Yip and Nordhaus (2016) collected historical Nuclear reactor-specific overnight construction cost ("OCC") data for 349 reactors in the US, France, Canada, West Germany, Japan, India, and South Korea, encompassing 58% of all reactors built globally.[26] The historical data shows that costs have not evolved in the same way in different countries. While OCC has increased in some countries over time (the US being an extreme case of this), some countries have shown stable costs over the long term while some have even experienced cost declines.

This difference in historical costs may motivate the use of hybrid costs. However, in using costs from various countries, it is also important that the reasons for the differing costs are taken into account. As observed by Lovering et al., the evolution of costs over time depends on different regional, historical, and institutional factors. Even with the same reactor

[25] Draft 2016 IRP, page. 9.

[26] Lovering, J.R., Yip, A. and Nordhaus, T., (2016), Historical construction costs of global Nuclear power reactors, Energy Policy volume 91, pages 371-382.

technologies, there is a large variance in cost trends over time. This implies that cost drivers other than learning-by-doing have a significant impact. Lovering et al. suggests that some of the cost drivers include utility structure, reactor size, regulatory regime, and international collaboration.[27] Thus it is not sufficient to only take the costs into consideration, without accounting for the factors that drive these costs.

Importantly, the Draft 2016 IRP has not taken delays and cost overruns into consideration when determining the predicted cost of Nuclear technology. This is especially important given South Africa's lack of experience with Nuclear power plants relative to some countries that may make up the hybrid cost estimates derived by the DoE. Nuclear technology has a history of delays and cost overruns.[28] An extreme example is the Watts Bar Unit 2 Nuclear reactor in the US which only neared operation in 2015 after construction began in 1973.[29] Also, in their World Nuclear Industry Status Report for 2016, Schneider and Froggatt found that Nuclear plant projects were delayed in 9 of the 14 countries analysed, and most of these were delayed by several years. These delays have occurred in countries such as China, Russia, US, Japan, France, Finland, Brazil and India.[30]

Hossen, Kang and Kim suggests that the LCOE increases by 8%-10% for every year that a nuclear project is delayed.[31] Delays and cost overruns have already been experienced in South Africa with the Medupi and Kusile plants, where costs grew from an estimated R69 billion and R80.6 billion in 2007 to R154.2 billion and R172.2 billion for Medupi and Kusile respectively.[32]

Conclusions on cost comparisons

In summary, the cost comparison analysis shows that conventional technology costs have increased markedly since the publication of the 2010 IRP. For Nuclear specifically, the LCOE derived using the Draft 2016 IRP assumptions are likely to be significantly lower than the LCOE derived using EPRI data, which means that the base case scenario will incorrectly infer that nuclear technology is a cost optimal solution.

Conversely, the costs for renewable technologies have fallen to the level where they have become cost competitive with conventional technologies. Given that the Draft 2016 IRP assumes a greater reliance on conventional technology, the expected tariff levels over the IRP period will be higher than the levels calculated for the 2010 IRP.

With the exception of Nuclear, the conventional technologies cost comparison analysis relies on EPRI data, which are based on EPRI's cost estimates for US based power plants, with adjustments to account for South African specific

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27 Ibid, page 380.
28 Carbon Connect (2014), Future electricity series part 3: Power from Nuclear, page 5.
29 Bulletin of the atomic scientists (2015), Watts Bar Unit 2, last old reactor of the 20th century: a cautionary tale, 8 October 2015, available: http://thebulletin.org/watts-bar-unit-2-last-old-reactor-20th-century-cautionary-tale8783.
30 Ibid, page 28.
31 Hossen, M.M., Kang, S., and Kim, J., (2015), Construction schedule delay risk assessment by using combined AHP-RII methodology for an international NPP project, Nuclear Engineering and Technology volume 47 (3), page 363.
32 Mail and Guardian, Sinking into Eskom's black hole, 6 February 2015, available: https://mg.co.za/article/2015-02-05-sinking-into-eskoms-black-hole%20%5b2016.

labour costs, productivity and material costs[33]. Conversely, the renewable technologies cost comparison uses actual Bid Window prices, which is based on long-term contractual prices between Eskom and IPPs. To the extent that the EPRI cost data understates the adjustments required to account for South African factors, the cost comparison analysis is likely to understate the cost competiveness of renewable technologies.

Nuclear technology is only selected by the model in the least-cost option when the 2 artificial / erroneous assumptions regarding the cost and build-rate of wind and PV technologies are included. As indicated above, by simply including more realistic cost and build-rate assumptions, the nuclear technology is never selected the least-cost scenario. Other nuclear points:

In addition, a flexible approach which allows new supply to come on-line rapidly and in smaller quantums manages technology, fiscal and over-supply risk much better. Large nuclear plants (there are no small nuclear plants) expose the country to being locked-in to a single technology and a “scale problem”.

IRP constraints on Renewable Energy

The base case modelled in the Draft 2016 IRP has self-imposed limits placed on annual new build of Wind and Solar PV. These constraints are 1,600 MW of Wind and 1,000 MW of Solar PV per annum.[34] No reasons for these constraints are given, except for the fact that these constraints were imposed as a result of “Government policy positions” in the 2010 IRP and have been maintained in the Draft 2016 IRP.[35] The 2010 IRP indicated that these constraints were introduced in the Balanced Scenario (and later in the Revised Balanced Scenario) and not in the base case.[36]

Furthermore, no reasons for these constraints were given in the 2010 IRP and thus it is not clear why these constraints were originally imposed and why it is necessary to maintain them in the Draft 2016 IRP. Note that constraints are only placed on Wind and Solar PV in the 2016 base case, and all other technologies are unconstrained.

These constraints are specified as an annual limit on the Renewable Energy capacity added to the grid, as opposed to a proportion of the total capacity of the grid i.e. these limits are constant over a 30 year period even as the power system almost doubles in size from 44,916 MW (system peak load) in 2020 to 85,804 MW in 2050.[37] Thus, as the grid grows to 2050, the proportion of energy added to the grid annually from Wind declines from 3.6% in 2020 to 1.9% in 2050, and that from Solar PV declines from 2.2% in 2020 to 1.2% in 2050.

BUSA believes that to essentially reduce the proportion of the renewable elements of the electricity generation mix over the period of the IRP is contrary to international trends and cannot be justified by the current costing of these technologies, particularly over the longer term.

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[33] EPRI 2015, page 1-3
[34] Draft 2016 IRP, page 24.
[35] Draft 2016 IRP, page 24.
[36] See 2010-30 IRP, table 6, page 24.
[37] Draft 2016 IRP, page 26.

As argued elsewhere in this submission of the least cost case was used as the base case the reduction on the proportion of renewable energy would not have materialized.

GRID CAPACITY CONSTRAINTS

As stated above, no reasons have been cited in the Draft 2016 IRP and its accompanying presentations for the annual limits placed on Wind and Solar PV capacity additions. In addition, no official explanations for these limits in any other DoE policy or other documentation can be found. The DoE and Eskom have indicated in public consultations and in the media that there are grid capacity constraints for Renewable Energy capacity additions and that Renewable Energy technologies are generally less reliable and stable. We deal with each of these points in turn below.

According to the DoE, the issue with connecting Renewable Energy capacity to the national electricity grid is that Renewable Energy projects tend to be in isolated places with insufficient connection points.[38] Further complications arise because of delays in securing sites and servitudes as well as obtaining the necessary environmental and other statutory approvals, which have been highlighted in Eskom's latest Transmission Development Plan ("TDP").[39]

In this regard, BUSA wishes to state that:

Firstly, no evidence has been found to support these claims. The public needs to understand the extent of these constraints, and where in the country they exist. The link between the constraints placed on Wind and Solar PV in the base case needs to be quantified so that the final IRP is based on sound information.

Secondly, no other technologies are constrained in the base case. The issues arising from connecting Wind and Solar PV to the grid should also apply to other renewables such as Solar CSP. Similarly, grid capacity constraints should also apply to conventional technologies, such as Coal and Nuclear plants, which can be bulky in terms of their capacity relative to the size of the grid and particularly in the case of nuclear are likely to be located in relatively isolated places, as is the case for renewable projects.

Despite what has been reported in the media, it appears that Eskom intends to facilitate the connection of Renewable Energy sources to the grid. According to the aforementioned TDP, Eskom is committed to connecting Renewable Energy (and conventional) Independent Power Producers ("IPPs") to the grid, both in the short- to medium-term, and in the long-term. Long-term plans include the creation of Renewable Energy Development Zones ("REDZ") and Power Corridors, and in February 2016 eight REDZ and five Power Corridors were gazetted.[40] According to the Department of

[38] See for example Greve, N. (16 February 2017) Playing dirty with clean energy: How government is putting jobs and investment at risk", Finweek.

[39] Eskom (2016) Transmission development plan 2016-2025, pg. 3: http://www.eskom.co.za/Whatweredoing/TransmissionDevelopmentPlan/Documents/TransDevPlan2016-2025Brochure.pdf.

[40] https://www.environment.gov.za/mediarelease/cabinet_gazetting_redz.

Environmental Affairs ("DEA"), the REDZ and Power Corridors are geographical areas where Wind and Solar PV capacity will be incentivized by directing grid expansion and streamlining regulatory processes.[41]

REDZ: Eight areas have been identified in the country (two each in the Western Cape, Eastern Cape and Northern Cape; one in the North West, and one traversing the Free State and Northern Cape) where Renewable Energy technologies can be developed in concentrated zones. This will facilitate a focused expansion of the grid, as well as accelerating connection by reducing the waiting time for an Environmental Assessment from 300 to 147 days i.e. only a basic assessment will be required and not a full Environmental Impact Assessment ("EIA").

Power Corridors: Five power corridors have been identified – one running from the south to the north of South Africa, one along the east coast and one along the west coast, and two providing connections with Botswana, Namibia and Zimbabwe to accommodate imports and exports of electricity. It is anticipated that it will take eight years to construct these corridors. As with the REDZ, the development of these corridors will speed up grid connections as only a basic assessment will be required and not a full EIA.[42]

The costs of transmitting and distributing electricity do not form part of the IRP process, but intuitively they would impact on total costs which would feed into the final decision making on appropriate technologies. However, according to the 2010 IRP, technology choices should not be impacted upon by transmission costs. In the discussion of network issues in the 2010 IRP, the following was noted:

"Transmission and distribution costs are not included in the modelling. These costs are not covered under the new scenarios as the forecasting is not disaggregated into local areas. The costs are not a significant part of the overall costs of supply, especially the transmission costs, and would not particularly skew the technology choices."[43]

[Emphasis added]

Grid capacity constraints and grid costs may be a factor in the choice of technologies, but these need to be unpacked properly in order for the full extent of the issues to be understood. If these do limit the amount of Wind and Solar PV that the grid can accommodate, then these should be modelled as a scenario in the next phase of the modelling.

[41] Ibid.
[42] https://www.cliffedekkerhofmeyr.com/export/sites/cdh/en/news/publications/2016/projects/downloads/Projects-and-Infrastructure-Alert-25-February-2016.pdf.
[43] 2010-30 IRP, page 37.

UNRELIABILITY AND INSTABILITY OF RENEWABLE ENERGY TECHNOLOGIES

The premise that Renewable Energy technologies are unreliable and unstable in South Africa has been challenged in a recent study by the CSIR.[44] This comprehensive study examined Wind and Solar PV resources across the country and made the following observations:

Wind and Solar resources across the country are both "extremely good", and Wind resources are better than previously believed[45];

Wind and Solar PV are on a par in terms of magnitude and cost competitiveness;

Wind and Solar PV can be built as complementary technologies, as Wind supply peaks in the evening and Solar PV in the middle of the day;

There is low seasonality in both Wind and Solar resources in South Africa;

Wind farms should be located across the country, as "(s)hort term fluctuations in the aggregated Wind power feed-in are significantly reduced by wide spatial distribution".[46]

The CSIR indicates that there is further work to be done on this subject, but their analysis suggests that Renewable Energy technologies are more reliable and stable than previously believed. If reliability of Renewable Energy technologies is still a concern for the DoE, this should be modelled as a scenario as opposed to in the base case, as the latest scientific research shows that Wind and Solar PV are in fact reliable.

The case for Renewable Energy

The international trends discussed above confirm that the case for increasing the use of Renewable Energy technologies is strong. The advantages of Renewable Energy technologies over traditional technologies which use fossil fuel sources are well known. These include the reduced environmental impact in terms of CO_2 and other emissions, lower operational costs and socio-economic benefits.

As highlighted in the section on technology costs, there are compelling cost reasons for the increased use of Renewable Energy technologies in South Africa. Also, the discussion above regarding the reliability and stability of Renewable

[44] Knorr et al (2016) Wind and Solar PV Resource Aggregation Study for South Africa: Final Report: https://www.csir.co.za/sites/default/files/Documents/Wind%20and%20Solar%20PV%20Resource%20Aggregation%20Study%20for%20South%20Africa_Final%20report.pdf. This study conducted by the CSIR in collaboration with the South African Energy Development Institute, Eskom and the Fraunhofer Institute for Wind Energy and Energy Systems in Kassel, Germany.

[45] More than 80% of South Africa has enough Wind for high load factors.

[46] Dr. Stefan Bofinger, Britta Zimmermann, Ann-Katrin Gerlach – Fraunhofer IWES, Dr. Tobias Bischof-Niemz, Crescent Mushwana – CSIR (3 March 2016) "Wind and Solar PV Resource Aggregation Study for South Africa: Public presentation of results." http://www.wasaproject.info/docs/PVWindAggregationstudy.pdf.

Energy technologies indicates that these traditional concerns should be reevaluated by decision makers. In addition, the following facts enhance the case for the increased use of Renewable Energy:

Lead times are shorter than that for Coal and Nuclear, which make the building of Wind or Solar PV farms more flexible and thus more responsive to changing demand conditions, which is important in an economy where there is a lot of uncertainty surrounding future electricity demand. In South Africa, a flexible plan should be preferable, where there is scope to review electricity demand over the years and change new build plans accordingly. Wind and Solar PV fits the criteria for technologies that are less lumpy and have shorter lead times.

The Renewable Energy Independent Power Producer Procurement Programme ("\REIPPPP") has achieved great success in procuring Renewable Energy capacity since 2013. To date, 98% of IPPs scheduled to be operational started commercial operations, with the average lead times for these projects at 1.9 years.

Finally, there is scope for reductions in transmission costs if Renewable Energy projects are installed close to end-consumers.

THE CASE FOR COGENERATION

There have been two Ministerial Determinations for Cogeneration totalling 1 800 MW and two rounds of RFPs for the procurement of this power. The response to the two RFPs by the cogeneration developers has not been good, with only one small project reaching preferred bidder status. The RFPs were intended to capture the potential of existing installations but were inappropriately structured to achieve this objective.

The 2015 GIZ sponsored Cogeneration study referred in the "Cogeneration Cost Assumptions" section above identifies a potential of over 5 500 MW (larger than a Medupi or Kusile). The potential lies in a variety of industries where both heat and power is required, and the heat is currently being produced separately to the purchase of grid power. The biggest potential lies in SA's chemical industries (1 580 MW), but sugar, pulp and paper, commercial and industrial buildings and iron and steel each have potentials of over 500 MW each.

The same study highlights the benefits of energy generation from cogeneration sources and it is worth repeating these benefits here to be reminded of the multiple benefits of cogeneration. -

"In summary cogeneration offers:

- *Energy efficiency gains through improvements in fuel conversion efficiency and the use of waste resources and fuels.*
- *Reduction in Utility infrastructure investment due to decentralisation of energy production, as well as Transmission and Distribution equipment*
- *Reduced Transmission and Distribution losses*

- *Fuel saving by improved thermal efficiency compared to Eskom coal generation*
- *Reductions in greenhouse gas emissions (CO_2)*
- *Economic benefits due to reduction in power outages, avoided costs of back-up power and reduced energy costs.*
- *Opportunities for creating employment in the Industrial Sector*
- *Reduces the burden on Eskom and the State in project development, financing and project risks of electricity generation.”* [23]

In concluding the case for Cogeneration, it is recommended that Cogeneration should be included in the Base Case.

THE CASE FOR EMBEDDED GENERATION

The draft licensing exemption and registration notice published on 2 December for public comment stated the intention for the IRP to specify an allocation for embedded generation facilities up to a total of 10MW in installed capacity.

BUSA believes that this intention should be reflected in the revised IRP and that the allocation should be reconsidered on the following basis:

Embedded generation comprises a range of different technologies, one of which is cogeneration as referred to above.

It is proposed that the allocation should be based on the realities of different embedded technologies. The cap of 10MW as contemplated in the notice referred to above is significantly lower than what would be appropriate. For example, given that investments in Roof Top PV, of the order of 150 MW – 200 MW pa are currently taking place as investors see the potential in cheaper power from their own generation and so off-setting more expensive grid power, a more appropriate cap for this embedded technology would be 200 MW. In respect of cogeneration the amounts referred to above are significantly higher than 10MW, which should also be taken into account if the intention referred to above is to be implemented. It is clear from these two examples alone, that a much more consideration of this issue is required. Another approach would be to have a single allocation for embedded generation but to set the cap at a realistic level, particularly given what is already happening in the market.

<u>Other Assumptions</u>

The Draft 2016 IRP base case scenario contains a number of macroeconomic assumptions, including demand forecasts, discount rate and the $US/ZAR exchange rates. BUSA’s assessment of these assumptions is detailed below.

Demand forecast

The Draft 2016 IRP uses expected demand as forecast by the CSIR in its Demand Forecast Report.[47] The update uses the CSIR's "high (less energy intense)" forecast which is lower than that used in the 2010 IRP. The figure below shows the wide spread of forecasted demand, depending on the assumptions and economic growth scenarios considered.

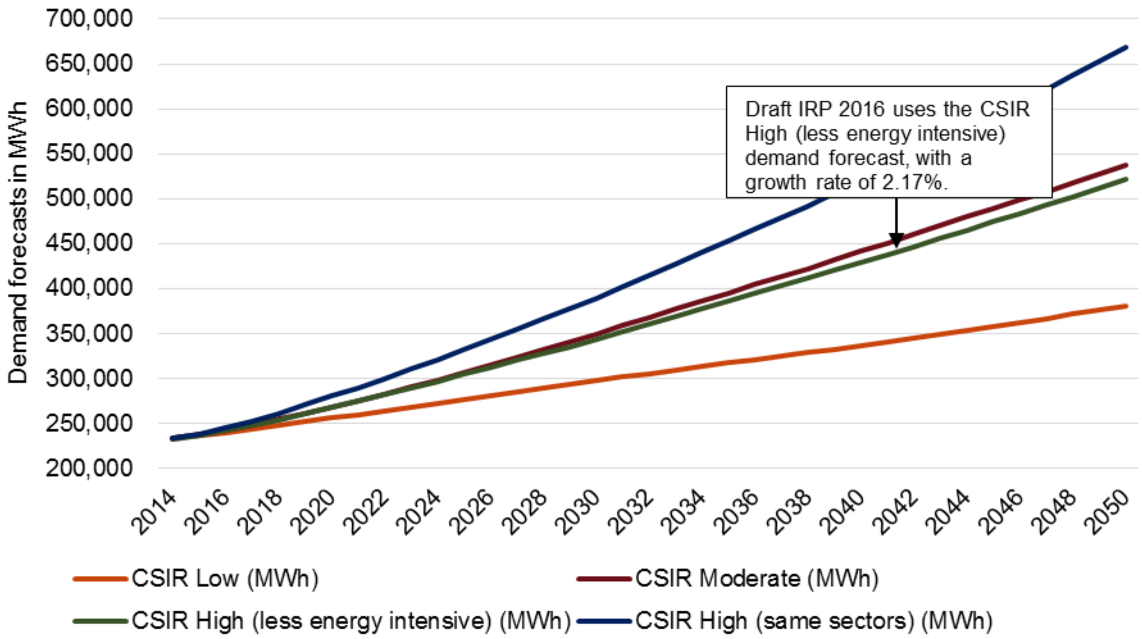

Figure 4: Forecasted demand in MWh (2014 – 2050)

Note: The CSIR High (less energy intensive) is the demand forecast used in the Draft 2016 IRP.

Source: Draft 2016 IRP, pg. 9.

With a changed electricity landscape the underlying trend indicates a lower projected demand trajectory relative to previous planning assumptions. Electricity demand in 2030 is now projected to be in the range of 297,459 - 389,904 MWh as opposed to 454,357 MWh projected in the policy-adjusted IRP2010.[48]

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[47] Forecasts for electricity demand in South Africa (2014 – 2050) using the CSIR sectoral regression model, page 16. Accessed: http://www.energy.gov.za/IRP/2016/IRP-AnnexureB-Demand-forecasts-report.pdf.

[48] 2010-30 IRP, page 51.

It is critical that the projected demand in an IRP is as accurate as possible, as the implications for a mistake in projecting demand are non-trivial. If demand is over estimated this leads to wasteful investments in too much capacity, and if underestimated this leads to electricity shortages.

Firstly, no justification was given in the Draft 2016 IRP as to why the CSIR High (less energy intensive) demand forecast was chosen over the other demand projections undertaken by the CSIR. The CSIR itself does not specify its preferred forecast to be used in the base case in its Demand Forecast Report.

Secondly, there are concerns that projected demand may still be too high, despite the downward shift in the demand curve between 2010 and 2016. The fall in demand in the latest IRP implies less capacity is required in the latest IRP. Despite this, there are concerns that the projected demand growth of 2.17% per annum between 2016 and 2050 is still too high. For example, Eskom's projected demand in this period is between 0.4% and 1.8%.[49] In order to assess these concerns, the following analyses were undertaken:

Compared the projected energy demand in the 2010 IRP to actual energy demand from 2010 to 2016 to determine how previous modelling undertaken in the IRP has fared against figures actually realised;

Examined current developments in the energy market to determine factors that may influence demand in the future.

Accuracy of previous demand projections used in the IRP

The demand projections used in the 2010 IRP were much higher than actual electricity demand between 2011 and 2015. The figure below shows projected versus actual national electricity demand for 2011 to 2015. This result indicates that there has been overestimation of electricity demand in the past and thus care needs to be taken that this does not occur in the latest IRP.

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[49] Initial comments on IRP and IEP. Energy Research Centre. Presented at consultation workshop convened by Department of Energy. 13 December 2016. Cape Town. Accessed: http://www.energy.gov.za/irp/irp-presentaions/cape-town/ERC-Initial-comments-on-IRP-and-IEP.pdf.

[50] 2010-30 IRP, page 51.

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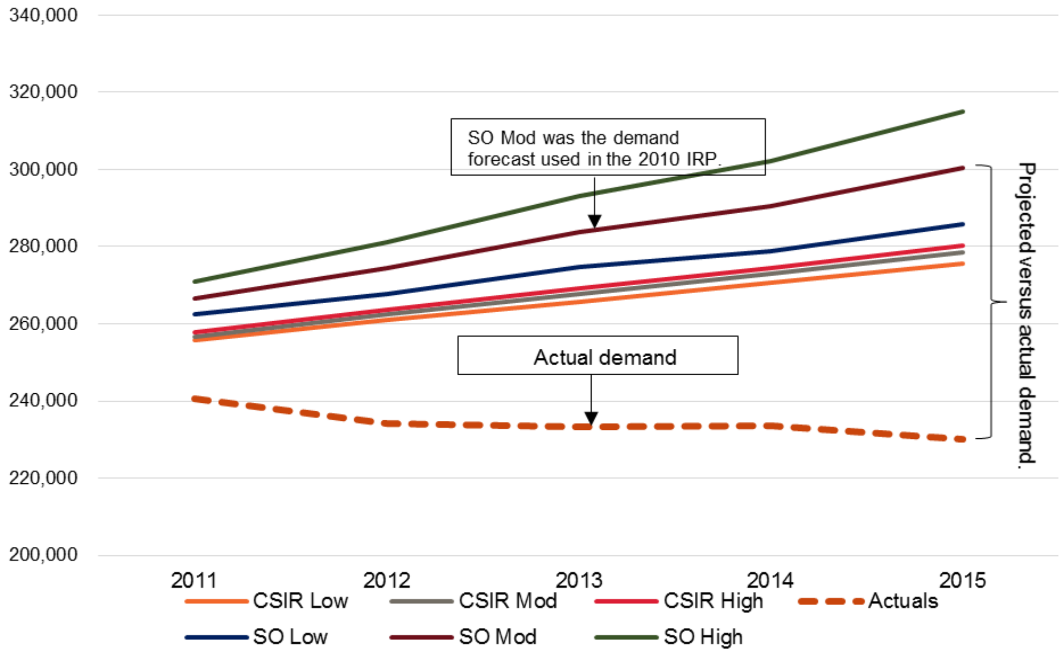
[51] Initial comments on IRP and IEP. Energy Research Centre. Presented at consultation workshop convened by Department of Energy. 13 December 2016. Cape Town. Accessed: http://www.energy.gov.za/irp/irp-presentaions/cape-town/ERC-Initial-comments-on-IRP-and-IEP.pdf.

Figure 5: Forecasted vs. actual demand MWh (2011 – 2015)



Note:

System Operator Moderate was the demand forecast used in the policy-adjusted 2010 IRP.

Source: StatsSA (for actual), 2010 IRP (forecasts)

Factors impacting future demand

The demand for future grid based electricity will be subject to a number of uncertainties, given the significant forces and technologies at play both now and in the next years ahead to 2050, such as rapidly rising Eskom electricity prices, the possibility of further significant cost reductions for Solar PV, and grid-defection and energy switching for example to Gas power, which are not factored into demand projections.[52]

Embedded generation refers to generating electricity at a specific location and connecting the generated electricity to the electricity network. Generation technology used for embedded generation includes OCGT, hydro, Wind and Solar PV.[53] There is anecdotal evidence to suggest that both individuals and businesses are increasingly looking at Small Scale

[52] Energy Intensive Users Group. High-level Comment on the Draft IRP Base Case. December 2016. Accessed: http://www.energy.gov.za/IRP/irp-presentaions/High-level-Comment-on-the-Draft-IRP-Base-Case-EIUG.pdf.

[53] TasNetworks, available: https://www.tasnetworks.com.au/our-network/new-connections-and-alterations/embedded-generation-and-information-packs/.

Embedded Generation (SSEG) options such as Solar Photovoltaics (PV) to provide electricity on-site.[54] This was also recognized in the unpromulgated 2013 update of the IRP, which states the following:

Given the recent reduction in the cost of photovoltaic generation it has become highly probable that electricity consumers (commercial, residential, and to some extent industrial) will begin installing small-scale (predominantly roof-top) distributed generation to meet some or all of their electricity requirements.[55]

[Emphasis added]

The 2013 IRP update projects that by 2050 there will be 30,000 MW of SSEG installed capacity[56] in South Africa, which equates to 23% of the total new build options installed capacity in the Draft 2016 IRP.[57] This is a significant amount of SSEG anticipated, and it is not clear if this has been taken into account in the demand projections used in the Draft 2016 IRP update.

The draft licensing exemption and registration notice regulations for comment, stated the Government's intention to specify an allocation for embedded generation facilities of up to 10 MW installed capacity in the IRP. This proposed provision is intended to facilitate the licensing or registration of these facilities thus removing the need for the Minister to consider applications for deviation from the IRP for these facilities. While the intention is in principle supported the unintended consequence of the draft regulations which extend the regulatory requirements to all own generation which was not previously the case needs to be addressed.

Impact of overestimating demand

If projected demand over the IRP period is overestimated, additional capacity will be built prematurely and Eskom would incur unnecessary capital costs and/or IPP costs. These costs would have to be recouped from Eskom's revenue allowance, and may result in an unsustainable electricity price path. If Eskom is unable to price up to this level due to adverse demand responses, the excess capacity will result in Eskom not being able to recoup sufficient revenue to cover its costs, placing further strain on its finances.

An accurate estimation of future demand is perhaps the single most important factor to consider. Overestimation exposes the country to a series of interlinked risks, not the least of which is an ever-increasing tariff path.

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[54] See, for example: http://www.fin24.com/Economy/Consumers-will-eventually-produce-their-own-power-PwC-20150423 which reports that, according to a 2015 PricewaterhouseCoopers (PwC) report, "Consumers in the future will likely produce their own power to the point of self-sufficiency."
[55] IRP 2013 update, page 33.
[56] IRP 2013 update, figure 23, page 33.
[57] Draft 2016 IRP, Table 12, page 26 shows that in 2050 there will be a total of 128,927 MW of new build installed capacity.

DISCOUNT RATE

One of the main economic parameters used for the Draft 2016 IRP is the discount rate, which is the rate applied to the capital investments made to add generation capacity. The DoE have assumed a "net discount rate before tax" of 8.2%", which it claimed was calculated by the National Treasury for the IEP process. This rate is expressed in real terms, i.e. net of inflation.

The IRP assumed discount rate differs slightly from the IEP assumed rate of 8.4%, which was also sourced from the National Treasury.[58] Ideally, both discount rates should be consistent as even slight adjustments to the discount rate can make material differences in the LCOE for technologies that are capital intensive, such as Wind and Solar PV.

Deriving accurate discount rates is crucial for the development of the IRP as it is a key component of the LCOE estimate. The higher the discount rate, the higher the capital costs for any given technology. Capital intensity (capital costs as a percentage of LCOE) differ markedly across technologies, which reflects the variances in overnight construction cost per MW of capacity built. As shown in Table 9, the proportion of the LCOE made up of capital costs varies from 62% for Coal FBG to 95% for Solar PV.

Table 9: Comparison of capital cost intensity across generation technologies

	Coal with FGB	Nuclear Areva EPR	Wind	Solar PV
Capacity	750 MW	1600 MW	100 MW	10 MW
Capital costs (ZAR/MWh)	733.9	1,603.0	1,921.1	2,642.2
LCOE (ZAR/MWh)	1,187.9	1,959.6	2,219.1	2,781.9
Capital costs percentage	61.8%	81.8%	86.6%	95.0%

Source: EPRI: Power Generation Technology Data for Integrated Resource Plan of South Africa, pages xi to xviii

The above table emphasises the importance of deriving the correct discount rate for the IRP. If the discount rate is overstated, generation technologies with relatively low capital cost percentages become more attractive (i.e. Coal). Conversely, an understated discount rate favors the use of technologies with relatively high capital cost percentages (i.e. Wind and Solar PV).

The majority of the generation capacity currently being added to the grid is done by Eskom, which is regulated by NERSA. In its most recent tariff determination (MYPD3), NERSA provided for a real pre-tax cost of capital of between 3.4% and 4.7%, which it claimed was sufficient to enable Eskom to meet its debt obligations.[59] A strict application of

[58] Integrated Energy Plan, Department of Energy, page 59.

[59] NERSA Decision on Revenue Application – Multi Year Price Determination 2013/14 to 2017/18 (MYPD3), Table 9.

NERSA's tariff methodology would have provided Eskom with a real pre-tax WACC of between 5.14% and 7.65%, which is materially below the IRP assumed rate of 8.2%.[60]

Given the sensitivity of LCOE estimates to the discount rate assumed, and the magnitude of the variance between the Draft 2016 IRP assumed discount rate and the NERSA allowed MYPD3 discount rate, an additional IRP scenario is required that assumes a lower discount rate. A lower real discount rate is justified by the relatively low systemic risk of electricity generation and the relatively low cost of debt incurred by Eskom. Although the Draft 2016 IRP period extends to 2050, all inflationary risk is eliminated by virtue of the discount rate being expressed in real terms and Eskom's Regulatory Asset Base being indexed by the CPI each year. An IRP scenario that assumes a real pre-tax discount rate of around 6.4% (median of 5.14% and 7.65%) would make Renewable Energy technologies significantly more attractive.

EXCHANGE RATE

Another important economic parameter used for the IRP is the exchange rate. The Draft 2016 IRP assumes a ZAR/$ exchange rate of 11.55, which was the prevailing exchange rate in January 2015. The DoE states that the assumed rate will be changed to reflect the current rate in the final plan, and adds that the rate used does not matter as "this is a comparative analysis and all options are impacted equally."[61]

The exchange rate assumption will impact on all cost variables for all generation technologies as they are all expressed in $US by EPRI, including capital cost, fuel costs (e.g. Coal and Gas), fixed costs and variable operations and maintenance (O&M) costs. The weaker the exchange rate assumed over the period, the higher the LCOE for each type of generation technology. If the assumed exchange rate is constant over the period, then the effect on the LCOE (in ZAR terms) will be the same on all technologies.

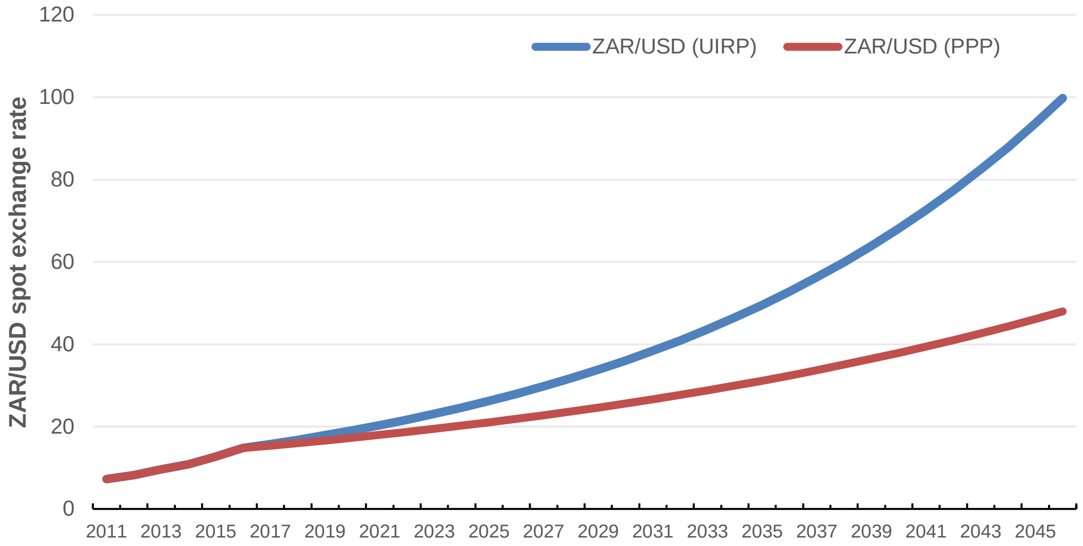
However, when the exchange rate changes over time, the relative change in the LCOE (in ZAR terms) will differ across technologies. This is because certain generation technologies have a greater portion of its costs incurred at the beginning of their economic lives, i.e. those technologies with greater capital intensity. For example, if the ZAR were to depreciate over the Draft 2016 IRP period, then the LCOE will increase further for lower capital intensive technologies relative to higher capital intensive technologies. This is because a greater portion of costs are incurred later in the Draft 2016 IRP period, when the ZAR is weaker.

The long-term weakening of the ZAR against the $US can be assumed credibly by referring to the differentials in long-term South Africa and United States government bond yields and applying the uncovered interest rate parity formula.[62]

[60] Depending on the risk-free rate used – see NERSA Decision on Revenue Application – Multi Year Price Determination 2013/14 to 2017/18 (MYPD3), Table 8.
[61] Draft 2016 IRP, page 10.
[62] The interest rate parity states that the average annual depreciation in the ZAR can be forecast using the annual differences in SA and US forward interest rates. We used SA and US 30-year government bond yields.

The weakening of the ZAR against the $US can also be assumed by referring to the differentials in long-term inflation expectations between South Africa and the United States and applying the purchasing power parity formula.[63]

Figure 6: Comparison of forward looking ZAR/$US exchange rate (Uncovered interest rate parity vs. purchasing power parity)



Source: Genesis calculations using Bloomberg, SARB and US Federal Reserve data

Under the ZAR depreciation scenarios as shown in Figure 6, the generation technologies with higher capital intensities become more attractive as a means of providing generation capacity. This is because a greater portion of the ZAR levelised cost of the generation asset is incurred at the beginning of the period when the ZAR is relatively strong. Accordingly, the Draft 2016 IRP should consider amending its constant ZAR/$US assumption in its base case, or alternatively develop another scenario that assumes the long-run weakening of the ZAR against the $US.

COST OF UNSERVED ENERGY

The IRP lists the "Costs of Unserved Energy" (COUE) as one of the key economic parameters. The COUE is the value (in ZAR per kWh) assigned to a unit of energy not supplied due to an unplanned outage of short duration. The COUE value assumed in the Draft 2016 IRP is R77.3/KWh, which the DoE claim is based "on a NERSA study".[64] No

[63] The purchasing power parity states that the average annual depreciation in the ZAR can be forecast using the annual differences in SA and US expected inflation rates. We used SARB and US Federal Reserve target inflation rates.
[64] Draft 2016 IRP, page 10.

explanation is provided on how this COUE estimate was calculated and whether this estimate is applied throughout the whole Draft 2016 IRP period. This explanation is important as COUE estimates are inherently difficult to measure as they are typically derived from customer research. In addition, estimates differ markedly across industry sectors.

Further, it is not clear from the Draft 2016 IRP how this economic parameter is a relevant consideration for determining the generation mix. According to the 2010 IRP Input Parameter information sheet, the COUE can assist in "*deciding on the optimum level and mix of plant to invest in."*[65] However, the same document states that the COUE range in 2010 was between R35/KWh and R150/KWh, which means that any COUE estimate is likely to be well above the LCOE for all types of generation technology. The document also states that "*the optimal reserve margin is relatively insensitive to the real value of COUE'.*[66]

The optimal reserve margin should be based on the generation capacity needed to meet contingencies such as unplanned equipment outages and unexpected fluctuations in demand, and planned outages for plant maintenance. This is an operational consideration that should be assed independently of any estimate of COUE.

COST OF EXTERNALITIES

The costs of externalities are presented in Table 11 of the Draft 2016 IRP. Externalities were not taken into account in the 2010 IRP base case[67] but it is not clear if they were taken into account in any of the 2010 scenarios. Externalities are costs and benefits that do not accrue to the parties involved in an activity and can include a number of different costs and impacts, as have been included in the Draft 2016 IRP. Including externalities in the Draft 2016 IRP may have a significant effect on the viability of different generating technologies, as studies that attempt to monetize them show.[68]

In general, including externalities in the Draft 2016 IRP will add to the cost of fossil fuel technologies. Carbon emissions have been given a zero-externality cost in the Draft 2016 IRP, whilst costs have been provided for nitrogen oxides (NOx), sulphur oxides (SOx), mercury (Mg) and particulate matter (PM). However, it is not clear from the Draft 2016 IRP how these costs are incorporated into the model and how they impact on costs. This should be detailed in the next version of the IRP.

The omission of an externality cost for CO_2 will reduce the cost of Coal and thus bias the use of Coal technology in the generation mix. The Draft 2016 IRP uses a zero-carbon dioxide cost and instead applies a maximum annual limit to CO_2 emissions as a means to incorporate South Africa's emission's targets into the model. As a result, Coal is not penalized for CO_2 emissions, until the limit is reached. Excluding CO_2 emissions reduces the Coal cost.

[65] Cost of Unserved Energy (COUE) - 2010 IRP Input Parameter information sheet (Supply input), page 2.
[66] Cost of Unserved Energy (COUE) - 2010 IRP Input Parameter information sheet (Supply input), page 3.
[67] 2010-30 IRP, table 6, page 24.
[68] See for example: Roth, I.F. and Lambs, L.L. 2004. Incorporating externalities into a full cost approach to electric power generation life-cycle costing. Energy (29). pages 2125-2144.

Additional externalities related to Coal ignored in the Draft 2016 IRP include the existing environmental levy, the pending carbon tax, and considerable other externalities such as the cost of negative health impacts. These would further add to the cost of Coal if included in the model.

Finally, it is unclear if and how the Draft 2016 IRP has quantified and incorporated water externalities.

UPDATE SCENARIOS TO BE MODELLED

Section 6 of the Draft 2016 IRP contains 11 suggested update scenarios that the DoE intends to model to "inform the policy adjustment of the IRP update". Presumably, each of these scenarios will comprise of a change to one the key assumptions used in the base case. For these assumptions to be useful in informing Government and other stakeholders of the tariff implications of adopting certain policy objectives, it is crucial that the capacity and cost assumptions for each of the scenarios are specified. These assumptions should be disclosed in the next draft of the IRP.

The following proposed scenarios are supported.

Low demand trajectory

Embedded generation (Rooftop PV) and

Electricity Network Implications.

Comments on the other proposed scenarios are as follows.

As indicated above it is imperative that these scenarios are modelled as adjustments to the least cost case.

Carbon budget as an instrument to reduce GHG emissions.

Under a least cost base case scenario where there are unconstrained additions of Renewable Energy, there should be no requirement for an alternative scenario that limits GHG emissions. This is because the majority of new additions would be met with Wind and Solar PV, which represents the most cost effective option according to CSIR. However, if there is doubt about this it is recommended that the carbon trajectory which result from the least cost case should be compared against the desired carbon trajectory over the period of the IRP and if additional carbon constraints are required they can be modelled separately as a policy adjustment to the least cost case.

The use of the term "carbon budget" in the context of the electricity sector is not understood as carbon budgets are a mitigation instrument imposed on individual entities not on sectors. The recently released report on the national mitigation system make this clear. It is suggested that the approach set out in this report be used as the basis of developing the carbon constraint that should be imposed on the sector. In addition, the increase in the cost of electricity generated from fossil fuels as a result of the imposition of a carbon tax should be modelled as a separate scenario, if it is not included in the least cost case.

Primary fuel price tipping point (Coal, Gas, Nuclear). Again, this scenario would not be required where there are unconstrained additions of Renewable Energy. If the DoE insists on modeling the tipping points of costs for conventional technologies, it should focus on overnight capital costs rather primary fuel costs. The assessment of the Draft 2016 IRP Nuclear cost assumptions (Table 8) shows that the overnight capital cost estimates are likely to be understated. Also, given the high sunk costs and long lead times involved in constructing Coal and Nuclear plants, it is not clear how primary fuel price tipping points would alter the capacity build once they have commenced. If the DoE insists on modelling this scenario, it should disclose clearly what the primary fuel price tipping points are and how they affect capacity additions and the tariff path.

Low Eskom plant performance. The Draft 2016 IRP states that a "moderate to low plant performance" will be used in the base case.[69] It is not clear how this would differ materially from the "low Eskom plant performance" scenario that is also listed in the document. Rather, this scenario should model "high plant performance" to reflect the impact that lower plant performance (utilised in the base case) has on electricity costs over the IRP period.

Regional options (Hydro, Gas). It is not clear what is meant by "Regional", i.e. whether it refers to regions within South Africa or Southern Africa. If the former, then significant regional development opportunities already exist under the Draft 2016 IRP base case. This scenario contains 17,600 MW of Solar PV, which can be deployed throughout South Africa given the abundant Solar radiation potential across the country.[70] The existing REIPPPP is already targeted towards local community development, and its aims are stated as "*socio economic and enterprise development, local ownership and local job creation*"[71]. Presumably, this programme will be expanded significantly for the new Solar PV roll-out, even under the constrained Renewable Energy assumptions applied for the base case.

The IEP 2016 emphases the significant employment and localization potential of Solar PV:

"Solar technologies also present the <u>greatest potential for job creation and localization</u>. Incentive programmes and special focused programmes to promote further development in the technology, as well as solar roll-out programmes, should be pursued."[72]

[Emphasis added]

If "Regional" refers to Southern Africa, then our suggestion is that the IRP 2016 is limited to South Africa capacity additions only given that the document is meant to be a long-term planning tool for the South African electricity industry.

Un-constrained Renewable Energy. As argued repeatedly in this report, the base case scenario should contain <u>unconstrained</u> Renewable Energy additions. To the extent that the DoE is concerned about potential implications of unconstrained Renewable Energy on the grid, this should be modelled under the proposed **Electricity Network Implications** scenario, which would limit the additions of Renewable Energy capacity to levels utilised under the base case.

[69] Draft 2016 IRP, page 11.
[70] http://www.energy.gov.za/files/esources/renewables/r_Solar.html.
[71] WWF: A review of the local community development requirements in South Africa's Renewable Energy procurement programme (2015), page 2.
[72] IEP 2016, page 19.

The main purpose of the IRP is to determine the long-term electricity demand for South Africa and to plan how this demand should be met in terms of generating capacity, type, timing and cost[73]. In light of this defined purpose, the Draft 2016 IRP should asses and consider material exogenous factors that can potentially affect timing and cost of new generation capacity. For this reason, the **Additional Sensitivity Analysis** scenarios in the Draft 2016 IRP should model the effects of these factors on available capacity and costs. These factors include changes to macroeconomic variables, constraints on the additions of renewable technologies, delays in the construction of conventional technologies and the availability of primary fuels. Specifically, the Draft 2016 IRP should include the following scenarios in addition to the proposed base case scenario:

Constrained Renewable Energy. We argue in this report that the case for increasing the use of Renewable Energy technologies is strong and that the removal of Renewable Energy constraints in the base case is consistent with developing a least cost option. As explained above, CSIR have calculated that a base Case without Renewable Energy constraints would be R90 billion per year cheaper by 2050 than the current Draft 2016 IRP base case. If potential grid capacity constraints and the reliability of Renewable Energy remains a concern (despite evidence to the contrary), then these constraints should be incorporated as an additional scenario, and not as part of the base Case. This scenario would highlight to stakeholders the cost implications of a constraining Renewable Energy on the grid.

Western Nuclear costs: There remains significant doubts regarding the cost competitiveness of Nuclear. The Draft 2016 IRP assumes Asian costs, which are significantly lower than the Nuclear costs observed in Western countries. More specifically, the Draft 2016 IRP assumes lower overnight capital cost and variable O&M costs than those observed in Western countries. If these assumptions are not applicable to South Africa, the base case scenario will incorrectly infer that Nuclear technology is a cost optimal solution. The IEP 2016 states that:

"Controlling the capital costs of nuclear projects is the critical factor if nuclear is to remain a competitive and viable supply option"[74]

Accordingly, if the DoE insists on retaining Nuclear in its base case and assuming Asian costs, an alternative scenario that models the cost of Nuclear using Western cost assumptions is required, particularly in assessing the viability of this technology under more realistic capital cost assumptions. It is noted that the 2010 IRP included a "High Nuclear Cost" scenario[75].

Delayed capacity build for conventional generation technologies. A key feature of conventional technologies (Coal and Nuclear) is the relatively long lead times required for capacity to be built. According to EPRI, Coal and Nuclear require lead times of between 8 or 9 years, which is markedly longer than the lead times of other conventional and Renewable Energy technologies. This makes Coal and Nuclear more vulnerable to delays in construction, particularly given South Africa's lack of experience with constructing Nuclear power plants and its recent performance in constructing Coal plants. As explained earlier, Nuclear technology has a history of delays and cost overruns in other countries. With regards to Coal plants, the IRP 2010 anticipated that all six units of Medupi would be available by 2017[76],

[73] Executive Summary of the Draft Integrated Electricity Resource Plan for South Africa - 2010 to 2030 IRP 2010, 28 October 2010, page 1.
[74] IEP 2016, page 48.
[75] 2010-30 IRP, Table 42
[76] 2010-30 IRP, page 14

whereas the Draft IRP 2016 anticipates the final completion of these units in 2020[77]. Importantly, the Draft 2016 IRP has not taken delays and cost overruns into consideration when determining the predicted cost of Coal and Nuclear technology. Accordingly, an alternative scenario that factors in these potential delays is required so as to reflect their impact on overall costs.

No Shale Gas. The Draft 2016 IRP assumes in its base case that 21,960 MW of CCGT capacity will be added over the IRP period. Apart from Wind, this technology contributes the most capacity additions to the grid. It appears that this capacity is dependent on Shale gas being economically viable and abundant[78]. The IEP 2016 has a "No Shale Gas" Scenario, which tests the impact of Shale Gas being less economically viable than projected "*due to the high uncertainty associated with the levels of recoverable gas"*.[79] In addition, there remains uncertainty around the environmental impacts of Shale Gas, which had halted the granting of licences for exploration[80]. In these circumstances, it would be appropriate to model a scenario that limits the addition of CCGT capacity on the basis that exploration Shale Gas may become unviable. In addition to being consistent with the IEP, this approach would allow the DoE to assess the cost implications of switching to alternative generation technologies.

Depreciating ZAR. One of the main macroeconomic variables that will affect the costs of generation capacity is the exchange rate. As explained earlier, a marked depreciation of the ZAR relative to the $US would substantially increase the ZAR value of expenditure in the later years of the Draft 2016 IRP period. This is particularly relevant for the nuclear build in the base case scenario. This scenario shows that 87% of the proposed 20,385 MW of nuclear capacity is expected to be built after 2040. Even factoring in the relatively long lead times, a significant portion of the nuclear capex will be incurred in the later part of the IRP period. This makes the cost feasibility of proposed nuclear build vulnerable to long-term movements in ZAR. Under a depreciating ZAR scenario, there are cost benefits of adding capacity sooner rather than later.

Low demand. In order to quantify the tariff impact of assuming the CSIR's "high (less energy intense)" demand scenario, an alternative scenario that assumes low demand increases over the IRP period (say in line with Eskom's long-term demand forecast) would be informative. This scenario should assume the same capacity additions as the base case, but with a more realistic demand growth. As explained earlier, an overstatement of demand will mean additional capacity will be built prematurely and Eskom would incur unnecessary capital costs and/or IPP costs. These costs would have to be recouped from Eskom's revenue allowance, and may result in an unsustainable electricity price path.

PROCESS QUESTIONS

The current document makes no reference to the process that will be followed after the comments submitted have been incorporated. It is requested that the consultation process on the results of the scenarios modelled and the final

[77] Draft IRP 2016, page 12
[78] IEP 2016, page 140
[79] IEP 2016, page 140
[80] IEP 2016, page 49

proposed IRP be clearly articulated in a document that is sent to stakeholders while the development of the final IRP is continued.

CONCLUSIONS AND RECOMMENDATIONS

In general, the document contains numerous statements and approaches which are not substantiated. It is recommended that all decisions made as part of the methodology in the final version of the IRP should be substantiated in a transparent way that allows stakeholders to follow the reasoning.

BUSA's analysis has identified several shortcomings of the Draft 2016 IRP document. The cost comparison analysis shows that the cost of Coal has increased markedly since the publication of the 2010 IRP. The Draft 2016 IRP cost assumptions are likely to understate the Nuclear LCOE over the IRP period. Accordingly, the base case scenario, with its continued reliance on Coal and Nuclear, is unlikely to be a cost optimal solution.

In recent years, Renewable energy costs have fallen to levels that are competitive with conventional technologies. Renewable energy also has significant non-cost benefits, such as less lumpy capacity additions and shorter lead times. The constraints on Wind and Solar PV in the Draft 2016 IRP is a major deviation from the approach adopted in the 2010 IRP, where the base case represented an unconstrained least-cost option. Lifting these constraints would eliminate the need for Nuclear under the base case.

In addition, the reduction in ZAR per KW costs appear modest when compared to the learning rates observed from academic literature. For example, in the Draft 2016 IRP, Solar PV costs are expected to fall by only 20% and Wind by 10% over the 35 year IRP period. The learning rates derived from academic literature indicate that costs would decline by a significantly greater margin over that period.[81]

BUSA therefore recommends that the latest actual costs tariff as per Bid Window 4 (expedited) be used for the base case, which should not include any constraints on specific technologies.

There are also potential issues with the macroeconomic assumptions applied in the Draft 2016 IRP. For example, there is a real risk that projected demand over the IRP period is overestimated, resulting in additional capacity being built prematurely and creating an unsustainable electricity price path. In addition, the constant exchange rate assumption has the potential of understating the cost of capacity additions for technologies with long lead times.

The Draft 2016 IRP includes scenarios (such as the Carbon budget, Primary fuel price tipping point and Un-constrained Renewable Energy) that would not be required if constraints on Renewable energy were removed. Alternative scenarios have been identified that would provide better insights into the tariff implications of technology choices and of the consequences of certain macroeconomic assumptions being proved inaccurate. These alternative scenarios include

[81] https://www.andrew.cmu.edu/user/ilimade/Ines_Azevedo/papers/Rubin_2015.pdf. This study established the mean learning rates (i.e. % cost reduction from doubling of cumulative installed capacity) for Solar PV as 12% and 16.5% for Wind. Given that installed capacity is expected to grow exponentially over the IRP period, the reduction in costs is likely to be significantly greater than these percentages.

adopting Western Nuclear costs, assuming delayed capacity build for conventional generation technologies, assuming no Shale Gas exploration, assuming a depreciating ZAR and assuming a low forecast demand trajectory.

Lead times are shorter for renewable technologies than those for Coal and Nuclear, which make the building of Wind or Solar PV farms more flexible and thus more responsive to changing demand conditions, which is important in an economy where there is a lot of uncertainty surrounding future electricity demand. In South Africa, a flexible plan should be preferable, where there is scope to review electricity demand over the years and change new build plans accordingly. Wind and Solar PV fits the criteria for technologies that are less lumpy and have shorter lead times.

Finally, there is scope for reductions in transmission costs if Renewable Energy projects are installed close to end-consumers and consideration should be given to accommodating an approach which takes this into account in the final version.