

# Valuation of pumped storage in capacity expansion planning – a South African case study

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**Abstract**—According to the South African Integrated Resource Plan more flexible generation will be required to integrate the increased variable renewable energy generation and this will be provided by gas turbines and batteries. More studies need to be done to verify whether a renewables, gas/diesel and battery mix will provide the energy security South Africa currently obtains from base load stations. Supplementary reactive power and additional inertia may be needed to ensure system stability with the addition of high proportions of non-synchronous PV and wind generators. Pumped Storage can alleviate this issue as it is another form of flexible generation with fast ramping capacity, stored energy, and system inertia to provide security and stability to the grid. This paper investigates why Pumped Storage (PS) was not included in the future plan, and highlights potential issues with the modelling of PS in the current long-term energy planning model. The paper investigates the services and contributions of PS on the South African grid and makes recommendations for ancillary services costs to be included in the modeling methodology. The paper further highlights the uncertainty in technology costings and the impact thereof through sensitivity analyses using levelized cost of energy curves for pumped storage, gas turbines and batteries. Correctly valuing pumped storage and the ancillary services the technology provides is vital to accurately modelling the technology in long term energy planning models.

**Keywords**— *Pumped storage, ancillary services, variable renewable energy, gas turbine, flexible generation*

## I. INTRODUCTION

Long-term energy planning is critical for a country to meet future energy demand at minimum cost while supporting various policy objectives. In South Africa the national utility, Eskom, and the Department of Energy (DoE) utilize modelling to identify the most compatible and cost-effective energy alternatives to meet the country's future energy demands. By running different scenarios, alternative energy mixes can be compared and the costs and benefits for each plan estimated. The Integrated Resource Plan (IRP) of South Africa is based on the outcomes of this modelling process.

During long-term energy modelling two processes are typically used; capacity expansion modelling which models a few selected days in a typical year for the next e.g. thirty years and optimizes the energy mix based on certain criteria, and adequacy assessment modelling which simulates a full year at much higher resolution for a selected scenario.

Additional pumped storage (PS) was not included in the recently published South African long-term energy plan, the 2019 IRP [1]. Instead, gas turbines and batteries were selected for peaking and flexible generation.

This paper explores the hypothesis that new PS was excluded from the most recent South African IRP due to inaccurate costing inputs used in the long-term capacity expansion modelling, and constraints inherent to the current modelling methodology.

This hypothesis is informed by literature which highlights that methodologies and model input values for representing storage during capacity expansion modelling are not yet well defined, especially in the interaction between variable renewable energy generators and storage technologies. Issues such as chronology, capacity value and cost representation have yet to be addressed in most large-scale modelling frameworks used for this purpose. An example would be where the value of storage that can shift energy across days (such as PS) cannot be reflected in a model that does not maintain chronology across periods longer than 24 hours [2].

The above hypothesis will specifically be investigated from two perspectives in this paper. Firstly, in section II, the cost of PS and its value specifically for the provision of ancillary services are explored using international literature. Within this context the South African case is then considered, analyzing the constraint that current modelling software cannot account for the value of these ancillary services separately.

In section III the second perspective is explored: the sensitivity of the modelling outcomes to uncertainty in the technology costings used as input into capacity expansion modelling. Within the South African context, the paper will analyze the PS costs historically used to inform IRPs, and compare PS, gas and batteries through levelized cost of energy (LCOE) calculations to investigate the importance of accurate estimation of PS costs.

Section IV will conclude the paper and offer recommendations.

## II. VALUATION OF PS ANCILLARY SERVICES IN CAPACITY EXPANSION PLANNING

### A. Cost and value of PS ancillary services internationally

The international estimated costs for PS technologies differ widely as these costs are highly site dependent and depends on which type of pumped storage unit is used. PS units generally fall within three categories of technology: fixed speed, variable/adjustable speed, and ternary. Compared to the traditional fixed speed units, adjustable speed units can adjust the rate in which water is pumped thereby giving more regulation services while ternary units have a separate pump and turbine which allows for higher

flexibility, efficiency and response times as quick as 25 seconds [3]. Estimated cost for adjustable speed units are 10–20 percent higher than for fixed speed units [4]. For a 10-hour, 300 to 1 000 MW plant, 2017 costs were estimated to be in the wide range of \$1 700–\$5 100/kW [3]. Estimates from the US Department of Energy in 2019 have placed PS between \$1 700/kW and \$3 200/kW, averaging \$2 638/kW [3].

As an energy storage technology, PS supports a wide variety of power system operations through various services. These PS services range from inertial response and flexible ramping to primary/secondary frequency control and reduced curtailment of variable renewables [5]. The financial value of such services are expected to increase in the future as the percentage of variable renewable energy sources in the power system increases: a study estimated that ancillary services and energy arbitrage in the US offered by 100 MW of storage can result in yearly revenues in excess of \$30 million [6]. More specifically, the estimated cost for ancillary services have been given in Lazard’s Cost of Storage. This includes frequency regulation up/down at \$9.71/MWh and for Australia ancillary services (lower & raise, 6-second, 5-minute, regulation, restart and reactive) at \$10.56/MW [6].

Recently the United States Department of Energy completed several studies through the Argonne National Laboratory on Pumped Storage Hydropower. One of the studies specifically focused on the modelling and analysis of the value of this technology [5]. The study was done in collaboration with National Renewable Energy Laboratory (NREL), Siemens and Energy Exemplar. A main goal of this was to determine the value of PS by calculating the saving in production cost of the power system and revenue analyses using Energy Exemplar’s PLEXOS model. The benefits and value of PS was analyzed for different types of PS in both regulated and competitive electricity market environments in the United States. The study highlighted that currently, in most existing markets, there are no established mechanisms to provide revenues for many of the services and contributions of PS to the power grid. Both in traditional and restructured market environments, most of the PS services are not explicitly monetized [7], and since PS plants inherently provide multiple services, it is difficult to distinguish the value of certain benefits (e.g., inertial response, voltage support, transmission deferral, energy security) [5].

In the US, PS can only receive revenue for limited services including energy generation, regulation reserve, spinning reserve, non-spinning reserve and the provision of black-start capability arranged through a long-term contract. Estimates were calculated for PS providing these ancillary services and were given as \$10/MW for up/down regulation, \$5/MW for increase/decrease flexibility, and for spinning and non-spinning reserves \$1-3/MW [5].

These costs are however estimates based on various assumptions and dependent on a particular market structure; therefore it is important to understand PS within a South African context and the ancillary services it provides.

### B. Value and function of PS on the South African Grid

The following requirements are defined by Eskom as ancillary services for the South African grid: reserves, black

start, islanding, reactive power supply, voltage control, and constrained generation [8]. Figure 1 describes the activation and sustained times of reserve for Eskom in response to frequency deviations outside the dead band of 49.85 Hz to 50.15 Hz [8].

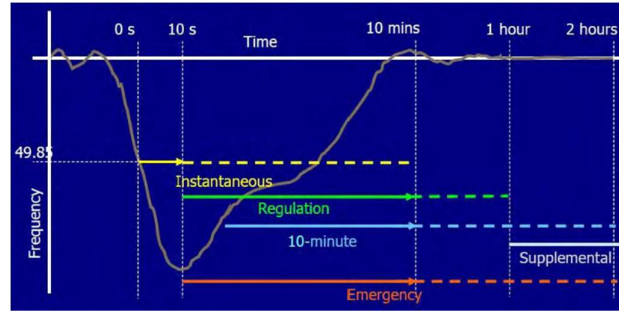


Figure 1. Activation and sustained times of reserve for Eskom to restore frequency. [9]

Coal units on automatic generation control (AGC) are used for the regulation reserve and operate at partial load in order to increase their output to balance the minute by minute supply and demand. PS units are currently fixed speed units and not on AGC and operate in the 10-minute reserve as shown in Table 1 [9]. PS in the reserve allows the system operator to export 200 – 250 MW to the grid in approximately 2-3 minutes. The speed of response is quicker than the response of a coal station which is only 15 MW/minute [9].

TABLE I. OPERATING RESERVE FOR ESKOM TO RESTORE FREQUENCY. [9]

Reserves	Response Time	Full Activation	Sustained for	Type	Control	Main Function	Minimum Requirements
Instantaneous	Immediately	10 s	10 min	Spinning	Direct	Quick arrest of frequency excursion beyond dead band	Sufficient for largest single contingency
Regulating	10 seconds	10 min	1 hr	Spinning	AGC	Bring frequency back to 50Hz and regulate tie-line flows	Cater for expected/forecasted deviations and meets CPS1 and CPS2
Ten-minute	-	10 min	2 hr	Spinning or non-spinning	Direct or manual	Restore shortfall of instantaneous and regulating reserve and forecast errors	Ten-minute = Total operating - instantaneous - regulating

Currently Eskom’s operating reserves for 2020 require 438 MW spinning reserve, 438 MW quick reserve and 876 MW operating reserve [10]. From an emergency point of view, the PS can be used as a black start facility as well as to arrest frequency drop following a severe frequency event. Hydro generators have the advantage of stable operations during a Rate of Change of Frequency (RoCoF) events ranging from 0.5 Hz/s to 2 Hz/s [10].

On the South African grid, the PS units’ response to frequency deviations is controlled by the primary governor which is installed at local plant level. The System Operator ensures that there is PS capacity in the reserves at all times, except during the morning and evening peak times as pumped storage is used to compensate for the slower ramp rates of OCGTs and coal fired generators [8]. This improves the economics of the overall system, as excessive ramping leads to a less than optimal operating efficiency for thermal plants designed for high constant output, and leads to more equipment stress and increased maintenance costs. Over the night minimum period, the pumped storage allows base load

generators to remain synchronized to the power system by adding demand to the system, thereby increasing the base load utilization level and optimizing operating costs.

PS is not just used in the reserve and for black start, but also provides reactive power and voltage control services [8]. PS units are synchronous machines and when unloaded act as synchronous condensers. The PS generator supplies reactive power to the grid which can also be the action of a capacitor bank. In large sizes synchronous condensers are cheaper than capacitor banks and provide convenient and continuous control of reactive power by adjusting the field current. Generally, there is one or two hydro/PS units at a plant generating or providing voltage control through Synchronous Condenser Operation (SCO) mode [9]. This mode adds inertia and voltage control capability to the network. This decreases fault levels in the network and smooths out variation in voltage caused by load changes and disturbances [11].

Currently the PS units provide around -3 MW output during SCO pump mode [9]. Changes in mode is estimated at 5 to 20 times a day per unit by Eskom Operators [11] as shown in Figure 2.

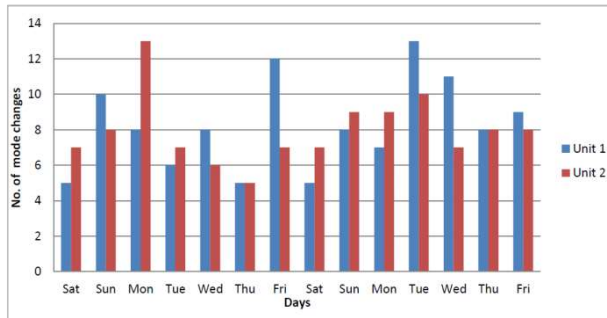


Figure 2. Daily mode changes for Palmiet PS. [9]

The current fixed speed turbines used in South Africa have a non-minimum phase response, which means that immediately after a request for power increase, which opens the guide vanes, the power actually drops before increasing to the new setpoint. This means frequency regulation using fixed speed pumped storage is not recommended [9]. However, international PS has been installed with variable speed turbines, which can also be used in frequency regulation [2]. Further improvements in design have also been done with different arrangements where the turbine runner is placed on its own runner shaft with a fly wheel between turbine and generator which decreases water hammer and can increase the units requirements for synchronization, isolated mode and grid conditions.

### C. Analysis

As was demonstrated in the previous sections, PS can provide a range of services to the power system, which again is attributed a range of values depending on the market structure and grid characteristics of the specific region.

Specific to South Africa, PS operations currently fall within a vertically integrated national utility where its services are not explicitly valued [11]. This is about to change, with Eskom to be unbundled resulting in an independent system operator, and the IRP allocating more

than 30% of the country's total generating capacity to VRES by 2030. Within this context it is likely that an ancillary services market will develop, resulting in more realistic valuation of PS-supplied ancillary services.

Current capacity expansion modelling in South Africa is done using an analytic tool called PLEXOS, which at the time of modelling the IRP did not model ancillary services as separate costs but only as implicit outcomes of different cost-optimizations when including ancillary services as an explicit system requirement.

PLEXOS at the time of writing is further limited in time scale variations as shown in Figure 3 and therefore cannot account for the value contained in services such as operating reserves, voltage stability, grid faults/stability or regulation, and the potential revenue streams these represent.

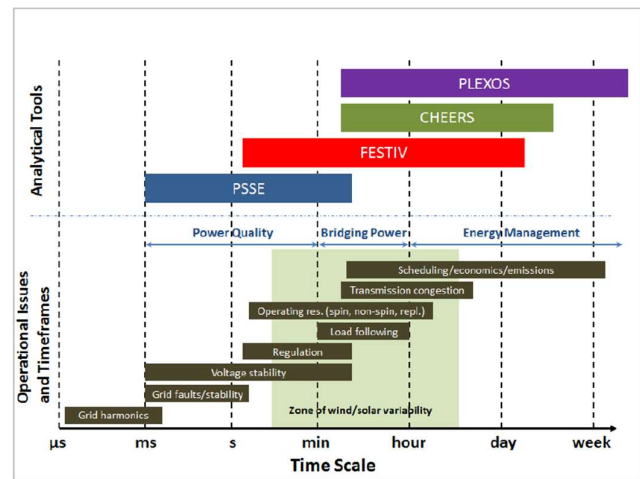


Figure 3. Power System Timeframes and Operational Issues [5]

### D. Recommendation

International markets with Day Ahead dispatch value the different ancillary services and consider marginal energy costs, start-up costs, ramping rates, operating reserves, and transmission constraints [10]. The current ancillary services provided by PS in South Africa can be valued by analyzing such international market mechanisms especially concerning the spinning/non spinning, flexible ramping up and down and reactive power/ voltage control. Potential revenues from frequency regulation can also be included for future variable turbines with improvements in turbine-generator arrangements.

In system planning and economic operation of power systems, generators are typically not operated at their limits but at equal incremental costs (taking into consideration the line losses) on an instantaneous basis. PS, however, is different as the incremental cost is not known. The cost is varying as it may be based on excess VRES or on generation from thermal power stations [11]. Therefore prediction and forecasting is required to allow for PS to reduce the overall production cost of the system by generating at the peak times, lowering capacity building, storing excess energy generation and operating during off peak to allow for constant operation of the thermal units at night [12].

### III. PS COSTS AS INPUTS INTO CAPACITY EXPANSION MODELLING

#### A. PS allocations in recent South African IRPs

PS has not been included in new capacity solutions for South Africa since the capacity expansion modelling software used to inform the South African IRP changed from Egeas to PLEXOS in 2008 [14].

Previous costs showed PS was modelled as R7 913/kW in 2010 IRP [15] to R21 997/kW in 2018 IRP [1]. A potential reason why PS is not chosen anymore in the cost optimizing energy model (PLEXOS) relates to the model's cost inputs which are based on the escalated cost implications from Ingula PS. This may have allowed for other technologies such as OCGT and batteries [16] to replace PS as the main generating capacity for peaking generation in South Africa's future energy mix as shown in IRP 2019 [13].

Current local estimates for costs of PS in South Africa ranges from R13 000/kW [17] to R22 000/kW [18] based on the recently constructed Ingula PS, and the feasibility study for the proposed Kobong PS. The implications for choosing an incorrect cost value for PS may considerably affect the results in PLEXOS. This theory is investigated in the next section.

#### B. Background to LCOE curves

The input assumptions in the PLEXOS model for the IRP was investigated and the costs incorporated into the model compared for Pumped Storage, Open Cycle Gas Turbines (OCGT) and Batteries as these were the competing technologies for peaking and flexible generation.

In order to test the results of the long-term modelling software PLEXOS, the inputs for each technology were used to create Levelized Cost of Energy (LCOE) curves. LCOE is merely an aggregate but can be used as a comparison tool for different technologies with unequal capacity, capital cost, lifespan, risk and return. The calculation was utilized to show a comparison of the competing technologies as it measures lifetime costs divided by energy production [19].

As a cost optimizing tool an energy modelling software such as PLEXOS should chose the lowest cost prediction. A power plant should be designed to have the lowest LCOE over the life time of the plant in order to ensure a viable project. LCOE for a power plant is calculated by the following formula [19]:

$$LCOE = \frac{\text{Sum of cost over lifetime}}{\text{Sum of electric energy over the lifetime}} = \frac{\sum_{t=1}^n \frac{C_t + OM_t}{(1+r)^t}}{\sum_{t=1}^n \frac{E_t}{(1+r)^t}}$$

where  $C_t$  = The capital cost expenditure in a year;  $OM_t$  = The Operation and Maintenance (O&M) expenditure in a year;  $E_t$  = The annual energy generation (kWh);  $r$  = The economic discount rate, and  $n$  = The lifetime of the plant.

By calculating and comparing the LCOEs of PS and the competing flexible generation technologies, value can be measured across the longer term, showing projected life-cycle costs. Each of the technologies were calculated for the

different load factors for each plant. Load factor is the ratio of the actual power output of the plant over one year compared to the amount of electricity it would produce if it ran continuously at its rated capacity for a year.

#### C. LCOE technology inputs and assumptions

The LCOEs for PS, OCGT and Lithium-Ion batteries were calculated from the inputs for the modelling in PLEXOS for IRP 2010 [15], IRP 2016 [20] and IRP 2018 [1].

To compare the sensitivity of the model inputs the different costs for PS were included from the feasibility studies for Tubatse PS [14] and Kobong PS [17], and different fuel prices were used to compare OCGT costs. Table II and Table III show the data used to develop the curves.

TABLE II. IRP 2010 AND 2016

Technology Input	OCGT 2011	IRP Diesel 2011	PS IRP 2011	OCGT 2016	IRP LNG 2016	OCGT 2016	IRP Diesel 2016	PS IRP 2016
cost overnight R/kW	3955		7913	7472		7472		20410
Fuel Cost	R200/GJ		-	R115/GJ		R200/GJ		0
Capacity MW	114.7		1500	132		132		333
O&M Variable R/MWh	0		4	2.2		2.2		0
O&M Fixed R/kW/a	70		123	147		147		184
Life time of project	30		50	30		30		50
Discount rate	8		8	8.2		8.2		8.2
Phasing in Capital Spent %	90,10		3,16,17,21,20,14,7,2	90,10		90,10		1,2,9,16,22,24,20,5

TABLE III. IRP 2018 WITH KOBONG AND TUBATSE PS

Technology Input	OCGT LNG \$4.56/GJ	Ingula PS	Lithium -lon (1hr)	Lithium -lon (3hr)	Kobong PS	Tubatse PS	OCGT Diesel R10.8/l
cost overnight R/kW	9226	21997	11165	27432	13389	16446	9226
Capacity MW	132	333	3	3	1200	1500	132
O&M Variable R/MWh	2.7	0	3.6	3.6	0	0	2.7
O&M Fixed R/kW/a	181	184	697	697	184	184	181
Life time of project	30	50	20	20	50	50	30
Discount rate	8.2	8.2	8.2	8.2	8.2	8.2	8.2
Phasing in Capital Spent %	90,10	1,2,9,16,22,24,20,5	100	100	14,8,12,17,15,14,16	1,2,9,16,22,24,20,5	90,10

The following assumptions were made in order to generate the curves:

- For the debt model a total loan facility of the overnight cost amount was made available, at 8% (IRP 2010) and 8.2% (IRP 2016, 2018) rate and for a period of 20 years. An assumed interest and capital payment moratorium for the first years of the loan, during construction, then an amortized loan facility.

- For the IRP 2011 the pump storage pumping cost was according to the methodology of Egeas, based on the variable cost of coal of the "available" base load plants in the system, i.e. base load plants with a relatively high variable coal cost [14]. For purposes of comparing the screening curves, an average coal cost of R200/t [15] was assumed with

a variable component, i.e. the pumping cost was based on a coal cost estimated at R200/MWh as the energy charge (fuel) component of the total levelized cost.

- The IRP 2018 input values for OCGT and Lithium-Ion batteries were taken from the EPRI report 2018 while the pumped storage costs were based on the Ingula PS scheme. The storage technologies do not include a marginal or variable cost for the power [1].

- Kobong and Tubatse feasibility costs used compounded South African inflation rate to give an estimate of the overnight costs.

**D. LCOE curves results**

The results for the developed LCOE curves for IRP 2011 and 2016 are shown in Figure 4 while IRP 2018 is shown in Figure 5.

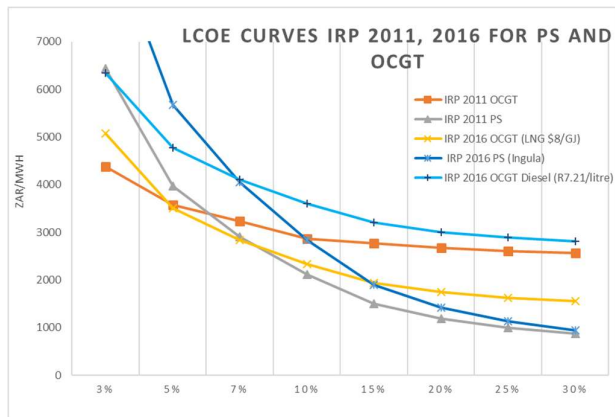


Figure 4. LCOE curves for IRP 2011 and 2016

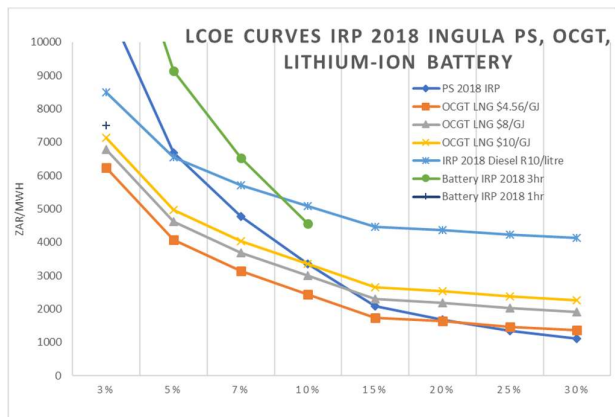


Figure 5. LCOE curves for IRP 2018

Analyzing the results from the curves shown in Figure 4 from the IRP 2010; OCGT diesel at R7.26/litre [15] is favored at load factors below 6%. This is including a pumping ‘fuel’ cost for pumped storage.

For IRP 2016 the results show how pumped storage was competitive before in 2010 at a cost of R7 913/kW [15] but when Ingula’s PS cost of R20 410/kW[20] was used PS was replaced by OCGT LNG at \$8/GJ as the new competing technology in IRP 2016.

Figure 6 provides a comparison for IRP 2018 with Ingula, Kobong and Tubatse PS included.

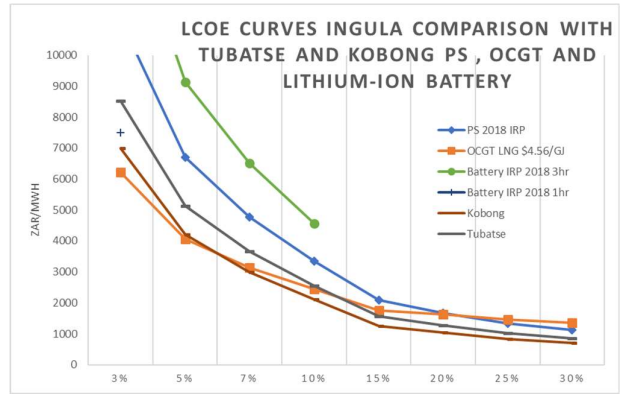


Figure 6. LCOE curves for IRP 2018 including Tubatse and Kobong

From the results the preferred scheme is shown to be Kobong PS and competes with OCGT LNG even at \$4.56/GJ to load factors of 5%.

**E. Analysis of LCOE curves**

The levelized costs for each technology were given for certain load factors in the IRP reports. These values were used to compare and verify the developed LCOE curves. The curves showed PS can be competitive with OCGT especially with decreased capital costs. Therefore, there is a valid argument for PS as a more cost-effective option for peaking generation than OCGT.

These results also correspond to the outcomes of a study done in the US with Capital Costs for Pumped Storage Hydropower (PSH) at R30 000/kW and Gas Turbines (GT) at R9 400/kW [5]. The study showed that lowered capital costs for PS, with ancillary services costed in, would be competitive with gas turbines (see Figure 7).

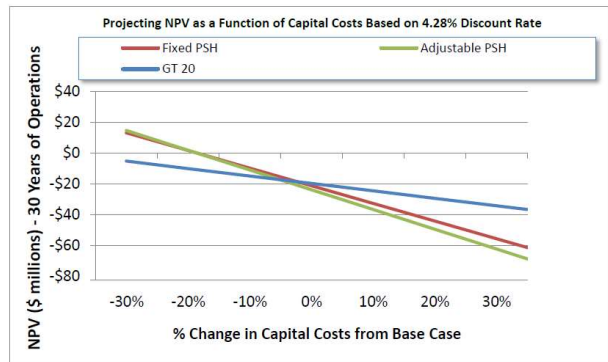


Figure 7. Study Comparing Net positive value of Pumped storage versus Gas turbines [5]

Figure 8 shows the results from another study conducted in the US [3] in 2019, with PS as more cost effective than Lithium ion and gas turbines even when valued at R37 000/kW.

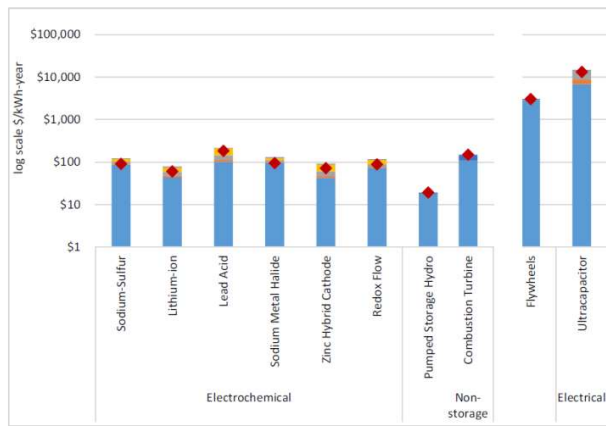


Figure 8. Cost comparison between Batteries, Pumped Storage and Gas Turbines [3]

#### IV. CONCLUSIONS

This paper explored the hypothesis that new PS was excluded from the most recent South African IRP due to inaccurate costing inputs used in the long-term capacity expansion modelling, and constraints inherent to the current modelling methodology.

The paper focused on the costs related to pumped storage and the ancillary services the technology provides the grid. The paper showed that, on a power system dominated by base load coal fired generation, PS offered flexibility, ramping speed and demand over low loading periods. Currently these services do not have revenue streams for PS on the South African grid. Further potential revenue for ancillary services provided by PS were also limited by the inability of the modelling software's timeframes to capture fully the operational issues on the power system. Future studies should include additional costs for these services in the energy model to understand the benefits PS provides the grid. The value of storage in lowering production costs of grid systems should be addressed as well as modelling the benefit of shifting energy across days. This issue needs to be resolved as currently it cannot be reflected in a model that does not maintain chronology across periods longer than 24 hours.

The input assumptions for PS in the PLEXOS model for the IRP was investigated in this paper. The LCOE curves developed assisted in supporting the hypothesis that an economic case can still be made for PS in South Africa, however this is dependent on how PS is currently modelled in the energy planning software. The results showed PS to have far lower LCOE values than batteries and diesel turbines. The cost competitiveness of PS and gas turbines was shown to be dependent on the gas price used and the chosen PS overnight cost. From this it was concluded that the chosen value of PS should rather be a comparative value instead of only been related to a single previous scheme and should also reference feasibility studies from proposed projects as PS costs are very site dependent.

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